BIOMASS COGENERATION

A BUSINESS ASSESSMENT

MASTER

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NOVEMBER 1981

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WSUN--113

DE82 011773

DOE Contract No.: **DE-AC02-79CS30159**

Produced for: **WESTERN SOLAR UTILIZATION NETWORK**

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A program of the Western States to increase business activity, sales, and consumer satisfaction in solar energy and renewable resources. Serving Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming.

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STUDY ABSTRACT

The objective of this business assessment is to identify the important business issues associated with the adoption and operation of biomass cogeneration systems and to provide options in addressing these issues. Due to the localized characteristics of biomass supplies and to the site specific nature of matching thermal and electrical loads for cogeneration, each firm must evaluate biomass cogeneration within the framework of its own particular situation.

This guide has been developed for use by firms considering biomass cogeneration and for use by financial organizations that could provide funding for such projects. It serves as an overview of the biomass cogeneration area and provides direction for more detailed analysis. The business assessment is based in part on discussions with key officials from firms that have adopted biomass cogeneration systems and from

organizations such as utilities, state and federal agencies, and banks that would be directly involved in a biomass cogeneration project.

In certain situations, biomass cogeneration can reduce energy costs, improve fuel and electricity supply reliability, utilize proven technology, reduce environmental compliance costs, and receive favorable tax treatment. Considering these benefits, biomass cogeneration is a viable and cost-effective energy alternative under existing conditions. Presently, there are over 40 biomass cogeneration facilities in the 13 Western states served by Western SUN. This number is expected to grow based upon the number of inquiries made by companies to engineering design firms and financing organizations and upon the improving competitive conditions for biomass cogeneration.

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INTRODUCTION

Rapidly increasing energy costs and concern over supply reliability have sent many businesses looking for new and exotic technologies to solve their energy problems. Biomass and cogeneration applications are neither new nor exotic. **Biomass**, most typically in the form of wood, is one of the world's oldest energy resources. With the continued increase in petroleum prices and the deregulation of natural gas prices, wood is used more and more as an industrial energy resource. Forest products firms have been burning wood wastes for years, and now many firms without such "captive" wood resources are turning to wood. For example, the *Energy User News* (June 1, 1981) reported that a metal fabricating company reduced fuel costs by 84 percent in switching from No. 6 oil to wood. This energy saving translated into a two-year payback on the company's investment.

Biomass utilization is now extending beyond traditional wood resources. Forest residues, wooden pallets, waste paper, walnut shells, almond shells, peach pits, and cotton gin waste are being burned for energy. Bagasse, the waste from sugar cane, is being burned to produce process heat and electricity by every single sugar producer in Hawaii. Biomass resources presently account for 2 percent of the country's total energy production. The Forest Service estimates that, within 10 years, about half of the available forest residues could be recovered economically. This utilization would increase the contribution of biomass to 8 percent of the domestic energy supply.

Traditionally, biomass has been burned in boilers producing steam for process heat. With the large increases in electricity prices, it is becoming cost-effective to use the biomass-produced steam in a **cogeneration** mode—i.e., to use the steam output to produce both electricity and process heat. Because of the thermodynamics associated with cogeneration, overall system efficiencies can be significantly greater when compared to generating electricity and process heat separately.

In the United States, cogeneration is actually an old idea that is being rediscovered. When industries began to use electricity some 80 years ago, most factories cogenerated their own heat and electricity. As recently as 1950, all forms of cogeneration provided 15 percent of the country's electricity; but by 1980, the figure had

fallen to 4 percent due to the availability of inexpensive power from utilities. Now, because of rapidly rising fuel costs, uncertainties associated with electricity supplies, improved federal incentives, and environmental constraints, an increase in new cogeneration applications seems imminent. *Business Week* (April 6, 1981) reported that the number of cogenerators in the U.S. could triple by 1990.

The economic potential for industrial firms generating excess electricity has been significantly enhanced by the Public Utility Regulatory Policies Act (PURPA). This legislation requires utilities to purchase cogenerated electricity at rates based on their avoided costs. Avoided costs are the incremental generation expenses the utility would have incurred had the industrial cogenerator not produced power. These rates, termed buyback rates, can provide strong incentives to cogenerate. For example, buyback rates offered by Pacific Gas and Electric Company have increased from 0.4¢/kWh four years ago to more than 7.0¢/kWh. The cogenerator must decide which option is more cost-effective: selling power to the utility or serving the firm's own electrical requirements.

As separate approaches to energy supply or in combination, biomass cogeneration can offer a number of benefits to industrial firms.

- **Reduced energy costs.** In some parts of the country, wood and other biomass material prices are one-third that of petroleum fuels on a Btu-output basis. Biomass will become even more cost-effective than natural gas as natural gas prices are deregulated. Many firms are now burning their biomass wastes instead of securing waste disposal sites.
- **Proven technology.** The technology associated with wood waste and with cogeneration has been around for a long time. Forest products firms can attest to overall system reliability. Recent experience with other biomass materials, such as crop residues (straw, stalks, tree prunings), agriculture processing residues (fruit and vegetable pits, nutshells, gin trash), and industrial waste (pallets, cardboard), has also been positive.
- **Reduced environmental compliance costs.** Essentially no sulfur emissions are associated with the utilization of biomass. The particulates associated with biomass combustion can be controlled effec-

tively with present collector technology. Ash disposal requirements are typically low. Biomass systems that can completely burn fuel have received a positive review by environmental agencies at both state and federal levels.

- **Favorable tax treatment.** Biomass cogeneration is consistent with the overall objective of the country's energy plan to reduce dependence on imported petroleum. As such, much of the recent energy and tax legislation enhances the viability of biomass cogeneration. Tax credits of 20 percent are available at the federal level. Other federal and state programs have been designed to further increase biomass cogeneration development.
- **Stabilized industry energy supply and therefore support to the local economy.** Biomass cogeneration utilizes local resources. Instead of buying fuel from outside sources, biomass cogeneration uses fuel typically found within a 50-mile radius. In some cases, biomass cogeneration has proven to be the only means of providing energy in a cost-effective manner. Firms on an electricity curtailment list can enhance their supplies with cogeneration. A reliable, cost competitive energy source can provide security to industrial firms and to the community itself.

Considering these benefits, biomass cogeneration can be a viable and cost-effective energy alternative under existing conditions. Presently, there are over 40 biomass cogeneration facilities in the 13 Western states served by Western SUN. This number is expected to grow at a steady rate based upon the number of inquiries made by companies to engineering design firms

and financing organizations and upon the improving competitive conditions for biomass cogeneration.

The objective of this business assessment is to identify the important business issues associated with the adoption and operation of biomass cogeneration systems and to provide options in addressing these issues. Due to the localized characteristics of biomass supplies and to the site specific nature of matching thermal and electrical loads for cogeneration, each firm must evaluate biomass cogeneration within the framework of its own particular situation.

This guide has been developed for use by firms considering biomass cogeneration and for use by financial organizations that could provide funding for such projects. It serves as an overview of the biomass cogeneration area and provides direction for more detailed analysis. The business assessment is based in part on discussions with key officials from firms that have adopted biomass cogeneration systems and from organizations such as utilities, state and federal agencies, and banks that would be directly involved in a biomass cogeneration project. The guide is organized into five chapters:

- Biomass Cogeneration Systems
- Biomass Cogeneration Business Considerations
- Biomass Cogeneration Economics
- Biomass Cogeneration Project Planning
- Case Studies.

BIOMASS COGENERATION SYSTEMS

The technology required for biomass cogeneration has been fully developed and has established a strong record of predictable performance and reliability. The forest products industry, for example, has been burning wood waste for many years. The use of other biomass materials, such as bagasse, nut shells, and fruit pits, is also proving successful.

Biomass cogeneration is based on the integration of six separate steps or technologies: harvesting, transportation, storage and handling, combustion, cogeneration (use of steam for electrical generation and subsequently for process heat), and waste disposal. Of these steps, combustion and cogeneration involve the greatest amount of technical specification and hardware. Naturally, in the case of site generated wastes, such as mill residues and agricultural processing wastes, the harvesting and transportation activities would not apply.

Wood and other biomass **harvesting** techniques generally fall into three categories: clear-cutting systems, selective cutting systems, and residue collection. Most harvesting equipment can be used in any of these systems, although local site and economic conditions will influence the type, size, and combinations of equipment required. Improved technology is being developed to harvest and process (chip) the resource in the field, thus reducing handling and transportation costs. Wood harvesting technology could be incorporated into and supported by improved forest management policies. Fuel acquisition could be facilitated by the development of a fuel supply infrastructure.

Transportation of biomass materials is primarily by truck or rail. Because of the low energy density and high moisture content of biomass, there are limits to the distance biomass can be moved. A rough estimate of this limit would be 50 miles based on estimated transportation costs of 8¢/ton/mile.

Storage and handling requirements for solid fuels are more extensive and costly than for liquids or gas. There are trade-offs between outdoor and indoor storage and between small and large inventory levels. One of the issues associated with using several types of biomass resources is maintaining a consistent fuel quality or blend. Some combustion systems are more flexible than others in this regard. Another issue is combustion

hazards in storing biomass, but new technology is being developed to monitor the temperature levels of biomass storage facilities, thus limiting the potential for spontaneous combustion. Pile management methods are well established in the forest products industry.

Combustion technology appropriate for biomass utilization can be grouped into four categories: pile burning, grate burning, suspension burning, and fluidized bed combustion. Fluidized bed combustion is a relatively recent development which has great promise for biomass combustion. Advantages of fluidized bed technology include the capability to burn fuels over wide ranges of size, shape, moisture content, and impurity level. In addition, fluidized bed systems can be designed to effectively control environmental emissions. Descriptions of combustion technologies, along with a comparative evaluation, is provided in SERI's *Decision-maker's Guide to Wood Fuel for Small Industrial Energy Users*.

Cogeneration involves the sequential generation of power (or mechanical energy) and process heat. Interest in cogeneration stems from its inherent efficiency. A turbine generating electricity can be run with very little additional fuel when added to a process steam system—an overall system efficiency of 65 percent can be achieved. In contrast, a biomass facility dedicated to electrical production only will convert approximately 28 percent of its energy input to electricity, allowing the remaining 72 percent to escape as heat loss.

In general, there are two types of cogeneration systems, differentiated on the basis of whether electrical energy or thermal energy is produced first. The most commonly used are topping-steam cycles that burn fuel to produce high-temperature heat which, in turn, produces high-temperature, high-pressure steam that can then be expanded through a turbine to produce electric or mechanical power. The exhaust steam from the turbine is then used in an industrial process. The turbine can be designed to provide a single steam outlet (i.e., back pressure turbine) or to allow extraction of steam at varying temperatures and pressures (i.e., extraction turbine). Bottoming-cycle systems produce process heat first subsequently using reject heat to produce electricity. Unfortunately, the temperature requirements of

COMPARISON OF CONVENTIONAL ELECTRICAL AND PROCESS STEAM TECHNOLOGY WITH COGENERATION

(A) Conventional Process-Steam System Requires the Equivalent of 1-3/4 Tons of Greenwood Chips to Produce 9600 lb of Process Steam

(B) Conventional Electrical-Generating System Requires the Equivalent of 1 Ton of Greenwood Chips to Produce 680 kWh Electricity

(C) Cogeneration Topping System Requires the Equivalent of 2-1/4 Tons of Greenwood Chips to Generate the Same Amount of Energy as Systems A and B

Adapted from *Cogeneration: Technical Concepts, Trends, and Concepts*, U.S. Department of Energy, DOE-FEU-1703, September, 1978.

typical industrial processes are too low to economically generate electricity with the available waste heat. Therefore, topping cycle applications seem to hold the most promise for most industrial processes.

Disposal costs are reduced if biomass is used as fuel

rather than being landfilled or burned in open fields. The ash associated with biomass combustion typically amounts to less than 1 percent of the fuel volume and is environmentally safe to landfill. Environmental impacts associated with the disposal activity would be reduced with biomass utilization.

BIOMASS COGENERATION BUSINESS CONSIDERATIONS

In assessing any major technology, there are a variety of business related considerations. For the assessment of biomass cogeneration, the principal factors involve:

- Fuel sources and reliability
- Utility interface
- Financing and operating considerations
- Environmental and institutional factors
- Regulatory uncertainty.

Each of these items is discussed in the following section in terms of its relative significance to biomass cogeneration.

