

Renewable Energy Options: Robins AFB

Submitted by

Georgia Environmental Facilities Authority
Georgia Tech Strategic Energy Institute
University of Georgia Engineering Outreach Service
Herty Advanced Material Development Center

February 2009



The University of Georgia



**Georgia Institute
of Technology**



HERTY Advanced Materials
Development Center

Table of Contents

LIST OF FIGURES.....	V
LIST OF TABLES.....	VI
EXECUTIVE SUMMARY	1
1. INTRODUCTION	2
1.1 PURPOSE	2
1.2 SCOPE	2
2. ROBINS AFB ENERGY NEEDS.....	3
2.1 ELECTRICAL LOADS.....	3
2.2 THERMAL LOADS.....	7
2.3 TRANSPORTATION FUEL USAGE	10
3. ROBINS AFB RENEWABLE ENERGY RESOURCES.....	11
3.1 BIOMASS FUEL POTENTIAL ASSESSMENT	11
3.1.1 <i>Agricultural Residues</i>	11
3.1.2 <i>Commercial and Industrial Woody Biomass Waste</i>	13
3.2 SOLAR ENERGY RESOURCE.....	15
4. LARGE-SCALE ELECTRIC POWER GENERATION (>10 MW).....	17
4.1 TRADITIONAL STEAM TURBINE PLANT	17
4.1.1 <i>Description of Technology</i>	17
4.1.2 <i>Plant Size Estimate</i>	19
4.1.3 <i>Conceptual Design</i>	19
4.1.4 <i>Conceptual Location(s)</i>	19
4.1.5 <i>Budget Estimate</i>	19
4.1.6 <i>Plant Economics Estimate</i>	19
4.2 BIOMASS GASIFICATION	24
4.2.1 <i>Description of Technology</i>	24
4.2.2 <i>Fuel Handling and Processing</i>	25
4.2.3 <i>Plant Size Estimate</i>	26
4.2.4 <i>Conceptual Design</i>	26
4.3 MUNICIPAL SOLID WASTE-TO-ENERGY	31
4.3.1 <i>Description of Technology</i>	31
5. SMALL-SCALE POWER GENERATION (<10 MW).....	34
5.1 LANDFILL GAS OPPORTUNITIES	34
5.2 ANAEROBIC DIGESTION OF FOOD WASTE.....	34
5.3 FUEL CELLS	36
5.3.1 <i>Description of Technology</i>	36
5.3.2 <i>Plant Size Estimate</i>	38
5.3.3 <i>Conceptual Design</i>	38
5.3.4 <i>Conceptual Location</i>	38
5.3.5 <i>Economics Estimate</i>	39
5.5 PHOTOVOLTAICS.....	52
5.5.1 <i>PV Technologies</i>	52
5.5.2 <i>Generation Potential</i>	52
5.5.2 <i>System Economics</i>	54
6. THERMAL SYSTEMS.....	56
6.1 COMBINED HEAT AND POWER	56
6.2 DISTRICT HEATING	56

6.2.1 Description of Technology	56
6.2.2 Plant Size Estimate.....	56
6.2.3 Conceptual Design.....	56
6.2.4 Conceptual Location	56
6.2.5 Economics Estimate	57
6.3 DISTRICT HEATING AND COOLING.....	60
6.3.1 Description of Technology	60
6.3.2 Plant Size Estimate.....	60
6.3.3 Conceptual Design.....	61
6.3.4 Conceptual Location	61
6.3.5 Thermodynamic Estimate.....	61
6.3.6 Economic Estimate.....	64
6.4 SOLAR THERMAL.....	67
6.4.1 Description of Technology	67
6.3.2 Size Estimate	70
6.3.3 Conceptual Design.....	70
6.3.4 Conceptual Location	71
6.3.5 Economics Estimate	71
6.5 GEOTHERMAL HEAT PUMPS.....	73
6.5.1 Description of Technology	73
7. TRANSPORTATION FUELS.....	75
7.1 ETHANOL	76
7.1.1 Biochemical Conversion	76
7.1.2 Thermochemical Conversion.....	77
7.2.1 Biodiesel.....	78
7.2.2 Syn-diesel	83
8. CONCLUSIONS AND RECOMMENDATIONS.....	85
11. APPENDICES.....	86
APPENDIX A : BIOMASS FUEL AVAILABILITY ASSESSMENT	87
APPENDIX B: ETHANOL PRODUCTION FACILITIES	114
APPENDIX C: SUPPORTING FIGURES FOR SECTION 4.1	128

List of Figures

FIGURE 2.1-1: AVERAGE RAFB ELECTRICAL LOADS.....	3
FIGURE 2.1-2: TYPICAL WEEKDAY AND WEEKEND ELECTRICAL LOADS	4
FIGURE 2.2-1: ESTIMATED COOLING AND NON-COOLING LOADS	7
FIGURE 2.2-2: MONTHLY CENTRAL PLANT STEAM LOADS	8
FIGURE 2.2-3: AVERAGE DAILY CENTRAL PLANT STEAM LOADS	9
FIGURE 3.1-1: TOTAL COMMERCIAL BIOMASS BY TYPE IN STUDY AREA (TONS/MONTH).....	14
FIGURE 3.2-1: RAFB INCIDENT SOLAR ENERGY BY MONTH.....	15
FIGURE 5.3-1: FUEL CELL CONCEPT.....	36
FIGURE 5.3-2: COST OF ELECTRICITY TRENDS, 2007-2010 INSTALLATION	42
FIGURE 5.3-3: COST OF ELECTRICITY TRENDS, 2016-2020 INSTALLATION	42
FIGURE 5.4-1: JENBACHER TYPE 6	44
FIGURE 5.4-2: EXAMPLE RECIP COGENERATION SYSTEM.....	45
FIGURE 5.5-1: SOLAR PV ELECTRICITY GENERATION POTENTIAL BY MONTH, 5 MILLION SQ. FT. ARRAY AREA	53
FIGURE 5.5-2: ANNUAL SOLAR PV ELECTRICITY PRODUCTION, 5 MILLION SQ. FT. OF ARRAY AREA	54
FIGURE 6.2-1: CONVENTIONAL ELECTRIC, HEATING, AND COOLING SYSTEM.....	62
FIGURE 6.2-2: WOOD-FIRED COGENERATION SYSTEM CASE1 (POWER GENERATION, HEATING, AND COOLING)	62
FIGURE 6.2-3: WOOD-FIRED COGENERATION SYSTEM CASE 2 (POWER GENERATION AND HEATING) WITH CONVENTIONAL COOLING	63
FIGURE 6.4-1: EXAMPLE OF GLAZED FLAT PLAT COLLECTOR.....	67
FIGURE 6.4-2: EXAMPLE OF EVACUATED-TUBE COLLECTOR	68
FIGURE 6.4-3: INTEGRAL-COLLECTOR-STORAGE (ICS) SYSTEM.....	69
FIGURE 6.4-4: ACTIVE, INDIRECT SOLAR THERMAL SYSTEM	70

List of Tables

TABLE 2.1-1: SIZING OF RENEWABLE ELECTRICITY GENERATION (LOW EXTREME)	5
TABLE 2.1-2: SIZING OF RENEWABLE ELECTRICITY GENERATION (HIGH EXTREME)	6
TABLE 2.3-1: ROBINS AFB YEARLY TRANSPORTATION FUEL USAGE	10
TABLE 3.1-1: BIOMASS RESOURCES IN GEORGIA	12
TABLE 3.1-2: BIOMASS BY TYPE (TONS/MONTH)	14
TABLE 4.1-1: COST OF ELECTRICITY FOR \$20/GREEN TON WOOD	21
TABLE 4.1-2: COST OF ELECTRICITY FOR \$30/GREEN TON WOOD	22
TABLE 4.2-1: STEAM CYCLE ELECTRICAL GENERATION COST ESTIMATES \$/KWH	30
TABLE 4.2-2: IGCC ELECTRICAL GENERATION COST ESTIMATES \$/KWH	30
TABLE 5.2-1: ESTIMATES OF ANAEROBIC DIGESTION OUTPUT FOR RAFB	35
TABLE 5.3-1: COMPARISON OF FUEL CELL TECHNOLOGIES	37
TABLE 5.3-2: EXAMPLE SPECS FOR 200 kW PAFC SYSTEM	39
TABLE 5.3-3: EXAMPLE OF FUEL CELL COSTS AND PERFORMANCE	40
TABLE 5.3-4: COST OF ELECTRICITY FOR EXAMPLE FUEL CELL SYSTEM (2007-2010)	41
TABLE 5.3-5: COST OF ELECTRICITY FOR EXAMPLE FUEL CELL SYSTEM (2016-2020)	41
TABLE 5.4-1: EXAMPLE SPECS FOR 2.4 MW JENBACHER TYPE 6	46
TABLE 5.4-2: EXAMPLE OF GAS-FIRED RECIPROCATING ENGINE COSTS	47
TABLE 5.4-3: RECIPROCATING ENGINE COSTS PERFORMANCE SPECIFICATIONS	48
TABLE 5.4-4: 1.6 MW RECIPROCATING ENGINE HEAT REJECTION	48
TABLE 5.4-5: COST OF ELECTRICITY FOR \$3/GALLON BIODIESEL, 1.6 MW PLANT SIZE	49
TABLE 5.4-6: COST OF ELECTRICITY FOR \$5/GALLON BIODIESEL, 1.6 MW PLANT SIZE	49
TABLE 5.4-7: COST OF ELECTRICITY FOR \$8/MMBTU BIOGAS, 2.4 MW PLANT SIZE	50
TABLE 5.4-8: COST OF ELECTRICITY FOR \$12/MMBTU BIOGAS, 2.4 MW PLANT SIZE	50
TABLE 5.4-9: EXAMPLE FUEL COSTS MITIGATED THROUGH RECIP COGENERATION PER YEAR	51
TABLE 6.2-1: COST OF STEAM FOR \$20/GT WOOD, 66,000 LB/HR	58
TABLE 6.2-2: COST OF STEAM FOR \$20/GT WOOD, 33,000 LB/HR	58
TABLE 6.2-3: COST OF STEAM FOR \$30/GT WOOD, 66,000 LB/HR	59
TABLE 6.2-4: COST OF STEAM FOR \$30/GT WOOD, 33,000 LB/HR	59
TABLE 6.3-1: COST OF ELECTRICITY FOR \$20/GREEN TON WOOD	65
TABLE 6.3-2: COST OF STEAM FOR \$20/GT WOOD; 85,000 LB/HR OF 150 PSI STEAM AND 154,000 LB/HR OF 22 PSI STEAM	65
TABLE 6.3-3: COST COMPARISON OF CHILLERS, BY TYPE	66
TABLE 6.4-1: EXAMPLE CAPITAL COSTS OF SOLAR HOT WATER SYSTEMS	71
TABLE 6.4-2: COST OF HOT WATER (CENTS/GALLON)	72
TABLE 7.1-1: CELLULOSIC ETHANOL TECHNOLOGY COMPANIES	77
TABLE 7.2-1: BIODIESEL PRODUCTION COST SUMMARY AT \$0 FEEDSTOCK	80
TABLE 7.2-2: CHANGES IN COST PER GALLON FOR 2% BIODIESEL BLEND (B2)	81
TABLE 7.2-3: CHANGES IN COST PER GALLON FOR 20% BIODIESEL BLEND (B2)	81
TABLE 7.2-1: EPA TEST EMISSIONS FOR BIODIESEL	82

Renewable Energy Options: Robins AFB

Executive Summary

The following report was produced for Robins Air Force Base under the direction of the Georgia Environmental Facilities Authority, headquartered in Atlanta, Georgia. The team conducting the study consisted of researchers from the Georgia Institute of Technology and the University of Georgia (the principal research universities in the state of Georgia). Various renewable energy technologies were examined, and the conclusions and detailed results are presented herein. In summary, it is recommended that the following technologies be pursued by Robins Air Force Base as candidate technologies in greater detail:

1. Biomass-fired steam/electric Plants and cogeneration options

The wood fuel survey contained herein shows an adequate supply within a reasonable hauling distance to power a steam/electric plant that could greatly assist the Base in meeting its renewable energy use goals.

2. Biomass-fired gasification plants

As with the category above, since there are adequate supplies of wood fuels in the areas surrounding the Base, gasification of biomass should also be considered, particularly for smaller applications located on the Base.

3. Photovoltaic electric power generation

Since RAFB has much flat roof area available, the installation of photovoltaic systems to displace some of the base electric load should be seriously considered. On a purely economic basis, the paybacks will not be as attractive as some of the other alternatives, but these applications could help the Base reach its renewable energy and efficiency goals.

4. Cellulosic ethanol motor fuels

It is recommended that the base keep abreast of developments in the production of synthetic motor fuels from biofuels, and possibly consider the co-location of biomass to liquid fuel facilities with some of the other energy projects in the future.

5. Remote landfill gas electricity

Although there appear to be potential legal and infrastructure impediments to supplying the base with electricity produced in remote landfills, it is recommended that this alternative be more fully investigated.

6. Solar thermal and geothermal hot water systems

These systems can have relatively attractive paybacks, and there are numerous potential applications at Robins AFB that should be examined more fully. These technologies would also aid in meeting energy use reduction goals.

The following topics do not deserve further consideration at this time:

1. Municipal solid waste power generation (for RAFB)
2. Anaerobic Digestion of Food Waste
3. Fuel cells for electricity generation

1. Introduction

1.1 Purpose

Under this contract Robins AFB seeks to determine the feasibility and cost effectiveness of utilizing renewable energy sources and technology to meet Robin's energy needs. The Georgia Environmental Facility Authority's Energy Innovation Center, working with Georgia Tech, the University of Georgia, and the Herty Advanced Material Development Center will analyze commercially-available renewable energy sources and conversion technologies to determine feasibility of displacing energy currently supplied through fossil fuel sources. The Authority will provide its professional opinion on new and emerging renewable energy technologies that may have an application at Robins. This feasibility analysis shall be the basis for renewable projects on Robins to allow the base to meet federal law, DOD, and AF goals for energy, fossil fuel, and greenhouse gas reduction. The authority shall work with Robins AFB personnel to determine feasibility as well as cost and savings potential of renewable energy.

1.2 Scope

This study shall analyze opportunities for implementation of biomass, solar thermal, solar photovoltaic, fuel cells, biodiesel, syn-diesel, ethanol and other renewable energy resources. The renewable analysis shall include reports by scientist in each field outlining the current state of renewable energy and technology, detailing where the technology is heading and the anticipated state of renewable energy in their field in 10 - 15 years.

According to Robins AFB personnel, the Department of Defense utilizes the same definitions for renewable energy as the U.S. Department of Energy (USDOE). USDOE compiles information on the following energy categories through their Renewables Information Team: biomass, municipal solid waste, wood /wood waste, landfill gas, geothermal energy, geothermal heat pumps, hydroelectric, solar thermal, solar photovoltaic, and wind. The Renewable Information team provides information on U.S. renewable energy consumption, capacity, and electric generation.

(http://www.eia.doe.gov/cneaf/solar.renewables/page/renew_info/geninfo.html)

2. Robins AFB Energy Needs

2.1 Electrical Loads

Electrical load data from January 1, 2006 through July 31, 2008 were provided by Robins AFB. These data, averaged over the time period and adjusted for the day of the week, are shown in Figure 2.1-1.

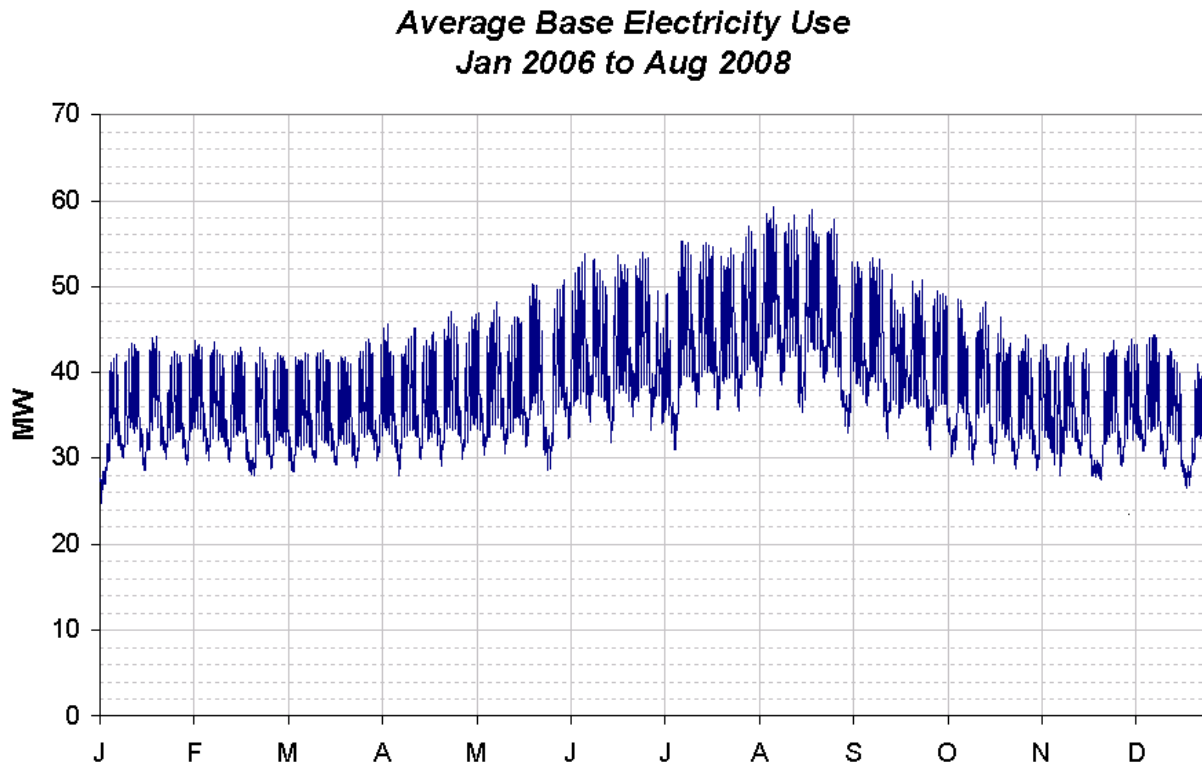


Figure 2.1-1: Average RAFB Electrical Loads

As shown in Figure 2.1-2, the Base's electricity use follows a typical pattern of low electricity use on weekends with peak usage during standard business hours. In addition, due to the climate at its location, electricity usage greatly increases in the summer air-conditioning months, with summer peaks topping 58 MW. Figure 2.1-2 also illustrates representative winter and summer daily load profiles.

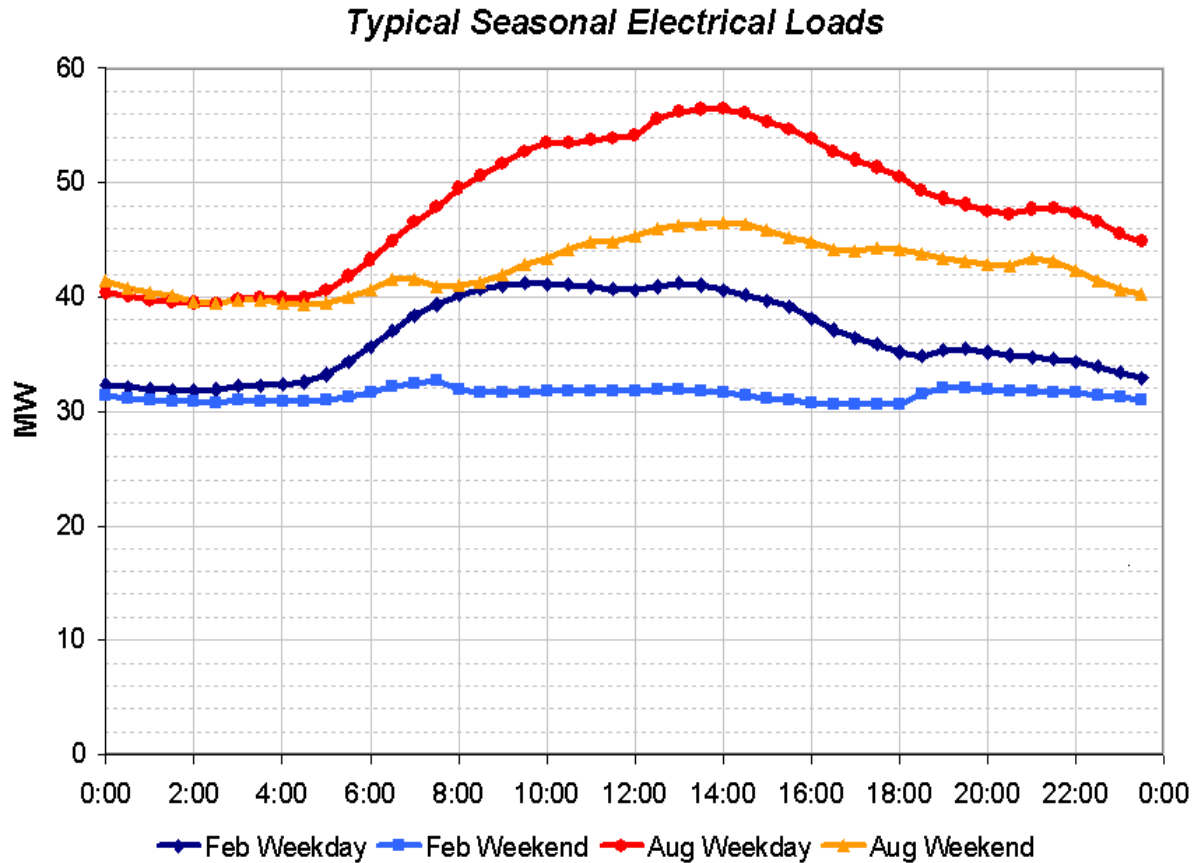


Figure 2.1-2: Typical Weekday and Weekend Electrical Loads

Over the 2-1/2 year span of data provided, the Base consumed an average of almost 335,000 MW-hr per year. According to President Georgia W. Bush's Executive Order (E.O.) 13423, issued on January 24, 2007, all federal agencies must reduce their energy intensity by a total of 30% by the end of fiscal year 2015 or 3% annually through fiscal year 2015. The baseline consumption to be used is the energy intensity recorded in the 2003 fiscal year (Bush, 2007). These savings can be derived from a reduction in electricity use, natural gas use, transportation fuel use, or any other site energy source. Assuming (1) the energy intensity of the Base has remained constant from 2003 to the last 2-1/2 years, (2) the Base square footage remains constant through fiscal year 2015, and (3) all of the energy savings is in the form of electricity use reduction, Robins AFB would be consuming roughly 234,500 MW-hr per year by the end of fiscal year 2015.

In conjunction with E.O. 13423, the Energy Policy Act (EPAct) of 2005 stipulates that all federal agencies increase their use of renewably-generated electricity. The goals set forth in this act are the following: (1) 3 percent of total in fiscal years 2007 through 2009, (2) 5 percent of total in fiscal years 2010 through 2012, and (3) 7.5 percent of total by fiscal year 2013 (EERE, 2008). In addition, the U.S. Department of Defense and U.S. Air Force have regulations for meeting these and other goals (need more info from Judah et al).

Given that regulations and guidelines change, Table 2.1-1 lists various levels of renewable electricity generation. This table can be used as a rough guideline to size systems to meet minimum renewable electricity requirements.

Table 2.1-1: Sizing of Renewable Electricity Generation (Low Extreme)

Percent of Base Electricity	Capacity Factor				
	50%	60%	70%	80%	90%
7.5	2.9 MW	2.4 MW	2.1 MW	1.8 MW	1.6 MW
10	3.8 MW	3.2 MW	2.7 MW	2.4 MW	2.1 MW
15	5.8 MW	4.8 MW	4.1 MW	3.6 MW	3.2 MW
20	7.7 MW	6.4 MW	5.5 MW	4.8 MW	4.3 MW
25	9.6 MW	8.0 MW	6.8 MW	6.0 MW	5.3 MW
50	19.2 MW	16.0 MW	13.7 MW	12.0 MW	10.6 MW

Please note that Table 2.1-1 assumes that all required energy reduction is derived from electricity consumption.

Table 2.1-2 represents the sizing of renewable energy generation needed if no energy reduction is in the form of electricity.

Table 2.1-2: Sizing of Renewable Electricity Generation (High Extreme)

Percent of Base Electricity	Capacity Factor			
	50%	60%	70%	80%
7.5	5.7 MW	4.8 MW	4.1 MW	3.6 MW
10	7.6 MW	6.4 MW	5.5 MW	4.8 MW
15	11.5 MW	9.6 MW	8.2 MW	7.2 MW
20	15.3 MW	12.7 MW	10.9 MW	9.6 MW
25	19.1 MW	15.9 MW	13.7 MW	11.9 MW
50	38.2 MW	31.9 MW	27.3 MW	23.9 MW

While the sizing of generation is shown in Table 2.1-1 and 2.1-2, generation equipment could be much larger in scale. Several scenarios could occur where this would be appropriate such as the following: (1) the cost of generating electricity with a larger system is much less than a smaller system, (2) electricity not wanted by the Base could be sold offsite, or (3) the Base would like to exceed the current standard.

Please note again that these estimates assume that the Base does not grow or shrink in square footage. Any substantial change in building floor space would change the requirements of total energy reduction and renewable electricity purchase or generation.

Section 2.1 References

Bush, 2007 <http://www.whitehouse.gov/news/releases/2007/01/20070124-2.html>

EERE, 2008 http://www1.eere.energy.gov/femp/renewable_energy/renewable_fedrequire.html

2.2 Thermal Loads

Thermal Loads at RAFB are met by both central plants, which supply steam and chilled water to buildings located on their circuits, and individual building units. Information regarding buildings off of central lines was not provided for use in this study; however, some information regarding their use of energy and the energy use of central vapor-compression chillers can be discerned from seasonal electricity use (Figure 2.2-1).

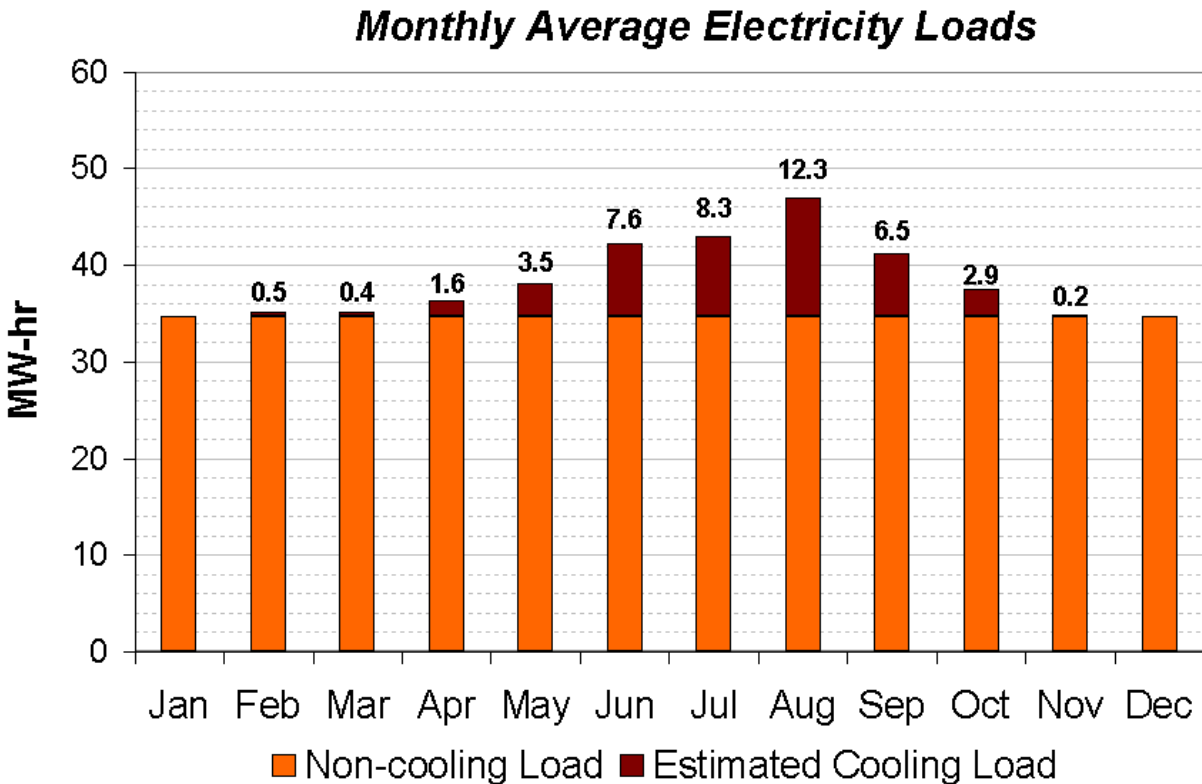


Figure 2.2-1: Estimated Cooling and Non-Cooling Loads

By assumption, winter months have very minimal cooling needs. Peak cooling occurs in August, with an electricity need of approximately 12 MW, while the needs in shoulder months do not exceed 4 MW.

Displacing cooling loads met with conventionally-generated electricity with renewable energy sources could be accomplished through one or more of the following means: (1) purchasing or generating renewable electric power, (2) using direct-drive vapor-compression chillers run on biogas or biodiesel, or (3) implementing absorption chillers directly-fired with renewable fuels such as biogas or as waste heat recuperators in a combined heat and power (CHP) system. While options 2 and 3 do not aid in meeting

guidelines set forth in EAct 2005, they could be viable options if RAFB would like to exceed standards in renewable energy consumption or use waste heat recovery as an energy-efficiency measure.

Monthly central steam plant data for 2007 were supplied by Robins AFB. The total loads are shown in Figure 2.2-2.

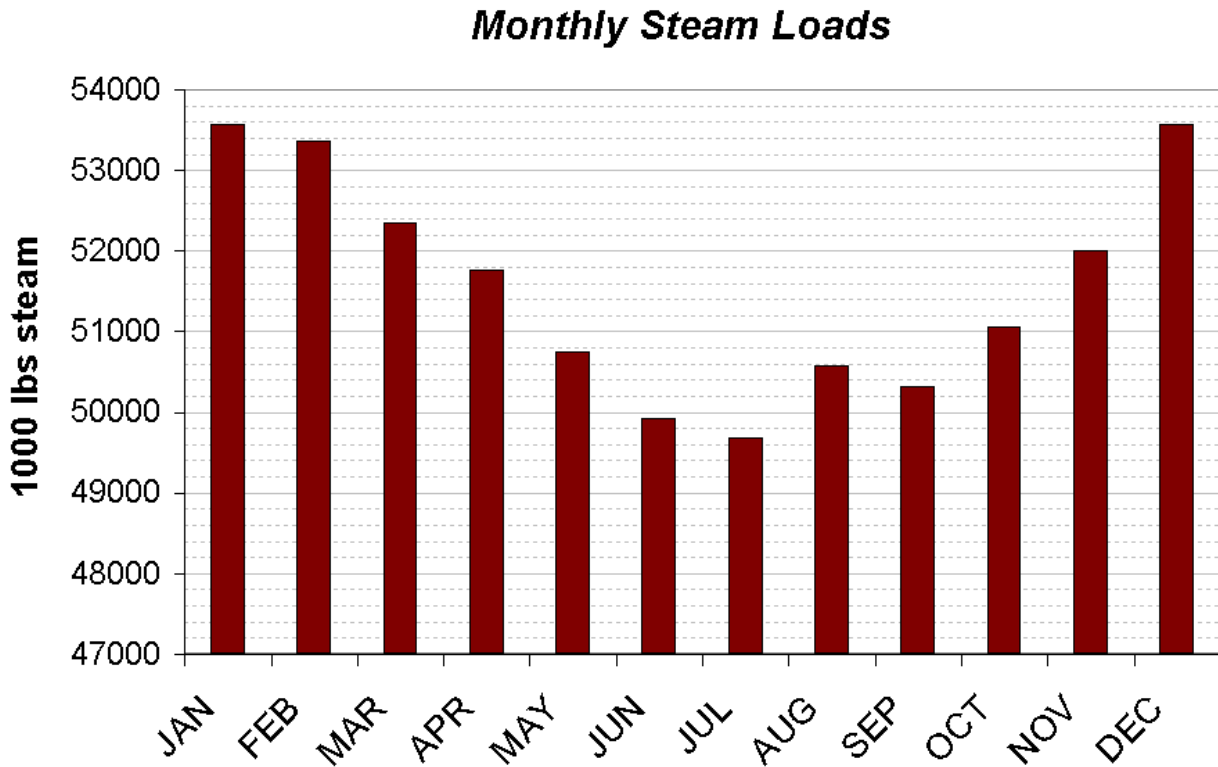


Figure 2.2-2: Monthly Central Plant Steam Loads

Average daily loads are shown in Figure 2.2-3. As stated previously, data for heating loads of buildings off of central lines were not available.

Average Daily Steam Loads

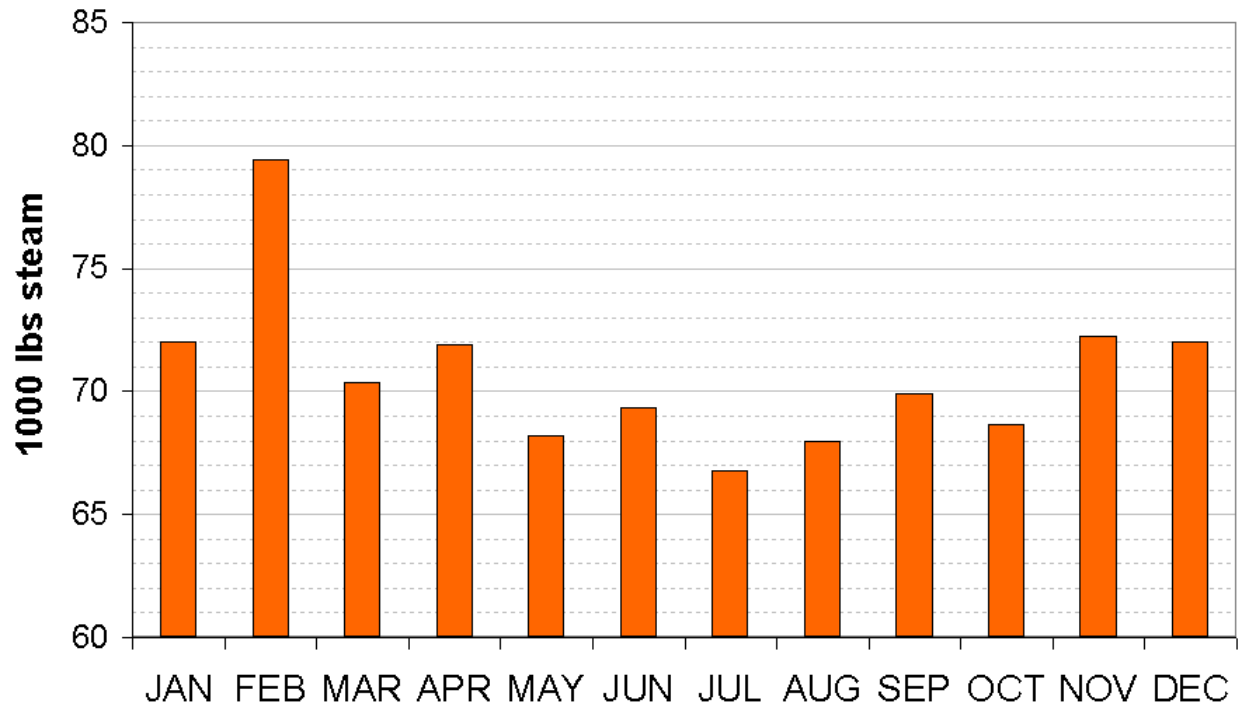


Figure 2.2-3: Average Daily Central Plant Steam Loads

Displacing heating loads met with natural gas with renewable energy sources could be accomplished through one or more of the following means: (1) steam generated by burning wood, other biomass, or gasified biomass, (2) recuperating waste heat from a combined heat and power (CHP) system, (3) solar thermal systems, or (4) geothermal heat pumps. While these options also do not aid in meeting guidelines set forth in EAct 2005, they could be viable options if RAFB would like to exceed standards in renewable energy consumption or use waste heat recovery as an energy-efficiency measure. Also, these methods could be used to contribute to overall energy savings as they generally have higher energy efficiencies relative to conventional heating technologies.

