BIOMASS-GASIFIER/GAS-TURBINE APPLICATIONS IN THE PULP AND PAPER INDUSTRY: AN INITIAL STRATEGY FOR REDUCING ELECTRIC UTILITY CO_2 EMISSIONS

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ABSTRACT

Biomass produces no net carbon dioxide when used sustainably for energy: growing biomass absorbs carbon that is released when the biomass is used for fuel. Bioenergy use can lead to reductions in CO_2 emissions to the extent that it can replace fossil fuels. For power generation and cogeneration using biomass requires technologies that offer attractive economics at modest scale--a criterion that could be satisfied by biomass-gasifier/gas-turbine (BIG/GT) technologies. While eventually BIG/GT units might be fired with biomass grown on energy plantations, initial applications will likely be based on the use of residues from ongoing industrial or agricultural activities. The prospects for BIG/GT cogeneration at kraft pulp mills are explored here. The performance, cost and developmental status of two BIG/GT systems are assessed, one utilizing solid biomass for fuel (e.g. wood chips), the other utilizing kraft black liquor. Based on a case study for a large pulp mill in the Southeastern US, advanced BIG/GT cogeneration technology at an energy-efficient mill could produce over three times as much electricity using currently available hog fuel and black liquor as is typically produced today. On-site steam and electricity requirements, which are met with steam-turbine cogeneration today, could be met and a large surplus of electricity would be available for export to a utility grid. Using currently unutilized forest residues in addition, total electricity production could be over 5 times today's level. The levelized busbar cost (assuming utility ownership) of producing electricity in excess of on-site needs would be about 4 cents per kWh. At projected rates of growth in pulp production, biomass residues associated with pulp production in the year 2020 could support up to 105 GW of BIG/GT capacity worldwide, 30 GW of which would be in the US. Export electricity production would be equivalent to 10% of the electricity generated worldwide from fossil fuels. In the US, the export electricity would be equivalent to 17% of the electricity presently generated by utilities from coal in pulp-producing regions, or 14% of total US coal-electricity.

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INTRODUCTION

Worldwide total emissions of carbon dioxide, the predominant greenhouse gas, were some 7 billion tonnes of contained carbon in 1987, 3/4 from fossil fuel burning (Fig. 1a). The US contributed about 20% of the total (Fig. 1b), essentially all from fossil fuels. US electric utilities emitted about 1/3 of this, primarily by burning coal (Fig. 1c).

Biomass (wood, grasses, crop residues, and other products of photosynthesis) could offset fossil fuel CO_2 emissions through increases in net forest coverage and/or the production of wood and paper products, both of which provide long-term sequestering of carbon [1]. The use of bioenergy as a fossil fuel substitute could also reduce CO_2 emissions. If grown sustainably, bioenergy produces no net CO_2, since biomass absorbs the same amount of carbon in growing as it releases when consumed as fuel.

Globally biomass is produced in equivalent energy terms at a rate of 1200 EJ per year [2]. About 55 EJ are currently used for energy [3], accounting for about 13% of global energy use in 1988. In developing countries biomass accounts for 1/3 of total energy use, but it is used very inefficiently, primarily for cooking. In industrialized countries, is accounts for 3% of total energy use, primarily for meeting on-site industrial energy needs.

In the US, potential biomass energy supplies are estimated by the Oak Ridge National Laboratory (ORNL) to be about 9 EJ per year for wood and herbaceous energy crops alone and 29 EJ per year for biomass from all sources, target costs for which are \$2 per GJ or less [4]. (For comparison, the price of coal to electric utilities in 1989 was \$1.4 per GJ [5], and is projected to be \$1.8 per GJ in 2010 [6].[1]) A report prepared for the US Department of Energy [7] indicates that by using all potentially available surplus cropland, plantation energy crops eventually costing less than \$2/GJ could contribute as much as 26 EJ per year, which would raise total potential biomass supplies from the level estimated in the ORNL report to 46 EJ per year, equivalent to more than 1/2 of total US energy use today. Potential biomass supplies in other parts of the world may be even more substantial, e.g. in tropical countries with climate well suited for biomass production. Thus, even though land and water constraints will ultimately limit the extent to which biomass can be produced for energy, potential supplies are large enough to warrant giving serious attention to the bioenergy option.

A major challenge to bioenergy development is to identify technologies for providing biomass-derived modern energy carriers (electricity and gaseous, liquid, and processed-solid fuels) at competitive costs for the modest-scale installations needed for biomass conversion, as dictated by the dispersed nature of the biomass resource.

A promising set of options for "modernizing" bioenergy are power generation and cogeneration technologies based on pressurized, air-blown biomass gasifiers coupled to various cycles involving aeroderivative gas turbines, which have the potential for high efficiency and low unit capital cost at modest scale [8]. Advanced biomass-gasifier/gas-turbine (BIG/GT) technologies could potentially produce as much electricity as was provided by coal in the US in 1987 using 12 EJ of biomass feedstocks; if biomass instead of coal had provided this much electricity, total US CO_2 emissions would have been 28% lower that year [9].

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[1] The US gross national product deflator has been used to express all costs in this paper in constant first-quarter 1990 dollars.

Eventually biomass grown on plantations dedicated to energy production could be used to fuel BIG/GT units. In the US, average costs for biomass from energy plantations are projected to be \$3.0-\$3.6 per GJ (including pre-processing for gasification) in the year 2000 (based on [10]), compared to \$1.8 per GJ for coal in 2020 [6]. Even with nearly double the fuel cost, BIG/GT systems could be competitive with coal-fired power (Fig. 2). Costs of producing biomass in tropical regions of the world are probably lower than in the US [8], making BIG/GT systems perhaps even more attractive for many developing countries.

The development of large-scale biomass plantations will take time. Initial markets for BIG/GT systems are likely, therefore, to be for applications where biomass fuels already exist as residues from existing industrial activities. One such application would be in the sugar cane processing industries using bagasse (residues left after crushing the cane) and barbojo (the tops and leaves of the cane plant) as fuel. The 1987 global level of cane production (970 million tonnes) could support 95 GW of BIG/GT capacity. Some 94% of this capacity would be in the 80 cane-producing developing countries, where the produced electricity (807 TWh) would be equivalent to half of all utility electricity produced there that year [11]. If the electricity had replaced that generated from fossil fuels, total fossil-fuel CO_2 emissions from all sources in all developing countries would have been about 12% lower.

This paper assesses the prospects for using BIG/GT technologies in the kraft pulp industry as another initial application using residues as fuel.

BIOMASS-GASIFIER/GAS-TURBINE TECHNOLOGY

The estimated performance, cost and development status of alternative BIG/GT technologies are described here. One gasifier considered would use solid fuels (e.g. wood chips, wood waste, crop residues, etc.); the other, black liquor from kraft pulp production. Steam-injected gas turbines (STIGs) and intercooled steam-injected gas turbines (ISTIGs) are alternative aeroderivative turbine cycles that are considered [12]. Steam-turbine/gas-turbine combined cycles based on advanced aeroderivative turbines are also potential candidates.[2]

Solid-Biomass Gasifier/Gas Turbines

A biomass-gasifier/steam-injected gas turbine (BIG/STIG) fueled with solid biomass (Fig. 3) would be similar in many respects to the more familiar coal-gasifier/gas-turbine (IGCC) technology demonstrated at Cool Water. Important differences would include the use of air-blown instead of oxygen-blown gasification and a steam-injected gas turbine instead of a combined cycle. The sensitivity to scale of oxygen plants and conventional combined cycles makes the Cool Water technology uneconomic for relatively smaller applications (See Fig. 4 and [16]. Also, while the gas exiting the gasifier must be cleaned, so doing would not require advanced cleanup technologies, because most biomass contains negligible sulfur.[3] Furthermore, the looser molecular structure of biomass compared to coal makes it more reactive and easier

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[2] Some advanced, potentially low-cost aeroderivative turbines will be better suited to combined cycles than to steam injection. For example, the LM-6000, which will enter commercial service in 1992, will produce 42.4 MW at a simple-cycle efficiency greater than 36% (HHV basis, natural gas fuel) and will have an estimated gen-set equipment price of \$230/kW to \$250/kW [13], much less than the \$400/kW price for the most efficient (33%) aeroderivative gas turbine available today [14]. (See [15] for discussion of other advanced engines.) An LM-6000 based combined cycle would produce some 53.3 MW at an expected efficiency of some 48% [13]. Because the gas turbine involved in this combined cycle would be cheap and because the steam turbine would provide only 1/5 of the output (compared to 1/3 for a combined cycle based on the use of industrial gas turbines), the LM6000 combined cycle may prove competitive with much larger combined cycles based on industrial turbines.

