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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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- Transportation

UC Davis Technology Assessment for Advanced Biomass Power Generation is the final report for the SMUD ReGen project (Contract Number 500-00-034), conducted by UC Davis. The information from this report contributes to PIER's Renewable Energy Technologies program.

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Abstract

This report examines advanced biomass conversion processes, technologies, economic performance, and environmental considerations associated with the use and management of biomass within the Sacramento Municipal Utility District (SMUD) region.

Advanced biomass power systems include thermal gasification systems from small combined heat and power systems to medium and large scale integrated-gasifier-combined-cycle systems, thermochemical and biochemical systems suitable for municipal solid waste and other biomass, and combustion boilers designed for straw fuels. Also considered advanced is the variety of methods for biomass cofiring with fossil fuels (solid fuel cofiring, solid biomass with natural gas superheat, gasified biomass and natural gas, etc.).

Though there is some development of advanced systems in California and the Midwest and Northeast, most advanced biomass power systems development is occurring in Europe and Japan. The systems selected for analysis include three types and scales of thermal gasifiers, a straw-fueled combustion boiler, green waste and municipal solid waste anaerobic digesters, and dairy manure digester systems.

Some of the successfully demonstrated or operating systems in Europe could compete in California while others will need some level of support to achieve commercial status. One of the hurdles facing transfer of the technology to California is the high risk perceived by financiers due to a lack of demonstrated facilities permitted and operating in the state. Recommendations to address the transfer of these technologies to California are provided.

Keywords: Biomass, combined heat and power, municipal solid waste, straw fuels, anaerobic digesters, dairy manure digester systems

Executive Summary

SMUD ReGen Program – An Assessment of Advanced Biomass Power Generation Technologies.

The Sacramento Municipal Utility District (SMUD), situated in the center of California and spanning urban, agricultural, and wildland areas, has access to a diverse supply of biomass resources and is well poised to pursue a variety of technologies to generate additional amounts of renewable biomass energy for its customers. This report examines conversion processes, technologies, economic performance, and environmental considerations associated with the use and management of biomass within the SMUD region. Included in Section 1 is a brief background of biomass conversion, biopower generation in the United States and California, and an estimate of biomass resources in the Sacramento region. Biopower capacity in the United States is currently about 11 gigawatts (GW), of which about 55 percent is fueled by forest products and agricultural residues, the remaining based on municipal solid waste, including landfill gas. California's installed capacity is about 1 gigawatt of electricity, which includes 640 megawatts (MW) from combustion of forest and agricultural residues, 210 MW from landfill gas conversion facilities, and 65 MW from municipal solid waste mass burn facilities. Gross biomass resources in the Sacramento region (including the central Sierra Nevada region) represent 8.8 terawatt hours of electricity (from 1 GW), though only about half that is estimated to be technically available.

Advanced biomass power systems include:

- A variety of methods for biomass cofiring with fossil fuels, such as solid fuel cofiring, solid biomass with natural gas superheat, gasified biomass and natural gas.
- Thermal gasification systems from small combined heat and power systems using reciprocating engines to medium and large scale integrated-gasifier-combined-cycle systems.
- Thermochemical and biochemical systems suitable for municipal solid waste and other biomass.
- Combustion boilers designed for straw fuels.

Though there is some development of advanced systems in California and the Northeast, most of the advanced developmental work on biomass power systems is occurring in Europe and Japan. Advanced systems include solid-fuel direct combustion units capable of burning fuels that cannot be consumed in the existing facilities in California, small to medium scale automated gasifier combined heat and power systems, commercially operating farm-scale and industrial-scale anaerobic digester systems, and more. Section 1 devotes significant attention to new and existing biomass power systems overseas that might serve as models for future California and SMUD development.

Section 2 contains data on environmental impacts of biomass power systems and suggestions or techniques for improvement to meet increasingly stringent California regulations and objectives. Environmental impacts of concern include concentrations of heavy metals in solid residues, quality, and amount of liquid discharges, and air emissions. Because much of California is not meeting federal and state attainment standards for ambient ozone, air emissions (especially nitrous oxides), are among the most important environmental impacts. The Sacramento region is not in attainment for ozone and, except for Amador County, not in attainment for particulate matter. Table ES-1 compares air emissions from operating and developmental biopower facilities in the United States and Europe.

Section 3 contains an engineering and economic analysis of selected technologies presented in Section 1. An economic model was used to estimate revenue requirements in the form of levelized cost of energy or levelized required tipping fee, the latter applied when using municipal solid waste in a case study of anaerobic digestion.

The selected technologies analyzed in Section 3 are:

Gasification

- Circulating Fluidized Bed, 5.4 MW combined heat and power facility based on a unit under development in Skive, Denmark.
- Fixed bed, 1.8 MW combined heat and power facility in development in Kokemäki, Finland.
- BIGCC-pressurized Circulating Fluidized Bed 12.5 MW.

Straw combustion system

- Straw fueled vibrating grate boiler, steam cycle power plant, 38 MW, based on the power plant in Ely, England.

Municipal solid waste/green waste anaerobic digestion systems

- Anaerobic digestion of green waste and the organic fraction of municipal solid waste based on a generic system using 100,000 wet tons/year and generating 1.2 MW of electric power.
- Anaerobic phased-solids green/food waste digester system using 76,000 wet tons/year and generating 1.2 MW of electric power.

Dairy manure digester systems

- Preliminary data from the California Dairy Power Production Program.
- Plug-flow, covered lagoon, and mixed tank systems with capacities ranging from 30 kW to 1 MW.
-

The results for the base case estimated cost of energy and the range of potential values from sensitivity analyses are shown in Figure ES-1. Base case levelized cost of electricity ranges from a low of $0.037 per kilowatt hour for fully amortized existing solid-fueled direct combustion units, to more than $0.13/kWh for dairy anaerobic digestion systems with short-term financing. The cost of electricity from municipal solid waste digestion depends heavily on tipping fees available and assumptions regarding labor and other operating and maintenance costs. Larger scale demonstration in California of advanced technologies will be needed to refine cost estimates.

The project included developing a database of biomass technology developers, consultants, research organizations, resource managers, and other stakeholders. The database contains 120 technology suppliers and 265 industry and other stakeholder contacts and is published and available as a separate document.

This report examines advanced biomass conversion processes, technologies, economic performance, and environmental considerations associated with the use and management of biomass within the SMUD region.

Table ES-1. Air emissions from biomass fueled power systems

Prime Mover	Control Technology	Units	NOx	CO	UHC/THC	ROGs	PM	SO_2	Source
California solid fuel biomass boilers	SNCR, flue gas recirc., & PM control	lb/MWh	0.64 - 0.95	0.1 - 1.5	0.01 - 0.09	-	0.09 - 0.55	0.02 - 0.26	1,2
BIGCC, various fuels (Värnamo, Sweden)	Gas turbine -Untreated	lb/MWh or (ppm dry gas)	2.2 - 9.8	(50-450)	(<1)	-	(<1)	0.2-2.0	3
Reciprocating Engines fueled by gasified biomass	Lean burn	(ppm, 15% O_2)	(30 - 300)	(100 - 1,000)	(<10)	-			4,5
	Rich-burn SI engine w/ 3-way catalytic converter (single test, CPC)	lb/MWh	0.65	0.03	0.03	-	-	-	6
Reciprocating Engines fueled by biogas (LFG, WWTP, manure digesters)	Large, lean burn	lb/MWh	.65-1.9	6.4-10.6	-	.36-1.7	-	-	7
	Rich Burn, 3-way catalyst (dairy, 300 kW)	lb/MWh	0.95	5.84	-	0.08	-	-	8
	Rich Burn -no controls (swine manure -100 kW capacity operating @ 45 kW)	lb/MWh	12	58	-	112	-	23	9
	CARB BACT Recommendation	lb/MWh	1.9	1.9	-	7.8	-	-	10
Gas Turbine 30 kW (LFG)	uncontrolled	lb/MWh	0.2-0.24	0.6-0.72	2.4 ppm, (3% O_2)	-	-	est. 1.03	11
Gas Turbine (<3 MW) fueled by biogas	CARB BACT Recommendation	lb/MWh	1.25	-	-	-	-	-	10
Fuel Cell, LFG fuel	uncontrolled	lb/MWh	0.0017	0.025	0.017	-	-	nd	11

- = not reported or specified
nd = not detected
Sources; See Table in Section 2

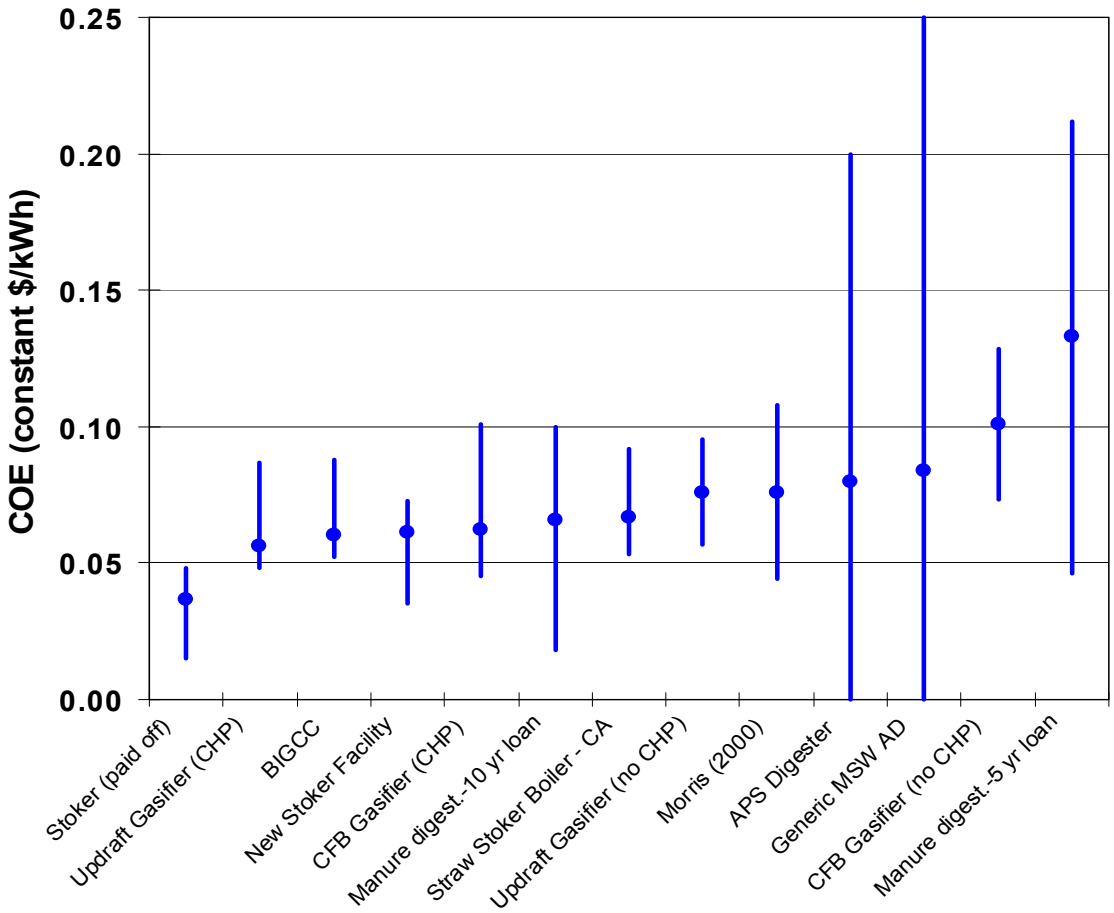


Figure ES-1. Cost Of Electricity estimates for biomass power conversion technologies.
Source: UC Davis Research Team

Advanced biomass power systems include thermal gasification systems from small combined heat and power systems to medium and large scale integrated-gasifier-combined-cycle systems, thermochemical and biochemical systems suitable for municipal solid waste and other biomass, and combustion boilers designed for straw fuels. Also considered advanced is the variety of methods for biomass cofiring with fossil fuels (solid fuel cofiring, solid biomass with natural gas superheat, gasified biomass and natural gas, etc.).

Though there is some development of advanced systems in California and the Midwest and Northeast, most advanced biomass power systems development is occurring in Europe and Japan. Section 1 devotes significant attention to new and existing biomass power systems overseas that might serve as models for future California and SMUD development.

Section 2 contains data on environmental impacts of biomass power systems and suggestions or techniques for improvement to meet increasingly stringent California regulations and objectives.

Engineering and economic analyses for selected systems are examined in Section 3. The systems selected for analysis include three types and scales of thermal gasifiers, a straw-fueled

combustion boiler, green waste and solid waste anaerobic digesters, and dairy manure digester systems. A revenue requirements model was used to estimate the levelized cost of energy or levelized required tipping fee, the latter applied when using municipal solid waste in a case study of anaerobic digestion.

Some of the successfully demonstrated or operating systems in Europe could compete in California while others will need some level of support to achieve commercial status. One of the hurdles facing transfer of the technology to California is the high risk perceived by financiers due to a lack of demonstrated facilities permitted and operating in the state. Recommendations to address the transfer of these technologies to California are provided.

Project Approach

The project activities included an extensive review of the literature, discussions with technology developers, state and local regulators, consultants and academics, attendance of regional conferences and one international conference, and numerous facility inspections within the United States and Europe.

Significant portions of the information were developed from related work funded by the California Integrated Waste Management Board.

Economic modeling to determine levelized cost of energy (and/or required tipping fee) was conducted for selected technologies.

Project Outcomes

The primary project outcome is this final report. Included in the report is:

- A biomass resource inventory using county level resource information developed by the California Biomass Collaborative.
- An extensive review of biomass power systems including status in California and the United States and current development overseas, especially Europe.
- A discussion of environmental impacts with particular emphasis on NOx production, methods of control, and current emissions levels for various technologies.
- An estimated cost of energy or required tipping fees from economic analysis and modeling.
- A set of recommendations to help SMUD (or the state) develop advanced biomass power systems.

A database of suppliers, consultants, and research institutions in the biopower field was also developed which was submitted separately from the final report.

Conclusions and Recommendations

Environmental and energy policies in Europe and Japan have created a vibrant biomass power industry and research and development sector. These policies create high feed-in tariffs for renewable energy while simultaneously imposing high landfill costs that enable solid waste conversion technology development and deployment. In California, no new solid fuel combustion facilities have been commissioned since 1992 and several facilities have shut down or converted to natural gas fuel as a result of poor economic conditions including coincident loss of associated industries such as sawmills supplying fuel to cogeneration facilities. Recent biomass power related activity in California has largely been driven by environmental concerns over manure from confined animal operations such as dairies and opportunities for greater use of landfill gas and sewage digester gas. California's renewable portfolio standard now provides one of the primary mechanisms for long term contracting for renewable energy, but higher generation costs associated with many biomass technologies in competition with lower cost wind and geothermal resources have so far restricted biomass entry into this market. Increasing interest in renewable transportation fuels is creating market opportunities for biomass, but power generation will remain a key industry for further biomass development, including an integral part of biorefineries.

Some of the successfully demonstrated or operating systems in Europe could compete in California while others will need some level of support before achieving commercial status. One of the hurdles facing transfer of the technology to the United States is the high risk perceived by financiers due to the lack of demonstrated facilities operating in California and satisfying permit requirements. To address these issues of technology transfer, SMUD may wish to consider various development alternatives, including the following:

- Form a public-private partnership to demonstrate advanced thermochemical conversion (i.e., biomass integrated gasifier combined cycle) and other technologies in California using pilot or commercial scale designs.
- Increase the biomass power facilities within the utility district. SMUD is already involved in the development of biomass power projects that enhance local waste management (i.e., green and food waste and manure).The large resource in the region composed of forest and agricultural thinnings and residues represent an opportunity for SMUD to significantly increase its biomass power portfolio. Specific project recommendations are:
    - Transfer existing biomass combined heat and power technology (500 kW to 2 MW) to a suitable heat client in the Sacramento region (heat clients include absorption cooling applications).
    - Exploit the fuel potential in the region's rice straw and other crop residues with transfer of existing technology.

- Increase research and development funding and activity to obtain more detailed and more reliable operating, economic, and environmental data for new anaerobic digestion and other facilities and participate in or motivate related state efforts to enhance the overall quality of information available on biomass systems.
- Work with the state and federal governments to increase research and demonstration activity on concepts to improve technology and reduce emissions from biomass conversion, including:
    - Investigate advanced reburning using biomass fuels to reduce nitrogen oxide (NOx) emissions for retrofit or new facility design.
    - Evaluate Selective Catalytic Reduction and regenerative Selective Catalytic Reduction NOx control techniques.
    - Investigate ozone injection to assess feasibility as a NOx control technique for solid-fueled and other biomass systems.
- Improve emissions performance of reciprocating engines, including:
    - Improve fuel gas cleaning.
    - Extract hydrogen sulfide and siloxane from biogas to enable greater use of catalytic after-treatment of combustion gases and other control measures.
    - Reduce nitrogen compounds (ammonia, hydrogen cyanide) in producer gas from thermal gasification systems.
- Continue development of hydrogen enriched fuel gas for improved lean burn engine performance.
- Improve efficiency of micro-turbines.
- Reduce costs of stationary fuel cell power systems.

Ongoing and new demonstration or "first commercial" biomass gasification with combined heat and power facilities overseas present a timely opportunity for observing and monitoring these facilities. Further development of existing association with the project developers in order to facilitate exchange of information is recommended. In addressing the greater use of biomass within its territory and surrounding region for renewable generation and improved environmental quality, SMUD will serve as a model for development in the rest of the state. SMUD actions can help shift state waste management policies to more appropriate resource management strategies.

Commercialization Potential and Benefits to California

There has not been any substantial increase in biopower generating capacity in California since the early 1990s. In order for biomass power to make a significant contribution to the supply of renewable electricity in California, the aging fleet of biomass facilities will need to be re-powered and large amounts of new capacity must be developed. If this is to occur, new strategies for utilization of biomass resource will be required including increasing the range of feedstocks used, newer and updated conversion technologies, and a more consistent policy approach.

Because of extensive research and development overseas, advanced biomass power systems that are built in California will likely be imported technologies and designs.

With the higher natural gas prices recently experienced, automated biomass combined heat and power systems are commercially viable if a suitable client for the heat is available. Without heat co-product, the economics of advanced (as well as the standard stoker or circulating fluidized bed boilers) biopower systems are marginal at current electricity market prices.

Depending on which set of Renewable Portfolio Standard goals are pursued (20 percent renewables by 2017, or 33 percent by 2020), new renewable generation capacity will be required at the rate of 3,200 to 5,000 MW each year. Current biopower capacity is approximately 1,000 MW, and biomass contributes about 2 percent to the state's total power or 25 percent of renewable power consumed in the state. If biomass power were to continue to provide a quarter of non-hydro renewable generation under the Renewable Portfolio Standard, then new biopower capacity would need to be added at the rate of 800 to more than 1,200 MW each year.

The descriptions, problem identification, and analysis in the report, as well as the contact database, can be used to help define a strategy for building increased biopower capacity in California. Increasing biopower production benefits California by increasing the renewable content in the electricity portfolio, generating economic activity in the fuel supply and logistics sector, providing a number of stable jobs at the generating facility, and utilizing some of the vast biomass resource in the state that otherwise would be consumed in prescribed burns or wild fires, disposed in landfills or left in field or forest for eventual decay.

The information and analysis in this report addresses advanced biopower technologies and includes recommendations for moving forward. This report can serve as a technology reference and information source for those involved in mapping a state biomass power strategy that contributes to the Renewable Portfolio Standard. Used in this way, the report (and project) will save the Energy Commission, and possibly other state agencies, time and money.

1.0 Introduction

According to the Energy Information Agency (EIA 2003), electricity generated from biomass sources was 11% of all renewable electricity in the United States in 2001 and 59% of non-hydro renewable electricity. United States-installed biomass power capacity is substantial, currently at about 11 gigawatts (GW). About 6.2 GW is fueled by forest products and agricultural residues and about 3.5 GW is municipal solid waste (MSW)-based including landfill gas (EIA 2003).

The biopower industry grew quite substantially after enactment of the Public Utilities Regulatory Policy Act (PURPA) in 1978. PURPA required utilities to offer to purchase electricity from small (less than 80 MW) independent generators. The Federal Energy Regulatory Commission (FERC) established rules defining qualifying requirements. Many contracts were initially written for a price of energy equal to the utilities' short-run avoided cost based on natural gas although in California Standard Offer 4 was developed with a 10-year firm pricing structure based on the forecasted price of electricity and additional payments for dispatchable capacity. Between 1980 and 1995, grid-connected biopower capacity tripled (from 3.5 to 10.5 GW) (EIA 1997) because of PURPA, favorable federal tax policies for investments in renewable energy, and state incentives (Morris 2000). Standard Offer 4 was suspended by the California Public Utilities Commission in 1986 due to excess proposed capacity additions and the collapse in world oil prices. In the mid 1990s, the lack of new capacity with Standard Offer 4 contracts resulted in declining biomass energy capacity growth due to unfavorable pricing as utility short-run avoided cost dropped below biomass power generation costs. Any growth was largely associated with those projects already having Standard Offer 4 contracts and landfill and digester gas projects that had other incentives, including tipping fees for resources.

The installed biomass capacity in the United States primarily consists of direct combustion steam Rankine systems with an average size of 20 MW (the largest is near 75 MW) (Bain et al. 2003). Typical efficiencies are around 20%, due mostly to the small plant size but also to fuel quality (moisture).

1.1 Biomass Power in California

In California, total operating grid-connected electrical capacity from biomass resources is approximately 900 MW. This includes some 640 MW from solid fuel combustion in steam Rankine facilities (Morris 2002), 210 MW from landfill gas conversion facilities (Simons et al. 2002), and 39 MW from digester gas produced from anaerobic digestion of sludge at waste water treatment plants (including 24 MW from two Los Angeles treatment plants) (Zhang 2003).

The development of the solid fuel combustion biomass power industry in California followed a trend similar to that of the rest of the nation. Prior to 1978, biomass use for energy (other than home heating) in the state existed primarily at wood processing facilities which utilized wood residues to fuel steam boilers for process heat and in some

cases combined with power generation when economically advantageous. Between 1980 and 1984, 13 biopower facilities began operation, and 23 more came on line in the period 1985 through 1989. The year 1990 saw the start-up of 11 facilities. By the end of 1990, the operating biopower capacity in the state from non-MSW biomass sources was at its peak of approximately 770 MW (Morris 2000). The facility average capacity was about 18 MW with two at 50 MW.

The mid-1990s saw a decline in operating capacity of about 25% partly due to shutting down of some older less economical plants, fuel supply and pricing issues because of the decline in wood product activity in the state, as well as policies enacted by the California Public Utilities Commission in light of the coming electricity deregulation which created incentives for electric utilities to buy out the power purchase agreements of biomass facilities that were being paid based on the utility's short-run avoided cost or would soon become subject to short-run avoided cost following completion of the higher priced 10-year firm contract period ("year 11 price cliff"). Some facilities that were nearing the end of the their Standard Offer 4[1] contracts opted to sell the contracts and shut down because the short-run avoided cost then in place was much lower than the fixed price portion of the contract.

The substantial increase in wholesale electricity prices that occurred with the California electricity crisis of 2000 to 2001 spurred at least 10 shuttered facilities to investigate restarting (Morris 2000). Five facilities re-started in 2001 and 2002, and the other five abandoned the effort. There are approximately 28 solid-fueled biomass facilities currently operating in the state comprising a total of 570 MW capacity, not including three MSW combustion facilities that together generate another 70 MW. Another 31 facilities with combined capacity of 343 MW are idle, dismantled, or have been converted to natural gas fuel (See Table 1-1).

Another significant component of existing biomass power in California is the conversion of organic matter to methane (CH_4) through anaerobic microbial action with subsequent conversion of the methane to electricity. Many wastewater treatment plants (WWTP) utilize anaerobic digestion as part of the stabilization process. The organic fraction of in-place MSW in landfills degrades anaerobically as well.

1. The Interim Standard Offer No. 4 was favorable contracts made available to independent biomass power developers by PG&E and SCE. Available for signing in 1984 and 1985 with a 5-year window to bring projects online, the SO4 guaranteed firm energy prices for 10 years based on the relatively high short-run avoided cost rates in effect at that time ($.05 to $.06 per kWh) and escalating to more than $.12/kWh. At the end of the 10-year fixed rate portion, generators would receive the current market short-run avoided cost, which had significantly declined by the late 1990s.

Table 1-1 Disposition of solid fuel biomass power facilities in California.

Fuel	Disposition	Number of Facilities	Net Capacity (MW)
Solid Biomass	Currently Operating	28	570
MSW	Currently Operating	3	70
	Operating Total	**31**	**640**
Solid Biomass	Idle	15	159
Solid Biomass	Dismantled	11	73
Solid Biomass	Converted to Natural Gas	5	112
	Not Operating or Converted Total	**31**	**343**

Source: UC Davis Research Team ; Source: Robert Williams

There are some 278 active landfills accepting MSW in California (hazardous waste and used tires are disposed in facilities separate from MSW sites). There are more than 2,750 landfills that are closed, inactive, or abandoned in the state (SWIS 2003). Currently there are 51 landfills in the state recovering landfill gas for use as energy (LFGTE) with a combined generating capacity of 210 MW. Their distribution over several technologies is shown in Table 1-2. An additional 70 landfills are recovering and flaring gas. There are reportedly 26 other landfill sites planning to install LFGTE systems (Simons et al. 2002).

Some WWTPs utilize biogas from the anaerobic digestion of sewage sludge for power generation. Sewage is treated generally using combinations of aerobic and anaerobic processes. Several treatment plants in California produce sufficient methane to justify converting to heat and/or power, while others may flare the methane. The Sacramento Regional Waste Water Treatment facility generates approximately 2.8 MW from treatment of an average wastewater flow of 180 million gallons per day (gpd). There are 10 WWTPs in California with grid connected power generation (combined gross capacity of 38 MW) (Zhang 2003). The two largest are in Los Angeles County (24 MW from 770 million gpd wastewater, combined.)

There are three operating dairy digesters producing electricity in California with combined capacity of approximately 500 kilowatts (kW). There is one swine facility in the state with an operating digester.

Table 1-2. Current California LFGTE activity by technology type.*

Technology	No. of Landfills	Total Electrical Capacity (MW)
Reciprocating Engine	32	112
Gas Turbine Combined Cycle	2	57
Steam Turbine	3	31
Gas Turbine	5	10
Direct Use (thermal)	7	-
Upgrade for Pipeline Use	2	-

* Adapted from Simons et al. 2002. Landfill Gas-To-Energy Potential In California, California Energy Commission Staff Report 500-02-041V1.

1.2 Biomass Resource assessment for the Sacramento Region

A biomass resource assessment for the Sacramento region was conducted. The biomass types and sources considered are:

- The biogenic fraction of MSW.
- Residues from agriculture.
- Field and seed crops.
- Orchard and vine crops.
- Vegetable crops.
- Animal manure.
- Biosolids from waste water treatment.
- Forest operations residues and potential thinnings.

For MSW, only amounts disposed in or transshipped from Sacramento County were considered. The area covered in assessing the agricultural crop residues, dairy manure, and wastewater treatment facilities includes 16 counties in the region defined as Sacramento and the adjacent counties as well as those outlying in the Sacramento Valley north to Tehama and the San Joaquin Valley south to Stanislaus. Nevada and Calaveras counties were included in the outlying counties region (see Table 1-3 and Figure 1-1). Forest biomass resource accounting includes four additional counties in order to account for all forest biomass in the Central Sierra Nevada Range (Table 1-3). The data comes from a recently completed biomass resource inventory of California (von Bernath et al. 2004).[2]

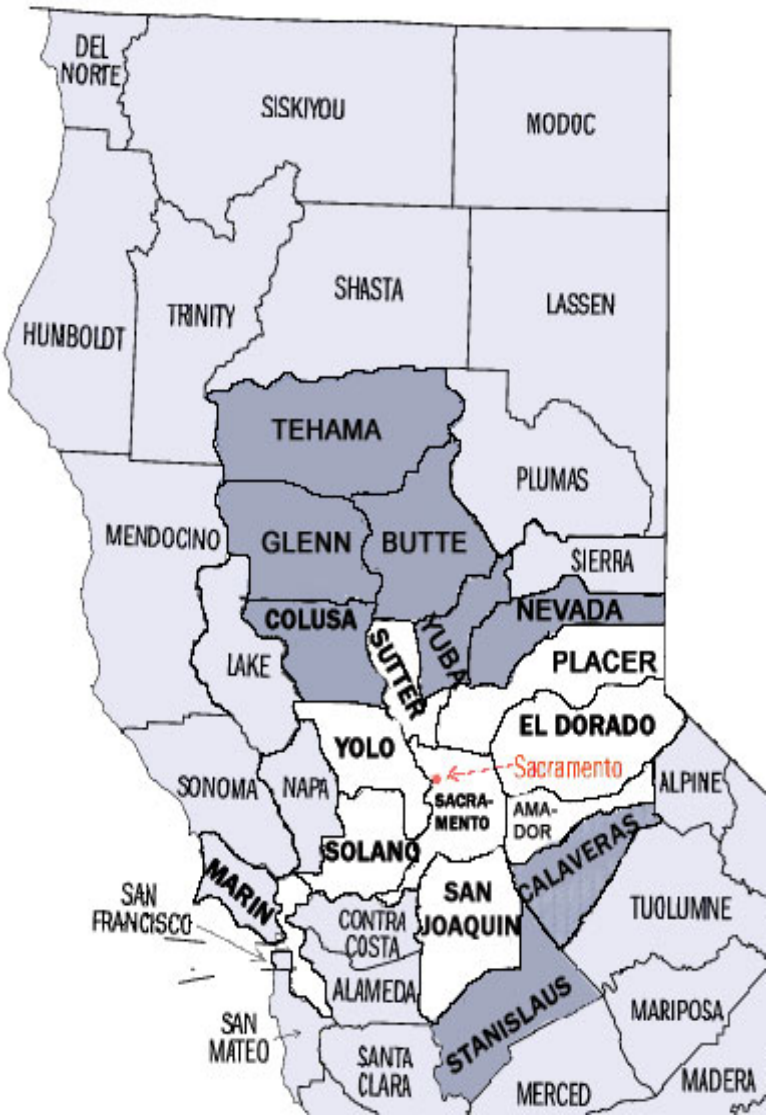
2. Forest biomass information provided to the CBC inventory by M. Rosenberg and J. Spero from the California Department of Forestry and Fire Protection.

Table 1-3. List of counties used for resource assessment for some biomass types.

Sub Regions	Counties	
Sacramento and Adjacent Counties	Sacramento Placer Sutter Yolo	Solano San Joaquin Amador El Dorado
Outlying Counties	Butte Calaveras Colusa Glenn	Nevada Stanislaus Tehama Yuba
Remaining Central Sierra Nevada Counties (for regional forest biomass assessment)	Plumas Sierra	Tuolumne Alpine

Source: UC Davis Research Team ; Source: Robert Williams

The total amount by weight of each type of biomass generated or disposed (in the case of MSW) was estimated. Total primary energy was determined by multiplying energy content of each type of material by the total mass. Potential gross generation capacity was then determined by multiplying the primary energy value by an appropriate conversion to electrical power factor (efficiency). Factors for technical availability (i.e., the amount of resource estimated to be practically and economically obtainable) are estimates used in the California Biomass Resources Inventory. The technical availability factors range from 0.34 for chaparral to 0.70 for orchard prunings and removals. These factors are uncertain and it is recommended that some effort be spent to reduce the uncertainty.



(White = Sacramento and adjacent counties; Dark grey = Outlying counties. Contra Costa County was not considered because of minimal non-MSW biomass resource).

Figure 1-1. Map of counties included in biomass resource assessment.

Source: UC Davis Research Team

Municipal Solid Waste

All solid waste jurisdictions in Sacramento County together disposed 1.5 million tons of municipal solid waste during 2003. Figure 1-2 shows the distribution of disposed solid waste by jurisdiction of origin. Sacramento, Citrus Heights, and the unincorporated areas of the county account for 86% of disposed waste. The municipalities of Elk Grove, Folsom, Rancho Cordova, Galt, and Isleton contribute the remaining 14%.

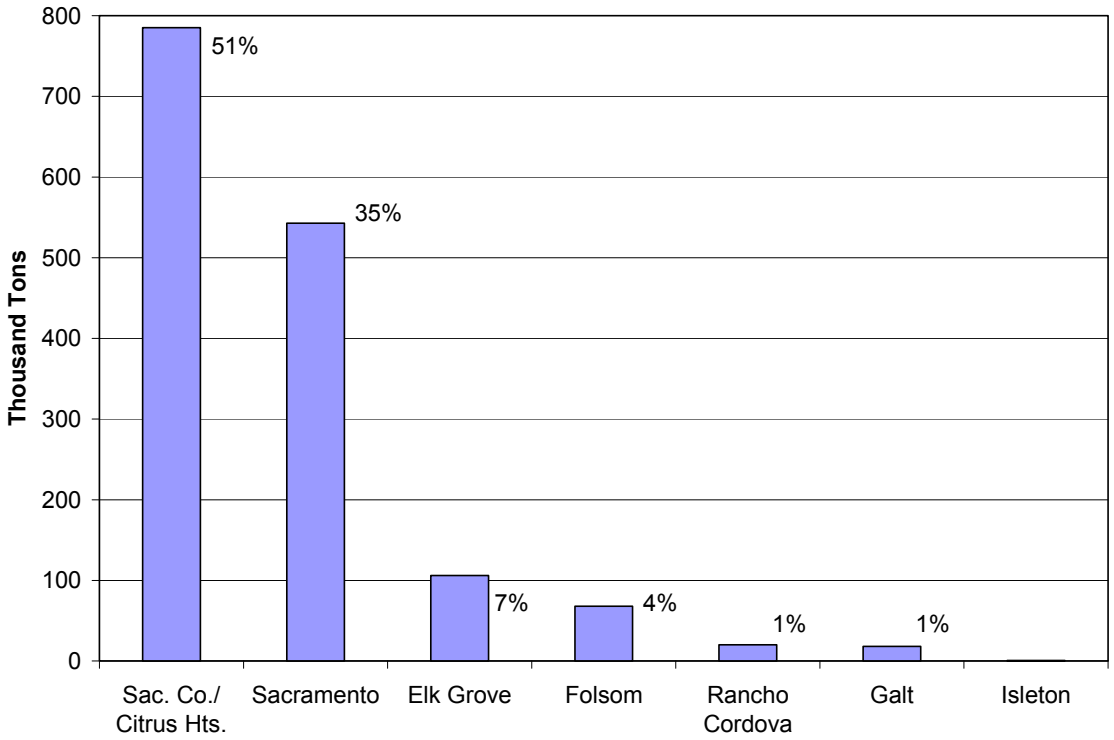


Figure 1-2. 2003 Sacramento County disposed solid waste by origin

Photo Credit: CIWMB Disposal reporting system, http://www.ciwmb.ca.gov/lgcentral/drs/Reports/default.asp

Sacramento County jurisdiction solid waste is disposed in a variety of locations. For 2003, 52% was disposed at one of two county landfills, 28% at a landfill near Manteca (San Joaquin County), 13% was shipped to Nevada[3] with the remainder going to other landfills in the region (See Figure 1-3).

3. The draft version of this report (2003) used disposal data from 2001, during which Sacramento County waste jurisdictions disposed 1.3 million tons, including 20% export to Nevada.

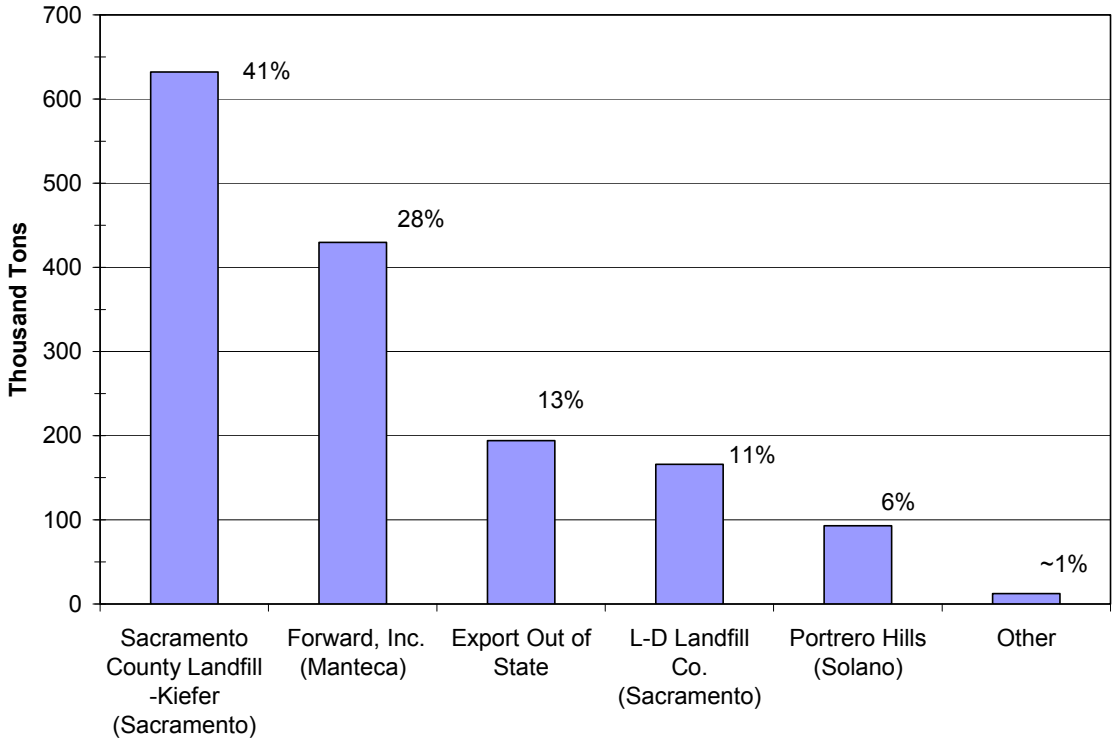


Figure 1-3. 2003 Sacramento County solid waste disposal by destination
Source: CIWMB Disposal reporting system.

The Kiefer landfill disposed about 630,000 tons of Sacramento County MSW (total disposal at Kiefer was 640,000 tons). The L-D Landfill received some 186,000 tons of solid waste, of which 165,000 tons came from County jurisdictions. The 195,000 tons of waste originating in the County that is transshipped to Nevada for disposal passes through one or more of the solid waste transfer stations in the County. See Table 1-4 for a list of solid waste facilities in Sacramento County.

The amount of material currently sent to landfill in Sacramento County (and in all of California) represents a substantial resource. Table 1-5 contains an analysis of the total energy and the electricity generation potential represented by the 2003 disposal of MSW at the two Sacramento County landfills. Component fractions of the MSW stream are taken from the California Integrated Waste Management Board (CIWMB) waste characterization study of 1999.[4] The distribution of components in disposed solid waste has likely changed somewhat but more recent characterization data are not yet available (a new four-season waste characterization study is currently being conducted). For each component of the waste stream, the table lists amount landfilled, typical moisture and ash contents, and higher heating values (HHV) in both as-received and moisture-free basis. Of the 820,000 tons landfilled, some 560,000 tons are of biological origin, 90,000 tons are plastics and textiles (assumed to be all synthetic textiles), and the remaining 170,000 tons are mineral and other inorganic material (glass, metal, non wood construction/demolition waste).

4. http://www.ciwmb.ca.gov/WasteChar/Study1999/OverTabl.htm

Table 1-4. Solid waste facilities in Sacramento County.[5]

Facility Name	Address	Activity	Status	Permitted Throughput ($t\ d^{-1}$)
Kiefer Landfill	12701 Kiefer Blvd	Solid Waste Landfill	Active	10815
L and D Landfill Co.	8635 Fruitridge Road	Solid Waste Landfill	Active	2540
Elder Creek Recovery and Transfer Stn.	8642 Elder Creek Rd.	Large Volume Transfer/Processing Station	Active	2000
North Area Transfer Stn.	4450 Roseville Road	Large Volume Transfer Station	Active	1800
South Area Transfer Stn.	8550 Fruitridge Road	Large Volume Transfer Station	Active	348
Florin Perkins LF Inc.,(Inerts)		Inert Waste Disposal site	Active	100
Florin Perkins LF Inc., MRF&Trans. Stn.	4201 Florin Perkins Rd.	Large Volume Transfer/Processing Station	Active	250
Sacramento Compost Facility	20 28th Street	Green Waste Composting	Active	
Sacramento Recycling and Transfer	8191 Fruitridge Road	Large Volume Transfer/Processing Facility	Active	2000
Folsom MRF & Composting	N. of New Prison Complex off Natoma	Large Volume Transfer/Processing Facility, Composting,MRF	Active	300
Galt Transfer Stn./MRF	104 Industrial Rd.	Large Volume Transfer/Processing Facility, Composting,MRF	Planned	300
Pilot Green Project	9700 Goethe Rd.	Green Waste Composting	Planned	
BLT Transfer Stn.	Raley Blvd& Vinci Ave.	Large Volume Transfer/Processing Facility	Planned	

CIWMB SWIS database, http://www.ciwmb.ca.gov/SWIS/Search.asp

Potential primary energy estimates were made by simply multiplying the appropriate material energy content on a per weight basis (HHV) by the amount of that material available. This is done for each component in the waste stream.

5. CIWMB SWIS database, http://www.ciwmb.ca.gov/SWIS/Search.asp

For estimating the amount of electrical generation capacity that could be developed from the current waste stream, it was assumed that the stream would be separated based on moisture content. The high moisture components are perhaps most appropriately converted through biochemical systems (anaerobic digestion (AD), for example). Though AD is suitable for high moisture feedstocks, a major disadvantage of AD is that conversion is incomplete; some 50% of the organic material is not converted. Lignin and other refractory organics are not converted and remain as residue for composting or landfill. The aerobic processing of digester sludge through composting can further reduce volume, but anaerobic conditions maintained in most landfills may not reduce volume except over very long periods of time. If only the produced biogas is converted to electricity (no energy production from the digestate), this process has an overall energy conversion efficiency (electrical energy out/waste stream energy in, based on dry HHV) of about 10%.

The lower moisture components are assumed to be converted by thermal means (gasification, pyrolysis, or combustion). The energy and/or heat in the product gases can be used in a boiler to run a steam cycle or the gases (from a gasifier or pyrolyzer) can run a gas engine or turbine for electricity production. These methods have overall electrical generation efficiencies of about 25%. Biomass integrated gasification combined cycles (BIGCC) have projected electrical conversion efficiencies of 35% or above, but are not yet commercial. Natural gas fired combined cycles have electrical efficiencies above 55% by comparison, but utilize non-renewable fuel. The application of combined cycles to biogas produced by anaerobic digestion is a possibility but digesters tend to be small for the scales typically employed, and digestion of MSW or MSW organics is still developmental for the most part in North America. Biogas co-fired with natural gas in large combined cycle power plants is a way to improve the net efficiency of biogas to electricity production if the opportunity exists. Fuel cells offer another high efficiency and clean option for biogas and fuel gases produced by thermochemical means, but these systems are also developmental and fuel purification is an issue.

Table 1-5 includes the gross electrical generation estimates from Sacramento MSW. The values were determined from the potential primary energy by applying the appropriate thermochemical or biochemical conversion efficiency and assuming an availability of 100% (meaning the conversion facilities operate 100% of the time at rated capacity). Table 1-5 indicates that 43 MW could be supported by conversion of the biogenic fraction of the currently disposed waste stream in Sacramento County. Figure 1-4 shows the mass and potential energy of the disposed solid waste stream by component. Though capture and conversion of 100% of the biogenic fraction of the MSW is unlikely, it may be feasible to capture and convert 50 to 75% of the biomass portion of solid waste with properly specified systems. If the biomass fraction of Sacramento waste currently being shipped out of state were accessible as well, then the technical electrical generating capacity from the biomass fraction of Sacramento County MSW is estimated to be 53 MW.

Table 1-5. MSW disposed in Sacramento County; Amount, characterization, energy, and gross potential electrical generation capacity.

Component	Landfilled[a] (1000t y^{-1})	% of Total	Ash[b] (% wb)	Ash (1000t y^{-1})	HHV[b] (MJ/kg, ar)	HHV contribution to composite stream (MJ kg^{-1} as received)	Moisture[b] (%wb)	Landfilled (1000t y^{-1} dry)	HHV (MJ/kg, dry)	Primary Energy by Component (PJ)[c]	(MMBtu)x10^6	Electricity Potential[d] (MWe)	(GWh y^{-1})
Paper/Cardboard	249.3	30.2	5.3	13.2	16	4.83	10	224.4	17.8	3.6	3.4	29	251
Food	130.0	15.7	5.0	6.5	4.2	0.66	70	39.0	14.0	0.5	0.5	3	29
Leaves and Grass	65.3	7.9	4.0	2.6	6	0.47	60	26.1	15.0	0.4	0.3	1	10
Other Organics	57.6	7.0	10.0	5.8	8.5	0.59	4	55.3	8.9	0.4	0.4	4	31
C&D Lumber	40.6	4.9	5.0	2.0	17	0.84	12	35.7	19.3	0.6	0.6	5	43
Prunings, trimmings, branches and stumps	19.8	2.4	3.6	0.7	11.4	0.27	40	11.9	19.0	0.2	0.2	2	14
Biomass Components of MSW Total	**562.6**	**68.1**		**30.8**		**7.7**		**392.4**		**5.7**	**5.4**	**43.2**	**379**
All non-Film Plastic	41.5	5.0	2.0	0.83	22	1.10	0.2	41.4	22.0	0.8	0.8	7	57
Film Plastic	32.1	3.9	3.0	0.96	45	1.75	0.2	32.0	45.1	1.3	1.2	10	91
Textiles	17.4	2.1	7.0	1.22	17.4	0.37	10	15.7	19.3	0.3	0.3	2	19
Non-Biomass Carbon Compounds Total	**91.0**	**11.0**		**3.01**		**3.22**		**89**		**2.4**	**2.3**	**19**	**168**
Other C&D	54.3	6.6	100	54.3	-	-	-	54.3	-	-	-	-	-
Metal	50.4	6.1	100	50.4	-	-	-	50.4	-	-	-	-	-
Other Mixed and Mineralized	44.1	5.3	100	44.1	-	-	-	44.1	-	-	-	-	-
Glass	23.6	2.9	100	23.6	-	-	-	23.6	-	-	-	-	-
Mineral Total	**172.4**	**20.9**		**172.4**		**-**		**172.4**				**0**	**0**
Totals	**826**	**100**		**206**		**10.89**		**653.9**		**8.2**	**7.7**	**62**	**546**

a) Total disposed at Kiefer and L&D Landfills from a query of the CIWMB Disposal Reporting System (July 1, 2003).
California waste stream composite data (http://www.ciwmb.ca.gov/WasteChar/Study1999/OverTabl.htm), Accessed Sept. 1, 2003.
b) Adapted from Tchobanalglous, G., Theisen, H. and Vigil, S.(1993), "Integrated Solid Waste Management", Chapter 4, McGraw-Hill, New York & Themelis, N. J., Kim, Y. H., and Brady, M. H. (2002). "Energy recovery from New York City municipal solid wastes." Waste Management & Research, 20(3), 223-233.
c) PJ = 10^15 J (petajoule).
d) Electricity calculations assume thermal conversion means for low moisture stream (paper/cardboard, other organics, construction and demolition lumber, all plastics and textiles) and biological means (anaerobic digestion) for the high moisture components (food and green waste). Energy efficiency of conversion of matter to electricity by thermal means is assumed to be 20%. Biomethane potentials of 0.29 and 0.14 g CH4/g VS for food and leaves/grass mixture respectively are assumed for biogas production which is converted at 30% thermal efficiency in reciprocating engines. Capacity factor of 1 is used.

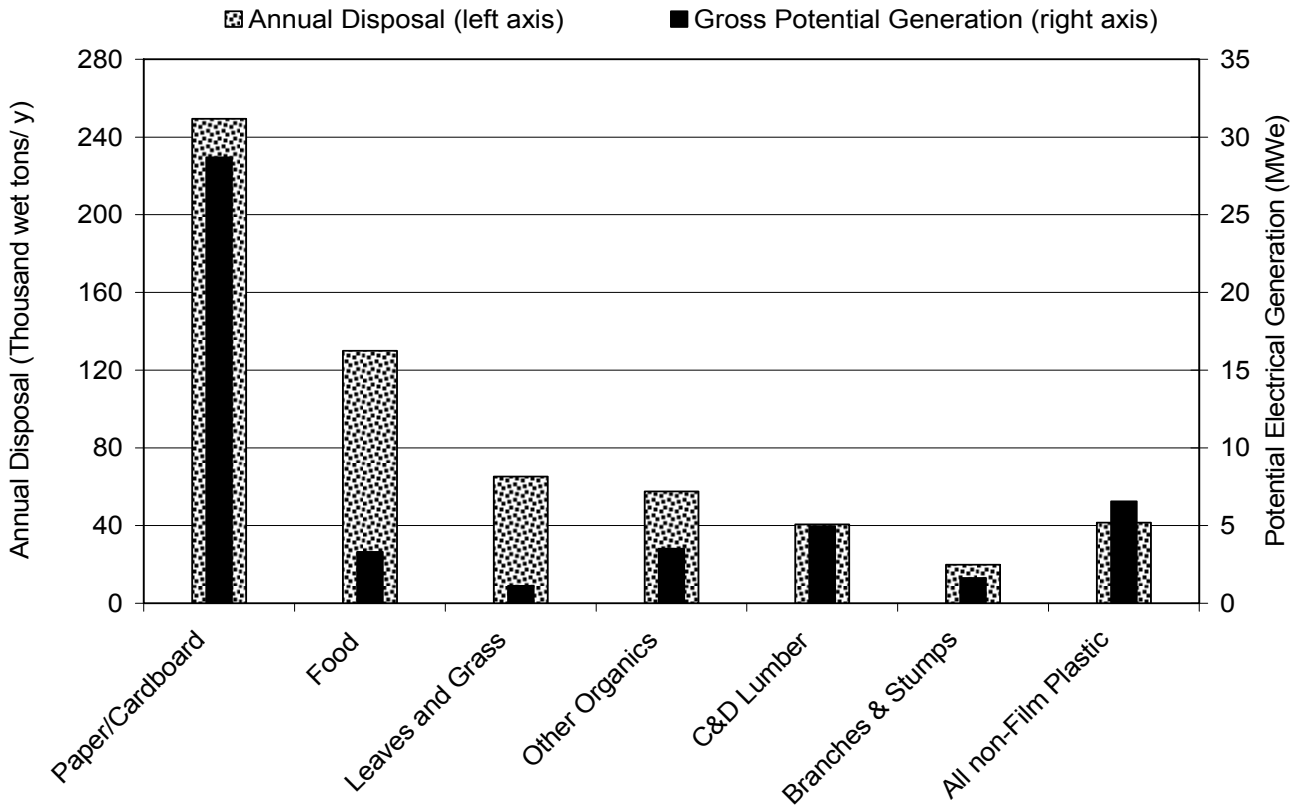


Figure 1-4. 2003 Sacramento County waste stream component disposal amounts and gross potential power generation

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Agricultural Cultivation in Region

The Sacramento region has a large and diverse agricultural sector. For this analysis, the Sacramento region is taken to be Sacramento County and the adjacent counties[6] as well as those in the "outlying region" extending north to Tehama County in the Sacramento Valley, south to Stanislaus in the Northern San Joaquin Valley and northeast and southeast foothill and several mountain counties[7] This is a large region geographically but was selected as such to illustrate the depth and breadth of agricultural resources (and residues) in the area. It is recognized that transportation of low density residue materials (which applies to many agricultural residues) constitutes a significant portion of fuel procurement costs. This effect typically manifests itself by defining a limiting fuel procurement radius from the conversion facility for each type of fuel. However, it is also

6. Sacramento and adjacent counties: Sacramento, Placer, Sutter, Yolo, Solano, San Joaquin Amador, and El Dorado.

7. Outlying region counties: Butte, Calaveras, Colusa, Glenn, Nevada, Stanislaus, Tehama, and Yuba.

recognized that SMUD could have interest in a biomass power facility outside of its immediate service area as is the case with SMUD owned wind generation and hydro-power facilities.

Table 1-6 shows year 2001 data for cultivated acres in the Sacramento region by county and major crop type (Field and Seed, Orchard and Vineyard, and Vegetable crops). Vegetable crops are included in the table for completeness but are not considered here as a feedstock for biomass power because residues are either too low, difficult to collect or high in moisture. Figure 1-5 shows the distribution graphically. The 2.5 million cultivated acres in the region represents fully 30% of all cropland currently being farmed in California.[8] The following are inventory data and energy potential of residues from field & seed crops, and orchard and vineyard. Residues from vegetable crops are not likely to be used for conversion to energy and are not included in this inventory.

Crop Residues in Field and Seed Crops

Table 1-7 gives the estimated residual biomass left in the field after harvest of the food or principal commodity component of the field or seed crop. The gross and technical potential electrical generation from each residue type is also shown. Figure 1-6 shows the residue information graphically and Figure 1-7 displays technical generation potential for each residue type. One half of the estimated field crop residues is rice straw from the Sacramento and Northern San Joaquin Valleys. Severe restrictions on open field burning of rice straw are in force. Many alternative management methods and off-field uses for the residual straw have been attempted.

8. Total cultivated land in the region is 2.5 million acres. There are some 8.6 million acres under cultivation in California.

Table 1-6. Cultivated acres by crop category in the Sacramento region

County	Orchard Vineyard Crops	Field and Seed Crops	Vegetable Crops
Sacramento	32,940	88,351	5,255
Placer	1,350	15,458	-
Sutter	55,437	151,251	13,863
Yolo	26,985	229,822	43,738
Solano	15,189	125,103	14,155
San Joaquin	195,570	298,523	71,680
Amador	4,077	2,221	-
El Dorado	2,996	350	-
Sacramento/adjacent Total	334,544	911,079	148,691
Butte	73,927	110,667	-
Calaveras	1,510	440	-
Colusa	30,410	189,053	20,250
Glenn	52,115	169,911	-
Nevada	348	-	-
Stanislaus	147,310	208,919	31,570
Tehama	36,715	18,871	-
Yuba	26,821	42,484	-
Outlying Region Total	369,156	740,345	51,820
Total Sacramento Region	703,700	1,651,424	200,511

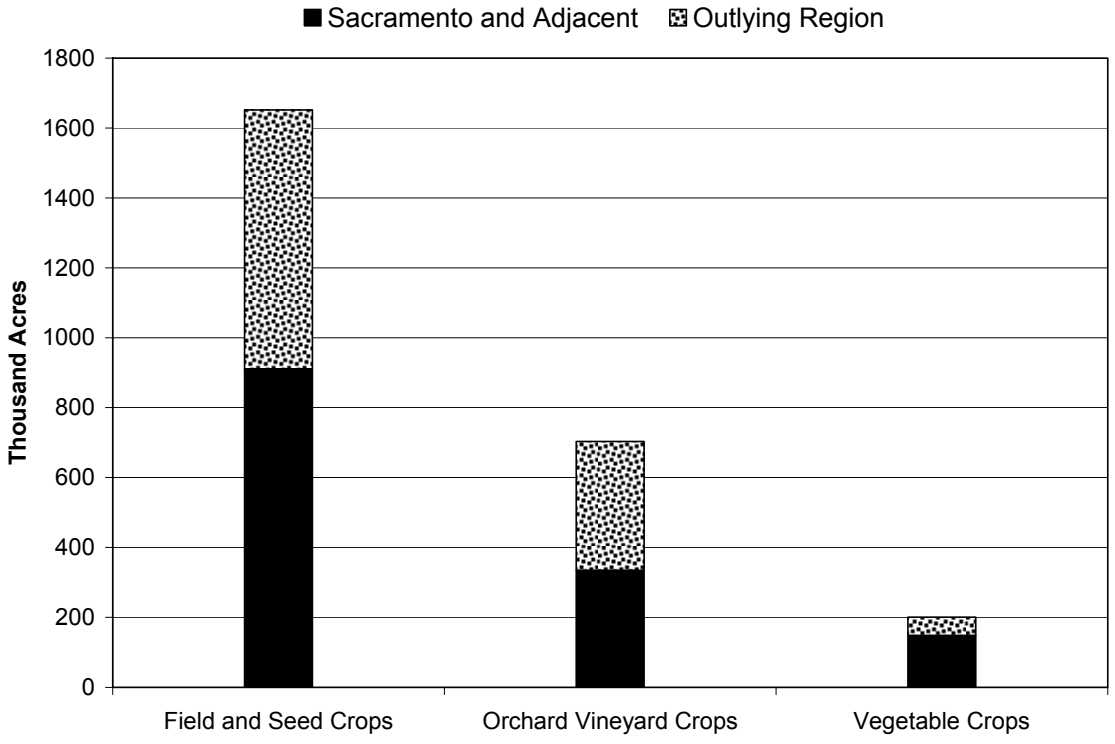


Figure 1-5. Acres under cultivation in the Sacramento region by crop category

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Beyond limited flooding of rice straw in fields for bird refuges and hunting clubs, the principal commercial uses for rice straw are in animal feeding and erosion control, but these do not support substantial quantities. A large residual remains that potentially can be harvested for energy.

Corn stover and wheat straw together account for 36% of the field crop residue. Corn stover is typically chopped and/or re-incorporated into the soil. Wheat straw is incorporated, baled for feed and bedding, or field burned. Gross generation potential from field and seed crops in the Sacramento region is 250 MW; technical generation is estimated at about half or 125 MW.

Crop Residues in Orchards and Vineyards

Table 1-8 gives recent data for residues from orchard and vineyard operations in the region (includes estimated electrical generation potential). Figure 1-8 is a graphical representation of residue amounts. Figure 1-9 shows technical generation capacity for each residue type. Almond, walnut, plums/prunes, and peach orchard prunings together account for 63% of the estimated 670,000 dry tons generated annually in this category. Some of this material finds its way into existing biomass fired facilities; other material is shredded and left in the orchard or pushed to the edge of the orchard and pile-burned. It is estimated that approximately 50 MW could be supported assuming 70% of the residue is recovered for this purpose.

Recent legislation (SB 705, Florez) essentially eliminates any burning of agricultural residues in the San Joaquin Valley Unified Air Pollution Control District starting in 2005 and proceeding in phases through 2010. Proposed legislation by Florez (SB 403 *California Clean Air Bond Act)* would put before the voters a $4.5 billion bond that, if passed, would create a clean-air fund. This fund would provide grants, loans and other support mechanisms for assisting (among others) projects directed at reducing agricultural air and water impacts. Orchard and vine crop residues and dairy manure are specific biomass types mentioned in the proposed legislation.

Table 1-7. Annual field crop residues (tons dry weight per year) in Sacramento region and generation potential*

County	Rice	Corn	Wheat	Field & Grass Seed	Safflower	Cotton	Sorghum	Barley	Oats	**Total** (BDT/yr)
Sacramento	29,988	99,238	26,374	40	4,172	-	1,607	585	702	162,706
Placer	44,719	-	-	-	-	-	-	-	-	44,719
Sutter	272,952	23,380	19,158	3,302	12,635	-	570	-	649	332,646
Yolo	89,817	72,171	72,331	33,580	20,159	4,200	-	-	-	292,259
Solano	-	53,916	65,021	5,274	4,388	-	11,632	5,519	1,125	146,875
San Joaquin	20,643	227,852	78,158	3,173	6,197	-	-	-	-	336,023
Amador	-	1,589	-	-	-	-	-	-	-	1,589
El Dorado	-	-	-	-	-	-	-	-	-	-
Sacramento & adjacent Total	**458,120**	**478,146**	**261,042**	**45,369**	**47,551**	**4,200**	**13,809**	**6,104**	**2,476**	**1,316,816**
Butte	277,931	-	5,783	10,431	656	-	-	-	-	294,801
Calaveras	-	-	-	86	-	-	-	-	-	86
Colusa	367,877	18,055	37,344	110	7,838	14,885	-	304	-	446,413
Glenn	281,137	87,230	25,985	6,210	678	2,748	757	-	-	404,745
Nevada	-	-	-	-	-	-	-	-	-	-
Stanislaus	7,100	-	5,288	5,124	-	-	-	883	-	18,395
Tehama	2,993	3,942	4,957	2,032	142	-	-	-	-	14,066
Yuba	112,043	-	-	1,575	-	-	-	-	-	113,618
Outlying Region Total	**1,049,081**	**109,227**	**79,357**	**25,568**	**9,314**	**17,633**	**757**	**1,187**	**-**	**1,292,124**
Total Sacramento Region (BDT)	**1,507,201**	**587,373**	**340,399**	**70,937**	**56,865**	**21,833**	**14,566**	**7,291**	**2,476**	**2,608,940**
HHV (MJ/kg, dry basis)	16.3	17.7	17.5	18.0	19.2	18.3	15.4	17.3	17.0	-
Gross Generation Potential (MWe)	141	60	34	7	6	2.3	1.3	0.7	0.2	253
Technical* Generation Potential (MWe)	**71**	**30**	**17**	**4**	**3**	**1.1**	**0.6**	**0.4**	**0.1**	**127**

* Generation is based on thermal conversion of identified resource with net efficiency of 20% and facility availability of 100%. Technical generation assumes 50% of the gross residue material is available.

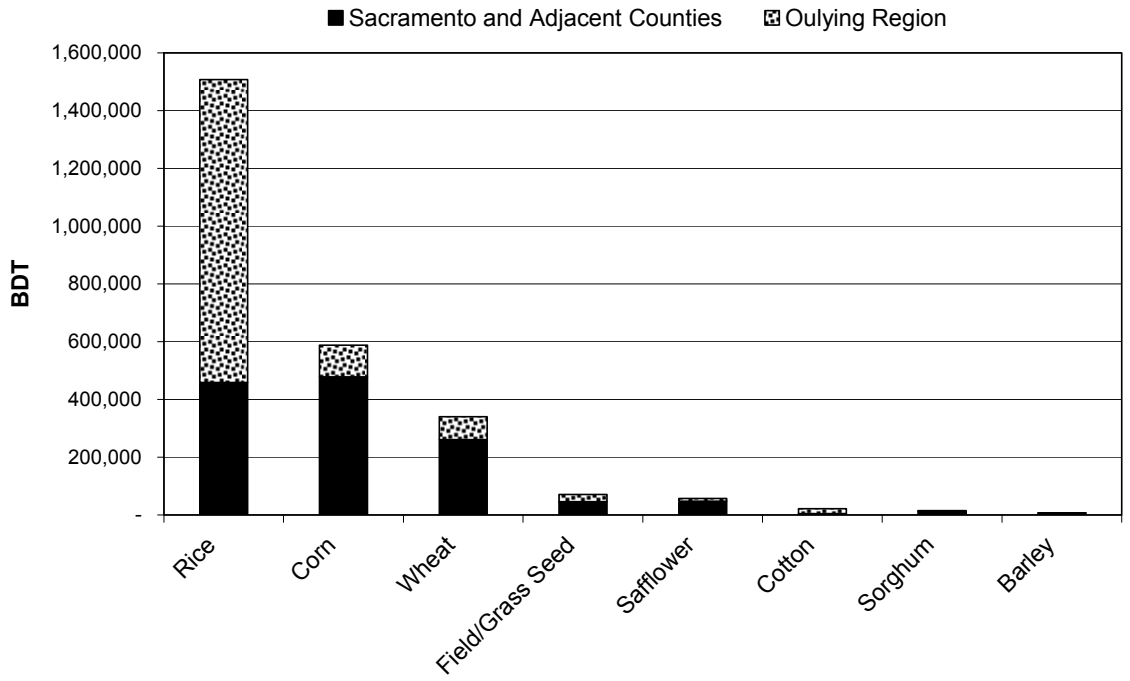


Figure 1-6. Annual field crop residues in the Sacramento region (dry tons)

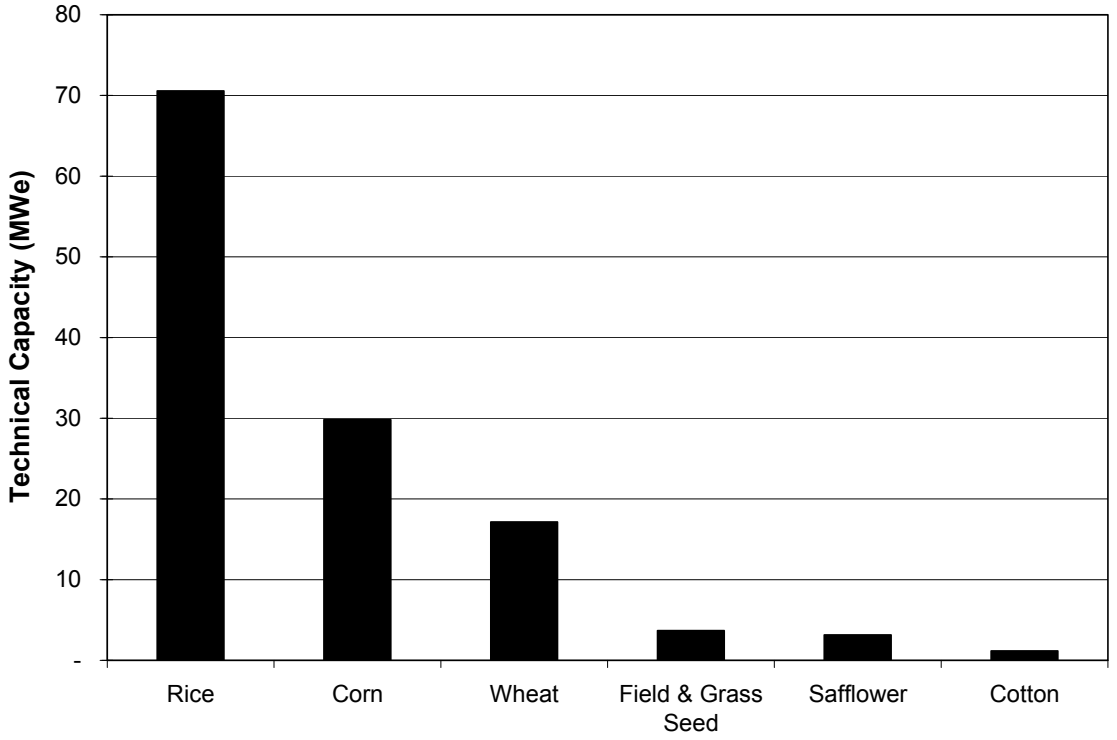


Figure 1-7. Technical generation capacity from field crops in the region

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Table 1-8. Annual orchard and vineyard prunings (tons dry weight per year) in the Sacramento region and electrical generation potential*

County	Almonds	Grapes	Walnuts	Plums & Prunes	Peaches	Apples	Apricots	Pears	Olives	**Total (BDT/yr)**
Sacramento	-	35,076	186	-	-	506	-	8,802	-	44,570
Placer	-	54	553	151	154	93	-	53	-	1,058
Sutter	4,307	-	10,317	23,471	12,598	324	-	537	-	51,554
Yolo	5,717	13,923	5,257	2,234	-	-	-	-	-	27,131
Solano	1,499	5,536	3,500	2,115	401	-	676	1,354	-	15,081
San Joaquin	36,420	115,197	27,399	-	3,900	7,811	3,321	863	-	194,911
Amador	-	4,950	288	-	-	-	-	-	-	5,238
El Dorado	-	1,691	143	55	148	1,127	-	589	-	3,753
Sacramento/adjacent Total	**47,943**	**176,427**	**47,643**	**28,026**	**17,201**	**9,861**	**3,997**	**12,198**	**-**	**343,296**
Butte	32,744	-	12,627	11,653	3,087	302	-	-	1,314	61,727
Calaveras	-	639	462	-	-	189	-	-	202	1,492
Colusa	19,763	-	2,945	3,526	-	-	-	-	-	26,234
Glenn	23,568	1,834	5,489	9,068	-	-	-	-	4,837	44,796
Nevada	-	473	-	-	-	-	-	-	-	473
Stanislaus	79,496	18,760	16,571	-	10,736	2,430	8,872	-	-	136,865
Tehama	6,129	-	8,993	10,141	-	-	-	-	5,609	30,872
Yuba	711	321	6,008	10,482	7,234	-	-	-	-	24,756
Outlying Region Total	**162,411**	**22,027**	**53,095**	**44,870**	**21,057**	**2,921**	**8,872**	**-**	**11,962**	**327,215**
Total Sacramento Region (BDT)	**210,354**	**198,454**	**100,738**	**72,896**	**38,258**	**12,782**	**12,869**	**12,198**	**11,962**	**670,511**
HHV (MJ/kg, dry basis)	19.5	19	19	19	19	19	19	19	19	-
Gross Generation Potential (MWe)	24	22	11	8	4	1.4	1.4	1.3	1.3	74
Technical* Generation Potential (MWe)	**17**	**15**	**8**	**6**	**2.9**	**1.0**	**1.0**	**0.9**	**0.9**	**52**

* Generation is based on thermal conversion of identified resource with net efficiency of 20% and facility availability of 100%. Technical generations assumes 70% of the gross residue material is available

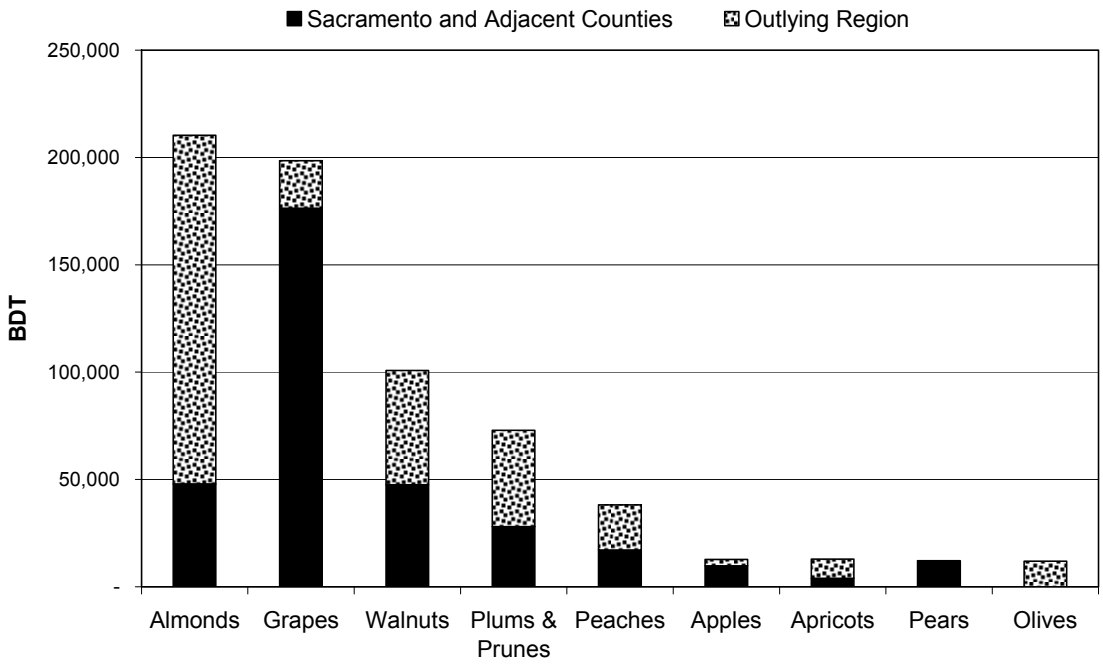


Figure 1-8. Annual orchard and vineyard prunings in the Sacramento region (dry tons)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

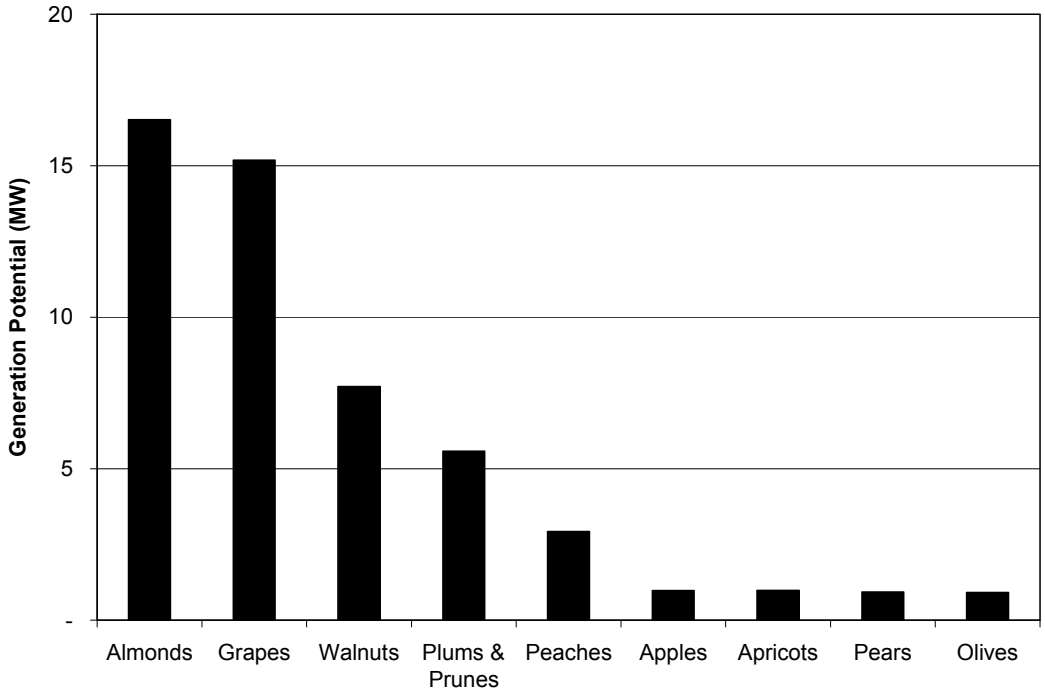


Figure 1-9. Technical generation capacity from orchard tree and vine prunings in the region

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Animal Residues (manure)

The total agricultural animal population in the state is close to 280 million, of which 230 million are broiler chickens. The total state cattle inventory is estimated to be 5.2 million head.[9] Of these cattle, 1.6 million are lactating dairy cows, 760,000 are beef cattle, and 2.8 million are in a category that includes heifers, bulls, steers, veal calves, and cow replacements (other beef and dairy calves and non-lactating dairy cows and heifers). At this stage of the assessment, only dairy cow manure is included as a resource for these reasons:

- Dairy cows are typically confined and manure is removed from the pens often using water flush or scraped manure handling systems that allow manure to be concentrated for utilization.
- Dry lot feed cattle pens are scraped on an intermittent basis and manure has therefore undergone significant biodegradation by the time it is collected.
- Dry lot feed cattle manure is typically scraped into piles during which it is mixed with soil and this leads to downstream handling problems in digesters and other conversion devices.

Rangeland cattle manure is too dispersed for practical collection.

Table 1-9 includes the Sacramento region inventory of dairy cows and estimated manure production with gross and technical potential electricity generation from this resource. Gross and technical generation potentials for the region are estimated at 44 MW and 22 MW, respectively (for Sacramento County, gross and technical generation are about 2 and 1 MW, respectively). The generation potentials were determined based on typical digestible solids in practical systems (See assumptions accompanying Table 1-9). Size of dairy power systems is dependent upon the manure collection efficiency and process as well as the number of animals at the facility. A very large dairy with 6,000 to 8,000 cows might be expected to generate 1 MW gross if manure collection is very efficient. The California Energy Commission reports one operating anaerobic digestion system at a dairy in the Sacramento region (Zhang 2003). This is the Langerwerf Dairy in Butte County (Durham), which has been generating power from digester methane since 1982. There are approximately 400 lactating cows and the facility is generating about 40 kW (with some exported to the grid).

9. California Agricultural Statistics Service, 2002.

Table 1-9. Dairy cows, annual manure, and gross power production (by digestion) for the Sacramento region

County	Number of lactating cows	Manure (BDT)	Volatile solids consumed by digestion[a] (BDT)	Biogas Produced (million ft^3)	Gross Potential[c] Electrical Capacity (MWe)	Technical Potential[d] Electrical Capacity (MWe)
Sacramento	16,700	36,573	13,714	329	2.3	1.2
Placer	-	-	-	-	-	-
Sutter	-	-	-	-	-	-
Yolo	2,000	4,380	1,642	39	0.3	0.1
Solano	3,900	8,541	3,203	77	0.5	0.3
San Joaquin	103,000	225,570	84,585	2,030	14.3	7.1
Amador	-	-	-	-	-	-
El Dorado	-	-	-	-	-	-
Sacramento/ adjacent Total	**125,600**	**275,064**	**103,145**	**2,475**	**17**	**9**
Butte	900	1,971	739	18	0.1	0.1
Calaveras	-	-	-	-	-	-
Colusa	-	-	-	-	-	-
Glenn	17000	37,230	13,961	335	2.4	1.2
Nevada	-	-	-	-	-	-
Stanislaus	164000	359,160	134,680	3,232	22.7	11.4
Tehama	5300	11,607	4,352	104	0.7	0.4
Yuba	3200	7,008	2,628	63	0.4	0.2
Outlying Region Total	**190,400**	**416,976**	**156,360**	**3,753**	**26**	**13**
Total Sacramento Region	**316,000**	**692,040**	**259,505**	**6,228**	**44**	**22**

a.) Assumes volatile solids (VS) are 83% of total solids and 45% of VS are typically consumed in practical systems. Assumes manure is collected daily with flush systems.
b.) Assumes biogas production is 12 ft^3/lb VS destroyed and biogas is 60% CH_4, 40% CO_2.
c.) Assumes 35% conversion efficiency of biogas to electricity in gas engines.
d.) For technical availability, it is assumed that 50% of gross biomass is recoverable for energy.

Recent legislation (Senate Bill 5X) appropriated monies for assisting dairies in California in the installation of systems to create power from dairy wastes. This led to the establishment of the Dairy Power Production Program (DPPP) by the Energy Commission, the purpose of which is to encourage the development of biologically based anaerobic digestion and gasification ("biogas") electricity generation projects in the State. Objectives include developing commercially proven biogas electricity systems to help California dairies offset the purchase of electricity, and providing environmental benefits through reduction of air and ground water pollutants associated with storage and treatment of livestock wastes. Approximately $10 million was appropriated including program administration costs.

Western United Resource Development, Inc. (WURD) was selected by the Energy Commission to manage the program. The program can provide two types of assistance for qualifying dairy biogas projects: (1) buy-down grants that cover a percentage of the capital costs of the proposed biogas system, or (2) incentive payments for generated electricity. In general, buy-down grants cover a maximum of 50% of the capital costs of the biogas system based on estimated power production, not to exceed $2,000 per

installed kW, whichever is less. Electricity generation incentive payments are based on 5.7 cents per kWh of electricity generated by the dairy biogas system paid out over a maximum of five years. The total cumulative payments under the incentive payment route are intended (after five years) to equal the amount of funding that would be provided for an equivalently sized digester-to-electricity system under the buy down approach. Table 1-10 lists dairy power projects proposed or under construction in the state that are receiving assistance from incentives enabled by SB 5X.

Table 1-10. Dairy digester for power systems, under construction or proposed in California[10]

Location	County	Type of Digester	No. of Milking Cows	Estimated Capacity (kW)
Atwater	Merced	Cov'd Lagoon	4,686	300
Button Willow	Kern	Cov'd Lagoon	3,600	280
El Mirage	San Bernardino	Plug Flow	1,900	160
Lodi	San Joaquin	Cov'd Lagoon	1,600	160
Visalia	Tulare	Plug Flow	1,500	260
Tulare	Tulare	Cov'd Lagoon	1,258	150
Strathmore	Tulare	Cov'd Lagoon	1,050	120
Lakeside	San Diego	Plug Flow	600	130
Marshall	Merced	Cov'd Lagoon	237	75
San Luis Obispo	San Luis Obispo	Cov'd Lagoon	175	30
		TOTALS	**16,606**	**1665**

Source: Report on progress of Dairy Power Production System (wurdco.com).

Three types of anaerobic digesters are commercially available for the digestion of dairy manure: complete mix, plug flow, and ambient temperature covered lagoon. The choice of digester is dependent on the type of manure collection system used on the dairy. Dairies with flush manure collection systems (2 to 3% total solids) would typically use an ambient temperature covered lagoon digester whereas a dairy with a mechanical scrape system of collection (10 to 13% total solids) would be a candidate for a plug flow digester. Complete mix anaerobic digesters operate on manure that has 3 to 10% total solids and can be used with both flushed and scraped manure. Both complete mix and plug flow digesters are heated using heat captured from a boiler or an engine generator. The steady gas output that results from the heating of the digester allows for ease of cogeneration. An Upflow Anaerobic Sludge Blanket (UASB) digester has also been successfully demonstrated by the University of Florida to digest the liquid portion of the waste generated at a flush dairy. UASBs and other attached-growth anaerobic digesters are, however, most successful at digesting soluble waste and tend to plug up when operated on manure with a high solids content and are therefore not commercial for manure digestion at this time. The attached-growth designs do have the advantage of increasing mean cell residence time compared to complete-mix systems.

Manure digestion systems typically have five subsystems: a mix tank, a digester, an effluent tank, a solids separator, and a power plant or other gas energy conversion

10. Report on progress of Dairy Power Production System (wurdco.com).

system (see Figure 1-10). Manure is typically removed from the barns using a flush system or by mechanical scraping. The manure is directed to a mixing tank where it is mixed prior to introduction into the digester. The minimum retention time within the digester is typically 20 days although digesters can operate for shorter periods of time, especially attached-growth types. From the digester, the digestate is sent to an effluent tank for storage until it is pumped to a screen separator or a screw press. The solids are collected and used for bedding or composted and sold as a soil amendment. The liquid is sent to longer term storage, usually a lagoon, until it is needed for irrigation or sold as liquid fertilizer. Gas from the digester is sent to a boiler for generation of heat or an engine-generator set or other power plant (e.g. microturbine) type to generate electricity. In order to maintain high levels of gas production, the manure at the dairies must be collected regularly and for best results should not be greater than three days old.

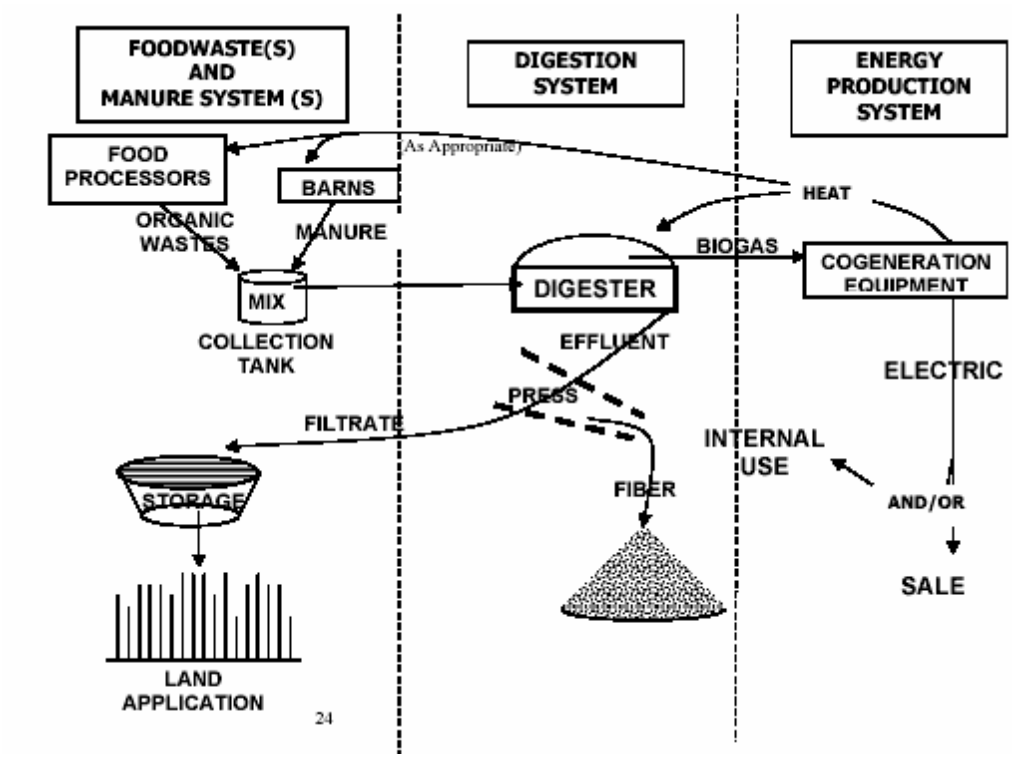


Figure 1-10. Schematic of digester subsystems (typical of low solids dairy effluents). (Mattocks 2003)

Source: Mattocks 2003

Anaerobic digestion of dairy manure is commercially viable and has been demonstrated at numerous dairies across the country (see Kramer 2002 for example). Europe has developed and is operating many anaerobic digestion systems of varying designs or configurations. The advantages of this approach are:

- Electricity generation that offsets the use of power on the farms.
- Odor control.
- Reduction in the emission of greenhouse gases such as methane.

