Advanced Biomass: Technology Characteristics, Status and Lessons Learned

TR-111882

Final Report, November 1998

EPRI Project Manager
E. Hughes

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS PACKAGE WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) NAMED BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS PACKAGE, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS PACKAGE IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS PACKAGE OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS PACKAGE.

ORGANIZATION(S) THAT PREPARED THIS PACKAGE

Appel Consultants, Inc.

ORDERING INFORMATION

Requests for copies of this package should be directed to the EPRI Distribution Center, 207 Coggins Drive, P.O. Box 23205, Pleasant Hill, CA 94523, (925) 934-4212.

Electric Power Research Institute and EPRI are registered service marks of the Electric Power Research Institute, Inc. EPRI. POWERING PROGRESS is a service mark of the Electric Power Research Institute, Inc.

Copyright © 1998 EPRI, Inc. All rights reserved.

CITATIONS

This report was prepared by

Appel Consultants, Inc.
23905 Plaza Gavilan
Valencia, CA 91355

Principal Investigator
G. Wiltsee

This report describes research sponsored by EPRI, DOE's Western Regional Biomass Energy Program, Nebraska Energy Office and the National Renewable Energy Laboratory.

The report is a corporate document that should be cited in the literature in the following manner:

Advanced Biomass: Technology Characteristics, Status and Lessons Learned, EPRI, Palo Alto, CA: 1998. TR-111882.

REPORT SUMMARY

Biomass, primarily wood, is a significant source of heat and power in the U.S. Advances in fuel supplies and in conversion technology are needed to make renewable biomass a major source of grid-connected power. This report presents both the characteristics expected of advanced technology and some lessons learned from current wood-fired power generation.

Background
As part of the Sustainable Electricity Partnership agreement between DOE and EPRI, both parties have sponsored data gathering and analysis by the author of this report. This work has covered biomass fuel supplies, power plants, and future power systems. In 1997, EPRI joined with DOE, the National Renewable Energy Laboratory (NREL) and DOE contractors to publish EPRI Report TR-109496 “Renewable Energy Technology Characterizations.” As an extension of the biomass part of that 1997 effort, EPRI sponsored the preparation of this report.

Objectives
To describe the advances necessary to significantly expand biomass power generation, especially in the United States. To present and interpret information on existing power plants and projects in a way that suggests the potential future role of biomass power, paths toward that role, and characteristics of selected advanced biomass technologies.

Approach
The author reviewed the results of his work for EPRI and DOE, as well as the joint EPRI/DOE “Technology Characterizations” report (TR-109496). From the urban wood waste resource study for NREL, an analysis of costs of crops and power done for EPRI, the EPRI/DOE technology characterizations report, and the work-in-progress on lessons learned from existing biomass power plants, the contractor prepared this report in close collaboration with the EPRI project manager.

Results
Urban wood-wastes—which include tree wastes and brush, construction/demolition debris, spent pallets, and many other types of manufactured wood wastes—constitute the best opportunities for low-cost biomass fuel, except for those wood wastes already captured and largely used by the pulp, paper and lumber industries. The amounts of such urban wood wastes have been projected for the entire United States from a 30-city

survey, giving an estimate of 38 million dry tons/year. Existing biomass power plants use less than 10 million tons/year from such sources, plus about 30 million tons/year of mill wastes.

The total U.S. wood waste resource base is estimated to range from 13 to 30 GW (about 3-10% of total U.S. coal-based generating capacity). If 10% to 20% of the total electric generation is defined as a "major role," then biomass would have to provide 350-700 of the approximately 3500 billion kWh (3500 TWh) of electricity now generated annually in the United States. This would require 50 to 100 GW of generating capacity at 7000 hours/year. For biomass to reach that level, advanced fuels (i.e., energy crops) and advanced conversion technologies will be needed.

This report gives relevant data and interpretation regarding both (1) the energy crop fuels that would be required for biomass to reach such a major rle, and (2) the advanced combustion, gasification, and other options also important in reaching a major role. The information presented in the report characterizes today's biomass supplies and power technologies, the "easy" next step that can be taken via cofiring in coal-fired plants, and some steps that will assist in moving from today's situation to a major role for renewable biomass in the nation's electricity supply.

EPRI Perspective

This report provides a basis for evaluating biomass options that are likely to be of interest to a number of organizations and individuals: utilities, power generators, fuel planners, environ-mental compliance officials, and research planners. It shows how the existing biomass power industry provides a basis and relevant lessons for building a future, larger industry. However, it also shows why the existing fuels and technology will not be characteristic of those that may come to play a major role in the future. The report also suggests the paths and the research areas that can lead to a major role for biomass energy sources.

Interest Categories

Biomass
Renewables
Solar power
Fossil fuel assessment and cost management
Global climate
Pulp and paper industry
Agriculture

Key Words

Biomass	Energy crops	Combustion
Wood	Power plants	Gasification

ABSTRACT

This report provides members of EPRI's Renewables and Green Power Marketing Target with current information on, and evaluations of, advanced biomass technology. Member utilities can use this information in planning their own renewables and green power marketing programs. The report identifies implications for research, development, and demonstration (RD&D) on advanced biomass energy systems. Advanced biomass technology, as defined in this report, is technology that is developed and demonstrated, but not yet in wide commercial use, for the generation of electric power from biomass. Advanced biomass technology has the ability to increase the use of biomass as an energy source, either by improving the cost and performance of the technology compared to existing commercial systems, or by extending the technology to market or fuel applications that are not currently addressed. The main topics included in this report are waste fuels (the biomass fuels used at present); energy crops (the way to expand biomass into a major role in the U.S. energy system); advanced combustion; gasification; and small-scale systems.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION

Biomass is currently the largest renewable energy source in the United States, other than hydroelectric power. Wood wastes account for at least 95% of the biomass currently used as fuel. Energy produced from biomass is estimated to contribute about 3% of the U.S. primary energy supply. Electricity generating capacity from biomass is about 7 GW. This is about 10% of hydroelectric generating capacity, and about five times the current wind generating capacity in the United States. The annual electricity generation from biomass is about 40 TWh, which is about 1% of the U.S. total, about ten times that of wind, and about 2.5 times that of geothermal.

However, existing biomass power technology is not likely to expand biomass' contribution from 1% of U.S. electricity supply to the 5-20% range. The problem: at \$1500 to \$2500 / kW capital cost and \$1.00 to \$2.00 / million Btu (MBtu) fuel cost, electricity from a large (50 MW) biomass power plant comes out at about 9¢ / kWh. Table 1-1 shows how this fits in the context of other "green" and conventional power generation technologies. This report presents the characteristics of advanced biomass technology in the context of the economics shown in the table.

The use of forestry and agricultural wood residues in direct combustion systems for cogeneration of electricity and process heat has been well-established in the forest products industry for many years. Starting in the 1980s following the passage of the Public Utilities Regulatory Policy Act (PURPA), the use of wood wastes (including urban wood wastes) in small, mostly independent electric power plants grew in many areas of the country. The most rapid growth occurred in California and New England. These small wood-fired power plants (the largest in the 50-80 MW range and the majority in the 10-20 MW range) have relatively high capital costs, high fixed operating costs, and low thermal efficiencies. Fuel costs, which would be expected to be low because the fuels are waste materials, have in fact proven to be quite high except in specific cases (discussed in section 3). Low energy densities, high moisture contents, difficult grinding and handling properties, dispersed sources, and competition for limited supplies can all contribute to the high cost of obtaining wood waste fuel at a power plant. The low thermal efficiency of the plant (typically 15,000-20,000 Btu / kWh [17-23%], to about 11,700 Btu / kWh [29%] in the best case) translates a high received wood cost into a high fuel cost per kilowatt-hour.

From less than 200 MW in 1979, U.S. biopower capacity grew to 6 GW in 1989 and to today's capacity of about 7 GW. In 1989 alone, 1.84 GW of capacity was added. Most of these plants were designed and initially contracted (under PURPA-derived state laws) to provide baseload power, and annual capacity factors in the 80-95% range were common. In many cases, utility companies renegotiated these contracts to peaking power contracts, and many biopower plants now operate with annual capacity factors between 10% and 50%. The present low buyback rates from utilities, combined with uncertainties about industry restructuring, have slowed industry growth and led to the closure of a number of facilities in recent years.

Table 1-1
Cost of Green Power vs. Conventional Power

	Captl. Cost $/kW	Annual Capital Recovry	Cpcy. Fctr.	Captl. Cost ¢/kWh	Fuel Cost $/MBtu	Heat Rt. Btu/kWh	Fuel Cost ¢/kWh	O&M Cost ¢/kWh	Total ¢/kWh
I. 1998 VALUES:									
Nat. gas CC, 744 MW, $2/MBtu	663	0.21	0.85	1.85	2.00	7,780	1.56	0.24	3.65
Coal, advanced PC, 744 MW	1516	0.21	0.85	4.24	1.25	9,480	1.19	0.52	5.94
Landfill gas, 2 MW	1100	0.21	0.85	3.07	0.50	14,000	0.70	1.00	4.77
Biomass, stoker or FBC, 50 MW	2000	0.21	0.85	5.59	1.50	14,000	2.10	1.70	9.39
Biomass cofiring, 10/100 MW	100	0.50	0.80	0.71	0.25	10,480	0.26	0.27	1.25
Wind, 18 mph, 100 MW	864	0.21	0.34	6.04	0.00	no fuel	0.00	0.72	6.76
Solar PV, central, 75MW	4334	0.21	0.24	42.90	0.00	no fuel	0.00	0.54	43.44
II. "GOAL" VALUES:									
Nat. gas CC, 744 MW, $4/MBtu	435	0.21	0.85	1.22	4.00	6,400	2.56	0.24	4.02
Coal, advanced PC, 744 MW	800	0.21	0.85	2.24	1.25	9,480	1.19	0.52	3.94
Landfill gas, 2 MW	1100	0.21	0.85	3.07	0.50	14,000	0.70	1.00	4.77
Biomass, IGCC, 100 MW	1066	0.21	0.85	2.98	1.50	7,580	1.14	1.02	5.14
Biomass cofiring, 10/100 MW	100	0.50	0.80	0.71	0.25	10,480	0.26	0.27	1.25
Wind, 18 mph, 100 MW	603	0.21	0.45	3.18	0.00	no fuel	0.00	0.31	3.49
Solar PV, central, 75 MW	831	0.21	0.24	8.23	0.00	no fuel	0.00	0.09	8.32

Source: EPRI / DOE *Renewable Energy Technology Characterizations* [1] and additional calculations.

The EPRI / DOE report *Renewable Energy Technology Characterizations* [1] described how the next generation of biomass technology is expected to substantially reduce the high costs and efficiency disadvantages of today's industry. Continued development of direct-fired combustion technology and biomass fuel acquisition strategies will improve efficiency and reduce the cost of electricity produced, hopefully to the 3-5¢ / kWh range. One existing 60 MW boiler has a heat rate under 11,700 Btu / kWh, burning 100% sawmill wastes obtained at no cost and generating steam at 1575 psig and 950_F. This performance level can be exceeded in future biomass plant designs by incorporating multi-pressure, supercritical, reheat and regenerative steam turbine cycles, as well as thermally integrated fuel drying. Reducing biomass fuel cost to zero or below is possible by siting plants in urban areas and integrating their operations with those of wood waste recyclers who supply the fuel. Very little experience has been gained yet with this “tipping fee fuel” strategy. One plant in Florida is using it successfully.

The utility industry is testing cofiring of biomass in existing coal-fired power plants, which allows wood to be converted to electricity at nearly the same efficiency as coal (nominally about 10,500 Btu / kWh, or 32.5%). Cofiring does not add new generating capacity to the system, but it does directly substitute renewable carbon for fossil carbon, and reduces the power plant’s SO_2 and NO_x emissions. Based on the tests to date, it appears practical to replace about 5-15% of the coal in many boilers with wood, without significant loss of generating capacity or other impacts. A capital investment of about $100 / kW of wood-fired capacity is required to provide wood fuel handling, storage, and feeding systems. To pay off this investment, the wood wastes delivered to the boiler must cost significantly less per Btu than the coal being displaced. This will be a challenge in many locations.

Researchers in the United States and Europe have been developing biomass gasification technology for power generation. The technology is approaching commercial availability with a small integrated gasification / combined cycle plant operating in Sweden, DOE-sponsored demonstrations in Hawaii and Vermont, and several other projects in various stages of design and construction. Gasification promises to provide high efficiency, even at low scale, through use of combined cycle systems. Gasification systems will also be able to provide biomass-derived syngas to fuel cells, which hold the promise of high efficiency and low cost at a variety of scales. The key to success for small-scale biomass gasification technology will be to achieve low capital costs through mass manufacturing, which in turn will require the development of mass markets for these systems. The commercialization of fuel cells and PV systems also require mass market development in order to bring manufacturing costs down to competitive levels.

The other sections of this report present the details as follows:

Section 3, Waste Fuels, examines the factors that account for the large differences in fuel costs from one biomass power plant to another. The four major categories of biomass wastes -- urban wood wastes, mill wastes, agricultural residues, and forest residues -- include a large number of sub-types, which vary widely in availability, cost, and quality as power plant fuels. The discussion includes information gathered from a select group of biomass power plants about siting and fuel strategies, types, quality, and costs.

Section 4, Energy Crops, examines the potential for short rotation woody crops and herbaceous crops to become the primary fuels for advanced biomass energy systems. Only high yielding crops, grown on millions of acres, can provide enough biomass feedstock to contribute 10% to 25% of the energy in the United States, instead of the 2% to 6% possible from biomass residues. Costs of crops, competition from higher-value products, and competing land uses are significant barriers to achieving this goal.

Section 5, Advanced Combustion, reviews the lessons learned from a group of large existing biomass power plants, and identifies evolutionary changes in technology that could help reduce the cost of electricity from future plants. These include: (1) the siting of plants in urban areas to take advantage of tipping fees for urban wood wastes; (2) cofiring biomass in coal-fired boilers; (3) the addition of fuel dryers to stokers and fluidized bed boilers, and the upgrading of steam temperatures and pressures; and (4) the use of Whole Tree Energy™ technology when dedicated short rotation woody crops for energy become economic.

Section 6, Gasification, updates EPRI’s past analysis of biomass gasification combined cycle processes and projects, and discusses two “low-tech” variations: (1) near-atmospheric pressure gasification in a gas turbine combined cycle; and (2) mild gasification, again atmospheric and, in this case needing little or no gas cleanup, feeding a boiler or heat recovery steam generator. This is an option that is appropriate for cofiring in both coal- and gas-fired power plants.

Section 7, Small-Scale Systems, covers commercial technologies and concepts applicable at small unit sizes: (1) landfill gas energy; (2) anaerobic digestion, such as covered lagoon digesters to control animal waste disposal while also producing useful energy; and (3) small modular biomass energy systems suitable for portable units, village power, or supporting fire prevention brush clearing operations.

Section 8, Conclusions, interprets the material presented in the preceding sections, with emphasis on: (1) possible paths from today’s commercial biomass energy to future major use of biomass in energy conversion systems; and (2) implications for research, development and demonstration of biomass energy systems.

2

OBJECTIVES AND SCOPE

Objectives

The primary objective of this report is to provide members of EPRI's Renewables and Green Power Marketing Target with current information on, and evaluations of, advanced biomass technology. Member utilities can use this information in planning their own renewables and green power marketing programs. In addition, this report is intended to help identify high priority research, development, and demonstration (RD&D) needs that can be addressed by EPRI, the U.S. Department of Energy (DOE), industry, and others.

Scope

Advanced biomass technology, as defined in this report, is technology that is developed and demonstrated, but not yet in wide commercial use, for the generation of electric power from biomass. Advanced biomass technology has the ability to increase the use of biomass as an energy source, either by improving the cost and performance of the technology compared to existing commercial systems, or by extending the technology to market or fuel applications that are not currently addressed.

3

WASTE FUELS

In planning a new biomass energy project, it is of paramount importance to select the most favorable site and to develop an associated strategy for acquisition of low-cost and acceptable-quality biomass fuels. The long-term economic success of the project will depend heavily on the initial research and decisions about siting and fuels. In a group of large, existing biomass power plants for which we were able to obtain or estimate fuel costs, the range goes from about 0¢/kWh to about 3¢/kWh. This is an enormous difference in the increasingly competitive energy industry. In this section we will examine the factors that account for such large differences in fuel costs from one plant to another.

Most biomass power plants operating today burn at least one of the following types of fuel:

- Urban wood wastes
- Mill wastes
- Agricultural residues
- Forest residues

These major categories of biomass wastes include a large number of sub-types, which vary widely in availability, cost, and quality as power plant fuels. The following four subsections discuss these factors for each biomass waste category and their implications for project development. The discussion includes information gathered from a select group of existing biomass power plants about siting and fuel strategies, types, quality, and costs.

Urban Wood Wastes

Urban wood wastes consist of:

1. wood wastes disposed of with, or recovered from, the municipal solid waste (MSW) stream (“MSW wood”);

2. industrial wood wastes such as wood scraps and sawdust from pallet recycling, woodworking shops, and lumber yards; and

3. wood in construction / demolition (C / D) and land clearing debris.

Metropolitan areas in the United States differ considerably in the amounts of the three basic types of urban wood wastes generated and then disposed of or recovered for commercial use. The variations in the methods and costs of urban wood waste disposal and reuse are related to factors such as landfill tipping fees, access to and regulations concerning rural dumping and burning, public policies that promote waste diversion or recycling, and the proximity of large wood waste users (e.g., power plants, cogeneration plants, pulp and paper mills, and medium-density fiberboard plants). Table 3-1 shows the ranges and the weighted average of per capita urban wood resources found in a recent study [2]. The units are in tons of wood (including moisture) generated per year per person.

Table 3-1
Urban Wood Resources, Tons/Year/Person

	Low	High	Weighted Average	Regression Coefficient
MSW wood	0.134	0.538	0.209	0.203
Industrial wood	0.001	0.488	0.048	0.039
C/D wood	0.015	0.250	0.076	0.091
Total urban wood	0.156	0.829	0.333	0.333

Source: Wiltsee 1998 [2].

When the wood waste resources in the 30 metropolitan areas in this study were examined city-by-city, the estimates showed that the resources would support the generation of between 5 and 50 MW per million people, with figures between 15 and 25 MW per million people being most common. This represents about 1% to 2% of the total electricity needs of a typical U.S. urban area.

Table 3-2 shows the primary uses and disposal methods for urban wood wastes. There is great variation from one city to another, but in general the two most common are grinding the wood to mulch for land application, and landfilling or incinerating the wood along with MSW or C / D debris. These two end uses account for almost 73% of the total urban wood resource. Biomass fuel comes in a distant third, at 12%. In half of the 30 cities surveyed, none of the wood wastes are used as fuel; in two metropolitan areas (Boston and Lakeland, Florida) about 46% of the urban wood wastes go to power plants. Clearly there is potential for much greater use of urban wood waste as fuel, and the potential also exists for power plants to obtain much of this wood at a negative cost (tipping fee).

Table 3-2
Primary Uses and Disposal Methods for Urban Wood Wastes

	Percent	$/ton
Mulch	39.3	-45 to 3
Landfill or incineration	33.4	-85 to -20
Biomass fuel	12.0	-45 to 0
Firewood	7.4	-5 to 0
Furnish, logs, pulp chips	5.1	-25 to 12
Rural dumping or burning	1.4	-5 to 0
Animal bedding	1.2	0 to 3
Specialty products	0.2	-9 to 0
Total	100.0	

Source: Wiltsee 1998 [2].

Four distinct categories of urban wood waste, two or more of which are present in every metropolitan area studied, combine to create the “anatomy” of an urban wood waste supply curve. In ascending order of price ($/ton), these categories are:

1. Wood disposed of in landfills or municipal solid waste incinerators (-$85 to -$16/ton)

2. Wood delivered to (or picked up by) processors (private or public) for recycling (-$42 to -$5/ton)

3. Wood privately dumped or burned, or informally recycled as mulch or firewood (-$5 to $0/ton)

4. Wood processed by its generators and sold as products, such as mulch, biofuel, pulp chips, and furnish ($3 to $24/ton)

As an example of an urban area with all four of these categories, Figure 3-1 and Table 3-3 present the supply curve for urban wood wastes in the Richmond-Petersburg, Virginia metropolitan area. The table helps explain the data or assumptions contained in the “steps” of the supply curve. Wood processing (recycling) companies charge tipping fees lower than landfill tipping fees. In every metropolitan area, some wood is informally recycled, dumped, or burned by its generators (disposed of at or near zero cost). The most common form of this behavior is the conversion of tree trimming wastes into mulch and firewood.

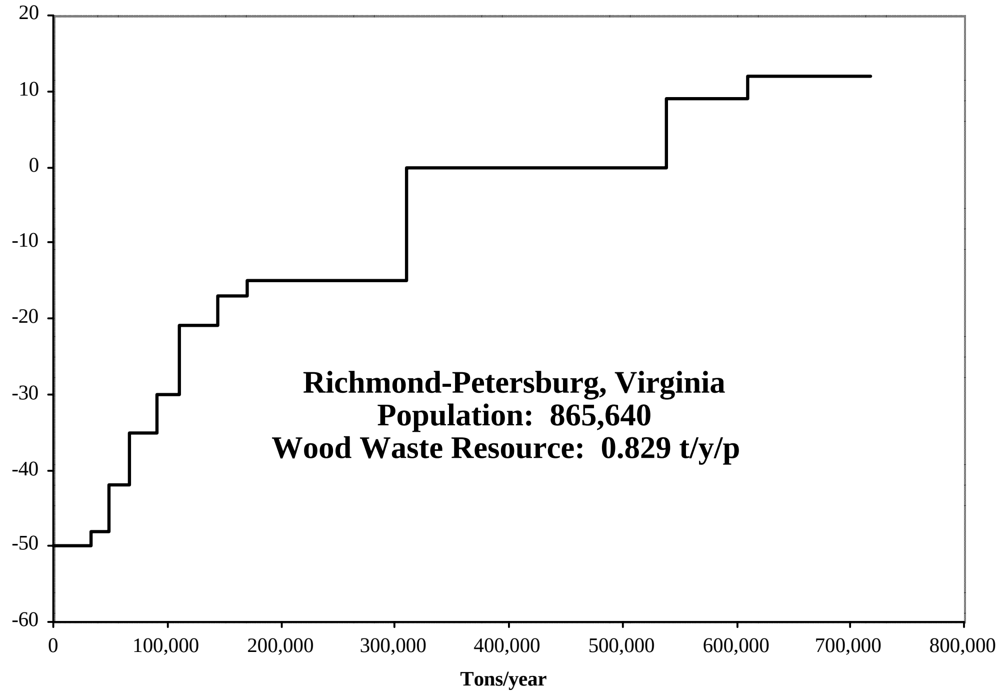

Figure 3-1
Supply Curve for Urban Wood Wastes in Richmond-Petersburg, Virginia

Table 3-3
Data and Assumptions Used in Supply Curve for Richmond-Petersburg

Tons/year	Cumulative	$/ton	Assumptions/Comments
34,000	34,000	-50	Landfilled with MSW and C/D - public landfills
15,000	49,000	-48	Landfilled with MSW and C/D - private landfills
18,000	67,000	-42	Pallet wood processors - biofuel, animal bd, mulch
24,000	91,000	-35	Landfilled with MSW and C/D - private landfills
20,000	111,000	-30	Pallet wood processors - biofuel, animal bd, mulch
33,000	144,000	-21	Landfilled with MSW and C/D - private landfills
26,000	170,000	-17	Pallet wood processors - biofuel, animal bd, mulch
140,000	310,000	-15	Land clearing wood processors - fuel, logs, chips,
228,000	538,000	0	Firewood and mulch - given away
72,000	610,000	9	Biofuel, animal bedding, mulch - sold
108,000	718,000	12	Pulp chips - sold

Source: Wiltsee 1998 [2].

