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Fuel to Burn: Economics of Converting Forest Thinnings to Energy Using BioMax in Southern Oregon

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Abstract

Small-scale gasification plants that generate electrical energy from forest health thinnings may have the potential to deliver substantial amounts of electricity to the national grid. We evaluated the economic feasibility of two sizes of BioMax, a generator manufactured by the Community Power Corporation of Littleton, Colorado. At current avoided-cost electricity prices in Oregon, it would not be economical to operate a small-scale (100-kW) BioMax without a subsidy or tax credit, even if fuel were delivered to the plant at a forest landing at no cost. Given a tax credit, a 1,000-kW system could be operated profitably. If it were possible to sell merchantable logs (removed as part of forest health treatments) for an average of $175/thousand board feet, most acres on gentle slopes in southern Oregon would provide net operating surpluses. Most steeply sloped acres would generate operating deficits. If merchantable timber were sold separately, biomass from forest health thinnings on timberland in 15 western states could potentially provide from 2.3 to 14.3 billion kWh of electricity to the national grid. Our results suggest that if a forest landing is located near an existing power line, distributed energy generation is an option that may be worth considering.

Keywords: break-even analysis, wood gasification, small-diameter timber, forest health treatment, economic evaluation.

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Contents

Cover: BioMax, a 15-kW biopower system that uses high-density biofuels to produce heat and power. Photo courtesy of Community Power Corporation, Littleton, Colorado.

Executive Summary

Small-scale gasification plants that generate electrical energy from forest health thinnings may have the potential to deliver substantial amounts of electricity to the national grid. We modeled the economic feasibility of BioMax, a small-scale heat and power generator manufactured by the Community Power Corporation of Littleton, Colorado, for converting forest thinnings to energy. BioMax can run on a variety of biofuels, including forest residues, coconut shells, palm-nut shells, corncobs, and chicken litter. We evaluated the economics of distributed electricity generation using two sizes of BioMax, a 100-kW unit and a 1,000-kW unit.

Our primary objectives were (1) to evaluate the economics of operating generators at a forest landing, specifically determining the ability of such generators to pay for delivered wood both without and with an energy tax credit; (2) to model the wood and cash flows from forest health operations in a selected area when a BioMax generator is included; and (3) to evaluate the potential impact of distributed energy generation on energy supplies and forest health in 15 selected western states.

The advantage of distributed energy, i.e., locating a plant at a forest landing, is that transport costs for the biomass from the forest to a centrally located plant are avoided. These costs commonly range from $0.20 to $0.60/bone-dry ton (bdt) per mile. The disadvantage is that the excess heat produced does not have an obvious alternative value (e.g., to displace natural gas in heating buildings).

At current avoided-cost electricity prices in Oregon and using a pre-tax nominal return on invested capital of just over 23%, it would not be economical to operate either a 100-kW or 1,000-kW gasification plant at a forest landing without a subsidy or tax credit, even if fuel were delivered to the plant at no cost. With a Federal energy tax credit of $0.018/kWh, indexed for inflation, a 100-kW BioMax located at a forest landing and selling its power into the grid at Oregon's weighted average avoided-cost rate of $0.0437/kWh would still provide a negative present value. Such a system would require an average electricity price of $0.0728/kWh and fuel delivered to the plant at no cost, or an additional subsidy of $14.13/bdt to break even. Given the same tax credit, a 1,000-kW system would have a positive net present value and a real after-tax internal rate of return of 18.1%. The larger system could afford to pay up to $6.62/bdt for fuel at the landing while still providing its owners with their required rate of return on invested capital. Alternatively, if fuel was delivered to the larger plant at a forest landing at no cost, the plant could break even with an electricity sales price as low as $0.0345/kWh.

Critical assumptions in this analysis included the initial plant purchase costs per kilowatt, the delivered fuel price, the required rate of return on equity capital, and the value of the electricity produced. Other sensitivity analyses are automatically calculated by varying fixed and variable operating costs, the depreciation method used, and the amount of financial gearing.

Initial per-kilowatt plant purchase costs used were $2,000 and $1,500 for the 100- and 1,000-kW plants, respectively. The price of fuel delivered to the landing was assumed to be $0. For the 100-kW plant, every $5/ton increase increased the break-even electricity price by just over 10%. For the 1,000-kW plant, each $5/ton increase in fuel prices increased the break-even electricity price by 23%. For the 100-kW plant, changing the before-tax risk premium on equity capital by 2% changed the break-even electricity price by just over 3%. For the 1,000-kW plant, the same change in risk premium changed the break-even electricity price by just over 5%. Changing the sales prices for electricity had a large impact on the profitability of the plants and their ability to pay for their delivered fuel. For both sizes of plants, every half-cent increase in the electricity sales price enabled the plant to pay an additional $3.58/bdt for delivered fuel. There were no differences between the plants with this measure because conversion efficiencies were assumed to be the same with both sizes of plants.

Most forest health operations will produce at least some larger trees. If there were insufficient larger trees to make a sort for sawlogs worthwhile, or if these larger trees had defects making them unsuitable for sawlogs, then they would have to be utilized for biomass only. Under such conditions, most forest health operations would run at a deficit. The size of the deficit would depend largely on the amount of timber that must be removed and the harvest costs, which would in turn depend in part on whether the plot is on a gentle or steep slope. Average deficits ranged from $1,004/acre on gentle slopes to $4,306/acre on steep slopes. However, if it were possible to sell merchantable logs (removed as part of forest health treatments) for an average of $175/thousand board feet, most acres on gentle slopes in southern Oregon would provide net operating surpluses. Most steeply sloped acres would generate operating deficits.

If merchantable timber were sold separately, biomass from forest health thinnings on timberland in the 15 western states in question could potentially provide from 2.3 to 14.3 billion kWh of electricity to the national grid per year. In 2000, this would have represented 4.7% to 28.9% of the non-hydro renewable electricity generated in the United States.

Neither the 100-kW nor the 1,000-kW wood gasification plant is yet being produced commercially. Our results suggest that if such plants were commercially produced and if a forest landing were located near an existing power line, distributed energy generation is an option that may be worth considering, especially for a gasification plant with a capacity of 1,000 kW or greater.

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Background

Nearly a century of successful fire suppression has resulted in dense over-stocked stands prone to catastrophic wildfires. Approximately 190 million acres (77 million ha) of Federally managed land is at risk of catastrophic fire in the near future (U.S. Congress 2003). Across all land ownerships, more than 70 million acres (28 million ha) is at risk for higher than normal mortality from insect infestation and disease, which in turn increases the risk of wildfire and results in watershed degradation, changes species diversity and productivity, diminishes fish and wildlife habitat, and decreases timber values.

Uses need to be found for woody material removed from the forest to reduce the risk of wildfire. One option is to burn the wood for energy. Another is to convert the wood into a low-value commodity. However, a problem accompanies these options: the cost of transporting wood chips from the forest to the mill. Haul rates range from $0.20 to $0.60 per bone dry ton (bdt) per mile (1.6 km), depending on truck configuration, travel speed, and payload factors (Rummer and others 2003). Hauling costs determine the economically viable distance between the forest treatment site and a processing facility.

Transport costs alone may be higher than the value of the chips. If the chips are worth $20/bdt at an energy plant, then at most they could be shipped only from 33 miles (54 km) at $0.60/bdt/mile shipping cost to 100 miles (161 km) at $0.20/bdt/mile shipping cost, assuming that transport costs alone would be recovered. (For example, $20/bdt per $0.60/bdt per bdt mile = 33 miles.) A conventional rule of thumb is that biomass for energy can be economically gathered only within a 50-mile (80-km) radius from the combustion site (EIA 1998).

One way around the problem of delivering chips to a distant plant is to eliminate the transport cost. If the chips could be utilized on a forest landing (e.g., in a power generator), the total cost of biomass removal would consist only of harvesting and delivery to a landing.

Small-scale power generators are being developed by a number of companies, which include Carbona Corporation (Atlanta, Georgia), Community Power Corporation (Littleton, Colorado), External Power (Indianapolis, Indiana), and Flex Energies, Inc. (Mission Viejo, California). BioMax is an example of a small-scale heat and power generator manufactured by the Community Power Corporation. BioMax units can run on a variety of biofuels, including forest residues, coconut shells, palm-nut shells, corncobs, and chicken litter. The systems can range in size from 5 kW for home-power applications to as large as 200 kW for small industrial applications (Community Power Corporation 2002a).

In a demonstration project at the Tsemeta Forestry Regeneration Complex, which is owned and operated by the Hoopa Valley Indian Tribe in California, a small BioMax system converted three different forms of forest residue fuels to energy and heat. In addition, the generator has delivered power to the Pacific Gas & Electric grid (Community Power Corporation 2002b).

But do the BioMax units make financial sense? What, if any, is the potential of distributed energy production to contribute to the fuels reduction problem? And under what conditions might it be economically feasible to locate a BioMax generator on a forest landing and eliminate the added cost to transport chips to a distant plant?

Objectives of Analysis

The objectives of our analysis of two BioMax units, 100- and 1,000-kW generators, were as follows:

- to determine the total subsidy required to operate the generators or the total profit gained,
- to compare the economics of operating the generators at a forest landing,
- to evaluate the impact of a potential energy tax credit on the economics of such a system,
- to determine the area of forest that could be treated to provide fuel for each size of BioMax generator,
- to determine the maximum amount that potential BioMax owners could afford to pay for delivered fuel,
- given three different silvicultural prescription options in a given region, to estimate the cost for fuel from forest thinnings delivered to a BioMax generator on a forest landing,
- to estimate the potential impact of distributed energy generation located on a forest landing on energy supplies in the western United States, and
- to evaluate the potential role of distributed energy generation in ameliorating forest health problems in the western United States.

Our analysis was threefold: (1) evaluation of the economics of distributed electricity generation using a BioMax unit; (2) assessment of timber stand treatment costs and returns in relationship to delivered quantities and costs of biomass fuel to landings in southern Oregon forests; and (3) analysis of the potential role of a distributed energy system on a forest landing in the utilization of unwanted biomass in 15 western states.

BioMax Economics

A bio-powered distributed energy system produced by the Community Power Corporation was used as an example of a distributed energy system that might be used to effectively dispose of surplus wood. The unit dries and gasifies wood chips. It produces electricity by burning the producer gas in an internal combustion engine. Heat and shaft power are also produced. The BioMax generator is shown on the cover and basic specifications are listed in Table 1.

A spreadsheet model was constructed to analyze the financial feasibility of two possible BioMax systems. A copy of the spreadsheet is available on the Forest Products Laboratory website as part of this report (www.fpl.fs.fed.us).

The spreadsheet calculates before- and after-tax net present values (NPVs) and internal rates of return (IRRs), all in nominal terms, which include inflation, and in real terms,

Table 1—Specifications for BioMax generator

Fully automatic startup, operation, and shutdown	Electrical power: 5- to 50-kW modules
Microprocessor-based control system	Thermal power: 50,000 to 500,000 Btu/h
Co-Gen (CHP) power modules	Footprint: 5 by 5 m
Non-condensing system, dry gas clean-up	Weight: 1,500 kg
No liquid effluents, no toxic wastes	Gas: LHV 5 mg/m^3 <5 ppm tars/particulates
Combined heat and power	Fuel conversion: ~1.5 kg wood/kWh
Able to use a variety of woody biomass fuels (e.g., wood chips, pellets & scraps, nutshells)	Gas composition: (~)O_2 0%, H_2 20%, CO 20%, CO_2 7%, CH_4 2%; balance N_2
Optional automatic dryer/feeder	Turndown ratio: >10:1
Designed for high-volume, low-cost manufacture	Full cold starting on wood gas: ~15 min
Trailer or skid-mounted, simple installation	Dispatchable power within 30 s

Source: Community Power Corporation. www.gocpc.com/products/BioMax%20Spec%20Sheet.PDF

Table 2—Summary of wood consumption and output for BioMax systems with 7,876 annual productive hours

	BioMax system	
Consumption and output	100-kW	1,000-kW
Annual biomass consumed (bdt)	1,132	11,324
Annual electricity production (kWh)	787,600	7,876,000
Annual thermal production (1,000 Btu)	3,000,000	30,000,000

which do not include inflation. In addition, it automatically calculates the break-even electricity sales price. The model also calculates either the break-even fuel charge (extra amount owners could afford to pay for fuel) or the additional fuel subsidy required to provide the owners with their required after-tax IRR.

All break-even calculations include the owners' required return on investment. In other words, at each of these break-even amounts (such as for fuel subsidies, fuel charges, electricity sales prices), if everything else in the analysis is held constant, the after-tax real NPV will be zero and the IRR will exactly equal the owners' required alternative rate of return.

Although current BioMax units are in the 15- to 50-kW range, such units would be too small to make much of an impact on the biomass produced in the western forests. For example, given the conversion of 3.3 lb (1.5 kg) of wood chips/kWh, fuels removals of 50 bdt/acre (112 tonnes/ha), and an 81.7% capacity factor, a 15-kW BioMax would consume the fuel from approximately 3 acres (1.2 ha)/year. We chose to model the economics of a 100-kW and a 1,000-kW unit to do a preliminary evaluation of their financial feasibility and ability to contribute to a forest health program. A sample printout of the BioMax spreadsheet model for a 1,000-kW generator is included in the Appendix.

Wood consumption and output for 100- and 1,000-kW BioMax generators are shown in Table 2. In terms of physical size and output, we have not assumed any economy of size with respect to energy efficiency and conversion.

Avoided Costs

Whether or not electricity generation is economic depends on the price of electricity and the value, if any, of thermal production. Locating a generator at a forest landing near a transmission line would eliminate chip delivery costs. However, excess thermal production (i.e., energy not used to dry chips) would probably not be utilized and as such would have no value. The only product for which revenue would be received would be electricity delivered to the grid.

Disclaimer

BioMax generators are still in their pre-commercial development phase. Although several demonstration units have been constructed, no 100- or 1,000-kW units have been built. Therefore, there is a degree of speculation associated with the costs used in our analysis. Our costs and projections may be representative of a commercial model. However, we would strongly encourage anyone considering investment in such a facility to do a full site-specific engineering feasibility analysis in addition to a financial analysis using costs and benefits that are appropriate for that facility in the State in which it is to be established. The USDA Forest Service is not liable for losses incurred on investments made on the basis of information contained in this analysis.