[3] The commercial viability of hot-gas desulfurization appears to be the major hurdle remaining in the development of coal-IGCC systems using hot-gas cleanup [17].

to gasify (Fig. 5), so that fixed-bed and fluidized-bed gasifiers, which operate at lower average temperatures than entrained-beds such as the one at Cool Water, can provide essentially complete carbon conversion and high gasification efficiency [8].

Gasifier Options. The fixed-bed gasifier is attractive for relatively dense fuels (wood chips, hog fuel, or densified biomass) because of its simplicity and high efficiency [8]. Among several fixed-bed units on which there has been development work during the last decade, the Lurgi dry-ash gasifier, which has been evaluated for coal-IGCC applications [17], appears to be a good candidate for biomass applications [18]. Successful, but limited, pilot-scale testing of a Lurgi-type unit has been carried out by General Electric using biomass pellets [19] and RDF/coal briquettes [20]. More extensive testing is required to determine the suitability of fixed-bed gasification for biomass and the degree of fuel processing needed to make alternative biomass feedstocks acceptable for use with this gasifier.

Fluidized-bed gasifiers have higher throughput capabilities and greater fuel flexibility than fixed-beds, including the ability to handle low-density feedstocks (e.g. undensified crop residues or sawdust) [8]. A major drawback of fluidized-bed gasifiers is the higher level of particulates in the raw gas, which makes gas cleanup more challenging. Atmospheric-pressure fluidized-bed gasifiers are commercially operating with biomass fuels. Pressurized units are under development for coal-IGCC applications. A significant amount of work has also been done on pressurized biomass-fueled units designed for applications to methanol production.

One promising fluidized-bed technology for pressurized biomass applications appears to be the Rheinbraun/Uhde HTW (High Temperature Winkler) gasifier. A pressurized (13.5 bar) commercial unit is operating on peat in Finland [8]. A 25-bar coal-fueled pilot plant has been running since November 1989 in Germany. Rheinbraun/Uhde recently joined with the Lurgi Company to plann construction of a 275 MW coal-IGCC demonstration plant in Germany that will use a pressurized gasifier marrying the HTW system to Lurgi's circulating fluidized bed technology [21]. The plant is scheduled for startup in 1995.

The Finnish company, Tampella, recently entered into a licensing agreement with the Institute of Gas Technology (IGT) in Chicago to commercialize the IGT U-GAS gasifier, which has undergone successful pressurized pilot-scale operation on a variety of biomass feedstocks [8]. Tampella is now building a 10 MW_{fuel}, 35-bar demonstration unit at its research headquarters in Tampere, Finland. Startup is scheduled for early 1991. Coal will be the primary fuel. Tampella is also planning to construct, starting in 1993, a commercial-scale unit (150 MW_{fuel}) that will fuel a gas turbine. The plant will most likely to be located at one of Tampella's own pulp mills, using coal, waste bark, and pulp mill waste sludge for fuel [22].

Perhaps the most important development issue for BIG/GT technology is gas cleanup, specifically removal of alkali compounds[4] and particulates at elevated temperatures [25]. Alkali compounds in biomass gas would form primarily from potassium and sodium in the feedstock. The extent of alkali production and required removal from biomass gas have not been tested. Based on coal-related work, it appears that the gasifier exit temperature largely determines whether alkalis exit in vapor or condensed from. At fixed-bed gasifier exit temperatures (500-650°C) most of the alkali condenses on entrained particles and can thus probably be removed with particulates. Particulate cleanup with fixed-bed gasifiers may be possible using cyclones, based on data for coal (Fig. 6). Alkali that reaches the combustor would be in a chemically bound form and would not vaporize in short residence-time combustors [26]. With fluidized-bed gasifiers, some cooling of the gas would probably be required to condense alkali. Also, more efficient particle removal technology would probably be needed, e.g. barrier filters. Demonstration of a significant new design for ceramic barrier

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[4] Most estimates of the tolerable concentration of alkali vapors in fuel gas for gas turbine applications are very low--100 to 200 parts per billion [23,24].

filters, intended in part to overcome the problems that traditional candle filters have in withstanding thermal and mechanical shock, is ongoing in Finland [27].

Performance and Costs. The estimated performance of BIG/STIG and BIG/ISTIG systems in cogeneration and power-only modes of operation are compared in Table 1 to the performance of a double-extraction/condensing steam turbine (CEST) system. Like CEST systems, steam-injected gas turbines offer flexibility in handling variable process steam demands [12]. Operated in the cogeneration mode, gas turbine systems produce much less steam (as a fraction of fuel input, in energy units) than CEST. Operated in either cogeneration or power-only modes, gas turbines are much more efficient electricity producers.

Gas turbine systems would also have a capital cost advantage over CEST systems (Table 1). A BIG/STIG based on the LM5000 gas turbine is estimated to cost $1150/kW.[5] For comparison, the natural-gas LM5000 STIG has been estimated to cost $450/kW (engineering study assuming use of a once-through boiler [29]), $650/kW (actual experience with the first commercial unit installed [30]), and $760/kW (current estimate for new plants [31]).[6] The cost advantage of the BIG/GT units would increase over the CEST, the smaller the plant size, because of the lower sensitivity of gas turbine system costs to scale (Fig. 7).

Technology Status. The Vermont Department of Public Service, cooperating with Green Mountain Power and Central Vermont Public Service Corporation, is planning a commercial demonstration of a biomass-gasifier/gas-turbine which will be fueled by wood chips derived from forest management operations [34]. An assessment of forest resources for purposes of siting the plant has identified more than adequate wood supplies at reasonable costs. The US Department of Energy, US Environmental Protection Agency, and the US Agency for International Development will jointly support pre-project gasification tests of the fuels that are likely to be used in the demonstration plant. The General Electric Corporate Research Center has proposed undertaking these studies using its fixed-bed gasifier/gas-turbine simulator facility in Schenectady, NY. A demonstration effort at the 20-MW level is expected to cost $40-50 million [26], and little (if any) additional scale-up work would likely be needed, since 20 MW represents a commercial size for many biomass applications.

Kraft Black Liquor Gasifier/Gas Turbines

Worldwide, some 2.6 EJ of black liquor, a lignin-rich by-product of cellulose extraction from wood chips in kraft (sulphate) pulping, was produced at kraft pulp mills in 1988, 40% of this

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[5] This is consistent with the estimated cost for a 37 MW BIG/combined-cycle plant designed in a feasibility study carried out at the Shell International Petroleum Company [28]. The Shell design consisted of an Ahlstrom circulating fluidized-bed gasifier with ceramic-filter gas cleanup feeding a Rolls Royce RB211 aeroderivative gas turbine, which would provide 27 MW of the plant's output. Overall efficiency on 15% moisture content wheat straw was estimated to be 38-40% (HHV). The total installed capital cost was estimated to be $1200-1300/kW for plants built subsequent to the demonstration plant, which was estimated to cost $1600/kW to $1700/kW.