In some metropolitan areas (such as Richmond-Petersburg), large lumber mills produce significant quantities of sawdust and shavings, which they sell as fuel and pulp chips to paper mills and as fuel to power plants. This causes a series of "above zero" steps to appear on the supply curve. This portion of the urban biomass resource is a byproduct rather than a waste.

Projecting from the results of the survey of 30 metropolitan areas, Figure 3-2 shows the national urban wood waste supply curve. The total estimated urban wood waste resource in the United States is 64 million tons/year, or about 38 million dry tons/year at an assumed average moisture content of 40%. About 30% is landfilled (at -$85 through -20/ton); 22% processed and recycled (at -$19 through -$2/ton); 43% privately dumped (at $0/ton); and about 5% is sold (at $3 through $24/ton).

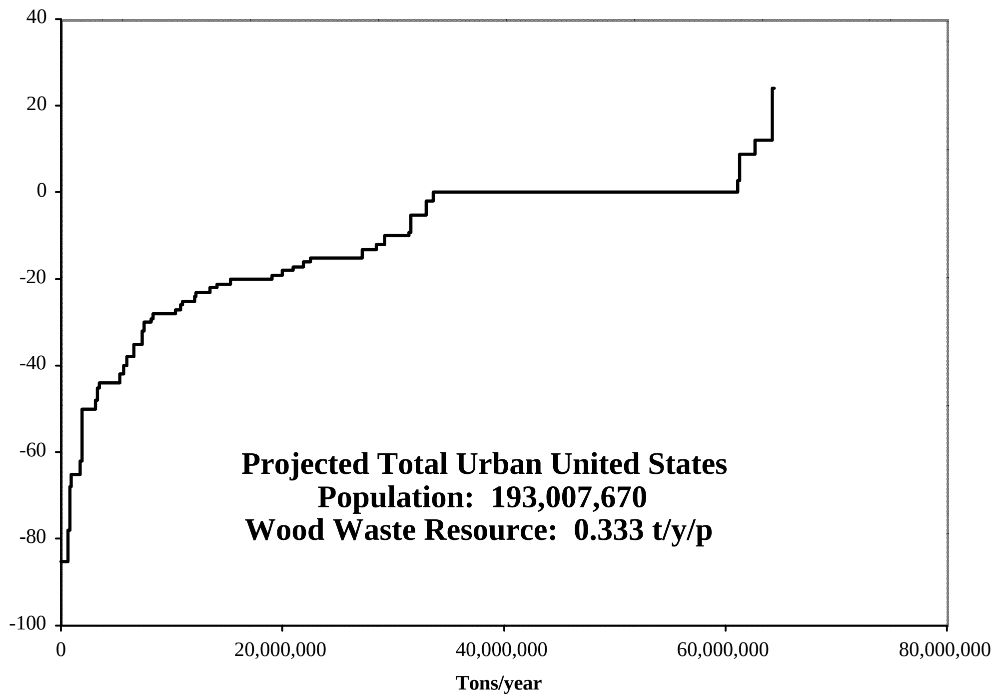

Figure 3-2
Urban Wood Waste Supply Curve Projected for the United States

Four basic types of processing operations convert urban wood wastes to fuel-grade material: recycling facilities, C/D waste processing facilities, materials recovery facilities (MRFs), and composting facilities. The processing of urban wood wastes to fuel includes sorting and screening, shredding in a tub grinder or hammermill, removing tramp iron with a magnet, screening and returning oversized material to the shredder, fines removal, and loadout. Wood processing facilities try to sell as much product as possible into higher-value markets, such as furnish for particleboard plants, pulp chips, specialty mulches, and colored chips. It is difficult to find markets large enough to sell most or all of the processed wood wastes. Most processing facilities end up giving away large quantities of biomass fuel, mulch, alternate daily cover for landfills, etc. These facilities make profits from the differences between the tipping fees they charge and the processing costs. Wood processors' tipping fees are usually about half of the local landfill tipping fees (which can range from $16 to $85/ton). Wood processing costs range from about $5 to $15/ton. Generally, urban wood waste processing facilities can make a profit even if most of their product has to be given away.

In California, biomass power plants collectively use millions of tons/year of urban wood wastes, and generally pay little or nothing more than the cost of transportation. The distances from the urban wood waste processing facilities to the power plants range from 20 miles to well over 100 miles. No California biomass power plants are located in major urban areas where they can be integrated with urban wood waste processing facilities. Even so, urban wood wastes are generally the cheapest fuels most California plants can obtain -- transportation costs are about $5-12/ton, or about $0.37-1.40/MBtu (at 20-50% moisture). At a "typical" net plant heat rate of 14,000 Btu/kWh, this range of urban wood waste fuel costs translates to about 0.5-2.0¢/kWh. The opportunity exists for developers to relocate existing unprofitable plants or build new plants in the urban areas, and reduce fuel costs to or below zero.

One plant that comes very close to this urban integration strategy, and operates with a zero or negative fuel cost, is the Ridge Generating Facility near Lakeland, Florida. The unit burns waste wood, waste tires, and landfill gas, and nets about 40 MW in sales to Florida Power Corporation. Generally, the plant operates at full capacity from 11:00 am to 10:00 pm, and reduces load at night. The facility receives wood wastes and tires from local haulers and communities within about a 50-mile radius. (Tampa is within this radius, as are parts of Orlando.) About 20% of the wood wastes and all of the tires come in with tipping fees. The rest of the wood wastes are obtained at very low cost. The waste wood includes a great deal of vegetative waste, which has a high moisture content. Varying moisture content is one of the major control problems the plant experiences, but the use of the tires and the landfill gas assists in controlling the combustion process. The generating station paid for the landfill gas wells, gathering system, and pipeline from the landfill to the plant, but does not pay a fee for the gas. The station does pay to place ash from the combustion process back in the landfill.

The plant accepts all types of wood and yard wastes, including treated wood. The only type not accepted is palm trees, which are too fibrous and cause problems during processing. The vast majority of the urban wood waste fuel is tree wastes, brought to the plant by tree service companies and land clearing companies. About 10-15% of the total wood waste is C/D wood debris; industrial wood wastes such as pallets and scraps account for a smaller percentage.

Tipping fees charged by the plant for wood wastes are quite low -- \$5/ton for wastes that require a minimum of processing and \$12.50/ton for more difficult-to-process wood wastes. For comparison, Polk County landfills charge tipping fees of \$44/ton for household garbage and \$25/ton for yard waste or C/D debris. The BFI landfill tipping fees are \$15/ton for C/D debris and \$18/ton for yard waste. These data indicate that the Ridge Energy plant sets its tipping fees significantly lower than the landfill tipping fees in the area in order to attract wood wastes. The tipping fees of \$5/ton and \$12.50/ton are probably very close to the actual cost of grinding, screening, and blending the wood wastes in Ridge Energy's fuel yard. The plant does not "purchase" any biomass fuel, although it does pay the transport cost for some wood waste suppliers within a 50-mile radius. The tipping fee charged for scrap tires, \$60/ton, provides the plant a significant net revenue stream, since the tire shredding system is a fairly simply one. Overall, the net fuel cost must be very close to \$0/MBtu as the three fuels enter the boiler.

This fuel strategy need not be limited to stand-alone biomass power plants. Utilities with fossil fuel power plants in urban areas should be able to obtain urban wood wastes at zero cost for cofiring using the same strategy -- when the plant sites are suitable. It would be necessary to set up a tipping fee wood processing facility onsite or on an adjacent property connected by conveyor belt. Contracting with an experienced wood recycling company already operating in that city would be the lowest risk and lowest cost approach. That company would agree to move an existing facility to the power plant site (or start a new one), and would guarantee the power plant a certain amount of biomass fuel at zero cost. The processor would take the risk that his tipping fees and other income would more than cover the cost of grinding and screening the fuel to meet the power plant's specifications. The contract could also provide for a sharing of "profits" when the differential between the tipping fees and the processing costs exceeded a certain level. This would give the processor a strong incentive to reduce the cost of fuel below zero. Scenarios in which the net <u>revenues</u> from urban biomass fuel are equivalent to several cents per kWh, offsetting O&M and capital recovery costs, are not out of the question.

This type of arms-length business arrangement between a utility (or biomass power plant owner) and an urban wood waste processor is a win-win situation. If a utility or biomass power developer were planning a biomass cofiring or power project in the urban area, the existing wood waste processor would be much better off to join forces with that project, rather than trying to compete with it for raw materials. Similarly, the utility or power plant developer would be much better off incorporating the processor's expertise, contacts, and equipment into its project, rather than trying to compete with it (or buying fuel from it requiring transport).

Wood processing facilities, which are present in all large urban areas, have everything needed except the most crucial element -- a power plant onsite. Frequently their biggest problem is marketing hundreds of thousands of tons per year of ground up biomass. Often they give it away as mulch and as biomass fuel, but the recipients must pay the transport costs, which are considerable. When an urban wood waste processing facility integrates its operations with a power plant:

- Significant costs and logistical problems are eliminated for both parties;
- The biomass fuel delivery truck traffic and emissions are eliminated;
- The renewable carbon "loop" is closed locally;
- Power plant investment and jobs are created locally; and
- The power producer gets zero cost fuel while producing green power.

Mill Wastes

Fuel from mill wastes (wood products manufacturing) comes from both primary and secondary conversion operations. Primary conversion sources include sawmills and solid-wood panel plants. Secondary sources include remanufacturing, cabinet, and door plants. The differences in fuel produced are the moisture content, and the amount and type of material left in the fuel.

Primary wood products manufacturing fuel includes bark, sawdust, shavings, and hogged wood. Normally it contains 45 to 55% moisture. It is by far the largest volume fuel source in the mill waste category. Fuel from secondary wood products manufacturing includes sawdust, shavings, and hogged wood. It has an average moisture content of 10 to 12%. Although this type of wood waste represents a smaller resource overall, and is often given away as animal bedding and for other uses, wood wastes from large manufacturing operations (such as the Andersen Windows factory near St. Paul, Minnesota) can be important local sources of biomass energy.

Mill wastes can provide very low cost biomass fuel, even free in some situations analogous to those described above for urban wood wastes. For example, at the 60 MW Williams Lake Generating Station in British Columbia, Canada, five sawmills that are located within three miles of the power plant supply the fuel at no cost. Conveyor belts were considered, but short haul trucking is the mode of transport used for the fuel. The power plant pays for the transportation, and paid approximately $2 million to install fuel preparation equipment at each sawmill. The sawmills pay the operating expenses for the fuel preparation equipment. The fuel mix is about 40-50% bark, and the rest is an assortment of sawdust, chips, and slabs.

Washington Water Power Company's 46 MW Kettle Falls Station in eastern Washington is more typical of biomass power plants that burn primarily mill wastes. Fuel consists of bark, sawdust, shavings, and slabs -- milling byproducts from about 15 log processing plants located in northeast Washington, southeast British Columbia, and northern Idaho -- approximately a 100-mile radius. All fuel is received by truck. The average one-way haul from suppliers under contract is about 46 miles. Average transportation costs were estimated in 1983 at 10.8 ¢/ton-mile. Average delivered fuel costs were estimated in 1983 to be about $12.00 per green ton (approximately $1.40/MBtu). At the plant's net heat rate of about 14,100 Btu/kWh, this is equivalent to about 2¢/kWh.

Examples of other biomass power plants that burn large percentages of sawmill residues include:

- Wheelabrator Shasta (49.9 MW) in Anderson, California -- fuel costs not disclosed, but based on geography should be similar to those at Kettle Falls.
- Camas Mill (220,000 lb/hr hog fuel cogeneration boiler), Fort James Corporation, Camas, Washington (near Portland, Oregon) -- buys hog fuel on the spot market, for about $8/dry ton ($0.47/MBtu).
- Multitrade Project (79.5 MW) in Hurt, Virginia -- buys fuel on the spot market from 225 vendors in a 200-mile radius; average fuel cost is about $12/green ton (~$1.20/MBtu).

These examples indicate that mill residues can range in cost from about zero (in the unusual case when the supply is 100% local) to about $1.40/MBtu (roughly 2¢/kWh) when the supply radius is 100 miles or more.

Agricultural Residues

Almond, walnut, and fruit orchards and vineyards provide wood fuel via prunings and renewals. Growers prune their orchards and vineyards each year. The quantity removed averages about 20% of the annual growth stock. The moisture content ranges from 10 to 50%. Orchards can yield up to 1.5 dry tons/acre/year of prunings. A conservative average estimate is one dry ton/acre/year. Vineyard pruning yields 0.75 to one dry ton/acre/year. Pruning of tree crops (almonds, walnuts, and fruits) is seasonal, beginning in October, reaching a peak in early November, and continuing at a high rate through February. Vineyard pruning normally begins in December or January and ends in March.

Renewal of orchards, to remove over-mature orchard stock and replace it with new, more productive trees, offers a more substantial and less costly fuel source. The stock usually reaches its productive limit after eight to twelve years. A specialized service company removes the whole trees and converts them to fuel. This typically occurs after the growing season. Stock removal from orchards can yield as much as 24 to 30 dry tons of fuel per acre.

Many of the biomass plants in California use orchard residues as fuel (usually referred to as “ag fuel”). The use of these residues generates emission offsets because the orchard owners’ alternative disposal method is to burn the prunings and removed trees at the edges of their properties. The smoke from open burning of orchard residues contains much higher levels of particulate matter, soot, CO, and NO_x than the flue gas from biomass power plants. In some cases, the air quality permits of biomass power plants located in non-attainment areas require the use of specified amounts or percentages of ag fuels in order to produce emissions offsets.

An example of this is the Tracy Biomass plant, which burns a little over 50% orchard wood waste (as required by its air quality permit) and a little under 50% urban wood waste (which is significantly less expensive fuel at the Tracy location). The plant is in a good location, near the intersection of major freeways I-580 and I-5 about 35 miles east of Oakland. Highway 99, which runs through the heart of California’s agricultural San Joaquin Valley, is about 15 miles east of Tracy. One million acres of orchard land are both north and south of the plant, and the major landfills for the San Francisco Bay Area are in the vicinity (as is the Stanislaus County Waste-to-Energy plant). Thus the plant is well situated to receive both agricultural and urban wood wastes.

During 1990-1993, Tracy Biomass built up an orchard wood waste service operation, including two large chippers, a fleet of trucks, and drivers. They were able to pull whole trees out of the ground and feed them through a $400,000 chipper, removing five to ten acres of orchard trees per day. They provided excellent service to orchard owners, assisting in removal of the wood waste from both tree removals and prunings. This was during the high biomass fuel price era, which ended in 1994 when the California Public Utilities Commission published its proposal to restructure the California electric utility industry and PG&E began renegotiating and buying out contracts. Biomass fuel demand and prices plummeted, and Tracy Biomass sold its orchard wood waste service. The prunings are much more expensive to collect than the whole trees harvested during orchard removals, because the yield per acre is much lower as discussed above. Tracy Biomass no longer uses prunings, and the orchard owners have gone back to burning them. Tracy Biomass mostly takes orchard removals as its ag fuel now. The cost of this fuel delivered to the plant was not disclosed, but is probably about $15-20 / dry ton (~$0.88-1.18 / MBtu).

In contrast, urban wood waste fuel processed and delivered to Tracy Biomass costs about $5 / ton (~$0.35 / MBtu). One of Tracy Biomass’ main fuel suppliers is a fuel processing company in Livermore, which charges tipping fees for wood wastes. The wood wastes probably come from all over the East Bay Area. The distance from the processor to the Tracy Biomass plant is about 15 miles over the Altamont Pass. The plant pays about $5/ton for the urban wood waste from the processor. The average moisture content is in the low 20% range.

Forest Residues

Timber management activities that produce in-forest fuel include logging, thinning (precommercial and commercial), cull log conversion, and site conversion. The quantity of residue that remains in the forest varies, depending on species, type of soil, terrain, forest management standards, and logging operations. In-forest fuel includes treetops, branches and limbs, whole trees too small for sawmill processing, defective logs, and noncommercial species.

The economic fuel supply radius varies with topography and infrastructure. It is normally about 70 miles, or a range that permits two round trips between the fuel-using site and the fuel source in an eight- to ten-hour workday.

Forest residues can be very expensive compared to other biomass waste fuels. In the western United States, the cost of gathering, processing, and transporting forest residues is on the order of $40-60/dry ton ($2.40-3.50/MBtu). Yet there is a real need, and a strong public interest, in developing effective forest management programs for over 100 million acres in the West. Extensive logging in the late 1800s and the near-total suppression of fire over the last century have created conditions whereby the widely-spaced, mature stands that once dominated the landscape have been replaced with thick, crowded stands of small-diameter trees. In many areas, recent drought and insect infestation have caused a significant buildup of dead and dying trees in 30 to 80% of the forest.

The combination of accumulated fuels, dead and dying trees, and overstocked forest stands places the western forests at significant risk of experiencing catastrophic wildfires. Standing and fallen dead and dying trees increase the risk by serving as ladders for low-intensity understory fires to leap to forest crowns. Crown fires burn so intensely that they are virtually unstoppable, killing everything in their path and sterilizing the soil. The integrity of wide areas of the forest and associated watersheds can be severely damaged for hundreds of years. A variety of organizations have been working on developing solutions to this problem, most of which hinge on finding mechanisms to supply the harvested forest residues to biomass power plants at costs that are borne by the landowners or the public (justified by the greatly reduced cost of firefighting and fire losses). Concepts are also being explored for the use of the forest biomass fuel in small, mobile systems that power the saws and other equipment needed to produce finished products onsite rather than at distant mills. [3,4]

A market assessment of potential outlets for biomass produced from planned forest management activities in the Lake Tahoe Basin found that seven of the seventeen biomass power plants in northern California are operating below their capacity and have significant potential to use the Basin thinnings. However, these plants currently pay $8-25 / dry ton for biomass fuel, compared to the estimated $44-54 / dry ton estimated delivered cost for the Basin forest thinnings. [4]

In New England, previous forest management practices have left a legacy of greatly diminished forest value. The 50 MW McNeil Plant in Burlington, Vermont gets most of its fuel as a result of modern forest management practices that are designed to improve the value of the forests over time. An average of 75-80% of the wood fuel used by the plant consists of whole tree chips from low-quality trees and harvest residues that are cut and chipped in the forest, and transported by trailer truck to the station or a railcar loading site in Swanton, VT. The remaining 20-25% of McNeil's wood requirements are met by sawmill residues and a small amount of clean urban wood wastes. The resulting fuel cost at the plant is about $2.20 / MBtu.

Summary of Biomass Waste Fuel Costs

The preceding discussion indicates that the cost of biomass fuel from both urban wood wastes and mill wastes can range from about $0 / MBtu to about $1.40 / MBtu, depending on the distance from the fuel source to the power plant. Getting to zero fuel cost depends on locating a power plant in an urban area next to a wood waste processor, or locating a power plant next to a large sawmill or group of sawmills. Very few biomass power plants have done this yet, but deregulation and competition will make this zero fuel cost strategy important in the future.

Agricultural residues (primarily orchard tree removals) can be processed into fuel and delivered to nearby biomass power plants for about $1.00 / MBtu. Only if open burning of agricultural residues is completely prohibited will it be possible to transfer some or all of this cost to the orchard owners.

Forest residues are much more costly ($2.40-3.50 / MBtu), due to the high costs of gathering the material in remote and difficult terrain, processing it to fuel, and transporting it to power plants. There are strong arguments for government programs to bear the costs of forest management and fire prevention. Only if such programs are created will forest residues be a cost-competitive fuel in the future.

4

ENERGY CROPS

While the use of biomass wastes to produce electricity can certainly be expanded, the total resources are limited to less than 10% of total electricity demand. The development of a biomass industry capable of providing substantially more than 10% of the nation's electricity will require the large-scale production of dedicated energy crops. The key to success is the development of biomass crops that are fast growing; natural to the territory; and resistant to drought, pests, disease, and chemicals. Research to achieve these objectives with grasses and trees has been underway for nearly two decades. This includes selection, breeding, cloning, many clone-site tests, biotechnology-guided selection and breeding, harvesting, and, increasingly, genetic engineering. Continued progress in these areas is expected to reduce biomass fuel costs from about $2.50/MBtu today to about $1.25/MBtu in 2030.

Conventional crops such as alfalfa can be used for the dual purpose of fuel and feed, providing greater and more economic use of the crop. Already, about 100,000 acres of short rotation woody crops are planted as feedstock for pulp mills in the United States. Residues from these "fiber farms" are used for biomass fuel. As pulp and paper companies develop faster growing clones and perfect the methods for "fertigation" (fertilizers and nutrients precisely delivered via drip irrigation), the total biomass yield, and thus the yield of residues (bark, tops, and limbs) from fiber farms will become very significant. Thirty years from now, a fiber farm that yields 30 dry tons/acre/year of total biomass will produce 6-9 dry tons/acre/year of residues. Six to nine dry tons/acre/year is a goal for the total biomass yield for non-irrigated short rotation woody crops. The significant benefit of coproduct systems is that the residues (fuel) can be obtained for the cost of transportation alone.

