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Combined Heat and Power Potential using Texas Agricultural Wastes

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Executive Summary

As one of the nation's leading agricultural states, Texas produces significant agricultural waste volumes that are a potentially valuable energy resource. Agricultural wastes produced during the harvesting or mill processing of many crops and agricultural goods can be used as fuel for waste-to-energy facilities. Waste-to-energy plants convert agricultural waste streams into biogas or steam using direct combustion, anaerobic digestion, or gasification technologies. Biofuels produced in this way can be used in reciprocating engines, or in steam or gas turbines to generate electricity and thermal energy needed by rural energy consumers. Where possible, the capture and use of thermal energy along with electricity production, so called combined heat and power (CHP) solution, offers the greatest efficiency and improves project feasibility.

This study examines opportunities to develop waste-to-energy projects using the following agricultural wastes available in the state:

- Beef Cattle Manure
- Beef Cattle Processing Waste
- Cotton Gin Trash
- Corn Stover
- Dairy Cow Manure
- Hog Manure
- Peanut Shells
- Poultry Manure
- Poultry Processing Waste
- Rice Hulls
- Sugarcane Bagasse
- Wheat Straw

Waste-to-energy facilities can be located at the farm or mill where the wastes are created or they can be located at other facilities with higher energy needs, provided those facilities are nearby. Where sufficient fuel is available to support development of small systems suitable for individual farms, ranches, mills, or processing plants, transportation costs to relocate the waste is avoided. In a number of areas with concentrated agricultural operations, potential exists to transport and combine waste streams to support larger waste-to-energy facilities. In evaluating the potential for waste-to-energy facility development, this report considers both resource availability and the need for energy (especially thermal energy) at the location where wastes are produced. Technical and economic considerations are taken into account to estimate waste resources available for waste-to-energy facilities. The methodology and data used to estimate quantity availability is described in detail in the report.

Study Results

The study found cattle manure is the single best agricultural waste resource for waste-to-energy facilities. Assuming only 15% of the manure can be collected, cattle manure amounts to about one-third of the state’s waste-to-energy potential. Major crops, including cotton, corn, and wheat, create substantial wastes with great energy potential, although seasonality and geographical distribution limit the suitability of these resources in small, on-farm systems. The top five waste streams analyzed create over 80% of the energy potential. Energy production estimates for waste-to-energy facilities fueled with the twelve agricultural waste resources analyzed in the report are shown in Table 2-1.

Estimated Waste-to-Energy Facility Outputs Using Texas Agricultural Wastes

Statewide Overview	Gross Electrical Capacity (MW)	Net Electrical Capacity (MW)	Gross Electrical Energy (MWh/yr)	Net Electrical Energy (MWh/yr)	Gross Heat Produced (MMBtu/yr)	Net Heat Recoverable (MMBtu/yr)
Beef Cattle Manure	150.8	96.2	1,254,827	800,672	9,400,601	4,512,289
Cotton Gin Trash	218.3	152.8	605,593	423,915	12,275,146	5,892,070
Corn Stover	64.5	45.1	536,440	375,508	11,850,747	5,688,359
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Notes: Net numbers reflect output after parasitic loads needed to operate the waste-to-energy facilities are met.

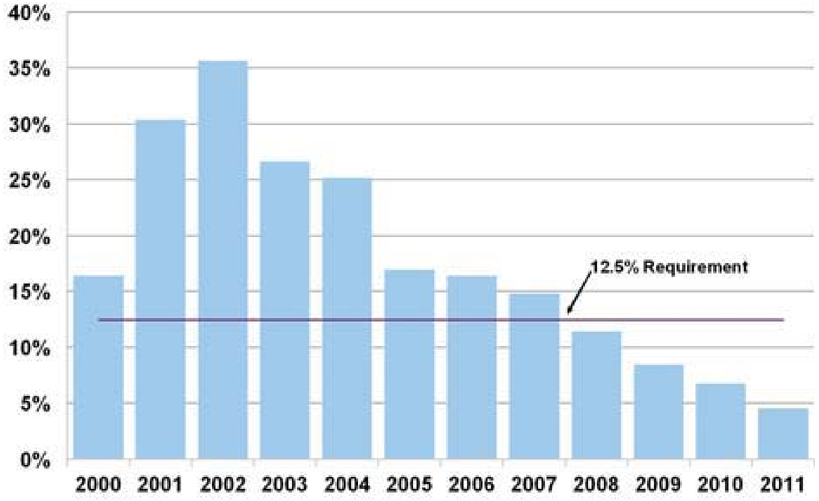
Sufficient agricultural wastes exist to produce an estimated 3.9 million MWh of electrical energy each year using waste-to-energy plants. After powering new equipment needed for the waste-to-energy plant, a net 2.6 million MWh is estimated to be available to meet existing energy needs at the host site or for export to the electrical grid. In full year operation, waste-to-energy plants could provide an estimated 620 MW of electrical capacity, although this capacity would increase to nearly 900 MW if the facilities are operated for only 12 hours per day or well over 1200 MW if operations are limited to week days. Taking parasitic loads needed to operate the waste-to-energy plant into account, net capacity additions are estimated to be between 420 to 830 MW. Waste-to-energy plants could also provide an estimated 52.9 million MMBtu of thermal energy to host facilities, although anticipated heat recovery losses would reduce the amount of useful heat available to host facilities to an estimated 25.4 million MMBtu. Locating waste-to-energy plants at host sites with suitable thermal loads would help ensure the greatest possible economic use of the recovered thermal energy.

Waste-to-energy plants designed with the flexibility to use multiple waste streams could help overcome resource seasonality and volume issues. A number of examples are discussed where modest transportation of wastes could substantially improve the outlook for waste-to-energy plant development. In particular, poultry litter and processing plants could benefit, as would certain locations in the Panhandle, where for example, cotton gin trash, wheat straw, cattle manure, peanut shells, and beef rendering wastes are all available in relatively close proximity. In addition, locating waste-to-energy facilities at or near an existing processing or industrial plant requiring steam or thermal energy would increase project viability. These factors suggest that low transportation costs could be instrumental in achieving greater amounts of the existing waste-to-energy potential in the state.

1.0 Introduction

Rapid economic growth is driving increased demand for energy in all sectors of the Texas economy. Nowhere is this more important than in the Texas electricity market, where demand is beginning to surpass supplies. As shown in Figure 1-1, electric generating reserve margins are anticipated to fall below the minimum 12.5% requirement in 2008. The acute need for new electricity generating capacity is coming at a time when prices for traditional fossil fuel resources are at unprecedented highs, when concerns over the environmental impacts of energy production and use are mounting, and when threats to national security are increasing the desire to utilize domestic sources. As a result, power plants fueled with biomass resources are receiving more attention, especially because the construction of dirty coal power plants is increasingly seen as unappealing.

Figure 1-1: Reserve Margin Forecast in Texas

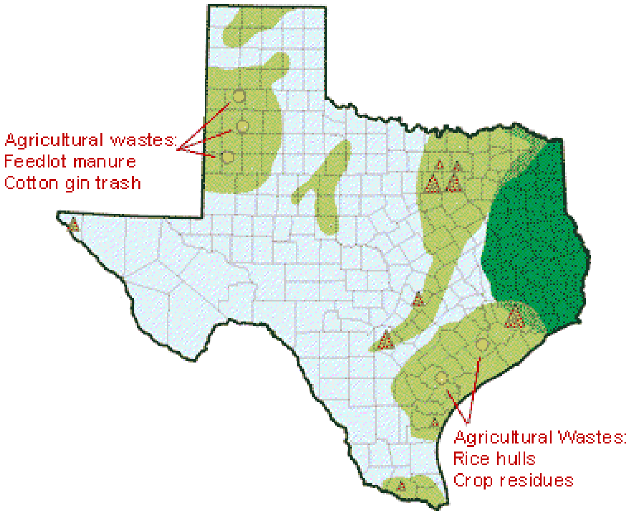


Source: Electric Reliability Council of Texas (ERCOT)

The state took significant steps towards addressing these issues in 1999 when the Legislature established a renewable portfolio standard (RPS). The Texas RPS calls for a total of 5,880 MW of new renewable energy capacity installed by 2015 and requires at least 500 MW of this total to come from resources other than wind.(DSIRE, 2007) Currently, Texas leads the country in wind power with 3,953 MW of installed capacity and another 1,358 MW under construction. (AWEA, 2007) As a consequence of the RPS, all retail electric providers (REPs) in the state are required today to obtain renewable energy credits (RECs) for each MWh of renewable electrical energy mandated to be sold in the state. Because REPS cannot own generation under the Texas deregulation statues, REPs must purchase RECs from renewable energy system owner, thereby creating a market for the tradable security. Because of the changing energy supply equation and the RPS mandate in Texas, an intense interest in renewable energy resources has taken hold in Texas in the past few years, at least in so far as electricity is concerned.

The 500 MW of non-wind capacity mandated by the state's RPS provides a significant opportunity to many alternative energy sources including energy derived from biomass materials. Biomass resources are created from a wide variety of activities including agricultural operations, forestry operations, and from urban industries including municipal solid waste disposal, wastewater treatment, and other activities that generate organic waste streams. The general location and sources of major biomass waste streams are shown in Figure 1-2.

Figure 1-2: Map of Texas's Biomass Resources



▨ **Agricultural Sources**	🟩 **Forest Sources**	▲ **Urban Sources**
• Field and harvest residues	• Logging Residues	• Municipal Solid Waste
• Mill process wastes	• Lumber Mill Residues	• Wastewater Treatment
• Animal manure	• Pulp & Paper Wastes	• Landfill Gas
• Meat processing wastes	• Forest Thinning Wastes	• Construction debris
• Energy crops	• Woody Energy Crops	• Used Cooking Oils

Because biomass resources are considered renewable under the state's RPS rules, owners of biomass fueled energy generation projects can take advantage of the state's REC trading program producing credits Biomass fueled electricity generation projects are eligible to produce tradable RECs for all electricity generated and for the amount of thermal energy captured and used to offset loads that would otherwise be served by the electrical grid. This is good news for those with substantial biomass resources, such as farmers, livestock producers, and processing mills.

This report is solely focused on the potential to produce energy from existing agricultural wastes. The report does not consider energy crops specifically grown and harvested for their energy content. The report does not analyze the potential opportunities to generate energy from either forest or urban sources. In addition, the report does not evaluate the resource potential or development opportunities that might exist at secondary food processing plants making consumer products including, for example, breweries, salsa producers, and canning operations, or from food distribution points such as grocery stores, farmers markets, and restaurants.

Agricultural Biomass Resources

As one of the nation's leading agricultural states, Texas produces significant agricultural waste volumes that are potentially valuable sources of energy. Major field crop waste streams include corn stover, grain sorghum residues, wheat straw, while major animal waste streams include the poultry industry and beef cattle production. Based on general criteria needed for waste-to-energy system project viability, twelve agricultural waste streams were chosen for further analysis. Table 1 provides a list of the crop and animal wastes streams evaluated in this report.

Because these resources are low cost or free to the farmer or operator generating the waste, and in some cases, their use can avoid a tipping fee for disposal, all of these resources have some potential to support waste-to-energy biomass systems. However, viable projects require a stable and sufficient supply of reasonably high quality wastes located on-site or in close proximity. The general likelihood of project success depends on the geographical distribution, seasonality, and volume of the resource. Resource available at a grain or processing mill are typically provide greater stability and are available in higher volumes than crop residues remaining on the field. Similarly, animal wastes produced in confined operations or processing plants are better suited for waste-to-energy plants than are widely dispersed resources that are hard to collect.

Most waste-to-energy projects require a minimum volume of at least 10,000 dry tons per year, although some small projects can potentially be developed with less resource, provided that the resource is available throughout the year. A number of agricultural waste resources such as grape pomace, sunflower seed hulls, pecan hulls, soybean hulls, and hog processing wastes were not considered to be good candidates for waste-to-energy plants. While projects could potentially be developed using these wastes on an opportunistic basis or where these resources contribute a portion of the total fuel, they are not considered in the report.

Manure from egg-laying chickens is not included in the report. Even though it was determined to be a substantial resource, the industry is thought to be too dispersed to allow effective aggregation of the manure. Grain sorghum residues are also not included in the study, as insufficient data was found to support the analytical approach. The use of these and other resources are certainly feasibility, but need to be considered on a case by case basis.

Table 1-1: Major Agricultural Waste Streams in Texas

Product	Primary Geographic Locations of Resource by Agricultural District	Resource Production	Unit	Waste Resource	Waste Quantity (dry tons)
Beef Cattle	South Central, Blacklands, East Texas North, East Texas South, Cross Timbers, Upper Coast, Edwards Plateau, South Texas, Northern High Plains, Northern Low Plains, Southern Low Plains, Trans-Pecos, Southern High Plains	13,800,000	head	**Manure**	1,951,515
Cotton	Southern High Plains, Northern High Plains, Coastal Bend	1,659,484	tons	**Trash**	1,495,670
Corn	Northern High Plains and the Blacklands	7,227,676	tons	**Stover**	1,249,961
Wheat	Northern High Plains, Blacklands, Southern Low Plains, Northern Low Plains, Cross Timbers, Southern High Plains, Edwards Plateau	2,755,452	tons	**Straw**	619,977
Beef Meat	South Central, South East Texas, Blacklands	3,774,400	tons	**Processing Waste**	261,151
Broilers	East Texas North, East Texas South, South Central, Blacklands, Cross Timbers	592,450,000	bird	**Manure (Litter)**	347,116
Poultry Meat	North East Texas, South East Texas, South Central	1,184,900	tons	**Processing Waste**	84,614
Dairy Cattle	Cross Timbers, East Texas North, Blacklands, Northern High Plains	327,500	head	**Manure**	603,179
Rice	South Central and Upper Coast	698,100	tons	**Hulls**	275,422
Hogs	Northern High Plains, South Central, East Texas North	933,333	head	**Manure**	153,300
Sugarcane	Lower Rio Grande Valley	1,701,667	tons	**Bagasse**	280,775
Peanuts	Southern High Plains, Northern Low Plains, South Texas	415,508	tons	**Shells**	73,429

Note: Please see Appendix A for map of Texas's agricultural districts

Table 1-1 provides a list of crop and animal wastes streams included in the report along with the assumed technologies used to analyze the energy potential of each waste resource. Each resource has a number of different technology options for converting the waste into useful energy and using that energy to generate electricity and heat. In this report, direct combustion and anaerobic digestion are analyzed, although other technologies including gasification and fermentation could be feasible also.

Table 1-2: List of Selected Biomass Resources

Waste Resource	Conversion Technology	Prime Mover Technology
Beef Cattle Manure	Anaerobic digestion	Recip. Engine
Cotton Gin Trash	Direct combustion	Steam Turbine
Corn Stover	Direct combustion	Steam Turbine
Wheat Straw	Direct combustion	Steam Turbine
Beef Meat Processing Waste	Anaerobic digestion	Recip. Engine
Broiler Manure	Anaerobic digestion	Recip. Engine
Poultry Processing Waste	Anaerobic digestion	Recip. Engine
Dairy Cattle Manure	Anaerobic digestion	Recip. Engine
Rice Hulls	Direct combustion	Steam Turbine
Hog Manure	Anaerobic digestion	Recip. Engine
Sugarcane Bagasse	Direct combustion	Steam Turbine
Peanut Shells	Direct combustion	Steam Turbine

Biomass Waste-to-Energy Systems

Converting agricultural waste streams into useful energy involves a three-step process. In the first step, the biomass must be prepared for the energy conversion process. While this step is highly dependent on the waste stream and approach, drying, grinding, separating, and similar operations are common. In addition, the host facility will need material handling systems, storage, metering, and prep-yard systems and handling equipment. (EPA, 2007) In the second step, the biomass waste stream must be converted into a useful biogas fuel or into steam. Finally, the biogas or steam is fed into a prime mover to generate useful electricity and heat.

The moisture content of the resource is a primary factor used to select a waste to fuel conversion technology. Three major technology options are available for such systems including:

- Anaerobic digestion – used for high moisture content (>50%) resources
- Direct combustion – used for low to medium moisture content (10% - 50%) resources
- Gasification – used for low moisture content (<10%) resources

Anaerobic digestion and gasification produce biogas similar to natural gas, but with a Btu content about 60% as much as standard natural gas (i.e., 600 Btu/cf compared to 1000 Btu/cf for natural gas). In most cases, biogas can be used directly in a prime mover like a reciprocating engine or gas turbine, or it can simply be combusted in a boiler to produce steam. In some cases where the starting resource is particularly contaminated, like municipal waste water treatment plants, the resulting biogas must be cleaned before it can be supplied to the prime mover, but this is rare in agricultural settings. More information on conversion technologies is provided in Table 1-3.

Table 1-3: Comparison of Conversion Technologies

Technology	Conversion Process Type	Major Biomass Feedstock	Energy or Fuel Produced
Anaerobic Digestion	Biochemical (anaerobic)	• Wet manure and litter • Animal processing wastes • Wet crop residues	Biogas
Direct Combustion	Thermochemical	• Field and crop wastes • Mill wastes • Dry manure	Steam
Gasification	Thermochemical	• Field and crop wastes • Mill wastes • Chicken litter	Hydrogen-rich Syngas

Source: *http://www.oregon.gov/ENERGY/RENEW/Biomass/BiomassHome.shtml#chart*

Direct combustion of the resource can be accomplished in a conventional boiler to produce high pressure steam. A steam turbine is used to generate electricity and drop the steam pressure for use in the facility. The back pressure steam turbine can be used if the facility has a need for high pressure steam, or a condensing steam turbine can be used where the thermal loads are primarily low pressure steam or hot water. As shown in Table 1-4, alternatives to the use of steam turbines are available, but for most agricultural operations, steam turbines provide low technology risk at attractive price points.

Table 1-4 identifies the major biomass conversion technologies, their commercial status and the associated prime mover technologies anticipated in many agricultural operations. Additional information about energy systems available for waste-to-energy conversion and prime movers for distributed generation of electricity is provided in Appendices B and C.

On-site Energy Production and Use

On-site energy production is concerned primarily with the opportunities to develop projects at the site where waste streams are generated, be it an individual farm, ranch, mill or processing plant. Individual projects would be engineered and sized for specific conditions of an actual operation, including both the size of the waste stream and the electrical and thermal demands of the operations.

In this study, projects are assumed to have the following general characteristics:

- Little or no transportation to relocate or aggregate waste streams (except as noted)
- Sized appropriate to the waste stream anticipated at an "average" operation
- Storage of agricultural wastes was assumed to be minimal
- Operated as a combined heat and power plant for high overall energy efficiency

In cases where a sufficient thermal load could not be identified on-site, aggregation of similar or dissimilar wastes at a centralized facility, especially one that has high thermal demand, may be possible. Examining the opportunities for aggregation is beyond the scope of this study, although the subject is mentioned in a number of the write ups for individual resources. While aggregation may improve the economic feasibility of developing waste-to-energy projects, it would not in itself impact the total amount of energy available to the state in agricultural waste streams.

Transportation

Transporting fuel to a power plant is a routine aspect of project operations. Because a number of low moisture fuels can be readily collected and transported to a centralized biomass plant location or aggregated to enhance project size, this opportunity should be evaluated on a case-by-case basis. This study evaluates the opportunity to develop biomass waste-to-energy plants at the location where the bulk of the agricultural waste stream is generated, without bearing the additional cost of transporting waste streams.

By downplaying the potential to transport and aggregate agricultural wastes, the analysis focuses on opportunities to develop smaller projects sized for the available resource as it is produced. While some potentially economical projects are overlooked by this process, smaller systems are in many cases a better match to the seasonal thermal needs of agricultural operations. Effective capture and use of thermal energy at the site for hot water, steam, and even chilled water needs raises the energy efficiency of the project, thereby improving the value of the waste-to-energy project.

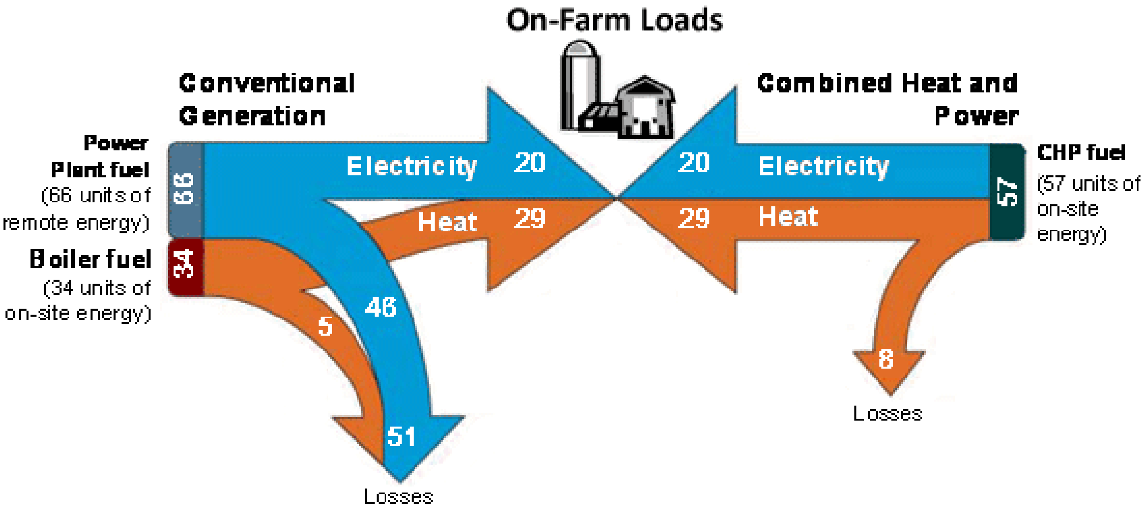
Regarding livestock operations, a direct link exists between feeding operations and meat processing plants. Typically, processing plants are centrally located to a number of feeding operations to reduce transportation costs involved in marketing mature animals. Thus, the manure waste stream and the residual parts generated at the processing plant may be in sufficiently close proximity to allow effective transportation of one to the other. Presumably, this would entail the transport of manure from a multitude of feeding operations to a single processing plant. This has the added advantage of placing the energy system at the processing plant where thermal energy can be most effectively utilized.

Project Size and Storage Potential

Agricultural operations databases compiled by federal, state, and private sources provide information aggregated by county or agricultural zone. Total agricultural production and waste stream calculation is not provided by individual farm, ranch, or mill location. To arrive at an estimate for wastes available at individual sites, a simple average was determined by dividing the waste stream flow by the number of characteristic operations involved in that activity. The size of the waste-to-energy plant was determined by estimating the largest unit that could be accommodated by the waste stream during the peak season. The storage of agricultural wastes was assumed to be limited, but not necessarily zero. Some storage would provide additional operational flexibility

Understanding the amount of the available waste stream and its seasonality is important to estimating the size of a potential energy project and the number of operating hours that the resource can sustain. In cases where the resource is seasonal, the system can be operated on a seasonal basis when waste is available, or, if warranted, it can be operated on an alternative biomass resource or natural gas during the off-season. Similarly, the system can be operated only during day light hours when the energy is most needed, thereby extending the operating season or increasing the capacity of the project.

Figure 1-3: Diagram of CHP Energy-Savings



Combined Heat and Power

The concept of capturing and using the thermal energy created by an electrical generator is termed combined heat and power (CHP). Compared to conventional energy supply, which involves the purchase of natural gas and electricity from separate utilities, the CHP approach is nearly twice as efficient. As shown in Figure 1-3, conventional generation requires a total of 189 units of energy to meet the same loads that a CHP system can meet with 100 units of fuel. The use of CHP systems in agricultural operations ensures that the maximum amount of work is accomplished with the waste resources. In cases where the energy resource is required to operate during part of the year on natural gas, the use of CHP ensures the most efficient use of that fuel.

Table 1-4. Commercialization Status of Biomass Conversion Systems for Power and Heat Generation

Energy Conversion Technology	Conversion Technology Commercialization Status	Integrated CHP Technology (Prime Mover)	Prime Mover Commercialization Status
Anaerobic Digestion			
Anaerobic digester	Commercial technology	Internal combustion engine	Commercial technology
		Microturbine	Commercial technology
		Gas turbine	Commercial technology
		Fuel cell	Commercial introduction
		Stirling engine	Emerging
Direct Combustion—Boilers			
Fixed bed boilers (stoker)	Commercial technology – Stoker boilers have long been a standard technology for biomass as well as coal, and are offered by a number of manufacturers.	Steam turbine	Commercial technology
Fluidized bed boilers	Commercial technology – Until recently fluidized bed boiler use has been more widespread in Europe than the United States. Fluidized bed boilers are a newer technology, but are commercially available through a number of manufacturers, many of whom are European-based.		
Cofiring	Commercial technology – Cofiring biomass with coal has been successful in a wide range of boiler types including cyclone, stoker, pulverized coal, and bubbling and circulating fluidized bed boilers.		
Modular* direct combustion technology	Commercial technology – Small boiler systems commercially available for space heating. A small number of demonstration projects in CHP configuration.	Small steam turbine	Commercial technology
		Organic Rankine cycle	Emerging technology – Some “commercial” products available.
		"Entropic" cycle	Research and development (R&D) status

		Hot air turbine	R&D status
Energy Conversion Technology	**Conversion Technology Commercialization Status**	**Integrated CHP Technology (Prime Mover)**	**Prime Mover Commercialization Status**
Gasification			
Fixed bed gasifiers	Emerging technology – The actual number of biomass gasification systems in operation worldwide is unknown, but is estimated to be below 25. A review of gasifier manufacturers in Europe, USA, and Canada identified 50 manufacturers offering commercial gasification plants from which 75 percent of the designs were fixed bed; 20 percent of the designs were fluidized bed systems.	Gas turbines – simple cycle	Prime movers have been commercially proven with natural gas and some medium heating value biogas. Operation on low heating value biogas and the effects of impurities on prime mover reliability and longevity need to be demonstrated.
Fluidized bed gasifiers		Gas turbines – combined cycle	
		Large internal combustion (IC) engines	
Modular* gasification technology	Emerging technology – A small number of demonstration projects supported with research, design, and development funding.	IC Engine	Commercial technology – But operation on very low heating value biogas needs to be demonstrated.
		Microturbine	
		Fuel cell	Commercial introduction
		Stirling engine	Emerging technology
Modular* hybrid gasification/combustion	Emerging technology – limited commercial demonstration	Small steam turbine	Commercial technology – But integrated system emerging

*Small, packaged, pre-engineered systems (smaller than 5 MW).

