Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 10 – Capital and Operating Cost Estimates

This chapter describes the development of estimated capital costs that are required for the example systems defined in Chapter/Task 14 and the additional operating costs associated with using these biomass systems. It was primarily prepared by project participants at the University of Minnesota in cooperation with AMEC E&C Services.

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Report for Task 10, "Capital and Operating Cost Estimates"

Background of the Task

The technical analysis for integrating biomass energy into the dry-grind ethanol process is described in detail in Chapter/Task 14 – Technology Options and Integration with the Dry-Grind Ethanol Plant. Some of the important features are summarized here. The analysis was performed primarily using Aspen Plus process simulation software. An Aspen Plus model of the dry-grind ethanol process was obtained from the USDA Agricultural Research Service (McAloon et al., 2000; McAloon et al., 2004; Kwiatowski et al., 2006), and was used as the basis for the energy conversion system models that followed. Biomass systems that produce 190 million liter (50 million gallon) per year of denatured ethanol were modeled. The primary components of the process such as fermentation, distillation, and evaporation were not changed. Only those components impacted by using biomass fuel were modified. They included steam generation (biomass combustion or gasification), thermal oxidation, co-product drying, and emissions control. Process data from several ethanol plants participating in the project were also taken into account in the modeling process. Several sensitivity analyses were performed on each simulation to ensure good performance.

Three biomass fuels were included in the analysis – distillers dried gains with solubles (DDGS), corn stover, and a mixture of corn stover and "syrup" (the solubles portion of DDGS). Three levels of technology were analyzed for providing energy at dry-grind plants. They included 1) process heat only, 2) process heat and electricity for the plant – combined heat and power (CHP), and 3) CHP plus additional electricity for the grid. The limit for the third case was defined in terms of the maximum energy available if all of the DDGS were used to provide process heat and electricity. A conventional ethanol plant using natural gas and electricity was also modeled to provide comparison information for the economic analysis.

Fluidized bed combustion was used for corn stover and the mixture of corn stover and syrup. Fluidized bed gasification was used for DDGS to overcome problems with low ash fusion temperatures. Appropriate drying modifications were made to accommodate each configuration. The necessary emissions control technologies, primarily for oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and chlorine (HCl) were also modeled for each configuration.

Estimating Capital Costs

The Aspen Plus model estimates important material and energy flows which allowed us to specify the capacities of the required capital equipment. Using these capacities, we worked with a consulting engineering firm to specify equipment to meet these requirements. The consulting engineering firm then estimated equipment costs using data from previous projects and by soliciting bids from potential vendors for some items. Cost estimates are categorized according to new equipment and the equipment that would be replaced (avoided cost) compared to a conventional dry-grind plant. We focused on the net change in equipment cost required to construct a dry grind ethanol plant to use biomass rather than natural gas and purchased electricity as energy sources.

In the biomass scenarios, we assumed that a package natural gas boiler would be included for backup and also perhaps to phase in biomass as a fuel source over time, so the cost of that equipment was not deducted from the conventional base case of a natural gas powered plant. However, because the dryer exhaust was routed to the combustion unit in the biomass systems, we were able to eliminate the capital costs of the thermal oxidizer that would be required in the natural gas-fired conventional plants.

Equipment costs for new items were first estimated, and then other costs associated with the project were added. Among these were installation, building, electrical, contractor costs and fees, engineering, contingency, and escalation to arrive at the total project cost for new items. The resulting capital costs for new items for all fuel and technology combinations are shown in Table 1. Total project costs for new items were divided by total equipment costs for new items to yield a project cost/equipment cost factor. The resulting factors ranged from 3.31 to 3.33 for the nine fuel/technology combinations in Table 1.

Avoided equipment costs and corresponding total project costs were also estimated and included in Table 1 for each fuel/technology combination. Recent estimates of total project costs (including operating capital) for conventional (natural gas) dry-grind plants obtained from design-build firms and bankers (Eidman, 2007) also are included in Table 1. Net (new – avoided) project costs for biomass systems are added to the cost of conventional plants to obtain total capital cost estimates for 190 million liters (50 million gallons) per year biomass fueled plants.