Fuel Sources and Reliability

Biomass resources supply 2.2 quads* of the country's annual energy needs of 80 quads. Most of this amount is made up of wood and mill wastes burned by firms in the forest product industry. The Forest Service estimates that about 9.6 quads of unused forest residues are available annually, excluding stumps and roots. Much of this available resource is in the form of unharvested dead timber, remnants of commercial tree species left behind after logging operations, low valued species, and unused mill wastes. The agricultural processing industry, in which fruit pits, nut shells, and cotton gin trash are produced, can provide an additional 6 to 10 million tons (roughly 0.15 to 0.25 quad) annually of residue suitable for energy conversion. More complete use of these wastes and residues could save valuable fuel oil and lower the operating costs of forestry and farm businesses.

Far more important than estimates of nationwide fuel availability is an intimate knowledge of biomass resources in the vicinity of the biomass cogeneration site. The low-density, high moisture nature of this fuel makes it generally uneconomical to transport beyond 40 or 50 miles. Thus, one of the first steps in assessing the viability of biomass cogeneration is to conduct a comprehensive survey of available resources including:

- **Residues from the forest.** Wood and bark suitable for fuel include waste from logging operations—such as tree tops, limbs, and cull logs—as well as other on-the-ground or standing timber. The volume of non-commercial timber may amount to 40 percent or more of the forest inventory. Forest management with a view toward the value of timber as an energy source could add to the biomass resource potential.
- **Residues from forest products facilities.** Mills producing lumber, plywood, veneer, and other wood products generate substantial quantities of waste that are suitable for fuel. Only about half of the volume of logs used by a sawmill is turned into lumber. The remainder is waste. Wastes from the secondary forest products industry, such as furniture plants, are another potential fuel source. For example, nearly one-half of the lumber used in producing furniture is waste. While residues from forest products facilities are the most obvious and cost competitive source of biomass fuel, they are the most used already.
- **Residues from agricultural crops.** The residues left in the fields after a harvest represent hundreds of millions of tons in unused biomass resource. Examples of such wastes include corn stover, wheat straw, stalks, and tree prunings and thinnings.
- **Residues from agricultural processing.** Fruit and vegetable pits (peaches, olives), nut shells (almonds, walnuts, peanuts), bagasse, and cotton gin trash are all biomass resources presently being used for fuel. These resources are collected at the plant during normal processing, thus transportation and handling costs are minimized and potential disposal costs reduced.
- **Residues from industrial wastes.** A number of firms are burning their waste paper, cartons, and pallets to reduce both their energy costs and disposal expense. A few cities and private firms have developed facilities to produce refuse-derived fuels (RDF) or to burn garbage.
- **Prepared biomass fuels.** Companies selling biomass fuels in pellet and briquette form operate plants in several parts of the country, and additional production facilities are under construction or in a planning phase. Although wood is the most commonly used material, agricultural residues, such as peanut shells, are being formed into logs for residential use.

* A quad equals 10^{15} Btu's. A Btu is roughly equivalent to the energy in a kitchen match. The present biomass utilization of 2.2 quads translates into approximately 90 million dry tons of resource.

In general, biomass materials have fairly similar characteristics and are priced at levels far below scarce fuels, such as petroleum and natural gas. Typical characteristics of the various biomass fuels are compared in the diagram below.

There are a number of factors which should be addressed in assessing the fuel supply for a biomass cogeneration system. Most of these factors focus on the future reliability of the fuel source.

- **Increased demand for biomass as a fuel.** If the long-term price and reliability of fossil fuel supplies continues to be unfavorable, the competition and price for biomass fuel will increase. Many firms that formerly sold their wastes on the market may begin using the fuel internally and many large facilities may forcibly move into the market, buying up available mill wastes to reduce their consumption of fossil fuels.
- **Competing uses for biomass.** Greater use of wood wastes in composite materials, in pulping, and in feedstocks will compete with biomass utilization as a fuel. Mill wastes are used in preparation of animal bedding and other absorbents, mulch, charcoal, and fireplace logs.
- **Shifts in the market volumes for wood products.** The economic downturn in the forest products indus-

try has clearly limited the supply of forest product wastes. Continued decreases in housing starts could force the closing of additional lumber and plywood mills in the years ahead.

- **Changes in technology.** Improved technologies being introduced into lumber mills—such as thinner saw blades—will decrease production of sawdust and planer shavings per unit of output. The greater use of advanced construction technology and of particle board and other composite materials could adversely influence lumber and plywood production.
- **Fuel supply seasonality.** Many potential biomass resources are only available during certain portions of the year. If year-round fuel supply is required, then extensive fuel storage or alternate fuel sources must be obtained. One of the facilities described in the case studies is planning to burn agricultural waste during the 5-month harvest season and wood wastes during the remaining months. Naturally, for those biomass cogenerators using their own internally supplied fuel, the level of available fuel supply is often directly related to their level of operations and thus to their level of energy requirements.
- **Volatility of the market.** Because of the seasonal nature of biomass resources and the sometimes rapid shifts in supply due to a plant closing, prices for biomass resources on the open market can

COMPARISON OF FUEL SOURCE CHARACTERISTICS

Fuel Source	Typical Units	Million Btu's Per Unit As Received	Typical Combustion Efficiency	Moisture Content Wet Basis (%)	Ash Content (%)	Sulfur Content (%)	Required Units Per Million Btu's of Output	Typical Cost Per Unit	Calculated Dollars Per Million Btu's Output
Fuel Oil (No. 6)	Gal	0.15	0.80	—	—	0.3-1.5	8.33	\$0.90/gal	7.50
Natural Gas	tcf	1.00	0.78	—	—	—	1.29	\$4/tcf	5.16
High Sulfur Coal	Tons	24.0	0.82	5	5-15	2-8	0.051	\$30-45/ton	1.52-2.28
Low Sulfur Coal (Eastern)	Tons	24.0	0.82	2.5	—	0.6-2	0.051	\$50-70/ton	2.34-3.56
Wood Pellets	Tons	15.3	0.78	10	2.7	Trace	0.084	\$40/ton	3.35
Greenwood Chips	Tons	8.5	0.67	50	2.7	Trace	0.176	\$10-20/ton	1.76-3.51
Bagasse	Tons	9.0	0.70	52	1.8	—	0.159	*	*
Almond or Walnut Shells	Tons	16.2	0.82	5	3.3	—	0.075	*	*
Peach Pits	Tons	18.4	*	10	0.6	Trace	*	*	*
Cotton Gin Trash	Tons	12.9	*	14	—	—	*	*	*
Wheat Straw	Tons	13.5	*	10	8.1	—	*	*	*
Corn Stover	Tons	7.9	*	47	3.0	0.08	*	*	*

*Information not yet established.

change quickly. Over a 12-month span, they have risen in some areas from \$10/ton to \$20/ton. Captive resources would naturally insulate the firm from such price volatility.

- **Transportation costs.** Transportation costs can be a major cost component of the fuel price. Present estimates range from 6 to 12¢/ton/mile. These costs tend to escalate with the price of petroleum. These transportation costs limit the distance at which it is still economically feasible to ship biomass.

There are no secrets in trying to guarantee a reliable fuel supply. The ideal strategy is to have the fuel supply within direct control of the company. Detailed resource analyses can give a good indication of the potential biomass fuel supply in the area. If the long-term availability of woodwaste from surrounding mills seems questionable, then the next level of resource—forest residue and noncommercial timber should be considered. Chipping in the woods of the tops and limbs and of noncommercial species has been demonstrated and is being done in several areas. The development of a supply infrastructure is necessary before forest residues can be considered a reliable source of fuel. Such structures are being developed in some regions.

A fuel supplier should be carefully selected, recognizing that there are few, if any, companies dealing in biomass resources that are comparable in size and experience to the energy companies that sell coal, oil, or natural gas. Further security against fuel shortages can be obtained by designing fuel handling, combustion, and pollution-control systems that are flexible enough to accommodate two or more fuels.

Utility Interface

There are a number of alternatives open to a firm deciding what to do with the electricity produced from its biomass cogeneration system. Selection of the best alternative is often difficult due to the uncertainty associated with future fuel and electric prices, the changing regulatory environment, and the potentially complex rate negotiations that could be required. The options for a firm include:

- Using the power within the company, selling it to a utility, or selling it to another industrial customer (internal use versus wholesaling versus retailing)
- Sending the power to a point within the service area of the firm's utility versus sending it outside the service area

- Sending the power to a point within the state versus sending it across state boundaries (intrastate versus interstate).

The combination of these three decision levels results in ten potential operating arrangements depicted to the right. Before these operating arrangements can be evaluated, a firm should carefully review the appropriate energy regulations to determine what effect they may have on the firm's decision.

Energy Legislation

Recent federal energy legislation has had the overall objective of encouraging a market-based price for energy resource transactions and decreasing our nation's dependence on imported petroleum. The pieces of federal energy legislation that most directly affect the viability of biomass cogeneration include the:

- Public Utilities Regulatory Policy Act (PURPA)
- Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Bill)
- Power Plant and Industrial Fuel Use Act of 1978.

THE PUBLIC UTILITIES REGULATORY POLICY ACT. The broad purpose of the Public Utility Regulatory Policies Act (PURPA), one of the five parts of the National Energy Act, is to encourage conservation of energy and efficient use of energy resources by public utilities. One means of achieving this end is to encourage production of electric power by cogeneration and by small power producers. The Public Utilities Regulatory Policy Act (PURPA) has two sections (201 and 210), which address the use of alternative energy sources. Small-scale electric power producers—including those operating systems fueled by biomass, solid waste, wind, and solar energy—can qualify under the legislation.

Adoption of PURPA enhances the viability of biomass cogeneration in a number of ways. First, utilities are required to purchase the electric power generated by biomass cogeneration facilities and are required to pay rates based on their avoided cost for this power. Avoided cost to the utility is the incremental cost of generating the power itself or purchasing it elsewhere. Second, the regulation allows the small power producing firms to continue purchasing their electricity requirements at standard industrial rates while selling power to the utility grid at avoided costs. Depending on the associated economics, the firm has the choice of serving its own load or selling power. Third, utilities cannot charge discriminatorily high rates for backup power needed by biomass cogenerators. Fourth, in most instances, biomass cogenerators are not subject to state and federal regulation as an electric utility.

OPTIONS IN THE USE OF COGENERATED ELECTRICITY

State public utility commissions retain the authority to establish rates and terms for the purchase and sale of electricity by biomass cogenerators. They can be contacted to determine the prevailing rates and specific conditions.

PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT. Objectives of the Pacific Northwest Electric Power Planning and Conservation Act (referred to as the Northwest Power Act) include:

- Helping the Pacific Northwest achieve an adequate power supply
- Holding utility rates lower than they would otherwise be
- Placing maximum reliance on conservation and renewable sources of energy in responding to growing demand for electricity.

The Northwest Power Act addresses several fundamental questions of power planning in the Pacific Northwest as encompassed by Washington, Oregon, Idaho, and the western portion of Montana. The Northwest Power Act settles long-standing disputes regarding access to the lesser expensive hydro-electric energy resources in the Northwest, sets priorities for

long-term electrical energy planning in the region, establishes a planning mechanism to assure adequate power supply, and creates a forum for debate on the significant electrical energy issues facing the region during the next decade. More specifically, the Northwest Power Act establishes a regional planning council with the responsibility of drawing up a plan for meeting the electrical needs of the region. The plan must give highest priority to cost-effective conservation and renewable sources of energy as means of responding to growing demands for electricity. Bonneville Power Administration (BPA) becomes responsible for meeting the loads of customers and managing the regional electrical system. The Act directs BPA to plan for and purchase as much conservation and renewable energy, and as many generating projects as are needed to prevent electricity shortages.

For the first time in several years, the investor-owned utilities in the region will sell BPA their average cost power. The lower cost power they purchase from BPA will be passed on to their residential and small farm customers. The publicly owned utilities in the region have always relied upon BPA for inexpensive federal power. That reliance will continue. In addition to the utility systems in the region, major industrial customers (direct service industries) will continue to purchase

power from BPA. In exchange for agreeing to higher power costs, they will be guaranteed a 20-year contract for present consumption levels.

