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The Impact of Biomass Availability and Processing Cost on Optimum Size and Processing Technology Selection

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Abstract Biomass processing plants have a trade-off between two competing cost factors: as size increases, the economy of scale reduces per unit processing cost, while a longer biomass transportation distance increases the delivered cost of biomass. The competition between these cost factors leads to an optimum size at which the cost of energy produced from biomass is minimized. Four processing options are evaluated: power production via direct combustion and via biomass integrated gasification and combined cycle (BIGCC), ethanol production via fermentation, and syndiesel via Fischer Tropsch. The optimum size is calculated as a function of biomass gross yield (the biomass available to the processing plant from the total surrounding area) and processing cost (capital recovery and operating costs). Higher biomass gross yield and higher processing cost each lead to a higher optimum size. For most cases, a small relaxation in the objective of minimum cost, 3%, leads to a halving of plant size. Direct combustion and BIGCC each produce power, with BIGCC having a higher capital cost and conversion efficiency. When the delivered cost of biomass is high, BIGCC produces power at a lower cost than direct combustion. The crossover point at which this occurs is calculated as a function of the purchase cost of biomass and the biomass gross yield.

Keywords Biomass availability · Optimum plant size · Biomass processing cost · Economy of scale · BIGCC · Power from biomass · Lignocellulosic ethanol · Fischer Tropsch · Biomass syndiesel

Introduction

Many fossil fuel projects are built at as large a scale as possible until some external constraint is reached. For example, one consideration in the size of coal-fired power plants is electrical grid stability in the event of a sudden unplanned unit outage. When biomass is

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transported from the field to a plant for processing into a usable energy form, e.g., electricity, ethanol, or syndiesel, two competing cost factors arise that vary as a function of the overall size of the processing plant. As plant size increases, the delivered cost of a unit of biomass increases because of an increasing average distance over which biomass must be transported. If a biomass source is relatively contiguous, i.e., available in equal amounts per unit area, then the approximate increase in the on-road component of the transportation cost will be proportional to the average driving distance, which is approximately proportional to (plant size)$^{0.5}$.

The cost of transport of biomass will depend on the availability of suitable biomass within an overall geographical area and the fraction that would be available to be sold to a biomass processing plant. The maximum availability, which we call the biomass gross density, is a product of the yield per cultivated hectare and the percentage of land that is cultivated to the target biomass source(s). Biomass gross density can be measured in tonnes or Joules per overall hectare, where the hectares are the total area within the collection region. Since some forms of biomass such as straw or corn stover have other uses, for example soil conservation and animal bedding, the second critical factor is what fraction of the biomass gross density is actually available to a processing plant. We call this biomass gross yield, also measured in tonnes or Joules per overall hectare. Other factors affecting biomass transport cost are the capital and operating cost of a transportation mode, usually trucks, and the average speed of transport. All of these factors vary from region to region. For example, in comparing Europe to western Canada, biomass gross density and average transportation speed can be expected to be lower in Europe due to its higher population density.

A second factor is processing cost. The cost of processing a unit of biomass within the plant decreases with increasing plant size, an effect often referred to as the economy of scale. An approximate equation relating the cost of capital equipment as a function of size is

$$\mathrm{Cost}_{\mathrm{Size\ 2}} = \mathrm{Cost}_{\mathrm{Size\ 1}} \times (\mathrm{Size\ 2}/\mathrm{Size\ 1})^{\mathrm{scale\ factor}}$$

where scale factor is an exponent less than 1 and usually falls in the range of 0.6 to 0.8 [1]. Scale factors can be applied to the total installed cost of overall plants, and engineering contracting firms that design and build power plants will apply scale factors over a very wide range when doing preliminary capital cost estimates. For example, the scale factor applied to the construction of direct combustion power plants is reported by two contractors at 0.67 and 0.7 [2] (Williams, D., Bantrel Corporation, an affiliate of Bechtel, Edmonton, Calgary, Alberta, Canada, 2002, personal communication); these scale factors are used over a wide size range, up to sizes exceeding 600MW (for a discussion of the validity of scale factors at large plant sizes, see [3]). A previous analysis of reported capital cost for anaerobic manure digesters in Denmark gave a scale factor of 0.6 [4]. In some projects, for example pipelines, scale factors can be lower than 0.6 (see for example [5–8]). Operating costs per unit of throughput also decrease with plant size so that overall processing cost (capital recovery plus operating costs) can also be modeled by a scale factor relationship.

Figure 1 illustrates the concept of competition between transportation and processing cost, assuming that biomass is available in the field for a fixed cost throughout the area from which the processing plant draws feedstock. From Fig. 1, it is evident that a lower gross yield of biomass will shift the cost of delivered feedstock up, shifting the optimum size lower, while a higher processing cost, i.e., a more expensive plant, will shift the optimum size higher, since the benefit of the economy of scale increases with increasing cost of a given technology. Note that if one assumes that the cost of biomass at the field is independent of size, e.g., all farmers are willing to sell straw or corn stover for a similar

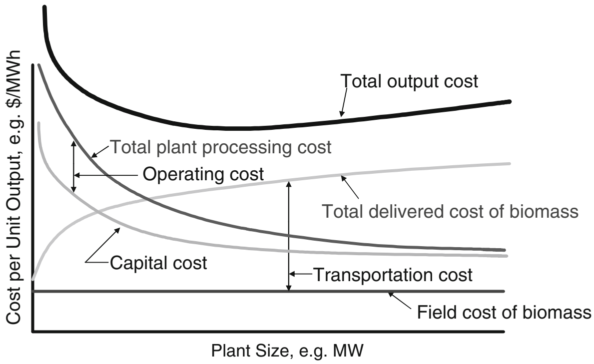

Fig. 1 Overall production cost of energy from a biomass processing plant as a function of plant size

price regardless of their distance from a processing plant, then the field cost of biomass at its point of origin has no impact on optimum size of a processing plant. Only feedstock costs that vary with distance, e.g., the distance variable component of trucking cost, impact optimum size.