Section 2.2 References

Bush, 2007 <http://www.whitehouse.gov/news/releases/2007/01/20070124-2.html>

EERE, 2008 http://www1.eere.energy.gov/femp/renewable_energy/renewable_fedrequire.html

2.3 Transportation Fuel Usage

According to RAFB personnel, the following transportation fuels are used on an annual basis, shown in Table 2.3-1:

Table 2.3-1: Robins AFB Yearly Transportation Fuel Usage

Fuel	Yearly Use
Jet Fuel (JP8)	11,800,000 gallons
Diesel Fuel	370,000 gallons
Gasoline	120,000 gallons

Substitution for these fuels with renewable fuels will be discussed in Section 7.

3. Robins AFB Renewable Energy Resources

3.1 Biomass Fuel Potential Assessment

A readily-available, cost-effective fuel supply is essential to any biomass energy facility. Georgia and the other southeastern states offer a variety of potential biomass feedstocks from traditional row and forage crops and intentionally-grown energy crops to the forest products industry.

3.1.1 Agricultural Residues

Georgia agriculture produces many types of row and forage crops, most of which have significant crop residues that could serve as potential biomass feedstocks. Several potential biomass feedstocks are detailed here. Cost estimates are based on current estimated delivered prices. In addition to these varied biomass feedstocks, a detailed analysis of available industrial/commercial waste wood is included in summary here and in detail in Appendix A.

Cotton Stalks

Most cotton producers in Georgia leave stalks in the field. These stalks are a potential biomass feedstock. According to McKissick et al, it was assumed that irrigated cotton yields 4,900 lbs per acre of residual stalks and non-irrigated yields 4,200 pounds per acre (2007). Approximately 35% of Georgia's cotton acreage is irrigated. Therefore, the total of estimated residual biomass from cotton stalks produced is 2.72 million tons. The cost to harvest cotton stalks using a forage harvester and nutrient replacement ranges from \$35 to \$55 per ton depending on the machinery used and irrigated versus non (Mckissick et al., 2007).

Gin Trash

Gin trash is another Georgia-produced potential biomass source; the current major use of gin trash is as an animal feed. Based on research performed at the University of Georgia, it is estimated that every bale of cotton ginned produces 185 pounds of gin trash.(Mckissick, 2007) Assuming an average weight of 500 pounds per bale, there are approximately 205,226 tons of gin trash produced in Georgia annually. Calculating the economic cost requires further assumptions.. Most gins give the gin trash away if someone will come and get it. Gin trash is a light material and, to be handled efficiently, it was assumed the gin trash would be placed in a module. The cost of packing gin trash into a module is estimated to be \$0.005 to \$0.007 per pound or \$10 to \$14 per ton.

Peanut Hulls - According to Georgia Farm Gate production data, approximately 289,000 tons of peanut shells are produced in Georgia each year. Currently, the four major uses of these peanut shells are cattle feed, filler for poultry houses, chemical carriers, and energy pellets. Depending on the intended use and market, hulls may be used directly after shelling, ground through a hammer mill, or pelletized. Prices range from \$15 per ton for bulk loads to \$75 per ton for pelletized peanut hulls.

Poultry Litter

The poultry industry is Georgia's largest agricultural sector, and Georgia leads the nation in poultry production. According to University of Georgia's Poultry Science Research, in 2007, it is estimated that 2.65 million tons of poultry litter were produced.

Today poultry litter is often used in Georgia as a fertilizer; however, mounting pressure from environmental groups, along with regulatory limitations on land application in certain soil types and in urban areas, is beginning to curtail usage in urban areas and on forage crops. Application is likely to continue in row crop agriculture areas because poultry litter is often viewed as a lower-cost source of nutrients, given the rising cost of more traditional petroleum/natural gas-based nitrogen fertilizers. In the northeast Georgia area, limited acreage of row crops exist, and alternative uses to land application of poultry litter are being sought. Following market conditions for fertilizer, the estimated cost of poultry litter is \$15 to \$25 per ton.

Table 3.1-1 summarizes the availability and cost of the various potential biomass feedstocks discussed above.

Table 3.1-1: Biomass Resources in Georgia

Biomass Resource	Production (1000 dry tons per year)	Cost Range (\$ per ton)	Current Estimated Utilization (percent)
Forest Residues	5314	28-30	5-10
Unmerchantable Timber	7956	28-35	0-5
Urban Wood Waste	1437	28-30	20
Agricultural Residues			
Peanut Hulls	289	15-75	80
Gin Trash	205	10-14	0
Cotton Stalks	2720	35-55	0
Poultry Litter	2650	15-25	50-60
Total	20571		

Sources:

- *Biomass Wood Resource Assessment on a County-by-County Basis for the State of Georgia*, November 2005. Report prepared for the Georgia Forestry Commission and the Southern States Energy Board.
- *The Feasibility of Generating Electricity from Biomass Fuel Sources in Georgia*, 2003.2007 Report The University of Georgia.
- *Geographic Perspective on the Current Biomass Resource Availability in the United States*, 2005. NREL Report No. TP-560-39181.
- 2004-2005 USDA Crop Production Data for Georgia

3.1.2 Commercial and Industrial Woody Biomass Waste

This section summarizes a physical inventory survey of the potential available biomass material generated from commercial and industrial sources within a seventy-five (75) mile radius of Robins, GA. This survey includes data concerning biomass generated from commercial and industrial businesses as well as the potentially-available biomass from landfills within the project area; however, it does not include specific details on forest logging data and availability. These data are available in a separate report from the Georgia Forestry Commission.

The survey area was identified as the area within a seventy-five-mile radius of Robins Air Force Base / Robins, Georgia. For the purposes of this study, it was assumed that 75 miles equates to 75 air miles.

The original economic sectors evaluated included businesses that maintain and harvest forests, primary and secondary forest products industries, inert waste landfills, construction and demolition waste landfills, agribusiness, and any other businesses within the survey area that generate biomass suitable for use. Since most companies have some form of waste biomass, it was necessary to define characteristic parameters in order to limit the scope of the survey.

This section focuses on business sectors that predominantly generate woody biomass. Inert construction and demolition (C&D), and municipal solid waste (MSW) landfills were included; therefore, some data reported by landfills might be accounted for in the data already collected from companies, duplicating results. This is an important consideration when evaluating the overall total of potential material available. In addition, it is likely that the data reported by C&D landfills are inflated due to the co-mingling of inert waste with biomass. Exact data for only organic biomass were not always able to be extracted from data provided by landfill personnel; therefore, landfill availability data are considered to be an estimate of volume available.

An extensive list of company types that were believed to have the greatest potential for biomass was generated. These types of companies were matched with their North American Industry Classification System (NAICS) code and yellow page listing. Although the list of NAICS codes that were selected initially included a wider spectrum of companies, Appendix A, Table 1 presents the primary NAICS codes that were used in this study.

According to data reported by the companies selected, the total amount of commercial biomass within the 75-mile radius is 203,967 tons/month. Of this number, 191,347 tons/month, or 93% of the biomass, are already being sold or utilized internally for fuel. This amount represents the greatest potential for use since it is already being used for similar processes. In many situations, it would be a matter of negotiating price and logistics for companies to change operational procedures. The remaining 12,621 tons/month are currently being disposed of on company land or in Subtitle D landfills, C&D landfills, or inert landfills. Table 3.1-2 and Figure 3.1-1 illustrate the quantities of biomass generated per month.

Table 3.1-2: Biomass by Type (tons/month)

Biomass type	Tons/month
Blocks	58
Clean chips	30,194
Dried chips	1,089
Engineered	1,106
Mixed	130,578
Mulch/Dirty	30,107
Pallets	2
Sawdust	10,835
Total	203,967

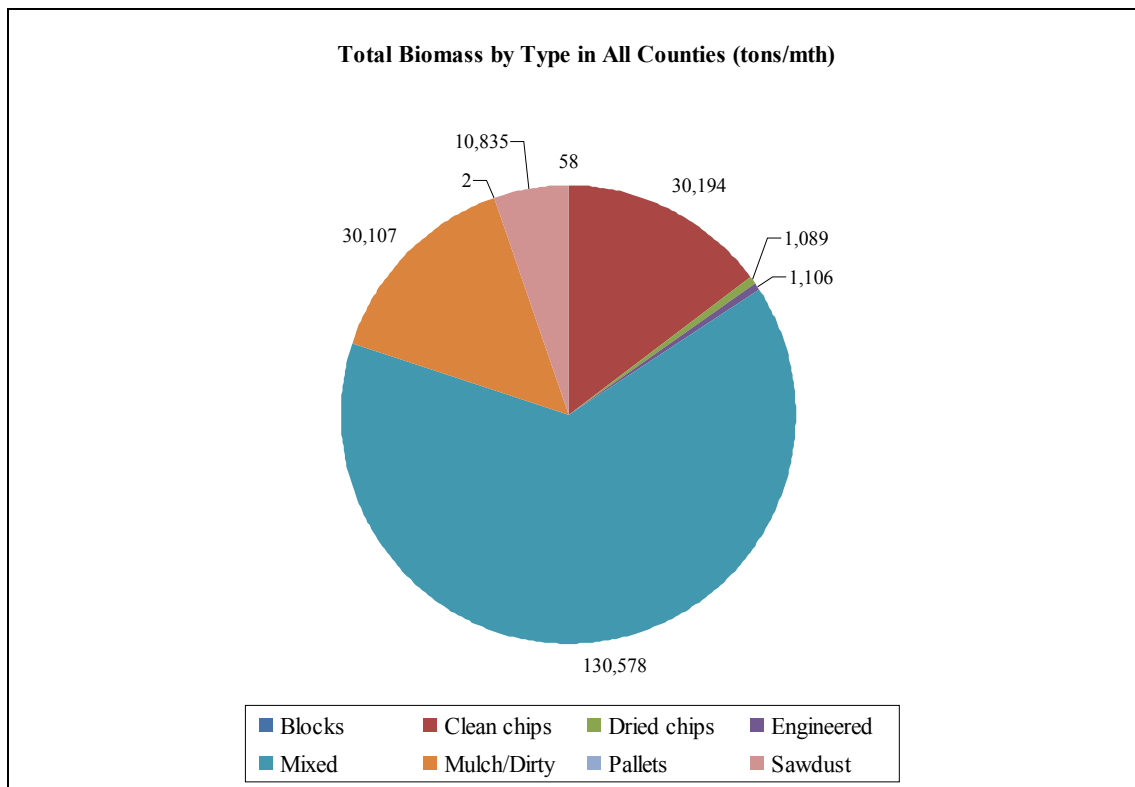


Figure 3.1-1: Total commercial biomass by type in study area (tons/month)

The entire body of this biomass assessment report summarized above is included in Appendix A.

Section 3.1 References

Biomass Wood Resource Assessment on a County-by-County Basis for the State of Georgia, November

2005. Report prepared for the Georgia Forestry Commission and the Southern States Energy Board.

The Feasibility of Generating Electricity from Biomass Fuel Sources in Georgia, 2003.2007

Report The University of Georgia.

Geographic Perspective on the Current Biomass Resource Availability in the United States, 2005.

NREL Report No. TP-560-39181.

2004-2005 USDA Crop Production Data for Georgia

3.2 Solar Energy Resource

According to NREL "Typical Meteorological Year" (TMY3) weather data and the PV F-Chart computer program, Robins AFB annually receives about 150.4 kWh of solar energy per square foot of flat surface area. For surfaces tilted 26° from the horizontal (the optimum angle determined by F-Chart for maximum annual energy) and facing due south, the annual incident energy is estimated to be 162.4 kWh/ft². Figure 3.2-1 shows monthly kWh/ft² for both flat and sloped surfaces at this location. Note that this is *incoming* solar energy; solar PV modules and solar thermal collectors are only able to convert a portion of this resource to useful energy depending on their efficiencies.

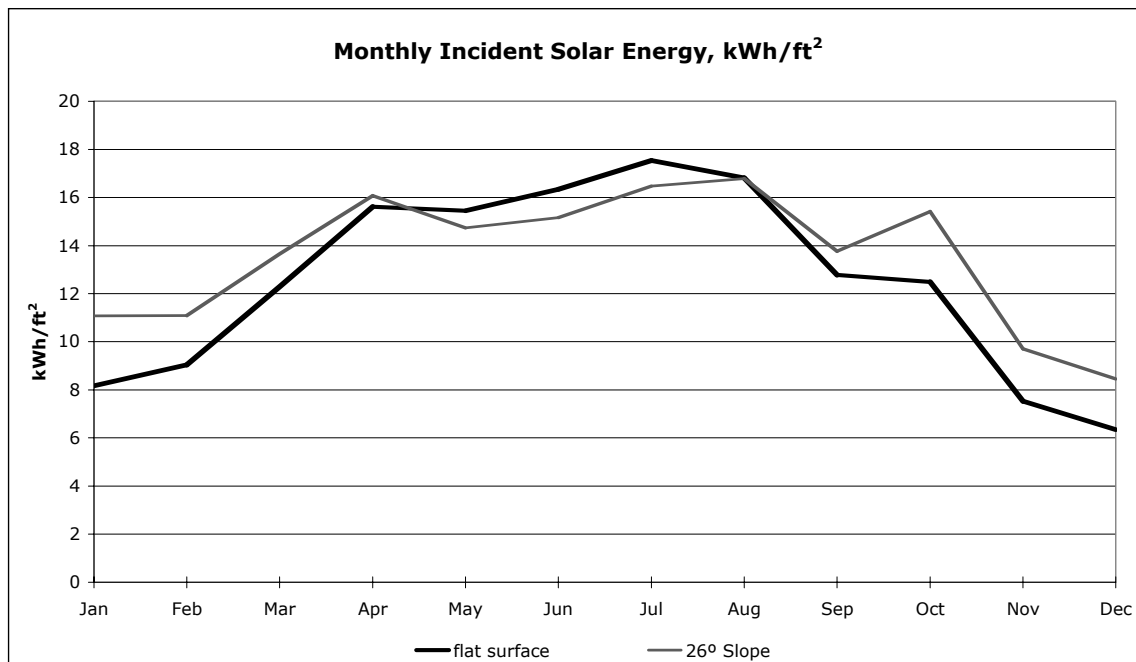


Figure 3.2-1: RAFB Incident Solar Energy by Month

According to Robins AFB personnel, the Base has 13.2 million square feet of roof area, of which it is estimated that 70% is flat. For the purpose of this study, the remaining 30%, which is presumed to be sloped or curved roof area, is disregarded. Thus, the total annual incident solar energy on the 9,240,000 ft² of flat roof area is about 1.39 billion kWh.

If PV modules or solar collectors were installed at a 26° angle over the entire roof area, the rows (oriented along the east-west direction) would need to be spaced far enough apart to avoid shading effects at low (winter) sun angles. For example, if the panels were 4 feet long then the rows would need 2.6 feet of space between them in the north-south direction. Therefore, while the 26° slope provides the optimum annual solar energy per unit of panel area, the actual panel area at this angle that could fit on a given roof would be less than if the panels were mounted flat. If we assume that a tilted panel area equal to 80% of the flat roof area could be installed, the incident solar energy would be 960 million kWh per year, or less than with the flat arrangement. It is important to note that this is only an issue if every foot of roof area is to be covered. In reality, a solar installation is more likely to be limited by system cost or energy demand rather than by space.

4. Large-scale Electric Power Generation (>10 MW)

4.1 Traditional Steam Turbine Plant

One technology that could be appropriate for application at Robins AFB is a traditional wood-fired steam turbine power plant, or perhaps a steam-only plant to interface with the base heating and cooling systems; however, the latter system would not contribute to meeting the federal renewable electricity mandate discussed in Section 2.1. These types of plants have been built all over the world over the past one hundred years and, have seen a recent increase in interest, particularly in the southeastern U.S.. In fact, currently, there are at least seven of these plants being discussed or planned for the state of Georgia. Possible locations for these plants are shown in Appendix C, Figure C-1. While these plants are being considered by independent developers as well as electric utilities (both investor-owned and electric membership corporations) it is unlikely that all will be built given the current economic climate. A cornerstone for financing such a plant will be a long term Power Purchase Agreement (PPA) that a bank will require to lend money for such a project.

Wood-fired steam plants are considered mature technology and can be expected to have a useful life of at least 25 years.

4.1.1 Description of Technology

The paragraphs which follow will give details of the type of equipment that could be used in a plant at Robins AFB. For illustrative purposes, general arrangements for 25 MW and 50 MW projects are shown as Figures C-2 and C-3 in Appendix C (courtesy of McBurney Corporation). In these figures, stoker boilers are shown, since they are currently the most cost effective. There is some question about permissibility of these plants due to air emissions, and the state of Georgia may require an "atmospheric fluidized bed" technology as "Best Available Control Technology." If that is the case, 5 to 10 percent must be added to the capital cost of the plant.

Technology for these plants should be considered fully developed, and bids to build such a plant should be available from multiple sources. Construction time should take about 12-24 months, and no major breakthroughs in technology are expected over the next 10-15 years, with the possible exception of improved emission control systems.

Fuel Processing

For purposes of this discussion, it is assumed that wood fuel will be received as chips, sawdust, bark, or similarly sized "small" material. This assumption will simplify the fuel processing system and keep the plant footprint requirements to a minimum. Again, to keep the design simple, it is assumed that all material will be delivered by truck (principally tractor-trailer). Thus, at least one truck/trailer truck unloader will be required. It may become apparent that a second truck unloader will be required sometime after plant startup. It is also possible that part or all of the wood deliveries could be made by rail. In that case, provision for unloading the rail cars would have to be provided. Due

to land area constraints at the Base, it might be desirable to locate the plant slightly removed from the Base, which could provide better access to the railroad. Several unloading options are shown in Appendix C, Figure C-4.

It is assumed that approximately 10 days of fuel storage will be needed on site. For the 25 MW plant, this equates to approximately 2 acres of storage in a woodyard, and for the 50 MW plant, this equates to approximately 4 acres, assuming an average pile height of no more than 15 feet. For security purposes, if more days' storage is required (large utility plants commonly have 30 days of coal storage) more acreage would be required. This security consideration will allow for disturbances in the wood supply due to weather and other unforeseen circumstances. The large amount of utility plant solid fuel storage (typical of a coal fired power plant) has been due to concerns about strikes by plant or rail workers and the inability of fuel suppliers to cross picket lines during such strikes. Presumably this would not be a problem at the RAFB.

Downstream of the truck unloader(s) a "disc screen" or vibrating screen will be necessary to separate oversize material that may be delivered with acceptable material, and a "hog" or chipper will be required to reduce the size of this oversize material to an acceptable standard. Magnetic separation equipment will also be required to remove tramp metal from the infeed to protect downstream equipment (See Appendix C, Figure C-5).

From the wood hog system, fuel can be conveyed to a fuel stacker or dumped on the ground to be managed by a front end loader or bulldozer blade.

Power Generation Equipment

Typically, power generation equipment used in this plant will be a standard steam turbine cycle. The boiler and turbine pressure can vary, but typically, in a plant of this size, steam pressure of 600 to 1200 psig is used. The owner/developer of the plant may be able to buy used equipment (such as a used steam turbine) of a certain rating from an older utility plant, which can be rebuilt to "as new" condition, or that has already been rebuilt. Since the steam turbine is typically the most expensive single component of the system, it will have a great influence on overall plant design. It is anticipated that an appropriate turbine would be of the condensing type, and a cooling tower would be fitted to close the steam cycle. Due to the potential close proximity to the Base's flightline and potential fogging issues, it may be desirable to utilize a "plume abated" cooling tower. The turbine would have at least one extraction point that would allow "process" steam to be extracted and sent to other areas of the Base for heating/cooling applications.

One concern related to locating a steam power plant at Robins is the exhaust stack height. It will be preferable to locate the plant as far as possible from the flight line. Anticipated heights for the stack will be 125 to 150 feet for a 25 MW plant and 175 to 200 feet for a 50 MW plant.

4.1.2 Plant Size Estimate

As noted above, the plant size will be 25 to 50 MW.

4.1.3 Conceptual Design

Envisioned design will be a spreader/stoker arrangement typical of paper mill or small central plant application. These boilers are available from multiple vendors in the U.S. and Europe. Emission control will be accomplished with standard, readily-available components including electrostatic precipitators, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), or wet scrubbers.

4.1.4 Conceptual Location(s)

The plant could be located in several places on the base including adjacent to Building 385 or near the "Pave Paws" radar site (Building 1408). While the primary purpose of this plant will be to generate electricity utilizing renewable feedstocks, it may be desirable to also pipe low pressure (less than 200 psig) steam to other areas of the Base for district heating or other applications. If steam extraction is desired, the plant should be located close to the thermal or process loads it will serve. The cost of the addition of a district heating system will be discussed in Section 5.

4.1.5 Budget Estimate

It is estimated that the "turnkey" price for such a project would be \$2300 to \$2700/kW. For a 25 MW plant, this equates to \$58 Million, and for a 50 MW plant, the budget would be \$135 Million. It is understood that the Air Force would not necessarily want to pay to build such a plant but would rather lease land to a third party (as has been done with the Georgia Power gas turbine facility on the Base) and allow that party to own and operate the facility. Contracts would then be negotiated between Robins AFB and the owner/operator for sales of electricity and steam. There is some question regarding legal issues related to the sale of electricity between a "third party" and RAFB since Georgia Power is already the Base's electricity provider. Since Robins AFB is a federal facility, this question may be irrelevant, but some legal opinions will need to be obtained.

4.1.6 Plant Economics Estimate

Many types of sensitivity analysis can be done on this type of plant, with variations made in such parameters as fuel cost, steam extraction, etc. Some examples of this are discussed below. The model used for the current study is based on a similar model used by an independent power developer to assess plant feasibility.

Table 41.-1 is based on wood that costs \$20 per green ton delivered to the plant. Two different interest rates are assumed: 4.5 and 8.5 percent. The lower one represents an interest rate that might be obtainable using financing from the Rural Electrification system; the higher rate represents what might be obtained from a commercial bank.

Two different levels are given for percentage of financing. Given the current status of lending and the economy, these numbers represent moving targets.

As can be seen from in Table 4.1-1, the lowest cost shown is 7.77 cents/kWh (in Year 1). This is probably above the current "industrial" rate available to Robins AFB from Georgia Power but is below the Georgia Power "green rate" which includes a 4.5 cent/kWh premium.

Future electricity rates charged by Georgia Power are unknown, but there is significant upward pressure on Georgia Power rates from the addition of more nuclear plants and the current cost of new coal or even combined cycle natural gas plants.

Table 4.1-2 represents the same data as Table 4.1-1 utilizing the average wood cost at \$30/green ton delivered.

Table 4.1-1: Cost of Electricity for \$20/Green ton Wood

Plant Size	Interest Rate	Financing	Cost of Electricity (cents/kWh)						
			Year 1	Year 4	Year 9	Year 14	Year 19	Year 24	Year 29
25 MW	4.5%	50%	10.11	10.89	12.42	13.94	15.78	17.85	20.20
	4.5%	75%	8.94	9.63	10.98	12.32	13.94	15.78	17.85
	8.5%	50%	10.72	11.54	13.15	14.78	16.72	18.92	21.40
	8.5%	75%	9.87	10.63	12.11	13.60	15.39	17.41	19.70
50 MW	4.5%	50%	9.03	9.73	11.10	12.45	14.09	15.94	18.03
	4.5%	75%	7.77	8.37	9.56	10.72	12.12	13.72	15.52
	8.5%	50%	9.69	10.44	11.90	13.56	15.12	17.10	19.35
	8.5%	75%	8.76	9.44	10.77	12.08	13.67	15.46	17.49

Assumes \$2600/kW for 50 MW and \$2300/kW for 25 MW, 2.5% escalation per year for fuel and O&M

Table 4.1-2: Cost of Electricity for \$30/Green ton Wood

Plant Size	Interest Rate	Financing	Cost of Electricity (cents/kWh)						
			Year 1	Year 4	Year 9	Year 14	Year 19	Year 24	Year 29
25 MW	4.5%	50%	11.65	12.55	14.29	16.06	18.18	20.56	23.27
	4.5%	75%	10.49	11.29	12.87	14.46	16.36	18.50	20.94
	8.5%	50%	12.27	13.21	15.04	16.91	19.13	21.658	24.49
	8.5%	75%	11.41	12.29	14.00	15.73	17.80	20.14	22.79
50 MW	4.5%	50%	10.40	11.20.	12.76	14.33	16.21	18.35	20.76
	4.5%	75%	9.15	9.86	11.24	12.62	14.27	16.15	18.27
	8.5%	50%	11.05	11.90	13.56	15.24	17.24	19.50	22.07
	8.5%	75%	10.14	10.92	12.44	13.97	15.81	17.89	20.24

Assumes \$2600/kW for 50 MW and \$2300/kW for 25 MW, 2.5% escalation per year for fuel and O&M

For use in this study, a request was made for details related to the primary electricity contract between RAFB and Georgia Power Company. These details were not available, so some assumptions as to revenues available have been made instead.

At this point in time, the state of Georgia is not subject to a Renewable Portfolio Standard (RPS) that would require electric utilities to generate a certain percentage of their electricity from renewable resources; however, there are many indications that the new Obama administration will be pushing for a national RPS through the federal legislative process in 2009. If a national RPS passes, it is likely that utilities in Georgia would be subject to a 5 to 15 percent RPS. In the case of Georgia Power, that would amount to the equivalent of 900 MW to 2700 MW of generation to be provided by renewable energy. At present, Georgia Power only has a 3.3 MW landfill gas project that qualifies as green energy; therefore, they would need to quickly implement many renewable electricity projects, depending on the timeframes involved.

In the past, utilities have argued that new nuclear facilities should be included in the renewable category, since CO₂ emissions would be minimized. If nuclear is considered "renewable", Georgia Power could count approximately 900 MW of generation from nuclear if Vogtle 3 and 4 are approved and built. If not, there will be substantial pressure to show generation from renewables in Georgia, and the value of renewable energy will escalate dramatically. At this time, power companies are willing to pay 6.5 to 7.5 cents/kWh for renewable electricity generated from biomass. As other new generation is brought online utilizing natural gas (or even new coal), the amount the utilities are willing to pay will rise. Of course, the average cost of electricity paid by Robins AFB will also rise substantially over the next ten years.

4.1.7 Plant Operational Arrangements/Energy Supply

It is anticipated that a steam/electric plant would be purchased and paid for by a third party who would then supply steam and electricity to the Base under a "Power Purchase Agreement (PPA)" or other instrument. There may be some legal challenges presented against such an arrangement in the state of Georgia. Some potential legal challenges could be skirted by having the Department of Defense be at least a partial owner of the facility.

Depending on the size of plant built, the wood fuel supply required (in green tons - up to 50% moisture content) will be approximately 250,000 tons/year for a 25 MW plant and 500,000 tons/year for a 50 MW plant. As presented in the previous section on wood availability, this material is expected to cost \$20 to \$30/green ton (delivered) for a plant starting up in the year 2012. While ownership of such a plant has not been determined, some discussion should be presented on fuel procurement options. The management of such a plant could have a staff person responsible for wood fuel procurement as part of his job, or as his entire job. Alternatively, a wood fuel procurement association or company could be contracted for these services. There are a number of companies in the Southeast with experience in this field that could provide such a service for a fee (typically a percentage of the price paid for the fuel). Another alternative might be to

have a recognized company with substantial forest landholdings (such as Plum Creek Timber Holdings) as a partner in the project, acting as the fuel procurement agent.

Georgia Tech personnel have had some preliminary discussions with independent power developers about owning and operating such a plant on an Air Force base, and the feedback about such an arrangement has been generally positive.

A possible additional synergy needs to be noted here: the production of certain synthetic fuels (such as cellulosic ethanol) can result in waste material (such as lignin) which could be burned as an additional fuel stream in the plant described above. This could result in a multi-purpose plant being built at Robins that could supply steam/electricity and also fuel for some of the Base's transportation needs.

It is anticipated that a 25 to 50 MW wood-fired plant would require approximately 25 fulltime personnel to operate on a 24 hour/day, 350-day per year basis. Annual scheduled shutdowns (preferably during off-peak times such as spring and fall) would be necessary for performance of plant maintenance.

4.2 Biomass Gasification

4.2.1 Description of Technology

Gasification or the production of a combustible gas from carbonaceous materials is not new technology. The thermal decomposition of fuel (biomass, coal) into a volatile synthetic gas was developed at a commercial scale in Europe in the early 1800s. This gas was initially used principally for street lighting in cities to help make the cities safer. By the 1920s commercial-scale gasifiers were operating for many industrial heat and power applications across the world. Most major cities contained a "gas works" that produced low or medium Btu gas from coal. In fact, Atlanta was served by a massive gas works operated by the predecessor of Atlanta Gas Light, which was located in the approximate present location of the Georgia World Congress Center. With the advancement of petroleum as a fuel, most gasification technology was replaced by fuel oil or natural gas.

Gasification is a thermochemical process for the conversion of carbonaceous materials, such as coal, petroleum, or biomass, into carbon monoxide and hydrogen by reacting the feedstock material at high temperatures with a controlled amount of oxygen. The resulting gas mixture, called synthesis gas or syngas, may be used directly as a fuel or as a feedstock for further processing into hydrogen or liquid fuels. Gasification is an efficient method of converting energy from many different types of organic materials into a useable and transportable form.

The utilization of syngas for power or electrical production had the potential to be more efficient than direct combustion of the original feedstock. Syngas may be burned directly in traditional gas-fired boilers for steam production or even in internal combustion engines for electric generation. Syngas is also used to produce liquid fuels

through catalytic reactions and has been used historically to produce synthetic fuels (gasoline and diesel) via the Fischer-Tropsch process.

Gasification of traditional fossil fuels, mainly coal, is used world-wide today at commercial and industrial scales to generate steam and electricity. Gasification technology can process most types of organic material as a feedstock; however, lignocellulosic woody biomass is of primary interest.

Low BTU Gasification

Low Btu gasification is gasification where the resultant syngas has an energy value of less than 300 Btu/scf, usually in the range of 200 Btu/scf.

Low Btu syngas is high in inert gasses, tars and other impurities and is generally used only as a fuel in a combustion system for heat/steam production. It is generally not of the quality to be used in combustion turbines or internal combustion engines for electrical generation.

Advanced Medium BTU Gasification

Medium Btu gasification is gasification where the resultant syngas has an energy value usually in the range of 400 to 450 Btu/scf.

Medium Btu syngas can be used directly in combustion boilers (as can low Btu syngas) but can also be cleaned of tars and compressed for use in combustion turbines or internal combustion engines for electrical generation. Medium Btu syngas also holds promise for downstream processing through catalytic reforming to liquid fuels.

4.2.2 Fuel Handling and Processing

As with the steam/power system described in Section 4.1, biomass fuel feedstock will need to be handled to varying degrees at RAFB. There are several options for fuel yard configuration. Two options are discussed here.

Chip Storage and Handling Yard

For this option, it is assumed that wood fuel will be received as chips, sawdust, bark, or similarly sized "small" (3 inch minus) material. This assumption will simplify the fuel processing system and keep the wood yard size requirements to a minimum. In keeping to a simple design plan, it is assumed that all material will be delivered by truck (principally tractor-trailer) at a 3 inch or less size. Thus, at least one truck/trailer truck unloader will be required. (It may become apparent that a second truck unloader will be required sometime after plant startup.) Additional off load facilities will be required for dump and walking-floor trailers. It is also possible that part or all of the wood deliveries could be made by rail. In that case, provision for unloading the rail cars would have to be provided.

It is recommended that a minimum of 10 days fuel storage on site. For storage of chips only for the 25 MW plant, this equates to approximately 2 acres of storage in the wood

yard, and for the 50 MW plant, this equates to approximately 4 acres and additional 2 acres required for the fuel handling equipment (listed below) for a total of 4 and 6 acres respectively.

Downstream of the truck unloader(s) additional equipment will be required (disc screen or vibrating screen) to separate oversize material that may be delivered with acceptable material, and a "hog" or chipper will be required to reduce the size of this oversize material to an acceptable standard. Magnetic separation equipment will also be required to remove tramp metal from the infeed to protect the downstream equipment (See Appendix C, Figure C-5).

Full Scale Fuel Yard

For additional flexibility and security, a full-scale wood/fuel-handling yard may be desired. Such a processing facility will be able to process 3 inch minus chips, sawdust, bark and other feedstock as detailed above and also process any feedstock type up to whole tree sizes including most commercial/industrial woody biomass waste.

It is assumed that all material will be delivered by truck (principally tractor-trailer). The facility will need at least one unloader. (It may become apparent that a second truck unloader will be required sometime after plant startup.) Additional off-load facilities will be required for dump and walking-floor trailers. Separate off-load facilities will be required feedstock not in the 3 inch minus size range. Storage space for whole tree deliveries will be required along with whole tree chipping equipment. It is also possible that part or all of the wood deliveries could be made by rail. In that case, provision for unloading the rail cars would have to be provided.

The whole tree operation and waste wood handling capability will expand the area needed for the fuel yard to approximately 12 acres. This 12-acre site will handle fuel processing for a plant in the range of 25 to 50 MW.

4.2.3 Plant Size Estimate

Estimated plant size based on the current energy use at Robins Air Force Base for the production of steam and/or electrical generation from biomass is a range of 25 to 50 MW. A biomass plant of this production capacity will consume approximately 600 to 1200 tons per day of biomass.

4.2.4 Conceptual Design

Several manufacturers and developers of biomass gasification equipment exist that could potentially meet the 25 to 50 MW requirement for electrical/thermal energy production on Robins Air Force Base. Several will be mentioned here with contact information provided.

In the early to mid 1980s there were a number of plants built producing low Btu gas that supplied this fuel directly to conventional gas-fired boilers that had been fitted with

special low Btu burners. The driving force behind these applications was the "Section 29" gas tax credit, which was in effect for certain synthetic gas projects until 1999. The tax credit obtained was dependent on a number of factors, but generally amounted to approximately \$1/MMBtu equivalent, which meant that the financial value of this tax credit could have a substantial impact on the cash flow of a given facility. One supplier that built several of these plants (including the Crisstad Plant in North Powder, OR) was Energy Products of Idaho. Their gasifier design was a bubbling bed gasifier, which produced fuel in the 150 to 200 Btu/scf range. This fuel was fired in a conventional gas-fired boiler to produce medium pressure (450 psig) steam. The steam was then used to power a conventional steam turbine-generator producing 6 MW. While the overall efficiency of the plant was not particularly high, the tax credit drove the finances. (EPI, 2008). Due to the expiration of the Section 29 credits, it is unlikely that such a project would be replicated today.

There have been a number of additional projects that have produced low and medium Btu gas for use in internal combustion engines, and purportedly also for gas turbines. At present, for example, Tecnoholding Ing. of Barcelona, Spain, is building a 6 MW biomass gasifier plant near Valencia, Spain which utilizes a bubbling bed gasifier to produce low Btu gas. The gas will be scrubbed and supplied to a GE Jenbacher spark ignition engine. This project is driven by high tariff rates available for biomass projects in the European Union (more than 20 cents/kWh). While the long term viability of this project is not yet proven, it shows promise, and the developer has plans to replicate it in several other locations in Europe.