The Northwest Power Act significantly enhances the viability of biomass cogeneration in the Pacific Northwest by:

- Providing a clear and comprehensive resolution to power planning questions which had contributed to regulatory uncertainty and hindered business investment planning in the Northwest
- Reducing a firm's risk in constructing a biomass cogeneration system by permitting BPA to pay the associated project costs if the project should fail
- Establishing \$1.25 billion dollars to be used strictly for power reductions or purchases resulting in conservation or renewable resource programs
- Allowing BPA to pay for feasibility studies and preliminary engineering for projects of less than 50 average MW's
- Enabling BPA to assist in financing of projects less than 50 average MW's
- Restricting BPA purchase of power from new conventional and nuclear facilities until it becomes apparent that regional electricity needs cannot be met by means of cost-effective conservation and renewables.

THE POWER PLANT AND INDUSTRIAL FUEL USE ACT OF 1978. In its original form, the Fuel Use Act prohibits the use of oil or natural gas in new electric utility generating facilities or in new industrial boilers having a fuel heat input rate of 100 million BTUs per hour or greater (approximately equivalent to a 75,000 lb per hour steam boiler or a 10 MWe electric plant) or an aggregation of units larger than 250 million BTUs per hour. New facilities must be designed to burn coal or an alternative fuel, which could include biomass. Exemptions to the requirements are possible if certain conditions are met.

The Power Plant and Industrial Fuel Use Act of 1978 enhances the viability of biomass technology by limiting the use of oil and natural gas by industrial firms. The restrictions are especially severe on firms seeking to expand boiler capacity. Biomass resources serve as a viable alternative to addressing the environmental and fuel supply reliability issues associated with coal. This Act is currently being revised and may be substantially changed in its final form.

Due to the nature of the regulatory environment, most biomass cogenerators have separated their electricity

purchases and sales. That is, because industrial rates are typically based on average cost pricing, these rates are sometimes lower than the rates at which the firm can sell to the utility. Thus in service areas where buy-back rates greatly exceed electric rates, firms sell all of the cogenerated power to the utility. This situation is already common in California. In some of the Mountain states and in Alaska, the buyback rate is much closer to the average industrial rate. In these situations, firms will use the power internally and sell (or buy) any excess (or shortage) power. In some cases, the exchange becomes a bookkeeping transaction in which the cogeneration system feeds directly into the grid and is separate from the firm's electrical demand system. The firm receives a credit for the produced power against its purchased power.

The selection of the best operating arrangement is based primarily on determining which option provides the greatest potential revenues or savings. Components that enter into the decision include:

- Present and future buyback rates
- Present and future electric rates
- Interconnection costs, stand-by charges, and wheeling charges.

These components are described in the following discussion.

PRESENT AND FUTURE BUYBACK RATES. As noted, buyback rates are based on the determination of avoided costs for the utility. Although the target deadline for this determination was set by PURPA for March 20, 1981, many of the rates are still in the process of being established. The table to the right gives an overview of buyback rates in each of the 13 Western states as of publication. In general, the utilities with the potential for offering the most favorable buyback rates would be those that:

- Are rapidly growing
- Have in-state siting problems
- Have a substantial gap between present costs and marginal costs
- Have high petroleum usage.

The majority of utilities serving the Western region have at least two of these characteristics. The importance of future buyback rates depends upon the nature of the contract between the utility and the biomass cogenerator. The typical arrangements include:

- Fixed-price, long-term (more than five years)
- Fixed-price, short-term (one to five years)
- Price adjusted to various indexes such as the price of petroleum or the level of avoided cost as it changes over time.

INDUSTRIAL ELECTRIC RATES AND BUYBACK RATES IN THE WESTERN REGION			
State	Average Industrial Rate (¢/kWh) ¹	Range of Buyback Rates (¢/kWh)	
		Energy Credits Only ²	Energy Credits plus Capacity Credits ^{1,3}
Alaska	5-8	3-5	No Capacity Credits
Arizona	4-6	*	*
California	3-7	5-7	5-8
Colorado	2-4	1-2	2-8
Hawaii	4-8	4-6	5-8
Idaho	1-3	2-3	4-5
Montana	1-3	1-3	1-5
Nevada	2-4	2-5	2-6
New Mexico	2-5	3-4	No Capacity Credits
Oregon	1-3	3-5	3-6
Utah	2-4	2-3	3-4
Washington	1-3	2-3	No Capacity Credits
Wyoming	2-3	0-2	0-3

¹Assumes a demand level of 1 MW and annual energy consumption of 5000 MWh (i.e., a capacity factor of 57 percent).
²Energy credits are the revenues paid by the utility for each kilowatt-hour of excess power (¢/kWh).
³Capacity credits are the additional revenues paid by the utility for each kilowatt of firm capacity produced by the biomass cogenerator (\$/kW/month).
*Rate levels were unspecified at the time of publication.

Naturally, the impact of increasing avoided cost estimates is most important in the latter two arrangements. It is clear that avoided cost estimates will continue to climb in the future. Future buyback rates could also be altered by changes in the manner in which they are calculated. While present regulations require using avoided costs, future rates could be calculated on an alternative basis.

PRESENT AND FUTURE ELECTRIC RATES. Present electric rates vary widely across the Western region. The presence of large amounts of hydroelectric power has enabled some utilities to offer electric rates far below the national average. However, most of the available hydro capacity has already been tapped. In order to develop additional resources, electric rates in the West have been increasing at rates above the national average. Some utilities have doubled rates over the past two years. As Western rates move toward the national average, the historically wide regional dis-

parity in industrial electric rates will gradually disappear.

INTERCONNECTION COSTS, STAND-BY CHARGES, AND WHEELING CHARGES. Under PURPA, the biomass cogenerator must pay the interconnection costs, stand-by charges, and wheeling charges associated with selling power back to the utility. Interconnection costs are those costs associated with linking a firm's power generation to the utility grid. Stand-by charges are those charges associated with the utility standing in reserve in the event of an outage of the firm's equipment. Wheeling charges are those charges associated with using a utility's transmission facilities to move power to other potential customers. Given the technical requirements involved, it is not expected that any of these charges will significantly impact the economics of biomass cogeneration. PURPA stipulates that many of these charges must be developed on a reasonable basis. Wheeling charges

and the permission to use transmission facilities are still not widely established. Very few utilities are in the business of transmitting power from biomass cogenerators although the technical and economic aspects are not expected to be significant. The problem is more one of institutional experience and orientation.

Utility Perspective

In approaching negotiations with a utility, it is best to understand the views many utilities have toward biomass cogeneration. Like all organizations, utilities are welcoming the possibilities of new technologies providing reliable, inexpensive, and environmentally compatible sources of energy. Biomass cogeneration certainly fulfills these criteria in many locations.

From the standpoint of the utility, biomass cogeneration has a number of advantages and disadvantages in helping the utility to meet the power demands of its customers. Theoretically, biomass cogeneration can assist the electric utility in rapidly attaining a more efficient system since lead times for construction of biomass cogeneration units are generally from 3 to 5 years, as compared to the 10 or more years required for large utility projects. These resources offer some flexibility in long-range planning and can assist in meeting short-term loads, especially in those situations where construction projects have experienced long delays. Since the qualifying facility would be primarily financed by non-utility entities, the strain of financing by the utilities in today's difficult markets would be lessened. Also, if the units are spread throughout the utility system, diversity of power generation would be established and could provide some protection to the utility from the disruption that occurs when large generating stations are forced out of service.

However, the buying back or wheeling of excess power generated by firms is not an altogether common concept. Even in the past when cogeneration was more prevalent than it is now, firms generated power for their own use and did not sell their excess power. Therefore, the idea of buying back or wheeling is not one that utilities can typically address by relying on previous experience. The issues associated with institutional inertia and reluctance to accept new ideas must be appreciated by firms beginning negotiations with a utility. With the passage of PURPA and the requirement that individual state regulatory commissions determine appropriate buyback rates and conditions, and with the relatively rapid increase in interest in biomass cogeneration, the impact of this barrier is being diminished.

There is no real agreement on the prices utilities should be required to pay for biomass cogeneration

capability. One of the basic problems in negotiations between utilities and cogenerators is the extent to which a firm's facility substitutes for the utility's planned expansion. It must be realized that:

- Utilities use a planning horizon of 6 to 20 years. Thus, the capacity benefits of a biomass cogeneration system are minimized when the short-run requirements of the utility are already being met by its construction program. Benefits will also be minimized if the utility is already experiencing over-capacity.
- Utilities cannot give capacity credits to biomass cogeneration unless the firm can assure a fairly high level of system availability.
- Overall biomass cogeneration reliability must not only encompass technical reliability (which has been good), but also market reliability to the extent that fuel, operating, and economic conditions affect the firm's ability to deliver capacity.
- Most biomass cogeneration system sizes have less than 40 MW capacity, representing a very small portion of the utility's overall power requirements. Most coal and nuclear power plants are upwards of 800 MW or some 20 times larger.
- There is no common agreement on the single proper way of calculating avoided costs. In addition, avoided costs can vary over the hours in the day and over the seasons.

There are several other factors that could affect the level of interest of a utility in biomass cogeneration including:

- **PUC commitment.** Many state public regulatory commissions have taken a strong public stand supporting biomass energy, cogeneration, or both. The positive environment for biomass cogeneration, due in large part to this support by state PUC's, has resulted in a wave of biomass cogeneration facilities.
- **Electricity generation competition.** It should not be forgotten that by providing substitutes for utility energy generation, biomass cogenerators are in some sense competing with the utilities with whom they are negotiating.
- **Customer base erosion.** Industrial firms tend to have the stable, high load factor electrical demands which the utility can most economically satisfy. In addition, the industrial class has, in some states, tended to help subsidize residential rates under life-line rate structures. Thus, with firms generating their own electrical requirements, utilities could be losing some of their best customers.
- **Utility system integrity.** One of the most important concerns of a utility is the reliability and integrity of its system. For this reason, some utilities have been cautious about linking up with generation sources

outside of its system for fear that the industrial system could damage the larger utility system, especially during, and after, outages. In most present applications of biomass cogeneration, the utility has been brought aboard early in the design phase to ensure that proper protection controls are incorporated in the biomass cogeneration system. Operation and synchronization of the transfer of electricity has not been a barrier.

Financing and Ownership Considerations

High interest rates, changing regulations, and the heightened interest in the national energy supply issue have all helped foster creative financing and ownership arrangements that facilitate the adoption of biomass cogeneration. Six arrangements seem to hold the most potential for biomass cogeneration and are described below. Four of these arrangements, as indicated, are represented in the case studies in the final section of this guide. Other financing possibilities are summarized in the Solar Energy Research Institute's (SERI) publication *Financing Options for Projects Converting Forestry and Farm Wastes to Energy*.

Sole Ownership and Funding

Sole ownership and funding by the firm operating the biomass cogeneration system is the most common form of financing and ownership arrangement. Funding is obtained through the company's pool of capital resources. These resources are typically generated from equity (retained earnings) or through debt financing. The most important advantage of sole ownership and financing is the elimination of any second parties, other than utilities or other organizations involved in the purchase of excess power. Sole ownership and funding ensures that all the potential benefits of biomass cogeneration accrue to the firm. Potlach Corporation is a case study example of this arrangement.

Cooperative Ownership with Utility

Cooperative ownership with the utility is typically represented by the private firm owning the boiler system and the utility owning the electrical generation equipment and purchasing steam from the private firm to run the turbines. This arrangement eliminates the need for the private firm to participate in the daily operation of the electrical system, a technology that is prob-

ably not well-known to the private firm's engineering staff and outside the firm's principal line of business. In addition, project participation by the utility reduces the capital requirements of the firm, lowers the overall project financing rate, and simplifies the contractual negotiations at the utility interface. On the other hand, the arrangement involves bringing in a project partner that may have differing business objectives. Potential tax incentives are decreased, because, in some states, utilities cannot take advantage of tax credits. Moreover, if the transfer price of steam is based on the associated incremental costs, then the primary benefits associated with energy efficient cogeneration typically accrue to the utility and its customers. Weyerhaeuser's Springfield facility is a case study example of this arrangement.

Leveraged Lease Arrangement

Leveraged lease arrangements probably represent the most innovative and potentially feasible arrangement illustrated in the case studies. Leveraged lease arrangements offer various structures that can usually be tailored to the requirements of the project. Structures can range from the lessor designing, constructing, owning, and operating a system to one in which the lessor is simply the system owner with a provision for eventual sale back to the industrial firm. The benefits of leveraged leases include the potential for transferring tax advantages to firms searching for such measures and the reduction of capital requirements for the industrial firm. These transfers will be greatly facilitated by the recent changes in the tax code with regard to leasing. In addition, with leasing the technical risk can be transferred from the industrial firm to the lessor developing the system. The disadvantages of leasing again rest primarily on the risk and uncertainty associated with a second party. The IMOTEK/California Almond Grower's Exchange facility represents one special version of this financing arrangement.