Under the Public Utility Regulatory Policies Act (PURPA) of 1978, a utility company must purchase power from an independent firm at the utility's cost of production, its so-called "avoided costs." Avoided costs are the prices paid by the utility for electricity delivered to the grid. They are linked closely to delivered natural gas costs. Avoided costs are more akin to wholesale costs. They are generally lower than retail rates because they do not include such costs as line charges and billing fees.

Under the Oregon statute, avoided costs are defined as

> …the incremental cost to an electric utility of electric energy or energy and capacity that the utility would generate itself or purchase from another source but for the purchase from a qualifying facility. (Oregon Revised Statutes 2003)

A qualifying facility is defined as a cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission in accordance with the PURPA of 1978 (EIA 2001). The capacity of a qualifying power plant must be no greater than 80 MW and the energy derived from renewable resources. While there is no size restriction for cogeneration plants, a qualifying cogeneration facility must have at least 5% of energy output dedicated to "useful" thermal applications (EIA 2001). For our analysis, we assumed that the BioMax generators may be classified as qualifying facilities.

In Oregon, the current annual average standard on-peak and off-peak avoided-cost rates for electricity purchases from qualifying facilities with a capacity of 1,000 kW or less are \$0.048 and \$0.026/kWh, respectively. However, the Public Utility Commission of Oregon recommended that these rates be raised to \$0.054 and \$0.030/kWh, respectively (McNamee 2003). We used these upward-revised avoided-cost rates in our analysis. On-peak hours are from 7:00 a.m. to 11:00 p.m., Monday through Friday.

We assumed that it would be possible to produce electricity with the BioMax units for 20 h/day, 358 days/year, resulting in a utilization rate of 81.7%. Using this rate and time produces a weighted average electricity avoided-cost rate of \$0.0437/(kWh), which we used for our analysis.

Basic Results

The basic results from our analysis are shown in Table 3. The data in Table 3 indicates that neither unit is financially feasible. The cash flows for the 100-kW unit are so poor that the IRR values are undefined. Both facilities have negative NPVs, and both have break-even electricity prices higher than Oregon's on-peak avoided cost. Neither unit comes close to the off-peak avoided cost.[1] Neither unit can produce electricity at an average price of \$0.0437/kWh, the average avoided cost in Oregon.

Unless the thermal output is worth something (in terms of heating value), both systems at forest landings would require subsidies or tax credits to break even, in addition to zero-cost wood fuel. The 100-kW plant would require an additional subsidy of \$40.06/bdt to break even and just return the cost of capital to its owners. The 1,000-kW system would require an additional \$12.62/bdt subsidy. Thermal output is not likely to have much value at forest landings.

Other Assumptions

Many assumptions we used were common to both the 100- and 1,000-kW units:

Table 3—Summary economics for BioMax systems with no energy tax credit[a]

	BioMax system	
Economics	100-kW	1,000-kW
After-tax NPV [b]	(\$151,102)	(\$476,163)
After-tax IRR (real)	Undefined	–1.6%
After-tax IRR (nominal)	Undefined	1.3%
Break-even electricity price (\$/kWh)[a]	\$0.0996	\$0.0614
Surplus available (subsidy required) (\$/bdt)[a]	(\$40.06)	(\$12.62)

[a]Delivered fuel cost of \$0/bdt, no thermal value, and avoided-cost electricity sales price of \$0.0437/kWh.
[b]At pre-tax nominal risk premium of 20% over bank interest rate of 3%.

- Expected before-tax nominal risk premium on invested capital, 20% (in addition to annual bank deposit interest rate)
- Federal energy tax credit, \$0/kWh
- Fuel consumption subsidy, \$0/bdt
- Plant life, 10 years with \$0 salvage
- Repairs and maintenance, 50% of straight-line depreciation over economic life of asset
- Variable labor cost, \$0.3333/h for 100-kW BioMax and \$3.333/h for 1,000-kW BioMax
- Periodic consumables cost, \$0.00142 kWh
- Fuel conversion, 3.3 lb (1.5 kg)/kWh
- Combined Federal and State tax rate, 33%
- *ad valorem* (property) tax mill rate, 0%
- Special first-year depreciation allowance, 30%[2]
- Depreciation method, diminishing value under general depreciation system (IRS 2003)

[1] Break-even prices or values occur when the after-tax net present value (NPV) is zero, if all other assumptions are held constant. In the example given, the break-even electricity price is the price the BioMax would have to receive to give the required rate of return to its owners, if all other assumptions were held constant (e.g., delivered fuel cost of zero, no value for thermal output).

[2] See IRS (2003) for detailed information on depreciation allowances. Special allowances are permitted if the assets are used on Indian reservations or in Special Enterprise Zones. We did not incorporate special allowances into our analysis.

The nominal risk premium on invested capital expected before taxes is a risk premium that is added to the bank deposit (safe) interest rate. This premium may be on the low side of what is expected in the power industry. For example, a large California organization expects 28% to 35% return on investment in this industry (personal communication, Mark Nechodorn, USDA Forest Service, Pacific Southwest Research Station).

Since the electricity generated by BioMax uses a modified internal combustion engine, major plant refitting will probably be necessary after 10 years. Haq (2002) assumed a project life of 30 years for the cost and performance of biomass integrated gasification combined-cycle generating plants. However, the capacity of the plant he analyzed was 100 MW. Our decision to use a 10-year life is conservative; allowing for a longer life would improve the economics. We test for this in the sensitivity analysis.

In regard to repairs and maintenance, the Department of Energy (1997) reported annual fixed maintenance and labor costs of $36.5/kW for a 75-MW plant in 1997. In 2000, this cost decreased to $30.47/kW. Adjusted for the initial capital value of the plant and expressed as a percentage of straight-line depreciation over the economic life (30 years) of the assets results in repairs and maintenance percentages of 54.4% and 48.3% of straight-line depreciation for the 100- and 1,000-kW units, respectively.

Labor charges are in addition to repairs and maintenance costs. The Department of Energy (1997) used a variable operating cost for labor of $0.0034/kWh for a 75-MW gasification-based biomass plant. We assumed that neither BioMax unit would require dedicated labor. Both units would be monitored by workers already performing other tasks, so the marginal cost of labor would be low. Adjusting the Department of Energy value for inflation using the consumer price index (CPI) resulted in $0.0040/kWh for 2004.

The model is structured so that a single hourly labor rate is entered. This single rate is applied to the scheduled annual operating time, even if a worker would not be present and doing BioMax-related work for that entire time. Multiplying $0.0040/kWh by the plant output and dividing by the scheduled operating hours results in an hourly labor charge of $0.3333 for the 100-kW unit and $3.333 for the 1,000-kW unit. These rates mean that labor cost amounted to 9% of total cost for both units.

The Department of Energy (1997) used a variable consumables cost of $0.0012/kWh (1997 dollars) in its base case for a gasification-based 75-MW biomass plant. We used the CPI to update this figure for inflation, resulting in a value of $0.00142/kWh for 2004.

In our analysis, we used diminishing value depreciation at a rate of 150% because this provided the most favorable financial outcome, assuming that the BioMax is not the sole revenue source of the firm. We also used a special first-year depreciation allowance of 30%.[3] However, because of the capital value of the assets, we did not allow for any section 179 deductions.[4] While our model allows use of alternative depreciation schedules, we do not present those results here. We assumed that the assets would be classified under IRS category 49.15 for an electric utility combustion turbine production plant (see A Question of Depreciation, page 7).

The main difference between the 100- and 1,000-kW units is our assumption regarding installed delivery price. We assumed that the 100-kW unit would cost $2,000/kW and the 1,000-kW unit would cost $1,500/kW as a result of economies of size relating to the construction of a larger unit. Increased efficiency in fuel conversion with a larger unit would further exacerbate the differences in the economics of the two units.

We also assumed some economies of size with respect to general administration costs regarding the two units; we allowed $5,000/year for the 100-kW BioMax and $10,000/year for the 1,000-kW BioMax. General administration costs accounted for 7% of total costs for the 100 kW unit and 2% of total costs for the 1,000-kW unit.

We ran our models with a delivered fuel cost of $0/bdt so that we could see how much (if anything) operators of BioMax generators could afford to pay for fuel, given the other assumptions. Any surplus represents cash that could go towards paying for fuel and forest health operations. Any deficit represents an additional subsidy that the owners would need in order to make their specified return on investment.

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[3] The special first-year depreciation allowance was put in place by the Job Creation and Worker Assistance Act of 2002. It is an allowance in addition to ordinary depreciation and is calculated after any section 179 deduction. If taken, it should be 30% of the adjusted book value (i.e., purchase price less any section 179 deduction), unless the facility may be classified as Qualified Liberty Zone Property. For further information see IRS (2003).

[4] Section 179 of the Internal Revenue Code allows investors the option to recover all or part of the cost of certain qualifying property by deducting it in the year the property is placed in service. In effect, it allows an investor to treat an asset purchase as an immediate expense. The IRS refers to this as a “section 179 deduction.” There are limitations and restrictions on this deduction. For more information, see IRS (2003).

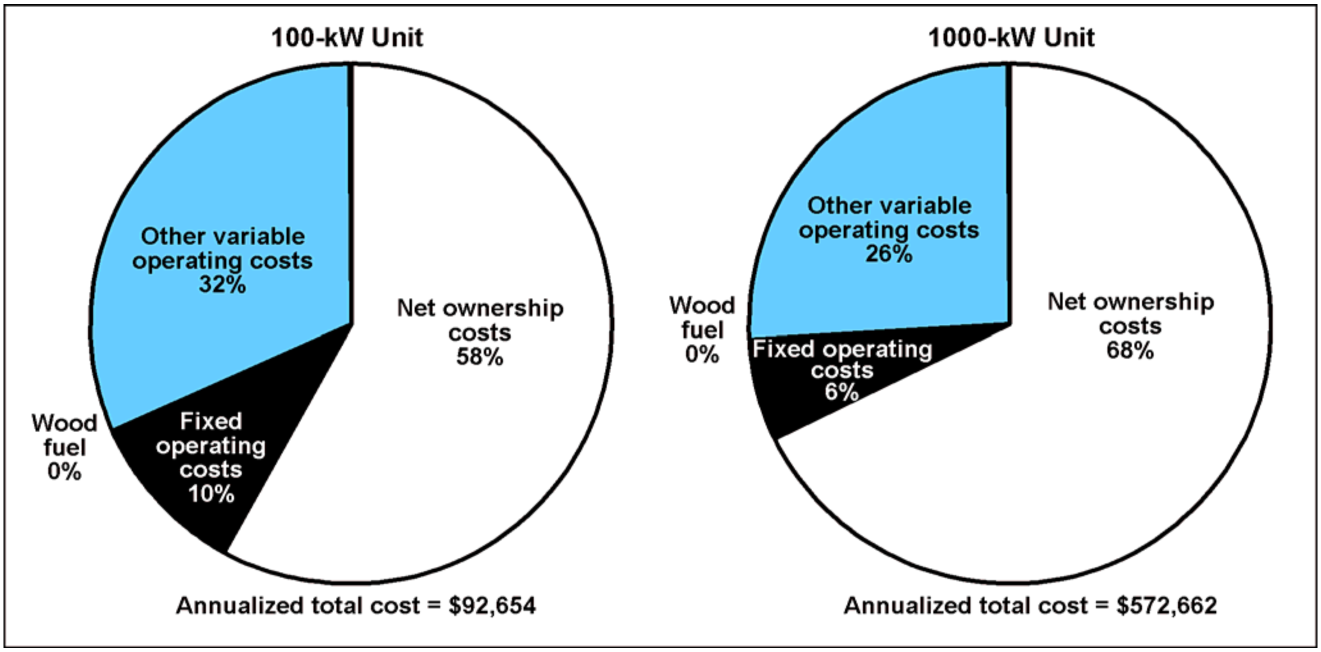

Figure 1—Pre-tax cost breakdowns for 100- and 1,000-kW BioMax generators.

Sensitivity Analysis

As with any economic analysis, the numbers presented in the results depend on the assumptions. Because the units we are modeling are not currently being produced, our results are based on many costs that are informed guesses. However, the sensitivity analysis does indicate which variables will be critical to monitor to keep the project economics favorable. The pre-tax cost breakdowns in Figure 1 indicate which variables cause the greatest impact on financial outputs.

Ownership costs make up a significant proportion of the total pre-tax costs of both units. The ability of either unit to pay for its delivered fuel is inversely related to initial capital costs, as shown in Figure 2. Negative numbers on the *y*-axis represent surplus funds that could go towards paying for delivered fuel.

Figure 2 shows that initial capital costs would have to decline to nearly $1,000/kW for even the 1,000-kW BioMax to be able to operate without additional subsidies. At $900/kW, the 100-kW unit would still require an additional operating subsidy of $11.52/bdt to provide its owners with a required nominal pre-tax rate of return of 23.04%.

The negative number for the 1,000-kW BioMax at a capital cost of $900/kW indicates that at this capital cost, operators would be able to afford to pay $2.95/bdt for fuel and still be able to pay the required rate of return to owners. At any given identical capital cost, the difference between the two units is $14.46/bdt. That is, operators of the larger unit could afford to pay an additional $14.46/bdt while achieving the same rate of return.

The owners' required risk premium on investment capital can be a key variable in determining the financial feasibility of a potential investment. The model is constructed so that the owners' required risk premium is in addition to the bank savings rate. Our base case uses a risk premium of 20% in addition to a bank savings APR of 3%. Figure 3 shows premiums of 2% to 28% over the bank rate and their impact on the break-even fuel cost for both BioMax units.

Figure 3 illustrates that even with a risk premium of just 2% above a bank deposit rate (assumed to be 3%), both BioMax units would still require subsidies to operate at a forest landing and sell electricity to the grid at the avoided-cost rate of $0.0437/kWh.

The avoided-cost rate itself is a major variable with respect to the economics of the BioMax units. Sensitivity to electricity prices is shown in Figure 4. Electricity prices would have to climb above $0.0996/kWh for the 100-kWh unit and above $0.0614/kWh for the 1,000-kW unit before the operators could afford to pay for delivered fuel. Below these prices, the operation would require additional subsidies if the owners were to achieve a required rate of return of 20% over the bank deposit rate.