The Tecnoholding project is similar to other projects that were constructed by the Duvant Corporation of France in the Philippines in the mid 1980s. These plants were funded on a cooperative basis between the French and Philippine governments but were never operated commercially due to political upheaval in the country.

Once gas has been produced in a gasification plant, it can be supplied to several different technologies, each of which needs to be analyzed from an economic standpoint. These technologies could include the following:

Gas Boiler/steam generation/steam turbine

This type of boiler system is quite straightforward and is typical of many cogeneration systems that were built in the 1980s. At today's prices this type of plant could be built for \$1200 - \$1600/kW.

Gas cleanup/internal combustion engine

Internal combustion engines in the 1 to 5 MW size range (either dual fuel diesel or spark ignition) will cost between \$1100/kW to \$1600/kW. Additional gas cleanup will be required to make the biomass gas acceptable for long term engine operation. This cost will probably fall in the \$300/kW range. These engines are somewhat similar to the Cooper-Bessemer engines installed at the Pave Paws site, and those engines could presumably be converted to wood gas firing. Systems of this type are discussed in more detail in Section 5.4.

Gas cleanup/gas turbine engine

While the cleanup of biomass gas for internal combustion engines is important, cleanup for gas turbine engines is absolutely critical. Simple cycle engines in the smaller size ranges (3 to 40 MW) will cost in the \$1000/kW - \$1600/kW range. Expect to add up to \$500/kW for adequate gas cleanup.

Gas cleanup/microturbine

It is conceivable that wood gas could also be burned in small microturbines and dispersed in various locations on the Base. These units will cost in the \$2600 - \$2700/kW range for sizes of 60 to 250 kW, and gas cleanup costs will be similar to the costs for the larger machines.

4.2.5 Budget Estimate

Budget estimates for gasification are wide-ranging and both technology- and site-specific. Actual estimates will need to be determined on a case-by-case basis.

In general it can be assumed that thermal production (steam only) will be considerably less capital intensive due to the lack of the power island for electric generation. However, in this case more conventional combustion systems provide adequate thermal energy and are significantly lower in capital and operational costs. (See thermal section above). In addition, thermal-only systems would not contribute significantly to the federal renewable electricity mandate.

Low BTU Steam Cycle Generation

On a total turn-key facility basis, typical low Btu gasification processing facilities in the range of 25 to 50 MW production capacities with electric generation will cost an estimated \$3.1 million per MW for 25 MW facility and \$2.9 million per MW for a 50 MW facility. Therefore an EPC contract price for low Btu gasification with steam cycle generation will range from of \$77.5 to \$145 million for a 25 MW and 50MW facility, respectively.

Medium BTU Gasification Integrated Combined Cycle Generation (IGCC)

Typical IGCC configuration facility will cost approximately \$3.6 million per MW for 25 MW facility and \$3.1 million per MW for 50 MW facilities. Therefore, an EPC contract price for medium Btu gasification with integrated combined cycle generation (IGCC) will range from of \$90 to \$155 million for a 25 MW and 50MW facility respectively.

4.2.6 Plant Economics Estimate**Syngas Production Cost Estimates**

The potential for gas generation from biomass may provide an excellent fuel for electricity production. Syngas produced from biomass has significantly less energy value than that of natural gas and, therefore, requires modifications to existing equipment before utilization. Relatively low-cost modification to burners and nozzles of standard gas-fired boilers permits the use of both low and medium Btu syngas.

Utilization of syngas as a pipeline gas for base-wide existing infrastructure is not considered a viable option for Robins AFB because of the reduced Btu value. Methanation of syngas creating synthetic natural gas (SNG) would be an option to provide a pipeline-quality gas to be used Base-wide in all existing natural gas infrastructure; however, this technology, while demonstrated on coal-derived syngas, has yet to be proven for biomass feedstocks. It could be considered for Base application in the 10 to 15-year timeframe.

It is recommended that if a gasification scheme is pursued that one of two syngas utilization options be followed for large-scale electricity generation: (1) “hot dirty gas” from low Btu gasification for thermal production and steam cycle generation, or (2) cleaned, medium Btu syngas for gas turbine generation with IGCC.

The costs for production of syngas via gasification vary with specified technologies. Production cost estimates for various technologies are in the range of \$4.50 to \$5.75 per MMBtu. Variable costs associated with feedstock depend on biomass type based on energy content of fuel.

Using an average energy value of 16 MMBtu per ton of biomass (8,000Btu/lb), the cost of biomass will affect the resultant cost of syngas by \$1.00 for every \$10.00 dollars of feedstock cost. Therefore, based an average estimated cost for feedstock of \$30.00 per ton the syngas production costs will range from \$7.50 to \$8.75 per MMBtu.

Electrical Generation Cost Estimates

The cost of producing electricity from gasification also varies depending on technology choice.

Syngas (natural gas retrofitted) Boiler with Steam Turbine - In this case, a standard gas-fired boiler will be used with modified burner/nozzle configuration for medium Btu syngas. Table 4.2-1 below estimates the generation cost per kWh of electricity from 25 and 50 MW facilities based on a gas-fired boiler, steam production, and steam turbine. Steam cycle generation has an efficiency of less than 50%.

Table 4.2-1: Steam Cycle Electrical Generation Cost Estimates \$/kWh

	Capacity	
	25 MW	50 MW
MWh per year	205,000	410,000
Total Capital	\$77,500,000.00	\$140,000,000.00
Capital/MW	\$3,100,000.00	\$2,800,000.00
Feedstock Costs	\$5,900,000.00	\$10,700,000.00
Estimated O&M	\$4,400,000.00	\$6,500,000.00
Cost of Capital	\$5,500,000.00	\$9,800,000.00
Cost per kWh	\$0.0771	\$0.0659

Assumptions: 100% debt at 6% for 25 years

Integrated Gasification Combined Cycle Generation:

Table 4.2-2 shows the production costs per kWh based on syngas production with electrical generation using combustion turbine integrated with combined cycle. It is estimated that the initial capital cost is \$2.6 million per MW. Efficiencies of IGCC plants are approximately 60%.

Table 4.2-2: IGCC Electrical Generation Cost Estimates \$/kWh

	Capacity (MW)	
	25 MW	50MW
MWh per year	205,000	410,000
Total Capital	\$92,500,000.00	\$162,500,000.00
Capital/MW	\$3,700,000.00	\$3,250,000.00
Feedstock Costs	\$5,428,000.00	\$9,844,000.00
Estimated O&M	\$4,900,000.00	\$7,000,000.00
Cost of Capital	\$5,500,000.00	\$11,375,000.00
Cost per kWh	\$0.0772	\$0.0688

Assumptions: 100% debt at 6% for 25 years

Section 4.2 References

EPI Website, 2008, <http://www.energyproducts.com/energy1.htm>

4.3 Municipal Solid Waste-to-Energy

Energy derived from municipal solid waste (MSW) is defined as renewable under a number of statutes, laws and executive orders including Section 203 of the Energy Policy Act of 2005, Section 9(h) of Executive Order 13434 and the Biomass Research and Development Act of 2000 as well as statutes in over 24 states.

The EPA (2007) recognizes combusting MSW for energy recovery as part of its integrated waste management hierarchy which includes the following four components, listed in order of preference:

- Source reduction (or waste prevention), including reuse of products and on-site (or backyard) composting of yard trimmings
- Recycling, including off-site (or community) composting
- Combustion with energy recovery
- Disposal through landfilling.

4.3.1 Description of Technology

The first commercially-available combustion MSW waste-to-energy (WTE) facilities came on line in the United States approximately 30 years ago. As of 2007, there were 87 WTE facilities in the United States. These WTE facilities combusted approximately 31.9 million tons of MSW to generate approximately 2,500 MW or 0.3% of the total national electrical power generated (EPA, 2007). A basic overview of a traditional WTE to energy facility involves the following process (Covanta, 2007):

- MSW is picked up by trucks at curbside and is unloaded at a MSW facility.
- Waste is combusted at high temperatures to create steam to generate electricity.
- Historically for every 10 tons of MSW, 5,200 kWh of power are generated and 500 lbs. of metal are recycled.
- Electrical power is fed back onto the grid
and/or
- Generated steam can be supplied to customers in close proximity to the WTE facility.

WTE facilities which have partnered with the federal government to provide steam include the following:

- The Huntsville, AL facility which serves the Army's Redstone Arsenal
- The Harford, MD facility which serves the Aberdeen Proving Grounds
- The Davis, UT facility which serves Hill Air Force Base
- The Hampton, VA facility which serves NASA (Michaels, 2008).

The “2007 IWSA Directory of Waste-to-Energy Plants” lists four major companies in the United States that design and operate WTE Facilities. In the Southeast, there is one WTE facility in Alabama and 11 WTE facilities in Florida, ranging in electrical generation capacity of 14.5 MW to 77 MW.

Concerns with WTE facilities are air emissions and ash production, which can contain hazardous metals. Currently, all WTE facilities in the United States comply with the EPA’s Maximum Achievable Control Technology (MACT) standards (Michaels, 2007). Under current regulations, MSW ash must be sampled and characterized using EPA’s EP Toxicity Test Protocol to determine whether it is hazardous or not. Hazardous ash must be managed and disposed of as hazardous waste. Depending on state and local restrictions, non-hazardous ash may be disposed of in a Class I MSW landfill, Class I ash monofill, or recycled for use in roads, parking lots, or daily covering for Class I sanitary landfills (EPA, 2008). MSW combined ash (bottom ash & flyash, including spent scrubber reagent) from current operating WTE facilities typically tests as non-hazardous using EPA’s EP Toxicity Testing Protocol.

4.3.2 Municipal Solid Waste Combustion for Electrical Generation for Robins AFB

The Houston County Landfill is the closest source for collection and supply of MSW for a WTE facility. This landfill is located 7.3 miles from Robins AFB’s center.

Houston County Landfill collected a total of 158535 tons of MSW in 2007, with an average daily collection rate of 434 tons. Covanta Energy Company and Veolia ES Waste-to-Energy, Inc. were contacted in order to determine the economic feasibility of forming a partnership to build and operate a MSW waste-to-energy plant to provide steam or electricity to Robins AFB.

Designers at Covanta Energy Company estimate that for today’s market, a 500 ton/day WTE facility would require an approximate \$125 million dollar capital investment, depending on many variables including soil conditions, type of electrical interconnect, distance to the power grid, etc. New MSW WTE facilities being proposed today would guarantee energy recovery in the range of 6500 kW for every 10 tons of MSW processed (Reardon, Tresler, 2008). With the source of approximately 434 tons MSW/day from the Houston County Landfill, a WTE facility designed by Covanta Energy Company would generate approximately 13 MW of renewable electricity. Newer MSW WTE facilities also have enhanced technology to improve environmental performance, including reduction of NOx emissions.

It is somewhat difficult to determine actual tipping fees required to economically run a MSW WTE facility without submitting Requests for Proposals to interested WTE designers and doing an analysis of avoided costs for independent power developers, etc. According to Covanta Energy Company, the ability to sell electricity in the \$0.10 to \$0.13/kW range would make development of a new MSW WTE facility feasible for investors/communities. This rate range is comparable to biomass power generator development projects.

4.3.3 Future Municipal Solid Waste Technologies for the United States

Several demonstration technologies are currently in use in Asia, Australia and Europe to minimize municipal solid waste to landfills and to derive energy from MSW. These technologies include

- Anaerobic digester
- Pyrolysis
- Pyrolysis combined with high temperature gasification
- Low temperature gasification
- Gasification and plasma technologies

Among other sites, California, Florida and Canada are exploring some of these technologies. Several of these areas have additional economic drivers for exploring these technologies, including state mandates to reduce solid waste to landfills as well as eventual local landfill closures (LACC, 2007). Estimated tipping fees for these technologies have been proposed in the \$50 to \$70 range. For the purpose of this assessment, an in-depth analysis of the above technologies was not considered to be feasible for Robins AFB at this time; however, some, if not all of these technologies may become economically viable for the Georgia area in the next 10 to 15 years depending on advances in technology, changes in electrical rate schedules, landfill rate changes and/or mandates from the State or Federal Government to reduce solid waste to landfills.

Section 4.3 References

U.S. Environmental Protection Agency, 2007, "Municipal Solid Waste in The United States: 2007 Facts and Figures."

Covanta Energy, 2008, "The Energy from Waste Basics,"
http://www.covantaholding.com/efw_basics.shtml.

Michaels, Ted, 2007, Integrated Waste Services Association, "2007 IWSA Directory of Waste-to-Energy Plants"

U.S. Environmental Protection Agency, 2008, www.epa.gov

Russell Reardon, Covanta Energy Corporation, RReardon@CovantaEnergy.com and Joseph Treshler, JTreshler@CovantaEnergy.com

[LACC] "Los Angeles County Conversion Technology Evaluation Report – Phase II October 2007", prepared by Alternative Resources, Inc.

5. Small-scale Power Generation (<10 MW)

5.1 Landfill Gas Opportunities

The production of electricity from landfill gas is considered green energy. In fact, Georgia Power is basing most of their green energy program on electricity generated at the Seminole Road landfill in Dekalb County, Georgia. At this landfill, up to 3.2 MW of electricity is generated utilizing two Caterpillar spark ignition engines. This plant went into operation in late 2007.

Another similar landfill project is being considered closer to Robins AFB. A draft proposal has been prepared between Flint Energy and Houston County for the project, which would serve as the sales agreement for the landfill gas to be sold to Flint Energy. This arrangement is still under negotiation.

Flint has reached an agreement with PowerSecure International. PowerSecure would be responsible for building the generating plant and would then sell the power to Flint Energy. It is possible that the plant could be operational as early as November 2009. By that time a new section of the landfill will open, which will allow the production of 2 to 3 MW of electricity. At present, only 660 KW could be generated from the existing cell.

Electricity generated from this landfill will be "green tag certified" and would be available for purchase to anyone. Robins AFB has expressed an interest, but the main base itself is served by Georgia Power; only the Robins AFB Air Museum is served by Flint EMC. Georgia Power has expressed no interest in cooperating in a project to get the electricity onto the Base. Since the Air Force is a federal organization, it could claim an exemption to the state retail sales law, but lawsuits would likely result, delaying the agreement. Conceivably, the Air Force could buy "green tags" from the landfill power project, which would still count towards their green energy goals, but an actual transfer of electricity would not take place.

5.2 Anaerobic Digestion of Food Waste

According to data provided by Robins AFB personnel, the total waste stream for FY2008 was 10,006 tonnes, of which 46 percent was sent to landfill while the rest was recycled. Because food waste was not specifically broken out in the data, it is assumed that it is included in the landfill waste category. It is difficult to quantify the exact amount of food waste that is available as an energy feedstock without conducting a detailed survey of the Base's waste stream. Before going through such an effort, it is reasonable to assume that 1251 tonnes of the overall waste stream is food waste, which is based on the 12.5 percent national average (EPA 2008).

Anaerobic digestion of food waste for methane production is prevalent in India and is gaining popularity in Scandinavia and other areas of Europe. In the U.S., anaerobic digestion has been typically limited to wastewater treatment plants and livestock manure management for the purpose of odor control, although energy production from the resulting methane is becoming more common.

Davidsson *et al.* (2007) provides a useful reference for estimating methane yield from a quantity of food waste. In their study they encountered a range of total solids (TS) content, volatile solids (VS) content, and methane yields per tonne of volatile solids loaded into the digester. Using the Davidsson *et al.* ranges, Table 5.2-1 below lists low and high estimates of daily methane yield based on the assumption of 1251 tonnes per year (3.43 tonnes/day) (Davidsson, 2007).

Using the lower heating value for methane, approximately 5.7 to 16.2 MMBtu could be produced daily. Assuming a range of electric generation efficiencies between 25% and 33%, the estimated annual electricity generation potential from anaerobic digestion is 152 to 571 MWh per year.

Table 5.2-1: Estimates of Anaerobic Digestion Output for RAFB

	Low	High
TS (% w/w)	22%	37%
VS (% TS)	81%	92%
VS, tonnes/day	0.61	1.17
Methane yield, Nm³/tonne VS_m	275	410
Methan, Nm³/day	168	478
LHV methane, MJ/Nm³	35.7	35.7
Energy, MJ/day	5,995	17,073
Energy, Btu/day	5,682,152	12,182,509
Electric conversion efficiency	25%	33%
Electric energy, kWh/day	416	1,565
kWh/year	151,956	571,249

Because even the high end of the potential generation is very small compared to the Base's needs, this option does not warrant detailed analysis at this time. However, in the future it might be worth exploring the option of a larger digestion facility that can accept food waste from the surrounding area for a tipping fee.

Section 5.2 References

Davidsson, A., *et al.*, 2007. *Methane yield in source-sorted organic fraction of municipal solid waste*. Waste Management 27, pp. 406-414.

EPA, 2008. *Municipal Solid Waste in the United States, 2007 Facts and Figures*. US Environmental Protection Agency, Office of Solid Waste. EPA530-R-08-010.

5.3 Fuel Cells

5.3.1 Description of Technology

Fuel cells, sometimes called flow batteries, produce electricity from the input of hydrogen and oxygen through an electrochemical reaction. An illustration of the general process is shown in Figure 5.3-1. The fuel cell itself consists of two catalyst-covered electrodes, an anode and a cathode, as well as an electrolyte, which conducts charged ions from one electrode to the other. Hydrogen enters the fuel cell at the anode and is split by the catalyst into protons and electrons. The electrons are then forced through wires and delivered

to a load as electricity. Oxygen enters the system at the cathode and is similarly split

into ions by a catalyst. Depending upon the specific fuel cell design, the electrolyte surface prevents transportation of one type of ion (positive or negative) and conducts the oppositely-charged ion towards the other electrode. The ions not permitted through the electrolyte combine with the transported ions to form water. These reactions also result in the net production of heat.

Many types of fuel cells currently exist. Table 5.3-1 compares the performance characteristics, applications, advantages, and disadvantages of the main types of fuel cells. Note that polymer-electrolyte membrane fuel cells (PEMFC) have an application in transportation while the primary application for phosphoric acid (PAFC), molten carbonate (MCFC), and solid-oxide fuel cells (SOFC) is stationary power. The latter group of fuel cells can also be used in combination of heat recovery devices due to their higher operating temperatures, which increases the overall system fuel efficiency. For the purposes of this study, only stationary power units are examined. Fuel cell-power transportation would be sold by a vehicle manufacturer and would not be a modification of a current combustion-driven vehicle performed specifically for RAFB. Specific vehicles performance characteristics and economics would be available from the manufacturer and a determination could be made by the Base as to whether or not to purchase and operate these vehicles.

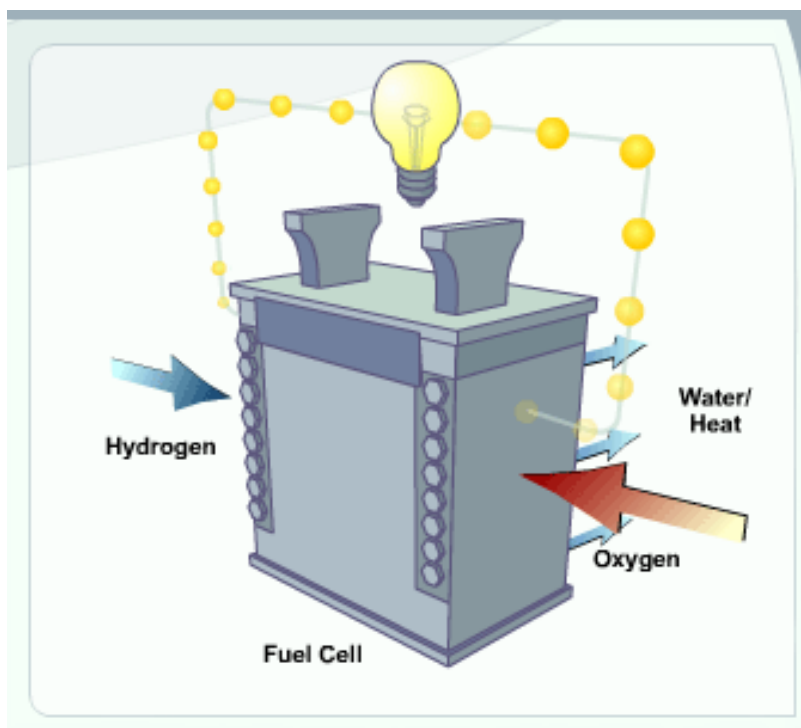


Figure 5.3-1: Fuel Cell Concept (EERE, 2008a)

Table 5.3-1: Comparison of Fuel Cell Technologies
(EERE, 2008b)

Fuel Cell Type	Common Electrolyte	Operating Temperature	System Output	Electrical Efficiency	Applications	Advantages	Disadvantages
Polymer Electrolyte Membrane (PEM)*	Solid organic polymer poly-perfluorosulfonic acid	50 - 100°C 122 - 212°F	<1kW – 250kW	53-58% (transportation) 25-35% (stationary)	<ul style="list-style-type: none"> Backup power Portable power Small distributed generation Transportation 	<ul style="list-style-type: none"> Solid electrolyte reduces corrosion & electrolyte management problems Low temperature Quick start-up 	<ul style="list-style-type: none"> Requires expensive catalysts High sensitivity to fuel impurities Waste heat temperature not suitable for combined heat and power (CHP)
Alkaline (AFC)	Aqueous solution of potassium hydroxide soaked in a matrix	90 - 100°C 194 - 212°F	10kW – 100kW	60%	<ul style="list-style-type: none"> Military Space 	<ul style="list-style-type: none"> Cathode reaction faster in alkaline electrolyte, leads to higher performance 	<ul style="list-style-type: none"> Expensive removal of CO₂ from fuel and air streams required (CO₂ degrades the electrolyte)
Phosphoric Acid (PAFC)	Liquid phosphoric acid soaked in a matrix	150 - 200°C 302 - 392°F	50kW – 1MW (250kW module typical)	>40%	<ul style="list-style-type: none"> Distributed generation 	<ul style="list-style-type: none"> Higher overall efficiency with CHP Increased tolerance to impurities in hydrogen 	<ul style="list-style-type: none"> Requires expensive platinum catalysts Low current and power Large size/weight
Molten Carbonate (MCFC)	Liquid solution of lithium, sodium, and/or potassium carbonates, soaked in a matrix	600 - 700°C 1112 - 1292°F	<1kW – 1MW (250kW module typical)	45-47%	<ul style="list-style-type: none"> Electric utility Large distributed generation 	<ul style="list-style-type: none"> High efficiency Fuel flexibility Can use a variety of catalysts Suitable for CHP 	<ul style="list-style-type: none"> High temperature speeds corrosion and breakdown of cell components Complex electrolyte management Slow start-up
Solid Oxide (SOFC)	Yttria stabilized zirconia	600 - 1000°C 1202 - 1832°F	<1kW – 3MW	35-43%	<ul style="list-style-type: none"> Auxiliary power Electric utility Large distributed generation 	<ul style="list-style-type: none"> High efficiency Fuel flexibility Can use a variety of catalysts Solid electrolyte reduces electrolyte management problems Suitable for CHP Hybrid/GT cycle 	<ul style="list-style-type: none"> High temperature enhances corrosion and breakdown of cell components Slow start-up Brittleness of ceramic electrolyte with thermal cycling

*Direct Methanol Fuel Cells (DMFC) are a subset of PEM typically used for small portable power applications with a size range of about a subwatt to 100W and operating at 60 - 90°C.

As stated above, to generate electricity, fuel cells require input of both hydrogen and oxygen. Currently, most hydrogen in the U.S. is generated from natural gas through a process called “reformation”. This process separates natural gas into smaller chemical components, one of which is H₂. To meet the definition of renewably-generated electricity, hydrogen used by a fuel cell would need to be reformed from a renewable fuel such as ethanol or biomass gas or generated by electrolysis using renewably-generated electricity. The former method is preferred for RAFB. A reforming unit would be required for all types of fuel cells except molten carbonate and solid-oxide. Due to the high operating temperatures of MCFCs and SOFCs, hydrogen-rich fuels can be directly reformed within those types of units.

5.3.2 Plant Size Estimate

Due to the modular nature of fuel cells, the sizing of a fuel cell plant is highly flexible. The only costs that vary with size on a per kilowatt-basis would be the reformer and interconnection with the electrical grid, both of which would slightly favor a larger system due to economies of scale. By comparison to the cost of fuel cells themselves and due to the limited amount of cost data regarding both of these components, the effects of plant size on a cost per kilowatt-basis is ignored in this study.

5.3.3 Conceptual Design

Without heat recovery—for the purposes of this study, only stationary power units are examined. Fuel cell-power transportation would be sold by a vehicle manufacturer and would not be a modification of a current combustion-driven vehicle done specifically for RAFB. The specific vehicles performance characteristics and economics would be available from the manufacturer and a determination could be made by the Base as to whether or not to purchase and operate these vehicles. Note that external reforming of a biofuel to produce hydrogen would be required.

5.3.4 Conceptual Location

Due to its relatively small footprint, low height, and low levels of noise, a fuel cell system could be located in many places throughout the Base. An example of these characteristics is shown in Table 5.3-2.

**Table 5.3-2: Example Specs for 200 kW PAFC System
(UTCP, 2008)**

Noise	60 dB at 30 ft without enclosure
Height	10 ft
Width	14 ft
Length	32 ft
Weight	41,700 lb

If heat recovery is chosen, the system should be located adjacent to buildings that could utilize as much of the hot water generated as possible. If the system is to be powered by biogas from anaerobic digestion or biomass gasification, it should be located within the design range of gas piping for other purposes, such as direct-fired boilers.

5.3.5 Economics Estimate

Data were obtained from Neal Elliott (2008) of the American Council for an Energy-Efficiency Economy regarding representative costs and performance of fuel cell units. Table 5.3-3 is a summary of those data.

Table 5.3-3: Example of Fuel Cell Costs and Performance

Fuel Cell System	Characteristic	2007-2010	2011-2015	2016-2020
200 kW PAFC	Installed Costs* (\$/kW)	6,310	4,782	3,587
	O&M Costs (\$/kWh)	0.038	0.017	0.015
	Heat Rate (Btu/kWh)	9,480	9,480	8,980
	Electric Efficiency	36.0%	36.0%	38.0%
300 kW MCFC	Installed Costs (\$/kW)	5,580	4,699	3,671
	O&M Costs (\$/kWh)	0.035	0.020	0.015
	Heat Rate (Btu/kWh)	8,022	7,125	6,920
	Electric Efficiency	42.5%	47.9%	49.3%
1200 kW MCFC	Installed Costs (\$/kW)	5,250	4,523	3,554
	O&M Costs (\$/kWh)	0.032	0.019	0.015
	Heat Rate (Btu/kWh)	8,022	7,110	6,820
	Electric Efficiency	42.5%	48.0%	50.0%

*includes cost of reformer

For economic analysis, a 1200 kW MCFC was chosen due to its higher efficiencies and potential for waste heat recuperation as well as its lower cost. Economically, any other system would have lower performance; therefore, this example is seen as a most-favorable case.

Results

Results are shown for a current model in Table 5.3-4 and Figure 5.3-2 while prices for a future installation (2016-2030 timeframe) are shown in Table 5.3-5 and Figure 5.3-3.

Table 5.3-4: Cost of Electricity for Example Fuel Cell System (2007-2010)

Interest Rate	Financing	COE (cents/kWh)				
		Year 1	Year 2	Year 3	Year 4	Year 5
4.5%	50%	24.53	25.14	25.77	26.42	27.08
4.5%	75%	23.38	23.96	24.56	25.18	25.81
8.5%	50%	25.37	26.80	26.65	27.32	28.00
8.5%	75%	24.64	25.26	25.89	26.54	27.20

Assumes unit life of 5 years and \$8/MMBtu fuel in starting year

Table 5.3-5: Cost of Electricity for Example Fuel Cell System (2016-2020)

Interest Rate	Financing	COE (cents/kWh)				
		Year 1	Year 2	Year 3	Year 4	Year 5
4.5%	50%	12.89	13.21	13.54	13.88	14.22
4.5%	75%	12.11	12.41	12.72	14.20	14.56
8.5%	50%	13.19	13.52	13.85	14.20	14.56
8.5%	75%	12.70	13.01	13.34	13.67	14.01

Assumes unit life of 10 years and \$9.75/MMBtu fuel in starting year

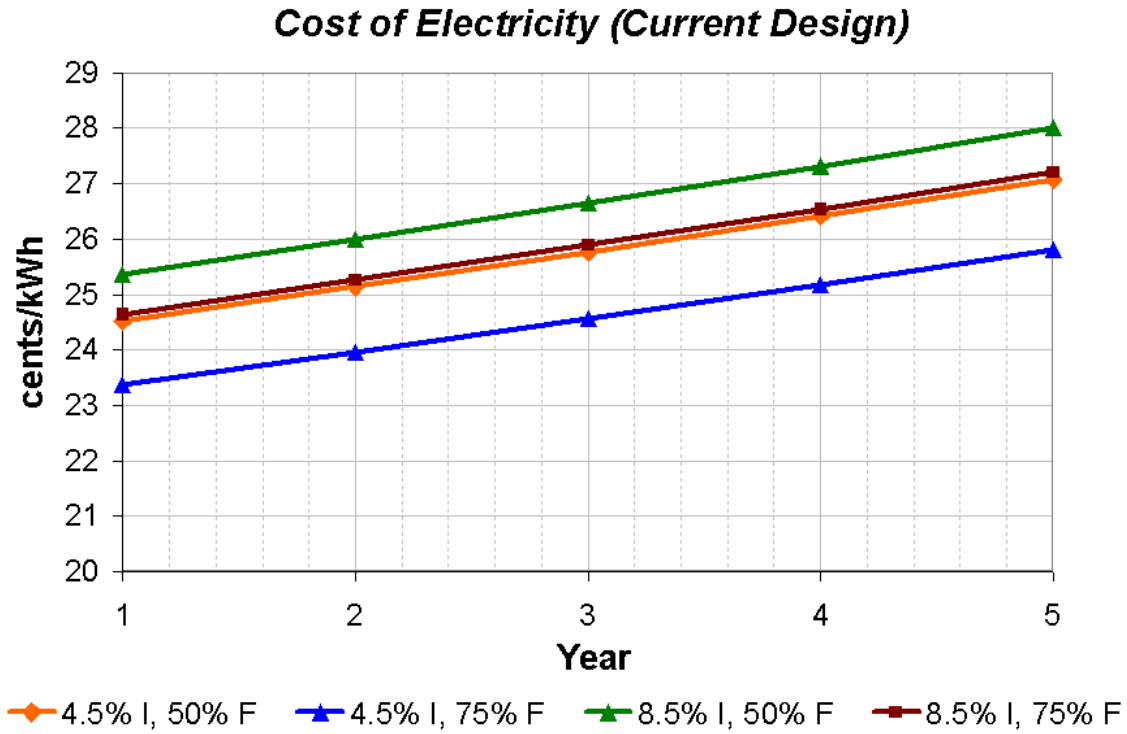


Figure 5.3-2: Cost of Electricity Trends, 2007-2010 Installation

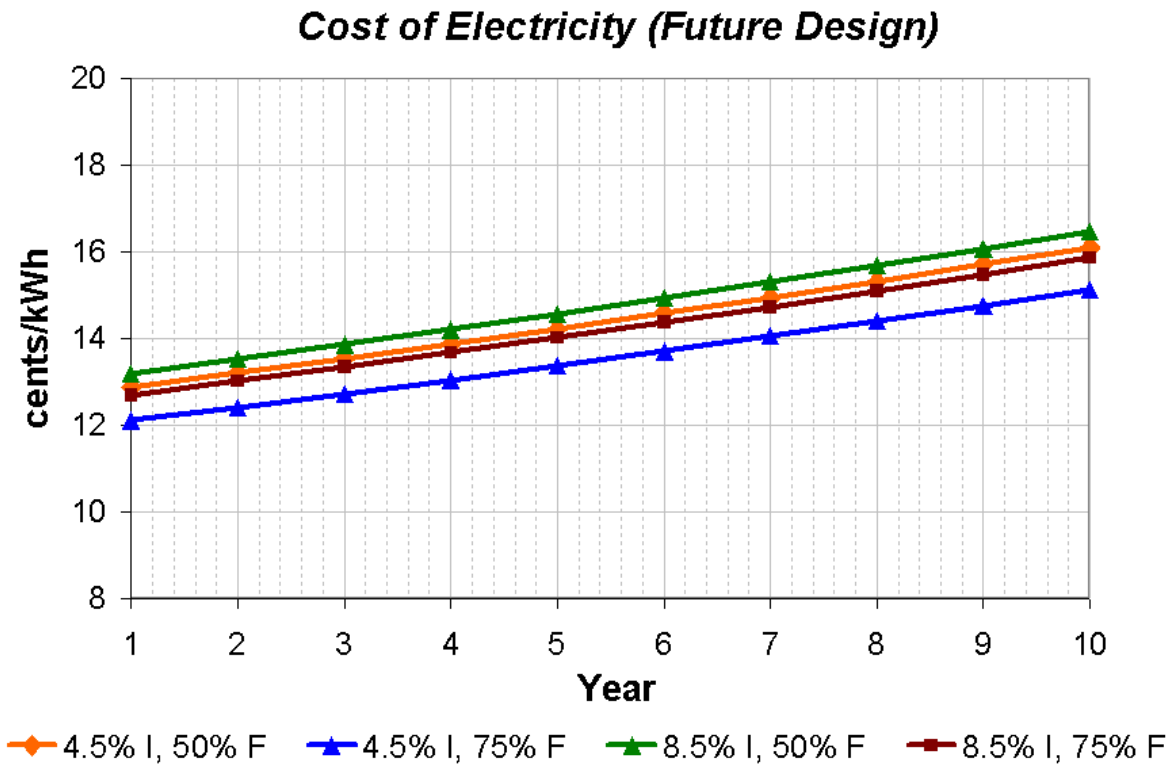


Figure 5.3-3: Cost of Electricity Trends, 2016-2020 Installation

Discussion

As seen in Table 5.3-4, the cost of electricity generated from a fuel cell today is much greater than conventionally-generated electricity. This is due in part to the limited numbers of systems manufactured as well as the expense of materials and shortness of system life. If research and development advances as predicted by some, these systems could become an attractive power generation technology for stationary application in the 10 to 15-year timeframe. A cost of electricity on the order of 12.2 cents/kWh is competitive with other power generation technologies, especially with units of such a small size.

Recommendations

While it is not recommended that fuel cells be pursued at this time for power generation only, it is recommended that they be re-investigated in the future for application at RAFB. When investigated in the future, systems including waste heat recuperation should be examined.

Section 5.3 References:

Elliott, R. Neal. 2008. American Council for an Energy-Efficient Economy (ACEEE). Personal Communication.

