Biomass-Fueled Cogeneration Systems

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CONTENTS

TABLES

Table		Page

FIGURES

1

INTRODUCTION -- COGENERATION SYSTEMS AND COMPONENTS

What is cogeneration and how does it reduce costs? Cogeneration is the production of power -- and useful heat -- from the same fuel. In a typical biomass-fueled cogeneration plant, a steam turbine drives a generator, producing electricity. The plant uses steam from the turbine for heating, drying, or other uses.

The benefits of cogeneration can most easily be seen through actual examples. For example, cogeneration fits well with the operation of sawmills. Sawmills can produce more steam from their waste wood than they need for drying lumber. Wood waste is a disposal problem unless the sawmill converts it to energy. The case studies in Section 8 illustrate some pluses and minuses of cogeneration.

The electricity from the cogeneration plant can do more than meet the in-house requirements of the mill or manufacturing plant. PURPA -- the Public Utilities Regulatory Policies Act of 1978 -- allows a cogenerator to sell power to a utility and make money on the excess power it produces. It *requires* the utility to buy the power at a fair price -- the utility's "avoided cost". This can help make operation of a cogeneration plant practical.

The systems involved in a conventional cogeneration plant are a boiler, a steam turbine, and a generator. The plant also should provide site space and equipment for fuel handling and storage, environmental control systems, and connections to the steam and electricity users. The prime mover (steam turbine) needs to operate most of the time. Both the electricity and the steam output should be at or near their design rates nearly always. Otherwise, the economics will not be good.

Steam Turbine Systems

The basic types of steam turbine systems are *backpressure (noncondensing)* and *condensing*. The steam turbines in these two systems are very similar. The difference is in how they connect to the other equipment. A backpressure or noncondensing steam turbine (see Figure 1) is in the steam line directly between the boiler and the steam load(s). It generates power only when there is a demand for steam by the process equipment. For example, the steam entering the turbine might be at 250 psig, and the process steam leaving the turbine might be at 15 psig.

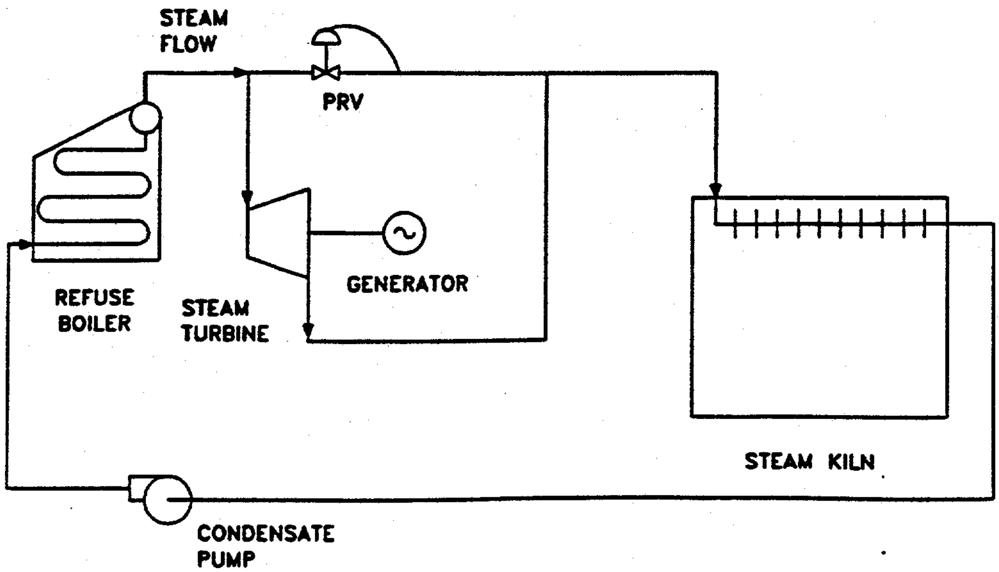

Figure 1. Backpressure (noncondensing) steam turbine system

In the simple cogeneration system shown in Figure 1, the process load (such as the heating of dry kilns) condenses the steam. The heat released during condensation of the steam (which is most of the energy produced in the boiler) dries lumber in the kilns. Condensate collected from the kilns returns to the boiler.

In a condensing steam turbine system (see Figure 2), the steam that flows through the turbine condenses as it leaves the turbine exhaust. Condensation creates a powerful vacuum as it dramatically reduces the volume of the steam. This vacuum increases the pressure drop across the turbine. This delivers more power to the electric generator.

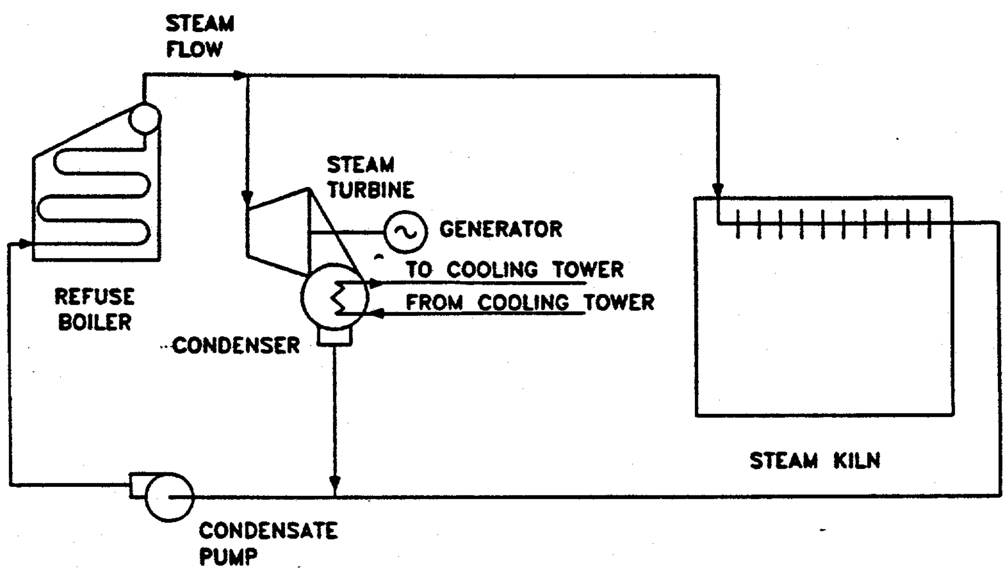

Figure 2. Condensing steam turbine system

The condensing steam turbine is *parallel* to the process steam load (kiln). It produces power only with the steam not required for the process (drying). In the condenser (a heat exchanger), cooling water absorbs the heat given off by the condensing steam. This heat dissipates in a cooling tower. In a power plant not using process steam, 44% of the useful energy is lost in this way. Cogeneration is a means of recovering this energy.

The noncondensing turbine system uses the energy in the fuel more efficiently than the condensing turbine system. This is not necessarily the objective, though. If the main objective is to consume residue (to avoid disposal costs) and to produce electricity, the condensing turbine system may be more desirable.

Companies often need to produce power at high efficiency from the available residue while also providing low pressure steam to a process. They could use two separate turbines (condensing and noncondensing). Instead they can use a condensing turbine with a port in its casing, and extract low-pressure steam through the port. This is an *extraction* turbine system (see Figures 3 and 4).