Source: U.S. EPA, Combined Heat and Power Partnership, Biomass Combined Heat and Power Catalog of Technologies, Sept. 2007, page 5-6.

2.0 Waste-to-energy Opportunities in Texas Agriculture

This report evaluates twelve waste resources existing in the state that have potential to support waste-to-energy projects and provides an indication of the types and scale of energy projects that could be supported by each resource. This report is not a comprehensive inventory of all biomass resources that may be suitable for waste-to-energy projects. Most agricultural operations that treat waste streams as byproducts deliver some economical value to the owner. Indeed, most biomass resources are currently used in some way today. These uses can include the development of niche products for sale (peanut shells used as industrial absorbents), casual uses for sale (rice hulls used for chicken coop bedding), and uses that don't involve a sale (wheat straw used on the farm to reduce soil erosion). This report does not consider whether energy production is the best use for any given waste resource.

A summary of the results are provided in Table 2-1.

Table 2-1: CHP System Outputs Estimated Using Texas Agricultural Wastes

Statewide Overview	Gross Electrical Capacity (MW)	Net Electrical Capacity (MW)	Gross Electrical Energy (MWh/yr)	Net Electrical Energy (MWh/yr)	Gross Heat Produced (MMBtu/yr)	Net Heat Recoverable (MMBtu/yr)
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Notes: Net numbers reflect output after parasitic loads needed to operate the waste-to-energy facilities are met.

Of the resources analyzed, cattle manure is the single best resource in the state. Even assuming only 15% of the manure can be collected, cattle manure amounts to about one-third of the state's waste-to-energy potential. Major crops including cotton, corn, and wheat create substantial wastes with great energy potential, although seasonality and geographical distribution limit the suitability of these resources in small, on-farm systems. The top five waste streams create over 80% of the energy potential.

Sufficient agricultural wastes exist to produce an estimated 3.9 million MWh of electrical energy each year using waste-to-energy plants. After powering new equipment needed for the waste-to-energy plant, a net 2.6 million MWh is estimated to be available to meet existing energy needs at the host site or for export to the electrical grid. In full year operation, waste-to-energy plants could provide an estimated 620 MW of electrical capacity, although this capacity would increase to nearly 900 MW if the facilities are operated for only 12 hours per day or well over 1200 MW if operations are limited to week days. Taking parasitic loads needed to operate the waste-to-energy plant into account, net capacity additions are estimated to be between 420 to 830 MW. Waste-to-energy plants could also provide an estimated 52.9 million MMBtu of thermal energy to host facilities, although anticipated heat recovery losses would reduce the amount of useful heat available to host facilities to an estimated 25.4 million MMBtu. Locating waste-to-energy plants at host sites with suitable thermal loads would help ensure the greatest possible economic use of the recovered thermal energy.

Waste-to-energy plants designed with the flexibility to use multiple waste streams could help overcome resource seasonality and volume issues. A number of examples are discussed where modest transportation of wastes could substantially improve the outlook for waste-to-energy plant development. In particular, poultry litter and processing plants could benefit, as would certain locations in the Panhandle, where for example, cotton gin trash, wheat straw, cattle manure, peanut shells, and beef rendering wastes are all available in relatively close proximity. In addition, locating waste-to-energy facilities at or near an existing processing or industrial plant requiring steam or thermal energy would increase project viability. These factors suggest that low transportation costs could be instrumental in achieving greater amounts of the existing waste-to-energy potential in the state.

2.1 Beef Cattle Industry

Beef cattle production is a very large industry in Texas and also a very large energy opportunity. Some 14.1 million head of cattle or 15% of the U.S. total are raised in Texas annually (TCFA, 2006), and the world's largest commercial cattle feeding operations are located in the Texas Panhandle.

Resource Characterization

Cattle feedlots are run year round, so the manure resource is stable and therefore can support waste-to-energy projects throughout the year. Manure collected quickly at the feedlot is high in moisture content, and will lose moisture content if not used quickly. Wet manure is best suited for anaerobic digestion, while dry manure is best suited for direct combustion or gasification technology. As shown in the table below, available cattle manure with an energy content of 7,416 Btu per pound can supply 28,944,870 MMBtu of gross energy.

Table 2-2 Cattle Manure Waste Stream

Resource	Resource Quantity (dry tons)	Energy Content (Btu/lb)	Gross Energy (MMBtu)
Cattle Manure	1,951,515	7,416	28,944,870

CHP Potential

As a potential opportunity fuel, beef cattle manure represents an excellent opportunity for CHP system development in Texas, especially in confined feedlots where the manure is highly concentrated and easily gathered. The best opportunity for waste-to-energy systems is at cattle feedlots with at least 1,000 head of capacity due to the high volumes of manure produced in a small area, which facilitates waste collection. In Texas, these large feedlots are found in 66 counties, with the largest concentration found in Castro, Deaf Smith, Parmer and Dallam counties. According to 2006 statistics from USDA, there were a total of 130,000 beef cattle feedlots in Texas; about 800 of these operations contained more than 500 head of cattle. (NASS, 2007)

Based on 2006 data from NASS, only about 10% of the Texas beef cattle are raised in this type of environment. Because most cattle feedlots in Texas have operating capacities less than 1,000 head or tend to graze animals in open fields, the amount of manure that can be collected is limited. Consequently, the anticipated collection rate for cattle manure is 15.6% statewide.

Even at this low rate, cattle manure is still a substantial resource in the state and it is concentrated operations predominantly located in the Panhandle region. Assuming that all of the recovered resource is used in waste-to-energy CHP plants, sufficient resource exists to produce nearly 150 MW of electrical capacity, which could generate some 1.25 million MWh annually. If waste heat recovery was built into these systems, an additional 9.4 million MMBtu of thermal energy would be produced, of which about 48% could be readily captured and used to meet local thermal needs.

However, because the waste is widely distributed among cattle ranches throughout the state, CHP development would likely be possible only at large animal feeding operations having over 1,000 head of cattle. In these operations, manure is produced in confined areas, facilitating collection efforts. The vast majority of the manure can be collected at the facility and fed into an anaerobic digester to convert the manure to a low Btu biogas suitable for combustion in a small reciprocating engine.

Similar to dairy farm manure, the development of larger and more economically viable systems could be promoted if nearby ranches and cattle operations aggregated manure resources at a centralized facility, especially one having a substantial thermal load. In fact, this is exactly what is being done at an ethanol plant being built in Hereford, Texas, This plant, which is using cattle manure as a primary fuel for the plant, will be the largest biomass fueled ethanol plant in the United States.[1] With local feed yards within 50 miles of Hereford plant generating 2.1 million tons of manure annually or four times the amount needed to fuel the facility, the plant has a stable fuel supply. (Panda, 2007) By using a renewable fuel (cattle

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[1] The Hereford plant will use gasification technology to generate the steam used in the ethanol manufacturing process. In the bubbling fluidized-bed gasifier employed at the plant, cattle manure is introduced into a bubbling sand bed which is maintained at a relatively low temperature. As the heat accelerates the decomposition of the manure, the organic material releases a hydrogen-rich gas which rises to the top of the fluid bed combustor where it is combusted to produce steam. Although the system deployed at Hereford is only a steam system with no on-site electrical generation, the viability of manure aggregation for waste-to-energy plants looks promising.

manure) to create a renewable fuel (ethanol), the facility is significantly reducing its exposure to natural gas price volatility and conserving the energy equivalent of 1,000 barrels of oil a day. Of course, by disposing of the manure, the plant is helping to address the environmental concerns such as water quality and odor.

A manure waste-to-energy plant could utilize either direct combustion or gasification technologies for dry wastes, or anaerobic digestion for an energy project handling manure with higher moisture content. Due to the low electrical and thermal loads existing at cattle feedlot operations, the most likely end user for this type of waste-to-energy plant is at an industrial location near the feedlot, such as a beef meat processing facility. The host facility would need to have a high thermal load to improve project feasibility. The high likelihood of an off-site project would require transportation and aggregation of manure, which would be most feasible with low density, dry manure. This in turn would increase the odds that an off-site manure project would utilize direct combustion or gasification technology as the conversion method. In addition, the need to dry manure for transport could create an on-farm thermal load that could be encourage the development of small on-farm systems using a small portion of the available manure waste stream.

Data and Methodology

Biomass Data Collection

The calculation to estimate the available quantity of beef cattle manure is borrowed from a report titled “Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State,” published by the Washington State Department of Ecology in 2005.

Cattle manure values were obtained by first taking the average county production for the combined total of cattle and calves for the years 2000-2005 and sub-dividing this total into 87% cattle and 13% calves. (NASS, 2006) Then, dry manure values of 5.52 lbs/cow day and 1.39 lbs/cow day for the respective cattle (793 lbs) and calves (200 lbs) were multiplied to the sub-category totals and added to get the overall production of dry manure. (USDA, 1985) An overall combination of collections within on farm and feedlot locations for the life of the cow is assumed to be 15.6%. The final calculation for the amount of beef cattle manure available for CHP waste-to-energy facilities is:

$$\textit{Manure (dry tons)} = (\#\,\textit{cattle} \times 0.87 \times 5.52 + \#\,\textit{cattle} \times 0.13 \times 1.39) \times 365/2000 \times 0.156$$

Where the collection factor of 0.156 is calculated by assuming that 90% of Texas cattle live in non-confined areas where only 6.5% of the manure is collectible and that 10% of Texas cattle are raised in confined feedlots where 97% of the manure is collectible. The complete calculation is provided in the table below.

Table 2-3 Calculation of Cattle Manure Availability in Texas

Avg # of Cattle	13,800,000
Cow (head) (87%)	12,006,000
Cow Manure (5.52 dry lbs per day each)	24,189,688,800
Calf (head) (13%)	1,794,000
Calf Manure (1.39 dry lbs per day each)	910,185,900
Total Manure (dry lbs)	25,099,874,700
Total Manure (dry tons)	12,549,937
Collection Factor (non-CAFO) (90% @ 6.5% collectible)	734,171
Collection Factor (CAFO) (10% @ 97% collectible)	1,217,344
Total Available Manure (dry tons)	1,951,515

Data Collection Concerns and Comments

Bedding was not inventoried in this report as most of the bedding would be from an organic recyclable that has already been counted in the inventory like straw.

Data

Table 2-4: Cattle Manure (Top Texas Counties)

Deaf Smith County	87,418 dry tons	Northern High Plains region
Anderson County	48,057 dry tons	North East Texas region
Parmer County	47,303 dry tons	Northern High Plains region
Castro County	46,761 dry tons	Northern High Plains region
Hansford County	35,071 dry tons	Northern High Plains region

2.2 Cotton Gin Trash

Cotton represents an important cash crop in Texas, as the state produced more than one-third of the national cotton crop. The gross value of Texas cotton production in 2005 was estimated at $2.07 billion. (Robinson, 2006) According to the Texas Cotton Ginners' Association, there are 256 operating gins in the state as of April 16, 2007. (Williams, 2007) Twenty-five of these gins are located in either Hale or Lubbock counties in the Texas Panhandle. The magnitude and concentration of the Texas cotton industry implies a very large regional fixed investment in cotton-related human capital, farm level machinery, gins, compresses and warehouses.

Texas cotton farmers grow two varieties of cotton, American Pima and Upland, although Upland cotton composes the majority of the state's annual cotton crop. American Pima cotton is grown only in West Texas. Upland cotton is grown mainly in the Panhandle and with smaller concentrations along the Texas coast line. Table 2-5, illustrates the majority of the cotton ginning industry operates in the Texas Panhandle according to 2005 data.

Table 2-5: Cotton Ginnings in Texas

Cotton Ginnings: All Cotton Running Bales Ginned and to be Ginned by County/District in Texas, Crop Year 2005		
County/District	**Running Bales Ginned**	**% of Total**
State Total	**8,338,850**	100.0%
District 12 (Southern High Plains)	4,244,600	50.9%
District 11 (Northern High Plains)	1,406,150	16.9%
District 22 (Southern Low Plains)	643,850	7.7%
Lubbock	584,350	7.0%
Hale	540,100	6.5%
Gaines	532,750	6.4%
Hockley	480,400	5.8%

Source: USDA-NASS, March 22, 2006

Resource Characterization

Cotton gin trash (CGT) accumulates as cotton fiber is separated from the seed at the gin. The CGT consists of residual plant parts remaining with the cotton following harvesting, remnant seeds, and lint produced in the ginning process. The predominant harvesting method used in the Plains region is stripper harvesting, which generates between 700 and 800 lbs of CGT per 480-pound bale. (Boman, 2007) Other areas of the state predominantly use spindle picker harvesting, which generates between 150 and 200 lbs of CGT per 480-lb bale. (Boman, 2007) Cotton gins operate during the cotton harvesting season and are idle in the off season. The cotton ginning season starts in the lower Southwest region of the country in midsummer and ends in late autumn/early winter. The bulk of the crop is ginned in six to eight weeks in most regions. (EPA, 1996) CGT is only available when the gins are operational. As shown in the table below, Texas cotton gin trash with an energy content of 7,058 Btu per pound can generate 21,118,637 MMBtu of gross energy in the state.

Table 2-6: Cotton Gin Waste Stream

Fuel Type	**Fuel Quantity (dry tons)**	**Energy Content (BTU/lb)**	**Gross Energy (MMBtu)**
Cotton Gin Trash	1,495,670	7,058	21,112,878

An average sized gin operation, processes from 10,000 to 50,000 bales per season. Assuming on average about 500 lbs of CGT are produced per bale of cotton, an average gin will need to dispose of from about 2,500 to 12,500 tons of CGT each season. CGT must be removed from the gin yard to avoid environmental hazards. Gins offer CGT as a free commodity to local farmers and others in exchange for removal. Over 50% of CGT is applied to farmland as a soil amendment. Less than 45% is fed to livestock. CGT is often used within 10 to 40 miles of the gin and seldom over 150 miles from its origin due to transportation costs. (IPM, 2001)

CHP Potential

The energy content of cotton gin trash is substantial and the resource is a potentially important energy resource for the state. With approximately 1,495,670 dry tons of cotton gin trash, the Texas cotton ginning industry could provide fuel in quantities sufficient to operate waste-to-energy plants with an electrical capacity of about 218 MW for about four months of the year. If these plants operated only during daylight hours, the capacity could potentially double to nearly 450 MW. A plant of this size could produce about 605,000 MWh and provide nearly 6 million MMBtu of thermal energy to neighboring facilities.

The seasonality of the resource is an impediment to the development of waste-to-energy plants at the cotton gin operation. The development of a waste-to-energy plant at an individual cotton gin operation may still be possible despite seasonality limitations. A cotton gin operation producing 10,000 tons of CGT could support a waste-to-energy plant for the four months the gin is operation and while residual CGT fuel remains available. For that four month period, the CGT could support about a 1.5 MW CHP plant operating around the clock or a 3.0 MW plant operating only during daylight hours. A waste-to-energy plant suitable for CGT would involve direct firing of a boiler to produce steam to turn a steam turbine. This system would likely be sited at another facility near the gin that had a larger need for thermal energy than the gin. If possible, the CHP system could potentially be turned down during nights and weekends. This strategy could extend the fuel resource and operating period to over half the year or allow development of a waste-to-energy plant with higher electrical capacity. The energy production values presented in Table 2-7 are based upon a four month operating period per year using only the available cotton gin trash.

Table 2-7: Potential Waste-to-energy Facility at a 10,000 Bale Cotton Gin Operation

CHP System Overview	
Gross Capacity Rating (MW)	1.5
Net Capacity (MW)	1.0
Gross Electrical Energy (MWh/yr)	4,048
Net Electrical Energy (MWh/yr)	2,834
Gross Heat Produced (MMBtu/yr)	82,049
NetHeat Recoverable (MMBtu/yr)	39,383

Assuming the CHP facility is built at the gin operation, the facility could potentially be kept operational throughout the year if another fuel source could be identified and secured. This additional fuel could be CGT from another cotton gin, another biomass resource available locally, or potentially natural gas. A second option is to move the CGT to another location. One option would be to augment cattle manure resources with CGT. About 1.38 million tons of CGT is produced within 150 miles of Lubbock, TX, in close proximity to major beef feed lots. (IPM, 2001) For example, a beef processing plant employing waste-to-energy concepts could benefit from the additional CGT fuel, thereby allowing a larger system to be utilized. Regardless of where and how the CGT is utilized, it is certainly an important resource for the state.

Data and Methodology

Cotton gin trash values were obtained by averaging the county production of both Upland and American Pima cotton crops in terms of total production (in bales) for the years 2000-2005. (NASS, 2006) We assumed that the cotton-producing counties in the western half of the state use stripper harvest (generating 700 pounds of cotton gin trash per 480-lb bale of cotton) (Brashears, 2007)and those counties in the eastern half of the state use picker harvest (generating 100 pounds of cotton gin trash per 480-lb bale of cotton). (Brashears, 2007) We also assumed moisture content of 10%. (Boman, 2007) The final calculation of the cotton gin trash available to support waste-to-energy facility development is:

CGT (dry tons) = [Cotton production (western counties) x 700 lbs / bale + cotton production (eastern counties) x 100 lbs / bale] x 0.90 / 2000 lbs/ton

Data Collection Concerns and Comments

This analysis assumes that Texas cotton ginners process Texas cotton only (i.e., no unginned cotton imports or exports occur).

Data

Table 2-8: Cotton Gin Trash (Top 10 Texas Counties)

County	Location	Dry Tons	Number of Operating Gins
Hale	Panhandle	117,385	14
Gaines	Panhandle	89,261	9
Lubbock	Panhandle	84,415	11
Lamb	Panhandle	78,467	8
Hockley	Panhandle	72,576	8
Lynn	Panhandle	71,867	0
Dawson	Panhandle	66,948	9
Crosby	Panhandle	62,286	7
Starr	Lower Valley	58,145	0
Floyd	Panhandle	54,558	8

2.3 Corn Stover

Corn is the United States' largest crop in terms of both volume and value. The United States grew 42 percent of the world's corn in during fiscal year 2006, producing 282.3 million metric tons (11.1 billion bushels). (USGC, 2007) According to the 2002 Census of Agriculture, Texas is ranked 12th in corn production, (USDA, 2002) where approximately 8,000 farms are scattered across the state. (Gibson, 2007) Major corn producing regions include the Rio Grande Valley, Coastal Bend, Blacklands, and the Panhandle. In fact, high concentrations of farms are found within 150-mile radius of Victoria, TX and within a 100-mile radius of the cities of Waco, Taylor and Dumas. (Gibson, 2007) The majority of the corn produced in Texas is used for livestock feed. Corn is harvested and sent to feed mills across the state, though primarily in the Panhandle and East Texas regions. Feed mills operate year-round and are typically located on or nearby livestock feeding operations.

Resource Characterization

Corn is planted from late January to early May. Growers in the Lower Valley, the Winter Garden, and South Texas will plant between late January and late February, while in the northern parts of the state, such as in the Plains and Cross Timbers regions, planting is from mid April to early May. The growing season for corn is about six months. The Northern High Plains (Panhandle) accounts for almost two-thirds of total Texas corn production, although other regions with significant corn production include the Blacklands (12%), the Upper Coast (6%) and South Central Texas (4%). (IPM, 2003)

When corn is harvested with modern combines, the machine strips the husks off each ear and removes the kernels from the cob as part of the harvesting process. The combine spreads the husks and cobs back onto the field as it moves, while storing the corn kernels in a holding tank until it can be unloaded into a truck.

Corn stover includes the stalks, leaves, cob, and husk that remain after the corn kernels have been harvested from the corn plant. Stover is bulky and has few alternative uses therefore it is typically left on the field where it helps maintain good soil fertility and structure. As shown in the table below, Texas corn stover with an energy content of 7,587 Btu per pound can produce nearly 19 MMBtu of gross energy in the state.

Table 2-9: Corn Stover Waste Stream

Resource	Resource Quantity (dry tons)	Energy Content (Btu/lb)	Gross Energy (MMBtu)
Corn Stover (dry tons)	1,249,961	7,587	18,966,908

CHP Potential

Corn stover is a large and growing potential energy resource for the state. In 2007, Texas acreage devoted to corn will increase by about 15% to about 2 million acreages. (TXFB, 2007) If all available stover in the state was used in waste-to-energy, the resource could support about 64 MW, assuming the systems operated 24 hours per day throughout the year. A system like this could generate about 536,400 MWh of electricity and produce about 11.8

million MMBtu of thermal energy, of which about 48% could be captured and used effectively. The harvest period in early summer is well timed with summer electrical system peak needs, which could increase the value of electricity generated from the resource.

As a field residue, corn stover is not aggregated either on the farm or at a mill. Consequently, stover would have to be collected from the field and aggregated before it could be used as an energy resource. As the corn harvest occurs once per year on any given farm, storage of stover would be required to provide a long-term stable fuel base. In addition, because little thermal demand exists on crop farms, on-farm projects are highly unlikely. Waste-to-energy CHP plants fueled with stover would likely involve transportation and aggregation of the resource at a centralized facility capable of utilizing it. Much like cotton gin trash, the role of corn stover in a waste-to-energy facility is to provide part of the fuel required by a larger, centralized facility capable of using a mixture of waste resources. Regardless of where and how the stover is utilized, it is certainly an important resource for the state.

Data and Methodology

Corn stover residue values were obtained by averaging the county production of corn in terms of total bushels produced for the years 2000-2005. (NASS, 2006) After converting bushels to tons, we assumed that for every ton of corn grain harvested, one ton of corn stover is produced. (ORNL, 2002) The amount of corn stover that can be collected from a field depends on a number of factors including the type and sequence of collection operations, the efficiency of the collection equipment, tillage, and crop management practices, and environmental restrictions, such as the need to control erosion, maintain soil productivity, and maintain soil carbon levels. For purposes of establishing the availability of stover for energy production, we assumed that one-third of the stover left behind on the field can be collected. (ORNL, 2002) The moisture content of corn stover is assumed to be 47 percent. (WSU, 2005) Therefore, the final calculation for available corn stover is:

$$\text{Corn Stover (dry tons)} = \sum \text{corn production (in tons)} \times 0.33 \times 0.53$$

Where corn production is summed across all Texas counties and converted from bushels to tons.

Data Collection Concerns and Comments

Production grain corn, not silage corn, was the only inventoried item. Also, the availability factor of 33% is a conservative value relative to values used in other similar reports.

Data

Table 2-10: Corn Stover (Top Texas Counties)

Dallam County	151,897 dry tons
Hartley County	127,146 dry tons
Sherman County	83,801 dry tons
Castro County	78,325 dry tons
Moore County	77,044 dry tons

2.4 Winter Wheat Straw

Wheat is the principal food grain produced in the United States. Wheat varieties grown in the United States are classified as "winter wheat" or "spring wheat," depending on which season it is planted. Winter wheat production represents 70-80 percent of total U.S. production. Hard red winter wheat, the variety grown in Texas, makes up 40% of total wheat produced in the U.S. About 50 percent of the wheat produced in the U.S is exported. (ERS-USDA, 2006)

In Texas, between 20,000 and 25,000 farms produce about 90 million bushels of wheat in an average year. Hard red winter wheat, which is processed into flour, is the predominant variety grown here. Between 40 and 60 percent of winter wheat is grown in the Panhandle region, according to the Texas Wheat Producers Board. The majority of wheat harvested is sent by rail to milling facilities in California, (Myers, 2007), although the website Flour.com indicates at least seven grain processing mills in Texas are capable of processing wheat into flour. These mills are shown in table below.

Table 2-11 Grain Processing Mills

Name	City/County	Estimated Processing Capacity (tons per day)
Horizon Milling Company	Saginaw/Tarrant County	1,125 tons/day
Horizon Milling Company	Galena Park/Harris County	700 tons/day
ConAgra Flour Milling Co.	Sherman/Grayson County	425 tons/day
ADM Milling	New Braunfels/Comal County	300 tons/day
Arrowhead Mills Company	Hereford/Deaf Smith County	260 tons/day
Pioneer Flour Mill	San Antonio/Bexar County	250 tons/day
Morrison Milling Company	Denton/Denton County	250 tons/day

Resource Characterization

In addition to the desired grain, the wheat plant also produces wheat straw, which consists of stems, leaves, roots, and chaff. When wheat grain is harvested, wheat straw remains on the fields. The straw may be left on the field for erosion control and eventually be plowed back into the soil when the farmer prepares for the next crop. In some cases, it may be burned or baled and removed. In Texas, the straw is typically remains on the field where it is incorporated back into the soil, although the landowner may consider other factors such as the quantity of material, the next crop to be planted, the weather conditions, soil erosion and nutrient needs, the slope of the land, and any markets that may be available for the straw.

Winter wheat varieties are sown in the fall, between August and October, and usually become established before going into dormancy when cold weather arrives. In the spring, plants resume growth and grow rapidly until summertime harvest. In Texas, wheat is harvested in June and July. Average Texas wheat production results in approximately 1.0 million dry tons of wheat straw, which could provide about 15.5 million MMBtu for waste-to-energy facilities.

Table 2-12: Winter Wheat Straw Waste Stream

Fuel Type	Fuel Quantity (dry tons)	Energy Content (BTU/lb)	Gross Energy (MMBtu)
Winter Wheat Straw	1,033,295	7,527	15,555,215

CHP Potential

The use of wheat straw as a feedstock for producing materials, fuels, and chemicals has been limited due to obstacles that include capital costs, energy consumption, waste streams, production logistics, and the quality of the biomass feedstock. U.S. Department of Energy is working to overcome these problems by developing commercially-viable technologies such as single-pass harvesting equipment that selectively harvests multiple crop components. With a single pass harvester, the wheat straw and grain will be more effectively harvested.