Biomass crops are considered more environmentally acceptable than food crops due to reduced fertilizer and pesticide use, tolerance to damaging weather conditions, and compatibility with native plants. (In fact, biomass crops are usually plants that have naturally existed in the area for millennia). Often these crops are ideally suited to land that has been overfarmed and needs restoration, land once used for food crops but no longer needed due to increases in productivity, unproductive forest land, and river bottom land subject to repeated flooding. Tens of millions of acres of such land are available in the United States, much of it set aside by farmers who are paid by the federal government not to grow food crops under the Conservation Reserve Program (CRP) and related programs. If environmentally suitable means of growing and harvesting energy crops on some of these lands can be developed, the result would be about one MW of electricity per 600-800 acres planted.

To put this in perspective, there are some 400 million acres of cropland in the United States, plus another 300-400 million acres of pasture land. Of the 38 million acres in CRP about half are estimated as suitable for energy crops. Another 50-150 million acres of cropland could become available for energy crops as a result of increased yields of food crops and changes in diet (less meat). At biomass crop yields expected in the future, 80 million acres could supply 20% of U.S. electricity.

Biomass energy crops are often the most misunderstood of the renewable energy options, with many not recognizing the recycling of carbon that occurs. Also, some assume that natural forest land will be used and that other negative environmental impacts will occur. As indicated in the above paragraphs, these crops will use agricultural land, not forest land. Also, biomass crops, when properly managed, help land and water quality and even provide natural habitat for wildlife, especially birds. In addition, fiber from biomass crops will replace some logging in forests.

POLYSYS Analysis of Near-Term Energy Crop Potential

The development of large-scale systems for production of dedicated energy crops raises many economic and environmental questions. Among the economic questions of interest are: (1) how many acres could be available for energy crops production; (2) what prices are needed to entice farmers to plant energy crops; (3) where is energy crop production most competitive with traditional crops; (4) what effects will large-scale production of energy crops have on the prices and quantities of traditional agricultural crops; (5) how will production of energy crops affect net farm returns; and (6) how might agricultural and energy policies affect energy crops production? To help evaluate these questions, the U.S. Department of Agriculture (USDA) and the U.S. Department of Energy (DOE) have modified an agricultural sector model (POLYSYS) to include energy crops (switchgrass, hybrid poplar, willow). Marie Walsh of Oak Ridge National Laboratory is leading this effort. [5]

POLYSYS contains the major agricultural crops (corn, wheat, soybeans, cotton, rice, grain sorghum, barley, oats) and livestock (swine, beef, dairy, poultry, sheep), and has been modified to include alfalfa and other hay crops as well as energy crops. Data are aggregated into 305 Agricultural Statistical Districts (typically containing five to eight counties) which can be combined to provide local, state, regional, and national level results. The model allocates land to each crop based on a comparison of its relative profitability (price times yield, minus production costs).

The land base in the model is currently limited to acres that are classified as cropland and planted to the eight major crops (261 million acres), alfalfa (27.3 million acres), and other hay crops (33.4 million acres). Of the total land contained in the model (321.7 million acres), 257 million acres are considered suitable for energy crop production and include land in the eastern half of the United States (for all three energy crops) and the Pacific Northwest (for poplar). Farm acres that are idled (either in CRP or for other reasons) have not yet been incorporated into the model -- an important area for improvement of the model that is being addressed by the USDA and DOE.

Because woody energy crops require multi-year rotations, POLYSYS uses a net present value approach to compare the relative profitability of energy crops and traditional agricultural crops. Production cost estimates include all variable cash costs (seed, cuttings, fertilizer, chemicals, fuels, etc.), labor costs, machinery costs (storage, insurance, depreciation, opportunity cost of ownership), and interest costs. Because the crops' profits were being compared against one another, land rent was not a factor in the analysis.

The preliminary analyses presented so far have set the year 2007 farmgate prices for three energy crops (switchgrass, poplar, and willow) at the same levels in dollars per million Btu -- $2.26/MBtu in one case, and $3.23/MBtu in another case. These prices are equivalent to $35 and $55/dry ton for switchgrass, and to slightly higher amounts per dry ton for the two woody crops. Transportation costs from the site of production to a storage or end user facility are not included; nor are storage costs and losses. Based on the cost estimates incorporated into the model, switchgrass is more profitable than poplar and willow in almost all locations. Thus, in the "low price" case ($2.26/MBtu), an estimated 9.66 million acres of switchgrass could be produced in the year 2007 at a profit at least as great as for traditional agricultural crops produced on the same land. Total production is about 50 million dry tons/year. At the same price per million Btu, an estimated 60,000 acres of poplar and 80,000 acres of willow could be grown, producing about 690,000 dry tons/year of biomass.

These results are summarized in Table 4-1, along with the results from the "high price" ($3.23/MBtu) case. In that case, the total acreage increases to over 17 million, and the total biomass yield increases to 88.3 million dry tons/year. The quantities of energy crop biomass produced in these two scenarios could support about 10,000 and 17,500 MW of generating capacity, respectively (assuming an average of 7750 Btu/dry pound, 10% losses in storage and handling, an average heat rate of 10,000 Btu/kWh, and an 80% capacity factor).

Figures 4-1 and 4-2 show the locations of switchgrass production by agricultural statistical district (ASD) for the two price scenarios. The analysis indicates that switchgrass can be produced in substantial quantities at lowest price in the Lake States, North Plains, South Plains, and Southeast. Parts of the Midwest and Northeast begin energy crop production as switchgrass price increases. Short rotation woody crop production (not shown on the maps) occurs primarily in Tennessee, Louisiana, Minnesota, and Oregon for poplar, and the Northeast and Lake States for willow.

Table 4-1
Estimated Impacts of Energy Crops (Year 2007)

Assumed Farm Gate Price:	$2.26/MBtu	$3.23/MBtu
Millions of acres switched:		
Switchgrass	+9.66	+17.34
Poplar	+0.06	+0.08
Willow	+0.08	+0.19
Hay and alfalfa	-5.68	-6.69
Wheat, soybeans, corn	-2.14	-8.41
All other crops	-1.96	-2.50
Millions of dry tons harvested:		
Switchgrass	50.0	87.0
Poplar and willow	0.69	1.3

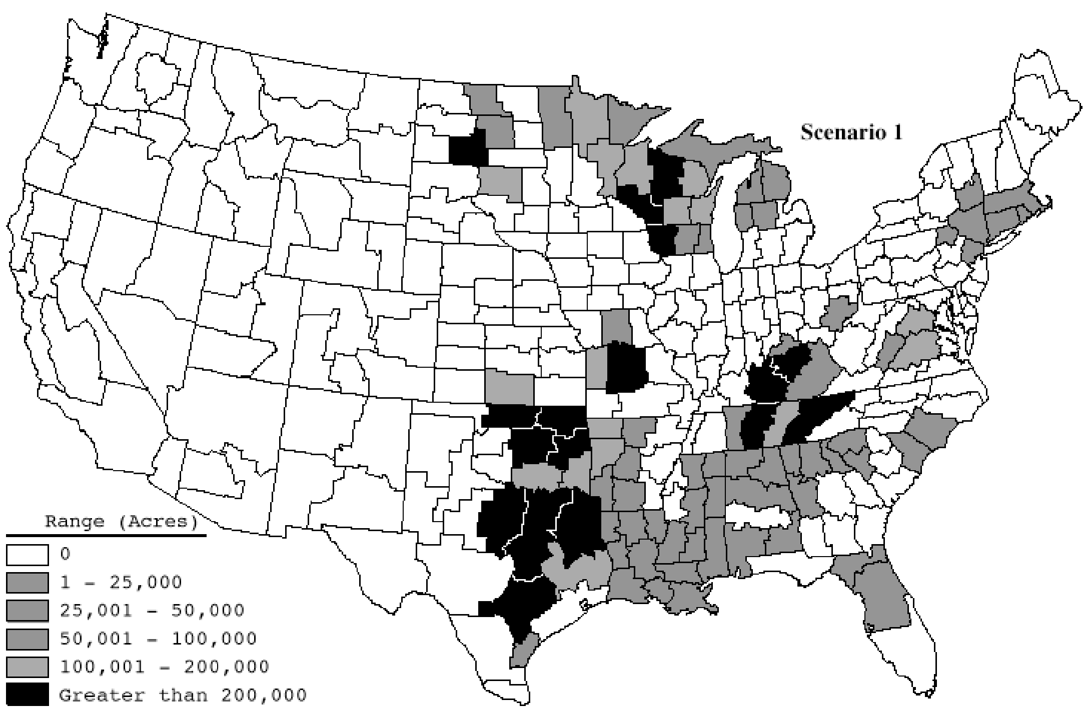

Figure 4-1
Acreage Planted to Switchgrass at $2.26/MBtu (Year 2007)

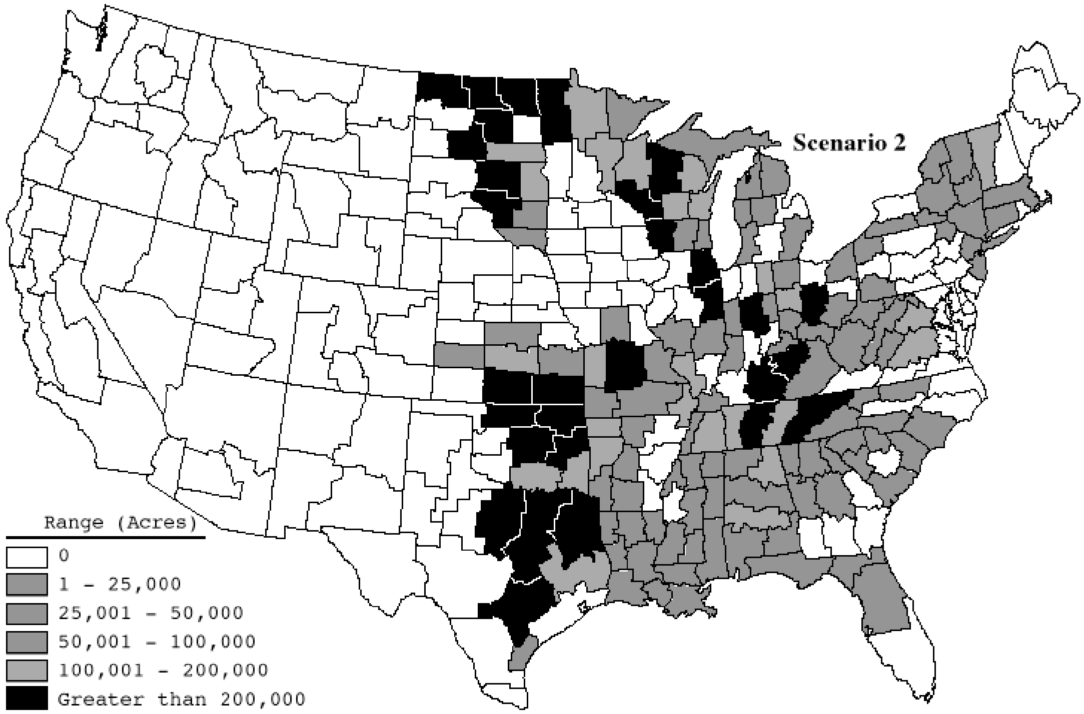

Figure 4-2
Acreage Planted to Switchgrass at $3.23/MBtu (Year 2007)

Use of CRP Lands for Energy Crop Production

The Conservation Reserve Program (CRP), enacted in the 1985 Farm Bill, removes environmentally sensitive cropland from production. While enrolled in the program, CRP acres must be maintained in conservation uses and not harvested. In return, farmers receive an annual rental payment from the government. While effective at maintaining environmental quality, the program is also expensive (approximately $1.8 billion annually) and during the 1995 Farm Bill debates, Congress explored ways of reducing its cost. Amendments, which were ultimately not included in the Farm Bill, proposed such changes as producing and harvesting energy crops in exchange for a reduced rental rate. An implication of such a policy is that CRP rental rates can serve as a subsidy for the production of energy crops. Analyses by Oak Ridge National Laboratory have shown that modest savings in Federal spending for the CRP Program can be achieved simultaneously with reduced energy crop costs on CRP lands. [6]

Some states, on a case-by-case basis, have discussed with the USDA arrangements for using CRP acres for energy crop production. For example, the Chariton Valley RC&D area in Iowa has received authorization from the USDA to use existing CRP land for a 4000 acre demonstration project supporting the development of a post-CRP alternative.

An existing coal-fired power plant, the 726 MW Ottumwa Generating Station of Alliant Power, will cofire the biomass fuel produced from the switchgrass harvested from the test acres. Costs of delivered switchgrass in this project are estimated to be in the range of $50-60/dry ton. [7]

Because the CRP lands are environmentally sensitive (e.g., subject to high erosion or flooding), farmers growing energy crops on these lands will have to leave buffers and make other concessions, resulting in biomass yields lower than the maximum possible, and not all acres being harvested. Still, with over 30 million acres as candidates, CRP lands could make a very significant contribution to biomass energy development.

Dedicated Woody Crops

Although switchgrass appears to have a cost advantage over woody crops in most locations according to the DOE/USDA analysis, wood is currently the preferred biomass fuel for power generation. If a substantial cost advantage for switchgrass over short rotation woody crops is proven in large-scale operations, efforts to develop better fuel feeding and conversion technologies for grasses will be justified, and will probably be successful. Previous EPRI analyses of energy crops have concentrated almost exclusively on woody crops. The key findings of those analyses are summarized briefly below.

Experience with establishment, cultivation, and harvesting of short rotation woody crops is limited but growing rapidly as a result of the efforts of pulp and paper companies and DOE programs. (See the web site for the Short Rotation Woody Crops Operations Working Group at www.esd.ornl.gov/bfdp/srwcwgrp/menu.html for technical papers and other information.) Projected costs for delivered fuels from short rotation woody crops are too high to allow farm-grown biomass to compete in the electric generation market. This is in the context of natural gas prices below $2.50/MBtu, coal prices well below $1.50/MBtu, and biomass yields on the order of 5 dry tons/acre/year for hybrid poplar, 7.5 dry tons/acre/year for hybrid willow, and 9 dry tons/acre/year for irrigated hybrid eucalyptus. Based on the limited experience to date, willow appears to provide lower costs than poplar or eucalyptus, primarily because of much lower harvesting costs. This is because agricultural-style harvesting machines (based on sugar cane harvesters) are commercially available for willow, but have not yet been demonstrated for the larger trees.

Biomass yields must increase significantly, by 50 to 100% from presently assumed values, before fuel costs will enter the competitive range. Although significant progress in biomass yields can be expected as better clones are developed and techniques are improved, it is difficult to predict the speed of those changes. Oak Ridge National Laboratory and others have pointed out that short rotation woody crops are in early stages of development and great potential for genetic improvement of yields exists. [8]

The other major opportunity for cost reduction is to reduce the harvesting costs for hybrid poplar and eucalyptus, which are grown for six to eight years and reach considerable diameter, height, and weight before being harvested. Agricultural-style harvesting systems for large trees have been proposed, and one prototype is being tested with DOE funding.

In 1995, EPRI analyzed the available data and studies on the costs of short rotation woody crops [9], and published a summary of the results in a conference paper. [10] Table 4-2 shows selected results of these analyses for three crops: hybrid poplar grown without irrigation in an upper midwestern location; eucalyptus grown with drip irrigation in northern California; and willow grown without irrigation in upstate New York. The data on hybrid poplar were provided by Bill Berguson of the Natural Resources Research Institute in Duluth, Minnesota and by Marie Walsh of Oak Ridge National Laboratory. The data on eucalyptus were provided by Bruce Hartsough of the University of California, Davis. The data on willow were provided by Ed White of the State University of New York. Part A of the table shows the estimated costs of producing, harvesting, and delivering fuel from the three systems, based on existing (best) yields and practices. Part B shows the greatly reduced costs projected for the future, assuming doubled yields and agricultural-style harvesting of whole trees for poplar and eucalyptus.

Crop systems that produce a higher-value main product, and biomass fuel as a byproduct, would seem capable of providing greater financial returns to land owners than systems that are 100% dedicated to fuel production. Examples are the production of lumber or pulp, with the residues going to fuel; the production of sugar, with the bagasse going to fuel; and the production of cattle feed from alfalfa leaves, with the stems going to fuel. In these cases the high markup on the primary product reduces the cost assigned to the fuel.

Examples of projects or systems that involve energy crops 100% dedicated to fuel are the Salix Consortium in New York, where willow is intended to be used 100% as boiler (cofiring) fuel, and the Whole Tree Energy™ technology. In both cases the intent is to minimize fuel cost by deleting or simplifying as many biomass processing steps as possible, and to maximize the production of solar-derived energy per unit area of land using fast-growing trees as the primary energy conversion and storage devices. However, these objectives are not necessarily the same as the land owner’s profit objective, which is the objective that will be decisive. If presented with several choices, the land owner will select the one that gives the highest profit per acre, among the choices that have acceptably low levels of risk.

Table 4-2
Short Rotation Woody Crop Cost Estimates

Part A: Current Costs	**Poplar**	**Eucalyptus**	**Willow**
Costs per dry ton, $/dt:			
Site prep and establishment	13.22	13.73	12.01
Annual costs	25.76	27.74	14.57
Subtotal: stumpage price	38.97	41.47	26.58
Harvesting and chipping	19.15	15.83	1.38
Transportation (40 miles)	8.50	8.50	8.50
Total: delivered fuel cost	66.62	65.80	36.46
Delivered fuel cost, $/MBtu	3.92	3.87	2.14

Part B: Future Costs	**Poplar**	**Eucalyptus**	**Willow**
Costs per dry ton, $/dt:			
Site prep and establishment	6.61	6.87	6.00
Annual costs	12.88	13.87	7.29
Subtotal: stumpage price	19.49	20.73	13.29
Harvesting	2.50	2.50	1.38
Transportation (25 miles)	6.25	6.25	6.25
Total: delivered fuel cost	28.24	29.48	20.92
Delivered fuel cost, $/MBtu	1.66	1.73	1.23

5

ADVANCED COMBUSTION

During the past fifteen years many new biomass power plants have been built in North America -- essentially all of them using well-proven combustion technologies to raise steam and drive steam turbine generators. Much has been learned about biomass power technology from the operation of the new projects. Biomass power plant owners, designers, and equipment suppliers have made improvements and cost reductions, although they face a moving target because the fossil power industry has become much more cost-effective at the same time.

The relatively mature stoker boiler technology was improved by the introduction of water-cooled grates, staged combustion air, larger boiler sizes up to 60 MW, higher steam conditions, and advanced sootblowing systems. Circulating fluidized-bed (CFB) technology achieved full commercial status. It provides more complete combustion, lower emissions, and better fuel flexibility than stoker technology provides, at a small premium in cost. Bubbling fluidized-bed technology also acquired an important market niche as the best process for difficult fuels such as agricultural residues or urban wastes, typically in smaller plant sizes.

Utilities are evaluating the cofiring of biomass with fossil fuels in both existing and new plants. Retrofitting existing coal-fired plants gives better overall cost and performance results than any of the dedicated (new plant) biomass technologies. Retrofit cofiring is essentially a fuel-switching strategy that provides no new capacity and is economically attractive only when very low or negative costs for the waste fuels, emissions credits, or government incentives are available to the utility.

Capital costs of large (50 MW) wood-fired power plants are typically in the range of $2000-3000/kW (in 1997 dollars). The 1993 EPRI report "Strategic Analysis of Biomass and Waste Fuels for Electric Power Generation" and the 1993 EPRI Technical Assessment Guide showed capital costs for 50 MW wood-fired stoker power plants at about $2100/kW (1997 dollars), and showed capital costs for 50 MW wood-fired circulating fluidized-bed power plants at about $2450/kW (1997 dollars).

A capital cost of about $2100/kW results in a carrying charge of about 3.5¢/kWh. Operating and maintenance (O&M) costs for biomass plants are approximately 1.3¢/kWh. Fuel costs typically range from zero to over 3¢/kWh, as discussed in Section 3. Thus, the full cost of electricity from a 50 MW biomass plant (including carrying charges) is in the range of 4.8 to 8¢/kWh. With the capital charges paid off, a zero fuel cost plant can generate electricity for under 1.5¢/kWh (or its O&M costs).

Cofiring biomass with coal in an existing power plant is much less expensive. Typically, there is a very small net increase in the cost of electricity from the plant as a result of cofiring, on the order of 0.1-0.3¢/kWh or less. In cases where “tipping fee fuels” can be obtained and processed onsite to produce a net revenue for the plant, the cost of electricity produced from biomass can be as low as minus 3 or 4¢/kWh, and the economics of the cofiring project can be attractive.

Stoker Grate Boilers

Stoker boilers have been available since the 1920s with inclined fixed grate designs. This was a major improvement over the older pile burning systems, providing more efficient combustion because of more even distribution of the fuel. The traveling grate was the next major improvement, providing a thinner and better distributed bed of burning fuel and continuous ash removal from the grate. This resulted in faster fuel burnout rates and less sensitivity to load variations.

Traveling grate boiler designs have been steadily improving for nearly 50 years, in grate and furnace water wall design and, in recent years, in combustion control for lower emissions. Various manufacturers evolved different configurations for the boilers to address the needs for grate cooling and water wall design to prevent slagging and fouling. Recent boilers use water-cooled vibrating grates, allowing the use of higher temperature undergrate air and a higher percentage of overfire air (as high as 50%) to control NO_x formation. The additional advantage of using lower quantities of underfire air is lower unburned particulate carryover.

Fuel switching capability of stoker boilers is usually limited. Traveling grate stoker boilers are usually designed for a given fuel size distribution and moisture content. Introducing more fines results in more suspension firing and carryover. Moisture content must typically be kept within about 10% of the design range. Fluctuations in moisture content outside this range result in significant changes in flue gas flows and heat transfer rates. The impact of fuel properties on boiler performance shows the need for good fuel preparation.

Certain ash constituents, particularly high concentrations of sodium and potassium, can lead to low melting ashes and slagging in stoker boilers. Other constituents, such as high concentrations of chloride, can lead to stress corrosion. Contaminants such as chlorides can be introduced in urban waste wood and in wood that has been in contact with salt water. Some agricultural wastes, particularly rice straw, contain low melting ashes. Because of problems associated with combustion of agricultural wastes (other than orchard wood wastes), the percentage of “ag fuel” in the total fuel going to the furnace is usually limited to less than 15% (by heat input).

Fluidized Bed Boilers

Significant commercial application of FBC technology began when circulating fluidized-bed processes were successfully demonstrated during the 1980s. Circulating fluid bed (CFB) boilers gained favor over bubbling beds for larger scale applications mainly because of greater ease of maintaining bed stability, more complete fuel burnout, better emissions performance, and the ability to handle larger variations in fuel particle size. Bubbling beds are generally favored for smaller plant sizes because of their lower capital costs; CFBs have significantly higher auxiliary power requirements due to fan horsepower.