A Question of Depreciation

How should BioMax generators be depreciated? It depends on how the assets are classified. It also depends on what depreciation method is chosen, diminishing value or straight line, and which depreciation system is used: the general depreciation system (GDS), which is based on the modified accelerated depreciation system (MACRS), or the alternative depreciation system (ADS), which provides for a longer depreciable life. How the unit is classified depends on its size and the method of electricity generation.

If the total capacity of the unit is in excess of 500 kW, it may be classified under asset class 00.4, Industrial Steam and Electric Generation and/or Distribution Systems, which gives the following recovery periods:

GDS (MACRS): 15 years ADS: 22 years

Alternatively, depending on how the electricity is generated, the unit may be classified under 49.13, Electric Utility Steam Production Plant, with the following recovery periods:

GDS (MACRS): 20 years ADS: 28 years

If classified under 49.15 Electric Utility Combustion Turbine Production Plant, the recovery periods are as follows:

GDS (MACRS): 15 years ADS: 20 years

It may be worthwhile to depreciate the gasification unit and the combustion unit separately. If so, the gasifier may be classified under 49.5, Waste Reduction and Resource Recovery Plants, with the following recovery periods:

GDS (MACRS): 7 years ADS: 10 years

Source: IRS (2003).

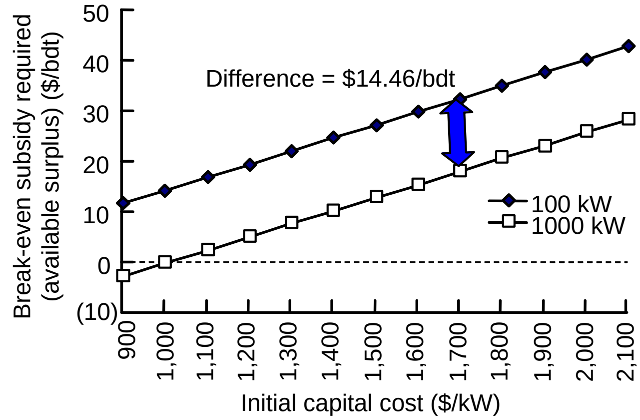

Figure 2—Sensitivity to initial capital cost given no energy tax credit: break-even subsidies required (surplus available) for 100-and 1,000-kW BioMax units assuming avoided-cost electricity rate of $0.04437/kWh.

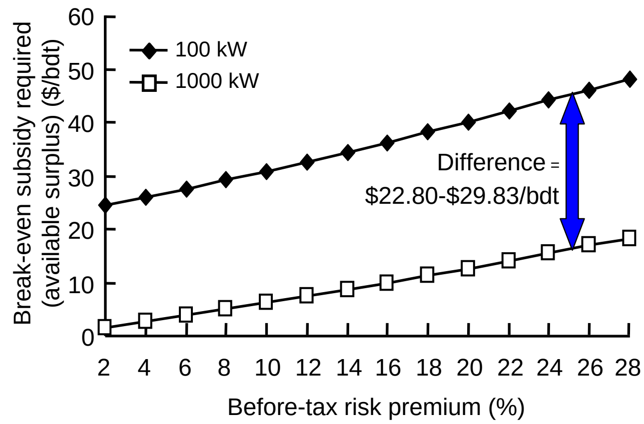

Figure 3—Sensitivity to before-tax risk premiums: break-even fuel subsidy for 100- and 1,000-kW BioMax units assuming no energy tax credit and electricity price of $0.0437/kWh.

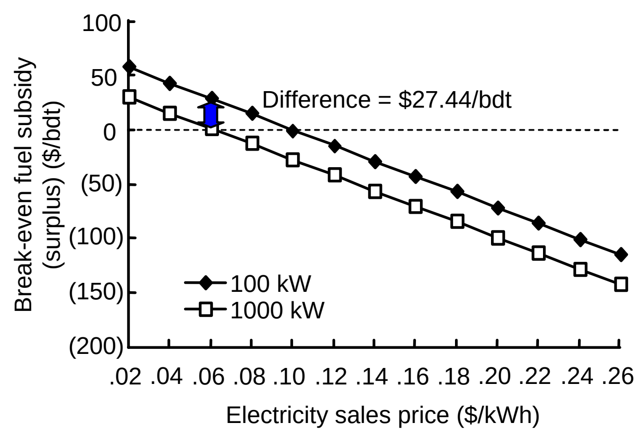

Figure 4—Sensitivity to delivered electricity prices assuming no energy tax credit: break-even fuel subsidy (surplus) for 100- and 1,000-kW BioMax units.

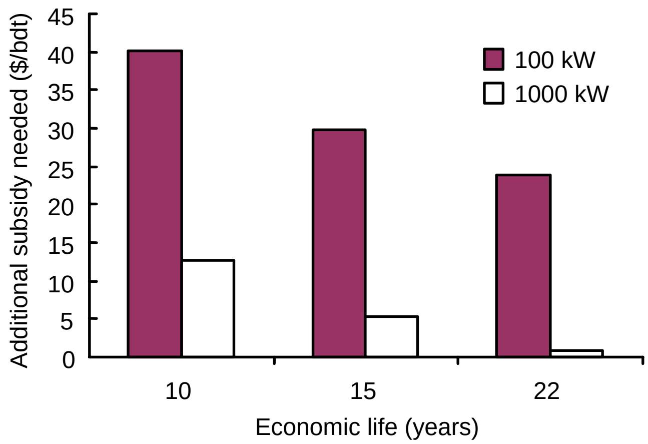

Figure 5—Impact of economic life on ability of 100- and 1,000-kW BioMax units to pay for fuel, given no energy tax credit.

We also assumed an economic life of 10 years for both units. In a sensitivity analysis, we tested for economic lives of 15 and 22 years, the same as the depreciation lives under the accelerated and alternative Internal Revenue Service schedules (IRS 2003), respectively. These longer lives improve the economics, but tax credits or other subsidies are still needed. The results for the 100- and 1,000-kW BioMax units are shown in Figure 5.

Without an energy tax credit, additional subsidies are required (in addition to zero-cost fuel) for both plants to provide their required rate of return. For the 100-kW unit, the subsidy drops to $23.25/bdt for a plant life of 22 years and for the 1,000-kW unit, the subsidy drops to $0.86/bdt (Fig. 5).

While using a longer economic life does make the returns look better, if a plant operates longer, there may be some additional maintenance costs or major replacement costs that are not included in this analysis.

All the calculations in the sensitivity analysis indicate that unless an energy tax credit or some other type of operating subsidy were available, neither the 100-kW nor 1,000-kW BioMax generator at a forest landing would probably be economic unless electricity prices were roughly 40% to 130% higher than the current avoided-cost rate in Oregon.

Impact of Energy Tax Credit

The disposal of biomass in high-efficiency burners (e.g., for power generation) may provide environmental benefits when compared with alternative disposal methods. Morris (1999) quantified emissions when biomass is used for energy compared with emission that would occur with open burning, landfill disposal, immediate or delayed composting, spreading, or forest accumulation. In most cases, controlled combustion in electrical generation plants provides lower emissions than do the alternatives. Open burning produces massive smoke emissions containing particulates and other pollutants. Disposition of biomass in landfill reduces landfill capacity and ultimately leads to higher greenhouse gas emissions compared with that from controlled combustion. Allowing forests to remain overgrown can depress forest health and productivity, increase the risk of catastrophic wildfire, and degrade watershed quality.

Using a base-case conservative analysis, Morris (1999) placed values (costs) on emissions and adjusted for time. He found that the value of controlled combustion in the United States is $0.114/kWh. This figure results from reductions in particulates, greenhouse gases, and depletion of landfill capacity. It does not include the value of the electricity produced or any benefits from rural employment, rural economic development, or security provided by distributed energy production. If such benefits are added to the value of energy production, then the production of energy with small, mobile generators on forest landings may be economic from a societal perspective as well.

Tax credits and other subsidies may help make biomass energy generation systems financially viable. Federal credits have been available through the Renewable Energy Production Credit (REPC) and were previously available through the Renewable Energy Production Incentive (REPI) (U.S. Department of Energy 2004). For the calendar years 2002 and 2003, both the REPC and REPI offered tax incentives or payments amounting to $0.018/kWh and indexed for inflation.

The REPI was available to private entities subject to taxation that generated electricity from wind and "closed loop" biomass facilities, which grew biomass specifically for energy production, harvesting and converting that biomass into energy, and selling the resulting electricity to unrelated parties.

Although the REPI formally terminated on December 31, 2003, it was re-enacted as part of the American Jobs Creation Act of 2004[5] (set to terminate on December 31, 2005), and was retroactively extended back to January 1, 2004 (see Public law 108–357, Section 710). This law modified Section 45 of the U.S. Internal Revenue Code (Title 26 or 26 USC). Under this extension, the provisions of the tax credit were broadened to include open-loop biomass. Open-loop biomass includes mill and harvesting residues, precommercial thinnings, slash, and brush. Production may be in any qualified facility placed in service before January 1, 2006.

[5] The American Jobs Creation Act of 2004 can be accessed from the Government Printing Office website at http://frwebgate.access.gpo.gov/cgi-bin/multidb.cgi

Table 4—Summary economics for BioMax systems at inflation-adjusted energy tax credit of $0.018/kWh[a]

Economics	BioMax system 100-kW	1,000-kW
After-tax NPV (at a real rate of 12.08%)	($78,507)	$249,790
After-tax IRR (real)	(4.4%)	18.1%
After-tax IRR (nominal)	(1.6%)	21.6%
Break-even electricity price ($/kWh)	$0.0728	$0.0345
Surplus available (subsidy required) ($/bdt)	($20.81)	$6.62

[a]At delivered fuel cost of $0/bdt, no thermal value, and avoided-cost electricity sales price of $0.0437/kWh.

Specific provisions in the law relate to phasing out this credit and to its applicability. Users should consult with accountants regarding their eligibility for this credit. Our purpose here is to analyze the impact of a $0.018/kWh tax credit on the economics of the BioMax gasifiers.

Tax credits can change the cash flows and the economics of the gasifiers. The results with an inflation-adjusted tax credit of $0.018/kWh are summarized in Table 4. Despite this credit, the 100-kW unit at a landing would still be unable to provide a positive rate of return. This unit would still require a break-even electricity price of $0.0728/kWh, which is higher than the on-peak avoided-cost rate in Oregon. On the other hand, such a subsidy would allow the 1,000-kW unit to operate profitably. In addition, the surplus of $6.62/bdt could be used to pay for delivered fuel, and owners would still achieve their required rate of return.

The sensitivity analysis graphs were adjusted to take into account an energy tax credit. The sensitivity to the initial capital cost with an energy tax credit is shown in Figure 6 (compare to Figure 2, which shows sensitivity without tax credit). The energy tax credit simply shifts both sensitivity lines to the left. The difference between the two lines, $14.46/bdt, remains the same in Figures 2 and 6. Figure 6 shows that initial capital costs would have to decline to about $1,200/kW for unsubsidized operation of a 100-kW BioMax generator. For a 1,000-kW unit, however, costs could rise to $1,750/kW before the cost of delivered fuel would be prohibitive. The negative numbers in Figure 6 (in lower capital cost ranges) represent available surpluses that could be used to pay for delivered fuel.

Results of the sensitivity analysis are similar for other figures. For example, an inflation-indexed energy tax credit of $0.018/kWh shifts the curves for sensitivity to

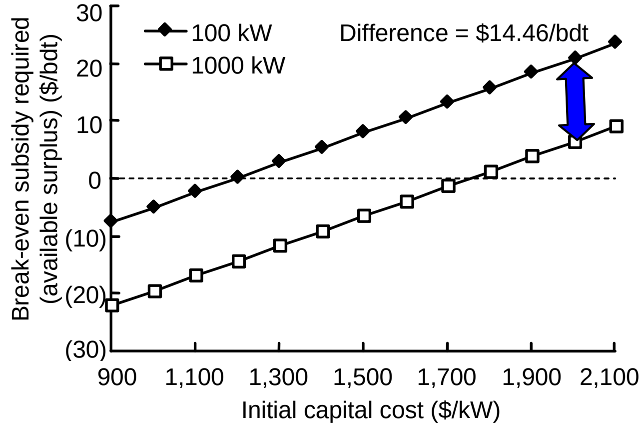

Figure 6—Sensitivity to initial capital cost given inflation-adjusted energy tax credit of $0.018/kWh: break-even subsidy required (surplus available) for 100- and 1,000-kW BioMax units.

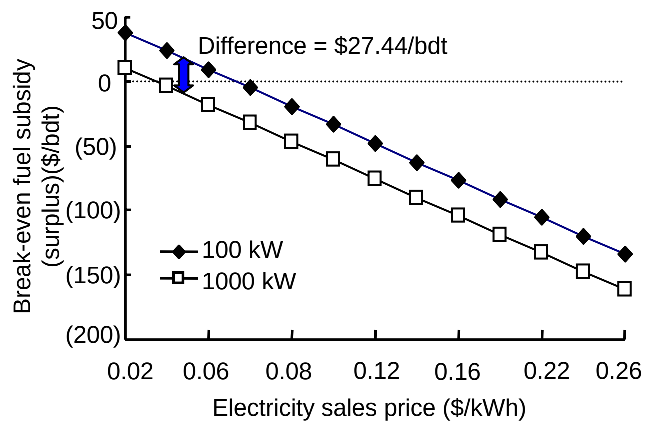

Figure 7—Sensitivity to delivered electricity prices assuming price inflation-indexed energy tax credit of $0.018: break-even subsidy required (surplus available) for 100- and 1,000-kW BioMax units. Compared with values in Fig 4., values are $19.25 lower for both 100- and 1,000-kW plants. Difference between plants remains $27.44/bdt.

electricity sales price downwards by $19.25/bdt (compare Figures 4 and 7). That is, at any given electricity sales price, an energy tax credit of $0.018/kWh increases the ability of the plant to pay for fuel by $19.25/bdt. However, while the curves are shifted downwards, the difference between the cost curves of the two plants remains unchanged at $27.44/bdt.