- Pathogen reduction.
- Mineralization of the nitrates in the manure allowing for easier uptake of the nutrients by plants.
- Elimination of the pollution of ground water.

One strategy to better utilize a digestion system is to co-digest animal manures with other organic wastes such as source separated food and restaurant wastes. The increase in methane production due to more (and higher strength) feedstock would be an economic trade-off against the higher costs of collecting and transporting the co-feedstocks. Another strategy that may be viable for multiple dairies located near each other is to set up a centralized digestion facility with the wastes transported from the satellite generation locations (e.g., the MEAD project in Tillamook County, Oregon).

Biosolids-Water Treatment Plants

WWTPs represent a biomass resource which can be exploited for energy and power. Sewage is treated generally using combinations of aerobic and anaerobic processes. Many treatment plants utilizing anaerobic processing create sufficient methane to justify converting it to heat and/or power, while others may flare the methane. After the aerobic/anaerobic primary treatment of the waste water, there is a solid (biologically stabilized) residue commonly referred to as biosolids. Biosolids contain the non-biodegradable components of the biomass in the wastewater as well as the mineral matter (ash). Table 1-11 displays the biosolids inventory for the region including gross and technical electrical production estimates from the biosolids.

The Sacramento Regional WWTP generates approximately 2.8 MW from the methane generated by the treatment of the wastewater. The average wastewater flow is estimated to be 180 to 190 million gpd (Fondahl 2000). There are 10 WWTPs in California with grid connected power generation (combined gross capacity of 38 MW) (Zhang 2003). The two largest are in Los Angeles County (24 MW from 770 million gpd wastewater, combined).

The solid residue (biosolid) of the process contains all the inert portion of the untreated sewage as well as a significant amount of organic material that is not biodegradable plus effluent cell mass. The non-biodegradable organic material contains energy that can be converted with thermochemical systems. Depending on degree of stabilization, some biosolid material is land applied as fertilizer. About 40% of the WWTP biosolids in the state are land applied. About 3% is burned in furnaces (usually co-fired with natural gas or landfill or digester gas), some of which recover heat for use by the WWTP. The remainder is either disposed in landfills maintained by the treatment facility or in city/county landfills.

Converted by thermal methods, the gross and technical generation from the region's biosolids is about 7 and 6 MW, respectively.

Table 1-11. Regional wastewater treatment biosolids (not currently landfilled) and electrical generating potential*

		Electrical Potential	
	Biosolids (bdt y^{-1})	Gross (MWe)	Technical‡ (MWe)
Sacramento	47,423	4.20	3.36
Placer*	-	-	-
Sutter	1,732	0.15	0.12
Yolo	2,215	0.20	0.16
Solano	5,323	0.47	0.38
San Joaquin	8,594	0.76	0.61
Amador*	-	-	-
El Dorado	2,112	0.19	0.15
Sacramento & adjacent Total	**67,398**	**6**	**5**
Butte*	-	-	-
Calaveras	9	0.00	0.00
Colusa+	-	-	-
Glenn	402	0.04	0.03
Nevada	392	0.03	0.03
Stanislaus	13,037	1.15	0.92
Tehama	552	0.05	0.04
Yuba	757	0.07	0.05
Outlying Region Total	**15,149**	**1**	**1**
Total Sacramento Region	**82,547**	**7**	**6**

*Data taken from Fondahl (2000) and escalated using 2003 county populations.
Electrical generating potential based on thermal conversion at 20% efficiency and HHV of 15.4. MJ kg^{-1}, dry basis and plant capacity factor of 1.
‡ Technical availability factor was assumed to be 0.8.
Data taken from Fondahl (2000) and escalated using 2003 county populations

Forest Biomass

Biomass from the forest includes mill residues, most of which are already used for steam or power generation, forest slash from timber operations, and forest thinnings coming from timber stand and other forest improvement operations. The latter resource is likely to increase substantially following presidential signing of the Healthy Forests Restoration Act on December 3, 2003.

Recent data developed by the California Department of Forestry and Fire Protection (Rosenberg, et. al. 2004) were used for estimating forest operations residues. Logging slash and potential thinnings are lumped together. Chaparral is listed separately. Chaparral represents a significant amount of resource and is included because it is a fuel that likely will be managed in forest fuel reduction programs, at least in some areas. Chaparral is not currently harvested or utilized in appreciable quantities, nor does it have many potential uses other than as a fuel for heat and power generation. Mill residues are estimated from current statewide logging activity and distributed to counties using data in a year 2000 report (Springsteen 2000).

Complete documentation is not yet available but the technical availability of the forest inventory assumes no disturbance of riparian (stream and lake) zones and other sensitive habitats, and the material in areas with slope greater than 30% would not be accessed. The technical accessible forest biomass is 59% of gross thinnings and slash biomass and 34% of the gross chaparral biomass. All public and private lands are included in the California Department of Forestry and Fire Protection inventory.

The geographic area used in the forest biomass analysis includes the same Sacramento region counties used above as well as four additional mountain counties (Plumas, Sierra, Tuolumne, and Alpine).

Table 1-12 shows gross forest resource (dry weight per year) and potential generation (using gross potential biomass and 20% thermal conversion to electricity efficiency). The amount of forest biomass in the 16 county Sacramento region (Table 1-12) is approximately 25% more than that of the agricultural residues for the region, and the generation estimate reflects this (gross and technical generation for the region's forest biomass is estimated at 451 and 213 MW, respectively). Table 1-13 displays the forest biomass and generation potential for the four additional counties completing the Central Sierra Nevada Range forest biomass resource.

Table 1-12. Forest and mill operations gross potential residues (tons dry weight per year) in the Sacramento region and generation potential‡ (Rosenberg et al. 2004).

County	Thinnings & Slash	Chaparral	Mill Residue	Total Forestry
Sacramento	4,304	17,317	-	21,621
Placer	3,180	8,016	-	11,196
Sutter	27,961	95,574	-	123,535
Yolo	391	180,702	-	181,093
Solano	1,360	2,374	-	3,734
San Joaquin	4,601	17,409	-	22,010
Amador	151,304	213,244	-	364,548
El Dorado	323,932	38,248	104,625	466,805
Sacramento/ adjacent Total	**517,033**	**572,884**	**104,625**	**1,194,542**
Butte	287,100	16,870	47,250	351,220
Calaveras	610,412	41,198	-	651,610
Colusa	249,812	105,162	-	354,974
Glenn	137,030	67,386	-	
Nevada	41,835	44,974	63,000	149,809
Stanislaus	62,938	275,959	-	338,897
Tehama	45,011	277,175	96,300	418,486
Yuba	35,759	572,458	46,350	654,567
Outlying Region Total	**1,469,897**	**1,401,182**	**252,900**	**2,919,563**
Total Sacramento Region (BDT)	**1,986,930**	**1,974,066**	**357,525**	**4,114,105**
HHV (MJ/kg, dry basis)	21	19	20	
Gross Generation Potential (MWe)	240	211	na*	451
Technical‡ Generation Potential (MWe)	**142**	**72**		**213**

‡Gross BDT (BDT = bone-dry ton equivalent, a unit of measurement used for biomass fuels. A BDT refers to an amount of material that contains a ton of moisture-free biomass fiber. Generally, one BDT is equivalent to 1.5 – 2.2 actual or green tons of biomass.) Amounts include public and private lands but exclude biomass from riparian zones, sensitive habitat, and terrain with slope greater than 30%. Technical generation potential assumes the forest thinnings and chaparral are (will be) available in the amounts of 59% and 34% of gross tonnages respectively, thermal conversion efficiency to electricity is 20% and plant availability is 100%.

* Assumes mill residues are already utilized for heat and power at the sawmill.

Adapted from Rosenberg et al. 2004

Table 1-13. Forest biomass in four mountain counties completing the Central Sierras ‡

County	Thinnings & Slash	Chaparral	Mill Residue	Total Forestry
Plumas	2103	561	144000	146664
Sierra	61121	122412	-	183533
Tuolumne	24472	513385	83475	621332
Alpine	696348	137578	-	833926
Other Sierra Nevada Counties Total (BDT)	**784,044**	**773,936**	**227,475**	**1,785,455**
HHV (MJ/kg, dry basis)	21	19	20	
Gross Generation Potential (MWe)	95	83	na*	178
Technical‡ Generation Potential (MWe)	**56**	**28**		**84**

Adapted from Rosenberg et al. 2004

‡Gross BDT amounts include public and private lands but exclude biomass from riparian zones, sensitive habitat, and terrain with slope greater than 30%. Technical generation potential assumes the forest thinnings and chaparral are (will be) available in the amounts of 59% and 34% of gross tonnages respectively, thermal conversion efficiency to electricity is 20% and plant availability is 100%.

* Assumes mill residues are already utilized for heat and power at the sawmill

Summary of Biomass Resources in the Sacramento Region

Table 1-14 summarizes the gross and technical[11] generation potential of the region's biomass inventory. Total gross and technical generation from the resource is estimated to be 872 and 442 MW, respectively. If the complete Central Sierra Nevada Range is included in the forest biomass category, an additional 178 MW (gross) and 84 MW (technical) biomass resource is identified. MSW going to landfill disposal is an opportunity for biomass to electricity conversion because it is generally available at central locations (landfills, transfer stations, material recycling facilities) and usually is available at no cost or negative cost (with a tipping fee). Some of this is already generating power for SMUD by way of landfill gas to energy systems. There are disadvantages due to the heterogeneous nature of the material both in particle size and moisture content of the various components. Orchard and crop residues are available in substantial amounts for conversion to energy and some of this material is also already being utilized. Some of the existing biomass facilities in the region use orchard residues and nut shells and other agricultural residues but new burning restrictions are being implemented in the San Joaquin Valley reducing disposal options for farmers. Rice straw is available in large amounts and currently has limited commercial uses and could benefit from expanded power generation capability using improved technology. Forest residues are expected to offer a substantial amount of resource with new federal

11. Gross generation potential is the capacity that could be supported if *all* the biomass from each category was converted to electricity based on energy contents and current technology conversion efficiencies. Technical generation assumes resource availability factors are less than one.

legislation enabling more forest thinning operations and heightened awareness and urgency due to the recent fires in Southern California.

Table 1-14. Summary of regional generation potential from biomass

Biomass Source	Gross Generation Potential (MW)	Technical Generation Potential (MW)
MSW	43	22
Field Crop Residues	253	127
Orchard and Vineyard Residues	74	52
Dairy manure	44	22
Waste Water Treatment Plant Biosolids	7	6
Forest Residues	451	213
Total	**872**	**442**
'Other' Sierra Nevada Counties Forest Residues	**178**	**84**

Source: UC Davis Research Team ; Source: Robert Williams

1.3 Conversion of Biomass

Conversion of biomass can proceed along three main pathways- thermochemical, biochemical, and physicochemical. Currently, all three pathways are utilized to various extents.

Thermochemical conversion is characterized by higher temperature and conversion rates. It is best suited for lower moisture feedstocks and is generally less selective for end-products although advances in gasification and pyrolysis processes are expanding the range of chemicals and materials that can be produced.

Thermochemical conversion processes include:

Combustion

Oxidation of fuel for production of heat at elevated temperatures without generating commercially useful intermediate fuel gases, liquids, or solids. Flame temperatures range typically between 1500 and 3000°F depending on fuel, stoichiometry, furnace design, and system heat loss. Particle temperatures in heterogeneous combustion can differ from gas temperatures depending on radiative conditions. Combustion of solids involves the simultaneous processes of heat and mass transport, pyrolysis, gasification, ignition, and burning, with fluid flow. It normally employs excess oxidizer to ensure maximum fuel conversion, but also can occur under fuel rich conditions. Products of

combustion processes include heat, oxidized species (e.g. carbon dioxide [CO_2], water [H_2O]), products of incomplete combustion and other reaction products (most as pollutants), and ash. Other processes, such as supercritical water oxidation and electrochemical oxidation can produce similar end products at lower temperatures.

Gasification

Typically refers to conversion via partial oxidation using substoichiometric air or oxygen or by indirect heating to produce fuel gases (synthesis gas, producer gas), principally carbon monoxide (CO), hydrogen (H_2), methane, and lighter hydrocarbons in association with CO_2 and nitrogen (N_2) depending on the process used. Gasification processes also produce liquids (tars, oils, and other condensates) and solids (char, ash) from solid feedstocks. Gasification processes are designed to generate fuel or synthesis gases as the primary product. Fuel gases can be used in internal and external combustion engines, fuel cells, and other prime movers. Gasification products can be used to produce methanol, Fischer-Tropsch (FT) liquids, and other fuel liquids and chemicals. Gasification of solids and combustion of gasification-derived fuel gases generates the same categories of products as direct combustion of solids, but pollution control and conversion efficiencies may be improved.

Pyrolysis

A process similar to gasification except generally optimized for the production of fuel liquids (pyrolysis oils) that can be used straight (i.e. as boiler fuel) or refined for higher quality uses such as engine fuels, chemicals, adhesives, and other products. Pyrolysis also produces gases and solids from solid feedstocks. Usually, processes that thermally degrade material without the addition of any air or oxygen are considered pyrolysis. Pyrolysis and combustion of pyrolysis-derived fuel liquids and gases also produce the same categories of end products as direct combustion of solids, but like gasification, pollution control and conversion efficiencies may be improved. Direct pyrolysis liquids may be toxic, corrosive, oxidatively unstable, and difficult to handle. Generation of refined fuel liquids has advantages in fuel handling and distributed or mobile power generation.

Biochemical conversion proceeds at lower temperatures and lower reaction rates but tends to offer greater selectivity in products than thermochemical conversion. Higher moisture feedstocks are generally good candidates for biochemical processes.

Biochemical conversion processes include:

Anaerobic digestion

A fermentation technique typically employed in some waste water treatment facilities for sludge degradation and stabilization but also the principal process occurring in landfills. Anaerobic digestion operates without free oxygen and results in a fuel gas called biogas containing mostly methane and carbon dioxide but frequently carrying impurities such as moisture, hydrogen sulfide (H_2S), siloxane, and particulate matter.

Anaerobic digestion requires attention to the nutritional demands of the facultative and methanogenic bacteria degrading the waste substrates. The carbon/nitrogen (C/N) ratio of the feedstock is especially important. Biogas can be used as fuel for engines, gas turbines, fuel cells, boilers, industrial heaters, other processes, and the manufacturing of chemicals.

Aerobic conversion

Includes, for example, composting and activated sludge waste water treatment processes. Aerobic conversion uses air or oxygen to support the metabolism of the aerobic microorganisms degrading the substrate. Nutritional considerations are also important to the proper functioning of aerobic processes. Aerobic processes operate at much higher rates than anaerobic processes, but generally do not produce useful fuel gases.

Fermentation

Generally used industrially to produce fuel liquids such as ethanol and other chemicals. Also operates without oxygen. Although fermentation and anaerobic digestion are commonly classified separately, both are fermentation methods designed to produce different products. Cellulosic feedstocks, including the majority of the organic fraction of MSW, need pretreatment (acid, enzymatic, or hydrothermal hydrolysis) to depolymerize cellulose and hemicellulose to monomers used by the yeast and bacteria employed in the process. Lignin in biomass is refractory to fermentation and as a byproduct is typically considered for use as boiler fuel or as a feedstock for thermochemical conversion to other fuels and products.

Physicochemical conversion

Involves the physical and chemical synthesis of products from feedstocks and is primarily associated with the transformation of fresh or used vegetable oils, animal fats, greases, tallow, and other suitable feedstocks into liquid fuels or biodiesel, frequently by transesterification (reaction of glyceride with alcohol in the presence of catalyst).

1.4 Advanced Biomass Power Systems

Systems that improve upon cost, conversion efficiency, installed capacity, environmental performance, public acceptance, or that can increase the range of available feedstocks and products compared with existing commercial technologies, are considered advanced.

Probably the least expensive means for increasing use of biomass in power generation is to cofire with coal in existing boilers by direct substitution of 10 to 15% of the total energy input with a suitable biomass fuel. Biomass cofiring directly substitutes renewable carbon for fossil carbon. In addition, cofiring has little or no impact on the overall conversion efficiency of the plant. Cofired biomass receives the benefit of the generally higher overall conversion to electricity efficiencies in large coal power plants

(typically 33 to 37%). Co-firing biomass can also reduce NOx and sulfur dioxide (SO_2) emissions from coal-fired power plants depending on type of biomass fired.

Gasification

Systems for gasification of biomass offer improvements in one of several ways. Close-coupled gasifier and boiler systems can increase the range of available fuels in certain cases. For example, an existing combustion boiler may not be able to economically consume some fuels because of disadvantageous ash properties experienced at combustion boiler temperature (slagging in a system designed for dry ash or release of alkaline and chlorine compounds which condense and form deposits on heat transfer surfaces). Installing a different conversion technology alongside existing facilities could increase usable fuel supply without incurring the cost of a complete new plant. Another reason for an add-on or close-coupled system might be for avoidance of contamination of ash product in instances where the ash from the original fuel has economic value. A third possibility for such systems is potential improvement of environmental performance in combination with increasing the range of fuels. A current PIER funded project to investigate close-coupled gasification for purposes of NOx emissions reduction with biomass boilers has completed its first phase[12]. If approved, a Phase II program would deploy a full scale demonstration at an existing biomass boiler, most likely in the Sacramento region.[13]

Gasification of biomass followed by cofiring the product gas with a fossil fuel either in steam cycle power generation or in natural gas fired gas turbines (with or without combined steam bottoming cycle) is a cofiring strategy that can take advantage of existing boilers and generating equipment, reducing the cost of implementing a biomass component of a power portfolio.

Gasification for use in integrated gasification combined-cycle systems (IGCC) offers the potential to increase the conversion to electricity efficiency compared to that of the existing biomass combustion boilers. Advanced biomass IGCC systems will benefit from substantial investments made in coal gasification combined cycle systems in the areas of hot gas particulate matter removal and producer gas combustion in gas turbines. The United States Department of Energy (DOE), as well as many research organizations in Europe, has sponsored much development work. Critical issues are gas cleaning and solid fuel feeding into pressurized reactors. Commercial scale demonstrators are in varying stages of completion.

Still early in developmental stages is biomass gasification for production of renewable hydrogen for fuel cells. These systems hold promise for high efficiency at a variety of scales. Utilization of methane from biomass in fuel cells is currently being demonstrated

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12. GE Energy and Environmental Research Corporation, Irvine, California. CEC Contract No. 500-98-037.
13. The facilities being considered are located in Woodland, Williams, and Anderson, California.

at several sites in the United States with support from the U.S. DOE and U.S. Environmental Protection Agency (EPA).

Small modular biomass power systems are gaining interest because of an increasing desire for distributed generation and wildfire hazard reduction activities which are likely to provide large amounts of woody biomass but at dispersed locations. Modular systems include combustion in small steam boilers for process heat or power generation in steam engines, combustion for heat for Stirling engines, and gasification for fueling microturbines or reciprocating engines and generator sets.

Biogasification, or production of methane from anaerobic microbes that consume biomass, is the process that takes place within landfills creating methane gas and carbon dioxide. Advanced landfill systems currently being investigated and demonstrated at full scale conditions include the bioreactor project at the Yolo County landfill. This project is one of the biomass related projects in the SMUD ReGen program. Current technology for the conversion of landfill gas to methane consists of reciprocating engines for scales up to several MW, usually with multiple engine-generator sets. The NOx emissions can be high from these engines running biogas which can make it difficult to site new generation of this type in many air districts in the state. Hydrogen-enriched biogas and other fuels can be used in lean-burn engines to reduce NOx emissions and this is a development area for the future. A part of the Yolo County investigation includes a study of a landfill biofilter that may be able to biologically react much of the NOx from landfill gas engines. Presently, this preliminary draft report does not address bioreactor landfills.

An innovative anaerobic digestion system suitable for high-solids green waste, manure, food, and food processing wastes has been developed by Professor R. Zhang at University of California, Davis, (UC Davis) and Dr. Z. Zhang, currently at the California Energy Commission. The innovation is the use of several batch loaded hydrolysis tanks and a single continuous methane generation reactor operated in the thermophilic range. The volatile solids destruction and biogas production is generally increased over that of standard high-solids single vessel digesters. A pilot facility on the UC Davis campus, funded by the California Energy Commission and industry partners, was to be operational early in 2005. The pilot facility will have a feedstock capacity of about 3 tons per day producing about 25 kW from a reciprocating engine. A 250 ton-per-day (wet) system using green and other organic wastes in this process is proposed for the California State University Channel Islands campus in Ventura County. This system offers potentially low cost electricity if average tipping fees for receiving the feedstock are charged. The company that has licensed the technology is Onsite Power Systems in Camarillo, California.

Overall electrical efficiency

Overall thermodynamic efficiency of electrical production, defined as

$$\left(\frac{\text{Net electrical energy out}}{\text{Higher heating value of fuel in}}\right)\times 100\%$$

varies from about 30 to 55% for modern large-scale fossil fueled power plants. Coal fired steam Rankine cycle power plants range between 30 to 45% net electrical efficiency. Efficiency improves with higher steam temperatures and pressures and generally improves with larger capacity facilities.[14] Natural gas fired gas turbine combined cycle (GTCC) power plants can achieve efficiencies as high as 55%.

Overall efficiency of biomass conversion to electricity is typically lower than large central station fossil power plants due to smaller facility size and lower fuel quality (i.e., comparatively high moisture in some cases). Efficiency of conversion for existing biomass based power systems ranges from less than 10% to about 25%. At the lower end of the range are combustion boiler-steam engine systems, small gasifier-engine systems, and anaerobic digestion–reciprocating engine systems. The upper range of efficiency is achieved by larger combustion boiler-steam turbine systems with more than 40 MW capacities.

Figure 1-11 shows overall efficiency versus net power output for several technology classes. The efficiencies shown are generally independent of fuel (liquid, solid, gas, fossil, or biomass). Also shown are efficiencies of the existing California solid fuel combustion biomass power industry (shown in blue and labeled "California steam cycle biomass"), and several operating or planned commercial demonstrations (red dots labeled by company name or location).

The California solid fueled biomass industry consists of facilities with net power capacity as low as 4 MW to three facilities with capacities between 47 and 50 MW. The net efficiencies range from about 15 to 25%. Facilities above 50 MW net have not been installed due to additional regulatory review required at this capacity and above.

The dots signify projects or systems that are discussed briefly in following sections of the report.[15]

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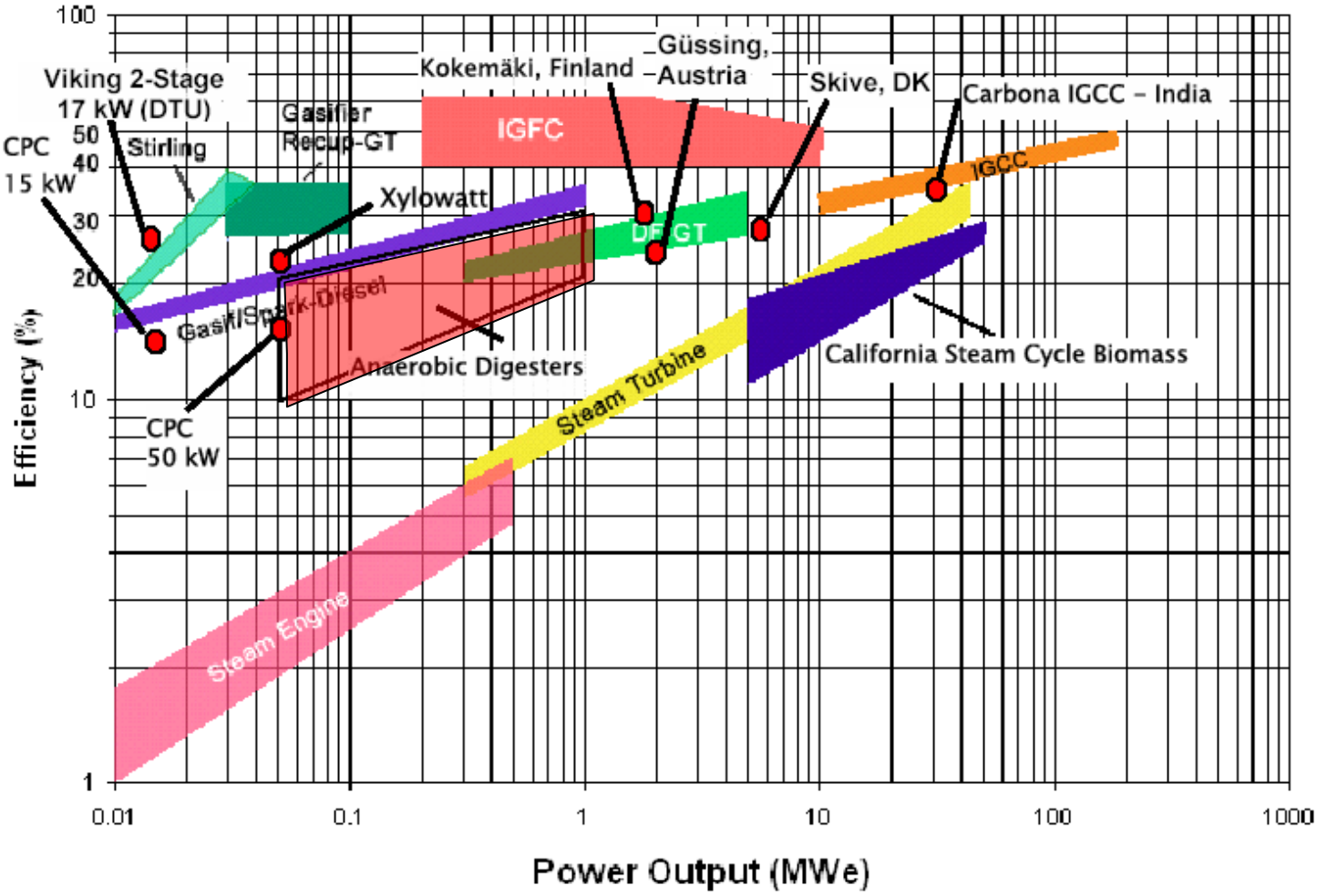
14. The highest efficiency steam cycles operate with supercritical steam conditions (i.e., steam pressure above the critical point of water; 22.1 MPa or 3200 psi). There are several hundred supercritical steam power plants world-wide with steam pressures ranging from 25 MPa (3600 psi) to 31 MPa (4500 psi). Maximum steam temperatures range between 540 °C and 620 °C (1000 °F to 1150 °F).

15. CPC is the abbreviation for Community Power Corporation (see Small Scale and Modular Biomass section). Xylowatt and Güssing can be found in the Small-Medium Scale Gasification for CHP (India and Europe) section and Carbona IGCC is in the Commercialization of Biomass IGCC section.



IGFC – Integrated Gasifier Fuel Cell
Turbine (simple cycle)
IGCC – Integrated Gasifier Combined Cycle

DF-GT – Direct Fired Gas

Figure 1-11. Efficiency versus net electrical power output for several prime movers.
Photo Credit: Adapted from R.P. Overend, 1998.

1.4.1 Biomass Cofiring with Fossil Fuels

Solid Fuel Cofiring

In 1996, the U.S. DOE and Chariton Valley Resource Conservation and Development, Inc. in Centerville, Iowa, began a study to look at the feasibility of using biomass to generate electricity in Southeastern Iowa. The project included studies of agronomic, economic, and technical issues, such as developing a fuel supply plan, optimizing the yields of energy crops on Iowa farmland, and examining the effects of co-firing switchgrass in existing coal boilers. In full scale experiments, switchgrass has been co-fired in amounts up to 25 tons/h, contributing 5% of the energy for the 735 MW (gross) nominally coal fired Ottumwa plant (Amos 2002).

Gasified Biomass Cofiring

With a fuel gas derived from biomass (whether producer gas from thermochemical gasification or biogas from biogasification), there is the capability to cofire with natural gas in gas turbine combined cycle (GTCC) facilities (assuming quality of the mixed gas meets the turbine requirements for energy content, hydrogen gas concentration and cleanliness).

There are at least three basic arrangements for biomass cofiring with a natural gas (NG) fueled GTCC: (1) biomass combustion boiler which adds steam to the GTCC (Figure 1-12), (2) Thermal gasification followed by gas conditioning then mixed with natural gas before firing in the turbine (Figure 1-13), and (3) a biogas (product of anaerobic digestion) stream that has been conditioned for cofiring in a natural gas fueled turbine (Figure 1-14).

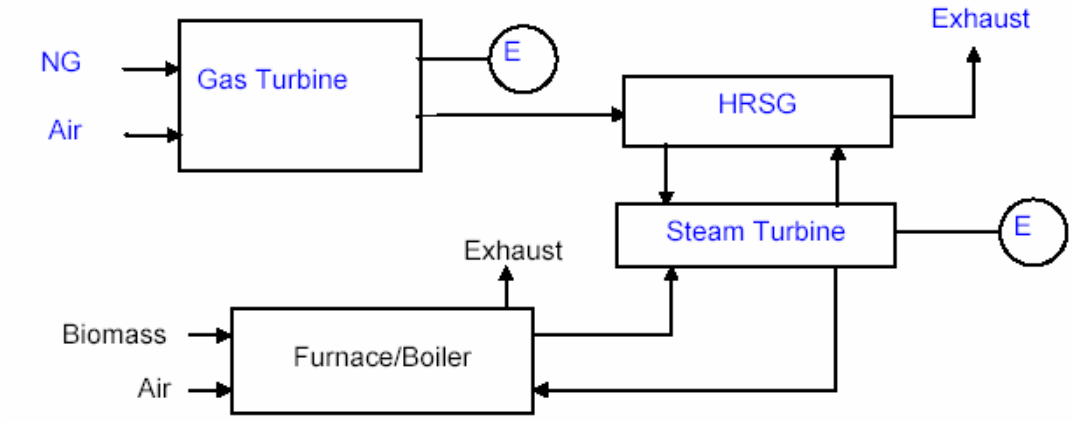


Figure 1-12. Indirect Co-firing with steam side integration.

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

The indirect co-firing with steam side integration is practical and has lower specific investment costs than stand-alone combustion. Steam addition from the biomass boiler is probably limited to about 10%. The energy efficiency of the biomass component is similar to that of conventional biomass fueled steam cycles (Zwart 2003).

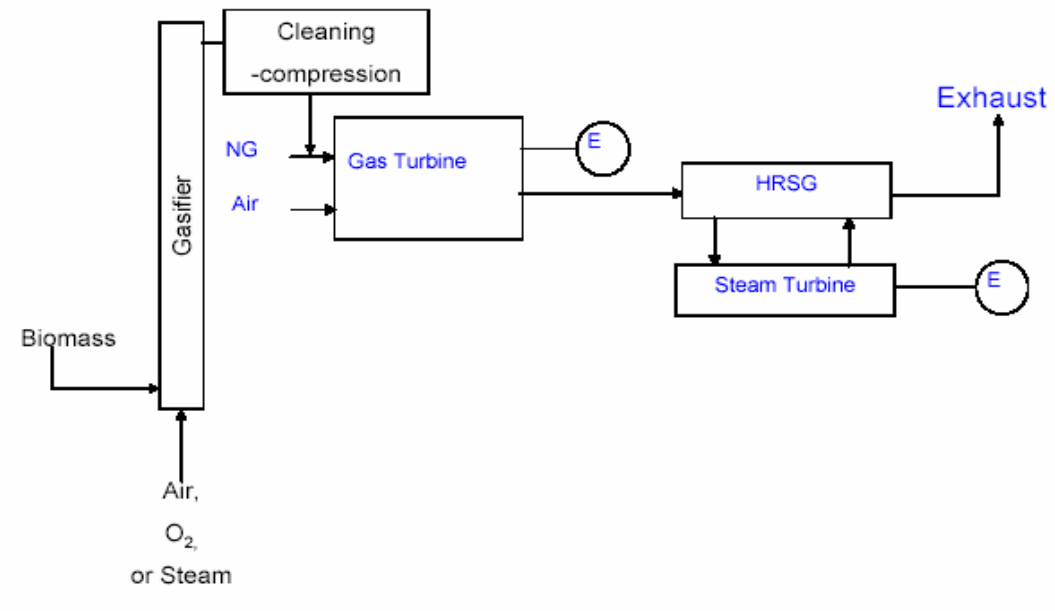


Figure 1-13. Direct cofiring with upstream thermal gasification.

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Upstream thermal gasification direct cofiring allows the thermal efficiency of the biomass portion of the fuel to approach that of pure natural gas combined cycle (50 to 55%) (Zwart 2003). It is estimated that in order to avoid major gas turbine modifications, the HHV of the gas mixture would need to remain above about 39 megajoule (MJ) per kilogram (HHV of natural gas is 50 to 55 MJ/kg) and the concentration of H_2 needs to be less than 5% (volume). These requirements will limit the biomass fuel contribution to the range of 2 to 8% (thermal basis). For a 500 MW facility, the 2 to 8% biomass fuel limitation is equivalent to 10 to 40 MW biopower.

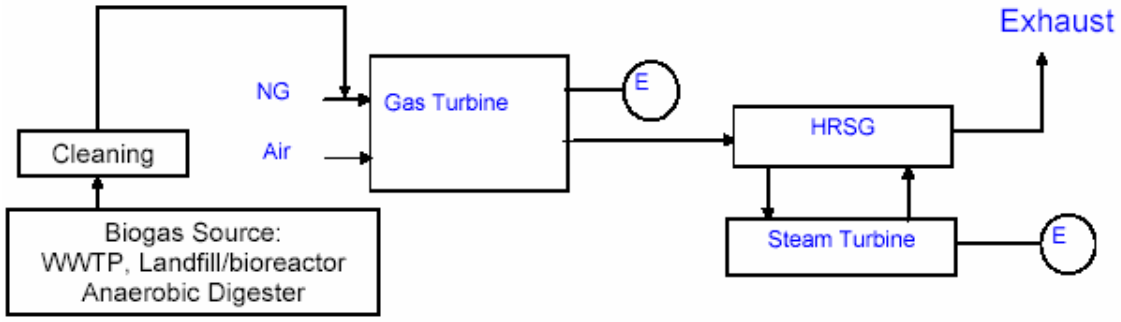


Figure 1-14. Direct cofire with biogas.

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Direct cofire with biogas is limited to the same fuel mixture requirements mentioned above in order to avoid major gas turbine modifications. However, biogas is generally easier to clean than producer gas (no tar and usually no particulate matter), resulting in

lower capital costs. Co-locating a biogas source with a GTCC facility is a simple way to boost the conversion efficiency of the biogas from the 25% to 40% level obtained in reciprocating engines or microturbines (simple cycle) to the higher GTCC efficiency of about 50%. The biogas can be upgraded to "pipeline quality" (i.e. like natural gas) by stripping the CO_2 and removing sulfur compounds that may be present. Upgraded biogas could be cofired in any proportion with natural gas.

Natural Gas Cofiring with Biomass

A PIER funded project was implemented at two California biomass power facilities which used natural gas cofiring to improve the environmental performance, reduce capacity problems associated with low quality fuels, and increase load following capability for the facilities. The low NOx gas burners were retrofitted to two existing boiler facilities in Northern California and demonstrations were completed. The technology purports to reduce carbon monoxide and opacity levels when low quality or high moisture biomass fuel is being burned. Additionally, the natural gas burners add ability to change the fuel feed rate more quickly which improves load following.[16]

1.4.2 Biomass Integrated Gas Turbine Combined Cycle Efforts

The U.S. DOE biomass power program supported development work on biomass integrated combined cycle systems in the 1990s. There were at least three projects undertaken in the nation that had various degrees of success. The European Union, through the THERMIE energy program, has been supporting commercial scale IGCC demonstration systems fueled by biomass. At this time, the only large scale demonstration that ran for any significant length of time was at Värnamo, Sweden between 1996 and 1999. The following are descriptions of IGCC commercial scale demonstration efforts worldwide. The first three were U.S. DOE supported projects.

Paia, Hawaii

In cooperation with the Hawaii Commercial and Sugar Company, the state of Hawaii, Gas Technology Institute (GTI, a merger of the former Gas Research Institute (GRI) and the Institute of Gas Technology [IGT]), Westinghouse Electric and others, U.S. DOE provided cost-shared funding to scale up a GTI gasifier (developed by IGT) to a demonstration scale that would consume 100 tons per day of bagasse (sugar cane residue). The demonstration was to include hot producer gas clean-up technology that could create a producer gas suitably clean for firing in a gas turbine. The gasifier was designed to operate with air or oxygen up to pressures of 300 psi. The unit operated for short periods at a fuel feed rate of about 50 t/day and a pressure of 150 psi but creating a producer gas that was flared. There were significant problems feeding the biomass to the pressurized reactor which were not solved with a redesign of the feed system. Funds were not available to continue the project after the second feeding system proved inadequate.

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16. CEC Project Factsheet:
http://www.energy.ca.gov/pier/renewable/projects/fact_sheets/GTI_FCTSHT.pdf

Burlington, Vermont

A Battelle (commercialized by FERCO) gasifier sized for 200 t/day wood chips was installed next to the boiler at the McNeil Generating Station in Burlington, Vermont. The McNeil facility is a 50 MW Rankine steam cycle biomass fired plant. The project consisted of scaling up the Battelle dual-fluidized bed gasifier to produce gas for co-firing in the McNeil boiler initially, followed by staged implementation of gas cleaning systems and a gas turbine to be operated on the producer gas as an IGCC. The gasifier uses steam and hot sand to gasify the biomass. The char and sand from the first fluidized bed is shuttled to a second fluidized bed reactor and the char combusted to heat the sand which is recirculated to the first reactor (See Figure 1-15). Steam is used as the fluidizing and gasification agent in the first reactor, avoiding dilution with nitrogen in air and producing a higher quality gas for use in the IGCC. It operates at near atmospheric pressure.

The project was successful in creating and co-firing producer gas in the McNeil boiler. A gas turbine has not yet been installed. It is uncertain if DOE will support demonstration with the gas-turbine as the emphasis on federal renewable energy research is now focusing on transportation fuels because of energy security issues. FERCO is not able to finance the demonstration with a gas turbine by itself.

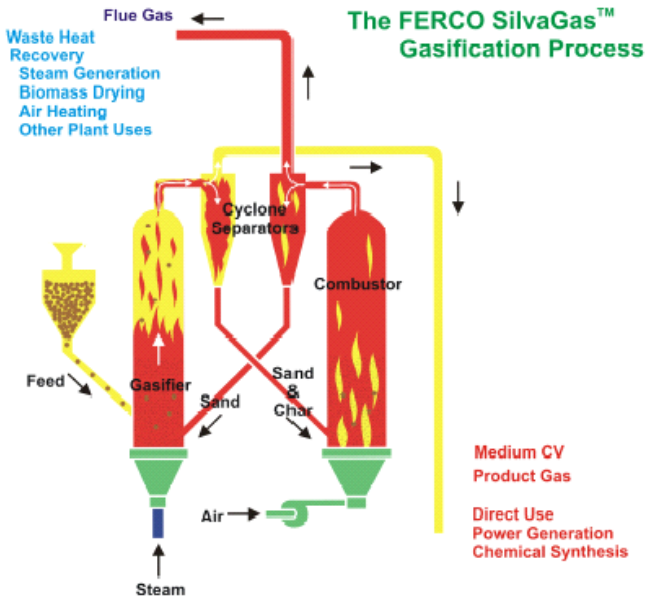

Figure 1-15. Schematic of the FERCO gasifier.
Photo Credit: Mark Paisley, FERCO (2004).

Granite Falls, Minnesota (MnVAP)

A growers' cooperative (Minnesota Valley Alfalfa Producers or MnVAP), electric utility, university, private partners, and state agencies formed a group to site a biomass power

station. U.S. DOE sponsored the program as well. The concept was to strip the leaves from the growers' cooperative alfalfa harvest (2,000 growers, 180,000 acres) and use them for creating high quality animal feed. The low protein stems were to be used for the biomass fuel. A 75 to 100 MW plant based on the GTI pressurized oxygen enriched air-blown gasifier (licensed to Carbona) supplying an IGCC system was specified. Expected required feed rate of alfalfa stems was 1,100 t/day. The DOE was providing up to $44 million of the $140 to $200 million cost for construction of the plant and associated facilities.[17] Significant milestones accomplished by 1999 included:

- Purchase of existing alfalfa-processing plant and development of stem and leaf separation technology.
- Signing a power purchase agreement with Northern States Power Company of Minneapolis, Minnesota, guaranteeing the long-term sale of electricity starting December 31, 2001.
- Formulated agreements with farmers to buy shares in the cooperative and making them future co-owners of the power facility.
- Obtaining a loan guarantee and 100 acres of land donated by the city of Granite Falls, Minnesota, for the power facility.
- Receiving a grant from the State of Minnesota to support alfalfa production and processing capabilities. The state also approved regulatory changes and tax exemptions worth more than $3 million per year to support the alfalfa producers' role in the project.
- Initiating environmental impact studies.

However, in 1999, key financing partners withdrew from the project because of uncertainties with fuel supply and the unproven technology (biomass IGCC) at this scale.

Värnamo, Sweden

The Värnamo plant was the world's first biomass-fueled IGCC plant that operated successfully for extended periods of time. This demonstration facility produced power and heat (6 MW, 9MWt/hour) and was developed by Sydkraft AB and Foster Wheeler International. The gasifier was a pressurized air-blown circulating fluid bed reactor that operated at pressures of 18 to 22 atmospheres. The facility used finely ground, dried wood and bark feedstock (10 to 20% moisture content) delivered to the power generation site from an adjacent preparation facility. Limited tests with pelletized straw and refuse-derived fuel (RDF) were also performed (Stevens 2001) with some success.

17. Federal Register Document 99-24457, filed Sept. 17, 1999. http://www.epa.gov/fedrgstr/EPA-IMPACT/1999/September/Day-20/i24457.htm

The gas cleaning system consisted of a cyclone separator, followed by heat exchange to cool the gas to about 350°C (from about 900°C) thereby condensing alkali vapors on particulate matter (Stevens 2001). The partially cooled gas was passed through a barrier filter (ceramic and/or sintered metal "candle" filters). Tar and alkali content in the filtered gas were less than 5 g/m^3, and 0.1 parts per million (by weight), respectively (Stahl and Neergaard 1998). The filtered gas was then fired in a gas turbine (European Gas Turbines, Ltd). The gas turbine generated about 4 MW, and the steam bottoming cycle produced an additional 2 MW (Engstrom 1998).

The Värnamo gasification system has more operational experience than any other biomass fired gas turbine system. Figure 1-16 shows a schematic of the Värnamo system. The gasifier was completed in 1993. In total, the gasifier operated for more than 7,000 hours. The gas turbine was modified for use with the low-energy gas in 1995, and test operations of the integrated biomass fueled power generation system began that year. By the end of 1999, the integrated facility had operated for a total of about 3,500 hours, with most of those during 1998 and 1999. The facility was built as a near-commercial demonstration and was not intended to provide long-term power generation on a commercial basis. The demonstration of the technology was completed in 1999, and the facility was closed (Stevens 2001). A non-profit company with ties to a local university has been established to utilize the facility for research which includes development of refuse derived fuels for use in an IGCC, production of hydrogen-rich synthesis gas, and pilot production of transportation fuels from synthesis gas (Stahl et al. 2004).

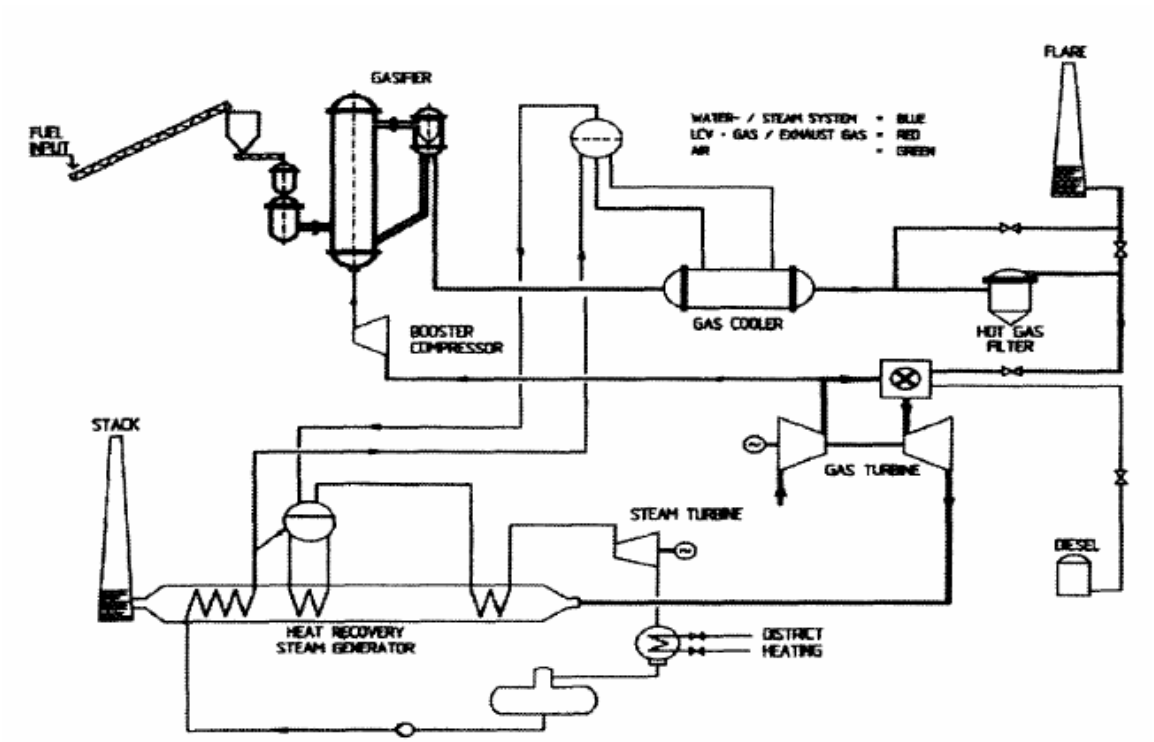

Figure 1-16. Schematic of the Värnamo, Sweden, BIGCC facility
Photo Credit: Adapted from Stahl and Neergaard 1998.

Eggborough, England (ARBRE)

This biomass fired IGCC project was selected for commercial demonstration by the European Commission THERMIE program in the mid-1990s (Pitcher et al. 1998). It is called ARBRE and was sited near forest operation residues but also includes a component to the project to grow short rotation coppiced willow for the main fuel source.

The capacity of the plant is 8 MW and uses a TPS (Sweden) atmospheric air-blown circulating fluidized bed gasifier. Gas conditioning is accomplished using sequential filtration and scrubbing. Particulate material is removed from the hot raw gas using a cyclone, and tars are then cracked while the gas is still hot. The gas is then passed through a heat exchanger to recover heat that is used for generating steam. The warm gas is then passed through bag filters to remove remaining particles, and the product then passes through a wet scrubber for final conditioning (Stevens 2001). A portion of the gas is combusted in a boiler and the remaining producer gas is compressed and injected into a Typhoon industrial gas turbine. The gas turbine and the steam cycle each produce about 5 MW with projected overall conversion efficiency of 31% (Stevens 2001).

Construction of the project began in 1998 and it has been operated in trial runs. The owner has suffered financial difficulties and the facility was reportedly sold in bankruptcy proceedings. The status of the facility is not determined at this time.

Other attempts

There are two other projects mentioned in the literature and on funding agency websites whose status is difficult to determine. One is located in Cascina, Italy, and owned by Bioelettrica SpA. This is another selection by the EC THERMIE demonstration program. The design includes a Lurgi CFB atmospheric air-blown gasifier sized for 43 MWt/hour fuel input. The plant should generate 14 MW (33% efficiency). The fuel is to be wood chips, and olive and grape pomace residues. The producer gas will be passed through cyclones for large particulate matter removal followed by cooling and wet scrubbing. The gas then is compressed for injection into the gas turbine. The plant was supposed to be operational in 2002 but has been delayed. The reasons for the delay have not been determined at this time.

The other project was slated for Brazil. Called the Brazilian wood Biomass Integrated Gasification-Gas Turbine Project (BIG-GT), development funds were provided by the World Bank and the UN through a program called Global Environmental Facility (GEF). In United States currency, $8 million was granted to do all preliminary development work including a fuel resource study, environmental impacts, plant component specification and selection and final design. The TPS gasification process and a General Electric (GE) gas turbine were selected (Babu 1999).

The design capacity was 32 MW. Fuel would include some wood residue and bagasse but primarily would be from a short rotation cultivation operation that was part of the

project. From the planning and design phases, the plant installation cost was estimated at $113 million (Carpentieri and Silva 1998), including land costs and short rotation crop operation. The project has not proceeded beyond the design stage. Apparently the high cost of the project and a downturn in the economy contributed to a decision not to continue.

Commercialization of Biomass IGCC

Though there are several operating commercial coal fueled IGCC facilities, some of which co-gasify biomass/MSW components (Williams et al. 2003), there are no strictly biomass fueled IGCC facilities commercially operating. This may be changing as Carbona and FERCO Enterprises report new projects are being developed.

Carbona IGCC

Carbona is a Finnish company active in biomass gasification and combustion projects. It has license to market the RENUGAS gasifier developed by GTI (pressurized air/ oxygen gasifier). The company was called Tampella Power and Enviropower in the past. It maintains a research and pilot facility in Finland. The company has developed proprietary gas cleaning systems (based partly on heated sintered metal filters and catalytic cracking) for use in biomass IGCC applications (Patel 2003).

Carbona is supplying the gasifier and gas cleaning system for an IGCC project in India. It is proposed to consume wood waste and cashew and coconut shells. Fuel feed rate is planned for 200 t/day and should net 12 MW. The project cost is $22 million. Project initiation is awaiting final decision from financing partners. See Figure 1-17 for a process diagram of the India project.

FERCO Enterprises[18]

An energy firm in the England (Peninsula Power) is planning to build a 23 MW (net) BIGCC facility using the FERCO gasifier and a Siemens Cyclone gas turbine. Fuel will come from a consortium of energy crop growers (short rotation willow coppice and miscanthus) and local forestry operation wastes. The project cost is reported to be $70 million of which $20 million is a renewable energy grant award from the government. The project is in the permitting stage.

18. Information gathered from personal communication with Mark Paisley, FERCO Enterprises, in 2004. Other sources include http://www.peninsulapower.co.uk/ and http://www.biggreenenergy.com, both accessed in 2004.

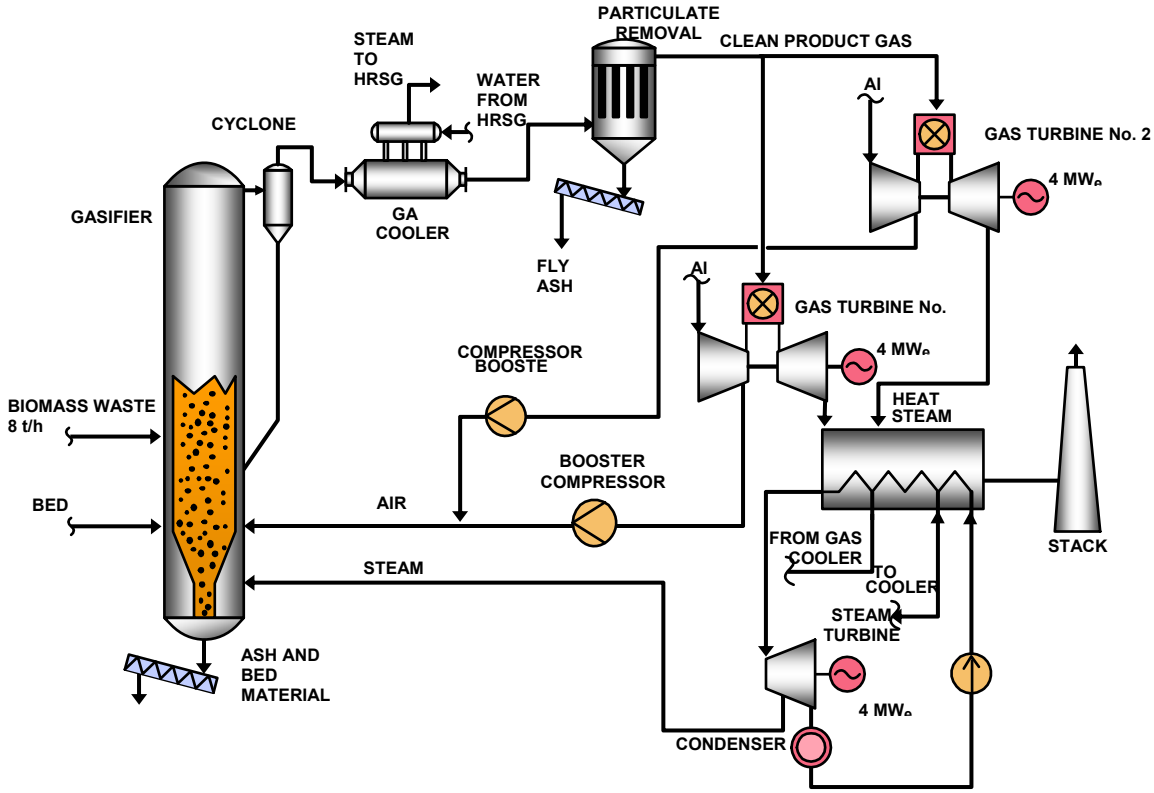

Figure 1-17. Process diagram of the Carbona India IGCC project.
Photo Credit: Carbona USA.

A project in Forsythe County, Georgia, is under development by Biomass Gas & Electric, LLC. The project will be located adjacent to a Construction and Demolition Debris landfill. Most of the fuel will be clean wood wastes supplied by the landfill operator. Supplemental fuel will be saw mill wastes and herbaceous crop residues. A FERCO gasifier has been selected. Initially, the gasifier will provide fuel for a steam boiler. Later plans call for installation of a gas turbine for combined cycle operation. The plant will consume 400 tons per day of fuel and produce approximately 20 MW. The project has received zoning approvals and environmental permitting is underway. Power purchasing agreements are being negotiated.

A third FERCO gasifier project is in development. This project is in the state of New York and will initially fuel a steam boiler and steam cycle with addition of gas turbines or reciprocating engines later. The project is obtaining zoning approvals. The fuel source was not reported.

BIGCC Conclusion

There is a general view that the U.S. DOE sponsored biomass IGCC projects failed because none of the projects ever operated in IGCC mode. This view is strengthened by the recent emphasis of Research, Development, Demonstration, and Deployment (RDDD) programs directed at biofuels and bioproducts (biorefineries) at the U.S. DOE

which necessarily reduces resources and, therefore, interest in biomass power development.

The reasons that the BIGCC demonstration projects in the United States never came to fruition are ultimately financial. The MnVAP project never reached the construction stage because bank financing backed out. The Paia, Hawaii, project was perhaps handicapped from the outset by a poor choice of fuel and reactor combination, creating an obstacle that could not be overcome by the budgeted time and money. The Burlington, Vermont (FERCO) project, by most reports, successfully demonstrated the Battelle gasifier at a commercial scale. Lack of funding, and perhaps interest in follow up, hindered installation of gas conditioning systems and the gas turbine to complete the project.

There remains a need to develop and demonstrate biomass IGCC in the United States in order to provide financiers a "homegrown" case study. There are few to no options available to developers when faced with repowering a facility that has reached its useful life, or in siting a new one. Developing improved efficiency of biomass conversion for heat and power in California and the nation so that they are available when the need arises (which many argue is now) is important because of the opportunities for increased diversity in the power generation fuel supply, load and voltage support to the grid from the distributed generation opportunities, improvements to rural economies, reductions in greenhouse gas emissions, and other environmental improvements.

The recently announced commercial projects by Carbona and FERCO are encouraging, especially because two of the FERCO developments are in the United States. The announced projects all target homogeneous fuel sources (mostly clean wood chips). Continued investigation which includes suitability of other fuels that comprise the diverse California biomass resource is necessary. Increased availability of clean wood fuels from forest thinning and related operations is not assured in the near term because permitting forest fuels reduction efforts on public lands is expected to be tied up in the courts. There are large amounts of non-forest biomass currently available in California, including agricultural residues, and MSW biomass.

1.4.3 Small Scale and Modular Biomass

In 1998, the NREL placed 10 cost-shared contracts to develop small, modular biomass power systems. These were the first phase of the Small Modular BioPower Initiative (three phases planned), which is aimed at determining the feasibility of developing systems that are fuel-flexible, efficient, simple to operate, and whose operation will have minimum negative impacts on the environment. Phase I was to determine the feasibility of developing cost-effective technologies and identifying the potential markets for each of the systems.

Small modular systems have potential applications in both domestic and international markets. They may have cost advantages in niche markets because of their modularity, standardized manufacture, and transport. Simple connections will require a minimum

of field engineering at operational sites. The intended power range for these systems is from 5 kW to 5 MW. The companies and projects awarded Phase I feasibility studies are listed in Table 1-15.

DOE Small Modular Biomass – Phase II

In 1999, Phase II awards were made to four of the Phase I project developers (Community Power Corp., External Power, FlexEnergy, and Carbona).

Community Power Corporation

Community Power Corp. (CPC) receives co-funding from the California Energy Commission (California small modular biomass- PIER) on this and other small scale biopower projects. For the small modular biomass program (U.S. DOE), the CPC system uses a fixed bed downdraft gasifier which runs a spark ignition (SI) engine and generator set ("Biomax"). The system uses engine intake vacuum to provide draft for the gasifier. The engine runs on propane during start-up. During steady-state operation of the gasifier, additional air is injected in the bottom of the gasifier to oxidize some of the char and maintain temperature. Some of the tar product is cracked or combusted by this action it is claimed. The producer gas is cooled to about 50°C where some tar is condensed (the gas is meant to remain above the dew point so that water vapor is inducted into the engine). The heat extracted in the cooling process is used to dry the feedstock in the short elevator conveyance that transfers fuel from the hopper to the gasifier. The cooled gas is then passed through a bag filter to remove most of the particulate matter. It was observed from operational experience that as a layer of carbon containing particulate builds up on the filter surface, tar concentration in the exit gas decreased. The material on the filter surface adsorbs and/or cracks some of the tar. Tar concentration of the gas sent to the engine is consistently below 50 parts per million (ppm), and levels of 10 ppm can be achieved. A considerable advantage is that the process emits no liquid effluent (which usually presents a waste mitigation issue); however the particulate material captured in the bag filter is likely to be hazardous and will require appropriate disposal (perhaps this material can be disposed of by re-injecting it into the gasifier). The market is for rural applications in the United States and developing nations in a capacity range of 2.5 to 100 kW (Figure 1-18). Currently, three or four 15 kW units are being deployed for long term field testing. The current design capacity is too small to gather much interest in the United States market. The United States Forest Service (USFS), NREL, and the Energy Commission are sponsoring CPC to develop a larger capacity unit. A 50 kW design is being discussed for demonstration in California early in 2005.

Table 1-15. DOE small modular biomass Phase I awards[19]

Company	Technology
Community Power Corporation, Aurora, CO	Gasification with spark ignition engine / generator
Sun Power, Inc. (External Energy) Athens, OH	Combustion with Stirling engine / generator
Carbona Corporation, Napa, CA	Up-draft gasification with boiler/steam turbine
Reflective Energies, Inc. (FlexEnergy) Mission Viejo, CA	Microturbine for biogas applications
Agrielectric Power, Inc. Lake Charles, LA	Fluidized-bed combustion with steam turbine
Bechtel National Incorporated, San Francisco, CA	Gasification with spark ignition engine / generator, combustion turbine, or fuel cells
Bioten General Partnership, Knoxville, TN	Direct-fired combustion turbine
Energy and Environmental Research Center Grand Forks, ND	Fluidized bed combustion, heat exchange fluid, steam generation, steam turbine
Niagara Mohawk Power Corporation, Syracuse, NY	Gasification with spark ignition engine / generator or combustion turbine / generator
STM Corporation Ann Arbor, MI	Gasification with Stirling engine / generator

See http://www.eere.energy.gov/biopower/projects.ia_tech_sm_exec.htm

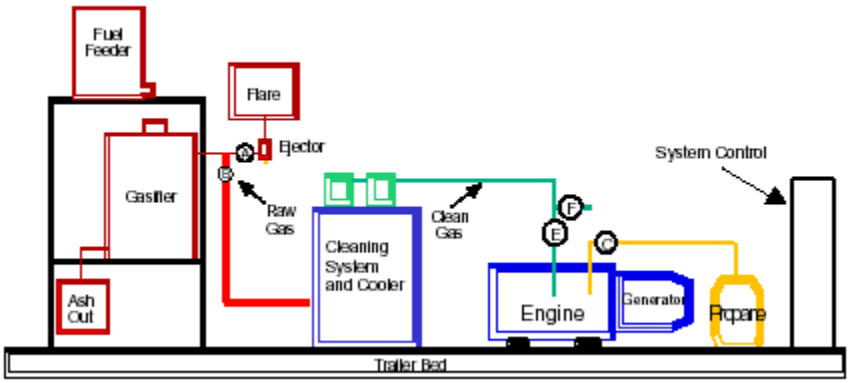

Figure 1-18. Schematic of CPC small modular system in Phase I stage
Photo Credit: Adapted from the Small Modular Biomass Phase I executive summary

A 12 kW system has been operated at the Hoopa Indian Reservation in Northern California including demonstration of grid-connected performance. In Combined Heat and Power (CHP) operation, the system has overall efficiency of approximately 60%[20]

19. See http://www.eere.energy.gov/biopower/projects.ia_tech_sm_exec.htm
20. CEC PIER 2002 Annual Report, http://www.energy.ca.gov/reports/2003-03-28_500-02-076F.pdf

although the electrical efficiency is 15 to 16% based on a stated fuel consumption of 3 lbs per hour per kW at a nominal wood moisture of 15% after drying. Fuel drying is one use of the engine reject heat. The objectives for the project to be commercial in California (for a CHP system) include capital cost of $1,000/kW, cost of electricity less than 15 cents/kilowatt-hour (kWh), and cost of heat less than $1.20/therm. The unit(s) in California have been operated on clean wood fuel typical of forest thinning operations and mill residues. Units in the Philippines operate on wood residues and coconut husks and shell.

CPC is also receiving U.S. DOE funds through the Small Business Innovation Research Program (SBIR) to fuel the system with poultry litter. This project is cooperating with FERCO, Iowa State, University of Arkansas, and others on this project. CPC claims to have been the first group to power a solid oxide fuel cell on gasified biomass. This was a small, less than 3-watt fuel cell developed by Ascent Power Systems.[21]

The CPC downdraft gasifier is nearly commercial when operated on clean wood fuels and may be an attractive option for distributed generation with fuel from forest thinnings. CPC has recently been awarded another grant from the Energy Commission for development of a 50 kW unit.

FlexEnergy

FlexEnergy is developing a Lean-Fueled catalytic Microturbine Technology. It is a microturbine capable of operating on low energy gas (biogas, air gasified biomass, etc.). The fuel gas is mixed with combustion air prior to compression which reduces parasitic losses from separate fuel gas compression. To eliminate explosion hazards, the fuel gas must be mixed at concentrations below the flammability limit and thereby requires a catalyst to initiate combustion. The turbine is an adapted Capstone C30 (30 kW) turbine. It has been run on simulated producer gas (CO and H_2) and biogas (natural gas diluted to represent the energy content of a digester gas) and reportedly developed full 30 kW power.

FlexEnergy is currently receiving PIER funds to demonstrate the technology using digester gas (Cal Poly) and land fill gas at the Puente Hills landfill near Los Angeles.

Future development work includes running the FlexEnergy microturbine on gasified biomass (wood) from CPC and other gasifiers. The Energy and Environmental Research Center at the University of North Dakota is currently setting up the test gasifiers to operate the microturbine. There is also a pending demonstration project to gasify pecan shells at a processing plant in Arizona (with support from the National Rural Electric Cooperative Association).

A further proposed and funded project is with the South Coast Air Quality Management District. This demonstration will use waste gases from an indoor composting facility in Chino, California, supplemented with digester gas in order to consume the Volatile

21. CPC media release, 2002. http://www.gocpc.com/

Organic Compounds (VOC) and ammonia emissions from the compost facility. This is attractive because the low temperature catalytic combustion has extremely low NOx emissions.

The FlexEnergy microturbine is still developmental but its potential advantage will be the ability to produce power from low energy fuel gas with very low NOx emissions, a significant innovation for biomass small modular technology.

Sun Power (External Energy)

This small modular biomass concept uses combustion of biomass to provide heat for a free-piston Stirling engine (external combustion engine) to generate 1 kW power and provide heat for space and water. This is targeted for residential scale use. During early stages of the Phase II portion of the U.S. DOE program, a prototype was developed and tested. There were technology ownership issues being disputed and the cost of pre-production engines was very high so the project was terminated (Bain et al. 2003).

Stirling Energy Systems, Inc.

Stirling Energy Systems (SES) is developing a Stirling engine to operate on digester gas and similar fuels. SES has a contract through the Hetch-Hetchy renewable generation project funded through the Energy Commission's PIER program (a companion project of the SMUD ReGen project) and is scheduled to demonstrate a unit at an Inland Empire Utility Agency (IEUA) site. SES is planning on using a modified Kockums (Sweden) Mark II engine.

Carbona

The Carbona small modular biomass project involves biomass gasification for combined heat and power. The system is being prepared for demonstration in Skive, Denmark. A fluidized bed gasifier fed by air and steam gasifies pelletized wood fuel (see Figure 1-19). Hot producer gas passes through a catalytic tar cracker reducing tar amounts (tar production and reduction amounts were not reported) followed by cooling before passing through bag filters for particulate matter (PM) removal. The producer gas then passes through a wet scrubber (presumably to capture some acid gases and remaining tars and PM). The disposition and quality of the gas scrubbing water was not reported.

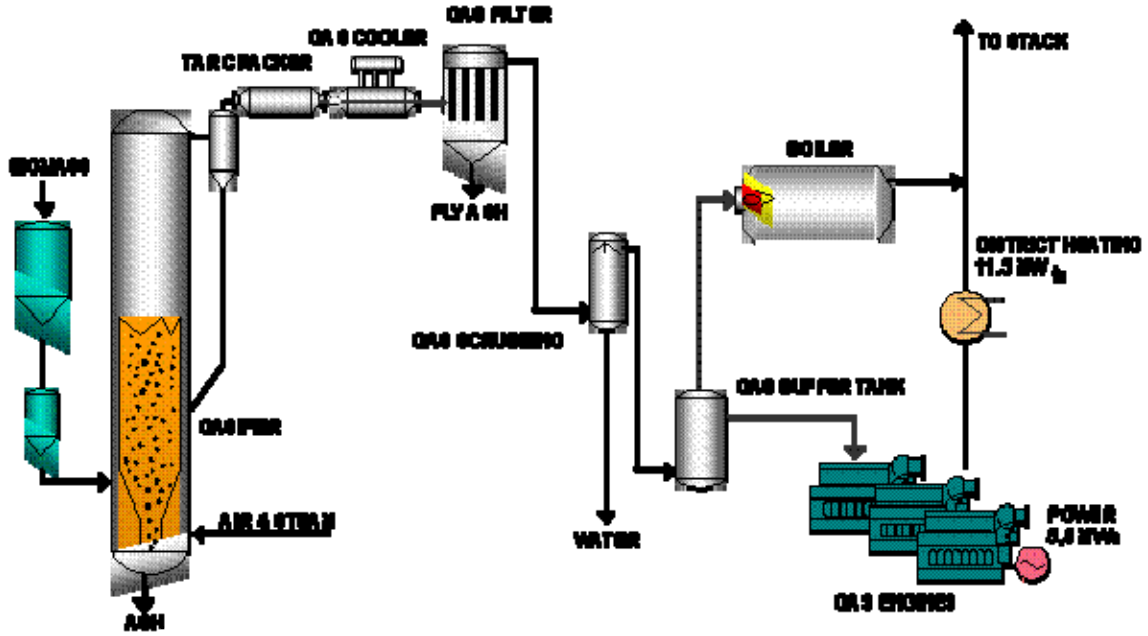

Figure 1-19. Simplified schematic of the Carbona Skive project
Photo Credit: Carbona Corporation

A portion of the gas stream is fired in reciprocating engine-gensets (GE Jenbacher GmbH) producing approximately 5 MW. The remaining gas stream is burned in a boiler and combined with engine heat; about 11 MW is produced for the district heating application. The relative amounts of heat and power are variable depending on seasonal needs. This system is expected to consume 100 tons per day of wood fuel.

The project cost approximately $24 million, of which $5 million is from European agencies and U.S. DOE. A recent press release indicates that a contract has been signed for delivery and installation of the CHP facility (Patel 2004).

Other Small Biomass Power Systems (United States)

There are many potential small scale (and/or modular) biomass systems being marketed in the United States. Most are solid fuel combustion in a boiler for heat and power generation. Some are based on gasifiers with a variety of prime mover technology for power generation. Following are brief descriptions of a project outside of California and two companies that are involved in small biomass gasification.

Connecticut Clean Energy Fund

The Connecticut Clean Energy Fund is sponsoring the installation of a biomass gasifier CHP system.[22] The project will consume sawmill residue and provide about 300 kW to the grid and hot water (as much as 500 kW) to the sawmill at North Canaan, Connecticut.

22. The CCEF can be found at http://www.ctcleanenergy.com/

The gasifier is a 1 MW downdraft air-blown reactor that will operate at about 1.5 atmosphere pressure (absolute). The gasifier, as well as the gas cleaning system, is designed by Puhdas Energia Oy of Tampere, Finland.

The gas cleaning system consists of direct and evaporative cooling (see Figure 1-20) followed by an electrostatic precipitator (ESP) for particulate matter and aerosol (condensed tars) removal. Following the ESP, the gas flows through a water scrubber which captures some of the remaining condensable compounds. There is potential for the ESP to create a small amount of slurried residue which reportedly can be disposed by mixing with the biomass fuel before drying (a potential air emission issue from the dryer) or burned in an accompanying combustor.[23]

The cleaned producer gas will fuel a Mercedes CI engine using diesel as a pilot fuel.

The system is currently undergoing preliminary start-up testing. There are several hundred hours of gasifier operation which includes some power generation (Miles 2005). Early estimated installed cost was $1.2 million ($4,000/kW) (Nadgauda 2004).

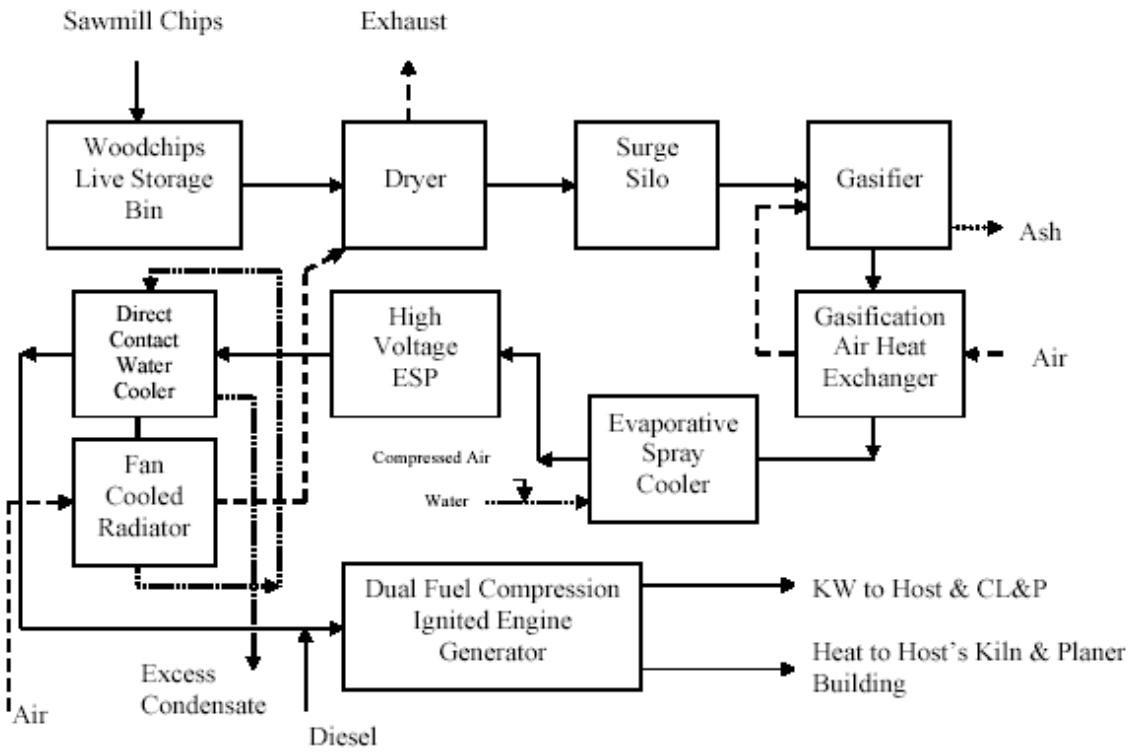

Figure 1-20. Schematic of gasifier CHP project at North Canaan, Connecticut
Photo Credit: Nadgauda, 2004

23. See write-up by Sampo Tukiainen at http://www.repp.org/discussiongroups/resources/gasification/pudhas1mw.html

Altex Technologies

Altex Technologies is an engineering services firm with expertise in low emission combustion systems and heat transfer applications. Under a U.S. DOE small business innovation research (SBIR) grant, Altex developed and demonstrated a system to create heat and power (25 kW) from the combustion of dairy waste.

The system consists of a staged cyclonic combustor, high temperature gas to gas heat exchanger, and a gas turbine powered by hot gas from the heat exchanger. Ancillary equipment included initial mechanical dewatering system (manure was obtained from the dairy waste sluicing system with initial 95% moisture content), a rotary drum dryer utilizing waste heat to for final fuel moisture conditioning, solid fuel storage and handling, and ash extraction systems.

Resources did not allow for selection of optimal system components (e.g., the gas turbine used was a surplus aircraft auxiliary power unit) and initial experiments showed that the fuel needed to be dryer than originally planned. John Kelley (President of Altex Technologies) indicated that with the suboptimal gas turbine used in the demonstration system, electrical production efficiency was less than 10%. With optimized components, this type of system burning dairy manure to power an external combustion gas turbine cycle could provide small scale electricity production efficiencies of perhaps 20% including fuel drying. In order for the combustion system to operate with the intended low emissions, the fuel was dried below that for the original design which resulted in higher combustion temperatures and causing the ash to become molten. The dry-ash extraction system would become blocked when molten ash solidified upon cooling. The system could operate for perhaps 20 to 30 hours before the ash removal system became inoperable. Slagging ash removal systems are existing technology used on wet bottom coal boilers and high temperature slagging gasifiers. A minimal modification to the combustor bottom and ash system would allow the system to operate for long periods with molten ash product.

The combustor burns fuel at a nominal energy input rate of 700,000 Btu/hour (205 kW) which for rice straw with a HHV of 15 MJ/kg requires about 50 kg/hour. Table 1-16 gives some currently available emissions data from tests on three biomass fuels.

Table 1-16. Emissions from the Altex combustor.

Fuel Type	NOx (ppm)	CO (ppm)
Dairy manure	150 (@3% O_2, dry gas)	200 (@3% O_2, dry gas)
Rice straw	150 (basis not reported)	nr
Yard waste	100 (basis not reported)	nr

nr = not reported

Source: UC Davis Research Team ; Source: Robert Williams ; Source: Altex Technologies

An advantage of the staged cyclonic combustor is that its physical size is smaller than a grate or suspension fired burner or boiler for a given solid fuel feed rate because like a fluidized bed system (bubbling or circulating), solid fuel particles remain in the high temperature reaction zone and until small enough to pass through the cyclone

separators with the combustion gases. Downstream ash fouling may be reduced because of fewer and smaller particles (which can serve as alkali vapor condensation sites) carried in the hot exhaust gases to heat transfer surfaces.

A report on the Energy Commission's EISG project is being prepared so more detailed information will be forthcoming. The executive summary for the power from dairy waste (SBIR Phase II) indicates that a commercialized system of 250 kW could have an internal rate of return (IRR) of 33% or even 40% (economic analysis conducted by Altex). The economic analysis used a retail price for electricity credited to the project (equal to the price of electricity the farm had to pay) of $0.10/kWh and relied on selling waste heat at $6.70/MMBtu and claimed a fertilizer value of $1.61/ton effluent from the dewatered manure.

Much of the detail from Altex's U.S. DOE SBIR work is proprietary at this time, so a more in-depth evaluation is not possible.

It should be noted that externally-fired gas turbine cycles (indirect Brayton cycles), a possible pathway to improve conversion efficiency of low quality or difficult solid fuels, is considered experimental with substantial technical issues still to overcome. These issues include heat exchanger materials and design for use with high temperature alkaline and chlorine vapors in the combustion gas as well as economical gas turbines for this size and application.[24]

Omnifuel

Omnifuel builds and markets fluidized bed gasifiers for biomass and refuse-derived fuel (RDF). The company has offices in Ontario, Canada and Folsom, California. The process originated from work in Canada in the late 1970s which involved RDF preparation and gasification. Two demonstration units were built in Canada (160 and 500 tons per day capacity) and one in French Guyana. All units operated successfully but did not continue past the demonstration period because of economics. The company and its partners are responding to several Request for Proposals (RFP) for renewable energy systems in the western United States.

Omnifuel is responding to the SMUD renewable power generation RFP under the emerging renewables category. The proposed system will be a CHP facility located adjacent to the Folsom Prison and utilize an existing (but idle) waste receiving and sorting facility. Two air blown fluidized bed gasifiers are proposed to convert 14 tons per hour of shredded wood and green waste to producer gas. The gas will be fired in a steam boiler to run a steam turbine and supply process steam for sale to the prison. The net electrical capacity is estimated to be about 3.5 MW (Figure 1-21).

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24. A development project is pending with the California Division of Forestry and Fire Protection, UC Davis, and other participants to develop and test a CHP system using an indirect-fired gas turbine consuming forest thinnings.

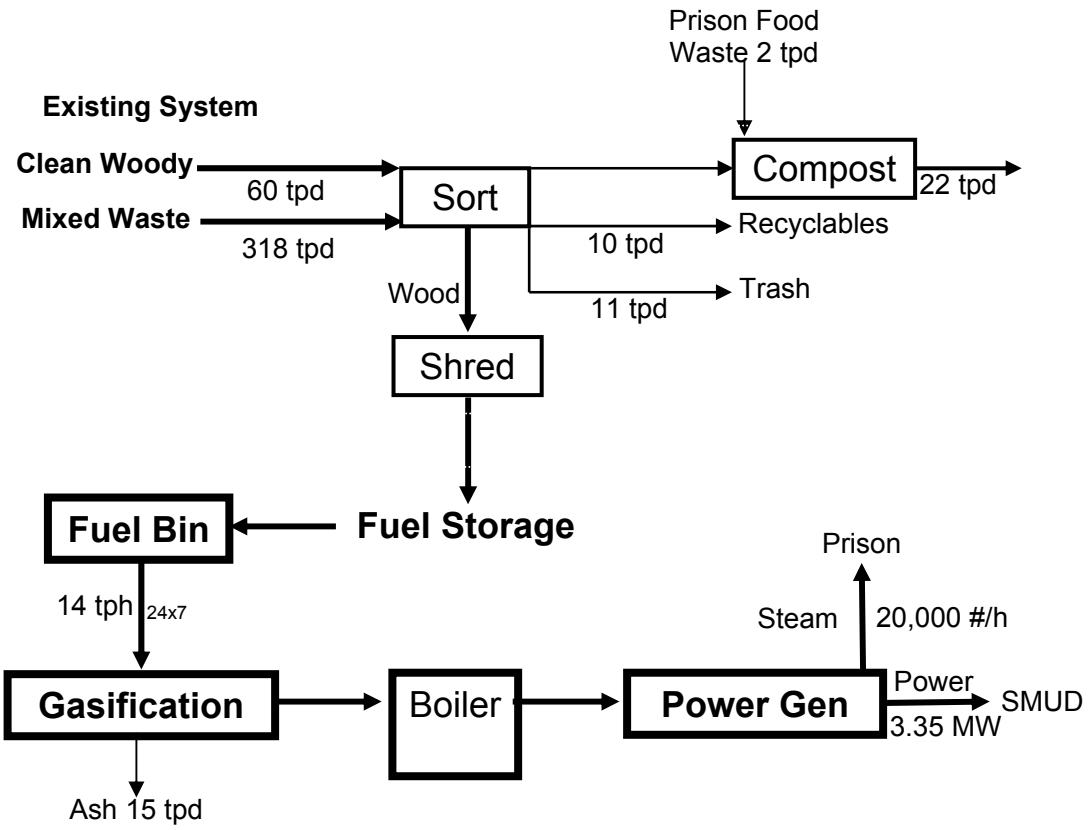

Figure 1-21. Schematic of proposed Omnifuel CHP facility

Photo credit: UC Davis Research Team; Photo credit: Robert Williams ; Photo courtesy of Omnifuel

Small-Medium Scale Gasification for CHP (India and Europe)

India

India has large and diverse biomass resources. Increasing population combined with a modernizing economy is resulting in a rapidly increasing energy demand. The Ministry of Non-conventional Energy Sources (MNES) in India is setting policy and gathering resource and energy statistics in order to increase use of non-fossil energy and increase rural electrification. The MNES reports that in India there are presently 1,840 biomass gasifiers for a combined capacity of 58 MW (30 kW average) (Girdhar 2004).

Ankur Scientific

Ankur Scientific in Gujarat, India, builds and markets downdraft gasifiers for heat and power production. There are many units employed, mostly in Asia in various sizes less than 500 kW. Many of the installations are used to replace a portion of diesel fuel in diesel engine generator sets (Ankur indicates that diesel fuel flow is reduced by about 70% when running in the dual-fuel mode). The Energy & Environmental Research Center (EERC) at University of North Dakota is operating an Ankur WBG-200 gasifier to supply fuel gas for Flex Microturbine testing.