Cost estimates for the 380 million liter (100 million gallon) per year plants are developed based on the ratio of the plant sizes (380/190 = 2). The cost estimating factor for the 380 million liter plant is $(2)^{0.7}$ or 1.6245. Thus, the cost for 380 million liter plant is estimated to be 1.6245 times the cost for a 190 million liter plant for a similar fuel and level. This technique of adjusting costs for scale is commonly used in many chemical and industrial processes. Based on responses from design/builders of ethanol plants, efforts to optimize and de-bottleneck plants can raise capacity 6% in the case of coal or biomass plants and 20% or more in the case of conventional plants (Nicola, 2005). Nameplate installed costs with necessary operating capital are summarized for the nine fuel/technology combinations in Table 2.

Table 1. Total project costs for 190 million liter (50 million gallon) per year plants for nine biomass fuel/technology combinations.

Corn Stover Combustion		**Process Heat Only**			**CHP**			**CHP plus electricity to the grid**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost
Biomass Fuel Handling	new	$1,275,000	6%		$1,400,000	5%		$1,750,000	5%	
Fluidized Bed Boiler & Steam System.	new	$10,394,000	50%		$13,203,000	49%		$15,314,000	47%	
Ash Handling	new	$650,000	3%		$650,000	2%		$650,000	2%	
Emissions Control	new	$2,520,000	12%		$2,575,000	10%		$2,950,000	9%	
Steam Turbine Generator & Acc	new	$0	0%		$2,900,000	11%		$5,566,000	17%	
Steam Tube Dryer	new	$6,129,000	29%		$6,312,000	23%		$6,312,000	19%	
Total Cost: new items		$20,968,000	100%	$69,749,000	$27,040,000	100%	$89,697,000	$32,542,000	100%	$107,773,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-43%	($30,430,000)	($9,000,000)	-33%	($30,430,000)	($9,000,000)	-28%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$11,968,000	57%	$39,319,000	$18,040,000	67%	$59,267,000	$23,542,000	72%	$77,343,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$151,819,000**			**$171,767,000**			**$189,843,000**

Syrup and Corn Stover Combustion		**Process Heat Only**			**CHP**			**CHP plus electricity to the grid**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost
Biomass Fuel Handling	new	$1,275,000	7%		$1,400,000	6%		$1,750,000	6%	
Fluidized Bed Boiler & Steam System.	new	$9,264,000	53%		$11,731,000	52%		$13,867,000	49%	
Ash Handling	new	$650,000	4%		$650,000	3%		$650,000	2%	
Emissions Control	new	$2,481,000	14%		$2,517,000	11%		$2,565,000	9%	
Steam Turbine Generator & Acc	new	$0	0%		$2,600,000	11%		$5,497,000	20%	
Steam Tube Dryer	new	$3,700,000	21%		$3,810,000	17%		$3,810,000	14%	
Total Cost: new items		$17,370,000	100%	$57,928,000	$22,708,000	100%	$75,465,000	$28,139,000	100%	$93,308,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-52%	($30,430,000)	($9,000,000)	-40%	($30,430,000)	($9,000,000)	-32%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$8,370,000	48%	$27,498,000	$13,708,000	60%	$45,035,000	$19,139,000	68%	$62,878,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$139,998,000**			**$157,535,000**			**$175,378,000**

DDGS Gasification		**Process Heat Only**			**CHP**			**CHP plus electricity to the grid**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost
Biomass Fuel Handling	new	$790,000	4%		$890,000	4%		$990,000	4%	
Fluidized Bed Gasifier & Steam System.	new	$9,054,000	49%		$10,586,000	45%		$12,216,000	43%	
Ash Handling	new	$350,000	2%		$350,000	1%		$350,000	1%	
Emissions Control	new	$2,300,000	12%		$2,414,000	11%		$2,673,000	10%	
Steam Turbine Generator & Acc	new	$0	0%		$2,870,000	12%		$5,556,000	20%	
Steam Tube Dryer	new	$6,129,000	33%		$6,312,000	27%		$6,312,000	22%	
Total Cost: new items		$18,623,000	100%	$62,045,000	$23,422,000	100%	$77,811,000	$28,097,000	100%	$93,170,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-48%	($30,430,000)	($9,000,000)	-38%	($30,430,000)	($9,000,000)	-32%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$9,623,000	52%	$31,615,000	$14,422,000	62%	$47,381,000	$19,097,000	68%	$62,740,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$144,115,000**			**$159,881,000**			**$175,240,000**

Table 2. Nameplate installed costs for conventional and biomass-fueled dry-grind ethanol plants.