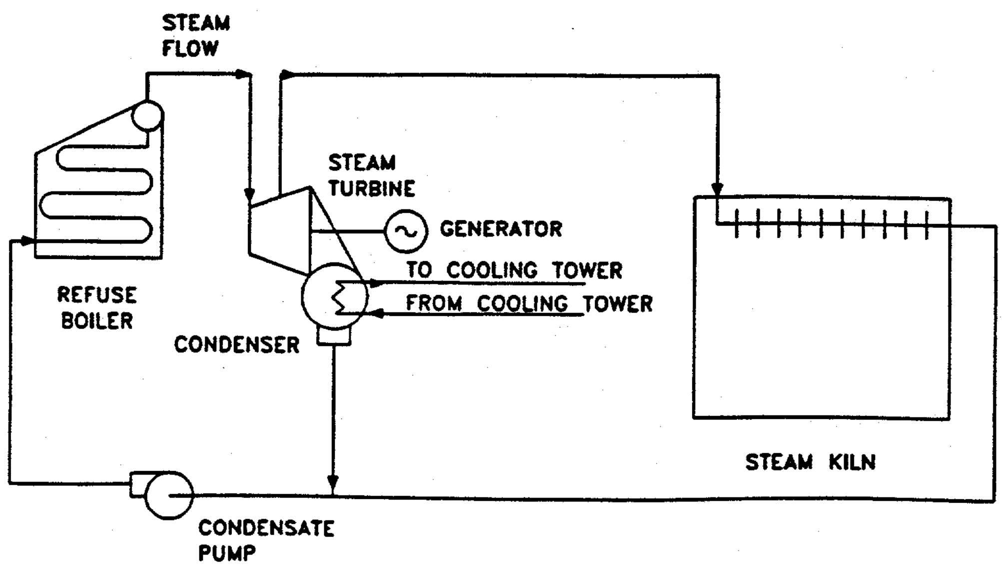

Figure 3. Extraction steam turbine system

Table 1 summarizes some common types of steam turbine systems used for industrial cogeneration. Both condensing and non-condensing turbines can have one or more steam extraction points. The consulting engineer who helps with your plant design will know the best type of system to meet your specific needs. The case studies in the back of this booklet include most of these systems.

A governor controls a steam turbine based on the type of turbine involved and its application. The governor usually holds steady (at all loads) either turbine shaft speed, exhaust steam pressure, extraction steam pressure, or inlet steam pressure. Governors also can hold combinations of these items steady.

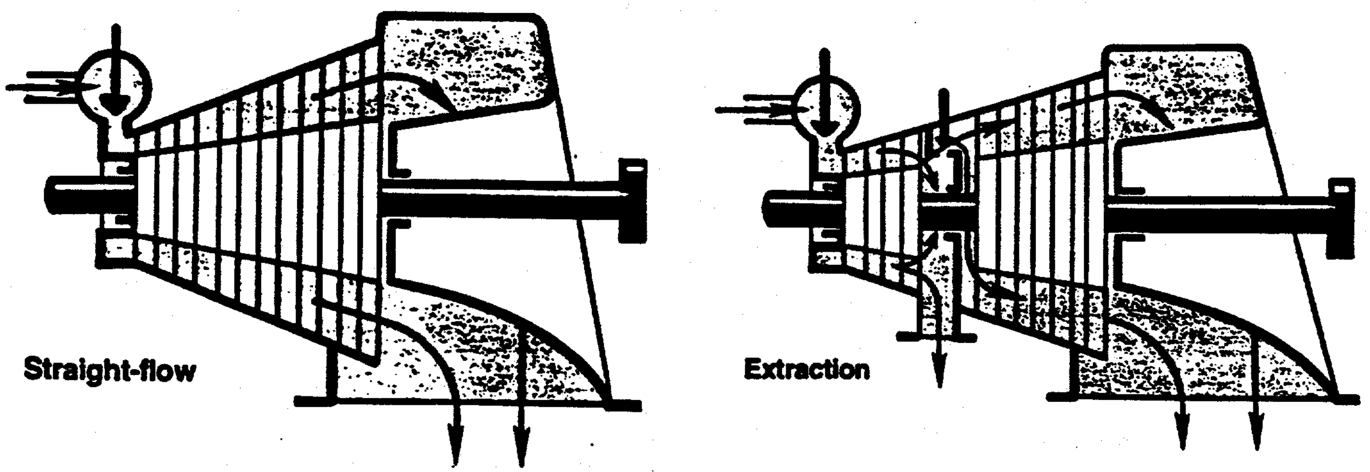

Figure 4. Internal arrangement of a straight (condensing or noncondensing) steam turbine (left) and an extraction steam turbine (right)

Table 1
Types of Steam Turbines for Industrial Cogeneration

Turbine Type	Application
1. Single automatic extraction (condensing)	Supplies process steam at one pressure level; meets variations in electrical load by varying boiler output
2. Double automatic extraction (condensing)	Supplies process steam at two pressure levels; meets variations in electrical load by varying boiler output
3. Backpressure (non-condensing)	Turbine exhaust meets process steam demand; electricity generation directly related to process steam flow
4. Single automatic extraction (non-condensing)	Supplies process steam at two pressure levels; electricity generation directly related to process steam flow
5. Double automatic extraction (non-condensing)	Supplies process steam at three pressure levels; electricity generation directly related to process steam flow

Most extraction turbines are single automatic extraction (condensing) design. A set of throttles controls the steam flow into the inlet of the noncondensing section. An extraction valve controls the amount of steam passing on to the condensing section. (This valve maintains constant extraction steam pressure by varying the flow to meet process needs.) The condensing section of the turbine receives only the balance of steam remaining after extracting the process steam.

The power output and extraction steam flow amounts are flexible. The benefits of flexibility require sacrifice in performance. This sacrifice is greater for a wider range of loads and extraction flows. Because of this, vendors custom design automatic extraction turbines to balance present and future requirements.

Condensers

The condenser serves two purposes -- to condense and recover steam exhausted from the turbine and to provide a vacuum for the turbine exhaust. Recovery of the exhaust steam reduces the makeup water requirements to 1-5%, instead of 100% in a system that does not condense and recover process steam.

Barometric condensers work by mixing exhaust steam with cold water. Surface condensers work better, because they are shell and tube heat exchangers that keep the condensing steam separate from the cooling water (or air). They can remove air from the condensate that returns to the boiler feedwater system. This reduces corrosion and scaling in the boiler.

Air removal is the most important factor in condenser performance. Otherwise the condenser becomes airbound and the pressure rises. Steam-powered ejectors or vacuum pumps remove the air from the water.

Heat Rejection

A condensing steam turbine cycle must reject heat from the condensing steam. The latent heat of vaporization or condensation of water is about 1,000 Btu/lb. Cooling water (or air) absorbs this heat and then dissipates it to the environment. The cross-flow cooling tower, which evaporates the cooling water, is the most popular method for rejecting the heat. The rejected heat is lost energy. Process steam heat is not.

Generators

The types of electric generators used for in-plant systems are the *induction generator* and the *synchronous generator*. The induction generator is simple, reliable, maintenance-free and inexpensive. It must be connected to a grid on which synchronous machines operate.

The synchronous generator can operate independently, or connected to an electrical grid. It may have a power factor of one or higher. It is slightly more complex and costly, and requires greater care when starting.

