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BIOMASS-TO-ETHANOL
TOTAL ENERGY CYCLE ANALYSIS

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TABLE OF CONTENTS

Page

Executive Summary v

1.0 INTRODUCTION 1

2.0 BACKGROUND 2

3.0 PROCESS DESCRIPTION 3

3.1 Dryer 5
3.2 Fluidized Bed Boiler 5
3.3 Steam Turbine Generator 7
3.4 Condenser/Makeup Water Heater 8
3.5 Deaerator 8
3.6 Boiler Feed Pump 8
3.7 Water Treatment 8

4.0 SYSTEM PERFORMANCE SUMMARY 8

4.1 Boiler/Dryer Subsystem 9
4.2 Turbogenerator/Condenser Subsystem 10
4.3 Boiler Feed Water Preparation Subsystem 11
4.4 Emissions Summary 11

5.0 COST SUMMARY 12

5.1 Equipment Costs 12
5.2 Installed Costs 13
5.3 Annual Operating Costs 13

6.0 DISCUSSION 14

6.1 Fluidized Bed Boiler 14
6.2 Fluidized Bed Dryer 15
6.3 Turbogenerator/Condenser 16
6.4 Boiler Chemical Treatment 17
6.5 Boiler Feed Water Preparation 17
6.6 Estimated Emissions 17

TABLE OF CONTENTS

Page

APPENDIX A - Fluidized Bed Boiler Performance Summary A-1
APPENDIX B - Turbogenerator Performance Summary B-1
APPENDIX C - Cost Analysis Summary C-1
APPENDIX D - Biomass-to-Ethanol Steam Cycle Basis D-1

LIST OF FIGURES

		Page
1	Boiler and Steam System Biomass-to-Ethanol Process	4

LIST OF TABLES

		Page
	LEGEND	19
1	Waste Stream Inputs - Pacific Northwest	20
2	Boiler/Dryer Subsystem - Pacific Northwest	21
3	Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Pacific Northwest	22
4	Waste Stream Inputs - Northeast	23
5	Boiler/Dryer Subsystem - Northeast	24
6	Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Northeast	25
7	Waste Stream Inputs - Southeast	26
8	Boiler/Dryer Subsystem - Southeast	27
9	Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Southeast	28
10	Waste Stream Inputs - Great Plains	29
11	Boiler/Dryer Subsystem - Great Plains	30

LIST OF TABLES (Continued)

		Page
12	Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Great Plains	31
13	Waste Stream Inputs - Midwest/Lake St.	32
14	Boiler/Dryer Subsystem - Midwest/Lake St.	33
15	Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Midwest/Lake St.	34
16	Waste Stream Inputs - Municipal Solid Waste	35
17	Boiler/Dryer Subsystem - Municipal Solid Waste	36
18	Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Municipal Solid Waste	37
19	Thermal Efficiency Summary	38
20	Emissions Summary	39
21	Equipment Cost Summary, $Million	40
22	Installation Costs, $Million	41
23	Operating Cost Summary, $Million	42

EXECUTIVE SUMMARY

Radian Corporation, under contract to National Renewable Energy Laboratory, has conducted a Total Energy Cycle Analysis for a waste-fired steam boiler. The boiler produces high pressure steam to drive a turbogenerator for the production of electrical energy for export and extraction steam for use in a Biomass-to-Ethanol Process. The energy cycle consists of a fluidized bed boiler, a slurry waste stream dryer, a turbogenerator, and boiler feedwater and make-up water treatment systems. Six cases were investigated having installed capital costs that range from $43.95 million to $58.17 million. Annual operating costs vary from $12.60 million to $16.73 million. Electrical power generation from the process has a minimum output of 15.90 MW for Case 6 and a maximum of 36.49 MW for Case 1. Extraction steam for the process is provided at a rate of 43,100 pounds per hour after pressure of 50 psig and between 155,400 and 172,000 pounds per hour at 150 psig pressure. The value of the energy produced ranges from $11.063 million to $18.991 million. Estimated emissions of SO_2, CO, NO_x, and VOC from the process may require additional air pollution control, based on the 1990 Clean Air Act Amendments.

1.0 INTRODUCTION

National Renewable Energy Laboratory (NREL) has been contracted by the Department of Energy to develop technologies that will produce fuel grade ethanol from renewable biomass resources. One such technology that is being investigated is the use of lignocellulosic biomass-to-ethanol. NREL will work closely with industry to move the new technology from the laboratory to the marketplace.

An important part of the biomass-to-ethanol conversion process is a waste-fired steam boiler which produces high pressure steam to drive the turbogenerator. Since the electricity produced by the turbogenerator, in excess of internal process demand, may be sold to provide revenue, the thermal efficiencies of both the boiler and the turbogenerator are important factors in the overall economics of the process.

One of the current projects in the overall Biomass-to-Ethanol program is the Biomass-Ethanol Total Energy Cycle Analysis. The objective of this analysis is to characterize the economic consequences of transportation fuel additives. NREL has contracted with Radian Corporation to perform this study. The major objective of this study is to evaluate the performance of a high pressure boiler system in the Biomass-to-Ethanol process including identification of inputs required, outputs generated, and emissions released.

Presented in this study is a proposed boiler system with system performance characterization for each of the cases provided. Included are the following:

1. Technical description of the proposed boiler system including the technologies assumed.

2. Preliminary equipment description and capital cost estimate for the proposed system.

3. Quantitative summary of the inputs required by, and the outputs and estimated emissions resulting from the operation of the boiler, including labor, boiler chemicals, electricity, makeup water, boiler blowdown, flue gas, ash, and steam.

4. A summary of the environmental emissions and effects of the fuel cycle as itemized in "Environmental Emissions and Concerns for Reformulated Gasoline Fuel Cycle Analysis", a copy of which is presented in Appendix A.

2.0 BACKGROUND

NREL has identified waste streams for six individual sites. These streams include two low-Btu gas streams, one liquid stream, and two sludge streams. The compositions, flow rates, temperatures, and pressures of the waste streams at the various sites are summarized in Appendix A. The waste stream information is based on projections for the year 2000 for one of the sites and the year 2010 for the remaining sites.

A conceptual design for the high-pressure steam cycle utilizing waste stream firing was presented in an earlier study by Badger. That performance evaluation was based on a system that included a boiler with steam distribution, a boiler feed water system, and a turbogenerator. A description of the Badger system is included in Appendix B of this report.

In general, the Badger system consisted of a boiler that burned gaseous and solid fuels to generate 1100 psia steam with 300°F superheat. Steam from the boiler was sent to a turbogenerator which produced about 36 MW of electrical power and supplied extraction steam to the biomass-ethanol process at 150 and 50 psig, respectively. The remaining steam was discharged and condensed in a surface condenser at 89 mm Hg. The condensate was returned to the boiler feed water system and recycled back to the boiler. The boiler feed water system consisted of a condensate collection system, a