The purpose of our initial analysis was to determine how much (if anything) users of a BioMax-type generator could afford to pay for delivered fuel at a forest landing. An alternative question is, given a range of possible subsidies or fuel costs, at what price would the generated electricity have to be sold to pay for its costs and provide the required rate of

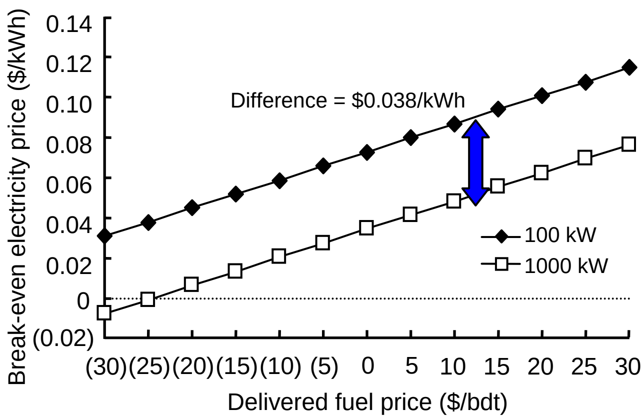

Figure 8—Sensitivity to fuel costs: break-even electricity prices for 100- and 1,000-kW BioMax units with energy tax credit of $0.018/kWh. Values in parentheses on *x*-axis are negative.

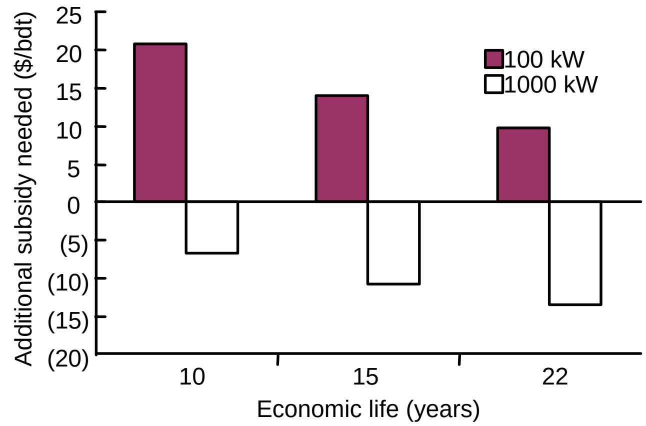

Figure 9—Impact of economic life on ability of 100- and 1,000-kW BioMax units to pay for fuel, given inflation-adjusted energy tax credit of $0.018/kWh.

be sold to pay for its costs and provide the required rate of return to the plant's owners?

A range of fuel costs, from a subsidy of $30/bdt to a charge of $30/bdt, was examined with respect to its impact on break-even electricity prices at the landing. In Figure 8, the subsidies (negative numbers, in parentheses) on the *y*-axis represent additional payments to BioMax owners that they would require to provide a 20% risk premium for combustion of wood waste at the electricity prices on the *x*-axis. The positive numbers on the *x*-axis represent possible payments for delivered fuel at the specified electricity prices.

Figure 8 shows that for any given fuel cost, the 100-kW unit requires a higher electricity sales price than does the 1,000-kW unit to break even. The difference is slightly more than $0.038/kWh. For example, at a delivered fuel cost of $20/bdt, the 100-kW unit would require an electricity price of $0.101/kWh, whereas the 1,000-kW unit would require just $0.062/kWh.

The sensitivity of the BioMax units to their economic life with no energy tax credit is shown in Figure 5. If a Federal energy tax credit of $0.018/kWh indexed to inflation were available, a 100-kW BioMax would still require an additional payment per ton ranging from $20.81/bdt for a plant with a 10-year economic life to $9.69/bdt for a plant with a 22-year economic life (Fig. 9). However, operators of a 1,000-kW BioMax could afford to pay $6.62 to $13.39/bdt for fuel if the unit's economic life increased from 10 to 22 years, respectively.

With an energy tax credit of $0.018/kWh, the 100-kW BioMax would still require an additional operating subsidy, under the economic lives we examined. If the plant were to last 22 years, the necessary subsidy would drop to $9.69/bdt for a 100-kW plant. The ability of operators of a 1,000-kW plant to pay for fuel increases with the economic life of the plant. If the economic life were 22 years, operators of a 1,000-kW plant would be able to pay $13.39/bdt for fuel.

Limitations of BioMax Analysis

Several assumptions in this analysis could be further refined:

The capability of the harvest system matches that of the generator—A 100-kW BioMax unit would burn 1,132 bdt/year and a 1,000-kW unit 11,324 bdt/year (see Table 2). Since a small feller–buncher and forwarder can produce about 15,000 bdt/year,[6] any mismatch between the harvesting system and the larger generator is minimal. However, a small chipper can produce about 37,500 bdt/year.[7] This means that a single chipper has to feed several units, a market is needed for the excess chips produced, or the chipper will operate at only one-third its capacity. If the latter is the case, then the harvesting and chipping costs will probably be higher than those specified in the following text.

The analysis assumes no value for waste heat produced—In reality, some heat would be used to dry the chips to 15% moisture content before combustion. However, the excess heat from a plant on a forest landing would have no value. If the generator were set up in a place where the surplus heat

[6] Assumes a small feller and forwarder can supply 5 green tons to a chipper every 15 min (Bob Rummer, USDA Forest Service, Southern Research Station, Auburn, Alabama; personal communication) and operates 6 h/day for 250 days/year. This equates to 30,000 green tons or 15,000 bdt.

[7] Assumes a small whole-tree chipper produces about 50 green tons/h (Todd Gustafson, Morbark Industries, personal communication).

had some positive value, then the economics of power generation would be more favorable.

The generator would be set up on a forest landing not far from a pre-existing power line—Transporting the wood chips would entail additional costs. Alternatively, additional costs would be incurred if lines had to be installed to transmit generated power from the landing to the grid.

The landing has sufficient space for the generator, chipper, and associated equipment and no additional cost is required for the land—Even if there were no cost for the land, some additional cost would be entailed in constructing a larger landing. Costs may also be associated with in-site restoration when the generator is moved. However, the absolute area required might be a problem (Todd Gustafson, Morbark Industries, Rapid River, Michigan; personal communication). For example, if the site required space for the BioMax, a 57-ft (17-m) flail chipper with a 48-ft (15-m) grinder, skidders, delimbers, and log makers, along with their associated equipment, problems may be encountered with the absolute size of the landing. In addition, if the harvesting and chipping system were not a good match with the generator, additional space may be required for one or two 48-ft (15-m) chip vans.

The firm must be able to take advantage of tax credits in the year in which they are earned—Tax credits occur when losses are incurred. Losses may result from negative cash flows or from accelerated depreciation policies. Credits can also occur when tax credits (e.g., energy tax credits) are greater than taxes payable. An implicit assumption in the model is that tax credits may be taken in the year in which they are incurred. This will provide the highest rate of return. For this to happen, the firm must have taxable income from other sources against which the credit may be applied.

If there is no taxable income from other sources, then any tax credits must be carried forward until a year in which there is taxable income. How long those credits may be carried forward depends on the nature of the credit. For Federal income taxes, capital losses may be carried forward until they are absorbed. Ordinary operating losses may be carried forward up to 20 years. The energy tax credit is allowed a 20-year carry-forward.

Conclusions for Distributed Energy Economics

- Preliminary economic analysis indicates that distributed energy systems may play a role in the disposition of wood waste generated from forest health treatments. However, given our base case numbers, without tax credits, neither system analyzed could be justified on financial grounds alone, even with no fuel cost. Initial capital costs would have to be lower than those we used, thermal output would have to have some positive value, avoided-cost electricity rates would have to be higher, or tax credits or other subsidies would need to be available to make such systems financially feasible.
- Economies of scale associated with larger generators will probably make such units able to produce electricity at a lower cost per kilowatt-hour.
- Morris (1999) justified a subsidy of $0.114/kWh on environmental grounds. Current legislation allows a tax credit of $0.018/kWh. Using our cost assumptions and this credit makes a 1,000-kW BioMax a financially justifiable investment. In addition, payment for fuel of up to $6.62/bdt would permit a nominal pre-tax rate of return of 23%.
- Smaller systems (<100 kW) would probably require much larger operating subsidies, in addition to fuel delivered at no cost, to make them viable economically.
- If the waste heat could be utilized, the economics of the systems might be more favorable. However, the benefits would have to be balanced against the possible costs of transporting the fuel to a point where the waste heat would have a positive value, rather than utilizing the fuel directly on the forest landing.

Timber Stand Treatment Costs and Returns in Oregon

Treatment Prescriptions

To determine probable per acre overall costs of an integrated thinning and biomass combustion program, three silvicultural prescriptions based on mechanical treatments and removal of thinnings from overstocked stands were simulated using the Forest Vegetation Simulator. The simulations were conducted using data from 1,542 plots representing 4.1 million acres (1.7 million ha) in southern Oregon and along the eastern slope of the Oregon Cascades, which have a basal area of at least 60 ft^2/acre (13.8 m^2/ha) (Fried and others 2003). The data were derived from the Forest Inventory and Analysis project (www.fia.fs.fed.us). The harvest costs were estimated by using STHARVEST (Fight and others 2003).

The plots covered all ownership classes and primarily consisted of mixed conifers and pines. The plots were classified as “gentle” (≤40% slope) or “steep” (>40% slope) to represent the difference between ground-based and cable or skyline operations. The silvicultural prescriptions regarding the smaller-diameter material differed on the gentle and steep sites.

The first two silvicultural prescriptions, A and C, were designed to reduce stocking and improve growth, while reducing some fuel loading in small trees. Seventy percent of the cut basal area for these silvicultural prescriptions is derived from trees 5 to 14.5 in. (127 to 368 mm) in diameter at breast height (dbh). The remaining removals come from trees larger than 14.5 in. (368 mm) dbh, if present. If larger trees are scarce or absent, somewhere between 70% and 100% of the basal area removed would come from trees <14.5 in. (<368 mm) in diameter.

For prescription A, the target residual basal area is 125 ft^2/acre (28.7 m^2/ha) and the maximum tree diameter to harvest is 21 in. (533 mm) dbh. Prescription C has a target residual basal area of 90 ft^2/acre (20.7 m^2/ha) and also a maximum tree diameter to harvest of 21 in. (533 mm) dbh. If the maximum diameter limit is reached before the prescribed basal area, then the prescribed basal area is not achieved. Under prescriptions A and C, big trees are not cut if they are more than 21 in. (533 mm) dbh.

Prescription H was designed to be more aggressive in reducing fuel loading, removing ladder fuels, and creating a more fire-resistant stand. Trees are removed from the smallest diameter classes first, until the target residual basal area of 60 ft^2/acre (13.8 m^2/ha) is met. In case studies on the Okanogan and Freemont forests, Mason and others (2003) found that the most overall effective treatment was to thin ponderosa pine and western larch to a basal area of 45 ft^2/acre (10 m^2/ha). Prescription H has no upper diameter limit on harvested trees.

After running the simulations, we discarded plots on which less than 300 ft^3/acre (21 m^3/ha) of stock would be removed, believing that such plots would probably not be treated because of the large fixed costs involved in transporting equipment to the sites. This left a total of 1,274 plots representing 3.4 million acres (1.4 million ha). Of this, 2.8 million acres (1.1 million ha) (82%) are on gentle terrain and 622,000 acres (252,000 ha) (18%) are on steep terrain.

The output from the Forest Vegetation Simulator is expressed in terms of cubic feet of wood harvested. This is divided into biomass volume and merchantable volume. We assumed that biomass volume would be chipped. We also assumed that merchantable volume could be sold as sawlogs. One difficulty is that prices in the market are generally expressed in terms of thousand board feet for lumber and bone dry tons for chips. We converted the Forest Vegetation Simulator output using the following factors:

- Sawlog conversion: 1 ft^3 = 6.07 board feet (derived from conversion of 1,000 board ft to 164.8 ft^3 (Haynes 1990))
- Chip conversion: 1,000 ft^3 = 13.445 bdt

The resulting harvest volumes are shown in Table 5 by slope and prescription.

We used a density of 53.78 lb/ft^3 (861 kg/m^3) to convert cubic feet/acre (cubic meters/hectare) of chips to green tons/acre, the average density from harvested trees for all plots. To convert green tons to bone dry tons (bdt), we multiplied by 0.5, assuming a 50% moisture content. The result is 26.89 lb/ft^3 (431 kg/m^3) bdt. To check the reasonableness of our conversion factor, we referred to the 1989 RPA (Haynes 1990), which converts softwood at 35 lb/ft^3 (561 kg/m^3) air dry tons. Assuming 20% air-dry moisture content, this becomes 29.17 lb/ft^3 (467 kg/m^3) bone dry. This is within 10% of the 26.89 lb/ft^3 (431 kg/m^3) that we used. Using our conversion, 1,000 ft^3 = (26.89)(1000/2000) = 13.445 bdt.

As expected, the largest average volume of trees is removed under prescription H. On gentle slopes, nearly half again as much volume per acre is removed under prescription H; on steep slopes, nearly 70% as much volume is removed under prescription H. Much of this material would be merchantable. On gentle slopes, merchantable volume represents just over two-thirds the total biomass removed in prescriptions A and C and three-fourths of the total biomass removed in prescription H. On steep slopes, merchantable volume represents 93% to 95% of the total volume removed.

Treatment Prescriptions

For all prescriptions:

- Check if sites meet target residual basal area of 125 ft^2/acre (28.7 m^2/ha) for prescription A, 90 ft^2/acre (20.7 m^2/ha) for C, and 60 ft^2/acre (13.8 m^2/ha) for H.
- For trees <3.5 in. (<89 mm) dbh, fell all trees, cut in two pieces, and leave on site.
- For trees 3.5 to 5.5 in. (89 to 140 mm) dbh, cut all trees:
  - On gentle slopes (≤40%), remove and chip at landing.
  - On steep slopes (>40%), cut and scatter all 3.5- to 5.5-in. (89- to 140-mm) trees on site.