There is now wide commercial experience with CFB boilers burning biomass fuels. California projects represent the largest component of this experience in the United States. About 165 MW of installed CFB capacity in California is based on wood and other biomass wastes. Additionally, approximately 100 MW of biomass-based capacity in the state is represented by bubbling bed installations. There are several other CFB boilers using biomass fuels in the United States, such as those at West Enfield and Jonesboro in Maine.

Because of the high residence time in CFB boilers, carbon burnout of highly reactive biomass fuels is virtually complete. Bubbling bed boilers provide lower carbon burnout than CFB boilers because of the lower fuel residence time in the furnace. Other principal advantages of CFB boilers over bubbling beds are fewer fuel feeding problems and less excess air use. The principal disadvantages of CFBs over bubbling beds are higher fan power requirements and greater cost.

CFB boilers can be designed to handle a wide range of fuel quality. However, to keep costs within reason, the boiler is usually designed for an anticipated set of fuels. Variations of fuel quality outside this range can lead to operating problems. Wide variations in particle size and density, as well as moisture content, can lead to boiler instability. Proper maintenance of solids inventory in the boiler is imperative for stable operation and efficient heat transfer. Maintenance of solids inventory requires good control over particle size distribution for both fuel and inert solid materials used in the bed. Wide swings in moisture content can lead to unstable combustion and to imbalances in heat transfer in both the convective and the furnace sections of the boiler.

Operating difficulties have been caused by ash composition, and by fuel impurities such as rocks and dirt, in nearly all biomass-fired CFB boilers. Most problems have been associated with high alkali content, which is most pronounced in agricultural residues. These low-melting ash constituents can cause fouling of boiler surfaces, deposition in cyclones, and agglomeration of bed materials. The best solution for this problem is limiting the quantities of undesirable materials and blending fuels for consistent quality of feed to the boiler. CFB boilers must be designed to allow periodic removal of rocks and agglomerates from the bed during operation.

Cofiring in Coal Boilers

Cofiring of biomass with fossil fuels is a well-established technology. In 1987, Power Magazine listed 182 companies who had at least some experience with cofired boilers, including 29 electric utilities. Most of the utility cofiring used biomass or RDF and coal in existing coal boilers. Wood waste is commonly cofired with coal in the pulp and paper industry. In 1987, the U.S. pulp and paper industry consumed 46.5 million tons of wood waste (at 50% moisture) and 13.4 million tons of coal. On an energy basis this is about 55% wood waste and 45% coal.

There is currently increased interest in the cofiring of biomass fuel with coal in existing utility boilers for the following reasons:

- Lower SO_2 and (sometimes) lower NO_x emissions than for 100% coal-firing. This is an important advantage for existing coal-fired utility boilers affected by the Clean Air Act Amendments (CAAA) of 1990. (The SO_2 reduction is certain; the NO_x reduction, probable.)

- Higher thermal efficiency than most existing 100% biomass-fired boilers -- although not much higher than the 60 MW Williams Lake wood-fired boiler, which has a net plant heat rate of 11,700 Btu / kWh (29.2% conversion efficiency, HHV basis). This is about the same heat rate that a 10,000 Btu / kWh coal-fired boiler achieves on wood that is cofired with the coal.

- Much lower capital cost than for a new 100% biomass-fired boiler. However, no new generating capacity is added; biomass is simply substituted for coal.

- In some locations, biomass fuels cost less than coal.

- Blending with coal reduces the impacts of the varying quality of biomass fuel.

- Using waste biomass as fuel helps ease solid waste disposal problems.

- Potential for generating ash waste in a better form, such as slag (in a cyclone furnace) and the mixing of biomass ash with coal ash. (On the other hand, adding waste components to an existing facility's coal ash might impact the utility's ability to sell the ash.)

- The ability to generate “green power” at low cost to meet market demand or renewable portfolio standards may become important.

- Carbon emission offsets may become important.

The key technical issue for cofiring is the potential negative impact on boiler performance. Cofiring can result in reduced power plant capacity and efficiency: reduced capacity if biomass is fed with coal through the pulverizers in a pulverizer-limited power plant; reduced efficiency due mostly to the moisture in the biomass. The capacity derating can be significant depending on the original boiler design and the properties of the biomass. Many biomass fuels contain high moisture content (e.g., 45% in green sawdust). Large amounts of excess combustion air can be required in biomass combustion. The higher flue gas flow can also contribute to capacity derating in addition to the inherent efficiency penalties due to moisture and hydrogen in the biomass fuel. The fouling and slagging index of some biomass and waste fuel ash can be severe and could, in theory, increase capacity derating as well as boiler maintenance.

Another technical issue in cofiring is the solid waste. Specifically, solid waste ash from coal-fired boilers is normally considered non-hazardous and, for electric utilities, is exempt from the Resource Conservation and Recovery Act (RCRA). However, cofiring of waste fuels such as RDF could lead to loss of the RCRA exemption which would increase disposal costs because of the possibility that mixed coal/RDF ash would require disposal in expensive hazardous waste landfills. Also, unrelated to RCRA and environmental regulations, sales of the fly ash from a cofired coal-fired boiler could become difficult due to the fact that cofired ash is, strictly speaking, no longer coal ash. The inability to sell fly ash could mean that a power plant must now pay for disposal rather than sell this ash. Proof that the cofired ash is just as good as 100% coal ash for sales to high-valued applications such as cement for structural concrete would only be a first step in a lengthy process of changing the relevant standards -- a process that might take up to 5 years.

In 1997 EPRI published its Biomass Cofiring Guidelines, based on a large number of tests in utility boilers. [11] The reader should refer to the Guidelines report for more details on cofiring technology.

Biomass—A “Niche” Industry

The successes and reversals of the biomass power industry in the last decade show that when generous subsidies are taken away, the only biomass projects likely to stay in business are those that have found special niches -- for example, situations in which fuel costs are eliminated. The existing biomass power industry is a “niche” industry. At heart, it is a waste management industry. The traditional niche has been the recovery of energy from sawmill wastes, which previously had been burned in "teepee" burners, creating unacceptable air quality problems. Another important niche, which has not yet been properly exploited, is the local recovery of energy from urban wood wastes.

The existing PURPA-created biomass power industry in California, New England, and elsewhere has done little to identify the most sustainable niches for biomass power plants. Driven by developers and bankers insisting on long-term fuel contracts, an expensive "fuel procurement" structure and mindset evolved in the industry, when what was needed was an income-generating "waste management" approach. Such an approach emphasizes siting power plants where biomass wastes can be obtained at below zero cost (tipping fees), or at worst, at close to zero cost. This means, for example, siting plants in urban areas and next to large sawmills.

Most biomass plants in California were sited to use forest residues and agricultural residues. Although there are significant benefits associated with the collection, processing, and use of these residues as biomass fuel, the costs are simply too high (see Section 3). Many biomass plants use urban wood wastes as fuel, but pay $10-15/ton in transportation costs. They are located in the wrong places to take advantage of tipping fee fuels. For example, the closest plants to the Los Angeles metropolitan area are about 120 miles away.

Unlike the situation in urban settings, in agricultural and forest settings there are no laws or policies that force the generators of biomass wastes to dispose of them responsibly at their own expense. Most agricultural residues are still burned in the field, under the watchful eye of the local Air Quality Management District. Most forestry residues (slash) are left in place, and second growth forests are not thinned as they should be, creating major fire risks and costs. Until laws or regulations are developed to deal with these situations, the only unexploited "niche" (other than new sawmills) with the potential to provide zero-cost fuel is urban biomass.

Lessons Learned from Existing Biomass Power Plants

Table 5-1 lists a sample of 11 operating biomass power plants in North America with rated capacities between 18.5 and 79.5 MW, and annual capacity factors between 19 and 106%. The list is in descending order of annual energy production (MWh/yr) for 1997 or 1996. At the top of the list, the Williams Lake plant is an excellent example of the "sawmill niche", and also holds the distinction of having the largest single boiler (60 MW) burning biomass, the lowest heat rate (11,700 Btu/lb) of any existing biomass power plant, and a capacity factor of 106%. Built and operated with no subsidies, this plant is very successful in its remote niche in British Columbia, receiving over 600,000 tons/year of free fuel from five nearby sawmills.

Near the bottom of the list, the Multitrade plant in rural Virginia has the largest rated capacity (79.5 MW generated by three boilers) of any biomass power plant, but operates as a peaking unit under contract to Virginia Power Company with a capacity factor of less than 20% and an annual biomass fuel consumption of about 220,000 tons / year. This plant received no subsidies either, and was built as a result of being selected by Virginia Power from a competitive procurement for capacity and energy (with no restrictions on fuels). This plant sits idle, sometimes for weeks at a time, and then responds within 12 hours to the utility's calls for energy.

The Wheelabrator Shasta plant (second on the list in Table 5-1) has the distinction of being the largest biomass fuel consumer, partly because of its 49.9 MW capacity and 96% annual capacity factor, but mostly because of its low efficiency (17,200 Btu / kWh). This plant was sited to take advantage of mill and forestry residues in northern California, but because of the high cost of obtaining these resources, also buys urban biomass fuel from as far away as Sacramento (~140 miles).

Table 5-1
Sample of Large Existing Biomass Power Plants: Summary Data

Plant	Location	MW	MWh/yr	Cap Fac, %	Btu/kWh	Tons/yr*
Williams Lake	British Columbia	60	558,000	106	11,700	768,000
Shasta	California	49.9	418,000	96	17,200	846,000
Colmac	California	49	386,000	90	12,400	563,000
Kettle Falls	Washington	46	330,000	82	14,100	547,000
Stratton	Maine	40	305,000	87	13,100	470,000
Ridge	Florida	40	200,000	57	16,000	376,000
Grayling	Michigan	36	186,000	59	13,600	298,000
McNeil	Vermont	50	137,000	31	13,700	221,000
Multitrade	Virginia	79.5	133,000	19	14,000	219,000
Tracy	California	18.5	130,000	80	14,000	214,000
Tacoma	Washington	40	94,000	27	20,000	221,000

*Calculated tons/year of wood waste, assuming 4250 Btu/lb at 50% moisture.

Information from work in progress on lessons learned from existing biomass power plants is presented below.

Williams Lake Generating Station, British Columbia, Canada

The Williams Lake Generating Station in British Columbia is located about 225 miles north / northeast of Vancouver and is the largest single unit biomass-fired power plant in North America. The project owner, NW Energy (Williams Lake) Limited Partnership, is two-thirds owned by Inland Pacific Energy Corp. and one-third owned by Tondu Energy Systems, Inc. The plant's rated capacity is 60 MW_e net, of which 55 MW is purchased by B.C. Hydro under contract. The plant is capable of producing 67-

69 MW, and frequently operates at that production level when the plant is able to sell its excess energy through Powerex, a marketing affiliate of B.C. Hydro. Because of this, the plant's annual capacity factor has actually exceeded 100% in several years: 104.6% in 1994, 106.1% in 1995, 99.6% in 1996.

The Williams Lake region was often beset with layers of smoke and a generous sprinkling of ash particles from wood waste burners at the five local sawmills. Beginning around 1988, concerted action by the provincial government, the local utility, the sawmill owners, and the general public resulted in construction of Williams Lake station. The plant solved a major environmental problem facing the sawmills, thereby improving their competitiveness and stability.

The boiler capacity is 561,750 lb/hr of 1575 psig, 950_F steam. The fuel is about 600,000 green tons/year of wood waste from sawmills in the Cariboo region. The plant started up in April 1993. Combustion takes place on and over three vibrating water-cooled grates inclined about 6% from horizontal. Small particles entering the furnace burn in suspension, while larger pieces burn on the grate. About 75-80% of the fuel particles are smaller than 1/4 inch (0.64 cm). Flue gas passes to the stack through a mechanical dust collector, the ID fan, and an electrostatic precipitator (ESP). Online stack gas analyzers continuously record NO_x, CO, O_2, and opacity.

Five sawmills that are located within three miles of the power plant supply the fuel at no cost. Since the mills are so close to the plant, conveyor belts were considered, but short haul trucking is the mode of transport used for the fuel. The power plant pays for the transportation, and paid approximately $2 million to install fuel preparation equipment at each sawmill. The sawmills pay the operating expenses for the fuel preparation equipment.

The fuel mix is approximately 40-50% bark, and the rest is an assortment of sawdust, chips, and slabs. Fuel specifications include moisture content between 35 and 55%. Typical fuel moisture content in the summer is 37-38%; in the winter, 50%. By hogging and blending at the mills, the power plant has been able to maintain consistent fuel quality. The plant is also able to use pulp quality chips because there are no paper mills in the vicinity.

Minor modifications were made to the plant after startup to improve performance, such as:

- Adding the ability to reverse the drag chains on the dumper hoppers, to make it easier to unplug fuel jams;

- Adding three more rolls to each disk screen (12 rolls were provided originally), to reduce the carryover of fine particles that tended to plug up the hog; and

- Retubing the air heater because corrosion had been noted in the cold end.

Efficiency (heat rate) is not a high priority because the fuel is almost free. However, the relatively high steam temperature and large unit size give the Williams Lake Generating Station a low heat rate (high conversion efficiency) compared to other biomass power plants. The unit consumes approximately 46 dry tons/hour of fuel while producing a net output of 67 MW. Assuming a higher heating value of 8500 Btu/lb for wood on a dry basis, the net plant heat rate is 11,700 Btu/kWh (29.2% conversion efficiency, HHV basis).

Wheelabrator Shasta Energy Company, Anderson, California (Shasta)

Wheelabrator Shasta Energy Company, an affiliate of Wheelabrator Environmental Systems Inc., manages a 49.9 MW (net) wood-fired power plant in Anderson, California (about 140 miles north of Sacramento, just south of Redding). The plant processes about 750,000 tons/year of mill wastes, forest residues, agricultural residues, and urban wood wastes from Shasta County and surrounding areas. The plant, which has three Zurn traveling grate boilers, became operational in December 1987. In 1996 the plant produced 418 million kilowatt-hours of electricity for sale to Pacific Gas and Electric Company under a Standard Offer #4 contract. The 10-year fixed price portion of the contract expired on April 30, 1998.

The Shasta plant has shown excellent performance. On-peak availability has been 100% since January 1, 1989, and overall availability exceeded 99% in both 1995 and 1996. The annual capacity factor in 1996 was 95%. The net plant heat rate, however, is about 17,200 Btu/kWh (about 19.9% thermal efficiency based on HHV). The furnaces are specially shaped and have staged overfire air to reduce NO_x emissions. Particulate emissions are controlled by high-efficiency electrostatic precipitators.

The plant has three Zurn traveling grate, staged combustion furnaces that consume a total of about 100 tons/hour of mill waste and forest residues at 50% moisture. The membrane waterwall boilers each produce about 170,000 pounds/hour of steam at 900 psig and 905_F. The plant has three Elliott condensing turbine generators. Heat is rejected through three surface condensers with two multicell evaporative cooling towers. (The fact that the Shasta plant really consists of three 16.6 MW plants with relatively low steam temperature and pressure is primarily responsible for a facility this large having such a high heat rate.)

Maintaining adequate fuel supply in the midst of a declining regional timber industry has been, and will continue to be, the single biggest challenge for Shasta. By 1991, competition for available fuel had become intense, with over 400 MW of wood-fired capacity in the region chasing perhaps 200 MW worth of mill waste. The remainder had to flow directly from the woods and farms, bypassing the milling operation, or appear as plant output curtailments, which became typical for many plants during off-peak periods. Battles between the logging industry and environmentalists over the spotted owl and other issues caused the wood fuel availability situation in the region to continue to deteriorate.

Almost from startup, Shasta has been attempting to diversify its fuel sources and reduce its demand for wood fuel. From an initial list of permitted fuels that included only mill waste, logging / thinning residue and cull logs, Shasta had added the following to its permitted fuel list by January 1992: agricultural residues such as almond, walnut and pistachio shells; orchard prunings and removals; hog fuel from eucalyptus and poplar plantations; hog fuel from clearing of PG&E and public road rights-of-way; hog fuel from permitted land development projects (roads, subdivisions); fuel from commercial tree trimming companies; fuel from yard waste processing operations; and fuel from city, county or state tree trimming activities. The last five items all fall under the general term “urban wood waste,” and the Shasta plant could hardly be in a more rural setting.

In order to reduce wood fuel usage, Shasta:

- Purchased off-peak auxiliary power from PG&E, rather than produce it themselves, breaking even on cost and eliminating 7% of their fuel demand.

- Purchased natural gas under long-term contract, supplemented by spot purchases, that displaced 12-20% of their wood fuel demand.

- Tested and implemented a fly ash reinjection system on all three boilers, lowering fuel demand by 3-4%.

All of these coping strategies employed by the Shasta plant represent important “lessons learned” by many other biomass plants as well. Expanding the list of fuels places a decided burden on a plant’s fuel quality program. The fuel mix that evolves, compared to the design fuel mix, often has a much greater variation in density, size, and moisture content. In addition, the fuels are often much dirtier and the plant is taking more risks with respect to ash properties. Operators learn to blend all of the fuels into a homogeneous mixture that allows the boilers to fire at a consistent rate and maintain maximum load under all conditions, without violating tight environmental standards, excessively corroding heat transfer surfaces, or slagging beyond the point where the boilers required cleaning more than twice per year. Plants accomplish this via fuel contracting and monitoring practices, operating practices, and equipment selection.

Colmac Energy, Mecca, California

Colmac Energy operates a 49 MW wood-fired power plant in Mecca, California (southeast of Palm Springs in Riverside County). The plant has two circulating fluidized-bed combustion (CFBC) boilers. The permit conditions, established and monitored by the South Coast Air Quality Management Board, are among the most stringent of any biomass power plant in the United States. The plant runs very well and has operated at a net plant heat rate as low as 12,200 Btu / kWh (thermal efficiency of 28.0%, HHV basis). The annual capacity factor during 1995-1998 ranged from 85% to 92%.

The Colmac plant is one of only three biomass plants in Southern California drawing fuel from the greater Los Angeles basin area. (One of these plants is currently shut down.) The Colmac plant is, by far, the largest combustor of urban wood wastes in the state, using 1000 to 1200 tons / day (including moisture content) of fuel, of which 80-90% would otherwise be deposited in landfills. The remainder of the plant fuel consists of agricultural residues, primarily from citrus and date orchard prunings and removals.

By virtue of its urban fuel consumption, the Colmac plant is a major factor in the ability of Riverside County to comply with California's mandatory landfill diversion and waste reduction requirements. Collection of orchard residues for use as fuel by the plant has almost completely eliminated open field burning in the Coachella Valley (the location of Palm Springs and other desert resort cities that depend on clear desert air for tourist attraction). The plant has made some good progress in obtaining lower fuel prices as the supply infrastructure has matured and wood waste processors have started to charge tipping fees. The plant's air quality permit was modified to allow the combustion of petroleum coke, which can be a very inexpensive fuel at times.

The plant has two circulating fluidized bed combustion (CFBC) boilers that were provided by ABB. The boilers have a combined output of 464,000 pounds / hour of superheated steam at 1255 psig and 925_F. Fines that exit the boilers are separated at the 10-15 micron level from the gas stream by cyclones and reinjected into the bed. The boilers are designed for limestone and ammonia injection to control SO_2 and NO_x emissions. Particulate emissions are removed in multiclones followed by pulse-jet fabric filter baghouses. Colmac Energy has made numerous improvements -- to the vortex tubes, cyclone separators, grid nozzles, high efficiency air preheaters, and furnace refractory. Natural gas input, which was required initially for flame stabilization, has been reduced to nearly zero.

Overall, the plant operation has been highly successful, with high annual capacity factors and a low heat rate for a biomass plant. During startup, a number of equipment malfunctions, wiring discrepancies, and control philosophy changes were experienced -- none major. The rotary fuel feed valves were increased in size to accommodate the varying density of the fuel. The valve motor operators were increased in horsepower and provided with reversing capability so any jams could easily be cleared. A modification was made to the boilers' wood storage day bin. To prevent potential motor overloads on the feed screws, the back portion of the bins was modified to stop biomass material from entering the last few feet of the screws. Changeout of control valve trim was required on three valves -- the condensate minimum flow control valve, the desuperheater valve, and the auxiliary steam control valve. The actual flows and pressures varied from design by an amount sufficient to warrant trim changes but not valve body changes.

Lessons that can be inferred from experience at the Colmac Energy project include the following:

- Urban wood waste can be a comparatively expensive fuel (~$1.50 / MBtu) if the plant is located far outside the urban area. The transportation cost is significant, but more importantly, a distant plant probably has no alternative other than to contract for fuel with wood processing companies that are located in the urban area. Processors add at least $1 / MBtu to the fuel cost.

- Non-woody agricultural residues such as straw were originally one of the plant's primary design fuels. Despite extensive fuel handling and preparation facilities that were provided for straw, the plant does not burn any significant quantities of this type of fuel.

- As at Tacoma (see below), Colmac Energy has found it worthwhile to modify its permit to allow the use of petroleum-based waste fuels such as petroleum coke. At times, waste fossil fuels can be more economical than biomass. It is wise to allow for such fuel flexibility during project development, design, and permitting phases.

Kettle Falls Station, Kettle Falls, Washington

The Washington Water Power Company (WWP) has operated a 46 MW wood-fired steam turbine power plant at Kettle Falls, Washington since 1983. WWP is an investor-owned utility company located in Spokane, Washington. The plant site is located 86 miles north of Spokane next to the Columbia River. Fuel for the Kettle Falls plant consists primarily of lumber mill wastes from mills in northeastern Washington.

Using wood waste as a renewable resource for power generation has proven to be a successful operation for WWP and a sound environmental solution for the wood products industry. Long-term residents in the Kettle Falls area reported major reductions in haze after the plant went into operation. The plant improved air quality by eliminating numerous wigwam burners in Stevens County.

The plant has consistently run very well throughout its history, with no major problems after the initial operating year. From the start of commercial operation in 1983 through the early 1990s, the station's capacity factor averaged 88.9%, which includes six months the plant was off-line for precipitator replacement shortly after opening. The capacity factor has been lower in recent years, not because of problems at the plant, but because of the very low market prices for hydroelectric energy in the Pacific Northwest:

Table 5-2
Capacity Factor at Kettle Falls Station

Year	MWh/year	Capacity factor, %
1992	291,600	72.4
1993	308,000	76.4
1994	329,800	81.9
1995	200,200	49.7
1996	284,200	70.5

The traveling grate spreader stoker boiler was furnished by Combustion Engineering (now ABB). The steam generator is a balanced draft unit with forced draft and induced draft fans. Design steam capacity is 415,000 lb/hr at 1500 psig and 950_F. Natural gas is the backup fuel and is used for ignition and for flame stability at loads below about 70% of maximum. An electrostatic precipitator removes particulate emissions.