Many studies have explored the dependency of product cost on plant size for individual biomass processing cases (see for example [5, 9–14]). These studies have each identified a cost curve as a function of size that has the characteristic of Fig. 1: a very rapid increase in overall unit cost at very small sizes and a somewhat flat cost profile at optimum size.

When two processing schemes producing the same product from the same feedstock differ in efficiency and capital cost, the selection of the most cost-effective technology can depend on the delivered cost of feedstock [3]. Two of the technologies in this study meet this criterion: production of electricity from biomass by air gasification and combined cycle has a higher capital cost and higher conversion efficiency than power from direct combustion and a single steam cycle. If the ratio of capital cost increase is greater than the ratio of efficiency increase, then as the delivered cost of biomass increases, either because of a high field cost of biomass or a low biomass gross yield that causes a high transportation cost, there should be a crossover point at which biomass integrated gasification and combined cycle (BIGCC) produces power at a lower cost than direct combustion.

One purpose of the present study was to enable an evaluation of optimum plant size by systematically analyzing the impact of biomass gross yield and processing cost and to explore the sensitivity of the optimum size, specifically how much of a reduction in plant size can be achieved with a small relaxation in the constraint of minimum cost. A second purpose was to define the crossover point for production of power by the two methods discussed above. In this study, all cost figures have been adjusted to 2006 US dollars by conversion of currency and adjustment for inflation [15].

Biomass Source and Transportation

In this study, the basic unit of biomass is straw/corn stover with the properties shown in Table 1. The biomass gross density is varied from 0.04 to 1.5t/gross hectare. Previous reports of 100% recovery of corn stover in an area of intense corn cultivation in the US Midwest showed a yield 0.882t/overall hectare [17], while 100% recovery of straw in Alberta, Canada showed an average seasonal biomass gross density of 0.420t/overall hectare [10]. The United States National Renewable Energy Laboratory has used an estimate of 10% collection of US Midwest corn stover in its economic analysis of biomass utilization [17]. Kumar et al. [10] assumed 80% availability of straw to a power generation

Table 1 Properties of straw/corn stover [16].

	Straw	Corn stover
Moisture content (%)	15	15
Hydrogen content (wt.%)	5.46	5.46
Bulk density (dry kg/m^3)	140	145
HHV (dry basis, MJ/kg)	18	18
LHV (MJ/kg)	13.9	13.9
Gross yield (actual tonne, GJ/ha)	0.440	0.882
Gross yield (GJ/ha)	6.12	12.25

plant from an area of high grain cultivation. In general, different agricultural practices, competing uses for biomass, and varying population densities will give a high variability in biomass gross yield.

The default value in this study for a payment to the farmer is \$25/t for baled straw or stover “as is”, \$29.40/dry t, for large bales delivered to a point on the farm from which it can be picked up by a road truck, e.g., at the roadside edge of a field or in the farmyard. The payment level is an arbitrary assumption. However, as noted above, the field cost of biomass does not have any impact on the calculated optimum plant size. \$25/t is equivalent to \$1.39/GJ of higher heating value (HHV) and at 15% moisture to 1.80/GJ of lower heating value (LHV). For an actual biomass processing plant, a payment adjustment for moisture would be required, with either dry weight or deviation in LHV being the predominant factor depending on the processing method.

Straw and corn stover are assumed to be contiguous, i.e., uniformly distributed in the overall region. The transportation mode is trucking, with a cost independent of distance of \$5.14/t that arises from loading and unloading and a distance-dependent cost of \$0.14/t km where the distance is based on one-way transport, i.e., the distance from field to plant. These values are representative of trucking costs in central and western North America [10].

For the parameters in this study, the transport cost of biomass, TC, in \$/actual t as a function of biomass gross yield and plant size (assuming a 90% plant operating factor, i.e., 329 operating days per year) can be expressed as:

$$\mathrm{TC} = \left(5.14 + 0.178 \times \left[\frac{(\text{plant size, dry t/d ay})}{(\text{gross yield, dry t/ha})}\right]^{0.5}\right).$$

Transport cost per GJ of LHV is TC × 0.0719; per GJ of HHV is TC × 0.0653.

Plant Processing Cost

In this study, we evaluate four different technologies for processing of biomass which differ in the capital cost per unit of biomass processed: direct combustion to produce electricity via a steam cycle, biomass integrated air gasification and combined cycle production of electricity (BIGCC), the production of ethanol by enzymatic hydrolysis of lignocellulose, and the production of synthetic diesel via Fischer Tropsch reaction of synthesis gas derived from oxygen gasification of biomass. The state of commercial development of these technologies varies. As a result, the capital cost estimates used in this study, detailed below, can be improved over time as additional data from demonstration and commercial scale plants become available.

For each source of data used in this study, an overall processing cost was calculated. Large biomass projects would likely use a mix of debt and equity to finance construction, with the current cost of debt significantly less than 12% and the equity component requiring an after-tax return of at least 12%. In this study, we apply a capital recovery factor based on a pre-tax return of 12% on total installed capital cost to approximate the overall cost of capital from a blend of debt and equity.

Estimates of annual maintenance costs vary widely between studies. For consistency, in this study, annual maintenance cost is estimated as a percentage of total installed capital cost based on the average of several studies of each technology. The maintenance costs for ethanol, Fischer Tropsch (FT), direct combustion, and BIGCC are 2.1%, 3.0%, 2.5%, and 3.0% of total installed cost, respectively. For direct combustion and air and oxygen gasification, 2.5% and 3%, respectively, are higher than values for other solid fuel processing plants; for example, coal-fired power plants have an annual maintenance cost of about 2% of installed capital cost [10]. The higher values in this study reflect expected challenges in the handling and preprocessing of biomass feedstock, which is more prone to moisture uptake and less easily comminuted. Other operating costs were drawn from each study. Capital recovery, maintenance, and other operating costs were then combined to calculate an overall processing cost, which was then best-fit to a relationship between processing cost and scale. While reasonable agreement was obtained for three of the four technologies, we note that the studies cited in this work were done in different settings over a span of years with differing degrees of scope definition, so caution must be exercised in using the results.

