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COST VERSUS SCALE FOR ADVANCED PLANTATION-BASED BIOMASS ENERGY SYSTEMS IN THE U.S.A. AND BRAZIL

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Abstract

A unique feature of biomass energy systems is that the feedstock must be gathered from a wide area around the energy production facility. For a small-scale facility, transport costs will be relatively low, but capital cost per unit of output will be high. For a large-scale facility, transport costs will be high, but capital costs will be relatively low. At some intermediate scale, the total cost of energy should reach a minimum. This paper examines the effects of scale on the prospective costs of electricity and alcohol fuels from plantation-grown switchgrass in the North Central and Southeast regions of the USA and from eucalyptus in Bahia state, Brazil.

Biomass cost-supply curves for the year 2000 and 2020 are developed for the USA sites using estimates by the Oak Ridge National Laboratory for switchgrass yields and costs. A geographic information system (GIS) is used to analyze soil quality (and yield) distributions and road transport distances. A simplified approach is outlined for developing biomass supply curves to avoid data-intensive, time-consuming GIS analysis. The approach is applied for the analysis of data collected at the Brazil site.

Conversion technologies considered include one commercial electric generating technology--the steam rankine cycle--and one nearing commercial readiness--the gasifier/gas turbine combined cycle. Two alcohol fuels are considered: methanol via thermochemical gasification and ethanol via enzymatic hydrolysis. Both of these processes could be commercially ready early in the next century. Estimates of installed capital costs for all of these conversion systems are based on published sources.

In all cases, the minimum cost of electricity (COE_{min}) or alcohol (COA_{min}) is reached at relatively large plant capacity, because up to that point the rate of decrease in unit capital costs is more rapid than the rate of increase in biomass transportation costs. However, around the capacity corresponding to COE_{min} or COA_{min}, there is a wide range over which costs change very little. In general, higher biomass yields lead to larger capacities at COE_{min} or COA_{min}. Costs in the USA are higher in the NC than SE region, and (in both regions) costs are lower using year-2020 biomass costs compared to year-2000 costs. Energy costs at the Brazil site, which assume present biomass production costs, are lower than in the USA, except in the SE region in 2020.

Introduction

A unique feature of biomass energy systems that is the focus of this paper is that the feedstock must be gathered from a wide area around the energy production facility. For a small-scale facility, transport costs will be relatively low, but capital cost per unit of output will be high. For a large-scale facility, transport costs will be high, but capital costs will be relatively low. At some intermediate scale, the total cost of energy should reach a minimum. This paper examines the effects of scale on the prospective costs of producing electricity and alcohol fuels from plantation-grown switchgrass in the North Central and Southeast regions of the US and from eucalyptus in the state of Bahia, Brazil.

The basic components of the total cost of energy supply from biomass are *(1)* the cost to grow and deliver the biomass to the conversion facility and *(2)* the cost of the conversion. A number of studies have examined these two elements independently, but there does not appear to have been any previous effort to marry biomass supply with biomass conversion studies, as we do here, to examine the issue of energy cost versus scale.

Biomass Costs

North Central and Southeast United States

Development of energy crops in the US is focussed on short-rotation woody crops for some regions and on herbaceous crops for others [Hohenstein and Wright, 1994]. Switchgrass is a primary candidate energy crop for the North Central (NC) and Southeast (SE) regions that are considered in the analysis here. Expected switchgrass production costs span a significant range between these two regions: relatively high in the NC region and relatively low in the SE region. The starting point for the analysis was the selection of a specific site to provide a case-study variation in soil quality and transportation distances for a typical agricultural area. A four-county area in South Central Iowa (Appanoose, Lucas, Monroe, and Wayne counties) was chosen. The total area is approximately 5100 km², over 90% of which is used for growing crops today. Soil type [IGS, 1973] and road [USGS, 1986] maps of the region were digitized and loaded into a geographic information system (GIS). (See Marrison [1995] for details of the digitization process.)

The GIS system was used to calculate road transport distances from each acre in the region to a central processing facility that was assumed to be located near the center of the region. The cost of growing biomass on each acre (dependent primarily on soil type) was then calculated and added to the transport cost associated with the distance between the acre and the conversion facility. We took the characteristics of the Iowa site (relative soil quality and road layout) to represent a typical agricultural area in the North Central (NC) region (which includes Iowa), and in the Southeast (SE) region.

Production costs and transportation costs

Switchgrass yield and cost projections made by analysts at the Oak Ridge National Laboratory [Walsh and Graham, 1995] provide the basis for the biomass production costs we present here. Walsh and Graham estimate per-hectare yields and costs for four regions of the US (Northeast, North Central, Southeast, and South Central). They identify sub-regions by land capability class (LCC). Among the 8 LCC levels, LCC 1 has few restrictions on use for crops. LCC 5 to 8 are generally unsuited for crop production. Within each LCC, soils are sub-defined by the primary reason for restrictions on their use as cropland. For each sub-class of each LCC, Walsh and Graham estimate the area, projected switchgrass yield, projected first-year establishment costs, projected annual plantation maintenance costs (incurred in ensuing nine years, after which it is assumed that replanting is required), and estimated annual land rents.

For the selected site, the available soil map included three grades of soil: loess, which is generally very good agricultural land; complex alluvial deposits, which are of intermediate quality for agriculture; and till-and-outcropping paleosols, which are the least desirable of the three for farming. The yields and costs of switchgrass from these three soil types were assumed to be the area-weighted averages of Walsh and Graham's estimates for sub-LCC2, sub-LCC3, and sub-LCC4, respectively (Table 1).

Table 1 provides the inputs for calculating levelized switchgrass production costs. The calculation accounts for an assumed zero yield in the establishment year, two-thirds of the steady-state (Table 1) yield in the next year, followed by eight years at the steady-state yield. Post-harvest losses of 10% are also included [UMinn, 1994] post-harvest losses. A 6.5% discount rate is assumed, as suggested by Walsh and Graham [1995].