[6] A recent study comparing STIGs and combined-cycles for utility applications [14] estimates the installed cost of a natural-gas LM5000 STIG as $1315/kW. This higher estimate is due in part to unusually extensive site preparation needed at the specific site selected for the study. In addition, contingencies, escalation factors, and allowance for funds during construction (AFDC) were introduced in the costing methodology for internal consistency, but may not be fully applicable in practice [32]. Indirect costs can generally be expected to be low for compact aeroderivative turbine technologies because a larger fraction of the construction can be carried out using mass production techniques in the factory [33]. In contrast, large power plants require more field construction. Adjusting the original cost estimate by assuming less site work and eliminating contingency, escalation and AFDC costs gives a total installed cost of about $630/kW, which appears to be in line with actual installed costs and other published cost estimates.

in the US.[7] It represents the largest single source of energy now used in the pulp and paper industry [37]. Black liquor will continue to be an important energy source in the US and other industrialized countries, as the pulp and paper industry is one of the few basic-materials processing industries that has strong growth potential in the industrialized countries [38]. Although the majority of chemical pulp is made in industrialized countries, production growth rates are highest in the developing world,[8] so black liquor will grow rapidly in importance in many of these regions as well.

Black liquor is typically consumed today in Tomlinson recovery boilers, a technology commercialized in the early 1900s. Steam is raised (usually to drive a steam turbine cogeneration system) and a chemical smelt is produced containing sodium carbonate and sodium sulphate. The smelt is converted into sodium hydroxide and sodium sulphate, which is recycled for use in the pulping process [40]. The high capital costs and smelt-water explosion risks of Tomlinson recovery boilers and the relatively low efficiency of recovery boiler/steam turbine cogeneration systems have motivated R&D work over the last 15 years on black liquor gasification for energy recovery. The market potential for retrofit applications alone is quite large, because many existing recovery boilers are expected to be due for replacement by the year 2000 [36].

Status of Gasification Technologies. Promising development efforts ongoing today are on an entrained-bed gasifier by Chemrec, a Swedish company [41], and on a fluidized-bed unit by MTCI, an American company [42]. In both cases the work is aimed at the development of modular atmospheric-pressure gasifiers that can be used in the near term to expand the black liquor processing capacity of a pulp mill without the capital-intensive replacement of the complete recovery boiler. The Chemrec and MTCI technologies are at roughly the same stage of development. A Chemrec pilot plant processing 3 tonnes per hour (dry black liquor solids) is currently under construction at a mill in Sweden, with a larger commercial-scale unit planned for installation in a mill in the US in the mid-1990s [43]. A 1 tonne per hour MTCI gasifier will be installed at a US mill in the fall of 1990 [44]. Pressurized versions of these technologies appear to be good candidates for gas turbine applications [45] (see also [46]).[9] Given black liquor's chemical composition, particular development effort should be focussed on alkali removal from the fuel gas to make it suitable for gas turbine use.

Performance and Costs. Estimates of the performance and costs of the MTCI technology are used here for a preliminary evaluation of gas turbine applications of black liquor gasification. The MTCI gasifier uses a pulse combustor with in-bed heater tubes to gasify the black liquor (Fig. 8). A product gas cooler and flue gas heat recovery steam generator produce

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[7] This is a rough estimate, based on 105 million tonnes of chemical pulp produced in 1988 (45 million tonnes in the US) [35], and 25.3 GJ of black liquor per tonne of pulp. The latter is a measured value from a 1000 tonne pulp per day mill in the Southeastern US using loblolly pine as the feedstock. Black liquor production from hardwood pulping is about 15% less than that from softwood like pine [36], so actual global and US black liquor production were probably slightly lower than indicated here.

[8] The expected growth rates in chemical pulp production, 1980 to 2000, are 2.1% per year, 4.2% per year and 6.8% per year in industrialized market economies, emerging capitalist economies, and developing countries, respectively [39]. The high growth in developing countries is driven by high expected demand growth there. Developing countries consumed 8 kg per capita of paper and paperboard products on average in 1984, compared to 133 kg per capita in all industrialized countries and 290 kg per capita in the US (the world's highest).

[9] While pressurization would be desirable, it may not strictly be necessary. For example, the MTCI technology produces a relatively high heating value gas (Table 2) without using oxygen, so that costs to compress the gas to gas turbine combustor pressures may not be prohibitive. To produce a gas with as high a heating value as the MTCI gas using the Chemrec technology would require use of oxygen instead of air, but at the relatively large scale of most pulp mills, oxygen could probably be provided at acceptable cost. (Many pulp mills will have oxygen plants on-site for other reasons.)

steam. Dry sodium carbonate ($NaCO_3$) is discharged from the gasifier, diluted with water and used to scrub the product gas of contaminants, including hydrogen sulfide (H_2S). The green liquor discharged from the scrubber is returned to the process. The expected performance of the pilot-scale MTCI plant is shown in Table 2. Assuming all carbon is converted, the overall gasification efficiency would be 60% on a higher heating value basis. Firing gas turbines with the gas would give estimated black liquor-to-electricity conversion efficiencies of 21% for an LM5000 STIG and 25% for an LM8000 ISTIG.[10] At a kraft pulp mill producing 1000 tonnes of pulp per day (tpd), the available black liquor would be sufficient to support a 55-MW STIG or a 64-MW ISTIG.

A preliminary estimate of the installed cost of an MTCI gasification unit for a 1000 tpd pulp mill is $60-80 million [44], compared to an estimated $50 million for a new Tomlinson recovery boiler [36]. Charging the extra costs for the MTCI unit ($20 million) to the gasifier/gas-turbine system gives rise to total installed capital costs of $1360/kW for an MTCI-gasifier/STIG and $1270/kW for an MTCI-gasifier/ISTIG at a 1000 tpd mill.[11]

BIOMASS-GASIFIER/GAS-TURBINES APPLICATION AT KRAFT PULP MILLS

Southeastern US Pulp Mill Case Study

The application of gasifier/gas turbine systems in the pulp and paper industry is illustrated here with a case study of a specific mill in the Southeastern region of the US producing 1000 tpd of bleached sulphate pulp from loblolly pine.[12] The biomass residues available at the mill currently consist of hog fuel derived from logs brought into the mill (7.0 GJ per tonne of pulp produced), purchased bark (2.0 GJ/tp), and black liquor (25.3 GJ/tp). The mill's energy requirements (net of the cogeneration plant) amount to 16.3 GJ/tp of process steam and 656 kWh/tp of electricity [47]. In addition, the calciner, used to regenerate calcium oxide from calcium carbonate in the chemical recovery loop of the mill, requires 2 GJ/tp of fuel oil (or comparably clean fuel).

Like many pulp mills, this one was designed to be energy self-sufficient. Steam raised in the recovery and hog-fuel boilers utilizing all of the available biofuels drives a single-extraction/ back-pressure-exhaust steam turbine producing just enough steam and electricity to run the mill. If an additional design objective were to increase production of electricty for export, as is being considered here, then improving the end-use energy efficiency of the mill and adopting cogeneration technologies with higher electricity-to-heat ratios would be important.

An electricity audit at the mill indicated that 25% savings in electricity use would be cost-effective[13] (an estimate consistent with others that have been made [48]), which would reduce

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[10] In cogeneration operation, the fraction of input black liquor energy converted to steam and electricity, respectively, would be an estimated 18% and 18% with STIG and 13% and 22% with ISTIG.

[11] The $20 million cost for the gasification plant and associated gas cleanup and heat recovery steam generators corresponds to $367/kW and $297/kW unit cost components of complete MTCI-gasifier/STIG and MTCI-gasifier/ISTIG plants, respectively. Other cost components are assumed to be the same as for solid-biomass/gas turbines, and total plant costs are assumed to scale in the same fashion as solid-biomass/gas turbine plants (Fig. 7).

[12] The mill is owned by a major producer that does not wish to be identified. Data we present relating to the mill are based primarily on measured values corresponding to a typical efficient summer day of operation.

[13] This estimate is based on a 3-week on-site audit of the existing electrical system at the mill. The potential savings would come largely from trimming pump impellers to reduce inefficiencies due to oversizing and installation of variable speed drives on large pumps and fans.

demand to 492 kWh/tp. Also, reducing steam use by as much as a factor of two appears to be technically and economically feasible (Table 3).