If all available wheat straw in the state was used in waste-to-energy, the resource could support about 53 MW, assuming the systems operated 24 hours per day throughout the year. A system like this could generate about 440 thousand MWh of electricity and produce about 9.6 million MMBtu of thermal energy, of which about 48% could be captured and used effectively. The harvest period in early summer is well timed with summer electrical system peak needs, which could increase the value of electricity generated from the resource.

The primary technical hurdles in utilizing straw as a feedstock is its broad distribution across several thousand farms and identifying the proper end-user who would benefit from a waste-to-energy system. Crop farms typically have little to no thermal loads like hot water or steam. Therefore, while the quantity of wheat straw available is significant, capturing this energy potential will depend on identifying the proper location to build the system. One idea is for individual farmers to collect and transport the straw to a large centralized facility capable of using the resource, most likely in a system capable of using a mixture of waste resources. Regardless of where and how the straw is utilized, it is certainly an important resource for the state.

Data and Methodology

Winter wheat straw residue values were obtained by averaging the county production of wheat in terms of total bushels produced for the years 2000-2005 (NASS, 2006). We assumed for every 60-pound bushel of wheat grain 100 pounds of wheat straw was generated. (Engel, 2005) The moisture content is assumed to be 10 percent. (Morgan, 2007) A collection factor of 25% is assumed to estimate the amount of wheat straw that can actually be collected. (Morgan, 2007) Therefore, the final calculation of winter wheat straw availability in Texas is:

Wheat straw (dry tons) = average county production (bu) x 100 lb/bu / 2000 lb/ton x 0.90 x 0.25

Data Collection Concerns and Comments

None.

Data

Table 2-13: Winter Wheat Straw Wastes (Top Texas Counties)

Sherman County	169,896 dry tons
Hansford County	145,878 dry tons
Dallam County	141,600 dry tons
Ochiltree County	125,370 dry tons
Parmer County	114,132 dry tons
Castro County	112,482 dry tons
Deaf Smith County	112,248 dry tons
Hartley County	101,694 dry tons

2.5 Beef Meat Processing Wastes

The beef packing industry is a very large industry in Texas and provides a significant energy opportunity for the state. Some 14.1 million head of cattle or 15% of the U.S. total are raised in Texas annually, and the world's largest commercial cattle feeding operations are located in the Texas Panhandle. (TCFA, 2006) Beef slaughterhouses are located around the state, although a significant concentration is located in the Panhandle, where some of the largest cattle slaughter plants in the U.S. can be found. Nationally, the industry is dominated by four major packers – Tyson Foods, Inc., Cargill Inc., Swift & Co., and Farmland Industries. Two of these companies, Tyson and Cargill, operate three beef processing facilities in the Panhandle. Other smaller (less than 2,000 head/day processing capacity) packing plants are scattered throughout the state.

Mega processing facilities, like Tyson and Cargill, are multi-plant, two-shift operations that employ economies of scale in order to produce at the lowest cost. These plants normally slaughter between 2,000 and 5,500 head per day on a double-shift basis. Smaller single plant facilities typically slaughter less than 2,000 head daily. (Johnson, 2003)

Resource Characterization

Beef processing wastes include inedible animal parts such as bone, fat, head, hair and internal organs. Today, these materials are sent to a rendering plant either on site or off site for processing into animal feed materials. Processing beef requires a year round operation, so large quantities of waste resources produced regularly. As a result, a stable supply of wastes is available for waste-to-energy projects. As shown in the table below, these processing wastes with an energy content of 7,455 Btu per pound can generate almost 4 million MMBtu of gross energy per year on average.

Table 2-14: Beef Processing Waste Stream

Fuel Type	Fuel Quantity (dry tons)	Energy Content (BTU/lb)	Gross Energy (MMBtu)
Beef Processing Waste	261,151	7,455	3,893,758

CHP Potential

Beef processing plants produce about 261,151 dry tons of wastes per year. While this resource is only a fraction of that available from cattle manure, it represents an excellent opportunity for CHP system development because meat processing plants typically have high thermal demands.[2] If all beef processing wastes generated in Texas were used in waste-to-energy projects, sufficient resource exists to support a 40 to 60 MW system that could generate roughly 340,000 MWh annually. Constructed in CHP mode with heat recovery, the system would provide an additional 2.5 million MMBtu of thermal of which about 48% could be readily captured and used to meet local thermal needs.

In fact, Cargill Meat Solutions installed a biogas recovery system (non-CHP) at its Friona, TX facility to recover methane gas from its anaerobic wastewater treatment lagoons. This project was one of the first of its kind in Texas. The facility was recognized for its accomplishment with a 2005 Texas Environmental Excellence award. (TCEQ, 2005)

Large facilities like the Tyson Foods Amarillo plant, which processes about 5,700 head per day (Reuters, 2007), and Cargill Meat Solutions plants in Friona and Plainview, which process 4,500 and 4,650 head per day respectively (CMS, 2007), present major opportunities for waste-to-energy plant development. Smaller processors like the Sam Kane Beef Processors in Corpus Christi (1,400 head/day), L & H Packing Co. in San Antonio (1,150 head/day), Caviness Packing Co. in Hereford (730 head/day) and similar facilities could also have viable opportunities for projects. (CBW, 2002)

Given the size distribution of plants in Texas, a 2,500 head per day beef cattle processing facility provides a good model for the type of waste-to-energy facility that could be developed at such facilities. Although CHP development is possible at larger and smaller processing facilities, 2,500 head per day is examined to provide a representative case study for a waste-to-energy plant possible within the beef processing industry.

Because beef processing wastes have high moisture content, anaerobic digestion would likely be the conversion technology of choice. With a daily waste stream of about 234 tons, the anaerobic digester is estimated to produce about 2,094 Mcf of biogas daily with an energy content of about 600 Btu per cubic foot. The biogas could be fed into reciprocating engines or a conventional boiler for steam production.

Assuming a heat rate of 10,904 Btu per kWh, the resulting waste stream could support a CHP project of about 4.8 MW in electrical capacity, assuming the project ran 95% of the time.

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[2] Of the total energy demand by a typical beef packing plant about 80-85% is thermal energy in the form of steam and hot water. (UNEP, 2001) Facilities also have a significant refrigeration load, some of which could be met by generating chilled water with a heat driven absorption chiller.

Because most beef processing plants use two-shift operations, the potential exists to turn down the system at night to save biogas. This in turn could allow the on-site energy plant to increase its capacity to about 7.2 MW. The proposed system is estimated to generate about 39,901 MWh annually.

Because the waste-to-energy plant would have internal loads to handle and process the wastes, the net output of the energy plant is assumed to be reduced by 30%. Therefore, the net electrical capacity is estimated to be between 3.1 to 5.0 MW, while the net electrical energy production would be just over 25,000 MWh. In addition, the heat recovery system could potentially displace thermal loads of about 140,000 MMBtu annually.

Table 2-15: 2500 Head/Day Cattle Processing Plant

CHP System Overview	
Technology: Anaerobic Digestion and Reciprocating Engines	
Gross Capacity Rating (MW)	4.8 – 7.0
Net Capacity (MW)	3.1 – 5.0
Gross Electrical Energy (kWh/yr)	39,901
Net Electrical Energy (kWh/yr)	25,460
Gross Heat Produced (MMBtu/yr)	298,918
Net Heat Recoverable (MMBtu/yr)	143,481

In addition to having their own waste streams suitable for energy production, beef processing facilities are typically located in rural areas close to the feedlots to reduce livestock transportation and feed costs, ensure more consistent quantities of animals, and thereby use processing plants around the clock and throughout the year because of fewer interruptions in livestock supply. If the thermal loads justified larger systems, transportation of cattle manure or other biomass waste suitable for the anaerobic digestion process available from these feedlots could be employed at these plants thereby increasing the size of the waste-to-energy plant.

Data and Methodology

The calculation used to estimate available beef processing wastes is borrowed from a report titled “Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State,” published by the Washington State Department of Ecology in 2005.

Biomass Data Collection

Beef meat processing values were first obtained by averaging state cattle weight sales for the years 2000-2005. (NASS, 2006) From the same report, the percentage of cattle in each county was determined and therefore the percentage of cattle weight sales by each county. An estimate of the weight of beef meat processing in each county was arrived at by multiplying the county weight sales by the ratio 0.187 tons of by-product/ton steer or cow live weight. (IA State, 2003). A moisture level of 64% was used to determine total dry matter. (IA State, 2003). Where required, the assumed weight per head is 1000 lbs. The final calculation was:

Beef processing wastes (dry tons) = ∑state beef weight sales (by county) x 0.187 x 0.36

Data Collection Concerns and Comments

No particular concerns exist in regards to the parameters used for the collection of this biomass data. However, this data represents an individual county's estimated contribution to the state's beef packing plants which are primarily located in the Panhandle and Central Texas regions. Beef meat processing wastes are generated only at these packing plants and not at the cattle feedlots.

Data

Table 2-16: Estimated Daily Processing Capacity of Selected Beef Meat Processing Plants in Texas

Company	Location	Production Capacity
Tyson Foods	Amarillo, TX (Potter County)	5,700 head/day
Cargill Meat Solutions	Friona, TX (Parmer County)	4,500 head/day
Cargill Meat Solutions	Plainview, TX (Hale County)	4,650 head/day
Sam Kane Beef Processors	Corpus Christi, TX (Nueces County)	1,400 head/day
L & H Packing Co.	San Antonio, TX (Bexar County)	1,150 head/day
Lone Star Beef Processors, LP	San Angelo, TX (Tom Green County)	730 head/day
Caviness Packing Co.	Hereford, TX (Deaf Smith County)	775 head/day
San Angelo Packing Co.	San Angelo, TX (Tom Green County)	650 head/day

2.6 Poultry (Broiler) Farms

The Texas poultry industry is estimated to contribute more than $1.6 billion to the state's economy, according to results from a survey of broiler, egg and turkey producers operating in 2003. Survey results indicate that Texas produced 615.6 million broilers and turkeys in 2003 and 4.7 billion table eggs. The USDA ranked Texas sixth in the U. S. in broiler production and seventh in egg production in 2003. (Carey, 2004) Texas remains one of the leaders in broiler production, raising over 600,000,000 broilers in 2006 alone. (NASS, 2006)

The U.S. broiler chicken industry began a rapid consolidation in the 1950s due in part to technological innovations in automated production, disease control, and nutrition, which allowed large, confined broiler operations to surpass the production capabilities of traditional poultry farms. (CU, 2000) Today, approximately 90% of all broiler chickens are raised by farmers under production contracts and the remaining 10% are raised on-site by the integrated poultry companies themselves. (CU, 2000) As of 2000, the largest percentage of broiler production in Texas is controlled by three companies – Pilgrim's Pride, Tyson Foods, and Sanderson Farms. (CU, 2000)

Overview of Poultry Farming in Texas

Most commercial broiler chickens produced in the U.S are grown on family-owned farms under contract with a vertically-integrated poultry company that owns the hatchery, birds, feed mills, and processing plants. According to the U.S. Poultry and Egg Association, Texas has nine broiler processing facilities, with capability to slaughter an average of 200,000 birds per day. (Kiepper, 2003) The major poultry processing plants in Texas are located in East Texas in the counties of Angelina, Brazos, Dallas, Guadalupe, Nacogdoches, Panola, Shelby, and Titus. According to the 2002 Census of Agriculture, the most recent data available for poultry farms, Texas has 2,479 broiler farms serving these nine processing plants. The counties with the greatest number of contract production facilities are Shelby (153 farms, 14,867,668 birds), Nacogdoches (127 farms, 15,449,908 birds total), and Gonzales (70 farms, 9,315,139). (NASS, 2002)

Broiler production is typically organized in a complex consisting of a feed mill and a processing plant, surrounded by sufficient contract production facilities to meet a typical production capacity of about one million birds per week. Broiler production facilities are typically located within a twenty-five mile radius of the processing plant. The typical broiler house produces 110,000 birds per year in multiple flocks each residing at the facility for about two months. (CPC, 2001)

Resource Characterization[3]

The poultry industry produces two resources, poultry litter and processing wastes. Poultry litter, which is the mixture of bedding material plus the manure generated by the birds, is generated at the production broiler houses. The bedding materials used are primarily high carbon content biomass and it contributes to the energy content of the litter. The litter is typically removed once each year, after which the house is thoroughly cleaned and disinfected and new litter placed in. Processing wastes, which include feathers, blood, skin, bone, beaks and trim scraps, are produced at the processing plant. Approximately 0.2 lbs of waste is generated for each four pound broiler processed.

As shown in Table 2-17, broiler litter generates nearly 80% of the total waste resource. However, the litter is spread out among the various broiler houses serving the nine processing plants. With over 2000 houses, this resource is too broadly distributed to provide a useful fuel for a CHP system without further aggregation. While a smaller resource, the nearly 85,000 dry tons of processing waste could potentially be a better resource for waste-to-energy plant development, because it is distributed among only nine processing plants. Together, however, over 5.5 million MMBtu of gross energy is available to support waste-to-energy projects located at poultry processing facilities

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[3] Egg laying chickens are not considered in this analysis because their proximity to the waste-to-energy plant presumed to be located at the processing plant is not known. Litter from the nearly 19 million egg laying chickens in Texas could add another 1.8 million dry tons to the fuel supply for the plant.

Table 2-17 Poultry Litter Waste Stream

Fuel Type	Fuel Quantity (dry tons)	Energy Content (BTU/lb)	Gross Energy (MMBtu)
Manure (Litter)	347,116	6,187	4,295,219
Processing Waste	84,614	7,455	1,261,590
Total Resource	431,730	6,204	5,556,809

CHP Potential

The potential for waste-to-energy plant development using poultry waste resources differs depending on whether the litter and processing wastes are considered separately or together. Due to economies of scale, establishment of a small volume independent processing plant on a single farm scale is typically not profitable.

Broiler Processing Wastes

Assuming broiler processing plant wastes are about evenly spread between the nine plants in the state, these operations would generate sufficient biomass wastes to consider on-site waste-to-energy solution. The waste-to-energy plant is assumed to utilize anaerobic digestion to convert processing wastes to low Btu biogas suitable for combustion in a reciprocating engine. Biogas production is estimated at about 640 Mcf/day at each processing plant. With an assumed heat rate of 10,904 Btu/kWh, each processing plant could host a generating plant of about 1.5 MW, assuming the system operates around the clock. A larger system could be implemented if the system operates only during peak daylight hours. The CHP system would generate about 12,213 MWh. Internal losses due to additional electrical requirements to handle the waste streams are estimated to reduce this output by 36%, leaving about 7,793 MWh of electricity to power the processing plant and for export to the electrical grid. The system would produce about 91,496 MMBtu/yr, although only about 43,918 MMBtu/yr could be recovered and used to meet existing thermal needs. Summary information for the potential CHP waste-to-energy plant is provided in Table 2-18.

Table 2-18: Poultry Processing Waste-to-energy Facility

CHP System Overview	
Gross Capacity Rating (MW)	1.5
Net Capacity (MW)	0.9
Gross Electrical Energy (MWh/yr)	12,213
Net Electrical Energy (MWh/yr)	7,793
Gross Heat Produced (MMBtu/yr)	91,496
Net Heat Recoverable (MMBtu/yr)	43,918

Broiler House Litter

Broiler house litter is a potential energy resource in Texas, but is widely dispersed among more than 2000 individual broiler houses. If all of the chicken litter produced in broiler houses could be aggregated at a single site, sufficient resource exists to build about 21 MW of electrical capacity, which could generate about 175,000 MWh annually. Constructed in CHP mode with heat recovery, the system would provide an additional 1.3 million MMBtu of thermal of which about 48% could be readily captured and used to meet local thermal needs.

However, assuming the waste is evenly distributed among broiler houses of the same size, the large number of broiler house operations in the state likely means that the quantities of chicken litter are likely going to be too widely distributed to support waste-to-energy plants located at any one broiler house. If large broiler house operations with multiple houses exist or if nearby but independent broiler house operations agree to aggregate resources, the potential exists for some waste-to-energy plants to be developed.

A waste-to-energy plant implemented at a broiler house would likely utilize anaerobic digestion to reduce the litter to low Btu biogas suitable for combustion in a reciprocating engine. Gasification can also be used to process the litter into hydrogen rich gases that can be combusted in a boiler to generate steam. Due to the low electrical and thermal loads existing at the broiler house operation, most of the electrical energy would be sold to the electrical grid and the thermal energy exported to a nearby load or simply wasted to the atmosphere.

Combined Waste and Litter System

Fortunately, the proximity of the broiler houses to the processing plant which was intentionally developed to minimized transportation costs for the chickens, lends itself to reasonable transportation costs for the litter. Assuming that litter can be made available to a centralized CHP plant located at the processing plant, CHP waste-to-energy could be viable at each of the nine processing plant locations in the state.

Seasonal variations in waste flow are minimal because the processing plants operate year round. However, broiler house operators typically harvest the litter once per year, limiting the availability of this resource unless cleaning operations could be spread out through the year to ensure a steady flow of manure to the waste-to-energy plant. For this analysis, a uniform flow of chicken litter is assumed.

The waste-to-energy plant is assumed to utilize anaerobic digestion to produce low Btu biogas for combustion in large reciprocating engines or to produce electricity using a conventional boiler and steam turbine. Biogas production is estimated at about 1,658 Mcf/day at each processing plant. With an assumed heat rate of 10,904 Btu/kWh, each processing plant could host a generating plant of about 3.8 MW. This plant could be operated around the clock and throughout the year, thereby producing about 31,634 MWh. Internal losses due to additional electrical requirements to handle the waste streams are estimated to reduce this output by 36%, leaving about 20,185 MWh of electricity to power the processing plant and for export to the electrical grid.

Thermal energy produced by the waste-to-energy plant would amount to about 237,000 MMBtu per year, although only an estimate 48% of this total or 113,753 MMBtu per year could be captured and used effectively. In poultry processing plants, heat can be used for process heat, sterilization, and refrigeration. To help remove feathers, broilers are scalded with water about 136º F (58º C). In addition, blades and surfaces must be routinely cleaned and sterilized using hot water or steam, and the processing plant also requires large amounts of refrigeration to keep the carcasses from spoiling until shipping. Summary information for the potential CHP waste-to-energy plant is provided in Table 2-19.

Table 2-19 Potential CHP using Broiler Litter and Processing Wastes

CHP System Overview	
Gross Capacity Rating (MW)	3.8
Net Capacity (MW)	2.4
Gross Electrical Energy (MWh/yr)	31,634
Net Electrical Energy (MWh/yr)	20,185
Gross Heat Produced (MMBtu/yr)	236,984
Net Heat Recoverable (MMBtu/yr)	113,753

Data and Methodology

The calculations used to estimate available broiler litter and poultry processing wastes are borrowed from a report titled "Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State," published by the Washington State Department of Ecology in 2005.

<u>Biomass Data Collection for Broiler Litter</u>

Poultry broiler manure was determined by using 0.93 tons of manure (30% moisture) per 1000 broilers (Coufal, 2006) and a 90% collectible factor. The final calculation used to determine the number of tons of poultry litter useful for fuel was:

Broiler Litter (dry tons) = #broilers x 0.93 tons / 1000 broilers x 0.70 tons/ton x 0.90 tons/ton

<u>Data Collection Concerns and Comments</u>

Poultry litter products other than the manure itself were not inventoried in this report because, like the other animal beddings, it was believed that the majority of the bedding was from recycled organic material that is already being counted in the inventory. Also layer chicken manure is not considered in this analysis due to lower energy content and widespread distribution of this resource.

Table 2-20: Poultry Manure Wastes (Top Texas Counties)

Tons of Dry Biomass ~ 5,806,010	
D51 Combined Counties	3,705,478
D81 Combined Counties	1,229,577
D52 Combined Counties	771,587
D98 Combined Counties	242,716
D90 Combined Counties	93,011
D40 Combined Counties	38,819
D30 Combined Counties	8,550

Biomass Data Collection for Poultry Processing Wastes

Poultry meat processing values were obtained by taking county broiler production multiplying this by 4 pounds/average broiler and assuming that 19.3% of the broiler weight is waste blood, heads, feet and intestines/organs. (Dupps, 2004) A moisture level of 63% was used to determine total dry matter. (Dupps, 2004) The final calculation was:

$$\text{Poultry processing waste (dry tons)} = \sum(\text{county total}) \times 4\ \text{lb/bird} / 2000 \times 0.193 \times 0.37$$

Data Collection Concerns and Comments

Only live-kill broilers were considered in this inventory. Egg laying chickens are not considered.

Poultry Processing Waste Data

Table 2-21: Poultry Processing Wastes (Top Texas Counties)

Tons of Dry Biomass ~ 84,614	
D51 Combined Counties	60,851
D52 Combined Counties	12,116
D81 Combined Counties	11,523
D98 Combined Counties	124

2.7 Dairy Farming

In Texas, the dairy industry comprises about 800 dairy farmers (TAD, 2007) with about 327,500 head of cattle. (NASS, 2006) The industry is concentrated in the nineteen counties just east of the Southern Low Plains area. Approximately 150 dairies are operating in Erath, Hamilton, and Comanche counties alone. Together, these dairies have approximately 100,000 cows. (TDR, 2005) Around the city of Dalhart in Dallam County there are feedlots with over 300,000 head of cattle including over 20,000 dairy cows. Erath County contains the largest number of dairy farms in the state. (TDR, 2005) With about 62,000 head of dairy cows, (NASS, 2006) Erath County generates almost 20 percent of the state's dairy manure.

Currently, most manure wastes are applied to fields as fertilizer. This practice is negatively impacting the air and water quality due to excessively high levels of phosphorus. Phosphorus loading is a major issue among environmentalists, concerned citizens, especially residents of Waco, TX which is located downstream from dairies operating in the North Bosque River watershed. The city is concerned that phosphorus from dairy cows is polluting Lake Waco, the city's sole source of drinking water.

Resource Characterization

Dairy cow manure is mostly produced in confined areas where the animals spend the most time. Dairy farming is a year round operation, so the manure resource is stable and can support waste-to-energy projects throughout the year. Dairy manure has a BTU rating of about 7,310 per pound.

Table 2-22: Dairy Cattle Manure Waste Stream

Fuel Type	Fuel Quantity (dry tons)	Energy Content (BTU/lb)	Gross Energy (MMBtu)
Manure	603,179	7,310	8,818,478

CHP Potential

The potential of utilizing manure to fuel waste-to-energy projects on dairy farms is excellent. In fact, a number of projects are already underway. In 2003, a demonstration project initiated by the Texas Farm Bureau to reduce phosphorus levels began operating on a Hamilton County dairy farm. The two-year project utilized both solid and liquid dairy waste through an anaerobic digester in a multi-step process that produced both electricity and compost, while reducing phosphorus in the waste stream by approximately 80 percent. The electricity was used primarily on the dairy farm with the excess sold to United Cooperative Services, a rural electric cooperative in Cleburne. (Barnett, 2003)The digester is a large covered lagoon type where solid and liquid dairy wastes are retained for 30 days, before they are sent through a polishing pond, flush tanks, a recirculation pond, and an oxidation pond. The action of the aerators in the oxidation pond helps to add oxygen back to the effluent, which in turn, grows algae and consumes nutrients. The bio-gas trapped under the digester tarp provides fuel to a generator that produces electricity. About 75,000 gallons of water from the dairy intermittingly passes through the digester system each day. (TDR, 2005)

In addition, another waste-to energy facility is planned at Duffau, a small community located in the southern part of Erath County. (Microgy, 2007) The Huckabay Ridge project will collect the manure from 10,000 cows and transport it back to a central facility where it will be processed through an anaerobic digester. Manure will be processed through the anaerobic digesters to produce natural gas that will be sold to a local market. Although these projects do not always use combined heat and power technologies, they do indicate that waste-to-energy projects are potentially attractive solutions to environmentally related problems.

An estimated 17 to 34 MW of electrical capacity could be generated if all of the dairy manure resource was used to fuel waste-to-energy CHP projects. These systems would provide a total of about 142,000 MWh to Texas dairy farmers. Even with parasitic loads estimated at 30%, the net resource would be nearly 11 to 22 MW and over 90,000 MWh of electrical energy. Capturing thermal energy for on-farm uses such as milk refrigeration, air conditioning, lighting, anaerobic digestion heat and similar needs, provides up to about 1 million MMBtu of thermal energy.

On-farm projects will be small, but appropriately sized for the electrical and thermal requirements needed by the farm. A potential waste-to-energy plant suitable for dairy farms is assumed to utilize anaerobic digestion to convert manure to low Btu biogas suitable for combustion in a small reciprocating engine. With 800 dairy farms in Texas having a total of 327,500 head of cattle, an average dairy farm of about 410 animals would only have sufficient biogas production to support a CHP system of about 20 kW. While this system is quite small, the energy production would be consistent with the needs of the farm. Dairy farms with 1,000 head of cattle could support slightly larger system of about 50 kW.

Potential projects are possible at both individual dairy farms and at centralized facilities that collect and aggregate manure.

If the dairy farm has little need for heat and power during the night time, the system could be cycled on and off each day. This would provide electricity and heat when it is most needed by the farm, and when energy prices are highest. For example, operating the engine for 12 hours a day could allow the engine generator to be doubled in size to 100 kW. A 100 kW on-site waste-to-energy project operating 12 hours per day would have the following energy production.

Table 2-23 Dairy Manure Waste-to-energy Plant (1000 Head)

CHP System Overview	
Gross Capacity Rating (MW)	0.052 – 0.100
Net Capacity (MW)	0.033 – 0.066
Gross Electrical Energy (MWh/yr)	433
Net Electrical Energy (MWh/yr)	276
Gross Heat Produced (MMBtu/yr)	3,242
Net Heat Recoverable (MMBtu/yr)	1,556

Another viable option is to transport manure to a centralized facility, where it can be aggregated at a single farm or a non-farm site. In this case, the biogas can be sold to the gas distribution company, or used in a combined heat and power facility to generate electricity and heat for a nearby industrial facility with high thermal loads.