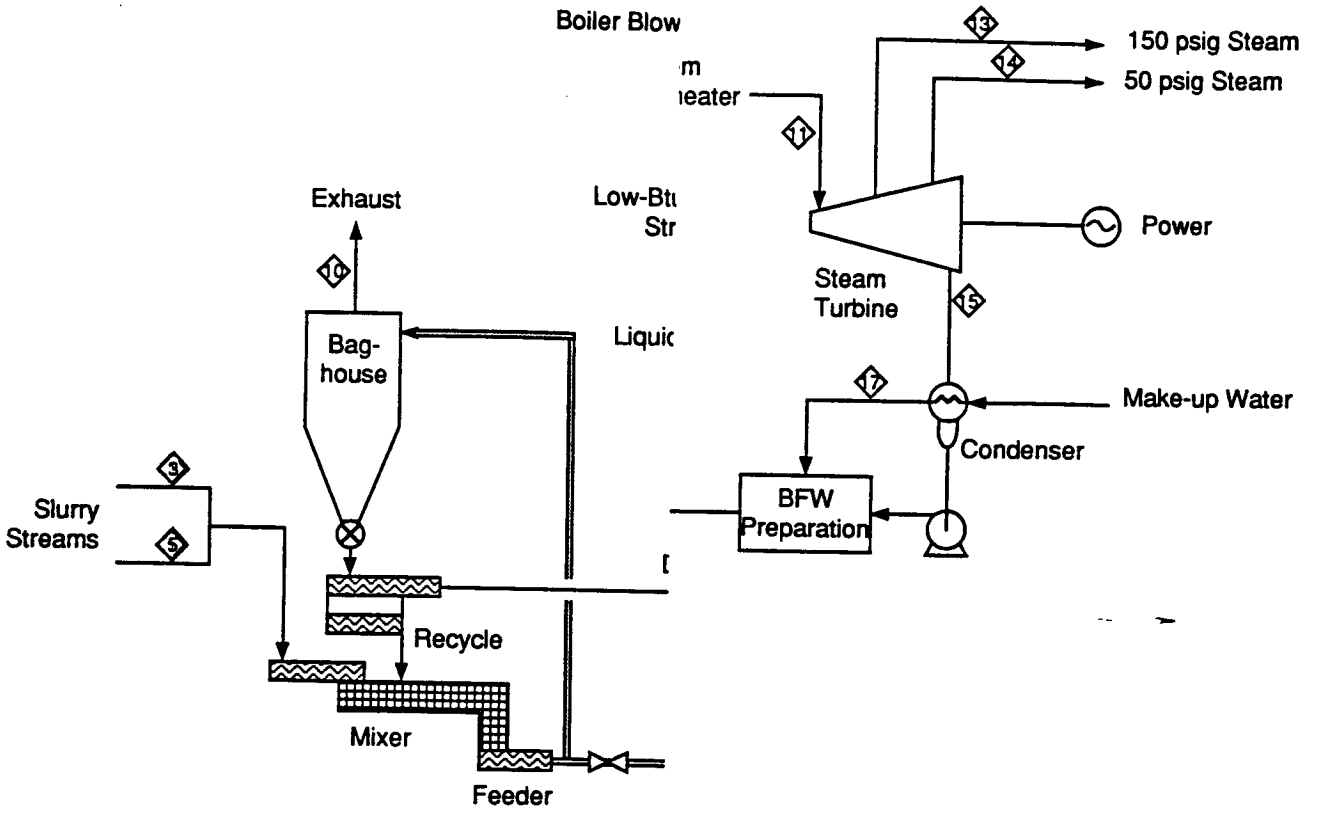
deaerator, and a chemical feed system consisting of hydrazine, ammonia, and phosphate addition.

3.0 PROCESS DESCRIPTION

The waste-fired boiler system selected for this study includes a fluidized bed boiler for waste stream combustion and high-pressure steam generation, a dryer/baghouse unit to reduce the moisture content of the two slurry waste streams and remove particulate matter from the flue gas, a turbogenerator with 150 psig and 50 psig process steam extraction, a turbine exhaust steam condenser, a boiler feed water preparation system, and a makeup water treatment system. The process is shown schematically in Figure 1.

From the six sites or cases considered for the Biomass-to-Ethanol process, the waste fuel streams were fed into the fluidized bed boiler system. Slurry streams 3 and 5 were introduced into a fluidized bed dryer for moisture removal by direct contact with boiler flue gas. For expediency of the study preparation, it was estimated that the fluidized bed dryer would lower the moisture in streams 3 and 5 to 35% by weight for introduction into the fluidized bed boiler. Subsequent to this assumption, the actual dryer data received from the suppliers indicated that the delivered moisture content of the Numbers 3 and 5 streams to the boiler may be limited to about 41%. This subject will be addressed in greater detail later in this report.

The vapor stream from the fluidized bed dryer passes through a baghouse to remove particulate matter which is then introduced into the boiler. An optional scrubbing step may be required if light organics are present in streams 3 and 5. The light organics could be stripped in the drying step and add greatly to the VOC loading in the flue gas vent stream.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Make-up Water
Condenser
Slurry
Streams
BFW
Preparation
Recycle
Mixer
Feeder

3.1 Dryer

A fluidized dryer was selected on a preliminary analysis because of the large quantities of boiler flue gas available at 300°F and the high moisture content of the Numbers 3 and 5 streams. This analysis was performed even though the fluidized boiler can accept and operate with fuels that have moisture contents over 50%.

Three suppliers were contacted for their preliminary inputs to the drying process. Two responded positively with caveats of a more precise analysis of the material being dried, while the third would only comment on an estimated moisture output content. All these suppliers recommended that testing be performed to verify the drying process for the specific slurry stream.

The drying process is very critical because lignin melts at 130°C; therefore, the material must be prevented from reaching that temperature. If a good distribution of the material can be reached in the feeding section, the flue gas at 300°F can be used without any dilution. A mechanical feeding system has been suggested feeding into a conical shaped inlet section permitting a high velocity and then expanding to give a 10 meter per second velocity. This depends greatly on the particle size breakdown; therefore, a detailed sieve analysis would be required as the next analysis step. For purposes of this study, we assumed the drying could be achieved.

For the six cases studies, the flue gas flow range is 842,000 lb/hr to 602,000 lb/hr at 300°F. Biomass fuel flow ranges from 123,000 lb/hr to 101,000 lb/hr.

3.2 Fluidized Bed Boiler

An Ahlstrom Pyroflow circulating fluidized bed combustion boiler was selected for purposes of this study because of its inherent high flexibility of fuel firing. In addition, a fluidized bed boiler has the capability for lower sulfur emissions, a high

combustion efficiency, elimination of slagging, and low NO_x emissions, as well as a high turndown rate. It was recommended that for optimum turbogenerator operating efficiencies, 1500 psia steam be generated at 950°F superheat.

Fuel and bed materials are fed into the lower portion of the combustion chamber in the presence of fluidizing air. The turbulent environment causes the fuel and bed materials to mix quickly and uniformly. Fluidizing air causes the fuel and bed materials to circulate and rise quickly throughout the combustion chamber and enter the hot cyclone collector. Hot flue gases and fly ash are separated from the coarse solids in the cyclone. Solids, including any unburned fuel, are reinjected into the combustion chamber through the non-mechanical loopseal. Continuous circulation through the system provides a longer fuel residence time, resulting in higher combustion efficiencies. The relatively low combustion temperature and the introduction of secondary air at various levels above the grid provides for staged combustion and limits the formation of NO_x. After the hot cyclone, the flue gas passes through the convection pass containing superheat, economizer, and air preheating surface. Flue gas then enters a dryer/baghouse system where the flue gas is cooled and particulate matter is removed.

Feed water enters the economizer and flows to the steam drum. Water from the steam drum is supplied from downcomers to the boiler walls where it is evaporated. As the steam water mixture absorbs heat, it rises up the water wall tubes and is collected in the upper header and is then transferred to the drum where steam and water are separated. Dry, saturated steam leaves the drum and is delivered to the superheater and is finally delivered to the main steam turbine steam header at 1500 psia with 950°F superheat.

For the six cases studied, steam conditions at full load range from 395,000 lb/hr to 213,000 lb/hr. Flue gas produced ranges from 842,000 lb/hr to 602,000 lb/hr. Ash produced ranges from 14,985 lb/hr to 8,284 lb/hr.

3.3 Steam Turbine Generator

The Biomass-to-Ethanol process required double steam extraction levels at 150 psig and 50 psig from the steam turbine. All six cases require 43,100 lb/hr of 50 psig steam. The requirements for 150 psig steam range from 155,400 lb/hr to 172,000 lb/hr.

We requested preliminary information from three turbine vendors. We received very complete information from two vendors. The third could not respond due to a heavy work load, but expressed a strong desire to support the project.

In both of the vendor responses, it was recommended that back-pressure turbines be supplied for all cases except Pacific Northwest. The remaining steam after extraction would be used to preheat the very large quantities of makeup water. The quantity of makeup water for this project estimated at over 400 gpm, as an example, is comparable to that of a 500 MW power plant. For Pacific Northwest, a condensing turbine was recommended for the approximately 80,000 lb/hr of steam remaining after extraction and feed water heating.

The turbines that were recommended were high speed, utilizing a reducing gear driving an 1800 rpm generator. The units selected are standard offerings with many years of reliable demonstrated service. In fact, one supplier provided information showing availability over 99.5%.

Modular designs were quoted offering case of installation, performance, servicing, operational cycling time, and reliability. The electrical output for the six cases ranged from 15.9 MW to 36.49 MW.

3.4 Condenser/Makeup Water Heater

Steam discharged from the turbogenerator is used to preheat boiler feed water to 335°F prior to being fed into the economizer. Case 1 requires that a condenser be furnished to condense steam at 89 mm of Hg. It was assumed that water for cooling was available at 50°F. Approximately 6500 square feet of condenser surface area is required. In Cases 2 through 5, the preheat requirement for the makeup water is sufficient to condense the steam discharged from the turbogenerator. In Case 6, there is not sufficient additional steam to provide makeup water preheat.

3.5 Deaerator

An 800 gpm unit was selected to ensure removal of noncondensable gases, oxygen, and carbon dioxide from the return condensate and makeup boiler feed water.

3.6 Boiler Feed Pump

Horizontal, centrifugal, multi-stage, electric-driven pumps were selected.