With reduced on-site energy requirements, the need for purchased bark could be eliminated, and cogeneration technologies with higher electricity-to-heat ratios could be utilized. Using only currently available hog fuel and black liquor firing CEST, BIG/STIG, and BIG/ISTIG systems electricity production at the mill would be 535, 1703, and 2083 kWh/tp, respectively. The corresponding steam production for meeting on-site needs would be 13.8, 9.8, and 8.1 GJ/tp [47].

Forest Residue Resources

The exportable electricity production from the mill could be significantly increased if currently-unutilized forest residues, produced during commercial harvesting of forests, were used at the mill. Residues, as defined here, excludes roots, stumps, branches, needles and leaves. The volume of forest residues currently produced in the Southeastern US is about 1/3 the volume of harvested roundwood (Table 4). Some 0.42 tonnes of currently unutilized residues (equivalent to 8 GJ in energy terms) are associated with each tonne of kraft pulp produced [47]. Additional residues equivalent to 21 GJ per tonne of pulp are produced in forest-industry operations other than pulpwood production. Subsequent analysis here will consider only the 8 GJ of residues, since pulp producers could reasonably be expected to be able to acquire these residues, but not necessarily the others.

The total residue production (Table 4) appears somewhat less than the estimated maximum allowable amount of residue removal from Swedish forests to maintain long-term soil productivity there.[14] While this suggests that it may be feasible to remove all of the residues in the Southeastern US without damage to long-term soil productivity, local effects of residue removal must be as well understood in this and other regions of the world as they are in Sweden before beginning large-scale use of residues for power.

In the harvest of coniferous trees today, about 3/4 of the above-ground biomass is typically removed as merchantable wood, containing 40% to 50% of the tree's above-ground nitrogen, phosphorus, potassium, calcium, and magnesium [49]. Some additional nutrients would be removed with residue use, but may not necessarily result in excessive nutrient depletion [50] or degradation of soil organic matter status. Knowing the nutrient balance alone appears insufficient to predict the effects of residue removal on subsequent soil productivity, because of complex, site-specific climatalogic, geologic, hydrologic and biological considerations [50,51,52]. It is clear, however, that forest productivity overall can be raised substantially through improved forest management and advanced genetic manipulations [53,54,55,56]. The consideration of residue removal for power generation might be made an integral consideration of such developments. Modifications in forestry practices may raise unit costs of producing biomass, or resulting productivity gains could lower unit costs.

Assuming productivity issues relating to residue removal can be adequately addressed, utilizing the 8 GJ per tonne of pulp of forest residues for electricity production at a pulp mill would lead to total electricity production from CEST, BIG/STIG, and BIG/ISTIG systems as shown in Fig. 9. The most efficient system, BIG/ISTIG, would produce nearly five times the electricity currently generated at the case study mill.[15]

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[14] Some 1.9 GJ of total forest-residue removal is feasible on a sustainable basis in Sweden per GJ of produced black liquor (see Table 7 in [8], compared to an estimated 1.7 GJ/GJ in the US.

[15] If all of the forest residues shown in Table 4 (equivalent to 29 GJ per tonne of pulp) were to be available for power generation at the pulp mill, the power production with BIG/ISTIG would be over nine times current production.

Economics

The economics of producing excess electricity will depend largely on the cost of the feedstocks. The hog fuel and black liquor are considered available at no cost, since they are by-products of mill operation. Costs for forest residues will vary by location, but would probably be in the range of \$2-\$3 per GJ delivered to the mill at 50% moisture content (for example, see [57,58]). (This is roughly the cost for wood that might be grown on energy plantations [1,4,10], which might provide a competitive alternative source of fuel.) Some sizing (e.g. hogging or chipping) and drying would be required for the gas turbine systems, raising the cost of residues to \$3-\$4 per GJ.[16] The CEST systems would not require the extra fuel processing.

The estimated costs of producing excess electricity at an energy-efficient pulp mill using alternative cogeneration technologies are shown in Table 5 assuming utility ownership. Using currently-available hog fuel and black liquor, the busbar costs are 8.1 cents, 4.0 cents, and 3.2 cents per kWh for the CEST, BIG/STIG and BIG/ISTIG, respectively. Adding the forest residues, the estimated costs are 6.7-7.7 cents per kWh for the CEST, 4.3-4.7 cents per kWh for the BIG/STIG and 3.5-3.8 cents per kWh for the BIG/ISTIG.

With private ownership, before-tax internal rates of return would be less than 2.5% per year for CEST, 10-13% per year for BIG/STIG and 16-18% per year for BIG/ISTIG when excess electricity is sold for 5 cents per kWh (Table 5). The revenues from selling the excess electricity at 5 cents per kWh would be up to \$127 per tonne of pulp. For comparison, producing bleached kraft pulp at a modern mill costs of about \$400 per tonne.

Industry and Electric Utility Impacts

The results from the case study mill can be extrapolated to provide a rough estimate of the global potential for use of BIG/GTs in the kraft pulp industry. Assuming global regional chemical-pulp production grows to the year 2020 at the rates projected for the period 1980-2000 by the Food and Agriculture Organization [39], up to some 694 TWh of exportable electricity could be produced using black liquor, hog fuel and forest residues as fuel (Table 6) from some 105 GW of installed BIG/ISTIG generating capacity. The total biofuel use would be some 11 EJ, or equivalent to 20% of estimated current global bioenergy use. The electricity production is equivalent to 10% of the current global total from fossil fuels (14% of the total from coal). Carbon dioxide emissions would be some 180 million tonnes of carbon less than if the biomass-derived electricity had been generated from coal instead.

For the US, which has the world's largest kraft pulp industry, the 1988 level of chemical pulp production would allow production of up to 114 TWh per year of excess electricity, or about 9% of the utility electricity currently produced from coal in pulp-producing regions (7% of all US coal-electricity). The maximum associated export electricity production in 2020 would be 209 TWh per year from some 31 GW of installed capacity, which is equivalent to 17% of the current electricity generation from coal in pulp-producing regions (Table 7).[17] The corresponding biofuel consumption would be 3.3 EJ, or 7% of the potential US biomass resources noted earlier. If coal-fired electricity were displaced by the biomass-generated power, emissions of 55 million tonnes of carbon as CO_2 would be avoided (Table 7), corresponding to 12% of current utility carbon emissions.

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[16] Drying 150 MW of biofuel (roughly the fuel use for an LM5000 BIG/STIG) from 50% to 20% moisture content is estimated to cost about \$0.55/GJ [59], based on use of a commercial system using direct contact drying with superheated steam (at about 15 bar) and producing useable saturated process steam (at about 3 bar) together with the dry fuel. The capital, electricity, and drying steam costs come to \$0.80/GJ of fuel produced. A steam credit of \$0.25/GJ of fuel arises, assuming the low-pressure steam produced has a value of \$1/GJ.

[17] This assumes a 1.9% per year growth rate in pulp production to 2020 (see Table 7, note e).

To achieve such high levels of electricity production would require some energy efficiency improvements at pulp mills and the use of all of the forest residues associated with pulpwood production. Attractive rates of return may make large-scale biomass electricity production an interesting proposition for the pulp industry. The expertise in the industry with producing, harvesting and processing biomass fuels and the projected continuing market strength of the industry worldwide make it particularly well-positioned to undertake such an endeavor. Utilities might take an interest because the power generation would represent small increments of relatively low capital cost capacity that would be competitive at the busbar with many other new sources of utility electricity.

CONCLUSIONS

The biomass-gasifier/gas-turbine (BIG/GT) is a promising technology for biomass electricity generation because of expected high efficiencies and low unit capital costs at the modest scales appropriate for biomass applications and the good near-term propects for its commercialization. A project to commercially demonstrate BIG/GT technology using solid biomass for fuel is underway. BIG/GT systems that would use kraft black liquor for fuel in gasifiers similar to ones now undergoing commercial development for other applications show promise over a longer time frame.