Type	190 MM liter (50 MM gallon) Plants		380 MM liter (100 MM gallon) Plants	
	Capital Cost	Name Plate Cost $/L ($/gal)	Capital Cost	Name Plate Cost $/L ($/gal)
Conventional	$112,500,000	$0.59 ($2.25)	$182,757,000	$0.48 ($1.83)
Corn Stover				
Process Heat	$151,819,000	$0.80 ($3,04)	$246,631,000	$0.65 ($2.47)
CHP	$171,767,000	$0.90 ($3.44)	$279,036,000	$0.73 ($2.79)
CHP + Grid	$189,843,000	$1.00 ($3.80)	$308,401,000	$0.81 ($3.08)
Corn Stover + Syrup				
Process Heat	$139,998,000	$0.74 ($2.80)	$227,427,000	$0.60 ($2.27)
CHP	$157,535,000	$0.83 ($3.15)	$255,916,000	$0.67 ($2.56)
CHP + Grid	$175,378,000	$0.92 ($3.51)	$284,902,000	$0.75 ($2.85)
DDGS				
Process Heat	$144,115,000	$0.76 ($2.88)	$234,116,000	$0.62 ($2.34)
CHP	$159,881,000	$0.84 ($3.20)	$259,727,000	$0.68 ($2.60)
CHP + Grid	$175,240,000	$0.92 ($3.50)	$284,678,000	$0.75 ($2.85)

Estimating Operating Costs and Other Baseline Assumptions

Table 3 contains the key baseline assumptions that affect profitability of the dry-grind ethanol plants being evaluated. It includes assumptions about the levels of debt and equity in the plant as well as the overall interest rate charged on the debt. A hurdle rate of return on equity can be established, and the number of years assumed for depreciation can be established.

Baseline ethanol price is established at $0.61/liter ($2.30/gallon) received at the ethanol plant. Corn price is assumed to be $197/tonne ($5.00/bushel) (for the next ten years) based on the 2007 Baseline Report of the U.S. Department of Agriculture. Natural gas is established at $10 per decatherm (1.06 million kJ or 1 million BTUs). Electricity is assumed to be priced at 6¢/kWh under baseline conditions, whether the plant is buying or selling.

DDGS are established at the price of $160/tonne ($145/ton). In the scenarios when the syrup is combusted, the resulting by-product is DDG, which we assume has a market value 110% of conventional DDGS. We base this on presumed attributes of greater consistency and the higher inclusion rates that DDG should offer to producers. Corn stover is assumed to be priced at $88/tonne ($80/ton) when it is delivered in a dry, densified form at the plant gate (Sokhansanj and Turhollow, 2004; Petrolia, 2006). The value of ash is assumed to be $220/tonne ($200/ton) based on reported values for the ash collected at Corn Plus Ethanol in Winnebago, MN.

The low-carbon premium is established at 5.3¢/liter (20¢/gallon) for each unit of ethanol produced using biomass, based upon the savings in transportation costs that accrue when California ethanol buyers are able to purchase ethanol having a carbon imprint 1/3 that of ethanol produced at conventional dry-grind plants using natural gas and purchased electricity. In biomass cases that produce only process heat, it is assumed that 90% of the maximum credit is captured when biomass substitutes for process heat. The Federal Renewable Energy Electricity Credit of 2¢/kWh is assumed to be received by the ethanol plant (even though it may be necessary for a private or corporate entity with sufficient passive income and tax liability to own the electrical generation equipment). There are additional minor assumptions including the Renewable Fuel Standard tradable credit of 1.8¢/liter (7¢/gallon) based on recent sales of Renewable Identification Number (RIN) certificates.

Table 4. Common assumptions for all systems.