Assuming manure could be collected from ten dairy farms, the number of projects could be reduced from 800 to 80, although transportation costs would increase. Aggregation would also increase the average project size from about 20-50 kW to about 200 kW each. Similar to the on-farm solution, 12-hour daily operation could double the size of the project to give it more capacity value on the electrical grid. A centralized system provides similar energy benefits for the state as smaller individual systems since the quantity and availability of the manure resource remains unchanged.

Methodology

The calculation used to estimate available dairy manure is borrowed from a report titled “Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State,” published by the Washington State Department of Ecology in 2005.

Biomass Data Collection

Dairy manure values were obtained by first taking the average county production for the combined total of milkers and calves for the years 2000-2005 and sub-dividing this total into 87% milkers and 13% calves. (NASS, 2006) Then, dry manure values of 13.1 lbs/cow day and 3.66 lbs/cow day for the respective milkers (1,200 lbs) and calves (330 lbs) were multiplied to the sub-category totals and added to get the overall production of dry manure.

(USDA, 1985) An 85% collection availability factor was used for the state and its preponderance of medium to large confined animal operations. (Jaycor, 1990) The final calculation was:

Manure (dry tons) = ∑ [(county total x 0.87 x 13.1 lb/day) + (county total x 0.13 x 3.66 lbs/day)] x 365 days / 2000 lbs/ton x 0.85

Data Collection Concerns and Comments

Bedding was not inventoried in this report as most of the bedding would either be from an inorganic nature like sand or from an organic recyclable that may already been counted in the inventory like straw.

Data

Table 2-24: Dairy Manure Wastes (Top Texas Counties)

Erath County	143,075 dry tons
Hopkins County	60,502 dry tons
Comanche County	50,250 dry tons
Archer County	25,171 dry tons
El Paso County	23,483 dry tons
Lamb County	22,224 dry tons

2.8 Rice Hulls

Rice production and processing contributes more than $200 million to the state’s economy each year. The rice production and milling industry is concentrated in the upper Texas coast in the counties of Austin, Bowie, Brazoria, Calhoun, Chambers, Colorado, Fort Bend, Galveston, Hardin, Harris, Hopkins, Jackson, Jefferson, Lavaca, Liberty, Matagorda, Orange, Red River, Victoria, Waller, and Wharton. Texas rice production is decreasing. Rice acreage continues to shift from the Texas Gulf Coast to the Mississippi Delta. (Childs, 2006) Texas rice area dropped from almost 600,000 acres in 1980 to 181,000 acres in 2003, due to increasing production costs specifically irrigation expenses. (Childs, 2006) According to the USA Rice Federation, Texas is home to six rice mills as shown in the table below.[4]

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[4] USA Rice Federation, website: www.usarice.com/processing/suppliers.html

Table 2-25: Texas Rice Mills

Name	City/County	Products
American Rice, Inc	Freeport/Brazoria	Parboil, white
Beaumont Rice Mills, Inc.	Beaumont/Jefferson	
Doguet's Rice Milling Co.	Beaumont/Jefferson	Long/medium grain rice, organic rice, brown rice, basmati rice
Gulf Rice Arkansas, LLC	Houston/Harris	
Gulf Rice Milling, Inc./ Gulf Pacific Rice	Houston/Harris	Long grain, parboiled, brown, wild
RiceTec, Inc	Alvin/Brazoria	Aromatic, sushi

Resource Characterization

Rice hulls are produced at rice mills during the processing of raw rice kernels. Rice hulls are the hard protecting coverings of grains of rice. When rice arrives at the mill, it is ushered through a series of sorting machines that separates the kernels encased in an inedible hull or husk from any debris. The rice is then sent on its way through the multi-faceted milling process. The rough rice passes through "sheller" machines that remove the hull. Once separated from the rice grain, hulls can be used as a building material, animal bedding, fertilizer, insulation material, or fuel. As shown in the table below, rice hulls with an energy content of 6,575 Btu per pound can generate over 3.6 million MMBtu of gross energy on average annually.

Table 2-26: Rice Hull Waste Stream

Fuel Type	Fuel Quantity (dry tons)	Energy Content (BTU/lb)	Gross Energy (MMBtu)
Rice Hulls	275,422	6,575	3,621,799

CHP Potential

The potential for waste-to-energy plant development at a rice mill facility is good, especially for larger mills that operate year round. For example, ARI's Freeport facility, which is thought to be the largest rice mill in Texas, is a 24 hour per day operation that could be well suited for a rice hull project. Other Texas mills, which may more typically run a single 10 to 12 hour shift per day, 5 to 6 days per week, could also be potential hosts.

Estimating dry hull availability at a large mill, a 4.1 MW steam turbine could be operated on a 24/7 basis, 365 days per year. A larger system could be implemented if the system was turned down at off-peak times or operated only part of the year. Each CHP system would generate about 34,145 MWh of electrical energy annually, however new electrical loads needed to handle and process the hulls for use in the waste-to-energy plant are estimated to reduce this output by 30%, leaving about 23,902 MWh of electricity to power the mill's existing loads. Any surplus energy would be available for export to the electrical grid. Each system would produce about 650,000 MMBtu per year, although only about 313,766 MMBtu per year is estimated to be recoverable to meet existing thermal needs at the plant. Summary information for the potential CHP waste-to-energy plant is provided in Table 2-27.

This waste-to-energy plant is assumed to utilize direct combustion of the hulls to generate high pressure steam. A backpressure steam turbine is used to produce electricity, while thermal energy can be recovered to meet the thermal needs of the mill. For example, some mills produce parboiled rice, which involves a steam pressure process in which rough rice is soaked, steamed, and dried before milling. Other thermal loads such as drying ovens, and other warm and cool temperature processing used to control moisture and final product quality could be served by the waste-to-energy plant.

Due to the proximity of the rice industry and milling operations in the Gulf Coast region, the potential exists for millers to aggregate rice hulls or to identify another nearby biomass waste stream, such as cotton gin trash, wood wastes, or cattle manure, to allow a larger plant to be developed. The value of such a system would depend highly on the existence of a high quality thermal load well-matched to the output of the system, and to the transportation costs needed to aggregate the resources in a central location.

Table 2-27: Rice Hull Waste-to-energy Plants

CHP System Overview	
Gross Capacity Rating (MW)	4.1
Net Capacity (MW)	2.9
Gross Electrical Energy (MWh/yr)	34,145
Net Electrical Energy (MWh/yr)	23,902
Gross Heat Produced (MMBtu/yr)	653,699
Net Heat Recoverable (MMBtu/yr)	313,776

Data and Methodology

Texas rice milling is estimated to be 15.7% of the total US milling industry using value of total shipments. (US Census, 1997) For the purposes of this calculation, we use the value of total shipments to estimate the portion of milling activity taking place in Texas. Total US milled production of rice for the 2005/06 milling year was 7,088,000 metric tons. (USA Rice, 2007) Rice hull quantities in Texas are estimated by multiplying the production by the size of the Texas rice milling industry. Rice hulls are estimated to be 20% of the total weight of the unmilled kernel and moisture content is assumed to be 10%. (Doguet, 2007)Therefore, the final calculation of rice hull availability in Texas is:

$$\text{Rice hulls (dry tons)} = 7{,}796{,}800 \text{ tons} \times 0.157 \times 0.2/0.8 \times 0.9$$

2.9 Hog Manure

In 2005, Texas ranked 14th in hog production with 930,000 head (TPPA, 2005) at 3,800 operations. Seventeen of these operations had 5000 or more hogs. (NASS, 2001) The Panhandle represents the largest region for hog production in the state with 855,000 head. (NASS, 2002) In fact, a large number of the confined feeding operations for hogs are concentrated around Sherman County and Ochiltree County. Hog production also occurs in central and eastern areas of the state.

Resource Characterization

Hog manure is mostly produced in confined areas where the animals spend the majority of their time. Hog farming is a year round operation, so the manure resource is stable and can support waste-to-energy projects that operate throughout the year. Manure collected quickly at the feedlot is high in moisture content, but will dry if not used quickly. Wet manure is best suited for anaerobic digestion, while dry manure is best suited for direct combustion or gasification technology. As shown in Figure 2.X, approximately 153,300 dry tons of hog manure is available in Texas. With a BTU rating of about 7,368 Btu per pound,[5] hog manure offers a gross energy content of about 2.26 million MMBtu to support waste-to-energy plants in Texas.

Table 2-28: Hog Manure Waste Stream

Resource	Resource Quantity (dry tons)	Energy Content (BTU/lb)	Gross Energy (MMBtu)
Hog Manure	153,300	7,368	2,259,029

CHP Potential

The Texas hog industry produces sufficient manure resource to support waste-to-energy CHP facilities. Assuming that all of the available resource is used in waste-to-energy CHP plants, sufficient resource exists to produce nearly 11.3 MW of electrical capacity, which could generate some 94,245 MWh annually. If waste heat recovery was built into these systems, about 706,000 MMBtu of thermal energy would be produced, of which about 48% could be readily captured and used to meet local thermal needs.

According to a report from the U.S. EPA, only thirteen operations are considered to be good sites for waste-to-energy CHP facilities using anaerobic digestion. (EPA, 2005) The criteria used in this report was based on existing hog farms with more than 2,000 hogs using flush, pit recharge, or pull-plug pit manure systems or those with more than 5,000 hogs and deep pit manure systems. These 13 operations house about 845,000 head of hog or about 90% of the Texas industry.

Potential waste-to-energy projects are possible at both individual hog operations and at centralized facilities that collect and aggregate manure. On-farm projects will be relatively small, but appropriately sized for the electrical and thermal requirements needed by such facilities. A potential waste-to-energy plant suitable for hog operations is assumed to utilize anaerobic digestion to reduce manure to low Btu biogas suitable for combustion in a reciprocating engine. With the hog industry concentrated in thirteen operations having a total of 845,000 hogs, an average hog farm has about 65,000 animals. An operation of this size could create sufficient biogas to support a CHP system of about 780 kW.

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[5] The assumed value is an average of 6500 Btu/lb (Frazier, 2004) and 8,400 per pound on a dry basis. (Koger, 2002)

This system could have energy production consistent with the needs of such operations. If the hog farm has little need for heat and power during the night time, the system could be cycled on and off each day. This would provide electricity and heat when it is most needed by the farm, and when energy prices are highest. Operating the engine for say 12 hours a day could allow the engine generator to be doubled in size to 1.5 MW. Heat from the on-site system could be used for on-farm thermal loads such as water heating or to maintain the temperature of the anaerobic digester system. A potential CHP waste-to-energy facility operating on-site of the animal feedlot is shown in Table 2-29.

Table 2-29: Hog Manure Waste-to-energy Plant (65,000 Head)

CHP System Overview	
Gross Capacity Rating (MW)	0.78 – 1.6
Net Capacity (MW)	0.50 - 1.0
Gross Electrical Energy (MWh/yr)	6,525
Net Electrical Energy (MWh/yr)	4,163
Gross Heat Produced (MMBtu/yr)	48,880
Net Heat Recoverable (MMBtu/yr)	23,462

Another viable option is to transport manure to a centralized facility, where it can be aggregated at a single farm or non-farm. In this case, the biogas can be sold to the gas distribution company, or used in a combined heat and power facility to generate electricity and heat locally. Locating this centralized facility at a facility with a substantial need for thermal energy would help the economics of such projects. Aggregation of manure resources would provide greater economies of scale to support project development, although project location would dictate the potential or effective heat utilization. The location of the hog industry, especially in Ochiltree, is nearby other cattle operations and processors, so manure aggregation with other types of biomass waste may also be an opportunity to consider.

Data and Methodology

The calculation used to estimate available hog manure is borrowed from a report titled "Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State," published by the Washington State Department of Ecology in 2005.

Biomass Data Collection

Hog manure values were obtained by finding the average number of hogs per county over the years 2000-2005 (NASS, 2006) and then multiplying this by a manure production factor of 0.9 dry lbs per animal per day assuming an average weight of 150 pounds. (USDA, 1985) Lastly, the manure total was assumed 100% collectible. (Jaycor, 1990) The final calculation for available dry hog manure is:

Hog manure (dry tons) = # of animals x 0.9 lbs/day x 365 days/2000 lbs/ton

Data Collection Concerns and Comments

No particular concerns exist in regards to the parameters used for the collection of this biomass data.

Data

Table 2-30: Hog Manure Wastes (Top Texas Counties)

D11 Combined Counties	136,218 dry tons	Counties in the northern high plains region
D81 Combined Counties	5,366 dry tons	Counties in the south central region
D51 Combined Counties	3,340 dry tons	Counties in the north east region

2.10 Sugarcane Bagasse

The sugarcane industry in Texas is located in the lower Rio Grande Valley in the counties of Cameron, Hidalgo, and Willacy. This area is the 4th largest source of U.S. sugarcane and the home of the sole sugar mill currently operating in Texas. (IPM, 2003) The Rio Grande Valley Sugar Growers, Inc (RGVSG) is a member-owned cooperative comprised of over 125 growers in a three-county area. Together, the facility processes more than 1.5 million tons of sugar cane annually, producing nearly 160,000 tons of raw sugar and 60,000 tons of molasses. (RGVSG, 2007)

Resource Characterization

Bagasse is the matted cellulose fiber residue from sugar cane that has been processed in a sugar mill. Historically, bagasse was burned as a means of solid waste disposal, although today most bagasse is burned as fuel in on-site boilers. The composition, consistency, and heating value of bagasse varies and is dependent on factors such as climate, soil type, cane variety, harvesting method, amount of cane washing, and the efficiency of the milling plant. In general, bagasse has a heating value between 3,000-4,000 Btu/lb on a wet, as-fired basis. Most bagasse has moisture content between 45 and 55 percent by weight. (EPA, 1993) Sugarcane harvesting period is from October to April. The RGVSG sugar mill operates for six months during the sugarcane harvesting season. During the off-season, the facility is assumed to be non-operating. As shown in Table 2-31, approximately 280,775 dry tons of bagasse is available for waste-to-energy plants in Texas. With an energy content of about 3,500 Btu/lb, bagasse offers nearly 2 million MMBtu of gross energy that can support waste-to-energy projects.

Table 2-31: Statewide Bagasse Resource

Fuel Type	Fuel Quantity (dry tons)	Energy Content (BTU/lb)	Gross Energy (MMBtu)
Bagasse	280,775	3,500	1,965,425

CHP Opportunity

The potential for waste-to-energy plant development using bagasse is excellent, and the state’s sole sugar mill has historically used such a system. Currently in operation is a 7.5 MW system consisting of three 2.5 MW steam turbines, although the mill is currently expanding the facility to implement a 16 MW steam. The waste-to-energy plant utilizes direct combustion of the biomass waste to generate high pressure steam. A backpressure steam turbine is used to produce electricity, while thermal energy can be removed to meet the thermal needs of the mill, including boiling sugar juices, molasses production, and other process needs. When the larger facility is completed, it will generate sufficient electricity and heat to meet its needs, while allowing an addition 4.5 MW to be exported to the Texas electrical grid.

With 280,000 dry tons of bagasse, we estimate that the mill could operate a 13.4 MW steam turbine around the clock for six months out of the year. If this system operates for only two shifts per day a larger system could be implemented. The CHP system would generate about 55,588 MWh. Electrical loads to handle and process the bagasse waste stream are estimated to reduce this output by 30%, leaving about 38,912 MWh of electricity to power the mill, with any surplus energy being available for export to the electrical grid. The system would produce about 566,505 MMBtu per year, although only about 271,922 MMBtu per year is estimated to be recoverable to meet existing thermal needs at the mill and potentially any nearby facilities. Summary information for the potential CHP waste-to-energy plant is provided in Table 2-32.

Table 2-32: Sugarcane Bagasse Waste-to-energy Plant

CHP System Overview	
Gross Capacity Rating (MW)	13.4
Net Capacity (MW)	9.4
Gross Electrical Energy (MWh/yr)	55,588
Net Electrical Energy (MWh/yr)	38,912
Gross Heat Produced (MMBtu/yr)	566,505
NetHeat Recoverable (MMBtu/yr)	271,922

Data and Methodology

Biomass Data Collection

Sugarcane bagasse values were obtained by first averaging county production of sugarcane for the years 2000-2005. (NASS, 2006) We assumed that of the total quantity of sugarcane harvested 30% will become bagasse. (Rangnekar, 1986) A moisture level of 45% was used to determine total dry matter. (EPA, 1996) The final calculation using was:

$$\text{Bagasse (dry tons)} = \sum \text{crop harvested (tons)} \times 0.30 \times 0.55$$

Data

Table 2-33: Bagasse Wastes (Top Texas Counties)

Hidalgo County	132,539 dry tons
Cameron County	108,303 dry tons
Willacy County	38,462 dry tons

2.11 Peanut Hulls

Peanut shellers and processing plants provide a number of peanut products including raw shelled and raw in shell peanuts, blanched peanuts, crude peanut oil, peanut meal, and specialty products like peanut flour, aromatic roasted peanut oil, and peanut extract. Shellers also provide the fiber products using the peanut hulls. Peanut hull products are primarily used in animal feed, as pesticide and fertilizer carriers, and as industrial absorbents. Peanut hulls are an excellent source of cellulose and crude fiber. Principal advantages of peanut hulls are their high liquidity absorbency, chemical inertness and biodegradability. Demand for peanut hull products is high, so any potential for waste-to-energy facility development using this resource would have to offer economic advantages exceeding current uses.

Texas has four peanut shelling facilities in Texas. Birdsong Peanuts operates the largest shelling plant in Brownfield, TX. Golden Peanut, LLC operates two plants, one in Seagraves and the other in DeLeon. Wilco Peanut Company operates a shelling plant in Pleasanton, Texas. The top two shellers, Birdsong and Golden Peanut, are located within 60 miles of each other. (TPPB, 2007)

Resource Characterization

Peanut hulls are the shells in which the nut grows. Shells have a low moisture content of 6% and high relative energy content over 8,000 Btu/lb, which makes them an excellent candidate for boiler fuel. Although the Texas peanut crop is seasonal, peanut shelling and processing occurs throughout much of the year, typically from around October to July of the following year. Peanut quantities shelled at Texas facilities are highly correlated with the Texas crop, and this analysis assumes no imports or exports of peanuts from the state. As shown in Table 2-34, approximately 73,429 dry tons of peanut hulls with a gross energy content of about1.2 million MMBtu are available to support waste-to-energy plants in Texas.

Table 2-34: Peanut Hull Waste Stream

Fuel Type	Fuel Quantity (dry tons)	Energy Content (BTU/lb)	Gross Energy (MMBtu)
Peanut Shells	73,429	8,031	1,179,411

CHP Potential

The potential for waste-to-energy plant development at a peanut shelling facility using peanut shells is excellent. The waste-to-energy plant is assumed to utilize direct combustion of the hulls to produce high pressure steam fed into a backpressure steam turbine to generate electricity. The thermal energy recovered can be used to meet the thermal needs of the mill, which includes roasting in ovens up to 800 degrees F, hot water and steam for blanching, and other warm and cool temperature processing to control moisture and final product quality.

Texas peanut shelling plants typically operate 5-6 days per week, 8-10 hours per day for about 9 to 10 months each year. Assuming that the 73,000 dry tons of hulls are evenly split among the four Texas peanut mills, a 1.4 MW steam turbine could be operated at each mill on a 24/7 basis during the operating months. Each CHP system would generate about 8,455 MWh of electrical energy annually, however new electrical loads needed to handle and process the hulls for use in the waste-to-energy plant are estimated to reduce this output by 30%, leaving about 5,919 MWh of electricity to power the mill's existing loads. Any surplus energy would be available for export to the electrical grid. Each system would produce about 195,009 MMBtu per year, although only about 93,604 MMBtu per year is estimated to be recoverable to meet existing thermal needs at the plant. A larger system could be implemented if the system was turned down at off-peak times or operated only part of the year. Summary information for the potential CHP waste-to-energy plant is provided in Table 2-35.

Table 2-35: Peanut Hull Waste-to-energy Plant (Typical Shelling Plant)

CHP System Overview	
Gross Capacity Rating (MW)	1.4
Net Capacity (MW)	0.9
Gross Electrical Energy (MWh/yr)	8,455
Net Electrical Energy (MWh/yr)	5,919
Gross Heat Produced (MMBtu/yr)	195,009
NetHeat Recoverable (MMBtu/yr)	93,604

Due to the proximity of the two largest plants to each other and to Lubbock, an area with a variety of other biomass waste streams including cattle manure for example, the potential exists for a larger plant fueled with an appropriate combination of peanut hull waste with other resources. The value of such a system would depend highly on the existence of a high quality thermal load well-matched to the output of the system, and to the transportation costs needed to aggregate the resources in a central location.

Data and Methodology

Peanut shell values were obtained by determining the average peanut production rate for Texas for 2004, 2005, and 2006. (USDA, NASS, 2006) Peanut shell weight is assumed to be 20% of the weight of peanut. About 6% of the Texas crop is assumed to be sold as unshelled product. The shell moisture content is assumed to be 6%. (Golden, 2007) The final calculation used to estimate the peanut hull availability in Texas is:

$$\textit{Peanut hulls (dry tons)} = \textit{Avg. Texas peanut production} \times 0.20 \times 0.94 \times 0.94$$

Data Collection Concerns and Comments

This data assumes that Texas peanut shellers process only the Texas peanut crop (i.e., no imports or exports of peanuts from the state). Data on production rate was only available for 2004 through 2006, which may be too short of a time to capture long-term averages.

3.0 Future Energy Possibilities in Agriculture

Introduction

Bioenergy and biobased products – produced from resources such as crops, trees and agricultural, industrial, municipal and forestry wastes – hold great promise for the U.S economy. Harnessing the molecular building blocks and components of plants to heat our homes, run our cars, light our buildings, and provide industrial and consumer products for every day use can substantially improve our economy, national security and environment.

The area of biobased products represents a major new market for domestically grown biomass resources. It will be a new source of revenue for not only those who produce the feedstocks, but also for the farmers and others who are involved in the production of biobased products themselves. Currently, production of biobased textile fibers, polymers, adhesives, lubricants, soy-based inks, and other products is estimated at 12.4 billion pounds per year. (BIO, 2002) The growth opportunities for biobased products are predicted to be substantial.

Texas produces a significant amount of agricultural wastes that can be used to generate energy and also processed into additional products through biorefineries. While still in the conception phase, the establishment of a biobased industry in Texas offers another outlet for certain agricultural wastes. In addition, Texas has begun creating the necessary infrastructure and incentives to support a robust biorefinery industry. The recently formed BioEnergy Alliance between Chevron and Texas A&M University creates a focused research unit in the state. Feedstock availability, the critical key to success, is readily met by the nearly 8 million dry tons *agriculture-based* biomass annually by just the twelve resources analyzed in this report. Finally, the state has established the Texas Biofuel Incentive Program that rewards biofuel producers for producing ethanol and biodiesel. These factors make Texas a prime contributor to the nation's growing biobased industry.

This chapter discusses the existing infrastructure, opportunities and hurdles involved in establishing a robust biobased industry as a step beyond utilizing biomass resources for energy production.

The Biorefinery Concept

Industrial biorefineries have been identified as the most promising route to the creation of a new domestic biobased fuels industry. The Biomass Research and Development Technical Advisory Committee (2002) of the U.S. Departments of Energy and Agriculture defines a biorefinery as:

> *"A processing and conversion facility that (1) efficiently separates its biomass raw material into individual components and (2) converts these components into marketplace products, including biofuels, biopower, and conventional and new bioproducts."*

The biorefinery concept is analogous to today's petroleum refineries, which produce multiple fuels and products from petroleum. Wet corn milling and pulp & paper refineries are also examples of existing biorefineries. By producing multiple products, a biorefinery can take advantage of the differences in biomass components and intermediates and maximize the value derived from the biomass feedstock. A biorefinery might, for example, produce one or several low-volume, but high-value, chemical products and a low-value, but high-volume liquid transportation fuel, while generating electricity and process heat for its own use and perhaps enough for sale of electricity. The high-value products enhance profitability, the high-volume fuel helps meet national energy needs, and the power production reduces costs and avoids greenhouse-gas emissions.

Besides the existing corn to ethanol biorefineries, there are two other types of advanced biorefineries – lignocellulosic and oleochemical. Lignocellulosic biorefineries are of the greatest interest because cellulosic ethanol is the only viable scenario to replace 30% of the U.S. petroleum use. (NREL, 2006) Lignocellulosic biomass is composed of two polysaccharides -- cellulose (30-57%) and hemicellulose (8-40%) -- and lignin (11-25%), a complex polymer that provides structural integrity in plants. (DOE, 2007) (Rials, 2007) Corn stover is the dominant near-term source of agricultural cellulosic biomass, with substantial contributions from wheat straw, other small grain straw, soybeans and corn fiber. (BIO, 2006) Determining how to convert lignocellulosic biomass feedstocks, such as corn stover, sugarcane bagasse and straw, into ethanol and other biobased products is the current focus of research and development efforts in the United States.

The Biorefinery Industry

Petroleum refining and wet corn milling were both born in the middle of the 19th century: the first wet mill opened in 1844; the first petroleum refinery in 1861. Both began by producing single products – kerosene and starch. Each has since evolved continuously, creating increasingly diverse product portfolios in response to an ever-changing marketplace. Now wet corn mills produce various starch derivatives such as lactic acid, lysine and citric acid along with other by-products such as corn oil and animal feed. These could be considered simple biorefineries.

The major driving force behind the multi-product refinery concept is improved process economics. A petroleum refinery, for example, can significantly improve its profit margin by co-producing high value products such as lubricants. Corn wet mills are fewer in number than petroleum refineries in the U.S. and more uniform in terms of processing: all wet mills have the same basic configuration. They do, however, vary in size: daily dry grind capacities range from 35,000 bushels per day to more than 500,000 bushels per day.