Energy Efficiency and Renewable Energy (EERE). 2008a. *Fuel Cell Animation (Text Version)*. U.S. Department of Energy.
http://www1.eere.energy.gov/hydrogenandfuelcells/fc_animation_text.html

_____. 2008b. *Comparison of Fuel Cell Technologies*. U.S. Department of Energy.
http://www1.eere.energy.gov/hydrogenandfuelcells/fuelcells/pdfs/fc_comparison_chart.pdf

UTC Power (UTCP). 2008. *PureCell™ 200 Commercial Fuel Cell Power System*.
http://www.fuelcellmarkets.com/images/articles/DS_PureCell.pdf

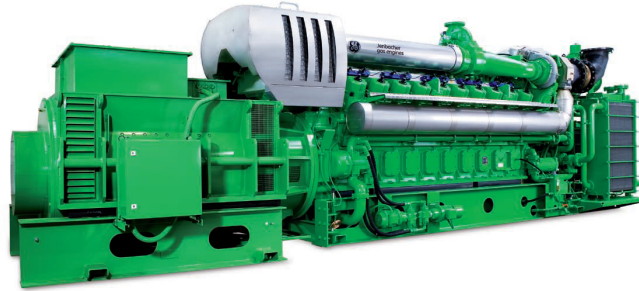
5.4 Reciprocating Engines

5.4.1 Description of Technology

Reciprocating engines, like the one shown in Figure 5.4-1, convert pressure created from the ignition of fuel into rotating motion, which is then used directly or converted into electricity. Often, engines used to generate electricity are powered by either natural gas or petroleum-derived diesel fuel to serve as backup power, load peakers, or continuous generation units.

While fossil fuels are the conventional source of energy for these machines, biofuels such as biodiesel and biogas can also be used, and manufacturers such as Caterpillar and GE market and sell engines for these applications.

In addition to providing electricity, reciprocating engines can also be used to generate hot water and steam for building heat applications. This application requires that the system be located close to a thermal load. An illustration of an example cogeneration system is shown in Figure 5.4-2.



**Figure 5.4-1: Jenbacher type 6
(GE, 2008)**

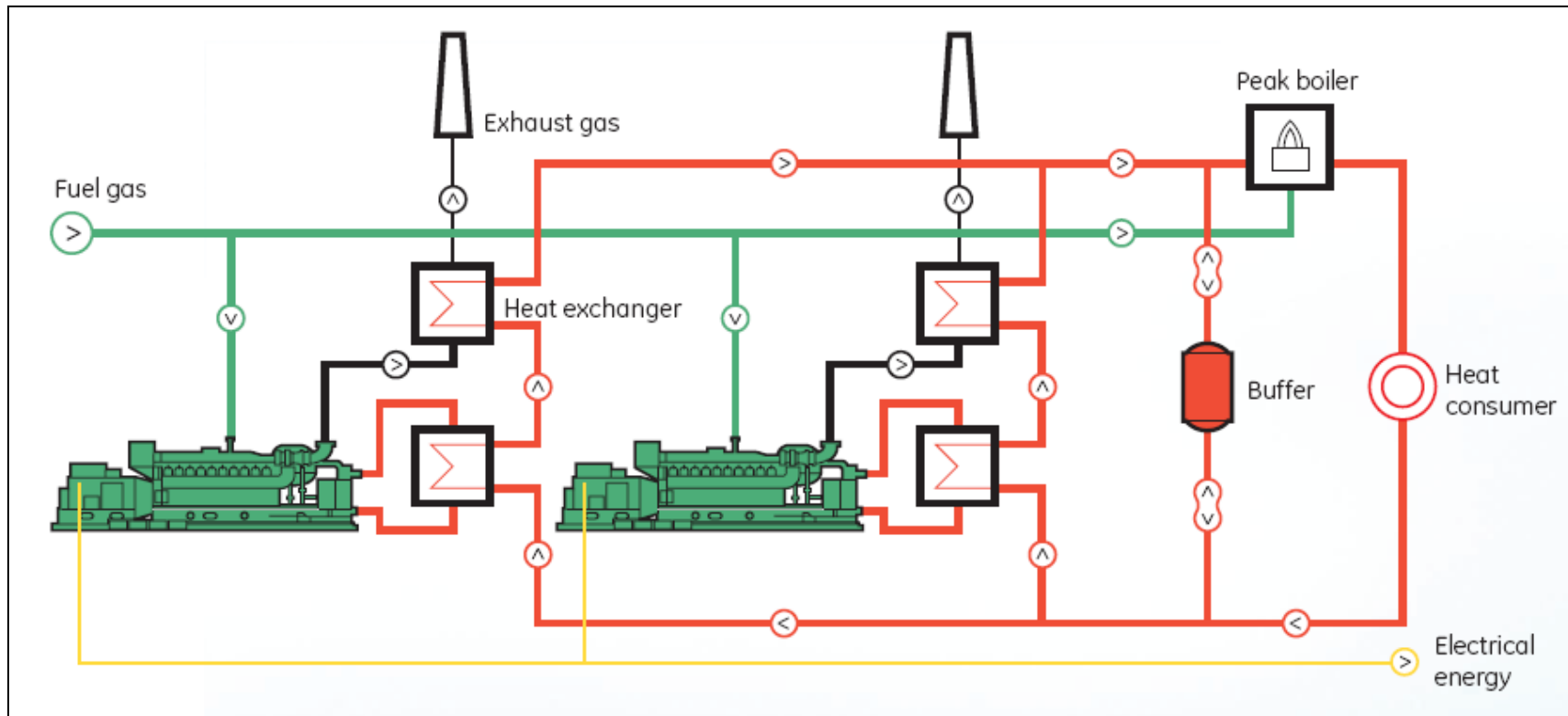


Figure 5.4-2: Example Recip Cogeneration System (GE, 2008)

Reciprocating engines often have two sources of useful heat: combustion exhaust gas and liquid coolant. Liquid coolant can be used alone to make hot water for building use or can be coupled inline to preheat water that is then used to produce hotter water or steam in a heat recovery heat exchanger with the engine exhaust or a directly-fired hot water heater/boiler. The latter case is shown in Figure 5.4-2.

5.4.2 Plant Size Estimate

Engine sizes in the 1.6 to 2.4 MW range were chosen for this study to meet the minimum projected renewable electricity needs of Robins AFB. Machines of these sizes are also currently manufactured, and basic information regarding performance was also available. If diversification of electricity sources is desired, smaller reciprocating engines could be coupled with solar PV or other technologies to meet the renewable energy needs of the Base. In addition, large engines could be installed, if desired, to generate more than the minimum requirement of renewable energy.

5.4.3 Conceptual Design

For comparison, both biogas and biodiesel systems are examined. An example case of cogeneration is also presented.

5.4.4 Conceptual Location

Due to its relatively small footprint and low height, a small recip system could be located in many places throughout the Base; however, noise abatement and exhaust emissions must be considered; a sound-damping enclosure will likely be necessary if locating the engine near office or other inhabited buildings. An example of system physical specifications is shown in Table 5.4-1.

**Table 5.4-1: Example Specs for 2.4 MW Jenbacher
type 6
(GE, 2008)**

Height	9.2 ft
Width	8.3 ft
Length	35 ft
Weight	66,180 lbs / 67,500 lbs cogen

If heat recovery is chosen, the system should be located adjacent to buildings that could utilize as much of the hot water generated as possible. If the system is to be powered by biogas from anaerobic digestion or biomass gasification, it should be located within the design range of gas piping.

To simplify installation, a cogeneration system could be located near new construction to mitigate issues with building retrofit. Alternatively, if a location near any of the existing district heating plants is more desirable, steam from the reciprocating engine system could be fed into the central lines.

5.4.5 Economics Estimate

Data were obtained from Neal Elliott (2008) of the American Council for an Energy-Efficiency Economy regarding representative costs and performance of natural gas-fired reciprocating engines. Table 5.4-2 is a summary of those data.

Table 5.4-2: Example of Gas-fired Reciprocating Engine Costs

Fuel Cell System	Characteristic	2007
3 MW	Installed Costs* (\$/kW)	1,690
	O&M Costs (\$/kWh)	0.006
	Aftertreatment Costs (\$/kW)	210
10 MW	Installed Costs (\$/kW)	1,298
	O&M Costs (\$/kWh)	0.006
	Aftertreatment Costs (\$/kW)	140

For economic analysis, the costs associated with the 3 MW were chosen for the biogas system while it was assumed that the aftertreatment costs for the biodiesel system were double. Sizing and performance information were taken directly from manufacturers' published product information and are shown in Table 5.4-3.

**Table 5.4-3: Reciprocating Engine Costs
Performance Specifications**

Characteristic	Caterpillar (Cat, 2008)	GE (GE, 2008)
Size (MW)	1.6	2.4
Fuel	Biodiesel	Biogas
Electric Efficiency	36.9%	39.1 %
Heat Rate (Btu/kWh)	9248	8727
Useful Thermal Output (MMBtu/hr)	8.50	9.48

When determining costs associated with cogenerating hot water/steam, the incremental capital costs of the heat exchangers are assumed to be negligible when compared with the capital costs of conventional equipment that would be needed to fulfill the loads. While heat recovery heat exchangers would be larger in size than traditional equipment, due to lower heat exchange temperatures and pressure limitations on reciprocating engines, conventional hot water heaters and boilers require burners and more complex control systems.

As an example of the fuel savings cogeneration could provide, the 1.6 MW Caterpillar engine was examined. The technical data provided by the manufacturer separately specify heat rejection to the coolant steam and combustion exhaust. These data, at rated conditions, are shown in Table 5.4-4.

**Table 5.4-4: 1.6 MW Reciprocating Engine Heat Rejection
(Cat, 2008)**

Characteristic	Value
Max Coolant Temperature	194 °F
Heat Rejection to Coolant	2.47 MMBtu/hr
Exhaust Temperature	886 °F
Heat Rejection to Exhaust	6.04 MMBtu/hr

Results-Electricity only

Results for the 1.6 MW biodiesel system operated on \$3/gallon and \$5/gallon fuel are shown Tables 5.4-5 and 5.4-6, respectively. The biodiesel fuel is assumed to be bought from off-site producers. All calculations assume fuel and O&M escalation of 2.5 percent per year. The 0-0 case assumes that the reciprocating engine is owned and operated by Robins AFB with a rate of return of 3 percent to account for inflation. In all other cases, the rate of return for the owner/operator (external to RAFB) is assumed to be 15 percent.

Table 5.4-5: Cost of Electricity for \$3/Gallon Biodiesel, 1.6 MW Plant Size

Interest Rate	Financing	Cost of Electricity (cents/kWh)				
		Year				
		1	5	10	15	20
0%	0%	21.37	23.58	26.68	30.19	34.16
4.5%	50%	22.66	25.01	28.30	32.02	36.23
4.5%	75%	22.18	24.48	27.70	31.33	35.45
8.5%	50%	23.01	25.40	28.73	32.51	36.78
8.5%	75%	22.69	25.04	28.33	32.06	36.27

Table 5.4-6: Cost of Electricity for \$5/Gallon Biodiesel, 1.6 MW Plant Size

Interest Rate	Financing	Cost of Electricity (cents/kWh)				
		Year				
		1	5	10	15	20
0%	0%	35.26	38.92	44.03	49.82	56.37
4.5%	50%	36.54	40.33	45.63	51.63	58.41
4.5%	75%	36.05	39.79	45.02	50.93	57.63
8.5%	50%	36.88	40.71	46.06	52.11	58.96
8.5%	75%	36.56	40.35	45.66	51.66	58.45

Results for the 2.4 MW biogas system operated on \$8/MMBtu and \$12/MMBtu fuel are shown Tables 5.4-7 and 5.4-8, respectively. In this instance, system fuel would be produced at RAFB from either wood gasification or anaerobic digestion.

Table 5.4-7: Cost of Electricity for \$8/MMBtu Biogas, 2.4 MW Plant Size

Interest Rate	Financing	Cost of Electricity (cents/kWh)				
		Year				
		1	5	10	15	20
0%	0%	7.66	8.45	9.56	10.82	12.24
4.5%	50%	8.84	9.76	11.04	12.49	14.13
4.5%	75%	8.40	9.27	10.49	11.87	13.43
8.5%	50%	9.15	10.10	11.43	12.93	14.63
8.5%	75%	8.86	9.78	11.07	12.52	14.17

Table 5.4-8: Cost of Electricity for \$12/MMBtu Biogas, 2.4 MW Plant Size

Interest Rate	Financing	Cost of Electricity (cents/kWh)				
		Year				
		1	5	10	15	20
0%	0%	13.37	14.75	16.69	18.88	21.37
4.5%	50%	12.47	13.77	15.58	17.63	19.94
4.5%	75%	12.03	13.28	15.02	17.00	19.23
8.5%	50%	12.78	14.11	15.96	18.06	20.43
8.5%	75%	12.49	13.79	15.60	17.65	19.97

Results-Cogeneration of hot water/steam

Because the thermal product of reciprocating engine cogeneration systems is a result of waste heat, fuel costs are zero. These costs are incorporated into the electricity rates shown above. Comparing efficient natural gas hot water heaters and boilers (both approximately 85 percent efficient) with cogeneration of these products, fuel savings RAFB could realize are shown in Table 5.4-9.

Table 5.4-9: Example Fuel Costs Mitigated through Recip Cogeneration per Year

	Natural Gas Cost		
	\$7.06/MMBtu	\$8/MMBtu	\$12/MMBtu
Hot Water	\$174,991	\$198,290	\$297,436
Steam	\$427,914	\$484,888	\$727,332
Total	\$602,905	\$683,179	\$1,024,768

Discussion

Because reciprocating engines are available in a wide variety of sizes, a system could be chosen to generate renewable electricity for RAFB that meets but does not exceed federal mandates. If desirable, ready-to-use fuel could be purchased, lowering the level of complexity at the Base-level needed to meet renewable energy needs; however, there is a cost premium to this simplicity. As seen above, electricity generated from biogas is as much as 65 percent less expensive than that generated by biodiesel purchased off-site. If biogas is generated at RAFB, a reciprocating engine could use a small amount of this gas while the remainder is burned in boilers to produce district heating. At \$8/MMBtu, this solution would likely be cost competitive with current Base steam generation (depending on natural gas rates) while also generating renewable electricity to meet mandates at a reasonable rate.

Another consideration when determining which system is best for RAFB is utility contracts. A third party owner/operator may not be permitted to sell electricity to the Base. In order to meet renewable electricity goals, the Base may need to be a full or partial owner of any electricity generation system. A small reciprocating engine system would likely be the least burdensome system to own and operate due to its size and relative ease of operation. Biodiesel produced on or off Base or biogas generation facilities could still be owned and operated by third parties.

To increase renewable energy use and mitigate costs, cogeneration of hot water and steam for building use could save RAFB a substantial amount in fuel costs. At natural gas prices of \$7.06/MMBtu, fuel costs of over \$600,000 per year could be saved.

Recommendations

On a cost basis, a biogas reciprocating engine system is a cost competitive solution to meet the minimum renewable electricity generation needs of RAFB; however, it would require a source of biogas. If the Base wants to meet minimum mandates with minimum complexity, biodiesel-driven reciprocating engines, powered by fuel purchased off Base, may be of interest. If either reciprocating engine system is chosen, cogeneration of building hot water and heat should be incorporated into the design.

Section 5.4 References

Caterpillar (Cat). 2008. "Continuous 1640 kW 2050 kVA 60 Hz 1800 rpm 480 Volts". <http://www.cat.com/cda/components/securedFile/displaySecuredFileServletJSP?x=7&fileId=847283>

Elliott, R. Neal. 2008. American Council for an Energy-Efficient Economy (ACEEE). Personal Communication.

General Electric (GE). 2008. "Jenbacher type 6 Brochure". http://www.ge-energy.com/prod_serv/products/ recip_engines/en/downloads/type6_usver.pdf

5.5 Photovoltaics

5.5.1 PV Technologies

The U.S. Department of Energy (SETP, 2008) provides a comprehensive look at current and near-future solar technologies. For this study, stationary, flat panel photovoltaic technology were considered. Other solar technologies include concentrating solar and motorized tracking systems.

Wafer silicon solar panels are a mature technology and are the most popular worldwide in terms of production and sales. Current production models have real-world efficiencies in the range of 12 to 18 percent, and efficiencies are expected to increase to 15 to 21 percent by 2015 (SETP, 2008). Recent advancement in "black silicon" may yield an unexpected leap in efficiency, but this has yet to be seen in practice.

Thin film or film silicon PV technology is relatively new compared to crystalline silicon and has a small but growing market share. Thin film PV is characterized by lower cost per area; however it is less efficiency and has a higher output degradation due to aging (1 percent per year) when compared to wafer silicon. Current efficiencies are in the range of 5 to 8 percent for amorphous silicon (a-Si) and 5 to 6 percent for crystalline silicon (c-Si). These efficiencies are expected to increase to 10 to 13 percent and 13 to 16 percent, respectively, by 2015 (SETP, 2008).

5.5.2 Generation Potential

As noted earlier, Robins AFB has about 9,240,000 square feet of flat roof area. Rather than assume that all of this area would be covered with PV panels, an array area of 5,000,000 square feet was chosen. This takes into account obstructions (e.g. exhaust

stacks) and areas with unsuitable structure while also simplifying comparison between flat and tilted panels.

Nine scenarios were compared using PV F-Chart software. Three systems representing thin film installations were examined with conversion efficiencies of 5, 6, and 8 percent. All of these systems were assumed to be installed flat. Wafer systems with efficiencies of 12, 15, and 18 percent were also examined. Unlike the thin film systems, the wafer systems were assumed to be installed two different ways: flat and at 26° angles.

PV F-Chart requires several input parameters. The default values of 111.2 °F and 82.4 °F for the cell temperature at NOCT conditions and the efficiency reference temperature, respectively, were assumed¹. Temperature coefficients of 0.001/°F and 0.004/°F were assumed for the thin film and wafer scenarios, respectively. The temperature coefficient parameter describes the module's degradation in conversion efficiency with increasing temperature. Finally, it was assumed that the power conditioning efficiency was 90 percent. This efficiency value accounts for losses in inverters and transmission lines.

Figures 5.5-1 and 5.5-2 show the monthly and annual electricity generation potential at Robins AFB using 5 million square feet of array area.

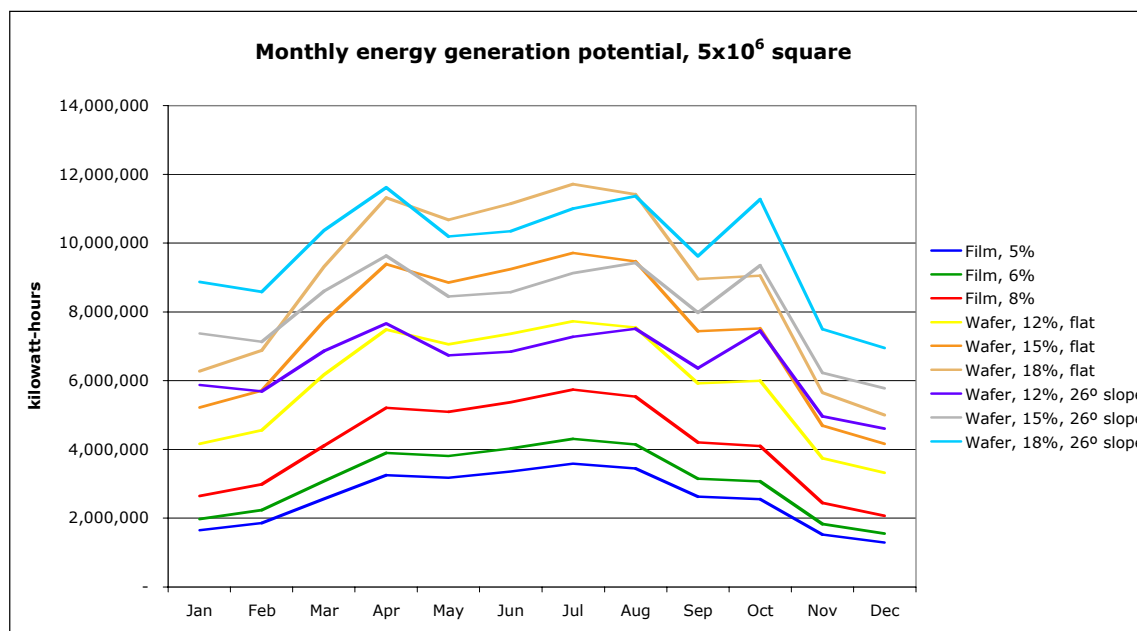


Figure 5.5-1: Solar PV Electricity Generation Potential by Month, 5 million sq. ft. array area

¹ Parameters related to testing and specification of the modules

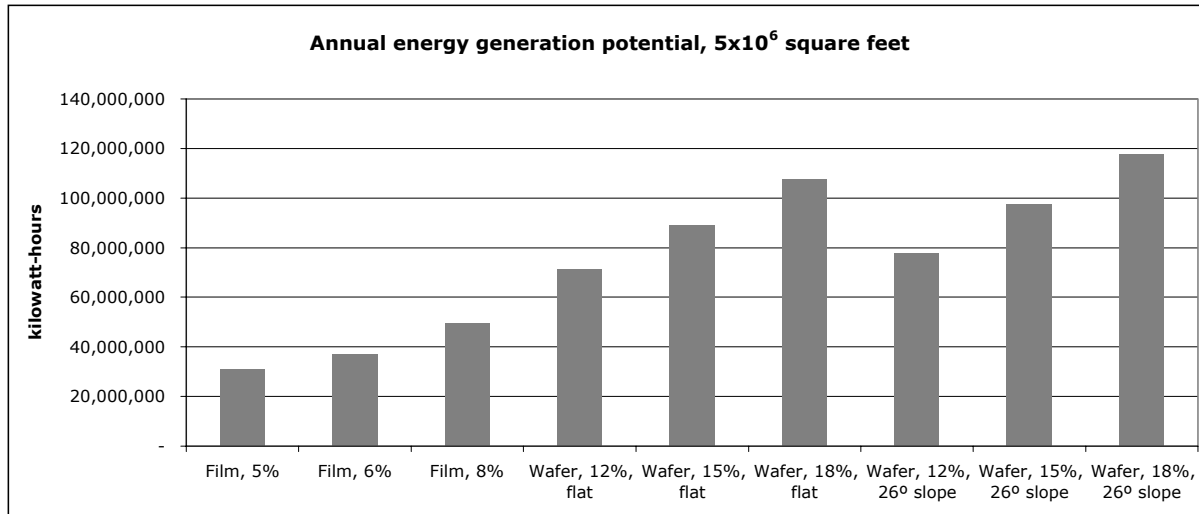


Figure 5.5-2: Annual Solar PV Electricity Production, 5 million sq. ft. of array area

5.5.2 System Economics

Renewable buy-back program

Georgia Power offers a renewable energy buy-back program under its Renewable and Non-Renewable rate tariff. It is important to differentiate this buy-back program from a *net metering* program. With net metering, a single meter is used to measure electricity coming in (consumed by the customer) and going out (generated by the customer). If there is a net deficit, the customer is billed for what they consumed minus what they generated, typically on a monthly basis. If the customer generated a net surplus, they are paid by the utility for the amount of electricity they generated minus the amount they consumed. Depending on the location and utility, the surplus payment rate varies from nothing (i.e. surplus generation is not compensated) to slightly above the market rate per kilowatt-hour (kWh).

Under the Georgia Power buy-back program, the customer's consumption and generation are metered separately. Consumption is recorded and billed according to the customer's ordinary rate schedule. The customer's generating system is connected to the grid and is given its own meter, and all of the outgoing electricity is purchased by Georgia Power at the specified buy-back rate. At the time of this writing, the buy-back rate is \$0.1774 per kWh.

Commercial customers are limited to a 100 kW generating capacity under this program (a 100 kW system would require about 10,000 square feet of roof area). According to the Georgia Public Service Commission, there are no current opportunities for bidding above the 100 kW limit as a large generator (i.e. 1 to 2 MW). A recent request for proposals for large solar projects was closed early due to low demand for solar generation in the state. However, in late September 2008, Georgia Power was granted approval to introduce to its customers a Premium Green Energy option with a minimum 2 percent solar component, which, if successful might stimulate the development of more large solar generation projects in 2009.

Federal tax incentive

The federal Investment Tax Credit (ITC) for solar PV systems covers 30 percent of the installed system cost with no price cap. This incentive was due to expire at the end of 2008, and repeated attempts to extend it had been delayed. However, the recently passed Emergency Economic Stabilization Act of 2008 (the “bailout”) included an 8-year extension of the ITC for commercial and residential solar. To qualify, the equipment must be operational in the year for which the credit is applied, and the system must have been constructed by the taxpayer seeking credit.

Georgia Clean Energy Property Tax Credit

This state tax credit will reimburse 35 percent (up to \$500,000) of the installed cost of a “clean energy property” such as a solar energy system. Application for the credit (submitted through GEFA) can only be made after the system is installed and operating. The credit payout cannot exceed the company’s state tax liability for the year in which the application was made, but credit can be carried over for up to five subsequent years.

Section 5.5 References

SETP, 2008. *Multi-Year Program Plan 2008-2012*. Solar Energy Technologies Program, US Department of Energy, Office of Energy Efficiency and Renewable Energy.

6. Thermal Systems

6.1 Combined Heat and Power

The combined heat and power (cogeneration) systems analyzed in the current study are described in Section 5.4.

6.2 District Heating

6.2.1 Description of Technology

District heating is a system of providing space heating and hot water to multiple buildings by generating hot water or steam at a central location and distributing it through a system of insulated pipes to surrounding facilities. District heating systems can produce heating by directly firing boilers or cogenerating steam or hot water. Direct-fire boilers have the advantage of simplicity and modularity while cogenerating systems can have cost and efficiency advantages.

6.2.2 Plant Size Estimate

Based on average daily heating needs of Robins AFB, an average hourly steam load of 66,000 lb would meet the requirements for steam in August. For this study, this load was assumed as an upper limit; for comparison, half of the average August load (33,000 lb/hr) was also assumed. It is feasible that a plant could be sized larger or smaller than these values. Factors that could affect the plant sizing determination could be wood supply contracts, actual peak hourly demands, and the need or desire to increase non-electrical renewable energy use.

6.2.3 Conceptual Design

To reduce cost and footprint, a central heating plant co-located with a wood-fired steam electric power plant is proposed. This district heating plant would make use of wood handling facilities, pumping, and other equipment used to generate electricity and would only require addition piping and the initial installation of a larger boiler at the time of initial construction.

6.2.4 Conceptual Location

Since the district heating plant would be integrated into a traditional steam power plant, they would be co-located. The option of adding a centralized district heating facility would limit the options of power plant locations to somewhere near thermal load centers.

6.2.5 Economics Estimate

Results

For economic analysis, steam loads of 66,000 lb/hr and 33,000 lb/hr were chosen for investigation. Results are shown for a \$20/GT wood supply in Tables 6.2-1 and 6.2-2 while results for \$30/GT are shown in Tables 6.2-3 and 6.2-4. All results assume the same financing and other assumptions as in the electric-only modeling with the exception of incremental boiler cost. Cost figures related to the boiler expansion required to generate steam for district heating were provided by a confidential industry contact and are proprietary.

Table 6.2-1: Cost of Steam for \$20/GT Wood, 66,000 lb/hr

Plant Size	Interest Rate	Financing	Cost of Steam (\$/1000 lb)						
			2012	2015	2020	2025	2030	2035	2040
25 MW	4.50%	50%	\$9.41	\$10.39	\$11.75	\$13.30	\$15.04	\$17.02	\$19.26
	4.50%	75%	\$8.25	\$9.11	\$10.31	\$11.66	\$13.19	\$14.93	\$16.89
	8.50%	50%	\$10.07	\$11.11	\$12.57	\$14.22	\$16.09	\$18.20	\$20.60
	8.50%	75%	\$9.21	\$10.17	\$11.50	\$13.01	\$14.72	\$16.66	\$18.85
50 MW	4.50%	50%	\$9.36	\$10.34	\$11.70	\$13.23	\$14.97	\$16.94	\$19.16
	4.50%	75%	\$7.94	\$8.77	\$9.92	\$11.22	\$12.70	\$14.36	\$16.25
	8.50%	50%	\$10.17	\$11.22	\$12.70	\$14.37	\$16.26	\$18.39	\$20.81
	8.50%	75%	\$9.15	\$10.10	\$11.42	\$12.93	\$14.62	\$16.55	\$18.72

Table 6.2-2: Cost of Steam for \$20/GT Wood, 33,000 lb/hr

Plant Size	Interest Rate	Financing	Cost of Steam (\$/1000 lb)						
			2012	2015	2020	2025	2030	2035	2040
25 MW	4.50%	50%	\$10.11	\$11.16	\$12.63	\$14.29	\$16.17	\$18.29	\$20.69
	4.50%	75%	\$8.81	\$9.72	\$11.00	\$12.44	\$14.08	\$15.93	\$18.02
	8.50%	50%	\$10.87	\$12.00	\$13.58	\$15.36	\$17.38	\$19.66	\$22.25
	8.50%	75%	\$9.92	\$10.95	\$12.39	\$14.01	\$15.86	\$17.94	\$20.30
50 MW	4.50%	50%	\$10.95	\$12.09	\$13.68	\$15.47	\$17.51	\$19.81	\$22.41
	4.50%	75%	\$9.19	\$10.15	\$11.48	\$12.99	\$14.69	\$16.63	\$18.81
	8.50%	50%	\$11.99	\$13.24	\$14.98	\$16.94	\$19.17	\$21.69	\$24.54
	8.50%	75%	\$10.75	\$11.87	\$13.43	\$15.19	\$17.19	\$19.44	\$22.00

Table 6.2-3: Cost of Steam for \$30/GT Wood, 66,000 lb/hr

Plant Size	Interest Rate	Financing	Cost of Steam (\$/1000 lb)						
			2012	2015	2020	2025	2030	2035	2040
25 MW	4.50%	50%	\$10.74	\$11.85	\$13.41	\$15.17	\$17.16	\$19.42	\$21.97
	4.50%	75%	\$9.59	\$10.58	\$11.97	\$13.55	\$15.33	\$17.34	\$19.62
	8.50%	50%	\$11.37	\$12.56	\$14.21	\$16.07	\$18.18	\$20.57	\$23.28
	8.50%	75%	\$10.54	\$11.63	\$13.16	\$14.89	\$16.84	\$19.06	\$21.56
50 MW	4.50%	50%	\$10.55	\$11.64	\$13.17	\$14.90	\$16.86	\$19.07	\$21.58
	4.50%	75%	\$9.13	\$10.08	\$11.40	\$12.90	\$14.60	\$16.52	\$18.69
	8.50%	50%	\$11.34	\$12.52	\$14.16	\$16.02	\$18.13	\$20.51	\$23.21
	8.50%	75%	\$10.34	\$11.41	\$12.91	\$14.60	\$16.52	\$18.70	\$21.15

Table 6.2-4: Cost of Steam for \$30/GT Wood, 33,000 lb/hr

Plant Size	Interest Rate	Financing	Cost of Steam (\$/1000 lb)						
			2012	2015	2020	2025	2030	2035	2040
25 MW	4.50%	50%	\$11.44	\$12.63	\$14.29	\$16.16	\$18.29	\$20.69	\$23.41
	4.50%	75%	\$10.14	\$11.19	\$12.66	\$14.33	\$16.21	\$18.34	\$20.75
	8.50%	50%	\$12.18	\$13.44	\$15.21	\$17.21	\$19.47	\$22.03	\$24.93
	8.50%	75%	\$11.25	\$12.41	\$14.04	\$15.89	\$17.98	\$20.34	\$23.01
50 MW	4.50%	50%	\$12.13	\$13.39	\$15.15	\$17.14	\$19.40	\$21.95	\$24.83
	4.50%	75%	\$10.38	\$11.46	\$12.96	\$14.67	\$16.59	\$18.77	\$21.24
	8.50%	50%	\$13.16	\$14.53	\$16.44	\$18.60	\$21.04	\$23.81	\$26.94
	8.50%	75%	\$11.94	\$13.18	\$14.91	\$16.87	\$19.09	\$21.59	\$24.43

Discussion

Final determination of whether or not to pursue centralized district heating coupled with steam-driven electricity generation will be based upon several factors including (1) desire to have large-scale electric power generation located at the Base, and (2) current costs of purchasing renewably-generated electricity from other sources and natural gas prices. Assuming the average natural gas rate for electric utilities in Georgia for 2006 of \$7.06/MMBtu (EIA, 2008) and a boiler efficiency of 80-85%, the fuel-only cost of generating 1000 lb of steam for use in the central system is \$10.88 to \$10.24, respectively. Please note that the fuel-only cost of wood gas steam would be equal to or would exceed that of the 2006 natural gas steam prices. These costs do not include any capital or O&M costs. On a cost of steam-basis, incorporating of a centralized district heating plant with a wood-fired steam power plant is highly cost-effective.

Recommendations

If wood-powered steam electricity generation is pursued for Robins AFB, it is recommended that district heating be incorporated as part of the system design, and optimization of steam plant sizing should be performed.

Section 6.2 References

Energy Information Agency (EIA). 2008. *State Data Directory: State Data for Prices, Table S6a. Electric Power Sector Energy Price Estimates by Source, 2006*. U.S. Department of Energy.
http://www.eia.doe.gov/emeu/states/sep_sum/html/sum_pr_eu.html

6.3 District Heating and Cooling

6.3.1 Description of Technology

District heating and cooling is a system of providing space heating, hot water, and chilled water to multiple buildings by generating hot water or steam at a central location and distributing to it through a system of insulated pipes directly to surrounding facilities. Chilled water is also produced and distributed to surrounding facilities. District heating and cooling systems can produce heating by directly firing boilers or cogenerating steam or hot water; chilled water can be produced by using cogenerated steam or hot water to drive absorption chillers or by use of conventional vapor-compression chillers (electric or natural gas-fired). Conventional systems have the advantage of simplicity and modularity while cogenerating systems can have cost and/or efficiency advantages.

6.3.2 Plant Size Estimate

Based upon internal studies at Robins Air Force base, the Base Energy Office has identified a "preferred case" for a wood fueled combined heat and power scenario that would warrant further study. This scenario contains the following parameters:

- A. Nominal Electricity Generation - 20 MW
- B. Low Pressure (135 psig) steam production - 85,000 lb/hr
- C. Absorption Chilling refrigerant capacity - 8500 refrigerant tons (RT)

6.3.3 Conceptual Design

In this case, most of the existing natural gas use that is being expended on steam production would be replaced by steam extracted from the new steam turbine installed in the wood steam plant. In addition, another extraction point on the turbine will supply lower pressure (8 psig) steam to power the absorption chilling systems. Use of the steam condenser would be minimized to reduce waste heat losses, recognizing that some portion of condensing must be maintained to allow load following for the entire system, and to deal with system upsets and seasonal variations.

6.3.4 Conceptual Location

Since the district heating and cooling plant would be integrated into a traditional steam power plant, they would be co-located. The option of adding a centralized district heating and cooling facility would limit the options of power plant locations to somewhere near thermal load centers.

6.3.5 Thermodynamic Estimate

Results and Discussion

Based on the case suggested by Base personnel, the following configurations (shown in Figures 6.3-1, 6.3-2, and 6.3-3) were chosen to evaluate on a thermodynamic basis. These three systems (conventional, Cogen Case 1, and Cogen Case 2) meet steady-state electric, heating, and cooling loads. While there is always a need for 20 MW or more of electricity supply at RAFB, heating and cooling loads fluctuate with outside temperature as well as building occupancy and work needs. To more accurately assess these types of systems for RAFB, hourly heating and cooling loads should be provided, spanning a period of no less than one year. If data such as these are not able to be provided for future study, additional building modeling could be performed to simulate loads; however, actual data would likely provide a more accurate assessment of the Base's needs and enable better optimization of a system for RAFB.

Figure 6.3-1 illustrates a conventional electricity supply system with centralized heating and cooling. With the given loads of 20 MW for non-cooling electricity, 8500 refrigeration tons (RT) of cooling supplied by electric vapor-compression chillers, and 106 MMBtu/hr of steam generated from natural gas boilers, the total system needs approximately 404 MMBtu/hr in primary energy. This system energy estimate assumes that the electrical grid generates and delivers electricity to the RAFB at a 32 percent efficiency. The coefficient of performance (COP) of 5.43 for the electric chillers was calculated based upon values supplied by RAFB staff while the natural gas boiler efficiency was estimated at 80 percent.