Dedicated bioenergy plantations are likely to cost-effectively provide fuel for BIG/GT applications in the long term, but initial applications are likely to be fueled by residues generated as by-products of industrial processes. Large quantities of residues are currently available at reasonable cost. The kraft pulp industry is a major producer of residues (black liquor, hog fuel, and forest residues) today in industrialized countries and is increasing rapidly in importance in developing countries. BIG/GT systems using residues for fuel at kraft pulp mills could produce large quantities of electricity in excess of on-site needs at total levelized busbar costs of about 4 cents per kWh (assuming utility ownership) or internal rates of return up to 18% per year (assuming private ownership).

Large quantities of electricity exported from pulp mills could play a role in reducing fossil-fuel CO_2 emissions. At the projected global chemical pulp production level in 2020, excess electricity production using advanced BIG/GT systems would be equivalent to 10% of current utility electricity generation, which accounts for 1/4 of all fossil-fuel CO_2 emissions. The efficient conversion of bioenergy to electricity would avoid some 180 million tonnes of carbon emissions if the electricity would otherwise have been generated using coal.

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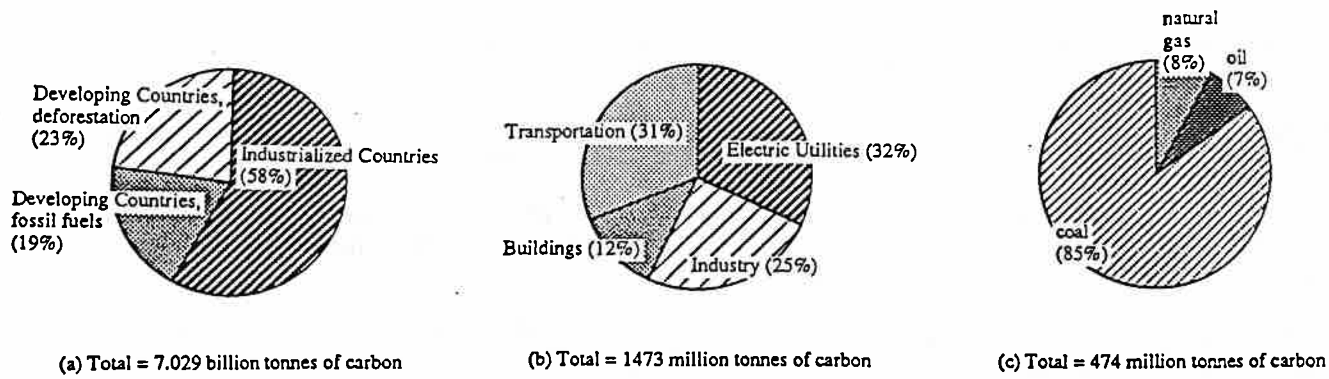


Figure 1. (a) Estimated global carbon dioxide emissions (in contained carbon) in 1987 [60]. Utility power generation accounted for about 1/4 of all fossil-fuel CO_2 emissions [61]; (b) Estimated US fossil-fuel CO_2 emissions in 1988, based on energy use data from [5] and assuming for coal 24 kg carbon/GJ, oil 20 kg/GJ, and natural gas 14 kg/GJ; and (c) Estimated US electric utility CO_2 emissions in 1988, based on [5].

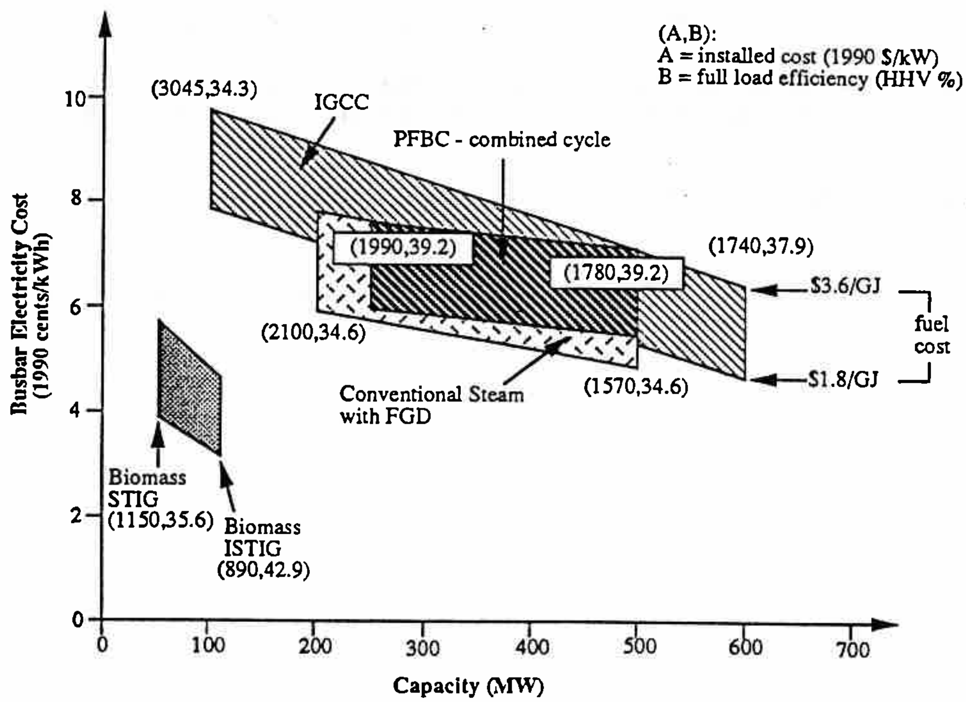
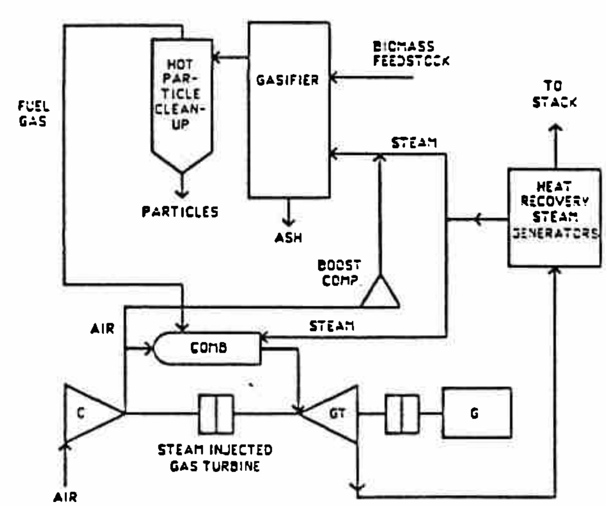


Figure 2. Estimated levelized busbar costs including capital, fuel, and O&M for electricity production with coal and biomass (in 1[st] quarter 1990 dollars), adapted from [8]. For each technology, high fuel cost ($3.6/GJ) and low fuel cost ($1.8/GJ) results are shown. A 6% discount rate, 30-year life, and 70% capacity factor are used in all cases, and taxes and insurance are not considered. Estimates for the coal-fired technologies are based on [62]. The biomass estimates are based on discussion in the text.

Figure 3. Biomass-gasifier/steam-injected gas turbine cycle.



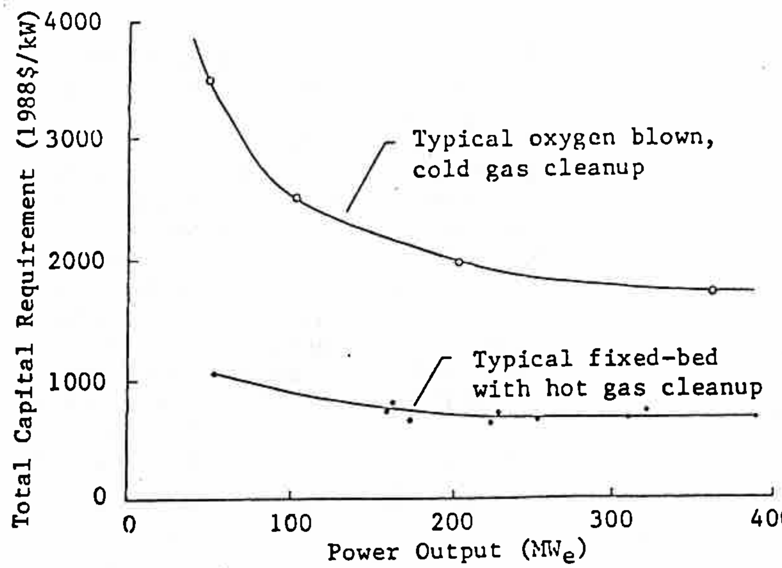


Figure 4. Cost comparison of coal-gasifier/gas-turbine power plants [63]. The upper curve represents technology like the Cool Water demonstration unit (see also [16]). The lower curve represents systems using air-blown fixed-bed gasification with hot gas clean up. The points on the lower curve are calculated costs for specific plants using integral numbers of gasifiers and commercial gas turbines.