Direct Combustion for Power Generation

The use of biomass as a fuel for conventional power generation is the most developed of the four technologies, with biomass boilers operating at a wide variety of scales. The largest, the Alholmens power plant in Pietersaari, Finland, is designed to run on any mixture of woody biomass and coal and has a nominal gross capacity of 240MW [18]. Numerous studies have looked at the capital cost of power generation from straw, stover, and wood (see for example [10, 19–22]). Figure 2 shows the capital cost per net MW of capacity for each of these studies as well as reference data on the capital cost of coal-fired power. Note that gross power produced by the plant is higher than net power by the amount of parasitic power usage, i.e., power consumed by the plant itself. Parasitic power use is assumed to be 8% of gross power production for both direct combustion and BIGCC. Italicized points in Fig. 2 were used in the analysis of biomass power generation cost.

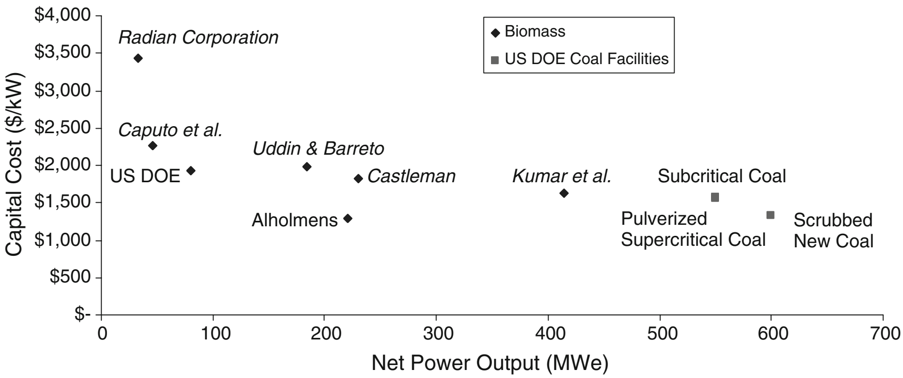

Fig. 2 Capital cost of biomass direct combustion power plants as a function of plant scale

Scale also has a significant impact on the conversion efficiency (gross power output, MW_e, per unit of energy input, LHV MW_{th}) of a direct combustion plant, with small boilers having an efficiency as low as 20% while large plants such as Alholmens achieving an efficiency of 38.5% [3, 18]. In this study, direct combustion conversion efficiency increases linearly from 20% at 250 dry t/day (9MW net) to 38.5% at 2750 dry t/day (200MW net).

Figure 3 shows an overall processing cost per MWh calculated as described above. Best-fitting the data in Fig. 3 and rounding gives the equation:

$$\text{Processing Cost, USD per MWh} = 151\,(\text{Plant Size, MW})^{-0.3}$$

which implies a scale factor of 0.7. Given the reasonableness of the best-fit scale factor, we use this estimate of processing cost in subsequent analysis.

BIGCC for Power Generation

Integrated air gasification and production of power via combined cycle has been applied to coal to increase power production per unit of fossil carbon emissions. Previous studies have noted that production of power via gasification gives a lower overall power cost for more expensive fuels [3]. Unlike direct combustion, however, there are no large-scale BIGCC plants in operation, and capital and operating cost estimates are therefore less certain. Figure 4 shows capital cost per total MW of capacity for five studies of BIGCC [14, 22–25] and also includes values for coal IGCC from a recent US DOE study [26]. In Fig. 4, we show a line that fits the US DOE study of coal IGCC capital costs and a second line that best fits the BIGCC studies, with a scale factor set to 0.7 for both lines. The capital cost for BIGCC is 59% of the coal IGCC data, whereas one would expect BIGCC to have a higher capital cost than coal IGCC because of the more difficult nature of biomass as a solid fuel in gasification. We therefore develop two cases in this study: the data from the BIGCC studies shown in Fig. 4, called the base BIGCC case, and a modified BIGCC case in which the processing cost is 75% higher than the base BIGCC case arising from a capital and annual maintenance cost slightly higher than the DOE coal IGCC values in Fig. 4. Given the low state of commercial development of BIGCC, we consider the modified case to be the more accurate predictor of future BIGCC costs.

As with direct combustion, scale can be expected to have a significant impact on the conversion efficiency (gross power output, MW_e, per unit of energy input, LHV MW_{th}) of a

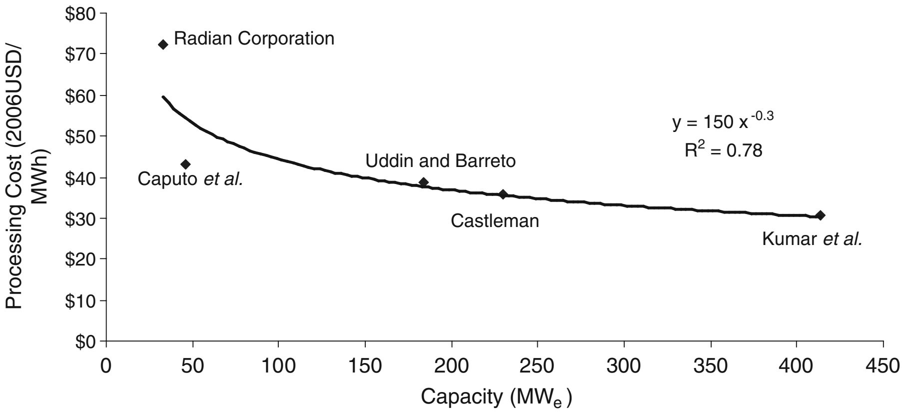

Fig. 3 Processing cost for production of power from biomass via direct combustion