The standard form for biomass transport costs is: Cost (in $/tonne) = A + (TC·TD), where A is the fixed cost (e.g. truck loading and unloading), TC is the variable transport cost ($/tonne-km), and TD is the one-way transport distance in km. After reviewing several transport cost studies (see Marrison and Larson [1995]), baseline values for transport of switchgrass bales were selected: A = $3/dry tonne and TC = $0.18/dt-km.[1]

Total costs of biomass delivered to a conversion facility

Production and transportation costs associated with each acre of land were summed to derive the total cost of biomass delivered to the conversion facility from each acre of land. Fig. 1a shows qualitatively the cost distribution. Fig. 1b shows the production costs against the total tonnage of biomass available at that cost or less within the four-county area studied (assuming 94% of the area is used for switchgrass production, which excludes, primarily, towns and lakes).

For the NC region in 2000, biomass costs start at $71/dry tonne, or $3.9/GJ.[2] The maximum production within a radius of about 32 km (the limit of the four-county area examined[3]) is 1.7 million dry tonnes/year, with a marginal cost of $79/tonne ($4.3/GJ) and average cost of $77/tonne ($4.2/GJ). Using projections for 2020, biomass costs start at $55/dry tonne ($3.0/GJ), and the maximum production is 2.4 million dry tonnes/year [marginal and average costs of $63/tonne ($3.4/GJ) and $61/tonne ($3.3/GJ)]. Biomass costs are considerably lower in the SE region. For example, using 2020 projections biomass costs start at $32/dry tonne ($1.7/GJ) and rise to an average cost of $39/dry tonne ($2.1/GJ).

[1] The actual transport cost we assume per tonne of useable biomass at the conversion facility is [3 + 0.18*TD]/0.9, which assumes 10% storage losses at the facility.

[2] All fuel energy contents in this paper are given on a higher heating value basis. The higher heating value for switchgrass is assumed to be 18.44 GJ per dry tonne.

[3] The area analyzed is not circular (see Fig. 1a), but the greatest transport distance was limited in the analysis to the minimum distance between the conversion facility (near the center of the four county area) and the outer border of the area. This defined a circle with a radius of about 32 km.

Table 1. Average Projected Yields and Costs (in 1994$)[a] for North Central and Southeast USA.[b]

Land Class	Year 2000 Yield (dry t/ha/yr)[c]	Year 2000 Year-1 cost ($/ha)	Year 2000 Year 2-10 ($/ha/yr)	Year 2020 Yield (dry t/ha/yr)[c]	Year 2020 Year-1 cost ($/ha)	Year 2020 Year 2-10 ($/ha/yr)
	NORTH CENTRAL REGION					
LCC2	10.4	539.11	504.71	14.8	549.02	554.87
LCC3	10.0	537.68	502.80	14.2	547.57	552.58
LCC4	9.2	519.46	478.44	13.1	528.92	523.18
	SOUTHEAST REGION					
LCC2	15.2	486.99	356.42	21.7	501.04	448.50
LCC3	14.2	486.99	356.42	20.3	501.04	448.50
LCC4	13.6	486.99	356.42	19.4	501.04	448.50

(a) Costs are expressed in 1994$ using US GDP deflators [Council of Economic Advisors, 1995].

(b) See Marrison and Larson [1995] for details of the calculation of area-weighted average yields and costs. All costs shown in this table include land rent (assumed to be the same in 2000 and in 2020) as follows in 1994$/ha/yr: For the NC region land rent in LCC2 = $212; LCC3 = $209; and LCC4 = $191. For all LCCs in the SE region, land rent = $71/ha/yr.

(c) Dry metric tonnes per hectare per year, before losses.

Southern Bahia state, Brazil

For comparison with the above USA-based analysis, a similar, but simplified analysis is carried out for a site in southern Bahia state, Brazil. A simplified approach is used because the GIS-based method used above is cumbersome and time-consuming. Here, the simpler approach is derived, tested against GIS-derived results, and applied to the Brazil site. (See Marrison [1995] for details of this approach.)

Simplified approach to calculations

In the above analysis, the GIS was used to determine production and transportation costs for each map-unit as a function of the soil quality and road layout. A first assumption simplifies the production cost calculation: all land in a given area is assumed to have a yield (Y) and production costs that are area-weighted averages for the region.

A second assumption simplifies the transport cost calculation. For purposes of the analysis, we assume that biomass is grown in concentric rings at a distance, r, from the conversion facility, with one segment of the ring removed to account for "no-grow" areas--towns, roads, lakes, etc. The total biomass supply from an area of radius, R, around a conversion facility can then be calculated by integrating the production over each ring: total biomass production = $Y\rho\pi R^2$, where ρ is plantation density: ρ = 1 - ("no grow" area/total area).

For each ring, the transport distance to the conversion facility is $F \cdot r$, where F is a constant that accounts for the layout of the road system. For roads spreading radially from the conversion facility, F = 1.0. For the road system at the Iowa site, which is typical for agricultural regions in the US, F = 1.4, as derived from the GIS data [Marrison, 1995]. For a square grid road system, F = 1.25 [Marrison, 1995]. From a circular area of radius R, the average transport distance, which is used to calculate transport costs, is $F \cdot (2/3) \cdot R$.

The average levelized cost of delivered biomass is then the sum of the production cost per tonne (including the fixed portion of transportation costs) and the variable transportation cost per tonne (= \$/tonne-km x average transport distance). Figure 2a compares results from the full-GIS analysis (also shown in Fig. 1b) against results obtained for the same region using the simplified approach. The two agree well, especially for larger supply tonnages. The larger difference between the full-GIS and simplified curves at the lower tonnages is due primarily to the fact that the full-GIS analysis takes account of asymmetry introduced by the large lake in the center of the region (Fig. 1a).