The Kettle Falls plant is designed to burn approximately 500,000 tons per year of 50% moisture wood waste. Fuel consists of bark, sawdust, shavings, and slabs -- milling byproducts from about 15 log processing plants located in northeast Washington, southeast British Columbia, and northern Idaho -- approximately a 100-mile radius. The average fuel higher heating value (HHV) is about 4,700 Btu/lb as received.

All fuel is received by truck. The average one-way haul from suppliers under contract is about 46 miles. Average transportation costs were estimated in 1983 at 10.8 ¢/ton-mile. Using the GDP deflator to adjust from 1983 to 1997 dollars, this would be 16.3¢/ton-mile. Average delivered fuel costs were estimated in 1983 to be about $12.00 per green ton (approximately $1.40/MBtu).

Originally rated at 42.5 MW (net), the Kettle Falls plant is capable of operating continuously at 46 MW (net). On average, the plant generates 1000 kWh of electricity for every 1.5 tons of sawmill waste burned. This is equivalent to a net plant heat rate of about 14,100 Btu/kWh (24.2% thermal efficiency, HHV basis).

Stratton Energy, Stratton, Maine

The 40 MW Stratton Energy plant is the largest of the biomass-fired independent power projects that were developed in Maine in response to PURPA regulations enacted by the state Public Utilities Commission. Central Maine Power (CMP) issued a series of requests for project proposals during the 1980s. The plant owner is Stratton Energy Associates, a partnership of the ARS Stratton Group and CMS Generation Company. The in-service date was November 1989, and the first “power year” (11/1/89 - 10/30/90) was the only year so far in which the plant did not deliver its full contracted amount of electricity to CMP.

The original contract with CMP called for delivery of 295 million kWh/year. In 1994 the amount was increased to 305 million kWh/year. The contract is complicated, calling for some zero dispatch and 19.8 MW output periods on weekends. The annual capacity factor in the 1996 power year was 87%, based on slightly over 305 million kWh delivered, and 39.8 MW net committed capacity contracted to CMP. Plant availability has been consistently in the 97-98% range.

The actual rated net capacity of the power plant is considerably higher than 39.8 MW. Twice each year the New England Power Pool (NEPOOL) runs a capability audit. Based on these audits, the Stratton Energy plant is capable of delivering up to 47.68 MW of electricity to the grid.

The plant has one traveling grate stoker boiler, provided by ABB-CE, that can produce 400,000 lb/hr of 1,485 psig, 955_F steam. Mitsubishi provided the steam turbine and Brush provided the generator. Mechanical dust collectors and an electrostatic precipitator remove the particulate matter from the stack gas. Staged combustion air is used to reduce NO_x emissions to the 0.18-0.20 lb/MBtu range.

The only area of the plant that required significant modifications after startup was the fuel yard. The owners spent about $1.8 million in the first year of operation to improve the operation of the fuel yard. Since that time the plant has operated reliably.

The biomass fuel for the plant consists of about 65-70% sawmill residue (sawdust and bark), and about 30-35% whole tree chips (which are mostly chips produced from unmarketable tops and limbs). A variety of fuel purchasing arrangements are used: five-year, three-year, and one-year contracts, plus some spot market purchases. The annual biomass usage is about 464,000 tons (as-received basis at nominally 50% moisture). The average net plant heat rate is about 13,500 Btu/kWh (25.3% thermal efficiency, HHV basis).

Ridge Generating Station, Auburndale, Florida

The Ridge Generating Station Limited Partnership owns an independent power producing unit between Auburndale and Lakeland, Florida that burns waste wood, waste tires, and landfill gas. The unit has a gross capacity of 45 MW and nets about 40 MW in sales to Florida Power Corporation. Generally, the plant operates at full capacity from 11:00 am to 10:00 pm, and reduces load at night. Wheelabrator Ridge Energy, Inc., a division of Wheelabrator Environmental Systems, Inc., operates the plant under contract to the owner. One of the Polk County landfills is adjacent to the plant site. The project developers signed a Power Sales Agreement with Florida Power Corporation in March 1991; construction began in late 1992, and the plant came online in August 1994.

The plant processes about 250,000 tons/year of wood wastes and 35,000 tons/year of scrap tires. The plant includes a Zurn traveling grate boiler, a turbine generator, and a lime slurry spray dryer/baghouse system plus a non-catalytic NO_x reduction system to control air pollutants from the combustion process. The boiler generates about 345,000 pounds/hour of steam at about 1500 psig and 980_F. Wood typically provides about two-thirds of the total heat input; tire-derived fuel (TDF) provides about 30%; and landfill gas provides about 3-5%. Wood is injected to the boiler about two feet above the grate; TDF about two feet above the wood; and landfill gas enters about halfway up the furnace. The plant has operated well, although it has experienced some of the typical problems with boiler tube fouling, etc., caused by the use of waste fuels containing alkali, chlorine, sulfur, and other contaminants.

The facility receives waste wood and tires from local haulers and communities within about a 50-mile radius. (Tampa is within this radius, as are parts of Orlando.) About 20% of the wood wastes and all of the tires come in with tipping fees. The rest of the wood wastes are obtained at very low cost. The waste wood includes a great deal of vegetative waste, which has a high moisture content. Varying moisture content is one of the major control problems the plant experiences, but the use of the tires and the landfill gas assists in controlling the combustion process. The generating station paid for the landfill gas wells, gathering system, and pipeline from the landfill to the plant, but does not pay a fee for the gas. The station does pay to place ash from the combustion process back in the landfill.

The total annual wood consumption at the plant is about 250,000 tons/year, of which an estimated 1/3, or about 80,000 tons/year, come from the Lakeland-Winter Haven metropolitan area (population ~410,000). Lakeland is about midway between the much larger metropolitan areas of Tampa and Orlando, which sprawl from about 40 miles to about 70 miles from the plant. The vast majority of the urban wood waste fuel is tree wastes, brought to the plant by tree service companies and land clearing companies. About 10-15% of the total wood waste is C/D wood debris; industrial wood wastes such as pallets and scraps account for a smaller percentage.

The power sales agreement with the utility is an arms-length transaction for peaking power. In order to generate a profit on the plant's operation, Wheelabrator Ridge Energy must obtain net revenues from the tipping fees it charges for wood wastes and scrap tires, and must hold its O&M costs to an absolute minimum.

Tipping fees charged by the plant for wood wastes are quite low -- $5/ton for wastes that require a minimum of processing and $12.50/ton for more difficult-to-process wood wastes. For comparison, Polk County owns and operates two class 1 landfills and one C/D landfill (which send about 41,000 tons/year of brush to the Ridge Generating plant). The Polk County landfills charge tipping fees of $44/ton for household garbage and $25/ton for yard waste or C/D debris. The BFI Cedar Trails Landfill in Polk County receives mostly C/D debris (and sends about 10,000 tons/year of clean wood waste to the Ridge Generating plant). The BFI landfill tipping fees are $15/ton for C/D debris and $18/ton for yard waste. These data indicate that the Ridge Energy plant sets its tipping fees significantly lower than the landfill tipping fees in the area in order to attract wood wastes. The tipping fees of $5/ton and $12.50/ton are probably very close to the actual cost of grinding, screening, and blending the wood wastes in Ridge Energy's fuel yard. The plant does not "purchase" any wood fuel, although it does pay the transport cost for some wood waste suppliers within a 50-mile radius.

The tipping fee charged for scrap tires, $60/ton, probably provides the plant a significant net revenue stream. The tire shredding system at the plant is a fairly simply one, producing approximately 3-inch pieces, with no wire removal. Overall, the net fuel cost must be very close to $0/MBtu as the three fuels enter the boiler.

The contractual and business arrangements used by the Ridge Generating Station provide a good example of a key future niche for biomass power: an urban wood waste recycling operation. The primary product is electric energy, marketed to the utility (or in the future, to the power exchange) mostly during peak hours. Urban wood wastes are the primary fuel, but not necessarily the only fuel. Other opportunity fuels (tires and landfill gas at Ridge; petroleum coke, waste oil, and asphalt shingles at other plants) can provide higher tipping fees and also higher heating values. Depending on regulatory definitions and market prices, the fuel mix might be controlled so that the electricity will qualify as "green power" and command a premium price.

The important concept illustrated by Ridge Generating Station is that of a waste recycling facility, versus the concept of a power plant buying biomass fuel. The fuel manager does not buy "bone dry tons" of fuel under long-term contracts and does not force suppliers to meet strict fuel quality specifications. He works within the local and regional waste management infrastructure to provide a low-cost recycling service to waste generators, and to provide a free or negative-cost fuel mix to the plant for energy production. A wood processing contractor (the largest in Florida with grinding operations at many sites) provides and operates the tub grinder in the Ridge fuel yard.

In order to operate in this way, a plant must be designed for maximum fuel flexibility. This includes the plant's fuel processing and feeding systems, combustion system, air quality permit, and emissions control systems. The Ridge fuel yard can handle essentially any type or size of wood waste and places no restrictions on what it will accept, except for palm trees. The simple and reliable traveling grate stoker boiler can burn these mixed wood wastes, including yard wastes, and can also burn crude TDF and landfill gas. This combustion system, unlike other good candidates such as fluidized beds, does not require more expensive processing to remove wire from tire-derived fuel. The emission control system with ammonia injection for NO_x control and a lime spray dryer and baghouse can remove almost any significant pollutant encountered in these wastes. At some point in the future it may become standard to include a selective catalytic reduction unit for really low NO_x emissions, especially in large urban areas where these types of biomass plants will be most useful and economic.

Another key to success for an urban wood waste power plant is location. Ridge has some pluses and minuses in this regard. Two negatives are the 40-70 mile distance from really large metropolitan areas, and the lack of direct freeway access to the plant site. The location next to a landfill is a positive for several reasons: the landfill gas, the relatively easy permitting, and the fact that waste hauling trucks were already commonplace on the local roads. Finding suitable sites and obtaining permits for similar plants in the immediate Tampa or Orlando areas might be significantly more difficult. If it could be done, however, the net revenue opportunities from waste fuels would be improved.

Grayling Generating Station, Grayling, Michigan

The 36 MW Grayling generating station in north-central Michigan near Grayling provides electricity to a remote region, using waste material from local industries as fuel. The town's treated municipal wastewater is used as raw cooling water in the plant, and fly ash from woodwaste combustion is applied as a soil conditioner on local farms. The plant is owned by the Grayling Generating Station Limited Partnership. Members include Decker Energy International Inc., Winter Park, FL; CMS Generation Co., a subsidiary of CMS Energy, the non-utility subsidiary of Consumers Energy Company; and Primary Power, Bay City, MI.

The ability to use woodwaste with a high fines content is a unique feature of Grayling. Forty to fifty percent of the fuel particles are under 1/4 inch. The plant is designed to handle fuel with a higher heating value of 4500 Btu/lb and a moisture content of 48%.

Plant startup was very smooth and performance has been excellent. Commercial operation began 90 days ahead of schedule, with the owners taking possession August 1, 1992. Through March 1993, availability averaged over 95%, including five days of scheduled outages. On February 20, 1997 the plant was on its 235th consecutive day with 100% availability. The plant is dispatched into the Consumers Energy Company system, with output fluctuating typically between 15 and 36 MW. Annual capacity factors for 1995 and 1996 were as follows:

Table 5-3
Capacity Factor at Grayling Station

Annual capacity factor, %	1995	1996
On-peak	68.14	72.17
Off-peak	49.40	48.51
Total	57.58	58.85

An average of 40 trucks/day deliver sawmill and forestry wastes. Typically, the fuel mix consists of about 15-20% sawdust and planer shavings from an adjacent sawmill, 15-20% small woodchips from area mills, and about 40% hogged material from a nearby paper mill. The balance is forest chips left over from forest management practices mandated by the Michigan Department of Natural Resources.

Up to seven weeks pass between the time fuel enters the yard and when it is sent to the furnace. This yard storage is necessary to provide adequate drying time. Fuel mix to the furnace averages 40-45% moisture but may reach 50% after a heavy rain. High moisture levels adversely impact plant operation -- conveyors plug up, fuel does not blow into the furnace efficiently, and CO emissions increase.

The plant uses a single Zurn Energy traveling grate spreader stoker boiler. Although stoker-fired, the furnace resembles a pulverized-fuel design because of the ability to efficiently burn fines. Approximately 60% of the total combustion air is overfire and 40% undergrate air -- the reverse of most woodwaste-fired boiler designs. Most of the fuel burns in suspension. The fuel/ash bed on the grate is relatively shallow. The boiler produces 330,000 lb/hr of steam at 1280 psig and 950_F. The plant's net heat rate, as tested, is 13,600 Btu/kWh (25.1% thermal efficiency, HHV basis). Char collected in downstream cyclones and separated from non-combustibles is reinjected into the boiler.

Magnesium oxide is used to control boiler slagging. MgO is added at the wood bins feeding the boiler reinjection lines twice a day. The compound conditions the material so that the slag is loose, not glasslike, which makes it easier to remove from boiler tube surfaces with sootblowers.

Urea is injected into the upper sections of the furnace to reduce NO_x emissions by 50%. Because the plant is on full dispatch by the utility, it operates at low loads, around 15

MW, during off-peak hours. During this time, urea injection is minimal. During peak periods, the plant is dispatched at 36.17 MW and the urea injection system is needed.

Fly ash is collected in a three-field electrostatic precipitator (ESP) downstream of the cyclones. The plant has been permitted to land-spread fly ash in lieu of lime on farmland for adjusting pH upwards. The pH of the ash generally runs around 12-13.

Since startup, the hopper under the air heater has been modified to avoid the recirculation and subsequent slagging of heavy sand. The plant has also installed plates to divert flow from the air heater to the ESP hopper and a sand classifier which keeps sand out of the fly ash transport system. Original level detectors in the live-bottom fuel feed bunkers did not provide sufficient sensitivity and were replaced with ultrasonic level detectors. Screw feeders were modified to prevent bridging that occurred during startup caused by high levels of bark in the fuel. In 1997, the ID fan wheel will be replaced; ash buildup on the fan has caused vibration, and stress cracks have developed in the wheel.

McNeil Generating Station, Burlington, Vermont

The Joseph C. McNeil Generating Station of the Burlington Electric Department, located in Burlington, Vermont, has a nominal capacity of 50 MW_e and has operated since 1984. This plant is the largest U.S. utility-owned plant burning wood. When it was built, it was the largest dedicated wood-fired electric generating station in the world.

The plant cost approximately $67 million to build, or $1340/kW (1984 dollars) Adjusted using the GDP deflator, this is about $1940/kW in December 1997 dollars. The plant was built by a consortium that included Burlington Electric Department, Central Vermont Public Service Authority, the Vermont Public Power Supply Authority, and Green Mountain Power Corporation.

Plant operation has been successful. However, New England Power Pool (NEPOOL) economic dispatch procedures have limited the amount of operation. The plant was retrofit in 1989 to burn natural gas, either alone or in combination with wood. The plant has cycled and switched fuels frequently, as demanded by fuel prices, fuel availability, and NEPOOL's requirements. It has had to start up as often as 210 times annually. Between 1990 and 1994, about 2/3 of the fuel requirements were supplied by wood and 1/3 by gas. In 1995, about 7% of the energy input was from natural gas, and in 1996 natural gas prices rose to over $3.00/MBtu in Vermont, so that virtually all of the fuel burned by the McNeil plant was wood. The average wood fuel cost at McNeil is consistently about $18.90/wet ton (about $2.22/MBtu at 50% moisture).

Production increased in 1996, and was expected to be relatively high in 1997, because of several nuclear plants being out of service in New England. Production statistics for the McNeil Station for 1995 and 1996 were as follows:

Table 5-4
Capacity Factor at McNeil Station

	1995	1996
Net generation, MWh/year	136,000	137,000
Annual capacity factor, %	31.0	31.1

The plant net heat rate when burning wood was 13,714 Btu / kWh (24.9% thermal efficiency, HHV basis) in the early years of operation, but is now reported as 14,125 Btu / kWh or higher (24.2% thermal efficiency or lower, HHV basis). The suspected causes are higher fuel moisture content, test inaccuracies, and some loss of performance in the boiler. Plant management is working on improving the boiler performance.

The plant uses a spreader-stoker boiler that was furnished and erected by Zurn Industries. The boiler has two traveling grates and is rated at 480,000 lb / hr at 1300 psig and 950_F when burning 100% wood at 55% moisture content. Whole tree chips, at a nominal moisture content of 50%, originally made up about 75% of the wood fuel; the remainder consisted of sawmill residues and clean urban wood waste. The plant is burning more sawdust and mill residue than previously; more of these materials are available with the demise of Vermont farms that used sawdust as bedding material. Flue gas is cleaned via a bank of cyclones and an electrostatic precipitator. The ash is mixed with agricultural grade limestone and used as a soil conditioner for farmlands.

The McNeil Station is hosting the DOE-cost-shared demonstration of the Battelle wood gasification technology (see Section 6). The gasifier is initially configured to provide product gas to one of the McNeil gas burners. Once operation in this mode is demonstrated, the owners will study whether to install a gas turbine.

Multitrade Project, Hurt, Virginia

The world’s largest stand-alone wood-fired power plant came online in June 1994 in Hurt, Virginia. The 85.1 MW (79.5 MW net) independent power plant was built under contract to Virginia Power as the result of an open solicitation for additional power. The plant provides peaking power upon demand from the utility and has operated at annual capacity factors between 10 and 20%. The capacity payment that Virginia Power pays under the 25-year contract is sufficient to keep the plant in operation at these low capacity factors.

Table 5-5
Capacity Factor for Mullitrade Project

	1995	1996	1997
Net generation, MWh/year	133,000	85,500	100,000
Annual capacity factor, %	19.1	12.3	14.4

Multitrade Group of Ridgeway, Virginia received the original contract from Virginia Power and built the plant at a total cost of $114 million. The general partner in the limited partnership that now owns the plant is ESI Energy, a wholly owned subsidiary of FPL Group. Hurt is located in south central Virginia about 20 miles south of Lynchburg and 100 miles north of Greensboro, North Carolina. Construction on the project started in November 1992 after over four years of battles and $4 million in expenses to obtain 28 permits to construct and operate the plant. Plant startup began in December 1993, and commercial operation began in June 1994.

Originally, investors would not participate in the project without assurance of long-term fuel supplies. Fuel suppliers either would not sign such contracts or it was deemed impossible to enforce such contracts. Adequate fuel supplies have been developed in the area, and continue to be developed to provide investor confidence.

The Multitrade plant's role is to provide 79.5 MW of capacity on Virginia Power's system. It is a peaking plant that burns 100% wood, none of which can originate from potentially contaminated sources such as pallets or construction / demolition debris. Virginia Power normally provides 12 hours notice to Multitrade, at 6:00 pm, that the plant needs to be generating at 6:00 am. In some seasons of the year, weeks can go by without being dispatched.

Three fixed-grate, Riley Stoker boilers generate steam at 1500 psig and 950_F from the wood waste fuel. The design steam rate for each boiler is 242,000 pounds / hour, and the boilers are rated at 250,000 pounds / hour each. The design plant output of 79.5 MW (net) can be achieved with the boilers each generating about 239,000 pounds / hour of steam. Steam blowers are used to clean the fixed grates when the boilers are operating at low load. Two ABB steam turbine / generators generate electricity. Urea is injected into the flue gas from each boiler for NO_x control. Each boiler has a cyclone collector and an electrostatic precipitator to remove fly ash. The flue gas from the three electrostatic precipitators is combined and exhausted through a single stack.

Fuel is purchased entirely on the spot market and averages around $12 per green ton. Chips from sawmills and whole tree chippers account for about 78% of the total fuel and average about $14 / ton; sawdust accounts for about 17% of the total fuel and averages about $9 / ton; shavings, bark, and tub grindings account for about 5% of the total fuel and average about $11 / ton. The fixed grate boilers operate very well with fine fuel sizes. The plant has used up to 45% sawdust in the fuel blend. The maximum particle size specification is 4 inches, although less than 2.5 inches is preferred. The moisture content averages about 40-45% for both chips and sawdust.

The fuel yard is kept at least 1/2 full at all times to be ready for full-capacity operation. The plant buys from a total of about 225 fuel vendors, throughout southwest Virginia, plus 16 or 18 counties in North Carolina, and one county in Maryland. The effective fuel supply radius is about 200 miles. Within a 30-mile radius or so, there are three large paper mills and three strand board plants, which are all in the market for large quantities of biomass fuel as well. Multitrade has established cooperative relationships with several of these plants. The primary benefit of cooperating is to keep fuel suppliers in business, by coordinating with each other during periods of fluctuating wood procurement rates.

The plant has been successful, both technically and financially. All major milestones were met on schedule, and the plant has consistently supplied power to the grid, and profits to its owners, on schedule. “Readiness” is the primary priority for a peaking plant. The guaranteed heat rate was 14,447 Btu/kWh and startup tests verified this heat rate. During commercial operation the net plant heat rate has ranged from 14,200 to 13,600 Btu/kWh (24.0-25.1% thermal efficiency, HHV basis).

The plant owner receives a capacity payment from Virginia Power that keeps the plant ready to run. During operation, additional payments for fuel and O&M are received. These are currently on the order of 2.0¢/kWh for fuel and 0.5¢/kWh for O&M. (At a heat rate of about 14,000 Btu/kWh, 2.0¢/kWh is equivalent to $1.43/MBtu. Assuming a wood heating value of 8,500 Btu/lb on a dry basis, this is equivalent to about $24/dry ton of wood. Assuming an average wood moisture content of 50%, this is equivalent to about $12/ton of wood.)

Tracy Biomass Plant, Tracy, California

The Tracy Biomass plant is an 18.5 MW (net) wood-fired plant that burns a little over 50% orchard wood waste (“ag fuel”) and a little under 50% urban wood waste. The ag fuel is required by the permit, which provides an offset from open burning emissions. The plant has a heat rate in the 13,500-14,000 Btu/kWh range. Plant availability has been high, and the annual capacity factor (about 80%) is more a function of contractual requirements than availability.

The plant is in a good location, near the intersection of major freeways I-580 and I-5 about 35 miles east of Oakland. Highway 99, which runs through the heart of California’s agricultural San Joaquin Valley, is about 15 miles east of Tracy. One million acres of orchard land are both north and south of the plant, and the major landfills for the San Francisco Bay Area are in the vicinity (as is the Stanislaus County

Waste-to-Energy plant). Thus the plant is well situated to receive both agricultural and urban wood wastes.