3.7 Water Treatment

We have assumed high mineral content for the makeup water, therefore, requiring a large water treatment system. It will include carbon, multimedia, and cartridge filtration utilized in conjunction with a reverse osmosis system and mixed bed exchangers.

4.0 SYSTEM PERFORMANCE SUMMARY

The biomass-to-ethanol high-pressure boiler system is designed to burn gaseous, liquid, and sludge waste streams in a fluidized bed boiler and generate 1500

psia steam with 950°F superheat. Moisture in the sludge streams is reduced to 35% in a dryer which utilizes flue gas from the fluidized bed boiler to vaporize water. The steam is used to generate electricity in a turbogenerator and provide process steam at 50 psig and 150 psig by extraction from the turbine. Excess steam is condensed by preheating makeup boiler feed water, with both streams being treated by a boiler feed water preparation system. The system performance is evaluated in three subsystems consisting of a boiler/dryer section, a turbogenerator/condenser section, and a boiler feed water preparation section.

Process information is presented for all six sites in Tables 1-18. The discussion of system performance that follows is primarily for the Pacific Northwest site with exceptions as noted for variations at the other five sites.

4.1 Boiler/Dryer Subsystem

Waste streams 1 and 2 are vapor streams which are combined and injected directly into the fluidized bed boiler in addition to stream 2, a liquid waste. Streams, 3 and 5, are sludge wastes which are combined and sent to a dryer for moisture removal prior to being introduced into the boiler. Flue gas from the boiler, at a temperature of 300°F, contacts the sludge streams and reduces the moisture content to about 35%. The saturated flue gas exits the dryer at about 150°F and passes through a baghouse where the "dried" solids are removed, collected, and conveyed to the boiler.

Water removal to achieve 35% moisture in the solids represents the maximum which can be achieved with 300°F flue gas for this case, since the flue gas is cooled to saturation under these conditions. This may not be practical if a baghouse is required for solids capture. The large exposed surface area in the baghouse may cause condensation of water vapor in the flue gas and lead to plugging problems in the bags. In order to ensure that the bags remain dry, it may be necessary to operate the boiler with a flue gas exit temperature of 450°F in order to make certain that the flue gas from

the dryer has a minimum temperature of 300°F. The bags will remain dry, as condensation should not occur at this temperature. If this should be necessary, it may be better to eliminate the dryer and feed waste streams 3 and 5 with no external drying. The boiler efficiency will be essentially the same for the case where "wet" sludge streams are fed to the boiler with 300°F flue gas as for the case where the boiler is operated at a flue gas temperature of 450°F for moisture removal across the dryer.

The bed of the boiler is operated at approximately 1600°F with 20% excess air to ensure that adequate combustion of the waste streams is achieved. As shown in Table 19 - Thermal Performance Summary, a total heat release of 607 million Btu/hr occurs in the boiler. The boiler generates 395,000 pounds per hour of 1500 psia steam with 950°F superheat. Based on vendor calculations, the boiler efficiency is 75.05% at 300°F flue gas outlet temperature, which includes a 6.5% loss due to moisture in the fuel and a 1% loss due to unburned carbon. If the dryer is eliminated, the boiler will generate 355,500 pounds per hour steam and the efficiency will drop to 69.05%.

4.2 Turbogenerator/Condenser Subsystem

The turbogenerator capacity is based on steam at 1500 psia with 950°F superheat. The output for Case 1 is about 35 MW and the turbogenerator efficiency is 28.3% not including the extraction steam. The overall efficiency including extraction steam is 61.38%.

The condenser portion of the subsystem condenses the non-extraction portion of 150 psig and 50 psig steam discharged from the turbine by heating incoming boiler feed water makeup. For Case 1, additional steam is discharged into vacuum from a low-pressure turbine and requires additional condenser surface and cooling water. For Cases 2 through 5, the boiler feed water heaters have sufficient duty for condensing the 150 psig and 50 psig steam discharged from the turbine. For these cases, the low-

pressure turbine is not required. In Case 6, there is not sufficient steam remaining after the extraction steam has been removed to justify boiler feed water heaters.

4.3 Boiler Feed Water Preparation Subsystem

Condensate is collected from the boiler feed water heaters and the surface condenser, combined with return condensate from the process and makeup water in the condensate collection tank. Condensate and makeup water is transferred by the deaerator feed pumps to the deaerator. The deaerator operates at 10 psig and is supplied low-pressure steam from the 50 psig steam header.

Deaerated boiler feed water is treated with hydrazine and ammonia in the deaerator. Ammonia is mixed with condensate in the ammonia addition unit and then is fed to the deaerator. Phosphate dumped from bags is mixed with condensate in the phosphate addition unit and then used to dose the boiler steam drums.

Deaerated and treated boiler feed water at 220°F is heated to 335°F in boiler feed water heaters and transferred by the high-pressure boiler feed water pumps into the boiler.

4.4 Emissions Summary

The primary source of emissions is the vapor vent from the baghouse. The emissions of concern are SO_2, NO_x, CO, VOC, acetaldehyde, formaldehyde, and PM10. A summary for these is presented in Table 20 for each case. The values are estimates based on Pyropower's experience with wood wastes as a fuel and Radian's extensive emission monitoring of fluidized bed boilers firing coal. The emission rates in Table 20 are estimates, assuming no additional air pollution controls such as the injection of limestone for SO_2 removal or ammonia for NO_x control.

The only liquid release is the boiler blowdown stream. This stream contains 5 ppm dissolved solids and will have a temperature of 300°F. This stream may require treatment prior to discharge from the plant.

Ash from the fluidized bed boiler, consisting primarily of gypsum, will be collected in the baghouse and cyclone for disposal. The bottom ash removal is cooled to about 200°F in an ash cooler that utilizes flue gas or combustion air. Light particles are entrained by the combustion air and injected back into the fluidized bed for ultimate removal from the baghouse. The estimated split between bottom ash and flyash is 50% - 50%.

5.0 COST SUMMARY

A cost analysis was performed for each of the six sites plus two optional cases for Site 1. The complete spreadsheets used for the economic analyses are presented in Appendix A.

5.1 Equipment Costs

Budget estimates for the equipment items were provided by vendor quotes. Table 21 shows the total equipment costs for each of the six sites. These costs range from $25.4 million to $33.76 million. A listing of the vendors supplying pricing is as follows:

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Equipment	Vendor
Dryer	Carrier Vibrating Equipment ABB Environmental Systems
Fluidized Bed Boiler	Ahlstrom Pyropower
Turbogenerator	ABB Power Generation GEC Alsthom International General Electric
Boiler Chemical Feed Treatment	Betz Laboratories
Boiler Feedwater Preparation	Zurn/Permutit Fluid Systems Sales Co. Joy/Ecolaire
Make-up Water Pretreatment	Zurn/Permutit

5.2 Installed Costs

The factors for the installation and indirect capital cost were taken directly from the values suggested by the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual printed by the EPA in January 1990. The manual provides cost factors, as a fraction of the total equipment cost, in order to determine total installation (foundations, erection, electrical, etc.) and indirect capital (engineering, contractor fees, start-up, etc.) costs within ±30 percent accuracy. Total capital cost is then determined by the sum of the total equipment cost, total installation cost, and total indirect capital cost. Table 22 shows the total capital cost for the eight different cases. Installation costs range from $16.44 million to $21.71 million.

5.3 Annual Operating Costs

Total annual operating costs were calculated for all eight cases. These are shown in Table 23. The total annual operating cost is made up of recurring expenses (such as labor, maintenance materials, utility credits and costs, and ash disposal) and indirect costs (such as capital recovery, overhead, insurance, and taxes). Major contribu-

tions to the total annual operating costs are maintenance materials, utility credits, ash disposal, and capital recovery.

Export electricity and steam are shown as a utility credit which offsets the actual operating cost. These costs are most dependent on the unit values selected for utility credits. For example, Site 1 shows a net profit of $2.2 million with the assumption that the site could sell produced electricity for $0.05 per kw hr. A $0.01 change in the value of electricity would result in a $2.8 million change in the credit. Minor changes in the other major contributors do not have this dramatic affect. There is a significant cost for each site for ash disposal. These values were calculated using a landfilling cost of $75 per cubic yard and an ash density of 80 lb per cubic foot. Annual operating costs vary from $16.73 million for Case 1 to $12.60 for Case 3. These costs are offset by utility credits that vary from $18.95 million for Case 1 to $11.06 million for Case 6.