Small power systems often use the induction generator because of its simplicity and ease of operation. When driven above its synchronous speed by the steam turbine, it feeds AC power back into the grid. The faster its shaft turns, the more kilowatts it feeds to the utility network. Because the network frequency controls its speed and because it cannot generate power when the network is dead, it normally needs very little protective relaying. (Still, utilities often demand extensive protective relays for induction generators that are almost as complex as those required for synchronous generators.)

Large generating systems, and systems that operate independently of the grid, use the brushless synchronous generator. The speed of a generator connected with the utility network cannot vary because of the magnetic coupling between the rotor and stator. A droop governor controls the torque supplied by the steam turbine, allowing it to change slightly with load. For a generator not connected to the grid, adjusting the steam flow with the throttle maintains constant speed and frequency.

Electric utilities have standards that cogenerators must meet if they want to connect to the grid. These relate to safety, liability, protection of facilities, power quality, reliability, metering, and interconnection costs. Before approving interconnection, the utility will review the cogenerator's application. This includes layout drawings, equipment specifications, functional and logic diagrams, control and meter diagrams, power requirements, interference factors, synchronizing methods, and operating manuals. The utility will require a manual disconnect switch and will reserve the right to open the switch, and lock it open with a padlock. The cogeneration plant owner pays for the interconnection up to the utility line.

Before beginning any interconnection work, the utility may require the cogenerator to provide a certified copy of a liability insurance policy. This policy will jointly protect and indemnify the cogenerator and the utility against all liability or claims for injuries or damages arising from the interconnection.

Biomass Boilers

The wood products industry has well-proven technology for using wood fuel in boilers. In the *firetube boiler*, combustion gases flow through tubes submerged in water in a pressure vessel. In the *watertube boiler*, the water flows through tubes heated on the outside by hot gases. Generally, in plants requiring boilers with a steam capacity of more than 25,000 lb/hr and 125 psig, watertube boilers are more economical.

Watertube boilers may be either packaged or field built. Packaged boilers have steam capacities up to 50,000 lb/hr. Field built watertube boilers have steam capacities up to 600,000 lb/hr. The steam produced may be low pressure saturated steam or superheated steam with pressure to 2400 psig and temperature to 1050 °F. Typical steam conditions in small industrial cogeneration plants are about 150 to 500 psig and 366 to 725 °F. (See the case studies in Section 8.)

One of the most frequent and costly mistakes made when buying a boiler that will be used in the future for cogeneration is to buy a low pressure boiler. Operation of a steam turbine requires a minimum of 100 psig. Sometimes high pressure boilers have low pressure controls.

The four most commonly used furnace designs for wood firing are *pile burners*, *stoker grate boilers*, *fluidized-bed boilers*, and *suspension burners*.

Pile Burner

Fifty years ago, all common ways of burning wood waste involved some form of pile burning. Pile burners are simple and can handle very moist fuel with large quantities of dirt and debris. They are less efficient than other boiler types and need to shut down periodically for cleaning.

Modern pile burning systems range from 15,000 lb/hr to 380,000 lb/hr of steam, in configurations varying from one to six cells. Each cylindrical, refractory lined cell has a water-cooled grate floor. The fuel forms a pile 2-4 feet high on the grate. Combustion air enters under the grate (~30%), tangentially above the fuel pile (~60%), and at the top of the cell (~10%). Burning gases leave the cell and enter a large chamber that has both refractory lining and boiler water wall.

The unit controls emissions through a lengthy combustion process, a low flame temperature, and staged combustion. Cyclonic air movement throws ash particles against the cell walls, where they melt. Slag flows down the wall and solidifies on the water-cooled grate. Manual or automatic systems remove the slag.

Stoker Grate Boiler

Developed in the 1920s and 1930s, stoker fired boilers with grates are the leading type of boiler design for wood firing. The grates may be sloped, flat, moving or stationary, and made of either cast iron or refractory brick. Moving grates provide better control over the burning than stationary grates. Moving grates can automatically discharge ash.

Spreader stokers feed fuel to the furnace pneumatically or mechanically. Designers locate fuel distributors as low in the furnace as possible to cover the grate with an even layer of fuel. Small particles entering the furnace burn in suspension; larger pieces burn on the grate.

To meet NO_x emission standards, stokers now include staged combustion systems and more accurate combustion control than they did ten years ago. Overfire, or secondary, air accounts for about half the total. Excess air levels are typically 40%. Three fans provide the necessary control: one for undergrate combustion air, one for overfire air, and one for the pneumatic fuel distributors.

Fluidized-Bed Combustor (FBC)

Industry installed many FBCs to burn biomass fuels in the 1980s. The bottom of an FBC furnace is a perforated steel plate. Air blown through the plate suspends a hot bed of sand and fuel in bubbling motion. The fuel burns at a low temperature, which reduces NO_x emissions. FBCs can burn difficult fuels such as agricultural residues better than other types of boilers.

Suspension Burner

Burners can be designed for suspension firing of dry sawdust and shavings. Scroll type burners inject the fuel into a rotating ring between two turbulent streams of combustion air. Cyclonic burners inject air and fuel at high speed into a cylindrical burner, creating a cyclonic turbulence. Vertical cylindrical burners mix air and fuel, and inject the burning mass into a vertical, cylindrical furnace.

Suspension firing requires a fuel moisture content of less than 15% and a fuel particle size of less than 1/4 inch. Dry fine fuel particles create a potential explosion hazard.

2

FEASIBILITY OF COGENERATION

Cogeneration is probably cost-effective for you if:

- You have waste that is causing disposal problems or expense (a captive fuel source)
- You have a use for the power in-house, and a high electricity cost
- You have a steady, year-round steam use in-house or close

If you can generate power for your use at a cost equal to the utility's retail rate, you have a long-term advantage. Electric utility rates will keep rising because of environmental concerns and higher fuel costs. Cogeneration costs stay the same, except for labor and water treatment chemicals. The fuel is production residue; disposing of it in landfills will get more costly.

Most utilities in the southeast have an abundance of generating capacity and have low buy-back rates. Selling power may not make sense unless the utility has a need for power and gives favorable terms to cogenerators. By law, the utility must give you data on its present and anticipated future costs of energy and capacity.

If your plant has a boiler, a steady steam load, and surplus fuel, you probably can cogenerate electric power for in-house use and save money. The amount of power you can produce depends on two main factors: steam flow and pressure drop. Your boiler should be at least 125 horsepower, and provide steam to the turbine inlet at a pressure of 100 psig and a flow rate of 4300 lb/hr or more. The turbine inlet pressure must be at least 80 psi higher than, or 1.75 times, the pressure required at the dry kilns.

Your first task is to find out whether cogeneration is a good idea for your site. Only if cogeneration is viable at your site should you go further into issues of project development and ownership. If you hire an engineering consultant to help with the initial feasibility study, he or she will go through the steps outlined in Figure 5.

The early steps use easy-to-get information and the consultant's experience to decide if cogeneration could be successful at your site. If that decision is "yes", a more detailed analysis will tell you if cogeneration is viable. It also will tell you the type and size system that is best for your site, and the budgeted cash flows.