Venture Capital

Because of the favorable shifts in regulatory legislation, the benefits of biomass cogeneration may be great enough to encourage entrepreneurs to get into the business of producing energy using biomass cogeneration. For the case studies considered in this guide, biomass cogeneration produces energy which is an input to the firm's business, not a business by itself. Energy business ventures have been made in wind energy applications.

Recent changes in the capital gains tax rates for high-income investors and the level of public visibility of and interest in high technology and energy-related investments have resulted in substantial venture capital flows to well-conceived projects. Venture capital organizations typically make their investments in the

form of an equity position with the firm and they can often provide business guidance in addition to capital. Information on these firms may be obtained from the National Venture Capital Association in Washington, DC or the Western Association of Venture Capitalists, Menlo Park, CA. The membership of these associations is composed of individuals, private partnerships, funds set up by institutions such as banks and insurance companies, corporations that sponsor venture companies, investment banking companies, publicly held corporations whose purpose is venture funding, and some Small Business Investment Companies (SBIC).

Multi-Party Ownership

Multi-party ownership usually evolves out of large-scale projects which cannot be handled by a single firm. The arrangement is sometimes associated with the development of energy parks. In addition to reduced capital requirements and business risk, the advantage of multi-party ownership involves maximizing the economies of scale associated with large projects and the utilization of tax benefits and funding arrangements. The disadvantage focuses on the complexities associated with organizing such parties in a project effort.

Government Assistance

Federal legislation related to the financial aspects of biomass cogeneration can be grouped into two categories: fiscal incentives and direct incentives. The major fiscal incentives include the:

- Regular business investment tax credit
- Energy Tax Act of 1978 as supplemented by the Crude Oil Windfall Profit Tax of 1980.

Under the regular business investment tax credit, IRS allows a one-time credit of 10 percent of the cost of business equipment—buildings or building components do not qualify. The Energy Tax Act of 1980 and Crude Oil Windfall Profit Tax of 1980 created a Business Energy Investment Tax Credit, which offers an additional credit of 10 percent of the cost of energy saving or producing business equipment. Biomass fuel handling, storage, and preparation equipment, applicable pollution control equipment, buildings and equipment, and cogeneration equipment are also eligible for the extended 10 percent credit. The extended credit is reduced to 5 percent for investments financed in whole or in part by tax-exempt industrial development bonds or by government subsidized energy financing. The credits are available through 1985. Note that while the cogeneration related credits would expire in 1982, the cogeneration equipment would still qualify after that time because of the link to biomass.

There are a number of federal programs that are authorized to provide direct incentives such as loan guarantees, price guarantees, and purchase commitments to projects in the area of biomass cogeneration. It is estimated that in 1980 more than \$16 billion was made available to small and medium sized businesses—some of which went unused.

Although a number of programs are in danger of being phased out during 1981, some major programs could remain. The Energy Security Act of 1980 created the U.S. Synthetic Fuels Corporation to channel government incentives for synthetic fuel production. This funding program is part of the government's effort to stimulate production of alternative fuels that can replace two million barrels of oil per day by 1992. Over \$1.2 billion was designated for biomass projects—\$200 million of which was targeted for small-scale biomass energy projects. The Wood Residue Utilization Act of 1980 offers \$25 million annually for pilot and demonstration projects, on either private or public lands, to test the feasibility of and provide subsidies for removing waste wood and setting up collection and distribution centers. Other federal programs are summarized in the SERI guide *Financing Options for Projects Converting Forestry and Farm Wastes to Energy*. This guide is to be updated during the last part of 1981.

Many of the case studies included in this business assessment received financial assistance from the government in one form or another. For example, Geo-Products Corporation received partial funding to conduct feasibility studies of its proposed system.

Environmental and Institutional Factors

Many of the benefits associated with biomass cogeneration are related to its compatibility with environmental considerations. On a per unit basis, direct combustion of biomass emits far less SO₂ than does coal. For example, wood contains little or no sulfur. Therefore, in comparison to coal-fired boilers, wood-fired units may not require sophisticated and expensive SO₂ emission control equipment. In addition, utilization of biomass waste reduces the need to dispose of large quantities of ash and other waste materials (e.g., scrubber sludge). Ash from the combustion of wood typically amounts to less than 1 percent of the weight

of the wood fuel. In most cases, direct combustion of biomass produces ash which can be used in agricultural applications instead of being landfilled as is coal ash. Operating the facility in a cogeneration mode improves the overall energy efficiency of the system and thus reduces overall fuel requirements. The particulate emissions associated with biomass utilization can be high, but can be controlled with currently available collection equipment.

As noted earlier, biomass cogeneration encompasses a group of technologies—harvesting, transportation, handling, combustion, cogeneration, and disposal—which together comprise an integrated system. Environmental regulations that address each of these phases have been passed. The environmental concerns associated with these stages are summarized below.

Environmental Concerns

HARVESTING. The net environmental impact of harvesting wood and other biomass materials has not been established. Harvesting upsets the ecological balance of the affected forest or agricultural area. On the other hand, contemporary harvesting equipment and practices, when properly employed, minimize environment impacts such as soil erosion. In addition, harvesting provides a method of removing material which competes for moisture, sunlight, and nutrients needed by the healthier and stronger stands in the forest or agricultural area. The removal of agricultural and forest residue does not significantly impact wildlife and other ecosystems and generally reduces the potential hazard of fires, insects, and disease.

TRANSPORTATION. Due to the low energy density and high volume of biomass, transport of biomass materials could be a concern in their use. About 60 tractor-trailer loads of wood per day would be needed to supply a 50 MW power plant. Although transportation vehicle exhaust emissions contribute to air pollution, they are minor relative to the BTU content of the fuel being transported. Traffic congestion, noise levels, and road maintenance could be of concern to local officials.

HANDLING. The primary insurance and safety consideration associated with biomass cogeneration involves fuel storage. There have been incidents in which fuel piles have undergone spontaneous combustion. Firms seeking to locate biomass cogeneration systems in urban areas may have to overcome local regulations governing fuel storage. Many firms currently using biomass energy are actively exploring new technology

for monitoring biomass storage temperature and combustion potential. This technology could go a long way in overcoming the potential safety concerns. Of less concern are the fugitive dust emissions associated with machinery handling the biomass fuel.

COMBUSTION. The impact of burning biomass fuel is generally perceived as less severe than that of burning coal. In comparison to conventional fossil fuels, particulates from biomass combustion, are generally larger in size and are emitted at somewhat higher rates. As noted, particulate emissions are high, but can readily be controlled with currently available collection equipment. Cyclones, wet or dry scrubbers, electrostatic precipitators, and baghouses all have been used. The choice of a particulate collection device will depend on state and federal emission regulations and on the firing method used. Boiler vendors, as well as engineering firms, can provide satisfactory designs.

Depending upon the moisture content of the biomass fuel, the boiler temperature and the emission control system employed, some moisture may be released into the atmosphere as a visible, unaesthetic plume. In addition to particulates, incomplete combustion of wood may also result in emissions of carbon monoxide and hydrocarbons, some of which may be harmful. The characteristics of these potential emissions are under study now, and it is still not clear what problems might be associated with them. However, their control is a matter of achieving complete combustion. A properly designed and operated combustion system should provide the complete combustion necessary. Similarly, a properly designed and operated biomass combustion system should not create any significant water effluents.

COGENERATION. In general, environmental concerns of cogeneration facilities are the same as those for conventional coal-fired steam-electric power plants. However, because of their higher operating efficiencies, the magnitude of resource input and resulting residuals are somewhat less than when boilers are used to generate electricity and produce steam separately. A major institutional barrier associated with cogeneration is the lack of environmental performance standards which recognize the potential for fuel savings and reduced pollution levels.

DISPOSAL. In the area of solid waste, the ash from biomass systems must be disposed of, but is relatively inert, and presents no major problems. In general, the ash residuals from some biomass systems can be returned to the soil as fertilizer. Utilization of biomass materials discarded as wastes from other processes (e.g., sawmills) eliminates the need for disposal of such materials.

WESTERN STATE CONTACTS

State	Energy Offices	Energy Regulation	Environmental Regulation	Tax Incentives	Forest Service
Alaska	Div. of Energy & Power Development 338 Denali St. Anchorage, AK 99501 (907) 276-0508	Public Utilities Comm. Dept. of Commerce and Economic Dev. 338 Denali St. Anchorage, AK 99501 (907) 276-6222	Alaska Dept. of Environmental Conservation Pouch O Juneau, AK 99801 (907) 586-6721	State Dept. of Revenue Income Tax Div. Pouch SA State Office Bldg. Juneau, AK 99811 (907) 465-2326	Div. of Forest, Land and Water Management Dept. of Natural Res. 323 E. Fourth Ave. Anchorage, AK 99501 (907) 279-5577
Arizona	Energy Program Section Governor's Off. of Economic Planning and Dev. Rm. 507, Capitol Tower Phoenix, AZ 85007 (602) 255-3303	Public Utilities Comm. 2222 W. Encanto Blvd. Phoenix, AZ 85009 (602) 271-3624	Arizona State Div. of Environmental Health Services 1740 Adams St. Phoenix, AZ 85007 (602) 255-1130	State Dept. of Revenue Box 29002 Phoenix, AZ 85038 (602) 255-3831	Natural Res. Conservation Div. Land Dept. 1624 W. Adams Phoenix, AZ 85007 (602) 255-4633
California	Energy Res. Conservation and Dev. Comm. 1111 Howe Ave. Sacramento, CA 95825 (916) 920-6130	Public Utilities Comm. 350 McAllister St. San Francisco, CA (415) 557-1923	California Dept. of Conservation 1416 Ninth St. (13th Fl.) Sacramento, CA 95814 (916) 322-1080	Franchise Tax Board Sacramento, CA 95807 (916) 355-0370	Dept. of Forestry Res. Agency Rm. 1505, Ninth St. Sacramento, CA 95814 (916) 445-3976
Colorado	Off. of Energy Conservation Off. of the Governor 1600 Downing St., 2nd fl. Denver, CO 80218 (303) 839-2507	Public Utilities Comm. 500 State Services Bldg. 1525 Sherman St. Denver, CO 80203 (303) 839-3154	Colorado State Dept. of Health 4210 E. Eleventh Ave. Denver, CO 80220 (303) 320-8333	Colorado Dept. of Rev. Capitol Annex Bldg. 1375 Sherman St. Denver, CO 80203 (303) 839-5600	Forrest Service Colorado State Univ. Fort Collins, CO 80521 (303) 491-6304
Hawaii	State Energy Off. Old Federal Bldg. 335 Merchant St. Suite 110 Honolulu, HI 96813 (808) 548-4150	Public Utilities Comm. 1164 Bishop St. Suite 911 Honolulu, HI 96813 (808) 548-3990	Hawaii State Dept. of Health, Environmental Health Div. P.O. Box 3378 Honolulu, HI 96801 (808) 548-6505	State Tax Dept. P.O. Box 259 Honolulu, HI 96809 (808) 548-3270	Forestry Div. Dept. of Land and Natural Res. 1151 Punchbowl St. Honolulu, HI 96813 (808) 548-2861
Idaho	State Off. of Energy State House Boise, ID 83720 (208) 384-3258	Public Utilities Comm. 472 W. Washington St. Boise, ID 83720 (208) 384-3143	Idaho Bureau of Regional Environmental Services Statehouse 450 W. State St. Boise, ID 83720 (208) 334-4061	Idaho State Tax Comm. P.O. Box 36 Boise, ID 83722 (208) 334-3560	Div. of Forest Res. Dept. of Lands 121 State House Boise, ID 83720 (208) 384-3282

Environmental Regulations

The environmental regulations associated with each of these steps can be grouped under air, water, and land considerations. The regulation with the greatest impact on biomass cogeneration is the Clean Air Act. The impact of this legislation is a function of two major factors:

- The amount and type of pollutants emitted by a facility
- The designation of geographical areas as either non-attainment or prevention of significant deterioration (PSD) regions.