Category	Baseline Values
Debt-Equity Assumptions	
Factor of Equity	40%
Factor of Debt	60%
Interest Rate Charged on Debt	8%
Depreciation Period	15 years
Output Market Prices	
Ethanol Price	$0.61/liter ($2.30/gallon)
DDGS Price	$160/tonne ($145/ton)
Electricity Sale Price	6¢/kWh
Sale Price of Ash	$220/tonne ($200/ton)
CO_2 Price per liquid unit	$8.80/tonne ($8/ton)
Low-Carbon Premium	5.3¢/liter (20¢/gallon)
Government Subsidies	
Federal Small Producer Credit	2.6¢/liter(10¢/gallon)
RFS Ethanol Tradable Credit	1.8¢/liter(7¢/gallon)
Federal Renewable Electricity Credit	2¢/kWh
Feedstock Delivered Prices Paid by Processor	
Corn Price	$197/tonne ($5.00/bushel)
Energy Prices	
Natural Gas	$10/decatherm
Stover Delivered to Plant	$88/tonne ($80/ton)
Electricity Price	6¢/kWh
Propane Price	$0.40/liter ($1.50/gallon)
Operating Costs—Input Prices	
Denaturant Price per gallon	$0.79/liter ($3.00/gallon)
Denaturant Rate (volume units per 100 of anhydrous)	5
Ethanol Yield (anhydrous)	0.41 liter/kg (2.75gallon/bushel)

Certain expense items can be considered scale-neutral and are applied equally in 190 million liter (50 million gallon) and 380 million liter (100 million gallon) per year plants. These include per liter (gallon) expenses for enzymes, yeasts, process chemicals & antibiotics, boiler & cooling tower chemicals, water and denaturants. We assumed 1.1¢/liter (4¢/gallon) of enzyme expense, 0.11¢/liter (0.4¢/gallon) of yeast expense, and processing chemicals & antibiotics of 0.53¢/liter (2¢/gallon) (Shapouri and Gallagher, 2005). We also assumed boiler and cooling tower chemical costs of 0.13¢ /liter (0.5¢/gallon) and water costs of 0.08¢/liter (0.3¢/gallon) of denatured ethanol produced. We assumed $120,000 of real estate taxes, $840,000 of licenses, fees & insurance, as well as $240,000 in miscellaneous expenses per year in the 190 million liter (50 million gallon) per year plants, whether powered by natural gas or biomass, with these figures doubled in the case of 380 million liter (100 million gallon) per year plants. We applied the conclusion that management and quality control costs represent one third of labor costs for large and small plants (Nicola, 2005).

Maintenance expenses of biomass plants were established by starting with the costs per liter (gallon) of ethanol produced in a natural gas-fired plant (Shapouri and Gallagher, 2005) and then determining maintenance costs of the biomass technology cases in proportion to the capital costs of each biomass bundle. To establish maintenance costs for the 380 million liter (100 million gallon) per year biomass plants, we applied the same scale-up factor as used for capital costs ($(2)^{0.7}$ or 1.6245) to the maintenance costs of the 190 million liter (50 million gallon) per year plant.

Labor expenses of biomass plants were established by starting with the costs per gallon of ethanol produced in a natural gas-fired plant (Shapouri and Gallagher, 2005) and then adding the estimates of additional labor needed in the biomass technology cases. A 190 million liter (50 million gallon) per year biomass-powered plant producing process heat can be expected to have $184,000 more in labor expense than its natural gas-fired counterpart (Nicola, 2005). We assumed an additional $184,000 increase in labor expense for the 190 million liter (50 million gallon) per year biomass cases that generate electricity. For labor costs of 380 million liter (100 million gallon) per year plants, we applied the conclusion that the larger plants spend 75% as much per liter (gallon) produced as the smaller plants (Kotrba, 2006). Thus, a 380 million liter (100 million gallon) per year natural gas-fired plant can be expected to spend $4.5 million per year in labor versus $3 million in a 190 million liter (50 million gallon) per year plant. A 380 million liter (100 million gallon) per year biomass plant producing process heat is expected to have $368,000 greater labor expense than its natural gas-fired counterpart (Nicola, 2005). We assumed an additional $368,000 in labor costs for the larger plants that generate electricity.

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