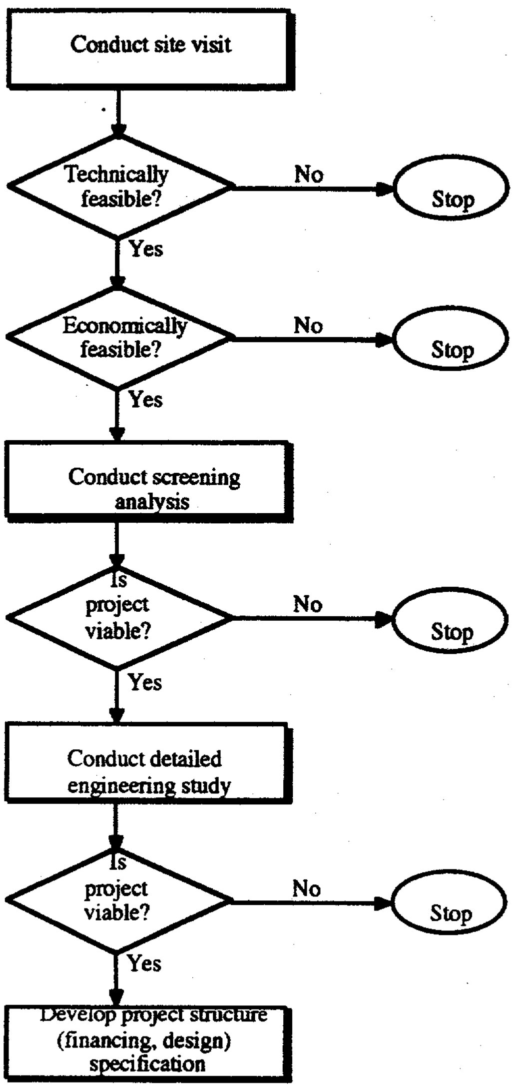

Figure 5. Cogeneration decision process

A screening study (the second analysis box in Figure 5) should include:

- *Assumptions* -- site data; financial information; fuel and electricity costs; utility's avoided cost
- *Fuels* -- quantities (by month) and qualities (heating value, moisture, ash)
- *Energy usage* -- monthly electric and gas bills; equipment horsepower; present and projected steam demand profile
- *System sizing* -- fuel available; boiler and turbine-generator size
- *System type and cost* -- equipment, engineering, insurance, and operating costs
- *Cash flows* -- Electricity and gas savings; plant costs; energy sales (if any)
- *Economics* -- Discounted cash flow analysis for the life of the project

The engineering analysis (the third analysis box in Figure 5) will give you a more detailed design and costing, and will consider the costs of meeting permit requirements. This will show whether you can produce power at a lower cost than the utility's retail rate.

3

BIOMASS CONVERSION TO ELECTRICITY

The amounts of steam and electricity produced depend on the system design and the biomass properties. Table 2 shows typical heating values and moisture contents of different types of biomass.

Table 2
Biomass Heating Values and Moisture Contents

Fuel	Moisture (% wet basis)	Higher heating value, Btu/lb (as received)	Higher heating value, Btu/lb (dry basis)
Bark	50	4000	8000
Whole tree chips	50	4250	8500
Sawdust	40	5100	8500
Planer shavings	10	7650	8500
Sanderdust	5	8075	8500
Cotton gin trash	10	6350	7060

Most species of wood and bark, when dry, have about the same chemical composition. The moisture content, particle size, and ash content vary over wide ranges, and influence the design of the plant. Sanderdust and furniture plant scraps contain the least amount of moisture of the wood fuels (less than 10%). These very dry fuels allow the highest boiler efficiencies. Bark from hydraulically debarked logs, or from trees in areas with high rainfall, and sawdust from mills using water-cooled saws, may contain 65% moisture or more. At such high levels, combustion becomes unstable, and the fire goes out. Hog fuel -- the mixture of wood and bark that fuels most plants -- normally contains 45 to 55% moisture.

Note that there are two ways to express moisture content -- the wet or the dry basis. Engineers usually calculate moisture from the as-received weight of the fuel; this is the wet basis. (This report uses the wet basis.) People in the wood products industries often calculate it from the dry weight. It is easy to convert from one basis to the other using the equations below. For example, 50% moisture (wet basis) and 100% moisture (dry basis) mean the same. Every pound of fuel contains a half-pound of water and a half-pound of bone-dry wood.

$$M_{wb} = M_{db}/(1 + M_{db})$$
$$M_{db} = M_{wb}/(1 - M_{wb})$$

where M_{wb} and M_{db} are the wet and dry basis moisture contents, respectively, expressed as decimals.

Table 3 shows how much energy can be produced from wood as a function of its moisture content. It also shows the relationships among steam inlet and exhaust pressure, flow rate, and power production, over the plant size range of 78 kW to 2 MW.

Table 3
Estimated Power Production for Wood-Fired Boilers

	Wood fuel, tons/hr		System power production, kW				
			125 psig inlet		225 psig inlet		
Boiler size, hp[1]	Dry[2]	Green[3]	Exhaust 15 psig	Exhaust 5 psig	Exhaust 15 psig	Exhaust 5 psig	Exhaust vacuum
150	0.47	0.87	78	94	98	113	NR[4]
200	0.62	1.15	105	129	136	164	NR
300	0.94	1.74	165	211	215	252	NR
400	1.25	2.31	225	285	300	342	790
500	1.56	2.89	293	361	377	432	988
600	1.88	3.48	344	425	448	508	1186
700	2.18	4.03	407	508	516	596	1369
800	2.50	4.62	476	587	596	684	1565
900	2.80	5.18	534	635	687	774	1760
1000	3.12	5.78	591	702	777	880	2000

Note:
1. One boiler horsepower = 34.5 lb/hr of steam (approximate, depending on steam conditions).
2. One ton of dry fuel (10% moisture content wet basis) will make about 11,000 lb/hr of steam.
3. One ton of green fuel (50% moisture content wet basis) will make about 6,000 lb/hr of steam.
4. Not recommended.

There are tradeoffs between system cost and efficiency. Generating efficiency increases dramatically as the size of the steam turbine increases, and as the temperature and pressure of the steam increase. Up to about 600 psig, boiler costs do not increase dramatically with increasing pressure.

4

SYSTEM COSTS

System costs are site-specific. Figure 6 shows installed costs (adjusted to December 1992) for turnkey cogeneration systems with total steam rates from 14,000 to 128,000 lb/hr. These costs are for complete cogeneration plants -- fuel handling systems, boilers, turbines, generators, controls, and hookups. The plants are in the southeastern and western U.S. The plants with boilers in the 15,000 lb/hr size range produce 350 to 700 kW of electricity and cost $450,000 to $1,000,000 (1992 dollars). The 60,000 lb/hr boilers produce 875 to 4,500 kW and cost $3,300,000 to $7,400,000. The 125,000 lb/hr boilers produce 7.5 to 12 MW and cost $11,000,000 to $22,000,000.