Delivered biomass costs at the Bahia site

The simplified approach to determining the biomass cost-supply curve is applied to the Brazil site. For inputs, presently achieved average yield and cost data for an operating industrial eucalyptus plantation in southern Bahia state were obtained from a site visit (see Marrison [1995]). This plantation was established well over a decade ago by Shell Brasil. At the site, eucalyptus is harvested on a six-year rotation, with total production of 60 dry tonnes expected from the year-6 harvest, 53 dry tonnes in year-12, and 43 dry tonnes in year 18. The maximum planting density is 0.8 (ρ = 0.8), because Brazilian law requires at least 20% of the area of a plantation to be left in natural vegetation. The road system is a square grid (F = 1.25). The year-zero establishment cost is \$471/ha.[4] Annual maintenance costs (including \$44/ha in fertilizer and \$24/ha in land rent) for years 1,7, and 13 is \$136/ha/yr; for years 2, 8, and 14 is \$99/ha/yr; and for other years is \$74/ha/yr. Assuming a 10% discount rate, the levelized cost of production is \$30.1/dry tonne (\$1.6/GJ). Harvesting plus fixed transport costs are \$4.4/dry tonne, chipping costs (from Perlack and Wright [1995]) are \$5.5/dry tonne, and the variable transport cost is \$0.20/dry tonne-km.[5] Fig. 2b shows the resulting cost-supply curve.

[4] Costs in 1992\$ have been converted to 1994\$ using the US GDP deflator. The establishment cost per hectare includes: \$57 for ground clearing, \$10 to mark and survey the site, \$93 for establishment of roads, \$51 for first plowing, \$10 for second plowing, \$38 for ant killing, \$70 for seedling production, \$10 for planting of seedlings, \$6 for replanting where originals died, \$44 for fertilizer, and \$82 for administration. A land rent of \$24/ha is included, based on estimated land values (\$120-364/ha) at several industrial plantations in the general vicinity of southern Bahia [Carpentieri et al., 1993].

[5] In Brazil, transport costs have been estimated as follows by Professor Carlos C. Machado (Dept. of Forestry, Univ. of Vicosa, Minas Gerais, personal communication, Sept. 4, 1992). For good forest roads, \$/dry tonne = $1.04 + 0.118 \cdot TD$, where TD is in km. For fair forest roads, \$/dt = $1.05 + 0.167 \cdot TD$. For poor forest roads, \$/dt = $1.05 + 0.23 \cdot TD$. These costs must be multiplied by 1.2 to account for administrative costs (J. Rivelli [formerly head forester at the Shell Brasil plantation], personal communication, Sept. 1992]). The estimate for fair forest roads is used here.

Energy Conversion Technology Costs

Several technologies are commercially available or under development for converting biomass into electricity or transportation fuels [Larson, 1993]. Several systems suited to the use of plantation-grown biomass are considered here. For electricity production, commercial steam-rankine cycle systems are considered (see EPRI [1992]), together with two varieties of gasifier/gas turbine combined cycles (BIG/GTCC)--one using low-pressure gasification and one using pressurized gasification [Consonni and Larson, 1994]. BIG/GTCC systems are not commercially established at present, but are likely to be commercially ready by the turn of the century. The pressurized BIG/GTCC is more efficient than the low-pressure version, but is expected to be more costly below a certain capacity range. Two alcohol production systems are considered: methanol via thermochemical gasification [Williams et al., 1995] and ethanol via enzymatic hydrolysis [Wyman et al., 1993]. For methanol production, only the initial gasification step is not commercial, but biomass gasifiers are under active commercial development worldwide. Advanced designs of enzymatic hydrolysis ethanol production are undergoing pilot-scale testing and development at the unit level in the USA [Wyman et al., 1993].

The analysis here requires only overall cost and performance characteristics, so details of the technologies are not discussed. The overall performance and cost characteristics assumed here are probably achievable within about the next decade with continued commercialization efforts. Still further advances in the technologies have been identified and are likely to improve performance and/or lower costs compared to those assumed here. Uncertainties in the cost estimates among the different technologies considered here are due largely to differences in the extent of commercial development and scaleup. Cost estimates for electricity technologies (especially the steam cycle) are more certain than those for the alcohol production systems.

Capital costs

The total installed capital cost per unit of output capacity for each technology is assumed to vary with capacity as follows:

$$UnitCost = C + D \cdot (Capacity)^E \qquad (1)$$

where C, D, and E are constants for a given technology, values for which can be determined from available cost projections. For electricity generation, *UnitCost* is given in \$/kW$_e$. For methanol and ethanol production, *UnitCost* is in \$/(MJ/hr)$_{output}$. For all technologies considered, E is a negative number (unit cost falls with increasing capacity), and thus C corresponds to the unit cost for a very large facility. If the costs for two facilities with different capacities are available, values for two of the three coefficients in Eqn. 1 can be determined, once a value for the third coefficient is established.[6]

[6] For example, if a value for C is established, then $D = (UnitCost_1 - C)/Capacity_1^E$, where $E = \{\log([UnitCost_1 - C]/[UnitCost_2 - C])\}/\{\log(Capacity_1/Capacity_2)\}$.

Table 2 summarizes all of the capital cost information used to establish the parameter values for Eqn. 1. Figure 3 shows the resulting capital cost versus capacity relationships. These relationships are most accurate in the capacity range shown in Table 2 (e.g. between 10 and 50 MW_e for the steam-rankine power plant technology).

To convert capital costs to annualized costs, we assume capital charge rates (CCRs) of 0.101 for electricity and 0.151 for alcohol production plants. The electricity CCR assumes utility financing.[7] For alcohol production, the CCR is based on average financial parameters for major US corporations between 1984 and 1988.[8]

Feedstock costs and operating and maintenance costs

Fuel/feedstock costs are determined by the efficiencies of the conversion systems. For simplicity, efficiencies are considered to be fixed with capacity for all except one technology (Table 2). Because the steam-rankine technology is commercial today, its efficiency at different capacities is well established, and an equation having the same form as Eqn. 1 has been fit to available performance estimates for use here.[9] For simplicity, operating and maintenance (O&M) costs per unit of output are also assumed fixed regardless of scale for each technology (Table 2).