The U.S ethanol industry is in a period of unprecedented expansion driven primarily by rising oil prices, national security concerns, and federal and state mandates. Current ethanol or biopolymer plants add fermentation units and residue processing to the corn milling process. However, in response to the increasing demand for ethanol, several producers have announced plans to begin construction of integrated biorefineries for the production of ethanol from cellulosic biomass. These biorefineries will be substantially more complex, requiring pre-treatment and enzyme production units upstream of fermentation and reprocessing of residues for power or coproducts. In this scenario the whole corn plant, for instance, will be converted to a variety of products including ethanol, bioplastics, renewable chemicals, food and feed. Industry experts predict that Texas's fledging ethanol industry will be producing 500 million gallons of ethanol per year by 2008.[6] This is the first step towards establishing lignocellulosic biorefineries in the state.

Texas Ethanol Plants under Development

- **Panhandle Energies**, Dumas - 30 million gallons/year; feedstock is corn and milo; Announced late 2004
- **White Energy**, Hereford (Panhandle) - 100 million gallons/year; feedstock is corn and milo; Operational by May 2007
- **Panda Energy**, Hereford (Panhandle) - 100 million gallons/year; feedstock is corn and milo; fuel is cattle manure and cotton gin waste; Operational by second half of 2007
- **Panda Energy**, Sherman County (Panhandle) - 100 million gallons/year; feedstock is corn and milo; fuel is cattle manure biogas; Operational by fourth quarter of 2007
- **Biofuels Energy Corporation**, Raymondville - 4 million gallons/year; Texas' first cellulosic ethanol plant (demonstration project); Operational by third quarter of 2006
- **Texas BioEnergy Marketing Associates**, Central Texas - five distilleries at 12 million gallons/year each; feedstock is sweet sorghum; Announced June 2006
- **Blackland Ethanol Corporation**, Central Texas - 50 million gallons/year; feedstock is corn and milo; Announced July 2006

Challenges of Cellulosic Biomass

The core challenge to utilizing cellulosic biomass is to determine the best method to convert these feedstocks into ethanol. Cellulose is resistant to hydrolysis, the chemical reaction that releases simple, fermentable sugars from a polysaccharide. Hemicellulose is relatively easy to hydrolyze but difficult to ferment into ethanol. Lignin remains as residual material after the sugars in the biomass have been converted to ethanol. It contains a lot of energy and can be burned to produce steam and electricity for the biomass-to-ethanol process. (DOE, 2007)

Both corn grain and cellulosic feedstocks are composed of about 70 percent sugars, making them good candidates for ethanol production. The challenge lies in extracting the sugars from these feedstocks. In corn grain, the sugars are all of the same variety, joined together with relatively simple bonds to form starch. These simple bonds are easily broken using commonly available amylase enzymes and water in a process called hydrolysis. In contrast, isolating sugars in cellulosic biomass is much more complicated due to the mixture of C6 and C5 sugars and their complex chemical bond with lignin. The biomass must first be pre-treated to separate the lignin and loosen the chemical bonds. Cellulase enzymes can then be used to break the sugar-to-sugar bonds via hydrolysis. (BIO, 2006)

A lignocellulosic biorefinery will produce ethanol via fermentation as its primary product. Carbohydrate derivatives such as nutritive sweetener and lactic acid, currently produced from corn-based biorefineries, are also appropriate secondary products for these fiber-based biorefineries. However, converting lignocellulosic biomass to ethanol is currently too expensive to produce commercially. Although recent biotech advances have made

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[6] Texas State Energy Conservation Office website: http://www.seco.cpa.state.tx.us/re_ethanol_plants.htm

significant improvements in cellulase enzymes and pentose-processing microbes, closing the gap on making cellulosic biomass conversion to ethanol economical.

Cellulosic biomass processing is expected to generate in excess of $4 billion annually in feedstock sales in the United States by 2010, growing to more than $15 billion annually by 2020, according to the Biomass Technical Advisory Committee to the USDA and DOE. (BIO, 2006) The following list contains brief descriptions of select projects currently in development worldwide.

- **Iogen Corporation** – In April 2004, the company delivered the world's first commercial-use ethanol fuel from cellulose (from wheat straw) at their 3 million-liter-per-year (800,000-gallon-per-year) demonstration plant in Ottawa, Canada. Their facility represents the final proving stage prior to the rollout of full-scale commercial ethanol from cellulose biorefineries, each designed to processed annually more than 1.5 million dry tons of crop residues into 100 million gallons of ethanol.
- **Abengoa Bioenergy** – In early October 2006, the company broke ground on a one-ton-per-day ethanol from cellulose pilot plant adjacent to its corn dry mill plant in York, Neb. The pilot biorefinery will be integrated to process cellulose from distiller dry grains (DDGs) and agricultural residues. In addition, the company is currently constructing the world's first commercial-scale ethanol from cellulose demonstration plant, a 1.3 million-gallon-per-year wheat straw to ethanol plant in Salamanca, Spain. The facilities are expected to be operational in 2007 and 2006 respectively.
- **DuPont** has teamed with Pioneer, Deere & Company, Michigan State University, NREL and Diversa, to develop an integrated corn-based biorefinery that would produce fuels and chemicals from the entire corn plant. DuPont has also partnered with BP to develop biobutanol, a more energy-rich fuel alcohol, first from starch and eventually from cellulose.
- **Broin** has announced plans to partner with DuPont to add cellulose capacity to an existing corn ethanol facility in Iowa. The plant will use a proprietary technology to remove the cellulose-rich bran from the kernel for processing with corn stover in the cellulosic unit. Ethanol yield is expected to increase 27 percent per acre. Broin has also partnered with Novozymes to develop a cold "no cook" starch hydrolysis process that substantially reduces energy inputs for starch ethanol.
- **Mascoma** has a cellulose-to-ethanol technology platform ready for demonstration and commercial products. With substantial investment from the VC community, Mascoma is creating partnerships, engineering designs and financing relationships to jointly develop ethanol from cellulose plants using a variety of feedstocks.

For these and other projects to become successful, a large, reliable, economic and sustainable feedstock is required. Current yields for ethanol from agricultural residues (corn stover, straw from wheat, rice and other cereals, and sugarcane bagasse) are about 65 gallons per dry ton. (BIO, 2006) Thus, a moderately sized 65 million-gallon-per-year cellulosic biorefinery would need 1 million dry tons per year of feedstock. Using the figures in this report for the same feedstocks, Texas has the potential to produce almost 400 million gallons of cellulosic ethanol. In addition to feedstock availability, a commercial-scale biorefinery should have cropland that meets the following criteria:

- **Large Area:** Minimum of 500,000 acres of available cropland;
- **Sustainable:** Cropping practice maintains or enhances long-term health of the soil;
- **Reliable:** Consistent crop supply history with dry harvest weather;
- **Economic:** High-yielding cropland; and
- **Favorable Transport:** Easy access from field to storage and processing facilities

Biobased Products from Advanced Biorefineries

Ethanol, food products, and pharmaceuticals are familiar biobased products. Advances in biorefinery technology are creating the possibility for producing industrial bulk and specialty chemicals from biobased feedstocks, replacing chemicals derived from crude oil.

The economics vary, but some biobased products have cost advantages over equivalent petroleum-based products, while others are experiencing declining cost premiums. Recently, some government entities and private businesses have begun specifying purchasing preferences for biobased products, increasing market demand. These trends suggest the opening of tremendous market opportunities for biobased products.

Although biobased feedstocks can be readily converted to fuels, profits can be enhanced by first extracting the highest value components out of the biobased product, and using residuals as fuel. For example, a food products company extracts valuable food flavoring from pyrolytic bio-oil, derived from sawdust, prior using the residual bio-oil as a boiler fuel. Other chemicals obtainable from pyrolytic bio-oil are resins for binding wood composites, and specialty chemicals.

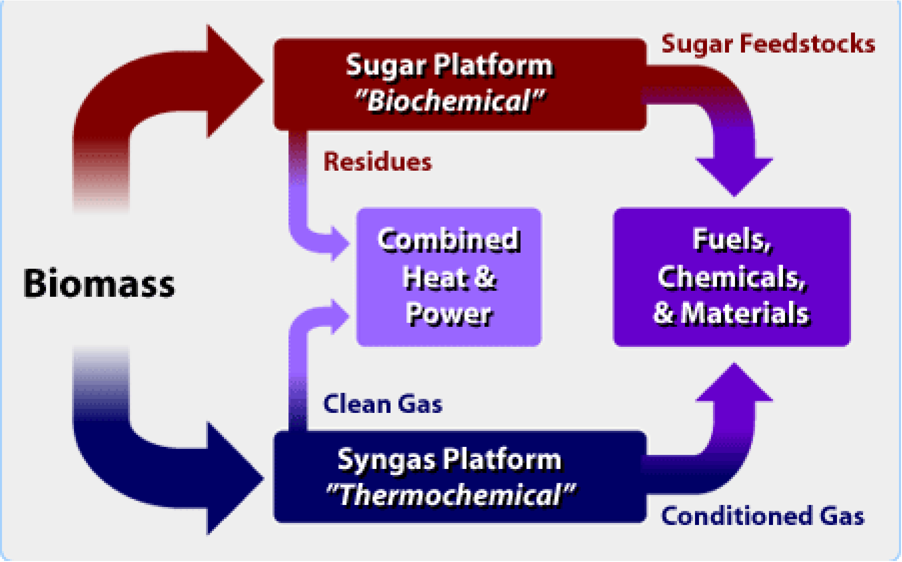
Some biobased products may be considered "platform" chemicals, from which many different products can be derived through additional process steps. For example, lactic acid can be produced through fermentation of sugar or starch. Lactic acid can be used as a feedstock to produce a biobased plastic, an environmentally-friendly solvent (ethyl lactate), and several other chemicals.

Role of Combined Heat and Power in a Biorefinery

The development of a biorefinery industry in Texas would also benefit the combined heat and power industry. As with petrochemical refineries, biorefineries will require electric power and heat for operation. Regardless of a given biorefinery core technology (biological or thermochemical) residue streams will be generated, e.g., bark, hog-fuel, and lignin. For optimum material, energy, economic, and environmental efficiency, these residues must be utilized. While some residues may be suitable as co-products, others will be better suited for conversion to on-site power and heat.

Thermochemical gasification of biomass residues to syngas is the preferred conversion route to combined heat and power generation because it is a fast, high yield process that is potentially omnivorous. In addition, syngas has been demonstrated in reciprocating internal combustion engines (ICEs) and gas turbines, with little modification from natural gas-based units. Furthermore, the potential exists for effective use of the product gas as fuel for high temperature fuel cells, such as the solid oxide type. (NREL, 2007)

Figure 3-1 Biorefinery Concept



Source: NREL, http://www.nrel.gov/biomass/biorefinery.html

Dry mill ethanol plants are an excellent application for CHP. They have large and relatively constant power and steam demands, and they operate 24 hours a day, 365 days a year. The size of the electricity and steam loads at ethanol plants closely matches the size of commonly available CHP technologies. Energy represents a large potion of dry mill ethanol production costs, second only to the cost of the corn used as the feedstock. Despite CHP's excellent fit, adoption in this industry has been slow. Currently, only five U.S. dry mill ethanol facilities incorporate CHP into their operations. (EPA, 2006)

A variety of CHP system options are available for dry mill ethanol facilities:

- **Gas turbines**, which are most commonly used in ethanol plants. Typically, these systems include a gas turbine-electric generator used with a waste heat boiler to provide electricity and process steam for the facility. If sized to the plant's electric load, additional steam capacity will be needed.
- **Boiler/steam turbines**, which generally have the shortest payback, but have limited electric capacity.
- **Gas turbine/supplemental firing**, which can provide about one-third of a plant's steam needs if sized to meet electric needs. With supplemental firing, this type of system can be sized to meet both steam and electric demands.
- **Biomass fueled**, which is the least-cost fuel option, but the most capital intensive. Distillers dried grains with solubles (DDGS-a byproduct of the ethanol production process) or other agricultural or forest waste can be used as the fuel source.
- **Integrated VOC destruction**, which can provide a low-cost solution for reducing VOC emissions from distilled grain solids dryers. Options for integrating VOC destruction into the generation process include producing power with steam recovered from conventional thermal oxidizers, or incorporating VOC destruction in gas turbine or boiler/steam turbine systems.

Wet corn mill facilities are typically larger than dry mills. Steam and power systems are also typically more complex. Large wet-mills often use coal fired boilers to produce high-pressure steam which is then let down across a steam turbine to produce power and low-pressure steam for processing heating. Natural gas fired combined heat and power systems are found more frequently in small to mid-sized facilities. Electrical power and thermal requirements for a wet mill producing ethanol are approximately them same as for a dry mill when compared on a per bushel grind basis. Thus, the power to heat ratio for both types of facilities is roughly 0.10-0.15 depending on whether superheated steam or fired heat is used for the drying operations. This relatively low ratio suggests that most cogeneration systems were designed primarily for steam production. (EPA, 2006)

The large corn wet milling industry is not driven primarily by a need for fuels and power. Each of the major corn wet milling companies manufactures ethanol as an alternative to higher-value products as markets dictate. In the future these biorefineries may also produce fermentation commodity bioactive compounds for animal and human therapeutic needs. In contrast, operators of the dry mill ethanol plants, which are devoted primarily to a single product, are motivated to find ways to improve the efficiency of ethanol manufacture and to adding the technology that will allow production of higher value products. Addition of more sophisticated fermentation and separation technologies will be required for significant additions to product diversity. However, the most significant impact of biorefineries on energy, greenhouse gases and climate change is likely to come from the conversion of lignocellulosic materials to ethanol.

Opportunities for Texas

The agricultural feedstock and chemicals subsector of the biosciences industry applies life sciences knowledge and biotechnologies to the processing of agricultural goods and the production of organic and agricultural chemicals such as ethanol, fertilizers and sustainable lubricants. According to the Biotechnology Industry Organization (BIO), in 2004, there were over 200 establishments operating in this subsector in Texas with a total employment of over 11,000 people. (Battelle, 2006) Texas, along with three other states, leads the nation in terms of employment in this subsector.

Texas is the nation’s largest chemicals producer, manufacturing 14 percent of the nation’s value of chemical output. The Gulf Coast complex of chemical plants and refineries is the largest petrochemical complex in the world, home to over 200 chemical plants. While the state’s largest complex of chemical plants is along the Gulf Coast, the industry itself is much more extensive. At least 124 out Texas’s 254 counties have some amount of chemical manufactured output. (TIP, 2005) The development of a biobased industry in the state will help reduce consumer costs by moving away from petroleum-based products and expand economic development opportunities into the state’s rural communities.

Texas has enormous quantities of lignocellulosic biomass at its disposal. In this study, we estimated that Texas could generate at least 7.8 million dry tons of agriculture-based biomass annually, including nearly 2.5 million tons of corn stover, cereal grains and sugarcane bagasse. Feedstock availability is crucial to a successful biorefinery and Texas is fortunate that much of its agricultural cellulosic biomass is concentrated in the Panhandle and Central Texas regions.

A fledging ethanol industry is finding roots in the Panhandle region with at least four ethanol plants predicted to be fully operable by the end of 2007. Two plants will be located in

Hereford (Deaf Smith County), one in Levelland (Hockley County) and a fourth in Dumas (Moore County). Together these plants will produce an estimated 270 million gallons of ethanol per year. In addition, the National Ethanol Board's E85 Refueling Station Database indicates a total of 37 refueling stations either open or under construction within Texas.

The Texas Department of Agriculture established the Texas Biofuel Incentive Program in 2006 to reward biofuel producers for producing ethanol and biodiesel. The program allows for Texas biofuel producers to register with the department to become eligible to receive grants based on the amount of biofuel produced by their facilities. Qualified producers will receive 20 cents per gallon of ethanol or biodiesel produced, limited to the first 18 million gallons produced per year for the first 10 years. (SECO, 2007)

Regarding research and development, the recently established Texas A&M University Agriculture and Engineering BioEnergy Alliance (http://bioenergy.tamu.edu) formed by the Texas A&M University System and two of its premier research agencies – Texas Agricultural Experiment Station and Texas Engineering Experiment Station - will address the growing global demand for clean, renewable alternative fuels. The Alliance will advance research projects on biomass feed stocks, biomass energy conversion, biofuels processing, biomass-enabled emissions reduction, next-generation engines and vehicles, and integrative systems engineering for new technologies. The formation of this research unit, focused on bioenergy and biorefineries, uniquely positions Texas to receive federal funding such as the most recent DOE solicitation announced in early May 2007 regarding the development of smaller-scale cellulosic biorefineries.

Conclusion

There is tremendous technical potential for combined heat and power technologies in Texas's agricultural sector. An analysis of just twelve resources revealed an estimated 111.8 MMBtu of gross energy potential. The technical success of a CHP system is based largely on effectively utilizing the captured waste heat to produce steam or heat for hot water, space heating/cooling and refrigeration. The coincident thermal needs of dairy farms, cotton gins, and meat processing plants make these sites solid candidates for combined heat and power systems.

Utilizing agricultural wastes as fuel for combined heat and power systems also provides support to the establishment of a new biobased industry in Texas. Recent activities including construction of ethanol plants, the establishment of research and development centers, and the availability of capital and incentives for start-up bio-based companies are generating significant moment in the state. The area of biobased products represents a major new market for domestically grown biomass resources. The challenge lies in discovering efficient methods to convert certain types of biomass wastes into usable building blocks for new products and determining the optimal allocation of agricultural resources for use in this new industry. Texas is well-positioned in terms of infrastructure, feedstock availability, and financial support to capitalize on future opportunities as advancements are made in research and development.

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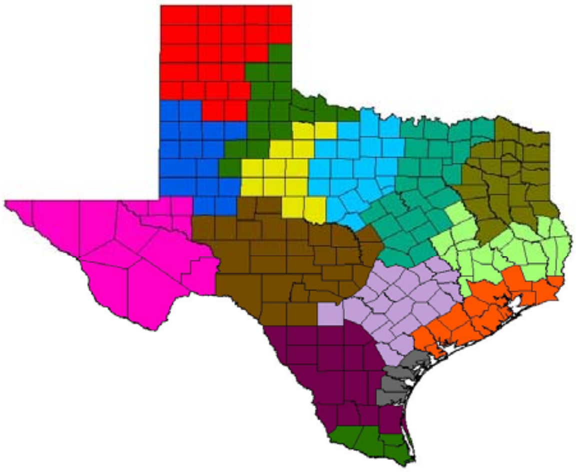
Appendix A

Texas Agricultural Districts



🟥	11	District 1 - North	Northern High Plain
🟦	12	District 1 - South	Southern High Plains
🟩	21	District 2 - North	Northern Low Plains
🟨	22	District 2 - South	Southern Low Plains
🟦	30	District 3	Cross Timbers
🟩	40	District 4	Blacklands
🟫	51	District 5 - North	North East Texas
🟩	52	District 5 - South	South East Texas
🟪	60	District 6	Trans-Pecos
🟫	70	District 7	Edwards Plateau
🟪	81	District 8 - North	South Central
⬛	82	District 8 - South	Coastal Bend
🟧	90	District 9	Upper Coast
🟥	96	District 10 - North	South Texas
🟩	97	District 10 - South	Lower Valley

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Appendix B
Agricultural Waste Conversion Technologies

1.0 Direct Combustion

Combustion is the simplest method by which biomass can be used for energy, especially in the form of heat. When biomass is directly-fired, or burned it must first be dried, as dry wood burns more efficiently, sized into smaller pieces, and then briquetted. Briquetting "is a densification process of loose organic material, such as rice husk, sawdust and coffee husk, aiming to improve handling and combustion characteristics." Once preparation is complete, the biomass is added to a furnace or a boiler to generate heat which is then run through a turbine which drives an electrical generator. The heat generated by the exothermic process of combustion to power the generator can also be used to regulate temperature of the plant and other buildings, making the whole process much more efficient.[1]

The most common ways to combust biomass are either in a direct-fired system or in a conventional steam boiler. Both systems burn biomass feedstocks directly to produce steam which in turn creates electricity. Differences in the methods lie within the boiler or furnace structure. In a direct-fired system, biomass is loaded in from the bottom of the boiler and air is supplied at the base. In a conventional steam boiler, the draft is forced in through the top but the biomass is also bottom loaded.[2] The figure below illustrates a typical direct-fired biomass electricity generating system configuration.

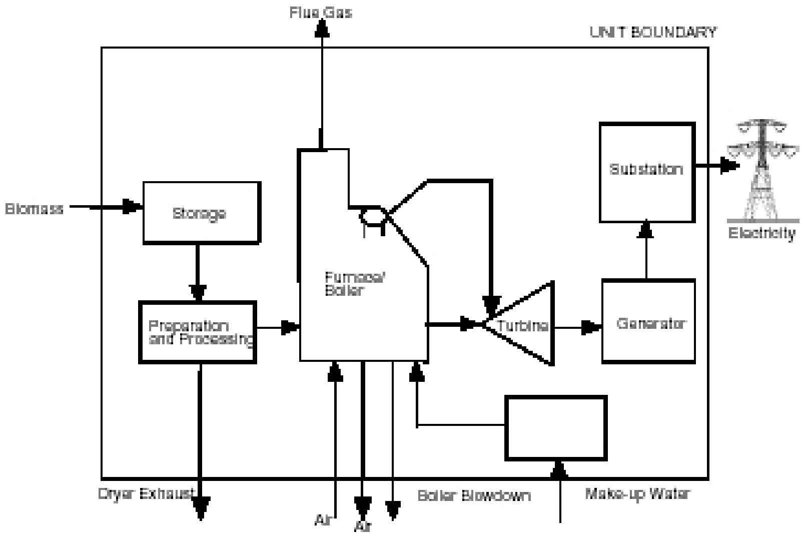

Figure 1. Direct-fired biomass electricity generating system schematic.

Source: Renewable Energy Policy Project, http://www.crest.org/bioenergy/direct-fired.jpg

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[1] Oregon State Department of Energy, "Biomass Energy," URL: *http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml#combustion (1/9/08)*

[2] Renewable Energy Policy Project website: *http://www.repp.org/bioenergy/link4.htm#DirectFired (2/26/07)*

Biomass Combustion Boilers[3]

The following are major types of biomass boilers.

Pile burners

Pile burners consist of cells, each having an upper and a lower combustion chamber. Biomass fuel burns on a grate in the lower chamber, releasing volatile gases. These gases then burn in the upper (secondary) combustion chamber. Operators must shut down pile burners periodically to remove ash. Although capable of handling high-moisture fuels and fuels mixed with dirt, pile burners have become obsolete with the development of more efficient combustion designs with automated ash removal systems.

Stationary or traveling grate combustor

A stationary or traveling grate combustor consists of an automatic feeder that distributes the fuel onto a grate, where the fuel burns. Combustion air enters from below the grate. In the stationary grate design, ashes fall into a pit for collection. In contrast, a traveling grate system has a moving grate that drops the ash into a hopper.

Fluidized-bed combustor

Fluidized-bed combustor consists of a hot bed of granular material, such as sand, where the biomass fuel is burned. Injection of air into the bed creates turbulence resembling a boiling liquid. The turbulence distributes and suspends the fuel. This design increases heat transfer and allows for operating temperatures below 972° C (1700° F), reducing nitrogen oxide (NOx) emissions. Fluidized-bed combustors can handle high-ash fuels and agricultural biomass residue.

Conventional combustion equipment is not designed for burning agricultural residues. Straws and grasses contain potassium and sodium compounds. These compounds (called alkali) are present in all annual crops and crop residues and in the annual growth of trees and plants. During combustion, alkali combines with silica, which is also present in agricultural residues. This reaction causes slagging and fouling problems in conventional combustion equipment designed for burning wood at higher temperatures.

Volatile alkali lowers the fusion temperature of ash. In conventional combustion equipment having furnace gas exit temperatures above 1450° F, combustion of agricultural residue causes slagging and deposits on heat transfer surfaces. Specially designed boilers with lower furnace exit temperatures could reduce slagging and fouling from combustion of these fuels.

Additional details on direct fired systems are available from the U.S. Environmental Protection Agency Report, "Biomass Combined Heat and Power Catalog of Technologies," September 2007, pg. 30-45.

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[3] All information contained in this section was directly obtained from the Oregon State Department of Energy website at: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml#Industrial_Biomass_Combustion

2.0 Anaerobic Digester

Anaerobic digester gas is a gas recovered from the decomposition of organic material by bacteria in the absence of oxygen. An anaerobic digester is a sealed, heated enclosure that provides a suitable environment for naturally occurring anaerobic bacteria to convert waste into methane gas. The source material is typically high moisture content organic wastes including animal manure, mill sludge, and animal processing wastes. The bacteria consume the waste and break it down into a low Btu biogas comprised of 50-80 percent methane and 20-50% carbon dioxide. Anaerobic digester biogas can provide a steady and reliable source of fuel for reciprocating engines, combustion turbines, and fuel cells or simply combusted in a boiler to produce steam.