6.0 DISCUSSION

6.1 Fluidized Bed Boiler

A fluidized bed boiler was chosen as the technology to treat the waste streams from the Biomass-to-Ethanol Process because of its capability to combust a variety of waste fuels, including gases, liquids, and solids. This approach offers the flexibility of accepting either "wet" or "dried" slurry wastes with essentially no decrease in combustion efficiency. The low operating temperature in the bed results in lower NO_x emissions and greatly eliminates the potential for slagging.

Thermal cycles within the boiler system include a superheat section, convection section, economizer, and air preheat. Flue gas exits the boiler at 300°F. The resulting thermal efficiencies based on higher heating values are 75.05% for Case 1 down to 67.75% for Case 6. The efficiency based on lower heating values would be 81.58% and 76.25% for the respective cases. Steam generation at 1500 psia with 950°F

superheat was chosen to maximize the electrical output of the turbogenerator within an acceptable operating pressure range for the boiler.

Thermal efficiencies for the boiler are based on gross or higher heating values for the waste fuels being fired. By operating at higher steam pressures and temperatures, the overall boiler efficiency could be increased by 1 to 2 percentage points. By utilizing a pressurized combustion system to provide a combined cycle approach (both gas- and steam-driven turbines for electrical power generation), the overall efficiency of the system could be increased by 10 percentage points.

6.2 Fluidized Bed Dryer

A fluidized bed dryer using 300°F flue gas from the boiler to remove moisture in the slurry waste streams from a nominal level of 50 wt % down to 35 wt % increases boiler efficiency by 5%. At this level of moisture removal, the flue gas from the dryer system will approach saturation for Cases 1 and 6 and will be approximately 50°F higher than saturation for Cases 2 through 5. Saturated flue gas may pose a problem for baghouse operation in Cases 1 and 2 due to the potential for condensation and bag pluggage.

This problem may be overcome by operating the boiler with a higher flue gas outlet temperature. Should a flue gas temperature of 450°F be required for the boiler outlet to achieve acceptable dryer performance, overall boiler efficiency will not significantly increase, compared to no moisture removal and a boiler flue gas temperature of 300°F. That is, the decrease in boiler efficiency due to the increase in flue gas temperature will approximately equal the increase in boiler efficiency due to moisture removal prior to combustion. For all cases, the dryer vendors recommend testing prior to applying dryer technology to the boiler system.

6.3 Turbogenerator/Condenser

The turbogenerator for Case 1 has a high-pressure turbine which takes steam in at 1500 psia with 950°F superheat and discharges at a nominal 50 psig. The 150 psig extraction steam requirement is produced in this stage along with an additional 24,698 pounds per hour of 150 psig steam that is used to preheat boiler feed water. Approximately 25 MW is produced in the high-pressure turbine. The 50 psig steam from the high-pressure turbine is then split to provide the 50 psig extraction steam requirement. Additionally, 59,377 pounds per hour is routed to the deaerator and approximately 112,000 pounds per hour is introduced into a low-pressure turbine which discharges at 89 mmHg pressure to produce about 10 MW of electrical energy. This steam is condensed and fed to the deaerator.

For Cases 2 through 6, a single high-pressure turbine takes steam in at 1500 psia with 950°F superheat and discharges steam at a nominal pressure of 50 psig. The 150 psig steam required by the process is extracted from the turbine and the 50 psig process steam is split from the discharge, with the remaining 50 psig steam going to the deaerator. Additional 150 psig extraction steam is used in the boiler feed water heaters. A process schematic for each case is presented in Appendix B.

Efficiencies vary with each size of turbine. The efficiencies quoted were conservative due to the budgetary nature of the quote. Actual operating efficiencies could be 1.5% higher for a rigorously designed turbogenerator system. By redesigning the steam injection nozzles, utilizing streamlined blade designs, and operating the turbine at higher speeds, the turbogenerator efficiency could be increased an additional one percentage point.

6.4 Boiler Chemical Treatment

A typical treatment system consisting of phosphate addition to minimize scale build-up, hydrazine addition for oxygen scavenging, and amine addition for pH balance was chosen. Although chemical addition requirements vary from site to site, typical addition rates were recommended by Betz Laboratories using their packaged products.

6.5 Boiler Feed Water Preparation

A conventional deaerator and boiler feed water heater system was chosen. The deaerator operates at 10 psig and uses 50 psig steam from the turbine to strip noncondensables from the condensate return and boiler feed water make-up streams. Most of the 50 psig steam is condensed in the deaerator and returned as boiler feed water.

6.6 Estimated Emissions

The estimated emissions rates for SO_2, NO_x, CO, VOCs, and PM10 were supplied by Pyropower, based on their experience with burning wood wastes. The values for PM10 were assumed to be the total particulate in the vent stream from the baghouse. The levels of acetaldehyde and formaldehyde were based on stack testing for coal-fired fluidized bed boilers for which these components were analyzed. The emission rates of SO_2, NO_x, and CO may result in the need for air pollution control devices to reduce the levels of emissions.

The Clean Air Act of 1990 regulates VOC, NO_x, and CO according to five classifications: 1) marginal (up to 10 tons/year); 2) moderate (between 10 and 24 tons/year); 3) serious (25+ to 50- tons/year); 4) severe (50+ to 10- tons/year), and 5) extreme (greater than 100 tons/year). The emission rates of both NO_x and CO will

be in the extreme category, while VOCs will fall in the severe range. All severe polluters must have treatment technologies in operation by the year 2007, and extreme polluters by 2010. NO_x can be reduced by about 60% by direct ammonia injection. VOCs and CO can be reduced by operating the bed at a higher temperature with additional excess oxygen.

The requirement for SO_2, beginning in the year 2000, will be 1.2 lb SO_2/million Btu. The emission rate for the maximum case (Cases 4 and 5) is 1.5-1.7 lb SO_2/million Btu. This level can be reduced to below the requirement by the addition of limestone to the bed.

LEGEND		
Case	Site	Conditions
1	Pacific Northwest	Sludge dryers; boiler flue gas at 300 °F; turbine exhaust to vacuum
1A	Pacific Northwest	Sludge dryer; boiler flue gas at 450 °F; turbine exhaust to vacuum
1B	Pacific Northwest	No sludge dryer; boiler flue gas at 300 °F; turbine exhaust to vacuum
2	Northeast	Sludge dryer; boiler flue gas at 300 °F; turbine exhaust at 50 psig
3	Southeast	Sludge dryer; boiler flue gas at 300 °F; turbine exhaust at 50 psig
4	Great Plains	Sludge dryer; boiler flue gas at 300 °F; turbine exhaust at 50 psig
5	Midwest/Lake St.	Sludge dryer; boiler flue gas at 300 °F; turbine exhaust at 50 psig
6	Municipal Solid Waste	Sludge dryer; boiler flue gas at 300 °F; turbine exhaust at 50 psig

Table 1

Waste Stream Inputs - Pacific Northwest

	Stream No. 1		Stream No. 2		Stream No. 3		Stream No. 4		Stream No. 5		Stream No. 6		Stream No. 7	
	Temperature 100°F		Temperature 100°F		Temperature 220°F		Temperature 100°F		Temperature 70°F		Temperature 100°F		Temperature 200°F	
	Pressure 10 psig		Pressure 25 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig	
Component	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
Water	0	0.00	45	33.68	58197	48.09	91	3.53	789	50.00	91	2.48	24742	28.01
Cellulose	0	0.00	0	0.00	8	0.01	0	0.00	0	0.00	0	0.00	8	0.01
Soluble Solids	0	0.00	0	0.25	5069	4.19	0	0.00	0	0.00	0	0.00	5069	5.74
Ash	0	0.00	0	0.09	2627	2.17	0	0.00	0	0.00	0	0.00	2627	2.97
Lignin	0	0.00	0	0.04	43701	36.12	0	0.00	49	3.09	0	0.00	43750	49.53
Crude Protein	0	0.00	0	0.03	1398	1.16	0	0.00	37	2.35	0	0.00	1435	1.62
Xylose	0	0.00	0	0.06	104	0.09	0	0.00	0	0.00	0	0.00	104	0.12
WHF	0	0.00	0	0.02	40	0.03	0	0.00	0	0.00	0	0.00	40	0.04
Gypsum	0	0.00	0	0.07	4884	4.04	0	0.00	78	4.93	0	0.00	4962	5.62
CO_2	0	0.00	0	0.00	0	0.00	1349	52.09	0	0.00	1349	36.76	0	0.00
Cellulase	0	0.00	0	0.00	21	0.02	0	0.00	0	0.00	0	0.00	21	0.02
Ethanol	57	5.25	0	0.00	0	0.00	0	0.00	0	0.00	57	1.55	0	0.00
Fusal Oils	0	0.00	87	65.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Glycerol	0	0.00	1	0.73	1332	1.10	0	0.00	0	0.00	0	0.00	1332	1.51
Acetaldehyde	1024	94.75	0	0.00	0	0.00	0	0.00	0	0.00	1024	27.90	0	0.00
Cell Mass	0	0.00	0	0.02	3624	3.00	0	0.00	625	39.63	0	0.00	4249	4.81
Methane	0	0.00	0	0.00	0	0.00	1149	44.38	0	0.00	1149	31.31	O	0.00
TOTAL	1080	100.00	134	100.00	121005	100.00	2590	100.00	1577	100.00	3670	100.00	88339	100.00