Facilities with emissions in excess of 100 or more tons per year fall under the jurisdiction of the Clean Air Act

in a PSD area. In a non-attainment area, the amount of pollutants allowed without falling under federal legislative jurisdiction is drastically reduced. An order of magnitude estimate is that any facility annually emitting at least one ton of any pollutant would be subject to provisions of the Clean Air Act. Firms would then be responsible for obtaining permits, record keeping, on-the-spot inspections and tests, and emission control. The specific steps associated with these activities are governed by local and state agencies.

Other major pieces of environmental legislation and their stipulations include:

- **1976 National Forest Management Act** — timber may be harvested only where soil or water conditions will not be irreversibly damaged, harvests

State	Energy Offices	Energy Regulation	Environmental Regulation	Tax Incentives	Forest Service
Montana	Energy Div. Dept. of Natural Res. and Conservation 25 S. Ewing Helena, MT 59601 (406) 449-3780	Public Service Comm. 1227 11th Ave. Helena, MT 59601 (406) 449-3017	Dept. of Health and Envmtl. Sciences, Envmtl. Sciences Div. Coswell Bldg. Helena, MT 59601 (406) 449-2544	State Dept. of Revenue Income Tax Section Sam Mitchell Bldg. Helena, MT 59601 (406) 449-2837	Forest Res. Div. Dept. of Natural Res. & Conservation 3001 N. Montana Ave. Helena, MT 59601 (406) 449-3633
Nevada	Dept. of Energy 1050 E. William St., #405 Carson City, NV 99710 (702) 885-5157	Public Service Comm. 505 E. King St. Carson City, NV 89710 (702) 885-4180	Nevada Dept. of Conservation & Natural Res. 201 S. Fall St. Carson City, NV 89710 (702) 885-4360	Nevada Dept. of Energy 1050 E. William, Suite 405 Carson City, NV 89701 (702) 885-5757	Div. of Forestry Dept. of Conservation and Natural Res. Rm. 330, Nye Bldg. Carson City, NV 89710 (702) 885-4350
New Mexico	Energy & Minerals Dept. 113 Washington Ave. P.O. Box 2770 Santa Fe, NM 87501 (505) 827-2471	Public Service Comm. Bataan Memorial Bldg. Santa Fe, NM 87503 (505) 827-2827	New Mexico Environmental Improvement Agency Crown Bldg. (P.O. Box 968) Santa Fe, NM 87503 (505) 827-5271	State Dept. of Taxation and Revenue Income Tax Div. P.O. Box 630 Santa Fe, NM 87503 (505) 827-3221	Natural Res. Dept. Land Office Bldg. Santa Fe, NM 87501 (505) 827-2312
Oregon	Dept. of Energy 111 Labor & Industries Bldg. Salem, OR 97310 (503) 378-4128	Public Utility Comm. 300 Labor & Industries Blvd. Salem, OR 97310 (503) 378-6611	Oregon Dept. of Environmental Quality P.O. Box 1760 Portland, OR 97207 (503) 229-5278	State Dept. of Revenue State Off. Bldg. Salem, OR 97310 (503) 378-3366	Dept. of Forestry 2600 State St. Salem, OR 97310 (503) 378-2511
Utah	Energy Off. Dept. of Natural Res. 231 E. 400 South, #101 Salt Lake City, UT 84111 (801) 533-5424	Public Service Comm. 330 E. 4th South St. Salt Lake City, UT 84111 (801) 533-5518	Utah State Div. of Health Health Services Branch 150 W.N. Temple, Rm. 426 Salt Lake City, UT 84110 (801) 533-6121	State Tax Comm. 200 State Off. Salt Lake City, UT 84114 (801) 533-5831	Dept. of Natural Res. 231 E. 400 South, Rm. 440 Salt Lake City, UT 84111 (801) 533-5439
Washington	State Energy Off. 400 E. Union Olympia, WA 98504 (206) 754-1350	Utilities & Transportation Comm. Highway-Licenses Bldg. Olympia, WA 98504 (206) 753-6430	Washington State Dept. of Ecology P.O. Box 829 Olympia, WA 98504 (206) 753-6874	Washington State Energy Off. 400 East Union Olympia, WA 98504 (206) 754-0788	Div. of Forest Land Mgt. Dept. of Natural Res. Public Lands Bldg. Olympia, WA 98504 (206) 753-0671
Wyoming	Energy Conservation Off. Capitol Hill Off. Bldg. Cheyenne, WY 82002 (307) 777-7131	Public Service Comm. Supreme Court Bldg. Cheyenne, WY 82002 (307) 777-7427	Wyoming Dept. of Environmental Quality Hathaway Bldg. Cheyenne, WY 82002 (307) 777-7391	Public Info. Specialist Wyoming Energy Conservation Off. 320 W. 25th Street Cheyenne, WY 82202 (307) 777-7131	Forestry Div. Public Lands State Capitol Cheyenne, WY 82002 (307) 777-7331

must be on a sustained yield basis, silvicultural prescriptions must be written to ensure that stands of trees will generally not be harvested until they are mature, clearcutting must meet certain standards, and land management plans must be written with public participation.

- **Water Pollution Control Act** — thermal, chemical and physical properties of wastewater discharges from energy facilities require that such discharges be treated to lessen the degradation of ambient stream quality and lessen the potential for contamination of underground water resources. Permits must also be obtained for authority to discharge pollutants into waterways.
- **Resource Conservation and Recovery Act** — regulation requires the disposal of residuals from com-

bustion chambers and environmental control systems in secure landfills and the analysis and reporting of the toxicity and contents of combustion wastes.

- **Occupational Health and Safety Act** — this legislation controls occupational environmental health hazards and public health and safety issues associated with potential effects on workers from noise, chemical agents, carcinogenic hydrocarbons, etc. and potential epidemiological risks to nearby communities from plant accidents, malfunctions, etc.

Legislation in the area of fine particulates and NO_x emissions has not been formalized, but is anticipated. Such legislation could impact biomass cogeneration, as well as all other combustion systems.

Regulatory Uncertainty

Biomass cogeneration facilities, like other industrial facilities, are subject to federal and state laws governing air pollution, the type of fuel that may be used, and the marketing of electrical power. The specific requirements that apply to a particular facility, however, vary dramatically depending on the facility's location, design, and ownership and operating arrangements. Legal requirements could therefore be as important as technical and economic variables in determining which location, design, and ownership structure will maximize the potential benefits of a proposed biomass cogeneration facility.

Planning biomass cogeneration investments with energy and environmental laws in mind is complicated by the fact that the laws:

- Are often interrelated
- Are supplemented by other regulations passed by the federal government or by other government units
- Define biomass cogeneration in different ways
- Are subject to legislative modification and alternative interpretation.

Government programs and legislation in the energy area have always been difficult to accurately track because of the rapid pace at which many new programs are created and old ones modified. Recent government legislation has tended to favor biomass cogeneration and other renewable or energy efficient technologies. The legislated advantages were in partial recognition of the fact that in past years nuclear and fossil fuels had been given primary priority. More important, the renewable energy programs offered an opportunity for the country to reduce its dependence on imported petroleum—the primary objective of the National Energy Conservation Policy Act of 1978.

Recently, the relationship between the Federal government and energy development has undergone a fairly dramatic shift. In general, it is apparent that the Fed-

eral government's role in energy development will be sharply reduced—especially in connection with those technologies such as biomass cogeneration that are technically and economically feasible under present conditions. Therefore, it can be expected that direct grants to biomass projects could be significantly reduced. Consistent with the philosophy that the Federal government should seek a reduced role in energy activities, the legislation governing PURPA and the Fuel Use Act could be modified. On the other hand, the shift in emphasis could enhance the overall viability of biomass cogeneration by promoting:

- A more favorable attitude toward business and a more positive environment for investment
- A streamlining of regulations that could otherwise delay biomass cogeneration implementation and operation
- A greater interest in developing domestic energy resources
- An increase in the biomass resource base available for energy production.

Overall energy prices will continue to increase making biomass cogeneration increasingly attractive from an economic standpoint. However, companies should be aware that regulations can be changed and should prepare for the resulting consequences. Other firms have successfully faced such regulatory uncertainty and are operating financially viable systems.

State and local agencies play a major role in the development and implementation of regulations impacting biomass cogeneration. The PURPA legislation leaves state regulatory commissions considerable flexibility in deriving appropriate estimates of utility avoided costs. Most environmental programs are carried out at the state or regional level. Many states have authorized financial programs to promote biomass cogeneration projects. Rather than cataloging the many state and local regulations that might impact biomass cogeneration, firms are advised to contact the government officials in their states and localities to obtain specific information. A list of appropriate state contacts has been provided on pages 18 and 19 to guide this search.

BIOMASS COGENERATION ECONOMICS

Determining whether biomass cogeneration is economical for a particular firm requires the analysis of many plant-specific variables, such as plant size, energy use patterns, plant load factors, energy costs, and type of biomass material. A company seriously interested in developing biomass cogeneration to supply either a portion or all of its own thermal and electrical power will require a plant-specific technical and financial analysis. However, a general indication of the viability of biomass cogeneration for a business application can be made using the information provided in this assessment.

Assessment of the economics associated with biomass cogeneration is complex for several reasons. First, biomass cogeneration refers to a group of technologies and not a single system. For example, the comparative economics associated with burning hog fuel versus rice hulls depends to a large extent upon the required level of fuel preparation, environmental protection, and boiler sophistication. Second, biomass cogeneration system costs are site specific and cost generalizations are difficult to make. Third, results of economic analysis are heavily dependent upon assumed future inflation rates and energy prices; factors which have proved difficult to predict in recent years. Fourth, cogeneration involves the generation of two products—typically process steam and electricity. Because these dual uses share common system components, such as the boiler, there is considerable latitude in allocating joint costs. Thus, it can be difficult to ascertain whether a biomass system should include cogeneration or whether it would be more cost-effective to implement a stand alone biomass process steam system and purchase electricity from the utility. For the purposes of this assessment, the decision to adopt biomass cogeneration is evaluated in two separate phases:

- The decision to adopt **biomass** as the preferred energy source to fuel the boiler
- The decision to include **cogeneration**.

Major Decision Considerations

In the assessment of energy investments there are a number of considerations that must be addressed in

order to develop an accurate appraisal. These considerations are briefly discussed below.

System Size

Economies of scale in biomass cogeneration systems can be significant. For example, costs for a biomass fueled boiler system on a \$/Btu/hour basis can decrease by 50 percent between 10 and 20 million Btu/hour and by an additional 20 percent between 20 and 40 million Btu/hour. Unit costs for electrical generation systems can decrease by 25 percent between 5 and 10 MW and by an additional 15 percent between 10 and 20 MW. Overall system efficiencies can also be affected by system size. System size may be limited, however, by the availability of biomass fuel in the local area.

Installation Date

Recently, construction costs have been increasing at an annual rate in excess of 12 percent. Estimates obtained from published reports and supplier quotes must be consistent with the expected system installation date.

Retrofit of Existing Equipment

Many firms are evaluating biomass cogeneration in terms of a retrofit to existing equipment. This practice can certainly reduce the capital costs of biomass cogeneration, especially if there is excess or unused boiler capacity and the boiler was originally designed to produce superheated steam suitable for a turbine. Retrofitting existing equipment has not been found to significantly affect the reliability of the associated facilities. Because the retrofit of existing equipment will often take it out of service for an extended period of time, the opportunity costs of such a loss must be included in the overall economic evaluation.

Fuel Type

Capital equipment costs and system performance parameters can vary significantly across the range of biomass fuels and combinations. The primary equipment differences lie in the required level of pollution abatement, fuel handling, and boiler technology.

Fuel Quality

For a given energy output, very dry fuels (5 percent moisture content) will require less investment in the energy conversion unit and fuel handling equipment than will wet fuels (50 percent moisture content). On the other hand, dry fuels are more expensive and require a greater investment in fuel storage to control the increased potential for spontaneous combustion arising from unsaturated oils or turpines contained in the fuel.

Fuel Source Proximity

Systems in which the fuel is not generated internally, but purchased outside, will involve higher initial costs to establish truck dumps and large fuel storage shelters, which in turn require more elaborate pollution abatement controls. Such fuel supply and storage systems can require substantial capital and operating expense.