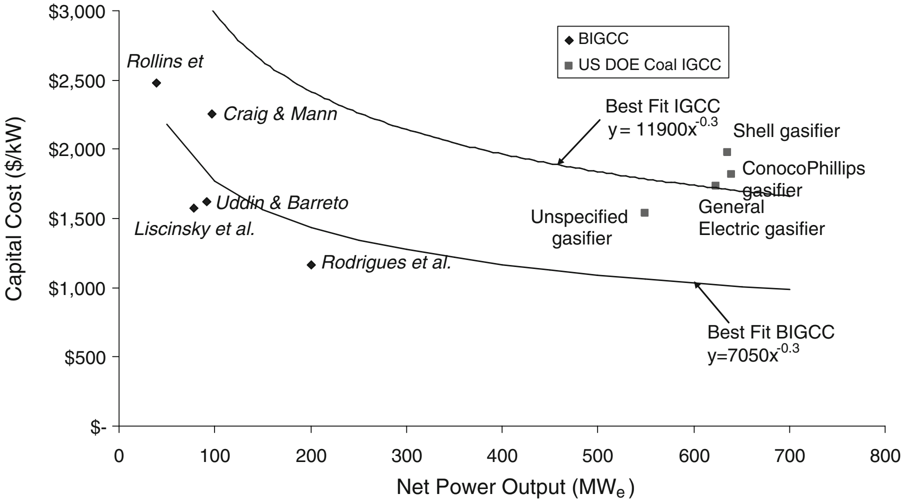

Fig. 4 Capital cost of BIGCC as a function of plant size

BIGCC plant [18, 22]. In this study, BIGCC conversion efficiency increases linearly from 35% at 250 dry t/day (17MW net) to 47% at 1,000 dry t/day (90MW net).

Figure 5 shows an overall processing cost per MWh calculated as described above. Best-fitting the data in Fig. 5 leads to an implied scale factor of 0.56 and a low R^2 value. Given the low state of development of the technology and the scatter in the data, we best-fitted a curve to the data imposing a scale factor of 0.7; rounding gives the equation:

$$\text{Processing Cost, USD per MWh} = 170\,(\text{Plant Size, MW})^{-0.3}.$$

For the modified BIGCC case,

$$\text{Processing Cost, USD per MWh} = 297\,(\text{Plant Size, MW})^{-0.3}.$$

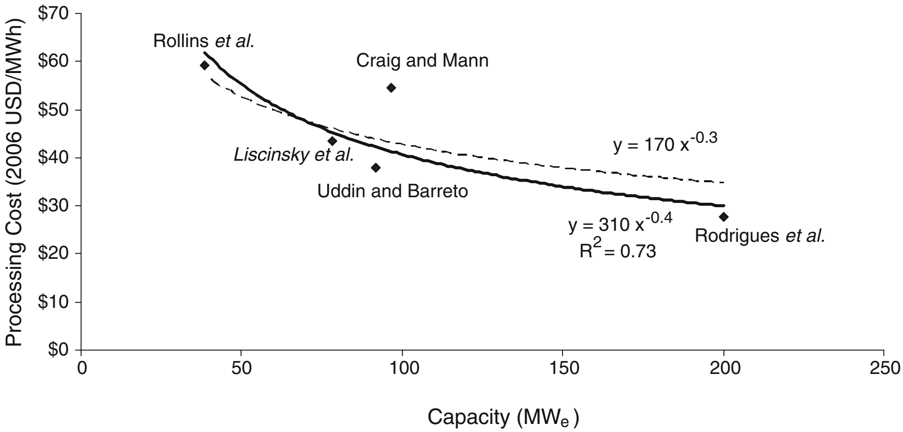

Fig. 5 Processing cost for production of power from BIGCC

The suspected low value of capital cost from previous studies for the base BIGCC case is of particular significance because the ratio of BIGCC processing cost to direct combustion processing cost is 1.13, which is less than the ratio of efficiency of the two processes, i.e., the power output per unit of biomass feed, 1.22 at maximum efficiencies. Hence, using the base BIGCC case will always show a lower power cost than power from direct combustion regardless of the delivered cost of biomass. As noted above, we are skeptical of reported capital costs from previous BIGCC studies, in particular relative to estimated costs for coal IGCC. We also note that coal IGCC does not appear to give a lower power cost over all ranges of the delivered cost of fuel relative to direct combustion of coal [26]. For the modified BIGCC case, cost of power relative to direct combustion will be higher for low delivered cost of biomass, but for high values of the delivered cost of biomass, the higher efficiency of BIGCC relative to direct combustion will eventually lead to a lower power cost. This crossover in power cost is discussed further below.

Lignocellulosic Ethanol

Production of ethanol from sugars produced by enzymatic hydrolysis of lignocellulosic (lc) feedstocks has been the subject of intense research and economic analysis (see for example [17, 27, 28]). More recently, six large-scale plants have been initiated in the USA with help from the US Department of Energy [29]. However, the proprietary nature of some of the technology for lc ethanol has limited the amount of data available on estimated capital and operating cost. Figure 6 shows capital cost per liter per year of capacity for five studies of ethanol from lc feedstocks [17, 27, 30–32]. Points shown in italics were used in calculating overall processing cost; the data of the study by Wooley et al. [30] were not included because this study was followed up and updated by the study of Aden et al. [17]. In this study, the efficiency of conversion was assumed to be 320L/dry t of biomass [17].

Figure 7 shows an overall processing cost per liter of ethanol calculated as described above. Best-fitting the data in Fig. 7 and rounding gives the equation:

$$\text{Processing Cost, USD per liter of ethanol} = 1.40\,(\text{Plant Size, L/year})^{-0.3}$$

which implies a scale factor of 0.7. Given the reasonableness of the best-fit scale factor, we use this estimate of processing cost in subsequent analysis.