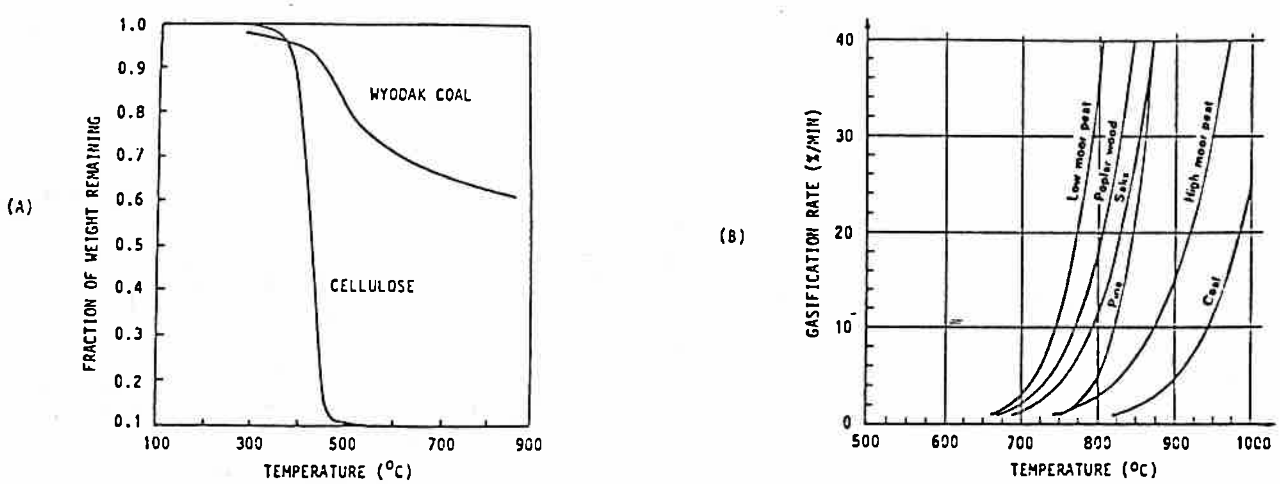
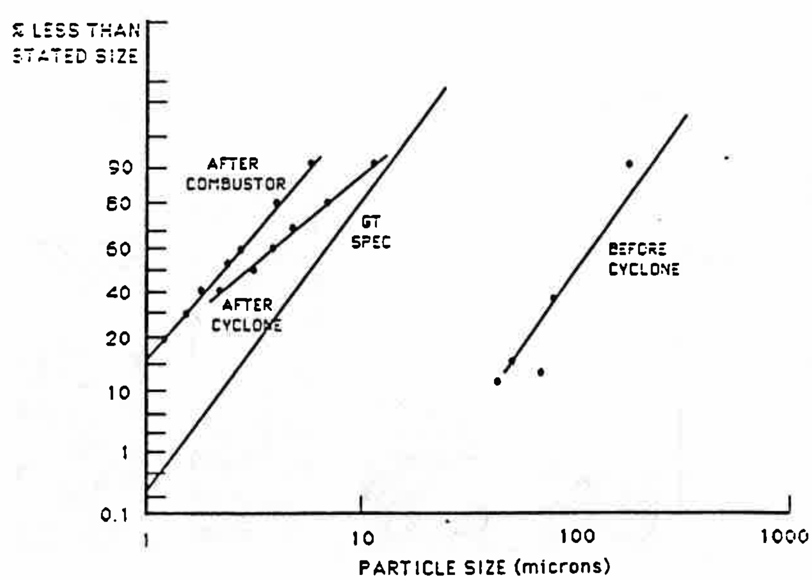


Figure 5. Comparison of the gasification characteristics of biomass relative to coal [8].

Figure 6. Test results showing the particulate size distribution in gas exiting a pilot-scale pressurized fixed-bed dry-ash coal gasifier, after hot-gas cleanup in cyclones, and after a simulated gas turbine combustor [64].



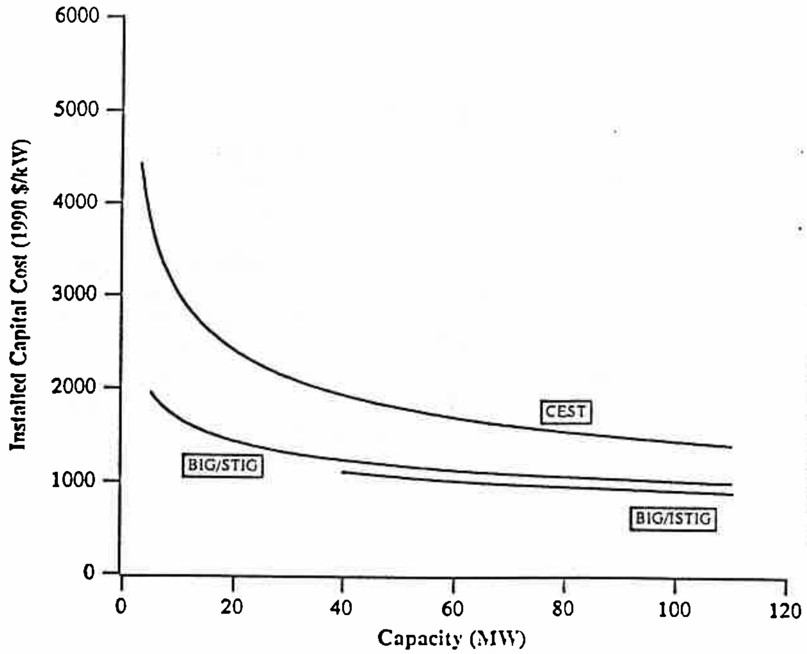


Figure 7. Installed capital cost estimates for alternative cogeneration technologies. The gas turbine costs are based on detailed cost estimates for coal-gasifier/gas turbine systems developed by General Electric [17], from which the costs for sulfur removal have been substracted [65,11]. Costs for the gas turbine systems are assumed to fall with plant size up to 110 MW, at which point scale economies are assumed to be exhausted. CEST costs are estimated to be \$2270/kW at 24 MW [62] and to scale with plant size as coal-fired steam plants do [62]. The equations describing the above curves are: $(\$/kW)_{ISTIG} = 2516(MW)^{-0.22}$, $(\$/kW)_{STIG} = 2746(MW)^{-0.22}$, and $(\$/kW)_{CEST} = 6279(MW)^{-0.32}$.

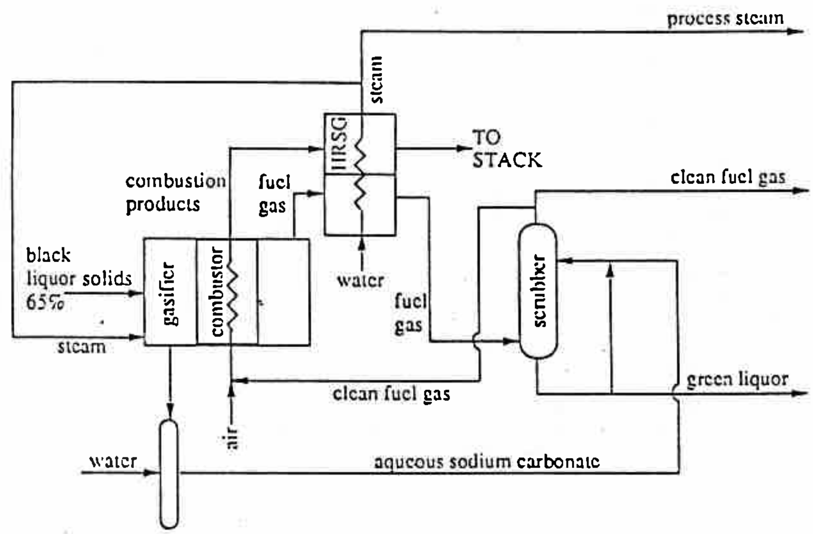


Figure 8. Schematic MTCI black liquor gasification system [66].