Total Cost of Electricity and Alcohol Fuels Versus Plant Capacity

For a specific conversion plant capacity, the total levelized cost per unit of output can now be calculated by combining the cost of the feedstock with the capital charge and O&M charges. The levelized cost of electricity (COE) in \$/kWh is:

$$COE = (C_b \cdot 3.6)/(HHV \cdot \eta_e \cdot 1000) + UnitCost \cdot CCR/(8766 \cdot CF) + OM \qquad (2)$$

where C_b is the average delivered cost of biomass in \$/dry tonne (e.g. from Fig. 1b), HHV is the higher heating value of the biomass (18.44 GJ/dry tonne for switchgrass, 19.34 GJ/dry tonne for eucalyptus), η_e is the electricity generating efficiency (Table 2 for BIG/GT systems and footnote 9 for steam-rankine systems), *UnitCost* is the installed capital cost in \$/kW (from Fig. 3), CCR is the capital charge rate (0.101 for power generation), CF is the capacity factor (assumed to be 0.75), and OM is the O&M cost (from Table 2). The levelized cost of alcohol (COA) in \$/GJ is:

$$COA = (C_b/HHV)/(\eta_a) + UnitCost \cdot CCR \cdot 1000/(8766 \cdot CF) + OM \qquad (3)$$

where elements on the righthand side are defined as for Eqn. 2, except that η_a is the efficiency of alcohol production (Table 2), *UnitCost* is the installed capital cost in \$/MJ/hr (Fig. 3), CCR is assumed to be 0.151, and CF is assumed to be 0.9.

[7] For the USA, the CCR is for utility-financed renewable energy power plants, based on a 30-year life, 6.2% real pre-tax discount rate, and 38% income tax [EPRI, 1993]. For Brazil, the CCR corresponds to an assumed 9.5% discount rate and 30-year plant life.

[8] Average financial parameters for major US corporations during 1984-1988 were 9.91% real return on equity, 6.2% real return on debt, 30% debt fraction, and 44% corporate income tax. The CCR also assumes a 25-year plant life and property tax plus insurance of 1.5% per year of the initial capital cost.

[9] For the steam-rankine cycle, η_e (%) = $100 \cdot [0.27 - 0.25 \cdot (MW_e)^{-0.56}]$. See Marrison and Larson [1995].

Table 2. Estimated Unit Installed Capital Costs (1994\$), Conversion Efficiencies, and Operating and Maintenance Costs (1994\$) for Biomass Energy Conversion Systems at Various Capacities.[a]

Electricity production systems	Capacity[b] (MW_e)	Generating efficiency (%)[c]	Capital cost (\$/kW_e)	O&M[d] (\$/kWh)
Steam rankine cycle	10	20	3510	0.0125
	50	n.r.[e]	1647	0.0125
	large	27	1200	0.0125
Biomass-gasifier/gas turbine (BIG/GT) combined cycle using near-atmospheric pressure gasifier and wet scrubbing cleanup	10	37	2577	0.008
	60	37	1288	0.008
	large	37	1200	0.008
Biomass gasifier/gas turbine combined cycle (BIG/GT) using pressurized gasifier and ceramic filter hot gas cleanup	30	40	1800	0.008
	60	40	1425	0.008
	large	40	1100	0.008
Alcohol fuel production systems[f]	**Capacity (GJ/hour)[g]**	**Production efficiency (%)**	**Capital cost (\$/MJ/hr)**	**O&M (\$/GJ)**
Methanol via indirectly-heated gasifier	811	60	317	2.61
Methanol via indirectly-heated gasifier, earlier design estimates	1049	n.r.	162	n.r.
	5245	n.r.	112	n.r.
Ethanol via enzymatic hydrolysis	1355	50	151	2.18
Ethanol via enzymatic hydrolysis, earlier (circa-1990) process design	590	n.r.	341	2.46
	2956	n.r.	230	2.46

(a) See Marrison and Larson [1995] for sources and other details.

(b) "Large" refers to the capacity at which it is assumed that the minimum unit installed capital cost is reached.

(c) 100 times the electricity or fuel production divided by the higher heating value of the input biomass.

(d) Assumed constant for all capacities.

(e) Not required for the analysis in this paper.

(f) Best estimates for methanol and ethanol system capital costs were available only for a single capacity. For these systems, the scaling exponent, E, in Eqn. 1 was assumed to be -0.3, a typical value for scaling total plant costs for many chemical processes. Coefficients C and D in Eqn. 1 were scaled from those determined using the "earlier design" estimates shown here. See Marrison and Larson [1995] for details.

(g) To convert GJ/hr to liters/hr, divide by the appropriate higher heating value: 0.0181 GJ/lit for methanol and 0.0228 GJ/lit for hydrous ethanol (95% ethanol, 5% water).

Baseline results are presented here. Marrison and Larson [1995] examine the impact of changing (for the USA sites) the variable transport costs ($0.18/dry tonne-km, baseline), planting density (0.94 baseline), switchgrass yields, and land rents.

Electricity production costs

Fig. 4a and 4b show the calculated results for the COE versus scale for the USA, and Fig. 5a shows results for the Brazil site. For small capacities, falling unit capital costs with scale for the conversion systems more than offset increasing biomass costs that arise from increased transportation costs. The total COE reaches a minimum (COE_{min}) at the capacity at which the rate of decrease in unit capital cost equals the rate of increase in the transport costs. At capacities larger than this, there is a very gradual rise in the COE as the transport costs become increasingly more important.

For a given technology, the considerably lower biomass costs projected for 2020 compared to 2000 or in the SE compared to the NC regions (Fig. 1b), lead to considerably lower COE_{min} in 2020 compared to 2000 and in the SE compared to the NC regions, and higher installed capacities at which these minima are reached (Table 3). At the Brazilian site, biomass costs, and correspondingly the values of COE_{min}, are somewhat higher than those for 2020 in the SE USA. However, for a given technology, the capacity at which the COE_{min} is reached is smaller at the Brazilian site than in either of the US regions. This is due in large part to the lower assumed planting density, ρ, (0.8 for Brazil vs. 0.94 for USA), which leads to a greater weighting of transport costs in Brazil.[10] If lower planting densities are assumed in the USA, the capacity at which COE_{min} is reached falls [Marrison and Larson, 1995].