For prescriptions A and C:

Objective: Reduction of stock

- If site has excess basal area, cut 70% of excess from trees >5.5 to 14.5 in. (>89 to 368 mm) dbh (40% yard loss).
- Cut remaining excess basal area over target limit from trees >14.5 to 21.5 in. (>368 to 546 mm) dbh. If basal area limit is not achieved, do not cut larger trees.

For prescription H:

Objective: Protection from fire

- Thin from below to target residual basal area.

Table 5—Harvest volume summary by prescription type and terrain for three modeled prescriptions on forestland in southern Oregon (volume/acre)[a]

	Avg. biomass (chips) removed (bdt/acre)		Avg. merchantable (logs) removed (thousand board feet/acre)		Avg. total volume removed[b] (bdt/acre)	
Prescription	Gentle	Steep	Gentle	Steep	Gentle	Steep
A	7.2	1.1	6.6	6.9	21.9	16.4
C	7.1	1.1	6.8	7.9	22.1	17.9
H	9.0	1.4	10.5	13.0	32.2	30.2

[a]Silvicultural prescriptions call for leaving smaller logs (<7 in., <178 mm) on site.
Gentle slopes are 0–40%, on which ground-based harvest/yarding systems may be used.
Steep slopes are >40%, on which cable-based harvest/yarding systems must be used.
1 acre = 0.4 ha.

[b]Total volume includes both biomass and merchantable volume.

Prescription Costs

Prescription costs do not include the impact of possible revenues from log sales. Prescription costs depend in large part on prescription, terrain, and stocking. On gentle terrain, prescription costs average between $929 and $1,175/acre ($1,175/0.4 ha), depending on the prescription. To compare cost distributions between treatments, we normalized the treatment cost data, weighting the costs in each plot by the number of acres represented by each plot and then dividing by the total treatment cost for each treatment type across all areas represented. The sum of the treatment cost categories for each treatment is 100. The resulting distributions for the gently and steeply sloped sites are shown in Figures 10 and 11, respectively.

Although sites steeply sloped are generally more expensive to treat than are gently sloped sites, the graphs are similar. Both have a long and expensive tail skewed to the right. These sites would probably require careful scrutiny if total prescription budgets were limited, although sites with the highest treatment costs often also have the greatest removals.

Net Operating Surpluses and Deficits With Sawlog Sales

Higher costs do not necessarily mean that the prescription will run at a deficit. The net prescription deficit or surplus depends on the value of the logs removed. (Surplus refers to revenue from sawlog sales that is greater than harvest cost. Deficit refers to revenue from sawlog sales that is less than harvest cost.) We assumed that sawlogs could be sold to a mill at an average value of $175/thousand board feet at the landing, with chips disposed of at the landing. Hartsough (2001) used delivered sawlog values ranging from $700/thousand board feet for 30-in. (762-mm) dbh

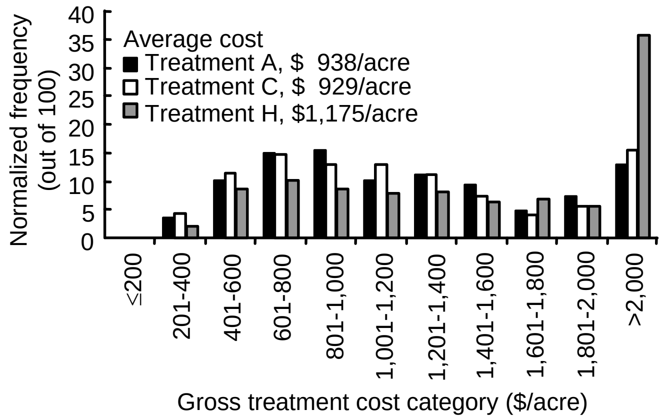

Figure 10—Normalized histogram of prescription costs on gently sloped sites in southern Oregon. 1 acre = 0.4 ha.

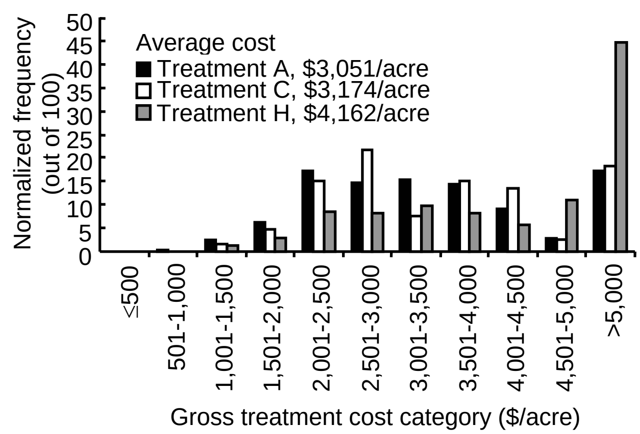

Figure 11—Normalized histogram of prescription costs on steeply sloped plots in southern Oregon.

Table 6—Average surplus (cost) to deliver chips to landing for three prescriptions on southern Oregon forestland by slope classification, with sawlog sales[a]

Prescription	Cost ($)/acre		Cost($)/bdt of chips	
	Gentle	Steep	Gentle	Steep
A	790	(1,753)	109	(1,601)
C	814	(1,762)	115	(1,624)
H	1,367	(1,775)	152	(1,289)

[a]Costs assume that all logs larger than 5.5 in. (140 mm) are sold as sawlogs for average of $175/thousand board feet.

trees to $300/thousand board feet for 10-in. (254-mm) dbh trees. The Oregon Department of Forestry (2003) reports "pond values" (delivered prices) for ponderosa sawlogs in the Klamath National Forest of $210/thousand board feet for 6- to 8-in. (152- to 203-mm) dbh logs to $540/thousand board feet for ≥22-in. (≥559-mm) logs. In the Grants Pass Unit, prices range from $75/thousand board feet for utility grade (suitable for chips) to $950/thousand board feet for No. 1 sawmill grade.

Surpluses and deficits with sawlog sales, assuming that chips could be processed at the landing, are shown in Table 6. Surpluses represent net positive returns from sawlog sales. Full forest health prescription costs are covered, as are the costs of getting both the logs and chips to the landing. Deficits represent amounts that would have to be recovered by chip sales if the individual forest health prescriptions were to break even.

Surpluses are generated on average on all three silvicultural prescriptions on gentle slopes. Deficits occur on steep slopes. That is, the projected revenue from sawlog sales would not cover the cost of removing the timber. While the averages are interesting, it is worth looking at the ranges, for both the gentle and steep plots. The range of the operating surpluses (deficits) on gentle slopes is shown in Figure 12; the data were normalized out of 100 so that the different treatment types could be directly compared.

The graph is not normally distributed. Although prescriptions on gently sloped sites generally run at a surplus, on roughly 10% of the sites, the mechanical treatments we modeled could only be run at a deficit. In addition, a small proportion of prescriptions could be performed at a large surplus (greater than $2,500/acre ($6,178/ha)).

These surpluses may be contrasted with the expected operating deficits that would be incurred in prescriptions on steep slopes (Fig. 13). Even with sawlog sales, prescriptions on most steep slopes could only be implemented with an operating deficit. Around 30% of the plots we simulated would require an operating subsidy of more than $2,000/acre ($4,942/ha). On steep sites, only about 5% of the plots would incur an operating surplus under prescriptions A and C and 55% under prescription H.

The number of sites that could be treated only at a deficit would depend in part on the value of the sawlogs at the landing. As sawlog value increases, the number of sites that could be treated only at deficit declines. This relationship is described for gently sloped (Fig. 12) and steep (Fig. 13) sites in the following text.[8]

For every $100 change in sawlog prices at the landing, the number of gently sloped sites that could be treated only at a deficit declines by approximately half. However, even at relatively high sawlog prices, around 10% of gently sloped sites would still require subsidies to apply any mechanical prescriptions that we simulated. Even at relatively high prices for sawlogs, a large portion (roughly 40% to 60%) of steep sites could be treated only at a deficit.

Net Costs to Deliver Chips Without Sawlog Sales

If markets did not exist for larger logs—i.e., if the closest sawmill was so far away that it would be uneconomic to haul the logs or if treatment volumes were so low that it would not be worthwhile selling the larger logs as sawlogs—then large logs might have to be chipped.

Hauling costs could be avoided if any chips could be disposed of on the forest landing rather than taken to a distant mill. Average costs to deliver chips to a landing range from $43 to $46/bdt on gentle slopes and $200 to $257/bdt on

[8] Historic (1965–2000) prices for saw timber sold on National Forests in the Pacific Northwest may be found in Warren (2002). Recent quarterly prices for stumpage sold by public agencies may be found in Warren (2003). Recent prices for logs delivered to a mill (pond value) may be obtained from the Oregon Department of Forestry, State Forests Asset Management Unit (www.odf.state.or.us).

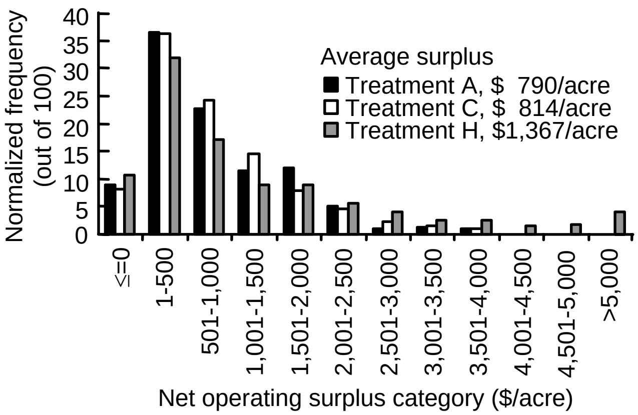

Figure 12—Normalized histogram of operating surpluses on gently sloped sites in southern Oregon by prescription type with sawlog sales worth average of $175/thousand board feet at landing and no chip production.

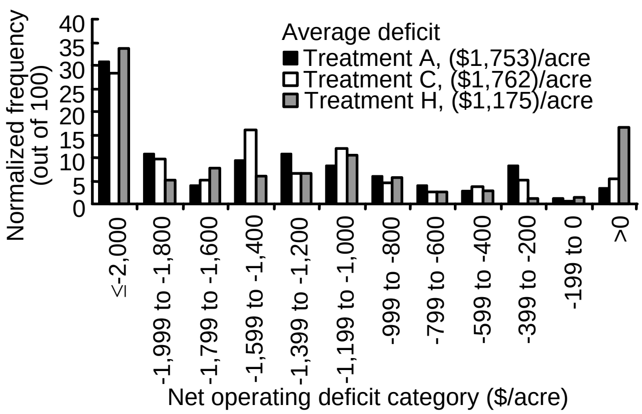

Figure 13—Normalized histogram of operating deficits on steep sites in southern Oregon by prescription type with sawlog sales worth average of $175/thousand board feet at landing and no chip production.

steep slopes (Table 7). These costs are generally greater than the estimated values of biomass chips. Softwood chip prices for the Pacific Northwest are $27/green ton delivered (International Woodfiber Report 2003). This equates to roughly $54/bdt. However, prices for pulp chips are higher than those for biomass chips. Pulp chips need to be relatively clean for papermaking, medium density fiberboard, and oriented strandboard. The chips are debarked. On the other hand, biomass chips are generally made from whole trees and debarking is not necessary. The resulting prices for biomass chips can be as much as one-third lower than those for pulp chips (Peter Ince, personal communication, 2004), which lowers the estimated delivered value for biomass chips to around $36/bdt. Hartsough (2001) used a value of $20/bdt for delivered biomass. Rummer and others (2003) used $30/bdt. With delivery costs ranging from $0.20 to $0.60 bdt/mile ($0.60/1.6 km), it is clear that biomass chips cannot be economically transported very far.

Table 7—Average cost to deliver chips to landing for three prescriptions on FIA plots in southern Oregon per slope classification, without sawlog sales[a]

Prescription	Cost ($)/acre		Cost ($)/bdt of chips	
	Gentle	Steep	Gentle	Steep
A	(1,011)	(3,128)	(46)	(190)
C	(1,004)	(3,258)	(46)	(182)
H	(1,291)	(4,306)	(40)	(142)

[a]Costs assume that all removed logs are chipped.

If the biomass must be removed from the site and if the sawlogs cannot be sold, then the costs from Table 6, plus any additional transport cost, would have to be recovered through chip sales alone if the silvicultural prescription costs are to break even. If sawlogs can be sold, more treatment costs can be recovered.

Prescription Cost Limitations

The prescriptions we chose were designed to provide some estimates of the possible magnitude of prescription costs. They were not chosen specifically for individual sites. We did not model the impact of the prescriptions on reduction in fire risk, nor did we attempt to optimize net benefits from fuel prescriptions. Such work might be performed by forest managers familiar with the sites in their fuel prescription plans.

While representative of possible fuel reduction prescriptions, the prescriptions we modeled would not necessarily be considered for all the sites. An understanding of this may be gained by looking at the ranges in maximum and minimum prescription costs in Figures 14 and 15. If a site is going to be particularly expensive to treat, a forest manager may well recommend a different prescription or that the prescription dollars be spent on more cost-effective sites.

Conclusions for Prescription Costs

- Surpluses are highest or costs lowest if larger diameter logs can be sold for higher valued products.
- If larger diameter logs cannot be sold for higher valued products because of limited markets or limited supply, average modeled costs to deliver chips to the landing range from $1,004 to $4,306/acre ($1,004 to $4,306/0.4 ha) or $40 to $219/bdt, depending on prescription and angle of slope (gentle or steep).

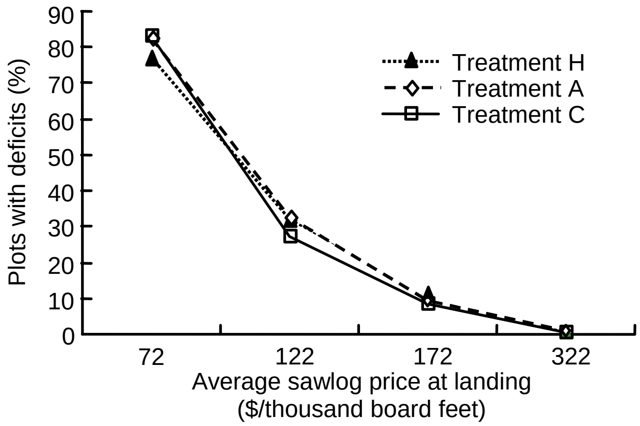

Figure 14—Percentage of acres on gentle slopes showing operating deficits with sawlogs sold at landing at various prices by prescription type.