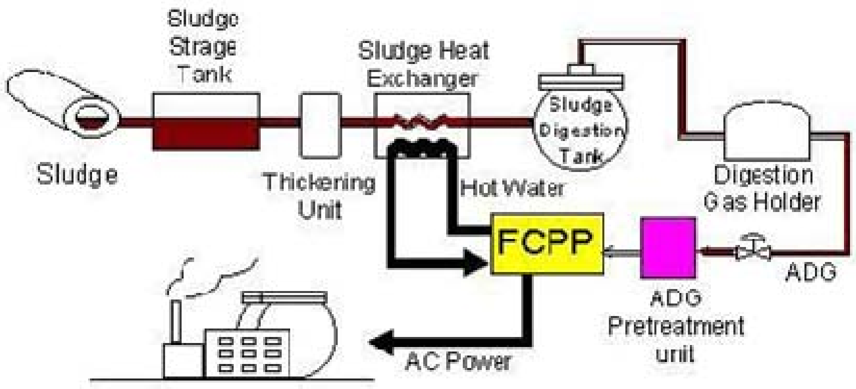

Figure 2-13. The Anaerobic Digestion Process: Converting Waste to Energy
Source: www.toshiba.co.jp/product/fc/fce/adg.htm

Anaerobic digestion works in a two-stage process to decompose organic material (i.e., volatile solids) in the absence of oxygen, producing bio-gas as a waste product. In the first stage, the volatile solids in manure are converted into fatty acids by anaerobic bacteria known as "acid formers." In the second stage, these acids are further converted into bio-gas by more specialized bacteria known as "methane formers." With proper planning and design, this anaerobic-digestion process, which has been at work in nature for millions of years, can be managed to convert a farmer's often problematic waste-stream into an asset.[4]

Biogas recovery systems have four basic components: a digester, a gas-handling system, a gas-use device, and a manure storage tank or pond to hold the treated effluent prior to land application. Biogas digester systems can accommodate manure handled as a liquid, slurry or semi-solid (with little or no bedding added). The total solids content of the manure – a measure of manure thickness – determines these classifications. Facilities best suited for biogas digester systems typically have stable year-round manure production and collect at least 50 percent of the manure daily.[5]

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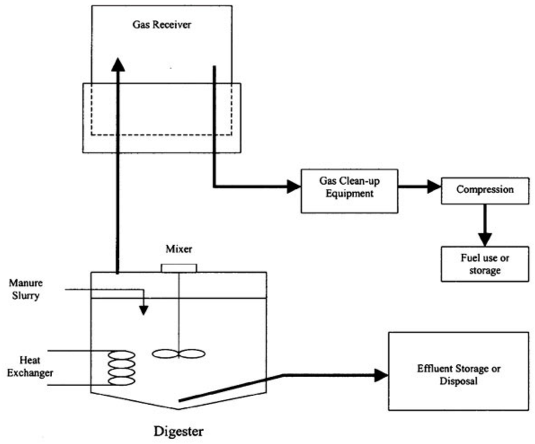
[4] Balsam, John, “Anaerobic Digestion of Animal Wastes: Factors to Consider,” Appropriate Technology Transfer for Rural Areas (ATTRA), October 2002

[5] U.S. Environmental Protection Agency, “Managing Manure with Biogas Recovery Systems: Improved Performance at Competitive Costs,” Winter 2002

Figure A-1. Basic Components



Types of Anaerobic Digesters[6]

The following are major types of anaerobic digesters.

Covered Lagoons

A covered lagoon is a pool of liquid manure topped by a pontoon or other floating cover. Seal plates extend down the sides of the pontoon into the liquid to prevent exposure of the accumulated gas to the atmosphere. Designed to use manure with 2% or less solid content, this type of digester requires high throughput in order for the bacteria to work on enough solids to produce gas. Most frequently used in warmer southern regions, where the atmospheric heat can help maintain digester temperatures, this is the least expensive of all designs to install and operate. About a third of all digesters presently in use are covered-lagoon systems.

Complete mix digester

A complete mix digester is a silo-like tank in which the manure is heated and mixed, designed to handle manure with 2-10% solids. This is the most expensive system to install and operate, but it's particularly appropriate for operations that wash out their manure. Less than a third of all digesters in use are of this type.

Plug flow digester

A plug flow digester is a cylindrical tank in which the gas and other by-products are pushed out one end by new manure being fed into the other end. This design handles 11-13% solids and typically employs hot-water piping through the tank to maintain the necessary temperature. Most appropriate for livestock operations that remove manure mechanically rather than washing it out, the plug-flow system accounts for more than a third of all digesters presently in use.

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[6] U.S. Environmental Protection Agency, “Managing Manure with Biogas Recovery Systems: Improved Performance at Competitive Costs,” Winter 2002

U.S. Government Information Sources

U.S. Environmental Protection Agency, U.S. Department of Agriculture and U.S Department of Energy offer resources on the design and performance characteristics and benefits of anaerobic digesters. Of particular note is the AgSTAR Program, a voluntary effort sponsored by the three agencies (www.epa.gov/agstar). The EPA Office of Wastewater Management, Municipal Technologies Branch also offers resources and information about anaerobic digesters, although with a municipal waste water treatment facility focus. The USDA Natural Resources Conservation Services has published design guidelines for three types of anaerobic digesters, including covered lagoons, complete mix, and plug flow digesters.

3.0 Gasification

Biomass gasification is a two-stage process. In the first stage, called pyrolysis, heat vaporizes the volatile components of biomass in the absence of air at temperatures ranging from 450° to 600°C (842° to 1112° F). Pyrolysis vapor consists of carbon monoxide, hydrogen, methane, volatile tars, carbon dioxide and water. The residue, about 10 percent to 25 percent of the original fuel mass, is charcoal. The final stage of gasification is called char conversion. This occurs at temperatures of 700° to 1200° C (1292° to 2192° F). The charcoal residue from the pyrolysis stage reacts with oxygen, producing carbon monoxide.[7]

Biomass gasification produces a combustible mixture of raw gases that vary according to the feedstock and gasification approach. Steam reformed, indirect, and oxygen fired direct gasification systems produce biobased syngas (also called “producer gas”), a medium energy combustible and reactive mixture rich in hydrogen and carbon monoxide Air fired direct gasification systems produce a low-energy, biobased fuel gas.[8]

The main systems of a gasification plant are fuel feeding, gasification, and gas cleanup. Fuel feeding systems may direct feed the biomass fuel, pelletize the biomass, or dry and grind the fuel to a uniform size. Biomass gasifiers have been built and operated using a wide variety of designs including updraft and downdraft fixed beds, fluidized beds and moving grate bed reactors. Gas cleanup systems may contain several components such as cyclones, scrubbers or filters; each of which removes one or more byproduct contaminants. These systems may also include secondary equipment to adjust the gas composition and temperature.[9]

Gasification technology is in the development stage. A few demonstration projects exist that use varied gasifier designs and plant configurations. However, pretreatment of biomass feedstock is generally the first step in gasification. Pretreatment involves drying, pulverizing and screening. Optimal gasification requires dry fuels of uniform size, with moisture content no higher than 15 percent to 20 percent.[10]

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[7] Oregon State Department of Energy, URL: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml#Gasification

[8] Wisconsin Biorefining Development Initiative, URL: http://www.wisbiorefine.org/proc/biomassgas.pdf

[9] Ibid.

[10] Oregon State Department of Energy, URL: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml#Gasification

Types of Gasification[11]

The following are major types of gasification processes.

Updraft Gasification

The updraft gasification configuration is the oldest and simplest form of gasifier; and it is still used for coal gasification. Also known as counterflow gasification, the updraft gasifier introduces biomass at the top of the reactor, and a grate at the bottom of the reactor supports the reacting bed. Air or oxygen and/or steam are introduced below the grate and diffuse up through the bed of biomass and char. Complete combustion of char takes place at the bottom of the bed, producing carbon dioxide and water. These hot gases (~1000°C) pass through the bed above, where they are reduced to hydrogen gas and carbon monoxide and cooled to 750°C. Continuing up the reactor the reducing gases pyrolyse the descending dry biomass and finally dry the incoming wet biomass leaving the reactor at a low temperature (~500°C).

The updraft gasifier has the following advantages:

- Simple, low-cost process
- Able to handle biomass with a high moisture and high inorganic content
- Proven technology

Although it’s syngas contains 10-20% tar by weight, which requires extensive syngas cleanup before engine, turbine or synthesis applications.

Downdraft Gasification

The downdraft gasifier has the same mechanical configuration as the updraft gasifier except that the oxidant and product gases flow down the reactor, in the same direction as the biomass. Also known as cocurrent-flow gasification, the downdraft gasifier can combust up to 99.9% of the tars formed. Low-moisture biomass (<20%) and air or oxygen are ignited in the reaction zone at the top of the reactor. The flame generates pyrolysis gas/vapor, which burns intensely leaving 5 to 15% char and hot combustion gas. These gases flow downward and react with the char at 800 to 1200°C, generating more carbon monoxide and hydrogen gas while being cooled to below 800°C. Finally, unconverted char and ash pass through the bottom of the grate and are sent to disposal.

The downdraft gasifier has the following advantages:

- Up to 99.9% of the tar formed is consumed, requiring minimal or no tar cleanup
- Minerals remain with the char/ash reducing the need for a cyclone
- Proven, simple and low cost process

Although it requires feedstock drying to lower moisture content to less than 20%, although with a secondary heat recovery system, the high temperature syngas exiting the reactor can be used for drying. In addition, as much as 4 to 7% of the carbon remains unconverted.

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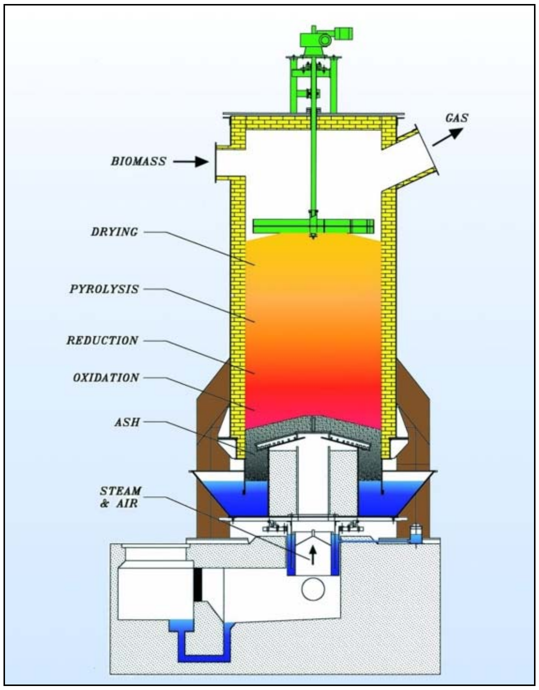
[11] Unless otherwise noted, information in this section is taken directly from the June 2002 report titled “Benchmarking Biomass Gasification Technologies for Fuels, Chemicals and Hydrogen Production” prepared by Jared P. Ciferno and John J. Marano for the National Energy Technology Laboratory



Source: http://www.volund.dk/technologies_products/gasification/the_gasification_process
Last accessed: February 26, 2007

Bubbling Fluidized Bed

The bubbling fluidized bed gasifier system consists of fine, inert particles of sand or alumina, which have been selected for size, density and thermal characteristics. As gas (oxygen, air or steam) is forced through the inert particles, a point is reached when the frictional force between the particles and the gas counterbalances the weight of the solids. At this gas velocity (minimum fluidization) bubbling and channeling of gas through the media occurs, such that the particles remain in the reactor and appear to be in a “boiling state”. The fluidized particles tend to break up the biomass fed to the bed and ensure good heat transfer through the reactor.

Although large bubble size may result in gas bypass through the bed, this system offers the following advantages:

- Yields a uniform product gas
- Exhibits a nearly uniform temperature distribution throughout the reactor
- Able to accept a wide range of fuel particle sizes, including fines
- Provides high rates of heat transfer between inert material, fuel and gas
- High conversion possible with low tar and unconverted carbon

Circulating Fluidized Bed

Circulating Fluidized Bed gasifers operate at gas velocities higher than the minimum fluidization point, resulting in entrainment of the particles in the gas stream. The entrained particles in the gas exit the top of the reactor, are separated in a cyclone and returned to the reactor.

Advantages of this system include:

- Suitable for rapid reactions
- High heat transport rates possible due to high heat capacity of bed material
- High conversion rates possible with low tar and unconverted carbon

Disadvantages include:

- Temperature gradients occur in direction of solid flow
- Size of fuel particles determine minimum transport velocity; high velocities may result in equipment erosion
- Heat exchange less efficient than bubbling fluidized-bed

Additional details on gasification systems are available from the U.S. Environmental Protection Agency Report, "Biomass Combined Heat and Power Catalog of Technologies, September 2007, pg. 45-62.

Appendix C
Distributed Energy Resource (DER) Technologies for Opportunity Fuels

Reproduced in its entirety from Resourced Dynamics Corporation, Opportunity Fuels and Combined Heat and Power: A Market Assessment, Section 3, pages 3-1 – 3-17, August 2006.

DER Technologies for Opportunity Fuels

Distributed energy resources (DER) are typically defined as small power generation sited at or close to the facility that uses the output. Most DER technologies can be used with opportunity fuels, including steam turbines, combustion turbines, reciprocating engines, microturbines, fuel cells and Stirling engines. Each of these technologies can be configured to capture waste heat and produce useful thermal output, typically referred to as combined heat and power (CHP). For solid fuels that are not gasified (TDF and wood fuels), a steam turbine and boiler unit is the only practical technology option, since solids can only be efficiently burned in a boiler. Gaseous fuels can also be burned in a boiler to produce steam, but the other prime mover technologies are also options for gaseous opportunity fuels. Each technology has its advantages and disadvantages, depending primarily on fuel characteristics and site electrical and thermal loads.

This chapter examines the various technologies used for producing power with opportunity fuels. An introduction and brief overview of the leading DER technologies[1] (steam turbine, combustion turbine, reciprocating engine, microturbine, fuel cell, and Stirling Engine) is given, discussing the history, operation, emissions, efficiency and costs associated with each technology. Then, equipment modifications and specializations required for opportunity fuels are discussed, and the associated costs are estimated. Maintenance issues are also identified for each technology and fuel, with estimated cost increases for each case. Finally, potential applications for the prime mover technologies are discussed. At the end of the chapter, the equipment and maintenance costs for each fuel are summarized in table form.

Steam Turbines

Steam turbines were invented in 1884 by Englishman Charles Parsons as an alternative to the reciprocating steam engines that dominated the era. They were first brought to America in the early 1900’s for industrial operations and power generating applications. The steam turbines produced electricity much more efficiently than reciprocating steam engines, and quickly became the American standard. Throughout the 1900’s, new developments in steam turbines were made, making them more efficient and capable of producing electricity at an extremely low cost. Improving the metallurgy of the turbines allowed for higher temperature and pressure steam, which improved the turbine performance. Electric efficiencies were improved to about 33 percent. However, the advent of combustion turbines slowed down the progress of the steam turbine, as combustion turbines can be sited more quickly. Still, steam turbines remain a consistent and reliable source of power. Although traditionally used for

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[1] Stirling engines were considered as a potential prime mover for opportunity fuels - one 55 kW Stirling engine, using ADG as a fuel, was recently installed at a wastewater treatment plant in Oregon, and another running on waste vegetable oil was recently installed at a food processing plant in New Jersey - but although Stirling engine technology has been around for over 100 years, their practical use for power generating applications has only recently begun to take shape and it will be some time before they are commercially available at a large scale - it is very difficult to generalize the price and performance of Stirling engine systems at this point.

large-scale power applications, steam turbines have proven themselves successful in many DER/CHP operations in the 5-50 MW range, particularly with solid waste and byproduct fuels.

Operation

A high-pressure boiler is used by steam turbine systems to generate steam. Water enters the boiler and is heated to a high temperature and pressure, creating steam that enters the turbine. The steam causes the turbine blades to rotate, creating power that is converted into electricity with a generator. A condenser and pump are used to collect the leftover steam and water, feeding it into the boiler and completing the cycle. This cycle is illustrated in Figure 3-1.

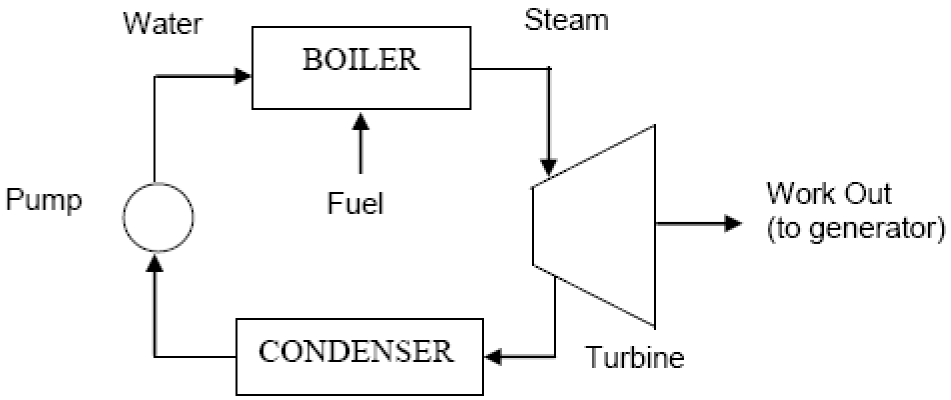

Figure 3-1. The Steam Turbine Cycle

Figure 3-1. The Steam Turbine Cycle

Emissions created in the operation of steam turbines are generated in the boiler, where the fuel is combusted. Because the working fluid in the turbine is steam, and not gas, there is no harmful exhaust from the turbine. For CHP applications, the steam is often used for process heating, and this can be done in two ways. With a topping cycle, the steam is first used in the turbine for electricity

generation, and the lower-pressure steam is then used for heating. With a bottoming cycle, the steam is used first for process heat, and is then sent to the turbine to generate electricity. The electric and thermal demands of a facility help dictate which method is chosen.

Emission Controls

Boilers using coal or other solid fuels usually produce more emissions than those using oil or gas because it is easier to control the combustion of liquids and gases.

NOx is one of the greatest environmental concerns, and emission regulations can be strict in certain areas. Selective catalytic or non-catalytic reduction can be employed after the fuel is combusted to reduce NOx emissions. In addition, low excess air firing, low nitrogen fuel oil, water or steam injection, and flue gas recirculation can all work to bring down the boiler NOx levels. The best choice will depend on local air pollution statutes, the boiler's characteristics, and the fuel that is used.

Sulfur compounds, or SOx, are also a major concern. Reduction methods include using low sulfur fuel (tire-derived fuel and wood fuels produce less sulfur than coal) and desulfurizing the fuel and/or flue gas. Dispersion methods, which use a tall stack to release the exhaust gas higher into the atmosphere, also help to reduce the harmful effects of sulfur emissions.

Carbon monoxide (CO) is another concern, but modern boilers are designed to limit the amount of CO produced in the combustion process. Proper burner maintenance should prevent CO from reaching undesirable levels. Volatile organic compounds (VOCs), hydrocarbons, and particulate matter are also potential emission problems. Like carbon monoxide, proper burner and boiler maintenance should keep these emissions at acceptable levels.

Efficiency

Modern steam turbine power plants have electric efficiencies of around 35 percent. Smaller turbines have a harder time reaching this number, and low-Btu opportunity fuels lead to even lower efficiencies. For CHP projects in the 5-50 MW range, electrical efficiencies of 20 to 35 percent are typical, depending on the turbine size and opportunity fuel used (a 5 MW turbine running on LFG might have an efficiency of 20 percent, while a 50 MW turbine running on CBM could have an efficiency of about 35 percent). Chemical deposits and corrosion in the boiler will bring the efficiency down over time, but this can be countered with regular cleaning and maintenance.

Equipment Costs

Compared to combustion turbines and reciprocating engines, steam turbine-based DER is usually more expensive to obtain and operate. The cost per kilowatt decreases significantly as the turbines get larger, making large facilities the most ideal locations. However, when working with a free or relatively cheap fuel source, smaller steam turbines can still be economical. Also, unless gasifiers are used, steam turbine boiler systems are the only technology that can utilize solid fuels.

The cost per kW to obtain a boiler-steam turbine system ranges from $600 to $1,000 per kW, plus $300- $500 per kW for installation. CHP units typically add another $100/kW to both equipment and installation costs. Overall, a CHP steam turbine system should cost between $1,000 and $1,600 per kW to install. The boiler makes up about 20-25 percent of the overall price.

Equipment Modifications for Opportunity Fuels

In a typical steam turbine setup, the only equipment that may require modification is the boiler system. Boilers are available that run on either solid or gaseous fuels, but only solid (coal) boilers are modified to run on solid opportunity fuels, and only gaseous (natural gas) boilers are retrofit to run on other gaseous fuels. The base costs for solid and gaseous boilers are comparable, but some fuels will require more modifications than others. Most opportunity fuels require higher flow rates and leave many deposits behind, so the boiler must be modified to accommodate the increased gas volume and resulting deposit buildup.

Solid Fuels

For solid-fueled boilers, the fuel is dried, pulverized (if necessary), and incinerated to generate heat and produce steam. Coal-fired boilers are specifically designed to burn pulverized coal, so modifications will be required if the fuel’s characteristics are different. Usually the opportunity fuel is broken down into chips so that it does not need to be pulverized. Stokers are often the best choice for incinerating opportunity fuels since they will work with almost any solid fuel and require no modifications, but fluidized bed boilers are sometimes required due to emissions. The amount of changes that are necessary, and how much the boiler would cost, depends on the boiler design and the fuel that is used, but some generalizations can be made.

Solid biomass fuels (wood and wood waste) have relatively low Btu contents and contain some impurities (especially urban wood waste). Typically, circulating fluidized bed or moving grate boilers are used. A boiler built for biomass fuels would cost between 50 and 100 percent more than a normal boiler, and some additional cleaning/filtration devices may be required. Because of these changes, the overall cost for a steam turbine system would increase by around 25 percent. Wood wastes typically contain more contaminants, so additional impurity removal equipment is usually required, adding on about 5 percent to the total cost.

Tire-derived fuel, unlike wood fuels, has about the same heat content and combustion characteristics as coal. If shredded and pulverized adequately, TDF should be able to power any coal-fired boiler with little to no necessary modifications. It is assumed that no modifications will be required, and that the equipment will cost about the same as for coal. However, most TDF grades have metal wires embedded in the tires, which can cause problems in the boiler and will likely increase maintenance costs.

Boiler Modification/Replacement

If a steam turbine system is already in place with a coal-fired boiler, the boiler may be replaced without any necessary changes to the turbine. Although most boilers can be customized to run on any suitable fuel, the modifications required can become expensive, and more maintenance is usually required. In these cases, it may make more sense to replace the boiler than it does to modify it. If a new boiler were built for an existing system, it could be custom-designed for the specific opportunity fuel. Since a boiler makes up about 25 percent of the price of the steam turbine system, replacing it would cost about 25 percent of the price of a new boiler-steam turbine system. Of course, cofiring with coal in an existing boiler is an option that would not require any modifications or equipment costs (as long as the fuel is thoroughly processed and kept below a maximum percent). However, even though cofiring can be advantageous, the market analysis presented later in this report focuses strictly on applications using 100 percent opportunity fuels.

Gaseous Fuels

Gaseous opportunity fuels can also be combusted in a boiler in order to operate steam turbines. A boiler designed to run on a low-Btu fuel such as ADG or LFG costs only slightly more than natural gas boiler. There is a slight decline in efficiency and power output, and more maintenance is required, but the boiler itself costs nearly the same as one designed to operate with natural gas. With these fuels, however, fuel treatment equipment is usually required to rid the gas of particulates such as siloxanes and hydrogen sulfide – this can also add to the capital costs. With everything considered, a steam turbine system designed to run on low-Btu fuels would cost about 25 percent more than the natural gas alternative. If an anaerobic digester is required to produce ADG, the capital cost for the digester alone is approximately $900-$1,500 per kW, depending on various factors. Biomass gas and coalbed methane should be able to use natural gas boilers without incurring any additional costs (except when a gasifier is required).

Boiler Modification/Replacement

Unlike solid-fueled boilers, existing natural gas boilers can easily be modified to operate on low-Btu fuels. With a few changes to the burner and manifolds, boilers can use these fuels with only a small decrease in efficiency and power output. The resulting cost per kW to modify existing equipment would not exceed 10 percent the price of a new boiler-steam turbine system. Coalbed methane, when it is of high enough quality, can replace natural gas in boilers without any noticeable degradation in quality, so no modifications are required and no additional costs are incurred. Biomass gas can also replace natural gas, with only about a 10 percent decline in power output (assuming a heat content of 600-800 Btu/ft3), although the purchase of a gasifier (about $1,000 per kW) would be required.

Maintenance Costs and Issues with Opportunity Fuels

For steam turbines with coal or natural gas-fired boilers, maintenance typically costs $0.005 to $0.015 per kWh. With most opportunity fuels, impurities and deposit accumulations in the boiler and boiler tubes increase, so more maintenance is usually required. As with equipment costs, maintenance costs per kWh tend to decrease as the system size grows.

Solid Fuels

For a steam turbine system running on wood fuels, the maintenance required for the boiler typically doubles. Since about half of the maintenance associated with a steam turbine system is for the boiler, maintenance for the system costs about 50 percent more than normal. With urban wood waste and mill residues, more impurities are present, so more cleaning and maintenance is necessary – an additional 10 percent is estimated. When boilers are designed specifically for wood fuels (as opposed to modified), the maintenance costs may not be as high.

Tire-derived fuel, however, burns somewhat cleaner than coal and does not require as much maintenance as the wood fuels. TDF requires varying levels of maintenance, depending on the level of wire removal, the size of the chips, and the incineration temperature. In general, maintenance costs are expected to increase by about 50 percent compared to coal, mainly because of the more frequent cleaning caused by metal scraps and other impurities embedded in the tires. Since the boiler represents about half of the overall system in terms of maintenance, the costs for TDF are increased by 25 percent.

Gaseous Fuels

For gaseous low-Btu fuels, a boiler's maintenance costs will increase by about 50 percent (corresponding to 25 percent for the entire steam turbine system). The low-Btu fuels produce more deposits than natural gas and increase fouling of the tubes, requiring additional and more frequent cleaning and maintenance. In addition, these fuels often require treatment to rid them of potentially harmful particulates like siloxanes and hydrogen sulfide. Operating and maintaining the treatment equipment adds on another 1-2 cents per kWh. For ADG, if an anaerobic digester is not already installed, the an additional $0.001 to $0.003 per kWh is required for maintenance. High quality biomass gas, a medium-Btu fuel, usually does not require additional maintenance costs except for the $0.001 to $0.005 per kWh required to operate and maintain the gasifier. Coalbed methane, a high-Btu and relatively clean fuel, should not require any additional maintenance costs.