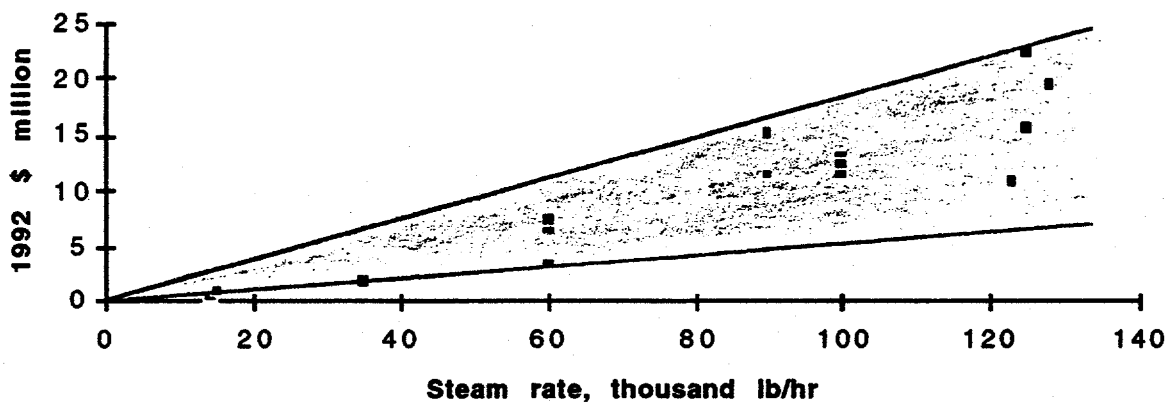

Figure 6. Cogeneration system costs

Some plant owners convert existing boilers to cogeneration systems by adding turbine-generators and electrical hookups. Figure 7 shows actual installed costs (adjusted to year-end 1992 dollars) for three conversions of this type. Note that different plants use different proportions of their steam output for process use and for electric generation. Thus, plotting turbine-generator costs against boiler steam output does not tell the whole story. The turbine-generator sets installed on the 20,000 lb/hr boilers in Figure 7 produce about 300 kW of electricity and cost $90,000 to $150,000 (1992 dollars). The turbine-generator set installed on the 60,000 lb/hr boiler produces about 6 MW of electricity and cost $1,900,000 (1992 dollars).

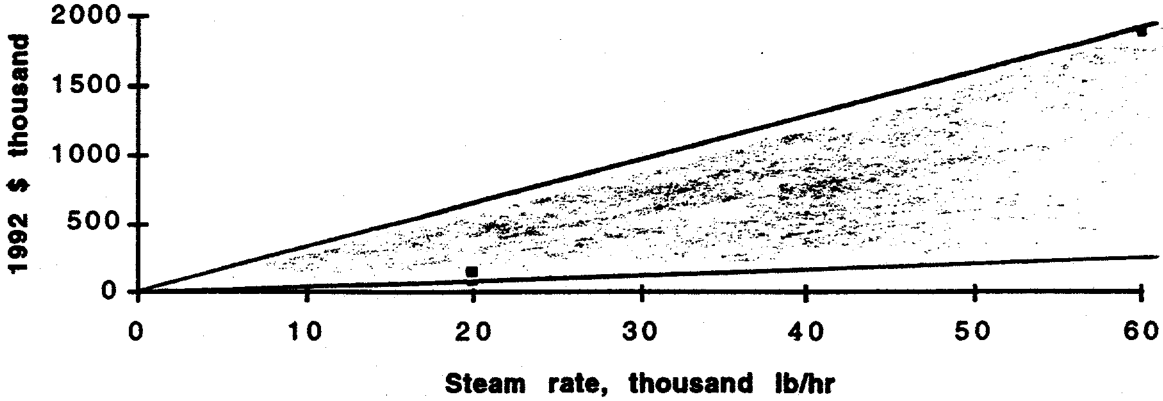

Figure 7. Costs of converting existing boilers to cogeneration systems

As these figures show, the cost of a cogeneration plant increases as the system size increases. *Unit* costs (costs per unit of steam generating capacity, lb/hr) generally decrease due to economies of scale. The complexity of the plant design, and its pollution control requirements, greatly influence the cost of a plant. Low quality fuel requires more screening and blending equipment, and sometimes requires more expensive combustion and particulate control systems. Site conditions (labor costs, limited space, etc.) also influence plant costs.

5

ELECTRICITY SALES CONTRACTS

The law governing utility buyback of power is the 1978 Public Utilities Regulatory Policies Act (PURPA). Each state, through its Public Utility Commission or similar agency, has implemented this law with specific requirements.

PURPA defines Qualifying Facilities (QFs) as non-utility cogeneration or small power plants that meet certain standards (see Glossary). Utilities must buy all power offered by QFs at rates based on their avoided costs. Avoided cost is the cost the utility would have to pay if it installed additional generating capacity equivalent to the amount purchased.

QFs may buy and sell electric power simultaneously. Utility rates for supplemental, back-up, and standby power must be non-discriminatory. QFs are exempt from state regulations on rates and financial disclosure; the Federal Power Act; and the Public Utility Holding Company Act.

Electric utilities with little extra capacity tend to view cogeneration as beneficial to them. Buying electricity from QFs can delay or even eliminate the need for a utility to build a power plant.

Some utilities have much greater capacity than they need. This can happen when sales or growth decline. Long-term planning has hurt some utilities since the growth rate for electricity slowed in the 1980s. These utilities with overcapacity tend to view cogeneration negatively. There is no incentive for them to cooperate. The utilities may ask their regulators for higher standby and demand charges with ratchet clauses to discourage prospective cogenerators. They may have tough interconnection requirements to "protect their systems", and charge a lot to install the equipment.

An owner who decides to go ahead with a project despite such conditions may find later that the utility will offer him a "buy-down" rate. This can make it more profitable not to sell power to the utility. PURPA and Federal Energy Regulatory Commission (FERC) rules for rates to be paid to QFs by utilities allow negotiated agreements. Rates, terms, or conditions can differ -- if both parties agree -- from those that would otherwise be required.

Energy is worth more during peak periods (when the utility is running its most costly units) than during off-peak periods. Biomass-fueled plants can operate reliably and predictably, scheduling outages when the utility's demand is low. If the utility can avoid building a new plant, the rate it pays for electricity can be based on both energy and capacity costs. (See Glossary, and the Wood Power case study.)

A utility may, with the consent of the cogenerator, transfer (wheel) electricity to another electric utility. (See Glossary.) A cogenerator can profit from this when the avoided costs of the second utility are higher than the avoided costs of the first utility.

The National Energy Policy Act of 1992 increased the access of independent power producers to utility transmission systems. It amended the Public Utility Holding Companies Act and gave the Federal Energy Regulatory Commission (FERC) more authority to order access.

6

PERMITS AND REGULATORY AGENCIES

You must obtain a Permit to Construct, a Permit to Operate, and possibly other permits, depending on your state and local requirements. If you are in an area that meets National Ambient Air Quality Standards (NAAQS), you must meet Prevention of Significant Deterioration (PSD) regulations. You must submit a PSD permit application if the plant will emit more than 100 tons/year of a criteria pollutant or if the plant will emit pollutants at levels considered "significant" (see Table 4). You should carefully check all applicable regulations for the specific site.

Table 4
Emission Levels Considered Significant Under PSD Regulations

Pollutant	Emissions Rate (tons/year)
Carbon monoxide	100
Nitrogen oxides	40
Sulfur dioxide	40
Particulate matter	25
Ozone (volatile organic compounds)	40
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl chloride	1
Fluorides	3
Sulfuric acid mist	7
Hydrogen sulfide (H_2S)	10
Total reduced sulfur (including H_2S)	10
Reduced sulfur compounds (including H_2S)	10

In the permit application, you must provide an air quality modeling analysis to assess impacts on NAAQS and allowable increments (see Table 5). You may have to provide one year of air quality data for the site if no such "baseline" data exist that meet EPA requirements. Submit the permit application to an EPA regional office, which will review the application and issue a permit. Table 6 lists the ten regional EPA offices.