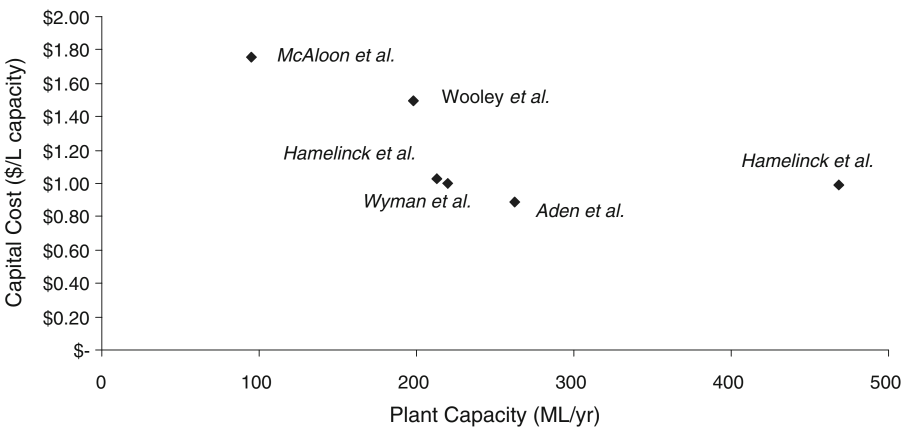

Fig. 6 Capital cost of straw/stover ethanol plant as a function of plant scale

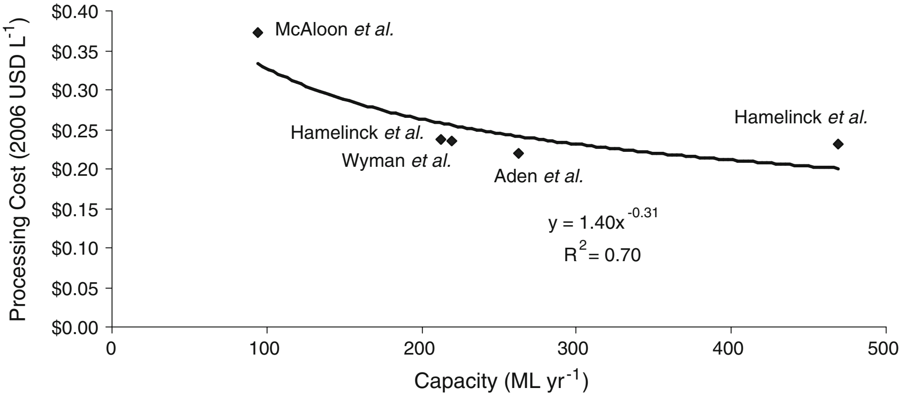

Fig. 7 Processing cost for production of ethanol from straw or stover

Syndiesel via Fischer Tropsch

FT production of liquid fuels from a synthesis gas formed from oxygen gasification of coal has been used in Germany and South Africa, in each case motivated by duress [33]. More recently, it has been applied to convert a synthesis gas derived from natural gas to liquid fuels, in particular where natural gas reserves do not support the development of liquefied natural gas facilities.

FT processing can be applied in a wide variety of configurations. It can be used on a once-through processing basis with the use of unconverted synthesis gas to produce electricity as a co-product, or it can recycle unconverted synthesis gas to maximize liquid production. It can be designed to maximize production of gasoline or diesel fractions, with cracking of high-molecular-weight waxes. It can be used to produce a mix of synthetic natural gas as well as liquid fuels. Specific configurations can be chosen to meet the needs of a specific application, but the wide variety of possible configurations introduces an element of uncertainty in estimating capital cost, processing cost, and conversion efficiency.

Recent work by Boerrigter [7] included a relation between cost data from natural gas FT plants to projected costs for biomass-based FT plants by applying a 60% increase to capital costs. Figure 8 shows the capital cost per liter per year of capacity from studies of FT processing of coal, biomass, and natural gas with the addition of a 60% premium as recommend by Boerrigter [34–46]. There is a high degree of scatter in the data, reflecting in part the fact that no large-scale biomass oxygen gasifier has ever been built, and in part the variability in FT configuration discussed above. In this study, an efficiency of conversion of 221L of diesel per dry tonne of biomass was assumed, a mid-range value for efficiencies reported in the literature [34, 36, 45, 46].

In order to minimize the impact of variability in FT plant configuration, we calculated processing cost based on five points from three studies [34, 35, 44] that provided sufficient detailed cost estimating information to allow development of a capital cost estimate for a consistent design that maximizes production of a diesel fraction. Figure 9 shows an overall processing cost per liter of diesel calculated as described above from the five selected studies. Best-fitting the data in Fig. 9 and rounding gives the equation:

$$\text{Processing Cost, USD per liter of diesel} = 3.02\,(\text{Plant Size, L/year})^{-0.3}$$

which implies a scale factor of 0.7. Given the reasonableness of the best-fit scale factor, we use this estimate of processing cost in subsequent analysis. However, the high scatter in the

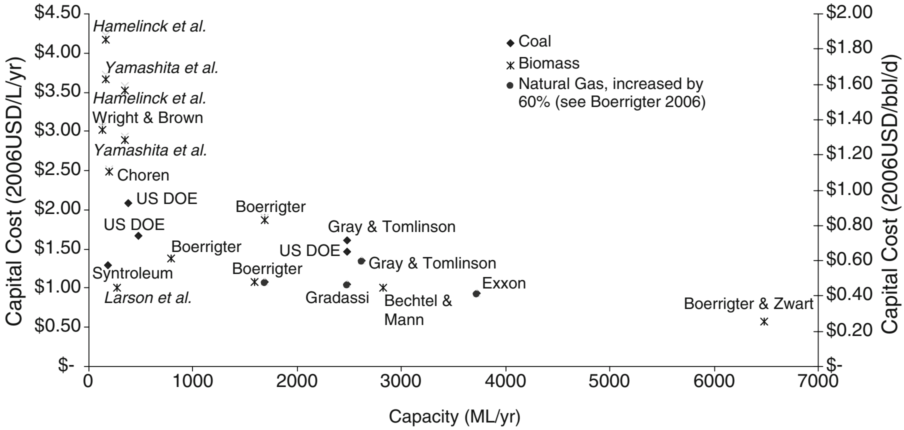

Fig. 8 Capital cost of Fischer Tropsch syndiesel plant as a function of plant scale

data in Fig. 8 is indicative of the high degree of uncertainty in estimating processing cost for biomass-based FT processing.