System Utilization

The number of hours that the system is in operation has a significant impact on the economics of biomass cogeneration. Higher utilization means capital resources are being used more efficiently. In many studies, system utilization rate of 70 percent is assumed to account for planned and unplanned system downtime. However, typical biomass cogeneration systems have achieved availability rates in excess of 95 percent. This increase may improve the overall economics of biomass cogeneration by as much as 5 percent. Other systems have experienced a lower utilization due to the seasonality of their fuel supply.

System Efficiency

The energy conversion efficiency of the boiler system can also significantly impact the economics of biomass cogeneration. An efficiency of 67 percent is commonly assumed for the burning of greenwood chips, although lower efficiencies due to incomplete combustion have been reported. Detailed design studies optimizing various performance parameters have been effective in increasing overall system efficiency by up to 10 percent. Such efficiency improvements could reduce overall biomass cogeneration energy costs by 8 percent.

System Financing

There are a number of creative financing techniques and tax incentives available that can substantially improve biomass cogeneration economics. A reduction in the effective loan interest rate from 15 percent to 12 percent or a tax credit of 20 percent will decrease over-

all biomass cogeneration energy costs by roughly 5 percent. Care should be used in making sure that the potential tax incentives are available for the particular financing arrangement planned.

Economic Evaluation of Biomass Systems

The economic attractiveness of biomass as an energy system is based primarily on its low fuel costs relative to petroleum and natural gas. Sufficient fuel cost savings must be obtained to offset the relatively high initial capital investment for biomass systems. Biomass systems are also attractive because they are more effective in surmounting environmental regulations, bypassing industrial fuel use restrictions, and reducing waste disposal costs.

In assessing the viability of biomass systems relative to other competing systems, several variables may need to be defined. These variables and their major sub-categories include:

- Capital costs
 - land and site preparation
 - unloading equipment
 - fuel processing equipment
 - storage capacity
 - energy conversion unit (boiler and auxiliary equipment)
 - generator
 - pollution abatement equipment
 - control systems
- Fuel costs
 - delivered price of fuel
 - start-up and stand-by fuel costs
 - ash disposal costs
 - required working capital for fuel inventories
 - relative efficiency of energy conversion
 - future fuel prices
- Operating costs
 - labor
 - materials
 - supervision, administration, taxes, insurance, and other overhead
- Financial and operating parameters
 - financing rate
 - depreciation method and period
 - federal and state tax credits
 - system utilization
 - system operating life.

In comparison with cogeneration systems fueled by other energy sources, biomass cogeneration will tend

to have higher capital costs but lower operating costs. The lower operating costs are due to the lower cost on a Btu basis of biomass relative to other fuels such as petroleum. The higher capital costs result from the larger equipment required to burn biomass. In most cases, biomass does not contain as much energy on a volume basis as do other fuels. Biomass cogeneration systems also involve a lower investment in pollution control equipment because they do not require sulfur control devices. On the other hand, biomass cogeneration systems do incur relatively higher fuel storage and handling costs.

The economic feasibility of a biomass cogeneration project depends on the interaction of the variables listed previously. An outline of a method to incorporate these variables and parameters into an evaluation framework is provided in the report titled *Economic Analysis of Wood- or Bark-Fired Systems*, General Technical Report FPL 16, 1978. This study is available from the Forest Products Laboratory, Madison, WI 53705.

A computer model, Wood III, is available to automate such an economic analysis and provide life-cycle cost comparisons with competing systems using other fuels. Wood III was developed through the Northeast Regional Commission and has been used extensively in evaluating biomass systems for firms in the Northeast. Access to the program can be obtained through the Models Library of the Solar Energy Research Institute, 1617 Cole Blvd., Golden, Colorado 80401.

For the purposes of this business assessment, the following evaluation compares biomass systems with systems fueled by low-sulfur coal and by No. 6 fuel oil. Note that although this comparison represents typical situations and costs, detailed study and designs are required before a specific application can be accurately assessed.

In developing the comparison among the three technologies, several common assumptions were made:

- Boiler horsepower: 500 bhp (16.7 million Btu/hr)
- Capital costs include installation and pollution abatement costs
- Tax credits: 20 percent for biomass systems; 10 percent for other systems
- Cost of capital (discount rate): 12 percent
- Inflation rate: 8 percent
- Fuel cost escalation above inflation: 2 percent
- System utilization rate: 70 percent
- System operating life: 20 years.

The table below further develops the economic parameters necessary for the comparison.

In general, the coal and biomass systems are much more capital intensive than petroleum systems. Differences between the coal and biomass systems rest primarily on localized differences in relative fuel prices and environmental regulations. Relative fuel costs are significantly higher for petroleum systems.

BIOMASS SYSTEM ECONOMIC EVALUATION — ASSUMPTIONS*

Description	Biomass System	Coal System	Petroleum System
System Size	500 bhp	500 bhp	500 bhp
Fuel Type	Wood Waste (50% moisture)	Coal (low sulfur)	Fuel Oil (No. 6)
Fuel Combustion Efficiency	.67	.82	.80
Fuel Heating Value	17,000,000 Btu/dry ton	24,000,000 Btu/ton	150,000 Btu/gal
Initial Capital Investment	\$740,000	\$640,000	\$144,000
Annual Operating and Maintenance Costs	\$44,400	\$38,400	\$8,600

*Adapted in part from the *Decisionmaker's Guide to Wood Fuel for Small Industrial Energy Users*, M P. Levi and Michael J. O'Grady, SERI/TR-8234-1.

The greatest uncertainties in the investment analysis are associated with the present fuel price, future fuel reliability, and future fuel prices. The diagram below addresses at least a portion of this uncertainty. Many combinations of coal, petroleum and biomass prices result in overall system costs favorable to biomass systems. As seen in the summary diagram, delivered fuel prices which are typically found today (e.g., biomass-\$15/ton, coal-\$58/ton, petroleum-90¢/gal) result in overall system costs of \$4.04 per million Btu output for biomass, \$4.33 per million Btu output for coal, and \$9.18 per million Btu output for petroleum. Those firms that are presently disposing of biomass resources would enjoy an even greater cost advantage because of

savings in fuel and disposal costs. Naturally, these conclusions are restricted to the assumptions employed in the analysis.

Economic Evaluation of Cogeneration

After determining the most cost-effective fuel source to supply the boiler, the next decision involves evaluating the viability of cogeneration. The economic attractiveness of including cogeneration with the biomass

system is based primarily on the potential overall system efficiency gains described in the technical assessment. In some cases, biomass cogeneration systems which are typically less than 50 MW in capacity can produce electricity more cheaply than can a newly installed utility facility ten times larger. The economics of cogeneration are enhanced under PURPA whereby utilities are required to buy back any excess electricity produced by the cogenerator at rates based on the utility's avoided costs. As industrial electricity rates continue to increase rapidly, many cogenerators may find it economical to use all of the generated electricity internally.

Analyzing the economics associated with cogeneration can be complex due to the problem of allocating joint costs; i.e., those expenses shared by both process heat production and electricity generation. Examples of joint costs include fuel costs and the costs of the boiler system. Other costs such as the turbine, generator, and switching equipment are clearly attributable to electrical production.

Most firms evaluate cogeneration on an incremental cost basis. That is, firms determine the net costs of generating electricity by establishing the overall costs of the cogeneration system (combined process heat and electricity production) and subtracting the costs associated with a process heat only system.* These electricity generation costs are then compared with the firm's purchased power costs or the utility's buyback

rates. In developing cost estimates for cogeneration, it is important to make sure that all the necessary components, such as electrical substations and transformers, are included.

The relative attractiveness of cogeneration rests on the costs and value of the electricity produced. The diagram appearing below depicts the interaction between the value of the electricity (whether it is sold or used internally in lieu of utility power purchase) and the costs of producing it. In addition to the financial assumptions listed earlier, the following assumptions were used in preparing the diagram:

- Tax credits: 20 percent for cogeneration systems
- Incremental fuel costs (first year): \$0.0106/kWh
- Incremental operation and maintenance costs (first year): \$0.008/kWh
- System utilization: 70 percent.

The diagram shows that for electricity rates in excess of 4.0¢/kWh, it is cost-effective to implement cogeneration as long as incremental costs associated with a cogeneration system are under \$1500/kW. The case studies include examples of cogeneration systems developed for under \$500/kW.

*Incremental costs can be determined by first deriving the incremental heat rate, which represents the amount of additional fuel needed to produce one kWh of electricity and which is expressed as Btu per kWh. The incremental heat rate of a cogeneration system is intimately linked to the design of the system and based on the system technology, throttle pressure and temperature, and back pressure or process steam pressure. The incremental heat rate when combined with the unit boiler system costs or with the unit fuel costs can be used to determine the incremental boiler system costs and fuel costs allocated to electrical production. For example, the heat rate associated with one cogeneration system with a throttle pressure of 500 psig and a back pressure of 50 psig is 5300 Btu/kWh. If the boiler fuel cost is \$2.00 per million Btu (e.g., wood waste prices at \$17 per ton as received with 17,000,000 Btu per dry ton and 50 percent moisture), then the fuel cost attributable to electricity production is \$0.0106 per kWh. This figure was derived using the calculations below:

$$\frac{\$2.00}{\text{mm Btu}} \times \frac{.0053}{\text{kWh}} = \frac{\$0.0106}{\text{kWh}}$$

BIOMASS COGENERATION PROJECT PLANNING

One of the objectives of this guide is to identify useful strategies in facilitating the successful adoption of biomass cogeneration systems. These suggestions were collected from key individuals in organizations which have implemented or are in the process of constructing biomass cogeneration systems. The suggestions were then supplemented by key individuals in organizations that are directly involved in biomass cogeneration systems: government agency staff, government energy experts, utility staff, equipment manufacturers and suppliers, public utility commission officials, and energy consultants.

The principal feature of biomass cogeneration that should be clearly recognized and frequently highlighted is that biomass cogeneration is attractive from a number of perspectives. As indicated earlier, biomass cogeneration can:

- Reduce our dependence on petroleum
- Lower energy costs
- Improve overall energy system efficiency
- Improve electrical and fuel supply reliability
- Reduce sulfur emissions
- Reduce needs for waste disposal
- Utilize off-the-shelf technology.

Probably the most important suggestion coming from present biomass cogenerators is the observation that the successful adoption of biomass involves the complex interaction of technical, environmental, fuel supply, utility interface, and economic issues. They are intimately related and cannot be effectively addressed independently. For example, the system cannot be designed until the environmental restrictions are considered. Environmental restrictions cannot be defined until the relative size of the system is specified. System size cannot be determined until the electrical generation requirements are defined, which cannot be completed until it is clear what buyback and wheeling rates and conditions will be in effect and so forth. Each major issue must be developed in concert with other issues. Neglect of an issue such as specifying the required technical protection for the utility grid system until later phases could cause a costly rethinking of the entire project.

A general framework for project implementation is presented below. Naturally, a single diagram cannot begin to represent every example of biomass cogeneration. However, it does show the logical and temporal relationship among the critical implementation activities. Depending on the extent of retrofitting and the severity of environmental restrictions, project implementation from the initial conceptual stage through design, construction, and start-up has taken anywhere from 14 to 36 months.

Firms can capitalize on the favorable characteristics of biomass cogeneration by greatly increasing the public

Review Biomass Cogeneration Information
Review Direct and Fiscal Incentives Programs
Review Applicable Environmental Codes
Determine Relative Level of Buyback Rates and Conditions
Develop Preliminary Analysis of Fuel Availability and Price
Establish Preliminary System Specifications
Conduct Preliminary Economic Evaluation of the Project
Incorporate Environmental Constraints into Design
Establish Technical Requirements for Utility Interface
Determine Financing Options and Potential
Develop Detailed Analyses of Local Fuel Availability
Develop Preliminary System Design
Develop Detailed Business Plan
Develop Public Relations Programs
Develop Detailed Engineering Design
Enter into Formal Negotiations with the Utility
Obtain Project Financing
Obtain Construction Permits
Order Equipment
Conclude Utility, Fuel Supply, and Financing Negotiations
Construct Facility
Test Facility
Obtain Operating Permits
Operate Facility

visibility of the project. Some firms have developed a formal presentation program that they can make to various interested groups. In general, community support has been very strong for biomass cogeneration. It is a positive solution to the problem; it gives the community some feeling of direct control over the energy situation; and it keeps and creates jobs for the community. Vocal community and regional support can go a long way in reducing any barriers to the project.