The plant came online in 1990, and will receive "year 1-10" Interim Standard Offer #4 (ISO4) payments for its electricity through 2000. Under a negotiated change in the contract, PG&E has the right to curtail the plant's operation by up to 1,000 hours/year, and does so. Tracy Biomass will pay off its construction loan by 2000, and the challenge will be to operate "lean and mean" enough to stay in business after the California Energy Commission transition payments and the ISO4 year 1-10 payments expire.

The boiler is a Detroit Hydrograte (water cooled vibrating grate) stoker. The plant has an ESP for particulate control. Ammonia is injected for NO_x control, and ammonia slippage causes a slightly visible plume. Fly ash is spread on farm fields and on cattle pens for pH adjustment. Bottom ash is stored at the plant and is occasionally used as aggregate material in road building and similar applications.

Operation has been mostly trouble-free. There is enough chlorine in the fuel to have caused serious stress corrosion cracking of superheater tubes, which were replaced with stainless steel.

During the early years of operation, Tracy Biomass built up an orchard wood waste service operation, including two large chippers, a fleet of trucks, and drivers. They were able to pull whole trees out of the ground and feed them through a $400,000 chipper, removing five to ten acres of orchard trees per day. They provided excellent service to orchard owners, assisting in removal of the wood waste from both tree removals and prunings. This was during the high biomass fuel price era of 1990-1993.

When the ISO4 contract buyouts began in 1994-1995 and biomass fuel prices dropped, Tracy Biomass sold the orchard wood waste service. The prunings are much more expensive to collect than the whole trees harvested during orchard removals, because the yield is about 1 ton/acre for prunings versus 20-30 tons/acre for removals. Tracy Biomass no longer uses prunings, and the orchard owners have gone back to burning them. Tracy Biomass mostly takes orchard removals as its ag fuel now. The cost of this fuel delivered to the plant is probably about $15-20/dry ton.

All fuel is processed offsite by independent wood processing companies and delivered in clean form. The chips (ag fuel) flow easily through the plant feed equipment. The shredded or tub-ground fuel particles (the urban wood waste) cause more difficulties, sometimes hanging up and making birds' nests.

One of Tracy Biomass' main fuel suppliers is a fuel processing company in Livermore, which charges tipping fees for wood wastes. The wood wastes probably come from all over the East Bay Area. The distance from the processor to the Tracy Biomass plant is about 15 miles over the Altamont Pass. The plant pays about $5/ton for the urban wood waste from the processor. The average moisture content is in the low 20% range.

The total fuel consumption by the Tracy Biomass plant is approximately 100,000-120,000 dry tons/year of waste wood (assuming 18.5 MW net output, a heat rate of 13,500-14,000 Btu/kWh, 17 MBtu/dry ton of wood, and 7,000-8,000 hours of operation per year). Slightly over half of the fuel is ag fuel, and the remainder is urban wood waste.

Tracy Biomass shows that urban wood waste can be a comparatively inexpensive fuel (~$0.35/MBtu) if the plant is located close to the urban area. Tracy Biomass also shows that compared to urban wood waste, orchard wood is a relatively expensive fuel because growers are used to simply pushing and burning it, and are generally not willing to pay a fee to have the wood removed for use as fuel. Tracy Biomass spends approximately $1/MBtu for fuel from orchard removals, and has stopped taking fuel from orchard prunings because it is significantly more expensive.

Tacoma Steam Plant No. 2, Tacoma, Washington

Tacoma Steam Plant No. 2 is a multi-fueled generating facility located on an urban site in the tideflats industrial area of Tacoma, Washington. The plant was originally built in 1931 and was repowered in the late 1980s with fluidized bed combustors to cofire wood, refuse-derived fuel (RDF), and coal. The repowered plant started commercial operation in August 1991. The plant is owned and operated by Tacoma Public Utilities, a municipal utility that provides water, electric, and rail service. On April 22, 1998 the Steam Plant was placed into reserve shutdown, and on June 15, 1988 the utility issued a Request for Qualifications for organizations to submit ideas and concepts about the possible acquisition or lease of Steam Plant No. 2 facilities and some adjacent properties.

The Steam Plant's two turbine generators have a total rated capacity of 50 MW_e (gross). However, the capabilities of the combustion and ash removal systems constrain the plant's maximum output to the range of 30-40 MW, depending on the fuel blend. In brief tests, the plant has operated at levels up to 42 MW. During normal operations, the highest net output from the plant has been about 18.5 MW, running one combustor and one turbine/generator. The supply of RDF, the demand for power, and prices available in the secondary energy market have determined operating levels at the plant. In 1997 and 1998, the price of electric energy in the Tacoma market was generally less than 1¢/kWh. A biomass/waste-fueled plant cannot produce power at these low prices unless the fuels command substantial tipping fees. Steam Plant No. 2 operated only as much as necessary to burn the RDF it received -- resulting in net generation rates of about 11-13 MW over the period 1994-1997. The plant has burned, on average, about 60% wood, 20% RDF, and 20% coal.

The plant began startup testing in December 1989 and was running on all three fuels by April 1990. Acceptance testing was performed starting in May 1990. Commercial operation began August 1, 1991. Power Magazine (April 1991), in awarding Steam Plant No. 2 its 1991 Powerplant Award, stated that "the major goal of the repowering project is to generate as much power as possible -- or as dictated by electric demands -- at the lowest cost, while combusting all of the city's 300 tons/day of refuse-derived fuel (RDF)." As it turned out, the amount of RDF delivered by the city's Refuse Utility and burned by Steam Plant No. 2 during the years 1993 through 1997 ranged from 28,539 to 48,412 tons/year, or about 78 to 133 tons/day.

Several design and mechanical problems were solved between 1991 and 1994, and a reliable mode of operation was established, which involved running one combustor at a time while the other was maintained on standby. From 1994 through 1997, net plant output was equivalent to about 11 to 13 MW, with an onstream factor of about 86-87%. Plant availability (to operate one combustor at a time and consume RDF) was maintained in the 90-96% range. Initially, the cost of power from the plant was competitive within the utility's system, but dramatic drops in market prices for electricity made the plant uneconomic. Significant reductions in fuel cost were achieved in 1997, and a plan was developed to convert the plant to a tipping fee facility that would generate net revenues from most or all of its fuels. Implementation of this plan required modifications to the plant's air quality permit, which were underway when Tacoma Public Utilities put the plant on reserve shutdown in 1998. The future of the plant depends on the outcome of negotiations with the successful bidder, on the operating and business strategy pursued by the new owner, on alternative disposal options for MSW, and on developments in electricity and fuel markets.

The repowering project consisted of the installation of two bubbling atmospheric fluidized-bed combustors, four refractory-lined cyclones that allow ash and unspent limestone to be reinjected into the combustors, and ductwork that connects the combustors to the existing boilers, which were converted to heat recovery steam generators (HRSGs). In addition, the project included the installation of a mechanical draft cooling tower to replace the use of salt water from the Hylebos waterway for steam condensing, the installation of fuel handling, pollution control and ash handling equipment, and the installation of a continuous emissions monitoring and computerized distributed control system.

The bubbling fluidized bed combustors provided by EPI were designed to cofire a combination of wood waste, coal, and RDF. The design values were 15% RDF, 35% wood, and 50% coal. The combustors are capable of firing 0-100% wood, 0-50% coal, and 0-50% RDF (permit limitation). The fuel mix is fed to the FBCs overbed, while limestone is added directly to the beds for SO_2 absorption. Bed temperatures are maintained at approximately 1550_F to minimize ash agglomeration and maximize sulfur capture.

Granular limestone is injected into the fluidized bed combustors to control SO_2 emissions. Two fabric filters, one for each flue gas exhaust train, control particulate emissions. The filters are designed to remove 99.8% of the particulate matter from the flue gas. Two induced draft fans direct the two flue gas streams to a common 213-foot tall stack. In 1997, an alkali sorbent injection system was installed upstream of the baghouses to remove trace amounts of HCl from the flue gas. The scrubber uses trona (sodium sesquicarbonate) to react with the chlorine to form sodium chloride, which is removed along with the fly ash in the fabric filters. The chlorine originates primarily from plastics and other chlorine-containing materials in the RDF. Uncontrolled HCl emissions were typically about 260 parts per million in the flue gas; with lime and trona injection, HCl emissions drop to about 19 ppm. Overall HCl removal efficiency averages about 93%.

During 1993-1996, all of the waste wood for the plant was purchased on the spot market from about 100 authorized suppliers. About 64% of the wood fuel was from mill and logging sources, 23% from land clearing, and the remaining 13% from urban and industrial waste. Moisture content ranged from 22% to 55%. The annual average price paid by the plant for wood waste ranged from \$0.72/MBtu to \$0.88/MBtu during 1993-1996. Wood waste prices tend to increase significantly during the winter months.

Beginning in 1997 a concerted effort was made to obtain lower-cost wood fuel, resulting in an annual average price of \$0.28/MBtu. In 1997, approximately 65 active vendors supplied waste wood to the plant on a spot market or tipping fee basis. Storm debris in February and land clearing wood in May through October were obtained at zero or nearly zero cost. The reduction in the cost of wood, plus the reduction in the amount of coal burned (which cost over \$1.70/MBtu), reduced the plant's fuel bill by over \$600,000 from 1996 to 1997.

Finding more "opportunity fuels" that command a tipping fee or can be obtained free became a high priority in 1997. Analysis showed that by setting up a wood processing yard onsite instead of buying prepared wood fuel from wood processors, the plant would be able to charge fees of about \$15-25/ton for stumps, tree wastes, and other wood wastes. The cost of grinding these materials onsite would be about \$5-15/ton. Wood processing yards in the area charge tipping fees for these types of wood wastes ranging from \$31 to \$46 per ton.

In addition, the utility investigated the possible use of a variety of industrial wastes, such as asphalt roofing shingles (tear-offs), wood laminates, on/off-specification oil, oil sludges, oil-contaminated sorbents and rags, textile and plastic waste, green petroleum coke, non-recyclable paper waste, and pulp mill clarifier solids, that could generate revenues if they were acceptable fuels. Tipping fees for some of these items are in the \$80-100/ton range, and transport distances to facilities that accept them are over 100 miles. Burning some of these petroleum-based waste fuels might allow the plant to operate with no coal in its fuel mix. Technically, it is believed the bubbling fluidized bed combustors and environmental control systems at the plant could handle any of these fuels.

During 1997-1998, Tacoma Public Utilities acquired permits and developed a test burn plan for many of these fuels. The permits allow a 180-day period to burn the various fuels and conduct all necessary testing and monitoring to determine operational constraints required to assure compliance with current regulations. By eliminating coal and replacing most or all of the purchased wood with tipping fee wood wastes, the plant's annual fuel cost, which in 1997 was still almost $870,000 / year or 1.0¢ / kWh, could be converted to a net revenue stream of at least that amount, and possibly more. The key factors that give the Tacoma plant the capability to exploit opportunity fuels of these types are its location in an urban industrial area, its bubbling fluidized bed combustors, and its emission control systems that were designed to handle RDF.

Future Evolution in Biomass Combustion Technology

The stoker and fluidized bed technologies described above will continue to evolve along the same paths as in the last several decades: larger unit sizes, higher steam temperature and pressure, more sophisticated steam turbine and reheat systems that formerly were only available in large (>200 MW) plant sizes, and, possibly, the integration of fuel drying into the system. The primary net result of all these incremental changes will be increased efficiency, most likely to the range of 10,000-11,000 Btu / kWh. Modest decreases in capital costs may also be seen.

As future plants are designed to take advantage of urban wood wastes and other tipping fee fuels such as those discussed above, fuel flexibility will be a high priority. Permits and air pollution control systems for the plants will also need to encompass a wide range of possible fuels.

Design of fuel yards and fuel feeding systems for plants burning urban wood wastes and other tipping fee fuels will need to incorporate feedback from successfully operating facilities such as Ridge and Tacoma. This kind of feedback has been conspicuously lacking in most of the projects described above. Nearly all of those plants had to replace or modify fuel processing and feeding equipment and procedures during the first year or two of operation.

Whole Tree Energy™

Whole Tree Energy™ is an advanced wood combustion technology that is specifically designed to use short rotation woody crops in a very efficient fashion. The technology is designed to use the whole tree in an intact form; otherwise the stationary deep bed drying technology and the deep bed gasification / combustion technology will not work properly. (Packed beds of small tree pieces and wood particles will not allow adequate air or gas flow.) Thus, Whole Tree Energy™ is not compatible with the biomass waste resources presently being utilized, including the bark, tops, and limbs from fiber farms harvested by pulp and paper companies. The commercial use of Whole Tree Energy™ technology must await the day when short rotation woody crops grown exclusively for energy can compete with other crops that could be grown on the same land.

Whole Tree Energy™ (WTE™) is a patented technology for dedicated wood firing in new or converted boilers. Several EPRI reports have presented details on the technology and on EPRI-sponsored tests that proved its technical soundness. EPRI evaluations indicate that WTE™ could produce electricity at a significantly lower cost than other biomass technologies. Energy Performance Systems, Inc. (EPS) in Minneapolis is working to commercialize the technology through license agreements with utilities and independent power producers.

Briefly, the cost and efficiency advantages of WTE™ are derived from the following features of the technology:

- Low-cost harvesting and no processing of fuel
- Handling and stacking wood in its natural form for drying, using low-temperature waste heat from the power plant
- Improved boiler efficiency, combustion rate, and combustion completeness due to use of dried wood
- Combustion similar to a gas-fired boiler, above a deep bed of whole trees that produce the fuel gas as they are heated and volatilized
- An efficient steam cycle using high pressure, high temperature superheated and reheated steam
- Stack gas cleaned and cooled by a condensing heat exchanger that transfers heat to the air used to dry the trees and also scrubs particulates from the flue gas
- Elimination of many items that add to the cost of coal-fired plants, such as the SO_2 scrubber, coal bunkers, coal pulverizers and related starters, controls and electrical wiring, structural steel and foundations

Several aspects of WTE™ technology are unique, but the most important from a project development standpoint is that the technology is designed to use whole trees that are grown on energy farms or harvested selectively for commercial forest improvement. An integral part of developing a Whole Tree Energy™ project is contracting with farm land owners to grow and harvest short rotation woody crops, and / or with commercial forest land owners to harvest trees. This attribute of the technology provides the advantages of a dedicated fuel supply and the benefits of rural economic development. However, the need to develop an economic fuel supply by contracting with hundreds of landowners and assisting them with land preparation, planting, cultivation, and harvesting of fast-growing hybrid trees presents some unfamiliar problems to power plant developers and financiers.

A potential barrier to development of dedicated fuel supplies for WTE™ plants is competition for the wood from the pulp and paper industry. Pulp chips have considerably higher commercial value than fuel wood, which must be delivered to a power plant for less than $1.50 / MBtu (about $25 / dry ton) if the electricity is to be competitively priced. Probably the best way to avoid competition with pulp and paper companies for the wood is to make the trees unattractive for pulping by planting 2000 trees or more per acre, and harvesting the trees when they are only 3-5 years old. Pulp and paper companies' fiber farms have about 600 trees per acre and are harvested after 6-10 years, when diameters at breast height are well over 1 foot.

EPS received a contract award from the U.S. Department of Energy under the "Biomass Power for Rural Development" program, similar to the awards made to the Minnesota Valley Alfalfa Producers project and the New York Salix Consortium. During the first phase of the contract in 1997-99, EPS will demonstrate an agricultural-style whole tree harvesting system that is designed to reduce the cost of harvesting hybrid poplar and eucalyptus trees by a large amount compared to conventional harvesting methods.

6

GASIFICATION

Biomass gasification / combined cycle technology has been described and evaluated in previous EPRI reports, and in a number of publications and papers by the U.S. Department of Energy and commercial vendors. The promise of the technology is its potential ability to convert biomass to electricity more efficiently than combustion technologies that use the steam cycle. Questions remain, however, about the cost-effectiveness of the technology and about the ability to operate commercial-scale systems reliably for long periods. It will be several more years, at least, before enough experience is gained with commercial prototypes of biomass gasification / combined cycle systems to determine whether the technology can compete economically with the simpler combustion / steam cycle technologies. The current status of the existing commercial prototypes is summarized briefly below.

Varnamo Project

Sydkraft (the largest privately-owned utility in Sweden) built the world's first integrated wood gasification / combined cycle cogeneration power plant in Varnamo, Sweden in 1991-1993. An Ahlstrom (now Foster Wheeler) pressurized fluidized-bed gasifier converts dried and crushed wood (forestry wastes) to low heating value gas. The gas is cooled, cleaned in ceramic filter candles, and burned in a gas turbine. Hot exhaust gas from the gas turbine supplies heat to a heat recovery steam generator. This steam, together with steam generated in the gas cooler, drives a steam turbine. The steam condenses in a district heating condenser, or optionally in air coolers.

The design electrical output of the demonstration power plant is about 6 MW_e. In addition, about 9 MW_{th} is extracted from the steam turbine and supplied to a district heating system. The heating value of the wood fuel input at design conditions is about 18 MW_{th}. When the gasifier is out of operation, the combined cycle can be run on light fuel oil. In this case the power output is lowered, as no steam is generated in the gas cooler.

Construction started in September 1991; startup began in March 1993. In 1992, Sydkraft estimated the investment in the power plant would be about $50 million, and planned to spend about $10 million / year for a 3-5 year R&D program at the facility. The main purpose of the Varnamo facility is to determine the costs of operating and maintaining commercial-scale plants, as well as to provide a basis for evaluating the likely capital cost of future plants. As a result the plant is intentionally not fully optimized. Technical development and the extent to which different types of fuel can be used in such plants have played a key role in this project.

As of mid-1994, the gasifier was operating continuously on wood feedstock, and testing of the candle filters was underway at low temperature. The power island was producing power and district heat, using natural gas and diesel fuel. In the fall of 1995, the plant was fully integrated and the gas turbine was successfully operated on gas produced in the gasifier. The first test runs were very short; operation on 100% product gas showed no adverse effect on either combustion performance or turbine behavior. However, leakage of liquid fuel caused a fire inside the gas turbine enclosure in October 1995, and the plant had to be shut down for several months while the turbine was repaired in the U.K. The plant was restarted in the spring of 1996, to begin an extensive two-year demonstration and development program.

Some members of the Gasification Users Association visited the plant in May 1996, at which time there had been about 3000 hours of operation on the gasifier. However, problems with the EGT Typhoon gas turbine had restricted its operation on syngas to only about 24 hours. Subsequent modifications to the gas turbine have been more successful, and as of October 1997 the plant had experienced over 4000 hours of gasifier operation and over 1000 hours of gas turbine operation on biogas, with individual runs over 250 hours. The funding for the present demonstration program is provided mainly by EdF, Sydkraft, and the Swedish National Board for Industrial and Technical Development.

Vermont Project

In August 1994 the U.S. Department of Energy (DOE) announced that it was entering into a cooperative agreement with Future Energy Resources Corp. (FERCO) to form and lead an industrial and utility consortium to design, construct, and validate large-scale integrated gasifier and gas turbine combined cycle (IGCC) technology at the McNeil Generating Station in Burlington, Vermont. The “Vermont Gasifier Project” will develop and operate a multi-fuel, indirect biomass gasifier developed by Battelle Columbus Laboratories, and commercialized by FERCO. In application, this project will supplement the electrical output of the Burlington Electric Department’s McNeil Station. Upon successful demonstration of the gasifier, a commercial-scale (15-20 MW_e) gas turbine will be incorporated into the system.

The three-phase effort was expected to cost a total of $29.1 million, of which DOE will provide $12.3 million (about 38%). Phase I, which has been completed, consisted of detailed scale-up design and permitting. Phase II, which began in June 1995 and was in progress in October 1998, includes the construction and testing of a facility to gasify about 200 tons/day of wood chips and generate hot product gas for combustion in the existing McNeil wood/natural gas-fired boiler. During the third phase, 6 months long, a slip stream and hot gas cleanup module and an advanced gas turbine will be installed, tested, and operated.

The Battelle gasification process is an indirectly-heated, circulating fluidized-bed system that has over 20,000 successful hours of operation at Battelle Columbus at the 10 t/d pilot plant scale. Wood or other biomass is gasified with a mixture of steam and hot sand. Hot medium-Btu gas leaves the gasifier with the sand and a small amount of charred wood. The sand is captured and recycled, while the charred wood is combusted in a fluidized-bed combustor that provides heat to reheat the sand, generate steam, and dry wet wood. Heat transfer for the gasification reactions is accomplished by circulating sand between the gasifier and the combustor. The process takes advantage of the high reactivity of biomass, and throughputs in excess of 3000 lb/hr-ft^2 can be achieved. The process operates at low pressure and produces a medium-Btu (nitrogen-free) gas without the requirement of an oxygen plant. The medium-Btu gas (400-500 Btu/scf) can be burned in gas turbines designed for natural gas; it will also make an excellent fuel for a direct carbonate fuel cell.

Construction was completed in August 1997 and initial shakedown began in October. Hot solids were circulated in the reactors in November 1997, and the first wood was introduced to the unit in combustion mode in December. The period from February through July 1998 was spent shaking down equipment and solving a variety of operational issues and challenges. These included leakage through the high temperature refractory causing high temperatures on the gasifier shell. Problems with the fuel feeding system were encountered and fixed. No drier was provided onsite, so dried wood is being procured from a facility in Massachusetts. Some of the sensors and controls in the distributed control system malfunctioned and had to be repaired or replaced. The solids circulation system is different from the one at Battelle, and must be kept running continuously. The scrubber proved difficult to operate, in terms of water level control, solids management, and organics accumulation.

The first steam gasification was accomplished on May 30, 1998. Runs were short and intermittent, mainly due to wood supply interruptions. Temperatures were low, and gasifier operation was far from its design point. The heating value of the gas was about 180 Btu/scf, much lower than the design value.

As of mid-July 1998, the plan called for a parametric testing program to be conducted from mid-August to the end of October to prove out the design, explore the throughput limits, optimize O&M costs (fuel moisture tolerance, MgO rates, sand makeup rates, etc.), measure cold gas conversion efficiency and product gas composition, and evaluate tar production and scrubber performance. After the parametric testing program, the plant will be shut down and inspected for two weeks, concluding Phase II.

Maui Project

The National Renewable Energy Laboratory (NREL) funded the construction and testing of a bagasse-fueled pressurized fluidized-bed gasifier at a sugar mill owned by Hawaiian Commercial and Sugar Company (HC&S) on the island of Maui, Hawaii. The Hawaii Biomass Gasifier Facility began as a joint venture with the Pacific International Center for High Technology Research (PICHTR), in conjunction with the Hawaii Natural Energy Institute, the Institute of Gas Technology (IGT), the Ralph M. Parsons Company, and HC&S. In 1996 Westinghouse Electric Company took over project management responsibility.