Results

Calculation of Optimum Plant Size and Sensitivity

A model was developed to calculate the total cost of processing biomass into power or fuel, incorporating field cost of biomass, transportation cost, and processing cost. For each processing technology, the cost of product as a function of plant size was calculated over a range of assumed biomass gross yield, expressed as tonnes of biomass per overall hectares in a region. The optimum plant size at which the lowest product cost was realized was then determined. Figure 10 shows a plane of calculated optimal plant size as a function of processing plant cost and biomass gross yield. Note that the axis representing processing

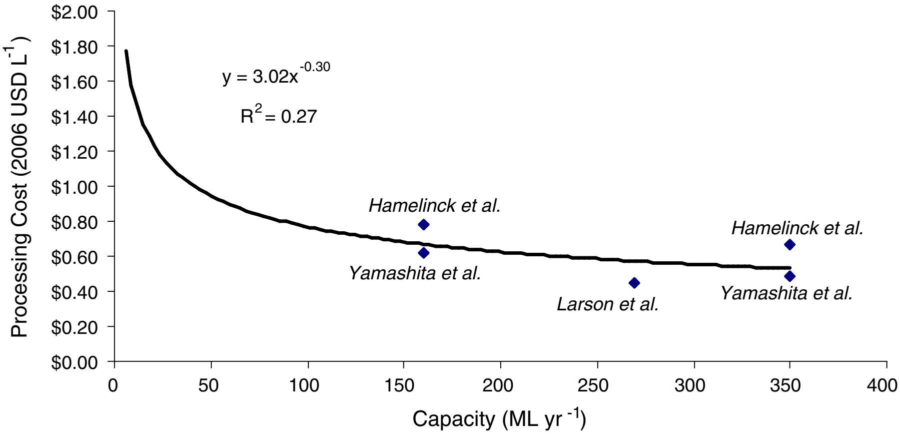

Fig. 9 Processing cost for production of Fischer Tropsch syndiesel from biomass

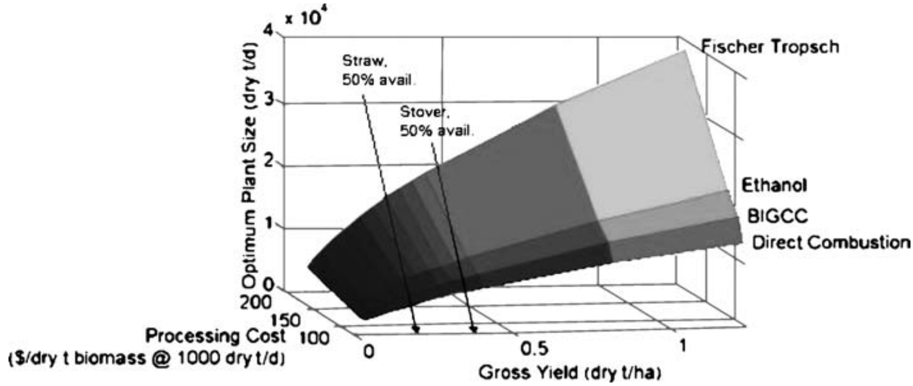

Fig. 10 Optimal plant size as a function of processing cost and biomass gross density

plant cost is expressed as capital cost at a fixed size of 1,000 dry tonnes per day, since comparable scale factors are assumed for each of the processing technologies over the size of plants shown in Fig. 10. As capital cost is the predominant factor in processing cost, both as capital recovery and as influencing annual maintenance cost, this choice of axis would allow any other technology with a comparable scale factor to utilize Fig. 10 in estimating optimum plant size. For biomass feedstocks other than straw/stover, the values in Fig. 10 are indicative but would have to be adjusted to reflect transportation cost, which can be affected by moisture content of biomass as well as local factors such as trucking cost per hour and average transportation speed.

Figure 10 confirms that optimum size increases with biomass gross yield and processing plant capital cost. For biomass gross yields greater than 0.04 dry t/ha, the optimum size for FT syndiesel is 2.9 times the optimum size for the production of power by direct combustion.

For most biomass projects, the profile of cost vs. size in biomass processing is relatively flat near the optimum point, i.e., the increase in cost of the total cost of electricity or transportation fuel is small for significant changes in plant size. Construction of biomass plants entails an element of risk which is higher than for well-established and proven technologies, and one means of mitigating risk is to reduce the overall size of a project. We therefore tested a revised criterion for plant size, that at which overall product cost is 3% higher than the theoretical optimum size. Note that the choice of 3% is arbitrary. Figure 11 shows the plant size for this criterion.

Table 2 shows the optimum size, the plant size for a 3% relaxation in the objective of minimum cost, and the percentage reduction between the two for the four technologies at three biomass yields. A yield of 0.42 dry tonne per gross hectare corresponds to 100% availability of straw in grain-growing regions in Alberta Canada and to 50% availability of corn stover in the US Midwest corn belt [10, 17]. Note that the 3% relaxation in the minimum cost objective leads to a more than 50% reduction in plant size for the high and medium yields of biomass. However, when biomass gross yield is low, for the two lowest capital cost cases, power from direct combustion and the base BIGCC case, the relaxation leads to a lower reduction in plant size, 18% and 28%, respectively. Lower capital cost and lower biomass gross yields make the selection of plant size more critical because the curve of cost vs. size is less flat. In effect, a low biomass gross yield/high transport cost makes the right-hand side of total cost in Fig. 1 climb sharply: the increase in transport cost with increasing size overwhelms the capital efficiency due to the economy of scale. The result is