Table 5
Allowable PSD Increments

Pollutant	Maximum Allowable Increase (Micrograms per cubic meter)		
	Class I*	Class II	Class III
Particulate matter:			
Annual geometric mean	5	19	37
24-hour maximum	10	37	75
Sulfur dioxide:			
Annual arithmetic mean	2	20	40
24-hour maximum	5	91	182
3-hour maximum	25	512	700

*Class I -- National parks, wilderness areas, national memorial parks
Class II -- All other areas except Class III (most areas in U.S. are Class II)
Class III -- Heavy industrial areas

PSD requires the use of Best Available Control Technology (BACT). BACT may take the form of a specific control technology or an emission limitation. For control of particulate emissions from biomass boilers, BACT requires wet scrubbers, electrostatic precipitators, or fabric filters.

Areas that have not met NAAQS are "nonattainment". If you are in one of these areas, you are not subject to PSD requirements. Major emission sources in these areas must:

- Arrange for emission reduction from existing sources in the region that more than offset the total emissions of the new plant, and

- Meet the Lowest Achievable Emission Rate (LAER) for the nonattainment pollutant. LAER is the lowest emission level met in practice or required by any state.

The Southeastern Regional Biomass Energy Program has a guidebook entitled "Permits-Regulations for Biomass Energy Facilities in the Southeast". It will help you plan your project by identifying permit requirements. It lists the regulations, permits, and standards for air quality, water quality, solid waste, safety, noise, and zoning/land use. It also lists agencies and services in the southeastern U.S. To obtain the guidebook, contact SERBEP at:

Tennessee Valley Authority
P.O. Box 1010
Muscle Shoals, AL 35660
205-386-3086 fax: 205-386-2963

Table 6
U.S. Environmental Protection Agency Regional Offices

EPA Regional Office, Air Programs Branch	States Included in Region
1. John F. Kennedy Federal Building Room 2303 Boston, MA 02203 617-223-6883	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
2. Federal Office Building 26 Federal Plaza New York, NY 10007 212-264-2517	New Jersey, New York, Puerto Rico, Virgin Islands
3. Curtis Building Sixth and Walnut Streets Philadelphia, PA 19106 215-597-8175	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia
4. 345 Courtland, NE Atlanta, GA 30308 404-881-3043	Alabama, Florida, Georgia, Mississippi, Kentucky, North Carolina, South Carolina, Tennessee
5. 230 South Dearborn Chicago, IL 60604 312-353-2205	Illinois, Minnesota, Michigan, Ohio, Indiana, Wisconsin
6. First International Building 1202 Elm Street Dallas, TX 75270 214-767-2745	Arkansas, Louisiana, New Mexico, Oklahoma, Texas
7. 324 E. Eleventh Street Kansas City, MO 64106 816-374-5971	Iowa, Kansas, Missouri, Nebraska
8. 1860 Lincoln Street Denver, CO 80295 303-837-3471	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming
9. 215 Fremont Street San Francisco, CA 94105 415-556-4708	Arizona, California, Hawaii, Nevada, Guam, American Samoa
10. 1200 Sixth Avenue Seattle, WA 98101 206-442-1230	Washington, Oregon, Idaho, Alaska

7

SELECTING A CONTRACTOR

To select a qualified contractor, identify some candidates, check references, get recommendations, and conduct interviews. The contractor should have successful experience in small-scale wood-fired cogeneration, familiarity with environmental regulations and permitting for the site area, and familiarity with the local utility's attitude towards cogeneration and power purchase agreements.

After evaluating potential contractors, ask the leading candidate to do an initial screening analysis of your site. If the results make sense and look good, ask the consultant for a preliminary system design and cost estimate.

There is no such thing as a "free cogeneration analysis". Equipment vendors, third party developers, and utilities will offer to provide analyses at no cost. Remember that none of these sources is in the business of providing consulting services.

- The equipment vendor seeks to sell boilers and turbines, and any analysis that it provides is only a part of that sales effort.

- A third party developer's objective is to develop independently owned cogeneration, not to provide objective advice.

- Utility personnel may be biased to sell cogeneration fuel or to preserve purchased power sales.

Lists of cogeneration design/build/installation contractors are available from SERBEP and other regional biomass energy program offices.

8

CASE STUDIES

The case studies that follow illustrate some different situations that were favorable for cogeneration systems using biomass fuel. The specifics of your situation will differ from these. If you have *some* of these conditions at your wood processing or manufacturing plant, then cogeneration may make sense -- and money -- for you.

M.C. Dixon Lumber Company, Eufaula, Alabama

M.C. Dixon Lumber Company of Eufaula, Alabama produces about 85,000 board feet of lumber per week. Until 1979, Dixon Lumber dried its lumber in a natural gas-fired kiln at a cost of $35,000/month. The company decided to install a cogeneration system in 1979 using its waste wood as fuel. The system has completely displaced the company's use of natural gas and purchased electricity.

A hog and screen size the fuel (sawdust, bark, and planer shavings). From a storage silo the fuel flows to a 60,000 lb/hr boiler. Part of the steam output (300 psig, 500 °F) goes to four lumber drying kilns. The rest of the steam powers two condensing steam turbine generators. One is rated at 1500 kW; the other, 1000 kW. Heat is dissipated in a cooling tower.

Alabama's pollution control agency has certified that the boiler and generator system comply with all standards. The boiler operates 24 hours a day, 6 days a week, powering the kilns. During the day, both turbine generators run to meet the plant's electric demand. At night only one generator runs.

The system cost about $2 million and has met expectations. The company raised funds through an Industrial Revenue Bond issue. It has not bought any utility electricity since installing the generators. It also cannot sell excess electricity to the utility at a profit. The generators remain connected to the grid for emergency back-up. Cost savings were about $373,000/year, leading to a payback of 5.3 years.

Colortile Manufacturing Company, Melbourne, Arkansas

Colortile Manufacturing Company is a division of Colortile Supermart, Inc., that produces hardwood flooring for sale through a chain of do-it-yourself home remodeling stores. The Melbourne plant began operation in 1980 in a rural area of

Arkansas where the main fuel choice is L.P. gas. The plant design included a biomass boiler cogeneration system from the beginning.

About 60% of the raw lumber used in manufacturing becomes waste. Disposal would cost $75,000 - $100,000 per year. Instead, the waste wood is an energy source for low-pressure process steam used for lumber drying, process paint drying, building heat, and electricity. Pneumatic pickups throughout the plant collect sawdust, shavings, and small pieces of wood for storage in two concrete silos.

Two pneumatic fuel injectors receive the waste wood from storage and blow it into the radiant section of a boiler. The boiler produces about 31,000 lb/hr of steam at 450 psig and 725 °F. The steam powers two backpressure turbines that exhaust it at 10 psig for lumber drying and space heating. The turbine generators produce about 900 kW for internal use.

Cost savings were $272,000/year for process steam, $150,000 for electricity, and $75,000 - $100,000 for waste disposal. These savings paid back the investment in about 1.6 years. The short payback was partly due to designing the system into a new manufacturing plant, and partly due to the high cost of fuel there.

The system works well. It costs $24,000/year for maintenance parts and materials. Four operators, one per shift plus weekends, operate and maintain the boilers around the clock.

In 1986, the company upgraded its generators to 2000 kW to meet all the plant's power needs during the work week. This allowed the use of higher efficiency turbines and more of the steam production. In hindsight, the company would have installed a larger boiler to allow for greater plant expansion.