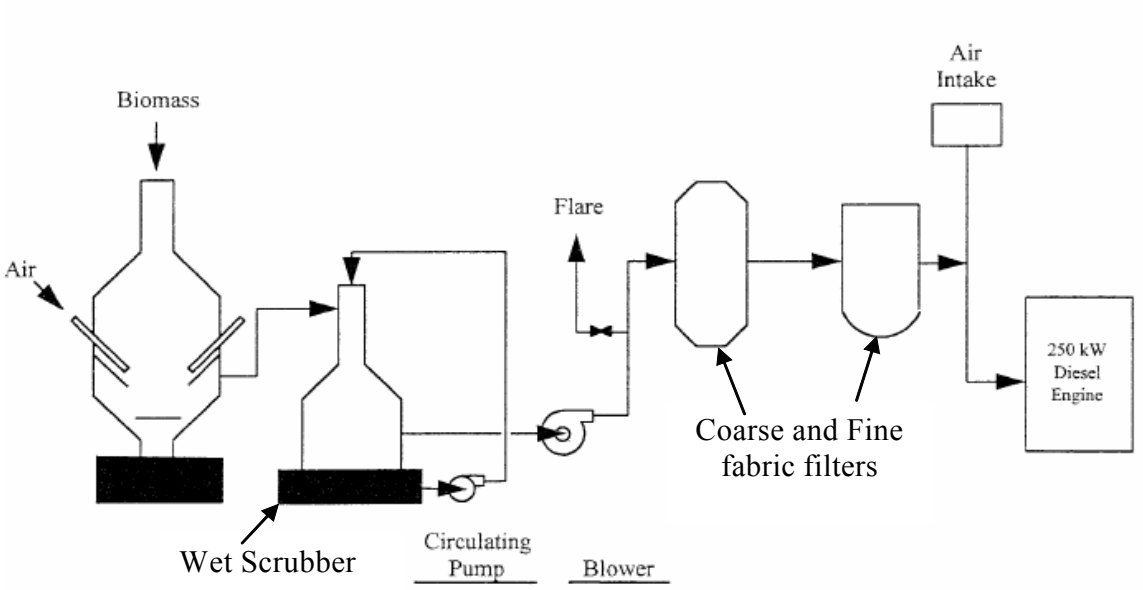

Figure 1-22. Schematic of Ankur downdraft gasifier with dual-fuel power generation configuration

Photo credit: UC Davis Research Team; Photo credit: Robert Williams ; Photo courtesy of Ankur Scientific

Gas clean-up for use in reciprocating engines is composed of a wet scrubber and coarse and fine fabric filters (see Figure 1-22). PM and tar concentrations were measured after gas cleaning for a BG-400 Ankur gasifier, presumably fueled by wood chips (Wen et al. 1999). Wen reports PM and tar concentrations to be 0.30 and 1.34 mg/Nm^3, respectively.

Table 1-17 lists approximate PM and tar limits for producer gas used to fuel reciprocating or gas turbine engines. These are postulated or rule of thumb values, though a piston engine operated for more than 1,500 hours on a producer gas with tar content of 300 mg/Nm^3 with no operational problems, suggesting that the upper limit on tar needs further investigation (Hasler et al. 1998). Nevertheless, the reported PM and tar contents of the Ankur system described by Wen et al. (1999) are well below the requirements for gas turbine fuel.

Table 1-17. Approximate producer gas quality requirements (Stassen 1993).

		Reciprocating Engine	Gas Turbine
Particulate Matter	mg/Nm^3	< 50	<30
Tar	mg/Nm^3	<100	<5
Alkali metals	mg/Nm^3	-	<0.24

Incomplete tests were done on the wet scrubber effluent which indicates presence of hydrocarbon contamination (as expected with scrubber water used in producer gas cleaning). The Ankur related literature does not discuss the amount of scrubber effluent

nor what degree of processing is required to treat the effluent before disposing. Hydrocarbon contaminated wastewater from producer gas cleaning remains an important environmental and/or economical issue.

Overall electrical efficiencies of the Ankur gasifier and reciprocating engine generator systems are about 15 to 20% based on reported wood fuel consumption of 1 to 1.3 kg/kWh.

Indian Institute of Science, Bangalore

The Indian Institute of Science (IISc) has been developing an open top downdraft gasifier (modified from an open top Chinese design) for many years. Professor Mukunda has been the lead investigator.

There are some 37 systems based on the IISc open top downdraft gasifier installed (31 are in India of which eight have electricity generation using dual fueled compression ignition or gas only fueled spark ignition engines). IISc is involved in United Nations development programs for rural electrification in India. Additionally, an IISc CHP system has been investigated and tested by the Swiss Federal Office for Education and Sciences and the Swiss Federal Office of Energy (Hasler et al. 1998; Hasler and Nussbaumer 1999; Hasler and Nussbaumer 2000). The Brazilian Reference Center on Biomass (CENBIO) at São Paulo University is investigating the IISc system for possible application in isolated communities in the Amazon region (Coelho et al. 2004).

Following the interest of the Swiss government, a company (Xylowatt SA) formed to market the systems in Europe. A facility was commissioned by Xylowatt in 2002 at a saw mill in Bulle, Switzerland. The facility is a CHP operation consuming about 55 kg/hour of wood residues from the sawmill (1.4 t/day based on 24 hour operation). The facility generates 50 kW and 108 kWth. The electrical generation and useful heat efficiencies are 22% and 48%, respectively (Giordano 2003).

Figure 1-23 shows a schematic of the Xylowatt facility. Gas is cleaned using a cyclone, followed by cooling, wet scrubbing, and finally filtering (fabric filter). Gas quality before and after cleaning is reported in Table 1-18. The gas cleaning system emits water and sludge at a rate of 14 kg/h and 0.2 kg/h, respectively (Giordano 2003). Analysis of waste water indicated it is acceptable for discharge under Swiss regulations. Analysis of the sludge discharge and whether the water was treated before discharge was not reported.

Table 1-18. Product gas tar and particulate matter concentration, Xylowatt Bulle facility (Giordano 2003)

Component	Raw Gas	Cleaned Gas	Units
Tar	250	106	mg/Nm^3
Particulate Matter	200	42	mg/Nm^3

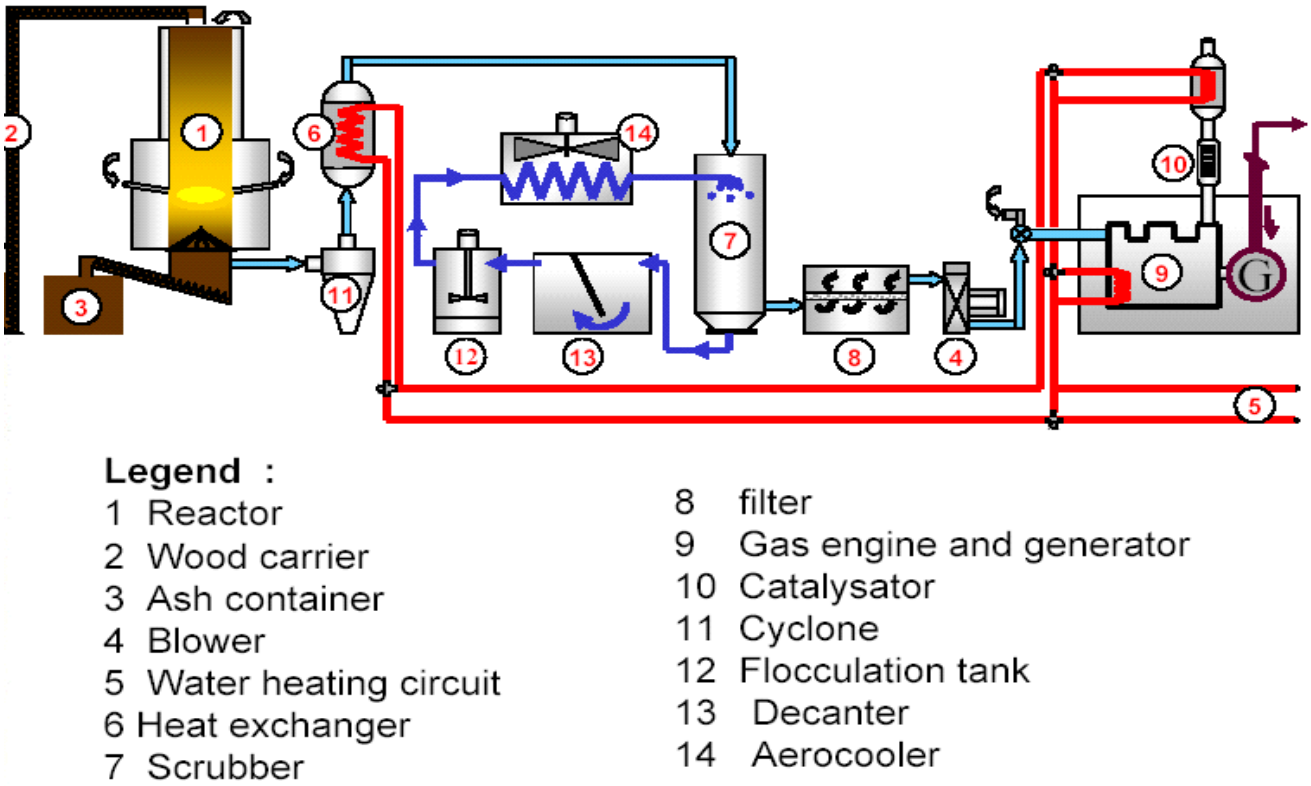

Figure 1-23. Schematic of a Xylowatt SA biomass gasifier CHP facility
Photo Credit: P. Giordano

Small Biomass CHP in Europe

There is much continuing development and implementation of biomass power and fuels production systems in Europe which includes many small wood gasifiers for heat and power in the pilot, "commercial demonstration," or demonstration status (see Table 1-19 for a partial listing). There are a number of facilities being permitted or under construction. A research and demonstration unit and a new commercial facility in Europe are discussed here. The Skive, Denmark, CHP facility is discussed in the U.S. DOE small modular biomass section above (because it is receiving some of its funding through the U.S. DOE program).

Table 1-19. Selected small scale gasifiers operating in Europe (Knoef 2003; Rauch et al. 2004; Buffinga and Knoef 2001).

Location		Supplier	System*	Fuel	Power (kWe)	Year Commissioned
Rossano	Italy	PRM	Updraft	Olive residue	4000	2003?
Güssing	Austria	Repotec	Dual Fluidized Bed [a]	Wood chips	2000	2002
Harboore	Denmark	Babcock & Wilcox, Volund	Updraft	Wood chips	1500	2000
Neustadt	Austria	AHT (modified)	2- stage Dowdraft	Wood chips	500	2003
Tervola	Finland	Entimos Oy	Combined Updraft/Downdraft	Wood chips	450	2003
Hogild	Denmark	Hollensen	Downdraft	Wood chips	400	1998
Regal	Belgium	Xylowatt-Beigium	Downdraft	Mill residue	300	2002
Armaugh (Blackwater Valley II)	N Ireland	Exus Energy (b9 Biomass)	Downdraft	Wood chips	200	2000
Spiez	Switzerland	Pyroforce	Downdraft	Wood chips	200	2002
Bulle	Switzerland	Xylowatt-Swiss (IISc design)	Open top Downdraft	Wood chips	200	2002
Hengelo	Netherlands	HoSt	Downdraft	Wood chips	200	2001
Gazel	Belgium	Xylowatt-Beigium	Downdraft	Mill residue	150	2000
London (Beddington Zero Energy)	UK	Exus Energy (b9 Biomass)	Downdraft	Wood chips	130	2002
Londonderry	N Ireland	Rural Generation Ltd.	Downdraft	Wood chips	100	2000
Armaugh (Blackwater Valley I)	N Ireland	Exus Energy (b9 Biomass)	Downdraft	Wood chips	100	1998
Bladel	Netherlands	BTG	Bubbling Fluidized Bed [b]	Chicken Manure	60	2002
Lyngby	Denmark	Technical University, Denmark (DTU)	Viking' 2-stage DTU	Wood chips	20	2002
Stubenberg	Austria	Grubl	Downdraft	Wood chips	15	1998

*Except where noted, systems are fixed bed air-blown, atmospheric gasifiers. Reciprocating engines are used for power generation (multiple engines in some cases)
a.) Steam Gasification with air fed char combustion (dual fluidized bed)
b.) Fluidized bed
Knoef 2003; Rauch et al. 2004; Buffinga and Knoef 2001

A novel gasifier CHP project is operating in Güssing, Austria. The facility can be described as a commercial scale demonstration. The system consumes wood chips producing 2 MW and 4.5 MWth. The gasifier is a dual fluidized bed reactor. The biomass is gasified with steam and heat from bed media in a bubbling bed reactor configuration. The char and bed media are transferred to a parallel reactor which operates in recirculating fluidized bed mode where air is introduced to combust the char which heats the bed media. The heated bed media is transferred to the biomass gasifier (See Figure 1-24). The concept is essentially the same as that employed in the FERCO SilvaGas units.

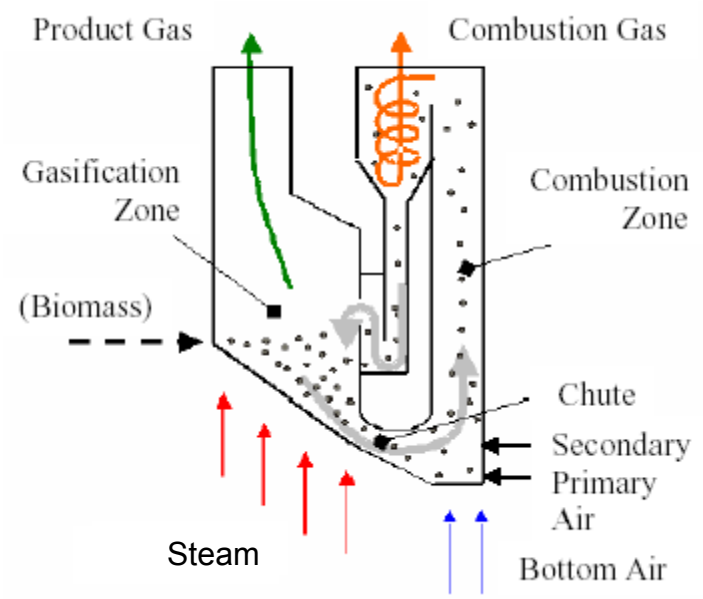

Figure 1-24. Schematic of the Fast Internal Circulating Fluidized Bed (FICFB) gasifier, Güssing, Austria

Photo Credit: Bolhar-Nordenkampf and Hofbauer 2004

One advantage of gasifying with steam is that the producer gas is not diluted with nitrogen as is the case with air blown gasification. The producer gas from the Güssing CHP facility is cooled and then cleaned in two stages. The first stage gas cleaning consists of a fabric filter which separates most PM and some tar. The material collected by the filter is recycled to the combustion reactor. The second gas cleaning stage is a wet scrubber. Table 1-20 shows levels of components in the producer gas that must be controlled before introduction to a reciprocating engine (before and after the gas clean-up system).

Table 1-20. Contaminants in Güssing producer gas before and after cleaning (Bolhar-Nordenkampf and Hofbauer 2004)

Component	Raw Gas	Cleaned Gas	Units
Tar	1,500 – 4,500	10-40	mg/Nm^3
Particulate Matter	5,000 – 10,000	< 5	mg/Nm^3
Ammonia	1,000 – 2,000	<400	ppm
Hydrogen Sulfide	not measured	20-40	ppm

Bolhar-Nordenkampf and Hofbauer 2004

Spent scrubber liquid containing tar and condensed material is evaporated and disposed in the combustion reactor. Cleaned producer gas is sent to a gas engine and boiler for heat. The relative distribution of gas to the engine or boiler depends on heat and power needs. Figure 1-25 shows a schematic of gas flow at the Güssing facility. The facility has an electrical efficiency and overall CHP efficiency of 25% and 81%, respectively (Rauch et al. 2004).

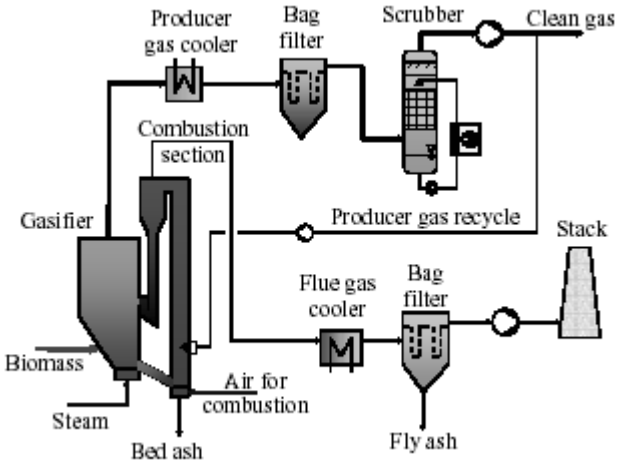

Figure 1-25. Schematic of the Güssing gasifier and gas clean-up
Photo Credit: Rauch et al. 2004

Kokemäki, Finland CHP

An updraft biomass gasifier for CHP is undergoing shake-down/commissioning trials at Kokemäki, Finland. This project is being managed by Carbona with cooperation from VTT.[25]

Novel Gasifier Background

The Novel gasifier was developed by VTT and Condens OY to overcome some of the technical problems experienced with the commercially successful "Bioneer" gasification systems operating in Finland. The Bioneer design uses an updraft, atmospheric pressure, air-blown reactor. The producer gas is conveyed to a near-by combustor where it is burned without any treatment of the fuel gas. The primary technical limitations of the Bioneer systems are; (1) not suitable for low bulk density wood residues (saw dust, bark, forest slash), (2) operates poorly when fuel moisture is above 45%, (3) tar buildup in product gas pipe requires frequent shutdown and cleaning, and (4) fuel feeding systems leak producer gas due to back pressure (Kurkela et al. 2000). The Bioneer gasifiers are applied mainly in district heating systems and began operation in the mid-1980s. Approximately nine Bioneer facilities have been constructed. In 2002, one was still in continuous operation and the others were fired as needed (IEA 2002). The Bioneer facilities are automated requiring minimal attention.

The Novel-Condens OY reactor is essentially the same as the Bioneer. The fuel feeding system has been improved to eliminate backflow of producer gas. The feed system also allows a broader range of fuel particle size and densities to be utilized such as sawdust and other fine material. Air for gasification is humidified in a water spray tank in order to reduce reactor temperature. Secondary air is added above the main reaction zone in order to crack some of the produced tars. The produced gas can be burned directly for

25. VTT is a large technical research contract organization in Finland.

heat applications or the gas can be conditioned for use in reciprocating or gas turbine engines.

Kokemäki, Finland CHP Plant

The Novel-Condens OY CHP plant at Kokemäki, Finland, is undergoing shake-down trials (summer/fall 2005). The anticipated fuel is urban and/or sawmill waste wood. The design includes gas clean-up and conditioning (e.g., tar reforming, gas cooling, and filtering and final scrubbing) before being fed to three 600 kW Jenbacher reciprocating engines (see Figure 1-26). Not shown is an auxiliary boiler used for periods of high heat demand; otherwise recovered engine heat satisfies the district heat and fuel drying requirements. The design capacity is 1.8 MW and 3.1 MWth without auxiliary boiler and 4.3 MWth with firing the auxiliary boiler. Electrical and overall efficiencies are 30% and 80%, respectively, for normal operation and 26% and 85%, respectively, when using the auxiliary boiler (see Table 1-21).

Table 1-21. Nominal energy balance for Kokemäki CHP plant (Patel 2004)

		Normal Operation	With Auxiliary Boiler
Fuel input	kW	6200	7200
Electricity Production	kW	1836	1836
Heat Production	kW	3100	4300
Fuel Drying (from existing separate heat plant)	kW	429	429
η_e*	%	29.6	25.5
η_{th}	%	50.0	59.7
$\eta_{overall}$	%	79.6	85.2

* η = efficiency (useful energy or work output divided by energy input)

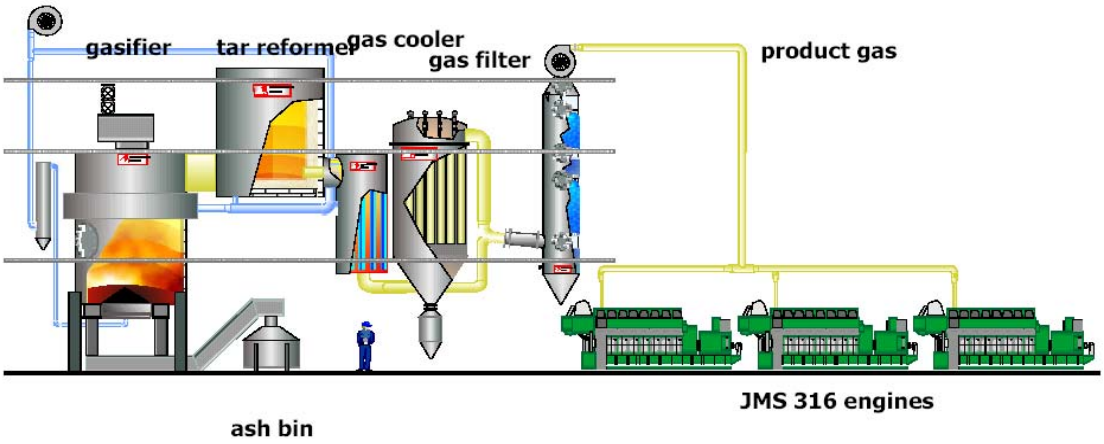

Figure 1-26. Schematic of novel gasifier CHP facility under construction at Kokemäki, Finland

Photo Credit: VTT Processes[26]

Investment cost for a Novel gasifier for heat only applications is similar to that of the Bioneer facilities (350 to 420 Euro/kWth in 2000) (Kurkela et al. 2000).

Fuel Cell from Biogas Demonstration

The South Waste Water Treatment plant in King County, Washington (Puget Sound area) will demonstrate operation of a 1 MW molten carbonate fuel cell using digester gas. The U.S. EPA is providing financial support. The fuel cell was developed by Fuel Cell Energy, Inc. (Danbury, Connecticut). A three-year demonstration period is planned. The potential advantage of fuel cell conversion of digester methane is improved conversion efficiency and essentially zero NOx emissions. Systems of this scale for operation on methane are developmental and very expensive. Design and construction/installation costs of the King County system were $22 million. Estimated annual operations and maintenance costs are $80,000 (Bush 2003). Phosphoric acid fuel cells have already been tested by EPA on landfill gas at several sites.

The Los Angeles County Sanitation Districts installed a molten carbonate fuel cell at the Palmdale Water Reclamation Plant. The Palmdale facility treats approximately 9.5 million gallons per day of wastewater. The anaerobic digesters at the facility generate about 80 scfm[27] of biogas containing approximately 55% methane (McDannel 2005).

The fuel cell, provided by Fuel Cell Energy is a molten carbonate type with internal reforming having a gross capacity of 250 kW (model DFC 300A).

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26. Small scale gasification processes for CHP. Technical note: http://www.vtt.fi.pro

27. Standard cubic feet per minute, which is a measure of air flow at a standard temperature and a standard pressure of 1 atmosphere.

For fuel gas treatment, the biogas is passed through a PM filter, a refrigeration unit, and activated carbon. The gas cleaning system consumes about 25 kW. Table 1-22 displays gas quality before and after the gas cleaning system.

Table 1-22. Palmdale fuel cell raw and treated fuel-gas quality

Contaminant	Raw Digester Gas	After Gas Clean-up
H2S, ppm	23	ND<0.5
Chlorobenzene ppb	180	0.7
P-dichlorobenzene, ppb	30	ND <1.0
D4 siloxane, ppm	0.40	ND<0.03
D5 siloxane, ppm	0.95	ND<0.03

Source: UC Davis Research Team ; Source: Robert Williams ; Source: McDannel 2005

The net electrical efficiency of the fuel cell is estimated at 41% (HHV). Emissions, reported by LA County Sanitation Districts, are shown in Table 1-23.

Table 1-23. Air emissions from the Palmdale WWTP fuel cell

Pollutant	ppm @15% O_2	lb/MWh
NOx	0.05	0.0017
CO	1.2	0.025
HC	1.3	0.017
SO_2	ND<0.02	-

Source: UC Davis Research Team ; Source: Robert Williams ; Source: McDannel 2005

Installed cost was $1.9 million ($8,400/net kW), of which 50% was paid with a grant from the California Public Utilities Commission. After Operation and Maintenance (O&M) costs are paid ($0.037/kWh which includes a reserve for fuel cell stack replacement), the power saves the District about $0.09/kWh delivered (assuming a $0.12/kWh retail purchase price). Simple payback of this system is about 12 years.

1.4.4 Rice Straw Combustion Systems

Rice Straw in the Sacramento Valley

Rice cultivation in California occurs primarily in the Sacramento Valley (more than 95% of California rice acreage).[28] It is an annual crop planted in spring and usually harvested beginning in late August and continuing through early November depending on when rains begin. Rice is harvested with combine harvesters that employ either a cutting or stripping type header device with a thresher and grain cleaning system all in a mobile machine. Separated grain is transferred to auxiliary vehicles (bank-out wagons) for delivery to road-trucks at the edge of the field while straw and stubble are left in the field. Newly introduced stripper-headers do not cut the stem but instead pull the grain from the panicle. The material other than grain passing through the combine is therefore greatly reduced, but these headers can only be employed where there is little or no lodging of the crop (collapse of the stem). Grain yield is 4 to 5 tons/acre of rough rice (with hull, 14% moisture content wet basis). The harvestable straw and stubble biomass

28. From the California Department of Food and Agriculture 2001 Annual Crop Report.

left in the field varies from 2 to 4 tons/acre dry weight. Approximately 1.5 million dry tons of rice straw is produced annually in California.

Historically, the straw and stubble were burned in the field in the fall and spring before planting. This was primarily due to cost and convenience, though some amount of disease control took place by burning. Now apparent is the advantage that burning had on weed control as well compared with incorporation of straw into the soil. In 1991, AB 1378 mandated reductions of permitted open field burning of rice straw. Allowable burnable acres decreased to a maximum of 25% of planted acres and only if burning is required for disease control. The reduction in open burning has created a need for off-field utilization of straw alternatives for the industry. Straw harvesting for off-field utilization also has advantages over soil incorporation in disease and weed control (similar to open burning), and in reducing greenhouse gas (methane, nitrous oxide [N_2O]) emissions from rice fields.

Markets for straw are currently limited, and although a number of industrial uses for straw have attempted to develop (e.g., fiber-board, ethanol and other chemicals, refined animal feeds), economics remain challenging. Limited quantities (20,000 to 30,000 tons per year) are being used for animal feeding and erosion control products (bales, plastic net-wrapped wattles).

Straw Fuel Issues

Straw fuels have proved to be extremely difficult to burn in most combustion furnaces, especially those designed for power generation. None of the biomass power plants built to date in California can economically fire straw, even though some were built with air permits requiring them to do so.

Issues concerning the use of rice straw and other herbaceous biomass for power generation have been widely discussed in the literature, and have been the focus of a number of research investigations. From a technical perspective, the most significant problem in the use of straw in combustion or other thermal conversion systems is that of managing ash fouling, slagging, and, in fluidized beds, agglomeration resulting from inorganic transformations and vapor/liquid formation at the temperatures occurring in biomass furnaces (Baxter 1993; Salour et al. 1993; Jenkins 1993; Jenkins 1998). The combustion of straw in power boilers leads to the rapid formation of unmanageable deposits on heat transfer surfaces (especially cross-flow screen tubes and superheaters). These deposits, comprised of alkali and alkaline earth chlorides, sulfates, carbonates, and complex silicates, retard heat transfer and are associated with accelerated corrosion of tube metal (Jenkins 1996). Deposits can bridge across tube bundles, reducing furnace gas flow or increasing fan work required to maintain flow. High ash content and low ash fusion temperature of rice straw result in slag formation in the furnace and grates, hindering fuel feeding, combustion, ash removal and handling.

The addition of rice straw to wood was shown[29] to reduce the alkali volatilization from wood, such that fuel blending may be useful as a fouling control technique when properly applied. Further investigation into this aspect of straw combustion is currently ongoing, and the relative advantages of the several approaches need to be established.

Leaching of alkali elements and chlorine from straw by rain-washing or other water washing methods has been demonstrated to substantially improve the fuel value of straw and other high-alkali biomass. Full-scale tests have demonstrated the technical feasibility of using leached rice straw in existing grate, suspension, and fluidized bed boilers in California (Jenkins 1997; Jenkins and Williams et al. 1999). However, handling costs to feed straw into existing boilers remain high and grinding and other processing requirements lead to the emission of fugitive dust, accelerated wear rates on fuel yard equipment, increased parasitic loads, and possible reductions in net power plant capacity (Jenkins and Bakker et al. 2000). Rain-washing by leaving the straw in the field over the winter is possible but leads to scheduling and timeliness difficulties for planting the next rice crop due to the limited predictability of the weather. Problems with straw use in what are essentially wood-based combustion design concepts has so far excluded this resource from contributing to renewable power generation in California.

Straw Fueled Power Generation in Europe

Europe, and in particular, Denmark, currently has the greatest experience with straw fired power and CHP plants. In 1990, Denmark embarked on a new energy policy with a goal to double the use of renewable energy by the year 2005 (Nikolaisen et al. 1992). A large component of the Danish effort is directed at utilizing surplus cereal straw for heat and power. By 1995, there were 61 straw fired plants with a total capacity of 230 MW (including CHP) consuming 286,000 metric tons of straw annually (Larsen and Evald 1996). In 1998, some 400,000 metric tons of straw were consumed for energy heat and power. By 2001, 750,000 metric tons per year were being consumed in power plants (in addition to straw consumed in more than 60 district heating plants in the country) (Schultz 2001). Technology developed includes combustion furnaces and boilers purportedly capable of operating with high alkali fuels and having handling systems which minimize fuel preparation. Much of this development has occurred with support of government policies on CO_2 emission reductions to help meet Kyoto agreements. Table 1-24 lists power plants developed in Denmark for firing straw. Some are part of CHP systems and others generate power only. Recently completed facilities in England and Spain were designed and built by the companies that developed the systems in Denmark.

The plants at Haslev, Slagelse, and Rudkøbing were developed in the late 1980s and are among the first modern plants in the world to fire straw on a grate. Straw was historically used as a fuel for stationary threshers but was abandoned with the advent of liquid fueled engines towards the beginning of the previous century. The Danish boilers

29. Thy et al. 2000.

apply a classical superheater design (superheater tubes oriented perpendicular to furnace gas flow, generally pendant designs in existing California facilities), where deposition and problems related to corrosion was experienced. They are still running and still experience problems with deposition and corrosion in case the steam temperature is raised above 520°C. Operational experience has determined that the maximum allowable steam temperature is 480°C for avoiding corrosion (Frandsen 2003).

Haslev

Haslev burns whole bales which are pushed into boiler by other bales on the feed conveyors ("cigar burner"). Combustion takes place on the surface of the front bales with high velocity air injected in the region to encourage stable combustion. Full load fuel input is 5,500 kg/h corresponding to 23 MWth (15.05 MJ/kg) (Jensen et al. 1997).

Slagelse

Slagelse burns straw on a moving grate. The bales are broken and loose straw is conveyed by nine screws into the boiler (Jensen et al. 1997).

Rudkøbing

Rudkøbing is also a "First Generation" straw plant. It employs a water cooled vibrating grate-straw firing system. Bales are stored and recalled automatically to a bale shredder. Fuel is pushed by hydraulic ram into the boiler. The fuel injection chamber is water cooled to prevent fuel burning while in injection mode. The superheaters are placed horizontally perpendicular to furnace gas flow. Deposition and corrosion studies conducted at this plant were done to understand the steam temperature and deposit/corrosion relationships (Michelsen et al. 1998; Montgomery et al. 2002). Figure 1-27 is a schematic of the Rukøbing facility.

Table 1-24. Large straw-fired power facilities developed in Denmark

Location	Country	Boiler Company	Fuel Type	Straw Consumption (metric t/h)	Wood Fuel Consumption (metric t/h)	Power (net MWe)	Thermal output (MWth)	Reported or Calculated (0.6 capacity factor) Straw Consumption (tonne y^{-1})	Steam Pressure (bar) 92 bar ~ 1300 psi	Steam Temperature (ºC)	Start Date
Haslev	Denmark	Volund (Cigar Burner)	Straw			5	13	25,000	67	450	1989
Rudkøbing	Denmark	FLS miljø (Bioener Aps)	Wheat Straw	3		2.3	7	12,500	60	450	1990
Slagelse	Denmark	Volund, Aalborg Ciserv, BWE	Straw (2/3) and waste(1/3)			11.7 (x2/3)	28 (x2/3)	25,000	67	450	1990
Grenå	Denmark		Straw/Coal (~50% each by energy)	10		18.6 (÷2)	60(÷2)	55,000	92	505	1992
Maabjerg	Denmark	Volund / Ansaldo Volund (Cigar Burner)	Straw and/or wood any combination of the two types	9.5	13			35,000	67	410 /520	1993
Masnedø	Denmark	FLS miljø (Bioener Aps)	Wheat Straw/ with wood chip back-up	8.3	3.3	8.3	20.8	40,000	92	522	1995
Aabenraa (Ensted EV 3)	Denmark	FLS miljø (Bioener Aps)	Wheat Straw/wood superheat	20	5.6	37.5		104,000	180 or 210	542	1997
Maribo-Sakskøbing	Denmark	FLS miljø (Bioener Aps)	Wheat Straw	8.1		9.7	20	40,000	92	542	2002
Ely (Cambridge)	UK	FLS miljø (Bioener Aps)	Straw	26.3		38	Dedicated power	136,760	92	522	2002
Sangüesa	Spain	FLS miljø (Bioener Aps)	Straw	20		25		104,000	92	542	2002
Avedore	Denmark		Straw/wood	25		45		130,000	300	?	2002

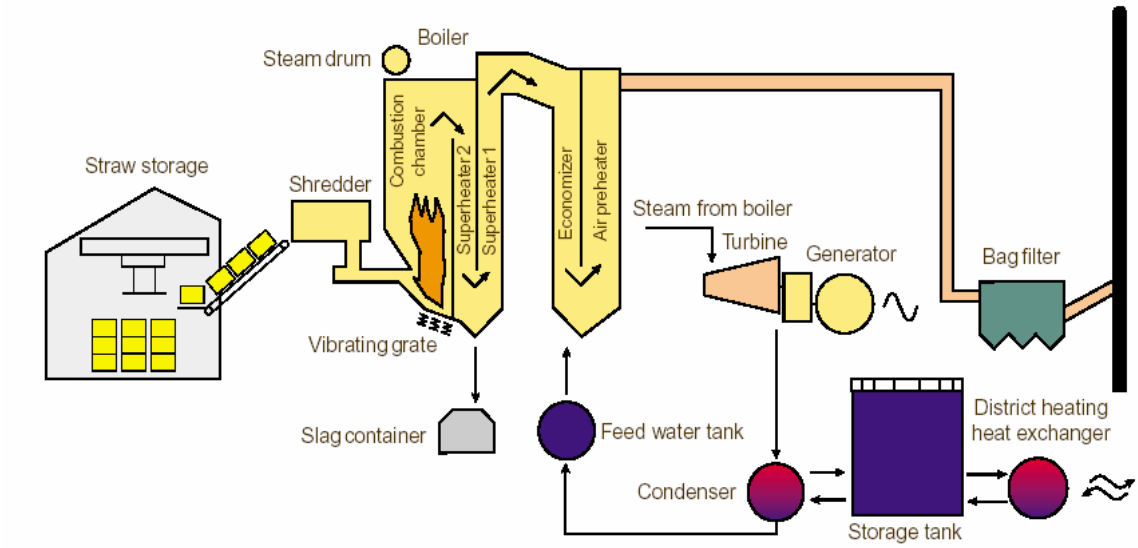

Figure 1-27. Schematic of facility at Rudkøbing, Denmark

Masnedø

The Masnedø Combined Heat and Power Plant CHP is a 33MWth unit (fuel feed rate) producing 8 MW electricity and 21 MWth for district heating. The boiler is stoker-fired with a water cooled vibration grate (Figure 1-28). Straw is the primary fuel, but wood chips are occasionally burned. The straw is conveyed into the boiler by two screw feeders, which receive straw from two separate straw shredders. The straw first lands on a primary (stationary) grate, where the fuel begins to pyrolyze and flaming occurs. The burning straw is pushed and falls off the primary grate onto the water cooled vibrating grate where it burns out as it moves across the bottom of the furnace and is removed by the ash handling system. The flue gas moves up through the furnace chamber to the superheaters and into the convection pass. The facility was built with a 2,000 bale covered storage (about three days capacity) and the bales are reclaimed from storage and fed to the boiler automatically. The plant is designed such that it can be operated unmanned for 16 hours per day.

Because of experience from the earlier straw-fired plants and a higher steam temperature (520°C compared to 450°C in the earlier designs), corrosion problems were expected. The boiler and superheater sections were designed so that the superheaters can be easily replaced in the event of corrosion. The superheater tubes are oriented parallel to gas flow, and a more corrosion tolerant alloy is used. The facility is not equipped with soot blowers. The parallel heat exchanger configuration reduces fouling, but also reduces convective heat transfer coefficient so requires greater surface area compared with cross-flow heat exchangers. For high-alkali fuels like straw the reduction in fouling has been of advantage.

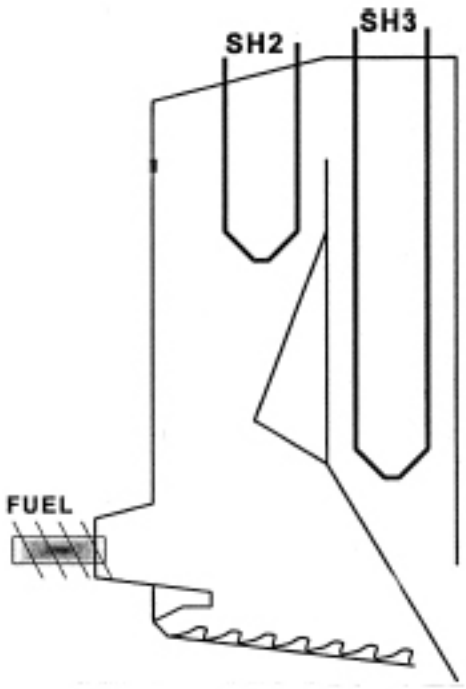

Figure 1-28. Masnedø Boiler
Photo Credit: Adapted from L.A. Hansen et al. 2000

Once the plant had been in operation for a while, measured corrosion rates were much less than anticipated. The reasons for this were investigated (Hansen et al. 2000) by the Technical University of Denmark, which resulted in some interesting findings and a new hypothesis. Previous work had shown that high superheater corrosion rates experienced in straw boilers was due to chlorine which is deposited on superheater surfaces by condensation of gaseous potassium chloride (KCl)[30] (Sander 1997). However, at Masnedø, it was found that mature deposits (less than one year old) did not have the characteristic potassium chloride (KCl) layer against the metal surface, rather a thin non-porous layer of potassium sulfate was observed as the innermost layer of the deposit. On top of the inner layer was typical KCl and K, Ca-silicate material with sintered fly ash particles deposited last. Short term (8 to 100 hours) deposit probes, however, did show the beginnings of the more typical KCl inner deposit layer. Hansen postulates that gaseous sulfite reacts with liquid KCl (known to be present and liquid at the superheater metal temperature) forming potassium sulfate, which is thermodynamically favored at the tube surface temperature. The sulfated potassium layer was found to be non-porous and disfavors chlorine diffusion to the metal surface. Sulfation of surface deposits is also known to lead to higher tenacity due to the greater compaction and bonding in the deposit.

One of Hansen's co-authors indicates that the results of the investigation changed operational procedures at the Masnedø and the Maribo-Sakskøbing plants such that when new

30. Potassium and chlorine are typically present in Danish straw in amounts of 1% and 0.4%, respectively, dry weight basis.

superheaters are installed, the straw is co-fired for a time with a heavy oil to insure the sulfation of KCl in contact with the fresh tube metal to potassium sulfate (Frandsen 2003). Thereafter, "a thick deposit is encouraged." Although this technique may reduce corrosion, the design needs to incorporate a larger surface area of heat exchange due to the reduced thermal conductivity from the deposit.

Aabenraa (Ensted EV3)

Aabenraa has a biomass boiler which raises steam for supplementing the steam produced by an existing coal heat and power station. Wood and straw are fired in two different sections of the biomass portion of the facility (sometimes referred to as a "combination boiler"). See Figure 1-29. The straw boiler produces 470°C steam which is then heated to 542°C by heat from the wood fired boiler. The combustion products from the straw section are not allowed to contact the final superheater in this "combination" arrangement. This design allows the alkali and chlorine containing straw fuel to be fired with minor deposit and corrosion problems (Montgomery et al. 2002) because of the lower steam temperature in the straw boiler. The steam raised by the biomass fuels combines with that from the coal boiler and then expands through the turbine. The electrical conversion efficiency of the biomass portion is essentially equivalent to the overall plant. The efficiency is claimed to be 40% (Lower Heating Value [LHV]).

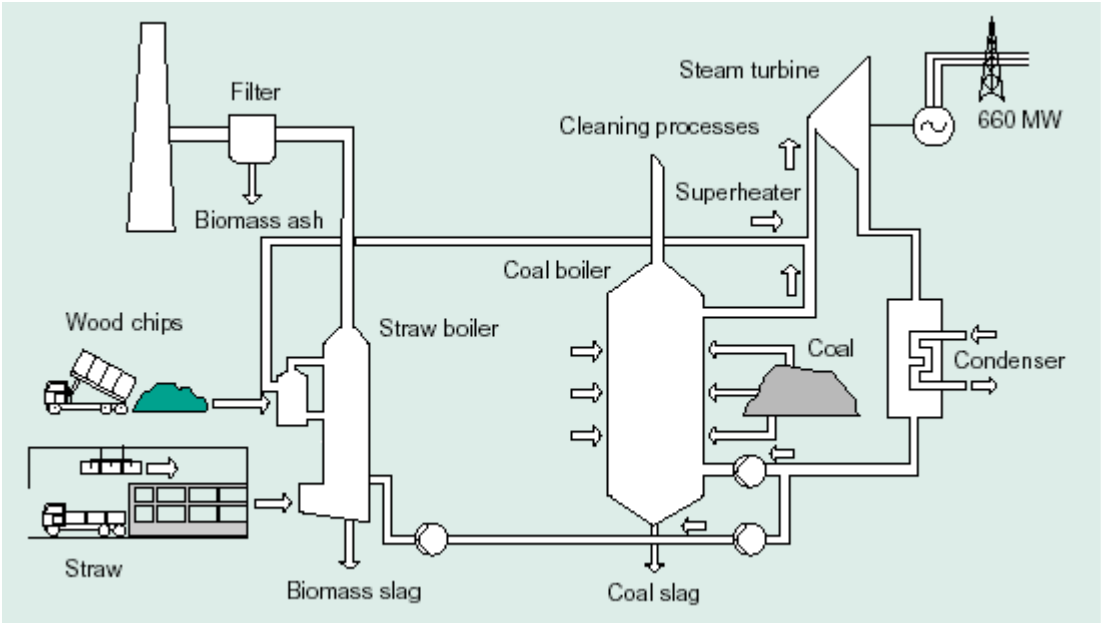

Figure 1-29. Schematic of Aabenraa Power Station

Photo Credit: Adapted from CADDET Technical Brochure No. 139, http://www.caddet-re.org/assets/no139.pdf

Maabjerg

This facility has three boilers, two fired by MSW, and one fired with straw and wood chips. Each of the boilers produces 410°C steam (Figure 1-30). Natural gas is fired for the final superheater (52°C steam temperature), which is located in a separate chamber where it does not

receive the biomass combustion products. Six "cigar burners" arranged three each on opposing sides of the boiler, allow for six bales to be burned simultaneously.

Maximum straw consumption is 9,500 kg/h, or about 19 bales/hr, but averages something less because of co-firing with wood.[31]

31. From H.H. Jakobsen's "Cofiring of Biomass-Evaluation of Fuel Procurement and Handling in Selected Existing Plants and Exchange of Information, Maabjerg Plant (Cofiring-Part 2)," dk-TEKNIK Energy & Environment.

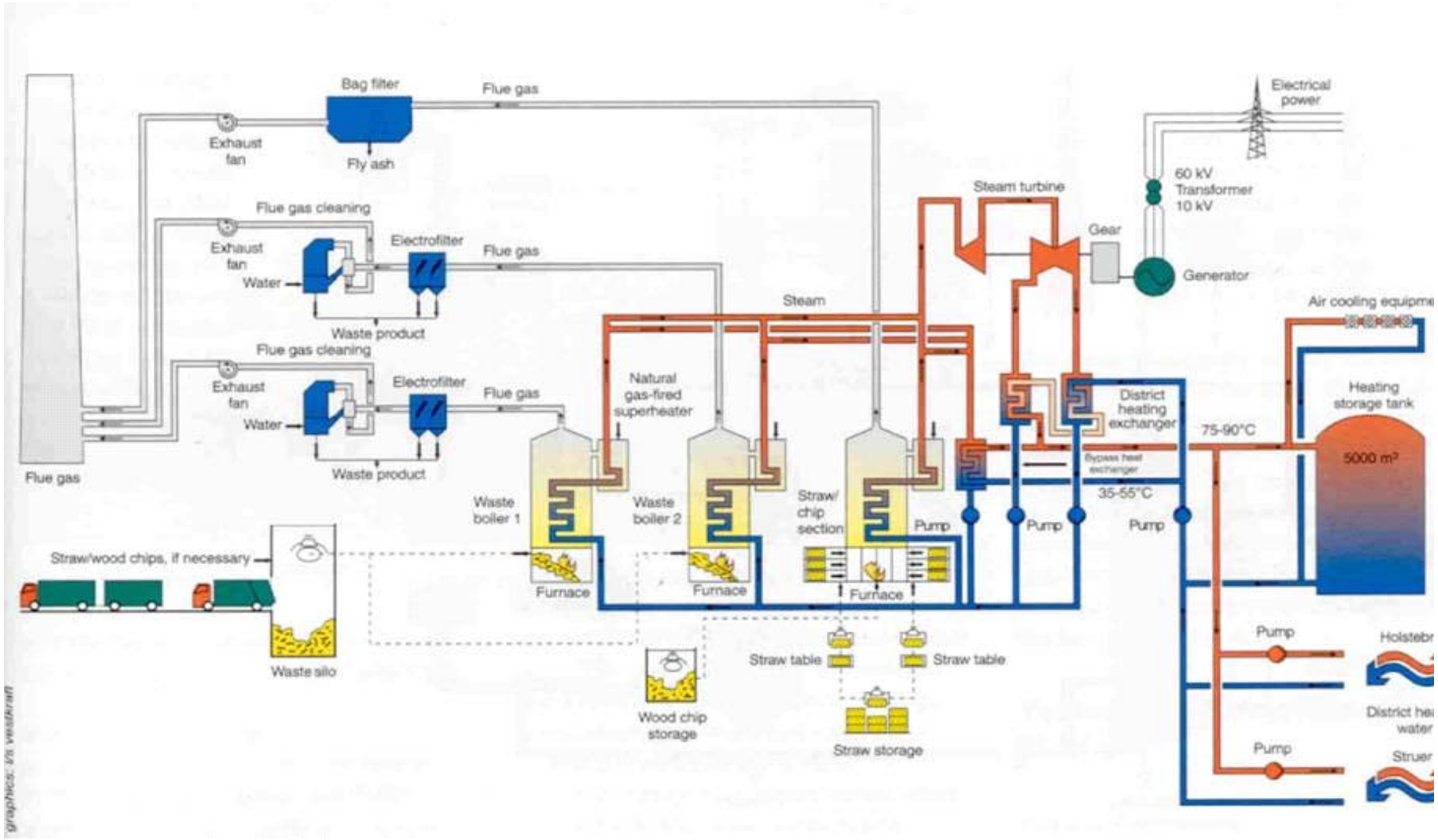

Figure 1-30. Schematic of Maabjerg facility

Avedore, Denmark

Avedore Unit 2 is a recently commissioned large combined heat and power plant. Its maximum capacity is 570 MW (when supplying no district heat) or 485 MW and 570 MWth in CHP mode. It has a large combustion boiler fuelled with natural gas and fuel oil, a set of gas turbines (in combined cycle with the steam cycle) and a biomass boiler that fires straw and wood. The biomass boiler contributes 47 MW to the plant output. The plant raises ultra-supercritical steam (300 bar, 600 °C) and has very high overall efficiency (reportedly 45 to 50% based on LHV). The steam temperature in the biomass boiler does not reach the final superheated value (again because of fouling issues). The biomass boiler steam continues to the fossil fuel boiler for final heating. See Figure 1-31.

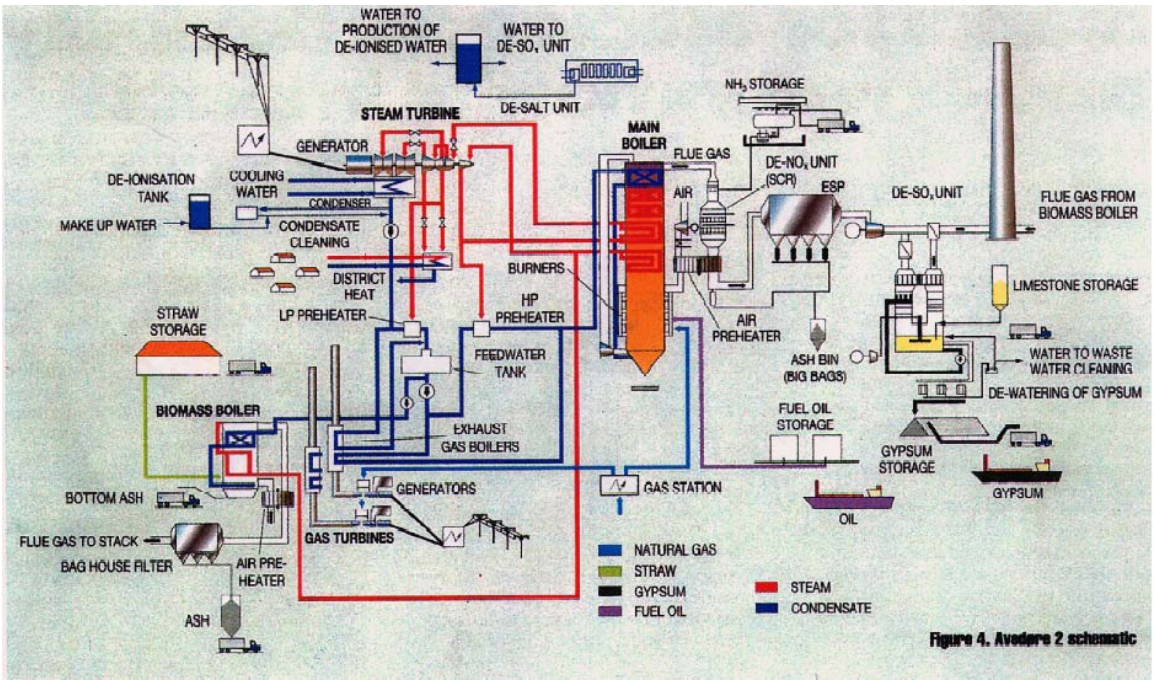

Figure 1-31. Avedore facility schematic.

Photo Credit: Adapted from Manczyk and Leach 2001.

Ely (Cambridge), England, and Sangüesa, Spain

There are two straw fired facilities recently commissioned outside of Denmark. Located in the England and Spain, they were designed and built by the Danish company (formerly FLS miljø). The England Ely plant is the largest straw-fired facility in the world (according to Bioener, ApS) consuming on the order of 150,000 to 200,000 metric tons per year. The facility uses natural gas as a stabilization fuel in the amount up to 10% total energy input. It produces only power (does not operate in CHP mode) reportedly with a capacity of 36 to 38 MW at an availability estimated at about 80%.

There are four separate whole bale fuel feed lines running into the single furnace. Bales are shredded before being injected into the boiler. The boiler uses a FLS miljø vibrating grate.

Others investigated the bale and straw handling and feeding systems at Ely for potential application to co-fire switchgrass with coal at the Ottumwa generating station in Chillicothe, Iowa (Miles and Ganz 2002). Their discussions at Ely yielded the following information:

- The capital cost was approximately $88 million (about $2,300/kW-gross installed).
- The facility is paid $0.0855/kWh.
- The plant is operated by the Danish builder, which guarantees 96% availability over 350 days.
- The company pays $31 to $42/ton for delivered straw, 80% within a radius of 55 miles from the plant, and 20% comes from a radius of 55 to 150 miles.
- The company was considering growing dedicated energy crops (switchgrass or miscanthus) to increase fuel supply.
- The plant has been operating since 2000 consuming about 22 tons/hr local cereal straw.

The Miles and Ganz (2002) report contains the following;

> "Bioener says its largest straw fired plant in world (at commissioning date). Miles' trip report discusses this plant and includes some contact info. Plant cost $88 M US to build (~$2,300/kWgross installed) and can sell power for $.0855/kWh). At 93% availability for 350 days, corresponds to ~$24.8 M receipts from electricity. 'Elean Power station'
>
> The Sangüesa, Spain facility is a 25 MWe dedicated power facility. A decentralized fuel storage concept was chosen in which straw is delivered from a set of regional storage sites. There is onsite storage sufficient to run the plant for approximately three days. The capital cost was approximately $59 million (~$2,360/kW)."

Both Ely and Sangüesa have high steam temperatures (520 to 540°C). The Ely boiler does not utilize a separate fuel for final superheat (combination boiler mentioned above). Specific boiler details could not be confirmed for Sangüesa, so it is not known whether it is a "combination boiler."

Grenå and Studstrupværket, Denmark

Both of these facilities co-fire straw with pulverized coal. Grenå is a circulating fluidized bed (CFB) boiler and Studstrupværket is a wall-fired suspension boiler. Frandsen

indicates that fouling and corrosion at these facilities is no worse than that experienced at 100% coal fired facilities (Frandsen 2003).

Straw handling and preparation for boiler

A variety of methods are employed by the Danish plants (and the two newest facilities in England and Spain)[32] to prepare straw for combustion. Most use automated truck unloading bridge cranes that clamp up to 12 bales at a time (Hesston type 4x4x8 feet) and stack them four to five bales high in covered storage (see Figures 1-32 and 1-33). The same bridge crane is used to reclaim bales from the stack and place them on conveying chains or carts which carry the bales out of the storage barn to the boiler house (Figures 1-34 to 1-37 show various images of bale handling systems). Bale moisture is measured by a microwave based system integral to the bale clamp mechanism (Figure 1-34). Fuel suppliers are paid based partly on the moisture content of the baled straw and bales that are received with too much moisture cannot be stacked or stored in the bale house because of potential for heating from microbial action leading to spontaneous bale and stack fires.

Figure 1-32. Bridge crane unloading trailers
Photo Credit: Miles and Ganz, 2002

Figure 1-33. Crane moving bales to storage

Some systems feed whole bales into the boiler. Probably the best known whole bale feeder is the "Vølund cigar feeding" concept, originally applied by Vølund (now Babcock and Wilcox-Vølund) (Koch 1997). Whole bales are pushed into the combustion chamber and the straw burned off the face of the bale. Some effort has gone into understanding the burning behavior of straw in bales, and improving the power density (Bech and Wolff 1995; Wolff and Bech 1995; Bech et al. 1996). However, the newer

32. Automatic straw bale handling systems are provided by Seelen A/S, http://www.seelen.dk/, a Danish automatic logistics and conveyor company. They have installed a straw handling system at a straw particle board factory in Manitoba, Canada.

Danish plants have moved away from whole-bale systems to shredded straw feed for higher efficiency. Bale feeders still have advantages in reducing overall handling.

Figure 1-34. Bale crane with moisture sensing

Figure 1-35. Conveyance to boiler house

Figure 1-36. Twine cutter-remover*
Photo Credit: Miles and Ganz 2002

Figure 1-37. Twin vertical screw de-baler

Other feed systems remove bale twine and shred or scarify the bales with loose straw being conveyed into the boiler by augers or counter rotating screws. Low speed hydraulic rams are also employed to push loose straw which has filled the exposed chamber when the ram is retracted. Many of these feeder systems employ water cooled sections so that heat from the boiler does not transfer into the straw loading chambers and begin pyrolysis or ignite the fuel.

For pulverized coal co-firing, the straw usually needs to be ground or cut to small sizes in order to burn completely within relatively short residence times (suspension fired systems) or to feed and mix upon injection with bed media in fluidized bed systems.

1.4.5 Systems for Conversion of MSW

A large and concentrated source of biomass is in the MSW stream. Advantages of this source are that it currently is delivered to central locations and it usually comes with a tipping fee or a charge the receiving facility imposes on the sender of the material. MSW is not without disadvantages. It is typically very heterogeneous, coming in a large range of particle sizes, moisture, and component characteristics. MSW and various fractions are burned in combustion facilities for conversion to energy in all parts of the world. It is estimated that 130 million tons annually are converted to energy in over 600 facilities worldwide. There are approximately 90 facilities in the United States currently burning MSW for energy recovery (about two-thirds of them on the East Coast) consuming 29 million tons of MSW annually (Themelis 2003). In California there are three operating power plants that consume MSW as the primary fuel with a combined generating capacity of approximately 65 MW (one facility is in Stanislaus County and two are in the Los Angeles area).

Chlorinated organic compounds, especially polychlorinated dibenzo-p-dioxins and dibenzofurans (PCDD/F) have been linked to combustion of MSW. In the late 1980s, combustion of MSW was listed as the leading source of dioxin emissions in the country (about 60% of total) Maximum available control technology (MACT) regulations promulgated by the U.S. EPA in 1995 forced the industry to retrofit with better emission control technologies where possible and shutdown facilities that could not be improved. Today, the level of dioxin air emissions from combustion of MSW in the United States has decreased from 8,900 grams toxic equivalent (TEQ) per year in 1987 to 12 g TEQ per year by 2000, a decrease of 99.9 %.[33] Dioxin emissions in the United States from all sources are now nearly an order of magnitude less (from 14,000 g toxic equivalent (TEQ) to 2,000 g TEQ) and solid waste combustion is responsible for less than 1% of the total.[34]

Though polychlorinated dibenzodioxin and dibenzofuran (PCDD/F) emissions have declined considerably due to improved combustion and air pollution control systems, public perceptions that unacceptable dioxin emissions are linked to solid waste combustion remains strong. Opponents of burning solid waste have influence with policy and decision makers and the public so that siting new facilities can be difficult. In California, current law (AB 2770) discourages solid waste combustion by not allowing material sent to new combustion facilities to be counted as diversion from landfill. The legislation also directs CIWMB to investigate and evaluate non-combustion conversion technologies suitable for post-recycled MSW. UC Davis (Department of Biological and Agricultural Engineering) conducted a preliminary investigation (Phase I) to identify (Williams et al. 2003) existing and near-term commercial technologies that may be suitable for the MSW stream. Recently, UC Davis and UC Riverside have completed a

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33. U.S. EPA Docket A-90-45, VIII. B.11 and USEPA Dioxin Source Inventory 2002. http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=20797
34. USEPA Dioxin Source Inventory 2002.

more detailed analysis and evaluation of the identified technologies and systems. Much of the information in this section was developed in the Phase I study.

Europe and Japan by far outrank North America in terms of numbers of installations using non-combustion thermal or biological MSW conversion. Europe's efforts have been motivated by higher landfill costs related to less available land and restrictions on material sent to landfill, greenhouse gas reduction goals, and producer responsibility requirements to recycle or reuse product waste. In Germany for example, carbon and energy limits have been set on disposed material. Material going to landfill is restricted to total organic carbon (TOC) of less than or equal to 18%, and energy content less than or equal to 6,000 kJ/kg (Ludwig 2003).[35] In order to reduce green house gas emissions in attempts to comply with the Kyoto Protocol, the European Union is implementing strategies which include increased use of energy produced from renewable sources. The European Community Directive 2001/77/EC (September 27, 2001) contains definitions for renewable electrical energy sources. Biomass is, of course, a renewable source. The EC Directive includes in the definition of biomass: "the biodegradable fraction of industrial and municipal waste"[36] (although this definition appears overly restrictive depending in turn on the definition of "biodegradable" that may discount some fraction of biomass). The Directive also advises that of the electricity produced by facilities that consume both renewable and non-renewable feedstocks, only that portion attributable to the renewable energy source is considered renewable electricity.[37] Electricity and heat from the organic portion of MSW is considered renewable in the Netherlands (Junginger 2004) and Switzerland. Currently, that fraction in Switzerland is 50%, based on a recent feedstock characterization for MSW combustion facilities (Ludwig 2003a). By comparison, the Sacramento resource is about 60 to 70% biomass (Table 1-5) if the characterization studies are accurate.

In Japan there are additional motives for improving upon alternatives to landfill. Japan's lack of significant domestic (traditional fossil) energy resources in combination with very limited space for landfills has led to the development of a large solid waste combustion for energy industry. Approximately 75% of the solid waste in Japan is converted in combustion facilities (Heermann et al. 2001). Environmental issues related to emissions from the waste combustion facilities and leaching problems from the generated ash caused the Japanese government to investigate and invest in better air pollution control technologies and methods to stabilize the ash. The Japanese Environmental Agency estimates that dioxin emissions in 1998 were reduced by 70% from 1997 levels, and legislation required 2002 emissions to be only 10% of the 1997 levels. A range of processes have been developed through this effort in Japan including high temperature gasification (oxygen blown or plasma arc) with ash melting and specific plasma arc systems for melting ash from MSW combustion facilities. Europe is

35. California average disposed MSW stream has HHV about 10,800 kJ/kg (Williams et al. 2003).
36. Directive 2001/77/EC, September 27, 2001. Article 2(b), http://europa.eu.int/eur-lex/pri/en/oj/dat/2001/I_283/I_28320011027en00330040.pdf
37. Directive 2001/77/EC, September 27, 2001. Article 2(c).

beginning to employ a range of thermochemical conversion methods (Table 1-25), and has made great progress with large biochemical conversion facilities (Table 1-26).

MSW Conversion Technology Database

A large part of the effort of the Phase I California MSW project mentioned above was the compilation of a current database of companies, institutions, and organizations with activity or interest in conversion technology suitable for MSW. Entities involved in any type of conversion with the exception of incineration and using either the whole or separated fractions of MSW were actively searched. Incineration (mass-burn) processes were specifically excluded in the contract due to existing legislative constraints. Some of the combustion technology suppliers as well as some firms not currently involved in MSW conversion (e.g., biomass conversion companies) are included because there is potential to apply their technologies to conversion of MSW by non-combustion means.

Also, some ancillary technology companies or institutions, such as MRF, handling and separation, IEA Bioenergy and MSW task forces, and industrial organizations are included because of relevance. The database is available through the internet at http://cbc1.engr.ucdavis.edu/conv/home.htm

The database contains a comprehensive list of companies, institutions, and related organizations with recent interest and activity in MSW conversion. The records that form the database contain varying amounts of information, from perhaps just a name of a company or person to fully developed notes and process descriptions, contact information, and some assessment of status.

Verification of status and detailed process descriptions and/or explanatory notes are missing for many of the records due to insufficient or unqualified information from suppliers. Validation will require substantial additional effort. The current ongoing Phase II effort includes an industry survey using the records from the database. The survey results and a portion of the evaluation component will support further database development.

Tables 1-25 and 1-26 list companies in the database that were identified as having MSW conversion facilities that are (1) currently operating commercially, (2) commercial scale demonstrations, (3) reportedly in commissioning, or (4) under construction. Table 1-25 lists 16 thermochemical conversion processors while Table 1-26 lists 12 biochemical process companies. Following these two tables are brief descriptions of the processes listed including some information on facility locations, history, and scale. The thermochemical processes are listed first followed by the biochemical processes. All of the thermochemical processes and a majority of the biological processes have the capability to produce power, some better than others.

Table 1-25. Companies using thermochemical conversion methods to process MSW

Company Name	Corp. Headquarters	Process Name	Process Type
Hitachi Metals Environmental Systems	Yoshii, Japan	-	Gasification (plasma arc)
Ebara/Alstom	France-Switzld-Japan	TwinRec & EUP	Gasification
Brightstar Environmental	Queensland, Australia	SWERF	Pyrolysis w/ Char gasification
Eco-Waste Solutions	Burlington Ontario	EWOX	Gasification
Enerkem	Sherbrooke, Quebec	BIOSYN	Gasification
Environmental Waste International	Ajax, Ontario	-	Pyrolysis (microwave heat)
Foster Wheeler Energia Oy	Finland	-	Gasification
Nippon Steel	Tokyo, Japan	Waste Melting	Gasification
PKA	Aalen, Germany	-	Pyrolysis w/ char gasification
SVZ	Schwarze Pumpe, Germany	-	Gasification
Thermoselect	Locarno, Switzerland	HTR	Gasification/pyrolysis
Thide Environmental	Bretonneux, France	Arthelyze	Pyrolysis
TPS	Nyköping, Sweden	-	Gasification
WasteGen UK	UK	-	Pyrolysis
IES	Romoland, CA	-	Pyrolysis
Plastic Energy LLC	Roseville, CA	-	Pyrolysis w/catalytic cracking

Table 1-26. Companies using biochemical conversion methods to process MSW

Company Name	Corp. Headquarters	Process Name	Process Type
Valorga	Montpellier, France	Valorga	Anaerobic Digestion (OS – HS)
Wehrle Werk AG	Emmendingen, Germany	Biopercolat	Anaerobic Digestion (MS-HS)
Wright Environmental Management	Ontario, Canada		In vessel Composting
CiTec	Finland/Sweden	Waasa	Anaerobic Digestion (OS – LS)
Linde-KCA-Dresden	Dresden, Germany		Anaerobic Digestion & composting (MBT)
Kompogas	Glattbrugg, Switzerland	Kompogas	Anaerobic Digestion (OS – HS)
U-plus Umweltservice	Ettlingen, Germany	ISKA	MBT followed by Anaerobic Digestion
Eco Tec	Finland	WABIO	Anaerobic Digestion (OS – LS)
Organic Waste Systems	Gent, Belgium	Dranco	Anaerobic Digestion (OS – HS)
BTA	Munich, Germany	BTA	Anaerobic Digestion (OS or MS – LS)
Arrow Ecology	Haifa, Israel	Arrow Bio	Anaerobic Digestion (MS – IS)
Masada Resource Group	Birmingham, Alabama	CES Oxynol	Acid Hydrolysis for ethanol production

OS= One Stage
MS = Multi Stage
HS = High Solids
LS= Low Solids
MBT= Mechanical-Biological Treatment

Thermochemical MSW Conversion Systems

Hitachi Metals Environmental Systems Company (Yoshii, Japan): Plasma Arc Gasification/melting of MSW (commercial/commercial scale demonstration)

After demonstration of the gasification technology for MSW at the pilot plant in Yoshii, Japan during 1999 and 2000, the Japanese government certified the technology for construction of a commercial size plant. A consortium called Eco Valley Utashinai, was formed by Hitachi Ltd., Hitachi Metals Ltd., Hokaido Prefecture, and the Utashinai City. The plant was completed in July 2002. This new plant uses primarily automobile shredder residue (ASR) as fuel with approximately 165 t/day capacity but has been designed to run with a 50% mixture of MSW. It can also process approximately 300 ton/d of 100% MSW. After commissioning, the plant was released to the customer for commercial operation in April 2003. In December 2002, the twin cities of Mihama and Mikata, Japan commissioned a MSW and sewage sludge treatment plant. Hitachi Metals Ltd. designed and installed this plant. It processes 24 t/day of MSW and 4 t/day of sewage sludge.

The R. W. Beck report for Honolulu (R. W. Beck 2003) indicates Hitachi and Westinghouse Plasma were co-developers of a MSW conversion plant in Yoshii, Japan. This ran at a scale of 166 ton/d so it can be considered commercial scale demonstration.

Electricity Potential From Plasma Arc Gasification of MSW

Plasma gasification facilities require a large amount electricity to operate the plasma torch. The Resorption Canada Ltd. (RCL) Plasma website[38] discusses material and energy flows for the plasma gasification process. RCL indicates that 704 kWh (about 2500 MJ) of electrical energy is required to process 1 metric ton (wet basis) of MSW. The RCL process analysis assumes the energy content of waste material used in their process is 10,900 MJ/ton.

The 2500 MJ required to gasify or pyrolyze MSW in a plasma system is for the most part energy that would be required to gasify/pyrolyze the material by other technologies (up- or downdraft or Circulating Fluidized Bed (CFB) gasifiers, or indirectly heated pyrolyzers or example). While these processes use part of the product gas to provide thermal energy by burning (internally for gasifiers, externally for pyrolyzers), the plasma arc system uses "high quality" electrical energy to create the heat for the reaction. Efficiency of electrical generation is about 30% for fuel burned in a gas engine (or large steam cycle, or California grid average electricity). This electrical energy used by the plasma torch requires about three times that amount in primary energy.

From energy flow data from the RCL Plasma website, net electrical production (or efficiency) from a plasma gasification facility (consuming MSW), is only about 7 to 10% based on the energy in the incoming feed and assuming Rankine steam cycle or reciprocating gas engine for power production (with producer gas to electricity conversion efficiencies of about 30%). See Table 1-27 below.

A report on new waste disposal systems for the City and County of Honolulu that reviewed plasma gasification of solid waste states that 900 kWh electricity (3240 MJ) can be produced per ton of refuse processed, but only 300 kWh (1080 MJ) would be available for export to the grid. These figures correspond with those from RCL as displayed in Table 1-27.

In comparison, the H-Power MSW combustion facility on Oahu, Hawaii, reportedly produces 534 kWh (1900 MJ) per ton of waste consumed (R. W. Beck 2003). R. W. Beck does not indicate if this is gross or net electrical energy production. Another MSW combustion facility exports to grid 610 kWh (2200 MJ) electricity per ton MSW consumed (overall efficiency of 18% based on 12 MJ/kg HHV of MSW used in facility) (Themelis 2003).

38. Resorption Canada Ltd. (RCL) is a company marketing plasma MSW gasification facilities. http://www.rcl-plasma.com/overview.htm

Table 1-27. Process energy and net electrical energy production per ton of MSW (wet basis) from a plasma arc gasification facility[39]

		Energy per ton MSW (MJ)	
Input	MSW	10900	
	Electricity to torch	2204	
Out puts	Torch loss	362	
	Slag losses	89	
	Vessel losses	60	
	Other losses	1278	
	Non Recoverable losses Total	**(1789)**	
	Gas Sensible Energy	1291	
Producer Gas	Chemical Energy (based on HHV)	10020	
			Recover sensible energy to Electricity (@ 20% eff.)
	Electricity Conversion Efficiency	0.3	
	Recover Gas Sensible Energy	0	258.2
	Electrical Energy Generated	3006	3264.2
	Less Electricity to Torch	2204	2204
	Net Electricity (MJ)	802	1060.2
	Net Conversion Efficiency (%) [Net Elect./MSW energy in]	**7.4**	**9.7**

Adapted from RCL website, http://www.rcl-plasma.com, September 2, 2003

Alstom/Ebara (France, Switzerland and Japan): "TwinRec" and "EUP" processes

Alstom Power (Meudon-la-Foret, France) acquired ABB Enertech in 1999 which had exclusive license of Ebara's (Japan) fluidized bed technology that has several commercial facilities in Japan (Heermann et al. 2001). Ebara builds and operates full MSW combustion facilities in Japan and some other Asian countries. Ebara also has developed the TwinRec and EUP gasification processes through the Japanese initiative to develop more sustainable waste disposal technologies.

TwinRec Process

Ebara has long experience with fluidized bed combustion systems for waste materials. They adapted their bubbling fluidized bed reactor to operate as a gasifier and coupled it

39. Adapted from RCL website, http://www.rcl-plasma.com, September 2, 2003.

with a secondary combustion chamber where the producer gas is burned with the addition of secondary air. This is an atmospheric pressure, air blown process. The larger ash particles along with metal and glass pieces leave the gasifier bed as bottom ash from which the metals can be separated. Smaller ash and char particles are carried over with the producer gas and enter the combustion chamber which operates at high enough temperature to melt the inorganic material carried over. This slag is water quenched which yields vitrified granules. It is possible to grind the bottom ash from the gasifier portion and inject it into the melting combustor (at higher processing and energy expense) to slag essentially all of the inorganic material present in the original feedstock This is the ash melting process used to meet the low leachability requirements for ash from conversion processes in Japan. Table 1-28 shows existing facilities using the TwinRec process.

The following is excerpted from Ebara web site engineering abstracts:[40]

> "Japan's first municipal waste, fluidized-bed, gasification-melting furnace system, equipped with a power recovery steam turbine, has started operation at Sakata City, Japan. The dioxin concentration in the exhaust gas of this system is being controlled to be below the allowable standard and the produced slag is effectively encapsulated and used as pavement material (inter-locking blocks). The exhaust gas from the furnace is used for driving a power recovery turbine (max. output 1990 kW) and excess electricity produced is being sold to the local electricity company."

UEP Process

Ebara and the Ube Industries Ltd. (a plastics and chemical company) developed this UEP process for recycling the chemicals in waste plastic. Based on the TwinRec process, the UEP system uses two pressurized gasifiers in series. The process operates up to 10 atmospheres and is oxygen blown. The first gasifier is essentially the same bubbling fluidized bed as used in TwinRec and runs at a relatively low temperature. The produced gas flows to the second chamber which, as in the TwinRec second reactor, receives secondary oxygen allowing higher temperatures to be reached and slagging inert material. There is still insufficient oxygen for complete conversion of the producer gas. The complete material flow through the second high temperature gasifier (gas and slag) is forced through a water trap which solidifies and captures the inert material. The remaining gas can be used for energy production, liquid fuels production, or chemical feedstocks. Table 1-29 shows existing facilities using the UEP process.

Alstom reportedly (Heermann et al. 2001) markets the Ebara reactor modified to operate as a gasifier and is targeted for higher energy containing fuels (automobile shredder residue, plastics, electronic scrap, tires), but can process other domestic and urban residues. But Ebara (Environmental Engineering Group) also has a Zurich, Switzerland,

40. Review No.197, 2002, http://www.ebara.co.jp/en/

office plainly stating it is the representative for the Ebara TwinRec and UEP processes in Europe.

No Alstom/Ebara European installations were identified, but there are several of the Ebara TwinRec and UEP facilities operating in Japan (See Tables 1-28, 1-29).

Table 1-28. Ebara TwinRec gasification facilities[41]

Location	Commissioning Date	Feedstock	Mass (%)	Scale (t/y)	LHV (MJ/kg)	Thermal Capacity (MW)	Output Elect. (MWe)
Kurobe	Dec, 2000	Automotive Shredder Waste Waste Plastics copper slag + sorbents	41 13 46	22,000	10.2	7.4	
Minami-Shinshu	Mar, 2003	MSW	100	34,000	8.4	2x4.5	
Joetsu City	Mar, 2000	Dry Sludge Waste Plastic	68 32	57,000	12.3	2.2	
Chuno Union	Mar, 2003	MSW	100	61,000	11.3	3x7.3	
Sakata Area	Mar, 2002	MSW	100	72,000	10.9	2x12.3	2
Ube City	Nov, 2002	MSW	100	72,000	12.5	3x9.5	
Nagareyama City	Feb, 2004	MSW	100	75,000	11.7	3x9.3	
Kawaguchi	Nov, 2002	MSW	100	153,000	13	3x21.0	12
Aomori	Feb, 2000	Automotive Shredder Waste Sewage Sludge	70 30	160,000	14.3	2x40	17
Kuala Lumpur Malaysia	May, 2006	MSW	100	548,000	9.6	5x33.3	

Adapted from Ebara Reference List: http://www.ebara.ch/downloads/ebara_Referencelist_TwinRec_100203.pdf

Table 1-29. Ebara UEP pressurized gasification for chemical recycling facilities[42]

41. Adapted from Ebara Reference List: http://www.ebara.ch/downloads/ebara_Referencelist_TwinRec_100203.pdf
42. Adapted from Ebara Reference List: http://www.ebara.ch/downloads/ebara_Referencelist_EUP_0103.pdf

Location	Commissioning Date	Feedstock	Scale (t/y)	Product
Ube City	1999	Waste Plastic	11,000	Fuel gas or feedstock for ammonia production
Ube City	2002	Waste Plastic	24,000	Feedstock for ammonia production
Kawasaki	Expected 2003	Waste Plastic	107,000	Feedstock for ammonia production

Adapted from Ebara Reference List: http://www.ebara.ch/downloads/ebara_Referencelist_EUP_0103.pdf

Solid Waste and Energy Recycling Facility (SWERF) Process

Brightstar Environmental (Queensland, Australia)

Energy Developments Limited (Australia) is the majority owner company of Brightstar Environmental. Brightstar Synfuels (Texas) is a minority holder.

The SWERF process accepts unsorted MSW. The material is first treated in an autoclave (steam and pressure) to create a manageable pulp and reduce odors and pathogens, after which standard material handling/separation equipment removes metals and rigid plastics for recycling or disposal. The remaining pulp is washed to remove sand and glass followed by pulp drying and storage. Energy for drying is provided by exhaust heat.

The core conversion technology consists of two steps, pyrolysis followed by char steam gasification. The synthesis gas is run through reciprocating internal combustion engines for process heat and power for export.

There is a commercial scale (50,000 t/year) demonstration in Wollongong, NSW, Australia, which has been undergoing commissioning since early 2001. There were problems with the char gasification component of the process which caused the parent company Energy Developments Ltd. to cease funding further development and search for a buyer of its portion of the Brightstar Environmental stock (about 88%). The Wollongong City Council announced that the SWERF facility has ceased operation in March 2004 because EDL could not find an international partner to help share the risk. The facility will be used as a municipal recovery facility (MRF) and transfer station.[43] It is not known whether SWERF technology proposals in England and the United States are proceeding.

Eco Waste Oxidizer (EWOX)

43. http://www.wollongong.nsw.gov.au/yourcouncil/mediareleases/index_106.htm, accessed October 17, 2004.

Eco Waste Solutions (Burlington Ontario)

These are relatively small scale systems, sized for 1 to 25 t/day. The process consists of a gasifier followed by burning the producer gas in a controlled combustion chamber. Units typically operate on a 24-hour batch cycle. The material is enclosed in the gasification chamber and then heated (presumably with natural gas or propane) until enough energy is released by the gasification reactions to sustain itself.

Systems are marketed to small scale and/or remote waste producers. Units are installed in Canada, Alaska, Belize, and Hawaii.

Canada's Environmental Technology Verification (ETV) program has verified Eco Waste Solutions' performance claims for both municipal and biomedical waste.

BIOSYN process

Enerkem, Université de Sherbrooke, and Kemestrie Inc. (Sherbrooke, Quebec)

Enerkem Technlogies Inc. is a subsidiary of the Kemestrie Inc. Group, a spin-off company of the Université de Sherbrooke, founded in 1992. It is the sole owner of a technology portfolio resulting from investments begun in 1981 by the Canadian Federal Government as part of its "National Energy Plan," and continued in partnership with the Ministère des Resources Naturelles du Québec, the Centre Québécois de Valorisation de la Biomasse (CQVB), the Université de Sherbrooke and Kemestrie Inc. A principal member of the company is Dr. Esteben Chornet, a member of the staff at NREL[44] and a professor Chemical Engineering at Université de Sherbrooke.[45]

Known as the BIOSYN process, it utilizes a bubbling fluidized bed (BFB) gasifier, with air or oxygen operating at pressures up to 16 atmospheres. The process includes proprietary catalysts for cracking tar and other components in the producer gas. The process is capable of operating on biomass, sorted MSW, and plastics. Enerkem will provide performance guarantees of minimum energy conversion efficiency (solids to conditioned synthesis gas) of 70%[46] as well as composition of the synthesis gas based on the composition of the feedstock

The Poligás plant in Ribesalbes (Castellón), owned by Poligás Ambiente, S.L., and built by Environmental International Engineering, S.L. (EIE) has recently gone into operation. Spain's Institute of Energy Diversification and Efficiency (IDAE), and the waste management company Revima participated in the project. Financing was provided by regional government (Valencia) and European Union funds. The plant is fuelled with discarded plastics wrappings from the ceramics industry. This plant reportedly

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44. http://www.nrel.gov/chemistry_bioenergy/staff_alpha.html#c
45. http://www.usherbrooke.ca/gchimique/personnel/profs/chornet/
46. Note: Energy conversion efficiency for overall process (through to electrical generation) would be about 20% (steam turbine) up to about 30% (large reciprocating internal combustion).

(Enerkem website[47]) is generating 7 MW (80 mmBtu/hour of synthesis gas) from approximately 25,000 metric t/year waste plastic.

In 2002, Enerkem began working with the City of Sherbrooke to convert waste into synthesis gas (BioSyngaz-Estrie project). Federal, provincial, and corporate monies financed the project. The pilot unit was designed and constructed with the capacity to convert 2.5 tons of sorted municipal waste residue per day.

MSW Pilot Plant in Sherbrooke (BioSyngasEstrie Project)

Enerkem, the City of Sherbrooke, and provincial and federal agencies have partnered to build and operate a pilot plant based on the BIOSYN process for sorted MSW. Apparently, the system ran at capacity of 2.5 metric t/day for much of 2002 with technical reports and feasibility studies that should be complete at this time.

Environmental Waste International (Ajax, Ontario)

EWI manufactures and markets systems that use microwave heating to pyrolyze the feedstock in an inert or low oxygen atmosphere. The basic process is pyrolysis with standard volatile gases, tars, and char as the products (relative amounts and compositions are feedstock dependant). Existing installations are used in destruction of medical wastes.

The company does not foresee a market for this technology in non-separated MSW conversion. They are investigating the process with feedstocks such as sludge, non-recyclable plastics, automobile shredder residue, diseased animal carcasses, and used tires. In fact, the company believes the destruction of used tires will be important to future operations due to the potentially valuable pyrolytic products including carbon black, steel, liquid and gaseous hydrocarbons.

Company press releases indicate it has an agreement with a private firm in England to design and build its first facility to pyrolyze waste tires with the microwave heating process. It would be capable of converting 3,000 tires per day.

A material and energy flow diagram on the company website claims that a tire conversion facility that consumes 6,000 tires/day can provide sufficient energy to drive a 6 MW steam turbine (if all pyrolysis oils and gases are burned in a boiler). The magnetrons and balance of plant will consume 3 MW of electrical power leaving 3 MW available for export.

Foster Wheeler Energia Oy (Lahti, Finland)

Foster Wheeler, in cooperation with Kymijärvi Power Station at Lahti, Finland has installed an atmospheric (air blown) circulating fluidized bed (ACFB) gasifier next to the coal/fossil fuel fired utility boiler (see Figure 1-38). Thermal capacity of the gasifier is 40 to 70 MWth depending on the moisture content of the fuel (which can be up to 60%).

47. http://www.enerkem.com/2002/pages_en/main_en1_ns.html

The producer gas from the gasifier is co-fired in the boiler. The ACFB is sized to provide up to 15% of the energy input to the boiler (replacing up to 30% of the coal feed). The lack of gas cleaning limits the fuels to woody biomass and low/no chlorine containing waste-derived fuels (some amount of separation of residential or municipal wastes to remove chlorinated plastics). See Table 1-30 for composition of the refuse derived fuel and Table 1-31 for fuel consumption by type for the years 1998 to 2002. The project demonstrates commercial scale feasibility of close coupled gasification of low quality "opportunity" fuels which otherwise could not be utilized in the combustion boiler.

A municipally owned, waste management company (Päijät-Hämeen Jätehuolto Oy) started the processing of refuse derived fuel in 1997. In the first year of operation, 1998, more than 17,000 tons of residential refuse fuel was gasified accounting for 22% of the energy through the gasifier (the bulk of the gasifier energy came from wood residues-71%).