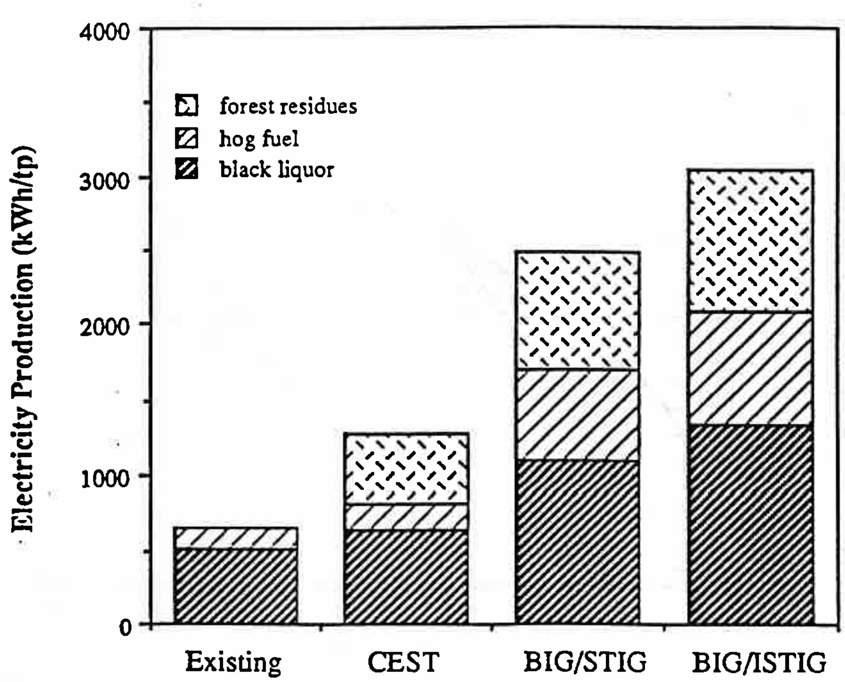


Figure 9. Electricity production at a 1000 tonne of pulp per day kraft pulp mill in the Southeastern US with alternative biomass cogeneration systems. The existing system produces 535 kWh/tp (not enough to meet on-site needs without purchasing supplementary biofuel). The production rates with CEST and BIG/STIG systems are based on the assumption that mill steam demand is 9.8 GJ/tp, while the mill demand with the BIG/ISTIG system is assumed to be 8.1 GJ/tp. (Calciner fuel demands are assumed to be met with purchased fuel at the mill with the CEST and with some of the residues at mills with the BIG/GTs.)

TABLE 1

PERFORMANCE AND CAPITAL COST ESTIMATES OF BIOMASS POWER GENERATING SYSTEMS

	PERFORMANCE: COGENERATION				PERFORMANCE: MAXIMUM ELECTRICITY PRODUCTION		INSTALLED CAPITAL COST[e]
	Electricity		*Maximum Process Steam*				
	MW	Effic. *(%HHV)*	*kg/hr*	Effic. *(%HHV)*	*MW*	Effic. *(%HHV)*	*1990 $/kW*
BIG/ISTIG[a,b]							
LM-8000	97	37.9	76,200	25.4	111.2	42.9	890
BIG/STIG[a,c]							
LM-5000	39	31.3	47,700	30.0	53	35.6	1150
LM-1600	15	29.8	21,800	33.8	20	33.0	1420
LM-38	4	29.1	5,700	32.4	5.4	33.1	1900
CEST[a,d]							
Double Extr.	37	10.0	319,000	52.1	77	20.9	1560

(a) For the BIG/STIG and BIG/ISTIG, the fuel is assumed to be 15% moisture content biomass. For the CEST it is 50% mc biomass. If 15% mc fuel were used in the CEST, efficiencies would increase about 25%.
(b) Preliminary performance estimate derived from performance with coal [11].
(c) Performance estimates adapted from [65], assuming here that the gasifier efficiency for biomass is the same as for coal.
(d) Boiler efficiency of 68%, feedwater temperature of 182°C, turbine inlet steam conditions of 6.2 MPa 400°C. Maximum process steam corresponds to operation with minimum flow to the condenser. Saturated process steam conditions are 12.9 bar (119 t/hr) and 4.4 bar (300 t/hr). Maximum electricity corresponds to minimum required extraction of 72 t/hr of saturated steam at 4.4 bar.
(e) See Fig. 7.

TABLE 2

HEAT BALANCE FOR THE MTCI PILOT PLANT BLACK LIQUOR GASIFIER WITH WET-SCRUBBER GAS CLEANUP.[a]

	Mass flow (kg/hr)	***Energy flow*** (GJ/hr)	***Energy per tonne of pulp*** Hardwood[b] (GJ/tp)	Softwood[b] (GJ/tp)
Black liquor dry solids input[c]	909	13.93	19.9	23.3
Outputs				
Fuel gas (10.6 MJ/Nm^3 HHV)	518.5	7.884	11.2	13.16
Export steam (42 bar, sat.)	950	2.557	3.65	4.27
Carbon recoverable	15	0.516	0.74	0.86
Losses				
Flue at stack	3171	1.586	2.27	2.65
Hot salts discharge	392	0.265	0.378	0.44
Process gas to scrubber	1222	0.925	1.32	1.54
Heat loss from gasifier	--	0.193	0.276	0.32

(a) From [66].
(b) Assuming 1.3 and 1.55 tonnes of dry black liquor are available per tonne of air-dry pulp produced from hardwood and softwood feedstock, respectively [36].
(c) The dry black liquor has a heating value of about 15 GJ/dry tonne [66]. The liquor is input to the gasifier as a 65% solids solution, the typical concentration of black liquor from evaporators at a kraft pulp mill.

TABLE 3

ENERGY USE (EXCLUDING POWERHOUSE USE) AT SWEDISH BLEACHED KRAFT PULP MILLS[a]

	1973	1980	1984	1990 *(projected)*
Steam (GJ/tp)	16.8	12.2	11.0	7.8
Electricity (kWh/tp)	790	740	740	590

(a) For 1973, the average Swedish mill [67]; for 1980, the most efficient Swedish mill [68]; for 1984, representing the most efficient Swedish mill [68], and; for 1990, the technically and economically feasible level of demand in a new Swedish mill [68].

TABLE 4

WOOD IN THE FORM OF ROUNDWOOD, LOGGING RESIDUES, AND OTHER REMOVALS IN THE SOUTHEASTERN REGION OF THE US IN 1986[a]

(Million cubic feet)	*Softwood*	*Hardwood*	*Total*
Growing Stock[b]			
Roundwood[c]	2,415	925	3,339
Logging residues[d]	192	193	385
Other residues[e]	229	214	443
Other Sources			
Roundwood[f]	111	276	387
Logging residues[g]	61	201	262
Other residues[h]	29	156	185
TOTAL			
a. Roundwood	2,526	1,200	3,727
b. Logging residues	253	394	648
c. Other residues	258	370	628
(b+c)/a	0.202	0.637	0.342

(a) From [69]. The Southeastern region of the US includes the states of Florida, Georgia, North and South Carolina, and Virginia.

(b) Growing stock is defined as the main stem (that can be used as sawtimber or poletimber) of live trees on timberland, between a 1-ft. stump and 4-inch diameter top (of central stem) excluding bark, or to the point where the central stem breaks into limbs.