Young Manufacturing Company, Inc., Beaver Dam, Kentucky

Young Manufacturing is a millwork company located in Beaver Dam, Kentucky. It is a small business that produces about 2 million board feet of product per year. Before switching to a woodwaste boiler in 1974, the company operated combination natural gas/woodwaste fired kilns that were inefficient and smoky.

As part of a plant expansion and upgrade, the company added a biomass-fired cogeneration system in 1974. The owner, Robert Young, visited 10 wood-fired boilers and contacted various vendors. He then bought the best elements from the systems he had seen.

A pneumatic pickup system inside the mill transports sawdust to two silos. A live bottom belt conveyor system delivers fuel to the boiler's forced air injection system. Fuel burns in suspension above a fixed grate. A large after-burn chamber burns out all particles.

Steam from the boiler originally powered two 350 kW steam piston generators -- rebuilt 1927 and 1934 models. (In 1987 and 1991 Young replaced the steam piston engines with turbine/generators.) One generator supplies power to the pneumatic blower and fuel feed system. The other supplies power to the rest of the mill. Low pressure steam from the turbines goes to the lumber drying kilns. Condensate recycles to the boiler. The system supplies 100% of the plant's heat load and about 35% of its electric load.

The boiler started up in 1974. One generator started up in 1976, the second in 1978. Plant personnel did much of the construction work. The boiler cost $250,000, the generators $100,000. Operating and maintenance costs were $70,000 and electricity costs were $24,000/year. These compared with an estimated $290,000/year for purchased energy. Annual savings after startup were at least $196,000, leading to a payback of 1.8 years. The system has been successful and reliable. The company received an award from the EPA for its excellent emissions record.

DeSoto Hardwood Flooring Company, Memphis, Tennessee

DeSoto Hardwood Flooring Company has been a manufacturer of oak flooring and hardwood lumber since 1912. The company has burned wood waste in boilers since the early 1920s. It still operates one of the original boilers; it replaced the other in 1976. The boilers produce steam to heat the company's dry kilns.

In 1983, a contractor proposed a cogeneration system. DeSoto estimated it could save 25% on energy by reducing peak electric purchases from the utility. The company decided in early 1984 to install a steam turbine generator and had it on line in July 1984.

Hogs and screens size the fuel (shavings, sawdust, knots, rough ends, and strips of waste wood). Silos store the fuel, and a pneumatic system injects it into a suspension-fired watertube boiler. About 20,000 lb/hr of steam (150 psig) power a backpressure turbine that runs a 300 kW generator. The steam leaving the turbine fires the kilns.

Electric bills dropped from $16-18,000/month to $12-13,000/month, saving $48-60,000/year. The turbine-generator cost $70,000 to install and $4800/year in O&M costs. The payback was less than 1.5 years. The company is happy with the system and may add capacity to use its waste material more fully.

Howes Leather Company, Frank, West Virginia

Howes Leather Company operates a leather tannery that employs 185 people and handles 1400 cattle hides a day. In 1980 the company began planning a switch from its oil-fired boiler to a new wood-fired system. It came on line in 1982. The company buys about 46,000 tons/year of bark, sawdust, and wood chips from sawmills within a 75-mile radius. Trucks dump the fuel; hogs and screens size it;

silos store it. Augers feed the fuel to a watertube boiler. The fuel burns partially in suspension and partially over a fixed grate.

The boiler produces about 60,000 lb/hr of steam (270 psig, 600 °F), which runs a backpressure generator. The 875 kW generator supplies about one-third of the plant's electricity. In the original plant, steam left the turbine at 100 psig. A heat exchanger and valve cooled and depressured it further for process and space heating. After successful operation of this system, the company installed a second steam turbine in line with the first. It produces an additional 650 kW and reduces the steam pressure to a level more suitable for process and space heating needs.

The original boiler/generator system cost about $2.3 million, and had a payback of about 4.2 years. The system has proven reliable. The original fuel oil boilers remain as a back-up system, but have not operated since the wood-fired system came on line.

Wood Power, Inc., Plummer, Idaho

In 1981 the owner of Pacific Crown Timber Products decided to install a cogeneration power plant near his sawmill in Plummer, Idaho. The Wood Power, Inc. cogeneration plant has benefitted the sawmill and the community. It is a profitable operation and it gives the sawmill a way to get rid of its wood waste. The sawmill meets all its dry kiln steam requirements with steam from Wood Power. It no longer has its own boiler to own and operate. The cogeneration plant emits far less pollution than the tepee burner the sawmill previously used. Residents of Plummer appreciate the improved air quality and feel that the cogeneration plant has made the sawmill a much more stable and strong business.

In 1981, Wood Power, Inc. and Washington Water Power (WWP) signed a 35-year power sales agreement for 6 MW of power. The contractor for the plant had done preliminary work for about a year. The contractor completed construction of the plant almost entirely with used equipment under a turnkey contract in 1984. Including the fuel storage building, it cost $5,136,000, or about $800/kW.

The plant is next to the Pacific Crown Timber Products sawmill. It has a hog fuel boiler and a 6 MW steam turbine-generator. The plant trades process steam to the sawmill for waste wood fuel. Pacific Crown uses steam and waste heat from Wood Power's plant to dry lumber products.

Wood Power paid for the project with a $3.6 million bank loan, demand notes (for interest only) from the owner and Pacific Crown totalling $907,000, and equity financing of $100,000. The collateral requirements for the bank loan were stringent. The company had to maintain minimum levels of cash deposits and net worth and could only spend so much per year for fixed assets and officer pay. Wood Power pledged all its assets as collateral, and the owner guaranteed the loan. The project has done well financially, with retained earnings of $3.2 million as of June 1989.

The contract requires Wood Power to deliver at least 39.42 million kWh/year to the WWP substation about one mile away. Wood Power delivers an average of 42 million kWh/year. Line losses between the plant and the substation are about 5%. The boiler operates best at 5.2 to 5.3 MW output, so the plant delivers an average of 4.9 to 5.0 MW to the substation. This means that the plant must operate about 90% of the time, or about 8,000 hours a year, to produce its contracted energy.

Wood Power built a new power line to deliver power to the WWP substation, at a cost of $121,800. Three wires deliver power from the plant to the substation, and three wires bring power back to the plant and the sawmill.

The plant uses 10 tons/hour of hog fuel (50% moisture). Air blows the hog fuel through a pipe from the sawmill to Wood Power's fuel storage building. The sawmill can supply all the fuel (waste wood) that Wood Power needs. Efficiency of the plant in converting hog fuel into delivered electricity is about 21%.

Operators move fuel from storage with a front end loader. A chain bar conveyor feeds augers and conveyors that carry the fuel to the boiler. Spreader stokers feed the fuel to the traveling grate boiler.

The steam turbine has three extraction points. High pressure steam and low pressure steam heat boiler feedwater in separate feedwater preheaters. Intermediate pressure superheated steam (50 psig, 510 °F) flows to Pacific Crown's dry kilns.

Wood Power sends hot air produced by bearing friction, generator cooling, and boiler heat loss to Pacific Crown for use in one of its drying kilns. In the summer, this kiln can dry wood in nine days; in the winter it takes nine weeks. By contrast, the kilns that use steam can dry wood in 30 hours in the summer and 50 to 60 hours in the winter.