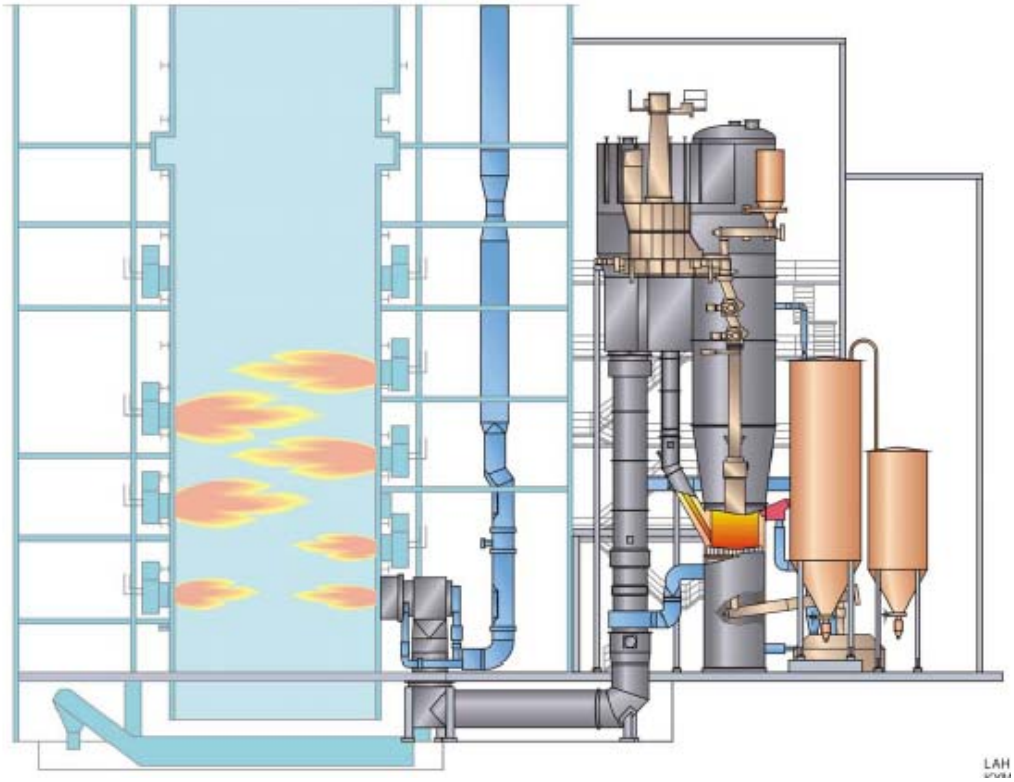

Figure 1-38. Drawing of Lahti gasifier and co-fueled boiler

Photo Credit: Foster Wheeler.

Table 1-30. Composition of refused derived fuel at Lahti[48]

Component	% by weight
Plastic	5-15
Paper	20-40
Cardboard	10-30
Wood	30-60

http://www.fosterwheeler.com/publications/tech_papers/powgen/bagasse3.cfm

Table 1-31. Annual feedstock consumption by type at Lahti gasifier (Foster Wheeler)

	Units	1998	1999	2000	2001	2002	Cumulative Fraction (%)
Biomass	(tons)	56729	60534	57834	71092	58128	61
RDF	(tons)	17578	24426	26622	30457	32178	26
Plastics	(tons)	-	13806	6885	14203	11418	9
Paper	(tons)	-	6372	184	348	2076	1.8
Railway Sleepers	(tons)	4395	106	275	-	-	1.0
Shredded Tires	(tons)	1199	956	-	-	-	0.4
Total		79900	106200	91800	116100	103800	100
Hours of Operation	(hours)	4730	5460	4727	7089	nr	

nr = not reported

48. http://www.fosterwheeler.com/publications/tech_papers/powgen/bagasse3.cfm

Varkaus Finland

Foster Wheeler installed a BFB as part of an integrated recycling process at the Corenso United Oy, a large paper and cardboard/packaging material manufacturer. Used multilayer packaging material (which includes plastic film and aluminum foil layers, for example, Tetrapak aseptic drink containers) is recycled by separating as much of the cellulose material from the plastic and aluminum as possible and then gasifying the remaining plastic and aluminum containing portion in the Foster Wheeler BFB. Aluminum is recovered from bottom ash and the product gas (presumably condensed from vapor form (see Figure 1-39). The aluminum is solidified into ingots and reused. The energy from the gas replaces some of the fossil fuel used to raise process steam. The gasifier is 40 MWth in capacity and recovers about 3,000 t/year of aluminum and gasifies 27,000 t/year of polyethylene. The facility has accumulated over 12,500 hours of operation between commissioning in spring of 2001 and May 2004 (Nieminen 2004).

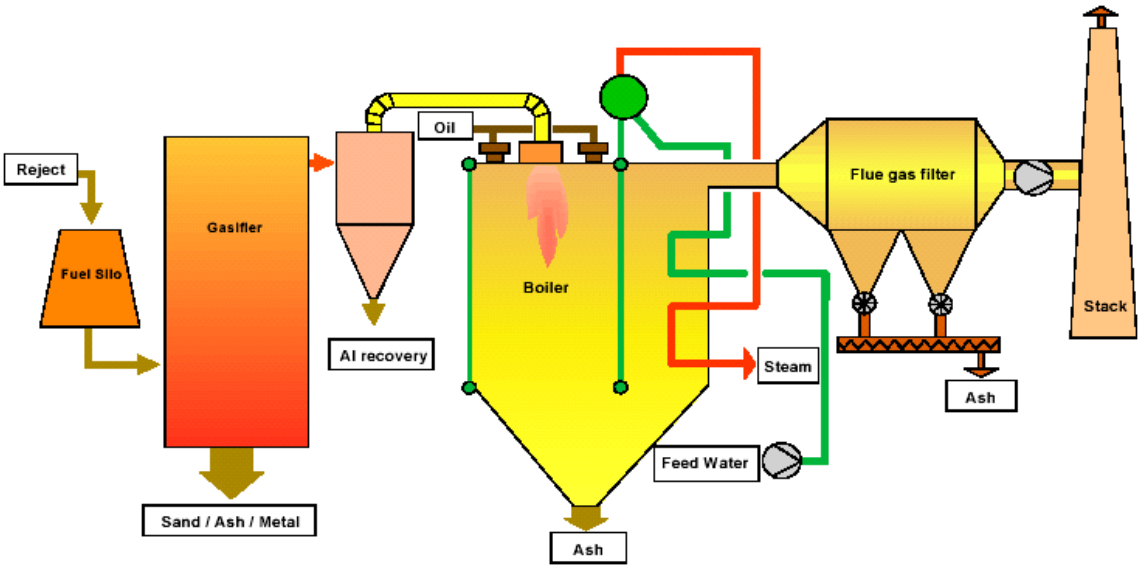

Figure 1-39. Schematic of Varkaus, Finland waste packaging gasifier and aluminum recovery facility

Photo Credit: Foster Wheeler

Nippon Steel (Tokyo, Japan)

Japan generates over 100 million t/year of MSW but has limited available land for disposal. Consequently, much of the waste (75%) (Heermann et al. 2001) is burned in combustion facilities. Concern over high levels of dioxin emissions led the Japanese government to institute programs to address the issue. These programs included tighter emissions limits, investment in more efficient facilities with better emissions control technologies and RDDD of alternatives to MSW combustion.

Results so far appear successful. The Japanese Environment Agency estimates that dioxin emissions in 1998 were reduced by 70% compared to those of 1997. Legislation

was in place to require 2002 emissions to be only 10% of the 1997 levels (Heermann et al. 2001).

One of the RDDD initiatives launched by the Japanese government was the "Technologies for the 21st century" which focused on developing gasification/pyrolysis systems and direct melting of waste. The non-combustion thermal technology thrust is to address the dioxin issue while waste melting programs address ash recycling and disposal problems.

A further motivator for Japan is its lack of significant domestic energy resources. Any energy that can be recovered from conversion of MSW and other solid wastes directly displaces imported coal or petroleum fuels.

Waste Melting Process

The Nippon Steel "Waste Melting Process" evolved from metallurgical processing technology. The process accepts unsorted MSW that has been processed to required particle size. Heermann et al. (2001) report that the Nippon Steel process uses a fixed bed gasifier (not clear if pressurized), with enriched oxygen air injection in the melting section. Coke is added to the MSW (about 50kg/ton MSW or 5% by weight) input feed which reacts with the oxygen and pyrolytic gases at the air injection and melting region. This is apparently done to help provide energy for full ash melting. Limestone is also added (about 5% by weight of input) to provide some pH buffering of the melt. The producer gas is burned in conventional steam boilers from which heat and power can be generated. Output materials include granulated slag (90 kg/ton input), recyclable iron (10 kg/ton input) and fly ash (approximately 30kg/ton input) which is sent to landfill. Mercury and heavy metals present in the waste are found in the fly ash and producer gas, requiring that these streams be managed appropriately before discharge.

There are perhaps a dozen plants (operational or being commissioned) in Japan utilizing the Nippon Steel waste melting process. The capacities range from 100 to 450 t/day.

Nippon Steel is a market leader in large scale MSW conversion applications.

PKA Umwelttecnik (Aalen, Germany)

This is a pyrolysis process followed by gas converter (cracker). MSW feedstock is preprocessed to remove glass, metals, and other marketable recyclables. The remaining material then goes through a size reduction process. Drying to below 15% moisture is recommended, but not mandatory. Other feedstocks that can be utilized with the system include automobile shredder residue (ASR), tires, industrial and plastic waste and contaminated soil.

The preprocessed material is conveyed into a rotary pyrolysis drum that is externally heated to 930 to 1020°F by hot combustion gas (from burning natural gas during start-up, or from burning a portion of the pyrolytic gas that can be recycled if available in sufficient quantity and quality). The feedstock material takes up to one hour to advance

through the drum. The pyrolytic product gases and vapors are then transferred to a gasification chamber where they are cracked to a producer gas at temperatures of 1830˚F, cooled, and cleaned according to the requirements for final use.

The pyrolytic char can be conditioned by grinding and separating out the ferrous and non-ferrous metals. Using a separate smelting reactor, the char fines can be gasified with added oxygen at a temperature between 2550 to 2730˚F to yield additional syngas for combustion and production of a vitrified slag.

A PKA facility in Aalen, Germany, has been operating on a blend of MSW, commercial waste, and sewage sludge since 2001. This unit has a capacity of 28,000 t/year. The facility includes a char/ash melter. PKA has a 31,000 t/year unit installed in Freiberg/Saxony, Germany, where high aluminium content industrial waste is pyrolyzed for recovery of the aluminium. The aluminium is sent to an adjacent melting plant. Pyrolysis gas is used to supply heat for the melting plant. This facility has been operating continuously since the summer of 2001. A 9,000 t/year sewage drying plant has been operating since 1993 in Bopfingen, Germany. A smaller 0.4 t/year facility has also been used for testing since 1994.

The PKA process technology is also licensed to Toshiba Corp. of Japan and is marketed under the name Product en Energie Centrale (PEC) in the Netherlands. PEC reportedly has received approval for a 150,000 t/year facility in Defile, Netherlands, that will have three lines each of 4 t/year capacity. ECN has also operated a similar 25 kW pilot plant since 1997 for testing of various biomass wastes.

SVZ (Sekundärrohstoff-Verwertungszentrum) Schwarze Pumpe, Germany Waste/Biomass

This facility, built to gasify petroleum residues and coal in the mid-1960s now processes MSW and household waste with lesser amounts of petroleum refinery residues and coal. The capacity of the facility is 495,000 ton/year and 55,000 ton/y of solid waste and liquid water/oil residues respectively.[49] A recent survey[50] of gasifiers utilized primarily in the fossil energy sector indicates annual feedstock flows at SVZ are 1.3 ton/y and 190,000 t/year for solid and liquid wastes respectively. The reason for this discrepancy has not been pursued, but material flow rates through this facility are substantial.

The products of the process are electricity (75 MW) and 300 t/day methanol (from all gasifiers and feedstocks).

SVZ claims to process plastics, waste wood, sewage sludge, domestic garbage (combined or source-separated), and other solid wastes. Liquid and slurry waste oils, solvents, paint sludges, etc. are processed as well.

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49. http://www.svz-gmbh.de/GB/Seiten/rahmen.html
50. SFA Pacific for U.S. DOE National Energy Technologies Laboratory (NETL): http://www.netl.doe.gov/coalpower/gasification/models/models.html

There are 10 separate gasifiers in the facility. Seven are "Lurgi Dry Ash" gasifiers, and one each of Lurgi multi-purpose, British Gas-Lurgi, and Noell KRC gasifiers.

The Lurgi (Lurgi Energie, Germany)[51] dry ash gasifier is a pressurized oxygen and steam blown "moving bed" gasifier. Dry ash refers to the condition that ash material does not reach its melting temperature which would produce a liquid slag. Solid feedstock enters the reactor through a lock hopper at the top and moves down through the bed, while oxygen and steam are injected in the bottom and move up counter-currently to the solid fuel. The Lurgi multi-purpose is a pressurized, oxygen blown gasifier and configured for liquid feedstocks.

British Gas-Lurgi fixed bed gasifier is pressurized and oxygen/steam blown similar to the Lurgi dry ash. The difference is the fuel is present as a substantial piled mass in the reactor and slowly moves down as the material in the bottom of the pile reacts and gasifies. Oxygen and steam are injected into the fuel mass with lances and reaction temperatures are allowed to be high enough to melt (or slag) the ash, which drains and is removed from the bottom. Synthesis gas leaves near the top of the reactor.

The Noell–KRC gasifier is an entrained flow gasifier (also pressurized and oxygen blown). The liquid or small-particle fuel is injected at the top of the reactor with oxygen. The falling fuel particles react with the oxygen and heat. Ash slags and runs down the reactor wall. Synthesis gas and slag exit the reaction chamber together through an orifice and are quenched with water condensing some of the tars and creating vitrified ash granules which eventually exit the pressurized vessel through lock hoppers.

Thermoselect (Locarno, Switzerland)

The Thermoselect High Temperature Recycling (HTR) process was commercially demonstrated beginning in Fondotoce, Italy, in 1989. The process uses slow pyrolysis followed by fixed-bed oxygen-blown (atmospheric pressure) gasification and ash melting (Calaminus et al. 1998). Some information indicates natural gas is burned along with a portion of the producer gas to the gasifier for supplemental energy for gasification. This may be due to variability of feedstock character (e.g. moisture, energetic value).

The process accepts unsorted MSW. Waste is loaded into a chamber which is pushed and compacted by hydraulic press and moved (in plug flow fashion) through a cylindrical heating chamber where drying and some pyrolysis occurs. At the end of this horizontal heating/pyrolysis tube, the solid material falls into a high temperature oxygen blown gasifier. Organic material is gasified, and ash is melted and allowed to separate by density before being cooled. Producer gas is cleaned and utilized appropriately. Recyclable metals and vitrified minerals are useable outputs. Gas cleaning creates a sludge containing heavy metals. Heermann et al. (2001) indicate that 23 kg/ton MSW of natural gas is an input. This represents about 12% of the energy contained in 1 metric

51. See Conversion Technology database for Lurgi Energie.

ton of MSW.[52] The synthesis gas can be used for energy production or possible chemicals or liquid fuels.

There is one client owned facility in Europe (Karlsruhe, Germany) and two in Japan. The Karlsruhe facility has been plagued by commissioning problems causing delays in licensing and designing other facilities in Germany. This led to cancellation of some of the European orders. Recent information indicates that the facility is having financial problems and may close (Vehlow 2004). The Japanese facilities seemed to proceed through commissioning more easily, perhaps due to different or better air pollution control systems.

The process is attractive because of minimal or zero feedstock preparation/processing. The reasons for the commission problems in Karlsruhe need to be learned.

A United States Company, Interstate Waste Technologies, is marketing the Thermoselect process in North America and the Caribbean. The website indicates potential projects in Costa Rica, U.S. Virgin Islands, and Puerto Rico (letters of intent, artist conceptual drawings of facilities, etc.)

Thide Environmental (Voisins Le Bretonneux, France)

The Thide "Arthelyse" process is a rotating drum pyrolysis scheme (similar to WasteGen UK, and PKA). Following materials sorting and drying, the material is conveyed into the rotating pyrolysis drum. Residence time is approximately 30 minutes. The synthesis gas is burned to provide the heat for the pyrolyzer and process steam for drying.

Thide seems to be trying to market the solid residue char as a solid fuel for use off-site. The company claims the char can be washed and separated from the metals, other inerts, and soluble salts. Even if char washing is effective, it seems that it would be costly and energy intensive possibly making it unattractive as an offsite solid fuel.

Thide reports that of the solids output (in % of input material mass), 4% is recyclable metal, 10% is ash, and 23% is the washed char.

Hitachi has the license for the process in Japan and there is a small plant located in Nakaminato operating since 1999 (capacity is about 10,000 ton y^{-1}). A larger facility (50,000 ton y^{-1}) is under construction in the town of Arras and was scheduled to debut in 2004.

TPS Termiska Processer AB (Nyköping, Sweden)

TPS is an employee-owned company in Sweden with a fairly long history in gasification and combustion for heat and power fueled by biomass and coal. A large amount of research and development is undertaken by the company from funds provided by the Swedish National Energy Administration, the European Community (various energy

52. Assumes natural gas Higher Heating Value of 55 MJ/kg and MSW HHV of 10 MJ/kg.

agencies), as well as private companies. TPS specializes in fluidized bed, both circulating (CFB) and bubbling (BFB) types, operating in combustion or gasification modes. Gasifier attributes include atmospheric or pressurized, using air, oxygen, or steam injection.

Their CFB designs are licensed (under the name of Studsvik) to several large boiler manufactures throughout the world including Babcock and Wilcox (United States), Kvaerner (Sweden), Austrian Energy (Austria), and SER Consortium (Brazil).

TPS is also involved in IGCC systems fueled by biomass. A demonstration plant of this type has been built in England (ARBRE project) and has been operated. It was intended to be wood fueled with a design capacity of 8 MW but the project has terminated (see section on Biomass IGCC). TPS was also investigating and designing two projects in Brazil which would use IGCC plants. One would be fueled by bagasse and sugar cane trash, and the other from eucalyptus trees. The projects are purportedly on hold due to lack of financing (see section on Biomass IGCC).

Greve, Italy

In the late 1980s, TPS licensed the CFB process to Ansaldo of Italy and provided the design of two gasifiers to be fueled by pelletized refuse derived fuel (RDF). The plant was built by Ansaldo and began operation in 1991.

The two 15 MWth CFB gasifiers consume 100 t/day (each) of pelletized RDF from nearby Florence. The gasifiers are air blown and operate slightly above atmospheric pressure near 850°C (below ash melting point). Raw gas leaving the cyclone particle separator is combusted in a boiler. The boiler raises steam which is expanded through a condensing turbine. System design is for 6.7 MW. The facility can feed gas to a nearby cement plant if electricity economics are unfavorable.

A recent case study of the Greve facility was published by the IEA Task 36[53] (Energy from Solid Waste Management Systems). Operational problems with the plant have been experienced. The gasifiers themselves reportedly operate flawlessly but the boiler fouls with fly ash and condensed tar. Steam production has been low. A two-phase remediation program was undertaken late in 1997 with planned completion in 2000. The modifications to the system include a new RDF plant with better quality control and better particulate removal from the gas before it enters the boiler. It was unknown at the time of Granatstein's publication whether the operational problems were fixed as the plant owners have not returned requests for information. The case study includes mass and energy diagrams and emissions information as well as economic data.

WasteGen UK[54]

WasteGen is marketing facilities they are calling Materials and Energy Recovery Plants (MERPS). This company seems to be the inheritor of the technology developed by PLEQ,

53. http://www.ieabioenergy.com/ourwork.php?t=36#36
54. http://www.wastegen.com/template.htm

a defunct East German company that developed a rotary kiln pyrolyzer to convert municipal solid waste. Franz-Eicke von Christen is the technical director for the company. He was a founder and director of the original PLEQ company.

A full scale unit has been operating in Burgau, Germany, since 1987. Reportedly, the plant is owned by the municipality. It consists of two rotary kilns, 20 meters long by 2.2 meters in diameter. Each processing line is capable of 3 t/hour. The Burgau plant is reviewed in by Heermann et al. (2001). Some 36,000 t/hour of waste material is pyrolyzed at the facility. A mixture of MSW, commercial waste, bulky wastes, and sewage sludge are mixed together from separate storage pits. Particle size is reduced to less than 4 inches and then conveyed to the rotary kilns. The kilns are heated by combustion of a portion of the pyrolytic gas. The remaining energy in the pyrolysis gas is recovered from combusting in a boiler producing steam for a 2.2 MW turbine/generator. It appears there is no sorting of the waste required. Ferrous metals are recovered after pyrolysis. The char product is not used and is sent to landfill. Dust and fly ash recovered in a baghouse gas cleaning system is considered hazardous because of heavy metals contamination and must be disposed of properly.

Energy recovery is claimed to be 470 kWh/ton of input material which corresponds to 4.7 t/hour of input feed. This feed rate on an annual basis (90% capacity factor) would be 37,000 t/year, which is essentially equivalent to the reported annual input. On a mass basis, 12% is recovered as recyclable metal and 21% (pyrolysis char and fly ash) is sent to landfill.

Heermann et al. (2001) give a very favorable review of the process with high marks for reliability, minimal preprocessing (no sorting), and decent energy recovery. The report concludes that the process should be regarded as a leader for medium to large scale pyrolysis mixed waste processing.

Biochemical MSW Conversion Systems

Anaerobic Digestion Overview

Biodegradation of organic material occurs in nature through the action of both aerobic and anaerobic microorganisms. In aerobic systems, partial oxidation of the ingested organic material is the result yielding carbon dioxide and water and undigested residue. Anaerobic bacteria will also degrade organic matter, including some abiogenic forms, in the absence of oxygen with ultimate products being non-reactive residues, carbon dioxide, and methane. These bacteria naturally occur in the environment in anaerobic "niches" such as marshes, sediments, wetlands, and the digestive tracts of ruminants and certain species of insects. Facultative organisms are capable of persisting in either environment.

Anaerobic digestion is a fermentation technique typically employed in many wastewater treatment facilities for sludge degradation and stabilization but also the principal process occurring in landfills. Large dairies and swine farms in the United States are turning to the use of AD primarily as a means to mitigate the environmental impacts of

manure lagoons with some capture of methane for energy production. Many household scale digesters are employed in rural China and India and elsewhere around the developing world for waste treatment and gas production. Approximately 5 million households in China use anaerobic digesters. The digesters produce biogas that is used as an energy source by the households, and produce fertilizer that is used in agricultural production (Henderson 2001). Europe, especially Denmark, has developed large-scale centralized systems for solid waste stabilization and energy generation as a by-product.

Anaerobic Digestion Process Description

Anaerobic digestion of lignocellulosic waste occurs in a three-step process. These steps are hydrolysis, acetogenesis, and methanogenesis. The molecular structure of the biodegradable portion of the waste that contains proteins and carbohydrates is first broken down through hydrolysis. The lipids are converted to volatile fatty acids and amino acids. Carbohydrates and proteins are hydrolyzed to sugars and amino acids. In acetogenesis, acid forming bacteria use these byproducts to generate intermediary products such as propionate and butyrate. Further microbial action results in the degradation of these intermediary products into hydrogen and acetate. Methanogenic bacteria consume the hydrogen and acetate to produce methane and carbon dioxide. A schematic of these pathways is given in Figure 1-40.

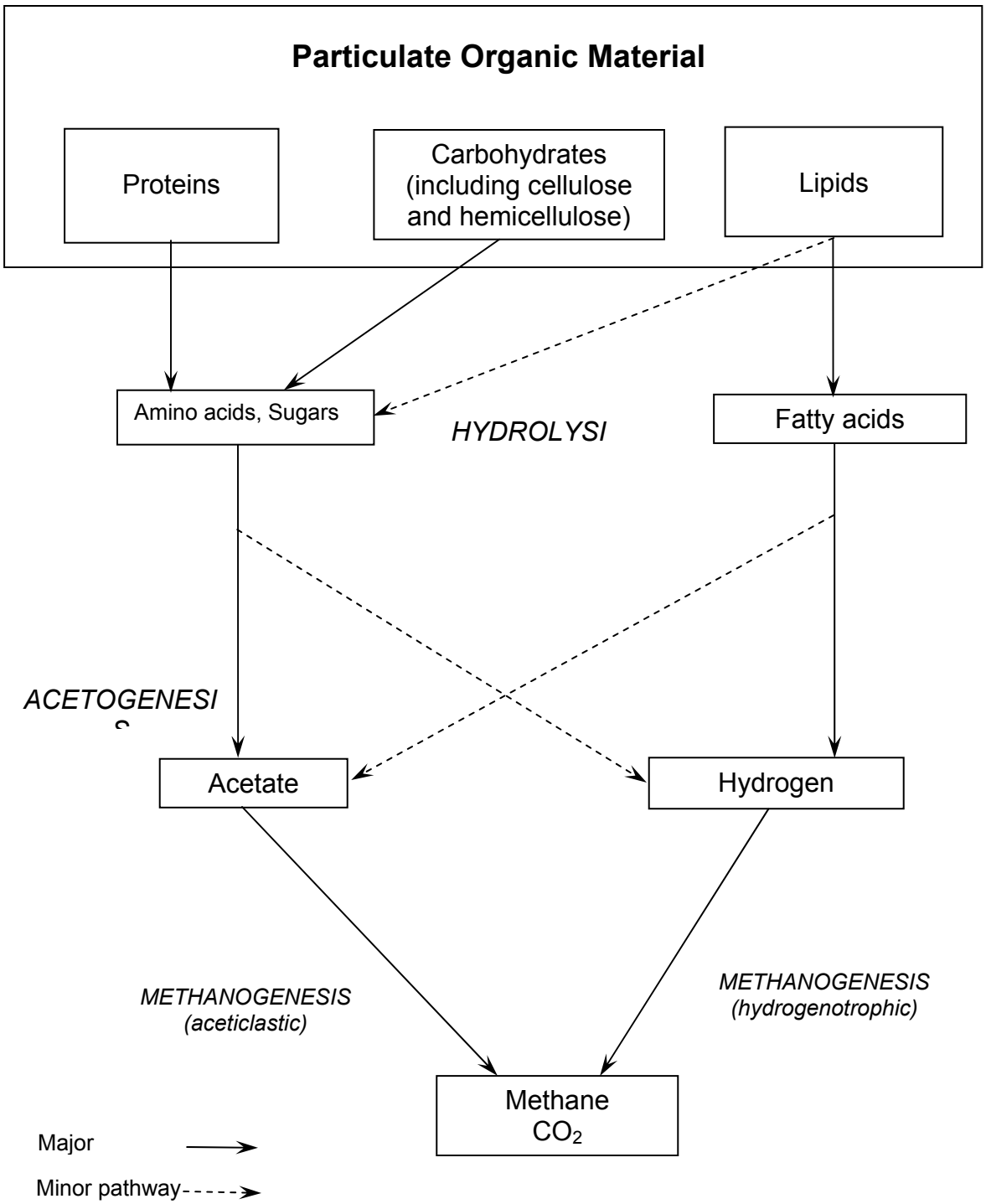


Figure 1-40. Anaerobic digestion pathways of presorted MSW
Photo Credit: Adapted from Gujer and Zehnder 1983

Anaerobic digestion operates without free oxygen and produces biogas. Biogas consists principally of methane and carbon dioxide but also has impurities such as moisture, hydrogen sulfide, and particulate matter. Anaerobic digestion requires attention to the

nutritional demands of the bacteria degrading the waste substrates. The carbon/nitrogen ratio of the feedstock is especially important. Biogas can be used as fuel for engines, gas turbines, fuel cells, boilers, industrial heaters, other processes, and the manufacturing of chemicals (with emissions and impacts commensurate with those from natural gas feedstocks).

Anaerobic digester systems can be categorized according to whether the system uses a single reactor stage or multiple reactors. In single stage systems, the essential reactions (hydrolysis/acidification, acetogenesis, and methanogenesis—Figure 1-40) occur simultaneously in a single vessel. With two- or multi-stage reactors, the reactions take place sequentially in at least two reactors.

Single stage systems are generally simpler to operate, have fewer components for maintenance or failure, and have smaller capital costs. Multistage systems offer the potential to increase the rate of methane production and the amount of overall biodegradation of the feedstock by separating and optimizing the different steps of the biochemical process. Multi-stage reactors separate the hydrolysis/acidification from the acetogenesis and methanogenesis stages.

Another important classification or design parameter is solids concentration in the reactor. Solids (or total solids, TS) are usually expressed as a fraction of the total mass of the prepared reactor feedstock (typically as a percentage by weight) and constitute the dry matter fraction of the substrate. The classification scheme for solids content is usually described as being either high solids (HS) or low solids (LS). HS systems are also called dry systems and LS may be referred to as wet. A prepared feedstock stream with TS less than 15% is considered low solids (wet) and feedstocks with TS greater than 15% are considered high solids (dry). In HS systems, solids content is usually kept in the range of 20 to 40% TS. Dilution with process water to desirable solids content is typically done in feedstock preparation stages.

Single-Stage Systems (Low Solids)

Single-stage wet (LS) anaerobic digestion systems are attractive because of their similarity to anaerobic stabilization of WWTPs. The solid wastes are pulped and slurried to less than 15% TS with water to a consistency not unlike that of biosolids before stabilization in WWTPs. Though conceptually simple, there are certain drawbacks to single stage wet systems including extensive pretreatment, higher water consumption and potentially high energy requirements to operate the system.

An early full-scale single-stage LS plant for treating MSW was built in Waasa, Finland, in 1989 (Figure 1-41) (Mata-Alvarez 2003). The feedstock is homogenized and diluted using water to obtain the required solids content in a pulping step. Hydrolysis of the carbohydrate substrate will begin in the pulping operation, although the majority of the hydrolysis phase takes place in the reactor tank.

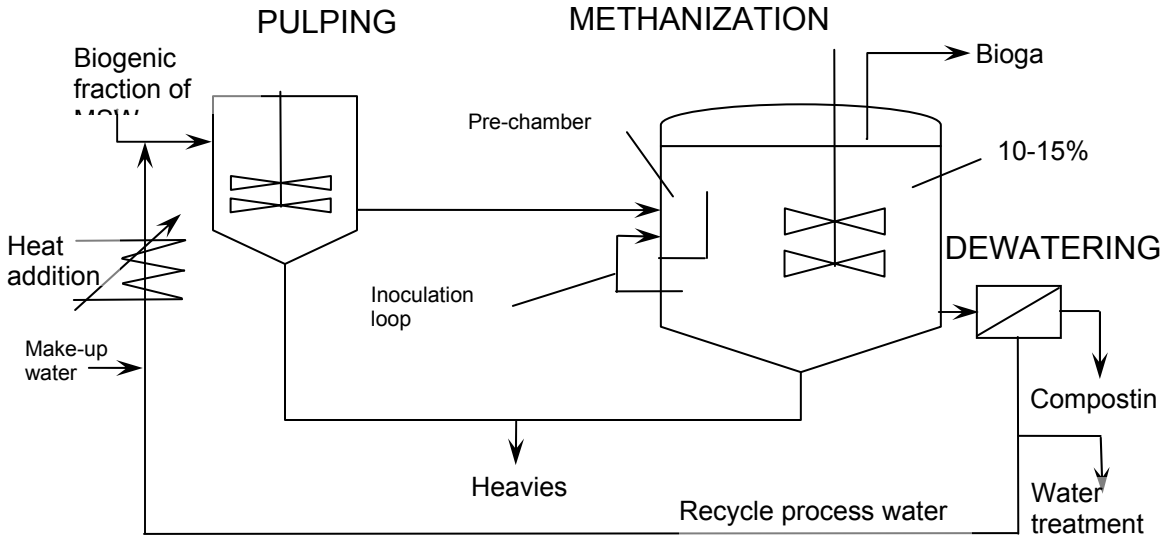


Figure 1-41. Schematic of a typical single-stage LS digester
Photo Credit: Adapted from Mata-Alvarez 2003

The slurry is pumped into a large complete mix reactor (also called a continuously stirred tank reactor [CSTR]) where active mixing keeps solids in suspension.

Pompano Beach, Florida (Chynoweth 2002)

In the mid 1970s, U.S. DOE funded Waste Management to design, construct, and operate/demonstrate the separations and AD conversion technology for MSW at a 50 to 100 t/day scale. Other agencies, including the National Science Foundation and the Gas Research Institute contributed funding. The project was called RefCoM (Refuse Conversion to Methane).

Extensive problems with the design and operation were experienced during a 2 ½ year period. Eventually, experimental runs lasting up to 70 days were performed for raw waste feed rates, up to 40 t/day.

The system consisted of extensive upfront preparation, including a materials recovery facility (MRF), and shredding and separating operations. The digester portion incorporated two 1300 m^3 CSTR reactors operated at thermophilic temperatures with TS concentration of 3 to 7%. Chynoweth (2002) reports that biogas production averaged 7.5 ft^3 (0.212 m^3) of total gas per pound of volatile solids (methane concentration was about 55%).

An economic evaluation conducted in 1990 indicated that a 400 t/day facility based on the Pompano Beach RefCoM design would require a tipping fee from $36.50 per ton up to $53 per ton depending on whether the facility is publicly or privately owned and energy prices (Chynoweth 2002).

The AD portion of the design was considered to be technically feasible by the RefCoM demonstration. The choice of a wet digestion system for mixed MSW, which required extensive up-front pretreatment/separation operations, is regarded as a flaw with the Pompano Beach project (R. W. Beck 2004).

A true CSTR system which has continuous inflow and outflow will experience something called "short-circuiting" which is the passage of a portion of the feed through the reactor with a shorter retention time than that for the average bulk material. Short-circuiting diminishes biogas yield and emits a less biologically stabilized effluent. To counteract short-circuiting in complete mix reactors, some systems use a pre-chamber where the feedstock is inoculated with organisms from the reactor vessel (Figure 1-41). The material in the pre-chamber moves in plug or "piston" flow, which takes several days to go from the point of injection to where it joins the complete mix portion of the reactor, thus ensuring all material entering the process has a guaranteed minimum retention time. The process can be operated at both thermophilic (approximately 130°F) and mesophilic (approximately 95°F) temperatures. The plant in Waasa, Finland, has both types running in parallel with the thermophilic process having a retention time of 10 days and the mesophilic process having a retention time of 20 days.

The pretreatment required to obtain adequate slurry quality while removing coarse or heavy contaminants is complex and inevitably incur a 15 to 25% loss of volatile solids (Farneti 1999). Mechanical mixing and/or injection of a portion of the biogas into the bottom of the reactor tank is used to keep the material continuously stirred and homogenous as possible. However, energy for vigorous mixing is substantial, so practical systems require means to remove heavy material that doesn't remain suspended as well as a floating scum layer which can build up to several feet thick.

Single-Stage Systems (High Solids)

In dry, or HS, systems, the fermenting mass is kept at a solids content of 20 to 40% TS (equivalent to 60 to 80% moisture). The physical characteristics of material at the higher solids content require different approaches to handling and pre-treatment (i.e., conveyor belts, screws, and special pumps for the highly viscous streams). As single stage wet systems were based on the well established anaerobic digestion of waste waters, research in the 1980s indicated the biogas yield and production rate were as high or greater in systems that kept the waste feedstocks in their original solid state (i.e., not slurried with water) (Farneti 1999). The challenge of these systems is handling, mixing, and pumping of the high solids streams rather than maintaining the biochemical reactions.

Although some of the handling systems may be more expensive than those for wet systems (such as high solids pumps), the HS systems are generally more robust and flexible regarding acceptance of rocks, glass, metals, plastics, and wood pieces in the reactor. These materials are not biodegradable and do not contribute to biogas production but they generally can pass through the reactor without affecting conversion

of the biomass components. The only pretreatment required is removal of the larger pieces (greater than 2 inches), and minimal dilution with water to keep solids content in the desired range.

Because of their high viscosity, material in HS reactors moves via "plug flow" with little mixing. This presents the problem of inoculating newly injected feedstock with a portion of the fermenting mass. At least three commercial-scale designs have been developed which adequately inoculates the feedstock by mixing a portion of the digested material or recirculating biogas (Figure 1-42).

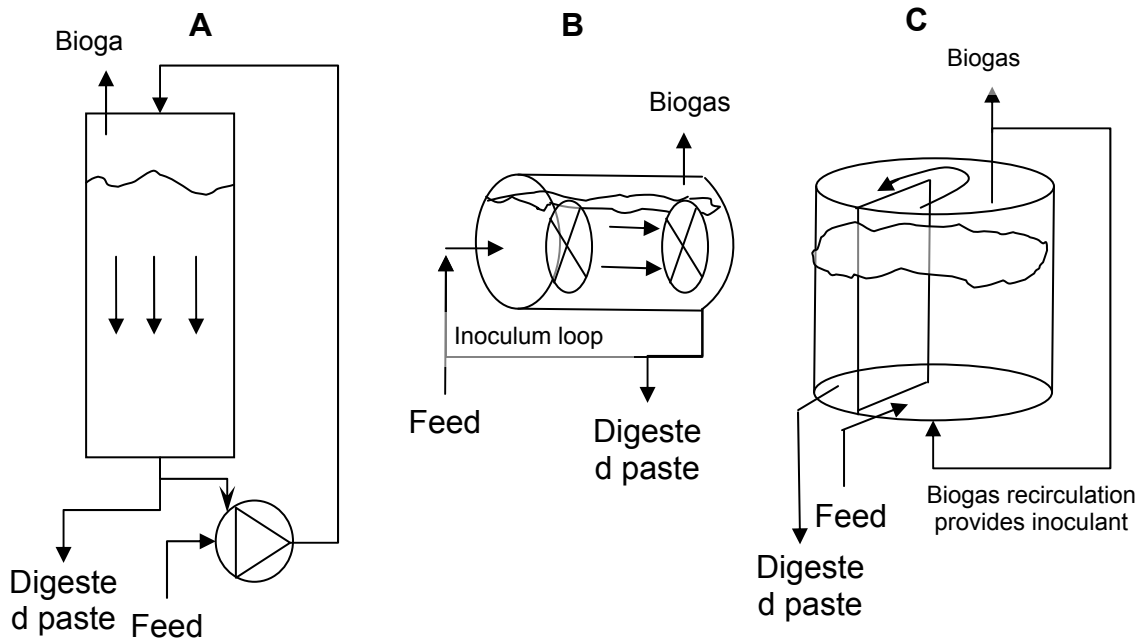


Figure 1-42. High solids single stage digester designs, A – Dranco, B – Kompogas, C – Valorga

Photo Credit: Adapted from Mata-Alvarez 2003

The Dranco process, diagrammed in Figure 1-42 (A), mixes some digested paste with the incoming feed and pumps the mixture to the top of the reactor vessel. Fermenting material flows downward, eventually exiting at the bottom with biogas being recovered through the top. The Kompogas reactor also mixes a portion of the digestate with the incoming feed. This process is a horizontal plug flow reactor with the material moving from the input end to the opposite end. The horizontal reactor has a set of internal impellers that slowly move the material along (some amount of mixing is provided as well). The Kompogas system requires a careful adjustment of TS to about 23% (Mata-Alvarez 2003). If TS is too low, heavy materials tend to accumulate on the bottom and do not exit the system, while higher TS values become too difficult to move. The third

concept in Figure 1-42 was adopted by the Valorga process. This reactor consists of a vertical cylinder with a vertical inner wall mounted along a diameter of the reactor but only extending about 2/3 of the way across to the opposite side. Material enters at the bottom on one side of the inner wall and must flow a circular path to pass to the other side-wall before it exits (DeLaclos 1997). Biogas is periodically re-injected in the base of the reactor on either side of the dividing wall effecting some vertical mixing and solids suspension with no mechanical mixing devices inside the digester. The gas mixing and solids circulation result in inoculum transfer to influent feed.

Multi-Stage Systems

Multi-stage systems are designed to take advantage of the fact that different portions of the overall biochemical process have different optimal conditions. By separately optimizing primary and secondary conditions, the overall rate can be increased. Typically, two-stage processes attempt to optimize the hydrolysis and acidification reactions in the first stage where the rate is limited by hydrolysis of cellulose. The second stage is optimized for acetogenesis and methanogenesis where the rate in this stage is limited by microbial growth rate. With multi-staging, it is possible to increase hydrolysis rate by applying a microaerophilic process. This process uses minimal air to allow some aerobic organisms to break down some of the lignin that makes more cellulose available for hydrolysis. The air would inhibit the methanogenic organisms if they were present as they would be in a single stage reactor. Figure 1-43 depicts a basic two-stage AD system with hydrolysis occurring in the high-solids first stage and methanogenesis occurring in the low-solids second stage.

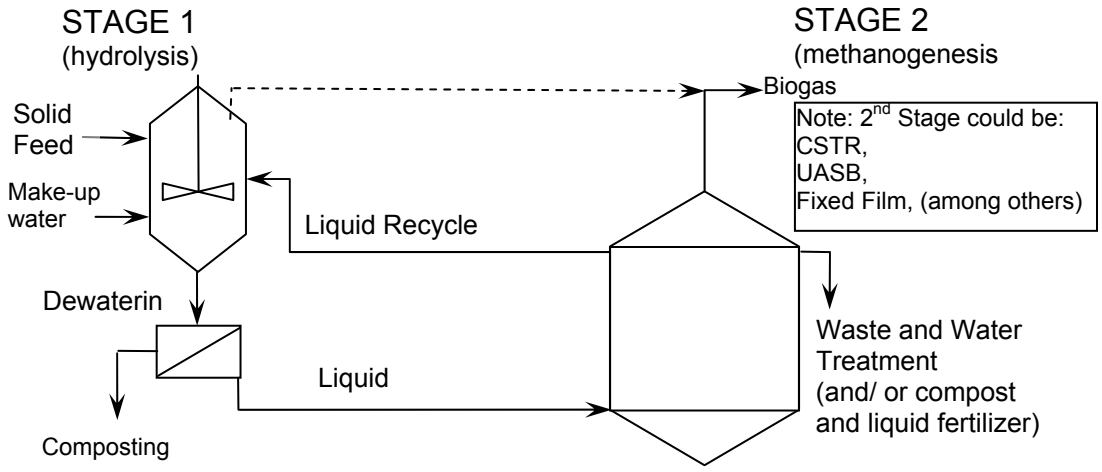


Figure 1-43. Simple schematic of two-stage anaerobic digestion system (high solids first stage, low solids second stage)
Photo Credit: Adapted from Mata-Alvarez 2003

As mentioned earlier, in Europe there are approximately 7 AD plants using two-stage designs and 79 single-stage plants. It was expected that more of the multi-stage systems would be in operation by now, but the degree of increased yield and rates demonstrated in lab scale multi-stage systems have not been achieved in commercial units.

Performance of Some Commercial and Practical Pilot Scale Facilities

Table 1-32 lists some methane production values reported on a per-VS basis for some commercial facilities in Europe and some pilot scale experiments. Some of the feedstocks are characterized.

These facilities are nominally operated at thermophilic temperature (around 130°F) and retention times of about 15 days.

The SEBAC experiments were conducted for 21 and 42 days with batch reactors at 120°F. This temperature was used because it "represented the natural temperature expected to result from metabolic heat as determined by systems calculations" (Okeefe et al. 1993).

Methane production from the Dranco plants cited in the literature seems respectable and reflects the fact the feedstocks are generally source separated and the food and green wastes are targeted for the AD.

Table 1-32. Performance data of some commercial and pilot AD facilities

Plant (or reference)	Feedstock	TS (%)	VS/TS (%)	VS (g/g input)	VS reduction (%)	CH_4 production (l/g VS)	CH_4 production (g /g VS)	CH_4 Energy (MJ/kg VS)	CH_4 Energy (MJ/kg Input)
Dranco, Salzberg (De Baere, 2000)	80%Kitchen 20% Garden wastes	31	70	0.217	70	0.34	0.24	13.6	2.9
Dranco, Bassum (De Baere, 2000)	"Grey" waste	57	51	0.2907	60	0.28	0.20	11.0	3.2
Dranco, Brecht (De Baere, 2000)	15% Kitchen 75% Garden 10% Paper wastes	40	55	0.22	52	0.26	0.18	10.2	2.2
Venice (Cecchi et al., 1989)						0.25	0.18	10.1	
France/Valorga (begouen et al., 1988)						0.22	0.16	8.7	
Marseille (Marty et al., 1986)		35				0.20	0.15	8.1	
SEBAC pilot 42 days (O'Keefe et al., 1993)	60% paper, 6% yard waste	71	81	0.5751	49.7	0.19	0.14	7.5	4.3
SEBAC pilot 21 days (O'Keefe et al., 1993)	95% paper, 2% yard waste	65.6	92.5	0.6068	40.6	0.19	0.14	7.5	4.6
SEBAC pilot 21 days (O'Keefe et al., 1993)	60% paper, 6% yard waste	71	81	0.5751	36.0	0.16	0.11	6.3	3.6
Venice (Cecchi et al., 1989)						0.16	0.11	6.3	

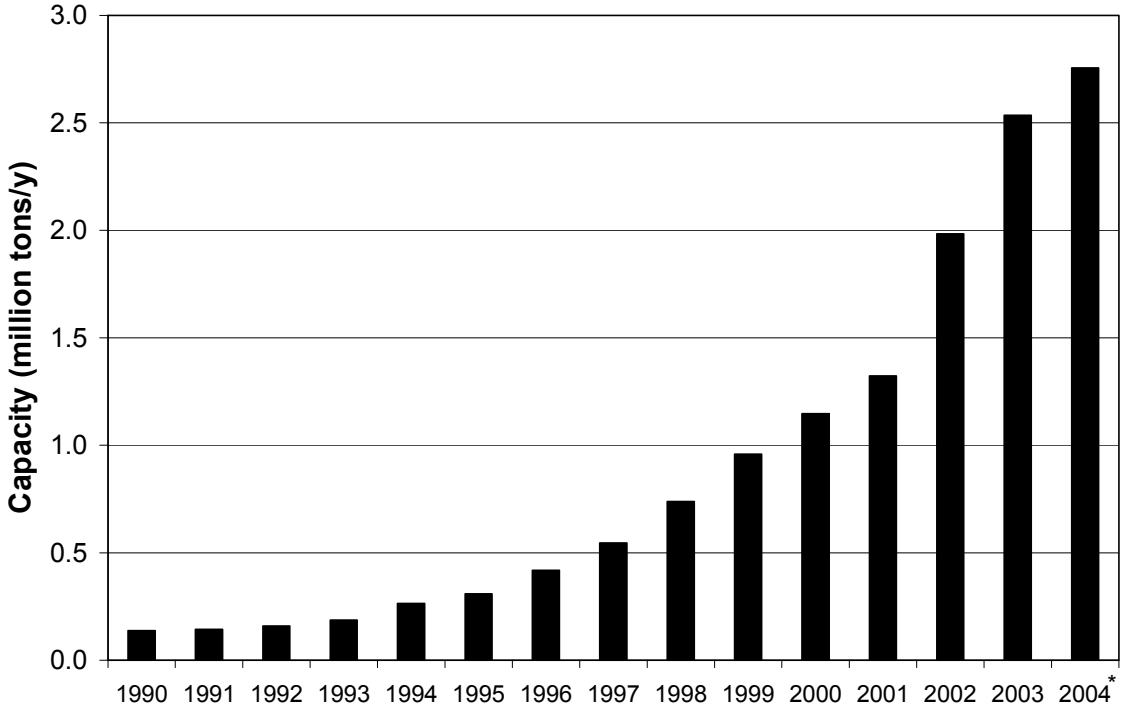
Status of MSW Anaerobic Digestion in Europe

Anaerobic digestion systems using solid waste feedstocks are more widely utilized in Europe. European Community policies have developed to minimize the amount of material being landfilled. These policies are driven by several factors including limited space for new landfills, and the needs for methane emission reductions and increased renewable energy production because of Kyoto Protocol requirements. Examples of policies implemented to reduce material flow to landfill in Europe include Germany's Extended Producer Responsibility (EPR) approach that requires manufacturers to be responsible for recovery of packaging material, and restrictions on the amount of biodegradable material that can be disposed in landfills

AD and aerobic composting of kitchen, food processor, and garden wastes is well established in Europe. To improve the quality of feedstocks used in AD and composting operations, source separation of household and commercial food and garden wastes is utilized extensively. At least 11 European Union countries have implemented or are about to implement source separation for food and green wastes.[55] In Switzerland for example, approximately 220 lb per person per year of source separated food and green waste is collected. About 12% of the material is stabilized by AD facilities, and the balance is composted (Ludwig 2003). Germany has more than 500 facilities that treat more than 8 million t/year of green and food wastes in biochemical treatment facilities, with the majority being aerobic compost facilities (Kubler et al. 2000).

A review of AD in the organic waste industry in Europe was done in 2000 and updated in 2003 (De Baere 2000; De Baere 2003). In the 2003 update, 86 AD facilities were identified as either operating or to be under construction by 2004 with capacity greater than 3,000 metric t/year, and with at least 10% of the treated feedstock from municipal or commercial organic waste. Many of these facilities will co-digest animal wastes and municipal waste water sludges. In Spain, the 13 large capacity plants, which average 70,000 t/year, will be anaerobically treating nearly 7% of the biodegradable MSW by the end of 2004 (De Baere 2003). For all of Europe, the installed capacity in 2000 was 1.1 million t/year and was projected to increase to 2.8 million t/year in 2004, an increase of approximately 250% in four years. Figure 1-44 shows installed capacity of MSW AD facilities between 1990 and 2004. Figure 1-45 shows how the capacity is distributed between single and two stage systems. Single-stage anaerobic digesters account for approximately 92% of the installed AD capacity in Europe.

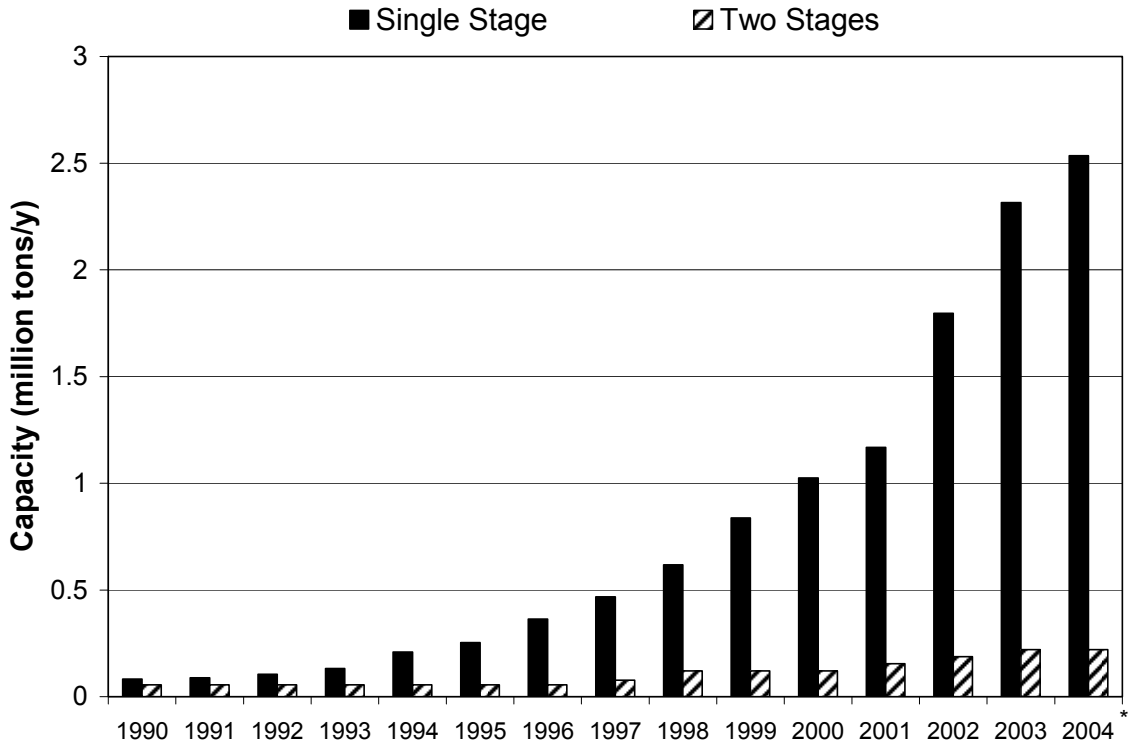
55. European Compost Network, http://www.compostnetwork.info/biowaste/index.htm



*Data projected for 2004

Figure 1-44. Growth of solid waste anaerobic digester capacity in Europe

Photo Credit: Adapted from De Baere 2000 and 2003



*Data projected for 2004

Figure 1-45. Installed AD capacity by stage in Europe

Photo Credit: De Baere, 2000 and 2003

Biochemical MSW conversion Facilities and Companies

Valorga (Montpellier, France)

The Valorga process was designed to treat organic solid waste. It is an anaerobic digestion process and accepts MSW after appropriate separation of recalcitrant fraction.

The process dilutes and pulps the organic fraction to about 30% solids content. This is considered a high solids process. Steam is used for heating/maintaining temperature in the reactors as necessary. Mesophilic or thermophilic systems are used depending on feedstock and economics.

The reactor is a continuous one-step plug-flow process. The reactor consists of a vertical outer cylinder with an inner wall about the 2/3 of the diameter of the outer one. Material enters at the bottom on one side of inner wall and must flow up one side and down the other side before it can exit (de Laclos et al. 1997). The retention time is on the order of three weeks. Biogas is injected in the base of the reactor and the bubbles serve as a means for mixing and keeping solids suspended (gas-mixed). The digestate is dewatered and can be composted. Table 1-33 lists existing facilities.

Table 1-33. Valorga process installations[56]

Location		Material	Capacity (ktonnes/y)	Start-up Date
Bottrop	Germany	Kitchen waste	6.5	1995
Geneva	Switzerland	Kitchen/Green waste	10	2000
Engelskirchen	Germany	Kitchen/Green waste	35	1998
Freiburg	Germany	Kitchen/Green waste	36	1999
Tilberg	The Netherlands	Kitchen waste	52	1994
Bassono	Italy	Sorted MSW/sludge	55	2003
Mons	Belgium	Sorted MSW	59	2002
Amiens	France	Sorted MSW	85	1988
Varennes-Jarcy	France	Sorted MSW	100	2002
Cadiz	Spain	Sorted MSW	115	2002
Barcelona	Spain	Sorted MSW	120	2004
Hanover	Germany	Sorted MSW/sludge	125	2002
La Coruna	Spain	Sorted MSW	142	2001

Adapted from corporate webpage, http://www.steinmuller-valorga.fr/index_en.php, and Velma 2002.

Wehrle Werk AG (Emmendingen,Germany)

Biopercolat Process

Werle Werk AG is a large company active in thermal conversion of biomass and MSW with several combustion facilities. The company is also active in waste water treatment which has led to its involvement with the solid waste digestion facility at Kahlenberg (2000 t/year). The facility uses the "Biopercolat" process.

The Biopercolat process is a multi-stage high solids process (Verma 2002), Figure 1-46. The first hydrolysis stage is carried out under partial aerobic conditions. Process water is continually percolated through the mechanically agitated (and slightly aerated) hydrolysis chamber (a horizontal tunnel much like the Wright MBT system). The leachate hydrolysis water is fed to an anaerobic plug flow filter filled with support material operating as an upflow anaerobic blanket sludge reactor. The process has a retention time of only seven days.

56. Adapted from corporate webpage, http://www.steinmuller-valorga.fr/index_en.php, and Velma 2002.

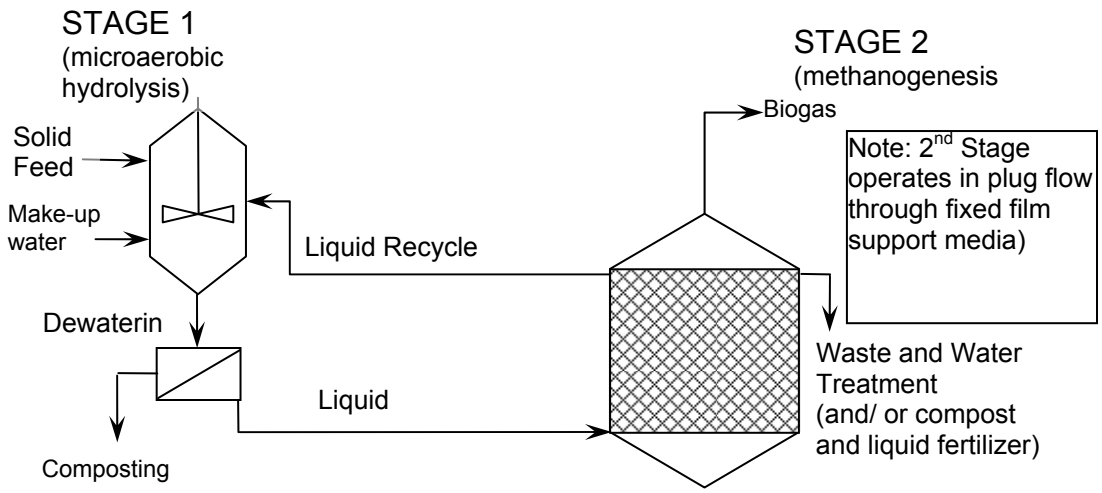


Figure 1-46. Simple schematic of Biopercolat process (high solids first stage, low solids second stage)

Photo Credit: Adapted from Mata-Alvarez 2003.

Wright Environmental Management (Ontario, Canada)

Wright Environmental Management supplies "in-vessel" composting systems. These are managed and accelerated aerobic conversion processes. The material is loaded into a tunnel like enclosure and moves slowly in plug flow. Any leachate is recirculated and air is actively pumped through the material throughout the length of the enclosure. In-situ mixing and moisture management results in a 10 to 14 day retention time for material. Excess air and gaseous products can be fed through a biofilter for odor control before release to the environment. The system is modular and capacities can be scaled from 600 lbs. to 30 tons per day through one enclosure tube.

MSW can be processed after appropriate separation of non compostable material.

The company lists several reference plants, which include:

Aberdeenshire, Scotland	32,000 t/y MSW
Isle of Wright, England	22,000 t/y mixed food/green waste
Dept. of Corrections, Powhatan, Va.	730 t/y food waste
Dept. of Corrections, Ogendburg, N.Y.	730 t/y food waste
Allegheny College, Pa.	365 t/y food waste
Albany, N.Y.	18,250 t/y organic fraction MSW

CiTec (Finland/Sweden)

CiTec is a group of Finnish and Swedish companies with the majority of operations originating from the Vaasa, Finland, office. The Waasa process was developed by CiTec.

The Waasa Process

This is a single stage "wet" (total solids less than 15%) AD system. For the organic fraction of MSW to be used in this system, it must undergo pretreatment in a pulper which shreds, homogenizes, and dilutes the material to the desired concentration of total solids (10 to 15% TS). Recycled process water and some fresh make-up water are used in the dilution. The slurry is then digested in large "complete mix" (completely stirred) reactors. The pretreatment required to obtain adequate slurry quality while removing coarse or heavy contaminants is complex and inevitably incur a 15 to 25% loss of volatile solids from the portion reaching the digester (Farneti 1999). Mechanical impellers and injection of a portion of the biogas into the bottom of the reactor tank are used to keep the material continuously stirred and as homogenous as possible. To reduce short-circuiting of the feed (i.e., passage of a portion of the feed through the reactor with a shorter retention time than that for the average bulk material), a pre-chamber within the main reactor tank is used. Fresh material from the pulper enters the pre-chamber along with some of the biomass from the main tank for inoculation. Figure 1-47 shows a schematic of the Waasa digester process. The pre-chamber operates in plug flow taking a day or two before the material makes its way into the main reactor, thus ensuring all material entering the process has a guaranteed few days retention time. Even with the pre-chamber arrangement, enough short-circuiting occurs that all pathogens are not eliminated requiring a pasteurization step in the pre-treatment. Steam is injected in the pulper to maintain feed at 70°C for one hour.

The process can be operated at both thermophilic and mesophilic temperatures and the plant at Vaasa has both types running in parallel (the thermophilic process has a retention time of 10 days while 20 days is required in the mesophilic design). The operational performance (manufacturer's summary data) indicates that gas production is in the range 100 to 150 m^3/ton of bio-waste added, volume reduction of 60%, weight reduction 50 to 60%, and a 20 to 30% internal consumption (heat) of biogas. The digestate can be further treated by aerobic composting, but this depends on the waste quality.

Several plants are operational in Europe and Japan based on the Waasa process. Capacities range from 3,000 to 90,000 tons per year (see Table 1-34).

Table 1-34. List of Waasa process AD sites[57]

Waasa (CiTec) System Locations		Feedstock	Scale (t/yr)	Temp. (ºC)	Year began Operation	Status	Output Elect. (kWe)	Output heat (kWth)
Kil	Sweeden	Biowaste	3000	55	1998	Operational	0	228
Vaasa	Finland	MSW	15000	55	1994	Operational	300	620
Pinerolo	Italy	MSW /Sludge	30000*	55	2003	Completion	1200	1880
Groningen	The Netherlands	MSW	85000*	55	1999	Operational	1920	3000
Friesland	The Netherlands	MSW	90000*	55	2002	Start-up	2000	3140
Tokyo	Japan (Ebara)	Biowaste/Sludge	500	55	1997	unknown		
Ikoma	Japan (Ebara)	Biowaste/Sludge	3000	55	2001	unknown		
Shimoina	Japan (Ebara)	Biowaste/Sludge	5000	37	2001	unknown		
Jouetsu	Japan (Ebara)	Biowaste/Sludge	12000	55	2001	In operation		

* From pretreatment

Adapted from CiTec Waasa Reference List

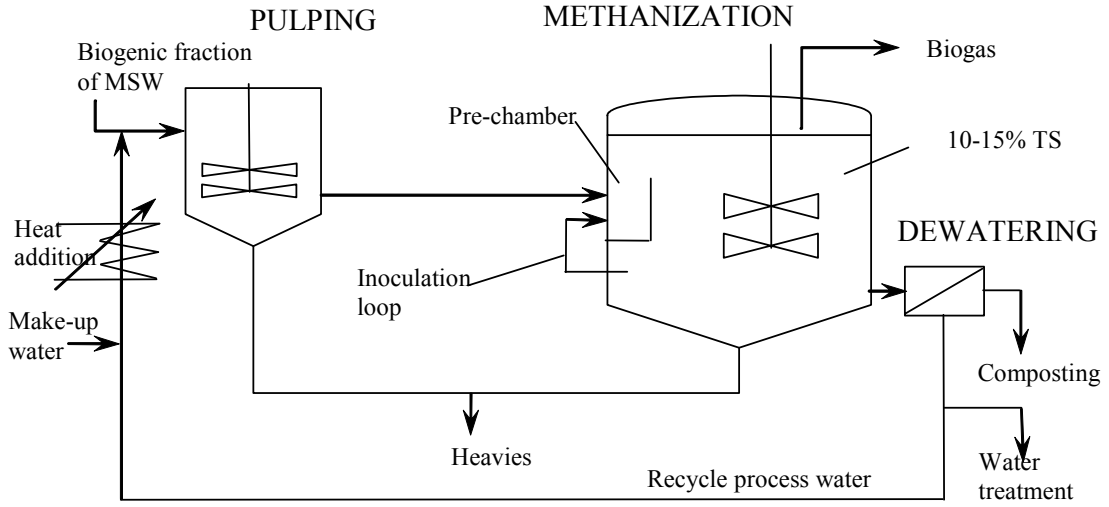


Figure 1-47. Schematic of single-stage low solids AD system, Vaasa, Finland

Photo Credit: Adapted from Mata-Alvarez 2003

Linde-KCA-Dresden GmbH (Dresden, Germany)

Linde-KCA is a large engineering design/build firm active in pharmaceuticals, chemical and wastewater and solid waste treatment.

The company is active in both low and high solids (wet and dry) digestion systems (see Figures 1-48 and 1-49), and mechanical-biological treatment systems (MBT) for separated MSW. MBT systems include aerobic composting systems with mechanical

57. Adapted from CiTec Waasa Reference List, http://www.citec.fi/ang/eng/enviroment/Wassa_process/Ref_biogas.pdf

manipulation of the feedstock and intensive aeration. Some systems include intensive aerobic digestion as a preprocess for a feedstock that is later anaerobically digested. The company reports it was the designer-builder of the world's largest compost facility in Bangkok, Thailand with an output of 1200 t/day.

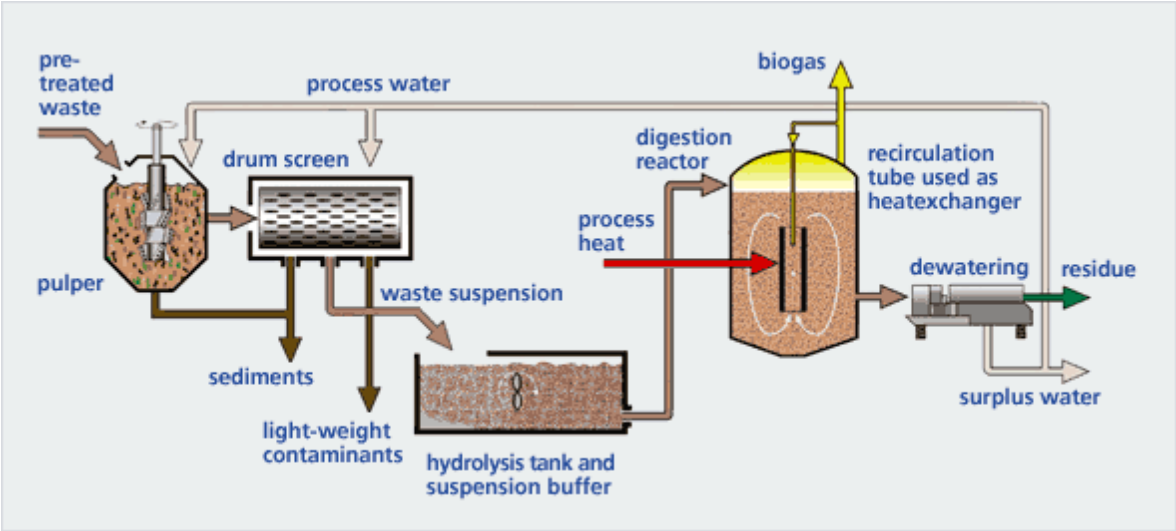


Figure 1-48. Linde-KCA two stage wet digestion system

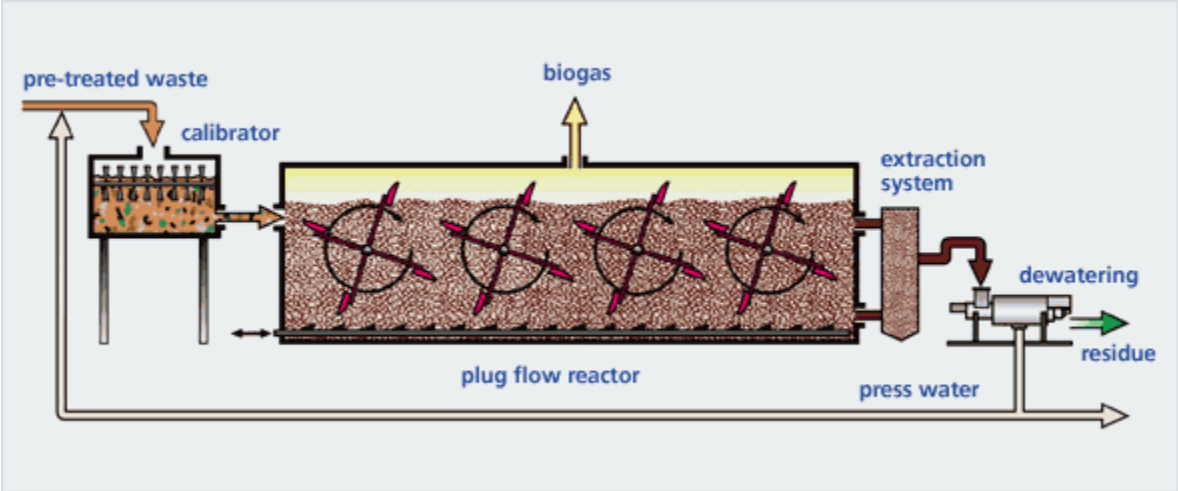


Figure 1-49. Linde-KCA dry digestion plug flow system
Photo Credit: Linde-KCA

Linde has designed, built, and operated a facility in Radeberg, Germany, which codigests source separated biogenic wastes from household and industrial sources along with sewage sludge from waste water treatment. The company reports that this co-digestion concept enhances degradation of the sewage sludge component of the feedstock (increases biogas production from the sewage sludge) and decreased capital and operating costs compared to those for two separate facilities.

Another co-digestion facility designed and built by Linde is located on a dairy farm in Behringen, Germany. The plant takes the low solids manure and codigests, with grease from restaurant grease traps, solids from pig manure, and a range of other food processing waste including brewery sludge, rape seed press cake, and low grade seed potatoes. The facility processes about 100 t/day (wet) of which 75% is dairy cow manure. The facility produces about 650 kW from two Jenbacher 450 kW gensets. Thirty percent of the power production is used on site for operating the plant and the dairy with the balance sold to the grid.

Recent orders for company projects include a mechanical-biological integrated waste treatment plant to be located at the landfill in Leipzig-Crobern. The facility will include material separation and recovery. The capacity will be 300,000 t/year. One third of the material will be recycled, one third thermally converted, and one third treated biologically. Residues from the thermal and biological treatments will be landfilled.

Another mechanical-biological waste treatment plant has been ordered for Fridhaff, Luxemburg.

Projects currently under construction include:

- Municipal Solid Waste Treatment Plant ECOARC I in Barcelona, Spain: wet pretreatment, AD, and composting of MSW.
- Municipal Solid Waste Treatment Plant PINTO in Pinto/Madrid, Spain: wet pretreatment, AD, and compositing for MSW.
- Biowaste Treatment Plant, Lisbon, Portugal: organic fraction of MSW.

Kompogas (Glattbrugg, Switzerland)

Kompogas has several operating or planned units throughout Europe. Kompogas plants are also in Japan and a facility in Martinique is under construction (total of approximately 25 operating or planned plants).

The process is optimized on green waste and kitchen waste for fermentation to biogas. The biogas will run small engines for heat and power or, in some cases, it is upgraded to natural gas standards (remove CO_2 and H_2O and other dilutents) and goes into Switzerland's well developed natural gas vehicle fueling systems, thus converting household organic wastes into a transportation fuel.

The Kompogas system is a high-solids, thermophilic single stage digestion system (Verma 2002). It can be classified as an MBT. The reaction vessel is a horizontal cylinder into which feed is introduced daily. Movement of material through the digester is in a horizontal plug-flow manner with digested material being removed from the far end of the reactor after approximately 20 days. An agitator within the reaction vessel mixes the material intermittently. The digestate is de-watered, with some of the press water being

used as an inoculum source and the remainder being sent to an anaerobic waste water treatment facility which also produces biogas.

ISKA (U-plus Umweltservice AG, Ettlingen, Germany)

The ISKA percolation process is used for the putrescible fraction of the waste stream. It involves a high degree of mechanical sorting/separating in the preprocessing steps as well as in the hydrolysis and digestion portions of the process finishing with the dewatering of the digestate. This is classified as MBT of MSW.

Biodegradable material is first separated from the stream and then is subjected to a hybrid aerobic/anaerobic degradation process. The ISKA process uses aerobic means for hydrolysis of insoluble organic material to reduce the overall process (retention) time. After this percolation step, the material passes to standard anaerobic methods for production of biogas and reduction of mass. The digestate is then dewatered and sent to aerobic composting or conversion by thermal means to energy or other products. ISKA literature[58] indicates that the energy available from the biogas production is roughly sufficient to power the process. To create exportable energy, the dewatered digestate and the non-digested stream must be converted (thermally). The ISKA company information also indicates it is pretreating MSW and sending the residual solid to SVS Schwarze Pumpe gasification facility which makes methanol and power.

The commercial scale demonstration plant at Buchen, Germany, will be expanded (to 150,000 metric tons/year) to accept MSW from the Ludwigsburg area. The ISKA process was chosen for a new facility near Sydney, Australia. The capacity will be 170,000 metric tons/year at full build-out. The construction broke ground in July 2003.

Eco Tec (Finland): WABIO Process

This AD process is targeted for the MSW stream. The system includes receiving, sorting, mechanical preconditioning, digestion, and dewatering of the digestate for possible further composting processing.

The digestion process occurs in a single-stage low-solids reactor. It operates in the mesophilic temperature region.

Three plants in Europe are listed in a partner company website.[59] Their locations are Vaasa and Forssa, Finland, and Bottrop, Germany (6500 t/year source separated waste). A United Nations Development Program website[60] discusses a proposed Wabio AD facility for the city of Kalyan, India. The scale would be 55,000 t/year. No schedule is given for the project and further searching could not determine the existence or status of the project.

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58. http://www.iska-gmbh.de/allgemeine%20grafiken/iska_engl.pdf
59. http://www.casa2000.net/wsludgewabioplants.htm
60. http://www.undp.org.in/programme/GEF/september/page16-20.htm

Organic Waste Systems (Gent, Belgium): Dranco Process and Sordisep System

Organic Waste Systems (OWS) was established in 1988 and maintains biodegradability labs in Belgium and Ohio. OWS also has an exclusive partner in Japan for proposed facilities there. The company designs, builds, and operates AD plants for MSW. The company also consults on biodegradation and waste management.

OWS has developed the Dranco (Dry Anaerobic Composting) process as well as the Soridsep (Sorting–Digestion-Separation) integrated waste system. The technology is patented under international patent number WO 02102966.

The Dranco process was developed in the late 1980s. It is a high solids (15 to 40% TS), single stage AD system that operates at thermophilic temperatures (Verma 2002). Feed is introduced into the top of the reactor, and moves vertically as plug flow. A portion of the digestate is recycled as inoculation material, while the rest is dewatered to produce an organic compost material. There is no mixing within the reactor, other than that brought about by the downward, plug-flow movement of the waste and some gas bubbling upwards. Source separated household and industrial wastes are preferred.

Existing commercial systems (see Table 1-35) are reported to have biogas production rates in the range of 6 to 10 m^3 biogas per m^3 reactor volume per day (or about 120 m^3 biogas per wet ton of feedstock, Table 1-36). The Dranco process produces a compost product and heat or electricity from the biogas. The company reports electricity production can range from 0.1 to 0.3 MWh/ ton feedstock.

Figure 1-50 shows a schematic with a mass balance for an operating DRANCO system. Figure 1-51 shows some of the reactor detail.

Table 1-35. Organic Waste Systems' Dranco References[61]

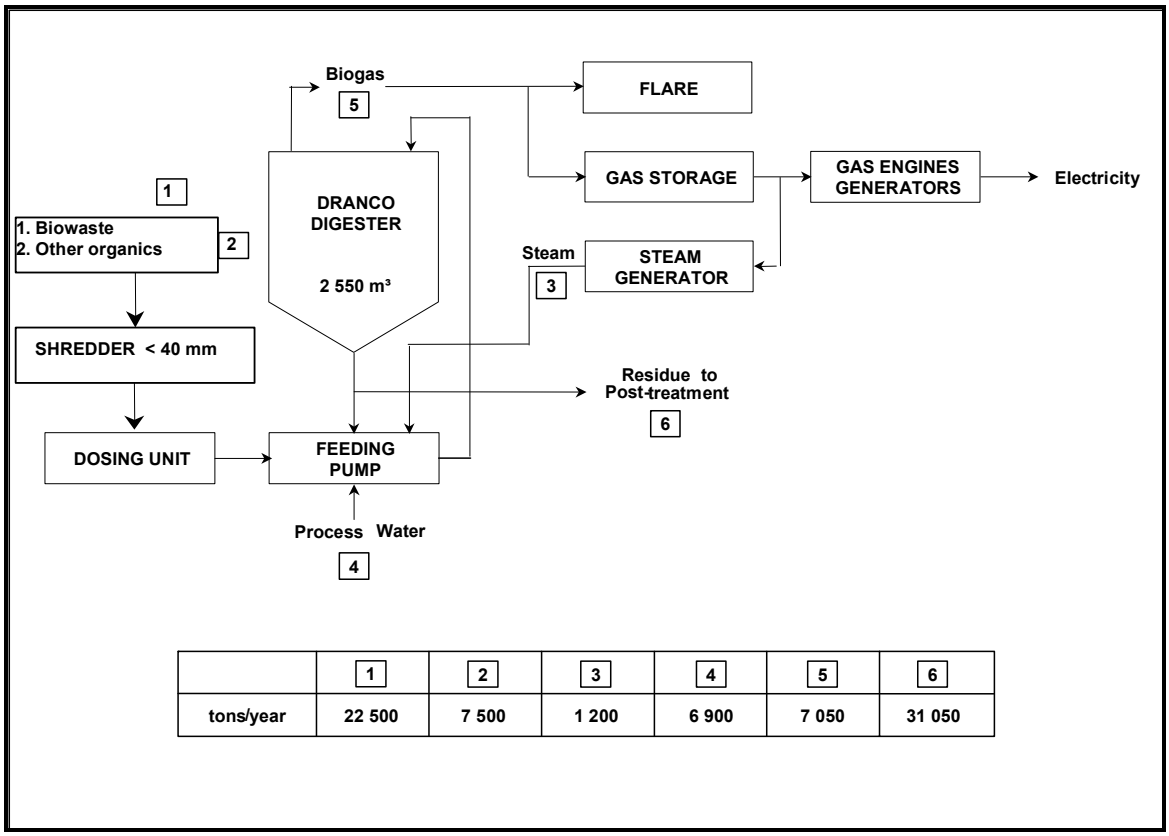
Dranco Process Locations		Scale (ktonne/y)	Year Began Operation
Brecht I	Belgium	20	1992
Salzburg	Austria	20	1993
Bassum	Germany	13.5	1997
Aarberg	Switzerland	11	1998
Villeneuve	Switzerland	10	1999
Kaiserslautern	Germany	20	1999
Brecht II	Belgium	50	2000
Alicante	Spain	30	2002
Rome	Italy	40	2003
Laeonberg	Germany	30	2004
Hille	Germany	38	2005
Münster	Germany	24	2005
Terrassa	Spain	25	2005
Pusan	South Korea	75	2005
Victoria	Spain	20	2006

http://www.ows.be/

Table 1-36. Feedstock and gas production for three Dranco facilities (De Baere 2000)

Plant	Feedstock	TS (%)	VS/TS (%)	VS (g/g Input)	VS reduction (%)	CH_4 Production			
						(l/g VS)	(g/g VS)	(MJ/kg VS)	(MJ/kg Input)
Salzberg	80%Kitchen 20% Garden wastes	31	70	0.22	70	0.34	0.24	13.6	2.9
Bassum	"Grey" waste	57	51	0.29	60	0.28	0.20	11.0	3.2
Brecht	15% Kitchen 75% Garden 10% Paper wastes	40	55	0.22	52	0.26	0.18	10.2	2.2

61. http://www.ows.be/



	1	2	3	4	5	6
tons/year	22 500	7 500	1 200	6 900	7 050	31 050

Figure 1-50. Schematic and mass balance of the Dranco process

Photo Credit: OWS

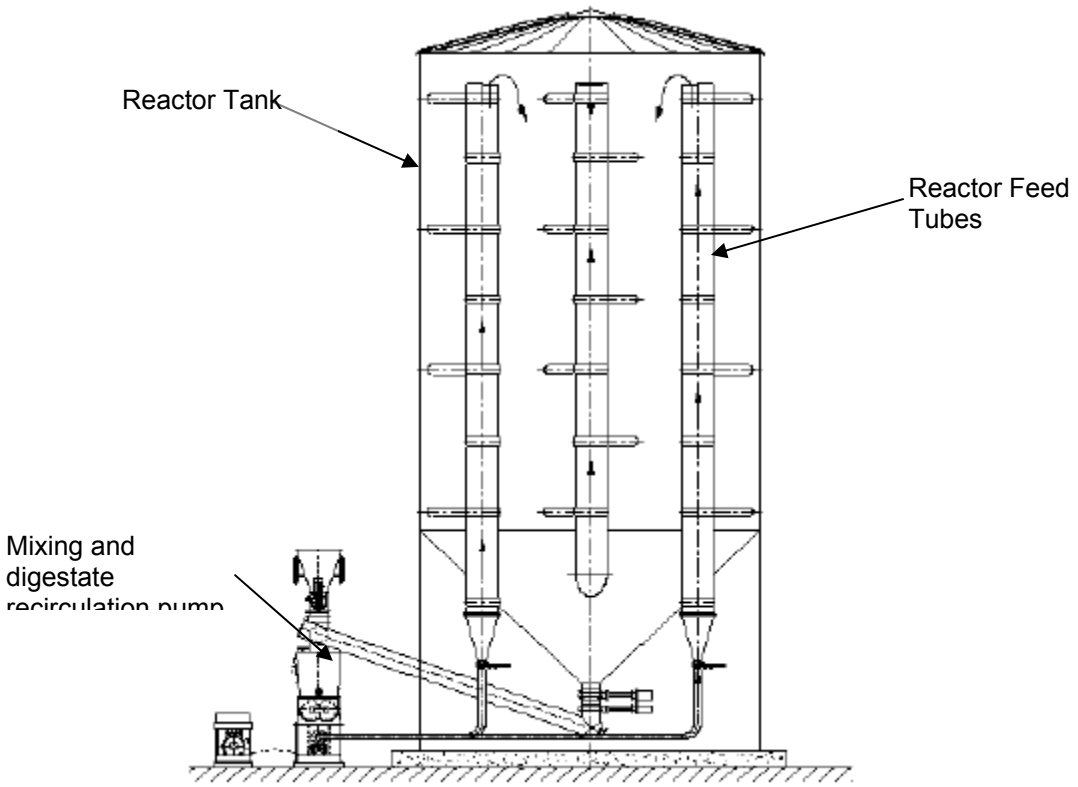


Figure 1-51. Drawing of the Dranco reactor
Photo Credit: OWS

BTA (Munich, Germany) (Canada Composting, North American Licensee)

BTA facilities can be single or multistage AD process for the organic fraction of MSW. Methane and compostable solid residue are produced as well as a liquid residue which can be marketed as liquid fertilizer. The process uses a "low solids" concentration slurry and can be operated in meso or thermophilic temperature ranges.

The process includes equipment to separate inorganic and some non-digestible organic (plastics) from the incoming waste material. After sorting, the organic fraction is diluted to about 10% (low solids concentration) and digested in single or multiple stages depending on facility and waste stream requirements. BTA has licensed the Process to MAT Müll- und Abfalltechnik for Western Europe to Biotec Sistemi, Genua, for Italy and Niigata Engineering, Tokyo, for Japan. An exclusive license for Canada and North America was given to Canada Composting, Newmarket/Ontario (CCI). Several cooperation agreements were made with non-European partners. Table 1-37 lists facilities using the BTA process.

The Canada Composting Newmarket Plant was operating for a period. It produced a gross power of 5 MW from burning the biogas in reciprocating internal combustion engines. The plant parasitic load was 2 MW with a net output of 3 MW. Capacity was 150,000 metric tons per year on a 5.4 acre site. According to Jeff Flewelling at York Region (Canada), CCI Newmarket went into receivership due to odor problems and

inadequate financial ability to remediate. The Newmarket plant, now operating, has been sold to Halton Recycling Limited (HRL) of Burlington, Ontario. Canada Composting has built a 25 kt/year pilot facility in Toronto.