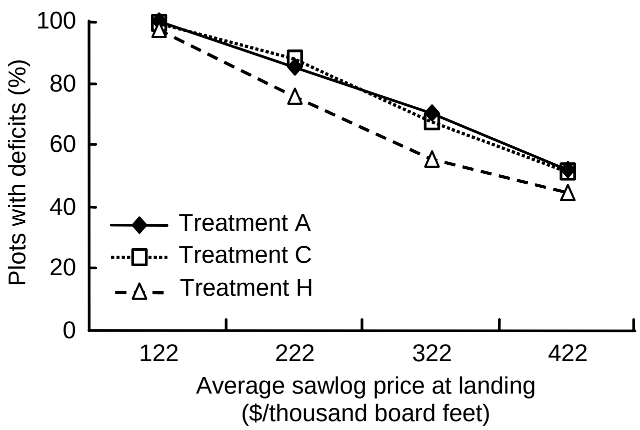

Figure 15—Percentage of acres on steep slopes showing operating deficits with sawlogs sold at landing at various prices by prescription type.

- If biomass woodchips need to be transported from the forest, transport costs can constitute a significant portion of total delivered fuel costs. The distance that chips can be economically transported will depend on chip value and transport cost.
- If smaller diameter logs must be removed from the forest for forest health reasons, unless a mill is within an economic transport distance, it may be more cost-effective to chip the logs and utilize the chips on the forest landing for energy.
- Presently, operating surpluses do not go back into forest health prescriptions, e.g., to subsidize chip disposal or forest health prescription costs on steeper sites and sites without larger sawlogs. If this were possible, then more acres could be treated for a given prescription budget.

Table 8—Estimates of potential recovery volumes from thinning treatments on timberland in 15 western states (million bone-dry tons)

Material	Lower bound estimate[a]	Upper bound estimate[b]
Merchantable timber	245	1,537
Biomass	101	617
Total	346	2,154

[a]Lower end assumes material is recovered from 17.1 million acres (6.9 million ha) (i.e., 60% of high-risk (Condition Class 3) areas).

[b]Upper end assumes material is recovered from 96.9 million acres (39 million ha) of treatable timberland.

Source: Rummer and others (2003).

Potential Role of Distributed Energy Systems in 15 Western States

Magnitude and Opportunity of Problem

In 15 western states,[9] Rummer and others (2003) determined that mechanical treatments are required to reduce hazardous fuel loading on at least 28 million acres (11 million ha) of Condition Class 3 timberland, i.e., timberland needing mechanical fuel reduction treatment before fire can be used as a restorative tool. This corresponds to a land area about the size of Ohio. If Condition Class 2 timberland (timberland needing fuel reduction treatment (fire or mechanical) to restore ecosystem function and historical fire regimes; also a condition of Condition Class 2) is also included, the area increases to 66.9 million acres (27 million ha)—about the size of Colorado. If all timberland with treatment opportunities is included, the area grows to 96.9 million acres (39 million ha), an area a bit larger than Montana.

Rummer and others (2003) determined that there is a wide range of potential recoverable volume on this "overstocked" western timberland, depending on assumptions about what lands are harvested. The breakdown between merchantable timber and biomass is shown in Table 8. If these volumes were thinned over 30 years, the increase in annual harvest would be 11 to 72 million bdt. To put this into perspective,

[9] Arizona, California, Colorado, Idaho, Kansas, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

Table 9—Basic summary statistics for BioMax generators that could be fueled with estimated potential biomass recovered from thinning treatments on timberland in 15 western states, assuming merchantable timber is sold separately

Production factor	Lower bound biomass estimate[a]	Upper bound biomass estimate[b]
100-kW BioMax generator	2,973	18,162
1,000-kW BioMax generator	297	1,816
Potential annual electricity generation (million kWh)	2,342	14,304
Potential annual revenue from power generation (at $0.0437/kWh)	$102 million	$625 million
Approximate initial capital cost (at $1,500/kW)	$495 million	$2.7 billion

[a]Lower end assumes material is recovered from 17.1 million acres (6.9 million ha) (i.e., 60% of high-risk (Condition Class 3) areas, from Table 3). Annual biomass = 101 million bdt/30 years = 3.37 million bdt/year.

[b]Upper end assumes material is recovered from 96.9 million acres (39 million ha) of treatable timberland (from Table 3). Annual biomass = 617 million bdt/30 years = 20.57 million bdt/year.

the total volume of timber removed in the studied 15 western states in 1996 was 64 million tons.[10]

Assuming the lower bound estimate of 101 million bdt and upper bound biomass estimate of 617 million bdt (from Table 8) would be generated over a 30-year period, and given the bioenergy conversions by the BioMax generators (from the BioMax assumptions), the potential number of generators that could be fueled with that biomass is shown in Table 9. These generators could produce from 2,342 million to 14,304 million kWh of electricity (Table 9). To put these data into perspective, the upper bound represents 2.2% of the electricity sales in the 15 western states in the year 2000. Total electricity sales by utilities to bundled ultimate customers in these states was 664,288 million kWh in 2000 (EIA 2000). The lower bound represents a bit more than that sold to the residential sector of Wyoming in the year 2000 (2,103 million kWh).

Annual potential revenue from power generation would range from $102 million to $625 million with initial capital investment costs from $495 million to $2.7 billion (Table 9). Such production would come at a cost. As noted previously, a 100-kW BioMax unit may require a subsidy in addition to zero-cost wood fuel as well as an energy tax credit to make it economic to operate at a forest landing. A 1,000-kW unit would probably not be able to be operated economically at a forest landing without an energy tax credit. With an energy tax credit of $0.018/kWh, operators of a 1,000-kW unit would probably be able to pay something for fuel delivered at a forest landing.

[10] This number was derived by summing the figures of softwood and hardwood timber removals from table 1.10 in Johnson (2001) and converting them using factors from Howard (2003): 1,000 ft^3 of softwood = 0.0175 tons and 1,000 ft^3 of hardwood = 0.0200 tons.

Conclusions for Role of Distributed Energy Systems

- Biomass from forest health thinnings in 15 western states has the potential to provide from 2 to 14 billion kWh of electricity to the national grid each year. The lower bound assumes sawlog sales from larger merchantable material. The upper bound assumes that all thinnings would be used for energy.
- Such generation capacity would probably require an initial capital investment of $500 million to $3 billion.
- For such generation to compete with existing fossil fuels on a cost basis, subsidies would probably be required. Such subsidies may be justified on the basis of the ancillary services provided by biomass power.
- To maximize the area that is treatable by individual generators, merchantable logs should be sold separately rather than utilized as fuel. This would increase the number of acres treatable by a single generator by a factor of about six.

General Discussion

BioMax-type generators may have a role to play in the combustion of surplus wood waste. This preliminary economic analysis indicates that their energy production costs are probably higher than current avoided costs. If the units are located on forest landings and given our assumptions, unless there is a tax credit or other operating subsidy, neither a 100-kW nor a 1,000-kW unit would provide its owners a return on invested capital, which was computed to a real rate of 12.1% after taxes, based on a 20% pre-tax nominal risk premium.

However, biomass combustion by BioMax units would help to ameliorate the problem of forest thinnings residue and would supply some power to the national grid. Whether or not such systems would be justifiable would in part depend on the costs of alternative disposal of the biomass generated from forest health thinnings and the policies that facilitate cost shifting.

Subsidies for biomass disposal may be socially beneficial. Morris (1999) evaluated the value of the non-market benefits of U.S. biomass power. He inferred values to compare residues used for energy production with other disposal methods. Proxy values were derived for reductions in sulfur dioxide, nitrogen oxide, carbon dioxide, methane, volatile organic compounds (VOCs), particulates, carbon monoxide, landfill capacity, and forest productivity. The value of utilizing forest residues for energy production compared with alternative disposal methods was $0.114/kWh. This value did not include the value of the energy produced. While this is not a value that could be recovered in the marketplace, it does indicate the magnitude of the value of the non-market benefits of biomass energy production.

Other factors may also favor such investments. According to the Energy Information Administration (EIA 1998), distributed generation may prove to be attractive in areas where it can defer transmission and distribution investment or improve reliability. Avoided costs and improved reliability are additional factors that should be considered in evaluating the potential for establishing distributed generation at any given location.

Based on recent U.S. experiences with energy supplies, there would appear to be a role for such units in the overall energy supply grid. Certainly, the process of gasification in BioMax units is more efficient and contributes less to air pollution than does uncontrolled combustion in wildland fires.

Given our assumptions, inflation-indexed energy tax credits or other operating subsidies equivalent to $0.018/kWh would make it economic to operate a 1,000-kW BioMax at a forest landing. Such a unit would even be able to contribute something towards its fuel costs while still providing owners with their required return on investment. However, even with this energy credit and zero-cost fuel, a 100-kW unit would not be economic to operate at a forest landing.

This analysis, however, was based on generation units that do not currently exist. Therefore, the cost estimates are preliminary at best. A follow-up analysis should be conducted if such generators are actually constructed. Our analysis was based on averaged modeled treatment costs in southern Oregon for generalized prescriptions. In reality, the prescriptions should be site-specific; the actual costs and volumes could differ from the averages we used.

Prior to the actual purchase and installation of a distributed energy system on a forest landing, the harvest costs and volumes for that location should be carefully evaluated, as well as the costs and potential revenues of that specific bioenergy generation system. As we showed on the southern Oregon sites, net harvest costs or revenues are highly variable, so that the economics of specific operations are also variable.

Whether or not mechanical treatments can be run at an operating surplus will depend in part on whether there are markets for any larger logs that must be removed as part of the prescription. With log sales, most gently sloped sites will probably generate a surplus. However, our analysis showed that even with sawlog sales, most steep sites could be mechanically treated only at a deficit.

Many sites could not be treated without a subsidy—either a direct subsidy or cross subsidy from profitable operations with sawlog sales. If surpluses could be used to subsidize treatments on additional sites (i.e., if cross subsidies were possible), then more area could be treated for a given budget. However, if each unit area is required to “pay its own way” in fuels treatments, then around 10% of gently sloped sites and 85% to 95% of steep sites could not be treated with these prescriptions and an average sawlog price at the landing of $175/thousand board feet.

In spite of these limitations, this preliminary analysis indicates that for any given forest health prescription in which unmerchantable biomass must be removed, a distributed bioenergy generation system is an option that is at least worth consideration.

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Glossary

Alternative rate of return. Rate of return possible on next best alternative of same risk. Firm's opportunity cost of money. Can be used to evaluate the net present value of a project or as a point of comparison with the internal rate of return. Also called discount rate.

Avoided costs. Incremental costs of energy and/or capacity, except for purchase from a qualifying facility; a utility would incur avoided costs itself in the generation of energy or its purchase from another source.

Basal area. Area of ground surface occupied by cross-section of tree taken at breast height.

Closed loop process. Process by which power is generated using feedstock grown specifically for the purpose of energy production.

Internal rate of return (IRR). Interest rate or discount rate that equates discounted present value of a project's benefits with discounted present value of its costs. Rate of return earned when net present value of investment equals zero.

Merchantable volume. Volume of main stem of tree between 1-ft (0.3-m) stump height and 4-in. (102-mm) top diameter (outside bark), including wood and bark. Common definitions used by FIA.

Net present value. Value equal to present value of future benefits less present value of future costs when both are discounted at alternative rate of return.

Public Utility Regulatory Policies Act of 1978 (PURPA). Measures designed to encourage conservation of energy, more efficient use of resources, and equitable rates; principally, retail rate reforms and new incentives for producing electricity by co-generators and users of renewable resources.

Appendix—Sample Printout for 1,000-kW BioMax Generator

A Financial Analysis of Gasification-based Biomass Electrical Generation — **Plant size** 1,000 kW — version BETA 1.03 — 8-Mar-05

E.M. Bilek — USDA Forest Service, Forest Products Laboratory, Madison, Wisconsin 53726-2398 — email: tbilek@fs.fed.us — Cells in **BLUE** may be changed.

Base Run with Plant Located at a Forest Landing with No Federal Energy Tax Credit

Delivered yr. 1 fuel cost = $ - **/bone dry ton** — **Avg. electricity value =** $ 0.0437 **/kWh** — **Thermal value ($/000 Btu) =** $ -

WARNING! The plant is getting a tax credit in at least one year. Unless the firm has other operations to utilize this credit, the actual rate of return and any break-even subsidy will be lower, and the actual break-even electricity price and any additional break-even profit will be higher than calculated here.

WARNING! IRS guidelines state that an electrical generation plant > 500 kW has a class life of 22 years. See: IRS Publication 942, Appendix B, Asset class 00.4.