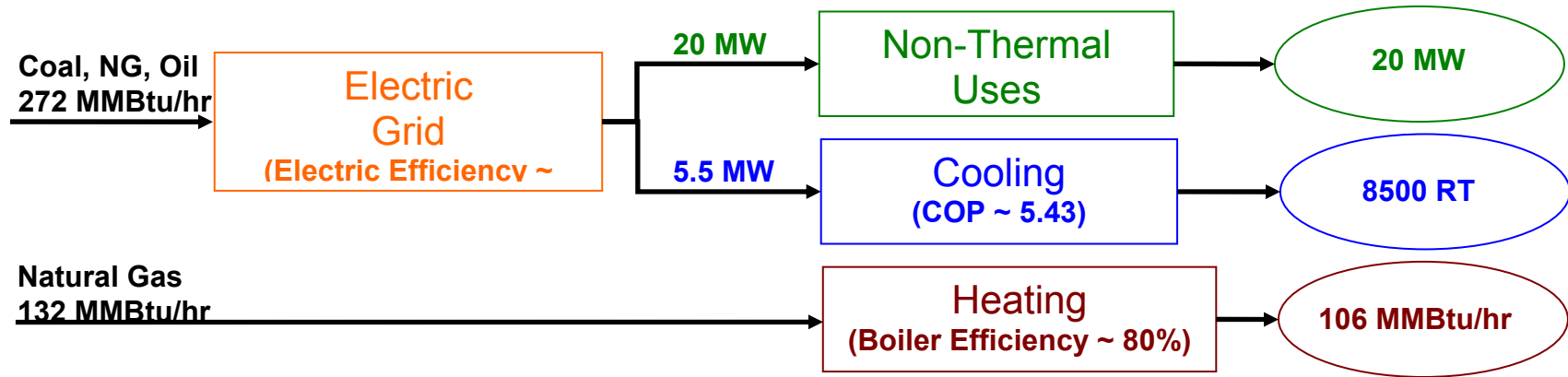


Figure 6.2-1: Conventional Electric, Heating, and Cooling System

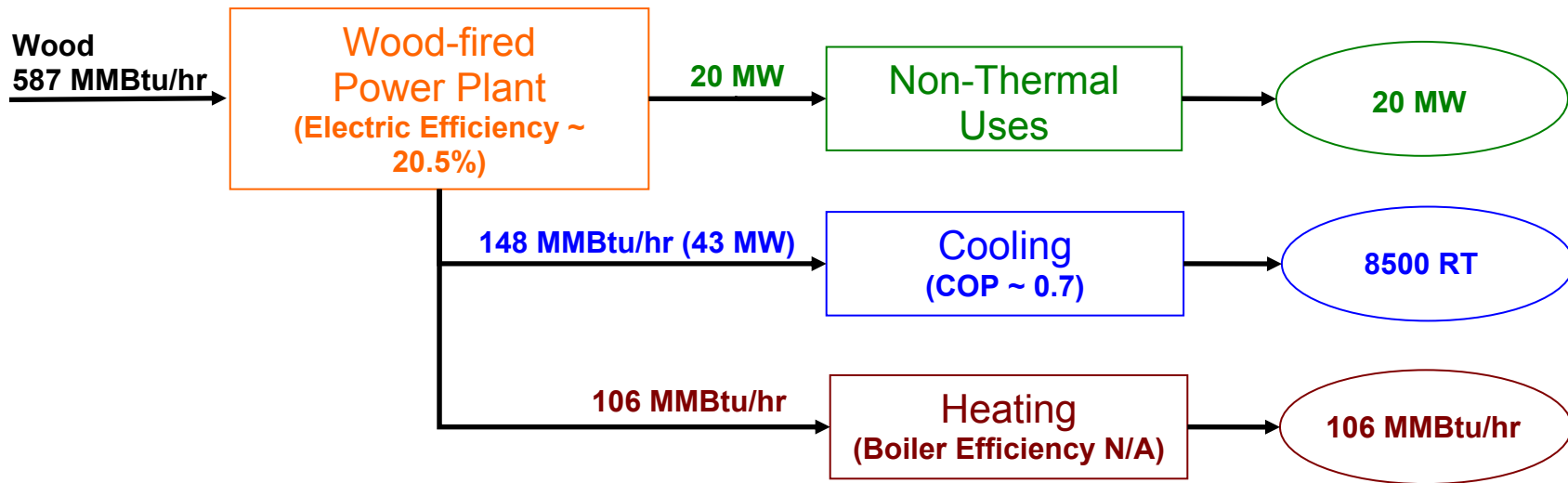


Figure 6.2-2: Wood-fired Cogeneration System Case1 (Power Generation, Heating, and Cooling)

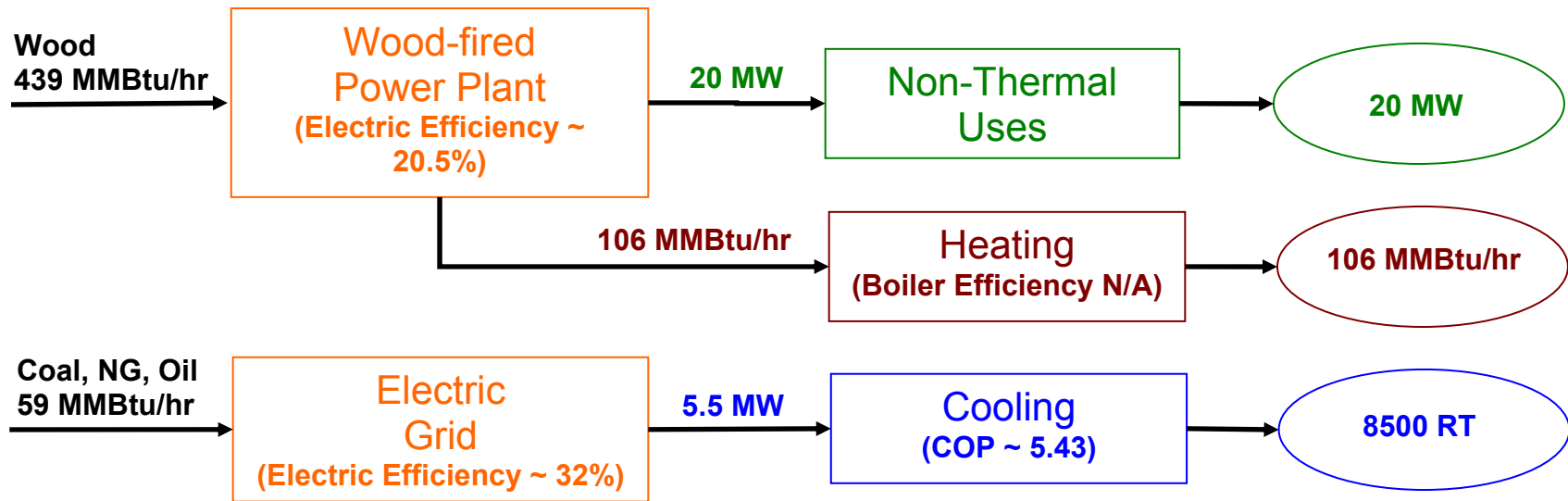


Figure 6.2-3: Wood-fired Cogeneration System Case 2 (Power Generation and Heating) with Conventional Cooling

A system combining electricity generation from wood with extraction for both heating and absorption chilling is shown in Figure 6.3-2. All of the loads met are the same as in Figure 6.3-1. The wood-fired power plant is of the same type as described in Section 4.1; however, the electricity generation capacity is lower, at 20 MW. Just as in the case presented in Section 6.2, steam is extracted at 135 psig to meet the Base's heating and hot water needs. In addition to this extraction, a lower pressure extraction (8 psig) is taken to drive single-effect absorption chillers with an average COP of 0.7. With an electric efficiency of 20.5 percent, this system would require an input of 587 MMBtu/hr of primary energy, all of which is renewable; however, it also requires consumption of 45 percent more primary (raw) energy than the conventional system. This energy requirement represents approximately 455,000 green tons of wood fuel annually, which as shown in earlier sections should be available within a reasonable supply radius of RAFB. Note that approximately 29,000 lb/hr of steam would be sent to a condenser under this scenario.

In comparison to the conventional and wood-fired plus heating and cooling systems (Figures 6.3-1 and 6.3-2), Figure 6.3-3 represents a system in which electricity and district heat are produced via a wood-fired plant while cooling loads are met conventionally using the Base's current chillers. The primary energy need for the Case 2 is approximately 498 MMBtu/hr, which is less than that of Case 1 but 23 percent more than the conventional system. The driver for increased use of energy in Case 1 is the low efficiency of single-effect absorption chilling. The Case 2 cogeneration system would send almost 183,000 lb/hr of steam to a condenser, which is significantly higher than the amount in Case 1.

6.3.6 Economic Estimate

Results and Discussion

Table 6.3-1 combines the findings from Section 4.1 with the cost of electricity for full cogeneration case. Note, the variation in capital costs assumed reflects the difference in availability of equipment to meet the plant needs. The costs of extraction steam at both 135 psig and 8 psig are shown in Table 6.3-2.

Table 6.3-1: Cost of Electricity for \$20/Green ton Wood

Plant Size	Interest Rate	Financing	Cost of Electricity (cents/kWh)						
			Year 1	Year 4	Year 9	Year 14	Year 19	Year 24	Year 29
20	4.5%	75%	8.43	9.07	10.27	11.62	13.14	14.87	16.82
25	4.5%	75%	8.94	9.63	10.98	12.32	13.94	15.78	17.85
50	4.5%	75%	7.77	8.37	9.56	10.72	12.12	13.72	15.52

Assumes \$2600/kW for 50 MW, \$2500/kW for 20 MW, and \$2300/kW for 25 MW;
2.5% escalation per year for fuel and O&M

Table 6.3-2: Cost of Steam for \$20/GT Wood; 85,000 lb/hr of 150 psi Steam and 154,000 lb/hr of 22 psi Steam

Plant Size	Steam Pressure (psig)	Interest Rate	Financing	Cost of Steam (\$/1000 lb)						
				Year 1	Year 4	Year 9	Year 14	Year 19	Year 24	Year 29
20 MW	135	4.50%	75%	\$6.66	\$7.35	\$8.32	\$9.41	\$10.64	\$12.04	\$13.63
	8	4.50%	75%	\$6.25	\$7.07	\$7.81	\$8.83	\$9.99	\$11.31	\$13.11

Representative costs of various types of chillers are shown in Table 6.3-3. While these costs were estimated in 2001, they do show the difference between electric absorption chillers by size. With an increase in commodity and labor costs, the difference between electric and absorption chillers would widen; absorption chillers require more material and labor to manufacture, with double-effect being the most expensive.

Table 6.3-3: Cost Comparison of Chillers, by Type

	Chiller Capacity, RT		
	300	500	1000
	Installed Cost, \$/ton		
Electric Centrifugal	340	340	350
Single-Effect Steam-Heated Absorption	520	430	365
Double-Effect Direct-Fired Absorption	625	625	625

(TA Engineering, 2001)

Maintenance costs range between \$18 to \$28 per ton for electric chillers and between \$18 and \$31 per ton for absorption chillers with single-effect being lower in cost than double-effect.

6.3.7 Recommendations

It is recommended that various cogeneration designs be evaluated in more detail, ideally using thermal load data from RAFB. Economic and thermodynamic optimizations could improve on primary energy consumption and overall cost; however, an improvement in energy consumption and economics is highly dependent on thermal loads. “Real-world” systems could have worse performance.

If heat-driven district cooling is pursued, double-effect absorption chillers should be considered. Conventional vapor-compression systems will be necessary to incorporate with absorption chillers for load following; absorption chillers should be used in base loading applications due to their response times.

Section 6.3 References

ORNL-funded Study by TA Engineering, Inc. for AGCC, June 2001, summary http://www.eere.energy.gov/de/equipment_costs.html#cooling

6.4 Solar Thermal

6.4.1 Description of Technology

Solar thermal systems use the sun's energy to heat water or heat transfer fluid in order to supply domestic hot water and heating to buildings. There are several different technologies available, which vary in system application, complexity, and efficiency. These technologies have two main components: solar collector and circulation. .

Solar Collectors

Flat plate collectors consist of a series of interconnected piping incased in an insulated box, the top layer of which is a layer of plastic glazing, as shown in Figure 6.4-1. These collectors are a simple and low-cost means of heating water to temperatures of up to 170°F (EERE, 2008b). They can be used in conjunction with any of the circulation methods.

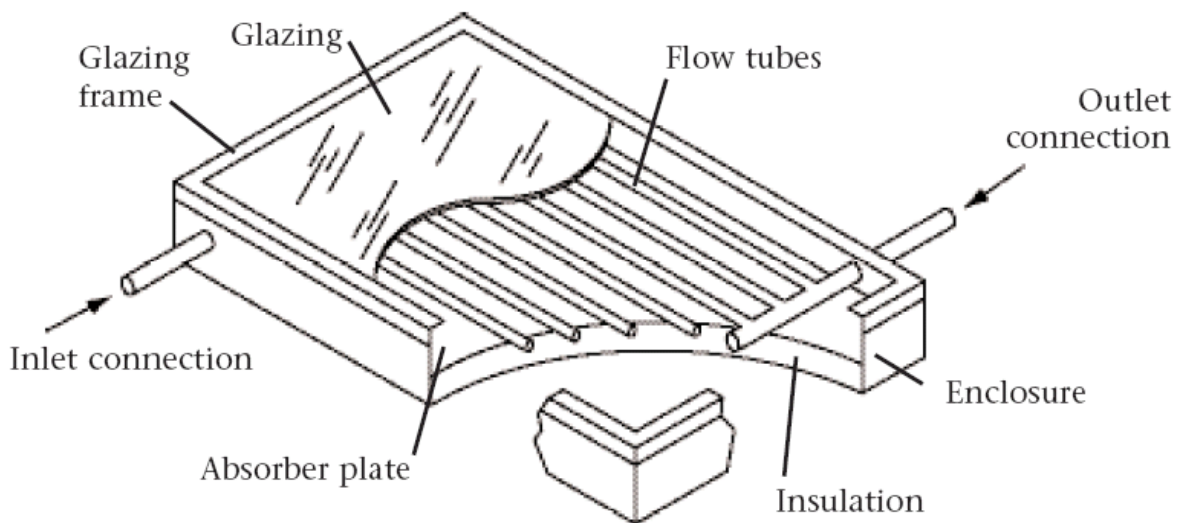


Figure 6.4-1: Example of Glazed Flat Plat Collector (EERE, 2008a)

Integral collector-storage systems use a darkly-colored tube or tank to preheat a “batch” of water before it is then emptied into a more conventional hot water heater tank. These systems can be thought of as increasing the efficiency of a traditional system and are simple and inexpensive to implement. Care must be taken during freezing temperatures; however, the climate at RAFB is conducive to the operation of these types of systems.

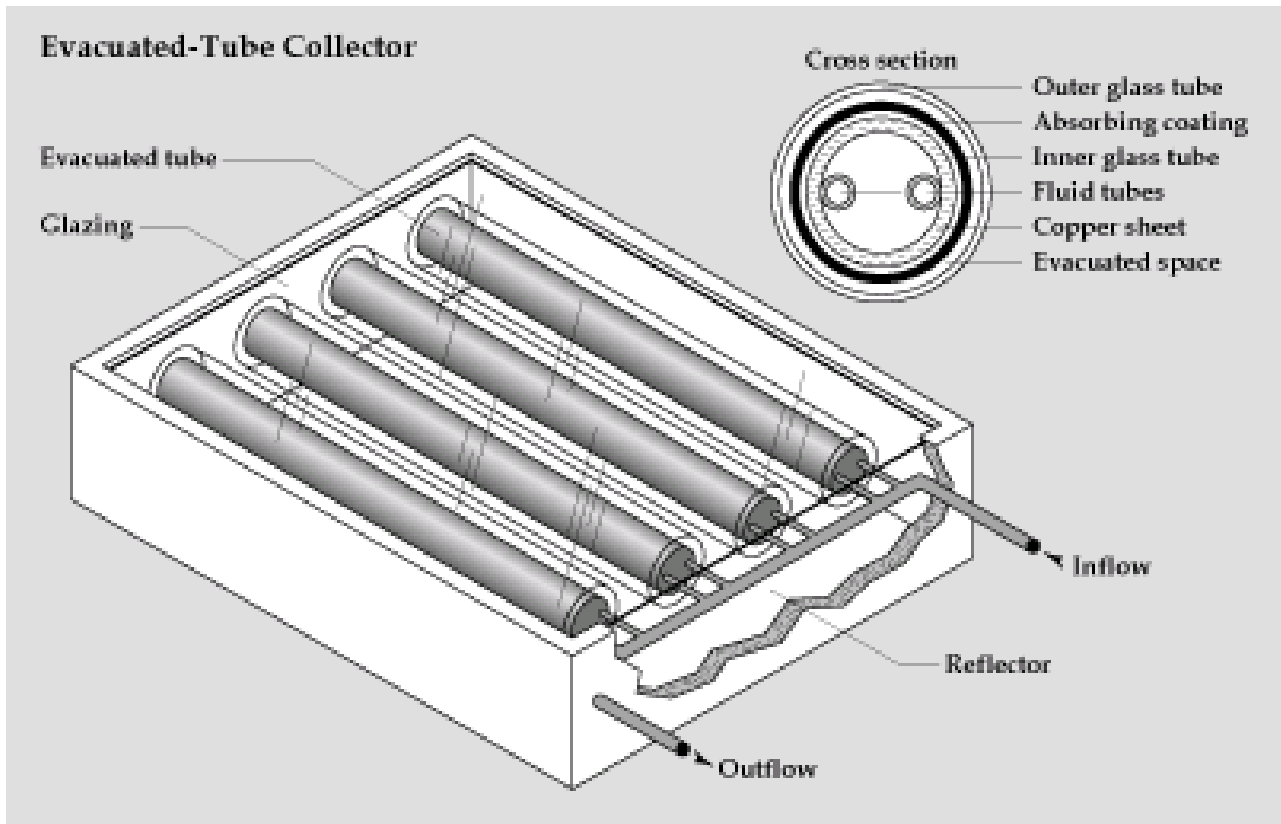


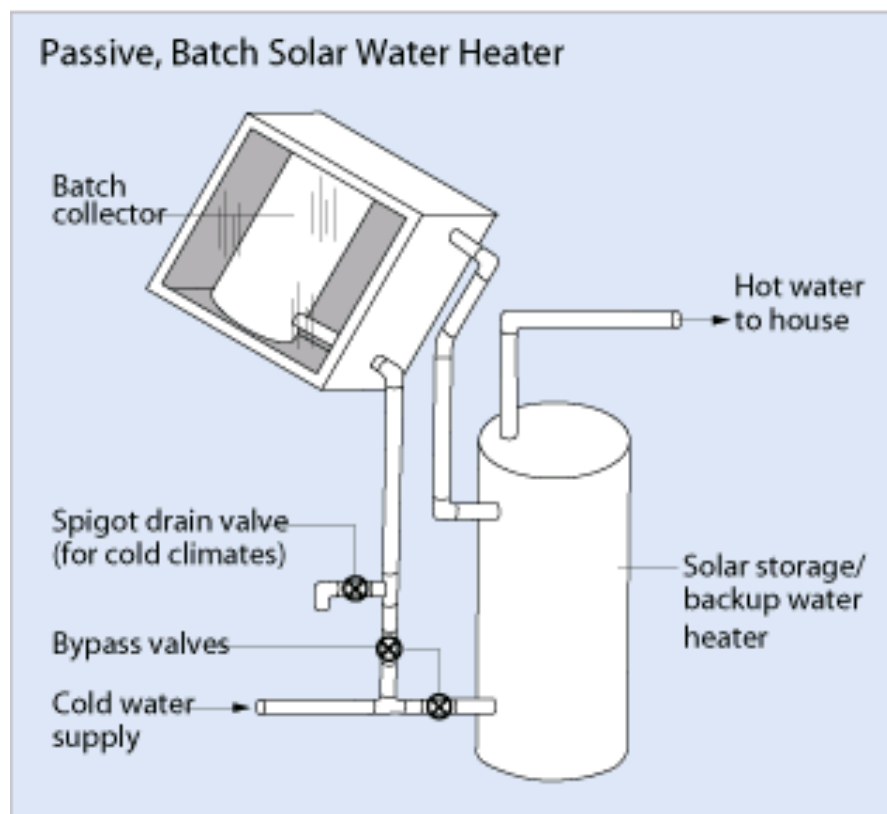
Figure 6.4-2: Example of Evacuated-Tube Collector (EERE, 2008b)

Evacuated-tube collectors (Figure 6.4-2) are the most expensive and complex type of solar hot water collector. Each tube has an inner metal tube coated with a highly-absorbent, low-reflection layer to increase radiative heat transfer to the water. The inner metal tube is then surrounded by an evacuated space to minimize conductive and convective heat transfer losses. The structure maintaining the vacuum around the metal core is a glass tube. Sealing between the metal and glass is crucial in order to maintain the vacuum over time. Due to the high level of heat transfer enhancement, evacuated-tube collectors can heat water to temperatures between 170°F and 350°F (EERE, 2008b).

Circulation

Circulation in a solar hot water system can provide protection from freezing or enhance efficiency. *Indirect* systems isolate the building water supply from the exterior of the building through the use of an anti-freeze liquid circulated through the solar collectors, eliminating the concern of system freeze. Conversely, *direct* systems circulate only end-use water. Direct systems are simpler, less costly, and more efficient because an intermediate heat exchanger and its associated heat transfer losses are not needed; however, if installed in a moderate to cold climate, direct systems would require draining during freezing conditions, negatively affecting life cycle costs by being off-line during part of the year.

The means of moving the fluids throughout the system are either active or passive. *Passive* systems rely on density changes to enhance mixing and gravity to cause movement within the system while *active* systems use pumps to move fluids between collectors and tanks.



Integral-collector storage (ICS) systems (Figure 6.4-3) are a type of direct, passive system. As discussed above, these systems heat water in batches within a dark tank. The heated water then transfers to a tank where it is heated to final temperature through conventional means such as electric resistance or natural gas flame.

Figure 6.4-3: Integral-Collector-Storage (ICS) System (EERE, 2008c)

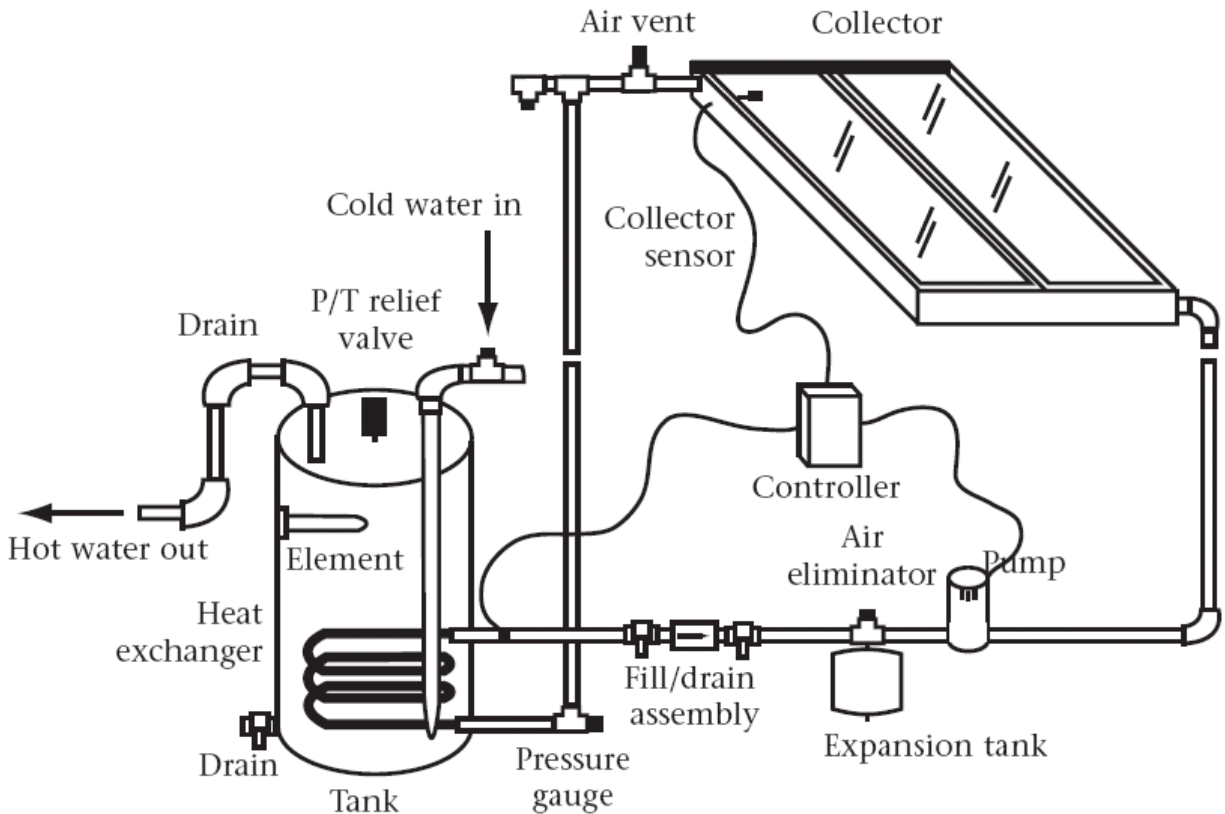


Figure 6.4-4: Active, Indirect Solar Thermal System (EERE, 2008a)

Active systems, such as the one shown in Figure 6.4-4, contain many more components and moving parts as compared with passive systems. The forced transfer of fluid can increase system efficiency; however, the addition of equipment increases system cost and decreases overall reliability in comparison with passive systems.

6.3.2 Size Estimate

Individual building loads were not provided for this study; therefore, specific system sizing is not available. Each system would be sized to meet some or all of the needs of a single building or a small complex of buildings located within very close proximity of each other. One building system could be installed, and, if results are favorable, more systems for additional buildings could follow.

6.3.3 Conceptual Design

For first installation, an ICS system would provide RAFB with an introduction to solar thermal technology with limited investment and maintenance. Upon successful demonstration on-site, more complex systems, such as an evacuated-tube collector system coupled with absorption chilling, could be considered for future (10 to 15 years) installation. Future advances in component design and manufacturing could prove the evacuated-tube to be a highly successful technology at the Base.

6.3.4 Conceptual Location

Locations to be targeted first would be buildings that are not served by any of the central heating plants and also have hot water and heating needs appropriate for the technology, especially daytime hot water needs.

6.3.5 Economics Estimate

Since RAFB currently owns and operates its own hot water equipment, it is assumed that a solar thermal system would also be owned and operated by the Base. Approximate cost information from Glumac, an engineering consulting firm, is shown in Table 6.4-1.

Table 6.4-1: Example Capital Costs of Solar Hot Water Systems

(Glumac, 2008)

	System 1	System 2
Collector Area	2,600 sq. ft.	3,000 sq. ft.
Storage Capacity	4,000 gal	4,500 gal
Cost	\$183,000	\$260,000

The system examined is a flat-plate collector ICS, which is recommended as a first system due to its simple design and low cost. Solar resource information was discussed in Section 3; however, specific system performance data were not available. A study conducted by Deholm (2007) of the National Renewable Energy Laboratory characterizes the conversion efficiency of solar thermal systems based upon geographic location, thereby taking into account solar resource. This information, along with the assumptions in Table 6.4-1, was used to determine system economics.

Results

Estimates of system economics are shown in Table 6.4-2.

Table 6.4-2: Cost of Hot Water (cents/gallon)

	System 1	System 2
10-year life	3.3	4.2
20-year life	1.6	2.1
30-year life	1.1	1.4

Assumed solar fraction of 0.55

Recommendations

It is recommended that a solar thermal system be examined in-depth for use at RAFB. Though these systems would not reduce electricity consumption measurably, they would contribute to increased renewable energy consumption and energy efficiency. In addition, as integrated evacuated-tube system technology advances, it is recommended that the Base investigate solar cooling systems, which would have a direct impact on reducing conventionally-produced electricity consumption.

Section 6.4 References

Denholm, P. 2007. *The Technical Potential of Solar Water Heating to Reduce Fossil Fuel Use and Greenhouse Gas Emissions in the United States*. National Renewable Energy Laboratory. <http://www.nrel.gov/docs/fy07osti/41157.pdf>

Energy Efficiency and Renewable Energy (EERE). 2008a. *Heat Your Water with the Sun—A Consumer's Guide*. U.S. Department of Energy. <http://www.nrel.gov/docs/fy04osti/34279.pdf>

_____. 2008b. *Solar Collectors*. U.S. Department of Energy. http://www1.eere.energy.gov/solar/sh_basics_collectors.html

_____. 2008c. *Solar Water Heaters*. U.S. Department of Energy. http://apps1.eere.energy.gov/consumer/your_home/electricity/index.cfm/mytopic=12850

Glumac. 2008. *Optimize LEED® Points with Solar Hot Water*. <http://www.glumac.com/section.asp?catid=140&subid=152&pageid=657>

6.5 Geothermal Heat Pumps

6.5.1 Description of Technology

Geothermal heat pumps (GHPs) are a technology that has been in existence since the 1940s and can save homeowners or commercial businesses money on supplying heating and hot water to their buildings. These ground-source heat pumps use the natural heat storage capacity of the earth or ground water to provide energy efficient heating and cooling. GHPs should not be confused with air-source heat pumps that rely on heated air.

Geothermal heat pumps use the relatively constant temperature of the ground or water several feet below the earth's surface as source of heating and cooling. Geothermal heat pumps are appropriate for retrofit or new installations, where both heating and cooling are desired. In addition to heating and cooling, geothermal heat pumps can provide domestic hot water. They can be used for virtually any size application in any region of the U.S.

A geothermal heat pump system consists of indoor heat pump equipment, a ground loop, and a flow center to connect the indoor and outdoor equipment. The heat pump equipment works like a reversible refrigerator by removing heat from one location and depositing it in another location. The ground loop, which is invisible after installation, allows the exchange of heat between the earth and the heat pump.

Geothermal heat pumps can be open- or closed-loop. Open-loop systems draw well water for use as the heat source or heat sink, and after use, return the well water to a drainage field or another well. Closed-loop or earth-coupled systems use a water and antifreeze solution, circulated in a ground loop of pipe to extract heat from the earth.

Ground loops can be installed in a vertical well or a horizontal loop. Vertical wells are usually more expensive and used where space is limited. The length of loop pipe required will vary with soil type, loop configuration, and system capacity. Loop length can range from 250 to 1,000 feet per ton of capacity.

Geothermal heating can be more efficient than electric resistance heating. These systems are also typically more efficient than gas or oil-fired heating systems. They are more energy efficient than air-source heat pumps because they draw heat from, or release heat to, the earth, which has moderate temperatures year round, rather than to the air (which is generally colder in winter and warmer in summer than the earth, resulting in less effective heat transfer).

Initial Cost

The initial cost of a geothermal heat pump system varies greatly according to local labor rates, lot geology and size, type of system installed, and equipment selected. Because drilling or installation in water is required, GHP systems are more costly to install than air source heat pumps. For either system, the cost of installed ducts should be identical. Equipment costs can be 50 to 100 percent more expensive for a geothermal heat pump system when the circulating pump, indoor tubing, and water source heat pump are considered. The ground loop is generally the most expensive component of a geothermal heat pump system and is highly dependent on local labor rates and drilling conditions.

Benefits/Costs

Geothermal heat pumps offer high efficiency and low operating cost. According to the EPA, GHPs can save owners 30 to 70 percent on heating and 20 to 50 percent on cooling costs over conventional systems. GHPs provide a high level of occupant comfort. There is a potential for utility bill savings, and many local utility companies provide incentives for investing in GHPs. Military bases have been examining these technologies, and a geothermal system has recently been installed in a new housing area at Tyndall AFB in Florida.

Section 6.5 References

"Geothermal Heat Pumps," ToolBase Services, NAHB Research Center, 400 Prince George's Blvd, Upper Marlboro, MD. <http://www.toolbase.org/Technology-Inventory/HVAC/geothermal-heat-pumps>

7. Transportation Fuels

As stated in Section 2, according to information provided by Robins AFB personnel, the Base uses the following fuels on an annual basis:

- Jet Fuel - JP8 - 11,800,000 gallons
- Diesel Fuel - 370,000 gallons
- Gasoline - 120,000 gallons

There is some interest in substituting renewable fuels for some or all of these requirements, and there may eventually be some interest in producing some of these fuels on the Base itself. The following sections will discuss activities related to transportation fuels.

Summary of the Biofuels Provisions - Title II

“DEFINITIONS (Sec. 201)

Establishes definitions for the renewable fuels program, including conventional biofuel, advanced biofuels, cellulosic biofuels and biomass-based diesel.

- *“**Conventional biofuel** is ethanol derived from corn starch. Conventional ethanol facilities that commence construction after the date of enactment must achieve a 20 percent greenhouse gas (GHG) emissions reduction compared to baseline lifecycle GHG emissions. The 20 percent GHG emissions reduction requirement may be adjusted to a lower percentage (but not less than 10 percent) by the U.S. Environmental Protection Agency (EPA) Administrator if it is determined the requirement is not feasible for conventional biofuels.*
- *“**Advanced biofuels** is renewable fuel other than ethanol derived from corn starch that is derived from renewable biomass, and achieves a 50 percent GHG emissions reduction requirement. The definition – and the schedule -- of advanced biofuels include cellulosic biofuels and biomass-based diesel. The 50 percent GHG emissions reduction requirement may be adjusted to a lower percentage (but not less than 40 percent) by the Administrator if it is determined the requirement is not feasible for advanced biofuels. (Cellulosic biofuels that do not meet the 60 percent threshold, but do meet the 50 percent threshold, may qualify as an advanced biofuel.)*
- *“**Cellulosic biofuels** is renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass, and achieves a 60 percent GHG emission reduction requirement. The 60 percent GHG emissions reduction requirement may be adjusted to a lower percentage (but not less than 50 percent) by the Administrator if it is determined the requirement is not feasible for cellulosic biofuels.”*

7.1 Ethanol

7.1.1 Biochemical Conversion

During the past ten years in the United States there has been a great deal of activity related to the production of fuel ethanol, principally produced from corn. In the aftermath of the first "Energy Crises" in 1974 and 1979, the U.S. Department of Energy promoted the production of fuel ethanol from various feedstocks, and a number of plants were built to produce ethanol from corn and other materials. Research was also started on producing ethanol from alternative feedstocks such as cellulose. Georgia Tech carried out a significant amount of research on production of ethanol from hardwood feedstocks in the late 1970s and early 1980s. Funding for this activity decreased significantly during the Reagan administration, and lower prices for fuel oil during the 1980s and 1990s took away much of the impetus for this activity.

The advent of high (greater than \$40/bbl) oil costs brought renewed interest in fuel ethanol production, and on December 19, 2007, the Energy Independence and Security Act of 2007 (H.R. 6) was signed into law. This comprehensive energy legislation amends the Renewable Fuels Standard (RFS) signed into law in 2005, growing the requirements to 36 billion gallons in 2022. By doing so, the bill seizes on the potential that renewable fuels offer to reduce foreign oil dependence and greenhouse gas emissions and provide meaningful economic opportunity, putting the U.S. firmly on a path toward greater energy stability and sustainability.