Key outside officials making critical assessments of the project should be informed early and kept supportive throughout the project. These officials include not only those individuals in charge of permitting at the federal, state, and local levels, but also those involved with the financial institutions and the cooperating utilities. Biomass cogeneration is not yet a common concept, so communication of complete and accurate information to these key officials can facilitate the decision process.

Other suggestions included:

- Talking with firms who have already adopted bio-

mass cogeneration systems to get a "hands-on" evaluation of the technology

- Planning for a flexible multi-fuel system (combustion, fuel handling, and pollution abatement) that can cope with changing operating conditions and fuel supply
- Retaining engineering expertise with the understanding that both biomass and cogeneration bring a special set of technical problems that might be different than those found in related technologies
- Understanding the special terminology and objectives used by utilities
- Scheduling equipment acquisition knowing that some components such as small turbines may take an unusually long time to obtain
- Investigating the applicability of new technology such as wood gasification, fluidized bed combustion, and multi-fuel boilers
- Utilizing the technical, environmental, fuel supply, regulatory, and economic expertise that exists at federal, state, and local government levels.

BIOMASS COGENERATION — IMPLEMENTATION STRATEGY

CASE STUDIES

There are over 40 biomass cogeneration facilities in the 13 Western states served by Western SUN. As the regional map indicates, these applications are concentrated in California, Washington, Oregon, and Hawaii. This trend is due in part to the availability of biomass resources and the strong positions favorable to buy-back rates taken by those individual state commissions. Nevertheless, many other parts of the region reflect proven applications and hold potential for opportunities in biomass cogeneration.

The firms included in this guide as case studies were selected to provide variety along a number of characteristics.

- **Location:** seven different states
- **Fuel Source:** mill waste, forest residues, bagasse, cotton gin waste, almond shells, and food processing waste
- **Stage of Experience:** long-term user, short-term user, construction phase, and planning phase
- **Ownership and Financing Arrangements:** outright ownership and financing, cooperative ownership with utility, leasing, and public financing
- **Fuel Supply:** captive and noncaptive resources
- **Utility Interface:** power used internally, transferred to other companies, or sold back to the local utility.

Tri/Valley Growers Modesto, California

Tri/Valley Growers is a cooperative of more than 450 fruit and vegetable growers generating sales in excess of \$400 million. Like many canneries, Tri/Valley faces rising energy costs, an uncertain supply of natural gas, and a problem in disposing of solid wastes, such as fruit pits and walnut and almond shells. These wastes represent a potential energy source equivalent to more than 30,000 barrels of fuel oil annually—a potential savings of \$1 million.

Tri/Valley is utilizing biomass in two of its facilities. The original application started in 1978 with the conversion of an existing 60,000 lb/hr boiler to burn pulverized peach pits. The project, undertaken in cooperation with the California Energy Commission, enabled the plant to generate steam from its cannery waste for cooking fruit, cleaning cans, and other uses. Tri/Valley expanded the project the next year to test other waste fuels such as olive pits, cherry pits, almond shells, and orchard prunings.

In 1980, Tri/Valley began installing a biomass cogeneration unit that will utilize 30,000 tons of biomass fuel annually while producing steam at 650 psig to generate 4.5 MW of power and exhausting steam at 50 psig for cooking and processing. Tri/Valley selected a furnace system designed to efficiently burn a wide range of biomass fuels—particle sizes of up to 3 inches and moisture contents of up to 50 percent. Potential fuel sources include peach pits, tree prunings, almond and walnut shells, prune pits, coffee grounds, and cubed rice straw. The original biomass facility has since been dedicated to sawdust and wood waste as the primary fuel, freeing the peach pits wastes for the cogeneration facility.

KEY FEATURES:

- **Fuel Supply Reliability.** Because of the short harvesting season and limited life of the fruits and vegetables processed in its plants, Tri/Valley has made considerable effort to ensure a reliable fuel supply. As indicated earlier, the furnace for the biomass cogeneration system was selected on the basis of its ability to efficiently burn the broadest range of fuels. These wastes will be generated by Tri/Valley or by other area firms. In addition, the system is equipped with a conventional gas and oil burner for stand-by purposes. The system operates 24 hours per day, year-round.
- **Multiple Sharing of Generation Power.** Tri/Valley has adopted an unusual mechanism for selling its cogenerated electricity. System power capacity has been sold to the Modesto Irrigation District. Electrical energy not required by the District is then transferred and sold to Pacific Gas and Electric Company under that utility's regular buyback program.
- **Early technical problems remedied; strong recent performance.** Two technical problems were identified during operation of the original biomass facility. First, the concentration of particulate matter from the stack gases was found to be three to four times the rates allowed under local air pollution control requirements. A power cyclone was installed to correct the situation, the cyclone system added 15 percent to the total capital outlays for the project. A second technical problem resulted from the unexpected need for additional grinding equipment to reduce fuel particle size to achieve better burning levels. Tri/Valley has been satisfied with the recent performance of its systems.

Hawaiian Commercial & Sugar Maui, Hawaii

Hawaiian Commercial & Sugar operates several bagasse fueled cogeneration facilities at its mills on Maui and on Kauai. The firm's seven generators, collectively rated at over 47 MW, produced in excess of 150 million kWh in 1979. Of this total, 35 million kWh were sold to Maui Electric Company. The firm plans a \$9 million expansion of its power generating facilities to include a 15 MW turbogenerator. The new system will add 65 million KWH to present production levels and will begin operating in early 1982. By 1984, the company expects to supply 12 percent of Maui Electric's total yearly power distribution.

KEY FEATURES:

- **Utilization of Bagasse.** Bagasse is the cane waste generated from sugar processing. Each of the fourteen sugar producers on the Hawaiian Islands are cogenerating and most are selling back excess electricity to the local utilities. The utilization of bagasse for cogeneration promotes conservation because the exhaust steam can be used a second time to boil cane juices and drive the sugar mill. It also strengthens the local sugar industry, one of Hawaii's most important, and allows energy dollars to be spent in Hawaii rather than on imported oil.
- **Increased Electric Buyback Rates.** Prior to passage of the PURPA regulations requiring utilities to pay the equivalent of their avoided costs for cogenerated electricity. Maui Electric, a subsidiary of Hawaiian Electric, was paying sugar plantation owners roughly 2¢/kWh for power from their bagasse-fueled cogeneration plants. In late 1980, the Hawaii Public Utilities Commission, adhering to the PURPA rules, approved new contracts that raised the rate above 4¢/kWh along with an additional \$5.50/firm kW/month. Because Maui presently receives 7 percent of its power requirements from industrial cogenerators, the fourfold increase in buyback rates will raise customer rates. However, customer rates would be even higher had Maui been forced to replace the cogenerated power with a utility-financed diesel plant.
- **Facility Expansion.** Biomass cogeneration has been successfully applied at Hawaiian Commercial & Sugar for decades. In addition to the buyback incentives provided by PURPA, several other factors led to the decision to expand, including excess boiler capacity and increased sugar production levels. Alexander & Baldwin, the parent company of Hawaiian Commercial and Sugar, is also considering further increases in energy production by investigating the feasibility of growing trees on marginal land for fuel.

Fort Apache Timber Whiteriver, Arizona

Fort Apache Timber installed a 700 kilowatt cogeneration facility in its lumber mill during 1979. The firm is proceeding with a second phase of the installation, which will include two additional units rated at 800 kilowatts each. The existing system burns sawdust, planer shavings, and bark, which the firm generates internally. The fuel supply averages 50 percent in moisture content and is not dried prior to combustion. Because of the large volume of wood waste generated internally, system efficiency has not been an especially important concern. Excess wood waste is presently transported to disposal sites. Overall system availability has been more than 80 percent.

KEY FEATURES:

- **System Expansion.** As noted above, Fort Apache Timber is satisfied with the results of the first phase of the project and is tripling the size of its system.
- **Federal Grants.** The Whiteriver facility is located on the Fort Apache Indian reservation. The project qualified for grants from the Economic Development Agency. Continued prosperity of Fort Apache Timber has helped to stabilize the local economy.
- **Power Exchanged.** Fort Apache Timber exchanges its generated power with the Navopache Electric Cooperative. Fort Apache receives a credit equal to the energy charge associated with power rates set by the utility. These power rates are approximately 4¢/kWh.
- **Successful Utility Linkup.** Fort Apache Timber has had no problems in achieving a synchronous linkup with the utility. The company retained the services of an engineering firm to design the system.

GeoProducts Corporation Susanville, California

GeoProducts was formed in 1975 to develop alternative energy technologies, emphasizing those that could be coupled with the utilization of geothermal resources. The firm has developed, and subsequently sold, a commercial vegetable greenhouse complex using geothermal energy as the only fuel for heat. GeoProducts is presently planning a power plant that will utilize geothermal heat and wood fuel to generate electricity. The geothermal resource is a low-to-medium temperature reservoir found at about 5,000 feet near Susanville. Preliminary surveys indicate that the temperature of the geothermal fluid at the primary heat exchangers will exceed 250 F. The project involves the use of 1250 tons per day of wood resources obtained from forest thinnings, slash, and culls. The wood will be used to produce electrical power in a 50 MW plant.

KEY FEATURES:

- **Geothermal Resource Utilization.** Geothermal reservoirs represent one of the most interesting alternative energy sources. The use of wood along with geothermal energy adds an important dimension to the power potential in the Western region. The contribution of wood in this energy application can be as much as 50 to 60 percent. More importantly, the synergy between wood and geothermal energy will permit economic power generation from resources heretofore considered unacceptable for such use. Both the required wood and geothermal facilities can be constructed with available technology and equipment.
- **Financing Arrangements.** The feasibility and planning phase of the project was financed in part by the California Department of Water Resources, the U.S. Department of Energy, and the U.S. Forest Service. Since that time, GeoProducts has received additional capital resulting from its acquisition by the Southern Pacific Land Company. One-quarter of the total project cost of \$60 million is expected to be financed through private investors in a limited partnership. The remaining portion will come through a long-term lender such as an insurance company or bank.
- **Noncaptive Fuel Supply.** All wood supplies will be obtained from outside sources. There are several million acres of commercial forest land within 100 miles of the project, with ownership divided between the U.S. Forest Service and the private sector. In addition, 16 sawmills operate in the area. GeoProducts has retained a consultant to make a detailed wood fuel resource, supply, and cost analysis.

Potlatch Corporation Lewiston, Idaho

The Potlatch plant in Lewiston, Idaho produces bleached pulp, paperboard, tissue, lumber, and plywood. The firm installed a 10 MW generator in 1951, a 9.2 MW unit in 1977, and a 28 MW unit in 1981. The 28 MW generator is associated with a 550,000 lb steam per hour waste-wood-fired boiler completed in 1980. Other boilers on the site are fueled with waste wood, natural gas, or black liquor in recovery boilers. With the addition of the 28 MW unit, the Lewiston facility can generate more than 75 percent of its electricity needs.

KEY FEATURES:

- **Low Average Utility Power Costs: Impact of PURPA and the Northwest Power Bill.** The existing utility system in the Northwest is characterized by a high component of low cost hydroelectric power, new construction of utility plants at very high cost, and the possibility of electricity supply shortages during droughts. The low average cost of hydroelectric power historically made generation for use by Potlatch uneconomical. The implementation of PURPA and the resultant avoided cost pricing has provided a market for power from qualifying facilities, but the capacity of those facilities must be committed for long periods to the utility grid to obtain full economic benefit. Self supply of power in a shortage and difficulties in assuring a long term biomass supply for energy conversion with major land ownership and associated wood supplies in federal control are major concerns in balancing the attraction of long-term capacity commitments. The Northwest Power Bill establishes that the Bonneville Power Administration must purchase alternate and renewable sources of power before it can acquire power from new thermal stations.
- **Consistent Technical Performance.** The Potlatch has been satisfied with the performance of its biomass cogeneration systems. System availability exceeds 95 percent, reflecting the degree of redundancy built into the system. Many biomass applications in industry must have such reliability in order to prevent a shutdown of an entire plant's operations.

Weyerhaeuser Springfield, Oregon

Biomass cogeneration operation at Weyerhaeuser's Springfield facilities presently consists of two generation systems totaling over 62 MW in nameplate capacity. The larger system (51.2 MW) is the product of a relationship between Weyerhaeuser and the local electric utility, Eugene Water and Electric Board (EWEB), and has been operating for over five years. EWEB installed and operates the turbine-generator on leased land within the mill site, while Weyerhaeuser is responsible for generating steam. The steam fed to the turbine is produced from two black liquor recovery boilers and one fossil fuel boiler at 875 psig. The steam is then returned to Weyerhaeuser through the turbine extraction valve at 165 psig and turbine exhaust at 65 psig to meet process steam requirements within the pulp and paper operations. The second system is completely owned by Weyerhaeuser and is fueled by wood waste. Depending on the market price for power, the electricity is wheeled through EWEB and sold to the Bonneville Power Administration or to other industrial firms.