In all cases, the capacity at which the COE_{min} is achieved is relatively large (e.g. up to 500 MW_e for the steam rankine cycle). However, because of the flatness of the COE curves around their minima, the COE_{min} is actually approached at much smaller capacities: the capacity at which the COE is within 1% (5%) of COE_{min} is about half (one-quarter) of the capacity at COE_{min} (Table 3).

For the steam-rankine cycle, the capacities for being within 5% of the minimum COE (85-111 MW_e for the lowest-cost cases in Brazil and the USA) are larger than existing biomass-fired steam-rankine power plants. Most such plants rely on low-cost biomass (e.g. byproducts of industrial processing), and their scales are set by the availability of feedstock, rather than by economies of scale.

The COE_{min} with BIG/GTCC cycles are approached at much smaller capacities than with the steam-rankine cycles (COEs within 5% of COE_{min} at 27-91 MW_e--Table 3), because most of the scale economy gains in capital cost occur at smaller capacities (Fig. 3).

At any scale, the higher efficiency (and lower capital costs) of the BIG/GT systems make them a significantly less costly source of electricity than steam-rankine cycles. With the

[10] Marrison [1995] shows analytically using the simplified approach to estimating delivered biomass costs, that the capacity at COE_{min} is determined not only by ρ, but by the interaction between ρ, E and D (coefficients in Eqn. 1), Y (yield), TC (variable transport cost), and F (road layout factor).

Table 3. Minimum Cost of Electricity (COE_{min}) as a Function of Installed Capacity for North Central and Southeast USA and for Southern Bahia, Brazil and Related Installed Capacities.

Electricity technology	Year	Minimum COE (1994$/kWh)	Installed Capacity (MW_e) For COE = minimum	For COE within 1% of minimum	For COE within 5% of minimum
NORTH CENTRAL USA					
Steam-rankine cycle	2000	0.090	366	212	86
	2020	0.077	470	227	101
Low-pressure BIG/GTCC	2000	0.066	114	60	27
	2020	0.057	127	61	30
Pressurized BIG/GTCC	2000	0.062	269	123	65
	2020	0.054	290	137	72
SOUTHEAST USA					
Steam-rankine cycle	2000	0.065	424	214	99
	2020	0.060	519	244	111
Low-pressure BIG/GTCC	2000	0.049	130	61	37
	2020	0.046	142	64	37
Pressurized BIG/GTCC	2000	0.046	285	140	85
	2020	0.043	319	154	91
SOUTHERN BAHIA STATE, BRAZIL					
Steam cycle	1995	0.065	280	155	85
Low-Pr. BIG/GT	1995	0.048	110	60	35
Press. BIG/GTCC	1995	0.046	230	135	80

costs in Table 3, BIG/GTs would be competitive with power from new coal-fired plants in the USA: coal-based electricity in 2000 and in 2020 is projected to cost $0.049/kWh and $0.052/kWh, respectively, in the NC region and $0.047/kWh and $0.049/kWh, respectively, in the SE region.[11] BIG/GTCC systems might become competitive in the

[11] These electricity costs are based on capital and operating costs and performance estimates of the Electric Power Research Institute for 300 MW_e pulverized coal subcritical-steam plants with flue gas desulfurization in the East-West Central and Southeast regions [EPRI, 1993] (corresponding to the NC and SE regions in the analysis in this paper) and on electric utility steam-coal prices projected by the US Department of Energy for the West-North Central and South Atlantic regions [EIA, 1995]. For the NC region (in 1994$), the capital cost for the coal facility is $1662/$kW_e$, with fixed and variable O&M costs of $48.8/kW-yr and $0.0021/kWh, and a heat rate of 10.719 MJ/kWh. For the SE region, the corresponding figures are

NC region only when year-2020 targets are achieved with the system using pressurized gasification. In the SE region, BIG/GTCC systems would compete in year 2000 as well as 2020. In Brazil, the low COEs (assuming present biomass production technology) are likely to be able to compete with a variety of other new power sources in the future, including new hydroelectric facilities (see Carpentieri, et al. [1993]).

Alcohol fuel production costs

Fig. 4c and 4d show calculated results for the COA versus scale for the US sites and Fig. 5b shows results for the Brazil site. Similar patterns are observed as with the electricity costs, with one major difference for the US sites: the capital costs of the fuel production facilities dominate the total costs for capacities up to those that can be supported by biomass supplied from the entire site used for our analysis (circular area of about 32 km radius). (No constraints were placed on the physical extent of the Brazilian site.) For the US sites, even at capacities requiring transport of biomass from the 32-km limit, capital costs are still falling at a faster rate than biomass transport costs are rising. No absolute minimum is reached within the limits of the capacity scale shown in Fig. 4c and 4d.

Table 4 gives values of the lowest COA's reached (subject to the biomass availability constraint) and related installed capacities. In general, when biomass costs are relatively lower, plant capacities that give minimum COAs are larger.

Methanol production costs reach 5% of the minimum COA at capacities of 1322 GJ/hr (169 million gal/yr) and 2018 GJ/hr (258 million gal/yr) for the NC and SE USA in 2000, respectively, and 1849 GJ/hr (236 million gal/yr) and 2786 GJ/hr (357 million gal/yr) in 2020. These capacities are comparable to those of the largest existing industrial biomass processing facilities or methanol-from-natural gas plants.[12]

Ethanol production costs approach a minimum at smaller plant capacities than for methanol due to the lower assumed capital intensity (Fig. 3) of ethanol plants. Capacities for a COA within 5% of the minimum range from 650-1470 GJ/hr (66-149 million gal/yr) among all of the cases considered (Table 4).