Table 2

Boiler/Dryer Subsystem - Pacific Northwest

Component	Stream No. 8		Stream No. 9		Stream No. 10		Stream No. 11		Stream No. 12		Stream No. 18	
	Temperature 100°F		Temperature 300°F		Temperature 150°F		Temperature 950°F		Temperature 609°F		Temperature 200°F	
	Pressure 0.5 psig		Pressure 0 psig		Pressure 0 psig		Pressure 1515 psig		Pressure 1640 psig		Pressure 0 psig	
	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
CO_2	0	0.00	146750	17.42	146750	16.74	0	0.00	0	0.00	0	0.00
O_2	171821	22.94	28560	3.39	28560	3.26	0	0.00	0	0.00	0	0.00
N_2	569689	76.06	569310	67.58	569310	64.94	0	0.00	0	0.00	0	0.00
H_2O	7490	1.00	97800	11.61	132040	15.06	0	0.00	0	0.00	0	0.00
SO_2	0	0.00	40	26 ppmv	40	26 ppmv	0	0.00	0	0.00	0	0.00
NO_x	0	0.00	243	215 ppmv	243	215 ppmv	0	0.00	0	0.00	0	0.00
CO	0	0.00	91	133 ppmv	91	133 ppmv	0	0.00	0	0.00	0	0.00
VOC	0	0.00	15	39 ppmv	15	39 ppmv	0	0.00	0	0.00	0	0.00
PM10	0	0.00	18	.08 gr/acf	18	.08 gr/acf	0	0.00	0	0.00	0	0.00
Ash	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8266	100.00
Steam	0	0.00	0	0.00	0	0.00	395000	100.00	0	0.00	0	0.00
Boiler Blowdown	0	0.00	0	0.00	0	0.00	0	0.00	3990	100.00	0	0.00
TOTAL	749000	100.00	842827	100.00	877067	100.00	395000	100.00	3990	100.00	8266	100.00

Table 3

Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystems - Pacific Northwest

Component	Stream No. 13 Temperature 366°F Pressure 150 psig lb/hr	Stream No. 14 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 15 Temperature 121°F Pressure 1.72 psia lb/hr	Stream No. 16 Temperature 335°F Pressure 1700 psig lb/hr	Stream No. 17 Temperature 50°F Pressure 50 psig lb/hr
Makeup Water	0	0	0	0	202490
Steam	43100	155400	196500	0	0
Boiler Feed Water	0	0	0	398990	0
TOTAL	43100	155400	196500	398990	202490

Table 4

Waste Stream Inputs - Northeast

	Stream No. 1		Stream No. 2		Stream No. 3		Stream No. 4		Stream No. 5		Stream No. 6		Stream No. 7	
	Temperature 100°F		Temperature 100°F		Temperature 220°F		Temperature 100°F		Temperature 70°F		Temperature 100°F		Temperature 200°F	
	Pressure 10 psig		Pressure 25 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig	
Component	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
Water	0	0.00	38	32.69	48704	46.60	144	3.53	1314	50.00	144	2.87	30763	35.00
Cellulose	0	0.00	0	0.00	7	0.01	0	0.00	0	0.00	0	0.00	7	0.01
Soluble Solids	0	0.00	1	0.93	14160	13.55	0	0.00	0	0.00	0	0.00	14160	16.11
Ash	0	0.00	0	0.21	4502	4.31	0	0.00	0	0.00	0	0.00	4502	5.12
Lignin	0	0.00	0	0.03	21405	20.48	0	0.00	32	1.22	0	0.00	21437	24.39
Crude Protein	0	0.00	0	0.20	6381	6.10	0	0.00	223	8.49	0	0.00	6604	7.51
Xylose	0	0.00	0	0.12	183	0.18	0	0.00	0	0.00	0	0.00	183	0.21
WHF	0	0.00	0	0.02	37	0.03	0	0.00	0	0.00	0	0.00	37	0.04
Gypsum	0	0.00	0	0.08	4911	4.70	0	0.00	75	2.87	0	0.00	4986	5.67
CO_2	0	0.00	0	0.00	0	0.00	2123	52.09	0	0.00	2123	42.24	0	0.00
Cellulase	0	0.00	0	0.00	21	0.02	0	0.00	0	0.00	0	0.00	21	0.02
Ethanol	60	6.30	0	0.00	0	0.00	0	0.00	0	0.00	60	1.19	0	0.00
Fusal Oils	0	0.00	76	65.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Glycerol	0	0.00	1	0.72	1139	1.09	0	0.00	0	0.00	0	0.00	1139	1.30
Acetaldehyde	890	93.70	0	0.00	0	0.00	0	0.00	0	0.00	890	17.71	0	0.00
Cell Mass	0	0.00	0	0.02	3072	2.94	0	0.00	983	37.43	0	0.00	4055	4.61
Methane	0	0.00	0	0.00	0	0.00	1809	44.38	0	0.00	1809	35.99	0	0.00
TOTAL	949	100.00	117	100.00	104522	100.00	4076	100.00	2628	100.00	5026	100.00	87894	100.00

Table 5

Boiler/Dryer Subsystem - Northeast

	Stream No. 8		Stream No. 9		Stream No. 10		Stream No. 11		Stream No. 12		Stream No. 18	
	Temperature 100°F		Temperature 300°F		Temperature 150°F		Temperature 950°F		Temperature 609°F		Temperature 200°F	
	Pressure 0.5 psig		Pressure 0 psig		Pressure 0 psig		Pressure 1515 psig		Pressure 1640 psig		Pressure 0 psig	
Component	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
CO_2	0	0.00	128010	18.77	128010	18.26	0	0.00	0	0.00	0	0.00
O_2	137640	22.94	22850	3.35	22850	3.26	0	0.00	0	0.00	0	0.00
N_2	456360	76.06	456870	66.99	456870	65.15	0	0.00	0	0.00	0	0.00
H_2O	6000	1.00	74130	10.87	93355	13.31	0	0.00	0	0.00	0	0.00
SO_2	0	0.00	130	102 ppmv	130	102 ppmv	0	0.00	0	0.00	0	0.00
NO_x	0	0.00	174	190 ppmv	174	190 ppmv	0	0.00	0	0.00	0	0.00
CO	0	0.00	65	117 ppmv	65	117 ppmv	0	0.00	0	0.00	0	0.00
VOC	0	0.00	11	34 ppmv	11	34 ppmv	0	0.00	0	0.00	0	0.00
PM10	0	0.00	13	.007 gr/acf	13	.007 gr/acf	0	0.00	0	0.00	0	0.00
Ash	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11022	100.00
Steam	0	0.00	0	0.00	0	0.00	276000	100.00	0	0.00	0	0.00
Boiler Blowdown	0	0.00	0	0.00	0	0.00	0	0.00	2788	100.00	0	0.00
TOTAL	600000	100.00	682393	100.00	701618	100.00	276000	100.00	2788	100.00	11022	100.00

Table 6

Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Northeast

Component	Stream No. 13 Temperature 366°F Pressure 150 psig lb/hr	Stream No. 14 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 15 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 16 Temperature 335°F Pressure 1700 psig lb/hr	Stream No. 17 Temperature 50°F Pressure 50 psig lb/hr
Makeup Water	0	0	0	0	208188
Steam	43100	162300	70600	0	0
Boiler Feed Water	0	0	0	278788	0
TOTAL	43100	162300	70600	278788	208188