(c) Logs, bolts, and other round timber generated from harvesting trees for industrial or consumer use.

(d) Downed and dead growing stock left on the ground--on timberland--after harvest.

(e) Other residues refers to unutilized wood from cut or otherwise killed growing stock on timberland during cultural operations (e.g. from precommercial thinning), or from timberland clearing.

(f) Roundwood "other sources" include salvable dead trees, rough and rotten cull trees, noncommercial tree species, trees less than 5-inches diameter at breast height, tops, and roundwood harvested from non-forest land (e.g. fence rows).

(g) Logging residue "other sources" include wood other than growing stock left on the ground after harvest that is sound enough to chip, including dead and downed cull trees and tops to a 4-inch diameter (measured without bark) and excluding stumps and limbs.

(h) Other residues from "other sources" include wood other than growing stock left on the ground after cultural operations (e.g. precommercial thinning), or timberland clearing that is sound enough to chip (including dead and downed cull trees and tops to a 4-inch diameter--excluding bark) and excluding stumps and limbs.

TABLE 5

ECONOMICS OF EXCESS ELECTRICITY PRODUCTION
AT A 1000 TPD KRAFT PULP MILL IN THE SOUTHEASTERN US

Fuels and Cogeneration Technologies[a]	Utility Ownership[b] (Busbar Cost, cents per kWh) Capital[d]	O&M[e]	Fuel[f]	TOTAL	Private Ownership[c] Internal Rate of Return	Electricity Sales (GWh/ year)	Electricity Revenues @ $0.05c/kWh ($/tp)
Black liquor							
+ hog fuel							
CEST	7.37	0.72	0.0	8.1	2.4	113	16
BIG/STIG	2.66	0.72	0.58	4.0	12.9	424	61
BIG/ISTIG	2.13	0.60	0.44	3.2	18.0	557	80
+ Forest residues							
(low-cost case)							
CEST	3.90	0.72	2.03	6.7	2.3	275	39
BIG/STIG	2.05	0.72	1.55	4.3	12.2	701	100
BIG/ISTIG	1.71	0.60	1.22	3.5	18.1	890	127
(high-cost case)							
CEST	3.90	0.72	3.05	7.7	neg.	275	39
BIG/STIG	2.05	0.72	1.95	4.7	10.0	701	100
BIG/ISTIG	1.71	0.60	1.53	3.8	16.1	890	127

(a) Steam demands met by the cogeneration systems are 9.8 GJ/tp for CEST and BIG/STIG and 8.1 GJ/tp for BIG/ISTIG. Electricity demand is 492 kWh/tp in all cases. Typical annual operating hours for a large pulping operation are assumed (8400 hours/yr).

(b) Assuming a 6.1% annual discount rate, an insurance charge equal to 0.5% of the initial capital cost per year and a 30-year life. With property and corporate taxes and existing tax preferences for renewable resource generating plants, the capital recovery factor (CRF) is 0.101 [62].

(c) Internal rate of return before taxes, assuming a 25-year life, an insurance charge equal to 0.5% of the initial capital cost per year, and electricity revenues of 5 cents per kWh.

(d) Separate gasifier/gas-turbine units are assumed for black liquor and solid feedstocks. Also, a capital cost credit (equivalent to the cost of a Tomlinson recovery boiler) is assumed since the gasification system would also be serving the mills chemical recovery requirements (see footnote 11). Use of a single steam turbine is assumed in estimating the CEST cost, and the cost of the Tomlinson recovery boiler is charged against pulp production, not power generation.

(e) The O&M costs for the BIG/ISTIG are based on [61]. BIG/STIG O&M costs are scaled from the ISTIG number by the ratio of STIG to ISTIG efficiency. The CEST O&M costs are assumed to be the same as for BIG/STIG.

(f) Fuel costs for CEST are assumed zero for hog fuel and black liquor. For BIG/STIG and BIG/ISTIG, $1/GJ is charged for hog fuel for drying and other pre-gasification handling. No charge for black liquor. The low and high forest-residue costs are assumed to be $3/GJ and $4/GJ charged to the gas turbine systems, respectively. CEST charges are $2/GJ and $3/GJ. The lower cost for CEST accounts for less required pre-processing (e.g. drying).

TABLE 6

GLOBAL ELECTRICITY PRODUCTION POTENTIAL OF THE KRAFT PULP INDUSTRY WITH BIG/ISTIG COGENERATION TECHNOLOGY

	1988			2020	
Region	Chemical pulp production[a] (10^6 tonnes)	Potential electricity from pulp[b] (TWh)	Utility fossil-fuel electricity generation[c] (TWh)	Projected pulp production[d] (10^6 tp)	Potential electricity from pulp[b] (TWh)
Industrialized	***95.8***	***244***	***5,231***	***204.6***	***520***
N. America	57.8	147	2,106	105.1	269
USSR	7.1	18	1,181	34.7	88
W. Europe	19.5	49	954	30.4	77
Japan	7.9	20	470	19.0	49
Oceania	0.93	3	116	11.2	28
E. Europe	2.7	7	404	3.7	9
Developing	***8.8***	***23***	***1,432***	***68.6***	***174***
Latin Am.	5.6	14	216	35.4	90
Asia	2.5	7	1,021	24.0	61
Africa	0.67	2	194	9.2	23
World	**104.7**	**267**	**6,662**	**273.1**	**694**

(a) From [35].
(b) Assuming 2,544 kWh/tp of electricity production in excess of process needs at efficient kraft pulp mills (characteristic of BIG/ISTIG technology).
(c) From [70].
(d) Assuming projected production growth rates, 1980-2000 [39] persist till 2020. The growth rates are 1.9%/yr, North America; 5.1%/yr, USSR; 1.4%/yr, Western Europe; 2.8%/yr, Japan; 8.1%/yr Oceania; 1%/yr, Eastern Europe; 5.9%/yr, Latin America; 7.3%/yr, Asia (excluding Japan); and 8.5%/yr, Africa.

TABLE 7

ELECTRICITY PRODUCTION POTENTIAL OF THE US KRAFT PULP INDUSTRY AND CO_2 EMISSIONS OFFSET WITH BIG/ISTIG COGENERATION TECHNOLOGY

	1988			2020		
Region[a]	Chemical pulp production[b] (10^6 tonnes)	Potential electricity from pulp[c] (TWh)	Utility coal electricity generation[d] (TWh)	Projected Pulp prod.[e] (10^6 tp)	Potential electricity from pulp[c] (TWh)	Coal CO_2 emissions offset (10^6t C/yr)
Northeast	4.03	10.3	139.4	7.4	18.7	4.9
North Central	4.02	10.2	449.9	7.3	18.7	4.9
Southeast	15.7	39.9	236.7	28.7	73.0	19.0
South Central	17.3	44.0	361.3	31.6	80.4	20.9
West	3.96	10.1	53.8	7.2	18.4	4.8
Total	**45.0**	**114.5**	**1,241.1**	**82.2**	**209.2**	**54.5**

(a) The regions consist of: NE: Maine, New Hampshire, New Jersey, New York, Pennsylvannia, Rhode Island, Vermont; NC: Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio, Wisconsin; SA: Maryland, Florida, Georgia, North and South Carolina, Virginia; SC: Alabama, Arkansas, Kentucky, Louisiana, Mississippi, Oklahoma, Tennessee, Texas; W: Alaska, Arizona, California, Idaho, Montana, Oregon, Washington.
(b) Total from [35], with regional distribution assumed to be the same as regional distribution of roundwood pulpwood production [37].
(c) Assuming 2,544 kWh/tp of electricity production in excess of process needs at efficient kraft pulp mills (characteristic of BIG/ISTIG technology).
(d) From [71]. Total 1988 US coal-electricity was 1,541 TWh, 57% of total utility generation.
(e) Assuming regional growth rates through 2020 equal to the growth rate projected by the Food and Agriculture Organization for North America (1.9%/yr) for 1980-2000 [39].