Overall Maintenance Costs

The overall maintenance costs are calculated for a 6,000-hour year of continuous operation. The maintenance costs for a natural gas or coal-fired system are multiplied by a percentage factor dependant on the opportunity fuel, and the fixed maintenance costs remain the same. Overall, the cost to maintain a steam turbine-boiler system running on low-Btu gas is about $0.007 to $0.015 per kWh. For biomass gas and tire-derived fuel, the cost is slightly less, at $0.006-$0.014 per kWh. For wood and wood waste, the total maintenance costs are higher at $0.007 to $0.016, and $0.008-$0.017, respectively. With coalbed methane, the annual maintenance costs are comparable to natural gas, in the range of $0.005-$0.012 per kWh.

Applications for Steam Turbines

Steam turbines are suitable for a number of CHP applications, but they are not common in the DER market, except in the paper, chemical and petroleum industries. Their efficiencies are higher with large industrial units, and they are believed by many to be outdated, expensive, and maintenance-prone. This is true to an extent, as they are generally more expensive than reciprocating engines and combustion turbines. Also, licensed boiler operators are sometimes required to maintain the boiler system, and a constant clean source of water is needed. However, maintenance costs are often lower than reciprocating engines and combustion turbines, and steam turbines tend to make a good choice for DER and CHP when waste fuels are utilized and leftover steam is used for heating. For solid waste fuels without gasification, steam turbine systems are often the only choice available, and for gaseous opportunity fuels they tend to require less modifications than combustion turbines. Furthermore, the emissions from boilers can be less than combustion turbines or reciprocating engines when using gaseous fuels. Still, the cost of a steam turbine-boiler system is more expensive than competing technologies and it is most likely to be used only with solid opportunity fuels.

Combustion Turbines

Combustion turbines have been used for power generation for decades, and range in size from simple cycle units starting at about 1 MW up to several hundred MW when configured as a combined cycle power plant. Units from 1-15 MW are generally referred to as industrial turbines, differentiating them from larger utility grade turbines and smaller microturbines. Units smaller than 1 MW exist, but very few have been installed in the U.S. since their price is high and electrical efficiencies are relatively low. Traditionally, turbine applications have been limited by lower electrical efficiencies to combined heat and power uses at industrial and institutional settings and peaking units for electric utilities. However, improvements in electrical efficiency have been made and combustion turbines are now being used for intermediate and baseload power.

Operation

Historically, industrial turbines have been developed as aero derivatives using jet propulsion engines as a design base. Some, however, have been designed specifically for stationary power generation or for compression applications in the oil and gas industries. In a combustion turbine, air is compressed, mixed with a gaseous or liquid fuel and ignited. The combustion products are expanded directly through the blades in a turbine to drive an electric generator. The compressor and turbine usually have multiple stages and axial blading. This differentiates them from smaller microturbines that have radial blades and are single staged.

Unfortunately, the intricacy of blade design and spacing, with combustion turbines means that most existing natural gas units cannot be feasibly retrofit to run on 100% low-Btu gases. However, coalbed methane can always be used in place of NG, and new units can be specially designed to run on low-Btu fuels. For an illustration of the combustion turbine cycle, see Figure 3-2. The intercooler shown in the figure is generally reserved for larger units that can economically incorporate this improvement.

Combined heat and power is easily achieved with combustion turbines, since their exhaust gas is extremely hot (about 1000oF). The gas can be used to produce steam in a heat recovery steam generator (HRSG). An HRSG is essentially a large heat exchanger that transfers the exhaust gas’ heat to water and produces steam. The exhaust gas is cooled to about 300oF – lower temperatures could cause condensation of the exhaust gases that could lead to corrosion, and the steam is heated to a high temperature and pressure. Combined cycle units (where steam from the HRSG is used to power a steam turbine) are commonly used by utilities and large industrial operations due to their high efficiency and power output. In DER sized units, the steam produced in the HRSG can be used for industrial processes or other heating applications.

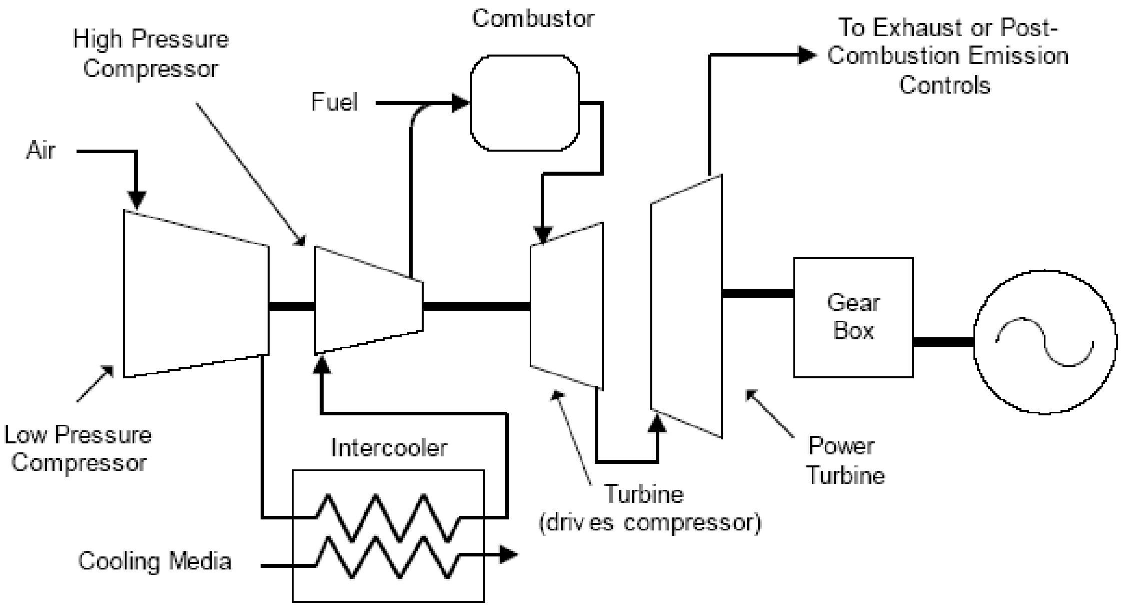

Figure 3-2. **Combustion Turbine System (with intercooler)**

Emission Controls

Given that combustion takes place outside of the turbine area (unlike reciprocating engines, where combustion takes place inside the cylinder), turbines have more flexibility in reducing NOx emissions. NOx emissions from uncontrolled natural gas turbines range from 75 to over 150 ppm, due to high combustion temperatures. Emissions control of combustion turbines can be accomplished by injecting water or steam to reduce the combustion temperature and reduce NOx levels down to 25-45 ppm. In addition, these methods increase power production and can increase the system efficiency. While these means have proven effective in limiting NOx emissions, the availability of water supply and space for storage tanks are constraints for some applications. Some turbines (especially those using low-Btu fuels) utilize diffusion flame combustors, which inject small amounts of air into the fuel prior to combustion, mixing the gases with turbulent diffusion and bringing NOx levels down to 25-35 ppm. In many states, these measures are deemed adequate to meet NOx regulations.

Dry Low NOx (DLN), conceptually similar to lean burn technology for reciprocating engines, creates a lean, homogeneous mixture of air and fuel that then enters the combustor. This minimizes hot spots and reduces the combustion temperature, which leads to lower NOx levels. DLN has become the standard for NOx control in natural gas combustion turbines, but it is not easily used with low-Btu fuels.

Although combustion turbines tend to generate lower emissions than reciprocating engines, in many U.S. states units must be installed with additional control technologies to further reduce NOx emissions.

Selective catalytic reduction is the primary option for further reduction of NOx. Catalytic combustors, one emerging NOx control option, fully convert the input fuel and air without the use of a flame. Since in a traditional combustor the majority of NOx is produced in the high-temperature region near the flame, catalytic systems substantially reduce these emissions. This system, however, is currently under demonstration and is not yet commercially available.

SCONOx, another emissions control development, uses a proprietary oxidation/adsorption/regeneration process to reduce NOx, CO, and total hydrocarbons to levels below U.S. standards. This technology is currently being developed, and may allow for economic installations of industrial turbines with single digit NOx emissions.

Efficiency

Electrical efficiencies of simple cycle combustion turbines in the 1-50 MW range fall between 25 and 40 percent. For combined cycle turbines, electric efficacies are more on the order of 30 to 45 percent. Low-Btu fuels and smaller applications will stay on the lower side of these ranges. More durable and temperature resistant materials (ceramics, single-crystal superalloys, and directionally solidified material) or advanced cooling schemes (transpiration and vortex) are needed for first stage turbine blades and combustors in order to increase the operating temperature/compression ratio and, therefore, efficiencies of turbines. Such developments will also result in less down-time and lower-cost maintenance.

Efficiency may be improved through the use of recuperators (air-to-air heat exchangers that use exhaust gases to preheat the compressed combustor inlet air). Although recuperation is not commonly employed for turbines in the >1 MW size range, Solar Turbines now offers its Mercury 50, a 4 MW recuperated unit with an electric efficiency of 38.5 %. Intercooling (cooling air between 2 or more compression stages) can increase efficiency by reducing air compression power requirements, and produces lower temperature air for better cooling of turbine parts, but this is unlikely for DER units. Ambient effects on efficiency are also important since peak turbine use is normally during high temperature periods when turbine maximum output is lowest. Current methods to lessen the effects of ambient temperature include evaporative, mechanical, or adsorption inlet air chillers, steam injection into the combustor for higher mass flow or NOx control, and compressed air storage/injection.

Equipment Costs and Modifications for Opportunity Fuels

Combustion turbines cost significantly less than most steam turbine systems on a per kilowatt-basis. The cost to obtain a natural gas combustion turbine ranges from $400 to $1,000 per kW, depending on the unit’s size and design, with between $200 and $400 per kW for installation. Smaller facilities will fall on the higher end of the price spectrum, and CHP systems can add about $100/kW to both costs. The total installed cost of combustion turbines then range from about $600/kW for the largest units to around $1,400/kW for small 1MW units in power only applications, or $800-$1,600 for CHP. Combined cycle turbines that use a heat recovery steam generator and a secondary steam turbine typically cost a few hundred dollars more per kW.

Combustion turbines can run on low-Btu gases, but it is not very practical and major modifications are almost always required. Gases with low heat contents require higher flow rates, and usually contain more impurities than natural gas. To accommodate this, modified nozzles, large combustion areas, heavy-duty compressors, large intake manifolds, and more cleaning devices are required. Since the gas must be compressed heavily, much of the power generated from the turbine would have to be used on the compressor. In addition, the gas collected from landfills and digesters does not always flow in a continuous stream, which could cause blade stalling and other issues for the turbine. Finally, most combustion turbines are designed for large-scale industrial applications, but most landfills and treatment plants do not produce enough gas for this, and are limited to small power production.

Because of all the modifications required, existing natural gas turbines cannot easily be retrofitted to run on low-Btu fuels. Combustion turbines designed for low-Btu gases generally cost at least 50 percent more than natural gas turbines on a per kW basis ($900-$1,900 installed for power-only, $1,000-$2,200 installed for CHP). If an anaerobic digester is to be installed, additional capital costs of $900- $1,500 per kW are incurred. Operation and maintenance costs for ADG and LFG also increase significantly when compared to natural gas. For these reasons, combustion turbines are usually not the most attractive option for low-Btu fuels. However, many turbines utilizing ADG and LFG have been installed successfully using a natural gas blend. Existing natural gas turbine designs require very few modifications when using blended fuel, and adding natural gas to low-Btu fuels increases their performance. However, this report is focusing on applications solely using opportunity fuels, so the market analysis presented later focuses on higher cost, more capable technology designed to use 100 percent opportunity fuels.

Biomass gasifiers typically produce a medium-Btu fuel that is much cleaner than ADG and LFG. This biomass gas can be used in most combustion turbines with little to no modifications. Coalbed methane can also be used in combustion turbines, since its properties are so similar to natural gas. The equipment and maintenance costs for biomass gas and coalbed methane are assumed to be the same as when using natural gas as a fuel, although for biomass gas the power output is decreased by about 10 percent (causing a 10 percent increase in equipment cost per kW), and a gasifier ($1,000 per kW plus $100-$200 per kW for installation) must be added to the capital costs.

Wellhead gas is a special case, in that it is a high-Btu fuel, but it contains so many impurities that it must be thoroughly cleaned and scrubbed before used in any application. So much cleaning is required for gas turbines and engines that microturbines (which can tolerate higher impurity levels) are usually the more attractive option, and they are generally the only technology used for these projects.

Maintenance Costs and Issues with Opportunity Fuels

Overall maintenance for combustion turbines costs between $0.004 and $0.01 per kWh for natural gas units. When a gas turbine is operating on a low-Btu gas, increased cleaning and more frequent maintenance check-ups are required, especially for the compressor. The increases are significant, causing maintenance costs for low-Btu gas turbines to rise anywhere from 50 to 100 percent. Variations in gas composition, turbine design, and other factors make the exact number hard to pinpoint, so an additional 75 percent ($0.007 to $0.018 per kWh) for turbines running on low-Btu gases is estimated. An anaerobic digester can add up to $0.003 per kWh in maintenance costs. For coalbed methane and high-quality biomass gas, the low price of $0.004-$0.01 per kWh is generally maintained, although for biomass gas, gasifier maintenance costs ($0.001-$0.005 per kWh) must be added.

Applications for Combustion Turbines

Combustion turbines are typically used for industrial and large commercial facilities for CHP applications. Large industrial applications often use combustion turbines in combined-cycle configurations, where the exhaust gas is used to produce steam for a secondary steam turbine. In both cases, considerable waste heat can be produced for CHP applications. For small DER projects like most opportunity fuels would provide, however, simple-cycle combustion turbines are likely the better fit. Coalbed methane performs just as well as natural gas, so it is an ideal opportunity fuel for combustion turbines. Biomass gas also performs well, although its methane content is not quite as high. Low-Btu gases like ADG and LFG are not very well suited well for combustion turbine applications, although Solar Turbines has created several small (<6 MW) units that can handle these fuels with relatively few problems. Overall, combustion turbines are one of the most prominent DER/CHP technologies, and they will be considered for all of the gaseous opportunity fuels.

Reciprocating Engines

Of all the electricity-generating technologies, reciprocating engines have been around the longest. Both Otto (spark ignition) and Diesel cycle (compression ignition) engines have gained widespread acceptance in almost every sector of the economy. For reciprocating engines to operate with gaseous opportunity fuels, Otto cycle engines are usually required. Reciprocating engines have been utilized worldwide for applications ranging from fractional horsepower units to large 60 MW baseload electric power plants. They have become common at landfills and wastewater treatment plants, burning low-Btu waste gases for combined heat and power applications. Reciprocating engines are also commonly used in coalbed methane projects.

Operation

Most engines used for power generation are four-stroke and operate in four cycles (intake, compression, combustion, and exhaust). The four-stroke process begins with fuel and air being mixed, usually before introduction into the combustion cylinder for spark ignited units (see Figure 3-3). In turbocharged applications, the air is compressed before mixing with fuel. The fuel/air mixture is introduced into a combustion cylinder that is closed at one end and contains a moveable piston. The mixture is then compressed as the piston moves toward the top of the cylinder. The pressure of the hot, combusted gases drives the piston down the cylinder. Energy in the moving piston is translated to rotational energy by a crankshaft. As the piston reaches the bottom of its stroke, the exhaust valve opens and the exhaust is expelled from the cylinder by the rising piston.

Reciprocating engine CHP systems can be designed to produce steam, hot water, or hot air. There are many different possible configurations for heat recovery, and all have their advantages and disadvantages. Standard heat exchangers are typically used to produce hot water and steam. Sometimes, however, ebullient cooling systems are used to produce steam and cool the engine in the process. With ebullient systems, a boiling coolant is circulated through the engine jacket and fed through an air-to-water heat exchanger along with the engine's exhaust. Forced circulation systems, which utilize higher temperature and pressure water in the engine jacket, are sometimes used to produce pressurized steam.

On certain occasions, exhaust gas from the reciprocating engine is used to directly dry certain products such as bricks and ceramics. This is referred to as "dirty drying" because of particulates and other contaminants in the engine's exhaust. The most common method of heat recovery from reciprocating engines, however, remains to be conventional heat exchangers that utilize the engine's hot exhaust gas, jacket water and lube oil to produce hot water and steam. This method is shown in the Figure 3-3 schematic.

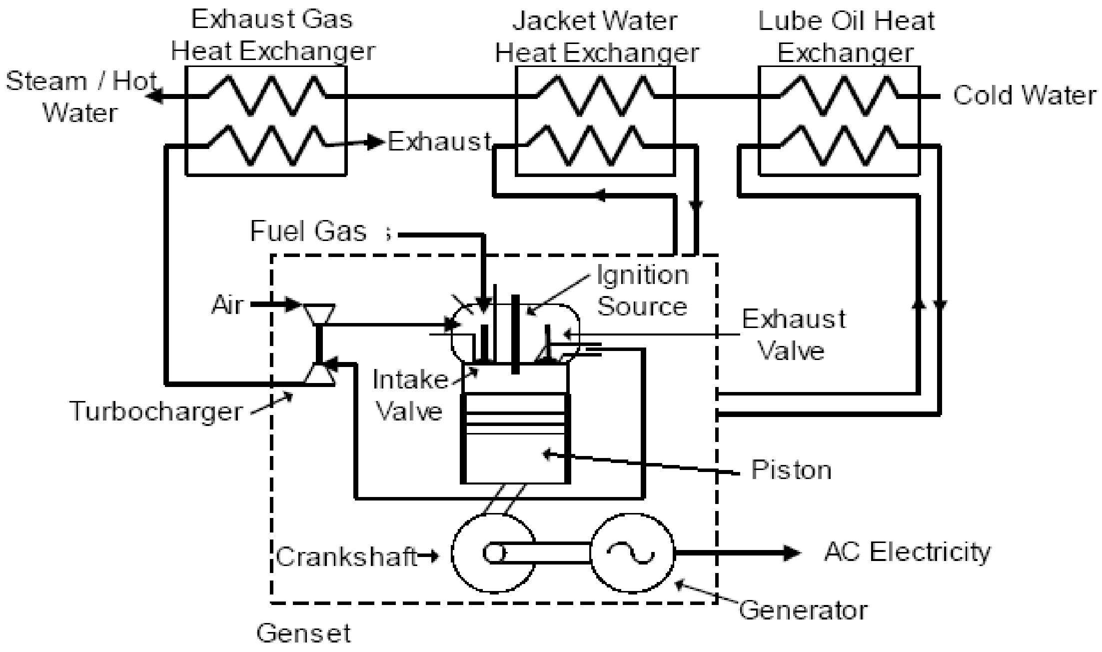

Figure 3-3. Schematic of an Otto (spark-ignition) Reciprocating Engine with Heat Recovery

Emission Controls

The combustion process produces NOx, carbon monoxide, hydrocarbon, and particulate emissions. Because reciprocating engines combust gas under high pressure, emission control technologies are harder to apply compared to turbines, and in general, more NOx is produced. Frequent and thorough maintenance helps reduce emissions, and this is needed even more so for most opportunity fuels. Control technologies like Selective Catalytic Reduction (SCR) and other post-combustion methods are complicated and expensive to implement and maintain. In certain areas with strict environmental regulations, SCR is required for larger reciprocating engines, even when using biogas. This can make it difficult to site units for certain DER/CHP applications. In addition, catalytic controls are hindered by siloxanes and hydrogen sulfide, which is usually found in ADG and LFG. Extensive fuel treatment would be required in order to prevent catalyst poisoning. However, with most engines under 5 MW in size, SCR is usually not required, as lean-burning can usually bring NOx emissions down to acceptable levels.

New emission control methods focus on lean-burning, or using a high air to fuel ratio. Lean-burning improves efficiencies and lowers NOx emissions, but it can also lower the power output. This can be compensated for by the incorporation of turbocharging, which increases the power density. Lean-burn technology, however, is not as effective for low-Btu fuels - the amount of excess air that can be used with low-Btu fuels is limited, since the fuel-air mixture can easily become too dilute. Still, lean-burn technologies are almost always used with LFG and ADG to reduce NOx emissions. Effective turbocharging is often necessary when using lean-burn engines with low-Btu fuels.

Efficiency

Electric efficiencies for reciprocating engines typically fall between 30 and 40 percent, with an overall efficiency of about 80 percent when CHP is utilized. Small engines running on low-Btu fuels will have a harder time reaching these numbers. Combustion chamber design is important not only to the efficient and complete combustion of fuels but also for the reduction of NOx emissions. How and when fuel is injected in the cycle plays an important role in how the fuel is combusted, and thus influences power, efficiency, and emissions. High efficiency engines will operate at higher-pressure levels that will require high-energy spark ignition systems with durable components. Effective turbocharging is key to increasing Brake Mean Effective Pressure, which in turn leads to increased efficiency. Turbocharged engines can achieve greater power density, allowing units to be placed in a smaller area and/or lessen foundation reinforcement requirements.

Equipment Costs and Modifications for Opportunity Fuels

While reciprocating engines have a lower capital cost than most other small power generating technologies, environmental siting, permitting, and other issues can make them expensive to install. Reciprocating engines are most common in the 500 kW to 5 MW size range, but single units as large as 20 MW do exist. The cost to obtain a natural gas-fueled reciprocating engine typically ranges from $500 to $800 per kW, with between $200 and

$500 per kW for installation. Once again, smaller units will fall on the high end of the price spectrum, and CHP units can add about $100/kW to both costs. Overall, a power-only reciprocating engine should cost between $700 and $1,200 per kW, while a CHP unit should cost $800-$1,400 per kW, installed.

Reciprocating engines have the same problems with low-Btu fuels as gas turbines, namely they must be modified to accommodate a higher flow rate and more impurities. However, these modifications are achieved much more easily. Modified fuel injectors and new manifolds are all that is required to accommodate these low-Btu constraints, typically adding about 5 percent to the cost of a natural gas engine. Fuel treatment equipment for siloxane, H2S and other particulate removal drives the cost up an additional 5-10 percent, and the lower heating values of landfill gas and anaerobic digester gas cause a 10 percent decrease in power output compared to a natural gas engine, which increases the overall cost per kilowatt.

With these factors considered, reciprocating engines designed to run on low-Btu fuels cost about 20 percent more per kW to obtain than their natural gas counterparts, bringing total costs to $900-$1,400/kW (power only) or $1,000-$1,700/kW (CHP). To modify an existing natural gas engine to run on a low Btu gas, it would generally cost around 25 percent of a new engine’s installed cost ($200-$400 per kW). For facilities installing an anaerobic digester, additional capital costs of $900-$1,500 per kW can be expected.

For engines fueled by biomass gas, no equipment modifications are required when the gas is of high enough quality, and only a 5-10 percent decrease in power output is seen. A (about $1,000 per kW) also must be added to the capital costs.

Coalbed methane can also power reciprocating engines, with no modifications required and only a slight decrease in power output. As with the other power generating technologies, the performance difference between natural gas and coalbed methane is negligible.

Maintenance Costs and Issues with Opportunity Fuels

The maintenance problems associated with reciprocating engines running on low-Btu fuels are increased wear and tear, more cleaning, and up to 8 times more frequent oil changes. Additional maintenance for fuel treatment equipment may also be required. Typically, maintenance for a low-Btu gas engine costs about 80 percent more than required for running on natural gas. Normally, the overall maintenance costs for reciprocating engines are about $0.008-$0.022 per kWh, when operating on a continuous basis. For low-Btu gases, costs rise to $0.014-$0.04 per kWh for a 6,000 hour year (plus $0.001-$0.003 per kWh if an anaerobic digester is installed). For coalbed methane and biomass gas, no additional maintenance is required except for gasifier maintenance ($0.001-$0.005 per kWh), so same costs required for natural gas engines can be assumed.

Applications for Reciprocating Engines

Reciprocating engines are used in a wide variety of applications, and are most often used for backup power (diesel engines). Natural gas models are most commonly used for small DER/CHP operations, particularly in areas with lenient emissions requirements. As for opportunity fuels, reciprocating engines are generally better suited for low-Btu gases than combustion turbines. They have been used successfully in many ADG, LFG and coalbed methane power-generating applications, and arguably make the best overall choice in areas where emissions are not an issue.

Microturbines

The technology used in microturbines is derived from aircraft auxiliary power systems, diesel engine turbochargers, and automotive designs. A number of companies have developed units for small-scale distributed power generation in the 30-300 kW size range. Capstone Turbines currently offers a line of 30 kW microturbines capable of operating on a number of different fuels, including anaerobic digester gas, coalbed methane, landfill gas, and wellhead gas. Ingersoll Rand currently offers a 70 kW model that will also run on opportunity fuels. Both of these units have been installed in various projects throughout the world, and many more projects are currently in the planning process.

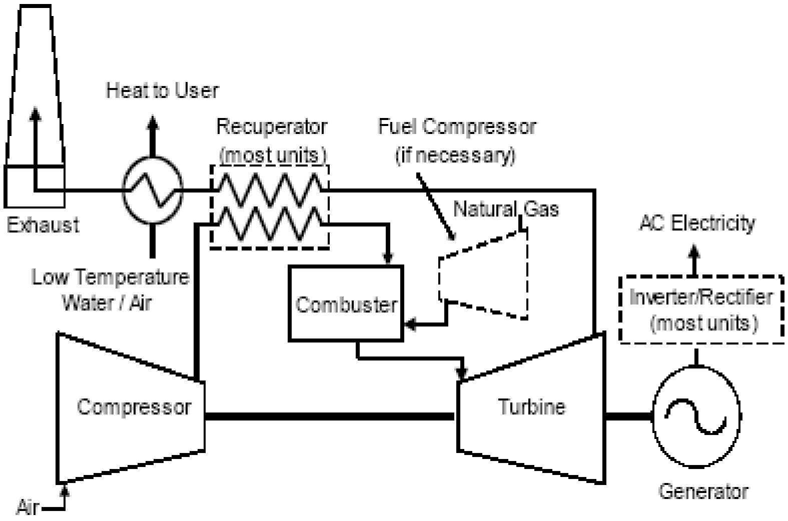

Figure 3-4. Microturbine System with Recuperator

Operation

Simple microturbines consist of a compressor, combustor, turbine, and generator. The compressors and turbines are typically radial-flow designs, and resemble automotive engine turbochargers. Most designs are single-shaft and use a high-speed permanent magnet generator producing variable voltage, variable frequency alternating current (AC) power. An inverter is employed to produce 60 Hz AC power. Most microturbine units are designed for continuous-duty operation and are recuperated to obtain competitive electric efficiencies. A typical microturbine system with a recuperator is depicted in Figure 3-4.