Table 7

Waste Stream Inputs - Southeast

	Stream No. 1		Stream No. 2		Stream No. 3		Stream No. 4		Stream No. 5		Stream No. 6		Stream No. 7	
	Temperature 100°F		Temperature 100°F		Temperature 220°F		Temperature 100°F		Temperature 70°F		Temperature 100°F		Temperature 200°F	
	Pressure 10 psig		Pressure 25 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig	
Component	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
Water	0	0.00	39	32.96	46592	47.18	143	3.53	1257	50.00	143	2.85	28766	35.00
Cellulose	0	0.00	0	0.00	7	0.01	0	0.00	0	0.00	0	0.00	7	0.01
Soluble Solids	0	0.00	1	0.69	10009	10.14	0	0.00	0	0.00	0	0.00	10009	12.18
Ash	0	0.00	0	0.16	3437	3.48	0	0.00	0	0.00	0	0.00	3437	4.18
Lignin	0	0.00	0	0.03	24868	25.18	0	0.00	38	12.53	0	0.00	24906	30.30
Crude Protein	0	0.00	0	0.15	4453	4.51	0	0.00	162	6.45	0	0.00	4615	5.62
Xylose	0	0.00	0	0.13	177	0.18	0	0.00	0	0.00	0	0.00	177	0.21
WHF	0	0.00	0	0.02	31	0.03	0	0.00	0	0.00	0	0.00	31	0.04
Gypsum	0	0.00	0	0.08	4921	4.98	0	0.00	81	3.22	0	0.00	5002	6.09
CO_2	0	0.00	0	0.00	0	0.00	2106	52.09	0	0.00	2106	41.97	0	0.00
Cellulase	0	0.00	0	0.00	20	0.02	0	0.00	0	0.00	0	0.00	20	0.02
Ethanol	62	6.34	0	0.00	0	0.00	0	0.00	0	0.00	62	1.24	0	0.00
Fusal Oils	0	0.00	78	65.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Glycerol	0	0.00	1	0.76	1081	1.09	0	0.00	0	0.00	0	0.00	1081	1.32
Acetaldehyde	913	93.66	0	0.00	0	0.00	0	0.00	0	0.00	913	18.19	0	0.00
Cell Mass	0	0.00	0	0.02	3161	3.20	0	0.00	975	38.80	0	0.00	4136	5.03
Methane	0	0.00	0	0.00	0	0.00	1794	44.38	0	0.00	1794	35.75	0	0.00
TOTAL	975	100.00	120	100.00	98757	100.00	4043	100.00	2514	100.00	5018	100.00	82187	100.00

Table 8

Boiler/Dryer Subsystem - Southeast

	Stream No. 8		Stream No. 9		Stream No. 10		Stream No. 11		Stream No. 12		Stream No. 18	
	Temperature	100°F	Temperature	300°F	Temperature	150°F	Temperature	950°F	Temperature	609°F	Temperature	200°F
	Pressure	0.5 psig	Pressure	0 psig	Pressure	0 psig	Pressure	1515 psig	Pressure	1640 psig	Pressure	0 psig
Component	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
CO_2	0	0.00	121000	18.23	121000	17.72	0	0.00	0	0.00	0	0.00
O_2	134428	22.94	22300	3.36	22300	3.27	0	0.00	0	0.00	0	0.00
N_2	445712	76.06	446050	67.20	446050	65.32	0	0.00	0	0.00	0	0.00
H_2O	5860	1.00	74340	11.20	93423	13.68	0	0.00	0	0.00	0	0.00
SO_2	0	0.00	87	70 ppmv	87	70 ppm	0	0.00	0	0.00	0	0.00
NO_x	0	0.00	178	200 ppmv	178	200 ppmv	0	0.00	0	0.00	0	0.00
CO	0	0.00	67	123 ppmv	67	123 ppmv	0	0.00	0	0.00	0	0.00
VOC	0	0.00	11	36 ppmv	11	36 ppmv	0	0.00	0	0.00	0	0.00
PM10	0	0.00	13	.007 gr/acf	13	.007 gr/acf	0	0.00	0	0.00	0	0.00
Ash	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9805	100.00
Steam	0	0.00	0	0.00	0	0.00	285000	100.00	0	0.00	0	0.00
Boiler Blowdown	0	0.00	0	0.00	0	0.00	0	0.00	2888	100.00	0	0.00
TOTAL	586000	100.00	664133	100.00	683216	100.00	285000	100.00	2888	100.00	9805	100.00

Table 9

Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Southeast

Component	Stream No. 13 Temperature 366°F Pressure 150 psig lb/hr	Stream No. 14 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 15 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 16 Temperature 335°F Pressure 1700 psig lb/hr	Stream No. 17 Temperature 50°F Pressure 50 psig lb/hr
Makeup Water	0	0	0	0	217988
Steam	43100	172000	69900	0	0
Boiler Feed Water	0	0	0	287879	0
TOTAL	43100	172000	69900	287879	217988

Table 10

Waste Stream Inputs - Great Plains

	Stream No. 1		Stream No. 2		Stream No. 3		Stream No. 4		Stream No. 5		Stream No. 6		Stream No. 7	
	Temperature 100°F		Temperature 100°F		Temperature 220°F		Temperature 100°F		Temperature 70°F		Temperature 100°F		Temperature 200°F	
	Pressure 10 psig		Pressure 25 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig	
Component	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
Water	0	0.00	36	32.33	47548	46.05	154	3.53	1426	50.00	154	2.93	30768	35.00
Cellulose	0	0.00	0	0.00	6	0.01	0	0.00	0	0.00	0	0.00	6	0.01
Soluble Solids	0	0.00	1	1.03	14386	13.93	0	0.00	0	0.00	0	0.00	14386	16.36
Ash	0	0.00	0	0.43	8502	8.23	0	0.00	0	0.00	0	0.00	8502	9.67
Lignin	0	0.00	0	0.03	16576	16.05	0	0.00	28	0.98	0	0.00	16604	18.89
Crude Protein	0	0.00	0	0.25	7099	6.87	0	0.00	275	9.63	0	0.00	7374	8.39
Xylose	0	0.00	0	0.14	216	0.21	0	0.00	0	0.00	0	0.00	216	0.25
WHF	0	0.00	0	0.02	33	0.03	0	0.00	0	0.00	0	0.00	33	0.04
Gypsum	0	0.00	0	0.08	4893	4.74	0	0.00	74	2.61	0	0.00	4967	5.65
CO_2	0	0.00	0	0.00	0	0.00	2265	52.09	0	0.00	2265	43.15	0	0.00
Cellulase	0	0.00	0	0.00	22	0.02	0	0.00	0	0.00	0	0.00	22	0.02
Ethanol	60	6.62	0	0.00	0	0.00	0	0.00	0	0.00	60	1.14	0	0.00
Fusal Oils	0	0.00	72	65.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Glycerol	0	0.00	1	0.69	1081	1.05	0	0.00	0	0.00	0	0.00	1081	1.23
Acetaldehyde	840	93.38	0	0.00	0	0.00	0	0.00	0	0.00	840	16.00	0	0.00
Cell Mass	0	0.00	0	0.02	2901	2.81	0	0.00	1049	36.78	0	0.00	3950	4.49
Methane	0	0.00	0	0.00	0	0.00	1930	44.38	0	0.00	1930	36.77	0	0.00
TOTAL	900	100.00	110	100.00	103262	100.00	4349	100.00	2853	100.00	5249	100.00	87909	100.00

Table 11

Boiler/Dryer Subsystem - Great Plains

Component	Stream No. 8		Stream No. 9		Stream No. 10		Stream No. 11		Stream No. 12		Stream No. 18	
	Temperature 100°F		Temperature 300°F		Temperature 150°F		Temperature 950°F		Temperature 609°F		Temperature 200°F	
	Pressure 0.5 psig		Pressure 0 psig		Pressure 0 psig		Pressure 1515 psig		Pressure 1640 psig		Pressure 0 psig	
	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
CO_2	0	0.00	117870	18.92	117870	18.38	0	0.00	0	0.00	0	0.00
O_2	125023	22.94	20750	3.33	20750	3.24	0	0.00	0	0.00	0	0.00
N_2	414527	76.06	415100	66.63	415100	64.73	0	0.00	0	0.00	0	0.00
H_2O	5450	1.00	69150	11.10	87356	13.62	0	0.00	0	0.00	0	0.00
SO_2	0	0.00	149	128 ppmv	149	128 ppmv	0	0.00	0	0.00	0	0.00
NO_x	0	0.00	155	186 ppmv	155	186 ppmv	0	0.00	0	0.00	0	0.00
CO	0	0.00	58	114 ppmv	58	114 ppmv	0	0.00	0	0.00	0	0.00
VOC	0	0.00	10	33 ppmv	10	33 ppmv	0	0.00	0	0.00	0	0.00
PM10	0	0.00	12	.006 gr/acf	12	.006 gr/acf	0	0.00	0	0.00	0	0.00
Ash	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Steam	0	0.00	0	0.00	0	0.00	241000	100.00	0	0.00	14973	100.00
Boiler Blowdown	0	0.00	0	0.00	0	0.00	0	0.00	2434	100.00	0	0.00
TOTAL	545000	100.00	623413	100.00	641619	100.00	241000	100.00	2434	100.00	14973	100.00

Table 12

Turbgenerator/Condenser/Boiler Feedwater Preparation Subsystem - Great Plains

Component	Stream No. 13 Temperature 366°F Pressure 150 psig lb/hr	Stream No. 14 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 15 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 16 Temperature 335°F Pressure 1700 psig lb/hr	Stream No. 17 Temperature 50°F Pressure 50 psig lb/hr
Makeup Water	0	0	0	0	207334
Steam	43100	161800	36100	0	0
Boiler Feed Water	0	0	0	243434	0
TOTAL	43100	161800	36100	243434	207334

Table 13

Waste Stream Inputs - Midwest/Lake St.