The fluidized bed gasifier based on the IGT RENUGAS™ technology is designed to gasify 100 dry tons / day of bagasse at pressures up to 300 psig and temperatures to 1800_F. The bed is operated under controlled pressure, temperature, fluidized bed height, and superficial gas velocity. The gasifier utilizes substoichiometric air to partially combust the bagasse to provide heat for the endothermic gasification reactions. Steam is also fed to the gasifier to increase fluidization and serve as a reactant for the devolatilized bagasse char. The gasifier is designed to entrain all of the ash overhead with the product gas. Carbon conversions on the order of 98%+ are obtained at optimal gasifier operating conditions.

Construction of the plant was completed in December 1995. Test Run #1 did not achieve steady gasification conditions due to significant problems with the feed system. Test Runs #2 and #3 were called “successful” in that no major problems with the gasifier were encountered; minor problems included cracking of refractory and clogging of air spargers and control valve ports. The flare and ash handling systems operated well. Total operating time was 107 hours, during which 169 wet tons of bagasse were gasified. The targeted feed rate and gas composition were achieved. Bagasse feed rate ranged from 20 to 33 wet tons / day during 48 operating hours in October 1995. Bagasse feed rate ranged from 33 to 48 wet tons / day during 58 operating hours in December 1995. However, problems with the bagasse feed system were severe, and included the following:

- The rotary drum dryer operated at less than design capacity due to choking of the bagasse flow at the airlock at high feed rates, difficulty in maintaining moisture control, and collection of rocks and debris in the dryer and feed piping.

- Blow-over of small stones and irrigation drip tubing caused excessive wear to the downstream feed system and plugged screens to the blowers handling the recycled air.

- The variable speed Detroit Slat Feeder plugged, produced poor feed uniformity, and operated at below design capacity.

- A tapered chute in the feed system plugged frequently until its interior was smoothed and coated, and a vibrator was added at the narrowest point.

- The plug screw feeder was difficult to operate, but met its design specifications; issues to be resolved include excessive wear and a tendency to plug when bagasse moisture drops below 15%.

Westinghouse Electric Company took over management of the project and by 1997 had completed the design and construction of four new systems: (1) a lock hopper feed system to replace the plug screw feeder; (2) an additional bagasse cutting machine for the feed preparation system, to ensure that all of the feed particles are sized at 0.5 to 0.75 inches in length; (3) a hot gas filter system capable of handling a 10% slipstream of product gas; and (4) an inert gas generator to reduce costs of the inert gas needed for operation. Westinghouse then managed the project's Technology Verification Phase, which was planned to move the project from the earlier Proof of Principles stage that verified the 10:1 scaleup of the RENUGAS™ process, to verification of the necessary feed systems and hot gas cleanup system necessary for commercial applications.

Following installation of the hot gas cleanup (HGCU) system, about 90% of the gas flow went to the hot gas cyclone and 10% to the newly-installed HGCU system. The temperature to the HGCU filter vessel, which uses ceramic candle filters for removal of entrained ash, was controlled by a water spray quench so as not to exceed 1300_F. Both product gas streams went to the flare.

The improvements and additions to the feed system proved to be difficult to operate with bagasse and took much longer to shake down than anticipated. Operational testing with the gasifier and HGCU system took place in October and November 1997. (November 15 was the deadline for completion of operations imposed by the sugar mill.) Although only obtaining 170 hours of gasification (50 with charcoal and 120 with bagasse), the feeding system delivered bagasse at low pressures and low feed rates for sufficient time to confirm the operability of the integrated gasifier and HGCU systems. The facility was then inspected, cleaned, and closed. Overall, the results of this project were not encouraging for biomass gasification / combined cycle power plants using pressurized gasifiers.

Minnesota Valley Alfalfa Producers Project

The Minnesota Valley Alfalfa Producers (MNVAP) is a farmer-owned cooperative with headquarters in Granite Falls, MN. Granite Falls is in southwestern Minnesota, an agricultural region where corn, soybeans, and sugar beets are the primary crops. MNVAP is leading a public / private effort that includes United Power Association and Enron to develop a $200 million alfalfa processing and biomass energy system that is scheduled to be fully operational in 2001. MNVAP will produce and process approximately 700,000 tons of alfalfa per year. Various high-value products will be produced with the alfalfa leaf material, and 75 MW of electricity will be generated in a gasification / combined cycle plant that will use alfalfa stems as the primary feedstock.

The power plant, known as Minnesota Agri-Power (MAP), will sell electricity to Northern States Power Company, which is under a state mandate to obtain 125 MW_e of biomass power by the year 2002. The gasification process is based on the Institute of Gas Technology's RENUGAS™ and U-GAS™ pressurized fluidized-bed gasification processes, which are licensed to Carbona Corporation. The plant design will be similar to those at Varnamo and Maui, but the scale will be substantially larger. Westinghouse will supply the hot gas filters and combustion turbine, which will use Westinghouse's multi-annular swirl burner to combust the low-Btu gas. Kvaerner is designing the gasifier and fuel handling systems, and Stone & Webster Engineering Corporation is developing the preliminary plant design and layout. In May 1997 gasification tests on alfalfa stalks were conducted at the Carbona pilot plant gasifier in Tampere, Finland.

Brazil Project

In 1984, Brazil began to evaluate use of biomass and gas turbines to generate electricity. Further research by Shell International, General Electric, and Princeton University concluded that the recently developed aeroderivative gas turbine technology, coupled with biomass gasification, could produce electricity at a competitive cost and with minimal environmental impact. This work led to the development of a biomass gasification combined cycle demonstration project in Brazil, with funding from the Global Environment Facility of the World Bank. Phase I, the preliminary investigation to scope out the project, was funded by the Rockefeller Foundation, Winrock International, the U.S. Environmental Protection Agency, and the U.S. Agency for International Development. It was completed in March 1992 and achieved a number of objectives:

- A Memorandum of Understanding was agreed to as a basis for cooperation in Phase II.

- Biomass gasification / combined cycle technology options were explored and process developers and equipment manufacturers were identified and shortlisted.

- A work program was outlined for process and equipment development and budgetary requirements were assessed.

- The economic potential of biomass gasification / combined cycle power generation was estimated both for the prototype plant and for the "n^{th}" commercial plant.

On the basis of the intermediate and final reports submitted in Phase I, the Global Environment Facility confirmed the availability of grant funding in two installments:

- Phase II -- a two year process development / engineering grant -- U.S. $7.7 million
- Phase III -- implementation grant -- U.S. $23 million

Two competing teams of engineering and equipment vendors developed Phase II designs and cost estimates for two different biomass gasification technologies in combination with the General Electric LM-2500 aeroderivative gas turbine: (1) the near-atmospheric pressure fluidized bed gasification technology offered by TPS Termiska Processor AB, using cold quench wet scrubbing to clean the product gas; and (2) the high pressure fluidized bed gasification technology offered by Bioflow, a joint venture between A. Ahlstrom Corporation in Finland and Sydkraft AB of Sweden, using hot gas ceramic filters to clean the product gas. (The Bioflow technology is used in the Varnamo project. Ahlstrom Corporation was acquired by Foster Wheeler Corporation.) After detailed evaluation of the designs and cost estimates, the TPS Termiska low pressure fluidized bed gasification technology was selected for the project.

According to the TPS process flowsheet, the demonstration plant generates about 32 MW of electricity. The feedstock is furnished primarily from short rotation eucalyptus tree farms, and is chipped onsite and dried using waste heat from the flue gas exiting the plant. The dried wood chips are fed to the air-blown fluidized bed gasifier operating at about 1.8 bar (about 26.5 psig). The wood chips and residual char are suspended by the upward flowing air injected at the bottom of the gasifier vessel and by the product gases released by the gasification reactions. Solids that are entrained with the product gases leaving the vessel are separated and removed by a cyclone separator and reinjected into the gasifier. Some fine particulate matter still remains in the product gas after passing through the cyclone.

The gas product is a mixture of methane, hydrogen, carbon monoxide, carbon dioxide, nitrogen, water vapor, ammonia, tars, ash, and other mostly trace components. Before passing to the gas turbine, the product gas is subjected to a series of conditioning steps to remove tars, ammonia, and fine particles that could damage or adversely affect the gas turbine. The product gas is first passed through a proprietary TPS tar cracker vessel to convert the condensable tars to noncondensable gases. The gases are cooled, and moisture and other condensate are collected in a knockout pot. Then the product gas is cooled further, scrubbed in a wet quench scrubber using water to remove ammonia and residual solids, and compressed in a mechanical compressor to the inlet pressure required by the gas turbine.

The gas turbine generates about 26 MW. The hot gas turbine exhaust is cooled first by passing it through the heat recovery steam generator (HRSG) and then through the wood chip dryer. Steam from the HRSG drives the steam turbine generator and produces an additional 14 MW of electricity. The total gross generating capacity is 40.4 MW, and auxiliary power consumption is 8.1 MW, resulting in a net generation of 32.3

MW. The net plant heat rate is projected to be 8982 Btu / kWh (38.0% thermal efficiency, HHV basis). The estimated biomass fuel consumption is 127,000 tons / year at an 85% capacity factor. The estimated cost of the wood fuel delivered to the dryer is $2.07 / MBtu ($1.37 of which is the cost of the harvested wood in the field). The combined fuel and O&M costs for the plant are expected to be about 3.1¢ / kWh. A decision on construction is anticipated in 1998.

Relative to some of the biomass gasification projects underway elsewhere, the Brazil project uses less risky low pressure gasification and wet gas cleanup technology, low cost fuel processing, and waste heat to dry the fuel. The selection of the simpler and less risky low pressure gasification / wet quench process creates several advantages:

- Wet quench gas cleanup easily removes ammonia from the fuel gas, thereby avoiding the possibility of conversion of fuel nitrogen to high NOx emissions in the gas turbine combustor.

- It is likely that the low pressure process will operate at higher availability and capacity factor and exhibit lower maintenance costs than high pressure gasification processes with hot gas cleanup.

Other Biomass Gasification Experience

The Directorate General for Energy of the European Commission initiated a targeted activity on the gasification of biomass for the production of electricity and heat within the framework of the THERMIE program in 1992. Five proposals were submitted and three were approved for financial support: “Biocycle” in Denmark, “Energy Farm” in Italy, and “ARBRE” in England.

The Biocycle project planned for Denmark could not be realized and a new possible site in Kotka, Finland was investigated. A project based on feeding birch bark to a Carbona air blown fluid bed gasifier, gas cleaning, and an EGT Typhoon gas turbine was studied. However, with the high investment cost and the periodic unavailability of the feedstock the project has been judged not feasible.

The Energy Farm project near Pisa, Italy will feature an atmospheric air blown Lurgi circulating fluid bed gasifier rated at 41 MW_{th} coupled to a heavy duty 10.9 MW_e gas turbine and a HRSG to provide steam to a condensing steam turbine of 5 MW_e. The design fuel is a mixture of wood chips and agro-industrial residues. The project is now in detailed design and it is anticipated that the plant will be commissioned in late 2000.

The ARBRE project in the U.K. is a joint venture of Yorkshire Water and TPS Termiska Processor AB of Sweden. It will use the TPS low pressure circulating fluidized bed gasification technology selected for the Brazil project, including the proprietary second circulating fluidized bed for the catalytic cracking of tars in the raw gas. An 8 MW gasification / combined cycle plant will be located in Eggborough in North Yorkshire, using short rotation forestry feedstock. It is planned for commissioning in 1999-2000.

The Dutch government and the E.U. are also supporting studies for a 30 MW biomass gasification / combined cycle power plant in the province of North Holland. Two bids (from Lurgi / Stork and Royal Schelde (KSG) / TPS) for atmospheric CFB gasifiers are currently being evaluated.

There are also several biomass gasification projects planned or underway in Europe where the atmospheric fluid bed gasification product gas is cofired in existing boilers (an approach that is also being considered in some U.S. cofiring projects). A project with Lahden Lampovoima Oy has started up at a coal-fired CHP plant in Lahti, Finland. A 30 MW_{th} Foster Wheeler (Ahlstrom) CFB gasifier supplies gas to a new gas burner that replaces a coal burner. The fuel is a mixture of sawdust, bark, railroad ties, and shredded tires. Although wire from the tires has caused problems with birdnests in the bottom of the gasifier, availability has been good in the first six months and operation of the gasifier has been very stable. With about 15% of the heat input from biomass, a modest reduction in the boiler's NO_x emissions has been noted.

A similar project is planned by EPZ in the Netherlands in their coal fired cogeneration unit Amer 9, which has a net production of 600 MW_e and 350 Mw_{th}. A third project (BIOCOCOMB) is planned in Austria at Daurkraft's Zeltweg 137 MW power plant with a 10 MW_{th} CFB gasifier supplied by Austrian Energy.

Pulp and Paper Industry

One of the major potential markets for biomass gasification is with the pulp and paper (forest products) industries. The two major applications of biomass gasification would potentially replace (1) the direct burning of wood residues in inefficient hog fuel boilers, and (2) the direct combustion of black liquor in Tomlinson boilers (a troublesome and high maintenance operation).

The main gasification experience with black liquor has been obtained on the Kvaerner Chemrec™ gasifier. This is an air-blown, downflow, refractory lined, single injector, entrained flow reactor system. An atmospheric unit with a capacity of 83 tons of dry solids / day has been operated at the Frovifors kraft mill in Sweden since 1991. The results from this unit provided the basis for the scaleup to the 330 tons dry solids / day unit that Kvaerner supplied to Weyerhaeuser at their New Bern, North Carolina mill. This unit was commissioned in 1997 but reports on its operation have been very limited. Kvaerner is also working on the development of a pressurized version for gas turbine combined cycle application, and since 1994 has operated a 7 tons dry solids / day pressurized pilot plant at a mill in Sweden. Potentially the Texaco and Noell (GSP) gasifiers could also be used for black liquor gasification.

A major cost-shared technology demonstration initiative has been proposed by Champion International Corporation, Georgia-Pacific Corporation, and Weyerhaeuser Company to work together with the DOE, EPA, and the American Forest & Paper Association (AF&PA) to demonstrate three different biomass and black liquor gasification technologies in three paper mills:

- Champion's Courtland, Alabama mill to demonstrate a full-scale pressurized, oxygen-based Kvaerner Chemrec™ Kraft black liquor gasification system;

- Georgia-Pacific's Big Island, Virginia mill to demonstrate semi-chem caustic / carbonate liquor gasification using MTCI / StoneChem PulseEnhanced™ Steam Reforming technology; and

- Weyerhaeuser's New Bern, North Carolina mill to demonstrate gasification of wood residues in a Battelle / FERCO gasifier.

Since the early 1970s, the industry has been looking for safer, less expensive, and environmentally improved alternatives to pulping liquor processing and wood residual combustion. Three promising technologies have been developed, piloted, and are ready for large scale demonstration. This comes at a time when many of the industry's recovery and power boilers are due for major rebuild or replacement. In addition, changes that have been made to the industry's processes and equipment have shifted (and will continue to shift) its energy demands to much more electricity and less steam. Benefits anticipated from the integration of gasification technologies include higher thermal energy efficiency, higher reduction efficiency for kraft cooking chemicals, and higher electric power generation -- up to three or four times higher.

Full replacement of the combustion systems at U.S. pulp and paper mills with gasification systems could increase the nation's renewable biomass generating capacity by over 30 GW. For example, if one takes the black liquor and hog fuel generated in a 1500 ton / day integrated Kraft mill, it is possible to generate about 70 MW of power using the current technology of a Tomlinson recovery boiler, a combination boiler, and a steam turbine generator. Replacing the Tomlinson recovery boiler with an integrated gasification combined cycle (IGCC) black liquor system increases the potential power generation to nearly 200 MW. The same black liquor and hog fuel supplied to a combination of black liquor and biomass cogeneration in IGCC configuration can generate nearly 300 MW of power.

Weyerhaeuser has been actively following and encouraging the development of biomass gasification technology for many years. The Battelle technology has been of special interest because of its low pressure, high throughput, and especially its ability to generate medium-Btu gas that can substitute directly for fuel oil or natural gas in lime kilns and combustion turbines. Weyerhaeuser has been an active participant in the Vermont project, and currently has Bechtel doing preliminary engineering for the New Bern installation, using chemical industry (rather than power industry) design practices. The proposed New Bern gasifier will process about 700 dry tons / day of wood residues and pulp mill sludges, compared to about 200 dry tons / day of wood in the Vermont unit. The medium-Btu gas from the New Bern system will replace oil currently being burned in the mill's lime kiln and power boilers -- so it will not be a fully integrated combined cycle system as initially configured. The preliminary schedule (which assumes 50 / 50 DOE cost sharing is contractually obligated by January 2000) calls for completion of construction by November 2001 and completion of shakedown and testing by November 2002.

Biomass Gasification/Fuel Cell Systems

The preliminary design for the 32 MW gasification / combined cycle plant in Brazil shows a net plant heat rate of 8982 Btu / kWh (38.0% thermal efficiency, HHV basis). This is a 30% improvement over the efficiency of the most efficient direct combustion biomass plant, the 60 MW Williams Lake plant (11,700 Btu / kWh or 29.2%). The next step up to a new efficiency curve will occur by combining fuel cells with biomass gasifiers. A recent design study by Energy Research Corporation (ERC) and NREL examined several configurations for power plants using the Battelle gasification technology and the ERC direct carbonate fuel cell technology. A gasifier / fuel cell system with thermal integration between the fuel cell and gasifier system, sized at 22.5 MW, had a net plant heat rate of about 7840 Btu / kWh (43.5% thermal efficiency, HHV basis).

Of the various biomass gasification processes available today, the Battelle gasification system appears to offer the greatest synergy with the direct carbonate fuel cell because of its low pressure and its use of indirect gasification, producing a nitrogen-free, medium-Btu fuel gas. Fuel cells have very low tolerances to impurities in the fuel gas: 0.1 ppm for both H_2S and HCl. Evaluation of gas compositions from gasification of hybrid poplar, switchgrass, and a "Vermont mix" indicated that gas cleanup units for both sulfur and chlorides will be needed. [12]

ERC's Direct Fuel Cell design incorporates an internal reforming feature which allows utilization of a hydrocarbon fuel directly in the fuel cell without requiring any external reforming reactor and associated heat exchange equipment. This approach provides upgrading of waste heat to chemical energy; thereby, it contributes to higher overall efficiency for conversion of fuel energy to electricity with low levels of environmental emissions. ERC plans to offer standardized, packaged MW-scale direct fuel cell power plants operating on natural gas or other hydrocarbon-containing fuels for commercial sale by the end of the decade. These power plants, which can be shop-fabricated and sited near the user, are ideally suited for distributed generation, industrial cogeneration, and uninterrupted power for military bases. After gaining experience from the early MW-scale power plants, and with maturing of the technology, ERC expects to introduce larger power plants operating on natural gas or on syngas from coal or biomass.

ERC operated a 1.8 MW plant at a utility site in Santa Clara, California in 1996-97. This was the largest fuel cell power plant that has ever operated in North America. The plant demonstrated high efficiency, low emissions, reactive power, and unattended operation capabilities. Based on the experience of this full-size power plant field test, ERC launched a product design improvement program focused on technology and system optimization for cost reduction, commercial design development, and prototype system demonstration. On an equal output basis, the fuel cell stack enclosure footprint, weight, and cost were reduced by factors of nine, four, and four, respectively.

The final design, prepared in collaboration with Fluor-Daniel, Inc., is highly modularized, featuring high efficiency, quiet operation, negligible emissions, and a small footprint that allows it to be sited in virtually any location. The plant has a rectangular footprint with a plot area of less than 4500 square feet. The height of the plant will not exceed 25 feet. The plant is designed for natural gas fuel, but modifications will allow use of other fuels such as landfill gas, digester gas, syngas, and military logistic fuels. The plant will provide unattended operation with remote dispatching capability. The fuel cell stack modules and the balance-of-plant skids (complete with pre-installed piping, valves, insulation, instrumentation, and electrical wiring) will be truck-transportable. [13]

7

SMALL-SCALE SYSTEMS

The use of advanced technology for recovery of energy from landfill gas, anaerobic digester gas, and other small biomass sources is receiving increased attention in the United States and the other developed countries because of environmental and waste management concerns. Sophisticated methods are emerging for capturing biomass or biogas that would otherwise escape into the environment, and converting them to energy and other useful commodities. While each system may be small and appear to have only local impacts (e.g., odor reduction), in the aggregate these small-scale biomass systems will account for significant amounts of greenhouse gas reduction as well as other benefits, and thus have global importance.

Biogas, produced by bacterial decomposition of organic matter in landfills and in anaerobic digestion of wastewater sludges and animal wastes, is a medium-Btu methane and carbon dioxide mix. It can fuel engines, boilers, gas turbines, and fuel cells to produce electricity and/or provide process heat, or it can be upgraded to pipeline quality gas or compressed LNG. The greatest current U.S. biogas recovery and energy use is at landfills. The U.S. EPA estimates that about 150 landfill gas-to-energy projects are operating (out of an estimated 750 potential projects that could be developed). [14] A 1994 estimate said that about 300 MW were being generated from about 80 landfill sites. [15] Wastewater treatment plants and confined animal waste management systems support additional electric power production.

Generation of electricity from biogas can present difficulties due to the generally small scale of the generating facility, variable energy content of the gas, fluctuating availability, contaminant problems, and often-demanding control needs. However, these difficulties are being successfully addressed.

The electricity from landfill gas and digester projects is usually not as cheap as that generated by large fossil-fueled plants (e.g., landfill gas operators have stated that they must receive 4-6¢/kWh for project success). Until recently, biogas projects were supported by the 1.5¢/kWh Section 29 Federal tax credit, but Section 29 has now expired. Future projects will most likely be supported by environmental requirements, greenhouse gas reduction programs, and green power programs. Biogas from U.S. landfills alone could fuel about 1% of U.S. electrical generation while giving a climate change benefit equivalent to reducing CO_2 emissions in the electricity sector by more than 10%. The potential for biogas recovery and electricity production from sewage sludges, animal wastes, and other organic resources such as agricultural residues is uncertain but probably exceeds the estimate for landfills. [15]

Landfill Gas

The majority of landfill gas projects generate 5 MW of electricity or less. For example, of 30 active landfill gas projects in California in 1996, 21 projects had a net capacity of 5 MW or below; eight projects were between 5 and 12 MW; and one project had a net capacity of 47 MW. About three-quarters of the active installations in the United States employ internal combustion engines. Gas turbines, and occasionally boilers and steam turbines are used in larger projects.