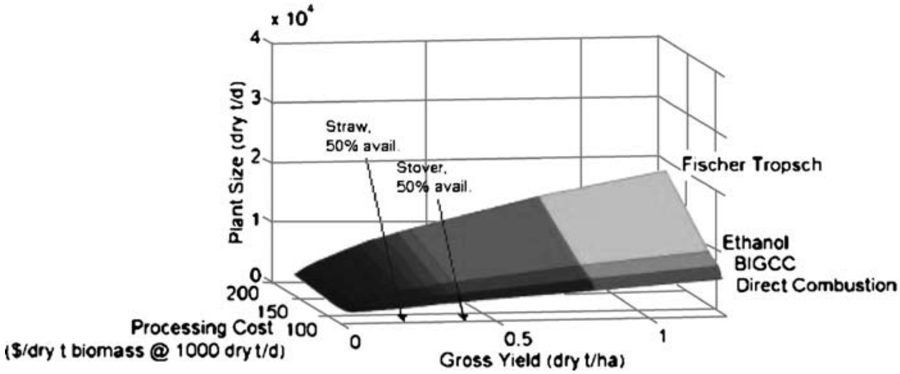

Fig. 11 Plant size that achieves a cost 3% higher than the minimum cost as a function of processing plant cost and biomass gross density

a cost vs. size curve that has a narrower dip, and a change in size has a greater impact on total product cost.

Crossover Point for Power Production from BIGCC vs. Direct Combustion

The delivered cost of biomass is affected by both the field (purchase) cost and the transportation cost; the latter is a function of biomass gross yield. We explore the impact of biomass delivered cost on power cost from direct combustion and the modified BIGCC case by holding the biomass gross yield constant at 0.21 dry t/ha and increasing the field cost of biomass. Note that holding the yield constant holds the optimum size constant (319MW for direct combustion, 978MW for BIGCC), since the biomass gross yield determines the distance variable component of transportation cost, and only this component of biomass delivered cost affects optimum size. Figure 12 shows the results and illustrates that as biomass delivered cost increases, the power cost from BIGCC becomes lower than from direct combustion. As noted above, the crossover occurs because for the modified BIGCC, the ratio of increase in processing cost relative to direct combustion is higher than the ratio of efficiency increase; the reduced usage of biomass per unit of power output becomes more significant as delivered cost of biomass increases. Note that for the base BIGCC case, there is no crossover: BIGCC produces power at a lower cost at any delivered cost of biomass because the processing cost increment is less than the efficiency gain.

In central and western North America, where transportation costs and average road speeds are relatively uniform, biomass gross yield and field cost are the prime variables

Table 2 Optimum plant size, plant size at a cost 3% higher than minimum cost, and the percentage reduction.

	Gross yield (dry t/gross ha)		
Technology	0.042	0.21	0.42
Direct combustion	2,000/1,650/18%	4,375/2,100/52%	6,750/3,100/54%
Base BIGCC case	2,000/1,450/28%	5,500/2,600/53%	8,500/4,000/53%
Modified BIGCC case	4,000/2,000/50%	11,000/5,250/51%	17,000/8,250/51%
Ethanol	2,500/1,200/52%	6,750/3,250/52%	10,250/4,750/54%
Fischer Tropsch	4,750/2,250/53%	12,750/6,250/51%	19,500/9,500/51%

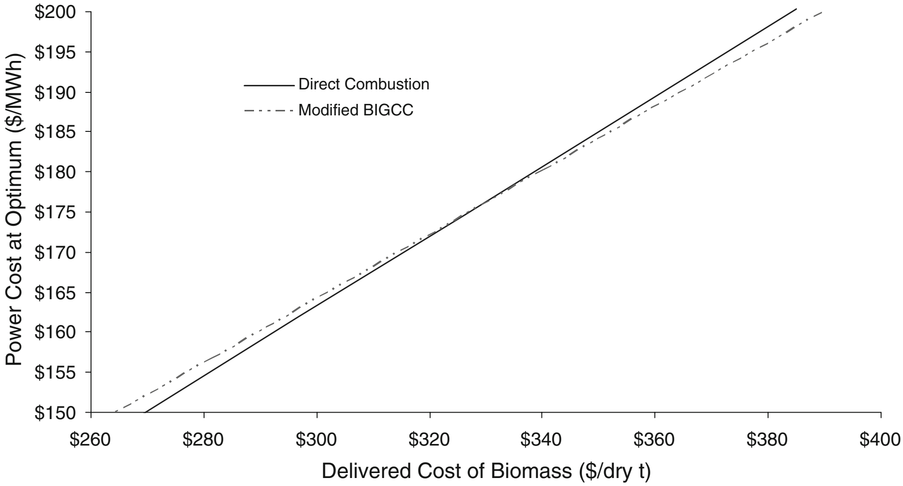

Fig. 12 Power cost vs. delivered cost of biomass for direct combustion vs. BIGCC showing the crossover point between the two technologies at a biomass gross yield of 0.21 dry t/ha

determining the delivered cost of biomass. For a case where the biomass resource or plant size is fixed, one can define regions in which BIGCC (modified case) is favored relative to direct combustion. Figure 13 illustrates this for a plant size of 4,500 dry t/day; the upper left region has a high delivered cost of biomass, and BIGCC leads to a lower net power cost. Note, however, that power cost at the point of crossover in Fig. 13 is \$270 per MWh and \$175 per MWh in Fig. 12; BIGCC, using the modified case data, economically displaces direct combustion only at a high produced cost of power.

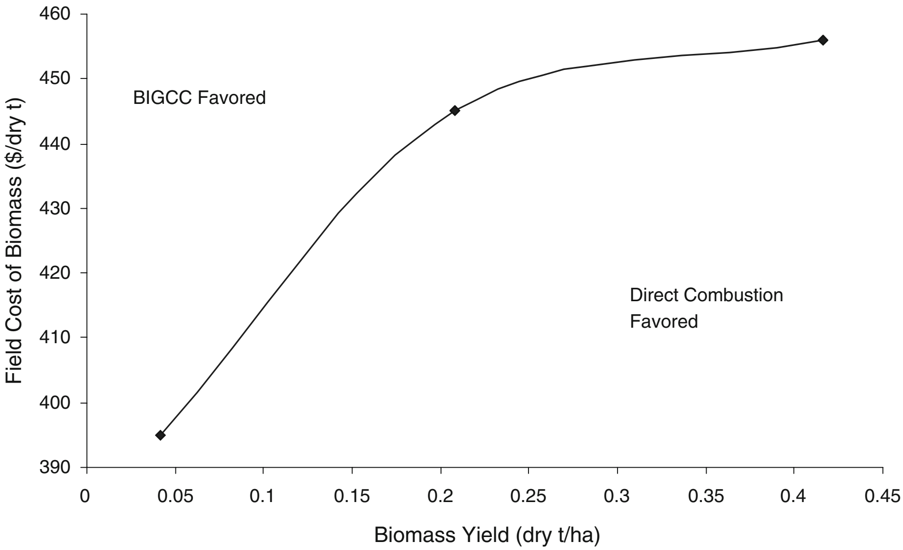

Fig. 13 Impact of field cost of biomass and biomass gross yield on whether power cost is lower from the modified BIGCC case or direct combustion