Component	Stream No. 1		Stream No. 2		Stream No. 3		Stream No. 4		Stream No. 5		Stream No. 6		Stream No. 7	
	Temperature 100°F		Temperature 100°F		Temperature 220°F		Temperature 100°F		Temperature 70°F		Temperature 100°F		Temperature 200°F	
	Pressure 10 psig		Pressure 25 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig	
	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
Water	0	0.00	40	32.70	49257	46.80	135	3.53	1265	50.00	135	2.80	30832	35.00
Cellulose	0	0.00	0	0.00	7	0.01	0	0.00	0	0.00	0	0.00	7	0.01
Soluble Solids	0	0.00	1	0.88	13217	12.56	0	0.00	0	0.00	0	0.00	13217	15.00
Ash	0	0.00	0	0.20	4263	4.05	0	0.00	0	0.00	0	0.00	4263	4.84
Lignin	0	0.00	0	0.03	22150	21.05	0	0.00	32	1.26	0	0.00	22182	25.18
Crude Protein	0	0.00	0	0.22	6887	6.54	0	0.00	232	9.16	0	0.00	7119	8.08
Xylose	0	0.00	0	0.11	166	0.16	0	0.00	0	0.00	0	0.00	166	0.19
WHF	0	0.00	0	0.02	33	0.03	0	0.00	0	0.00	0	0.00	33	0.04
Gypsum	0	0.00	0	0.08	4928	4.68	0	0.00	76	3.01	0	0.00	5004	5.68
CO_2	0	0.00	0	0.00	0	0.00	1998	52.09	0	0.00	1998	41.47	0	0.00
Cellulase	0	0.00	0	0.00	21	0.02	0	0.00	0	0.00	0	0.00	21	0.02
Ethanol	60	6.08	0	0.00	0	0.00	0	0.00	0	0.00	60	1.25	0	0.00
Fusal Oils	0	0.00	79	65.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Glycerol	0	0.00	1	0.74	1126	1.07	0	0.00	0	0.00	0	0.00	1126	1.28
Acetaldehyde	923	93.92	0	0.00	0	0.00	0	0.00	0	0.00	923	19.16	4121	4.68
Cell Mass	0	0.00	0	0.02	3196	3.04	0	0.00	925	36.58	0	0.00	0	0.00
Methane	0	0.00	0	0.00	0	0.00	1702	44.38	0	0.00	1702	35.33	0	0.00
TOTAL	983	100.00	121	100.00	105250	100.00	3836	100.00	2530	100.00	4818	100.00	88091	100.00

Table 14

Boiler/Dryer Subsystem - Midwest/Lake St.

Component	Stream No. 8		Stream No. 9		Stream No. 10		Stream No. 11		Stream No. 12		Stream No. 18	
	Temperature 100°F		Temperature 300°F		Temperature 150°F		Temperature 950°F		Temperature 609°F		Temperature 200°F	
	Pressure 0.5 psig		Pressure 0 psig		Pressure 0 psig		Pressure 1515 psig		Pressure 1640 psig		Pressure 0 psig	
	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
CO_2	0	0.00	127800	18.65	127800	18.13	0	0.00	0	0.00	0	0.00
O_2	138328	22.94	22960	3.35	22960	3.26	0	0.00	0	0.00	0	0.00
N_2	458642	76.06	459270	67.02	459270	65.15	0	0.00	0	0.00	0	0.00
H_2O	6030	1.00	75110	10.96	94800	13.44	0	0.00	0	0.00	0	0.00
SO_2	0	0.00	148	116 ppmv	148	116 ppmv	0	0.00	0	0.00	0	0.00
NO_x	0	0.00	176	191 ppmv	176	191 ppmv	0	0.00	0	0.00	0	0.00
CO	0	0.00	66	118 ppmv	66	118 ppmv	0	0.00	0	0.00	0	0.00
VOC	0	0.00	11	34 ppmv	11	34 ppmv	0	0.00	0	0.00	0	0.00
PM10	0	0.00	13	.007 gr/acf	13	.007 gr/acf	0	0.00	0	0.00	0	0.00
Ash	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	10588	100.00
Steam	0	0.00	0	0.00	0	0.00	279000	100.00	0	0.00	0	0.00
Boiler Blowdown	0	0.00	0	0.00	0	0.00	0	0.00	2818	100.00	0	0.00
TOTAL	603000	100.00	685694	100.00	705384	100.00	279000	100.00	2818	100.00	10588	100.00

Table 15

Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Midwest/Lake St.

Component	Stream No. 13 Temperature 366°F Pressure 150 psig lb/hr	Stream No. 14 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 15 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 16 Temperature 335°F Pressure 1700 psig lb/hr	Stream No. 17 Temperature 50°F Pressure 50 psig lb/hr
Makeup Water	0	0	0	0	213118
Steam	43100	167200	68700	0	0
Boiler Feed Water	0	0	0	281818	0
TOTAL	43100	167200	68700	281818	213118

Table 16

Waste Stream Inputs - Municipal Solid Waste

	Stream No. 1		Stream No. 2		Stream No. 3		Stream No. 4		Stream No. 5		Stream No. 6		Stream No. 7	
	Temperature 100°F		Temperature 100°F		Temperature 220°F		Temperature 100°F		Temperature 70°F		Temperature 100°F		Temperature 200°F	
	Pressure 10 psig		Pressure 25 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig		Pressure 10 psig		Pressure 0 psig	
Component	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
Water	0	0.00	49	33.11	64601	47.35	69	3.53	740	50.00	69	2.21	39073	35.00
Cellulose	0	0.00	0	0.00	8	0.01	0	0.00	0	0.00	0	0.00	8	0.01
Soluble Solids	0	0.00	1	0.62	14647	10.74	0	0.00	0	0.00	0	0.00	14647	13.12
Ash	0	0.00	0	0.16	24834	18.20	0	0.00	0	0.00	0	0.00	24834	22.25
Lignin	0	0.00	0	0.02	16644	12.20	0	0.00	23	1.56	0	0.00	16667	14.93
Crude Protein	0	0.00	0	0.16	5327	3.90	0	0.00	169	11.40	0	0.00	5496	4.92
Xylose	0	0.00	0	0.03	63	0.05	0	0.00	0	0.00	0	0.00	63	0.06
WHF	0	0.00	0	0.02	46	0.03	0	0.00	0	0.00	0	0.00	46	0.04
Gypsum	0	0.00	0	0.08	4926	3.62	0	0.00	77	5.17	0	0.00	5003	4.48
CO_2	0	0.00	0	0.00	0	0.00	1017	52.09	0	0.00	1017	32.54	0	0.00
Cellulase	0	0.00	0	0.00	31	0.02	0	0.00	0	0.00	0	0.00	31	0.03
Ethanol	52	4.42	0	0.00	0	0.00	0	0.00	0	0.00	52	1.66	0	0.00
Fusal Oils	0	0.00	95	65.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Glycerol	0	0.00	1	0.78	1564	1.15	0	0.00	0	0.00	1121	35.87	1564	1.40
Acetaldehyde	1121	95.58	0	0.00	0	0.00	0	0.00	471	31.86	0	0.00	471	0.42
Cell Mass	0	0.00	0	0.02	3734	2.74	0	0.00	0	0.00	0	0.00	3734	3.34
Methane	0	0.00	0	0.00	0	0.00	866	44.38	0	0.00	866	27.71	0	0.00
TOTAL	1173	100.00	147	100.00	136426	100.00	1952	100.00	1479	100.00	3125	100.00	111637	100.00