WWP pays Wood Power an average of 5.36¢/kWh for electricity. Wood Power buys electricity to operate the plant from the City of Plummer (a municipal customer of WWP) at an average of 3.65¢/kWh. Wood Power is better off buying electricity than using its own electricity to run the plant.

The project economics have been favorable (see Table 7). Not including overhead, the average monthly income exceeds the average monthly expenses by $58,000. (These figures are for the four years 1986-1989.) The capacity payment is $307/kW-year. Energy payments are equal to the number of kWh produced in a month times the latest approved avoided energy cost. (In 1989, this ranged from 0.7¢/kWh to 1.4¢/kWh.)

Wood Power got its air quality permit in one month. Visible emissions cannot exceed 20% opacity for more than three minutes in any hour. Emissions of particulate matter cannot exceed 0.080 grains per standard dry cubic foot of effluent gas corrected to 8% oxygen.

Table 7
Wood Power, Inc. Project Economics

Income (monthly average, $)		Expenses (monthly average, $)	
		Debt service	73,000
Capacity payment	153,000	O&M costs	40,000
Energy payment	34,000	Utilities	16,000
Total income	187,000	Total expenses	129,000

The plant initially had two multicyclones in series to clean the stack gas. Wood Power and its contractor knew this design might not meet the permit requirements, and it did not. The contractor made good on its guarantee and installed a wet scrubber. Since then, Wood Power has maintained emissions well within permit standards.

The state of Idaho does not inspect boilers. Wood Power's insurance company, Travelers, inspects and certifies the boiler each year. The state does not regulate the plant's ash disposal, because the plant is on an Indian reservation. The ash is filling in a low area at an elementary school nearby. Eventually the school will cover the area with topsoil.

The plant shuts down for 10 days of maintenance each year, after meeting its annual energy minimum. Every five years the shutdown is longer. Operators take the turbine apart, reset the diaphragm, and repair or replace blades. The sawmill has to plan to operate without any drying steam during the annual shutdown.

Wood Power changed its contract with WWP in 1988 from a January 26 year to a July 1 year. This allows Wood Power to shut down in June -- a better time than January for both parties. In June, WWP needs less energy, and Wood Power has better weather for doing repair work.

9

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10

GLOSSARY

Ash -- non-combustible fraction of a fuel; can also contain unburned char.

Avoided costs -- The Federal Energy Regulatory Commission (FERC) defines "avoided costs" for cogeneration transactions. They are the costs of energy or capacity (or both) that an electric utility would pay to generate or build itself, or buy from another source. They include both fixed and running costs that a utility can avoid by obtaining energy or capacity from a qualifying facility. (See also: capacity; dispatch; energy; qualifying facility.)

BACT -- Best Available Control Technology; air emissions control technology mandated by Federal regulations.

Baghouse -- a chamber fitted with fabric filters that collect solid material in the flue gas from boiler exhaust.

Boiler horsepower (bhp) -- the equivalent of heat required to change 34.5 pounds per hour of water at 212 °F to steam at 212 °F. It is equal to a boiler heat output of 33,475 Btu/hr.

Btu -- British thermal unit; a unit of heat equal to 252 calories. The quantity of heat required to raise the temperature of one pound of water from 62 °F to 63 °F.

Capacity costs -- Capacity costs are the costs associated with providing the capability to deliver energy. They are mainly the capital costs of facilities (power plants, transmission lines, etc.). If a purchase from a QF allows a utility to avoid buying new capacity, the avoided cost is the cost of the *new* capacity.

Cogeneration -- simultaneous generation of electricity and heat energy.

Dispatch -- Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. The utility's avoided *incremental* costs (not average system costs) are the avoided costs.

Electrostatic precipitator -- Gases flow through a device where particles receive an electric charge. A magnetic field drives the charged particles to collector plates before they can escape through the stack and into the atmosphere.

Energy costs -- Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours, kWh). They include the cost of fuel and some operating and maintenance expenses.

FERC -- Federal Energy Regulatory Commission. FERC regulates the incentive rates that utilities must pay to QFs under PURPA. An owner or operator of a QF must notify FERC and provide the necessary information for qualifying status.

Flue gas -- all gases and products of combustion that leave a furnace by way of a flue or duct.

Fluidized bed -- air blows through a sand bed to bubble or entrain the sand.

Fly ash -- Fine solid particles of ash and char carried out of a furnace by the draft.

Heating value -- of a fuel is the heat generated when 1 lb burns completely. Higher heating value (HHV) includes the latent energy of condensation of water. It is measured by burning a sample with pure oxygen in a calorimeter. Water absorbs the heat of combustion. The rise in the temperature of the water determines the heating value.

The lower heating value (LHV) is the heating value when the product water remains in the gaseous state (as it does in most boilers). For wood with a 50% moisture content, the LHV is about 18% lower than the HHV. For bone-dry wood , the LHV is about 6.2% lower than the HHV. The generating efficiency of a power plant calculated from the LHV of a fuel is higher (by the same percentage) than the efficiency calculated from the HHV. Europeans typically use LHV; Americans typically use the HHV.

Hog -- a machine for reducing the size of wood slabs, edgings, bark, and other material. Two types of hog exist: knife types chip the wood, and hammermills beat or grind the wood against a screen or spaced bars to reduce its size. Hog fuel is the sized product from the hog.

Interconnection costs -- A QF must reimburse an electric utility that purchases its electricity for any interconnection costs.

Payback -- a method to see whether it is worthwhile to invest in an item or a process that will increase income or reduce operating costs. The payback period is the number of years it will take for the investment to be recovered through cost savings or added income.

PUHCA -- Public Utility Holding Company Act of 1935. FERC has exempted QFs from all provisions of PUHCA related to electric utilities.

PURPA -- Public Utility Regulatory Policies Act of 1978. Before PURPA, utilities did not have to buy cogenerators' electricity at appropriate rates. Some utilities charged discriminatorily high rates for back-up service to cogenerators. Cogenerators ran the risk of regulation as electric utilities. PURPA removed these obstacles.

Qualifying facility -- There are two types of QFs: small power production facilities and cogeneration facilities. To qualify, no more than 50% of the equity interest in the facility may be held by an electric utility or a public utility holding company. (This discussion omits criteria for small power production facilities that do not cogenerate.) Cogeneration topping-cycle facilities must produce at least 5% of their total energy output as useful heat. Cogeneration topping-cycle facilities that burn any natural gas or oil must meet an efficiency test.

Sanderdust -- extremely fine waste wood product from any sanding operation (e.g., a plywood mill).

Scrubber -- an apparatus for removing impurities and contaminants from gases by use of water or a dry granular medium.

Silo -- an air-tight building used to store wood fuel under certain conditions.

Spreader stoker -- a device that throws or blows fuel into the firebox of a boiler so that it spreads evenly over the grate.

Suspension burner -- a device to burn fine particles of wood turbulently mixed with forced air over the main fuel bed.

Turndown ratio -- the lowest load for which a boiler will operate efficiently, divided by the boiler's full load capacity rating.

Turnkey system -- the contractor designs, builds, and installs a complete system.

Volatile matter -- the fraction of a solid fuel that evolves as the fuel heats up. The volatile matter burns as a gas.

Wheeling -- Transmission of electricity from one utility to another. With consent of the utilities and the QF, a utility can wheel a QF's power to another utility. The second utility buys the electricity at its avoided cost, taking transmission losses into account.