KEY FEATURES:

- **Cooperative Ownership.** The Weyerhaeuser/EWEB system exemplifies the possibility of the cooperative company/utility ownership and operating arrangement described in an earlier section. The division of ownership and responsibility for the various components of the system has been made on the basis of which party had the better business and operational knowledge. The production of steam is the sole responsibility of Weyerhaeuser. EWEB owns and is responsible for the turbine generator and the electrical output for use within the EWEB system. Other aspects of the relationship include:
 - No joint ownership arrangements or undivided interests of any facilities have been made due to legal and operational considerations.
 - A single engineering firm completed the design for the entire project, thereby reducing interface problems.
 - The price paid by the utility for steam is based on the kilowatt hours produced and indexed to the market price of petroleum.
 - Weyerhaeuser controls the rate of steam production, and thus exerts indirect control over the rate of electrical production.

- **Public Visibility.** The concept has been well received in the community and public attitudes toward each entity have improved measurably. Governmental agencies, both local and state, have offered considerable support to the program. The project is seen as one measure in the larger effort to deal with energy shortages in the Northwest and as providing some guarantee of continuing jobs in the area.
- **Good Technical Performance.** Facility availability has been in excess of 92 percent. A portion of this overall system dependability can be attributed to the use of multiple boilers instead of a single large unit. An overall fuel conversion efficiency of 81 percent has been achieved by the system.

Champion Packaging Missoula, Montana

Champion Packaging is a division of Champion International, a major paper and packaging company. Champion has been operating a biomass cogeneration system in its paper mill facilities since the 1960's. The firm currently generates an average of 7.5 MW with some peak capacity being held in emergency power reserve. The system is fueled primarily by boilers burning hog fuel and black liquor waste from the pulping process. System energy is supplemented to some extent by natural gas. Present generation capacity supplies 10 to 15 percent of the firm's total requirements for electricity.

KEY FEATURES:

- **Boiler Expansion.** Champion Packaging has recently quadrupled the hog fuel boiler capacity of its system by adding a 350,000 lb/hr boiler. This expansion has substantially reduced the company's natural gas requirements.
- **Large Fuel Purchase Radius.** Champion Packaging is collecting and utilizing hog fuel obtained from sources located up to 200 miles away. Much of this fuel is being obtained from other Champion facilities.

Louisiana-Pacific Samoa, California

Biomass cogeneration is not new at the Louisiana-Pacific facility in Samoa. In conjunction with the rebuilding of a sawmill in 1963, a 120,000-lb/hr hog fuel boiler and 8 MW turbogenerator were installed to satisfy electrical demands at the site. In 1965, a new pulp mill was built, which included a 200,000 lb/hr hog fuel boiler, two 165,000-lb/hr liquor recovery boilers, and a double-extraction, 20 MW turbogenerator. Subsequent to the initial energy crisis in 1973, the firm planned for an additional expansion consisting of a 160,000-lb/hr boiler with a 20 MW turbogenerator. The company goal is to become self-sufficient in electrical energy while reducing natural gas demand. Although the new system was, in fact, larger than the medium-term needs of Louisiana-Pacific, it was appropriate, recognizing the excess hog fuel availability in the area and the potential for excess power sales to the local utility. The project was financed internally.

KEY FEATURES:

- **Successful Utility Power Interface.** There have not been any particular problems from operating the power station in parallel with a utility grid system. The equipment for synchronizing, monitoring, and controlling are now standardized. No special skills or training were required. The firm sometimes intentionally disconnects its system from the grid during electrical storms when a power surge from the utility system could disrupt sensitive relays.
- **Widespread Experience.** In addition to the long history of biomass cogeneration at the Samoa facility, Louisiana-Pacific has installed systems in Ketichikan, Alaska and Missoula, Montana and is planning others at Antioch and Standard, California. The firm is investigating the possibility of wheeling power to nearby Louisiana-Pacific facilities.

Farmers Cooperative Gins, Inc. Buttonwillow, California

The Farmers Cooperative Gin, Inc. (FCG) is a cotton ginning operation. FCG anticipates a fall 1982 start-up of its \$1.6 million project to generate 1.65 MW of power and supply heat for cotton drying. The facility will utilize cotton gin waste generated at the site as the primary fuel source. The present heat source is natural gas. It is estimated that 60,000 million Btu of natural gas could be saved annually, while at the same time, 4.5 million kWh would be generated. Power that the cooperative cannot use will be sold back to the local utility. The project payback is less than 4 years, even if the system is operated only during the 5 month growing season. Additional revenues would be realized if off-season fuel sources, such as tree prunings, wheat straw, barley straw, or cotton stocks could be utilized. Once the project is completed, FCG will have essentially no fossil fuel consumption.

The boiler system has been designed to generate 500 psig steam at 42,000 lb/hr. The turbine exhausts the steam at 25 or 125 psig. The project has received its construction permit and major equipment pieces have been ordered.

FCG's cotton ginning facility at Buttonwillow is one of the largest in the country. The cooperative processes approximately 200,000 bales annually. Cotton is California's leading cash crop, with 3,333,000 bales produced in the state during 1980.

KEY FEATURES:

- **Utilization of Gin Trash.** On average, approximately 150 pounds of gin trash is produced in ginning a bale of spindle-picked cotton in the San Joaquin Valley. There are roughly 6,000 Btu's per pound of gin trash. In the spindle technique, the cotton is defoliated prior to harvesting. Cotton which is harvested by the stripper method generates 700 pounds of waste per bale due to the presence of leaf trash, stems, and burrs, which are also collected in the harvesting process.
- **Environmental Advantages.** Cotton gin trash has no commercial value and constitutes a significant waste disposal problem. Pile burning and land disposal are the most frequent forms of waste disposal. In the past, gin trash combustion has been difficult due to the environmental hazards posed by the ashes, which contain a large quantity of fine particulates—almost 40 percent at the submicron size. However, recent cotton gin waste projects such as the J. G. Boswell installation at Corcoran, California have demonstrated technology that can burn the trash in a controlled and uniform manner and within the limits specified by environmental codes.

California Almond Growers Exchange/IMOTEK, Inc. Sacramento, California

In late 1980, construction began at the California Almond Growers Exchange facilities on an \$11 million unit to convert almond shells into steam for electrical power and food processing. The Exchange represents approximately 50 percent of the nation's almond production and has annual sales in excess of \$250 million. The plant will initially burn almond shells at a rate of 50,000 tons per year—the amount of waste generated internally by the Exchange.

In order to take advantage of future growth in almond production, the plant has a capacity of 82,000 ton/year. The boiler will also accept other types of biomass, such as wood waste and annual almond tree prunings. The plant will be equipped to burn natural gas for start-up and stand-by purposes and, if necessary, to meet electrical and seasonal food processing peak load requirements. The facility will be built, leased, and operated by IMOTEK, Inc., a systems engineering firm, which also developed the 4.5 MW walnut shell burning facility in Stockton.

The production of 8.5 MW and associated steam (125,000 lb/hr at 600 psig and 750 F superheat) will save the equivalent of 125,000 barrels of oil imports per year. The almond shells are presently used in making charcoal—a venture which annually returned \$25,000 for the Exchange's entire volume of almond shell waste. Earlier, the shells were disposed of in teepee burners, until environmental considerations closed the teepee facilities.

Financing and Operating Arrangement. IMOTEK will build, lease, and operate the biomass cogeneration system. Two outside financial organizations have joined as the lessors of the project. California Almond Grower's Exchange will lease the land associated with the system to IMOTEK and will serve as a guarantor of the IMOTEK lease. The Exchange will sell almond shells to IMOTEK which in turn will produce steam to be sold back to the Exchange and to a nearby dairy operation. IMOTEK will also generate electricity to be sold to Pacific Gas and Electric.

- **Energy Output Utilization.** The electrical power, more than 70 million kWh/year, will be wheeled through the Sacramento Municipal Utility District and sold to Pacific Gas and Electric.
- **Addressing Safety Issues.** A key engineering aspect being investigated by the Exchange's staff focuses on the development of techniques for monitoring potential spontaneous combustion in fuel storage areas. Such incidents tend to form a lasting negative impression that could seriously impede biomass development in affected localities. The Exchange has been testing the use of infrared scanners to detect heat sources and CO₂ "gaseous" and "snowing" strategies to deal with spontaneous combustion situations.

Alaska Lumber and Pulp Co. Sitka, Alaska

Alaska Lumber and Pulp Company (ALP) has established two cogeneration units utilizing wood waste. One installation is a small unit at Wrangell, Alaska and the other is a 25 MW unit at Sitka. One of the problems with utilizing wood wastes in Alaska is that the wood frequently has been transported in water with significant salt concentrations. Burning such wood wastes can create a significant visibility problem. ALP also utilizes other mill wastes and the sludges from pollution control devices associated with its pulping operation. Bark has an excessively high moisture content and is landfilled rather than buried.

KEY FEATURES:

- **Expansion Solving Environmental Problems.** In anticipation of stricter EPA guidelines governing the generation of primary and secondary sludge, the ALP system is equipped to dispose of the sludge by burning. Thus, a potential environmental problem has been turned into an energy resource.
- **Power Trade Agreement.** Power generated by ALP is sold to the utility at a rate of 7¢/kWh. ALP's industrial rates are presently at 8-1/2¢/kWh. The difference in rates is a result of the utility receiving credit for its power shaping contribution.

Publishers Paper Oregon City, Oregon

Publishers Paper has established cogeneration units at a number of its Oregon locations. In 1963, the company removed a hog fuel boiler at one of its facilities and converted to petroleum. Because of rapidly increasing fuel prices, Publishers had switched back to hog fuel by 1974. A 5 MW unit was established in 1977 and in 1978, a 10 MW turbine was added. Although much of the wood fuel is generated internally, some is obtained from outside sources on a contract basis.

KEY FEATURES:

- **Consistent Performance and Current Expansion.** The biomass cogeneration facilities have had consistently good technical performance. Publishers has expanded its system a number of times and has recently installed a \$14 million, 20 MW, 300,000 lb/hr system at one of its sites.
- **Joint Ventures with Government.** One of the important advances in waste utilization energy systems is the Portland Metro Service District resource recovery facility. Plans call for a utilization rate of 700,000 tons of refuse each year. Publishers has contracted for the entire thermal production of the facility. The steam will be used in plant processes and in the generation of electricity to be used internally by Publishers. The plant is expected to be operating in 1984.

Lane Plywood Eugene, Oregon

Lane Plywood is in the process of installing an 800 kW biomass cogeneration system fueled by waste wood generated internally. Fuel includes bark from the logs peeled at the facility, sawdust and planer shavings from the sawmill, and plywood trim from the plywood plant.

The electrical generation equipment will be installed in conjunction with operations used to produce veneers. Steam at 185 psi from existing hogged fuel-fired boilers will drive the steam turbine. Exhaust steam from the turbine, at about zero lb pressure, will be ducted to a heat exchanger, which will heat water from a separate source to approximately 180 degrees. Condensate from the heat exchanger will be returned to the boiler. The water heated by the heat exchanger will be piped to concrete vaults and sprayed on peeler blocks used in producing veneers. The warm water will then be recycled and reused in the block treating system.

Preliminary negotiations indicate that the utility (Eugene Water and Electric Board) will furnish the equipment, such as breakers, relays, meters, etc., that is required in connecting the firm's cogeneration system with the utility grid. The design capacity of the electrical generation system will be 800 kW. It is estimated that the average operating rate will be 70 percent or 560 kW.

KEY FEATURES:

- **Replication Potential.** There are numerous wood products mills that are operating high pressure boilers to produce process steam for dry kilns, peeler block treating, etc. With modification, these facilities could be adapted to accommodate a small cogeneration system.
- **Utilization of Existing Equipment.** The cogeneration system incorporated an older existing boiler of the company. The boiler had previously been used to produce steam at 185 psig for plant processes. It was modified to produce steam for electrical generation and for plant processes at zero pressure.

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