Microturbines rotate at high-speeds (40,000+ rpm) and therefore require high-reliability bearing systems. Two configurations are currently being used: air bearings with a compliant foil system, and a pressurized lube-oil system with a pump. Systems with air bearings eliminate the oil system and are simpler, require less maintenance, and have no parasitic oil pump load. However, oil bearings generally last longer.

Microturbines do not produce as much heat as combustion turbines, but they can still be used to produce hot water and steam for CHP applications. Unrecuperated models have a much higher exhaust temperature than recuperated models, but at the sacrifice of electric efficiency and power output. If the microturbine is going to be used extensively for heating applications, the choice between recuperated and unrecuperated can be difficult. Ultimately, it depends on the facility's power needs.

Emission Controls

In general, microturbine emissions are lower than industrial turbines and reciprocating engines. NOx levels are reported as less than 9 ppm for the Capstone microturbine (30 kW) running on natural gas, without the use of any emission control technologies. Achieving less than 9 ppm is also the goal for microturbine projects using LFG and ADG, but this can be difficult to obtain if the methane percentage falls below 40 percent. Still, NOx emissions of less than 9 ppm can almost always be achieved as long as a 15% oxygen mix is used. Some field tests show that when operating at part-load, NOx emissions for microturbines are significantly higher than 9 ppm, but the units' small size usually exempts them from emissions regulations. Emission control technologies in microturbines would tend to focus on combustor design and flame control. However, because of their small size, these units can fall below most compliance requirement triggers. As a result, most microturbine installations have been exempt from emission regulations, and they are a popular choice for government-assisted ADG and LFG projects.

Efficiency

Recuperators (air-to-air heat exchangers that use exhaust gases to preheat the combustor inlet air) can improve microturbine electric efficiency to between 20-30% versus the 14-20% efficiency rates of typical non-recuperated units. Microturbines running on low-Btu gases are somewhat less efficient. Obtaining a higher efficiency may require higher engine temperatures necessitating improvements in recuperator materials (such as ceramics). Microturbine efficiency is impacted by the available fuel's pressure level. Units that are supplied high-pressure gas (50-60 psig) are 1-4% more efficient than those using low-pressure gas because of the parasitic requirements of the fuel compressor.

Equipment Costs and Modifications for Opportunity Fuels

Although microturbines are more expensive than traditional prime mover technologies, though they can be deployed in smaller applications and they do not produce as many harmful emissions. The cost to obtain a microturbine system ranges from $1,000 to $1,500 per kW, with between $400 and $700 per kW for installation. CHP equipment is usually included in the microturbine package, but an additional $100/kW for CHP installation should be expected. The total capital costs for microturbines range from $1,400 to $2,200 or $2,300 per kW.

Microturbines are a promising new power generating technology for DER and CHP applications. They only have one rotating part, so wear and tear and deposit accumulation are minimal. Microturbines were designed to work well with a variety of gases, and can handle methane contents as low as 35 percent, making them ideal for low-Btu gases like landfill gas and ADG. However, microturbines do have problems with hydrogen sulfide and especially siloxanes, so these particulates must be removed from the gas prior to combustion. Fuel treatment requirements can add 5-10% to the microturbine's capital cost. Also, with low-Btu biogases and coalbed methane, additional fuel compression will be required to compress the gas to 55 psig. The capital cost of the fuel compressor typically ranges from $100-$200/kW, with an additional maintenance cost of about $0.005/kWh. It also requires a good deal of power to operate - about 10 percent of the microturbine's power output. For example, a microturbine rated at 30 kW is only capable of producing 27 kW of usable power when a fuel compressor is required.[2]

Microturbines can handle low-Btu gases better than most engines and turbines because of their simple design. No modifications are required, but there is a small decline in power output (5-10 percent) when running on landfill or digester gas. With all of these factors considered, a 25 percent increase in price per kilowatt is typically seen for microturbines utilizing low-Btu gases. The only other drawback is slightly increased maintenance, discussed in the next section. With ADG, the purchase of a digester ($900-$1500 per kW) may be required. Coalbed methane and biomass gas can also be used to fuel microturbines, with relatively no decrease in power output and no necessary modifications (although a special fuel compressor may be required for coalbed methane, and in the case of biomass gas, a gasifier must be added).

Unlike most other power generating technologies, microturbines are capable of using wellhead gas as a fuel with minimal treatment, and their small size makes them ideal for oil and gas well applications. The wells are already required to flare excess wellhead gas to prevent pressure buildup, but it is difficult and costly to clean the gas of impurities so that it could be used in a conventional engine or combustion turbine application. Microturbines can handle higher levels of wellhead gas impurities, so the cleaning costs are not as demanding. Wellhead gas has an extremely high heat content (1,100 Btu/ft3), so there is no decrease in power output. No modifications are necessary for microturbines to run on wellhead gas, although fuel treatment may add 10% to the price and more cleaning and maintenance will definitely be required.

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[2] At temperatures above 65oF, the Capstone C30's maximum power output drops below 30 kW (25 kW at 90oF), and using a low-Btu fuel will further bring it down.

Maintenance Costs and Issues with Opportunity Fuels

Microturbines are different from normal steam and gas turbines in that they contain only one rotating part, and do not require liquids for cooling or lubrication. For a microturbine running on natural gas, overall maintenance typically costs between $0.015 and $0.02 per kWh. Microturbines are designed so that they can run on nearly any methane-based gas, including the low-Btu waste gases, with only a slight decrease in power output. More maintenance is required, however, especially for the fuel compressor, which requires an additional $0.003-$0.006 per kWh to maintain. Additional maintenance of fuel treatment equipment is also required. Overall, operation and maintenance costs about 60 percent more for low-Btu fuels, compared to natural gas ($0.024-$0.032 per kWh). Wellhead gas contains even more impurities than low-Btu gases, requiring more routine maintenance – overall costs for wellhead gas microturbines should be about the same as low-Btu fuels. With ADG, a digester’s maintenance costs between $0.001 and $0.003 per kWh. With coalbed methane and biomass gas, no additional maintenance should be required, although with biomass gas, an additional $0.001-$0.005 per kWh for the gasifier is added.

Applications for Microturbines

Perhaps the greatest advantage of microturbines is their ability to accept a wide range of fuel types. While most turbines and reciprocating engines must be redesigned to accommodate low-Btu or high-impurity fuels, off-the-shelf microturbines can operate on these lower-quality fuels with no necessary modifications. Microturbines also have a very small footprint, which makes them ideal for DER applications, and their design allows for easy CHP implementation. Microturbines produce low emissions, so they have become popular in New York and other areas with strict environmental regulations. They are often chosen for anaerobic digester gas and landfill gas power generation, and they are the only technology capable of producing power from untreated wellhead gas. As time goes by and costs go down, microturbines may become an increasingly common technology for DER/CHP applications, especially with gaseous opportunity fuels.

Fuel Cells

Fuel cells are an emerging small-scale power generation technology, mostly under 1 MW, although larger applications do exist. The first fuel cell was developed in 1839 by Sir William Grove. However, they were not used as practical generators of electricity until the 1960's when they were installed in NASA’s Gemini and Apollo spacecraft. One company, UTC Fuel Cells, currently manufactures a 200 kW phosphoric acid fuel cell that is being used in commercial and industrial applications. These fuel cells have been used successfully in ADG and LFG power applications, and many more projects are currently being planned. A number of other fuel cell companies are field-testing demonstration units, and commercial deliveries are expected in 2004-2005.

Operation

There are many types of fuel cells, but each uses the same basic principle to generate power. A fuel cell consists of two electrodes (an anode and a cathode) separated by an electrolyte. Hydrogen fuel is fed into the anode, while oxygen (or air) enters the fuel cell through the cathode. With the aid of a catalyst, the hydrogen atom splits into a proton (H+) and an electron. The proton passes through the electrolyte to the cathode, and the electrons travel through an external circuit connected as a load, creating a DC current. The electrons continue on to the cathode, where they combine with hydrogen and oxygen, producing water and heat. A typical fuel cell is illustrated in Figure 3-5. The main differences between fuel cell types are in their electrolytic material. Each different electrolyte has both benefits and disadvantages, based on materials and manufacturing costs, operating temperature, achievable efficiency, power to volume (or weight) ratio, and other operational considerations. Currently only Phosphoric Acid fuel cells are being produced commercially for power generation. Other types, such as solid oxide, proton exchange membrane, and molten carbonate fuel cells, have entered the testing and demonstration phases. The part of a fuel cell that contains the electrodes and electrolytic material is called the “stack,” and is a major component of the cost of the total system. Stack replacement is very costly but becomes necessary when efficiency degrades as operating hours accumulate.

Fuel cells require hydrogen for operation. However, it is generally impractical to use hydrogen directly as a fuel source; instead, it is extracted from hydrocarbon fuels using a reformer. Cost effective, efficient fuel reformers that can convert various fuels to hydrogen are necessary to allow fuel cells increased flexibility and commercial feasibility. Fuel reformers have been built to extract hydrogen from almost any type of fuel, including anaerobic digester gas and landfill gas.

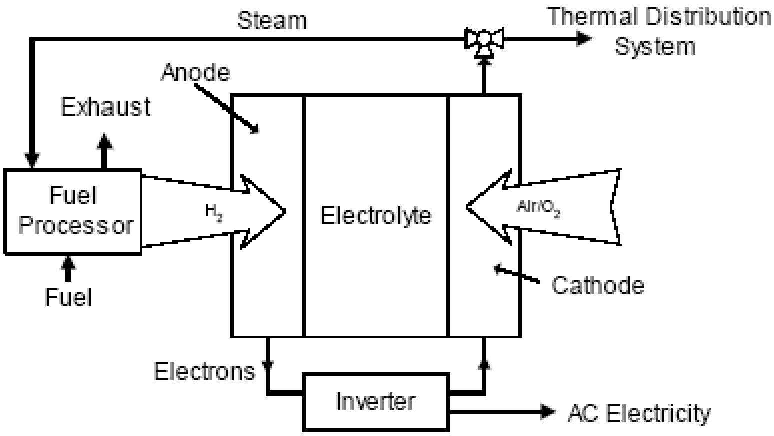


Figure 3-5. Fuel Cell Schematic

UTC’s phosphoric acid fuel cells can easily be used in two different types of industrial cogeneration applications: to produce hot water at around 140° F, or to produce hot water at around 140° F and low temperature steam at 250° F. Overall CHP efficiency for both is around 80%.

Proton exchange membrane and alkaline fuel cells operate at lower temperatures, so only hot water and space heating applications are possible. Solid oxide and molten carbonate fuel cells, however, operate at extremely high temperatures (over 1000oF) so they can be used in a number of cogeneration applications, as well as fuel cell-turbine hybrid systems.

Emission Controls

Fuel cells have very low levels of NOx and CO emissions because the power conversion process is electrochemical rather than combustion-based. For this reason, as emission standards become increasingly stringent, fuel cells will offer a clear advantage, especially in non-attainment zones. To date, fuel cells have been exempt from environmental regulations in most parts of the United States.

Efficiency

Fuel cells are the most consistently efficient power generating technology. PAFC’s generate electricity at about 35-40 % efficiency, with an overall efficiency of 70-80% if the by-product thermal energy produced by the fuel cell is used for cogeneration. Most of the other fuel cell designs have higher electric efficiencies, but still achieve an overall efficiency of about 80% when cogeneration is utilized. Operating temperatures for phosphoric acid fuel cells are in the range of 350-400oF.

Equipment Costs and Modifications for Opportunity Fuels

Fuel cells are very expensive to obtain at this time since they are a new technology, but their installation costs are average and maintenance costs are very low. As time goes by, the price of fuel cells may go down, and they may become more competitive with the other power generating technologies. The cost to obtain a fuel cell system is typically $4,000-$5,000 per kW, with about $300-$500 per kW for installation.

Fuel cells normally run on natural gas, using a fuel reformer to extract the free hydrogen. Fuel cells can also run on anaerobic digester gas or landfill gas, but they require a slightly different fuel reformer, with a larger fuel injector and larger piping. For ADG and LFG, extensive scrubbing is sometimes necessary to neutralize the sulfur and halides. While fuel cells running on natural gas cost close to $4,000 per kW, units operating on low-Btu fuels would cost slightly more to obtain, with a small decline in power output. For the purposes of this project, it is assumed that low-Btu fuels will add about 10 percent to the equipment cost. If the purchase of an anaerobic digester is required, an additional capital cost of $900-$1,500 per kW can be expected. Of course, coalbed methane and high-quality biomass gas could also be used to power fuel cells with minimal modifications (although with biomass gas, a gasifier will add around $1,000 per kW to the total cost).

Maintenance Costs and Issues with Opportunity Fuels

Today's fuel cells (phosphoric acid) cost about $0.015 to $0.03 per kWh to maintain. Because no combustion occurs in a fuel cell system, there is not as much deposit buildup, and the purity of the fuel used is not as much of an issue. However, since they are a relatively new technology, trained professionals must be contracted to maintain the unit, which increases maintenance costs. Most of the O&M issues with fuel cells stem from the fuel reformer, which converts hydrocarbon fuels into pure hydrogen. Using a lower Btu fuel with more impurities will require increased cleaning and maintenance of the fuel reformer. ADG and LFG powered fuel cells should cost between $0.02 and $0.04 per kWh to maintain, while biomass gas and coalbed methane should have roughly the same maintenance cost as natural gas. For biomass gas, the maintenance costs of a gasifier are added.

Applications for Fuel Cells

Since fuel cells are the newest DER/CHP technology, their availability is minimal, and they have not been utilized in many non-demonstration projects. Phosphoric acid and PEM units are less than 500 kW in size, but much larger units are possible in the future with solid oxide and molten carbonate fuel cell systems. Phosphoric acid fuel cells have been used in anaerobic digester gas projects at wastewater treatment centers, with special government funding, and the results have been mixed. Regardless, more ADG fuel cell projects are planned. Recently a fuel reformer has been designed to work with landfill gas, and projects are currently in the planning phases. As environmental regulations become stricter, and the price of fuel cells comes down, they may become more common for DER/CHP applications.

Stirling Engines

The Stirling Engine was invented in 1819 by Scottish minister Robert Stirling, but the invention did not take off in America until the 1850's. The engine was known for its ability to use any burnable material as fuel, its safe and quiet operation, and its low maintenance requirements. It was used primarily for low-power water pumping applications. However, the Stirling Engine disappeared from the commercial scene when internal combustion engines and electric motors arrived, offering higher power outputs at lower costs. Nevertheless, in 1980 the United States Agency for International Development began promoting the Stirling Engine for production and use in third world countries because of its easy manufacturability. Plans are now in the works to commercially produce an improved Stirling Engine design for various applications, including distributed generation with opportunity fuels.

Operation

The Stirling Engine uses the Stirling Cycle, where the engine's gases are inert and trapped inside. The gases are heated by an external heat source, so no combustion or explosions occur inside of the engine. The heat source does not require any specific type of fuel, making the Stirling Engine one of the most versatile of all engine designs.

A typical Stirling Engine consists of a two-cylinder, two-piston arrangement shown in Figure 1. The gas inside of one cylinder, usually hydrogen or helium, is heated up by an external heat source. This increases the pressure of the gas and forces the piston to move down, doing work that can be translated to a rotating shaft. This piston is then pushed back up by a mechanical device that also brings the other piston down, forcing the gas to enter the cool cylinder. In this process, the gas temperature and pressure is lowered, making it easy to compress. The piston in the cool cylinder is then pushed up, compressing the gas and sending it back to the heated cylinder where the cycle starts over again. To aid in the reheating process a regenerator, or heat storage device (such as a metal screen or mesh), is used in between the cylinders. While many different arrangements are possible for Stirling Engines, they all operate on this same basic principle.

The Stirling Engine only generates power during the first part of the cycle, when pressure from the heated gas displaces the piston. Increasing the pressure of the heated gas will increase the amount of work done by the engine. The easiest way to achieve this pressure increase is to raise the temperature of the heat source.

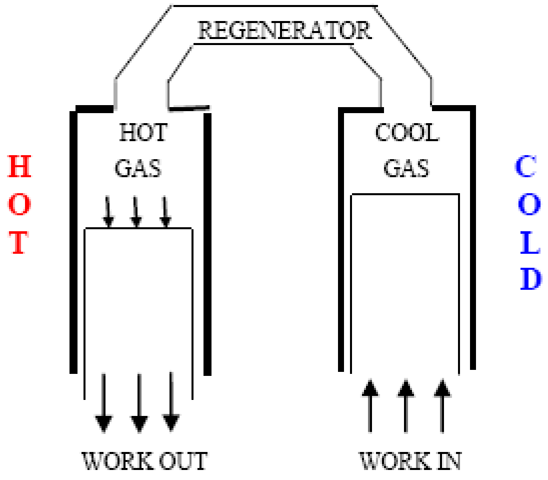


Figure 3-6. Typical Stirling Engine consisting of two cylinders, one hot and one cold

Another way to increase the work output is to lower the cool cylinder's temperature. The pressure of the cool gas decreases with its temperature, meaning less work is required to move the piston. In short, maximizing the temperature difference of the two cylinders works to increase the power output of the system.

Stirling Engines can come in many different arrangements, and can utilize a number of different technologies. Until recently, most Stirling Engines produced only small amounts of work and required an extremely sizable housing. Their only favorable aspects were minimal maintenance and low noise production. However, new materials and improvements in technology have yielded smaller, more efficient Stirling Engines. The 55 kW model from

STM Power will be the first commercially available on the market It utilizes hydrogen gas inside the pistons, and can be powered by low-Btu fuels.

Stirling Engines have many benefits compared to other technologies when operating on low-Btu fuels. They can handle a fluctuating Btu level – if the fuel stream's Btu content becomes low, the burner simply sucks in more fuel. Other technologies may require blending with natural gas when this problem occurs. In addition, Stirling Engine burners have a high tolerance for moisture, siloxane, and hydrogen sulfide, so much less fuel treatment is required. One of the drawbacks to Stirling Engines, however, is that CHP applications are limited to hot water, with temperatures typically reaching 130-140oF.

Emission Controls

The only emissions potentially produced by Stirling Engines come from the external heat source. Landfill gas or ADG will produce more emissions than natural gas, but the emissions are easily controlled with the external combustor. Emissions from Stirling Engines are moderate, and should not be an issue in siting potential DER/CHP applications.

Efficiency

Stirling engines have electric efficiencies of around 30 percent. The 55 kW STM model achieves a 28 percent efficiency when operating on low-Btu fuels, with a 78 percent overall efficiency when utilizing CHP.

Equipment Costs and Modifications for Opportunity Fuels

Because of the external combustion design, the only piece of equipment that may require alteration is the fuel burner. It is expected that most Stirling Engine models will have special burners for low-Btu fuels, as this is one of their target markets. As previously mentioned, Stirling Engines have many benefits compared to other technologies when operating on ADG or LFG. However, the capital cost for Stirling Engines is expected to fall between $1,200 and $1,500 per kW, plus an additional $300-$500 per kW for installation ($1,500-$2,000 per kW total). While this price level is competitive with microturbines, it is higher than conventional combustion turbines or reciprocating engines in most applications.

Maintenance Costs and Issues with Opportunity Fuels

Maintenance costs for Stirling Engines are expected to be very low – this has always been one of the technology's strong points. Projected estimates have maintenance costs falling between $0.008 and $0.01 per kWh. With STM's design, some of the maintenance costs come from the integrated hydrogen generator, which operates on the electrolysis principle. Because hydrogen inevitably leaks out of the engine, the bladder must be filled with water once a month. Other than that, the bulk of maintenance costs come from the burner, which may require slightly more maintenance depending on the quality of the fuel.

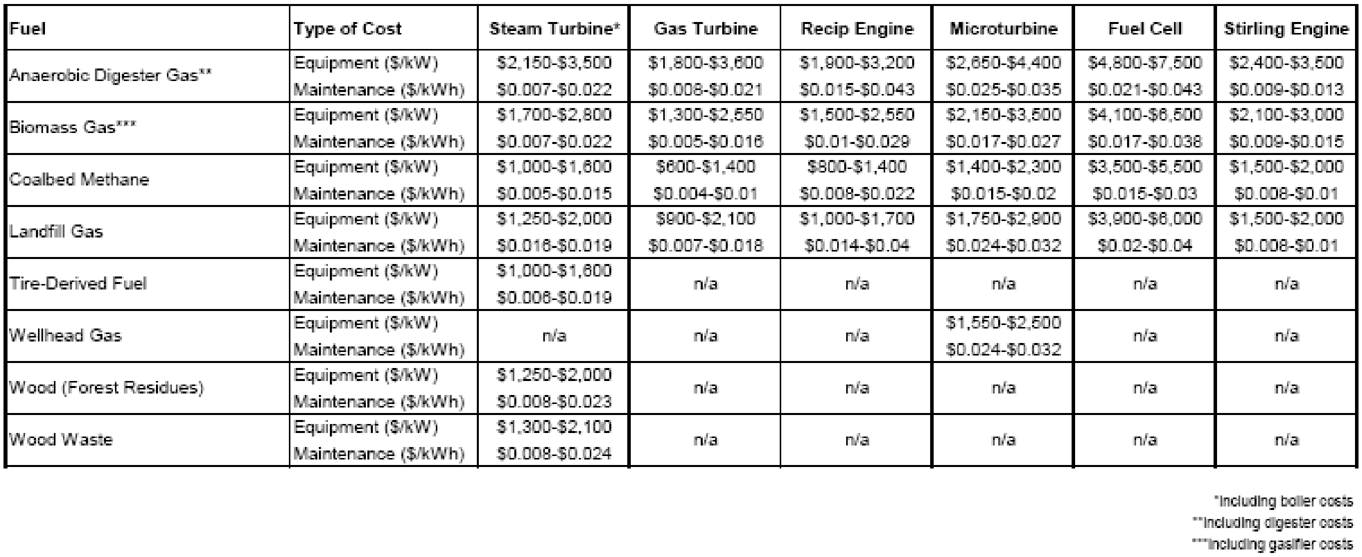
Applications for Stirling Engines

Stirling Engines are most likely to succeed in applications where a free fuel source can be obtained. Because of their high tolerance for moisture, siloxanes, and hydrogen sulfide, and their ability to handle fluctuating Btu loads, Stirling Engines are ideal for ADG or LFG applications. They could also prove useful with coalbed methane or biomass gas, although with these cleaner fuels, less expensive traditional DER/CHP technologies are more likely to prevail.

Summary

The equipment and maintenance costs for the eight chosen opportunity fuels are summarized in Table 3-1 on the following page. The data was obtained by taking the low and high costs for coal/natural gas systems (estimated using DOE technology characterizations and various data sources), and multiplying them by the percentage factors for opportunity fuels, obtained from equipment manufacturers. While the price ranges are often large, they give an idea to how much an average opportunity fuels project would cost in comparison with the different prime mover technologies. For anaerobic digester gas, it is assumed that the facility must purchase an anaerobic digester, so this is included in the costs. All of these installations are assumed to be combined heat and power applications.

In the following chapters, the availability and potential capacity of all eight opportunity fuels are examined, and the current status and future outlook of each fuel is discussed.



Fuel	Type of Cost	Steam Turbine*	Gas Turbine	Recip Engine	Microturbine	Fuel Cell	Stirling Engine
Anaerobic Digester Gas**	Equipment ($/kW)	$2,150-$3,500	$1,800-$3,600	$1,900-$3,200	$2,650-$4,400	$4,800-$7,500	$2,400-$3,500
	Maintenance ($/kWh)	$0.007-$0.022	$0.008-$0.021	$0.015-$0.043	$0.025-$0.035	$0.021-$0.043	$0.009-$0.013
Biomass Gas***	Equipment ($/kW)	$1,700-$2,800	$1,300-$2,550	$1,500-$2,550	$2,150-$3,500	$4,100-$6,500	$2,100-$3,000
	Maintenance ($/kWh)	$0.007-$0.022	$0.005-$0.016	$0.01-$0.029	$0.017-$0.027	$0.017-$0.038	$0.009-$0.015
Coalbed Methane	Equipment ($/kW)	$1,000-$1,600	$600-$1,400	$800-$1,400	$1,400-$2,300	$3,500-$5,500	$1,500-$2,000
	Maintenance ($/kWh)	$0.005-$0.015	$0.004-$0.01	$0.008-$0.022	$0.015-$0.02	$0.015-$0.03	$0.008-$0.01
Landfill Gas	Equipment ($/kW)	$1,250-$2,000	$900-$2,100	$1,000-$1,700	$1,750-$2,900	$3,900-$6,000	$1,500-$2,000
	Maintenance ($/kWh)	$0.016-$0.019	$0.007-$0.018	$0.014-$0.04	$0.024-$0.032	$0.02-$0.04	$0.008-$0.01
Tire-Derived Fuel	Equipment ($/kW)	$1,000-$1,600	n/a	n/a	n/a	n/a	n/a
	Maintenance ($/kWh)	$0.006-$0.019					
Wellhead Gas	Equipment ($/kW)	n/a	n/a	n/a	$1,550-$2,500	n/a	n/a
	Maintenance ($/kWh)				$0.024-$0.032		
Wood (Forest Residues)	Equipment ($/kW)	$1,250-$2,000	n/a	n/a	n/a	n/a	n/a
	Maintenance ($/kWh)	$0.008-$0.023					
Wood Waste	Equipment ($/kW)	$1,300-$2,100	n/a	n/a	n/a	n/a	n/a
	Maintenance ($/kWh)	$0.008-$0.024					

*Including boiler costs
**Including digester costs
***Including gasifier costs

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