For the USA sites, the COA_{min} for methanol in 2020 ranges from $10.1-12.4/GJ ($0.70-0.85/gallon), with the lower cost in the SE region (Table 4). The corresponding range for ethanol is $8.6-11.2/GJ ($0.75-0.97/gallon). For comparison, the average wholesale price of gasoline in 1993 in the US was about $4.5/GJ ($0.6/gallon), and is projected to rise

$1359/kW$_e$, $42.0/kW-yr, $0.0015/kWh, and 10.371 MJ/kWh. The DOE projects coal prices in 2000 and 2010. Assuming a continuation of the projected growth rate between 2000 and 2010 to estimate year 2020 prices, coal prices in the NC region in 2000, 2010, and 2020 would be $1.14/GJ, $1.27/GJ, and $1.40/GJ, respectively. For the SE region, the corresponding prices would be $1.56/GJ, $1.66/GJ, and $1.77/GJ.

[12] The Puenta Arenas facility in Southern Chile is among the largest methanol producing facilities operating today using natural gas as the feedstock. Its capacity is about 300 million gal/yr. The capacities of the largest facilities in the US producing ethanol from corn today are of this order, and the largest ethanol-from-sugarcane factories in Brazil are about half this capacity. The biomass input capacity of a typical modern large integrated pulp and paper mill today is equivalent to that of a methanol-from-biomass facility that would have a capacity of about 200 million gal/yr.

Table 4. Minimum Cost of Alcohol (COA) as a Function of Installed Capacity for North Central and Southeast USA and Southern Bahia, Brazil and Related Installed Capacities.

Alcohol Type	Year	Minimum COA (1994$/GJ)	Installed Capacity (GJ per hour): For COA = minimum[a]	For COA within 1% of minimum	For COA within 5% of minimum
NORTH CENTRAL USA					
Methanol	2000	14.2	> 2700	2373	1322
	2020	12.4	> 3800	3235	1849
Ethanol	2000	13.1	> 2200	1532	652
	2020	11.2	> 3200	2267	952
SOUTHEAST USA					
Methanol	2000	10.9	> 3800	3451	2018
	2020	10.1	> 5400	4930	2786
Ethanol	2000	9.4	> 3200	2435	1070
	2020	8.6	> 4500	3199	1471
SOUTHERN BAHIA STATE, BRAZIL					
Methanol	1995	10.9	10789	6178	2553
Ethanol	1995	9.7	3783	1898	795

(a) For all USA cases, the biomass available at the site was exhausted before an absolute minimum COA was reached. The COA_{min} indicated for these cases is the lowest COA achieved up to this limit in biomass supply.

to about $6.8/GJ in 2010 ($0.9/gal).[13] With these costs for gasoline, neither ethanol nor methanol are competitive on a per-unit of energy basis. However, ethanol and, especially, methanol will be suitable fuels for fuel cell vehicles (FCVs) that are under intensive development for commercial application early in the next century [Williams, 1994]. With gasoline-equivalent fuel economies[14] of methanol-FCVs expected to be some 2.4 times those for comparable gasoline internal combustion engine vehicles [Ogden et al., 1994], methanol would be able to compete on a cost-per-vehicle-km basis with gasoline with methanol prices (in $/GJ) up to 2.4 times those for gasoline.

[13] The 1993 gasoline cost is the 1993 average retail price of $8.64/GJ ($1.14/gal) (across all fuel grades of motor gasoline and including state and federal taxes) [EIA, 1995] minus $0.31/gal in state and federal taxes and $0.23/gal in distribution and filling station costs [Ogden, et al., 1994]. The US DOE projects an average retail gasoline price (including taxes) of $10.85/GJ ($1.43/gal) in 2010.

[14] For methanol, the gasoline-equivalent fuel economy (km/liter of gasoline equivalent) is the distance traveled per unit of methanol (in km/GJ) times 0.0349 GJ/liter, the higher heating value of gasoline.

Conclusions

This paper examined the impact of scale on prospective costs of electricity and alcohol fuels from plantation-grown biomass at sites in the USA and Brazil. All results are based on assumed biomass production and conversion technology costs, most of which have not yet been commercially demonstrated. A simplified approach was developed to estimate biomass supply costs for the Brazil site after validating the approach against a detailed GIS-assisted analysis. The simpler approach eliminates the need for the GIS analysis and provides a tool that can be used in future analysis of the type described in this paper.

A key conclusion of this paper is that for any of the technologies examined, the capacity needed to achieve a minimum levelized energy production cost is relatively large, but costs are relatively insensitive to large changes in the capacity around that value.

There are important distinctions among cost-capacity characteristics of different systems. The cost of electricity generation (COE) is considerably lower at all scales for gasifier/gas turbine combined cycles (BIG/GTCCs) compared to steam-rankine cycles, and BIG/GTCCs achieve minimum costs at much smaller capacities than steam-rankine cycles. Assuming year-2020 switchgrass production systems in the USA, the COE for steam-rankine cycles reaches within 5% of its minimum at 100-110 MW_e. BIG/GTCC COEs reach 5% of their minimum at capacities of 30 to 40 MW_e with unpressurized gasification and at 70 to 90 MW_e with pressurized gasification. The latter technology is the lowest-cost electricity producer at capacities larger than 50 to 75 MW_e. The lowest cost of electricity production is in the Southeast region (4.3 to 4.6 c/kWh for BIG/GTCC), where delivered biomass costs are the lowest. At the Brazilian site, COEs are slightly higher than for the year-2020 in the SE USA, but the biomass production costs are based on existing commercial plantations.

Projected costs of alcohol (COA) are lower for ethanol than for methanol by 8-10% at the NC USA site, 15% at the SE site, and 11% at the Brazilian site. Plant capacities that achieve a COA within 5% of the minimum for methanol are twice those for ethanol at the US sites and triple those for ethanol at the Brazilian site. Methanol facilities achieve COAs within 5% of the minimum when they are comparable in size to the largest existing industrial biomass processing facilities (e.g. a state-of-the-art pulp and paper mill).