Table 1-37. BTA process references (BTA)

BTA Process Locations		Scale (ktonne/y)	Year began Operation
Ko-Sung	Korea	3	2003
Karlsruhe	Germany	8	1996
Mertingen	Germany	11	2001
Erkheim	Germany	11.5	1997
Dietrichsdorf	Germany	17	1995
Waden-Lockweiler	Germany	20	1998
Kirchstockach	Germany	20	1997
Elsinore	Denmark	20	1991
Mülheim	Germany	22	2003
Toronto	Canada	25	2002
Villacidro	Italy	45	2002
Ieper	Belgium	50	2003
Newmarket	Canada	150	2000
Planned or under construction			
Alghoba	Libya	11	?
Krosno	Poland	30	~ 2005
Pamplona	Spain	100	~2005

Arrow Ecology Ltd. (ArrowBio process) (Haifa, Israel)

The ArrowBio AD process is designed to accept unsorted MSW. Inherent in the process is a fully integrated water-vat sorting and cleaning facility, which yields sorted recyclables much like a typical MRF (the exception being that all biomass components, including paper and cardboard, are eventually carried into the low solids biochemical treatment system; if paper recovery is desired, paper must be separated upstream of the water-vat stage). The sorting process also separates most of the non-recyclable inert material from the biodegradable matter.

The biochemical processing concept utilizes up-flow anaerobic sludge blanket technology commonly used by WWTPs. The company has experience with designing and building waste water treatment facilities.

The process outputs are sorted: ferrous and non ferrous metals, glass, and other mineral matter, plastics, biogas, nondigestible residue, and "low-strength" (low chemical oxygen demand (COD) or biochemical oxygen demand (BOD) wastewater. The biogas can be burned in gas engines onsite for heat and power or upgraded to pipeline quality gas, or processed to a liquefied natural gas (LNG) for use as transportation fuel. The emissions from the biogas utilization, therefore, depend on the end use of the gas, but would be similar to those from existing biogas and natural gas applications. The low-grade

wastewater can be used for irrigation (as is done at the facility in Israel for the onsite landscaping), or can be treated in the local municipal wastewater treatment plant.

Many of the company claims are difficult to corroborate as no independent review, data, or test results were made available. There is one existing commercial scale facility built and operated by Arrow Ecology. This is a 70,000 t/year facility at the Tel Aviv transfer station that presently handles approximately 1 million t/year for transport to a distant landfill. Arrow Ecology indicates that a 220 t/year facility (60,000 to 70,000 t/year depending on number of operating days) requires a footprint of approximately three acres.

Currently the operating plant in Israel receives $24.50 per ton of material processed, and a new "landfill tax" will bring this tipping fee to $33.30 per ton. The facility was financed with company funds and a bank loan. Additional information made available by the company[62] gives estimated capital costs (for a United States installation) of approximately $12 million for a 220 tpd plant. The required break-even tipping fee is approximately $50 per ton. Reported product types and value for the Tel Aviv facility are listed below:

Product ◊	**$/unit**
Electricity	$50/MWh ($.05/kWh)
Plastic	$72/ton
Metal	$63.5/ton
Glass	Given away
Organic soil amendment	Given away
Liquid water	Used internally as makeup process water, with the excess used for landscape maintenance

◊ Quantities of these products and Tel Aviv waste characterization were not reported.[63]

Arrow Ecology holds United States patent 6,368,500 (Asa 2002) for a waste treatment system. Though elaborate, the process utilizes a clever water-vat primary separator (noted above) creating three material feeds: (1) the heavier material (sinkers), mostly non-biodegradable material composed of metals, glass, plastic with specific gravity (SG) less than 1, mineral matter, etc.; (2) the lighter material (floaters), composed of floating plastics, containers, woody biomass, some food items, etc.; and (3) the neutrally buoyant material which is much of the biomass.

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62. 2003 WTERT Fall meeting at Columbia University, http://www.seas.columbia.edu/earth/wtert/meet2003/wtert-2003_finstein.pdf
63. The company website indicates the facility is expected to export 2 to 3 MW once in full operation. http://www.arrowecology.com/mainpage/index2.htm

The floating material is skimmed off the water pit and reunited with the heavy "sinkers" fraction that is dredged from the bottom of the water pit. This stream passes through standard MRF type separation and sorting mechanisms (See Figure 1-52).

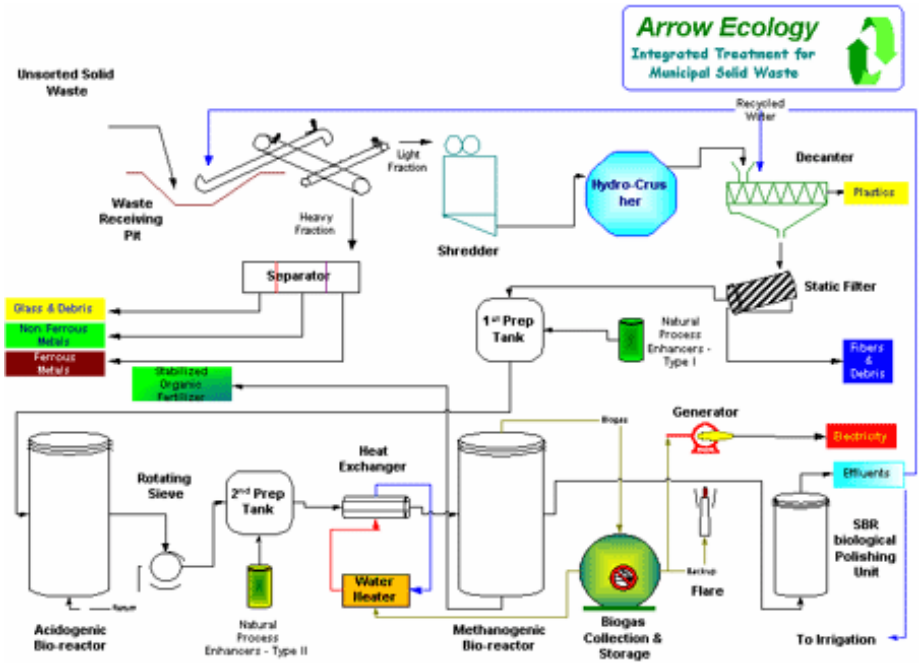

Figure 1-52. Schematic of the ArrowBio process
Photo Credit: http://www.arrowecology.com

Soluble biomass begins to dissolve with agitation in the water vat. Dissolved and water-logged/soggy biomass is carried out of the vat with liquid flow. Particle size reduction and dissolution of biodegradables continues with downstream travel. Size reduction is aided by passage through a slow speed rotary shear, followed by a special Hydro-Crusher device (which is an aspect of the patent). Oversize particles are screened and returned to the vat.

The biomass material received in various solid forms (food preparation and plate waste from homes and restaurants, food-tainted paper, vegetative trash, yard waste not diverted for composting, etc.) is transformed into a strong wastewater. As such, it is possible to apply low solids UASB wastewater treatment technology to the biodegradable fraction of MSW.

Biological processing

The prepared biomass-rich watery solution flows from the water-vat separator to acidogenic bioreactors (anaerobic), where intermediated organic acids are formed. Effluent from the acetogenic reactor is screened and the large particles returned to this first reactor. The liquid with smaller particles is heated to about 40°C before entering the

UASB reactor, where the methane is produced (see Figure 1-53). Presumably, the UASB reactor operates in the mesophilic temperature range.

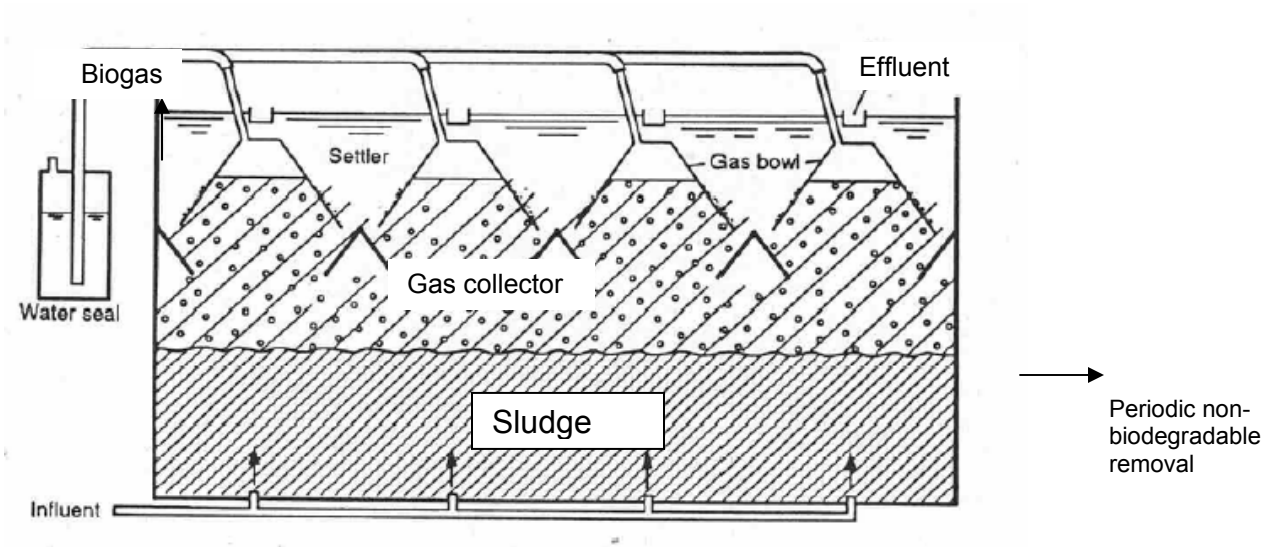

Figure 1-53. Schematic of a UASB bioreactor
Photo Credit: Grady et al. 1999

In the UASB, the inflowing organic acids and solids come in contact with the methanogenic microbial community residing in the reactor. The microbes selectively form themselves into discrete "granules" that, collectively, have very high surface area and mass transport capability. The microbe granules take in the organic acids and produce methane as a metabolic product. The granules and biomass solids arriving as influent are suspended and mix in the sludge blanket by movement of biogas bubbles that float upward. An advantage of UASB is that solids retention time (SRT) and hydraulic retention time (HRT) are decoupled. In the ArrowBio process, once in the UASB reactor, SRT is on the order of 75 days while HRT is about one day. The low HRT translates to relatively small reactor volumes, while long SRT generally provides for more complete biodegradation and high rates of methane production.

Table 1-38 shows the projected mass balance and electricity production from a California waste stream as provided in the survey response. Moisture content of the biodegradable portion of the waste stream was adjusted from that used in the survey response (from 40% to 30%). In addition, while UASB reactors can produce biogas with relatively high methane concentration, the 75% (volume) value claimed by ArrowBio seems high. Independent evaluation or test results are needed to corroborate this. For the material balance, methane concentration was adjusted to 65%. The survey indicates that approximately 80% of the biomass (dry matter or TS) is consumed in the biological reactors, which also is rather high. Approximately 7 to 15% of TS is inert ash and another 10 to 15% is non-biodegradable lignin (depending on waste stream). This leaves 70 to 83% of the biomass dry matter that is biodegradable (representing upper limits for

a perfect system). Finally, the material balance could not be closed using the provided information (i.e., about 15% of the mass could not be accounted for in the products).

Table 1-38. Mass balance and power production for ArrowBio process.[a]

		Tons per year	% of Input
	Waste Input	200,000	100
Outputs	Recovered (Non-Biodegradable for recycling)	35,330	17.7
	Soil Amendment (50% water)	40,890	20.4
	Biogas		
	CH_4 (26.6 Mm^3, 65% of total biogas volume)	20,943	
	CO_2	31,012	
	Biogas Total	51,956	26.0
	Water	23,340	11.7
	To Landfill	18,720	9.4
	Total Outputs	170,235	85.1
	Unaccounted	29,765	14.9
	Electrical Production	Gross	Net
	MWe	10.3	8.8
	kWh/ton (unsorted)	451	385
	kWh/ton (material to digester)	618	528

a) Based on ArrowBio survey response using Santa Barbara RFQ waste stream and 35% efficiency for electricity generation.

The process can accept any additional anaerobic biodegradable feedstocks that are collected separately or are outside the standard MSW stream including food processing and restaurant wastes, raw or partially treated sewer, and biodegradable industrial waste waters. More information including real operating data from the existing facility in Israel would be helpful for assessing the process. Certain claims must be met with skepticism until proven with real data. These include the methane production and its high concentration in the biogas, the high extent of biodegradation claimed (80% of total solids), and the amount of inert materials separated in the water-vat process.

Bioconverter (Santa Monica, California)

The company is part of McElvaney Associates Corporation. McElvaney has developed and patented (Patent No. 6,254,775) an AD system that can be characterized as a single stage low solids fixed (immobilized) film anaerobic digester. Recent announcements indicate the company has negotiated a 20-year agreement to provide the Los Angeles Department of Water and Power with electricity from the bioconversion of green wastes at $16 million per year ($48/MWh). The facility will begin operation in 2008 and consume 3,000 t/day of Los Angeles green waste and generate 40 MW of electricity. It is not clear whether there will be other costs to the city for the project (presumably, a tipping fee will also be paid to Bioconverter for disposal of the feedstock). Approximately 1,000 t/day of digester residue will be created, which potentially can be used in compost operations or as soil additives. If no market exists for the material, it will likely be disposed in landfills.

Another announced project is with the City of Lancaster, California. A $16 million facility is proposed to convert 200 t/day of local green waste and produce 5,000 gallons per day of compressed natural gas (CNG) that can be used as a transportation fuel. Press releases claim that digester residue will be used in poultry feeding operations. The project will pursue alternative fuel and air pollution reduction related grants through the local air pollution control district, but otherwise the facility is expected to be funded privately.

The feed material is primarily green wastes and source separated food wastes. It can also accept waste paper (magazines and junk mail, mixed residential, etc.), fats, oils, and grease, and "high-strength" wastewaters. Feed is comminuted as necessary and liquid added to obtain a slurry with TS of about 10%. Gas and liquid are recirculated in the digester to promote mixing.

The single stage digester relies on a fixed support matrix of polyethylene for growing and immobilizing methanogenic microorganisms. Reactor liquid and biogas are recirculated through the medium to maintain solids suspension. The system is probably operated in the mesophilic temperature range about 95°F) because of a solid retention time on the order of 30 days. Products are typical for AD systems and include methane and solid and liquid soil amendments/fertilizers. Table 1-39 shows basic information for the two announced Bioconverter projects (LADWP and City of Lancaster). The table shows simple energy conversion efficiency (energy in product/energy in feedstock) using a high and low estimate for feedstock energy content. The estimated efficiencies range from about 10 to 20% (depending on feedstock characteristics) that are reasonable though perhaps tending toward the optimistic end of the range that can be expected from AD systems.

Systems have been installed in the Caribbean[64] and Hawaii. In Hawaii, a 2 t/day system operated on food and green waste for four years with some sale of liquid fertilizer. The

64. See http://www.dwacaribbean.com/articles.html

company cooperated with the UNISYN system in Waimanalo, Hawaii, which used feedstock of manure from 2,000 cows, 250,000 poultry layers (egg laying hens), and waste from a United States Department of Agriculture (USDA) fruit fly rearing facility. The system was co-located with the animal operations as well as a greenhouse. Residue from the digesters was used as protein supplement in the poultry operation and aquaculture. The facility transitioned to processing food and grease wastes and was closed in 1999.

Table 1-39. Basic Bioconverter project input and output capacities.

Project	Green waste feed rate (Tons/day)	Capital cost ($M)	Payment from Agency ($million/year)[a]	Energy in feedstock (GJ / day)		Product		Energy in Product (GJ/ day)	Efficiency of Conversion (%)	
				High[b]	Low[c]	Electricity MWe	CNG (gallons/day)[d]		Low[c]	High[b]
LADWP	3000	?	16	30395	15997	40	-	3456	11.4	21.6
Lancaster	200	44	?	2026	1066	-	5000	198	9.8	18.6

a) $48 /MWh
b) 11.4 MJ/kg assuming all prunings, trimmings, branches (@ 40% moisture)
c) 6 MJ/kg assuming all leaves and grass (@ 60% moisture)
d) Assumes compressed to ~ 3600 PSI, with volumetric energy density equal to 30% that of gasoline
Source: UC Davis Research Team ; Source: Robert Williams

UC Davis Anaerobic Phased Solids (APS) Digester

This system was developed and patented by Professor Ruihong Zhang and Dr. Zhiqin Zhang from UC Davis (Zhiqin Zhang is currently at the California Energy Commission) (Zhang and Zhang 2002). The system is licensed to Onsite Power Systems for commercialization. Laboratory and pilot scale reactors are located at UC Davis.

A pilot facility on the UC Davis campus, funded by the Energy Commission and industry partners, will be operational early in 2005. The pilot facility will have a feedstock capacity of about 3 t/day, producing about 25 kW from a reciprocating engine.

An installation to be located on approximately two acres on the California State University–Channel Islands campus has been proposed. The facility would process 250 t/day of green waste diverted from Ventura County landfills and presumably some waste from the campus. It is estimated that sufficient biogas for generating 2 MW of power will be produced. A byproduct would be 25 to 50 t/day of fertilizer. The capital cost of the project is reported to be $12 million ($6,000/kW installed). Revenues from the project include the price of the energy displaced by the facility, fertilizer sales, and tipping fees from waste hauled in from off campus.

The facility would operate at thermophilic temperature (135°F) and have a solids retention time of 12 days.

The anaerobic phased-solids (APS) digester decouples solid-state hydrolysis and acetogenic fermentation from the methane producing fermentation, allowing for separate optimization of the two processes. The two reactors are connected through a closed liquid recirculation loop that transfers the solubles released in the hydrolysis

reactor to the biogas producer (methanogenesis) (Figure 1-54). The biogas reactor can be designed for relatively short liquid retention time by using suspended growth, attached growth, anaerobic moving bed reactor (AMBR), or UASB reactor types (Zhang and Zhang 1999).

The hydrolysis reactor can accept high solids feedstock that, depending on its characteristics, may need some kind of pretreatment such as shredding to increase hydrolysis rate. The hydrolysis reactor operates in batch mode. Because of this batch operation, the strength of the soluble compounds in the liquid being transported to the biogas reactor will vary from near-zero immediately after adding a fresh batch of feed to the hydrolysis vessel, to a maximum when the rate of hydrolysis is highest, subsequently tapering off as the remaining soluble biomass declines. Correspondingly, the biogas production rate will vary from low to high to low again because it depends on the strength and rate of the inflow liquid arriving from the hydrolysis stage.

By using several batch loaded hydrolysis reactors, the loading of each being timed (or phased) one after another such that the strength of the mixed substrate flowing from all hydrolysis reactors is more stable (Figure 1-55).

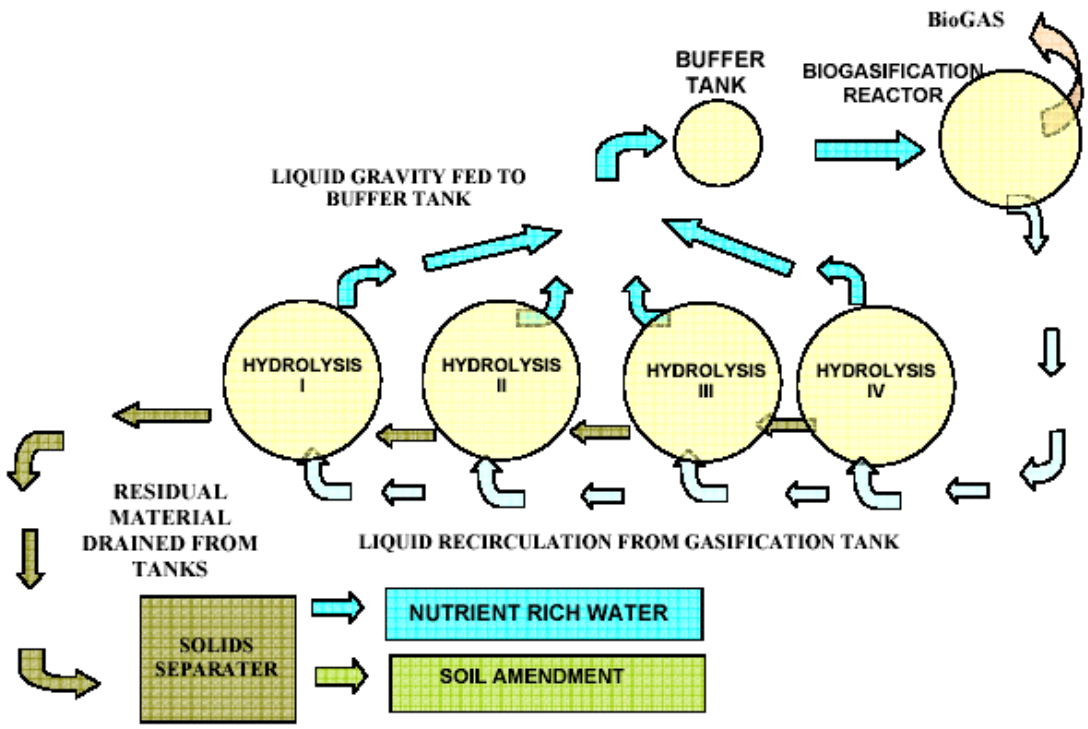

Figure 1-54. Schematic of APS digester system showing four hydrolysis vessels
Photo Credit: Courtesy of Ruihong Zhang

This relatively stable average strength liquid allows for suitable size and design of the single biogas reactor in order to optimize the methanogenic portion of the process.

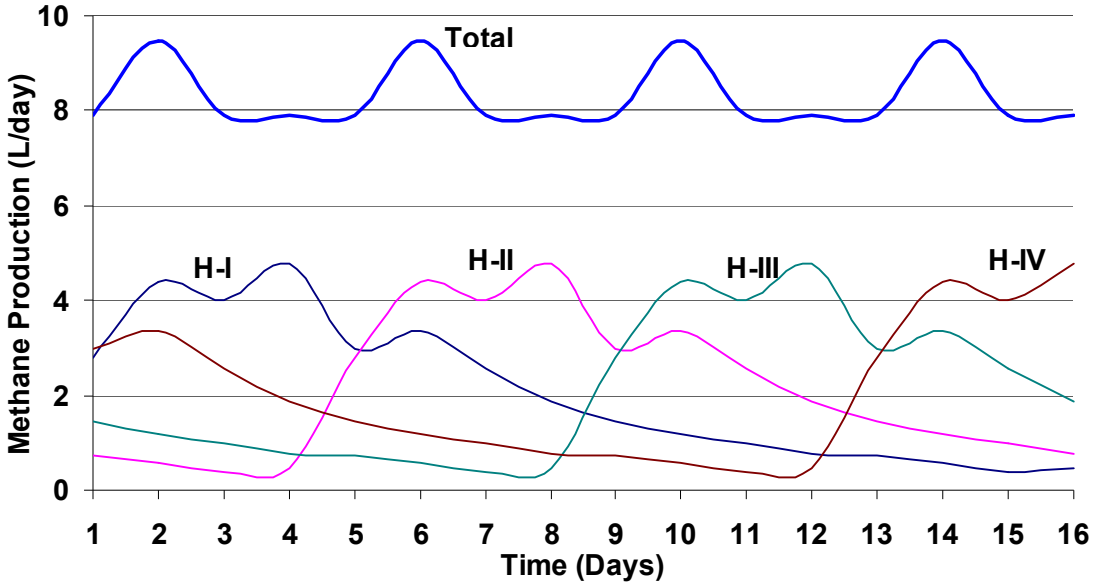

Figure 1-55. Simulated biogas production rate for lab-scale APS digester system
Photo Credit: Karl Hartman, UCD

1.5 Summary of Biomass Conversion

Power generated from combustion of biomass in the United States increased rapidly between 1980 and 1995 after enactment of PURPA in 1978. Favorable federal tax policies for investments in renewable energy and state incentives (e.g., the Standard Offer 4 contract that was available in California) contributed to the financial viability of biopower facilities. For the United States, installed biomass power capacity is substantial, currently at about 11 GW. About 6.2 GW is fueled by forest products and agricultural residues and about 3.5 GW is MSW-based including landfill gas. The United States' capacity primarily consists of direct combustion steam Rankine systems with an average size of 20 MW. Efficiency is typically about 20% due mostly to the small plant size but also to fuel quality (moisture).

The generating capacity of biomass power facilities in California followed a similar trend as that for the rest of the nation. Installed solid biomass direct combustion steam-cycle power capacity in California peaked at about 770 MW in 1990. Today, there are approximately 28 solid-fueled biomass facilities currently operating in the state comprising a total of 570 MW capacity not including three MSW combustion facilities that combined generate another 70 MW. Another 31 facilities with combined capacity of 340 MW are idle, dismantled, or have been converted to natural gas fuel.

Systems that produce power from biogas in California include some 50 landfill gases to energy facilities, 10 grid-connected waste water treatment plants, and several dairy or food processing waste digesters. The combined generating capacity from biogas in California is approximately 250 MW (210 MW from landfill facilities).

The type and scale of biomass conversion facilities depend to a large extent on the biomass resource type and amount that is technically and economically available for the expected life of the facility. Characteristics of the fuel are important in determining suitable conversion technology. In general, dryer biomass feedstocks are more suited for thermochemical conversion (combustion, pyrolysis, gasification) and the more wet feedstocks (e.g., wastewater, food wastes, some MSW green waste, some animal manures) are more suitable for biochemical conversion methods (anaerobic digestion). These are not absolute rules, so investigating a range of conversion methods is worthwhile.

A biomass resource inventory for the Sacramento region indicates that there is a technical generation potential of some 520 MW from an array of biomass residues. These include the biogenic fraction of MSW, agricultural crop residues, animal wastes, and forest biomass.

Advanced Systems

Systems that improve upon cost, conversion efficiency, installed capacity, environmental performance, public acceptance, or that can increase the range of available feedstocks and products compared with existing commercial technologies are considered advanced.

Overall efficiency of biomass conversion to electricity is typically lower than large central station fossil power plants due to smaller facility size and lower fuel quality. Efficiency of conversion for existing biomass based power systems ranges from less than 10% to about 25%. At the lower end of the range are combustion boiler-steam engine systems, small gasifier-engine systems, and AD-reciprocating engine systems. The upper range of efficiency is achieved by larger combustion boiler-steam turbine systems (more than 40 MW).

The California solid fueled biomass industry consists of facilities with net power capacity as low as 4 MW to three facilities with capacities between 47 and 50 MW. The net efficiencies range from about 15 to 25%. Maximum capacity has so far been constrained by additional regulatory and permitting requirements for facilities of 50 MW and above, and not by specific technical or fuel supply limitations. Delivered costs of biomass influence the optimal size of facilities, but economic and technical risk limitations to facility size have not so far been tested in California.

Solid Fuel Cofiring

Probably the least expensive means for increasing use of biomass in power generation is to cofire with coal in existing boilers by direct substitution of 10 to 15% of the total

energy input with a suitable biomass fuel. Biomass cofiring directly substitutes renewable carbon for fossil carbon. In addition, cofiring at low fuel ratios has little or no impact on the overall conversion efficiency of the plant. Cofired biomass receives the benefit of the generally higher overall conversion to electricity efficiencies in large coal power plants (typically 33 to 37%). Co-firing biomass can also reduce NOx and sulfur dioxide emissions from coal-fired power plants depending on type of biomass fired. Opportunities for co-firing in coal facilities are limited in California due to the limited amount of coal generation.

Gasified Biomass Cofiring

With a fuel gas derived from biomass (whether producer gas from thermochemical gasification or biogas from biogasification), there is the opportunity to cofire with natural gas in boilers or GTCC facilities (assuming quality of the mixed gas meets the turbine requirements for energy content, hydrogen gas concentration and cleanliness.)

There are at least three basic arrangements for biomass cofiring with a natural gas fueled GTCC:

Indirect Co-firing with Steam Side Integration

This mode is practical and has lower specific investment costs than stand-alone combustion. Steam addition from the biomass boiler is probably limited to about 10%. Energy efficiency of the biomass component is similar to that of conventional biomass fueled steam cycles.

Direct Cofiring with Upstream Thermal Gasification

This method of cofiring allows the biomass contribution of fuel input to enjoy essentially the same conversion efficiency as the natural gas. In a GTCC plant, the efficiency can approach 55%. Fuel quality requirements of the gas turbine (calorific value and hydrogen concentration) limit the contribution of the biomass fuel to 2 to 8% (thermal basis).

Direct Cofire with Biogas

The biogas and natural gas fuel mixture in this cofire mode has the same requirements as above in order to avoid major gas turbine modifications. However, biogas is generally easier to clean than producer gas. Co-locating a biogas source with a GTCC facility or upgrading biogas to pipeline quality are simple ways to boost the conversion efficiency of the biogas from the 25 to 40% level obtained in reciprocating engines or microturbines (simple cycle) to the higher GTCC efficiency of about 50%. Upgraded biogas could be cofired in any proportion with natural gas.

Thermal Gasification

Biomass Integrated Gasifier Combined Cycle

United States BIGCC demonstrations have not so far progressed to full system operation. United States federal development of bioenergy shifted away from biopower to bioproducts and biofuels with the 2001 change in administration in Washington D.C., along with the goal of addressing the nation's reliance on imported petroleum. Federal research and development support for biomass power generation has therefore diminished.

BIGCC is technically viable as demonstrated at Värnamo, Sweden. The reasons that the BIGCC demonstration projects in the United States never came to fruition are ultimately financial. The MnVAP project in Minnesota was not constructed due to loss of financing under perceived high risk. A project in Paia, Hawaii, was not continued to full system testing largely as a result of inadequate development of a fuel feeding system for the pressurized reactor. A dual-fluidized bed (Battelle-FERCO) project in Burlington, Vermont, by most reports, successfully demonstrated the Battelle gasifier at a commercial scale. Federal funding in support of full IGCC implementation did not occur and testing beyond gas co-firing to the solid fuel boiler was not conducted.

Commercial projects by Carbona and FERCO have been recently announced. These projects target homogeneous fuel sources (mostly clean wood chips). Continued investigation which includes suitability of other fuels that comprise the diverse California biomass resource is necessary if these technologies are to be considered for a range of feedstocks. Increased availability of clean wood fuels from forest thinning and related operations is uncertain in the near term because permitting forest fuels reduction efforts on public lands may be subject to litigation. There are large amounts of non-forest biomass currently available in California, including agricultural residues and MSW biomass.

There remains a need to fully demonstrate biomass IGCC in the United States in order to provide financiers a "homegrown" case study. There are generally few options available to developers when faced with repowering a facility that has reached its useful life, or when siting a new one. There are opportunities for advanced system development including increased diversity in the power generation fuel supply, load and voltage support to the grid from distributed generation opportunities, improvements to rural economies, reductions in greenhouse gas emissions and other environmental improvements.

Small Scale and Modular Biomass

Most recent development work in small scale and/or modular biomass power systems has been directed at atmospheric air blown gasifiers coupled with reciprocating engine generators. The U.S. DOE small modular biomass program (Phase I, 1998) selected four projects for a Phase II in 1999. The solicitation considered systems with electrical generation capacities in the range of 5 kW to 5 MW. Two of the four Phase II projects are based on thermal gasifier systems. A small scale system of 15 kW (Community Power Corporation or CPC) was awarded development funding and several units are or have

been tested in the western United States. The larger gasifier system to be awarded Phase II funding (developed by Carbona) is, unfortunately for many United States and California interests, being constructed in Denmark.

Europe and India have developed several independent gasifier based power systems under 8 MW. There has been progress addressing the gas quality and water effluent (depending on use of gas) issues that have impeded safe and reliable systems in the past. The Ministry of Non-conventional Energy Sources in India reports that more than 1,800 gasifier power systems are deployed in the country for a combined capacity of 58 MW. Systems developed for deployment in Europe tend to be configured for CHP and many are designed for low cost of labor in the operation (e.g., automatic with safety shutdowns). Systems developed in India generally are for rural and developing areas. Cheaper labor and the higher need for employment in these regions has led to systems that are not as automated as those in Europe. The Swiss Federal Office of Energy evaluated the IISc gasifier design both in India and at a research facility in Switzerland. The São Paulo University in Brazil is currently evaluating an IISc gasifier for rural electrification in the Amazon region.

With large amounts of forest biomass potentially available in the next few years from forest fuel reduction measures (permit litigation notwithstanding), California and federal agencies are interested in technologies that create some product or value from the resource. The alternative is prescription or pile burning or some other form of disposal. The CPC gasifier is being investigated as a possible technology for the resource but the prototype systems are small (15 to 50 kW). It is unclear how thoroughly overseas developments have been investigated for application in the United States.

Rice Straw as a Fuel

More than 95% of California's 500,000 acres of rice crop is grown in the Sacramento Valley. There are some 1.5 million dry tons of residue rice straw after harvesting rice in the fall. Historically, the straw and stubble were burned in the field in the fall and spring before planting. Legislation enacted in the 1990s restricted open field burning of rice straw to a maximum of 25% of planted acres and only if burning is required for disease control. Plowing the straw back into the ground is expensive and promotes germination and spread of weeds. Markets for straw are limited and only about 30,000 tons are used annually mostly for animal feeding and erosion control products (bales, plastic net-wrapped wattles). Currently, less than 15% of the acreage is burned.

Straw fuels have proved to be extremely difficult to burn in most combustion furnaces, especially those designed for power generation. The primary issue concerning the use of rice straw and other herbaceous biomass for power generation is fouling, slagging, and corrosion of the boiler due to alkaline and chlorine components in the ash. None of the biomass power plants built to date in California can economically fire straw, even though some were built with air permits requiring them to do so.

Europe, and, in particular, Denmark, currently has the greatest experience with straw fired power and CHP plants. In 1990, Denmark embarked on a new energy policy with a goal to double the use of renewable energy by 2005. Because of the large amount of cereal grains (wheat and oats) grown in Denmark, the surplus straw plays a large role in the country's renewable energy strategy. In 2001, 750,000 metric tons per year was being consumed in Danish power plants (in addition to straw consumed in more than 60 district heating plants). Recently completed facilities in England and Spain were designed and built by the companies that developed the systems in Denmark. The facilities each have the capacity to consume more than 100,000 tons per year of straw fuel.

Technology developed includes combustion furnaces, boilers, and superheat concepts purportedly capable of operating with high alkali fuels and having handling systems which minimize fuel preparation. Much of this development has occurred with support of government policies on CO_2 emissions reductions to help meet Kyoto agreements.

Opportunities afforded by achievements in Europe to develop power systems capable of using straw, including joint California-European projects, should be investigated.

Systems for Conversion of MSW

The amount of municipal solid waste from Sacramento County jurisdictions disposed in landfills was 1.5 million tons in 2003. Biomass comprises an estimated 70% of the disposed mixed waste stream (weight basis). If all the biomass material in the waste stream was converted to electricity, about 40 MW power would result. For all of California, about 40 million wet tons of MSW are landfilled annually. Some 27 million wet tons are biomass. Conversion of all California landfilled MSW biomass to electricity would generate approximately 2,000 MW (Williams et al. 2003).

Some advantages of this source of biomass are that it currently is delivered to central locations and is subject to disposal or tipping fees that add economic support. MSW is not without disadvantages. It is typically very heterogeneous coming in a large range of particle sizes, moisture, and component characteristics.

CIWMB is currently investigating conversion technologies as alternatives to landfill. Several jurisdictions in the State are interested as well. Combustion based systems (incineration) are likely to face strong opposition from some members of the public. Proposed regulations disadvantage thermal conversion of MSW by not allowing the material processed to receive full diversion credit. Only AD conversion systems will receive such credit. This is already influencing the selection of systems for waste jurisdictions in the State that are contemplating MSW conversion systems.

Due to the heterogeneous nature of mixed waste, extensive preparation and sorting would likely be required before introducing the feedstock to a conversion process. Gasifier designs and gas cleaning systems suitable for clean wood chips, for example,

will need to be modified if fueled with MSW components (unless source separated wood or paper is available).

Thermochemical Systems

Europe and Japan have developed several "non-combustion" conversion technologies for the purpose of treating or reducing waste. Thermochemical and biochemical MSW conversion systems are both operating overseas. Policies and energy prices in Europe and Japan help create market conditions that make some of these systems economically feasible. Higher tipping fees, waste management policies, and/or internalizing environmental benefits for avoiding landfills in California are probably needed before significant numbers of MSW conversion technologies are built in the state.

Non-combustion conversion technologies for MSW components are emerging technologies in the United States. Greater in-state experience is needed with integrated waste management systems that include conversion technologies for energy and other products. Fundamental understanding of fuels derived from MSW and their behavior in a variety of conversion processes is necessary in order to optimize performance including meeting environmental requirements.

Bioconversion Systems

AD is a fermentation technique typically employed in many wastewater treatment facilities for sludge degradation and stabilization but also the principal process occurring in landfills. Large dairies and swine farms in the United States are turning to the use of AD primarily as a means to mitigate the environmental impacts of manure lagoons with some capture of methane for energy production. The United States has approximately a dozen digester systems operating on animal wastes and producing power. Projects recently commissioned and under construction in California will add about a dozen more to the number. Many household scale digesters are employed in rural China and India and elsewhere around the developing world for waste treatment and gas production. Approximately 5 million households in China use anaerobic digesters. The digesters produce biogas that is used as an energy source by the households, and produce fertilizer that is used in agricultural production. Europe, especially Denmark, has developed large-scale centralized systems for solid waste stabilization and energy generation as a byproduct.

To improve the quality of feedstocks used in AD and composting operations, source separation of household and commercial food and garden wastes is utilized extensively in Europe. At least 11 European Union countries have implemented or are about to implement source separation for food and green wastes. In Switzerland for example, approximately 220 lb per person per year of source separated food and green waste is

collected. About 12% of the material is stabilized by AD facilities, and the balance is composted.

There are some 86 AD facilities in Europe either operating or under construction with capacity greater than 3,000 tons per year and with at least 10% of the treated feedstock from municipal or commercial organic waste. Many of these facilities will co-digest animal wastes and municipal waste water sludges. Total MSW and other organic waste AD capacity in Europe is about 2.8 million t/year. In Spain, the 13 large capacity plants, which average 70,000 t/year, were anaerobically treating nearly 7% of the biodegradable MSW by the end of 2004.

The primary drivers for these technologies have been environmental protection and waste management, with energy recovery secondary. More recent valuing of the renewable and distributed energy attributes of AD increases project desirability. Co-digesting multiple feedstocks can increase methane production and reduce capital costs compared to separately treating waste streams. Opportunities for applications of AD should continue to be investigated for certain biomass resources in the SMUD region as well as the rest of the state.

Improvements in biogas conversion to electricity should continue to be addressed as well. This includes gas cleaning and upgrading to pipeline standards in order to mix with and fire in natural gas power plants and improvements to reciprocating engine and microturbine performance when fuelled by biogas. For example, co-production of hydrogen gas either in AD systems or by reforming a portion of the methane in the biogas can lower NOx emissions from reciprocating engine generators which would improve the environmental performance of electricity production.

2.0 Environmental Impacts

2.1 Introduction

Environmental impacts from biomass power generation include those due to gaseous, liquid, and solid process emissions or byproducts, noise, nuisance and aesthetic factors, and indirect or life-cycle impacts. Indirect emissions can include fugitive emissions from fuel yard and feedstock operations such as dust, volatile organic compounds and odors from handling and fuel storage, and vehicle and equipment emissions from fuel, feedstock, residue, and other material transport and processing.

One of the most important environmental impacts related to biomass conversion technologies are air emissions, especially NOx, due to the fact that such a large portion of the State fails to meet federal and state ambient air quality standards for ozone. Ground-level, or tropospheric, ozone is rarely emitted by human activity but is formed when natural and anthropogenic ozone precursors, primarily NOx and VOCs, react in the presence of sunlight, hence the name "photochemical smog." Tropospheric ozone is controlled by managing precursor emissions.

Oxides of nitrogen are created by high temperature reactions of oxygen and nitrogen. The source of nitrogen for these reactions is primarily the combustion air but fuel-borne nitrogen can be significant. Though NOx is a criteria pollutant, it is not emitted at levels high enough to raise the ambient concentration above state or federal limits. Of the ozone precursors, the control, or reduction of NOx emissions are the more difficult and expensive. For the same fuel and power output, intermittent combustion systems such as reciprocating engines have higher uncontrolled NOx emissions than continuous combustion devices such as flares, boilers, and gas turbines.

The other important ozone precursors, VOCs, are usually emitted from combustion sources as products of incomplete combustion. They can be controlled with well designed and operated combustion systems for all types of fuels. Non-combustion anthropogenic VOC sources include evaporated hydrocarbon fuels, fugitive emissions from oil refineries and petro-chemical plants, fermented beverage manufacturing, large animal feeding operations and feed ensiling. Carbon monoxide emissions are also controlled by following good combustion techniques.

Particulate matter is currently controlled by standard methods that include cyclone separators, filtering, and electrostatic precipitators, often with multiple particle control devices used in combination. Control of sulfur and ammonia emissions are important for atmospheric PM reduction as well because of secondary reactions leading to the formation of sulfates and nitrates. Both sulfur oxides (SOx) and NOx also contribute to acid deposition in the environment ("acid rain").

Liquid emissions from gasifier systems (condensed tars and/or spent scrubber liquids) may be toxic and should not be released untreated. There are a variety of means to treat these liquids that are generally technically viable and are commercially applied in

handling industrial waste liquids. Whether the techniques can be economically applied to biomass fueled gasification systems in California remains uncertain as few large commercial-scale tests have been conducted, and none have occurred in California using biomass although research projects have been completed. Depending on the treatment, there may be toxic solids remaining which will require disposal as hazardous waste. The latter is potentially true for any biomass conversion technology handling unseparated municipal wastes.

Solid fuel combustion facilities such as biomass fired stoker or fluidized-bed combustors generally have low or zero liquid emissions. Usually, liquid emissions from these systems are associated with boiler blow-down or cooling tower discharges. These types of discharges are intermittent and/or of small volume and can be disposed through municipal sewer systems or kept on site in retention ponds where the water eventually evaporates.

Liquid emissions from AD systems can be substantial and may need treatment depending on the source of feedstock.

2.1.1 Organization

Environmental Performance Section

The first part of Section 2 contains results from a review of emissions and environmental impacts of selected biomass conversion systems (essentially the Task 1.1.2.1 report).

Emissions and impacts from small/modular gasifiers as well as a medium BIGCC unit are discussed. Solid fuel biomass boiler emissions in California are compared to the straw fired facility in Ely, England. Reciprocating engines are (or will be) the prime mover of choice for small/modular biomass gasifiers because of cost and efficiency. Several sources were consulted for recent emissions and operations experience from engines fueled by gasified biomass.

Information on solid waste environmental impacts is presented as well as information for dairy manure digester systems. The most used prime-mover for electricity from biogas is presently the reciprocating engine due to low cost and relatively high efficiency. Much effort was spent investigating reciprocating engine and emissions issues; recent source test results from biogas fueled engines are included. Gas turbines fueled by biogas offer improved emissions and are gaining a foothold in the market. Some emissions test results from the Los Angeles County Sanitation Districts are presented. Fuel cells that use reformed methane from biogas are being demonstrated in several locations in the United States. Though presently very expensive, they offer the advantage of extremely low emissions.

Air emissions from prime movers fueled by biomass are presented in Table 2-0.

Table 2-0. Air emissions from biomass fueled power systems.

Prime Mover	Control Technology	units	NOx	CO	UHC/THC	ROGs	PM	SO_2	Source
California solid fuel biomass boilers	SNCR, flue gas recirc., & PM control	lb/MWh	0.64 - 0.95	0.1 - 1.5	0.01 - 0.09		0.09 - 0.55	0.02 - 0.26	1,2
BIGCC, various fuels (Värnamo, Sweden)	Gas turbine -Untreated	lb/MWh or (ppm dry gas)	2.2 - 9.8	(50-450)	(<1)		(<1)	0.2-2.0	3
Reciprocating Engines fueled by gasified biomass	Lean burn	(ppm, 15% O2)	(30 - 300)	(100 - 1000)	(<10)				4,5
	Rich-burn SI engine w/ 3-way catalytic converter (single test, CPC)	lb/MWh	0.65	0.03	0.03				6
Reciprocating Engines fueled by biogas (LFG. WWTP, manure digesters)	Large, lean burn	lb/MWh	.65-1.9	6.4-10.6		.36-1.7			7
	Rich Burn, 3-way catalyst (dairy, 300 kW)	lb/MWh	0.95	5.84		0.08			8
	Rich Burn -no controls (swine manure, 100 kW capacity operating @ 45 kW	lb/MWh	12	58		112		23	9
	CARB BACT Recommendation	lb/MWh	1.9	1.9		7.8			10
Gas Turbine 30 kW (LFG)	uncontrolled	lb/MWh	0.2-0.24	0.6-0.72	2.4 ppm, (3% O_2)			est. 1.03	11
Gas Turbine (<3 MW) fueled by biogas	CARB BACT Recommendation	lb/MWh	1.25						10
Fuel Cell, LFG fuel	uncontrolled	lb/MWh	0.0017	0.025	0.017			nd	11

Sources:

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10) (2002). "Guidance for the permitting of electrical generation technologies." California Air Resources Board, Sacramento. Available at: http://www.arb.ca.gov/energy/dg/dg.htm
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Emission Controls and Recommendations Section

The latter part of Section 2 contains detailed discussion of emission control technologies as they apply to biomass conversion systems (primarily from the Task 1.1.2.2 report).

Earlier portions of this study examined biomass conversion technologies for application within the SMUD region and identified four principal types for further analysis. These are gasification, combustion of straw and other agricultural biomass, AD of separated municipal wastes and green wastes, and AD of dairy manure. Environmental reviews of each of these technologies were completed (Williams et al. 2003). This report addresses environmental limitations for the use of these technologies in California and describes potential improvements or remediation measures to allow implementation by SMUD or SMUD partners. The main environmental areas addressed are outlined below:

Conversion technology	Environmental Improvement Discussed
Gasification Fixed bed – small to medium scale BIGCC – medium scale	Engine or gas turbine NOx and CO, waste water or tar disposal, char utilization or disposal
Straw combustion system (solid fuel boiler)	Boiler NOx, PM emissions (esp. silica), ash disposal, emission offset credits
MSW/green waste AD systems	Gas engine NOx, biogas cleaning Emissions offsets from reduced transport of waste
Dairy manure digester systems	Gas engine NOx, biogas cleaning and sulfur removal for engine, turbine, CNG or pipeline upgrading, and fuel cell applications

The criteria pollutant status of the air quality districts in the Sacramento region is discussed and a review of the region's Air Pollution Control Districts' (APCD) permit requirements for stationary engines is presented. This is followed by a discussion of NOx sources and NOx formation. Control strategies and technologies are presented followed by suggestions for improved NOx performance for boilers and reciprocating engines.

Environmental impacts from biomass power systems include positive and negative impacts. The positive impacts of local biomass utilization for power are touched on only briefly here (e.g., calculation showing emissions reduction due to halting MSW transport from Sacramento to Reno), but there is a large body of information documenting benefits. Morris (2000) is a recent example.

Solid and liquid emissions from biomass conversion systems as well as noise, nuisance, and aesthetic factors may be "show stoppers" for a new facility depending on proposed location and process but they are not precisely technical problems.

Liquid emissions from some gasification cleaning systems are toxic and require treatment before disposal. This is an added cost for the facility but, generally, can be

accomplished with established methods. Improvements to systems in order to reduce or eliminate liquid emissions from gasification processes exist (tar cracking and/or hot gas cleaning and fired to gas turbine), or are being developed (for example the CPC downdraft gasifier, warm gas fired to engine).

Solid emissions (ash or char) can typically be disposed in conventional landfill or land applied. Some gas cleaning systems for gasified biomass rely on condensation of a portion of the tars in the gas onto char/ash particles which are then removed from the gas. In some cases, these solids (with condensed tar) present a handling and toxic waste disposal issue (the solids from the CPC system are an example). Whether the solids are toxic depends on the gasifier conditions, the gas cleaning system, and the fuel. Some systems may allow at least some of these solids to be recycled to the gasifier. Eventually, fuel ash must be removed and if it contains condensed tar compounds it is potentially toxic. For these types of tar and solids removal, gasifier start-up, turn-down, upsets, or sustained operation at "off-design" conditions can increase the chance of contaminating the solid residue.

Air emissions and technical issues for emissions reductions are the highest technical hurdle facing widespread use and acceptance of new biomass energy facilities in California. Control of NOx, VOC, and PM emissions are of highest importance in most California air basins.

For solid fuel biomass power plants, the Best Available Control Technology (BACT) is CFB boilers and SNCR (for NOx reduction). Current NOx emissions range from about 0.6 to 1 lb/MWh. For this class of technology, NOx emissions can be improved with fuel staging and reburning technology and/or SCR NOx reduction, both of which are developmental for solid fuel biomass boilers.

Biomass IGCC air emissions are expected to be controllable to acceptable limits using demonstrated fuel gas cleaning technologies and existing control systems. The hurdles for BIGCC are predominantly economic, accounting for the lack of operating commercial facilities even though the technology has been largely demonstrated in Europe.

Acceptable air emissions from gas engines fueled by biomass (biogas or producer gas) present a technical hurdle for installation in much of California. Providing the fuel gas is sufficiently clean, reciprocating engines fueled by biogas or producer gas should realize similar or improved emissions as compared to engines fueled by natural gas. Rich burn engines generally will need a three-way catalyst for control of NOx, CO, and hydrocarbons. The fuel gas must be cleaned of sulfur, potassium, chlorine, and metals in order for the catalytic converter to have an acceptable service life.

Lean burn engine technology is preferred by operators because reduction catalysts are not currently required and, therefore, the fuel gas quality requirement is less stringent. Lean burn engines are currently not available under about 180 kW.

Increased market interest may entice engine manufacturers to develop lean burn engines in the smaller capacities required for many dairy scale digesters and some of the smaller scale MSW AD systems that might develop. A market study was not performed, but SMUD is encouraged to consider investigating engine manufactures to assess lean burn for small engines.

Hydrogen mixed (or included) with the producer gas or biogas extends the lean burn flammability range. Investigating hydrogen-assisted lean burn technology should be pursued for small engine based biopower systems (this is currently being investigated for LFGTE). Improved hydrogen co-production methods from AD and gasification of biomass should be linked with emissions improvement for conventional power systems (engines) as well as for its fuel value. Full hydrogen production can also be investigated for the longer term, including use in stationary fuel cells as well as vehicles. Molten carbonate fuel cells are already operating on landfill gas.

Sulfur removal techniques can be improved to reduce costs. Biofilter methods that remove sulfur may offer benefits and should be explored. Biogas upgrading by stripping carbon dioxide also results in lowered sulfur content. For stationary power using digester gas, simple water scrubbing for sulfur and partial CO_2 removal would allow for easier catalytic conversion for emissions control and offers the potential for pipelining.

2.1.2 Recommendations

Solid Fuel Boilers and Straw Combustion Power Plants

Because of the large biomass resource in California, the aggressive RPS, the aging solid fuel biomass fleet, and the poor air quality in many California air basins, the state should continue and expand active participation in NOx reduction research for new and existing solid fuel biomass facilities.

For new solid fuel combustion of biomass, advanced reburning should be considered as part of the original plant design using gasified biomass for the reburn fuel or other reburning techniques such as direct biomass injection. For existing facilities, there remain unanswered questions regarding the viability of retrofit reburn systems using biomass gasification. Those questions likely won't be answered without a full scale commercial demonstration of a retrofit system.

For a rice straw fired power plant (based on recent European designs), uncontrolled NOx emissions are expected to be higher than that from a wood fired facility because of higher fuel-NOx resulting from the higher nitrogen content of straw compared to wood.

Selective catalytic oxidation (SCR) technology for NOx reduction in biomass fueled boilers is difficult to implement (because of catalyst de-activation issues) and is considered developmental. Research is ongoing both in the United States and Europe. California should monitor, or actively pursue SCR-biomass research.

So-called "regenerative" SCR (RSCR) may offer an improvement over the currently used non-selective catalytic oxidation (NSCR) method for NOx reduction. RSCR treats flue

gas after PM removal by re-heating the gas to a level required for the catalyst to function. Due to the expense and energy required for re-heat, RSCR systems do not necessarily operate at the optimal temperature for the catalyst. Therefore, NOx reduction from RSCR is expected to be not as good as standard SCR. Performance information from the two biomass facilities in the Northeast recently retrofitted with RSCR should be pursued. Whether RSCR is suitable (and sufficient) for California's needs should be determined.

Low temperature ozone injection (also called low temperature oxidation) is intriguing, but a detailed review was not completed during this project. The technique should be investigated as a candidate for installation at new biomass combustion facilities as well as for retrofit cases.

Power from AD of MSW

Improved gas engine emissions (NOx) and/or increased efficiency of gas turbine systems are needed to increase the desirability of each prime mover type in AD in MSW power applications.

Diverting the organic fraction of MSW to AD and landfilling the treated digestate (or completely bypassing the landfill by upgrading the digestate to value added products) will have positive long-term environmental impact (compared to simple landfilling of untreated waste streams). These benefits should be used to help offset costs or impacts of MSW conversion to energy.

Policy strategies, such as landfill taxes, extended producer responsibility (packaging and product take-back requirements), banning biodegradable materials in the landfill, and/or assigning life-cycle costs of waste management/disposal to the price of the product or service should be pursued. The emissions produced from truck traffic required to haul Sacramento waste out of state are calculated as an example of direct emission offsets that might be available if the practice was curtailed and the material was used locally in energy production.

Dairy Digester Power Systems

Managing dairy manure to decrease ground and surface water contamination and reduce uncontrolled air emissions may create opportunities for power production as a by-product of improved environmental performance of the dairy industry. If power is produced from dairy digester gas, the facility should be credited with emission offsets for emissions that would have occurred had the gas been flared.

Gas Engines

NOx emissions from engines can be reduced via catalytic after-treatment of exhaust gas, and, in some cases, treatment, or removal of nitrogen compounds in the fuel gas. However, catalyst deactivation can occur when sulfur, alkalis, and metals are present in the fuel gas.

For reciprocating engines powered by gasified biomass, the fuel gas is usually cooled before induction to the engine which should condense alkali and metal vapors onto particles or aerosols (sulfur is generally not an issue with producer gas because of low sulfur content in most biomass). Providing PM is sufficiently cleaned from the fuel, there may be fewer problems using catalytic emission control with reciprocating engines than with gas turbines and hot-gas clean up systems.

The potentially high concentration of H_2S in biogas presents a problem for emissions, both as a source of SO_2 emissions as well as the role it plays in deactivating catalysts.

Nitrogen, a macro nutrient required for plant growth, is present in biomass at variable concentration depending on species and cultivation practice. Fuel-bound nitrogen will be released predominantly as ammonia and hydrogen cyanide (HCN) in the fuel gas created by thermal gasification. When the fuel gas is combusted (in a boiler, gas engine, or gas turbine), these nitrogen compounds primarily transform to NOx (fuel NOx). It is difficult to remove ammonia by condensation in hot-gas cleaning systems. Catalytic means to reduce ammonia to nitrogen gas are being investigated.

Fuel gas cleaning in association with catalytic emissions control should be investigated in more detail. Fuel gas cleaning has other benefits as well, including reduced corrosion rates in gas handling and power generation equipment and as a technique to permit use as clean vehicle fuel or for addition to natural gas distribution pipelines.

Hydrogen mixed (or included) with the producer gas or biogas extends the lean burn flammability range. Investigating the effect of increased hydrogen in the fuel gas should be pursued for small engine-based biopower systems. Improved hydrogen co-production methods from AD and gasification of biomass should be linked with emissions improvement for conventional power systems (engines) as well as for its fuel value.

Ongoing and new demonstration or "first commercial" biomass gasification with CHP facilities present a timely opportunity for observing and monitoring these facilities. Further development of existing association with the project developers in order to facilitate exchange of information is recommended.[65]

65. These facilities include: United States—at least two CPC 50 kW or less small modular power systems, a CHP (1 MW) facility in Connecticut; England—Skive, Kokemäki, and many more. A list of industry contacts and potential project participants is included in Task 4.

2.2 Environmental Performance of Selected Technologies

2.2.1 Gasification Environmental Issues

Air emissions from power systems that combust biomass producer gases depend on the choice of prime mover. Many biomass fuels contain nitrogen which can form ammonia, or HCN, in the gas phase. These nitrogen compounds, in most circumstances, will completely oxidize to NOx when the producer gas is burned.

The next section on IGCC includes discussion on air emissions from a gas turbine firing producer gas from a variety of types of biomass. For more detail on reciprocating engines fueled by producer gas, see the section on reciprocating engines.

Liquid and solid residues

Gasifiers that cool the gas for clean-up and/or employ wet scrubbers will have significant levels of organic compounds in liquid or sludge form, some of them toxic. Systems that use hot gas clean-up before firing a gas turbine will have very little to no liquid residues for treatment or disposal (i.e., the Värnamo BIGCC facility).

Two similar gasifier systems available commercially use wet scrubbing (sometimes with chilled water) for gas cleaning before firing in an engine (see Figures 2-1 and 2-2). These systems are based on the Ankur and the IISc gasifiers, both developed in India.

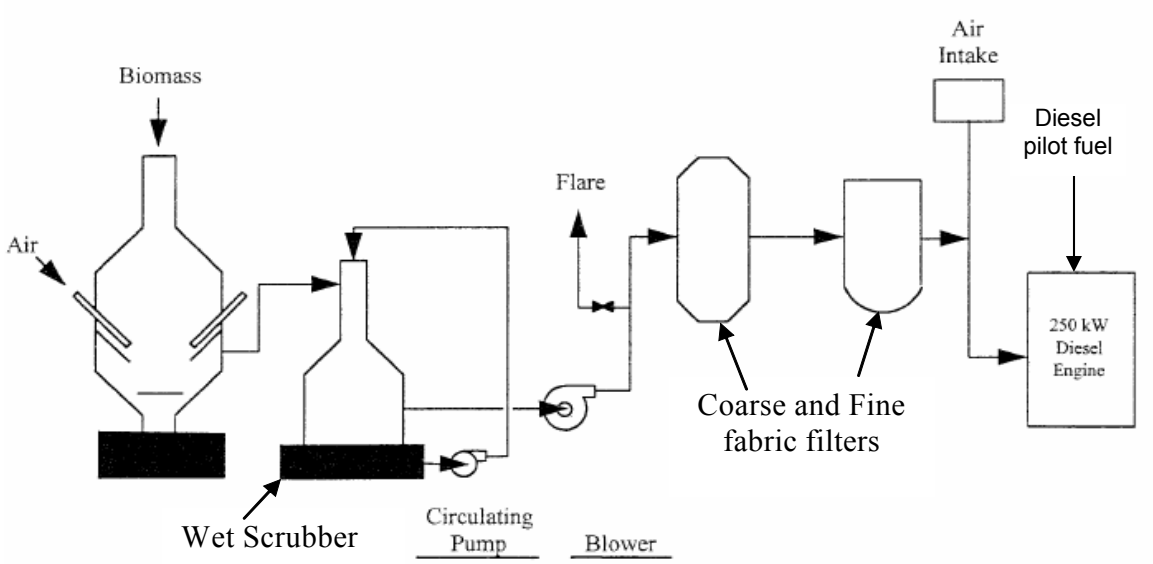

Figure 2-1. Schematic of Ankur downdraft gasifier with dual-fuel power generation configuration

Photo Credit: Wen 1999

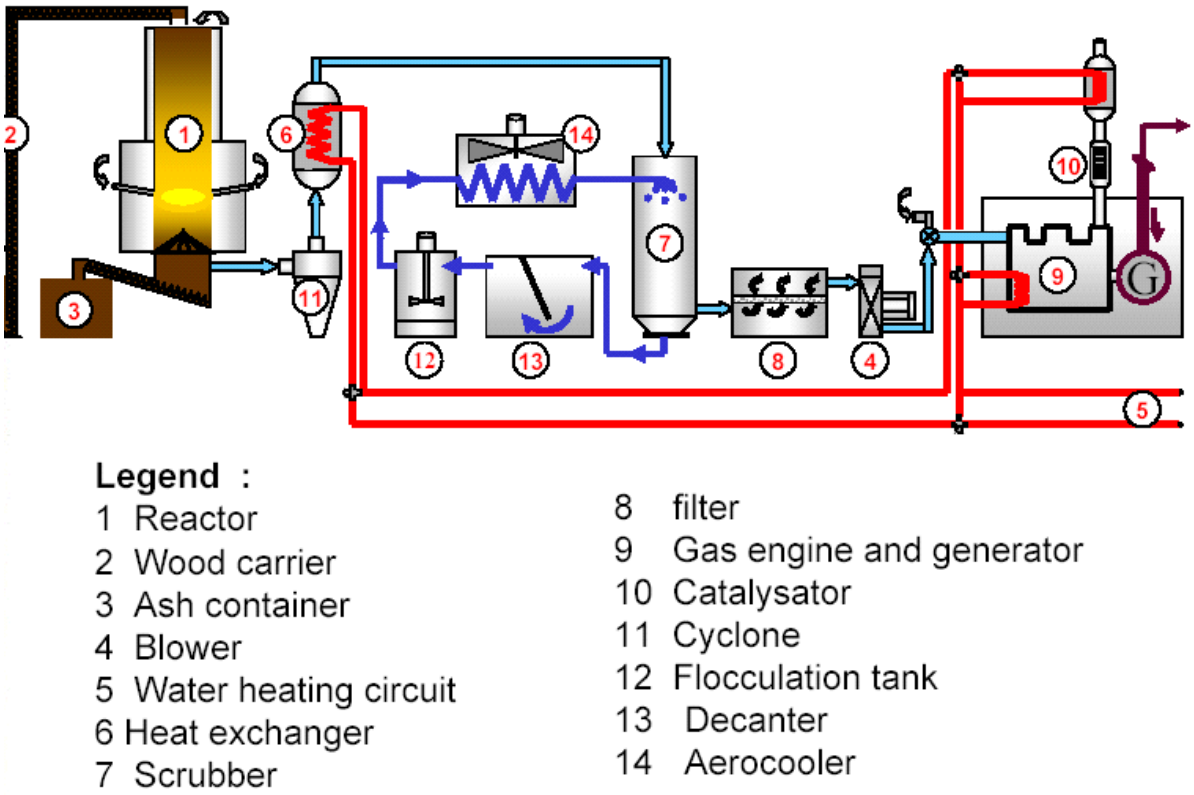

Figure 2-2. Schematic of a Xylowatt SA biomass gasifier CHP facility
Photo Credit: Giordano 2003

Table 2-1 displays analysis of some waste water from biomass producer gas wet cleaning systems. The table shows representative compound types and concentrations for both treated and raw wastewater. The waste water cannot be disposed without treatment. Water treatment can be accomplished by a variety of absorption and separation methods as well as biological remediation. Though technically achievable, the added complexity and expense of waste water treatment systems can make a project economically infeasible.

Dry gas clean-up systems can offer some advantage, therefore. Community Power Corporation has pursued this path for gas clean-up. This leaves only solid residue in the fabric filter and the ash and char in the gasifier that need disposal. There is a potential for the filter solids to contain toxic compounds which should be a consideration when specifying a system.

Table 2-1. Organic compounds in raw and treated producer gas scrubber water (Hasler et al. 1998)

Sample identification		JLR9 untreated	JLR9 treated	Red. %	JLR10 untreated	JLR10 treated	Reduction %	F400 / 2 treated
Sum of PAH acc. US EPA	µg/l	270	0.35	*99.9*	429	2.4	*99.5*	0.59
of which is Naphthalene	µg/l	180	0.25	*99.9*	290	0.9	*99.7*	0.37
Benzo(a)pyrene	µg/l	0.1	<0.1		<0.1	<0.1		<0.1
Benzene	µg/l	<10	<10		<10	<10		<10
Toluene	µg/l	<10	<10		<10	<10		<10
Xylene (o-,m-,p-)	µg/l	<10	<10		<10	<10		<10
Ethylbenzene	µg/l	<10	<10		<10	<10		<10
Methanol	mg/l	66	67		64	61	*5*	62
Ethanol	mg/l	27	25	*7*	26	24	*8*	20
Acetone	mg/l	40	15	*63*	30	12	*60*	4.6
Acetonitrile	mg/l	1.6	1.6		1.6	1.4	*13*	1
tert. Butyl alcohol	mg/l	<0.5	<0.5		<0.5	<0.5		<0.5
Propyl alcohol	mg/l	4.5	4	*11*	3.6	3.3	*8*	1.2
di Isopropyl ether	mg/l	<0.1	<0.1		<0.1	<0.1		<0.1
Methyl ethyl ketone	mg/l	6	3.1	*48*	5.5	2.7	*51*	<0.5
Acetic acid ethyl ester	mg/l	<0.5	<0.5		<0.5	<0.5		<0.5
Dissolved organic carbon (measured)	mg/l	1480	660	*55*	1800	670	*63*	490
Dissolved organic carbon (calculated)	mg/l	72	53		63	48		38

Photo Credit: Wen 1999

2.2.2 IGCC

The Värnamo, Sweden plant was the world's first (and so far, only) biomass-fueled IGCC plant that operated successfully for extended periods of time. This demonstration facility produced power and heat (6 MW, 9 MWth) and was developed by Sydkraft AB and Foster Wheeler International. The gasifier was a pressurized air-blown circulating fluid bed reactor that operated at pressures of 18 to 22 atmospheres. The facility used finely ground, dried wood and bark feedstock (10 to 20% moisture content) delivered to the power generation site from an adjacent preparation facility. Limited tests with pelletized straw and refuse-derived fuel were also performed (Stevens 2001) with some success.

The gas cleaning system consisted of a cyclone separator, followed by heat exchange to cool the gas to about 350°C (from about 900°C) thereby condensing alkali vapors on particulate matter (Stevens 2001). The partially cooled gas was passed through a barrier filter (ceramic and/or sintered metal "candle" filters). Tar and alkali content in the filtered gas were less than 5 g/m^3, and 0.1 ppm (by weight), respectively (Stahl and Neergaard 1998). The filtered gas was then fired in a gas turbine (European Gas Turbines, Ltd). The gas turbine generated about 4 MW, and the steam bottoming cycle produced 2 MW additional (Engstrom 1998).

The Värnamo gasification system has more operational experience than any other biomass fired gas turbine system. Figure 2-3 shows a schematic of the Värnamo system. The gasifier was completed in 1993. In total, the gasifier operated for more than 7,000 hours. The gas turbine was modified for use with the low-energy gas in 1995, and test operations of the integrated biomass fueled power generation system began that year. By the end of 1999, the integrated facility had operated for a total of about 3,500 hours, with most of those during 1998 and 1999. The facility was built as a near-commercial demonstration and was not intended to provide long-term power generation on a commercial basis. The demonstration of the technology was completed in 1999, and the facility was closed (Stevens 2001).

A non-profit company with ties to a local university has been established to utilize the facility for research which includes development of refuse derived fuels for use in IGCC, production of hydrogen-rich synthesis gas, and pilot production of transportation fuels from synthesis gas (Stahl et al. 2004).

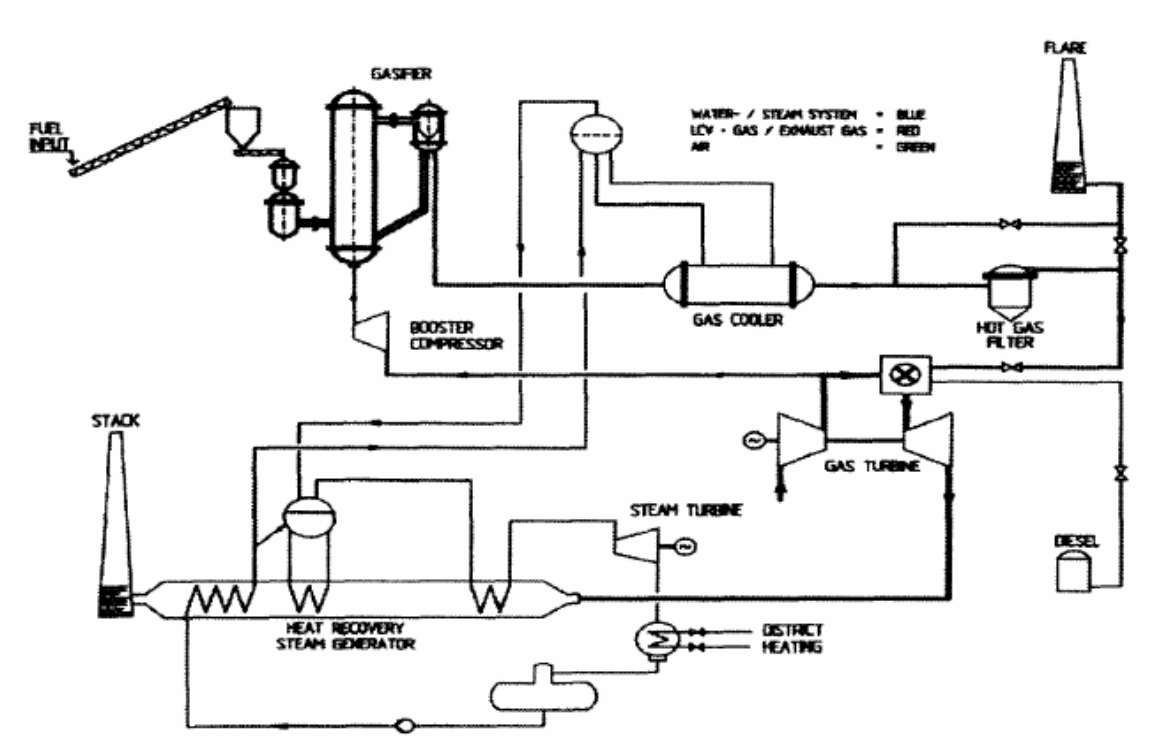

Figure 2-3. Schematic of the Värnamo, Sweden BIGCC facility
Photo Credit: Adapted from Stahl and Neergaard 1998

Emissions and Residues

Because the facility used a hot gas ceramic filter for gas cleaning, condensed tars and other material were not formed and there was no liquid to dispose. Solid residues are typical biomass ash similar to that from combustion systems.

The main issues with emissions from a gas turbine fired by biomass producer gas are NOx and CO. Unburned hydrocarbons and PM emissions are quite low because the cleaned producer gas contains only small amounts of each.

Because of comparatively low combustion temperatures experienced by the modified gas turbine operating on producer gas, thermal NOx was low (Stahl et al. 2004). Fuel derived NOx was quite high in some cases and dependent on fuel nitrogen content. See Table 2-2 and Figures 2-4 and 2-5.

However, the facility did not utilize any flue gas emission controls for NOx or CO. A commercial facility would include standard emission control equipment as required (such as SCR and CO oxidation catalyst for the exhaust as well as selective catalytic oxidation [SCO] of ammonia and HCN in the fuel gas.)

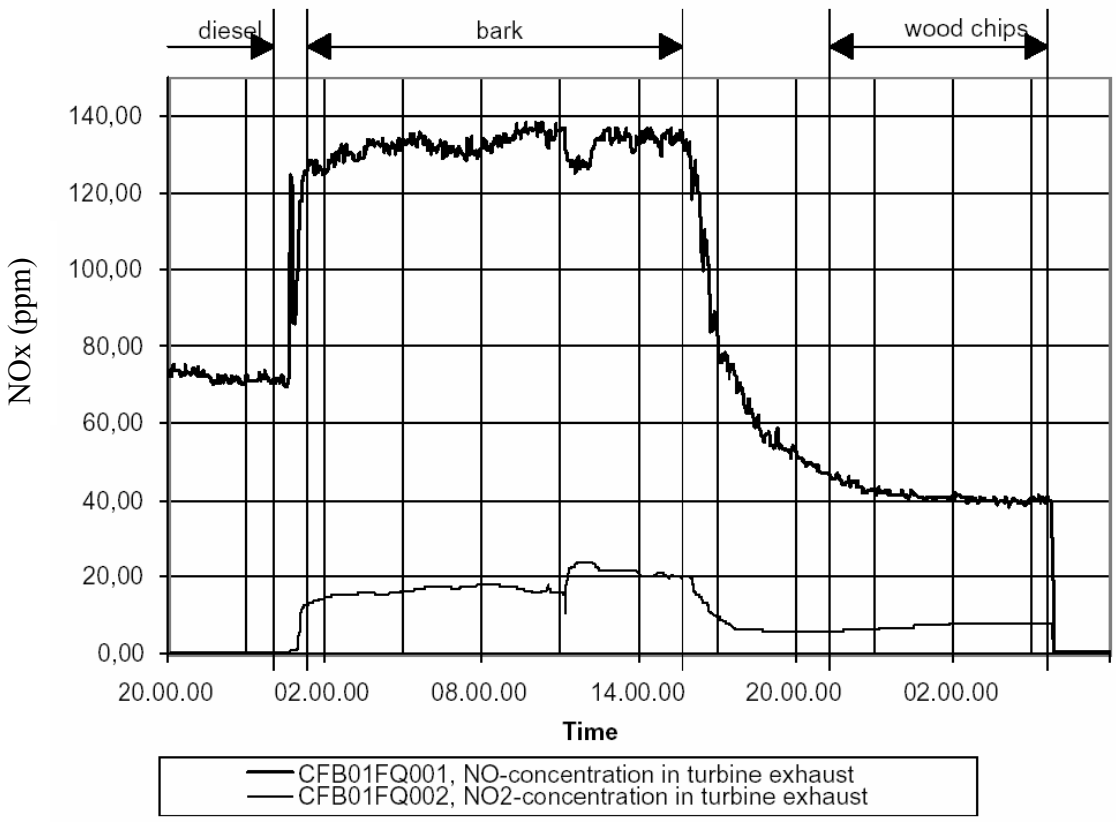

Figure 2-4. NOx emissions showing fuel dependence, Värnamo IGCC

Photo Credit: Stahl et al. 2004

Table 2-2. Fuel nitrogen and emissions for the Värnamo BIGCC facility (approx. 3% O_2) (Stahl 2001)

Fuel	Fuel LHV (MJ/kg, dry basis)	Gas Turbine Load (MW)	Fuel Nitrogen (% dry basis)	NOx (mg/MJ fuel)	CO (ppm, dry gas)	SO_2 (mg/MJ fuel)
Forest Slash and Bark	18.9	3.6	0.2 - 0.4	265	100-170	30
Wood Chips	18.7	3.8	0.1	95	50	10
Bark	20	4.15	0.55	290	80	30
Salix	18.3	3	0.55	390	180	50
Straw	17.1	2.9	0.9-1.7	430	300-450	90
RDF	20.6	3	0.2-0.8	110-210	150-250	30

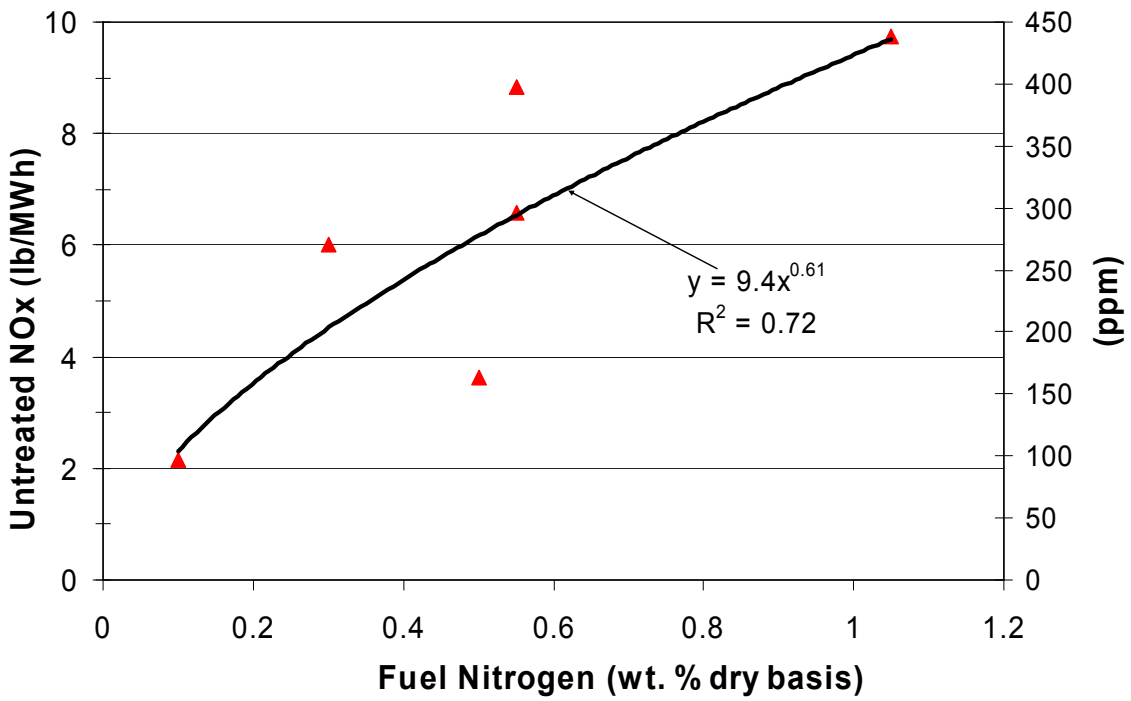

Figure 2-5. Untreated NOx emissions vs. fuel nitrogen content for the Värnamo IGCC facility

Photo Credit: Stahl 2001.

2.2.3 Straw Facility

There are two straw fired facilities recently commissioned outside of Denmark. Located in England and Spain, they were designed and built by the Danish company FLS miljø, now Bioener ApS. The Ely, England, plant, operated by Energy Power Resources, is purportedly the largest straw-fired facility in the world consuming on the order of 150,000 to 200,000 metric tons per year. The facility uses natural gas as a stabilization

fuel in the amount up to 10% total energy input. It produces only power (does not operate in CHP mode) with a capacity of about 34 MW (net) and 36 to 38 MW (gross) at an availability estimated at about 80%. Gross efficiency is about 33% (HHV basis).

Both Ely and the Sangüesa facility in Spain have high steam temperatures (520 to 540°C), and the steam pressure at Ely is 92 bar. The Ely boiler does not utilize a separate fuel for final superheat (combination boiler mentioned above). Specific boiler details could not be confirmed for Sangüesa, so it is not known whether it is a "combination boiler."

For the Ely, England, plant, there are four separate whole bale fuel feed lines running into a single furnace. Bales are shredded before being injected into the boiler. The boiler uses a FLS miljø vibrating grate (see Figure 2-6).

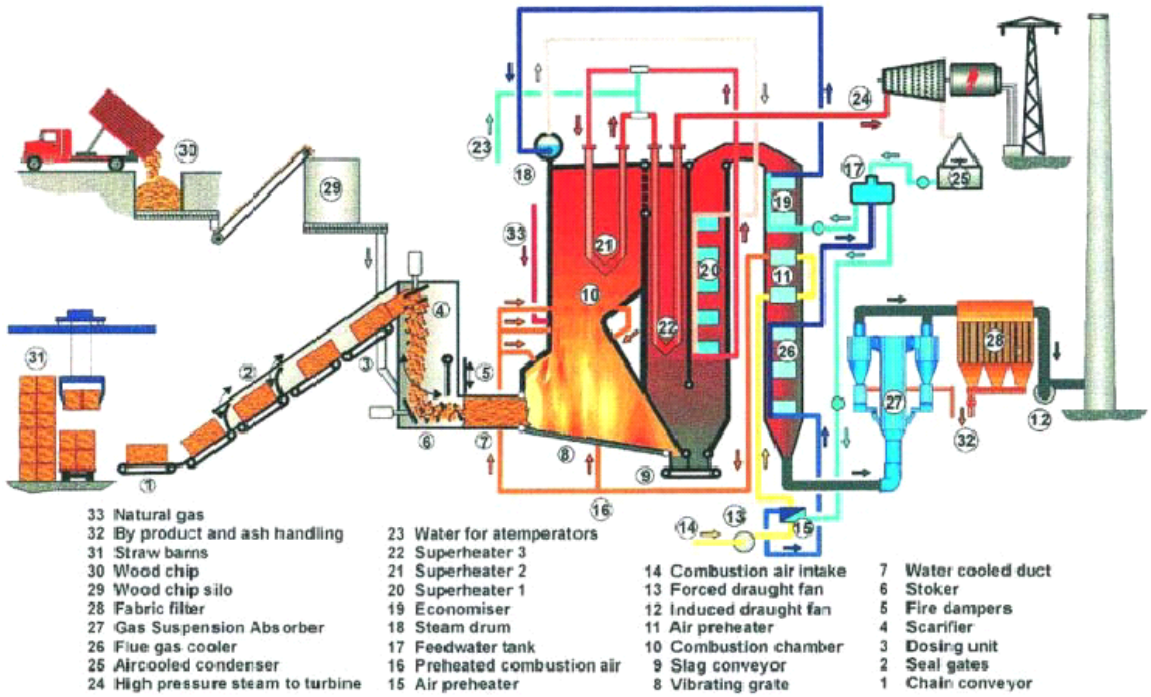

Figure 2-6. Schematic of Ely, England, Power Station
Photo Credit: Newman 2003

Air Emission Control Equipment

The facility at Ely, England, uses staged air combustion techniques and furnace temperature modulation is used for control of both NOx and CO (no ammonia or urea injection system is used). Fuel moisture is limited to a maximum of 26% (wet basis) and natural gas is co-fired (up to about 10% of total energy input), both of which aid in maintaining good conditions for straw combustion (the unburned components in the ash account for about 0.6% of the original biomass energy).

Sulfur dioxide and HCl are removed from the cooled flue gas in a gas suspension absorber (GSA) using fine dry lime (CaO) mixed with recirculated fly ash, a standard

acid gas control system. The lime reacts, producing solid calcium chloride ($CaCl_2$) and calcium sulfates. The lime is added as needed by a control system using continuous measurement of HCl and SO_2 in the stack. Lime injection rate varies from about 25 to 130 lbs/hr (100-500 t/year). The fly ash and calcium compounds (PM) are removed from the flue gas by a fabric filter system. The exhaust stack is nearly 47 meters high (153 feet) and is sized such that the mean stack gas velocity is greater than 15 meters per second during normal operating conditions.

Air Emissions and Comparisons

Table 2-3 shows the actual and permitted air emissions for the facility. The values in mg/Nm^3 are taken from a recent report describing performance tests using several fuel types (Newman 2003). Emission values in lbs/MWh and tons/year were calculated from furnace operating parameters. Actual emissions are about 50% of the permitted level for NOx and HCl. Carbon monoxide emissions are about 30% of permit level and SO_2 and PM emissions are about 20% or less of the permitted amount.

Table 2-3. Actual and permitted air emissions for straw facility, Ely, England (Newman 2003).

	mg/Nm^3 (11% O_2)		lbs/MWh		tons/y	
	Actual	Permitted	Actual	Permitted	Actual	Permitted
PM	4	25	0.05	0.32	6.1	37.8
SO_2	56	300	0.73	3.90	84.8	454.1
CO	79	250	1.03	3.25	119.6	378.4
NOx	149	300	1.94	3.90	225.6	454.1
HCl	15	30	0.19	0.39	22.7	45.4

Table 2-4 shows permitted air emission levels for several California solid biomass power facilities and the Ely, England, straw fired power plant. The emission limits are presented both in pounds per net MWh as well as tons per year (based on 85 % capacity factor).

Table 2-4. Air permit limits for several California solid fuel biomass power plants and one UK facility.