Summary Financial Measures:

	Before-tax & finance	*Before-tax*	*After-tax*
NPV	$ (918,399)	$ (649,850)	$ (476,163)
IRR (real)	0.8%	-1.2%	-1.6%
IRR (nominal)	3.8%	1.8%	1.3%

IRR seed = 10%

Yr. 1 Subsidies Required (Profits):

Per...	*bone-dry ton*	*acre*	*kWh*
Annualized operating subsidy	$ -	$ -	$ -
Additional B-E subsidy (profit)	$ 12.62	$ 113.61	$ 0.01815
Total B-E subsidy (profit)	$ 12.62	$ 113.61	$ 0.01815

B-E electricity price ($/kWh) (yr. 0): $ 0.0614

Other Financial Information:

Plant purchase price	$ 1,500,000
Salvage estimate	$ -
Loan principal	$ 600,000
Monthly loan payments	$ 7,280
Equivalent annual loan interest rate	8.30%
Equivalent annual deposit interest rate	3.04%
Average capital invested (ACI)	$ 825,000
Standard annual repairs & maintenance	$ 75,000
Standard productive time (hours/year)	7,160 hours

ACI =(((Purchase_Price-Salvage_Estimate)*(Economic_Life+1))/(2*Economic_Life)+Salvage_Estimate)

Required Returns on Invested Capital (ROIC):

Equivalent annual...	*Before-tax*	*After-tax*
Real required ROIC	19.46%	12.08%
Nominal required ROIC	23.04%	15.44%

Thermal Value Estimation:

Natural gas price	$ 7.50	/000 cubic feet
Calculated thermal value	$ 0.00730	/000 Btu

Discounted Revenue Pie Data:

Electricity generation	$ 1,763,646
Thermal output value	-
Operating subsidy	-
Federal energy tax credit	-
Other tax credits	-
Total	$ 1,763,646
Annualized total	$ 412,951

Annualized Subsidy Calculations:

	Gross revenue
Equalized annual actual	$ -
Equalized annual break-even	129,956
Difference	$ (129,956)

Weighted Avg. Electricity Rate Calculation:

On-peak rate:	$ 0.0540	/kWh
Off-peak rate:	$ 0.0300	/kWh
Weighted avg. rate	$ 0.0437	/kWh

Pre-tax Discounted Costs Pie Data:

Net ownership costs	$ (1,660,000)
Fixed operating costs	(149,269)
Wood fuel	-
Other variable operating costs	(636,477)
Total	$ (2,445,745)
Annualized total	$ (572,662)

Peak and Off-peak Annual Operating and Productive Hours and Capacity Calculations

	Operating	-------- Hours/Day --------			--- Scheduled annual productive hours ---				Scheduled annual	Capacity
	days/year	On-peak	Off-peak	Down-time	On-peak	Off-peak	Subtotal	Down-time	operating hours	factor
Weekdays	256	16	4	4	4,096	1,024	5,120	1,024	6,144	
Weekend days	102	-	20	4	-	2,040	2,040	408	2,448	
Total operating days	358			Total hours	4,096	3,064	7,160	1,432	8,592	81.7%

Summary Inputs and Outputs

	Equalized annual	Year 1	2	3	4	5	6	7	8	9	10
Biomass consumed (bone-dry tons)	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295
Acres treated	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Electricity production (kWh)	7,160,000	7,160,000	7,160,000	7,160,000	7,160,000	7,160,000	7,160,000	7,160,000	7,160,000	7,160,000	7,160,000
Thermal production (000 Btu)	27,272,727	27,272,727	27,272,727	27,272,727	27,272,727	27,272,727	27,272,727	27,272,727	27,272,727	27,272,727	27,272,727
Annual operating subsidy paid		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary Cash Flows

	Year 0	1	2	3	4	5	6	7	8	9	10
Cash flow before tax and financing	$ (1,660,000)	$ 180,213	$ 183,498	$ 189,002	$ 194,673	$ 202,831	$ 206,528	$ 212,724	$ 219,106	$ 228,288	$ 232,449
Cash flow before tax	$ (1,060,000)	$ 92,857	$ 96,142	$ 101,647	$ 107,317	$ 115,475	$ 119,172	$ 125,368	$ 131,750	$ 140,932	$ 145,093
Cash flow after tax	$ (1,060,000)	$ 237,170	$ 85,759	$ 84,643	$ 83,895	$ 85,030	$ 83,349	$ 85,834	$ 88,305	$ 92,503	$ 211,066

WARNING! You are getting a tax credit in year 1. See the taxes in the cash flow table. In order to take the Section 179 deduction and Special first-year depreciation allowance, you must have sufficient taxes due on income from other sources to take the resulting first-year tax credit.

Basic Assumptions

Note: all costs and revenues are in Year 0 dollars.

Gearing (% of total purchase price financed)	40%	*Plant purchase cost ($/kW)*	$ 1,500
Loan term	10 years	*Salvage estimate (% of purchase)*	0.0%
Loan and deposit payments per year	12	*Annual subsidy rates change with...*	Inflation
General depreciation system (GDS) life	15 years	*Thermal production (000 Btu/kWh)*	3.8
Alternative depreciation system (ADS) life	22 years	*Fuel conversion (lbs. of chips/kWh)*	3.3
Economic life	10 years	*Fuel moisture content*	15.0%
Loan interest rate (APR)	8.00%	*Fuel removal (bone-dry tons/acre)*	9.00
Deposit interest rate (APR)	3.00%	*Cost to hook the system into the national electricity grid*	$ 10,000
Expected annual risk premium on invested capital	20.00%	*Other start-up costs (pct. of purchase price)*	10.0%
Inflation	3.0%	*Standardized repairs & maintenance percentage*	50.0%
Income tax rate	33.0%	*Repairs & maintenance function*	Uniform
Federal energy tax credit	$ 0.000/kWh	*General administration ($/year)*	$ 10,000
Federal energy tax credit extends for	10 years	*Labor cost ($/hour)*	$ 3.333
Federal energy tax credit is inflation-adjusted (Yes/No)	Yes	*Periodic consumables cost*	$ 0.001416
Section 179 deduction	$ -	*Periodic consumables life*	7,160 hours
Special first-year depreciation allowance	30%	*Periodic consumables installation factor*	0%
Depreciation code	DB	*Additional periodic consumables cost*	$ 2,000.00
Declining balance factor	150%	*Additional periodic consumables life*	1,500 hours
Ad valorem (property) tax mill rate	-	*Annual insurance percent*	2.0%
Ad valorem (property) tax valuation basis	ACI	*Other fixed costs ($/year)*	$ -
		Misc. variable operating costs ($/scheduled hr.)	$ -
Fixed operating costs sensitivity factor	100%	*Other variable consumables cost ($/kWh)*	$ -
Variable operating costs sensitivity factor	100%		

WARNING! You're getting a tax credit in Year 1. Make sure you have sufficient revenue from other operations to offset the credit. If you don't, consider changing to straight-line depreciation.

WARNING! You are getting a tax credit in year 1. See the taxes in the cash flow table. In order to take the Section 179 deduction and Special first-year depreciation allowance, you must have sufficient taxes due on income from other sources to take the resulting first-year tax credit.

Basic Assumptions

	Year										
Annual operating and productive time	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Scheduled operating time (hours/year)		8,592	8,592	8,592	8,592	8,592	8,592	8,592	8,592	8,592	8,592
Annual productive time (hours/year)		7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160
Annual operating subsidies ($/bone-dry ton)											
Negotiated		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Inflation-adjusted		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Additional inputs:

Other tax credits - in the Cash Flow Table;
Custom depreciation (in the Depreciation Expense Template);
Repairs and maintenance "Fudge factors" (in the Repairs and Maintenance Template);
Custom repairs and maintenance (in the Repairs and Maintenance Template);
Custom *ad valorem* property tax valuation (in the Ad valorem (property) tax valuation template)
Starting points for the sensitivity analyses (in the Sensitivity analysis tables)
Incremental changes in the sensitivity analyses (in the Sensitivity analysis tables)

CASH FLOW ANALYSIS

Cash Flow Table (continued on next page)

	Year										
	0	1	2	3	4	5	6	7	8	9	10
Analysis in Current Dollars											
GROSS REVENUE											
Electricity generation		322,497	332,172	342,137	352,401	362,973	373,863	385,078	396,631	408,530	420,786
Thermal output value		-	-	-	-	-	-	-	-	-	-
Operating subsidy		-	-	-	-	-	-	-	-	-	-
Subtotal: gross revenue		$ 322,497	$ 332,172	$ 342,137	$ 352,401	$ 362,973	$ 373,863	$ 385,078	$ 396,631	$ 408,530	$ 420,786
OWNERSHIP COSTS (purchase & salvage)											
Purchase price	(1,500,000)										
Grid hookup fee	(10,000)										
Additional start-up costs	(150,000)										
Salvage value		-	-	-	-	-	-	-	-	-	-
FIXED OPERATING COSTS											
General administration		(10,300)	(10,609)	(10,927)	(11,255)	(11,593)	(11,941)	(12,299)	(12,668)	(13,048)	(13,439)
Insurance		(16,995)	(17,505)	(18,030)	(18,571)	(19,128)	(19,702)	(20,293)	(20,902)	(21,529)	(22,175)
Ad valorem (property) taxes		-	-	-	-	-	-	-	-	-	-
Other fixed costs		-	-	-	-	-	-	-	-	-	-
Subtotal: fixed operating costs		$ (27,295)	$ (28,114)	$ (28,957)	$ (29,826)	$ (30,721)	$ (31,642)	$ (32,592)	$ (33,569)	$ (34,576)	$ (35,614)
VARIABLE OPERATING COSTS											
Wood fuel		-	-	-	-	-	-	-	-	-	-
Labor		(29,499)	(30,384)	(31,296)	(32,235)	(33,202)	(34,198)	(35,224)	(36,280)	(37,369)	(38,490)
Repairs & maintenance		(77,250)	(79,568)	(81,955)	(84,413)	(86,946)	(89,554)	(92,241)	(95,008)	(97,858)	(100,794)
Periodic consumables		-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additional periodic consumables		(8,240)	(10,609)	(10,927)	(11,255)	(9,274)	(11,941)	(12,299)	(12,668)	(10,438)	(13,439)
Other variable consumables cost		-	-	-	-	-	-	-	-	-	-
Misc. variable operating costs		-	-	-	-	-	-	-	-	-	-
Subtotal: variable operating costs		$ (114,989)	$ (120,561)	$ (124,177)	$ (127,903)	$ (129,421)	$ (135,692)	$ (139,763)	$ (143,956)	$ (145,665)	$ (152,723)
Subtotal: fixed and variable operating costs		$ (142,284)	$ (148,675)	$ (153,135)	$ (157,729)	$ (160,142)	$ (167,334)	$ (172,355)	$ (177,525)	$ (180,241)	$ (188,336)
Cash flow before tax & financing	$ (1,660,000)	$ 180,213	$ 183,498	$ 189,002	$ 194,673	$ 202,831	$ 206,528	$ 212,724	$ 219,106	$ 228,288	$ 232,449
FINANCING											
Loan principal	$ 600,000										
Total loan interest payments		$ (46,524)	$ (43,135)	$ (39,465)	$ (35,490)	$ (31,185)	$ (26,523)	$ (21,474)	$ (16,006)	$ (10,084)	$ (3,671)
Total loan principal repayment		(40,831)	(44,220)	(47,891)	(51,866)	(56,170)	(60,833)	(65,882)	(71,350)	(77,272)	(83,685)
Cash flow before tax	$ (1,060,000)	$ 92,857	$ 96,142	$ 101,647	$ 107,317	$ 115,475	$ 119,172	$ 125,368	$ 131,750	$ 140,932	$ 145,093

Cash Flow Table (continued)	Year 0	1	2	3	4	5	6	7	8	9	10
Cash flow before tax	$ (1,060,000)	$ 92,857	$ 96,142	$ 101,647	$ 107,317	$ 115,475	$ 119,172	$ 125,368	$ 131,750	$ 140,932	$ 145,093
TAX ADJUSTMENTS											
Section 179 deduction		$ -									
Special first-year depreciation allowance		(450,000)									
Depreciation expense		(121,000)	$ (108,900)	$ (98,010)	$ (88,209)	$ (79,388)	$ (71,449)	$ (71,449)	$ (71,449)	$ (71,449)	$ (71,449)
Taxable gain (loss) on salvage †		-	-	-	-	-	-	-	-	-	(357,246)
Subtotal: tax adjustments		$ (571,000)	$ (108,900)	$ (98,010)	$ (88,209)	$ (79,388)	$ (71,449)	$ (71,449)	$ (71,449)	$ (71,449)	$ (428,696)
Income (loss) before taxes (or: Taxable cash flow)		$ (437,311)	$ 31,462	$ 51,527	$ 70,973	$ 92,258	$ 108,555	$ 119,800	$ 131,650	$ 146,755	$ (199,917)
Assessed taxes on cash flow ††		144,313	(10,382)	(17,004)	(23,421)	(30,445)	(35,823)	(39,534)	(43,445)	(48,429)	65,973
Federal energy tax credit		-	-	-	-	-	-	-	-	-	-
Other tax credits		-	-	-	-	-	-	-	-	-	-
Subtotal: taxes		144,313	(10,382)	(17,004)	(23,421)	(30,445)	(35,823)	(39,534)	(43,445)	(48,429)	65,973
Net income (loss) after taxes		$ (292,999)	$ 21,080	$ 34,523	$ 47,552	$ 61,813	$ 72,732	$ 80,266	$ 88,206	$ 98,326	$ (133,944)
After-tax cash flow	$ (1,060,000)	$ 237,170	$ 85,759	$ 84,643	$ 83,895	$ 85,030	$ 83,349	$ 85,834	$ 88,305	$ 92,503	$ 211,066

† If the salvage value is less than the purchase price less the accumulated depreciation, the firm takes a book loss on the investment and gets a tax credit.
If the salvage value is greater than the skidder cost less its accumulated depreciation, the firm pays income tax tax on recovery of excess depreciation.
Technically, the asset should be sold at the beginning of the next year following the end of its economic life, to allow the last depreciation expense to be taken..

†† If the firm suffers a tax loss, the model assumes that there is other income in the current period against which the loss may be deducted.

WARNING! If the subtotal containing taxes is positive in any given year, the cell will appear highlighted in YELLOW to draw your attention.
The model assumes that if there are tax credits, that there is income from other sources so that the credits may be taken in the year in which they are earned.