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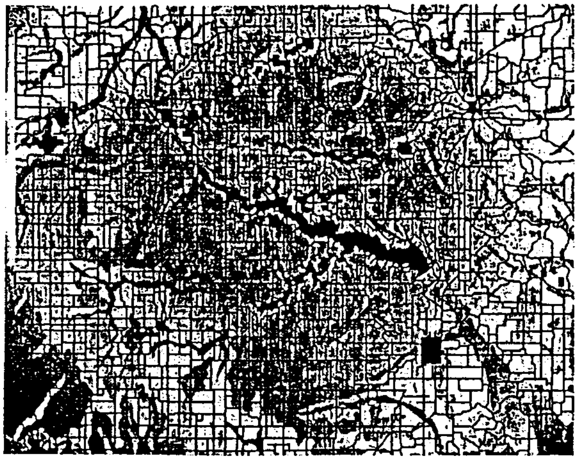
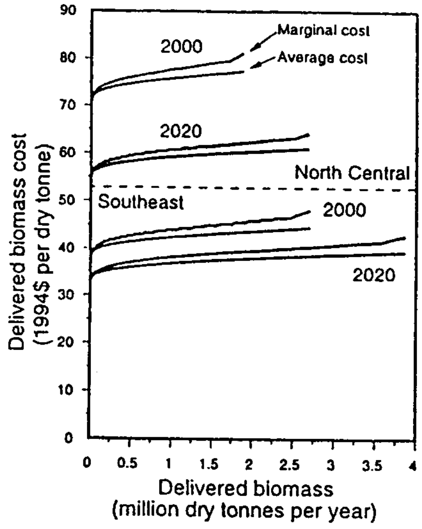
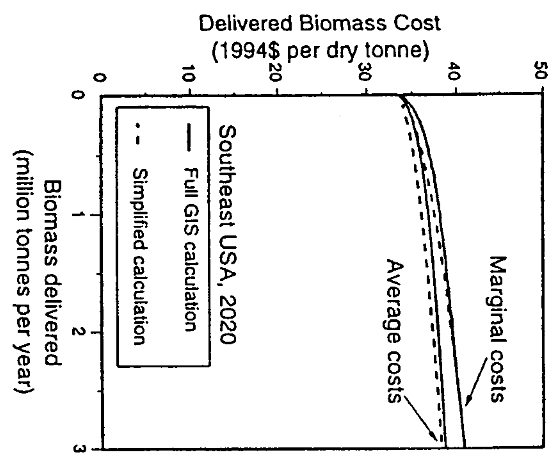


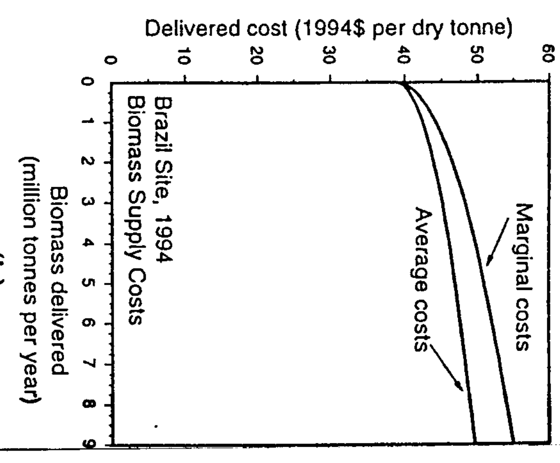


(b)

Fig. 1. Levelized costs of switchgrass delivered to an energy conversion facility from a 5100 km^2 area in south central Iowa, USA, as estimated from a GIS analysis.
(a) Qualitative results: extent of shading reflects relative cost, taking account of soil productivities and road-transport distances to the facility at a one-acre resolution. Black areas represent towns, lakes, and other areas where biomass cannot be grown. The conversion facility is assumed to be on the edge of the centrally located lake. Costs generally rise with radial distance away from the facility. In some places land that is physically further from the facility but more productive than land closer to the facility gives lower biomass costs. *(b)* Quantitative results: switchgrass cost-supply curve for production systems in 2000 and 2020 in the North Central and Southeast regions of the USA. Costs rise with tonnage supplied due to increasing transportation distances and/or decreasing soil productivities.



(a)



(b)

Fig. 2. *(a)* Comparison of the costs of delivered switchgrass bales for a site in the SE USA in 2020 as predicted by the GIS analysis (from Fig. 1*b*) and by the simplified approach outlined in the text. *(b)* Eucalyptus cost-supply curve for the Brazilian site, assuming present plantation practice in Brazil.