Discussion

As the world moves towards increasing use of renewable energy, two critical decisions face those contemplating using biomass as an energy source: what technology should be used and at what scale should the technology be adopted. This study, based on the best available cost information from the literature, illustrates that the selection of a biomass resource and a processing technology has a critical impact on the optimum size at which a technology should be developed. In particular, higher biomass gross yields and higher capital cost increase the plant size at which the minimum production cost is realized.

Although this study confirms that optimum size increases with increasing capital cost, a caution must be raised about the specific processing cost estimates in this study. Direct combustion of biomass is well advanced and being applied at large commercial scales today. Large plants making ethanol from lignocellulose are under construction today. Incorporation of improved capital and operating cost data if it becomes available from these large plants will substantially improve the quality of data on ethanol production cost and can be incorporated into a reevaluation of the optimum size of ethanol plants as a function of biomass gross availability. However, air and oxygen gasification of biomass has not been implemented at other than a small demonstration scale, and the cost estimates for these technologies are hence substantially more prone to error. This is well illustrated by the discrepancy between literature estimates of BIGCC and coal IGCC capital costs: coal should be cheaper, given its higher energy content and greater ease of handling and its ability to be crushed so that it can be completely gasified at high temperature in a single step, and yet recent cost estimates of coal IGCC are almost 70% higher than BIGCC values. A further concern about the validity of capital cost estimates in the literature is the duration of recent significant increases in the cost of capital equipment associated with a high rate of development in China and India. If the increase in capital equipment costs is permanent, then all capital cost estimates in this study would be low relative to current values. There are insufficient data available today to evaluate either the permanence of capital equipment cost increases or their magnitude.

Resolving the uncertainty around BIGCC capital and processing cost is critical to any decision about its selection relative to direct combustion. This work illustrates that if base BIGCC case estimates are valid (which we doubt), then BIGCC will always be more economic than direct combustion, whereas if the modified BIGCC case estimates are valid, then BIGCC is not economic relative to direct combustion unless the delivered cost of biomass, and hence the cost of produced power, is very high, e.g., $270 per MWh for a plant processing 4500 dry t/day. As more data become available over time on the cost of constructing and operating various biomass processing technologies, it is important to update this study's cost estimates.

Selecting the exact optimum size at which costs are minimized is not critical in most cases: this study shows that even a small 3% relaxation in the criterion of minimum cost can be achieved at a plant size of half the optimum size. However, all biomass plants show rapidly increasing costs when plant sizes get still smaller. For example, power cost from the direct combustion case in this study for a biomass gross yield of 0.21 dry t/ha is $58.87/MWh at optimum size (328MW), $60.24/MWh at half optimum size (164MW), $78.61/MWh at 25% of optimum size (53MW), $96.70/MWh at 10% of optimum size (21MW), and $115.19/MWh at 5% of optimum size (9MW). For direct combustion, the increase in power cost as size decreases is caused by two factors, decreasing efficiency and an increased unit processing cost from a reduction in economy of scale that is not offset at small plant size by a significant reduction in the transportation component of the delivered cost. Selecting a plant size near the optimum size becomes more critical when a widely dispersed biomass source is processed in a relatively low capital cost technology. Previous work by Kumar et al. [10] compared the cost of power from three biomass sources in Alberta. The curve of power cost vs. plant size for the most disperse biomass source, boreal forest harvest residues, shows a narrow optimum relative to more abundant biomass resources.

High cost technologies such as the modified BIGCC case or FT, when applied in an area of high biomass gross yield, have an optimum plant size that is very large. For example, using the modified BIGCC estimates the optimum size of plant for a biomass gross yield of 0.42 dry t/ha at 1,500MW. At such large sizes, the application of a scale factor of 0.7 loses validity because plant design substitutes multiple sub-plants of identical size for a larger single plant (for a discussion, see [3]). However, as noted above, engineering firms that construct plants consider scale factors to be valid to very large plant sizes, at least 600MW for power production and at least 10M L/day for liquid fuel processing based on oil refinery design practice. The implication for biomass processing, especially using technologies with a high capital cost, is that large size plants will be required to achieve reasonable economies of scale.

Conclusions

Key conclusions of this work are:

- Increasing biomass gross yield and biomass processing cost both cause an increase in the optimum size of a biomass processing plant at which the cost of produced energy is the lowest.
- For most cases explored in this study, the curve of product cost vs. plant size is relatively flat, and a 3% relaxation in the objective of minimum cost allows a plant size about half of that at minimum cost.
- The size reduction for a 3% increase in product cost over minimum is less for cases of low capital cost and low biomass gross yield, e.g., direct combustion of biomass drawn from a wide area.
- Electrical power can be produced from biomass by direct combustion with a simple steam cycle and by BIGCC. The modified BIGCC case in this study has an increase in capital and processing cost relative to direct combustion that is higher than the increase in efficiency. At low values for the delivered cost of biomass, power from direct combustion is less than power from BIGCC. As the delivered cost of biomass increases, a crossover point is reached where the cost of producing power from BIGCC is less then direct combustion; the crossover occurs at a high power cost. There is significant uncertainty in the cost of BIGCC which has a strong impact on technology selection.

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