Analysis in Real Dollars	Year 0	1	2	3	4	5	6	7	8	9	10
Before-tax & finance cash flow (nominal)	$ (1,660,000)	$ 180,213	$ 183,498	$ 189,002	$ 194,673	$ 202,831	$ 206,528	$ 212,724	$ 219,106	$ 228,288	$ 232,449
Before-tax & finance cash flow (real)	$ (1,660,000)	$ 174,964	$ 172,964	$ 172,964	$ 172,964	$ 174,964	$ 172,964	$ 172,964	$ 172,964	$ 174,964	$ 172,964
Before-tax cash flow (nominal)	$ (1,060,000)	$ 92,857	$ 96,142	$ 101,647	$ 107,317	$ 115,475	$ 119,172	$ 125,368	$ 131,750	$ 140,932	$ 145,093
Before-tax cash flow (real)	$ (1,060,000)	$ 90,152	$ 90,623	$ 93,021	$ 95,349	$ 99,610	$ 99,805	$ 101,936	$ 104,004	$ 108,013	$ 107,963
After-tax cash flow (nominal)	$ (1,060,000)	$ 237,170	$ 85,759	$ 84,643	$ 83,895	$ 85,030	$ 83,349	$ 85,834	$ 88,305	$ 92,503	$ 211,066
After-tax cash flow (real)	$ (1,060,000)	$ 230,262	$ 80,836	$ 77,460	$ 74,540	$ 73,348	$ 69,803	$ 69,791	$ 69,709	$ 70,896	$ 157,053

CALCULATIONS AND EXPENSE TEMPLATES

	Year 0	1	2	3	4	5	6	7	8	9	10
Depreciation Calculations											
Beginning book value		$ 1,660,000	$ 1,089,000	$ 980,100	$ 882,090	$ 793,881	$ 714,493	$ 643,044	$ 571,594	$ 500,145	$ 428,696
Less:											
Section 179 deduction		$ -									
Special first-year depreciation allowance		(450,000)									
Depreciable value	$ 1,660,000	$ 1,210,000	$ 1,089,000	$ 980,100	$ 882,090	$ 793,881	$ 714,493	$ 643,044	$ 571,594	$ 500,145	$ 428,696
Depreciation expense		(121,000)	(108,900)	(98,010)	(88,209)	(79,388)	(71,449)	(71,449)	(71,449)	(71,449)	(71,449)
Salvage write-off		-	-	-	-	-	-	-	-	-	-
Ending book value	$ 1,660,000	$ 1,089,000	$ 980,100	$ 882,090	$ 793,881	$ 714,493	$ 643,044	$ 571,594	$ 500,145	$ 428,696	$ 357,246
Accumulated depreciation		$ (571,000)	$ (679,900)	$ (777,910)	$ (866,119)	$ (945,507)	$ (1,016,956)	$ (1,088,406)	$ (1,159,855)	$ (1,231,304)	$ (1,302,754)
Depreciation Expense Templates											
Declining balance [DB]		$ (121,000)	$ (108,900)	$ (98,010)	$ (88,209)	$ (79,388)	$ (71,449)	$ (71,449)	$ (71,449)	$ (71,449)	$ (71,449)
Straight line (GDS life: Accelerated) [SLGDS]		$ (80,667)	$ (77,786)	$ (75,392)	$ (73,508)	$ (72,171)	$ (71,449)	$ (71,449)	$ (71,449)	$ (71,449)	$ (71,449)
Straight line (ADS life) [SLADS]		$ (55,000)	$ (51,857)	$ (49,005)	$ (46,426)	$ (44,105)	$ (42,029)	$ (40,190)	$ (38,106)	$ (35,725)	$ (32,977)
Straight line (economic life) [SLEL]		$ (124,630)	$ (128,369)	$ (132,220)	$ (136,187)	$ (140,272)	$ (144,480)	$ (148,815)	$ (153,279)	$ (157,878)	$ (162,614)
Custom		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Repairs & Maintenance Templates	Fudge Factor [†]										
Uniform		$ (77,250)	$ (79,568)	$ (81,955)	$ (84,413)	$ (86,946)	$ (89,554)	$ (92,241)	$ (95,008)	$ (97,858)	$ (100,794)
Increasing	0.99	$ (14,394)	$ (30,541)	$ (48,602)	$ (68,749)	$ (91,169)	$ (116,066)	$ (143,656)	$ (174,177)	$ (207,883)	$ (245,048)
Custom	0.35	$ (11,280)	$ (16,966)	$ (25,517)	$ (38,377)	$ (57,720)	$ (86,813)	$ (130,568)	$ (196,376)	$ (295,354)	$ (444,218)
Sums (for increasing R&M rates)	55	1	3	6	10	15	21	28	36	45	55

[†] The Fudge Factor may be used to ensure that the NPVs of the distributions are equal so that costing differences between models are not due to inequalities in R&M assumptions.
To make the NPV's equal, use "Goal Seek" to find a Fudge Factor which makes the difference between the NPV's = $0.

	0	1	2	3	4	5	6	7	8	9	10
Periodic consumables replacements											
Beginning consumables life (hours)	7,160	7,160	-	-	-	-	-	-	-	-	-
Replacement consumables hours	-	-	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160
Annual productive time		7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160
Remaining consumables life (hours)	7,160	-	-	-	-	-	-	-	-	-	-
Consumables replacements (number/year)		-	1	1	1	1	1	1	1	1	1

	Year 0	1	2	3	4	5	6	7	8	9	10
Additional periodic consumables	**Replacement calculations**										
Beginning life (hours)	-	1,500	340	680	1,020	1,360	200	540	880	1,220	60
Replacement hours	1,500	6,000	7,500	7,500	7,500	6,000	7,500	7,500	7,500	6,000	7,500
Annual productive time (hours)	-	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160
Remaining life (hours)	1,500	340	680	1,020	1,360	200	540	880	1,220	60	400
Total replacements (number/year)	1	4	5	5	5	4	5	5	5	4	5
***Ad valorem* (property) tax valuation**											
Straight-line book value (SLB)		$ 1,500,000	$ 1,431,818	$ 1,363,636	$ 1,295,455	$ 1,227,273	$ 1,159,091	$ 1,090,909	$ 1,022,727	$ 954,545	$ 886,364
Average capital invested (ACI)		$ 825,000	$ 825,000	$ 825,000	$ 825,000	$ 825,000	$ 825,000	$ 825,000	$ 825,000	$ 825,000	$ 825,000
Custom		$ 1,465,909	$ 1,397,727	$ 1,329,545	$ 1,261,364	$ 1,193,182	$ 1,125,000	$ 1,056,818	$ 988,636	$ 920,455	$ 852,273
Federal energy tax credit calculations											
Inflation-adjusted tax credit		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-inflation-adjusted tax credit		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Sensitivity Analysis **1,000 kW** Use Data, Table, Column Input Cell = Whatever cell is variable (eg: Inflation Rate, Gearing, ARR, etc.)

Purchase price ($/kW)	Nominal IRR After-tax	Real IRR After-tax	— Break-even subsidy (profit) — ($/bdt)	($/acre)	($/kWh)
$900	20.0%	16.5%	($2.95)	($27)	$0.0396
$1,000	15.9%	12.6%	($0.35)	($3)	$0.0432
$1,100	12.4%	9.1%	$2.24	$20	$0.0469
$1,200	9.2%	6.0%	$4.84	$44	$0.0505
$1,300	6.4%	3.3%	$7.43	$67	$0.0541
$1,400	3.8%	0.7%	$10.03	$90	$0.0577
$1,500	1.3%	-1.6%	$12.62	$114	$0.0614
$1,600	-0.9%	-3.8%	$15.22	$137	$0.0650
$1,700	-3.1%	-5.9%	$17.81	$160	$0.0686
$1,800	-5.1%	-7.9%	$20.41	$184	$0.0722
$1,900	-7.1%	-9.8%	$23.00	$207	$0.0758
$2,000	-9.0%	-11.6%	$25.60	$230	$0.0795
$2,100	-10.8%	-13.4%	$28.19	$254	$0.0831
		Purchase price increment change =			$100

Depreciation code	Nominal IRR After-tax	Real IRR After-tax	— Break-even subsidy (profit) — ($/bdt)	($/acre)	($/kWh)
DB	1.3%	-1.6%	$12.62	$114	$0.0614
SLGDS	1.3%	-1.7%	$13.02	$117	$0.0619
SLADS	1.2%	-1.7%	$13.59	$122	$0.0627
SLEL	1.5%	-1.5%	$11.83	$107	$0.0602
Custom	1.1%	-1.9%	$14.82	$133	$0.0644

Economic life (years)	Nominal IRR After-tax	Real IRR After-tax	— Break-even subsidy (profit) — ($/bdt)	($/acre)	($/kWh)
10	1.3%	-1.6%	$12.62	$114	$0.0614
15	10.7%	7.5%	$5.20	$47	$0.0510
22	14.8%	11.4%	$0.86	$8	$0.0449

Gearing	Nominal IRR After-tax	Real IRR After-tax	Break-even subsidy (profit) ($/bdt)	($/acre)	B-E elect. ($/kWh)
0%	2.7%	-0.2%	$18.51	$167	$0.0696
10%	2.5%	-0.5%	$17.04	$153	$0.0675
20%	2.2%	-0.8%	$15.57	$140	$0.0655
30%	1.8%	-1.1%	$14.10	$127	$0.0634
40%	1.3%	-1.6%	$12.62	$114	$0.0614
50%	0.6%	-2.3%	$11.15	$100	$0.0593
60%	-0.4%	-3.3%	$9.68	$87	$0.0572
70%	-1.9%	-4.8%	$8.21	$74	$0.0552
80%	-4.8%	-7.6%	$6.74	$61	$0.0531
90%	#NUM!	#NUM!	$5.27	$47	$0.0511

B-T Risk Premium	Break-even subsidy (profit) ($/bdt)	($/acre)	B-E elect. ($/kWh)
-10%	($4.12)	($37)	$0.0380
-5%	($1.91)	($17)	$0.0411
0%	$0.54	$5	$0.0445
5%	$3.23	$29	$0.0482
10%	$6.15	$55	$0.0523
15%	$9.29	$84	$0.0567
20%	$12.62	$114	$0.0614
25%	$16.15	$145	$0.0663
30%	$19.84	$179	$0.0714
35%	$23.68	$213	$0.0768
40%	$27.66	$249	$0.0823
45%	$31.76	$286	$0.0881
50%	$35.96	$324	$0.0939
55%	$40.26	$362	$0.0999
Risk premium increment change =			5%

Sensitivity Analysis (continued)

Delivered fuel cost ($/bone dry ton)	Nominal IRR	Real IRR	Break-even subsidy (profit)		B-E elect.
	After-tax	After-tax	($/bdt)	($/acre)	($/kWh)
($30)	30.8%	27.0%	($17.38)	($156)	$0.0195
($25)	26.6%	22.9%	($12.38)	($111)	$0.0265
($20)	22.3%	18.7%	($7.38)	($66)	$0.0334
($15)	17.7%	14.3%	($2.38)	($21)	$0.0404
($10)	12.8%	9.5%	$2.62	$24	$0.0474
($5)	7.4%	4.3%	$7.62	$69	$0.0544
$0	1.3%	-1.6%	$12.62	$114	$0.0614
$5	-6.1%	-8.8%	$17.62	$159	$0.0683
$10	#NUM!	#NUM!	$22.62	$204	$0.0753
$15	#DIV/0!	#DIV/0!	$27.62	$249	$0.0823
$20	#DIV/0!	#DIV/0!	$32.62	$294	$0.0893
$25	#DIV/0!	#DIV/0!	$37.62	$339	$0.0962
$30	#DIV/0!	#DIV/0!	$42.62	$384	$0.1032
		Fuel cost increment change =			$5

Electricity value ($/kWh)	Nominal IRR	Real IRR	— Break-even profit (subsidy) —		
	After-tax	After-tax	($/ton)	($/acre)	($/kWh)
$0.0200	#DIV/0!	#DIV/0!	$29.62	($267)	($0.0426)
$0.0400	-2.4%	-5.3%	$15.30	($138)	($0.0220)
$0.0600	14.5%	11.2%	$0.97	($9)	($0.0014)
$0.0800	27.4%	23.7%	($13.36)	$120	$0.0192
$0.1000	38.9%	34.9%	($27.69)	$249	$0.0398
$0.1200	49.7%	45.3%	($42.01)	$378	$0.0604
$0.1400	60.1%	55.4%	($56.34)	$507	$0.0810
$0.1600	70.2%	65.2%	($70.67)	$636	$0.1016
$0.1800	80.2%	74.9%	($85.00)	$765	$0.1222
$0.2000	90.0%	84.5%	($99.32)	$894	$0.1428
$0.2200	99.8%	94.0%	($113.65)	$1,023	$0.1634
$0.2400	109.5%	103.4%	($127.98)	$1,152	$0.1840
$0.2600	119.2%	112.8%	($142.31)	$1,281	$0.2046
		Electricity value increment change =			$0.0200

Variable operating costs sensitivity factor	Nominal IRR	Real IRR	Break-even subsidy (profit)		B-E elect.
	After-tax	After-tax	($/bdt)	($/acre)	($/kWh)
70%	5.6%	2.5%	$9.23	$83	$0.0566
75%	4.9%	1.8%	$9.80	$88	$0.0574
80%	4.2%	1.2%	$10.36	$93	$0.0582
85%	3.5%	0.5%	$10.93	$98	$0.0590
90%	2.8%	-0.2%	$11.49	$103	$0.0598
95%	2.1%	-0.9%	$12.06	$109	$0.0606
100%	1.3%	-1.6%	$12.62	$114	$0.0614
105%	0.6%	-2.4%	$13.19	$119	$0.0621
110%	-0.2%	-3.1%	$13.75	$124	$0.0629
115%	-1.0%	-3.9%	$14.32	$129	$0.0637
120%	-1.8%	-4.7%	$14.88	$134	$0.0645
125%	-2.7%	-5.5%	$15.45	$139	$0.0653
130%	-3.5%	-6.3%	$16.02	$144	$0.0661
	Variable operating costs sensitivity factor increment change =				5%

Fixed operating costs sensitivity factor	Nominal IRR	Real IRR	Break-even subsidy (profit)		B-E elect.
	After-tax	After-tax	($/bdt)	($/acre)	($/kWh)
70%	2.4%	-0.6%	$11.83	$106	$0.0602
75%	2.2%	-0.8%	$11.96	$108	$0.0604
80%	2.0%	-0.9%	$12.09	$109	$0.0606
85%	1.9%	-1.1%	$12.23	$110	$0.0608
90%	1.7%	-1.3%	$12.36	$111	$0.0610
95%	1.5%	-1.5%	$12.49	$112	$0.0612
100%	1.3%	-1.6%	$12.62	$114	$0.0614
105%	1.2%	-1.8%	$12.76	$115	$0.0615
110%	1.0%	-2.0%	$12.89	$116	$0.0617
115%	0.8%	-2.1%	$13.02	$117	$0.0619
120%	0.6%	-2.3%	$13.15	$118	$0.0621
125%	0.4%	-2.5%	$13.29	$120	$0.0623
130%	0.3%	-2.7%	$13.42	$121	$0.0625
	Variable operating costs sensitivity factor increment change =				5%