The Tables in Appendix B give details on current U.S. ethanol production. In 1980, 175 million gallons of fuel ethanol were produced in the U.S., and by 2007 6.5 billion gallons were being produced on an annual basis. As of the current time in the U.S., there are plants in operation capable of producing 11 billion gallons per year, and there are plants still under construction capable of producing an additional 1.6 billion gallons per year (principally from corn feedstocks). (Source?)

In October, 2008, the first commercial ethanol from corn plant in the state of Georgia was started up in Camilla, Georgia, by First United Ethanol, LLC. This plant uses corn feedstock supplied via train principally from the Midwest and will be capable of producing 100 million gallons of ethanol per year.

According to a January 2008 study, the economic impact of a 36 billion gallon RFS is as follows (LECG, 2007):

- Adds more than \$1.7 trillion to the Gross Domestic Product between 2008 and 2022
- Generates an additional \$436 billion of household income for all Americans during the same time period
- Supports the creation of as many as 1.1 million new jobs in all sectors of the economy
- Produces \$209 billion in new Federal tax receipts

There are a number of different companies exploring the production of fuel ethanol from cellulosic matter worldwide today. As of the present time, there are no fully commercial examples of this technology that are being carried out full-scale.

One example of a company developing a biochemical or "sugar platform" process to produce ethanol from cellulose is C2 Biofuels, a startup company located in Atlanta. This company is affiliated with Georgia Tech and the University of Georgia and has had meetings with Robins AFB to discuss potential siting of a plant at Robins AFB. C2 Biofuels is currently carrying out research programs with a joint team from Georgia Tech and the University of Georgia to convert southern pine wood feedstock into fuel ethanol. There are a number of other companies active in this field at the current time, as shown in Table 7.1-1.

Table 7.1-1: Cellulosic Ethanol Technology Companies

Producer	Primary Feedstock Target						
	Switch Grass	Corn Stover	Wheat Straw	Sugarcane Bagasse	Hard Wood	Douglas Fir	Southern Pine
C2 Biofuels							X
Mascoma	X				X		
Dupont Danisco		X		X			
Verenium				X			
Iogen			X				
Abengoa			X				
Lignol		X	X			X	
Pacific Ethanol							
Poet		X					

Source: C2 Biofuels, Inc.

7.1.2 Thermochemical Conversion

Thermochemical conversion of biomass to liquids involves two main process steps: (1) conversion of solid biomass to syngas via gasification; and (2) conversion of syngas to alcohols (mainly methanol and ethanol) via a catalytic reaction.

The process for thermochemical ethanol production is complex and, at present, more expensive than biochemical ethanol production; however, it is assumed that process evolution will lead to more efficient and economical conversion technologies. Current estimates are that thermochemical production will produce yields of ethanol from cellulosic biomass at 100 to 115 gallons of ethanol per ton of biomass with a resulting

production cost of \$0.40 to \$0.60 per gallon. This, however, has yet to be demonstrated at any significant scale above research pilot scale.

Georgia is the home to the first commercial cellulosic ethanol facility in the U.S. with Range Fuels in Soperton, GA. When completed in late 2010 the facility is slated to produce 100 million gallons of ethanol from cellulosic biomass per year.

7.2.1 Biodiesel

Biodiesel is a term that refers to a non-petroleum-based diesel fuel consisting of short chain alkyl (methyl or ethyl) esters of fatty acids, made by the transesterification of vegetable oil or animal fat. Biodiesel may be used alone, or blended with conventional diesel fuel. To be qualified as biodiesel the fuel must meet the ASTM D6751 standard.

There are a number of benefits to using biodiesel as a blended fuel in diesel engines: (1) biodiesel has a lower flash point than petroleum diesel and may reduce the risk of fire; (2) biodiesel combusts cleaner than petroleum diesel yielding lower emissions in particulate matter, nitrogen, carbon monoxide and non-combusted hydrocarbons; (3) odor of both liquid biodiesel fuel and its combustion byproducts (exhaust) is less offensive than petroleum diesel; (4) there are no necessary modifications needed to current diesel engines to enable the use of biodiesel; (5) transportation and storage systems for biodiesel are identical to petroleum diesel, and there do not need to be significant changes; and (6) engine performance and fuel mileage of vehicles using biodiesel is comparable to vehicles operating on petroleum diesel.

The technology for conversion of vegetable oils and animal fats into biodiesel is a well-known and established process. The standard industry process used to produce biodiesel is a base-catalyzed esterification process. This process involves mixing vegetable oil or animal fat with an alcohol (usually methanol - however ethanol may be used) and a base catalyst of either sodium or potassium hydroxide.

Capital Costs

Biodiesel requires a lower capital investment than other liquid fuel production systems such as ethanol. In general worldwide average capital investment for production facilities with a production capacity of 5 to 20 million gallons per year is \$1.0 to \$1.3 per annual production gallon; therefore, a 10 million gallon per year facility would cost approximately \$10 to \$13 million to construct. For smaller production facilities of less than 5 million gallons the capital investment costs have a much wider range averaging \$1.4 to \$3.0 million per annual gallon of production.

When small-scale, on-site production is considered (<1 million gallons per year), the capital investment can be much more cost effective. For example, reliable small-scale units capable of producing 500 gallons per day can be purchased for as little as \$20,000. The resulting capital cost per annual gallon of production for this type of

system can be as low as \$0.25. This low cost is attributable to the drastically reduced infrastructure, engineering, and permitting costs associated with these small production units.

Production Costs

The bulk of the production cost for biodiesel is incurred from the feedstock cost, which can be highly variable. For example, feedstock prices have ranged from \$0.16 to \$0.65 per pound (\$1.20 to \$4.88 per gallon) over the past year. Feedstock cost can account for up to 85 percent of the cost of fuel depending on commodity prices. The actual production cost (without feedstock) is relatively low. Average production costs range from \$0.27 to \$0.45 per gallon (not including capital amortization costs) for a 15 to 20 million gallon per year facility.

When considering small-scale, on-site facilities, the production cost is much higher as labor costs per gallon are increased due to small batch sizes. Quality control costs are also much higher in small-scale systems as per-batch quality assurance is required on all biodiesel produced in the U.S. Again, the small batch size increases the cost per gallon for fuel analysis. Off-site quality control analysis and certification is currently averaging approximately \$200 per batch. The cost of an on-site quality control laboratory is approximately \$300,000.

Robins Air Force Base Production Example

Robins Air Force Base uses approximately 370,000 gallons of diesel fuel annually. On site production of biodiesel is an option to potentially reduce fuel costs, reduce environmental impact, and provide a more secure fuel supply.

Table 7.2-1 below details the potential costs involved in biodiesel production at 7,500, 75,000, and 370,000 gallon annual production capacities. Estimated production costs of \$4.40, \$1.05, and \$0.77 per gallon, respectively, are shown. These costs are production costs only and do not include feedstock. Using the 2008 costs for biodiesel feedstock in Georgia, the final cost per gallon would range from \$5.60 to \$9.28 for a 7,500-gallon production facility, \$2.25 to \$5.93 for a 75,000-gallon facility and \$1.97 to 5.65 for a 370,000-gallon facility.

Table 7.2-1: Biodiesel Production Cost Summary at \$0 feedstock

Annual volume (gal)	7500	75000	370000
Batch Size (gal)	150	500	2000
Total Capital	\$15,000.00	\$25,000.00	\$100,000.00
Capital/gal	\$2.00	\$0.33	\$0.27
Batches per year	50	150	185
Fuel Analysis/batch	200	200	200
Fuel Analysis/gal	\$1.33	\$0.40	\$0.10
Estimated O&M	\$8,000.00	\$24,000.00	\$148,000.00
Estimated O&M/gal	\$1.07	\$0.32	\$0.40
Cost per gal	\$4.40	\$1.05	\$0.77

Choice of production capacity depends on intended final use for biodiesel. In general, biodiesel fuel is utilized as a blended fuel with petroleum diesel. In Table 7.2-1 above, the production capacities were determined by estimating potential end use fuel blends based on 370,000 gallon annual diesel fuel consumption at RAFB. The annual production rates above are set at 7,500 gallons for a 2% (B2) blend, 75,000 gallons for 20% (B20) blend, and 370,000 gallons for a 100% (B100) use.

Tables 7.2-2 and 7.2-3 below estimate the incremental change in the resulting fuel price (petrol diesel + biodiesel) at the selected blend rate on a per gallon blended fuel basis. These costs would be the end cost per gallon based on biodiesel price and petroleum diesel price and result in added cost or cost savings versus unblended petroleum diesel.

**Table 7.2-2: Changes in cost per gallon
for 2% Biodiesel Blend (B2)**

	Retail Diesel Prices Per Gallon				
	\$2.00	\$2.75	\$3.50	\$4.25	\$5.00
Biodiesel Cost 100% (B100)	Added Cost in Dollars per Gallon				
\$3.00	0.02	0.00	-0.01	-0.03	-0.04
\$3.75	0.04	0.02	0.00	-0.01	-0.02
\$4.50	0.05	0.03	0.02	0.00	-0.01
\$5.25	0.06	0.05	0.03	0.02	0.01
\$6.00	0.08	0.06	0.05	0.04	0.02
\$10.00	0.16	0.15	0.13	0.12	0.10

**Table 7.2-3: Changes in cost per gallon
for 20% Biodiesel Blend (B2)**

	Retail Diesel Prices Per Gallon				
	\$2.00	\$2.75	\$3.50	\$4.25	\$5.00
Biodiesel Cost 100% (B100)	Added Cost in Dollars per Gallon				
\$3.00	0.20	0.05	-0.10	-0.25	-0.40
\$3.75	0.35	0.20	0.05	-0.10	-0.25
\$4.50	0.50	0.35	0.20	0.05	-0.10
\$5.25	0.65	0.50	0.35	0.20	0.05
\$6.00	0.80	0.65	0.50	0.35	0.20
\$10.00	1.60	1.45	1.30	1.15	1.00

Environmental Impacts

Biodiesel is an effective alternative renewable fuel with many dramatically-reduced emissions. The Environmental Protection Agency has demonstrated the reductions in many standard air pollutants when using biodiesel, shown in Table 7.2-1

Table 7.2-1: EPA Test Emissions for Biodiesel
(Source: EPA 2001 data)

Air Emission	B100 (100% Biodiesel)	B20 (20% Biodiesel)
Carbon Monoxide	-43.2%	-12.6%
Hydrocarbons	-56.3%	-11%
Particulates	-55.4%	-18%
Nitrogen Oxides	+5.8%	+1.2%

Section 7.1 References

[LECG] *Economic Impact of the Energy Independence and Security Act of 2007*, LECG LLC

National Biodiesel Board: <http://www.nbb.org>

Study on the Feasibility of Biodiesel Production in Georgia George A. Shumaker, John McKissick, Christopher Ferland, and Brigid Doherty February 2003 FR-03-02

Summary Results From NBB / U.S. EPA Tier I Health And Environmental Effects Testing For Biodiesel Under The Requirements For U.S. EPA Registration Of Fuels And Fuel Additives (40 Cfr Part 79, Sec 21 1 (B)(2) And 21 1 (E)) Final Report, U.S. Environmental Protection Agency, March 1998

A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions: Draft Technical Report, Assessment and Standards Division Office of Transportation and Air Quality U.S. Environmental Protection Agency, EPA420-P-02-001, October 2002

7.2.2 Syn-diesel

Syndiesel, also known as green diesel, is a hydrocarbon fuel chemically identical to petroleum-based fuels; however, it is produced from non-petroleum sources such as coal or biomass. Production of syndiesel or green diesel from a syngas is not a new technology. Great efforts were made in Germany during World War II and in South Africa throughout the 1970s and 1980s to produce liquid fuels from coal syngas. Technologies for the utilization of biomass materials as feedstocks for gasification and conversion to liquid fuels are being developed and are in the initial stages of full commercial-scale implementation.

The process first thermochemically gasifies the feedstock (e.g. biomass, coal, etc.), and the resulting synthesis gas (mainly carbon monoxide and hydrogen) is then passed through a catalytic reactor containing specific catalysts, which convert the gas into the desired hydrocarbon product. Subsequent condensation of the gas yields liquid fuel.

(fischer-tropsch.org)

The primary process used worldwide today for syndiesel production is the Fischer-Tropsch process (FT) (or Fischer-Tropsch Synthesis). Originally developed in the 1920s, this process has been refined many times over the years, and the term “Fischer-Tropsch” now applies to a wide range of processes. FT is a catalyzed chemical reaction in which carbonaceous feedstock (coal or biomass) is converted into hydrocarbons of various forms. The most common catalysts in use today are based on iron, cobalt, and nickel. Catalysts are manufactured by large companies throughout the world. Haldor Topsoe in Texas and Sud Chemie in France are two of the largest.

Framtidsbränslen AB has operated a biomass gasification FT liquid facility in Sundsvall, Sweden, since 2003. In a 2005 report, the calculated diesel fuel cost from the Sundsvall plant was \$3.79 U.S. (2004 data) per gallon. The average U.S. cost for diesel fuel in 2004 was \$1.84 (Source EIA) per gallon or roughly one half the cost of syn-diesel or green diesel.

Other than those related to the case listed, there are very little data on the production of FT liquids from biomass at production scale. The production of FT liquids from coal is current technology used widely. The production costs from coal FT synthesis are not representative of potential biomass cost estimates at this time primarily due to the differences in the processes (mainly in the catalytic conversion of the syngas), feedstock characteristics, and feedstock consistency.

Reccomendation:

At this time, with available technology, large-scale FT synthesis for hydrocarbon fuels or alcohol fuels is not recommended by this report as a viable solution for application at Robins Air Force Base.

Section 7.2 References

Framtidsbränslen AB, *Sundsvall demonstration plant en förstudie för tillverkning av Fischer- Tropsch diesel från biomassa, 2005*

Hamelinck, Carlo N., Faaij, Andre P. C., den Uil, Herman, Boerrigter, Harold, *Production of FT transportation fuels from biomass; Technical options, process analysis and optimisation, and development potential*, Energy 29/2004 1743 – 1771

Dry, Mark E., *High quality diesel via the Fischer-Tropsch process – a review*, Journal of Chemical Technology and Biotechnology, 77/2001, 43-50

8. Conclusions and Recommendations

In summary, it is recommended that the following technologies be pursued by Robins Air Force Base as candidate technologies in greater detail, based on both economics and thermodynamics:

1. Biomass-fired steam/electric Plants and cogeneration options

The wood fuel survey contained herein shows an adequate supply within a reasonable hauling distance to power a steam/electric plant that could greatly assist the Base in meeting its renewable energy use goals.

2. Biomass-fired gasification plants

As with the category above, since there are adequate supplies of wood fuels in the areas surrounding the Base, gasification of biomass should also be considered, particularly for smaller applications located on the Base.

3. Photovoltaic electric power generation

Since RAFB has much flat roof area available, the installation of photovoltaic systems to displace some of the base electric load should be seriously considered. On a purely economic basis, the paybacks will not be as attractive as some of the other alternatives, but these applications could help the Base reach its renewable energy and efficiency goals.

4. Cellulosic ethanol motor fuels

It is recommended that the base keep abreast of developments in the production of synthetic motor fuels from biofuels, and possibly consider the co-location of biomass to liquid fuel facilities with some of the other energy projects in the future.

5. Remote landfill gas electricity

Although there appear to be potential legal and infrastructure impediments to supplying the base with electricity produced in remote landfills, it is recommended that this alternative be more fully investigated.

6. Solar thermal and geothermal hot water systems

These systems can have relatively attractive paybacks, and there are numerous potential applications at Robins AFB that should be examined more fully. These technologies would also aid in meeting energy use reduction goals.

The following topics do not deserve further consideration at this time:

1. Municipal solid waste power generation (for RAFB)
2. Anaerobic Digestion of Food Waste
3. Fuel cells for electricity generation

11. Appendices

Appendix A : Biomass Fuel Availability Assessment 75-mile Radius from Robins Air Force Base, Robins, GA.

Table of Contents

TABLE OF CONTENTS.....	87
LIST OF TABLES.....	87
LIST OF FIGURES.....	87
INTRODUCTION.....	88
METHODS.....	88
<i>Information Selection</i>	88
<i>Assumptions</i>	89
<i>Logistics</i>	90
<i>Types of Biomass</i>	90
<i>Data Units</i>	91
RESULTS AND DISCUSSION.....	93
<i>Section 1: Commercial Biomass</i>	93
<i>Section 2: Landfill Biomass</i>	100
APPENDIX A REFERENCES.....	106

List of Tables

TABLE 1 THE NORTH AMERICAN INDUSTRY CLASSIFICATION SYSTEM (NAICS) CLASSIFICATION FOR THE COMPANIES INCLUDED IN THIS STUDY.....	89
TABLE 2 AVERAGE HAULING COST PER GREEN TON WITH AN AVERAGE TRUCK LOAD WEIGHT OF 25 TONS.....	90
TABLE 3 AVERAGE BULK DENSITY FOR EACH BIOMASS CATEGORY.....	92
TABLE 4 COUNTIES WITHIN 75 MILE RADIUS FROM ROBINS.....	93
TABLE 5 NUMBER OF COMPANIES RESPONDING TO INQUIRY.....	94
TABLE 6 COMMERCIAL BIOMASS BY COUNTY WITHIN THE STUDY AREA (TONS/MTH).....	96
TABLE 7 COMMERCIAL BIOMASS PRODUCED BY TYPE AND COUNTY: (TONS/MTH).....	98
TABLE 8 NUMBER OF LANDFILLS RESPONDING TO INQUIRY.....	100
TABLE 9 LANDFILL BIOMASS BY COUNTY WITHIN THE STUDY AREA (TONS/MTH).....	102
TABLE 10 AMOUNT OF LANDFILL BIOMASS PRODUCED BY TYPE AND COUNTY: (TONS/MTH).....	104
TABLE 11 COMPANIES THAT PARTICIPATED IN STUDY.....	109
TABLE 12 LANDFILLS THAT PARTICIPATED IN STUDY.....	112

List of Figures

FIGURE 1 TOTAL COMMERCIAL BIOMASS BY TYPE IN STUDY AREA (TONS/MTH).....	100
FIGURE 2 TOTAL LANDFILL BIOMASS BY TYPE IN STUDY AREA (TONS/MTH).....	105
FIGURE 3 BIOMASS GENERATING COMPANIES.....	108
FIGURE 4 LANDFILLS.....	111

Introduction

Robins Air Force Base has contracted with the University of Georgia Engineering Outreach Service (EOS) to conduct a physical inventory survey of the potential available biomass material within a seventy-five (75) mile radius of Robins GA. This survey includes data concerning biomass generated from commercial and industrial businesses as well as the potentially available biomass from landfills within the project area.

Methods

There are a number of methods that were considered for conducting this type of survey. One such method is to obtain general business information based on the number of employees and/or annual gross sales and extrapolate what biomass should theoretically be available. It has been the experience of the EOS that although this is a viable method for obtaining widespread data, it often leads to exaggerated data. Since the results of this study are to be used for plant feasibility design and business plan modeling, it was decided to develop a survey protocol that would significantly increase the chance of obtaining accurate data. In an effort to obtain actual biomass availability in as many situations as possible, it was determined that the most reliable method would be to contact by telephone as many potential biomass generators as possible and interview them about their company's biomass generating activities. Once the telephone surveying was completed and the data reviewed, the largest and most probable sources of biomass were selected for follow up site visits to further verify the information obtained from phone conversations.

Information Selection

The survey area has been identified as the area within a seventy-five mile radius of locations in Robins, Georgia. Robins is located just south of Macon, GA on the east side of Interstate 75. For the purposes of this study, it was assumed that 75 miles meant 75 air miles.

The original economic sectors that were evaluated included businesses that maintain and harvest forests, primary and secondary forest products industries, inert waste landfills, construction and demolition waste landfills, agribusiness and any other businesses within the study area that generate biomass suitable for use. Since essentially every type of company doing business has some form of waste biomass that could be considered, it was necessary to determine defined characteristic parameters in order to limit the scope of the survey.

This study focused on business sectors that predominantly generate woody type biomass. Inert, construction and demolition (C&D) landfills as well as Municipal Solid Waste (MSW) landfills were included and therefore, some data reported by landfills might be accounted for in the data already collected from companies, essentially duplicating results. This is an important consideration when evaluating the overall total of potential material available. In addition, the data reported by C&D landfills is most likely inflated due to the co-mingling of inert waste with biomass. Exact data for only organic biomass was not always able to be extracted from landfill personnel.

An extensive list of company types was generated that were believed to have the greatest potential for biomass. These types of companies were matched with their North American Industry Classification System (NAICS) code and yellow page listing. Although the list of NAICS codes that were selected initially included a wider spectrum of companies, Table 1 presents the primary NAICS codes that were used in this study. The majority of information regarding the companies in the survey was developed using the Harris Infosource registry, which is an up-to-date data management system specializing in location-specific company profiles that have been combined with Dun and Bradstreet (D&B) information (Harris Infosource). This database offers complete coverage of approximately 14 million companies.

Table 1 The North American Industry Classification System (NAICS) classification for the companies included in this study

NAICS Code	Industry
113000-113999	Fruit & Tree Nut Farming
321000-321999	Wood Product Manufacturing
337110-337119	Wood Kitchen Cabinet & Countertop Manufacturing
337121	Upholstered Household Furniture Manufacturing
337122	Non-upholstered Wood Household Furniture Manufacturing
337129	Wood Television, Radio & Sewing Machine Cabinet Manufacturing
337211	Wood Office Furniture Manufacturing
337212	Custom Architectural Woodwork & Millwork Manufacturing
237200-237299	Land Subdivision
236115	New Single-Family Housing Construction (Except Operative Builders)
236220	Commercial & Institutional Building Construction
237210	Highway, Street & Bridge Construction
322224	Uncoated Paper & Multiwall Bag Manufacturing
323110	Commercial Lithographic Printing

Assumptions

The following is a list of the assumptions that were used to conduct the survey and analyze the data.

1. Mixed wood wastes from single source producers were included
2. Biosolids, sludges and “wet” organic residuals were excluded
3. Household garbage was excluded
4. Cardboard and paper products were excluded because of poor burning properties and direct competition with established recycling networks
5. Single family construction and demolition companies were excluded because of the very high potential for undesirable contamination in their waste products
6. Grading companies were excluded because of the unpredictability of requested clearing site, the frequency of contracts with logging companies for tree removal and burn on site for the remaining grubbed waste. Additionally, the majority of the available inert waste from such companies should be effectively captured in the landfill data.

7. Facilities that burn biomass for their own processes were included and classified as selling biomass. Essentially they are “selling” the biomass to themselves for internal use.
8. Recycling and giving away biomass was classified as selling.
9. Burning biomass not for useful energy was classified as disposal.
10. Dumping biomass onsite or on company land was considered disposal

Logistics

The feasibility of product availability is truly an economic factor. What does it cost to transport the amount of biomass from point A to point B? Many of the smaller producers will require multiple trips or “route running” to collect the widely distributed biomass. Large producers that meet the desired characteristics and are “close” to the proposed site are preferred.

There are many variables that go into determining shipping costs, including the type of material, the required truck type, the loading/unloading facilities, back haul availability, distance, fuel price and others. For the purposes of this report, trucking costs are assumed to be \$0.13 per ton per mile (\$0.13/ton/mile) with a flat minimum charge of 45 miles and then \$0.19 per additional mile. The average diesel price at the time of this report is \$3.00/gallon (Energy Information Administration). This works out to ~\$3.25/mile which is highly volatile and subject to change. Table 2 presents average costs per green ton of biomass using an average truck payload of 25 tons, which is typical for tractor trailer loads of wood chips and other similar biomass products. As an example, the daily trucking cost for transporting 25 tons/day of biomass from a company located 75 miles away would cost \$243.75/load [(75 miles)(0.13)(25 tons)] which is equivalent to \$9.75/ton.

Table 2 Average hauling cost per green ton with an average truck load weight of 25 tons.

Haul Distance	\$/Green ton ¹
<45 miles	\$5.85
60 miles	\$7.80
75 miles	\$9.75
100 miles	\$13.00

¹: Assuming an average haul rate of \$0.13/mile and a minimum of 45 miles

Types of Biomass

For the purposes of organization, the by-products generated from each of the facilities were placed into nine categories. These nine categories include blocks, clean chips, dried chips, engineered, mixed scrap, mulch/dirty chips, pallets, roundwood and sawdust. The forest resource materials are organized into commercial planted pine plantations and all natural forests.

Blocks - This is a broad category of natural wood pieces (mostly pine) that are dried lumber cut off the ends of boards. Size of blocks varies from a few inches up to two feet long and most are relatively clean and dry. Pallets could actually be part of this category but they have been separated out because of nail contamination. Blocks have a low bulk

density due to the irregular geometry and size of the blocks. Blocks are most often the product of cabinet shops and truss manufacturers .

Clean Chips - These are fresh logs (mostly pine) stripped of bark and reduced into manageable pieces of various sizes. Clean chips have relatively high moisture content and are not considered dry. The majority of clean chip operations produce chips that are clean (dirt free) and free of debris and contamination.

Dried Chips - These are clean kiln dried lumber (Block type material) that are segregated and used primarily as fuel. However, dried chips are not as common and have a higher value per unit than other categories because of the low moisture content and high BTU factor.

Engineered - This is a diverse category of plywood, medium density fiberboard (MDF) and particle board materials. They are in sawdust, chip and scrap forms as they are manufactured into similar products as natural wood. There is often a laminate covering serving as a surface color treatment for finished product. There is a possible concern of toxins generated during burning of engineered products

Mixed Scrap - This is a diverse open ended category of any combination of the other seven categories; Blocks, Clean Chips, Dried Chips, Engineered, Mulch/Dirty Chips, Pallets, and Sawdust. Most big producers like lumber yards separate their waste streams and do not produce Mixed Scrap. Smaller businesses tend to mix their wood residues and send them to land fills.

Mulch/Dirty Chips - Fresh logs ground into shreds and chips that include bark and other debris (leaves & dirt.) It is very wet when fresh but dries out over time. Many of the lumber companies produce dirty chips.

Pallets - Originating from clean kiln dried lumber these residues are similar to the Block category. Pallet wood is normally clean and dry with nails being the only contamination concern

Roundwood - This is a broad category covering any pieces of whole timber in their unprocessed state. It should be considered green though moisture content will vary depending on age. Larger diameter cuts of tree top slash and under story brush are in this category along with tree trunks, stumps and limbs. Land clearing type businesses such as logging companies produce roundwood biomass.

Sawdust - This is a diverse category involving particulate of different sizes. There is fine sawdust to course sawdust. Shavings vary in size from very course sawdust to large curls. Green sawdust is a separate category in itself and usually is course based on samples and site visits so far. Sawdust comes from pallet companies too. Engineered sawdust was classified under the Engineered category.

Data Units

It has been the experience of the EOS research team that when conducting waste audit surveys and interviews that data is more accurate when reported in volume rather than

tons. It is often very difficult or impossible to interview the actual plant manager and/or the employee directly responsible for byproduct biomass management of a facility. Since the person being interviewed may not always have a complete understanding of the biomass waste situation of the operation, it is often more accurate to have them tell the number of dumpsters, roll offs, etc, of waste removed per unit of time than the actual tonnage of the waste. The tonnage of these hauling units may not be known due to billing practices of charging for a number of “pulls per month” rather than actual tonnage removed. Volume of waste is easier to visualize than tons. When the company representative knew the exact tonnage of available biomass, that information was reported in tons, otherwise, data was gathered and reported in cubic yards per month (yds/mth) and converted to tons.

In order to determine tonnage data, samples from each type of byproduct from various companies was collected and analyzed to determine an average bulk density (pounds per cubic yard) for the biomass type and moisture content when applicable. This laboratory data was then compared to data in the literature to ensure quality of the laboratory testing (McDonald; Rynk, 1992). The bulk density figures that were used to calculate tonnage can be seen in Table 3. Actual bulk densities of individual materials will vary.

Table 3 Average bulk density for each biomass category

Category	Bulk Density (lb/yd³)
Blocks	1,250
Clean Chips	723
Dried Chips	430
Engineered	619
Mixed Scrap	661
Mulch/Dirty	707
Pallets	610
Roundwood	881
Sawdust	432

Results and Discussion

Table 4 presents the 67 counties that fall within the 75 mile radius. This section is broken up into two parts. The first part includes biomass from commercial and industrial companies that were individually contacted and interviewed about their biomass production. The second section includes biomass from landfills within the counties below.

Table 4 Counties within 75 mile radius from Robins

Baldwin	Hancock	Morgan	Toombs
Ben Hill	Harris	Muscogee	Treutlen
Bibb	Henry	Newton	Turner
Bleckley	Houston	Peach	Twiggs
Butts	Irwin	Pike	Upson
Chattahoochee	Jasper	Pulaski	Walton
Clayton	Jeff Davis	Putnam	Warren
Coffee	Jefferson	Rockdale	Washington
Coweta	Johnson	Schley	Webster
Crawford	Jones	Spalding	Wheeler
Crisp	Lamar	Stewart	Wilcox
Dodge	Laurens	Sumter	Wilkinson
Dooly	Lee	Talbot	Worth
Dougherty	Macon	Taliaferro	
Emanuel	Marion	Taylor	
Fayette	Meriwether	Telfair	
Glascok	Monroe	Terrell	
Greene	Montgomery	Tift	

Section 1: Commercial Biomass

Table 5 shows the number of companies within each county and the approximate tonnage of material available each month. The categories chosen in Table 5 represent increments of 100 tons of biomass. These increments include less than 100 tons/mth, from 100 to 400 tons/mth and 400 tons/mth and greater. There were 383 companies that the EOS research team was not able to contact because they were either out of business, did not want to contribute to the survey or did not respond to multiple inquiries. This represents a potentially significant amount of material whose availability is unknown but could be re-contacted again in the future. There were 445 companies that responded to the survey but only 58 companies had any biomass to report. Table 6 shows the number of companies contributing to the survey and the approximate volume of material that the collective companies in that county produce.

Table 5 Number of companies responding to inquiry

County	State	No Biomass	Have Biomass	1-100	101-400	400+	No Response	Positive Response	No. Contacted
Baldwin	GA	2	2	1	0	1	3	4	7
Ben Hill	GA	3	0	0	0	0	4	3	7
Bibb	GA	6	1	1	0	0	6	7	13
Bleckley	GA	10	0	0	0	0	7	10	17
Butts	GA	3	1	0	0	1	5	4	9
Chattahoochee	GA	5	0	0	0	0	4	5	9
Clayton	GA	1	0	0	0	0	2	1	3
Coffee	GA	8	0	0	0	0	5	8	13
Coweta	GA	3	0	0	0	0	7	3	10
Crawford	GA	2	0	0	0	0	3	2	5
Crisp	GA	8	3	1	1	1	5	11	16
Dodge	GA	4	0	0	0	0	3	4	7
Dooly	GA	3	0	0	0	0	6	3	9
Dougherty	GA	7	1	0	1	0	4	8	12
Emanuel	GA	4	3	1	1	1	7	7	14
Fayette	GA	20	0	0	0	0	18	20	38
Glascocock	GA	5	0	0	0	0	5	5	10
Greene	GA	2	0	0	0	0	2	2	4
Hancock	GA	6	0	0	0	0	5	6	11
Harris	GA	13	1	0	1	0	10	14	24
Henry	GA	8	3	2	1	0	4	11	15
Houston	GA	4	3	2	0	1	4	7	11
Irwin	GA	9	0	0	0	0	6	9	15
Jasper	GA	6	3	1	0	2	7	9	16
Jeff Davis	GA	11	0	0	0	0	8	11	19
Jefferson	GA	1	1	0	0	1	4	2	6
Johnson	GA	23	0	0	0	0	16	23	39
Jones	GA	5	1	1	0	0	5	6	11
Lamar	GA	8	1	0	1	0	6	9	15
Laurens	GA	3	3	3	0	0	2	6	8
Lee	GA	14	0	0	0	0	11	14	25
Macon	GA	5	0	0	0	0	6	5	11
Marion	GA	7	0	0	0	0	10	7	17
Meriwether	GA	3	0	0	0	0	4	3	7
Monroe	GA	1	3	0	1	2	2	4	6
Montgomery	GA	4	1	0	1	0	6	5	11
Morgan	GA	9	2	1	0	1	7	11	18
Muscogee	GA	5	0	0	0	0	5	5	10
Newton	GA	8	3	2	1	0	9	11	20
Peach	GA	3	1	1	0	0	4	4	8
Pike	GA	6	1	0	1	0	7	7	14
Pulaski	GA	3	0	0	0	0	5	3	8
Putnam	GA	4	4	1	2	1	7	8	15
Rockdale	GA	6	0	0	0	0	4	6	10
Schley	GA	4	0	0	0	0	7	4	11
Spalding	GA	3	5	3	2	0	3	8	11
Stewart	GA	8	0	0	0	0	8	8	16
Sumter	GA	5	1	0	1	0	5	6	11
Talbot	GA	8	0	0	0	0	7	8	15
Taliaferro	GA	5	0	0	0	0	5	5	10
Taylor	GA	5	0	0	0	0	3	5	8
Telfair	GA	4	1	0	0	1	6	5	11
Terrell	GA	5	1	1	0	0	6	6	12
Tift	GA	8	0	0	0	0	9	8	17

Toombs	GA	6	0	0	0	0	7	6	13
Treutlen	GA	5	0	0	0	0	5	5	10
Turner	GA	5	2	0	0	2	4	7	11
Twiggs	GA	2	0	0	0	0	6	2	8
Upson	GA	9	1	0	0	1	7	10	17
Walton	GA	7	1	1	0	0	6	8	14
Warren	GA	5	0	0	0	0	4	5	9
Washington	GA	2	1	0	0	1	4	3	7
Webster	GA	3	0	0	0	0	2	3	5
Wheeler	GA	2	0	0	0	0	2	2	4
Wilcox	GA	5	0	0	0	0	5	5	10
Wilkinson	GA	4	2	0	0	2	4	6	10
Worth	GA	6	1	1	0	0	8	7	15
Totals		387	58	24	15	19	383	445	828

The total amount of commercial biomass within the 75 mile radius from the companies that reported data is 203,967 tons/mth. Of this number, 191,347 tons/mth or 93% of the biomass is already being sold or utilized internally for fuel. This number represents the greatest potential for use since it is already being used for similar type processes. In many situations, it would be a matter of negotiating the price and logistics for the companies to change operational procedures. The remaining 12,621 tons/mth are currently being disposed of on company land or in Subtitle D landfills, C&D landfills or inert landfills.

Georgia Pacific was the one major anomaly for the entire study. Georgia Pacific, located in Jasper County, GA, uses all their wood biomass to operate plant dryers. Approximately 90,230 tons/mth of hog fuel, a mixture of bark and sawdust, as well as 19,470 tons/mth of plywood trim sanderdust is used in house for a total of 109,700 tons/mth. This quantity is 56,152 tons/mth greater than the amount from all other companies combined. In addition to this, Georgia Pacific imports an additional 18,320 tons/mth of mixed wood residue. A portion of this imported wood residue is being purchased from companies already in this study and the remainder is brought in from outside the project radius. As a result, this 18,320 tons/mth of additional biomass is not included in these sets of data.