Plant Name	Status*	Town/City	County	Net MW	Net Energy GWh/y @85% capacity factor	Permit Limits (lbs/(net MWh)) PM	SO_2	NOx	CO	VOC, total HC, NMHC	Permit Limits (tons/year) PM	SO_2	NOx	CO	VOC, total HC, NMHC	Source†
AES Delano	O	Delano	Kern	50	372.3	0.28	0.42	1.01	1.76	0.16	52.1	77.4	187.6	328.4	29.8	1
Wheelabrator Shasta	O	Anderson	Shasta	50	372.3	0.80	0.28	3.05	15.86	1.78	148.9	52.40	568.1	2952	331.3	1
Ely Straw	**O**	**Ely, UK**		**34**	**253.2**	**0.32**	**3.90**	**3.90**	**3.25**	**-**	**37.8**	**454.1**	**454.1**	**378.4**	**-**	**3**
Burney Forest Power	O	Burney	Shasta	31	230.8	1.29	0.71	1.85	8.66	1.54	148.9	81.9	213.7	1,000	178.0	1
Rio Bravo	O	Fresno	Fresno	25	186.2	0.23	0.40	1.18	0.49	0.42	21.6	37.2	110.0	46.0	38.7	1
AES Mendota	O	Mendota	Fresno	25	186.2	0.57	0.41	1.11	1.55	0.39	52.8	38.3	103.5	144.1	36.1	1
Woodland Biomass	O	Woodland	Yolo	25	186.2	0.29	0.53	1.06	47.52	0.70	26.8	49.50	98.60	4423	65.2	1
Madera Biomass	O	Madera	Madera	25	186.2	0.40	1.16	2.00	2.40	0.96	37.2	108.0	186.2	223.4	89.4	2
Pacific Lumber	O	Scotia	Humboldt	19	141.5	1.48	-	5.58	22.26	-	105.0	-	394.6	1575	-	1
Tracy Biomass	O	Tracy	San Joaquin	18.5	137.8	0.47	0.34	1.47	2.94	0.69	32.6	23.3	101.3	202.5	47.7	1
Covanta Oroville	O	Oroville	Butte	18	134.0	0.59	-	2.41	36.87	1.24	39.2	-	161.2	2471	83.1	1
Fairhaven Power	O	Eureka	Humboldt	17.5	130.3	0.72	-	2.71	10.86	-	46.9	-	176.5	707.4	-	1
Covanta Burney	O	Burney	Shasta	10	74.5	0.89	0.59	3.30	21.22	2.93	33.0	22.0	122.9	790	109.0	1
Chowchilla II	C	Madera	Madera	10	74.5	0.62	1.04	1.04	2.29	1.04	23.1	38.7	38.7	85.3	38.7	2
El Nido	C		Merced	10	74.5	0.60	0.80	1.04	2.29	1.0	22.3	29.8	38.7	85.3	37.2	2
SPI Burney	O	Burney	Shasta	9.5	70,.7	1.13	0.28	5.26	43.82	3.39	40.0	10.0	186.2	1550	120.0	1

* Status; O= Operating C= Closed

†Sources; 1). Title V airpermits available on-line at; http://www.arb.ca.gov/fcaa/tv/tvinfo/permits/permits.htm
2) Wiltsee, G. (2000). "Lessons learned from existing biomass power plants." *NREL/SR-570-26946*, Appel Consultants, Inc/NREL, Valencia, Calif.
3) Newman, R. (2003).

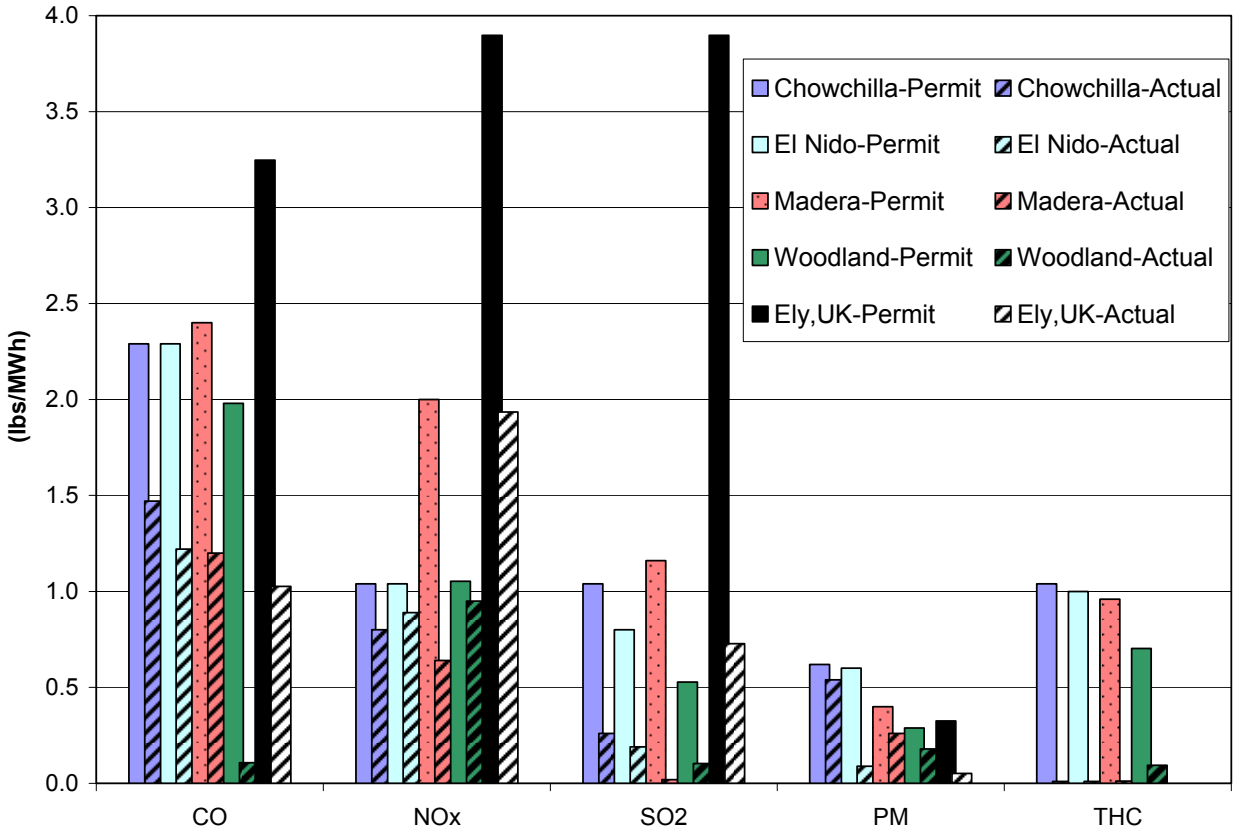

Figure 2-7. Permitted and actual emissions for several solid fuel biomass plants
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Figure 2-7 displays the permitted and actual emissions from four biomass power plants in California as well as the Ely, England, straw combustion power plant. The El Nido and Chowchilla facilities are currently idle, while Woodland, Madera, and Ely are operating. Note that for the California facilities shown, NOx emissions are generally running near the permitted levels (except for Madera which has the lowest NOx emissions of the plants shown but has a high NOx permit level). Cost of NOx control such as purchase of ammonia for SNCR and avoidance of ammonia-slip typically results in operations near permit levels for NOx. Particulate matter emissions are near permitted levels for the California facilities except for El Nido which emitted well below its PM permit limit. Emissions from the Ely, England, straw facility are well below permitted levels. In fact, except for SO_2 and NOx, Ely emissions are below the average permitted levels for the California facilities listed in Table 2-4.

Sulfur dioxide emissions derive from fuel borne sulfur. Sulfur content in the cereal straws (wheat and barley) fired at the Ely facility range from about 0.1 to 0.4 % (by weight, dry basis). Sulfur content of Sacramento Valley rice straw typically ranges from 0.06 to 0.09 % (dry basis) (Jenkins 1996; Jenkins 1989). Sulfur dioxide emissions from a facility fired by rice straw in California are not anticipated to be a control issue and

fluidized beds using limestone or dolomite injection to help control fouling will also assist in removing sulfur from the flue gas.

NOx emissions from the Ely straw facility are low considering that there is significant fuel nitrogen present (see Table 2-5) and no post-combustion NOx control devices are used. NOx at the Ely facility is controlled solely by managing the combustion parameters. In general, California solid fueled biomass facilities use SNCR and/or flue gas recirculation and combustion management for NOx control. Reburning has not so far been deployed for NOx reduction in California facilities, although investigated on a pilot or research level.

Table 2-5. Nitrogen content of several biomass types

Biomass	Nitrogen Content (% by weight, dry basis)	Sources*
Rice Straw	0.47 - 0.93	1,2,6
Wheat Straw (typical Ely, UK fuel)	0.44 - 0.91	1,4,5
Orchard Prunings (English and Black Walnut, Almond)	0.22 - 0.66	1,5,6
Fir / Pine / Spruce	0.05 - 0.30	3,5,6

*Table Sources:

1) Jenkins, B. M. (1989). "Physical Properties of Biomass." Biomass Handbook, O. Kitani and C. W. Hall, eds., Gordon and Breach, New York, 860-891.
2) Jenkins, B. M., Bakker, R. R., and Wei, J. B. (1996). "On the properties of washed straw." Biomass and Bioenergy, 10(4), 177-200.
3) Jenkins, B. M., Kayhanian, M., Baxter, L. L., and Salour, D. (1997). "Combustion of residual biosolids from a high solids anaerobic digestion/aerobic composting process." Biomass and Bioenergy, 12(5), 367-381.
4) Newman, R. (2003). "A trial burn of rape straw and whole crops harvested for energy use to assess efficiency implications." B/U1/00768/00/00 URN 03/1569, New & Renewable Energy Programme, ETSU/DTI (UK).
5) Phyllis, database for biomass and waste, Energy research Centre of the Netherlands, http://www.ecn.nl/phyllis
6) Rizeq, G., and Zamansky, V. (2004). "Utilization of waste renewable fuels in boilers with minimization of pollutant emissions." California Energy Commission contract no. 500-98-037, GE Global Research, Irvine.

Rice straw contains about the same amount of nitrogen as wheat straw (Table 2-5). Therefore, a facility in California burning rice straw would have similar NOx production (i.e., expect similar contributions to total NOx production from fuel borne nitrogen and thermal NOx). Uncontrolled NOx emissions when burning rice straw with wood have previously been shown to increase about 30% for a 20% blend (Jenkins 1994; Jenkins and Bakker et al. 2000). When fired as a blend in commercial power boilers, rice straw required increased ammonia injection to maintain NOx within permit levels adding about $0.08/MWh to the cost of generation (Jenkins and Williams et al. 1999).

Bottom and Fly Ash

The Ely facility consumes straw that has an ash content of about 6% (wet basis). For a straw consumption rate of 200,000 Mg per year, total solid residue is approximately 12,000 Mg or 13,230 short tons. This is equivalent to approximately 40 tons per day or

about two truckloads per day. The Ely facility returns most of the solid residue to area farms for land application. California rice straw has an ash content of about 15% (wet basis). Solid residue for a similarly sized facility burning rice straw will be approximately 2.5 times more or about 33,000 tons per year or 100 tons per day (four truckloads/day). Of some concern relative to wheat straw is the higher silica content of rice straw, leading potentially to the need for greater precautions in ash handling to avoid inhalation hazards.

Liquid Residues

If wet scrubbing systems are not used in emissions control, then liquid emissions from the facility would be very low, limited to boiler water blow-down and discharge sludge from cooling towers. A properly lined and sized holding pond should be sufficient to receive and evaporate all liquids from the facility. A number of facilities in California are already zero-discharge for wastewater.

2.2.4 MSW/green Waste AD Systems and Dairy Manure Digester Systems

Treatment of MSW and animal manures by AD systems are usually viewed as a waste management option with fewer negative environmental impacts than conventional disposal methods.

For MSW, conventional disposal is by landfill with some capture of the generated methane. Older landfills did not employ engineered low permeability liners for reducing leachate transport. Newer landfills are designed to restrict leachate leakage both during filling and after the landfill has reached capacity and ceased receiving material, but it is generally accepted that these systems will eventually fail with leachate intrusion into ground water. Short of monitoring leachate from closed landfills and then mining them to recover and treat or stabilize the material before groundwater contamination occurs, the only other means of ensuring stable waste disposal is to treat the material before landfilling or avoid landfilling altogether. Burning or biochemically stabilizing (composting or anaerobic digestion) wastes are treatment options that are now required in Europe, and only MSW residues can be landfilled.

Traditional animal manure disposal in the United States consisted of scraping pens and spreading manure on surrounding fields. Feeding operations used to be much smaller and ruminant animals used to spend a larger fraction of their lifetimes in pastures compared to confined animal feeding operations. Liquid wastes were allowed to be flushed into streams or simply held in lagoons with seepage controlled only by local soil conditions. Air and water emissions and odors were tolerated because of low animal and human population densities. Proper management to avoid overloading soils with salts was required to reduce salinization of farm lands. This remains a critical issue with land application of manures and digester residues today.

Agricultural operations in California are now subject to strict air and water emission regulations. Air permits are required for all agricultural operations with air pollution emissions that exceed one-half of the major source threshold of any criteria pollutant.

Nutrient limitations in water sheds also determine solids handling disposal to some extent.

Energy production from the biogas created in digester systems is an environmental benefit when compared to simple flaring with no energy recovery, or the fugitive methane and VOC emissions that would have occurred using the traditional options. As discussed in Task 1.1.3.3 (Economic Assessments), energy production from these systems is expensive and possibly uncompetitive if energy revenues alone are needed to finance the entire treatment system.

MSW AD Emissions

Emissions from MSW AD systems include air emissions from the use of biogas (usually stationary reciprocating engine, vehicle, gas boiler, gas turbine, or flare), air emissions from post treatment of solids/digestate (compost and/or land application), liquid emissions from excess process water and de-watering operations, and land emissions depending on how the solid digestates are used or disposed.

In addition, there can be fugitive gas and dust emissions that depend on control strategies, operational practices, and level of maintenance at a particular facility (e.g., enclosed receiving buildings which may have exhaust air treatment to minimize VOC and dust emissions from unloading and feedstock storage).

Air Emissions from Use of Biogas

Emissions from the use of biogas are typical of combustion processes burning methane with the exception of sulfur. Gaseous emissions include NOx, SOx, CO, unburned hydrocarbons, and particulate matter. If the biogas is consumed in applications other than simple flaring, the emissions should receive an offset credit by the amount that would have been created from the displaced fuel.

Very large landfills and waste water treatment facilities can produce enough biogas to justify relatively high capital cost prime movers such as gas turbines with heat recovery (combined cycle), or steam boilers for large scale combined heat and power. For the scales being considered for in-vessel MSW AD and dairy manure-to-power systems in California, reciprocating internal combustion engines are the most likely choice. In cases where NOx emission limits are very low, micro- or mid-sized gas turbines may be attractive. The conversion efficiency of turbines at these scales (less than 2 MW) are not as high as reciprocating engine efficiencies. Turbines generally are more expensive as well, but tend to have superior emissions control performance because of the greater control achievable with continuous combustion engines as contrasted with intermittent reciprocating-type engines and higher excess air. The choice of prime mover type depends on the value of power, heat, emission reductions, etc.

Depending on SOx emission limits and/or concentration of H_2S in the biogas, gas cleaning to lower sulfur and moisture content prior to use in reciprocating engines may be necessary. Wet scrubbing is typical and iron catalyzed oxidation and biological fixed-

film reactor gas scrubbing methods are also used for sulfur removal. In some cases, simple compression and cooling of the gas, a common moisture removal technique, is sufficient to lower sulfur content to a suitable level (Pierce 1997). Elemental sulfur is eventually deposited and can be safely disposed.

NOx is always produced to some degree when fuel is burned with air and can be emitted at high levels from uncontrolled reciprocating gas engines. In California, NOx emissions are usually the limiting factor for stationary power generation using reciprocating engines. Because of impurities in biogas such as sulfur, and in some cases siloxanes (principally associated with landfill gas and sewage digester gas), catalytic converters for control of NOx and unburned hydrocarbons are not often used. Flaring biogas generally emits lower NOx because temperatures with high excess air are lower than those encountered in combustion chambers, but there is no recoverable energy. Lean burn, pre-stratified charge, and exhaust gas recirculation technologies are used for reducing NOx emissions from this class of engine, but are currently not available for power sets below about 500 kW.

Carbon monoxide emissions can become an issue especially when implementing some NOx control strategies for reciprocating engines. For example, very lean burn conditions can lead to incomplete combustion or misfiring which will increase CO and unburned hydrocarbons in the exhaust.

The additional impacts of waste treatment by AD due to energy production are almost entirely due to products of combustion of the biogas and disposal or use of digester residues (digestates). A more detailed discussion of emission limits and behavior of reciprocating gas engines can be found below.

VOC Emissions from Composting of Digestate

Volatile organic compounds are a large group of anthropogenic or biogenic organic compounds with relatively high vapor pressures. VOCs can be potential air pollutants, due to their malodorous and hazardous properties and contribution to tropospheric ozone. In addition, VOCs can contribute to global warming and stratospheric ozone depletion. VOCs are usually defined as the organic compounds (except methane) with boiling points less than 175°F, while semi-volatile compounds are the organic compounds with boiling points between 175°F and 350°F (Komilis et al. 2004). Methane also participates with NOx in the formation of ozone, but the rates are slower and the effect is more important on a global atmospheric scale than on a local scale of diurnal variation.

VOCs are emitted from decomposing biogenic material including MSW and green waste compost facilities as well as post-treatment of digestate from MSW AD systems. The amount of VOC emissions are significant and need to be considered for installations in ozone non-attainment or transport air basins.

Smet et al. (1999) compared VOC and ammonia emissions from two different methods for biochemical treatment of biodegradable wastes. Source separated household and garden wastes (70% garden, 20% kitchen, and 10% paper wastes) were treated by (1) standard aerobic composting with upflow aeration, and (2) a combination of AD followed by aerobic stabilization of digestate. VOC and ammonia emissions were measured from each process. Assuming the biogas produced in the AD stage of treatment method (2) is flared or combusted in an engine, then the total volatile emissions for treatment (2) would come only from the aerobic stabilization portion of the treatment or 6% of those from treatment method (1) (i.e., 44 mg/ton from treatment (2) versus 742 mg/ton from treatment (1), see Table 2-6). Additionally, the partially stabilized digestate from the AD portion of the combined treatment requires about 1/10 the amount of air during the aerobic phase compared to the full aerobic treatment method (1), which requires a proportionately smaller fan and biofilter for final control. However, most of the volatile emission from treatment (2) was composed of ammonia (NH_3) (more than 500 mg per cubic meter) requiring ammonia scrubbing if the gas is to be passed through a biofilter prior to exhaust.

Table 2-6. Emissions for different biochemical treatment methods

Emission Compound	Treatment (a) Aerobic Composting Emission (mg/ton)	Treatment (b) Anaerobic Digestion Emission (mg/ton)	Treatment (b) Aerobic Stabilization Emission (mg/ton)
Total VOC	590	217	3
NH_3	152	1.8	41
H_2S	nd	17	nd
Total Volatiles	742	236	44

Source: UC Davis Research Team ; Source: Robert Williams

Komilis et al. (2004) found gaseous VOC emissions from all principal biogenic components of MSW compost. Total VOC emissions measured ranged from 570 μg per dry kg for food waste and yard wastes (mixed at 22% and 78% by dry weight respectively) to 6,060 μg per dry kg for mixed paper. A mixture to represent the biogenic fraction of MSW (mixed paper, food wastes and yard wastes) produced VOC emissions at the rate of 1,200 μg per dry kg. The VOC emissions are not proportional to, or additive with, the ratio of organic materials in the waste mixture implying interactions occur among the different substrates. The only chlorinated VOC detected was 1,4-dichlorobenzene, and emissions varied depending on the substrate. Komiliset al. (2004) contains a good review of VOC emissions from MSW and composting operations.

Landfill Gas Emissions

An evaluation of the emissions impacts of conversion technologies would not be complete without a discussion of landfill gas emissions, which represent the current state of waste disposal. The conversion of biodegradable material in AD systems will reduce eventual landfill gas production and emission and should receive emission credits that can be applied to offset emissions from the power production component.

As discussed above, the bacterial decomposition of biogenic landfilled material produces significant quantities of landfill gas, which is composed of approximately 50% methane and 50% carbon dioxide. The methane emissions from landfills are particularly important, since methane is a more potent greenhouse gas than carbon dioxide and since landfills represent the second largest source category of anthropogenic methane emissions behind the energy industry (see Table 2-7).

Methane emissions from United States landfills for 1990 to 2002 are presented on a total mass basis in Table 2-7. Total landfill methane production increased over the period, but corresponding increases in landfill gas recovery led to about a 10% reduction in net methane emissions to the atmosphere. A majority of the landfill gas produced by active landfills in the state is converted to electricity, and comparisons of electrical capacities provide a good comparison of the level of control of methane emissions from landfills in the state. For the state, landfill gas that is either currently used for electricity production, is planned for electricity use, or is flared, represents approximately 305 MW, while uncontrolled or vented landfills have a capacity of 31 MW (Hackett 2004).

Table 2-7. CH_4 emissions from United States landfills (Gg)[66]

Activity	1990	1996	1997	1998	1999	2000	2001	2002
MSW Landfills	11,599	13,520	13,802	14,047	14,385	14,659	14,954	15,221
Industrial Landfills	812	946	966	983	1,007	1,026	1,047	1,065
Recovered								
Gas-to-Energy	(824)	(1,360)	(1,618)	(1,938)	(2,177)	(2,376)	(2,630)	(2,748)
Flared	(478)	(2,059)	(2,390)	(2,692)	(2,750)	(2,764)	(3,146)	(3,325)
Oxidized▲	(1,111)	(1,105)	(1,076)	(1,040)	(1,047)	(1,055)	(1,022)	(1,021)
Total	9,998	9,942	9,685	9,360	9,419	9,491	9,202	9,192

Note: Totals may not sum due to independent rounding. ▲ oxidized in soil covering

Solid Residues

Lignin components of biomass cannot be degraded anaerobically. With practical AD systems, size, capital, and time constraints limit the portion of biodegradable material that is actually converted to something less than theoretical. This portion, combined with the lignin components, microbial cell biomass, and the inorganic (ash) components, result in substantial solid residue that may or may not have commercial use.

A potential product from AD of MSW is a compost or soil amendment resulting from aerobic stabilization of the solid residue or digestate. If a compost market does not exist or adequate quality cannot be achieved, then the solid residual may be used in thermochemical conversion or sent to landfill.

Compost quality consists of at least four aspects:

66. United States Environmental Protection Agency, 2004. "Inventory of U.S. Greenhouse gas Emissions and Sinks: 1990-2002. EPA report No. EPA 430-R-04-003.

- Content of toxic compounds such as heavy metals.
- Absence of pathogens.
- Content of undesirable goods such as plastic, metal, glass etc.
- Plant nutritional value, i.e. inorganic nutrients as well as content of organic compounds for improving the structure and humus content of the soil.

Compost Quality – Heavy Metals

The quality of composted digestate depends heavily on the quality or composition of the digester feedstock. Operators and regulations in Europe strongly encourage source separation of household and yard biogenic wastes from the "gray" or "rest" fraction for use in biochemical treatment for both improved digester performance and high quality or useable compost from the solid residue.

Heavy metals and other contaminants present in digester feedstock predominately end up in the solid digestate. Kubler et al. (2000) reported that 80% of the heavy metals introduced into the digester (after pulping and separation of heavy and light fraction) were discharged to the solid digestate. The balance was not reported but presumably most of the remaining heavy metals were in solution in the process water. Metals concentration is generally higher in the digestate compared to that of the feedstock because of biomass conversion to biogas. Edelmann et al. (2004) indicate that results from more than 1,000 analyses of compost from anaerobic digestion with aerobic stabilization or just aerobic treatment of source separated biogenic fraction of MSW showed heavy metal concentrations were less than half of the Swiss limits for compost (in ppm dry matter: Pb: 120, Cr: 100, Ni: 30, Zn: 400, Cu: 100, Hg: 1, Cd: 1).

Composted digestate quality and heavy metal concentration from operating commercial facilities in Belgium using the Dranco AD process is reported on the Organic Waste Systems company website and contained in a report by De Baere and Boelens (1999). Table 2-8 displays some of these data. It includes detailed analyses of finished compost from the Brecht, Belgium plant, which feeds source separated household biogenic and yard wastes to a thermophilic high-solids digester. The digestate is dewatered and composted in a covered facility with forced aeration. The finished compost meets the compost quality requirements for the Flanders region in Belgium (Table 2-8). Data for heavy metals content for composted digestate from the Bassum plant is also shown in Table 2-8.

Table 2-8. Compost analysis from two Dranco facilities in Belgium

	Units	Flemish Compost Standards	Average of Brecht Plant (source separated)	Bassum Plant (grey waste digestion)			
				Fiber material		Sludge Fraction	
				Untreated	Treated	Untreated	Treated
Lead (Pb)	(ppm TS)	<120	97	80	60	220	90
Nickel (Ni)	(ppm TS)	<20	8	25	18	30	18
Zinc (Zn)	(ppm TS)	<300	180	350	180	900	250
Copper (Cu)	(ppm TS)	<90	32	100	55	240	80
Cadmium (Cd)	(ppm TS)	<1.5	1	0.9	0.5	1.9	1.4
Chromium (Cr)	(ppm TS)	<70	23	60	40	40	36

TS = total solids
Source: Organic Waste Systems website and De Baere and Boelens 1999.

The feedstock used for digestion is the biogenic portion obtained from separation of the so-called "gray" or "rest" fraction of the waste stream. Gray waste is the remainder after recyclables, packaging, hazardous, and household biogenic waste fractions are source separated. About 60% of the gray waste stream becomes feedstock for the Bassum plant. Heavy metals content of the fiber and sludge fractions from composted digestate of a portion of the gray waste fraction is higher than that for source separated feedstocks. The compost from Bassum cannot meet the Flemish standards without first removing some of the heavy metals, especially zinc and copper, from the feedstock (De Baere 2003).

Kraus and Grammel (1992) examined compost in several regions within Germany and observed that heavy metals content in compost of source separated biogenic fraction averaged 25% that of mixed MSW compost (Table 2-9). Most, if not all, of these compost samples were from raw or non-AD treated feedstock.

Table 2-9. Heavy metal content in compost from solid wastes in Germany (Kraus and Grammel 1992)

Element	Mixed MSW Compost (ppm)	Source-separated Compost (ppm)
Lead (Pb)	420	83
Nickel (Ni)	84	26
Zinc (Zn)	919	224
Copper (Cu)	222	41
Cadmium (Cd)	2.8	0.4
Chromium (Cr)	107	61
Mercury (Hg)	1.9	<0.2

Dioxin in Trash and Compost

A common misconception in management of solid waste is that emissions (gas, liquid, solid) from biochemical processing of MSW, in contrast to thermochemical processing, are completely benign. Both processing strategies involve potentially hazardous emissions and exposure routes need careful inspection. Dibenzo-p-dioxin and dibenzofuran (PCDD/F or dioxin/furans) compounds are generated by many industrial processes. Operating waste-to-energy (WTE or incineration) facilities in the United States have been retrofitted to MACT standards and as a result, the industry emits approximately 12 g TEQ of PCDD/F per year constituting a decrease of 99.9% from 1987 emissions.[67] Among all dioxin sources, MSW combustion accounts for less than 1% of total air emissions in the United States.[68]

Dioxin/furans are present in detectable amounts in the environment. The compounds are persistent and fat-soluble and therefore tend to bio-accumulate. Because of the background accumulation of PCDD/F compounds in food and fiber, MSW in the United States is likely to contain detectible amounts which may need to be considered in overall environmental impacts.

Further discussion in the detailed report by Brinton (2000) of the Kraus and Grammel (1992) results reveals data from dioxin analysis of several types of compost and raw household solid waste from Germany (Figure 2-8). Averages from several samples of each category showed PCDD/F in raw household mixed waste was present in the amount of 57 ng/kg Toxic Equivalent. Composted mixed MSW had PCDD/F levels of 38 ng/kg TEQ , followed by compost of source separated household waste with 14 ng/kg TEQ and about 10 ng/kg TEQ in green and garden waste compost. Brinton (2000) did not indicate whether the composted mixed household waste was from the same source as the raw mixed household waste or why the PCDD/F concentration was lower in the composted mixed house waste.

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67. U.S. EPA Docket No. A-90-45, VIII. B11 and U.S. EPA Dioxin Source Inventory 2002.
68. U.S. EPA PCDD/F Emissions Database, http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=20797

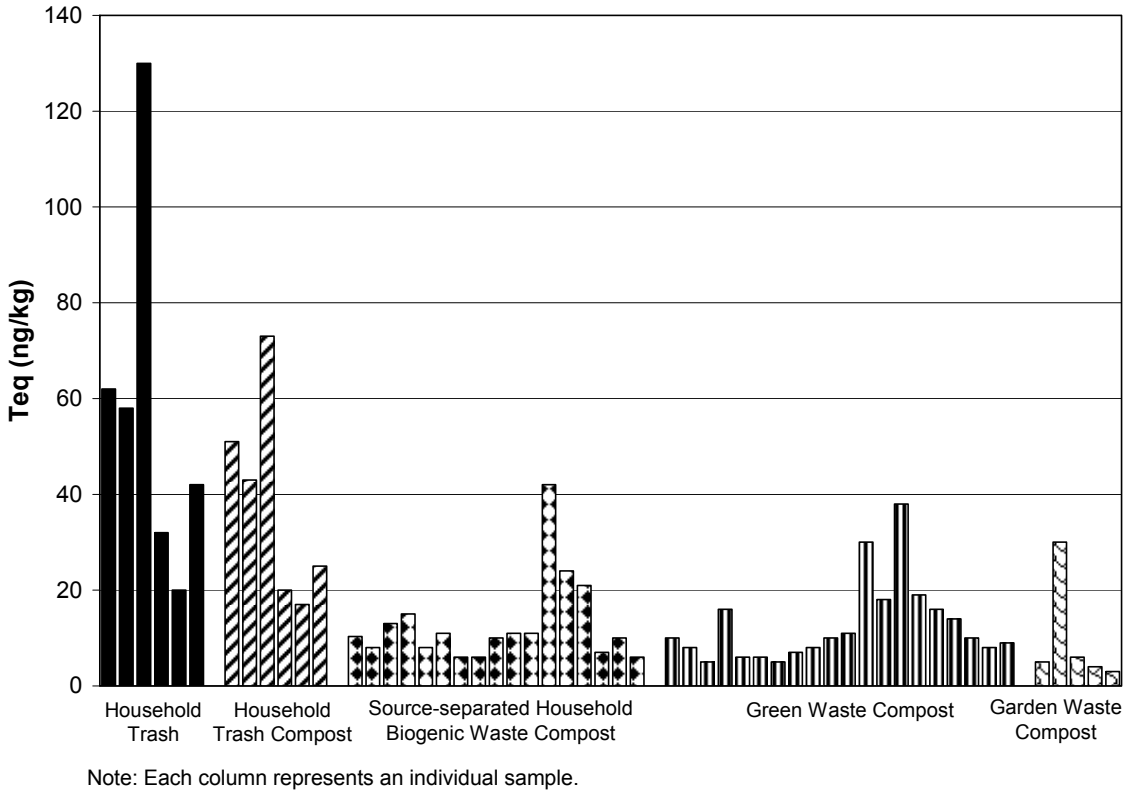

Figure 2-8. PCDD/F content of raw household wastes and several compost types
Photo Credit: Source Kraus and Grammel, 1992, as reported in Brinton (2000).

Pesticides and Herbicides in Compost and Composted Digestate

Certain synthetic pesticides or herbicides are known or suspected to persist in the environment after application. Clopyralid is a persistent herbicide used to control broadleaf weeds such as dandelions, clover, and thistle. It is harmless to humans or animals but survives animal digestion and compost processes.[69] Clopyralid has been banned from certain uses in Washington after it was suspected of damaging tomato crops fertilized with compost. The chemical has been detected in some compost in California but no crop damage has been confirmed. In an attempt to limit use, AB 2356, Statutes of 2002 requires clopyralid be sold only to qualified applicators.[70]

There is potential for detectable amounts of pesticides and herbicides in MSW AD feedstocks in California based on investigations done in Europe. These studies have shown presence of chemicals and pesticides in household organic or biowaste (Taube et al. 2002; Vorkamp et al. 2002; Vorkamp et al. 2003). Taube et al. (2002) examined samples of biogenic waste components of MSW crop protection products (CPP). Typical

69. http://agr.wa.gov/PestFert/Pesticides/docs/Clopyralid/ClopyralidFactSheet.pdf
70. http://www.ciwmb.ca.gov/Organics/Threats/Clopyralid/Background.htm

household and yard wastes in Germany over a four-season period distributed between rural and urban sources were examined for more than 50 pesticide/herbicide chemicals. All samples contained CPP residues. Tropical fruit peels and residues had significant concentration of thiabendazole and methidathion, which are typically applied post-harvest for protection in transport and storage. Dimethoat, dodemorph, endosulfan, and other fungicides were found in vegetable and garden wastes. Laboratory AD was carried out on raw samples and showed that some CPPs could be metabolized, modified, or otherwise stabilized to varying degrees. However, many are persistent (such as dodemorph) and can negatively affect plants and crops if the compost contains high enough levels.

2.2.5 Dairy Emissions

Emissions due to dairy power systems are influenced heavily by the prime mover. As indicated above, biogas production from even large dairies is not large enough to warrant medium to large gas turbines or even large reciprocating engines. See elsewhere in this report for discussion on reciprocating engines fueled by biogas and/or producer gas. The overall benefits of reductions in dairy and agricultural emissions which may be obtained with the utilization of digestion systems and manure solids handling should be assessed when permit levels for stationary engine operation are being determined. Energy production when combined with dairy emission reductions should be encouraged (and appropriate air permit levels granted) so that gas flaring is not the automatic default for biogas destruction.

State law (SB 700, 2002) requires agricultural operations to obtain air permits if emissions exceed greater than one-half the threshold for a major source of criteria pollutants.[71]

For the San Joaquin Valley Air Pollution Control District, dairies (and other confined animal feeding operations) that emit more than 12.5 t/year of VOC will require air permits. The size of the dairy (in number of animals) that will trigger the requirement for an air permit is currently being decided. The primary issue remaining is the determination of accurate VOC emissions from a facility. Methane emissions data from an early study was misapplied and taken as VOC emissions and written into the emission inventory.[72]

On 23 June 2005, the California Air Resources Board (CARB) approved definitions for large confined animal feeding operations (CAFO).[73] For dairies in ozone attainment areas, a large CAFO is a facility with 2,000 or more lactating cows (support stock is not

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71. http://www.valleyair.org/farmpermits/updates/draft_dairy_bact.pdf
72. Benedict and Ritzman (1938) determined methane emission factor to be 160 lbs/cow/year, which was later misinterpreted to be TOG emission factor. A 1980 U.S. EPA study determined that 8% of livestock TOG is reactive, or ROG. Taking 8% of 160 gives the 12.8 emission factor.
73. "Air Board sets stage for large dairy rules," 2005. CARB news release, available at: http://www.arb.ca.gov/newsrel/nr062305.htm

counted for purposes of the definition, but emissions from support stock must be accounted for in the permit to operate). For dairies in ozone non-attainment air basins, 1,000 lactating cows define a large CAFO. The VOC emission factor used by CARB for CAFO definition is still the disputed 12.6 lbs/cow-year figure so CAFO definition is subject to change.

The San Joaquin Valley and the South Coast air basins are both designated non-attainment for the federal 1-hour ozone standard. Using the 1,000 lactating cow number for CAFO determinant, 29% of dairies and 73% of animals in the San Joaquin Valley will be considered CAFs as well as 50% of dairies and 75% of animals in the South Coast air basin.[74] Individual air districts are free to use more stringent CAFO definitions.

CARB and the San Joaquin Valley Air Pollution Control District are funding ongoing investigations to determine air emissions from California dairies. Researchers from the University of California, California State University, Texas A&M, Iowa State, state agencies, and private consultants are engaged in several parallel measurement and modeling studies.

Preliminary results were recently presented.[75] Preliminary findings include those of Mitloehner (UC Cooperative Extension) who reports about 3.8 lbs/cow/year of VOC come directly from the animal mostly from rumination. Another 2.6 lbs/cow/year was measured from the fresh manure (up to three days old left in pen). Schmidt, an independent consultant, conducted an extensive suite of flux-chamber measurements of the following 11 types of emitting surfaces at a flushed lane dairy in Merced County:

- Flushed lanes: pre and post-flushed
- Solids storage piles
- Lagoon (inlet and outlet of lagoon)
- Solids in Solids separator
- Bedding in pile for freestall
- Freestall area
- Barn turnout and corral area
- Manure piles in turnout
- Heifer pens (dry cow area)
- Open feed storage (in barn feed lanes)

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74. "Initial statement of reasons for the confined animal facility definition," 2005. CARB staff report, available at: http://www.arb.ca.gov/regact/lcaf05/isor.pdf
75. Livestock Emissions Research Symposium, January 26, 2005, Fresno, California. Proceedings available at: http://www.arb.ca.gov/ag/agadvisory/lersymp.htm

- Milk parlor (wastewater effluent stream)

More than 40 flux chamber measurements were made with analysis for speciated reactive organic gases (ROGs or VOCs), ammonia/amines, total organic compounds, and methane. Schmidt's preliminary results indicate the VOC emission factor from dairy operation surfaces only (no cow belching, ruminating, etc.) ranges from 3.6 to 19 lbs/cow/year. The dominant ROG species is ethanol emitted from ensiled feed. Emissions from the wastewater lagoon were "relatively" low.[76]

Hobbs et al. (2004) measured non-methane VOC emissions from slurried manure in a chamber and estimates total emissions for livestock in England. Results for cattle manure (which includes that from dairy animals) managed with flushed stalls and wet storage indicates non-methane VOC emissions are 9 kg/cow/year (19.8 lbs/cow/year).

Using the preliminary data from Miltloener for direct animal emissions and results from Schmidt and Hobbs for VOC emissions derived from manure, total emission factor potentially ranges from 7.4 to 23.6 lbs/cow/year.

By law, the Air Pollution Control Officer (APCO) for the San Joaquin Valley Air Pollution Control District was to adopt a dairy emission factor by July 1, 2005 (since extended to August 1, 2005).[77] A report from the APCO with the determination of dairy VOC emission factors was recently released prior to a public workshop on July 11, 2005 (Crow 2005). The dairy VOC emission determined by the APCO in the Draft Report was **20.6** lbs/cow/year and revised downward to **19.3** lbs/cow/year in the Final Report released August 1, 2005 (Crow 2005). This is significantly larger than the value currently used by CARB (12.8 lbs/cow/year). The report discusses the process used to arrive at the determination and weighs the arguments behind the three different emission factor recommendations made by the Dairy Permitting Advisory Group (DPAG). The DPAG could not arrive at a consensus opinion before issuing its report. The three opinions in the DPAG report derive from each of three factions among the stakeholders: the dairy industry, the University of California, and the environmental community.[78] The DPAG recommends 5.6, 13.3, and 38.2 lbs./cow/year for dairy facility VOC emission factor (see Table 2-10).

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76. See presentation by Schmidt in proceedings at: http://www.arb.ca.gov/ag/agadvisory/lersymp.htm

77. Settlement Agreement. Western United Dairymen, Alliance of Western Milk Producers v. San Joaquin Valley Air Pollution Control District. Fresno Superior Court, 2004.

78. "Dairy Emissions Factors for Volatile Organic Compounds – Recommendations to the San Joaquin Valley Air Pollution Control Officer." Final report, May 6, 2005, Dairy Permitting Advisory Group. Available at: http://www.valleyair.org/busind/pto/dpag/DPA_%20EF_Report_Final.pdf

Table 2-10. Summary of recommended and SJVAPCD determination for VOC emission factors from dairy operations in the SJVAPCD.

	Constituent or process	Emissions (lb/hd-yr)				SJVAPCD Comments†
		Dairy Industry*	University of California*	NRDC*	SJVAPCD Determination†	
1	Emissions from cows and feed in environmental chamber	2.7	3.4	4.3	1.4† (2.7)◊	Underestimate and further research is recommended
2	Amines from dairy processes	0.2	0.2	11.0	0.2	"
3	VOCs (except VFAs and Amines) from miscellaneous dairy processes	1.2	1.2	1.2	1.2	Clearly understimate of actual emissions, further work recommended
4	VOCs (except VFAs and Amines) from lagoons and storage ponds	1.0	1.0	1.0	1.0	Underestimate and further research is recommended
5	VFAs from dairy processes	0.5	7.5	17.0	15.5	Most probably represents an underestimate of VFA emissions. Futher research is needed
6	Phenols from dairy processes	0	0	2.6	TBD, >0	Insufficient data available but emissions are known to be greater than zero
7	Land application	NA	NA	1.0	TBD, >0	"
8	Feed storage, settling basins, composting, & manure disturbance	Included above or insignificant	NA	0.1	TBD, >0	"
	Totals	**5.6**	**13.3**	**38.2**	**19.3**	

* Viewpoints 1, 2, and 3, from; (2005). "Dairy Emissions Factors for Volatile Organic Compounds - Recommendations to the San Joaquin Valley Air Pollution Control Officer." Final Report, May 6, 2005, Dairy Permitting Advisory Group.

† Crow, D. L. (2005). "Air Pollution Control Officer's Determination of VOC Emission Factors for Dairies." Final Report. August 1, 2005, SJVAPCD.

◊ Crow, D. L. (2005). "Draft Air Pollution Control Officer's Determination of VOC Emission Factors for Dairies." June 27, 2005, SJVAPCD.

The dairy industry recommends the lowest emission factor while the environmental community recommends the highest. The value determined by the APCO from a line-item examination of the data and the various arguments set forth in the DPAG report is slightly higher than a simple average of the DPAG recommendations (DPAG average = 19.0).

Notable in the discussion by the APCO in his report are the comments given in the line-item evaluation (the line-items are the eight VOC constituents or dairy processes listed in Table 2-10). The APCO states that the best available data underestimate the emissions for each of the eight line-items. The expectation then is that as better data become available, the VOC emission factor will increase above the current 19.3 lbs/cow/year.

This is an evolving issue. Besides the magnitude of the dairy VOC emission factor, there is discussion and disagreement over what compounds should be included in the VOC category (Capareda 2005). If the 19.3 lbs/cow/year emission factor is accepted, then CARB will need to change the large CAFO definition in non-attainment areas from 1,000

lactating cows to around 600 (CAFO in attainment areas would change from 2,000 lactating cows to around 1,200). As volatile fatty acids (VFA) constitute the largest source of VOC and the greatest uncertainty in the estimate, increasing attention will be focused on emission and reactivity of VFA.

One-half to 80% of the VOC emissions appear to be from manure which indicates dairy practices and manure management can play a large role in reducing dairy VOC emissions. The San Joaquin Valley Air Pollution Control District's draft dairy Best Available Control Technology (BACT) recommends covered lagoons as a component of BACT. Covered lagoons are one type of digester now being operated for dairy power systems deploying mostly internal combustion engines for biogas-fueled power generation. The other principal type is the plug-flow digester. Other design types, including attached-growth digesters are also being considered.

Other Air Emissions

Ammonia is a by-product of microbial decomposition of organic nitrogen compounds in manure produced by both anaerobic and aerobic fermentation. Ammonia accumulates in the liquid components of manure and volatizes upon drying. Ammonia does not participate in gas-reactions producing photochemical smog, but readily reacts with SO_2 and NOx to from ammonium sulfate and ammonium nitrate as aerosols in the atmosphere (Seinfeld 1986).

Hydrogen sulfide and other reduced sulfur compounds are by-products of anaerobic manure decomposition. Sulfur is present in amino acids in animal feed and in mineral feed additives such as copper and zinc sulfate. Hydrogen sulfide will oxidize to SO_2 contributing to ammonium sulfate production and/or acid precipitation (Seinfeld 1986).

Particulate matter (PM) can be emitted in substantial amounts from a large dairy. Sources include standing dry manure and manure storage and handling as well as dust from unpaved roads and surfaces.

2.2.6 Gas Engines

Internal combustion engines are a class of heat engines in which the combustion products are the working fluid as opposed to external combustion types requiring heat exchange to transfer energy to the working fluid. The energy in the combustion products is converted to work by expansion and movement of a piston or rotor. Internal combustion engines include reciprocating (piston), rotary (Wankel), and gas-turbine engines.

Gas turbine engines are continuous combustion machines whose operation is approximated by the ideal Brayton thermodynamic cycle, differing from the Otto and Diesel cycles of the reciprocating and Wankel engines. Compared to reciprocating engines, gas turbines have higher power to weight ratios and are used for propulsion in most commercial and military aircraft (i.e., jet engines). Because fuel is burned continuously in a gas turbine, the combustion chamber can be optimized for lower

emissions including NOx and products of combustion. Most large stationary power applications deploy aeroderivative gas turbines. More expansion or turbine stages are used to convert as much of the fuel energy into mechanical energy as possible (higher efficiency). Gas turbine power engines generate enough mechanical energy to drive the compressor, auxiliary equipment, and the electrical generator.

Reciprocating engines include spark ignition (SI) and compression ignition (CI) Diesel engines (Table 2-11). Spark ignition and diesel engines can be either four-stroke or two-stroke. The four-stroke engine requires two revolutions of the crankshaft for each power stroke of the piston (thus, the piston moves through four-strokes for each power stroke: intake, compression, expansion, exhaust). In a two-stroke engine, each piston has a power stroke for each revolution of the crankshaft. Two-stroke engines have higher power to weight ratios than four-stroke engines but generally have lower efficiency and higher emissions. CI engines operate at higher compression ratio and generally have higher efficiencies than SI engines. CI engines operate on heavy oils, diesel fuel, vegetable oil, biodiesel, and other biofuels. CI engines can be operated in a dual fuel mode using a gaseous fuel (natural gas, biogas, producer gas) with some amount (typically 10 to 30%) of diesel pilot fuel to control ignition timing and combustion stability. SI engines are required to reliably fire gaseous fuels and lighter liquid fuels such as gasoline.

Table 2-11. Classification schemes for reciprocating engines.

Classification Parameter	Label
Ignition method	SI or CI
Operating Cycle	2 or 4 Stroke
Air:Fuel Ratio	Rich or Lean Burn
Fuel State	Liquid, Gas, or Dual-Fuel
Method of fuel addition	Carbureted or metered injection (throttle-body, port, or direct cylinder)
Air Induction method	Naturally Aspirated , Turbo- or Supercharged

Most engines used for power generation from gaseous biomass derived fuels in the US are four-stroke SI type. Engine-generator efficiencies range from about 25% for the smaller sizes (less than 100 kW) up to about 45% for the largest sizes (more than 3 MW). In combined heat and power (CHP) applications, overall efficiencies approach 85%.

Emission Limits

Table 2-12 displays the range of emissions achieved in practice for reciprocating engines operating on biogas in California. The emissions are from actual measurement of engines fueled by landfill gas or WWTP digester gas. The engines are all spark ignition and employed lean-burn or pre-stratified charge technology (for NOx reduction). The smallest engine in the data set was 260 brake-horsepower (bhp) with a capacity of 195 kW. The largest was 4,235 bhp with a capacity of 3.1 MW.

Table 2-12. Emissions "achieved in practice" from reciprocating engines fueled by biogas in California[79]

	(g/bhp-hr)	(lb/MW-hr)
NO_x	0.31 - 0.6	1 - 1.9
VOC	0.05 - 0.54	0.16 - 1.7
CO	1.5 - 3.9	4.7 - 12.1
PM	NA	NA

Tables 2-13 and 2-14 show CARB-recommended BACT for reciprocating engine and gas turbine (less than 3 MW) distributed generation applications respectively. BACT emissions depend on the fuel type (waste gas or fossil fuel) and class of prime mover (turbine or reciprocating). The higher emissions allowed for biogas applications mainly reflect the fact that use of catalytic converters with biogas fuel is difficult and is not in routine practice. The "achieved in practice" emissions (Table 2-12) fall below the recommended BACT levels except for CO.

Table 2-13. CARB recommended BACT emissions for reciprocating engines (see footnote 79)

	'Waste gas' fired			Fossil fuel fired		
	(g/bhp-hr)	(ppmvd)‡	(lb/MW-hr)	(g/bhp-hr)	(ppmvd)	(lb/MW-hr)
NO_x	0.6	50	1.9	0.15	9	0.5
VOC	0.6	130	1.9	0.15	25	0.5
CO	2.5	300	7.8	0.6	56	1.9
PM	NA	NA	NA	0.02	-	0.06

‡ ppmvd – parts per million by volume dry - values are approximate for reciprocating engines

Table 2-14. CARB recommended BACT emissions for gas turbines less than 3 MW

	'Waste gas' fired (any capacity)			Fossil fuel fired		
	(g/bhp-hr)	(ppmvd)	(lb/MW-hr)	(g/bhp-hr)	(ppmvd)	(lb/MW-hr)
NO_x		25	1.25		9	0.5
VOC		-	-		5	0.1
CO		-	-		10	0.4
PM		-	-			

Distributed Generation Definition and Emission Requirements

Senate Bill 1298 (chaptered September 2000)[80] set air emissions standards for distributed generation (DG) units within California that are otherwise exempt from existing local air district rules. The Bill defined DG simply as "electric generation located near the place of use." There is no size or technology specified in the definition. A practical definition might be that DG is generation that is intended for consumption at the generation site

79. "Guidance for the permitting of electrical generation technologies," CARB 2002. Available at: http://www.arb.ca.gov/energy/dg/dg.htm
80. The chaptered version is available at: http://www.arb.ca.gov/energy/dg/sb1298bill20000927chaptered.htm

and/or generation that is connected to the local distribution system and not connected to the transmission system.

The bill directed CARB to issue electrical generating technology BACT guidelines for the local air districts. The CARB issued a regulation defining a DG certification procedure and setting a time line for emissions requirements.[81] Essentially, the emissions requirements for DG are that they meet BACT levels for central station power plants in California (Table 2-15).

Table 2-15. DG emission standards beginning January 2007

Pollutant	Emission Standard (lb/MWh)
NOx	0.07
CO	0.10
VOCs	0.02
PM	Corresponding to natural gas with fuel sulfur content no more than 1 grain/100 scf

Senate Bill 1298 and the resulting CARB regulation apply only to electrical generation systems that are not already covered by existing local air district rules. In general, local air districts have existing standards for reciprocating engines (usually more than 50 bhp), smaller gas turbines fueled by waste gas, and solid/liquid/gaseous fuelled boilers (which includes most biomass boilers). The DG emission limits generally apply to fuel cells, microturbines, and reciprocating engines below 50 bhp. Unless Senate Bill 1298 is changed, or individual local air districts enact more stringent BACT requirements for non-exempt devices, small (but more than 50 bhp) biomass fueled facilities that use reciprocating engines or solid fuel combustion boilers will not need to meet the central power plant emission levels or the limits in Table 2-15. It is unclear at this time if gas turbines fueled by biogas or synthesis gas will be required to meet these central station emissions.[82]

Emissions from Reciprocating Engines

Reciprocating engines combust fuel intermittently (as opposed to gas turbines which are continuous combustion devices), and as such they encounter higher peak temperatures and higher thermal NOx production in the combustion chamber and rapidly freeze the composition upon exhaust which increases the final NOx emission. Table 2-16 shows typical NOx emissions for general stationary reciprocating engines.

81. CARB Final Regulation Order – Establish a Distributed Generation Certification Program, available at: http://www.arb.ca.gov/regact/dg01/finreg.pdf

82. Note: CARB was supposed to complete an electrical generation technology review by July 2005 to determine what technologies will likely not meet the central station emission levels. As of early August 2005, this review had not been issued.

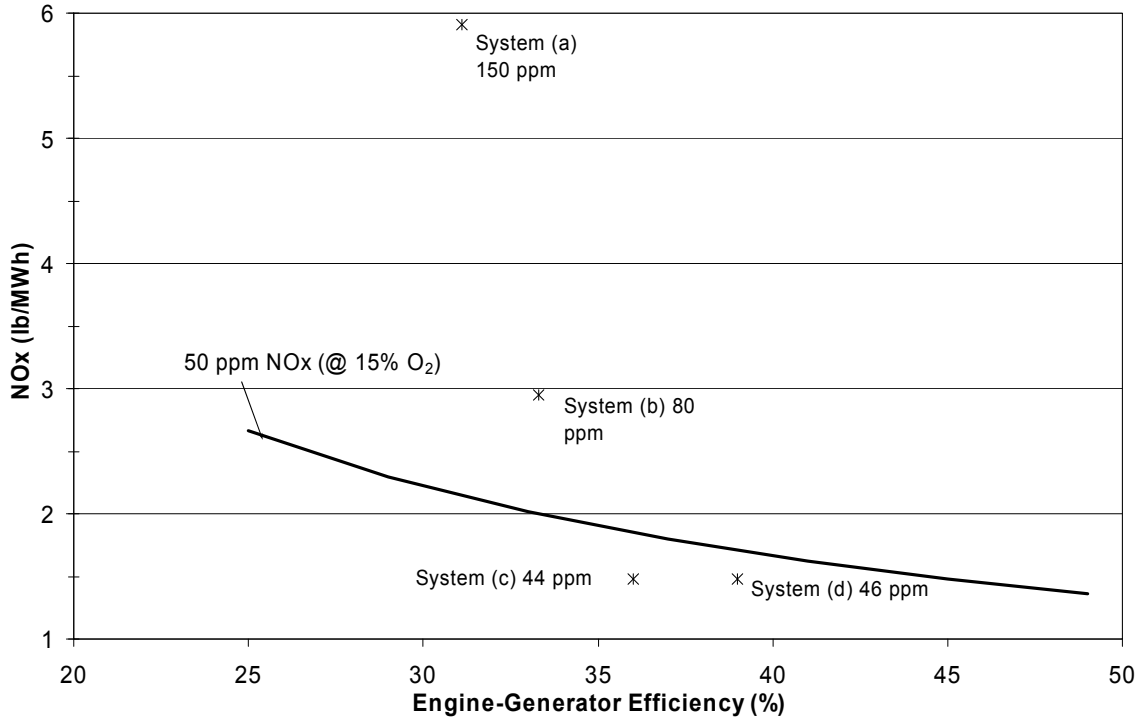
Carbon monoxide and PM emission requirements are generally met with biogas fueled engines or turbines. Biomass producer gas fueled engines may have high CO emissions. This is partly due to the high level of CO in the producer gas and the trade-off between adjusting air-to-fuel ratio and combustion temperature for NOx mitigation (lower temperatures to reduce NOx formation reduce oxidation rates for CO).

Table 2-16. Typical NOx emissions for reciprocating engines using fossil fuels[83]

Engine Type	Fuel	Eff (%)	NOx Emissions (Uncontrolled)		
			(ppmv)	(g/kWh)	(lb/MWh)
CI	Distillate	37-44	450 - 1350	7 - 18	15.4 - 39.7
CI	Heavy Oil	42-48	900 - 1800	12 - 20	26.5 - 44.1
SI	Natural Gas	35-42	45 - 150	0.7 - 2.5	1.5 - 5.5

Figure 2-9 illustrates the effect of engine efficiency on NOx mass emission rate for a constant concentration of 50 ppmv in the exhaust gas. Emission performance for several individual systems is plotted as points on the figure as well.

83. "Technology Characterization: Reciprocating Engines," Energy Nexus Group, 2002. Available at: http://www.epa.gov/chp/pdf/EPA_RecipEngines_final_5_16_02.pdf



System Descriptions (fueled by natural gas) (See footnote 83)
(a) 300 kW - Cummins GSK19G
(b) 800 kW - Caterpillar G3516 LE
(c) 1,000 kW - Caterpillar G3616 LE
(d) 3,000 kW – Wartsila 5238 LN

Figure 2-9. NOx emissions vs. efficiency for 50 ppmv exhaust concentration with quoted uncontrolled emissions for several engines fueled by natural gas

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Air-to-Fuel Ratio Effects

Engines operated in fuel lean configurations can result in significantly lower NOx emissions. Larger amounts of air result in cooler combustion temperatures thereby reducing thermal NOx production. For extremely lean conditions (high air-to-fuel ratios [AF]), partially burned fuel is emitted in the exhaust as combustion is quenched before completion and/or misfiring occurs.

A convenient dimensionless parameter for describing AF in the cylinder charge of an engine is λ (Greek lambda). Lambda is the ratio $AF_{actual} : AF_{stoich}$, or

$$\lambda = \frac{AF_{actual}}{AF_{stoich.}}$$

where $\lambda < 1$ denotes a fuel rich combustion. This is the condition where AF_{actual} is substoichiometric. $\lambda > 1$ is fuel lean, denoting excess air compared to stoichiometric requirements.

Figure 2-10 shows emissions versus λ for a gasoline fueled SI engine. Note hydrocarbon and CO emissions increase for the leanest conditions. Maximum power typically occurs under fuel rich conditions with elevated CO and hydrocarbon emissions. Maximum efficiency typically occurs under fuel lean conditions with elevated NOx emissions unless engine design permits sufficiently high levels of excess air to be utilized without engine misfiring.

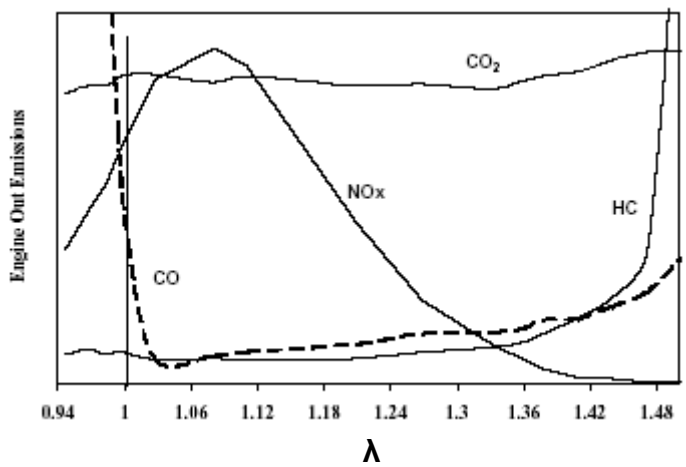


Figure 2-10. Gasoline engine emissions vs. Lambda
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Actual Emissions from Biogas Fueled Reciprocating Engines

Actual emissions from recent source testing for several engine-generator facilities operating on manure-derived biogas are presented. Source test results from engines at the Inland Empire Utility Agency (IEUA), the Joseph Gallo Cottonwood Dairy, and the Colorado Pork swine facility were obtained.

Emissions from three types of Waukesha lean-burn engines operating on biogas at IEUA are presented in Table 2-17. NOx emissions varied from about 0.8 lbs/MWh for the 1400 kW gen-sets to 1.9 lbs/MWh for the 864 kW unit. NOx concentrations varied from 17 to 34 ppmv (dry gas, 15% O_2). The permit values were not available but the emissions levels generally met the South Coast AQMD Rule 1110.2 (emissions from gaseous/liquid fueled engines).

Table 2-17. Emissions from Waukesha engines fueled by biogas at IEUA (Im 2004)*

	Waukesha 8L-AT27GL 1400 kW			Waukesha L7042GL 1050 kW			Waukesha L5790GL 864 kW IEUA Actual	
	IEUA Actual Unit1 / Unit 2		Factory Specs. (natural gas)	IEUA Actual		Factory Specs. (natural gas)		
	(g/bhp-hr)	(lb/MW-hr)	(lb/MW-hr)	(g/bhp-hr)	(lb/MW-hr)	(lb/MW-hr)	(g/bhp-hr)	(lb/MW-hr)
NO_x	**0.23 / 0.28**	**0.7 / 0.8**	1.9	**0.57**	**1.7**	2.7	**0.65**	**1.9**
CO	**3.3 / 2.2**	**9.8 / 6.4**	6.7	**3.58**	**10.6**	8.0	**4.667**	**13.8**
VOC	**0.16 / 0.12**	**0.47 / 0.36**	2.1	**0.4**	**1.2**	3.0	**0.57**	**1.7**

* South Coast AQMD Rule 1110.2 stipulates that NOx limits for these engines are approximately 45 – 50 ppmv (15% O_2) or about 1.7 – 1.9 lb/MWh

Results from recent performance and emissions testing of a biogas fueled engine at a swine waste facility in Colorado are shown in Table 2-18. The engine is a Caterpillar 3306 6-cylinder, 4-stroke SI engine. The engine-generator set is rated for 100 kW but gas production at the time of testing was only sufficient for 45 kW power production. No emission control equipment was installed with the engine. Note that all emissions are quite high. The engine was being operated below the minimum recommended power setting and is not necessarily representative of biogas fueled engines at this scale.

Table 2-18. Colorado Pork gas engine emissions at 45 kW[84]

	(ppmv, 15% O_2)	(lb/MWh)
NO_x	255	12
CO	1966	58
VOC	6724	112
SO_2	352	23

Source test results and permitted levels for the Caterpillar 300 kW engine-generator sited at the Joseph Gallo Cottonwood Dairy (a participant of the California Dairy Power Production Program funded through the California Energy Commission through SB 5X) are presented in Table 2-19.

The facility utilizes an iron sponge (iron-oxide impregnated wood chips) and chiller for H_2S and moisture removal. The engine operates near the stoichiometric air-fuel ratio (rich-burn) and employees a three-way (automotive type) catalytic converter for emissions control.

Permit limits for the criteria pollutants are given in g/bhp-h, which is an output based emission limit. The unit met the permit requirement for the measured criteria pollutants

84. "Environmental Technology Verification Report – Swine Waste Electric Power and Heat Production – Martin Machinery Internal Combustion Engine," Southern Research Institute and U.S. EPA. SRI/USEPA-GHG-VR-22, 2004.

at the time of the source test (December 2004). Since that time, the iron sponge and moisture removal unit were resized and relocated adjacent to the flare near the lagoon.

Apparently, the original sulfur removal system was undersized and required frequent changing of the media (Morris 2002). The air permit includes a requirement for maximum H_2S level in the engine fuel (or minimum H_2S removal efficiency). During the test, H_2S levels in the untreated biogas averaged 1,500 ppm. Removal efficiency at the time of the test was better than 97% but H_2S content of the fuel gas was 41 ppm. Apparently, the unit passed based on the removal efficiency requirement.

Table 2-19. Source test results for DPPP engine at the Cottonwood Dairy*

Parameter	Unit	Test Number 1	Test Number 2	Test Number 3	Average of tests	Permit Limit
Std. T	ºF	60	60	60	60	
Engine Load	MMBtu/hr	4.1	3.5	4	3.9	
Engine Load	%	74	74	74	74	
Flow Rate (M2)	DSCFM	568	584	574	575	
Flow Rate (M19)	DSCFM	611	525	598	578	
Generator Out	kW	250	250	250	250	
Brake Hp	hp	335	335	335	335	
Fuel F-factor	DSCF/MMBtu	9030.6	9027.1	9026.6	9028.1	
O2	%	0.04	0.02	0.03	0.03	
CO2	%	14.8	14.7	14.7	14.7	
H2O	%	16	16.9	17.2	16.7	
NOx	ppm	54.79	58.02	60.68	57.83	
NOx (@15% O2)	ppm	15.5	16.4	17.2	16.4	
NOx	lbs/hr	0.22	0.24	0.25	0.24	
NOx	lbs/day	5.4	5.8	6	5.7	
NOx	**g/bhp-hr**	**0.302**	**0.329**	**0.338**	**0.323**	**0.6**
NOx	lbs/MMBtu	0.059	0.0625	0.0623	**0.0613**	
CO	ppm	607.5	579.9	560.3	582.6	
CO	ppm	171.8	163.9	158.4	164.7	
CO	lbs/hr	1.5	1.48	1.4	1.46	
CO	lbs/day	36.1	35.5	33.7	35.1	
CO	**g/bhp-hr**	**2.036**	**2**	**1.9**	**1.979**	**2.65**
CO	lbs/MMBtu	0.3984	0.3801	0.3673	**0.382**	
THC (EPA 25C)	ppm	5889	5714	5344	5649	
CH4	ppm	5875	5700	5330	5635	
TNMHC	ppm	14	14	14	14	
TNMHC (@15% O2)	ppm	4	4	4	4	
TNMHC	lbs/hr	0.02	0.02	0.02	0.02	
TNMHC	lbs/day	0.5	0.5	0.5	0.5	
TNMHC	**g/bhp-hr**	**0.027**	**0.028**	**0.027**	**0.027333**	**0.25**
TNMHC	lbs/MMBtu	0.0052	0.0052	0.0052	0.0052	
Fuel Scrubber						
H2S Scrubber Inlet	ppm	1300	1600	1600	1500	
H2S Scrubber Outlet	ppm	40	41	42	41	23
H2S Removal Eff.	**%**	**96.9**	**97.4**	**97.4**	**97.2**	**80**

* SJAPCD Source Test ATC #N-1660-7-0 (12/17/2004)

Producer Gas and Reciprocating Engines

Reciprocating engines fueled by producer gas are the prime mover of choice for capacities ranging from 15 kW to about 5 MW because they are proven, relatively inexpensive, offer high efficiencies, and can be used in CHP applications. The main disadvantages are the potential for high uncontrolled NOx and CO emissions and the need for extensive gas cleaning.

Producer Gas Characteristics

Producer gas from air-blown biomass gasification is composed primarily of diluent nitrogen gas from the air used in gasification, CO_2, CO, H_2, CH_4, and small amounts of higher hydrocarbons (see Table 2-20), the latter four categories comprising the primary fuel species. Raw producer gas also contains PM, tars, nitrogen compounds (e.g., NH_3, HCN), volatile alkaline metals, sulfur as H_2S, and chlorine in amounts that depend on the biomass and the gasification process used.

Table 2-20. Composition of producer gas from air blown biomass gasifiers (Hasler and Nussbaumer 1999)

Component	Vol. %, dry gas
CO	10-22
H_2	10-30
CH_4	1-6
C_xH_y	0-2
CO_2	8-15
N_2	35-50
HHV	4-7 MJ/Nm^3

There are gas quality requirements for the sustained operation of reciprocating and gas turbine engines fueled by producer gas. Table 2-21 displays typical gas quality requirements found in the literature. Generally, gas turbines are more susceptible to operational problems from PM and alkali in the gas due to blade erosion and deposition issues, but do not need gas cooling. Reciprocating engines require PM removal as well but to a lesser degree. Tar in the gas is most problematic with reciprocating engines because of the need to cool the gas prior to intake in order to maintain high volumetric efficiency. Cooling the fuel gas to below tar dew points will condense tar material which can deposit on the cool intake surfaces of the engine. Gas turbines can accept tar in the fuel gas as long as the temperature remains above the tar dew point because tar remains in the gas phase until burned. Acid forming compounds (sulfur and chlorine) in the producer gas are a consideration for reciprocating engines. Acids can deposit on cool intake surfaces as well as cylinder walls where they are swept into the crankcase by the piston oil rings causing the engine oil pH to decrease over time. Acidic engine oil causes corrosion of bearing surfaces and shortens engine life. Acid forming compounds must either be removed from the fuel gas or more frequent engine oil changes are required.

Table 2-21. Gas quality requirements for engines (Hasler and Nussbaumer 1999)

Component	Unit	Engine type	
		Reciprocating	Gas turbine
PM	mg/Nm^3	<50	<30
Particle size	μm	<10	<5
Tar	mg/Nm^3	<100	-
Alkali metals	mg/Nm^3	-	< 0.24

Impurities in the producer gas that may not effect engine operation or service life but can degrade emissions performance include nitrogen compounds (NH_3, HCN), alkali metals, sulfur, and chlorine. The nitrogen compounds will primarily convert to NOx and sulfur compounds will be emitted as SO_2. The alkalis, sulfur, and chlorine can degrade emissions catalysts if they are being used. Depending on the local emissions limits and the fuel characteristics, proper gas cleaning, fuels, and emissions control strategies must be compatible.

Performance and Emissions of Engines Fueled by Producer Gas

Producer gas has improved lean flammability compared to natural gas. Producer gas also has high octane rating making it acceptable for high compression ratio SI engines with increased efficiency. A Ford industrial naturally aspirated SI engine fueled by producer gas from the DTU 2-stage Viking gasifier (wood fuel) is able to operate under very lean fuel conditions, to $\lambda > 3$). The same engine fueled on natural gas misfired and quit at $\lambda \sim 1.7$ (Ahrenfeldt et al. 2001). Figure 2-11 shows the brake fuel efficiency and power vs. λ for the Ford 1.1 liter SI engine fueled with natural gas and gasified wood (Ahrenfeldt et al. 2000).

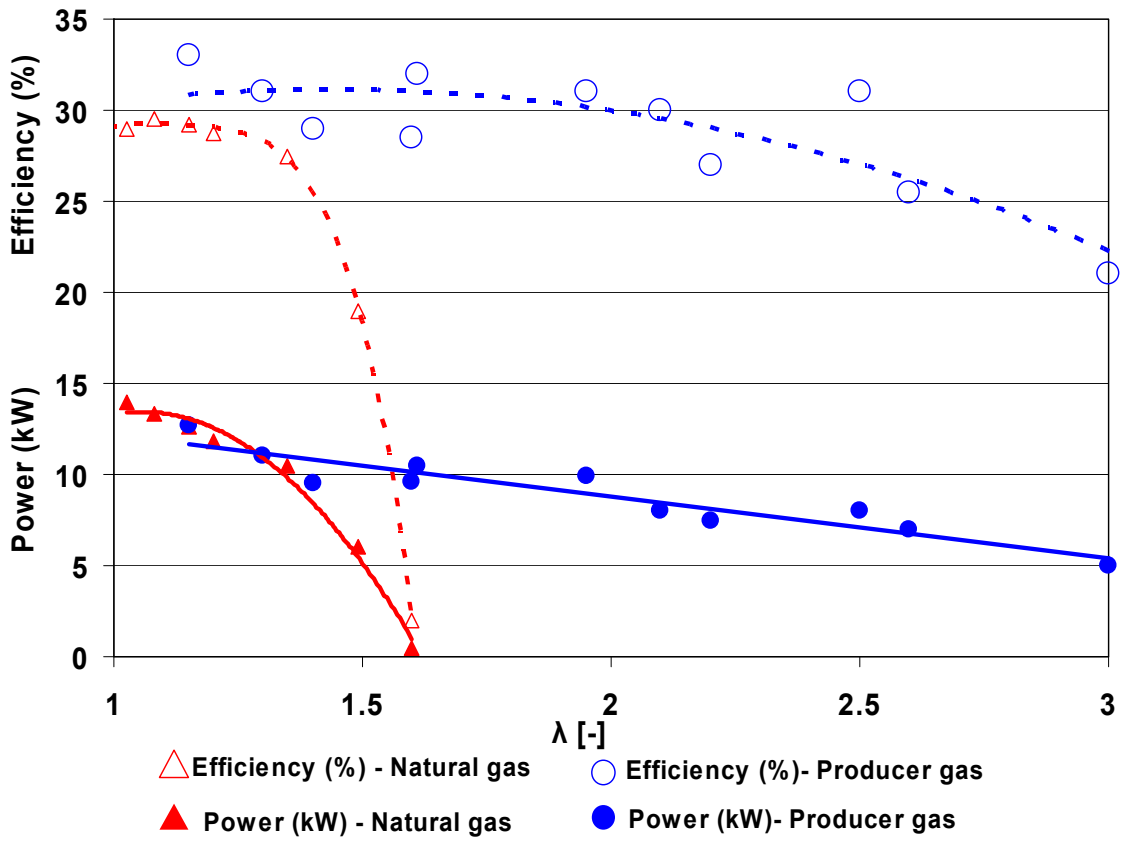


Figure 2-11. Brake fuel efficiency and power vs. λ, Ford VSG 411 fueled by natural gas and producer gas

Photo Credit: Ahrenfeldt et al. 2000.

For reciprocating engines fueled by producer gas, the primary difference experienced at high air:fuel ratios is the much higher CO emission or "slip" that occurs. This is due to CO passing through the engine unburned. Figure 2-12 shows the effect of varying AF on NOx and CO for the general case of SI engines fueled by gasified biomass (note the scale for CO is 10x that for NOx).

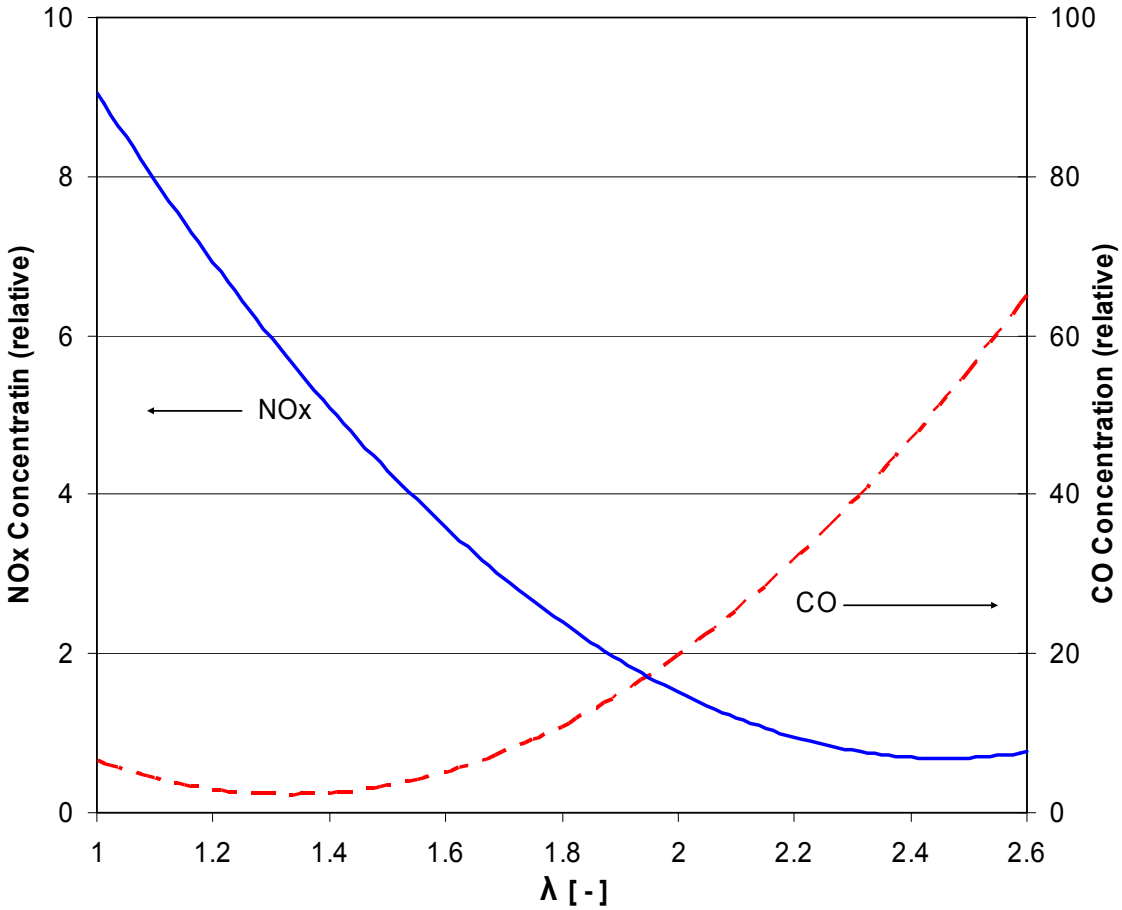


Figure 2-12. General emission performance vs. Lambda, producer gas fuel Note: the parabolic fit of the NOx curve would not be expected to trend upwards at high lambda.
Photo Credit: Ahrenfeldt et al. 2001; Jensen et al. 1997; Ahrenfeldt et al. 2000.

DTU Experience

Figure 2-13 displays NOx and CO emissions vs. λ for the Ford VSG 411 discussed by Ahrenfeldt et al. (2000 and 2001). Untreated emissions from natural gas fuel and a synthetic producer gas (a mixture created from bottled gases) are shown. The synthetic producer gas did not contain ammonia or HCN which would be present in raw or partially cleaned producer gas, but provides good control over gas composition for testing.

NOx emissions for both fuels pass through a maximum around $\lambda = 1.4$ and then steeply decline as λ increases until reaching the lean flammability limit for each fuel type. The untreated NOx emissions from the synthetic gas are lower than what would be expected from a real producer gas containing ammonia or HCN.

The CO emissions for both fuels increase rapidly for $\lambda > 1.4$ due to incomplete combustion in the case of natural gas and bulk flame quench in the case of the producer gas. For very lean combustion with producer gas, the combustion flame front in the

cylinder extinguishes before propagating through the cylinder volume, allowing unburned fuel which has high CO content to pass through the engine (partial firing of the fuel charge).

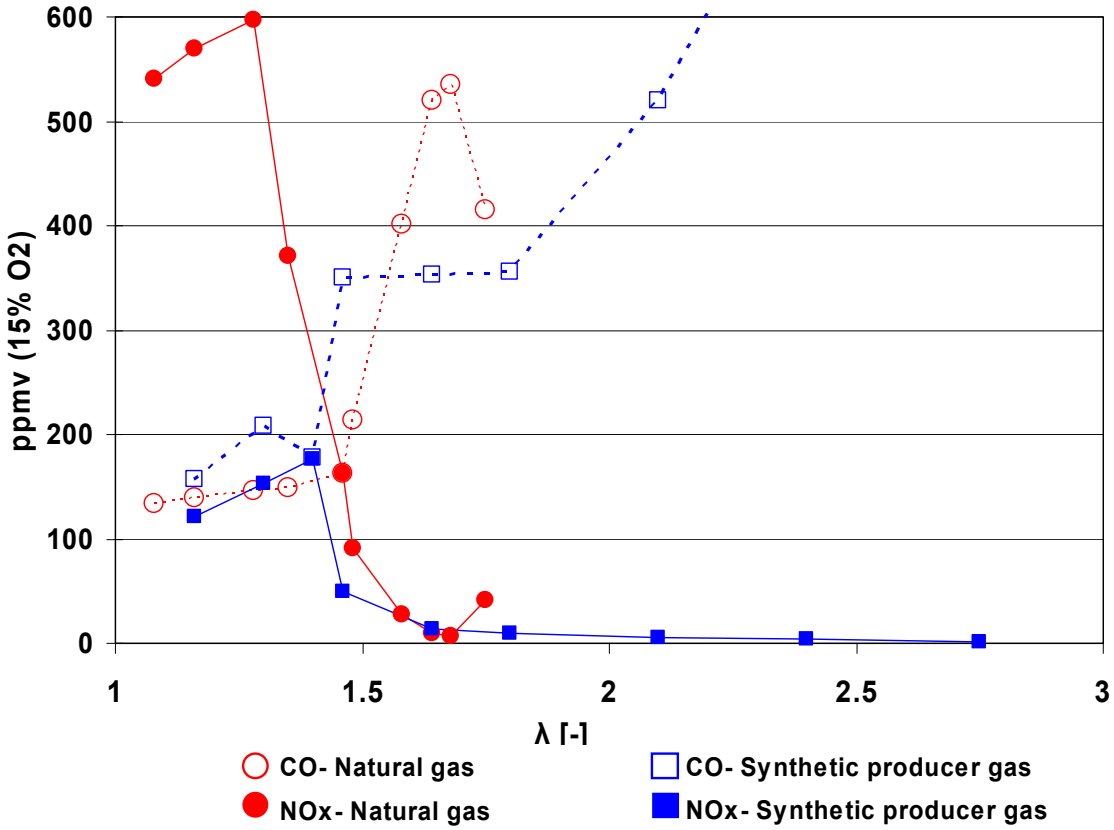


Figure 2-13. NOx and CO emissions from Ford VSG 411 fueled by natural gas and synthetic producer gas

Photo Credit: Ahrenfeldt et al. 2000

Jenbacher Engine Company Experience

GE Jenbacher of Austria has extensive experience with large reciprocating engines fueled by producer gas (as well as biogas). The report by Jenbacher to IEA Task 33 (Thermal Gasification of Biomass) describes some of the experience gained from supplying engines for and working with biomass gasification CHP developers/researchers (Herdin et al. 2004).

Jenbacher engines are used in at least four existing biomass gasification demonstration projects (Güssing, Austria; Harboøre, Denmark; Spiez, Switzerland; Wiener Neustadt [CV Nova], Austria) and are specified in at least two facilities under construction (Skive, Denmark, and Kokemäki, Finland). Engine sizes used in this application range from 180 kW to 2 MW.

The GE Jenbacher report (Herdin et al. 2004) also comments on the fuel nitrogen to ammonia to NOx pathway. Figure 2-14 illustrates the effect ammonia in the fuel gas has

on NOx production. Emissions from lean-burn Jenbacher engines, one powered with fuel gas containing very little ammonia (a Thermoselect MSW gasifier/pyrolyzer in Chiba, Japan), and a gas rich in ammonia (about 580 ppmv NH_3 input – gasified wood from Güssing, Austria). The AF of the engine at Güssing was adjusted to meet the NOx emission limit of 500 mg/Nm^3 (at 5% O_2) (about 90 ppmv, 15% O_2). In this instance, ammonia in the fuel gas is responsible for 85% of the NOx emission.