Sulfur is present in landfill gas typically from 50 to 100 parts per million by volume (ppmv). The majority of the sulfur is in the form of hydrogen sulfide (H_2S). Construction/demolition waste in landfills can significantly increase the H_2S content in landfill gas. Wallboard is primarily gypsum or calcium sulfate, which decomposes under the reducing conditions in the landfill to form H_2S. Gas from C/D landfills can have sulfur contents of over 10,000 ppmv.

Chlorinated compounds are present in landfill gas, typically from 100 to 300 ppmv. The chlorinated compounds are primarily from solvents and cleaning compounds in the solid waste that volatilize over time. Chlorinated compounds convert to hydrochloric acid (HCl) in the combustion process.

Silicones, also known as siloxanes, are present in landfill gas from a wide variety of consumer products including antiperspirants, shampoos, and cosmetics. Siloxanes are converted to small (sub-micron) silica particles in the combustion process. These small silica particles abrade the exhaust valves of reciprocating engines and adhere to the high temperature surfaces in boilers or gas turbines. They can also coat or “blind” the surfaces of catalysts used for emissions reduction. [16]

These contaminants, and others, have largely been allowed to enter the combustion systems (usually reciprocating engines) used in landfill gas projects to date. This has resulted in very high maintenance requirements and in less-than-desirable environmental performance as well. Some experience has been gained recently with landfill gas cleanup systems, which are considered “advanced” or “enhanced” technology. For example, a project in Seneca Meadows, New York has installed a two-stage refrigerant and liquid desiccant process to clean up and dry out the landfill gas to a standard beyond that typically demanded by engine manufacturers. The 5.6 MW, seven-engine facility is one of the first in the nation to adopt this more exhaustive treatment process, and it has now operated successfully for two years. It has virtually eliminated cylinder deposits and reduced the wear rates on the engines. The project manager estimates the gas cleanup system has more than doubled the rated engine life.

Installation costs for this enhanced technology are about 20% more than for a traditional landfill gas treatment unit, but the cost savings from decreased engine maintenance resulted in a one-year payback. [14]

The Orange County Transportation Authority is building a project in Irvine, California that will process landfill gas into a substitute for liquefied natural gas (LNG) for its bus fleet. The processing includes: (1) water scrubbing to remove soluble particulate matter; (2) three stages of compression, cooling, and scrubbing to remove water; (3) H_2S removal, cooling and drying of the gas; (4) filtration to remove compressor oils and activated carbon treatment to remove organic chemical contaminants; (5) filtration to remove dust from the carbon bed; (6) alternating heating and compression steps; and (7) CO_2 removal in membrane and molecular sieve beds. This system recovers more than 99% of the methane in the landfill gas, and reduces the gas to a liquid LNG stream. The LNG buses are low emission vehicle (LEV) certified, and many are ultra LEV (ULEV) certified. [14]

Fuel cells require essentially complete removal of all contaminants in landfill gas or digester gas. Some initial demonstration projects have been conducted with phosphoric acid fuel cells at landfills; these projects have shown that gas cleaning can be accomplished successfully. Demonstration projects using direct carbonate fuel cells can be expected in the next several years. Because of their high efficiencies, fuel cells will generate at least 50% more electricity from a given landfill than reciprocating engine generator sets would generate.

One significant improvement now being tested is “controlled landfilling.” The result of conventional practice under present landfill regulations is that waste within landfills remains relatively dry, for many years after filling. Waste decomposition to landfill gas normally proceeds only slowly and inefficiently, over decades. This results in inefficient gas recovery and substantial fugitive emissions. As little as half of the total amount of gas generated by a landfill may be captured. Waste decomposition and methane generation can be promoted by a number of factors including moisture, temperature, pH, and nutrients. Of these, moisture is paramount. Combining surface membrane containment with management of landfill moisture and temperature can speed completion of methane generation. A large-scale demonstration of controlled landfilling at the Yolo County Central Landfill in California is currently generating the highest rate of methane per pound of waste per year ever measured. The gas rate exceeds “normal” expectations by a factor of about ten, and suggests that completion of landfill gas production from that cell should occur in fewer than five years. Use of controlled landfilling technology would clearly provide major benefits to landfill gas energy project economics. [17]

Anaerobic Digesters

Anaerobic digesters are most commonly used in municipal wastewater treatment plants, on farms that raise cattle, dairy, hogs, or poultry, and in certain industrial operations that have wastewater or sludge containing organic materials. Farmer motivation for building and operating anaerobic digesters has expanded from solely energy benefits to include manure treatment cost savings, nutrient conversion, odor and pathogen control, and byproduct recovery. The changing face of agriculture with larger animal production units and recognition of the pollution potential of these farms has resulted in greater regulation in the United States.

The AgSTAR Program is sponsored by the U.S. EPA, USDA, and DOE to encourage farm methane recovery from anaerobic digestion. AgSTAR has provided technical assistance to seven farms in development, installation, startup, and operation of anaerobic digestion projects. Three dairy plug flow digesters in New York, Connecticut, and Oregon; three covered pig manure lagoons in North Carolina, Virginia, and Iowa; and one heated pig manure digester in Illinois have been placed in operation with AgSTAR assistance. All of these projects have reduced odors substantially or completely, a major benefit. Some of the projects have installed used engine generator sets ranging in cost from $8000 to $90,000. Other projects use the gas in boilers; others flare the gas. The projects that generate electricity place a value of from $10,000/year to $35,000/year on it. The net generating capacity in each case is below 100 kW. [18]

A covered lagoon methane recovery system has been constructed at the California Polytechnic Institute (Cal Poly) Dairy in San Luis Obispo. The design was based on the present and anticipated herd size, from 300 to 600 cows, heifers and calves. The new lagoon is covered with a flexible membrane incorporating buoyant material so that the cover floats on the surface, and a gas collection system. The predicted output of the lagoon for the present population of approximately 350 cows, heifers and calves is estimated to average 370 cubic meters of biogas per day. The biogas will fuel a micro-turbine electric generator, and produce up to 25 kW in parallel with the utility system. Odor control is the most important non-economic benefit. The methane recovery system will produce about 170,000 kWh/year, as well as 77,000 KJ of hot water, together worth about $16,000/year. Assuming O&M costs of $0.015/kWh, the $150,000 capital cost has a simple payback of over 11 years. The micro-turbine is to be provided in early 1999 at no cost by Reflective Technologies, Inc. Purchase of a 25 kW engine generator set would have added over $30,000 to the capital cost and over two years to the payback period. [19]

An example of anaerobic digestion applied to an industrial wastewater stream is the feasibility study now underway at the High Plains York Ethanol Production Facility in York, Nebraska. The Western and Southeastern Regional Biomass Energy Programs are cosponsoring the study, with Bryan & Bryan, High Plains Corporation, and Energy

Research Corporation the primary participants. ICM / Phoenix Bio-Systems has installed the bio-methanator (anaerobic digestion unit) at the ethanol plant, and Nebraska Public Power District (the plant's power provider) is a key member of the project oversight group.

The primary objective of the bio-methanator is to solve a wastewater treatment problem. After ethanol is recovered by distillation from the fermentation broth, yeast and other solids are separated and sold as a high-protein animal feed concentrate. The thin liquid that remains cannot be directed to the municipal wastewater treatment system, because if contains dissolved solids, chiefly proteins. The liquid can be evaporated to a gummy syrup, which is incorporated into the animal feed. However, condensate from the evaporators still holds enough dissolved solids to require treatment. This process stream is directed to the bio-methanator, which produces a methane-rich gas from the anaerobic digestion of proteins, and discharges clean water. The bio-methanator is designed to produce gas to augment natural gas used in the distillers grain dryers. This is essentially a break-even operation economically.

Incorporation of a fuel cell offers an opportunity to positively influence ethanol plant economics. Bio-methanator gas has a high methane fraction, typically exceeding 90% with the new systems. The biogas, and low-grade waste heat from the ethanol production process, can be fed to an ERC direct fuel cell to produce electricity and high quality heat, with a very high efficiency. Electricity will be consumed by the ethanol plant and bio-methanator, with the excess sold to local users or the utility. The heat is used in the ethanol process or for drying distillers grain solids. Residue from the bio-methanator is used as crop fertilizer, and clean water produced by both the fuel cell and the bio-methanator is used for the ethanol production process. [20]

Small, Modular Biomass Power Systems

Bechtel Corporation, Imatran Voima Oy, and EPRI scanned the existing biomass-fueled technologies that might be commercialized at the 50 to 250 kW capacity level for use in either grid-connected, onsite, or stand-alone remote power applications. A few technologies turned out to exist only on paper; some were under construction; a couple had as many as a dozen units in operation. The technologies are grouped into five categories and summarized below. [21]

Table 7-1
Small Biomass Systems: Advantages and Disadvantages

Gasification with Diesel or Spark Ignition Engines

Pluses	Minuses
• Good efficiencies (17-25%)	• Problematic gas cleaning
• Reasonably simply; low cost	• Dual fuel requirement (5-10%)
• Small unit fabrication feasible	• Dry fuel requirement

Gasification or Combustion with Indirectly Fired Gas Turbine

Pluses	Minuses
• Good efficiencies (15-24%)	• Heat exchanger not commercial
• Tar cleaning not required	• Gas turbine is “high tech”
• Drying may not be required	• Cost expected to be >$1200/kW

Directly Fired Gas Turbine

Pluses	Minuses
• Good efficiencies	• Problematic gas cleaning
• Simple process	• Dry fuel requirement
• Relatively low cost	• Fuel feeding presents challenge

Pyrolysis with Diesel Engine

Pluses	Minuses
• System flexibility	• Storage of oil problematic
• Moderate efficiency (18-21%)	• High pH effluent
• Coproduct option (revenue)	• Coproduct needed (investment)

Combustion with Conventional Steam Cycle

Pluses	Minuses
• Commercial technology	• Low efficiencies (8-12%)
•	• Turbines only >250 kW
	• Water management needed

Of all the small, modular technologies under development, small gasification units probably have the greatest chance of success, as well as a range of power generation options for the syngas. Micro-turbines and fuel cells offer the greatest promise long-term.

Two major applications for skid-mounted biomass power plants in the United States would be forest management operations and storm damage cleanup operations. The technology would solve major fire problems in our forests and waste cleanup and disposal problems following hurricanes and tornadoes. It would take advantage of large amounts of “free” renewable fuel that is generated every year, but is only “free” if the energy conversion system can be brought onsite and hooked up to a power grid.

8

CONCLUSIONS

The material presented in the preceding sections indicates possible paths from today's commercial biomass energy systems, which generate about 1% of U.S. electricity, to the possible biomass energy systems of the future, which could displace major amounts of fossil fueled-generation. The information in the preceding sections also has implications for research, development and demonstration (RD&D) of biomass energy systems.

Possible Paths

Two paths can be visualized: (1) a "toughening" of the present role of biomass energy plants as key niche players in the waste management sector; and (2) the development of a major biomass energy industry using energy crops and large, efficient power plants. The first path is certain to happen; the second is highly uncertain, maybe improbable. The first path (rationalizing the cost structure of the existing biomass industry) is beginning to take shape, as a result of the energy policy developments of the last four years. The second path (energy crops and efficient conversion) has been a major research goal for about two decades, and has produced some excellent initial results from a technical point of view. The costs of the biomass crops, however, are so high that the commercial implementation of this path appears to be at least two decades away.

Rationalizing the cost structure of the existing biomass industry means siting plants strategically to take advantage of zero cost fuels. The biggest opportunity at the present time is in major metropolitan areas, as discussed in Section 3. Over the next two decades, biomass plants (including coal-fired plants cofiring biomass) will sell power at low prices into highly competitive power markets dominated by natural gas combined cycle plants. Many of the biomass plants will be peaking units, and will sell green power, thus obtaining premium prices. They will be "higher tech" than today's plants, with gasifiers, bioreactors, combined cycles, and fuel cells entering the industry. Some plants may be skid-mounted and opportunistic, helping with storm damage cleanup and forest thinning projects. Government regulations that could help the industry grow may include renewable portfolio standards, carbon taxes, landfill gas recovery requirements, feedlot manure digestion requirements, prohibition of open burning of agricultural residues, etc. Following this path to a more-or-less complete utilization of all biomass waste sources for electricity generation would lead to a contribution on the order of 5% of the U.S. electricity supply.

Implications for RD&D

Waste fuels

The discussion of biomass waste fuels in Section 3 does not identify significant needs for research, development and demonstration (RD&D) on how to gather, process, or feed urban wood wastes and other biomass waste materials to power plants; the technologies for doing those things are reasonably well known (although often not by the plant design engineers, it seems). Cities and states, municipal utilities, and investor owned utilities can provide very significant institutional leadership in establishing opportunities for energy projects using local waste materials as feedstocks. This kind of leadership is crucial in bringing all of the necessary stakeholders and project elements together. R&D organizations such as EPRI and DOE (especially DOE's regional biomass programs) can initiate and support the efforts of utilities and city and state agencies to stimulate innovative biomass project development.

Energy Crops

The research needs for energy crops are highly technical and are well known to the people in the field. From the top-down perspective of what will meet the needs of a major industry using biomass crops for energy 20 or 30 years from now, the focus of the research should be on discovering how (or whether) ultra-high yields (>20 dry tons/acre/year) can be obtained. Preferably, the crops should be of the type that can be dedicated exclusively to energy, or if there is a higher-value component, that component should use less than three-fourths of the total biomass. For example, trees such as poplars and eucalyptus will be used primarily for pulp, and rarely as energy crops. Trees such as willow may be dedicated to energy, but only if their yields are high enough to reduce the cost of the fuel well below $2.00/MBtu. If ultra-high yields of such crops cannot be obtained, the "second path" discussed above is unlikely to happen. In that case, the effort to conduct large trials and demonstrations, harvester development, combustion and gasification tests, etc., using the modest-yield crops (~5 dry tons/acre/year) developed so far will have missed its prime energy production target.

Advanced Combustion

Advanced combustion technology for biomass will continue to benefit from RD&D for a long time. Most of the advancements are incremental and occur as a natural part of the competitive process among combustion system vendors. One of the important developments recently (mostly in coal combustion systems) has been the gradual introduction of high steam temperatures and pressures (which means metallurgies and design features) to smaller boilers. These types of improvements are gradually making their way from small coal boilers (~200 MW) to large biomass boilers (~50 MW). Some companies are developing advanced biomass drying technologies, which are definitely needed for gasification processes, but may also be integrated into combustion systems to increase efficiency and improve process control. Research organizations such as EPRI and DOE can selectively help with such advancements.

As utilities, EPRI, and DOE continue to conduct cofiring demonstrations and initiate commercial projects, opportunities to use the "free fuel" strategy discussed in Section 3 could be pursued at plants in suitable urban locations. The cost of the biomass fuel is at least as important to the success of a cofiring project as are the technical details of grinding, feeding, and boiler impacts.

If the RD&D on woody energy crops, including the shrub willow, appears promising enough, it might be worthwhile to fund a full-scale demonstration of Whole Tree Energy™ technology. The power plant should be built at the smallest size that will answer all of the technical and operational questions about the technology. This would provide a solid benchmark for comparison of cost and performance parameters with biomass gasification and with other combustion technologies.

Gasification

Several biomass gasification demonstration projects have been plagued with problems in their fuel preparation and feeding systems. Feeding dried biomass to a pressure vessel containing syngas that must not leak back into the feeding system is a much more difficult job than feeding biomass into a boiler. This high-priority issue could be addressed at a test facility (e.g., at NREL) specifically designed to test and compare systems feeding biomass feedstocks into a pressure vessel. The ideal solution would be to develop one standard system that would handle all biomass feedstocks with high reliability.

There may be a similar need to develop a reliable, standardized biomass feedstock drying system. Various types of systems (flue gas, steam, other) have been proposed and tested, but the experience with these systems to date is insufficient to allow us to understand their relative performance, costs, and issues.

Finally, it would be useful to establish a gas cleanup process development and test facility at the site of an operating biomass gasifier. Different approaches to gas cleanup to meet gas turbine and fuel cell specifications could be tried, their performance could be measured, and their reliability improved with continuous trial/modification experiments.

Biomass gasification technologies themselves now seem to fall into several well-defined categories (high and low pressure circulating fluidized beds, air-blown, indirectly heated, fisced beds, etc.), and there are multiple vendors working hard to improve them. R&D organizations such as EPRI and DOE can accelerate the commercialization of biomass gasification technology by supporting as many private sector projects as possible. The marketplace will sort out the technologies, identify and solve the problems.

Small-Scale Systems

The idea of controlled landfilling (as discussed in Section 7) is very attractive, and the initial demonstration at the Yolo County landfill is producing excellent results. This technology converts a landfill into a controlled bioreactor, and may ultimately make traditional waste-to-energy technology obsolete. More demonstrations, in a variety of locations and climates, are needed.

Thorough cleanup of the gas from landfills and anaerobic digesters is an absolute requirement for gas turbines and fuel cells. Some good work on landfill gas cleanup systems has been done, primarily by the EPA. The ideal result would be a packaged system that could operate unattended except for regular maintenance, and could guarantee to meet the pristine gas quality specifications of fuel cells.

Fuel cells are getting very close to commercial readiness, after nearly 30 years of RD&D. Biomass (solid and biogas) lends itself very well to fuel cell applications, and may turn out to be one of the fastest-growing early markets for fuel cells. The industry will need lots of demonstrations, in many different settings using different biomass feedstocks: digester gas, landfill gas, ethanol plants, other industrial plants, pulp and paper mills, and stand-alone power plants. (This topic crosses over into the previous area, gasification, but the early demonstrations are likely to be small-scale systems.)

9

REFERENCES

1. Renewable Energy Technology Characterizations. Electric Power Research Institute, Palo Alto, CA and U.S. Department of Technology, Washington D.C.: December 1997. Report TR-109496.

2. George Wiltsee, “Urban Wood Waste Resources in 30 U.S. Metropolitan Areas,” presented at BIOENERGY ‘98, Madison, Wisconsin (October 4-8, 1998).

3. William H. Carlson, “Lessons Learned in Burning Biomass,” presented at the Conference on Strategic Alliances for Biomass Energy, National Bioenergy Industries Association and Utility Biomass Energy Commercialization Association, Washington, DC (November 14-16, 1995).

4. Scott Haase, Timothy Rooney, Dave McNeil, and Suzanne Pearce, “Facilitating Forest Health Restoration Efforts in the Lake Tahoe Basin through the Development of a Biomass-Based Green Power Program,” presented at BIOENERGY ‘98, Madison, Wisconsin (October 4-8, 1998).

5. Marie E. Walsh, Daniel De La Torre Ugarte, Stephen Slinsky, Robin L. Graham, Hosein Shapouri, and Daryll Ray, “Economic Analysis of Energy Crop Production in the U.S. -- Location, Quantities, Price and Impacts on Traditional Agricultural Crops,” presented at BIOENERGY ‘98, Madison, Wisconsin (October 4-8, 1998).

6. Marie E. Walsh, D. Becker, and Robin L. Graham, “The Conservation Reserve Program as a Means to Subsidize Bioenergy Crop Prices,” presented at BIOENERGY ‘96, Nashville, Tennessee (September 15-20, 1996).

7. J. Cooper, M. Braster, and E. Woolsey, “Overview of the Chariton Valley Switchgrass Project: A Part of the Biomass Power for Rural Development Initiative,” presented at BIOENERGY ‘98, Madison, Wisconsin (October 4-8, 1998).

8. Marie E. Walsh and Robin L. Graham, “Biomass Feedstock Supply Analysis: Production Costs, Land Availability, Yields,” Oak Ridge National Laboratory, Biofuels Feedstock Development Program, Oak Ridge, Tennessee (January 18, 1995).

9. George A. Wiltsee and Evan E. Hughes. Biomass Energy: Cost of Crops and Power. Electric Power Research Institute, Palo Alto, CA: gray cover report, October 1995. TR-102107, Volume 2.

10. Evan E. Hughes and George A. Wiltsee, "Comparative Evaluation of Fuel Costs from Energy Crops," presented at the Second Biomass Conference of the Americas, Portland, Oregon (August 21-24, 1995).

11. Biomass Cofiring Guidelines. Electric Power Research Institute, Palo Alto, CA: September 1997. Report TR-108952.

12. P. Patel, G. Steinfeld, J. Ku, R. Sanderson, M. Ratcliff, and K. Craig, "Evaluation of Biomass Gasification / Fuel Cell System," presented at BIOENERGY '98, Madison, Wisconsin (October 4-8, 1998).

13. H. Maru, M. Farooque, G. Carlson, P. Patel, C. Yuh, C. Bentley, D. Glenn, and A. Kush, "ERC Direct Carbonate Fuel Cell Program Overview," presented at the FETC Fuel Cells 1997 Review Meeting, Morgantown, West Virginia (August 26-28, 1997).

14. Ed Coe, "Landfill Gas-to-Energy: Developing Projects Under Different Environments," presented at BIOENERGY '98, Madison, Wisconsin (October 4-8, 1998).

15. Don Augenstein, John Benemann, and Evan Hughes, "Electricity from Biogas," presented at BIOENERGY '94, Reno / Sparks, Nevada (October 2-6, 1994).

16. John P. Cosulich, P.E., "Landfill Gas - Impacts of Trace Contaminants on Equipment Performance," presented at BIOENERGY '98, Madison, Wisconsin (October 4-8, 1998).

17. D. Augenstein, R. Yadzani, K. Dahl, and R. Moore, "Yolo County Controlled Landfill Project," presented at Landfill Gas Assessment and Management Symposium, Ontario, California (April 1998).

18. Mark A. Moser, Richard P. Mattocks, Stacy Gettier, and Kurt Roos, "Benefits, Costs and Operating Experience at Seven New Agricultural Anaerobic Digesters," presented at BIOENERGY '98, Madison, Wisconsin (October 4-8, 1998).

19. D.W. Williams, M.A. Moser, and G. Norris, "Covered Lagoon Methane Recovery System for a Flush Dairy," presented at American Society of Agricultural Engineers meeting, Orlando, Florida (July 1998).

20. Frank Thompson, Jim Stark, and Pinakin Patel, "Potential Benefits of Applying Fuel Cells to Agricultural Waste Streams," presented at BIOENERGY '98, Madison, Wisconsin (October 4-8, 1998).

21. Jane Hughes Turnbull, Seppo Hulkkonen, and Raymond Dracker, “Development of Small, Modular Biomass Power Systems,” presented at BIOENERGY ‘96, Nashville, Tennessee (September 15-20, 1996).