Table 6 Commercial biomass by county within the study area (tons/mth)

County	State	Sold	Landfilled	Total
Baldwin	GA	2,608	8	2,616
Ben Hill	GA	0	0	0
Bibb	GA	1	0	1
Bleckley	GA	0	0	0
Butts	GA	440	0	440
Chattahoochee	GA	0	0	0
Clayton	GA	0	0	0
Coffee	GA	0	0	0
Coweta	GA	0	0	0
Crawford	GA	0	0	0
Crisp	GA	1,480	218	1,698
Dodge	GA	0	0	0
Dooly	GA	0	0	0
Dougherty	GA	108	0	108
Emanuel	GA	40,446	0	40,446
Fayette	GA	0	0	0
Glascocock	GA	0	0	0
Greene	GA	0	0	0
Hancock	GA	0	0	0
Harris	GA	197	0	197
Henry	GA	0	204	204
Houston	GA	6	7,123	7,130
Irwin	GA	0	0	0
Jasper	GA	110,928	0	110,928
Jeff Davis	GA	0	0	0
Jefferson	GA	2,940	0	2,940
Johnson	GA	0	0	0
Jones	GA	0	40	40
Lamar	GA	136	0	136
Laurens	GA	0	68	68
Lee	GA	0	0	0
Macon	GA	0	0	0
Marion	GA	0	0	0
Meriwether	GA	0	0	0
Monroe	GA	9,464	1,414	10,878
Montgomery	GA	104	0	104
Morgan	GA	2,600	0	2,600
Muscogee	GA	0	0	0
Newton	GA	0	301	301
Peach	GA	0	3	4
Pike	GA	0	143	143
Pulaski	GA	0	0	0
Putnam	GA	106	723	829
Rockdale	GA	0	0	0
Schley	GA	0	0	0
Spalding	GA	0	333	333
Stewart	GA	0	0	0
Sumter	GA	0	249	249
Talbot	GA	0	0	0
Taliaferro	GA	0	0	0
Taylor	GA	0	0	0
Telfair	GA	2,088	330	2,418
Terrell	GA	0	26	26
Tift	GA	0	0	0
Toombs	GA	0	0	0
Treutlen	GA	0	0	0

Turner	GA	3,199	0	3,199
Twiggs	GA	0	0	0
Upson	GA	10,053	0	10,053
Walton	GA	34	0	34
Warren	GA	0	0	0
Washington	GA	2,728	0	2,728
Webster	GA	0	0	0
Wheeler	GA	0	0	0
Wilcox	GA	0	0	0
Wilkinson	GA	1,680	1,421	3,101
Worth	GA	0	15	15
Totals		191,347	12,621	203,967

Table 7 drills down further into the data from Table 6. For commercial data in each county, the amount of biomass that is either landfilled or sold (or used internally) is presented by the type of material. Excluding data from the Georgia-Pacific plant in Jasper County, the major type of biomass available is mulch and dirty chips.

Table 7 Commercial biomass produced by type and county: (tons/mth)

County	State	Blocks		Clean Chips		Dried Chips		Engineered		Mixed		Mulch/ Dirty		Pallets		Roundwood		Sawdust		Co. Total	
		Sold	LF	Sold	LF	Sold	LF	Sold	LF	Sold	LF	Sold	LF	Sold	LF	Sold	LF	Sold	LF		
Baldwin	GA	0	0	1,562	0	0	0	0	0	0	8	873	0	0	0	0	0	0	173	0	2,616
Ben Hill	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bibb	GA	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1
Bleckley	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butts	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	440
Chattahoochee	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clayton	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coffee	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coweta	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crawford	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crisp	GA	0	0	80	0	0	0	0	0	1,400	208	0	0	0	0	0	0	0	0	10	1,698
Dodge	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dooly	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dougherty	GA	0	0	0	0	108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	108
Emanuel	GA	0	0	18,225	0	0	0	0	0	81	0	19,737	0	0	0	0	0	0	2,404	0	40,446
Fayette	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glascocock	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greene	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hancock	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Harris	GA	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	0	0	191	197
Henry	GA	0	0	0	0	0	0	0	0	0	5	0	170	0	0	0	0	0	0	29	204
Houston	GA	0	0	5	0	0	0	0	0	0	7,106	0	0	0	0	0	0	0	1	17	7,130
Irwin	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jasper	GA	0	0	1,227	0	0	0	0	0	109,700	0	0	0	1	0	0	0	0	0	0	110,928
Jeff Davis	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jefferson	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,940	2,940
Johnson	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jones	GA	0	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40
Lamar	GA	0	0	0	0	0	0	0	0	0	0	136	0	0	0	0	0	0	0	0	136
Laurens	GA	0	0	0	0	0	0	0	0	0	67	0	0	0	1	0	0	0	0	0	68
Lee	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Macon	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Marion	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Meriwether	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Monroe	GA	0	0	0	0	0	0	0	9,351	0	113	1,414	0	0	0	0	0	0	10,878	
Montgomery	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	104	0	104	
Morgan	GA	0	0	0	0	0	0	0	0	0	2,600	0	0	0	0	0	0	0	2,600	
Muscogee	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Newton	GA	0	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	285	301	
Peach	GA	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	4	
Pike	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	143	143	
Pulaski	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Putnam	GA	0	15	0	0	0	0	0	708	106	0	0	0	0	0	0	0	0	829	
Rockdale	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Schley	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Spalding	GA	0	3	0	0	0	0	0	149	0	0	159	0	0	0	0	0	23	333	
Stewart	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Sumter	GA	0	0	0	0	0	0	0	249	0	0	0	0	0	0	0	0	0	249	
Talbot	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Taliaferro	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Taylor	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Telfair	GA	0	0	1,446	0	0	0	0	0	0	0	0	0	0	0	0	0	642	330	
Terrell	GA	0	0	0	0	0	0	0	0	26	0	0	0	0	0	0	0	0	26	
Tift	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Toombs	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Treutlen	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Turner	GA	0	0	0	0	0	0	0	0	1,999	0	0	0	0	0	0	0	1,200	3,199	
Twiggs	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Upton	GA	0	0	6,448	0	0	0	0	0	0	2,176	0	0	0	0	0	0	1,429	10,053	
Walton	GA	0	0	0	0	34	0	0	0	0	0	0	0	0	0	0	0	0	34	
Warren	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Washington	GA	0	0	0	0	0	0	0	0	0	2,728	0	0	0	0	0	0	0	2,728	
Webster	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Wheeler	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Wilcox	GA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Wilkinson	GA	0	0	1,200	0	0	946	0	0	480	0	0	0	0	0	0	0	0	475	
Worth	GA	0	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	0	15	
Totals		0	58	30,194	0	143	946	0	1,106	123,123	7,455	28,363	1,743	1	1	0	0	9,523	1,312	203,967

Error! Not a valid link.

Figure 1 Total commercial biomass by type in study area (tons/mth)

Section 2: Landfill Biomass

All landfill biomass is categorized as either “Sold” or “Landfilled.” “Sold” refers to all biomass that is currently being processed by the landfill for redistribution. This designation can either imply the separation of clean wood waste for resell to another business or on-site processing of the wood waste into a usable mulch product. This mulch can be utilized by the landfill itself, given away to the public or sold.

“Landfilled” means the given biomass value is buried and not presently reused in any way. In these cases, a specific landfill is either very interested in reselling their accumulating biomass or not interested in separating wood waste from non-burnable biomass due to economical infeasibility.

Table 8 Number of landfills responding to inquiry

County	State	No Biomass	Have Biomass	1-100	101-400	400+	No Response	Positive Response	No. Contacted
Baldwin	GA	2	1	0	1	0	1	3	4
Ben Hill	GA	0	0	0	0	0	0	0	0
Bibb	GA	1	2	0	0	1	1	3	4
Bleckley	GA	1	0	0	0	0	1	1	2
Butts	GA	0	0	0	0	0	1	0	1
Chattahoochee	GA	2	1	0	0	1	0	3	3
Clayton	GA	2	0	0	0	0	1	2	3
Coffee	GA	1	1	0	1	0	2	2	4
Coweta	GA	0	0	0	0	0	1	0	1
Crawford	GA	3	1	0	1	0	2	4	6
Crisp	GA	2	0	0	0	0	1	2	3
Dodge	GA	0	1	0	1	0	1	1	2
Dooly	GA	0	0	0	0	0	0	0	0
Dougherty	GA	1	3	0	0	1	1	4	5
Emanuel	GA	0	1	0	0	1	1	1	2
Fayette	GA	1	0	0	0	0	1	1	2
Glascok	GA	0	0	0	0	0	1	0	1
Greene	GA	0	0	0	0	0	2	0	2
Hancock	GA	1	0	0	0	0	1	1	2
Harris	GA	0	1	1	0	0	1	1	2
Henry	GA	1	1	0	1	0	0	2	2
Houston	GA	0	2	0	0	1	1	2	3
Irwin	GA	1	1	1	0	0	1	2	3
Jasper	GA	0	1	1	0	0	0	1	1
Jeff Davis	GA	2	0	0	0	0	2	2	4
Jefferson	GA	0	1	1	0	0	1	1	2
Johnson	GA	2	0	0	0	0	2	2	4
Jones	GA	1	0	0	0	0	1	1	2
Lamar	GA	1	1	1	0	0	3	2	5
Laurens	GA	1	1	1	0	0	2	2	4
Lee	GA	0	1	1	0	0	1	1	2
Macon	GA	3	0	0	0	0	2	3	5
Marion	GA	0	1	0	0	1	1	1	2

Meriwether	GA	0	1	1	0	0	0	1	1
Monroe	GA	2	1	0	1	0	2	3	5
Montgomery	GA	3	0	0	0	0	2	3	5
Morgan	GA	1	1	0	1	0	2	2	4
Muscogee	GA	0	0	0	0	0	1	0	1
Newton	GA	0	1	0	0	1	2	1	3
Peach	GA	2	0	0	0	0	1	2	3
Pike	GA	1	0	0	0	0	0	1	1
Pulaski	GA	1	1	0	1	0	1	2	3
Putnam	GA	2	0	0	0	0	2	2	4
Rockdale	GA	0	0	0	0	0	1	0	1
Schley	GA	1	0	0	0	0	2	1	3
Spalding	GA	2	1	0	0	1	1	3	4
Stewart	GA	1	0	0	0	0	1	1	2
Sumter	GA	3	0	0	0	0	0	3	3
Talbot	GA	1	0	0	0	0	2	1	3
Taliaferro	GA	0	0	0	0	0	1	0	1
Taylor	GA	0	1	1	0	0	1	1	2
Telfair	GA	1	0	0	0	0	0	1	1
Terrell	GA	2	0	0	0	0	1	2	3
Tift	GA	1	1	0	0	1	1	2	3
Toombs	GA	2	1	0	1	0	1	3	4
Treutlen	GA	1	0	0	0	0	2	1	3
Turner	GA	1	3	0	1	0	1	4	5
Twiggs	GA	1	0	0	0	0	2	1	3
Upson	GA	0	1	0	0	1	1	1	2
Walton	GA	2	0	0	0	0	0	2	2
Warren	GA	1	0	0	0	0	1	1	2
Washington	GA	1	1	0	0	1	2	2	4
Webster	GA	0	0	0	0	0	2	0	2
Wheeler	GA	2	0	0	0	0	1	2	3
Wilcox	GA	1	0	0	0	0	1	1	2
Wilkinson	GA	1	0	0	0	0	2	1	3
Worth	GA	3	1	1	0	0	2	4	6
Totals		69	37	10	10	11	79	106	185

Of the 185 landfills that responded to the survey, they reported an almost equal amount of biomass that was currently being sold or used on site as was being permanently landfilled. It must be noted that data from some landfills is not strictly clean biomass as they were not always able to separate the inert concrete and rocks from the loads of wood waste. This inability to control incoming waste streams has most likely resulted in inflated numbers reported from the landfills. Although it might seem like a great deal of biomass could be available from a specific site, more detailed investigations of specific streams at individual facilities would need to be conducted toward a specific landfill's waste before making business decisions.

Table 9 Landfill biomass by county within the study area (tons/mth)

County	State	Sold	Landfilled	Total
Baldwin	GA	0	188	188
Ben Hill	GA	0	0	0
Bibb	GA	0	12,228	12,228
Bleckley	GA	0	0	0
Butts	GA	0	0	0
Chattahoochee	GA	0	940	940
Clayton	GA	0	0	0
Coffee	GA	394	0	394
Coweta	GA	0	0	0
Crawford	GA	0	132	132
Crisp	GA	0	0	0
Dodge	GA	0	193	193
Dooly	GA	0	0	0
Dougherty	GA	3,000	303	3,303
Emanuel	GA	0	413	413
Fayette	GA	0	0	0
Glascok	GA	0	0	0
Greene	GA	0	0	0
Hancock	GA	0	0	0
Harris	GA	0	41	41
Henry	GA	286	0	286
Houston	GA	0	1,260	1,260
Irwin	GA	0	37	37
Jasper	GA	0	80	80
Jeff Davis	GA	0	0	0
Jefferson	GA	99	0	99
Johnson	GA	0	0	0
Jones	GA	0	0	0
Lamar	GA	67	0	67
Laurens	GA	0	32	32
Lee	GA	43	0	43
Macon	GA	0	0	0
Marion	GA	1,600	0	1,600
Meriwether	GA	0	48	48
Monroe	GA	144	0	144
Montgomery	GA	0	0	0
Morgan	GA	0	200	200
Muscogee	GA	0	0	0
Newton	GA	417	0	417
Peach	GA	0	0	0
Pike	GA	0	0	0
Pulaski	GA	0	162	162
Putnam	GA	0	0	0
Rockdale	GA	0	0	0
Schley	GA	0	0	0
Spalding	GA	797	0	797
Stewart	GA	0	0	0
Sumter	GA	0	0	0
Talbot	GA	0	0	0
Taliaferro	GA	0	0	0
Taylor	GA	0	53	53
Telfair	GA	0	0	0
Terrell	GA	0	0	0
Tift	GA	0	1,000	1,000
Toombs	GA	0	400	400

Renewable Energy Options: RAFB

Appendices

Treutlen	GA	0	0	0
Turner	GA	42	85	127
Twiggs	GA	0	0	0
Upson	GA	514	0	514
Walton	GA	0	0	0
Warren	GA	0	0	0
Washington	GA	0	477	477
Webster	GA	0	0	0
Wheeler	GA	0	0	0
Wilcox	GA	0	0	0
Wilkinson	GA	0	0	0
Worth	GA	0	10	10
Total		7,402	18,283	25,684

Table 10 Amount of landfill biomass produced by type and county: (tons/mth)

County	State	Mixed		Clean Chips		County Total
		Sold	LF	Sold	LF	
Baldwin	GA	0	188	0	0	188
Ben Hill	GA	0	0	0	0	0
Bibb	GA	0	12,228	0	0	12,228
Bleckley	GA	0	0	0	0	0
Butts	GA	0	0	0	0	0
Chattahoochee	GA	0	940	0	0	940
Clayton	GA	0	0	0	0	0
Coffee	GA	394	0	0	0	394
Coweta	GA	0	0	0	0	0
Crawford	GA	0	132	0	0	132
Crisp	GA	0	0	0	0	0
Dodge	GA	0	0	0	193	193
Dooly	GA	0	0	0	0	0
Dougherty	GA	3,000	303	0	0	3,303
Emanuel	GA	0	413	0	0	413
Fayette	GA	0	0	0	0	0
Glascocock	GA	0	0	0	0	0
Greene	GA	0	0	0	0	0
Hancock	GA	0	0	0	0	0
Harris	GA	0	41	0	0	41
Henry	GA	286	0	0	0	286
Houston	GA	0	1,260	0	0	1,260
Irwin	GA	0	37	0	0	37
Jasper	GA	0	80	0	0	80
Jeff Davis	GA	0	0	0	0	0
Jefferson	GA	99	0	0	0	99
Johnson	GA	0	0	0	0	0
Jones	GA	0	0	0	0	0
Lamar	GA	67	0	0	0	67
Laurens	GA	0	32	0	0	32
Lee	GA	43	0	0	0	43
Macon	GA	0	0	0	0	0
Marion	GA	1,600	0	0	0	1,600
Meriwether	GA	0	48	0	0	48
Monroe	GA	144	0	0	0	144
Montgomery	GA	0	0	0	0	0
Morgan	GA	0	200	0	0	200
Muscogee	GA	0	0	0	0	0
Newton	GA	417	0	0	0	417
Peach	GA	0	0	0	0	0
Pike	GA	0	0	0	0	0
Pulaski	GA	0	162	0	0	162
Putnam	GA	0	0	0	0	0
Rockdale	GA	0	0	0	0	0
Schley	GA	0	0	0	0	0
Spalding	GA	797	0	0	0	797
Stewart	GA	0	0	0	0	0
Sumter	GA	0	0	0	0	0
Talbot	GA	0	0	0	0	0
Taliaferro	GA	0	0	0	0	0
Taylor	GA	0	53	0	0	53
Telfair	GA	0	0	0	0	0
Terrell	GA	0	0	0	0	0
Tift	GA	0	1,000	0	0	1,000

Toombs	GA	0	400	0	0	400
Treutlen	GA	0	0	0	0	0
Turner	GA	42	85	0	0	127
Twiggs	GA	0	0	0	0	0
Upson	GA	514	0	0	0	514
Walton	GA	0	0	0	0	0
Warren	GA	0	0	0	0	0
Washington	GA	0	477	0	0	477
Webster	GA	0	0	0	0	0
Wheeler	GA	0	0	0	0	0
Wilcox	GA	0	0	0	0	0
Wilkinson	GA	0	0	0	0	0
Worth	GA	0	10	0	0	10
TOTALS		7,402	18,090	0	193	25,684

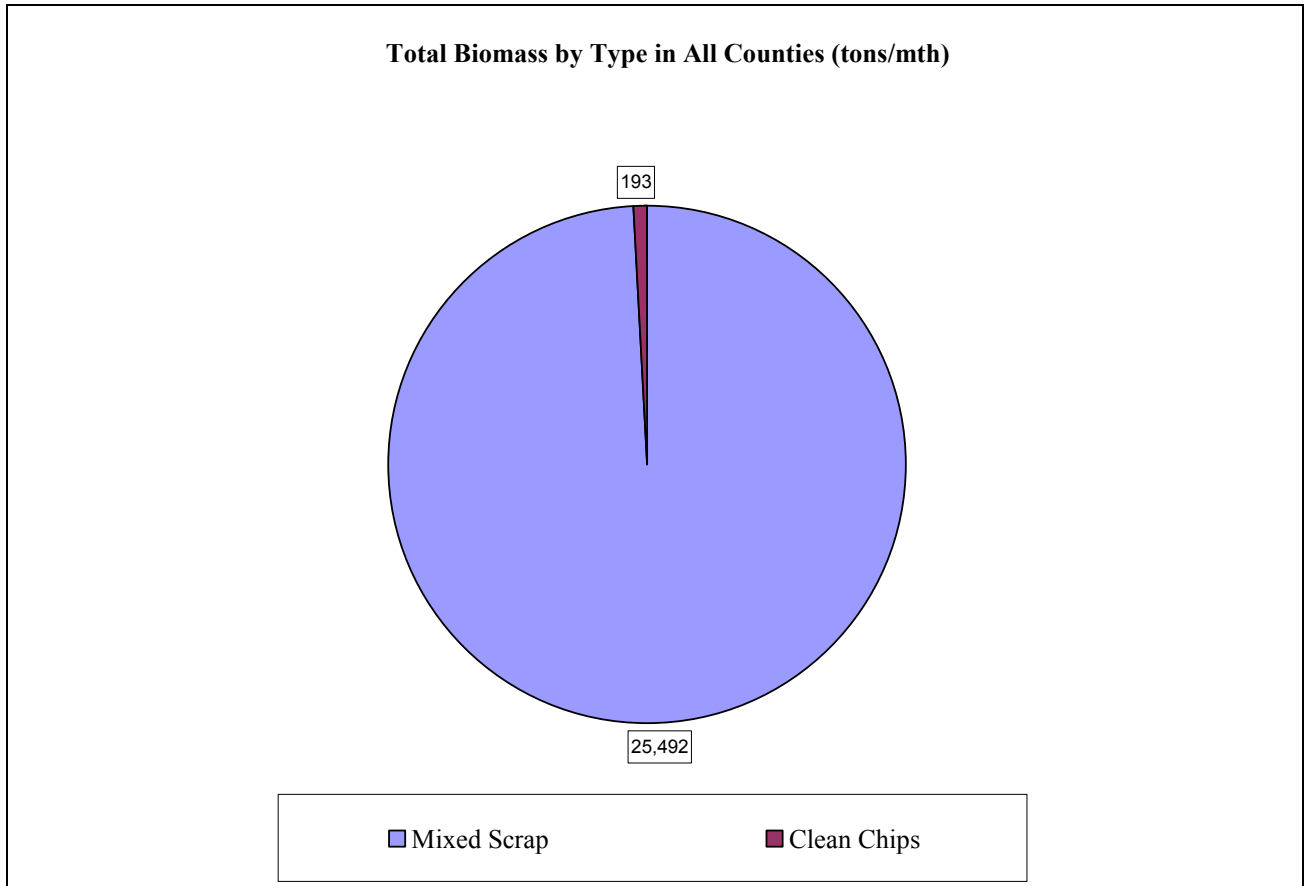


Figure 2 Total landfill biomass by type in study area (tons/mth)

Appendix A References

- Boatright, S.R. (editor) 2007. The Georgia County Guide. Center for Agribusiness and Economic Development, College of Agricultural and Environmental Sciences, University of Georgia, Athens, Ga.
- Dartnell, Devon. 2007. Personal Communication. Georgia Forestry Commission, Biomass Program Manager
- Energy Information Administration, Official Energy Statistics from the US Government, <http://tonto.eia.doe.gov/oog/info/gdu/gasdiesel.asp>
- Google Maps, 2007. <http://maps.google.com/>.
- Harris Infosource. <http://www.harrisinfo.com>. Business information and database services
- Heard, Chad. 2007. Personal Communication. Farmers Organic, Newton, GA.
- Kiepper, Dr. Brian. 2007. Personal Communication. Faculty of Engineering, University of Georgia, Athens, GA.
- Lamontagne, Dan. 2007. Personal Communication. Plum Creek. Macon, GA.
- Lockaby, Graeme. 2005 Personal Communication. Associate Dean of Research. School of Forestry. Auburn University, Auburn, AL.
- Merka, Dr. Bill. 2007. Personal Communication. Poultry Science Extension. University of Georgia, Athens, GA.
- McDonald, T. P., Stokes, B.J, and McNeel, J. F. Effect of Product Form, Compaction, Vibration and Comminution on Energywood Bulk Density. USDA Forest Service, Southern Forest Experiment Station, Auburn, AL
- Rynk, R. 1992. On-Farm Composting Handbook. Ithaca: Natural Resource, Agriculture, and Engineering Service. Document No. NRAES-54.
- Timber Mart South. 2006. Quarterly report of timber prices in the US South. 1st Quarter. Norris Foundation, Athens, Ga.
- Westbrook, M. D., Greene, W.D., and Izlar, R.L., 2006. Harvesting forest biomass by adding a small chipper to a ground-based tree length southern pine operation. Warnell School of Forestry & Natural Resources, University of Georgia, Athens, GA.

Figure 3 – Location of biomass generating companies

Table 10 – Companies that participated in study

Figure 4 – Landfills

Table 11 – Landfills that participated in study

Figure 3 Biomass generating companies

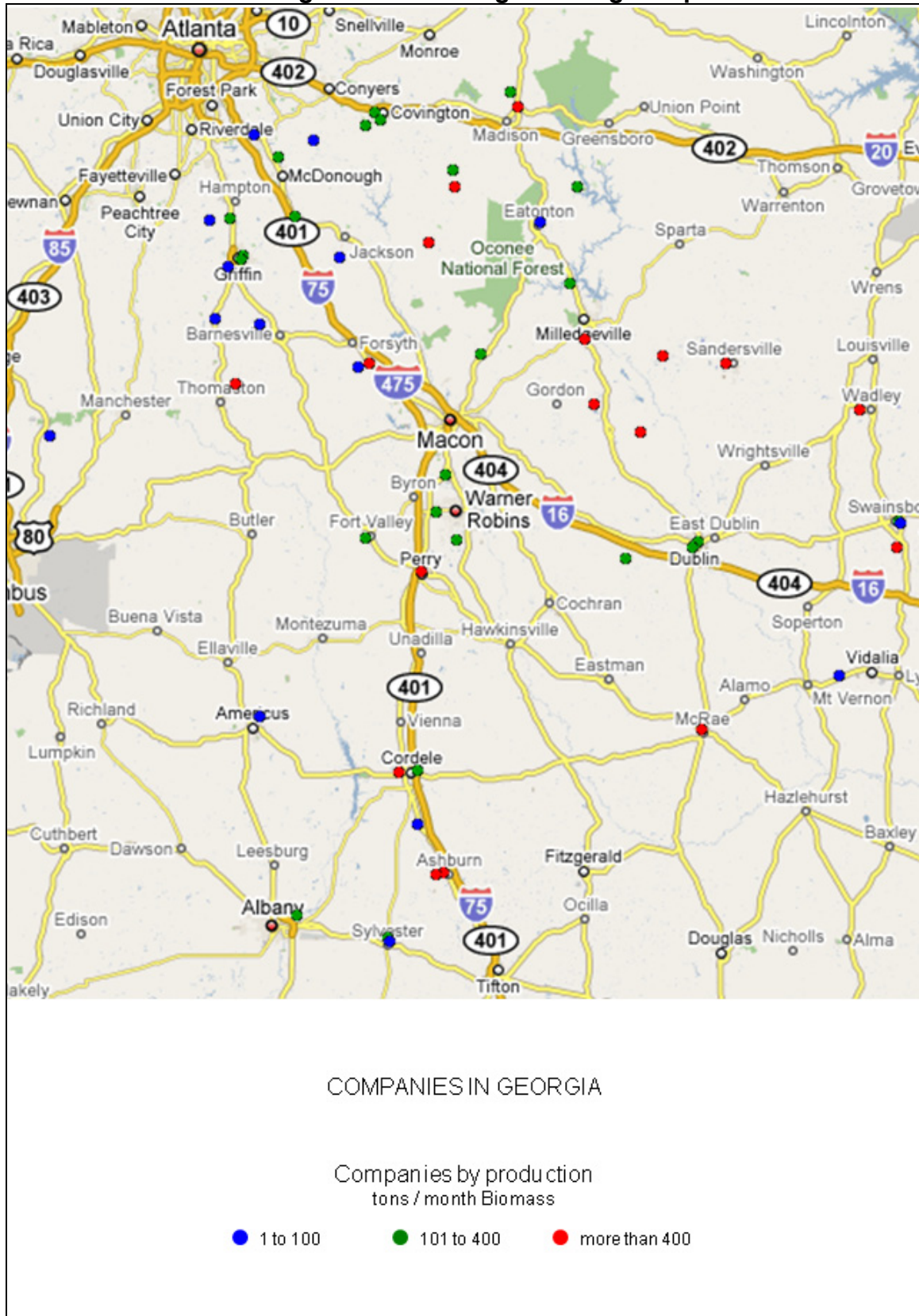


Table 11 Companies that participated in study

Company Name	Sold (tons)	LF (tons)	Total (tons)	Phone	City
American Door & Drawer Inc	80	0	80	478-289-9558	Swainsboro
American Testing Laboratories	0	163	163	706-485-7796	Eatonton
American Woodmark Corp	440	0	440	770-775-6013	Jackson
Authentic Pine Floors	0	29	29	770-957-6038	Locust Grove
Battle Lumber Co Inc	2,940	0	2,940	478-252-5210	Wadley
C and D Pallet Co	1	0	1	706-468-8116	Newborn
CAM Tree Service	0	109	109	770-460-8861	Griffin
Champion Lumber Co	1,227	0	1,227	706-468-6518	Shady Dale
Cleghorn Cabinets Inc	0	35	35	478-953-6996	Robins
Custom Cut Timber Products	113	0	113	478-994-0167	Forsyth
Darkotech Inc	0	26	26	229-883-0807	Albany
Dudley Cabinets Inc	0	66	66	478-676-3005	Dudley
Duffeys Cabinet Shop Inc	0	5	5	770-957-4022	McDonough
Dunns Tree Service	0	36	36	770-412-1022	Griffin
Erosion Tech	0	1,414	1,414	478 994-6009	Juliette
FCA Mfg Co	0	149	149	770-229-9355	Griffin
Forest Rayonier Resources LP	18,225	0	18,225	912-562-4441	Swainsboro
Forest Southern Industries Inc	9,351	0	9,351	478-994-0000	Smarr
Foy Insrd Tree Svc	35	0	35	706-342-7624	Madison
Fulghum Fibres Inc	2,728	0	2,728	478-552-9092	Sandersville
Georgia Norbord Inc	1,400	0	1,400	229-276-1734	Cordele
Georgia-Pacific Corp	109,700	0	109,700	706-468-8811	Monticello
Great Plains Residential Homes	0	15	15	229-777-7812	Sylvester
Gulf South Pole & Timber Company	1,200	0	1,200	229 567-9087	Ashburn
H V Thompson & T Lumber Co	104	0	104	912-583-2236	Ailey
HLS Enterprises	0	3	3	478-825-0007	Fort Valley
Hobby Shop	1	0	1	478-237-3698	Swainsboro
Horton Homes Inc	0	545	545	706-485-8506	Eatonton
International Paper Co	2,565	0	2,565	706-342-9700	Madison
Keadle Lumber Enterprises Inc	6,448	0	6,448	706-647-8981	Thomaston
Leggett & Platt Inc	0	1	1	478-274-9900	Dublin
Lumberjack Tree Service	0	170	170	770-389-8860	Stockbridge
M & W Pallet Co	0	65	65	478-929-2238	Bonaire
McDaniel Cabinet Co	1	0	1	478-781-8460	Macon
Nationwide Homes Inc	0	208	208	229-273-6150	Arabi
North American Container Corp	0	946	946	478-946-1400	Mc Intyre
Nova Cabinet Shop	0	8	8	478-452-5186	Milledgeville
Nova Cabinet Shop No II Inc	0	15	15	706-485-9924	Eatonton
Palco Industries Inc	0	143	143	770-567-8170	Zebulon
Rayonier, Inc.	136	0	136	770-358-6791	Barnesville
Reese Building Components Inc	108	0	108	229-435-6831	Sylvester
Roof Truss Co Inc	0	40	40	478-986-5234	Gray
S and S Woodcrafters	0	285	285	770-385-0556	Covington
Shamrock Custom Kitchens Inc	0	1	1	478-275-0392	Dublin
Smith Millwork Specialties Inc	0	8	8	678-625-5157	Covington
Southern Crates Co	191	0	191	706-628-5032	Pine MT
Spalding Truss Inc	0	3	3	770-229-9711	Sunny Side
Sylvan Hardwoods LLC	1,446	0	1,446	229-868-6436	Mc Rae
T & S Hardwoods, Inc.	873	0	873	478-454-3409	Milledgeville
T N T Custom Cabinets Inc	0	8	8	770-786-2122	Covington
Tatum Tree Service	0	0	0	770-228-0760	Griffin
Tolleson Lumber Co Inc	5	0	5	478-987-2105	Perry
Triwood Corp Of Georgia Inc	0	229	229	229-928-2233	Americus

rus Systems, Inc.	34	0	34	770-787-8715	Walnut Grove
Universal Forest Products - Eatonton	106	0	106	706-485-5952	Eatonton
Universal Forest Products Inc	1,999	0	1,999	229-567-3481	Ashburn
US Timber Co	80	0	80	229-276-0111	Cordele
Woody Lumber Co Inc	1,200	0	1,200	478-933-5312	Toombsboro

Figure 4 Landfills

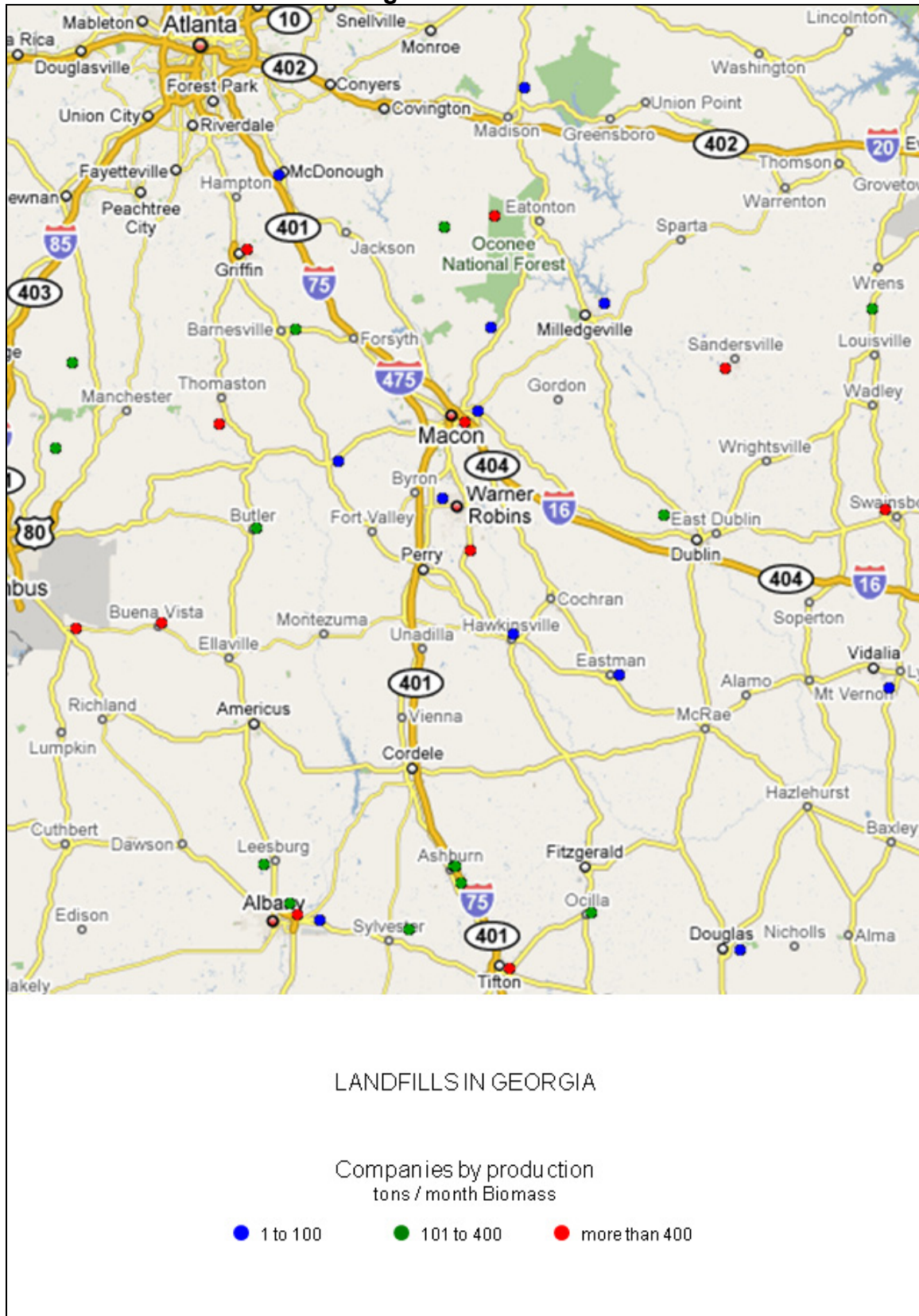


Table 12 Landfills that participated in study

Landfill Name	Owned	Type	Sold (tons)	LF (tons)	Total (tons)	Phone	City
A & R Inert Landfill, Attaway Waste Services	Private	Inert	0	188	188	478 453-4435	Milledgeville
Bibb County Inert Landfill	City/Cnty	Inert	0	12,000	12,000	478 751-9296	Macon
Southland Waste Systems	Private	Inert	0	228	228	478 746-7230	Macon
Chattahoochee County Inert Landfill	County	Inert	0	940	940	706 989-3422	Cusseta
OUTSIDE - City of Douglas Inert	City	Inert	394	0	394	912 389-3450	Douglas
Crawford County Inert Landfill	County	Inert	0	132	132	478 214-0710	Roberta
Dodge County Inert Landfill	County	Inert	0	193	193	478 374-4361	Eastman
Chehaw Wild Animal Park	County	Inert	0	3	3	229 407-0838	Albany
OUTSIDE - City of Albany Inert Landfill	City	Inert	3,000	0	3,000	229 435-4166	Albany
OUTSIDE - Maple Hill Landfill	Private	C&D/	0	300	300	229 903-8916	Albany
City of Swainsboro Inert Landfill	City	Inert	0	413	413	478 237-5078	Swainsboro
Harris County Inert Landfill	County	Inert	0	41	41	706 582-2982	Hamilton
Henry County Recycling Center	County	Inert	286	0	286	770 957-8073	McDonough
Davis Excavating And Grading Old Hawkinsville Rd. Inert Lf	Private	Inert	0	216	216	478 953-4918	Centerville
Houston Co - SR247 Klondike C/D Landfill	County	CD	0	1,044	1,044	478 987-0089	Kathleen
Irwin County	County	MSW	0	37	37	229 424-4028	Ocilla
Jasper County Inert Landfill	County	Inert	0	80	80	706 468-4917	Monticello
OUTSIDE - Jefferson County MSW/Inert Landfills	County	MSW	99	0	99	478 625-1221	Stapleton
Lamar County - Cedar Grove Regional Mswl	County	MSW	67	0	67	770 358-5215	Barnesville
Laurens County Inert Landfill	County	Inert	0	32	32	478 676-3963	Dublin
Lee County C&D/Inert Landfills	County	Inert	43	0	43	229 759-6009	Leesburg
Q & A Associates Inert Landfill	Private	Inert	1,600	0	1,600	229 649-7024	Buena Vista
Meriwether County Inert Landfill	County	Inert	0	48	48	706 672-0263	Greenville
Monroe County - Strickland Loop Rd	County	MSW	144	0	144	478 994-7291	Forsyth
Morgan County Inert Landfill	County	Inert	0	200	200	706 343-6447	Madison
Newton County - Lower River Rd Site #2 He Mswl	County	MSW	417	0	417	770 786-	Covington