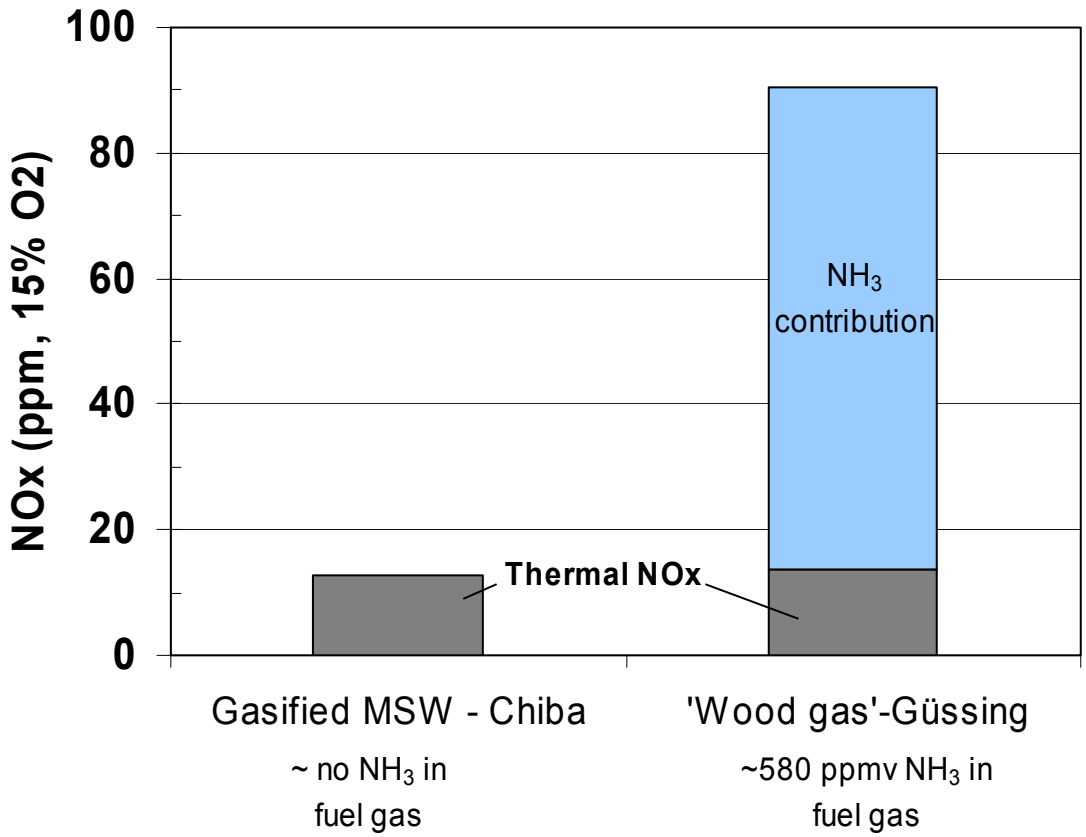
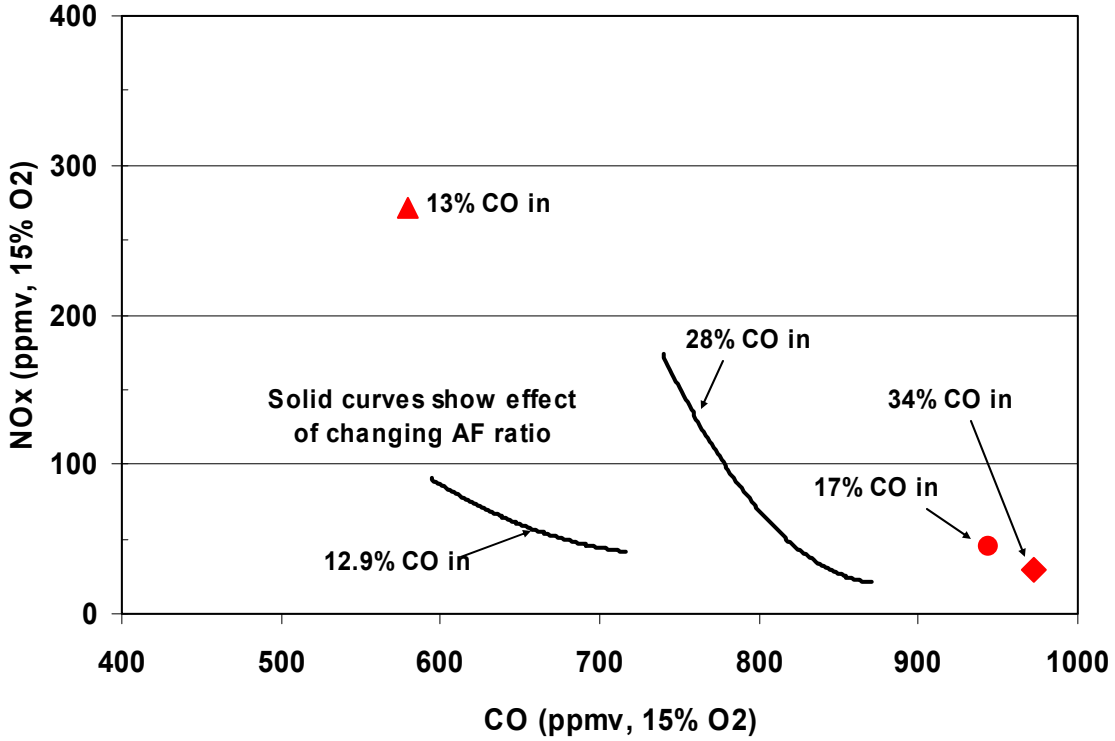


Figure 2-14. Effect of ammonia in fuel gas on uncontrolled NOx emission from reciprocating engines

The GE Jenbacher report, Herdin et al. 2004

The Jenbacher report also describes high CO emissions from lean-burn engines fueled by producer gas (explanation is similar to that by Ahrenfeldt above). Also, the CO-NOx trade-off from varying AF is confirmed by Herdin et al. (2004). Figure 2-15 shows NOx and CO emission levels in the untreated engine exhaust for several Jenbacher engines fueled by gasified biomass or MSW. The engines have been optimized for each installation depending on requirement or local limitations (capacity, efficiency, emissions, etc.).



Note: % CO in = CO concentration in the fuel gas. Engines optimized for individual conditions

Figure 2-15. Untreated emissions from Jenbacher engines fueled with producer gas
Herdin et al. 2004

The high CO emissions from lean burn low-NOx optimized engines fueled by producer gas are an issue that needs addressing. Some of the development projects discussed in the Jenbacher experience report have tried oxidation catalyst on the engine exhaust to reduce CO emissions. They have met with mixed results. Acceptable oxidation catalyst lifetime is possible with sufficient gas cleaning after the gasifier and or selection of fuel low in catalyst poisons (metals, alkalis, sulfur, and chlorine). The Harboøre, Güssing, and Spiez demonstration facilities have each successfully used CO oxidation catalyst technology. CO conversion rates varied from 70 to 90% with one facility reporting 2,000 operational hours on the catalyst and two reporting 3,000 hours.

Jenbacher also reports facilities that choose to control engine CO by combustion after-treatment. At least one facility takes advantage of co-location with a biomass boiler where its engine exhaust is fed into the boiler which oxidizes the CO. Other installations use commercial thermal-oxidizer treatment units which come with energy and cost penalties.

Other Producer Gas Engine Emissions

Information on emissions from engines fueled by producer gas is difficult to find. Table 2-22 displays emissions from two demonstration programs, one in England, and the other in the United States. The information was obtained from presentations posted on

the IEA Task 33 Thermal Gasification of Biomass website.[85] Actual test conditions and methods, fuel gas quality, and whether or not emissions control devices were in place (and their longevity) were not available in the presentation material.

Table 2-22. Emissions from producer fuel gas engines from two demonstration programs.

	Capstone C-330 microturbine (30kW)*	SI-Recip Perkins Model 2006*	CPC Biomax 15 kW (automotive SI engine)◊	
	ppm (15% O2)		ppm (?% O2)	(lb/MWh)
CO	26	1039	2	0.65
NOx	5	18	30	0.03
UHC	11	1	4	0.03
Source	A	A	B	

* Not stated whether emissions control devices are used. Gas quality (or ammonia content) not stated

◊ 3- way catalyst used. Gas quality (and ammonia content) not reported. Durability of catalytic converter not reported.

Sources;

A) Conner and Peacocke, Biomass Engineering Ltd. Warrington, England, 2004 IEA Task 33 Gasification Workshop, Copenhagen

B) R. Bain, NREL. 2004 IEA Task 33 Gasification Workshop, Copenhagen

The CPC Biomax 15 kW system that yielded the emissions in Table 2-22 was using a three-way catalytic converter (Sethi 2005). Other CPC systems are planned to be deployed for testing in California in late 2005 or early 2006. Emissions testing are anticipated but it is not known if emissions will be assessed throughout the demonstration program or just once after initial commissioning.

Microturbine and Fuel Cell Emissions Fueled by Biogas

The Los Angeles County Sanitation Districts are generating heat and power from LFG, digester gas from water treatment, and combustion of solid waste. Total electrical generating capacity from twelve facilities is 127 MW. Among these are microturbines (30 kWe units at the Calabasas landfill and a 250 kW unit at the Lancaster WRP) and a molten carbonate fuel cell at the Palmdale Water Reclamation Plant.

30 kW Microturbine Fueled by LFG

At the Calabasas landfill, ten Capstone 30 kW (nominal gross) microtubines are fueled by LFG. The fuel gas is pretreated using a compressor, chiller, and two sorbent vessels in series filled with silica gel. Table 2-23 displays NOx and CO emissions from a 30 kW (gross at 63°F inlet air temperature) Capstone turbine fueled by LFG. It is not known if these are results from the same unit. Net output is approximately 25 kW due inlet air temperature more than 63°F and parasitic losses in the gas clean-up system. NOx emissions range from 0.2 to 0.24 lb/MWh. CO emissions range from 0.6 to 0.72 lb/MWh. SO_2 emissions are estimated at about 1 lb/MWh (assumes all H_2S in the fuel gas was converted to SO_2).

85. See presentations from the October 2004 meeting: http://www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=iea/taskminutes.xml

Table 2–23. Emissions from a 30 kW (gross) microturbine at Calabasas Landfill

Parameter	Unit	Source Test Date				Limit	SCAQMD Rule
		2003 ◊		November, 2004 ‡			
		Inlet	Exhaust	Inlet	Exhaust		
O_2	%	-	-	0.5	17.89		
CO_2	%	-	-	35.8	2.7		
N_2	%	-	-	23.7	79.4		
H_2O	%	-	-	-	3.7		
H_2S	ppm	-	-	130-160	-		
CH_4	%	41	-	40	-		
NMHC	ppm	297	-	-	-		
Stack Flow Rate	dscfm	-	-	-	532		
LFG Flow Rate	dscfm	-	-	17.5	-		
LFG Flow Rate	dscfh	-	-	1052	-	1200	
Temperature	ºF	-	-	-	514		
LFG	Btu/scf	-	-	403	-		
NOX:							
	ppm	-	-	-	1.3		
	ppm @ 15% O2	-	3	-	2.5	25	1134
	lb/hr (as NO2)	-	0.006	-	0.005	0.017	
	lb/MM Btu (as NO2)	-	0.2	-	0.012		
	lb/MWh	**-**	**0.24**	**-**	**0.20**		
CO:							
	ppm	-	-	9.26	7.5	2,000	407
	ppm @ 15% O2	-	12	-	14.7		
	lb/hr	-	0.015	-	0.018	0.057	
	lb/MWh	**-**	**0.6**	**-**	**0.72**		
SO_2 (estimated)*:	lb/hr	-	-	-	0.026		
	lb/MWh	**-**	**-**	**-**	**1.03**		
NMHC							
	ppm (3% O2)	-	2.4	-	-		
Formaldehyde	ppb	-	15	-	-		

* $H2^S$ in inlet fuel is assumed to convert to SO2 and emitted in exhaust. 145 ppm H2S in fuel is ~ 0.014 lb/hr at inlet

◊McDannel, M., Wheless, E., Maguin, S., and Stahl, J. (2005). "Operating experience at two biogas-fired microturbine facilities." SWANA 2005.

‡ Wheless, E. (2005). LA County Sanitation Districts. Personal communication.

250 kW Fuel Cell Fueled by Digester Gas

A fuel cell is operating on waste water treatment digester gas at the Palmdale WRP. The Palmdale facility treats approximately 9.5 million gallons per day of wastewater. The anaerobic digesters at the facility generate about 80 scfm of biogas containing approximately 55% methane (McDannel 2005).

The fuel cell, provided by Fuel Cell Energy, is a molten carbonate type with internal reforming, having a gross capacity of 250 kW (model DFC 300A).

For fuel gas treatment, the biogas is passed through a PM filter, a refrigeration unit, and activated carbon. The gas cleaning system consumes about 25 kW. Table 2-24 displays gas quality before and after the gas cleaning system.

Table 2-24. Palmdale fuel cell raw and treated fuel-gas quality

Contaminant	Raw Digester Gas	After Gas Clean-up
H2S, ppm	23	ND<0.5
Chlorobenzene ppb	180	0.7
P-dichlorobenzene, ppb	30	ND <1.0
D4 siloxane, ppm	0.40	ND<0.03
D5 siloxane, ppm	0.95	ND<0.03

Source: McDannel 2005

The net electrical efficiency of the fuel cell is estimated at 41% (HHV). Emissions, reported by Los Angeles County Sanitation Districts, are shown in Table 2-25. NOx and CO emissions from fuel cells are extremely low.

Table 2-25. Air emissions from the Palmdale WWTP fuel cell.

Pollutant	ppm @15% O_2	lb/MWh
NOx	0.05	0.0017
CO	1.2	0.025
HC	1.3	0.017
SO_2	ND<0.02	-

Source: McDannel 2005

2.3 Air Permitting Process

Local air districts in California have the responsibility and authority for regulating stationary sources while the California Air Resources Board (CARB) has authority over mobile sources. Air district rules and regulations derive from the California and Federal Clean Air Acts.[86] When siting new sources in federal criteria pollutant non-attainment areas, rules are designed to achieve no net emissions increase of non-attainment

86. The Federal Clean Air Act was first enacted in 1963 and amended in 1977 and 1990. The California Clean Air Act was enacted in 1988. See California air quality timeline at: http://www.sparetheair.org/teachers/bigpicture/IIIc3.html

pollutants or their precursors. For areas that have good air quality, the district is obliged to "prevent significant deterioration" or maintain good air quality.[87]

In most California air districts, a permit to construct is required before work can begin for new or modified non-exempt stationary sources. For power plants 50 MW and over, the California Energy Commission has ultimate licensing authority for the facility. A permit to operate is required before operations can commence.

To receive a permit to construct, the project must undergo a new source review (NSR) by the local air district which may entail an engineering evaluation by district engineers. Each district determines what class or size of sources is exempt from air permits (for example, most districts exempt engines smaller than 50 bhp). For projects where there is uncertainty regarding the need for permitting, the NSR process will determine whether it is exempt or not from air permit requirements.

Depending on the area designation and the potential level of emissions, the facility may be required to use BACT. Although there is a codified definition[88] for BACT, it is determined at the district level which considers emission levels that are achievable on technical and cost effective bases as well as those that have been achieved in practice.

In addition to using BACT, new or modified sources in non-attainment areas may be required to provide emission offsets to mitigate the new source emissions. Most districts specify the emissions level above which offsets are required by the project (the so-called "offset trigger"). Offsets are obtained by retiring or reducing emissions from other sources. To be eligible, emission reduction offsets or credits must be surplus to any federal, state, or local laws or regulation, and must be enforceable, quantifiable, and permanent. Emission offsets or credits may be banked with the district for future use by the source that generated them, used concurrently to offset new sources, or sold to others for use as mitigation.[89] Each district sets rules for how credits are certified and banked. Individual air districts are required to collect and publish specific information on emission offset transactions including price paid per ton of offset, the amount of each pollutant traded, and the year of transaction. CARB publishes an annual report summarizing emission offset transactions within the state.[90]

2.3.1 Air District Attainment Status and Emission Limits

Air quality control districts in the Sacramento region include the Sacramento Metropolitan Air Quality Management District (AQMD), the Yolo-Solano AQMD, the

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87. See CARB discussion of new source review permitting programs at: http://www.arb.ca.gov/nsr/nsr.htm
88. California Health and Safety Code, section 40405.
89. California Health and Safety Code, sections 40709-40713, Emission reduction credit systems and banking.
90. Transaction summary reports dating to 1993 are available at: http://www.arb.ca.gov/nsr/erco/erco.htm

San Joaquin Valley APCD, the Feather River AQMD, and the single-county districts of El Dorado, Placer, Amador, and Colusa counties.[91]

These districts are all designated "Non-Attainment"[92] by the State's standards for ozone and PM_{10} (see Table 2-26), with the exceptions of the Colusa County APCD, which is transitioning to non-attainment for ozone and the Amador County APCD which is unclassified for PM_{10} (i.e., data is insufficient or inconclusive to determine designation). The San Joaquin APCD is rated "severe non-attainment" for ozone. The Sacramento Metropolitan and Yolo-Solano AQMDs and portions of the Feather River AQMD, Placer and El Dorado Counties are rated as "serious non-attainment" for ozone.

The Sacramento Metropolitan, San Joaquin Valley and the southern portion of the Feather River air districts are non-attainment for $PM_{2.5}$, with the other districts in the region currently unclassified. The region's districts are in attainment for NOx and SOx and in attainment or unclassified for CO.

For districts that are non-attainment for a criteria pollutant, tougher emission standards or limits are placed on sources within the district as well as for new sources in upwind districts. Ozone is not emitted in appreciable amounts directly by mobile or stationary sources, but ground-level concentrations depend heavily on these sources. Tropospheric ozone is formed by reactions of precursors in the presence of sunlight (photochemical smog). In order to minimize the formation of ground-level ozone, strategies, regulations, and technologies have developed to control the precursor compounds.

NOx and VOC (also known as reactive organic gases, or ROGs) are ozone precursors and are emitted in significant amounts from anthropogenic sources. Though the entire state is in attainment for NOx as a criteria pollutant, and VOCs are not criteria pollutants, both are heavily regulated because of their contributions to ozone formation.

Major stationary sources are classified by emission of a regulated pollutant in amounts greater than the threshold set by the air district. Major sources are subject to greater control and scrutiny under the permit process. Table 2-27 lists major source thresholds for several pollutants for the Sacramento region air districts.

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91. A map of California's air districts is available here: http://www.arb.ca.gov/drdb/dismap.htm
92. "Attainment" required that the standard has not been violated for three years anywhere in the air district. See designation definitions at: http://arb.ca.gov/desig/adm/Define.htm

Table 2-26. Criteria pollutant attainment status for air districts in the Sacramento region (California designations)[93]

Pollutant	Sacramento Metropolitan AQMD	Yolo-Solano AQMD	San Joaquin Valley APCD	El Dorado County APCD	Placer County APCD	Feather River AQMD	Colusa County APCD	Amador County APCD
Ozone	●	●	●	●	●	●	⊗	●
NOx	○	○	○	○	○	○	○	○
CO	○	○	○	UC	UC	○/UC*	UC	UC
SOx	○	○	○	○	○	○	○	○
PM_{10}	●	●	●	●	●	●	●	UC
$PM_{2.5}$	●	UC	●	UC	UC	●/UC*	UC	UC

Key; ●-Non-Attainment
○-Attainment (standard not violated for three years)
⊗-Transitioning to Non-Attainment
UC-Unclassified (insufficient or inconclusive data to determine designation)

* The Yuba County portion of the Feather River AQMD remains unclassified

Table 2-27. Emission levels (tons/year) required for designation as a major source and offset trigger limits[94]

Pollutant (Tons/ year)	Sacramento Metropolitan AQMD	Yolo-Solano AQMD	San Joaquin Valley APCD	El Dorado County APCD	Placer County APCD	Feather River AQMD*		Colusa APCD	Amador County APCD
						SFNA* Portion	North Portion		
	Rule 202, section 220	Rule 3.4, section 222	Rule 2201, section 3.25.1	Rule 523, section 523.2-X	Rule 502, section 225	Rule 10.1 section D.20		Rule 3.17 section b.20	Rule 102
ROG	25	25	25	25	50	25	100	100	100
NOx	25	25	25	25	50	25	100	100	100
SOx	100	100	70	100	100	-	-	100	100
PM10	100	100	70	100	100	100	100	100	100
CO	100	100	100	100	100	100	100	100	100

*SFNA means "severe federal non-attainment." The SFNA portion of the Feather River AQMD is south of a line connecting the northern border of Yolo County to the SW tip of Yuba County and continuing along the southern Yuba County border to Placer County.[95]

Emission thresholds above which BACT is required (BACT triggers) for new or modified sources in the Sacramento region are listed in Table 2-28. BACT triggers for ROG and NOx are generally 10 lb/day except for portions of the Feather River AQMD and the Colusa APCD which are 25 lb/day and the San Joaquin Valley APCD which is much lower at 2 lb/day. BACT triggers for oxides of sulfur and PM_{10} range from 2 to 80 lb/day. Carbon monoxide BACT thresholds range from 250 to 550 lb/day and the lead BACT trigger is 3.2-3.3 lb/day. The BACT thresholds reflect the general air quality in the district.

93. Attainment area maps are available at: http://www.arb.ca.gov/desig/adm/adm.htm#state
94. CARB database of air district rules can be found at: http://www.arb.ca.gov/drdb/drdb/htm
95. 40CFR Section 81.305 for the Sacramento metro area.

Table 2-28. BACT trigger thresholds for air districts in the Sacramento region◊

Pollutant (lb/day - unless noted otherwise)	Sacramento Metropolitan AQMD	Yolo-Solano AQMD	San Joaquin Valley APCD	El Dorado County APCD	Placer County APCD	Feather River AQMD*		Colusa APCD
						SFNA* Portion	North Portion	
	Rule 202, section 301	Rule 3.4, section 301	Rule 2201, section 4	Rule 523, section 523.3A1	Rule 502, section 301	Rule 10.1 section E.1		Rule 3.6 section c.1
ROG	10	10	2	10	10	10	25	25
NOx	10	10	2	10	10	10	25	25
SOx	10	80	2	80	80	80	80	80
PM10	10	80	2	80	80	80	80	80
CO	550	250	100 ton/y	550	550	500	500	500
Lead	3.3	3.3	-	3.3	3.3	3.2	3.2	3.2
Asbestos	-	-	-	-	-	-	-	0.03
Beryllium	-	-	-	-	-	-	-	0.002
Mercury	-	-	-	-	-	-	-	0.5
Vinyl chloride	-	-	-	5.5	5.5	-	-	5
Fluorides	-	-	-	-	-	-	-	15
Sulfuric acid	-	-	-	38	38	-	-	35
Hydrogen sulfide	-	-	-	55	55	-	-	50
Reduced sulfur	-	-	-	55	55	-	-	50

* See note for Table 2-27

◊ Amador County APCD requires air quality modeling to determine potential impacts of the new source on ambient concentrations in the air district. BACT and offset requirements are based on the modeling results. See Amador County Regulation IV- Authority to Construct Regulations.

Emission reduction offset trigger amounts are shown in Table 2-29. Sources that emit above the offset threshold levels must provide emission reduction offsets to mitigate emissions above the thresholds. Generally, sources emitting above the offset triggers are subject to BACT since the BACT thresholds are usually much lower (there seems to be an exception to this for the CO offset trigger amount for El Dorado and Placer County APCDs which is lower than the BACT threshold).

Because of pollutant transport between air basins, strict control of new NOx and VOC emissions in districts upwind of ozone non-attainment areas has been recently enacted. For the Sacramento Metropolitan and Yolo-Solano air districts, portions of which are generally upwind of the San Joaquin Valley air basin, the VOC and NOx offset trigger limits for new or modified sources have been lowered to 5,000 lb/quarter and 20,000 lb/year, respectively (Table 2-29). When new emissions exceed these amounts, the source is required to offset those emissions so that regional air quality is not degraded.

Table 2-29. Emission Offset Trigger Amounts for districts in the Sacramento region◊

Pollutant (Note Units)	Sacramento Metropolitan AQMD	Yolo-Solano AQMD	San Joaquin Valley APCD	El Dorado County APCD	Placer County APCD	Feather River AQMD*		Colusa APCD
						SFNA* Portion	North Portion	
	Rule 202, section 301	Rules 3.20, 3.4 sections	Rule 2201, section 4.5	Rule 523, section 523.3B1	Rule 502, section 302	Rule 10.1 section E.2		Rule 3.6 section c.2
ROG	5,000 lb/qtr	10 ton/y	10 ton/y	5,000 lb/qtr	7,500 lb/qtr	10 ton/y	25 ton/y	25 ton/y
NOx	5,000 lb/qtr	10 ton/y	10 ton/y	5,000 lb/qtr	7,500 lb/qtr	10 ton/y	25 ton/y	25 ton/y
SOx	13,650 lb/qtr	13,650 lb/qtr	27.4 ton/y	12,500 lb/qtr	12,500 lb/qtr	-	-	-
PM10	7,500 lb/qtr	13,650 lb/qtr	14.6 ton/y	7,500 lb/qtr	7,500 lb/qtr	10 ton/y	25 ton/y	25 ton/y
CO	49,500 lb/qtr	49,500 lb/qtr	100 ton/y	7,500 lb/qtr	7,500 lb/qtr	-	-	-

* See note for Table 2-27
◊ Amador County APCD requires air quality modeling to determine potential impacts of the new source on ambient concentrations in the air district. BACT and offset requirements are based on the modeling results. See Amador County Regulations IV- Authority to Construct Regulations.

Limits for Reciprocating Engines

For the air districts in the Sacramento region, emissions from reciprocating engines are regulated by limiting maximum concentration of a pollutant in the exhaust gas. CARB recommends output-based emission limits for engines (i.e., limit pollutant mass per unit of energy produced. See Tables 2-30 and -31). Emission limits based on exhaust gas concentration allow low efficiency systems to have increased emissions per output kWh. In general, stationary engines below 50 bhp (38 kW) are exempt from air permits to operate.

CARB BACT Recommendations

Tables 2-30 and 2-31 show CARB recommended best available control technology requirements for reciprocating engine and gas turbine (less than 3 MW) distributed generation applications respectively. BACT emissions depend on the fuel type (waste gas or fossil fuel) and class of prime mover (turbine or reciprocating engine). The higher emissions allowed for waste gas including biogas applications mainly reflect the fact that use of catalytic converters with biogas fuel is difficult and is not in routine practice. CARB limits include both output based as well as the approximate equivalent concentration based emission.[96]

96. For a given output based emission level, the equivalent concentration based emission level depends on the overall thermodynamic efficiency of the system.

Table 2-30. CARB recommended BACT emissions for reciprocating engines.

	'Waste gas' fired			Fossil fuel fired		
	(g/bhp-hr)	(ppmvd)‡	(lb/MW-hr)	(g/bhp-hr)	(ppmvd)	(lb/MW-hr)
NO_x	0.6	50	1.9	0.15	9	0.5
VOC	0.6	130	1.9	0.15	25	0.5
CO	2.5	300	7.8	0.6	56	1.9
PM	NA	NA	NA	0.02	-	0.06

‡ ppmvd – parts per million by volume dry - values are approximate for reciprocating engines
Source: CARB

Table 2-31. CARB recommended BACT emissions for gas turbines less than 3MW.[97]

	"Waste gas" fired (any capacity)			Fossil fuel fired		
	(g/bhp-hr)	(ppmvd)	(lb/MW-hr)	(g/bhp-hr)	(ppmvd)	(lb/MW-hr)
NO_x		25	1.25		9	0.5
VOC		-	-		5	0.1
CO		-	-		10	0.4
PM		-	-			

Sacramento Region Stationary Engine Emissions Rules

Table 2-32 displays current or proposed emission limits for NOx, CO, and VOCs from stationary reciprocating engines for the eight air districts in the Sacramento region (note that except for the Feather River AQMD, they are all concentration based limits). The limits are typically differentiated for spark ignited (SI) lean or rich burn and compression ignited (CI or diesel) engine types. NOx limits for reciprocating engines in the region vary from 25 ppmv at 15% O_2 in El Dorado County for a rich-burn engine greater than 50 bhp to 740 ppmv in Colusa County for a lean-burn engine less than 300 bhp.

The definition used to determine whether an SI engine operates as fuel-rich or fuel-lean (rich or lean burn respectively) varies slightly among the region's air districts.[98] For example, the Sacramento, El Dorado County, and Placer County air districts define rich-burn engines as having $\lambda \leq 1.1$.[99] The Yolo-Solano AQMD defines lean-burn as having exhaust gas O_2 concentration more than 2% by volume. The San Joaquin Valley (SJVAPCD) and the Colusa APCDs use exhaust gas O_2 concentration of more than 2% to define a lean-burn engine.

Only the rules from San Joaquin Valley APCD and the Feather River AQMD specify different limits for SI engines fueled with "waste gas." In addition, the recently amended San Joaquin Valley APCD Rule 4702 created a new engine class for stationary SI engines

97. CARB database of air district rules: http://www.arb.ca.gov/drdb/drdb/htm
98. CI or diesel engines operate in fuel-lean conditions but due to fundamental differences in operation and fuels, CI engines are classified separately.
99. The Greek letter *lambda* (λ) is the ratio AF_{actual}:AF_{stoich}, where AF is air-fuel ratio.

"Used Exclusively in Agricultural Operations" in the district. The rule allows NOx emissions from AO engines to be 90 and 150 ppmv (15% O_2) for rich and lean burn engines respectively. The AO designation was created in the new rule in order to allow continued operation of natural gas engines that had replaced diesel engines in stationary applications on farms. However, the rule appears to ease requirements for power generation from biogas fueled engines that are owned and operated by agricultural operations. Engines used in power production fueled by biogas at digester facilities sited at food processing facilities will need to meet the more strict requirements.

Efficiency Effects on Output Based NOx Emissions

In power systems, emission limits based only on concentration ignore the effect that conversion efficiency has on pollutant emission per unit of output energy (e.g. kWh or MWh). For a given concentration limit, less efficient conversion systems will have significantly larger emission rates (on an equal energy output basis) than more efficient devices (for reciprocating engine generating sets, the smaller capacities are typically less efficient).

Figure 2-16 shows reciprocating engine-genset NOx emission rate vs. conversion efficiency for a given exhaust concentration. For a system with 45% conversion efficiency and 65 ppm NOx in the exhaust, the NOx emission rate is about 1.9 lb/MWh of electricity produced (this would be a large engine generator, lean-burn with perhaps 2 to 3 MW capacity).[100] A system operating at 25% conversion efficiency with 65 ppm NOx concentration in the exhaust gas will emit at the rate of about 3.5 lb/MWh. The 25% efficient unit would need to have a NOx exhaust concentration of 35 ppm in order to emit at the same CARB recommended output based rate as the 45% efficient device emitting at 65 ppm (see Figure 2-17).

In the long term, the concentration-only based emission limits will be a disincentive to improved conversion efficiency. The California Air Resources Board as well as the U.S. EPA and the Regulator Assistance Project recommend output based emissions regulations for power generation systems.[101]

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100. The CARB BACT recommendation is 1.9 lb NOx/MWh for "waste" gas fueled reciprocating engines.

101. Information from CARB's "Guidance for the permitting of electrical generation technologies," available at: http://www.arb.ca.gov/energy/dg/dg.htm and The Regulatory Assistance Project's "Model regulations for the output of specified air emissions from smaller-scale electric generation resources," available at: http://www.raponline.org/Pages/Feature.asp?select=8. See also http://www.epa.gov/chp/chp_support_tools.htm

Table 2-32. Emission limits (ppmv at 15% O2- unless otherwise noted) for reciprocating engines in air districts within the Sacramento region ⊗

District		Sacramento Metropolitan AQMD	Yolo-Solano AQMD	San Joaquin Valley APCD		El Dorado County APCD	Feather River AQMD	Colusa APCD		Placer County APCD
Rule Citation ☼		Rule 412, RACT & located at major NOx source (25 t/y)	Rule 2.32	Rule 4702 ◊		Rule 233	Likely use Bay Area AQMD BACT guidelines‡	Rule 2.36		Rule 242
	Engine Size	> 50 hp (38 kW)	> 50 hp (38 kW)	AO▲ > 50 hp (38 kW)	> 50 hp (38 kW)	> 50 hp (38 kW)	> 50 hp-Rich (38 kW) > 250 hp-Lean (187 kW)	>50 & ≤300 hp (>38 & ≤225 kW)	> 300 hp (225 kW)	> 50 hp (38 kW)
SI **Rich**	Definition	$\lambda \leq 1.1$	not lean	not lean		$\lambda \leq 1.1$	-	not lean		$\lambda \leq 1.1$
	Fuel Type	Not specified	Not specified	Not specified	Waste gas	Not specified	Natural gas	Gaseous fuels		Not specified
	NOx	50 (or ↓ 90%)	90	AO▲; 90 (or ↓ 80%)	50 (or ↓ 90%)	25 (or ↓ 96%)	0.15 g/bhp-hr (~ 9ppmv)	640	90	90
	CO	4000 (or ↓ 90%)	2000	2000		2000	0.6 g/bhp-hr (~55 ppmv)	4500	4500	2000
	VOC / NMHC	250 (or ↓ 90%)	-	250		-	0.15 g/bhp-hr (~ 25ppmv)	-	-	-
SI **Lean**	Definition	not rich	>2% exh. O_2	>4% exh. O_2		not rich	-	>4% exh. O_2		$\lambda > 1.1$
	Fuel Type	Not specified	Not specified	Not specified	Not specified	Not specified	Waste gas	Gaseous fuels		Not specified
	NOx	125	150	AO▲; 150 (or ↓ 75%)	65 (or ↓ 90%)	65 (or ↓ 90%)	1.25 g/bhp-hr (~100 ppmv)	740	150	150
	CO	4000	2000	2000		2000	2.65 g/bhp-hr (~330 ppmv)	4500	4500	2000
	VOC / NMHC	750	-	750		-	1.0 g/bhp-hr (~215 ppmv)	-	-	-
CI (Diesel)	NOx	700	600	*		600	6.9 g/bhp-hr (~500ppmv)	700		600
	CO	4000	2000	*		2000	2.75 g/bhp-hr (~320 ppmv)	4500		2000
	VOC / NMHC	750	-	*		-	1.5 g/bhp-hr (~310 ppmv)	-		-

☼ District Rules Database maintained by CARB; http://www.arb.ca.gov/drdb/drdb.htm
◊ SJVAPCD Rule 4702, amended 16 June, 2005 Available at; http://www.valleyair.org/rules/currntrules/Rule_4702_0605.pdf
↓ = 'reduction of untreated amount by'
▲ AO means 'Used Exclusively in Agricultural Operations'
* EPA Tier 2,3, or 4 depending on size (See Table 2 in Rule 4702).
‡ (2005) Personal communication with Matt Baldwin, FRAQMD. See; http://www.baaqmd.gov/pmt/bactworkbook/default.htm
⊗ Amador County APCD has not promulgated specific rules for stationary engines.

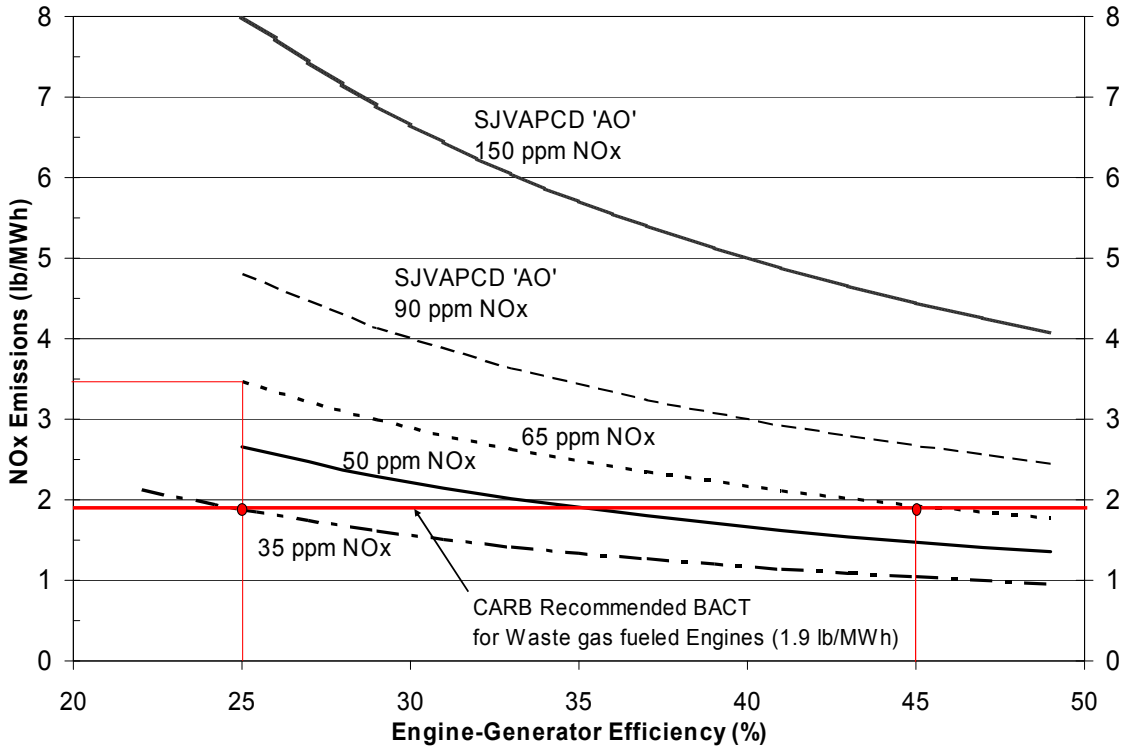

Figure 2-16. NOx emission rate vs. efficiency for given exhaust concentration (concentrations are at 15% O_2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

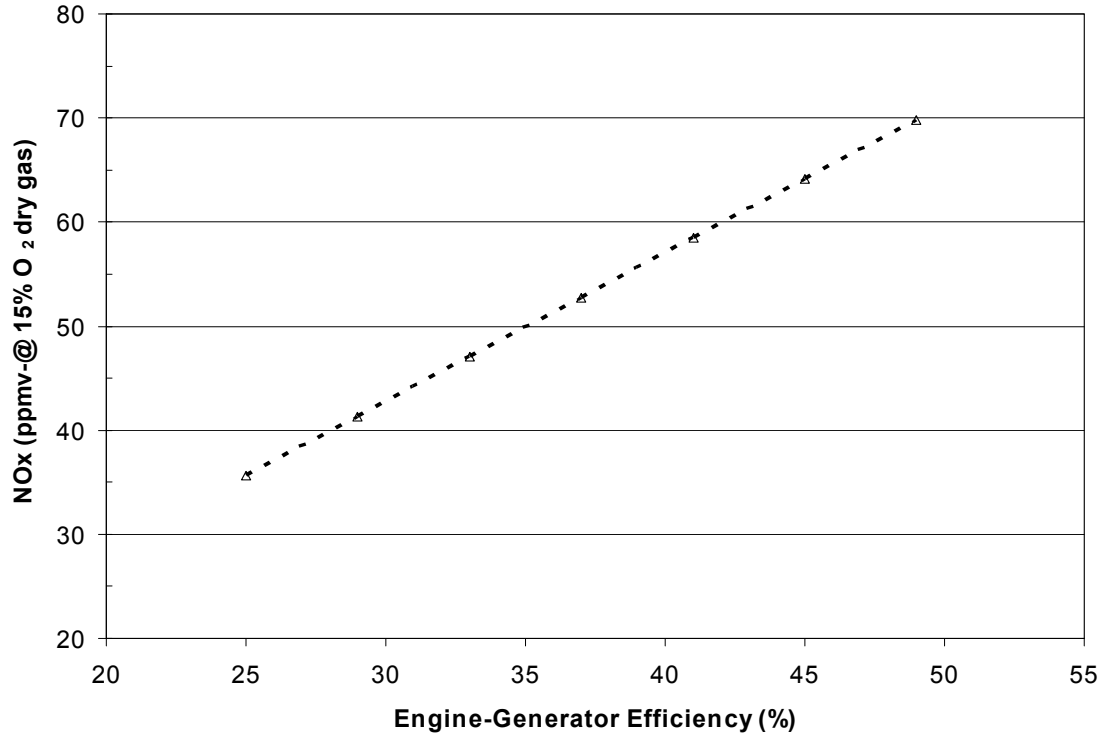

Figure 2-17. Maximum NOx concentration vs. efficiency for 1.9 lbs/MWh emission rate

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

2.4 Nitrogen Oxides Background and Control

NOx emissions comprise primarily nitric oxide (NO) and nitrogen dioxide (NO_2). Fossil fuel combustion accounts for about 40% of the global production of NOx and is the primary anthropogenic source (Seinfeld 1986). Nitrogen oxides are emitted from combustion sources principally as NO, although direct emissions of NO_2 are significant, especially from mobile sources (AQEG 2004). Nitric oxide is quickly converted to NO_2 in the atmosphere, hence the standard reporting basis for NOx as NO_2. Biomass burning in natural and human-caused forest and rangeland fires contributes about 25% of the world's NOx. Lightning and microbial soil activity are responsible for the remaining 35%. Total global NOx emissions (as NO_2) are about 165 Tg per year (180 million tons per year) (Logan 1983).

The United States' NOx emissions are about 23 million tons per year and have decreased by 15% since 1983.[102] In California, the estimated anthropogenic NOx emissions are 1.2 million tons per year with about 84% from mobile sources and 16% from stationary sources (Kato et al. 2004).

In addition to the role in ozone formation, atmospheric NOx is associated with acid deposition (acid rain) and acidification of aquatic systems, formation of aerosols, and degradation of visibility (Price et al. 1997). Ozone exposure is linked to a number of health effects, including significant decreases in lung function and aggravation of lung diseases such as asthma, leading to increased hospital admissions and mortality.[103] Though VOC, NOx, and appropriate atmospheric and daylight conditions combine to form ozone, the National Research Council suggests that in the gross average, after mixing, transport of ozone precursors, etc., NOx is the limiting factor in photochemical ozone production. Therefore, NOx control strategies are generally more effective than VOC control strategies for prevention of tropospheric ozone (NRC 1991).

2.4.1 NOx from Combustion Sources

There are two possible sources of NOx from fuel combustion (nitrogen in combustion air and nitrogen in fuel) and three mechanisms or pathways for NOx formation (thermal-, fuel-, and prompt-NOx) (Miller and Bowman 1989).

Reactions between N_2 and O_2 in air at high temperature lead to thermal-NOx formation. Activation energies of the several formation reactions involved in thermal NOx are high and thus the rate of thermal NOx production is strongly temperature dependent (the rate of NOx formation increases exponentially with temperature) and kinetic limited. Thermal NOx is formed in combustion near regions of peak flame temperature. In SI

[102] United States Environmental Protection Agency, Office of Air Quality Planning and Standards, 2002. From "More details on nitrogen dioxide based on data through 2002," available at http://www.epa.gov/aortremds/nitrogen2.html

[103] U.S. EPA, Office of Air Quality Planning and Standards. From "The Ozone Report – Measuring Progress through 2003," available at: http://www.epa.gov/airtrends/ozone/html

reciprocating engines, for example, this occurs in the packet of fuel and air near the spark plug which is the first to ignite. The first elements that burn also have the longest time at high temperatures enabling NOx formation to proceed nearly to equilibrium in this region. The rates of formation and dissolution of thermal NOx are such that rapid cooling of combustion gases occurring in reciprocating engines during expansion of the gases in the power stroke immediately after ignition, effectively "freezes" NOx in the gas because the dissociation reactions are much slower at the colder temperatures (Seinfeld 1986).

The nitrogen compounds contained in the fuel are the second source of combustion NOx. Biomass and coal differ in the form of nitrogen in the fuel. Nitrogen in solid-fuel biomass is present mainly in amine compounds. When converted to syngas, producer gas, or biogas, nitrogen is principally available as ammonia or hydrogen cyanide (HCN). Reductions during combustion lead to the formation of radicals such as HCN, N, CN, and NH. Because the nitrogen-carbon and nitrogen-hydrogen bonds have much lower activation energy than the nitrogen-nitrogen bonds in the molecular nitrogen in air, fuel nitrogen is more readily converted to NOx and does not depend strongly on flame temperature (as is the case with thermal NOx formation). Fifty to 90% of NOx formed in coal or heavy oil combustion in boilers is due to fuel-nitrogen depending on source and composition (some portion of the fuel N winds up in NOx, the remainder is mostly N_2 or nitrous oxide, N_2O) (Seinfeld 1986). Emission fractions for biomass are generally at the higher end due to the typically lower flame temperatures compared with coal, gas, or oil firing. The high N contents in straw compared with most woods leads to higher uncontrolled NOx emission levels. Figure 2-18 shows dependence of uncontrolled NOx on nitrogen content of the fuel for a BIGCC and coal/fuel oil facilities. Värnamo BIGCC data are from measurements in the combustion turbine exhaust at the Värnamo biomass IGCC demonstration facility in Sweden (mg NOx/MJ fuel). Coal and heavy oil data (ppm NOx) are from Seinfeld (1986) for utility boilers upstream of any NOx control devices.

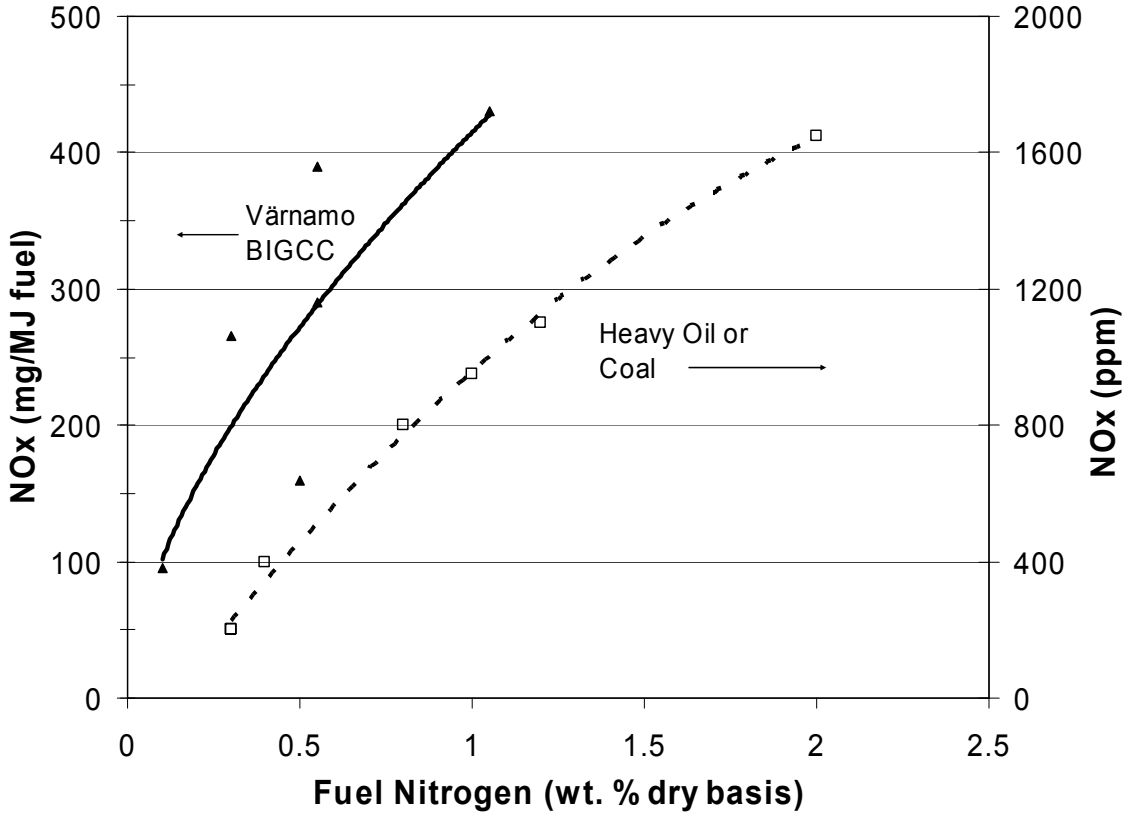

Figure 2-18. NOx vs. Fuel Nitrogen content (uncontrolled emissions)
Photo Credit: Stahl (2001), Seinfeld (1986)

The third NOx pathway is termed "prompt NOx." Prompt NOx is formed from N_2 from combustion air reacting with CH radicals forming HCN and CN compounds and monatomic N. The CN compounds and N quickly react with oxygen forming NO.

Prompt NOx formation is small compared to thermal and fuel NOx for lean and slightly lean combustion because there are relatively few CH radicals available. Prompt NOx becomes important and can be the dominant NOx mechanism in fuel rich mixtures (λ <1), especially with hydrocarbon fuels when rate of formation is faster than thermal NOx (Miller and Bowman 1989). Biomass-fueled boilers can have regions of fuel-rich combustion which may support prompt NOx formation, which is often overlooked in biomass emissions investigations (Grass and Jenkins 1994). Figure 2-19 displays NOx emission factors for several California solid fueled biomass facilities. Permitted NOx emissions range from about 1 to 2 lb/MWh. Emissions from source tests range from about 0.6 to 1.2 lb/MWh. Actual emissions average 70% of the permitted levels.

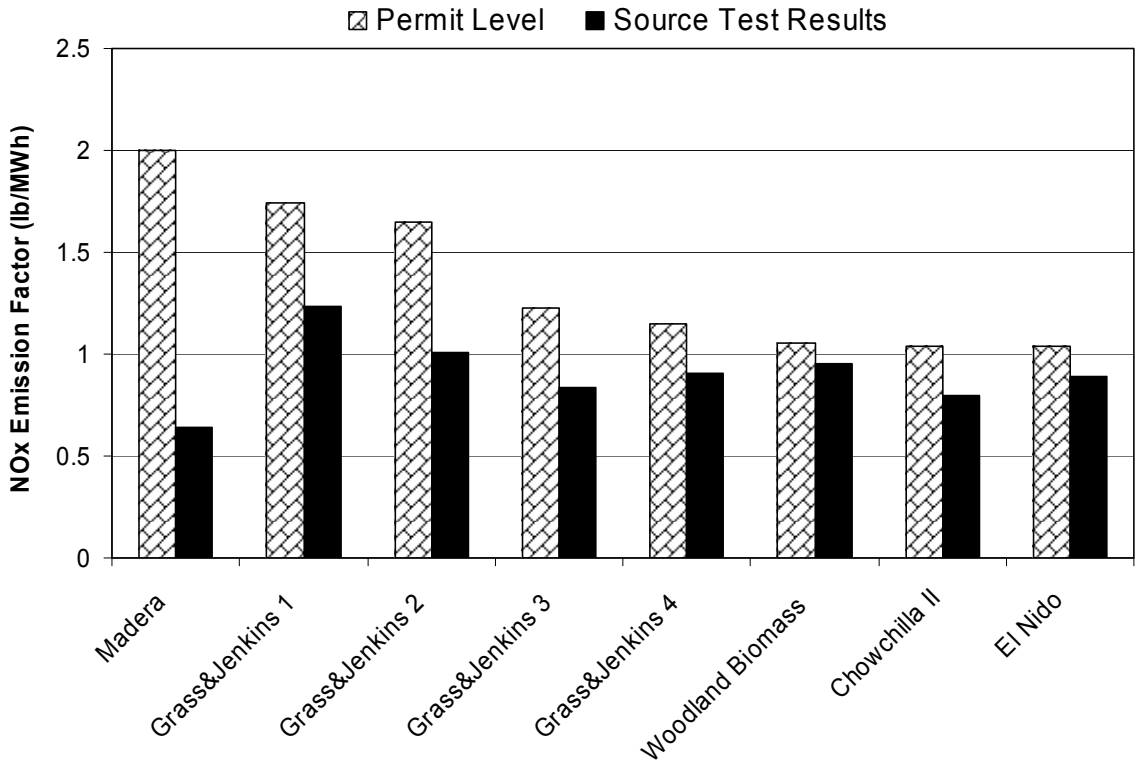

Figure 2-19. NOx emission factors for several California solid biomass facilities
Photo Credit: Figure Straw 2 Task 1.1.2.1 Report and Grass and Jenkins 1994

2.4.2 Controlling NOx

Strategies to control NOx emissions from combustion sources generally fall into one of two categories: (1) minimize NOx formation by managing combustion zone parameters and/or minimize fuel nitrogen (sometimes referred to as "primary control techniques') or (2) reduce NOx in flue gas before release to the atmosphere (also known as secondary control techniques or "add-on control technologies").

Primary Control Techniques–Boilers

Staging of Combustion

Staged combustion is a combustion management technique to control or minimize the production of NOx. The technique is commonly employed in the design of liquid and gas burners (low NOx burners) and can be used with grate fired boilers. Staged combustion can be accomplished by staging the air, staging the fuel, or a combination of the air/fuel staging. Combustion staging here refers to techniques for burners, boiler, furnaces, etc. For reciprocating engines, "pre-stratified charge" and pre-combustion chambers are forms of staged combustion primary control.

Air Staging

Air staged combustion starts with burning the fuel in a slightly fuel-rich zone. The mixture is chosen to promote conversion of fuel-nitrogen to N_2. Flame temperature is relatively low under fuel rich conditions so thermal-NOx production is low. Downstream, additional air is added to complete combustion. The gas temperatures in the burnout zone also remain low enough that thermal-NOx production is minimized. Figure 2-20 displays a schematic of a typical traveling grate stoker boiler showing air injection locations and combustion zones using air staging for NOx control.

Fuel Staging

Fuel staging or "reburning" is a three-step process in which the majority of the fuel and air charge are combusted under normal lean conditions with NOx being formed (from both thermal- and fuel-NOx pathways). This stage is followed by injection of additional fuel (with minimum air) creating a fuel rich reburn zone where NOx is reduced to N_2. Finally, overfire air is added to oxidize remaining unburned fuel. As in staged air, this burnout zone is at a low enough temperature to keep thermal NOx production to a minimum. Figure 2-21 shows the traveling grate stoker boiler configured for staged fuel NOx control. The reburn fuel need not be the same as the primary fuel. In the boiler arrangement shown, the reburn fuel should be capable of quickly volatilizing or burning in suspension mode if not a gaseous fuel (i.e., if fuel particles or droplets are sized incorrectly, they will either fall or fly out of the reburn zone and be less effective). The technique is employed in some coal fired facilities using natural gas or pulverized coal as the reburn fuel. NOx reductions of 50 to 60% are achieved (Harding and Adams 2000). Pilot scale experiments using solid and/or gasified biomass as the reburn fuel show promising results (Maly et al. 1999; Harding and Adams 2000; Vilas et al. 2004; Rizeq and Zamansky 2004; Rudiger et al. 1996; Dagaut and Lecomte 2003; Arumugam et al. 2005).

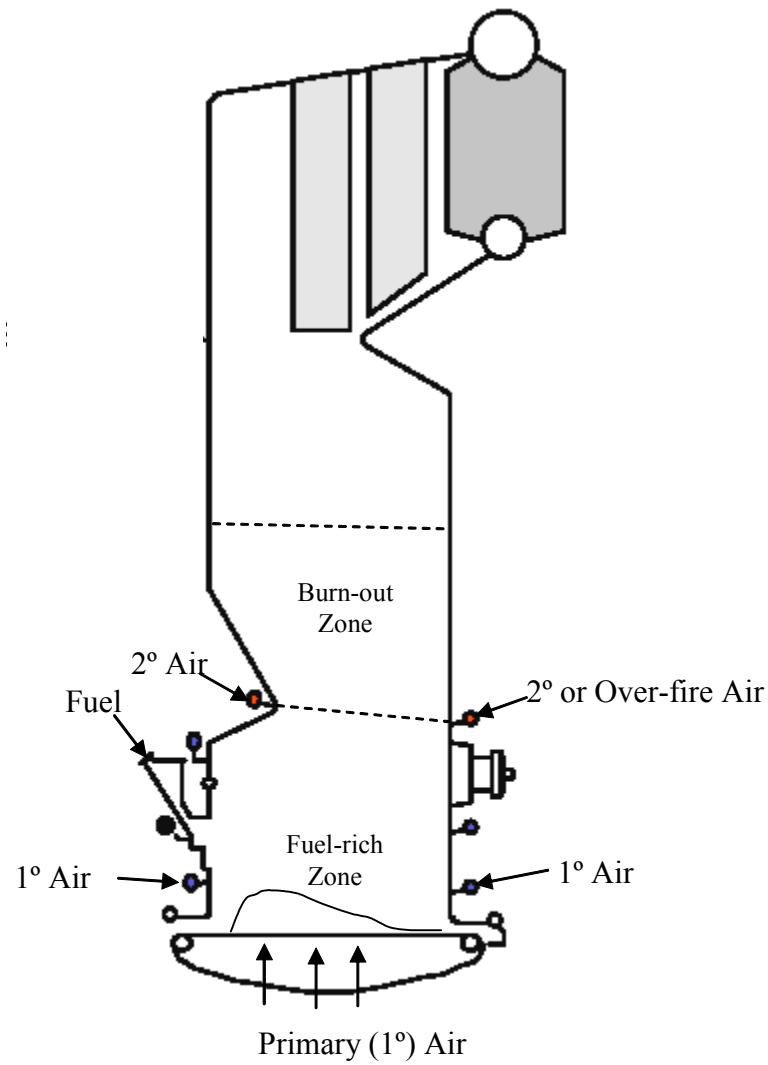

Figure 2-20. Staged air combustion in a traveling grate stoker boiler

Note: 2° = secondary

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

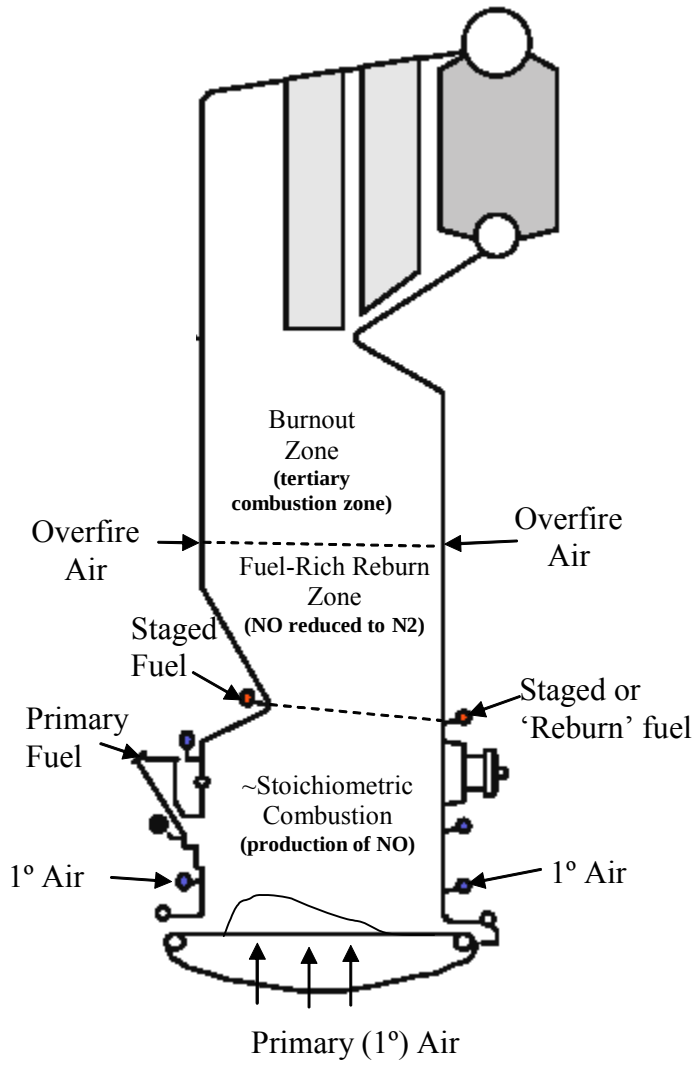

Figure 2-21. Staged fuel or "reburning" in a traveling grate stoker boiler
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Secondary Control Techniques–Boilers

Secondary controls are used to lower NOx after initial formation during combustion. The majority of techniques accomplish this by selectively reducing the NOx to molecular nitrogen (selective control). Low temperature NOx oxidation is an emerging technology with potential applications to engine or boiler exhaust streams.

Selective non-catalytic reduction (SNCR)

SNCR utilizes ammonia, urea, or other suitable amine based compounds that react selectively with NOx in the presence of oxygen. The SNCR technique reduces oxides of nitrogen to N_2. The reactions proceed at fairly high temperature and the temperature range for the reactions to occur is rather narrow at 1600 to 2100°F (900 to 1150°C) which is why the technique is also known as "thermal de-NOx" (Srivastava et al. 2005). At or below the lower end of this range, reactions are slow and require long residence times

which are limited by the furnace size. Temperatures higher than the range cause the nitrogen in the amine compounds to oxidize increasing NOx. Typically, more than stoichiometric amounts of ammonia or urea are injected in order to sufficiently drive the NOx reduction reactions which lead to certain amounts of ammonia passing unreacted through the system (so-called ammonia slip). Insufficient reaction time, low gas temperature, or too much ammonia injection lead to unacceptable ammonia slip which contributes to particulate matter emission and visible plumes.

SNCR is used extensively in industrial and utility boilers and furnaces, including biomass boilers. SNCR is a component of BACT for biomass boilers in California. SNCR performance is specific to each unique application. NO_x reduction levels from SNCR systems range from 30% to over 75%, with the majority of installations achieving more than 50% NOx reduction (Srivastava et al. 2005).

Selective Catalytic Reduction (SCR)

SCR reduces NOx through the same principle reactions as occur in the SNCR process but utilizes a catalyst that allows the system to operate at lower temperature. Typical SCR operating temperature range is 650 to 750°F (350 to 400°C). Typical catalysts include precious metal oxides (e.g., oxides of vanadium, platinum, palladium, etc.).

SCR systems can be highly effective at reducing NOx in the exhaust stream with reported NOx reduction exceeding 90%. The catalyst is susceptible to deactivation by poisoning or deposits covering active surface area but catalyst service lifetimes in coal fired facilities routinely reach 14,000 to 32,000 hours of operation. There are no known commercial biomass facilities using traditional SCR systems for NOx reduction. There are at least two facilities in the US Northeast that have been retrofitted with a "regenerative" SCR or "tail-end SCR" (see RSCR below).

Biomass Fuels and SCR Deactivation

A two year program was carried out in Denmark during which straw was co-fired with coal in a 150 MW pulverized coal boiler (Wieck-Hansen et al. 2000). SCR catalyst exposed to flue gas from 20% straw, 80% coal cofiring showed much faster catalyst deactivation than normally experienced with coal-only firing. For catalyst material exposed to flue gas before particulate matter removal, deactivation rates of approximately 8%/1,000 hours exposure were observed over a 2,900-hour test. Catalyst exposed to flue gas after PM removal by an ESP and bag-house filter showed deactivation rates of about 6%/1,000 hours exposure for a 2,350-hour test.

In Sweden, SCR tests have been carried out in a 125 MW circulating fluidized-bed plant firing forest residues and a 75 MW plant firing pulverized wood. When using a conventional honeycomb catalyst, 80% of the original activity remained in the case of the circulating fluidized-bed boiler after 2,100 hours, but only 20% remained in the pulverized wood boiler. The deactivation rate was reduced by about 66% using a catalyst with increased vanadium content compared to a conventional catalyst used in

coal fired boilers (Khodayari et al. 2000). Increased vanadium in the catalyst or higher catalyst operating temperatures do not necessarily improve catalyst lifetime (Zheng et al. 2004).

The exact mechanisms for catalyst deactivation from biomass fired systems are not defined but alkali and alkaline earth metals are poisons to vanadium catalysts (which includes all commercial SCR systems). Most biomass fuels contain significant amounts of alkali and/or alkaline earth metals. It is postulated that SCR deactivation from biomass fuels is some combination of direct vanadium catalyst poisoning and fouling/deposition from the volatile inorganics in the fuel (Baxter 2005).

At some point in the future, increased levels of NOx control may be required for new biomass facilities in California which may only be achievable using SCR systems. The increased rate of vanadium catalyst poisoning associated with biomass fuels will be an important problem to solve.

Regenerative SCR (RSCR)

"Tail-end" or Regenerative SCR (RSCR) is an SCR technique that has been applied to solid waste combustors, some coal fired facilities, and retrofitted to two solid-fuel biomass units in the Northeast United States. RSCR is typically located between the induced-draft fan the power plant exhaust stack, hence the name "tail-end."

RSCR may offer an improvement over the SNCR method for NOx reduction currently used in many biomass fired facilities in California. RSCR systems are a retrofit option for large coal power plants when space does not allow for installation upstream of PM and sulfur control. Because RSCR treats flue gas after cooling by gas cleaning systems, it is necessary to re-heat the gas to a level required for the catalyst to function. In large coal facilities with RSCR, the energy penalty for reheating the flue gas to 300°C (570°F) is about 3% of plant output. Babcock indicates the main advantage for "tail-end" or "low-dust" SCR arrangements is the extended working life of the catalyst because many of the catalyst poisons (arsenic, alkali and alkaline earth metals) have been removed upstream (Beckmann 2000).

Figure 2-22 depicts the RSCR arrangement for a coal fired power plant. Note that additional fuel is directly fired in the flue gas after a gas-gas recuperating heat exchanger. Ammonia is injected into the reheated flue gas where it's carried into the catalyst where it reacts with NOx.

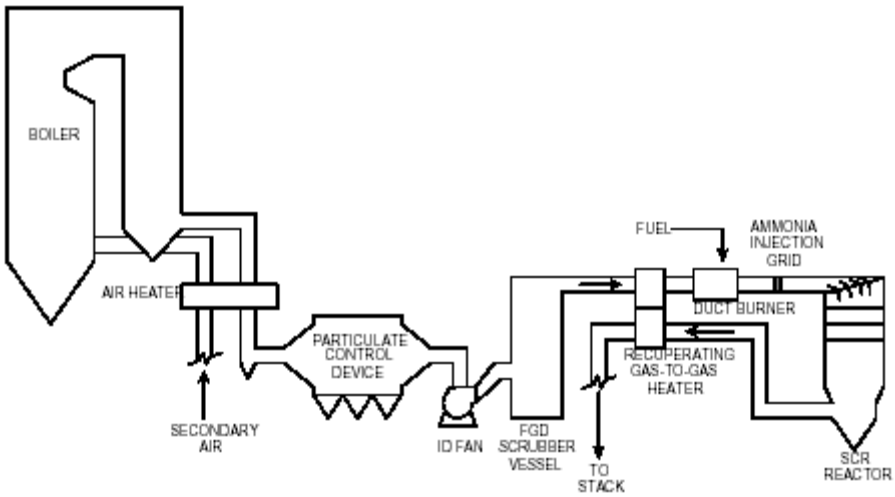

Figure 2-22. Schematic showing "tail-end" SCR arrangement
Photo Credit: EPA Air Pollution Control Cost Manual, 6th edition (EPA/452/B-02-001)

The two biomass facilities retrofitted with RSCR are the Whitefield, New Hampshire, 16 MW (net) Babcock-Wilcox wood fired boiler and the McNeil Generating Station 50 MW (net) stoker-boiler in Burlington, Vermont. Both facilities added RSCR for NOx reduction in order to qualify for the Connecticut Renewable Energy Certificate (REC) program.

The Connecticut RPS requires biomass facility NOx emissions to be less than 0.075 lb NOx/MMBtu fuel input. Connecticut RECs are worth about $0.035/kWh (Pletka 2005).

The draft operating permit for the Whitefield, New Hampshire, facility limits NOx emissions to 0.075 lb/MMBtu. Based on the boiler maximum fuel input of 220 MMBtu/h and the net power output of 16 MW, the maximum NOx emissions are approximately 1 lb/MWh. This level of NOx control is currently being achieved by several California biomass facilities using SNCR in the San Joaquin and lower Sacramento Valleys.

There are at least two companies offering tail-end SCR for biomass power plants; BD Heat Recovery Division, Inc. (Seminole, Florida) which is associated with a German heat exchanger manufacturer and Babcock Power Environmental (Worcester, Massachusetts).

Due to the expense and energy required for re-heat, RSCR systems do not necessarily operate at the optimal temperature for the catalyst. Therefore, NOx reduction from RSCR is expected to be not as good as with standard SCR but still may be an improvement over SNCR.

Performance information from the two biomass facilities in the Northeast recently retrofitted with RSCR should be pursued. Whether RSCR is suitable (and sufficient) for California's needs should be determined.

Low Temperature Oxidation Using Ozone

Ozone oxidation of NOx is considered an emerging technology in which ozone is injected into the low-temperature flue gas, which reacts with NOx producing N_2O_5. Nitrogen pentoxide reacts quickly with moisture in the gas stream forming nitric acid (HNO_3) which is easily removed from the gas by a water scrubber (removal efficiencies are 96 to 98%). The effective temperature range is 150 to 250°F (65 to 120°C). The technology requires an ozone generator (which usually requires industrial grade oxygen to be onsite) and a wet scrubber, and increases parasitic power demand. The wet scrubber could be integrated to remove PM and SO_2 as well. Figure 2-23 provides a schematic.

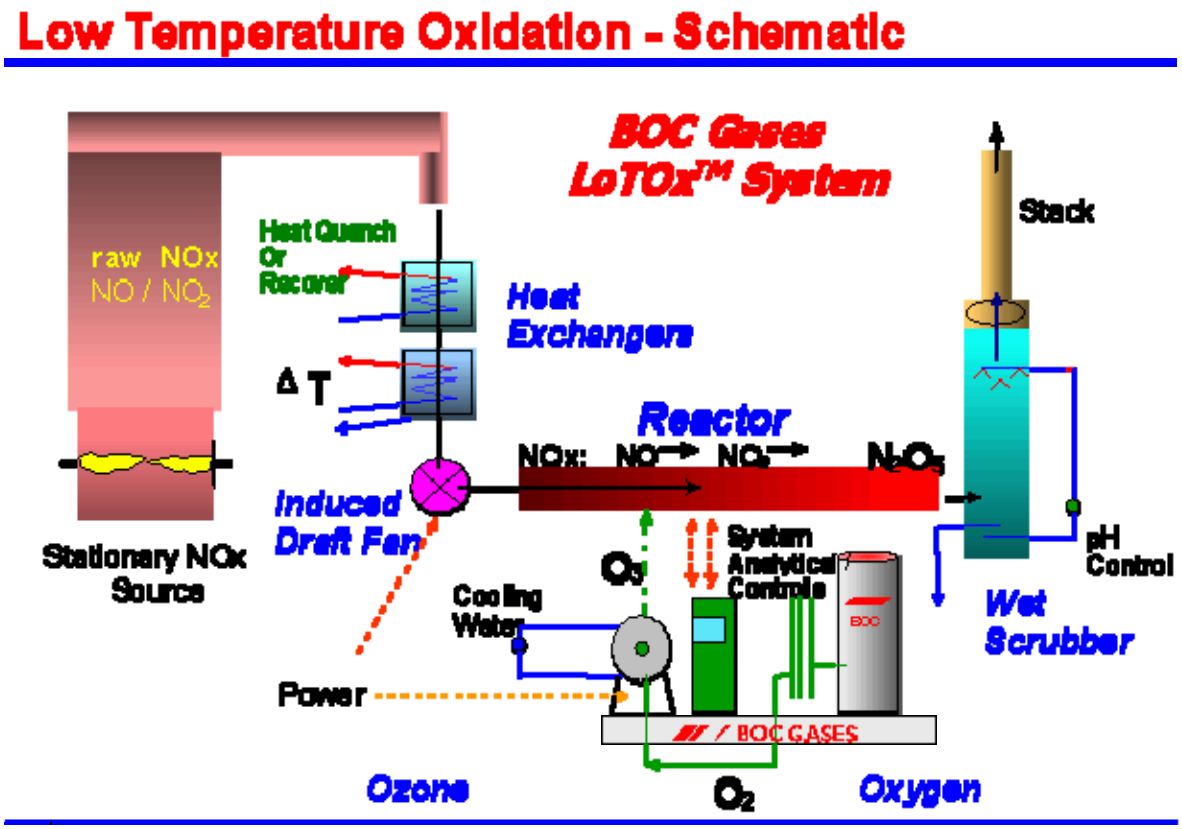

Figure 2-23. Schematic of BOC gases LoTOx system for NOx reduction

Photo Credit: CARB Innovative Clean Air Technology Grant Program, "Low temperature oxidation system demonstration at RSR Quemetco, Inc. Progress Report" (2000)[104]

The system has been demonstrated in several commercial boilers (natural gas and coal fired) and processing plants. Reported NOx removal efficiency is 80 to 95% depending on initial NOx concentration and other parameters. Treated NOx concentrations were as

104. Available at: http://www.arb.ca.gov/research/icat/projects/boc.htm

low as 5 ppm. A lead battery recycling facility in California served as a demonstration site where NOx was reduced by 80%.[105]

Primary Control Techniques- Reciprocating Engines

Combustion or primary NOx control techniques for reciprocating engines are aimed at reducing the peak temperature within the cylinder. Methods include air:fuel ratio (AF) adjustment, ignition timing retard, prestratified charge, pre-combustion chamber, water injection or water/fuel emulsions, exhaust gas recirculation (EGR), and charge air cooling (e.g., turbocharger compressor after-cooling) (Obert 1973).

Air:Fuel ratio (AF) management

AF is defined as the mass of air per mass of fuel in a combustion reaction. Lean combustion occurs when the actual AF (AF_{actual}) is more than the stoichiometric requirement (hence, fuel-lean conditions). Fuel rich combustion refers to cases where AF_{actual} is less than the stoichiometric requirement.

A convenient dimensionless parameter for describing AF in the cylinder charge of an engine is λ (Greek lambda). Lambda is the ratio $AF_{actual} : AF_{stoich}$, or:

$$\lambda = \frac{AF_{actual}}{AF_{stoich.}}$$

Thermal NOx is strongly dependent on temperature. For a reciprocating engine, the maximum flame temperature occurs for $\lambda \approx 1.1$, or slightly fuel lean. This is where maximum NOx production is expected (for a gasoline fueled engine, see Figure 2-24). For low emission operation, engines are operated either slightly rich (λ =1 or slightly lower) or lean-burn conditions where the value of λ depends on the fuel. It turns out that best fuel efficiency occurs with AF that achieves peak flame temperature. AF adjustments to lower NOx also decrease fuel efficiency (overall efficiency decreases by about 2 to 3%).

Rich burn conditions have limited oxygen available in the cylinder and flame temperature is relatively low because fuel is not completely burned. Unburned hydrocarbons (HC) and CO emissions can be high with rich burn engines (depending on the fuel and λ).

105. Information from CARB Innovative Clean Air Technology Grant Program, "Low temperature oxidation system demonstration at RSR Quemetco, Inc. Progress Report" (2000) and the Houston Advanced Research Center, The Woodlands, Texas, "Evaluation of potential control technologies for oxides of nitrogen from point sources in Ellis County, Texas" (2004).

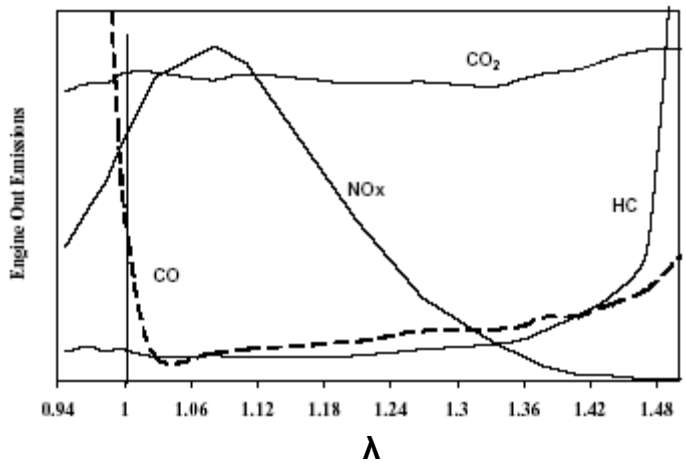

Figure 2-24. Gasoline engine emissions vs. Lambda
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Lean burn conditions reduce peak flame temperature by way of providing excess air effectively diluting the combustion gases. To minimize power de-rating in lean-burn engines, the charge air is often compressed by turbo- or supercharger (to allow more air and thus fuel into the engine). After-cooling of the compressed charge air before induction to the cylinder is recommended for peak flame temperature control. Lambda values for lean-burn engines operated on natural gas can be from 1.5 to 2.4 (excess air of 50 to 140%). Maximum λ is limited by the onset of misfiring at the lean limit. Unburned HC and CO emissions increase at the onset of misfiring. In some instances, high energy ignition systems (HEIS) can be used to reduce the chance of misfiring (and high emissions) when operating at very lean conditions.

Hydrogen enrichment of fuel gas can be used to extend the flammability limit to allow operation at a leaner AF, reducing peak flame temperature and, thus, reducing thermal NOx production. TIAX LLC is currently working on a hydrogen enrichment of LFG power system project. The system, called hydrogen assisted-lean operation (HALO) intends to use a portion of an LFG gas stream in a reformer to make hydrogen, which is then mixed with the remaining portion of the LFG and used as fuel in a reciprocating engine. TIAX expects to achieve 95% reduction of NOx emission (compared to uncontrolled, LFG fueled engine) to a level of 0.6 lb/MWh (TIAX 2002). The project could be undergoing field trials at a California landfill by early 2006. The project is supported by PIER funds through the California Energy Commission.

Pre-stratified charge

This is a method of injecting fuel into the intake manifold in distinct "slugs" which ends up creating stratified layers of rich and lean fuel mixtures in the cylinders. The rich packets are meant to improve ignition while the overall mixture is lean (SOTA 2003).

Pre-combustion chamber

This is another technique where overall lean-burn conditions are met using a rich mixture for ignition. A prechamber in which the spark plug is located receives a rich mixture ensuring ignition. The prechamber is vented to the main combustion chamber which has a fuel-lean mixture. As it expands into the main chamber, the ignited charge in the pre-chamber ignites the lean mixture.

Ignition timing retard

Peak flame temperatures can be lowered by moving the ignition event to later in the compression or to the beginning of the power stroke (ignition retard). In the latter case, by igniting the charge when the piston is after top-dead-center on the power stroke, the charge burns entirely while the chamber volume is increasing, rather than a decreasing volume first encountered by the burning mixture with early ignition time (before top-dead-center), although in the rock position near top-dead-center the volume change is small.

EGR and Cooled EGR

Recirculating exhaust gases into the intake of the engine serves to lower peak combustion temperature by acting as a diluent or heat sink. Effectively, this is a mixture leaning technique.

Water Injection and Water/Fuel Emulsions

Injecting water or including water in the fuel lowers peak temperature by virtue of the latent heat of evaporation of the water. Flame speed and temperature are lowered. This is a common method of NOx and engine knock (detonation) control for large slow speed CI engines.

Table 2-33 summarizes expected NOx reduction by employing combustion flame temperature management techniques using reciprocating engines.

Table 2-33. NOx reduction potential (%) by combustion management techniques (adapted from SOTA 2003

Peak flame temperature management technique	SI (natural gas or propane)	CI (diesel fuel)	Dual-Fuel CI (natural gas, diesel pilot)
λ Adjustment			
Rich-Burn	10 - 40	na	na
Lean- Burn	85	na	85
Pre-stratified Charge/ Precombustion Chamber	75-90	na	na
Ignition Timing	20-40	20 - 30	20 - 30
EGR	- -	50-80	- -
Water Injection / Water in Fuel Emulsion	25 - 30	25 - 30	25 - 30

Secondary Control Techniques–Reciprocating Engines

Nonselective Catalytic Reduction–NSCR

This is the principle employed in automotive catalytic converters. Typically, the catalyst sequentially reduces NOx compounds and oxidizes CO and unburned HC. It operates in a very narrow oxygen concentration range requiring an exhaust oxygen sensor and air/fuel controller. It is only applicable to rich burn engines because the catalyst requires very low oxygen amounts (less than 1%) in order for NOx reduction to take place. NSCR catalysts typically require exhaust temperature in the 800 to 1200°F range. The catalyst is subject to damage by sulfur compounds in the exhaust.

Selective Catalytic Reduction–SCR

As described above in the section addressing boilers and furnaces, SCR selectively reduces NOx by the injection of ammonia or urea reagent upstream of a precious metal oxide catalyst. This requires some oxygen in the exhaust stream and therefore is only applicable to lean burn SI, CI, and dual-fuel CI engines. The catalyst is also susceptible to sulfur adsorption rendering sites inactive. A certain amount of ammonia passes through unreacted which require monitoring in order to meet ammonia slip limits. An SCR system consists of reagent storage, feed and injection system, catalyst, and monitoring equipment for use in controlling ammonia slip. Predictive mapping and monitoring of engine parameters can be used for reagent flow control instead of exhaust monitoring.

Selective Non-Catalytic Reduction (SNCR)

The principle of SNCR was described above (boiler furnace section). The technique requires high temperature (1400 to 1500°F) which may require additional fuel injected into the exhaust to raise exhaust temperature to suitable level. A certain amount of ammonia slip is typical. Depending on exhaust gas heat recovery requirements, SNCR may not be the best choice for NOx control (i.e., if exhaust heat has been extracted it may be too costly or impractical to burn fuel in the exhaust to increase its temperature to that required for SNCR).

Lean NOx Catalyst Technology

Lean NOx catalyst is applicable to lean burn engines, such as CI. It is a potential technology for diesel fueled vehicles or stationary applications. The technique requires injection of a hydrocarbon in the exhaust stream which serves as a reductant. The literature describes tests using diesel fuel as the hydrocarbon source, achieving NOx reductions up to about 45%. A decrease in fuel economy of up to 5% was estimated (Heimrich 1997). There currently is no demonstrated catalyst technology that can satisfactorily reduce NOx in lean-burn automotive applications (CI-diesel) (Tonkyn et al. 2003). Other research investigated a lean-NOx catalyst that does not require hydrocarbon addition and can operate in cool exhaust gases (Paul et al. 1998). Lean-NOx catalyst technology for diesel and lean burn SI engines is developmental. There is much recent and ongoing development work (Traa et al. 1999; Pasquiers 2004; Lee et al. 2004). The technology currently has difficulty with the variable load conditions that transportation engines are subjected to. There may be opportunities to apply the technology to stationary engines that more commonly operate at constant load and speed.

Low Temperature Oxidation Using Ozone

Ozone injection into cooled engine exhaust will further oxidize NOx. The resulting nitrogen compounds are highly soluble in water and can be removed from the gas stream using liquid scrubbing techniques (see section on boilers/furnaces above).

Table 2-34 summarizes reciprocating engine NOx reduction potentials for the several control techniques.

Table 2-34. NOx reduction potential (%) using secondary controls (adapted from SOTA 2003)

Secondary NOx Control Technique	SI Rich-Burn (natural gas or propane)	SI Lean-Burn (natural gas or propane)	CI (diesel fuel)	Dual-Fuel CI (natural gas, diesel pilot)
NSCR	80 - 90	na	na	na
SCR	na	>90	90 - 98	90 - 98
SNCR	50 - 95	50 - 95	50 - 95	50 - 95
Lean-NOx Catalyst	na	?>90	?>90	?>90
Ozone Injection	85 - 95	85 - 95	85 - 95	85 - 95

2.4.3 Sulfur and Catalysts

Sulfur in engine fuel (as H_2S in most untreated biogas) oxidizes to SO_2 and is carried along in the exhaust. Precious metal catalysts used in catalytic converters for reduction of HC, CO, and NOx are susceptible to deactivation by sulfur dioxide. The SO_2 is adsorbed onto a catalyst site and can be oxidized to SO_3 or sulfate (-SO_4 compounds) such as sulfuric acid. The catalyst loses effectiveness as sulfur compounds continue to build.

Digester operators that have engines with catalytic converters and no H_2S removal have reported clogging and/or fires in the catalytic converter due to sulfur deposits.[106] Automotive emissions literature reports that it is possible to regenerate catalysts that have been degraded by sulfur compounds. Essentially, running the engine with lower sulfur content than used previously, or zero, will cause sulfur compounds to desorb from catalyst sites and exit with the exhaust. The catalysts usually do not recover fully by this method. Sulfur purge cycles have been shown to be effective in automotive systems. Essentially, this involves operating the engine in a fuel-rich mode for a period, followed by fuel-lean. Fuel-rich operation provides unburned fuel compounds to the catalyst which are oxidized during the lean portion of the purge cycle releasing heat which promotes sulfur compounds to oxidize further and leave the catalyst. The literature indicates that the catalytic converter must be at sufficiently high temperature in order to effectively purge sulfur, so several purge cycles may be required.[107]

Sulfur and Moisture Removal

Sulfur will need to be removed from biogas or producer gas before firing in an engine that uses catalytic conversion for NOx, CO, and/or hydrocarbon reduction in the exhaust gas. Information describing biogas sulfur content for acceptable exhaust catalyst life could not be found (there is copious literature detailing catalyst life versus sulfur content

106. From Dara Salour, RCM Digesters.
107. Information from "Effects of fuel sulfur on low emission vehicle criteria pollutants," American Automobile Manufacturers Association & Association of International Automobile Manufacturers," 1997; "CRC Sulfur – Low emission Vehicle Program," Coordinating Research Council Inc., CEC Project No. E-42, 1997.

in liquid fuels). Information regarding sulfur limits in gaseous fuels will be very helpful for designing biogas power systems that will be sited in ozone non-attainment areas.

Removal of moisture is helpful as well because it reduces chance of forming sulfuric acid which is highly corrosive and may shorten engine life. Engines using biogas with no catalytic exhaust control can operate with high levels of H_2S in the gas (up to 1,000 ppm though lower is preferred)[108] (Cockrell 2005). This is a general guideline but engine life is shortened with higher sulfur content in the fuel gas. More frequent oil changes are required as corrosive sulfur compounds collect in the oil from blow-by gases and from deposits removed by piston rings from the cylinder walls.