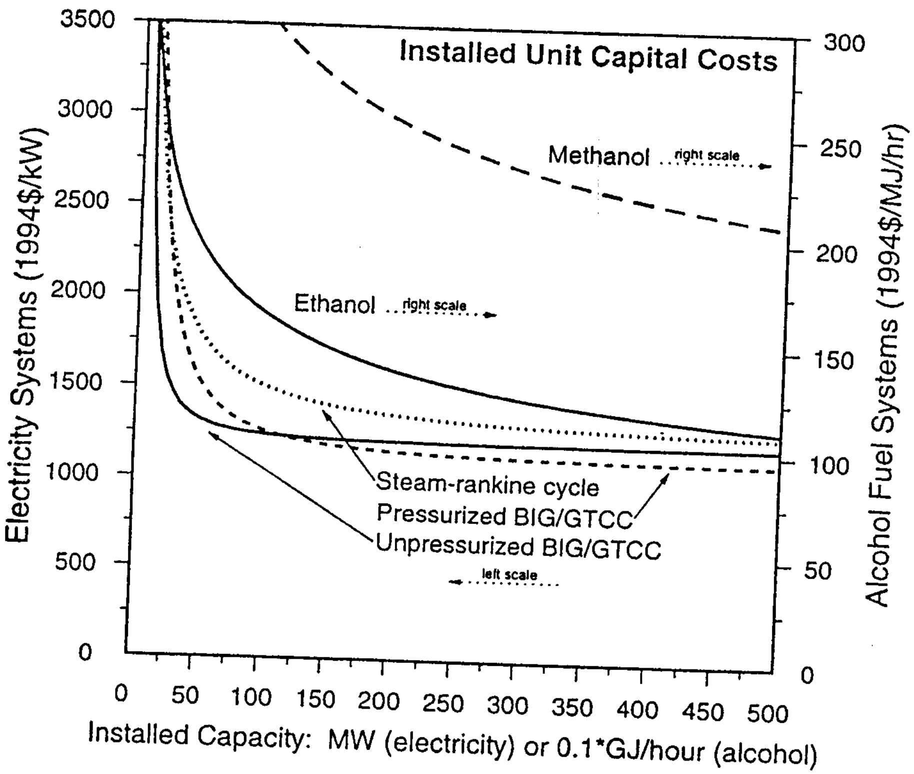


Fig. 3. Estimated installed capital costs of biomass-fed electricity generation and alcohol fuel production. See Marrison and Larson [1995] and Marrison [1995] for details. The curves plot the following derived relationships:
Steam-rankine cycle, $\$/kW = 1200 + (22195)\cdot MW^{-0.93}$
Pressurized BIG/GTCC, $\$/kW = 1100 + (110420)\cdot MW^{-1.42}$
Unpressurized BIG/GTCC, $\$/kW = 1200 + (47198)\cdot MW^{-1.56}$
Methanol: $\$/MJ/hr = 57.7 + (1934)\cdot(GJ/hr)^{-0.3}$
Ethanol: $\$/MJ/hr = 28.0 + (1070)\cdot(GJ/hr)^{-0.3}$

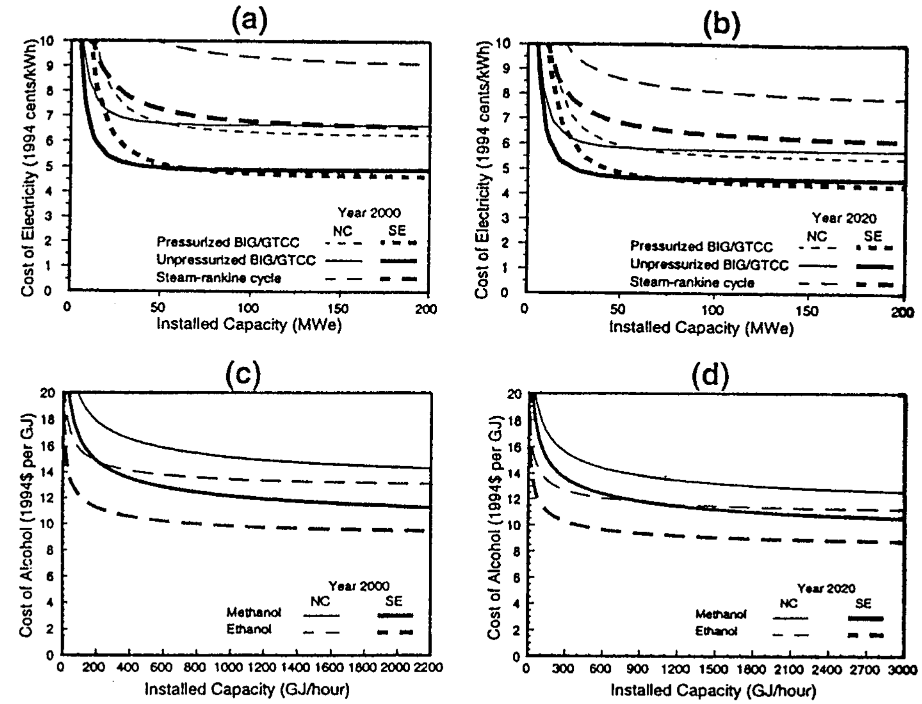


Fig. 4. *(a) and (b)* Total levelized cost of electricity production as a function of installed capacity for the selected site in the NC and SE regions of the USA in year 2000 and year 2020. *(c) and (d)* Total levelized cost of methanol and ethanol production as function of capacity.

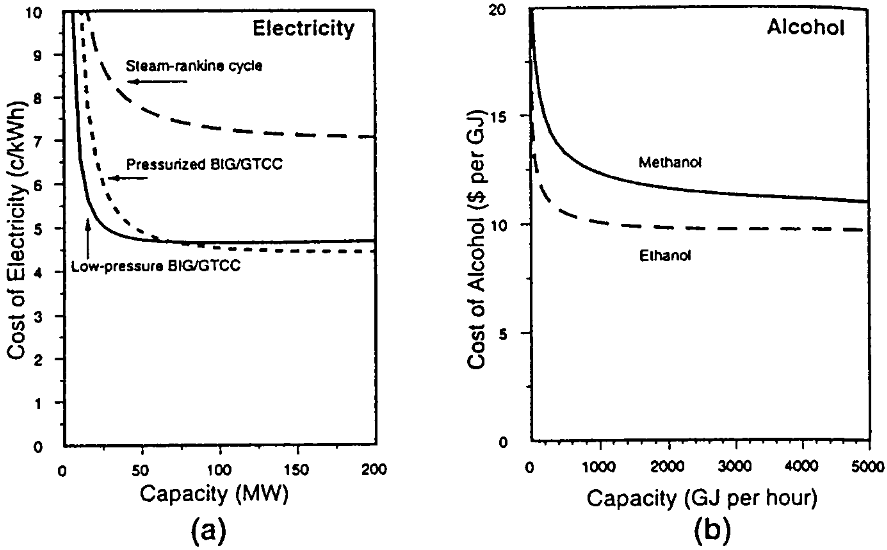


Fig. 5. Total levelized cost of *(a)* electricity production and *(b)* alcohol fuel production, as functions of installed capacity for the Brazilian site, assuming delivered eucalyptus costs from Fig. 2b, corresponding to present industrial plantation practice in the region of the selected site.

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