Table 17

Boiler/Dryer Subsystem - Municipal Solid Waste

Component	Stream No. 8		Stream No. 9		Stream No. 10		Stream No. 11		Stream No. 12		Stream No. 18	
	Temperature 100°F		Temperature 300°F		Temperature 150°F		Temperature 950°F		Temperature 609°F		Temperature 200°F	
	Pressure 0.5 psig		Pressure 0 psig		Pressure 0 psig		Pressure 1515 psig		Pressure 1640 psig		Pressure 0 psig	
	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %	lb/hr	wt %
CO_2	0	0.00	114020	18.95	114020	18.15	0	0.00	0	0.00	0	0.00
O_2	118600	22.94	19680	3.27	19680	3.13	0	0.00	0	0.00	0	0.00
N_2	393230	76.06	393570	65.41	393570	62.67	0	0.00	0	0.00	0	0.00
H_2O	5170	1.00	74310	12.35	100578	16.02	0	0.00	0	0.00	0	0.00
SO_2	0	0.00	115	104 ppmv	115	104 ppmv	0	0.00	0	0.00	0	0.00
NO_x	0	0.00	145	183 ppmv	145	183 ppmv	0	0.00	0	0.00	0	0.00
CO	0	0.00	54	113 ppmv	54	113 ppmv	0	0.00	0	0.00	0	0.00
VOC	0	0.00	9	33 ppmv	9	33 ppmv	0	0.00	0	0.00	0	0.00
PM10	0	0.00	11	.006 gr/acf	11	.006 gr/acf	0	0.00	0	0.00	0	0.00
Ash	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	30096	100.00
Steam	0	0.00	0	0.00	0	0.00	213000	100.00	0	0.00	0	0.00
Boiler Blowdown	0	0.00	0	0.00	0	0.00	0	0.00	2152	100.00	0	0.00
TOTAL	517000	100.00	602034	100.00	628302	100.00	213000	100.00	2152	100.00	30096	100.00

Table 18

Turbogenerator/Condenser/Boiler Feedwater Preparation Subsystem - Municipal Solid Waste

Component	Stream No. 13 Temperature 366°F Pressure 150 psig lb/hr	Stream No. 14 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 15 Temperature 298°F Pressure 50 psig lb/hr	Stream No. 16 Temperature 335°F Pressure 1700 psig lb/hr	Stream No. 17 Temperature 50°F Pressure 50 psig lb/hr
Makeup Water	0	0	0	0	205952
Steam	43100	160700	9200	0	0
Boiler Feed Water	0	0	0	215152	0
TOTAL	43100	160700	9200	215152	205952

Table 19

Thermal Efficiency Summary

Case	10^6 Btu/Hr Waste	Q, Steam 1500 psia	Eff., %[1]	Q, Turbogenerator	Eff., %[2]	Q, Extraction Steam 150 psig	Q, Extraction Steam 50 psig	Generator and Extraction Steam Eff., %[3]	Eff., %[4] Overall
1	607	456	75.05	124.54 (36.49 MW)	21.58	52	183	62.31	59.23
1A	607	422	69.47	115.08 (33.72 MW)	21.55	52	183	65.54	57.67
1B	607	424	69.85	115.71 (33.90 MW)	21.54	52	183	65.30	57.78
2	436	319	73.10	69.65 (20.41 MW)	17.25	52	191	77.44	71.71
3	446	329	73.82	72.20 (21.15 MW)	17.31	52	202	78.22	73.14
4	388	278	71.76	60.36 (17.69 MW)	17.12	52	190	85.73	77.93
5	440	322	73.16	70.52 (20.66 MW)	17.29	52	196	78.12	72.39
6	363	246	67.75	54.29 (15.90 MW)	17.42	52	188	94.47	81.07

[1] Eff = $\frac{\text{Total Enthalpy of Steam - Enthalpy of BFW}}{\text{Total Heat Release based on HHV}}$

[2] Eff = $\frac{\text{Electrical Energy}}{\text{Total Enthalpy of 1500 psia Steam}}$

[3] Eff = $\frac{\text{Electrical Energy + Total Enthalpy of 150 psig Steam + Total of 50 psig Steam}}{\text{Total Enthalpy of 1500 psia Steam}}$

[4] Eff = $\frac{\text{Electrical Energy + Enthalpy of 150 psig Steam + 50 psia Steam}}{\text{Total Heat Release Based on HHV}}$

Table 20

Emissions Summary

Case	SO_2		NO_x		CO		VOC		Acetaldehyde		Formaldehyde		PM10	
	lb/hr	ppmv	lb/hr	ppmv	lb/hr	ppmv	lb/hr	ppmv	lb/hr	ppmv	lb/hr	ppmv	lb/hr	gr/scf
1	40.45	26	242.94	215	91.10	133	15.18	39	0.20	<0.5	0.13	<0.5	18.22	0.012
2	129.97	102	174.27	190	65.35	117	10.89	34	0.16	<0.5	0.11	<0.5	13.07	0.010
3	87.16	70	178.21	200	66.83	123	11.14	36	0.15	<0.5	0.10	<0.5	13.37	0.010
4	148.78	128	155.01	186	58.13	114	9.69	33	0.15	<0.5	0.10	<0.5	11.63	0.009
5	148.27	116	176.04	191	66.01	118	11.00	34	0.16	<0.5	0.11	<0.5	13.20	0.010
6	114.75	104	145.11	183	54.42	113	9.07	33	0.14	<0.5	0.09	<0.5	10.88	0.009

Table 21

Equipment Cost Summary ($Million)

Description	Case 1	Case 1A	Case 1B	Case 2	Case 3	Case 4	Case 5	Case 6
Dryer w/Baghouse	2.09	2.09	0.00	2.09	2.09	2.09	2.09	2.09
Fluidized Bed Boiler	23.35	23.35	24.00	21.10	20.55	20.10	21.25	18.30
Turbogenerator	6.70	6.26	6.29	3.98	3.98	3.93	3.98	3.80
Condenser	0.13	0.13	0.13	0.00	0.00	0.00	0.000	0.00
Boiler Feedwater Heaters	0.14	0.14	0.14	0.08	0.08	0.06	0.08	0.02
Boiler Feedwater Pumps	0.18	0.18	0.18	0.13	0.13	0.13	0.13	0.10
Deaerator w/Chem Feed	0.07	0.07	0.07	0.05	0.05	0.05	0.05	0.05
Water Treatment	1.10	0.94	0.95	1.13	1.18	1.13	1.16	1.12
TOTAL	33.76	33.16	31.76	28.56	28.06	27.49	28.74	25.48

Table 22

Installation Costs ($Million)

Description	Case 1	Case 1A	Case 1B	Case 2	Case 3	Case 4	Case 5	Case 6
INSTALLATION								
Foundation and Supports	2.92	2.87	2.74	2.47	2.42	2.38	2.48	2.20
Handling and Erection	5.11	5.01	4.80	4.32	4.24	4.16	4.35	3.85
Electrical	1.46	1.43	1.37	1.23	1.21	1.19	1.24	1.10
Insulation	0.36	0.36	0.34	0.31	0.30	0.30	0.31	0.28
Piping	0.73	0.72	0.69	0.62	0.61	0.59	0.62	0.55
Painting	0.36	0.36	0.34	0.31	0.30	0.30	0.31	0.28
TOTAL	10.94	10.74	10.29	9.25	9.09	8.91	9.31	8.26
INDIRECT COSTS								
Engineering/Supervision	3.65	3.58	3.43	3.08	3.03	2.97	3.10	2.75
Construction/Field Cost	1.82	1.79	1.72	1.54	1.52	1.48	1.55	1.38
Contractor Fees	3.65	3.58	3.43	3.08	3.03	2.97	3.10	2.75
Start-Up	0.36	0.36	0.34	0.31	0.30	0.30	0.31	0.28
Performance Test	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Contingencies	1.09	1.07	1.03	0.93	0.91	0.84	0.93	0.83
TOTAL INDIRECT	10.77	10.59	10.15	9.15	8.99	8.81	9.20	8.18
TOTAL INSTALLATION COST	21.71	21.33	20.44	18.40	18.08	17.72	18.51	16.44

Table 23

Operating Cost Summary ($Million)

Description	Case 1	Case 1A	Case 1B	Case 2	Case 3	Case 4	Case 5	Case 6
Labor	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Maintenance Materials	2.55	2.51	2.40	2.16	2.12	2.08	2.17	1.93
Utility Costs	0.44	0.44	0.43	0.44	0.46	0.43	0.45	0.43
Ash Disposal	1.82	1.82	1.82	2.43	2.16	3.30	2.33	6.64
Indirect Costs	11.66	11.45	10.98	9.89	9.72	9.53	9.95	8.85
TOTAL	16.73	16.48	15.89	15.16	12.60	15.60	15.16	16.17
Utility Credits	(18.95)	(17.73)	(17.84)	(12.68)	(13.26)	(11.58)	12.91)	(11.06)
Net Operating	(2.22)	(1.25)	(1.95)	2.48	(0.66)	4.02	2.25	5.11