						5808	
Hawkinsville Inert Landfill	City/Cnty	Inert	0	162	162	478 783-9250	Hawkinsville
City Of Griffin/Spalding County Inert Landfill	City/Cnty	Inert	797	0	797	770 229-6421	Griffin
Taylor County Inert Landfill	County	Inert	0	53	53	478 862-3336	Butler
OUTSIDE - City of Tifton Inert Landfill	City	Inert	0	1,000	1,000	229 391-3975	Tifton
OUTSIDE - Toombs County Inert Landfill	County	Inert	0	400	400	912 537-9966	Lyons
City Of Ashburn Inert Landfill	City	Inert	0	40	40	229 567-3431	Ashburn
City Of Sycamore Inert Landfill	City	Inert	42	0	42	229 567-4296	Sycamore
Turner County	County	MSW.	0	45	45	229 467-2737	Ashburn
Upson County Inert Landfill	County	Inert	514	0	514	706 647-8445	Thomaston
Washington County Landfills	County	Inert	0	477	477	478 553-0145	Tennille
Worth County Inert Landfill	County	Inert	0	10	10	229 776-8226	Poulan

Appendix B: Ethanol Production Facilities

(Source: Renewable Fuels Association)

U.S. FUEL ETHANOL INDUSTRY BIOREFINERIES AND PRODUCTION CAPACITY

Company	Location	Feedstock	Operating Capacity (mgy)	Expansion Capacity (mgy)	Under Construction Capacity (mgy)
Abengoa Bioenergy Corp. (Total)			168.0		176.0
 Abengoa Bioenergy Corp.	Madison, IL	corn			
 Abengoa Bioenergy Corp.	Mt. Vernon, IN	corn			
 Abengoa Bioenergy Corp.	Colwich, KS	corn/milo			
 Abengoa Bioenergy Corp.	Ravenna, NE	Corn			
 Abengoa Bioenergy Corp.	York, NE	Corn			
 Absolute Energy, LLC*	St. Ansgar, IA	Corn	100.0		
 ACE Ethanol, LLC	Stanley, WI	Corn	41.0		
 Adkins Energy, LLC*	Lena, IL	Corn	40.0		
 Advanced Bioenergy	Fairmont, NE	Corn	100.0		
 Ag Energy Resources, Inc.	Benton, IL	corn			5.0
 AGP*	Hastings, NE	Corn	52.0		
 Agri-Energy, LLC*	Luverne, MN	Corn	21.0		
 AI-Corn Clean Fuel*	Claremont, MN	Corn	42.0		
 Amaizing Energy, LLC*	Atlantic, IA	Corn			110.0
 Amaizing Energy, LLC*	Denison, IA	Corn	48.0		
Archer Daniels Midland (Total)			1,070.0	550.0	
 Archer Daniels Midland	Cedar Rapids, IA	Corn			
 Archer Daniels Midland	Clinton, IA	Corn			
 Archer Daniels Midland	Decatur, IL	Corn			
 Archer Daniels Midland	Peoria, IL	Corn			

Archer Daniels Midland	Marshall, MN	Corn			
Archer Daniels Midland	Wallhalla, ND	Corn/barley			
Archer Daniels Midland	Columbus, NE	Corn			
Arkalon Energy, LLC	Liberal, KS	Corn	110.0		
Aventine Renewable Energy, LLC (Total)			207.0		
Aventine Renewable Energy, LLC	Pekin, IL	Corn			
Aventine Renewable Energy, LLC	Aurora, NE	Corn			
Badger State Ethanol, LLC*	Monroe, WI	Corn	48.0		
Big River Resources, LLC*	West Burlington, IA	Corn	52.0		
BioEnergy International	Clearfield, PA	Corn			110.0
BioFuel Energy - Buffalo Lake Energy, LLC	Fairmont, MN	Corn	115.0		
BioFuel Energy - Pioneer Trail Energy, LLC	Wood River, NE	Corn	115.0		
Blue Flint Ethanol	Underwood, ND	Corn	50.0		
Bonanza Energy, LLC	Garden City, KS	Corn/milo	55.0		
Bunge-Ergon Vicksburg	Vicksburg, MS	corn	54.0		
Bushmills Ethanol, Inc.*	Atwater, MN	Corn	40.0		
Calgren Renewable Fuels, LLC	Pixley, CA	Corn			55.0
Cardinal Ethanol	Union City, IN	Corn	100.0		
Cargill, Inc.	Eddyville, IA	Corn	35.0		
Cargill, Inc.	Blair, NE	Corn	85.0		
Cascade Grain	Clatskanie, OR	Corn	108.0		
Castle Rock Renewable Fuels, LLC	Necedah, WI	Corn	50.0		
Center Ethanol Company	Sauget, IL	Corn	54.0		
Central Indiana Ethanol, LLC	Marion, IN	Corn	40.0		

 Central MN Ethanol Coop*	Little Falls, MN	Corn	21.5		
 Chief Ethanol	Hastings, NE	Corn	62.0		
 Chippewa Valley Ethanol Co.*	Benson, MN	Corn	45.0		
 Cilion Ethanol	Keyes, CA	Corn			50.0
 Clean Burn Fuels, LLC	Raeford, NC	Corn			60.0
 Commonwealth Agri-Energy, LLC*	Hopkinsville, KY	Corn	33.0		
 Corn Plus, LLP*	Winnebago, MN	Corn	44.0		
 Corn, LP*	Goldfield, IA	Corn	50.0		
 Cornhusker Energy Lexington, LLC	Lexington, NE	Corn	40.0		
 Coshocton Ethanol, OH	Coshocton, OH	Corn	60.0		
 Dakota Ethanol, LLC*	Wentworth, SD	Corn	50.0		
 DENCO, LLC	Morris, MN	Corn	21.5		
 Didion Ethanol	Cambria, WI	Corn	40.0		
 E Caruso (Goodland Energy Center)	Goodland, KS	Corn			20.0
 E Energy Adams, LLC	Adams, NE	Corn	50.0		
 East Kansas Agri-Energy, LLC*	Garnett, KS	Corn	35.0		
 Elkhorn Valley Ethanol, LLC	Norfolk, NE	Corn	40.0		
 ESE Alcohol Inc.	Leoti, KS	Seed corn	1.5		
 Ethanol Grain Processors, LLC	Obion, TN	Corn	100.0		
 Front Range Energy, LLC	Windsor, CO	Corn	40.0		
 Glacial Lakes Energy, LLC*	Watertown, SD	Corn	100.0		
 Global Ethanol/Midwest Grain Processors	Lakota, IA	Corn	95.0		
 Global Ethanol/Midwest Grain Processors	Riga, MI	Corn	57.0		
 Golden Cheese Company of California*	Corona, CA	Cheese whey	5.0		
 Golden Grain Energy, LLC*	Mason City, IA	Corn	110.0	50.0	









 Golden Triangle Energy, LLC*	Craig, MO	Corn	20.0		
 Grain Processing Corp.	Muscatine, IA	Corn	20.0		
 Granite Falls Energy, LLC*	Granite Falls, MN	Corn	52.0		
 Greater Ohio Ethanol, LLC	Lima, OH	Corn	54.0		
 Green Plains Renewable Energy	Shenandoah, IA	Corn	50.0		
 Green Plains Renewable Energy	Superior, IA	Corn	50.0		
 Hawkeye Renewables, LLC	Fairbank, IA	Corn	115.0		
 Hawkeye Renewables, LLC	Iowa Falls, IA	Corn	105.0		
 Hawkeye Renewables, LLC	Menlo, IA	Corn	110.0		
 Hawkeye Renewables, LLC	Shell Rock, IA	Corn	110.0		
 Heartland Corn Products*	Winthrop, MN	Corn	100.0		
 Heartland Grain Fuels, LP*	Aberdeen, SD	Corn	9.0		
 Heartland Grain Fuels, LP*	Huron, SD	Corn	12.0	18.0	
 Heron Lake BioEnergy, LLC	Heron Lake, MN	Corn	50.0		
 Homeland Energy	New Hampton, IA	Corn			100.0
 Husker Ag, LLC*	Plainview, NE	Corn	26.5		
 Idaho Ethanol Processing	Caldwell, ID	Potato Waste	4.0		
 Illinois River Energy, LLC	Rochelle, IL	Corn	50.0		
 Indiana Bio-Energy	Bluffton, IN	Corn	101.0		
 Iroquois Bio-Energy Company, LLC	Rensselaer, IN	corn	40.0		
 KAAPA Ethanol, LLC*	Minden, NE	Corn	40.0		
 Kansas Ethanol, LLC	Lyons, KS	Corn	55.0		
 KL Process Design Group	Upton, WY	Wood waste	1.5		
 Land O' Lakes*	Melrose, MN	Cheese whey	2.6		
 Levelland/Hockley County Ethanol, LLC	Levelland, TX	Corn	40.0		

 Lifeline Foods, LLC	St. Joseph, MO	Corn	40.0		
 Lincolnland Agri-Energy, LLC*	Palestine, IL	Corn	48.0		
 Lincolnway Energy, LLC*	Nevada, IA	Corn	50.0		
 Little Sioux Corn Processors, LP*	Marcus, IA	Corn	52.0		
 Marquis Energy, LLC	Hennepin, IL	Corn	100.0		
 Marysville Ethanol, LLC	Marysville, MI	Corn	50.0		
 Merrick & Company	Aurora, CO	Waste beer	3.0		
 MGP Ingredients, Inc.	Pekin, IL	Corn/wheat starch	78.0		
 MGP Ingredients, Inc.	Atchison, KS				
 Mid America Agri Products/Horizon	Cambridge, NE	Corn	44.0		
 Mid America Agri Products/Wheatland	Madrid, NE	Corn	44.0		
 Mid-Missouri Energy, Inc.*	Malta Bend, MO	Corn	45.0		
 Midwest Renewable Energy, LLC	Sutherland, NE	Corn	25.0		
 Minnesota Energy*	Buffalo Lake, MN	Corn	18.0		
 NEDAK Ethanol	Atkinson, NE	Corn			44.0
 New Energy Corp.	South Bend, IN	Corn	102.0		
 North Country Ethanol, LLC*	Rosholt, SD	Corn	20.0		
 Northeast Biofuels	Volney, NY	Corn	114.0		
 Northwest Renewable, LLC	Longview, WA	Corn			55.0
 Otter Tail Ag Enterprises	Fergus Falls, MN	Corn	57.5		
 Pacific Ethanol	Madera, CA	Corn	40.0		
 Pacific Ethanol	Stockton, CA	Corn	60.0		
 Pacific Ethanol	Burley, ID	Corn	50.0		
 Pacific Ethanol	Boardman, OR	Corn	40.0		
 Panda Ethanol	Hereford, TX	Corn/milo			115.0
 Parallel Products	Rancho Cucamonga, CA				
 Parallel Products	Louisville, KY	Beverage waste	5.4		

 Patriot Renewable Fuels, LLC	Annawan, IL	Corn	100.0		
 Penford Products	Cedar Rapids, IA	Corn	45.0		
 Phoenix Biofuels	Goshen, CA	Corn	31.5		
 Pinal Energy, LLC	Maricopa, AZ	Corn	55.0		
 Pine Lake Corn Processors, LLC*	Steamboat Rock, IA	Corn	20.0		
 Platinum Ethanol, LLC*	Arthur, IA	Corn			110.0
 Plymouth Ethanol, LLC*	Merrill, IA	Corn			50.0
 POET Biorefining - Alexandria	Alexandria, IN	Corn	68.0		
 POET Biorefining - Ashton	Ashton, IA	Corn	56.0		
 POET Biorefining - Big Stone	Big Stone City, SD	Corn	79.0		
 POET Biorefining - Bingham Lake	Bingham Lake, MN		35.0		
 POET Biorefining - Caro	Caro, MI	Corn	53.0		
 POET Biorefining - Chancellor	Chancellor, SD	Corn	110.0		
 POET Biorefining - Coon Rapids	Coon Rapids, IA	Corn	52.0		
 POET Biorefining - Corning	Corning, IA	Corn	65.0		
 POET Biorefining - Emmetsburg	Emmetsburg, IA	Corn	55.0		
 POET Biorefining - Fostoria	Fostoria, OH	Corn	68.0		
 POET Biorefining - Glenville	Albert Lea, MN	Corn	42.0		
 POET Biorefining - Gowrie	Gowrie, IA	Corn	69.0		
 POET Biorefining - Hanlontown	Hanlontown, IA	Corn	56.0		
 POET Biorefining - Hudson	Hudson, SD	Corn	56.0		
 POET Biorefining - Jewell	Jewell, IA	Corn	69.0		
 POET Biorefining - Laddonia	Laddonia, MO	Corn	50.0		
 POET Biorefining - Lake Crystal	Lake Crystal, MN	Corn	56.0		
 POET Biorefining - Leipsic	Leipsic, OH	Corn	68.0		

Leipsic						
	POET Biorefining - Macon	Macon, MO	Corn	46.0		
	POET Biorefining - Marion	Marion, OH	Corn			65.0
	POET Biorefining - Mitchell	Mitchell, SD	Corn	68.0		
	POET Biorefining - North Manchester	North Manchester, IN	Corn	68.0		
	POET Biorefining - Portland	Portland, IN	Corn	68.0		
	POET Biorefining - Preston	Preston, MN	Corn	46.0		
	POET Biorefining - Scotland	Scotland, SD	Corn	11.0		
	POET Biorefining- Groton	Groton, SD	Corn	53.0		
	Prairie Horizon Agri-Energy, LLC	Phillipsburg, KS	Corn	40.0		
	Quad-County Corn Processors*	Galva, IA	Corn	27.0		
	Range Fuels	Soperton, GA	Wood waste			20.0
	Red Trail Energy, LLC	Richardton, ND	Corn	50.0		
	Redfield Energy, LLC *	Redfield, SD	Corn	50.0		
	Reeve Agri-Energy	Garden City, KS	Corn/milo	12.0		
	Renew Energy	Jefferson Junction, WI	Corn	130.0		
	Renova Energy	Torrington, WY	Corn	5.0		
	Riverland Biofuels	Canton, IL	corn	37.0		
	Show Me Ethanol	Carrollton, MO	Corn	55.0		
	Siouxland Energy & Livestock Coop*	Sioux Center, IA	Corn	60.0		
	Siouxland Ethanol, LLC	Jackson, NE	Corn	50.0		
	Southwest Georgia Ethanol, LLC	Mitchell Co., GA	Corn	100.0		
	Southwest Iowa Renewable Energy, LLC *	Council Bluffs, IA	Corn			110.0
	Sterling Ethanol, LLC	Sterling, CO	Corn	42.0		
	Tate & Lyle	Ft. Dodge, IA	Corn			105.0
	Tate & Lyle	Loudon, TN	Corn	67.0	38.0	

 Tharaldson Ethanol	Casselton, ND	Corn				110.0
 The Andersons Albion Ethanol LLC	Albion, MI	Corn	55.0			
 The Andersons Clymers Ethanol, LLC	Clymers, IN	Corn	110.0			
 The Andersons Marathon Ethanol, LLC	Greenville, OH	Corn	110.0			
 Trenton Agri Products, LLC	Trenton, NE	Corn	40.0			
 United Ethanol	Milton, WI	Corn	52.0			
 United WI Grain Producers, LLC*	Friesland, WI	Corn	49.0			
 Utica Energy, LLC	Oshkosh, WI	Corn	48.0			
VeraSun Energy Corporation (Total)			1,310.0			110.0
 VeraSun Energy Corporation	Albert City, IA	Corn				
 VeraSun Energy Corporation	Charles City, IA	Corn				
 VeraSun Energy Corporation	Ft. Dodge, IA	Corn				
 VeraSun Energy Corporation	Hartley, IA	Corn				
 VeraSun Energy Corporation	Linden, IN	Corn				
 VeraSun Energy Corporation	Lake Odessa, MI	Corn				
 VeraSun Energy Corporation	Welcome, MN	Corn				
 VeraSun Energy Corporation	Hankinson, ND	Corn				
 VeraSun Energy Corporation	Albion, NE	Corn				
 VeraSun Energy Corporation	Central City, NE	Corn				
 VeraSun Energy Corporation	Ord, NE	Corn				
 VeraSun Energy Corporation	Bloomington, OH	Corn				
 VeraSun Energy Corporation	Aurora, SD	Corn				
 VeraSun Energy Corporation	Marion, SD	Corn				
 Verenium	Jennings, LA	Sugar Cane bagasse	1.5			
 Western New York	Shelby, NY		50.0			

Energy LLC					
 Western Plains Energy, LLC*	Campus, KS	Corn	45.0		
 Western Wisconsin Renewable Energy, LLC*	Boyceville, WI	Corn	40.0		
 White Energy	Russell, KS	Milo/wheat starch	48.0		
 White Energy	Hereford, TX	Corn/Milo	100.0		
 White Energy	Plainview, TX	Corn	100.0		
 Wind Gap Farms	Baconton, GA	Brewery waste	0.4		
 Xethanol BioFuels, LLC	Blairstown, IA	Corn	5.0		
 Yuma Ethanol	Yuma, CO	Corn	40.0		
TOTALS			11,051.4	656.0	1,580.0
			mgy for	mgy for	mgy for
			180	expanding	21
			operating	refineries	refineries under
			refineries		construction

* locally owned

Last updated: December 4, 2008

HISTORIC U.S. FUEL ETHANOL PRODUCTION

[back to top](#)

Year	Millions of Gallons
1980	175
1981	215
1982	350
1983	375
1984	430
1985	610
1986	710
1987	830
1988	845
1989	870
1990	900
1991	950
1992	1,100
1993	1,200

1994	1,350
1995	1,400
1996	1,100
1997	1,300
1998	1,400
1999	1,470
2000	1,630
2001	1,770
2002	2,130
2003	2,800
2004	3,400
2005	3,904
2006	4,855
2007	6,500

ETHANOL INDUSTRY OVERVIEW

[back to top](#)

Year	January 1999	January 2000	January 2001	January 2002	January 2003	January 2004	January 2005	January 2006	January 2007
Total Ethanol Plants	50	54	56	61	68	72	81	95	110
Ethanol Production Capacity	1701.7 mgy	1748.7 mgy	1921.9 mgy	2347.3 mgy	2706.8 mgy	3100.8 mgy	3643.7 mgy	4336.4 mgy	5493.4 mgy
Plants Under Construction/Expanding	5	6	5	13	11	15	16	31	76
Capacity Under Construction/Expanding	77 mgy	91.5 mgy	64.7 mgy	390.7 mgy	483 mgy	598 mgy	754 mgy	1778 mgy	5635.5 mgy
Farmer Owned Plants	14	18	21	25	28	33	40	46	46
Farmer Owned Capacity	293.3 mgy	340.3 mgy	473 mgy	645.6 mgy	796.6 mgy	1041.1 mgy	1388.6 mgy	1677.1 mgy	1677.1 mgy
% of Total Cap Farmer	17%	19%	25%	28%	29%	34%	38%	39%	39%
Farmer Owned UC Plants/Expanding	5	3	3	10	8	12	10	4	4
Farmer Owned UC Capacity	77 mgy	60 mgy	60 mgy	335 mgy	318 mgy	447	450 mgy	187 mgy	187 mgy
% of Total UC Capacity	100%	66%	71%	86%	66%	75%	60%	11%	11%
States with Ethanol Plants	17	17	18	19	20	19	18	20	21

2008 MONTHLY U.S. FUEL ETHANOL PRODUCTION/DEMAND

[back to top](#)

Month	Production, b/d (1000s)	Production (1000 barrels)	Stocks (1000 barrels)	Stocks: days in reserve	Production (1000 gal)	Imports (1000 gal)*	Exports (1000 gal)^	Stocks change (1000 gal)	Demand (1000 gal)	Demand, b/d (1000s)
Jan	510	15818	10674	20.5	664356	20677	0	6930	678103	521
Feb	518	15025	10465	18.6	631050	21371	0	-8778	661199	562
Mar	561	17387	11391	20.1	730254	21498	0	38892	712860	566
Apr	562	16868	11539	19.3	708456	49378	0	6216	751,618	597
May	598	18543	12044	19.6	778806	44169	0	21210	801,765	616
Jun	585	17544	12304	19.4	736848	71828	0	10920	797756	633
Jul	614	19042	13186	20.8	799764	64334	0	37044	827054	635
Aug	647	20059	14882	22.5	842478	89788	0	71232	861034	661
Sep	640	19197	15994	23.2	806274	107535	0	46704	867105	688
Oct										
Nov										
Dec										
Ave.	581.7	17720.3	12497.7		744254	54508.7			773166	608.8

2007 Monthly U.S. Fuel Ethanol Production/Demand

Month	Production, b/d (1000s)	Production (1000 barrels)	Stocks (1000 barrels)	Stocks: days in reserve	Production (1000 gal)	Imports (1000 gal)*	Exports (1000 gal)^	Stocks change (1000 gal)	Demand (1000 gal)	Demand, b/d (1000s)
Jan	375	11621	8593	20.8	488082	44433	0	-6468	538983	414
Feb	386	10795	8749	21.0	453390	42824	0	6552	489662	416
Mar	384	11892	8529	20.6	499464	30398	0	-9240	539102	414
Apr	391	11716	8791	21.5	492072	35304	0	11004	516372	410
May	406	12573	8950	21.0	528066	34532	0	6678	555920	427
Jun	418	12553	9067	20.5	527226	36005	0	4914	558317	443
Jul	421	13051	9696	21.7	548142	59028	0	26418	580752	446
Aug	434	13458	10309	22.2	565236	66416	0	25746	605906	465
Sep	441	13222	11509	27.3	555324	26593	0	50400	531517	422
Oct	452	14018	11423	23.6	588756	37343	0	-3612	629711	484
Nov	479	14356	11194	22.5	602592	13374	0	-9618	625944	497
Dec	489	15161	10509	20.3	636762	8929	0	-28770	674461	518
Totals		154416			6485472	435179			6846647	
Ave.	423	12868			540456	36265			570554	446

2006 Monthly U.S. Fuel Ethanol Production/Demand

Month	Production, b/d (1000s)	Production (1000 barrels)	Stocks (1000 barrels)	Stocks: days in reserve	Production (1000 gal)	Imports (1000 gal)*	Exports (1000 gal)^	Stocks change (1000 gal)	Demand (1000 gal)	Demand, b/d (1000s)
Jan	288	8942	6173	21.4	375564	2687	0	25620	352631	271
Feb	302	8452	7376	24.4	354984	25578	0	50526	330036	281
Mar	301	9338	8708	28.9	392196	28586	0	55944	364838	280
Apr	289	8656	9087	31.4	363552	32620	0	15918	380254	302
May	293	9093	7848	26.8	381906	20291	0	-52038	454235	349
Jun	318	9532	6731	21.2	400344	50812	0	-46914	498070	395
Jul	316	9804	7727	24.5	411768	98180	0	41832	468116	360
Aug	329	10185	9160	27.8	427770	133188	0	60186	500772	385
Sep	333	9992	9727	29.2	419664	82466	0	23815	478315	380
Oct	333	10308	9814	29.5	432936	79202	0	3654	580484	391
Nov	343	10279	9212	26.9	431718	64517	0	-25284	521519	414
Dec	356	11023	8747	24.6	462966	37561	0	-19530	520147	399
Totals	3801	115604			4855368	653304			5377417	4205
Ave.	317	9634			404614	54648			448118	350

b/d = barrels/day

*Source: International Trade Commission

^Jim Jordan and Associates

U.S. FUEL ETHANOL DEMAND (MILLIONS OF GALLONS)

[back to top](#)

	2002	2003	2004	2005	2006	2007
U.S. Production	2,130	2,800	3,400	3,904	4,855	6,500
Imports	46	61	161	135.0	653.3	450
Exports	n/a	n/a	n/a	7.99	n/a	n/a
Stocks Change	-91	39	-31	-17.98	108.1	
Demand	2,085	2,900	3,530	4,048.9	5,377.4	

Source: RFA, International Trade Commission, Jim Jordan & Associates

2007 WORLD FUEL ETHANOL PRODUCTION

Country	Millions of Gallons
USA	6498.6
Brazil	5019.2
European Union	570.3
China	486.0

Canada	211.3
Thailand	79.2
Colombia	74.9
India	52.8
Central America	39.6
Australia	26.4
Turkey	15.8
Pakistan	9.2
Peru	7.9
Argentina	5.2
Paraguay	4.7
Total	13,101.7

Source: F.O. Licht

**ANNUAL WORLD ETHANOL PRODUCTION BY COUNTRY
(MILLIONS OF GALLONS, ALL ETHANOL GRADES)**

[back to top](#)

Country	2004	2005	2006
Brazil	3,989	4,227	4,491
U.S.	3,535	4,264	4,855
China	964	1,004	1,017
India	462	449	502
France	219	240	251
Russia	198	198	171
South Africa	110	103	102
U.K.	106	92	74
Saudi Arabia	79	32	52
Spain	79	93	122
Thailand	74	79	93
Germany	71	114	202
Ukraine	66	65	71
Canada	61	61	153
Poland	53	58	66
Indonesia	44	45	45
Argentina	42	44	45
Italy	40	40	43
Australia	33	33	39
Japan	31	30	30
Pakistan	26	24	24
Sweden	26	29	30
Philippines	22	22	22
South Korea	22	17	16
Guatemala	17	17	21
Cuba	16	12	12
Ecuador	12	14	12
Mexico	9	12	13
Nicaragua	8	7	8
Mauritius	6	3	2

Zimbabwe	6	5	7
Kenya	3	4	5
Swaziland	3	3	5
Others	338	710	270
Total	10,770	12,150	13,489

Source: F.O. Licht

U.S. FUEL ETHANOL IMPORTS BY COUNTRY (MILLIONS OF GALLONS)

[back to top](#)

Country	2002	2003	2004	2005	2006	2007
Brazil	0	0	90.3	31.2	433.7	188.8
Costa Rica	12	14.7	25.4	33.4	35.9	39.3
El Salvador	4.5	6.9	5.7	23.7	38.5	73.3
Jamaica	29	39.3	36.6	36.3	66.8	75.2
Trinidad & Tobago	0	0	0	10.0	24.8	42.7
Canada						5.4
China						4.5
Total	45.5	60.9	159.9	135.0	653.3	426.2

Source: International Trade Commission

Appendix C: Supporting Figures for Section 4.1

Mill Location & Wood Usage in Georgia

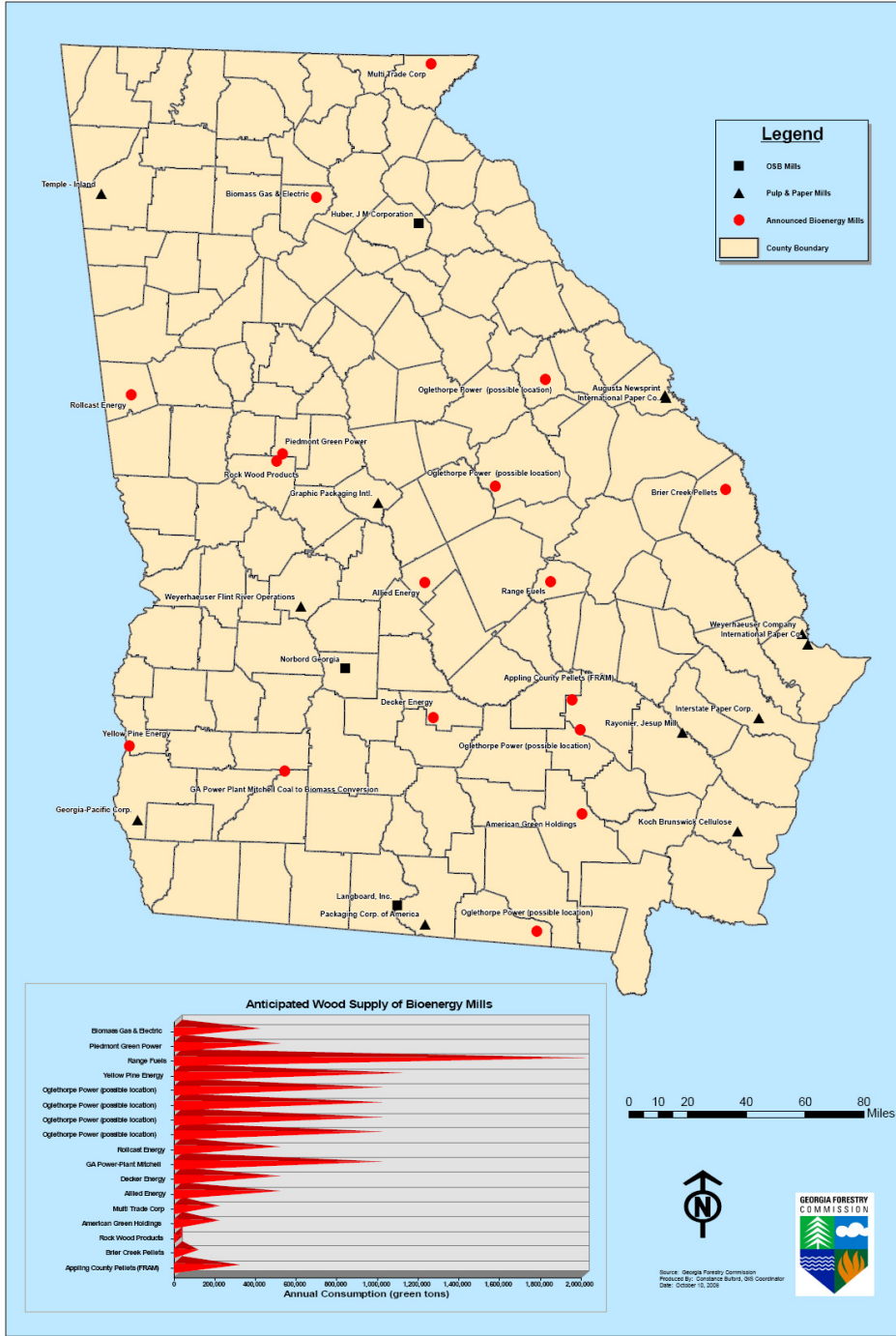


Figure C-1: Locations of Mills in Georgia and Wood Supply

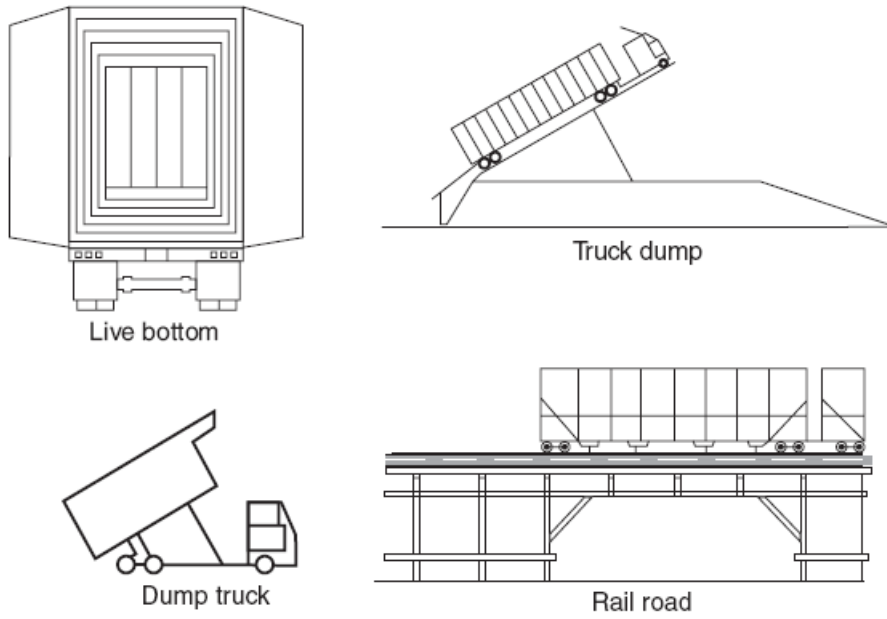


Figure C-4 Unloading Systems

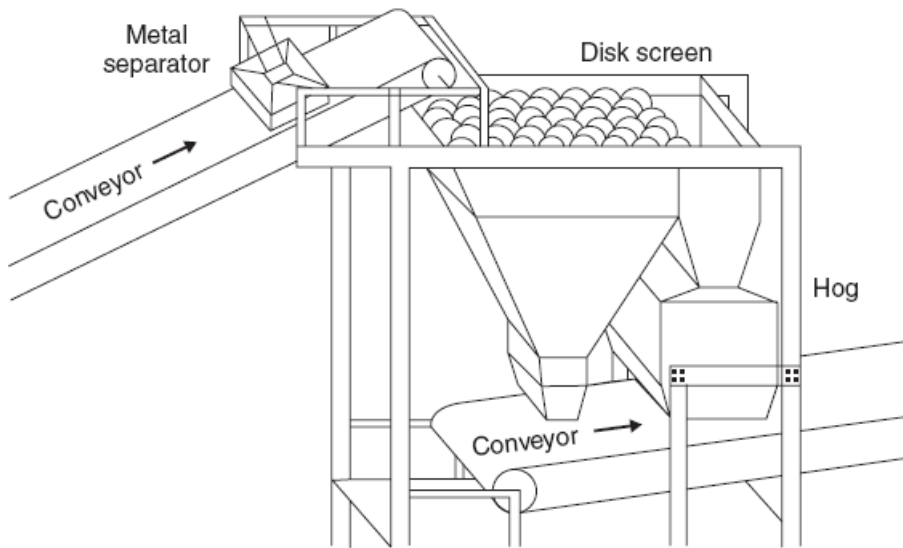


Figure C-5 Disk Screen System