Moisture can be removed by one or a combination of several techniques. For entrained droplets and aerosols, mechanical separation such as cyclone separators and/or settling chambers can be used. Mist elimination screens and filters can be used as well.

Adsorptive liquids and solids such as glycols, silica gel, molecular sieves, etc., are techniques for water vapor removal. The media requires regeneration periodically by heating or exposing to low humidity air streams. Probably the most used moisture removal technique for biogas is simple gas compression and cooling (or just cooling) which decreases the dew point temperature causing water (with some H_2S) to condense.

Sulfur Removal

Hydrogen sulfide removal from natural gas or biogas is straightforward and can be accomplished by a number of techniques. Perhaps the most widely used is the so-called "iron sponge" method. By passing sulfur containing gas through a medium containing iron oxide (Fe_2O_3), H_2S will react with the iron oxide forming iron sulfide. Steel wool can serve as the iron oxide medium, but more commonly wood chips impregnated with Fe_2O_3 or Fe_2O_3 pellets are used (much improved surface area compared to steel wool). The iron sponge must be periodically regenerated by oxidation with air, an exothermic reaction requiring caution especially with Fe_2O_3 impregnated wood chips. Iron sponge systems can remove H_2S to below 5 ppm.

Selective solvents can be used in scrubber operations for H_2S removal. Water, NaOH solution, alkanolamine, and ethylene glycol are all effective solvents for hydrogen sulfide removal as well as CO_2.

Biofilters

Thiobacillus is a naturally occurring, ubiquitous, sulfur-oxidizing bacteria that converts H_2S to sulfite (SO_3^{-2}). A variety of biofilter methods have been developed that use *Thiobacillus* and other bacteria for odor control which includes the removal of H_2S. Hydrogen sulfide removal efficiencies from biogas of greater than 99% by biofiltration have been reported from laboratory and pilot scale experiments and commercial demonstrations. Recent work reports 80% removal efficiency using cow manure as

108. Biogas upgrade reference EU.

biofilter media (Zicari 2003). Commercial biofilter systems used in odor control (which oxidize H_2S) exist (e.g., Biopuric and Thiopaq). A recent report documents the performance of the Thiopaq system treating biogas from an industrial waste water treatment plant reduced biogas H_2S content by 99.9% (from 19,300 to 28 ppm). Because of a water scrubbing step in the process, the gas was slightly upgraded by removal of some CO_2 (methane content went from 62 to 69%, dry gas basis).[109] Investigations into sulfur removal by biofiltration for waste and water management systems are currently ongoing (Chung et al. 2004; Ng et al. 2004; Li et al. 2003; Nicolai and Janni 2001; Ding et al. 2000; Chitwood et al. 1999; Kong and Allen 1997).

In-situ Methods

In-situ sulfide abatement techniques include addition of iron chlorides, phosphates, or oxides into the digester (iron chlorides are added to municipal wastewater treatment digesters for odor control). This method can achieve reductions in biogas H_2S down to about 100 to 200 ppm with careful attention being paid to digester pH. Soluble sulfide levels will increase in the digester which will inhibit methane production if not managed. The insoluble iron sulfides add to solids build-up in the digester which is a concern for mixed systems. Additional sulfur removal techniques will be required if very low levels of H_2S in the biogas are needed (Zicari 2003).

2.5 Lean Engines with High CO in the Fuel

Good quality producer gas from air-blown biomass gasification can contain 10 to 25% (volume) carbon monoxide. A lean burn engine optimized for low NOx can emit large amounts of unburned CO. This is experienced in some of the demonstration facilities in Europe. Oxidation catalysts for CO reduction in the engine exhaust have been employed with some success, though specifics are not reported (Herdin et al. 2004). Additional after-treatment includes thermal oxidation by air injection into (with or without using an oxidation catalyst) the engine exhaust to convert unburned fuel components.

2.5.1 Nitrogen Removal from Producer Gas

Nitrogen in biomass primarily appears as ammonia (NH_3) with smaller amounts of hydrogen cyanide (HCN) in the producer gas (or synthesis gas). Ammonia concentration in the untreated producer gas can range from 400 to 5,000 ppm (dry gas) depending on the fuel nitrogen content and the gasification process (Mojtahedi et al. 1995; Proll et al. 2005; Turn et al. 1998; Stahl 2001). When combusted, essentially all of the NH_3 can be expected to convert to NOx. Some gas cleaning systems will remove much of these nitrogen compounds (e.g., water scrubbing) before firing the producer gas in the gas turbine. However, hot gas clean-up is preferred for some power gasifier systems because tars and other condensables remain in the vapor phase and thermal efficiency is improved by not cooling the gas.

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109. U.S. EPA, "Technology Verification Statement; Paques THIOPAQ." Available at: http://www.sri-rtp.com/Thiopaq%20Verification%20Report%20Statement.pdf

Selective catalytic oxidation (SCO) technology for conversion of ammonia in hot producer gas is being developed and may prove effective in ammonia reduction before combusting the producer gas (Simell 2002). The catalyst is susceptible to deactivation by poisoning from alkali metals and sulfur as well as deposition from ash and/or tar constituents. A brief literature review of SCO for NH_3 treatment follows.

In lab tests using synthetic producer gas, nickel and chromium catalysts showed highest reactivity in the 700 to 900°C temperature range (Darvell et al. 2003). Using nickel based monolithic catalysts on lab scale biomass (pine wood chips) producer gas, Corella et al. (2005) achieved NH_3 reductions that ranged from 44 to 96.5% (volume). The gasifier was an atmospheric bubbling bed reactor which used silica bed material with dolomite and later olivine to reduce tar production. The producer gas, except for some PM removal in a cyclone separator, was not otherwise treated before being sent to the catalyst. The catalyst was not long lived because of ash deposition and site poisoning (Corella at al. 2005).

Wang et al. used hot gas from a pressurized fluidized bed gasifier which had passed through a ceramic hot filter for particulate matter removal. The filtered gas was passed through a high pressure fixed bed nickel catalyst for NH_3 and light tar destruction. Ammonia removals of 35 to 95% were observed, results that were rather low compared with those obtained for synthetic gas. Ammonia concentrations leaving the catalyst section trended toward 200 ppm. Light tar destruction was 90 to 95%. The producer gas contained about 150 ppm of H_2S which did not cause measurable catalyst deactivation during tests of six hours. Catalytic reactor temperature of 900°C resulted in maximum ammonia conversion. Hydrocarbons in the producer gas are more competitive than ammonia for reaction sites, thus sufficient surface area and residence time is required for the ammonia to react. Modeling showed that the higher the concentration of H_2 in the producer gas, the lower the conversion of NH_3 in the catalytic reactor (Wang 2000; Wang 1999; Wang 2002).

As an example of a gas cleaning commercial design, Table 2-35 below presents fuel gas cleaning performance achieved (or expected to be) by the Novel/Condens Oy gasifier for engine and combined heat facilities they are designing (see information on Kokemaki CHP facility elsewhere in this report). For PM, tar, and nitrogen compounds in the fuel gas, greater than 95% removal efficiencies are claimed.

Table 2-35. Gas cleanup recommendations/capabilities, Novel CHP facilities (Simell 2004)

Impurity	Control Method	Concentration, [mg/Nm^3] (removal efficiency %)
PM	Bag filters	< 10 (>99%)
Tars	Catalytic reformer	< 100 (>95%)
Nitrogen compounds (NH_3, HCN)	Catalytic reformer and gas scrubbing	< 10 (> 95-99 %)
Sulfur	Low sulfur feedstock and gas scrubbing	< 10

Chlorine	Low chlorine feedstock and gas scrubbing	<10

Some, or all, of these systems are in place at the Kokemäki, Finland, CHP facility. This facility will be undergoing commissioning soon presenting an opportunity for monitoring its progress and to learn how it may apply to installations in California.

2.6 Improvements for Biomass Boilers

Solid fuel biomass combustion facilities in the state utilize a combination of combustion parameter management, SNCR, and adherence to low nitrogen in the fuel blends for NOx control. In existing biomass boilers, SNCR is estimated to remove up to about 50% of the flue gas NOx content (Rizeq and Zamansky 2004). Improvements are limited but might include reburning techniques using gaseous fuels (either fossil or renewable re-burn fuels — see below). For biomass gasification, the effect of fuel nitrogen can be largely neutralized by water scrubbing the ammonia from the producer gas before firing in engines or turbines.

Advanced Reburning for Biomass NOx Emissions Control

Advanced reburning tests were conducted by Energy and Environmental Research Corporation (now part of GE Global Research) in Irvine, California (Maly et al. 1999). The facility used is a 300 kW boiler simulator. Advanced reburning refers to the use of nitrogen agents and/or promoters injected either with the reburn fuel or in the overfire air. In the experiments, coal or natural gas was used as the majority fuel. Ammonia was added to the flame as necessary to create NOx concentrations between 200 and 1300 ppm in the gas before entering the reburn zone. Several reburn fuels were used (See Table 2-36). Basic reburning achieved 70% NOx reductions which is similar to using natural gas as a reburning fuel. Advanced reburning using urea nitrogen agent and sodium promoter (Na_2CO_3) achieved NOx reductions of 85 to 95% with reburn heat input of 10% and incoming NOx concentration of 600 ppm. Wood particles as reburn fuel and urea and sodium injected achieved 95% NOx reduction, yielding a final concentration of less than 30 ppm.

Table 2-36. NOx reduction achieved in pilot scale advanced reburning experiments (Maly et al. 1999)

Reburn Fuel	NOx Reduction for Type of Reburn Process		
	Basic	Advanced (urea as N- agent)	Advanced w/ Na_2CO_3 promoter (30 ppm in gas)
Natural gas	47%	81%	91%
Biomass (fir mill waste)	50%	90%	96%
Carbonized RDF	50%	75%	94%
Coal fines	44%	70%	78%

The fact that biomass and RDF achieved good results led GE Global Research to pursue further investigations of advanced reburning using biomass fuels (see Maly et al. 1999). The Energy Commission funded a project with GE Global Research that included researchers at Stanford, UC Davis, and a private consultant as subcontractors. The goal of the effort was to investigate the feasibility of using low-grade, generally unused, biomass as a gasifier fuel, with producer gas used as a gaseous reburn fuel in existing solid fueled biomass power plants. The potential would be to help create a market for the low-grade biomass as well as reducing NOx emissions from existing or new facilities.

The investigation included a survey of biomass resources in the state (a more recent effort has been done by the California Biomass Collaborative[110]), laboratory characterizations of six selected fuels, pilot scale testing, and economic analysis for eventual scale-up of an add-on gasifier to one of three existing biomass fueled power stations in the Sacramento Valley.

Results from pilot scale experiments using gasified biomass as the reburning fuel were variable as far as effectiveness of treatment and depended heavily on fuel nitrogen content. Sewage sludge, with a nitrogen content of 3 to 5% (dry basis) is not suitable as a gasified reburning fuel (use of this fuel resulted in an increase of NOx rather than a decrease due to the very high ammonia production). Results from the other fuels (orchard prunings, whole tree wood waste, rice straw, non-recyclable paper, and almond shells) showed that effectiveness as a reburn fuel is directly proportional to fuel nitrogen content. Depending on the combination of fuel type and reburning process (basic, advanced, advanced with alkali promoter), effects on NOx ranged from increasing formation to reducing NOx up to 65%.

110. See http://biomass.ucdavis.edu/pages/assessment.html

Using the pilot scale results and modeling, the projected NOx reductions using biomass producer gas as a reburning fuel in retrofitted biomass power plants in California were 20 to 65% of uncontrolled NOx emissions (Rizeq and Zamansky 2004).

The overall costs of the several retrofits analyzed depend strongly on reburn fuel price. Rizeq and Zamansky (2004) concluded that at least for retrofit reburning systems using gasified biomass, the "opportunity" fuel used in the gasifier will need to be priced below the majority fuel by at least $12/ton. Their study did not address the costs of incorporating this kind of NOx control into a new facility. It's likely that the cost of NOx reduction using such a system that had been part of the plant's original design would be lower than for a retrofit system. Gasified biomass reburning should be considered for NOx reduction on new solid biomass combustion facilities.

Harding and Adams (2000) experimented with wood as reburn fuel for purposes of NOx reductions at coal fired facilities (Harding and Adams 2000). Pilot scale experiments at the University of Utah that were conducted in a 3 kW combustion facility fired with natural gas doped with ammonia (in order to create the desired NOx concentration in the gas entering the reburn zone) achieved 60 to 70% NOx reduction (from 500 ppm to about 175 ppm).

Using results from the pilot scale experiments, simulations of biomass fueled reburning were done with a model of an operating 265 MW coal fired boiler. Estimates of NOx reduction from the modeling effort varied from 40 to 55% which is similar to real systems using natural gas as the reburn fuel. A major factor in the desirability of advanced reburning is its economics. Rizeq and Zamansky (2004) estimate the cost of NOx reductions using standard SNCR techniques is between $550 to $700/ton of NOx reduced. They suggest that the reburn fuel will need to be significantly cheaper than the majority fuel for the technique to be economic. This is not out of the question, as some opportunity fuels have low cost due to their current low desirability.

2.7 Out of State Transport of Sacramento MSW and Potential for Emissions Reduction

Sacramento transports a substantial amount of solid waste to a landfill near Reno, Nevada, because the tipping fees in the Reno area are about $5 to $10 per ton, which is significantly lower than the $26 per ton published value for Kiefer landfill. In 2003, about 195,000 tons of MSW from Sacramento County were trucked to the Reno area.[111] At 25 tons per truckload, this represents about 7,800 trips per year or 26 trips per day (6 days per week, 50 weeks per year). Roundtrip distance between Sacramento and Reno is about 260 miles. MSW transportation to Reno results in 2 million truck-miles, which consumes 338,000 gallons of fuel (using 6 mpg average fuel economy). Total fuel costs are $574,600 per year ($1.70/gallon or $2.95/ton of MSW transported).

111. Task 1.1.1 Report.

Disposing or converting this MSW locally instead of hauling to Reno would reduce heavy truck traffic, fuel consumption, and emissions associated with MSW transportation. In addition to fuel savings and vehicle wear and tear, there may be a monetary value to NOx reductions that would result from reducing or eliminating MSW transportation.

The following discusses the potential value of NOx reduction credits associated with reducing or eliminating the transportation of Sacramento MSW to Reno.

NOx Offset Transactions in California

In 2003, some 650 tons of NOx emission credits were traded resulting in total transaction value of more than $15 million (average price per ton of NOx was $23,574) (Marquis and Werner 2004). Table 2-37 shows selected NOx offset transaction details (Figure 2-25 charts NOx offset tons per transaction against price per ton). In the Sacramento region, about 21 tons of NOx offset credits were sold for more than $30,000 per ton. The single largest transaction in the state occurred in the Mojave Desert APCD where 175 tons were traded for an amount of $2.275 million.

Heavy Duty Diesel NOx Emissions

Cocker et al. measured NOx emissions with a mobile laboratory that serves as the semi-trailer for a heavy duty diesel truck-tractor. With a gross vehicle weight (GVW) of 60,000 lbs, NOx emissions averaged 20 g/mile for the 106 mile round trip between Riverside and Victorville, California (with an altitude change of 3,000 feet between the two cities).

Table 2-37. Selected NOx offset transaction details for 2003 in California

Region	Relevance	Transaction details		
		Tons	Price ($/ton)	Total Transaction ($)
Sacramento Metropolitan AQMD	Local	20.5	$32,500	$666,250
Placer County APCD	Local	0.97	$30,041	$29,140
Mojave Desert APCD	Largest transaction in State	175	$13,000	$2,275,000
San Diego APCD	Highest price per ton in state	3.73	$140,000	$522,200
State of California	Overall totals and $/ton average	647.6	$23,574	$15,266,056

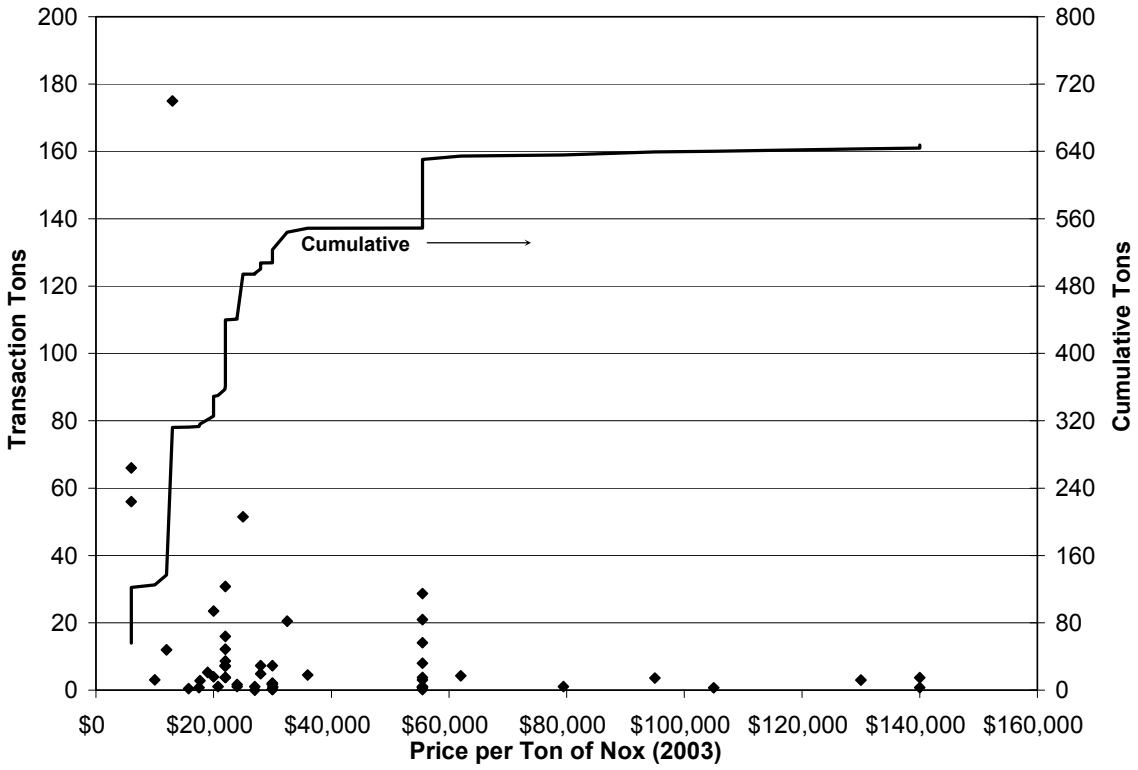

Figure 2-25. NOx offset transaction tons versus price per ton for California in 2003.
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

CARB EMFAC (CARB's on-road motor vehicle emissions model) gives NOx emissions from 13.4 to 23 g/mile for vehicles manufactured between 1984 and 2002.[112]

Sacramento to Reno roundtrip distance is approximately 260 miles. NOx emissions for a heavy duty diesel truck (Class 8) making this roundtrip will be approximately 5.2 kg (using an emission factor of 20g NOx/mile). Payload is approximately 25 tons (50,000 lbs.)[113] Estimated NOx emissions for transporting solid waste from Sacramento to Reno are, therefore, 0.46 lb/ton (0.208 kg/ton). The 195,000 tons of Sacramento MSW trucked to Reno are responsible for approximately 45 tons of NOx emissions distributed along Interstate 80.

Using the statewide average of $23,500/ton of NOx offset credit price, reducing NOx emissions from Sacramento MSW transport to Reno has a potential value of $1 million (if the region average NOx offset credit value of $32,400 is used, MSW transport NOx reductions represent $1.5 million). On a per-ton of MSW basis, transport NOx offset credits would be $5 to $7.50. If Sacramento (or the waste hauler) was able to stop transporting MSW to Reno and instead sell the forgone NOx emissions as offset credits,

112. http://www.arb.ca.gov/msei/on-road/downloads/tsd/HDT_Emissions_New.pdf
113. Maximum gross vehicle weight (GVW) is 80,000 lbs.

the resulting revenue could be credited against the cost of treating or disposing the material locally.

PM and CO2 Emissions

From CARB EMFAC, approximate emission factors for PM and CO_2 are 0.4 g/mile and 2,000 g/mile respectively. Therefore, emissions of diesel engine PM and CO_2 due to MSW transport from Sacramento to Reno are about 0.9 and 4,400 tons respectively (see Table 2-38).

Table 2-38. Summary of emission and costs associated with transporting Sacramento MSW to Reno

	Savings	Unit	Unit price ($)	Total ($)	Per ton MSW Transported
Fuel	338,000	gallons	1.70	574,600	$2.95
NOx	45	Tons	23,500 - 32,400	1 - 1.5 million	$5.40 - $7.40
CO_2	4400	Tons	-	-	45 lbs CO_2
PM	0.9	Tons	-	-	4 g
Vehicle miles	2,028,000	miles	?	?	?

Emission factors used are 2,000, 0.4, and 20 g/mile for CO_2, PM, and NOx, respectively.

MSW Transportation Summary

Sacramento disposes about 195,000 tons of MSW per year in a landfill near Reno, Nevada. This represents about 7800 truck loads per year. The round trip distance is about 260 miles, which means more that 2 million truck-miles are needed to haul MSW to Reno. Approximately 338,000 gallons of diesel fuel are consumed per year with annual total emissions of 45, 4,400, and 0.9 tons of NOx, CO_2, and PM, respectively. Associated fuel cost is $2.95 per ton of MSW hauled and potential value of NOx credits is $5 to $7.70 per ton of MSW using state and region average NOx offset credit values from 2003.

There is precedent for receiving emissions offsets due to reduced vehicle trips. Sacramento Metropolitan AQMD Rule 2056 addresses reduction credits from mobile sources. The rule specifically states that reduction of vehicle trips can be used as a basis for emission reductions (the rule mentions telecommuting as a means for vehicle trip reduction).

2.8 Recommendations

Improvements for Solid Fuel Boilers including Straw Combustion Power Plants

Because of the large biomass resource in California, the aggressive RPS, the ageing solid fuel biomass fleet, and the poor air quality in many California air basins, the state should continue and expand active participation in NOx reduction research for new and existing solid fuel biomass facilities.

For new solid fuel combustion of biomass, advanced reburning should be considered as part of the original plant design using gasified biomass for the reburn fuel or other reburning techniques such as direct biomass injection. For existing facilities, there remain unanswered questions regarding the viability of retrofit reburn systems using biomass gasification. Those questions likely won't be answered without a full scale commercial demonstration of a retrofit system.

For a rice straw fired power plant (based on recent European designs), uncontrolled NOx emissions are expected to be higher than that from a wood fired facility because of higher fuel-NOx resulting from the higher nitrogen content of straw compared to wood.

Selective catalytic oxidation technology for NOx reduction in biomass fueled boilers is difficult to implement (because of catalyst de-activation issues) and is considered developmental. Research is ongoing both in the United States and Europe. California should monitor, or actively pursue SCR-biomass research.

So-called regenerative SCR may offer an improvement over the currently used NSCR method for NOx reduction. RSCR treats flue gas after PM removal by re-heating the gas to a level required for the catalyst to function. Due to the expense and energy required for re-heat, RSCR systems do not necessarily operate at the optimal temperature for the catalyst. Therefore, NOx reduction from RSCR is expected to be not as good as standard SCR. Performance information from the two biomass facilities in the Northeast recently retrofitted with RSCR should be pursued. Whether RSCR is suitable (and sufficient) for California's needs should be determined.

Low temperature ozone injection (also called low temperature oxidation) is intriguing, but a detailed review was not completed during this project. The technique should be investigated as a candidate for installation at new biomass combustion facilities as well as for retrofit cases.

Improvements in MSW Related Power

Improved gas engine emissions (NOx) and/or increased efficiency of gas turbine systems are needed to increase the desirability of each prime mover type in AD of MSW power applications.

Diverting the organic fraction of MSW to AD and landfilling the treated digestate (or completely bypassing the landfill by upgrading the digestate to value added products) will have positive long-term environmental impact (i.e., future methane and leachate releases from landfills are reduced.)

Most of Europe is now requiring all biodegradable waste to be stabilized before landfilling. Digestion, composting, or thermal conversion with energy recovery are preferred methods. Refer to the Task 1.1.2.1 Report (Summary review on environmental assessment). These benefits should be used to help offset costs or impacts of MSW conversion to energy.

Policy strategies, such as landfill taxes, extended producer responsibility (packaging and product take-back requirements), banning biodegradable materials in the landfill, and/or assigning life-cycle costs of waste management/disposal to the price of the product or service should be pursued to realize this. The emissions produced from truck traffic required to haul Sacramento waste out of state are calculated as an example of direct emission offsets that might be available if the practice was curtailed and the material instead used locally in energy production.

Dairy Digester Power Systems

Managing dairy manure to decrease ground and surface water contamination and reduce uncontrolled air emissions may create opportunities for power production as a by-product of improved environmental performance of the dairy industry. If power is produced from dairy digester gas, the facility should be credited with emissions offsets for emissions that would have occurred had the gas been flared.

Improvements for Reciprocating Engines

Gas engine emission reductions represent the nearest term improvement for LFG power systems and biogas utilization AD systems. Reciprocating engines are still preferred due to cost and high efficiency compared to simple cycle gas turbines.

An increased market will likely entice engine manufacturers to develop lean burn engines in the smaller capacities required for many dairy scale digesters and some of the smaller scale MSW AD systems that might develop. Deutz markets a lean burn engine-generator for digester and LFG at capacities as low as 180 kW (The model TCG2015V6 is available at least in Europe) and Waukesha sells a 280 kW lean burn gen-set for digester and LFG (model family VGF280).

NOx emissions from engines can be reduced via catalytic after-treatment of exhaust gas, and, in some cases, treatment, or removal of nitrogen compounds in the fuel gas. However, catalyst deactivation can occur when sulfur, alkalis, and metals are present in the fuel gas.

For reciprocating engines powered by gasified biomass, the fuel gas is usually cooled before induction to the engine which should condense alkali and metal vapors onto particles or aerosols (sulfur is generally not an issue with producer gas because of low sulfur content in most biomass). Providing PM is sufficiently cleaned from the fuel, there may be fewer problems using catalytic emission control with reciprocating engines than with gas turbines and hot-gas clean up systems.

Nitrogen, a macro nutrient required for plant growth, is present in biomass at variable concentration depending on species and cultivation practice. Fuel-bound nitrogen will be released predominantly as ammonia and HCN in the fuel gas created by thermal gasification. When the fuel gas is combusted (in a boiler, gas engine, or gas turbine), these nitrogen compounds primarily transform to NOx (fuel NOx). It is difficult to

remove ammonia by condensation in hot-gas cleaning systems. Catalytic means to reduce ammonia to N_2 gas are being investigated.

Fuel gas cleaning in association with catalytic emissions control should be investigated in more detail. Fuel gas cleaning has other benefits as well, including reduced corrosion rates in gas handling and power generation equipment and as a technique to permit use as clean vehicle fuel or for addition to natural gas distribution pipelines.

Sulfur removal techniques can be improved to reduce costs. Biofilter methods that remove sulfur may offer benefits and should be explored. Biogas upgrading by stripping carbon dioxide also results in lowered sulfur content. For stationary power using digester gas, simple water scrubbing for sulfur and partial CO_2 removal would allow for easier catalytic conversion for emissions control but could also allow for a smaller engine because the gas has a higher energy content.

Hydrogen mixed (or included) with the producer gas or biogas extends the lean burn flammability range. Investigating the effect of increased hydrogen in the fuel gas should be pursued for small engine based biopower systems. Improved hydrogen co-production methods from AD and gasification of biomass should be linked with emissions improvement for conventional power systems (engines) as well as for its fuel value.

Ongoing and new demonstration or "first commercial" biomass gasification with CHP facilities present a timely opportunity for observing and monitoring these facilities. Further development of existing association with the project developers in order to facilitate exchange of information is recommended.[114]

114. These facilities include: United States – at least two CPC 50 kW or less small modular power systems, a CHP (1 MW) facility in Connecticut; England – Skive, Kokemäki, and many more. A list of industry contacts and potential project participants is included in Task 4.

3.0 Engineering and Economic Analysis

3.1. Economic Analysis Introduction

A subset of the technologies presented in Task 1.1.1, Technology Assessment for Biomass Power Generation, were analyzed using a model to estimate revenue requirements in the form of levelized cost of energy levelized required tipping fee for a scenario of MSW anaerobic digestion.

The technologies analyzed in this task are:

<u>Gasification</u>

- Circulating Fluidized Bed (CFB), reciprocating engine generators, medium scale; Carbona/GTI gasifier CHP facility under construction in Skive, Denmark, 5.4 MW.
- Fixed bed, reciprocating engine generators, small to medium scale; Novel/Carbona CHP facility under construction in Kokemäki, Finland, 1.8 MW.
- BIGCC – medium scale; Carbona/GTI pressurized gasifier, waiting financing in India, 12.5 MW.

<u>Straw combustion system</u>

- Straw fueled inclined-vibrating grate boiler, steam cycle power plant, large scale; Ely, England, facility designed and built by FLS miljø of Denmark, 38 MW.

<u>MSW/green waste AD systems</u>

- Generic green waste and organic fraction of MSW system based on review of industry; 100,000 wet tons per year feedstock capacity, 1.2 MW.
- APS green/food waste digester system based on CSU-Channel Islands proposal configured for electricity production; 76,000 wet tons per year feedstock capacity, 1.2 MW.

<u>Dairy manure digester systems</u>

- Review of preliminary cost information for projects in the California Dairy Power Production Program (DPPP); Plug-flow, covered lagoon, mixed tank systems with estimated capacities ranging from 30 kW to 1 MW.

3.2 Selected Technologies

3.2.1 Thermochemical Biomass Power Systems

Gasifiers

Carbona – Skive, Denmark CHP

One of the thermal systems selected for analysis is the Skive, Denmark, small modular biomass CHP project being developed by Carbona. The project consists of a Carbona licensed circulating fluidized bed gasifier and a nickel catalyst tar cracker combined with Jenbacher gas engine-generators for CHP generation. The design output capacity is 5.4 MW and 11.5 MWth. Nominal fuel feed rate is 3.7 Mg/h of high quality wood pellets. The plant net electrical and overall (electric plus thermal) efficiencies are 25.7% and 80.2%, respectively (based on HHV of fuel). Table 3.2-1 lists design and performance characteristics.[115]

Figure 3.2-1 shows a schematic of the major unit operations for the facility. Table 3.2-1 shows basic design and operational data for the facility.

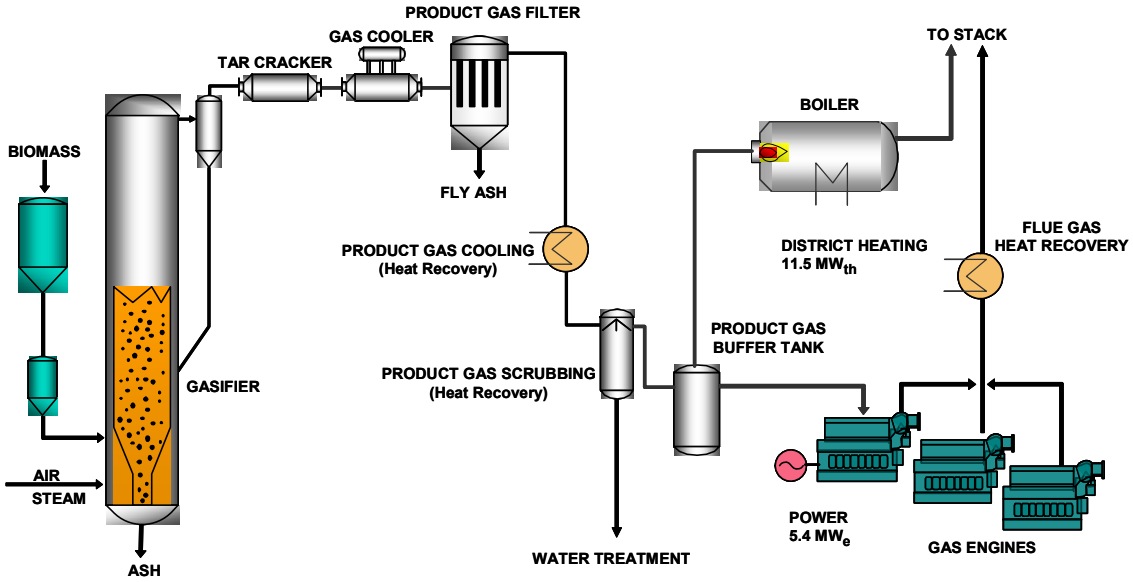

Figure 3.2-1. Schematic of Skive CHP facility
Photo Credit: Carbona USA.

115. The project is financed in part by the U.S. DOE. More information regarding this facility can be found in the Task 1.1.1 Report.)

Table 3.2-1. Design/Operating data for Carbona-Skive[116]

Load		**base**		**base**
Gas engine BEMP	bar	13	psi	189
GASIFICATION PLANT				
Fuel type	-	wood pellet		wood pellet
Fuel moisture content AF	%w	9.5	%w	9.5
Fuel LHV (db)	kJ/kg	18986	Btu/lb	8163
Fuel HHV (db)	kJ/kg	20260	Btu/lb	8710
Fuel feed rate	kg/s	1.149	lb/h	9119
Fuel thermal input (LHV)	kJ/s	19488	MMBtu/h	66.5
Fuel thermal input (HHV)	kJ/s	21067	MMBtu/h	71.88
Dolomite feed rate	kg/s	0.012	lb/h	95
Gasifier ash flow rate	kg/s	0.006	lb/h	48
Filter ash flow rate	kg/s	0.016	lb/h	127
Process condensate flow rate	kg/s	0.150	lb/h	1190
Gasifier operation pressure	bara	2.00	psia	29
Gasifier operation temperature	°C	850	°F	1562
Product gas LHV (to GE)	kJ/kg	5214	Btu/lb	2242
	kJ/m3n	5530	Btu/scf	141
Product gas HHV (to GE)	kJ/kg	5633	Btu/lb	2422
	kJ/m3n	5973	Btu/scf	152
Product gas from gasifier	kg/s	3.146	lb/h	24968
Product gas flow rate (to GE)	kg/s	2.995	lb/h	23770
Total product gas after treatment	kg/s	2.995	lb/h	23770
Total PG chemical heat LHV	kJ/s	15616	MMBtu/h	53.3
Total PG chemical heat HHV	kJ/s	16871	MMBtu/h	57.6
DH generation in GP (net)	kJ/s	3451	MMBtu/h	11.77
Aux. electricity consumption in GP	kW	427	kW	427
Cold gas efficiency	%	80.1	%	80.1
GAS ENGINE PLANT				
Gas engines in operation	pcs	3	pcs	3
GE efficiency	%	37.80	%	37.8
Fuel gas thermal input (LHV)	kJ/s	15620	MMBtu/h	53.3
Fuel gas thermal input (HHV)	kJ/s	16875	MMBtu/h	57.6
Electricity generation	kW	5904	kW	5904
DH generation in GE (net)	kJ/s	8031	MMBtu/h	27.4
BGGE PLANT PERFORMANCE				
Fuel thermal input (LHV)	kJ/s	19488	MMBtu/h	66.5
Fuel thermal input (HHV)	kJ/s	21067	MMBtu/h	71.88
Gross electricity generation	kW	5904	kW	5904
Auxiliary consumption	kW	483	kW	483
Net electricity generation	kW	5421	kW	5421
District heat production	kJ/s	11482	MMBtu/h	39.2
Gross electrical efficiency (LHV)	%	30.3	%	30.3
Net electrical efficiency (LHV)	%	27.8	%	27.8
Overall gross efficiency (LHV)	%	89.3	%	89.3
Overall net efficiency (LHV)	%	86.7	%	86.7
Gross electrical efficiency (HHV)	%	28.0	%	28.0
Net electrical efficiency (HHV)	%	25.7	%	25.7
Overall gross efficiency (HHV)	%	82.5	%	82.5
Overall net efficiency (HHV)	%	80.2	%	80.2

116. Courtesy of Jim Patel, Carbona USA.

Condens Oy - Kokemäki, Finland CHP

Another gasification concept that was selected is modeled after the Kokemäki, Finland biomass CHP facility currently nearing completion of construction. This project is being managed by Carbona with cooperation from VTT.[117] The Novel-Condens OY gasifier has been specified (atmospheric, fixed-bed, updraft). Initial shakedown operation is expected to begin early in 2005. The discussion and results of the economic analysis appear below.

Novel Gasifier Background

The Novel gasifier was developed by VTT and Condens OY to overcome some of the technical problems experienced with the commercially successful "Bioneer" gasification systems operating in Finland. The Bioneer design uses an updraft, atmospheric pressure, air-blown reactor. The producer gas is conveyed to a near-by combustor where it is burned without any treatment of the fuel gas. The primary technical limitations of the Bioneer systems are: (1) not suitable for low bulk density wood residues (saw dust, bark, forest slash); (2) operate poorly when fuel moisture is above 45%; (3) tar buildup in product gas pipe requires frequent shutdown and cleaning; and (4) fuel feeding systems leak producer gas due to back pressure (Kurkela et al. 2000). The Bioneer gasifiers are applied mainly in district heating systems and began operation in the mid 1980s. Approximately nine Bioneer facilities have been constructed. In 2002, one was still in continuous operation and the others were fired as-needed (IEA 2002). The Bioneer facilities are automated requiring minimal attention.

The Novel-Condens OY reactor is essentially the same as the Bioneer. The fuel feeding system has been improved to eliminate backflow of producer gas. The feed system also allows a broader range of fuel particle size and densities to be utilized such as sawdust and other fine material. Air for gasification is humidified in a water spray tank in order to reduce reactor temperature. Secondary air is added above the main reaction zone in order to crack some of the produced tars. The produced gas can be burned directly for heat applications or the gas can be conditioned for use in reciprocating or gas turbine engines.

Kokemäki, Finland CHP Plant

The Novel-Condens OY CHP plant is currently under construction at Kokemäki, Finland. The anticipated fuel is urban and/or sawmill waste wood. The design includes gas clean-up and conditioning (e.g., tar reforming, gas cooling and filtering and final scrubbing) before being fed to three 600 kW Jenbacher reciprocating engines (see Figure 3.2-2). Not shown is an auxiliary boiler used for periods of high heat demand, otherwise recovered engine heat satisfies the district heat and fuel drying requirements. The design capacity is 1.8 MW and 3.1 MWth without auxiliary boiler and 4.3 MWth with firing the auxiliary boiler. Electrical and overall efficiencies are 30% and 80%,

117. VTT is a large technical research contract organization in Finland.

respectively, for normal operation and 26% and 85%, respectively, when using the auxiliary boiler (see Table 3.2-2).

Table 3.2-2. Nominal energy balance for Kokemäki CHP plant (Patel 2004)

		Normal Operation	With Auxiliary Boiler
Fuel input	kW	6200	7200
Electricity Production	kW	1836	1836
Heat Production	kW	3100	4300
Fuel Drying (from existing separate heat plant)	kW	429	429
η_e*	%	29.6	25.5
η_{th}	%	50.0	59.7
$\eta_{overall}$	%	79.6	85.2

* η = efficiency (useful energy or work output divided by energy input)

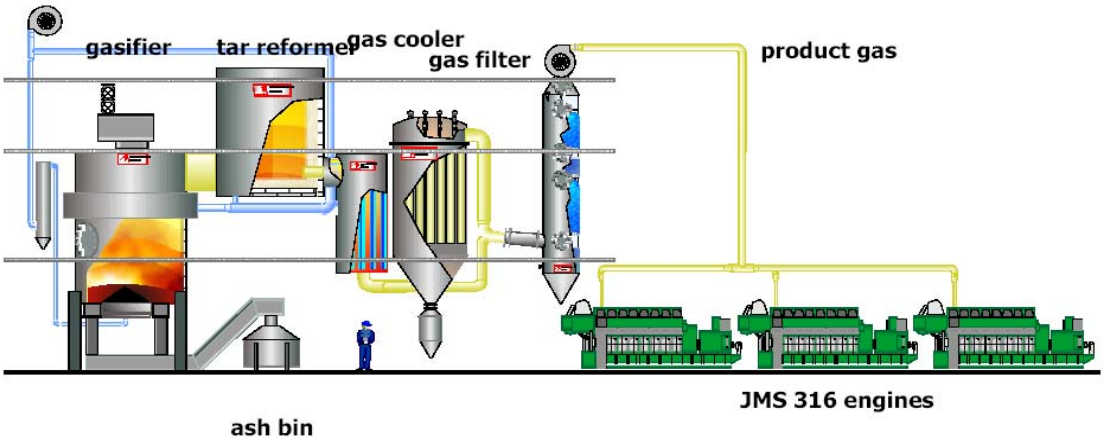

Figure 3.2-2. Schematic of Novel gasifier CHP facility under construction at Kokemäki, Finland.

Photo Credit: VTT Processes

Investment cost for a Novel gasifier for heat only applications is similar to that of the Bioneer facilities (350 to 420 Euro/kWth in 2000) (Kurkela et al. 2000).

Carbona—India BIGCC

A third gasifier based system was selected for analysis, the BIGCC concept which offers higher overall conversion efficiency. A proposed and designed facility for India was analyzed using California based cost parameters.

Carbona is supplying the gasifier (RENUGAS gasifier licensed from GTI) and gas cleaning system for an IGCC project in India. It is proposed to consume wood waste and cashew and coconut shells. The facility includes the pressurized air/oxygen blown RENUGAS gasifier, catalytic tar cracker developed with VTT, gas cooling and gas filtering. Two gas turbine generators, about 4 MW each, are specified. Gas turbine exhaust raises steam in a recovery boiler which powers a single steam turbine for about 4.5 MW additional. Fuel feed rate is planned for approximately 210 t/day and should net 12.5 MW (the Task 1.1.1 report has more information).

Nominal fuel characteristics used for energy and efficiency calculations are 20% moisture content and 18.7 MJ/kg (HHV, dry).[118] Overall plant efficiency is estimated to be 34.3%. The project cost is $22 million (Patel 2004). Project initiation is awaiting final decision from financing partners. See Figure 3.2-3 for a process diagram of the India project.

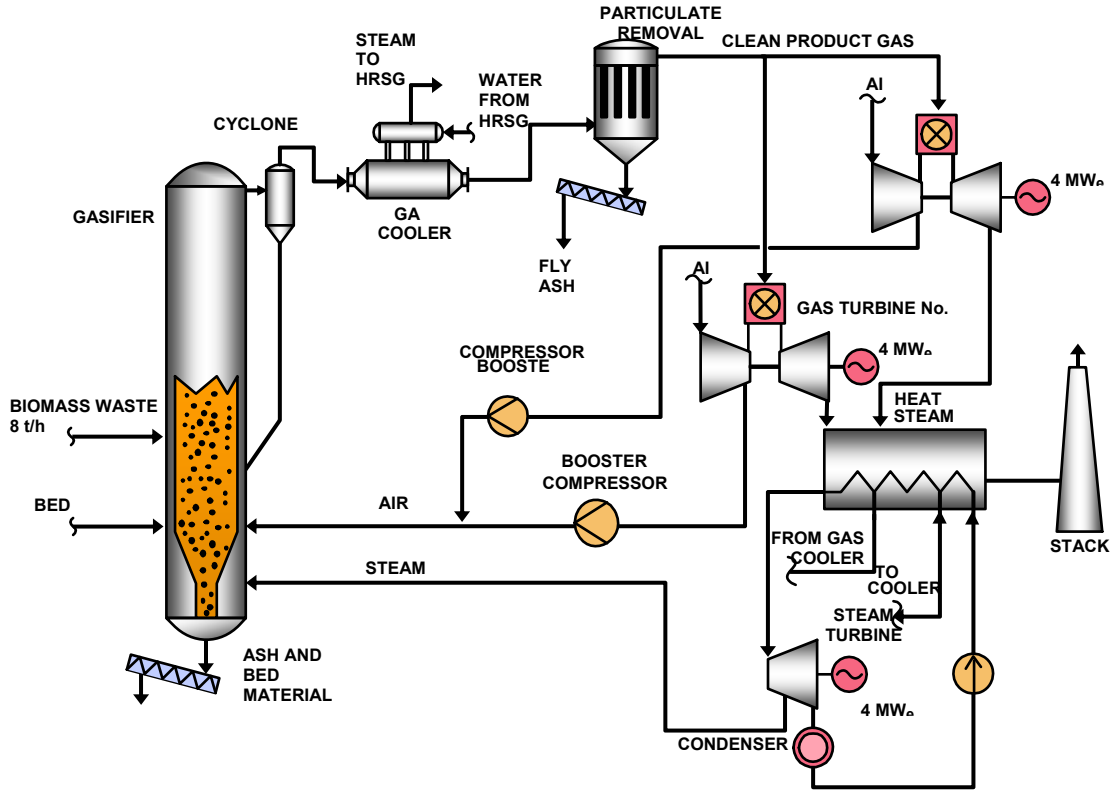

Figure 3.2-3. Process diagram of the Carbona India IGCC project

Photo Credit: Carbona USA.

118. Based on reported fuel lower heating value (LHV) of 17.5 MJ/kg (dry basis).

Combustion

Straw Fired Combustion Facility

The final thermochemical biomass conversion system selected for analysis is a stoker grate fired system designed for straw fuel. Denmark has been firing straw for heat and power as a matter of policy for the last decade. Consequently, government and industry have invested substantial efforts to design straw combustion systems including fuel logistics, handling, and storage. The Danish design has now been exported (refer to Task 1.1.1 Report for more information).

There are two straw fired facilities recently commissioned outside of Denmark. Located in England and Spain, they were designed and built by the Danish company (formerly FLS miljø). The Ely Power Station in England is the largest straw-fired facility in the world (according to Bioener, ApS), consuming anywhere from 150,000 to 200,000 metric tons per year. The facility uses natural gas as a stabilization fuel in the amount up to 10% total energy input. It produces only power (does not operate in CHP mode) with a capacity of 36 to 38 MW at an availability estimated at about 80%.

Both Ely and Sangüesa have high steam temperatures (520 to 540°C), and the steam pressure at Ely is 92 bar. The Ely boiler does not utilize a separate fuel for final superheat (so called combination boiler used in Europe with problematic biomass fuels). Specific boiler details could not be confirmed for Sangüesa, so it is not known whether it is a "combination boiler."

There are four separate whole bale fuel feed lines running into the single furnace. Bales are shredded before being injected into the boiler. The boiler uses a FLS miljø vibrating grate (see Figure 3.2-4).

Others investigated the bale and straw handling and feeding systems at Ely for potential application to co-fire switchgrass with coal at the Ottumwa generating station in Chillicothe, Iowa (Miles and Ganz 2002). Their discussions at Ely yielded the following information:

- Capital cost was approximately $88 million (about $2,300/kW-gross installed).
- The facility is paid $0.0855/kWh.
- The plant is operated by the Danish builder, which guarantees 96% availability over 350 days.
- The company pays $31 to $42/ton for delivered straw, 80% within a radius of 55 miles from the plant, and 20% comes from a radius of 55 to 150 miles.
- The company was considering growing dedicated energy crops (switchgrass or miscanthus) to increase fuel supply.
- Plant has been operating since 2000 consuming about 22 tons/hr local cereal straw.

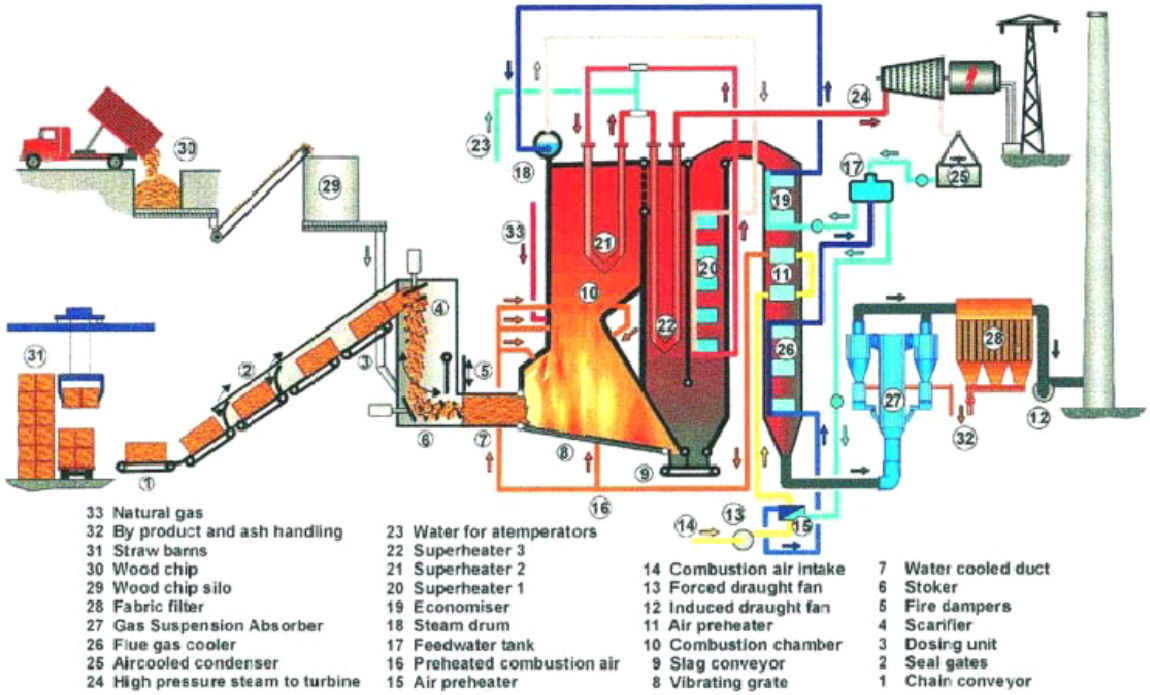

Figure 3.2-4. Schematic of the Ely Power Station

Photo Credit: Newman 2003.

3.2.2 Biochemical Conversion to Power

Anaerobic digestion and MSW AD systems

Generic MSW AD

Two AD systems using MSW components as feedstock and dairy manure digesters were the selected technologies. One of the MSW systems analyzed was a "generic" design that was modeled using a range of performance and cost values found in the literature and from personal contacts. Figure 3.2-5 shows a schematic of a typical single stage digester system for organic wastes (including portions of the MSW stream).

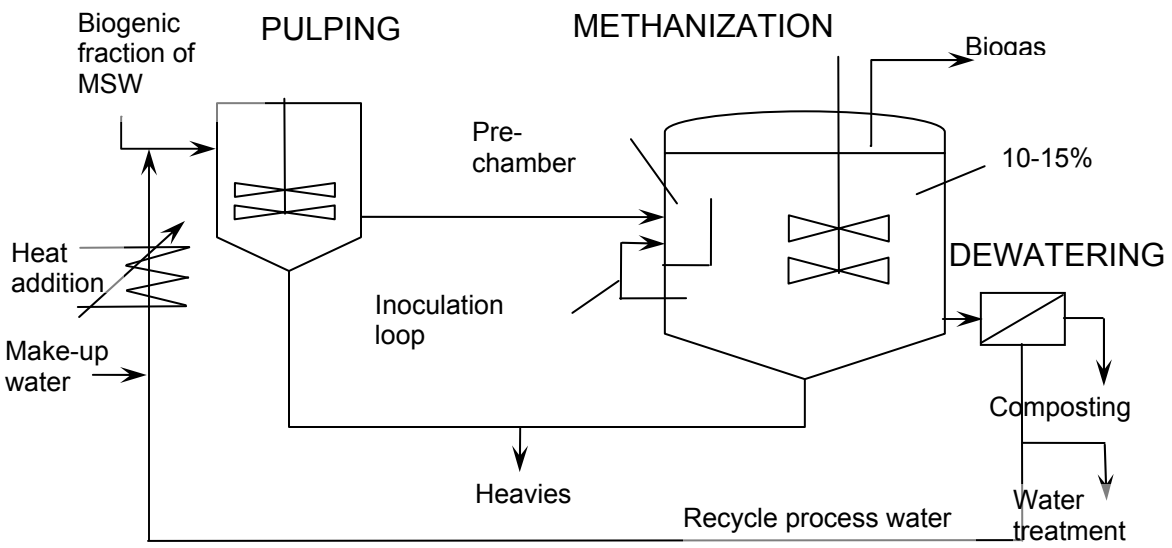

Figure 3.2-5. Schematic of a Typical Single-Stage Digester
Photo Credit: Adapted from Mata-Alvarez 2003

UC Davis Anaerobic Phased Solids (APS) Digester

The other system investigated was the APS (UC Davis) design using cost and performance parameters supplied by an independent consultant as well as from the system designers.

Background

This system was developed and patented by Professor Ruihong Zhang and Dr. Zhiqin Zhang from UC Davis (Zhiqin Zhang is currently at the California Energy Commission) (Zhang and Zhang 2002). The system is licensed to Onsite Power Systems for commercialization. Laboratory and pilot scale reactors are located at UC Davis.

A 3 t/day pilot facility on the UC Davis campus, funded by the Energy Commission and industry partners, will be operational early in 2005. The pilot facility will accept food and green wastes and is expected to generate about 25 kW from a reciprocating engine.

Onsite Power Systems has proposed a green-waste processing facility using the APS digester for the California State University-Channel Islands campus in Ventura County (Figure 3.2-6). The facility would process 250 t/day of green waste (or about 76,000 t/year) diverted from Ventura County landfills and presumably some waste from the campus.

The facility would operate at thermophilic temperature (135°F) and have a solids retention time of 12 days. Biogas would be piped to a nearby cogeneration facility where it would be used to displace some of the natural gas fuel. Revenue sources include a tipping fee (net of processing costs), gas sales, compostable material sales, and some value for using excess process water to displace campus irrigation water.

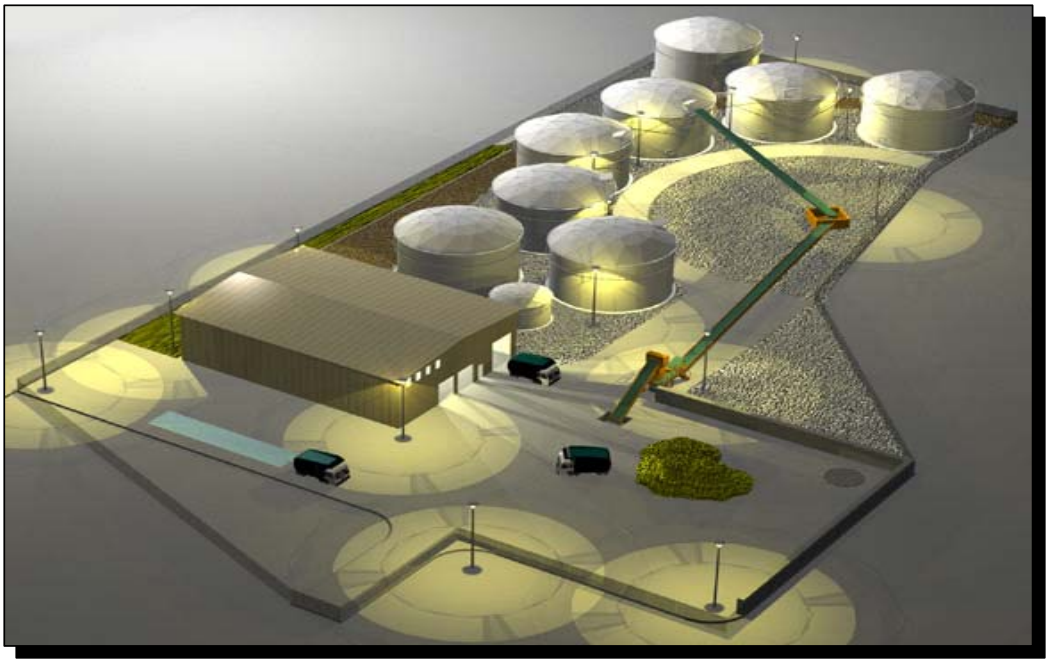

Figure 3.2-6. Conceptual drawing of APS digester at CSU-Channel Islands
Photo Credit: Karl Hartman

The anaerobic phased-solids (APS) digester decouples solid-state hydrolysis and acetogenic fermentation from the methane producing fermentation, allowing for separate optimization of the two processes. The two reactors are connected through a closed liquid recirculation loop that transfers the solubles released in the hydrolysis reactor to the biogas producer (methanogenesis). The biogas reactor can be designed for relatively short liquid retention time by using suspended growth, attached growth, anaerobic moving bed reactor (AMBR), or upflow anaerobic sludge blanket (UASB) reactor types (Zhang and Zhang 1999).

The hydrolysis reactor can accept high solids feedstock that, depending on its characteristics, may need some kind of pretreatment such as shredding to increase hydrolysis rate. The hydrolysis reactor operates in batch mode. Because of this batch operation, the strength of the soluble compounds in the liquid being transported to the biogas reactor will vary from near-zero immediately after adding a fresh batch of feed to the hydrolysis vessel, to a maximum when the rate of hydrolysis is highest, subsequently tapering off as the remaining soluble biomass declines. Correspondingly, the biogas production rate will vary from low to high to low again because it depends on the strength and rate of the inflow liquid arriving from the hydrolysis stage.

By using several batch loaded hydrolysis reactors, the loading of each being timed (or phased) one after another such that the strength of the mixed substrate flowing from all hydrolysis reactors to the biogasification reactor is more stable, should lead to relatively

stable gas production (Figure 3.2-7). This phased solids loading approach is used in both the UCD pilot plant and the Channel Islands designs.

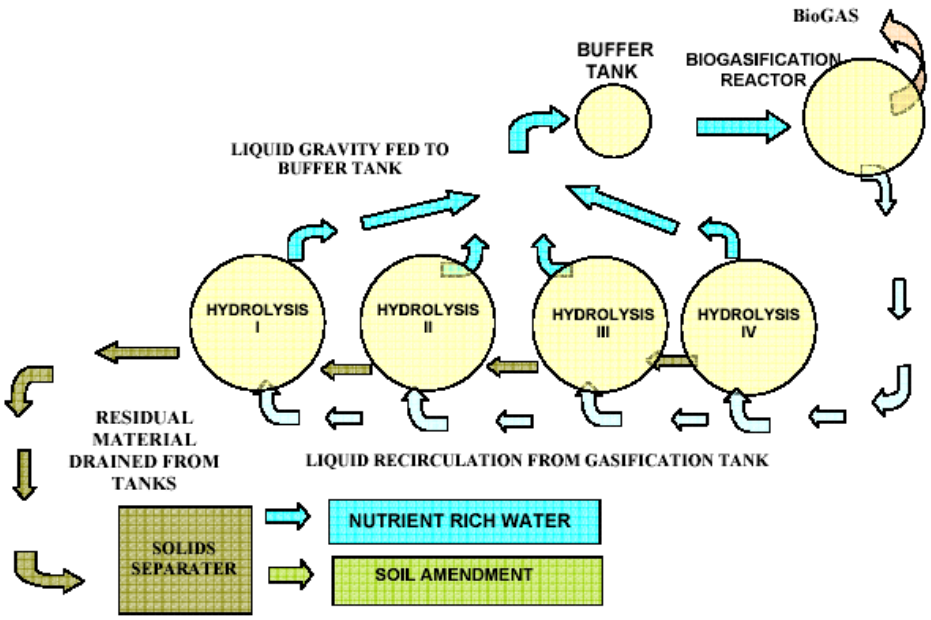

Figure 3.2-7. Schematic of APS digester system showing four hydrolysis vessels
Photo Credit: Courtesy of Ruihong Zhang

Dairy Manure Digesters

Three types of anaerobic digesters are commercially available for the digestion of dairy manure: complete mix, plug flow, and ambient temperature covered lagoon. The choice of digester is dependent on the type of manure collection system used on the dairy. Dairies with flush manure collection systems (2 to 3% total solids) would typically use an ambient temperature covered lagoon digester whereas a dairy with a mechanical scrape system of collection (10 to 13% total solids) would be a candidate for a plug flow digester. Complete mix anaerobic digesters operate on manure that has 3 to 10% total solids and can be used with either flushed or scraped manure. Both complete mix and plug flow digesters can be heated using heat captured from a boiler or an engine generator.

Manure digestion systems typically have five subsystems: a mix tank, a digester, an effluent tank, a solids separator and a power plant or other gas energy conversion system (see Figure 3.2-8).

Recent legislation (SB 5X) appropriated monies for assisting dairies in California in the installation of systems to create power from dairy wastes. This led to the establishment of the Dairy Power Production Program by the California Energy Commission in order to encourage the development of biologically based anaerobic digestion and gasification (biogas) electricity generation projects in the state. Objectives include developing commercially proven biogas electricity systems to help California dairies offset the

purchase of electricity, and providing environmental benefits through reduction of air and ground water pollutants associated with storage and treatment of livestock wastes. Approximately $10 million was available including program administration costs.

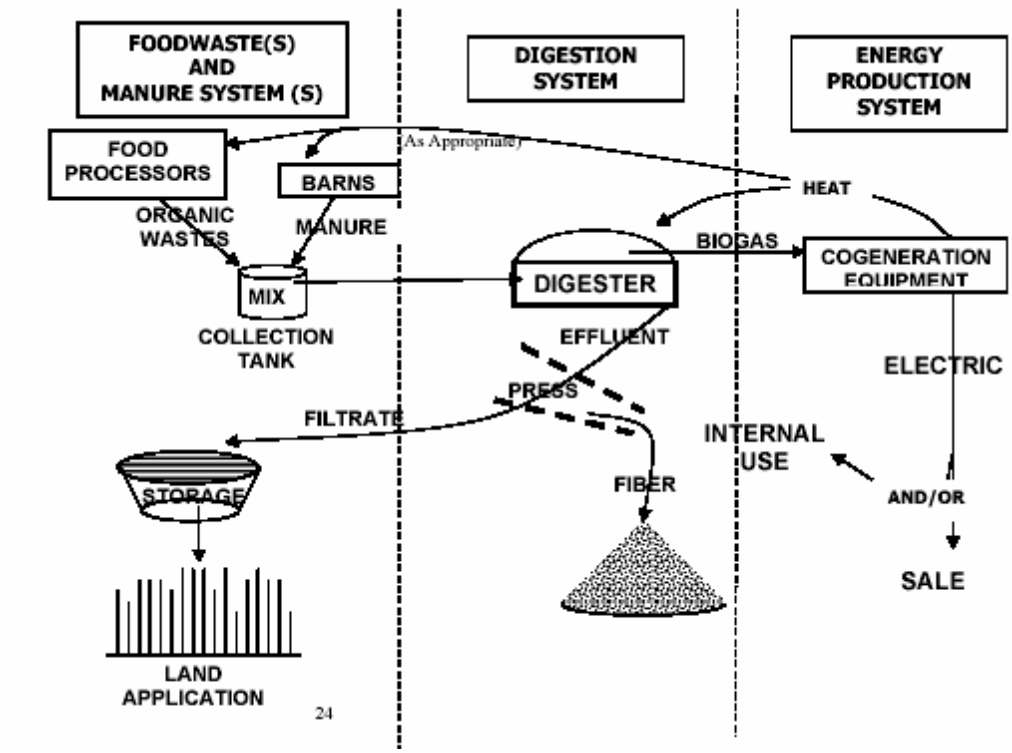

Figure 3.2-8. Schematic of digester subsystems (typical of low solids dairy effluents)
Photo Credit: Mattocks 2003

Approximately 14 dairies in California have been awarded grant monies for construction of digesters under the DPPP. This includes seven covered lagoon systems, six plug flow designs, and a complete-mix reactor design. Performance and cost estimates are discussed below (also refer to Task 1.1.1 Report for more information).

3.3. Economic Analyses

A standard required revenue model was used to compute levelized cost of energy or required tip fee for a set of base case assumptions.[119]

The cost of energy calculator employs a standard revenue requirements method to calculate the energy revenue ($/kWh) required to earn the desired rate of return. The

119. The model utilized was a modified version of the cost of energy calculator available at http://faculty.engineering.ucdavis.edu/jenkins/CBC/Calculator/cal.html

model computes level annual cost of energy in current dollars (which does not include the effect of inflation in the analysis), and constant or inflation adjusted dollars.[120]

Values for capital cost, fixed and variable operating costs, fuel/feedstock price (or tipping fee; negative price), and system (plant) performance characteristics are needed for computing the project revenue requirements. In addition, financing details (such as ratio of debt to equity and interest rate associated with each), inflation/escalation rates, tax rates and credits, and depreciation schedules are used in the required revenue or cost calculator.

3.3.1. Tax treatment in the Model

Because the revenue requirement method specifies a rate of return (or interest on debt that must be met), taxes must be computed indirectly because they are implicit in the revenues required.

A combined tax rate can be computed,

$$t = t_F(1-t_S) + t_S$$

where t_F and t_S are federal and state tax rates, respectively. The taxes required for each year of the analysis can be determined from

$$T = \frac{t}{1-t}(C_r - D_t + I_r - D_i)$$

where

Cr = capital recovery (principal) payment

Dt = depreciation (depreciation amounts are calculated using the modified accelerated cost recovery system (MACRS) for the five or ten year property class)

Ir = return on investment.

Di = interest on debt

Because of accelerated depreciation, the tax for the project in the first years of the project may be negative. For large profitable companies (i.e., companies with taxable profits from other enterprises), "negative" taxes can be taken as a tax credit to the project against other income. A company that does not generate enough taxable income elsewhere to be offset by these "negative" taxes, or for which the project constitutes the whole of the corporate activity, cannot credit these negative taxes to the project and instead simply reduces tax to zero. More sophisticated treatments allowing for forwarding of tax benefits or costs are not handled within the model used here. The base case and most sensitivity analyses treat negative taxes as credit to the project.

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120. A background and model description can be accessed at http://faculty.engineering.ucdavis.edu/jenkins/CBC/Calculator/CalculatorBackground.pdf

Production tax credits (PTCs) are assumed to be available for these projects, at least for the first five years.[121] For "open-loop" biomass fuel (biomass not specifically grown for energy), the PTC is 0.9 cents/kWh.

3.3.2 General Procedure

A "Base Case" composed of expected costs, revenues, inflation, tax and finance rates was created for each technology and input to the model which yielded the Base Case revenue requirement in total dollars per year and per energy unit (kWh), or per ton of feedstock for the cases when a required tipping fee was of interest. Then, the sensitivity of the required revenue was investigated by making changes to the input assumptions. This was done by changing a single input variable at a time while holding all others constant at their base case values. Plots showing the change in revenue requirements over the span of input variable were generated and appear in the individual system results section.

3.3.3 Base Case Results

The base case results are tabulated below (Table 3.3-1) and shown in Figure 3.3-1. The table shows the levelized COE (constant $/kWh) required for the project to meet expenses and profit defined in the assumptions for each base case (See Figure 3.3-2 for a comparison of capital cost for biomass and other power generation technologies). A key to headings (project names) in Table 3.3-1 is immediately below the table.

The upper and lower COE extremes determined by a sensitivity analysis are shown as well. The lower end of the COE range presented is due to changes in fuel price or tipping fee for all technologies except the dairy digester category (DPPP) of which its COE range is due to a large spread in capital costs. The fuel or tipping fee used in the base case as well as the value necessary to reach the lower end of the COE range are shown in the table. Changes in other parameters (such as capital or operating costs) can result in COEs outside the range shown but it is not likely these will vary by the 50 to 100% from the base case assumption that would be necessary to produce a COE outside the range shown. Fuel and tipping fees can easily vary by such large magnitudes over time or by location.

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121. The Section 45 tax credits (PTC) were extended when HR 4520 (American Jobs Creation Act) was enacted on October 22, 2004. Geothermal, solar, wind, and closed-loop biomass are eligible for the 1.5 cents/kWh credit indexed for inflation (now at 1.8 cents/kWh). Open-loop biomass, municipal solid waste, and small irrigation hydroelectric are eligible for only half of that, hence the current 0.9 cents/kWh credit for those categories. Refined coal (essentially synfuels) gets a credit of $4.375/ton. Wind, closed-loop biomass, and refined coal can receive PTC for 10 years, and the others are good for five years. **Note: A new energy bill has recently been signed into law. The new bill has not yet been consulted for relevant changes to this footnote.**

Table 3.3-1. Results of Base Case Analyses

	CA (paid off)	C-K (w/CHP)	C-I	CA	C-S (w/CHP)	DPPP	Straw Facility	Morris (2000)	C-K (noCHP)	APS	MSW AD	C-S (noCHP)	DPPP (5 yrs)
Capital Cost ($/kW)	0	2451	2800	2000	3700	1500 - 6000	2300	2000	2451	13,500	20,000	3700	1500 - 6000
Cost ($/ton capacity)	-	-	-	-	-	-	-	-	-	222	250	-	-
Fuel/Feedstock Price (Base Case)	$20/bdt	$30/bdt	$30/bdt	$20/bdt	$45/bdt	-	$34/bdt	$20-30/bdt	$30/bdt	-$27/wet ton	-$26/wet ton	$45/bdt	-
Fuel/Feedstock Price (Lower limit)	$10/bdt	-$10/bdt	-$10/bdt	$10/bdt	-$10/bdt	-	$17/bdt	-	-$10/bdt	-$40/wet ton	-$33/wet ton	-$10/bdt	-
Levelized COE (Constant $/kWh)													
Low End	0.015	0.048	0.052	0.035	0.045	0.018	0.053	0.044	0.060	0.000	0.000	0.073	0.046
Base Case	0.037	0.056	0.060	0.061	0.062	0.066	0.067	0.076	0.076	0.080	0.084	0.101	0.133
High End	0.048	0.087	0.088	0.073	0.101	0.100	0.092	0.108	0.099	0.200	0.250	0.129	0.212

Key to Table Headings

CA (paid off)	Existing California steam cycle biomass plants with capital fully amortized
C-K	Fixed Bed Novel Gasifier being installed in Kokemäki, Finland (Carbona)
C-I	Carbona BIGCC project specified for India
CA	Existing California steam cycle biomass plants still paying capital loans or new facility
C-S	CFB Carbona (GTI) Circulating Fluidized Bed Gasifier being installed in Skive, Denmark
Straw Facility	Concept using Danish design installed in California and firing rice straw
DPPP	California Dairy Power Production Program Capital cost used for base-case is $3600/kW, (15 yr. economic life, 10yr loan repayment) DPPP (5 yrs) means loan repayment in 5 years, productive life remains 15 years
Morris (2000)	Estimates for California solid fuel biomass industry
APS	Advanced Phased-Solids digester using Channel Islands proposal as basis
MSW AD	Generic digestion facility using of MSW as feedstock
W/ CHP	Sales of co-generated heat are credited to the project (C-K and C-S are evaluated both with and without heat sales)
noCHP	Effect of no combined heat generation from C-S and Kokemaki (capital costs were not reduced for the no CHP cases)
5 yrs	Effect on COE of requiring all investment and borrowed money to be recovered in 5 years (similar to a 5 year payback period)

Data collected by Robert Williams

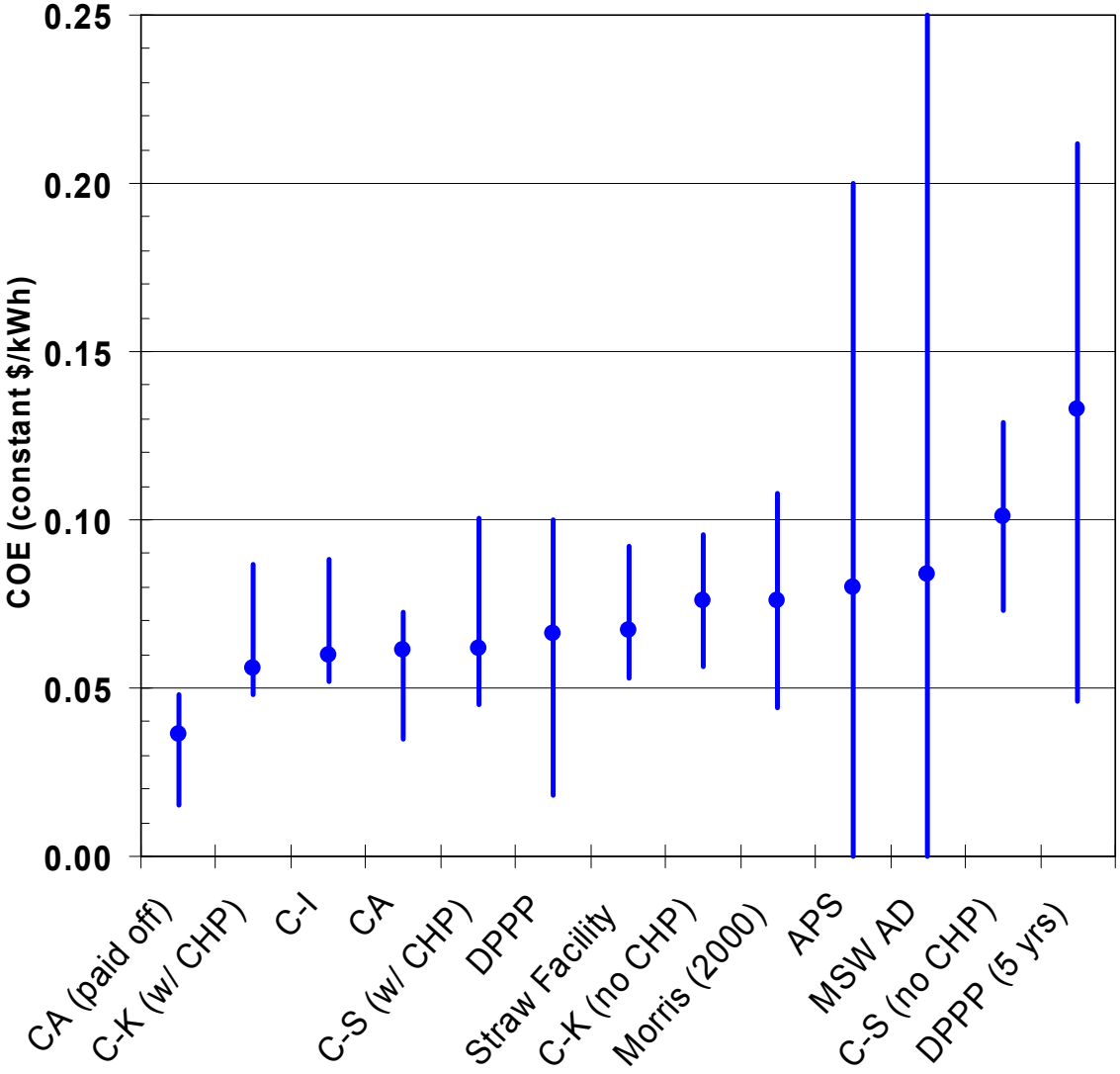
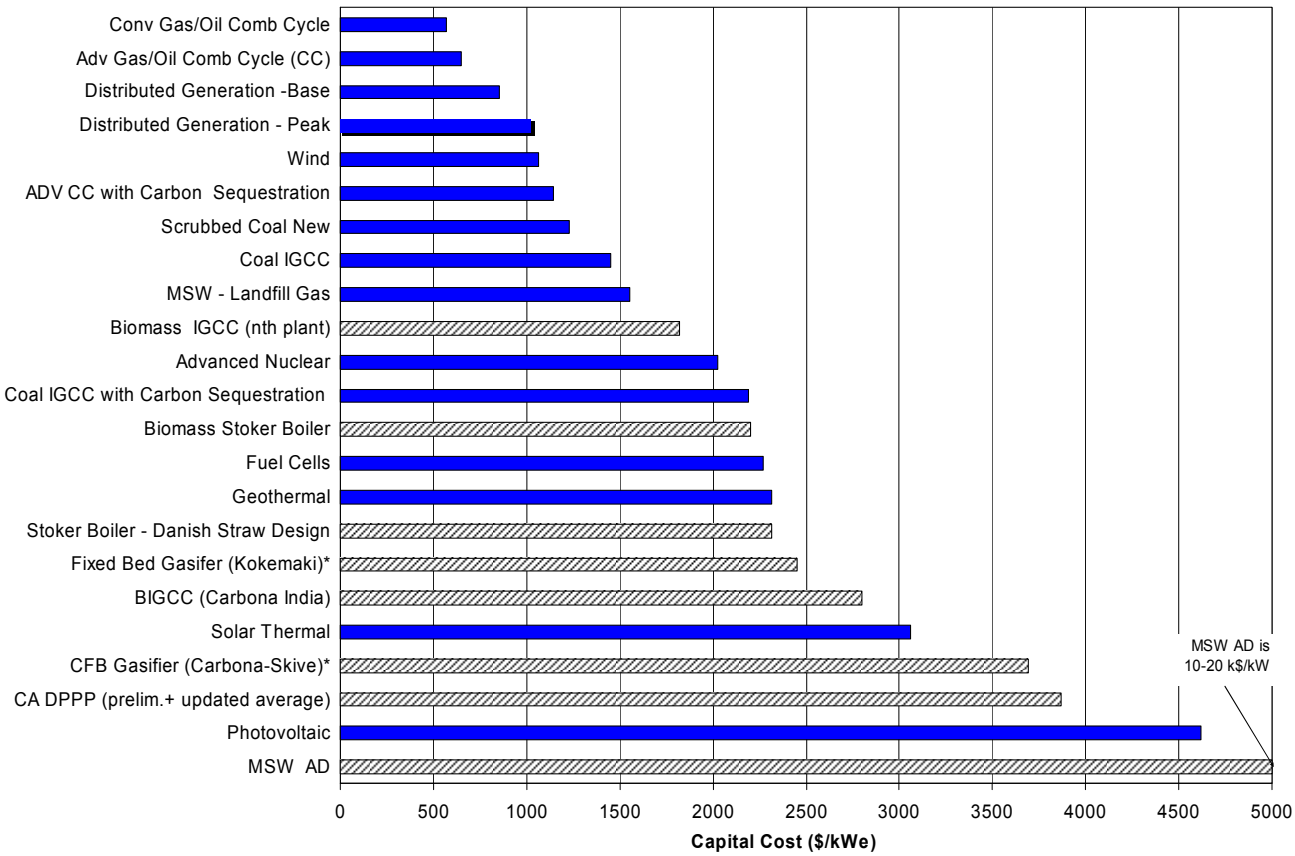


Figure 3.3-1. COE estimates for biomass power conversion technologies
Photo credit: UC Davis Research Team; Photo credit: Robert Williams; Photo Credit: Jenkins 2004

The base case COEs vary upward from $0.037/kWh for existing solid fuel biomass power plants in California that have paid off the original capital loan (Jenkins 2004). It is not known explicitly whether any operating solid fuel biomass power plants in California have paid off their capital debt but the bulk of operating capacity began operations between 1985 and 1990 (33 facilities with combined 650 MW came on-line during this period) (Morris 2000) and anecdotal information suggests most capital has been repaid for many of the existing fleet. New facilities or those still making payments based on installed costs of $2,000/kW and fuel cost of $10 to $20/bone dry ton have estimated COEs that range from $0.035 to $0.073/kWh (Jenkins 2004) and $0.044 to $0.108/kWh (Morris 2000).



*Kokemäki and Skive are CHP facilities-heat recovery equipment costs included
Textured bars are technologies in this report, Solid bars are adapted from EIA 2004.

Figure 3.3-2. Installed costs of power generation technologies
Photo Credit: Assumptions to the Annual Energy Outlook 2004, DOE/EIA-0554

The second lowest base case power cost estimate is $0.056/kWh for the Fixed Bed Novel Gasifier CHP project being installed in Kokemäki, Finland (by Carbona). Base case COEs in this analysis range upward to the estimated $0.133/kWh representing an average for the California Dairy Power Production Program projects (14 proposed or operating facilities) with a five-year loan repayment period. The Carbona-Kokemäki and DPPP estimates are discussed in detail in this report.

The two projects that include combined heat production/sales are projects being constructed in Europe by Carbona. These are the C-K (w/CHP) and the C-S (w/CHP) circulating fluidized bed gasifier fueling reciprocating engines. When heat sales are set to zero, the COE rises substantially for each; COE increases 0.02 and 0.039 $/kWh for the C-K and C-S projects, respectively. Clearly, there are significant cost and energy efficiency advantages to CHP at these scales.

The estimate for COE of a biomass integrated gasification combined cycle is $0.060/kWh (project C-I in Table 3.3-1). This is for an installation proposed in India by Carbona. This

estimate compares well with an energy cost estimate that can be determined using the assumptions published by the Energy Information Agency for advanced biomass power plant in the Annual Energy Outlook (cost of $1,731/kW, and a low operation and maintenance of $0.0094/kWh).[122] Using the EIA assumptions, a COE from BIGCC is $0.03 to $0.045/kWh. Craig and Mann (1996) estimated COE values from $0.051 to $0.063/kWh for several BIGCC system designs (no capacity payments).

The straw combustion facility is estimated to cost similar to the existing California solid fuel biomass combustion industry (for a new facility). The technology is similar and special fuel handling systems needed for straw have been developed over seas. The most variable or volatile parameter is straw fuel cost and delivery infrastructure.

MSW and dairy manure digesters are costly and require high energy prices if financed solely by electricity sales. Energy production is comparatively small from AD systems (capital costs in this report for AD vary from $1,500 to $20,000/kW). Tipping fees and/or compostable material sales revenues are usually relied upon for financial viability. There are likely cases where the systems are financially viable on energy revenue if the facility is a large electricity consumer and the onsite generation can offset retail electricity prices. Heat recovery for beneficial use is almost always financially attractive if there is a convenient heat client, such as nearby food processing operation.

3.4. CFB Gasifier- Carbona – Skive, Denmark CHP

Assumptions (base case)

Table 3.4-1 shows the basic input parameters to the model for the base case (some of the values are calculated from the inputs). Capital cost is approximately $20 million, or nearly $3,700/kW installed (this is high but includes heat recovery equipment) (Patel 2004). Capacity factor (here taken as availability) is 91% and station electrical efficiency is 25.7% (from the operating parameters in Table 3.2-1). Fuel energy content, net efficiency, and capacity factor are used to calculate fuel consumption rate. The technical and economic life of the facility is assumed to be 15 years.

Costs

Base case fuel cost is assumed to be $45/dry short ton (about $30/dry ton material plus $15/dry ton for pelletizing; fuel price in the model is $49.50 per dry metric ton).[123] Fuel cost in terms of net electrical energy is 3.4 cents/kWh. Non-fuel operating and maintenance costs are assumed to be about 3 cents/kWh. The non-fuel operating expenses are default values appropriate for typical combustion boiler biomass facilities currently in operation in California and may be different for this kind of facility using different technology (Morris 2000).

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122. Assumptions to the Annual Energy Outlook 2004, available at: http://www.eia.doe.gov/oiaf/aeo/assumption/index.html

123. Fuel price in Denmark is approximately $75/ton (unclear if short ton or metric ton).

Table 3.4-2 shows individual expense categories in both $/kWh net electrical energy and annual amounts. Total operating costs used in the base case amount to 6.4 cents/kWh of electricity delivered. Depending on the level of automation that can be incorporated into this type of facility and maintenance requirements, operating costs may be lower than used in this analysis.

Table 3.4-1. Economic model base case parameters, Carbona-Skive

Cost and Performance Assumptions	
Total Capital cost ($)	20,000,000
Capital Cost ($/kW)	3,689
Net Plant Capacity (kW)e	5,421
Net District Heat Production (kW)th	11,482
Capacity Factor (%)	91
Net Station Electrical Efficiency (%)	25.7
Fuel Heating Value (kJ/kg, dry basis)	20,260
Fuel Consumption Rate (dry Mg/h)	3.748
Fuel Ash Concentration (%)	2
Annual Production (kWh)e	43,214,044
Annual Production (kWh)th	91,529,911
Annual Fuel Consumption (dry Mg/y)	29,878
Annual Ash Disposal (Mg/y)	598
Annual Hours	7972
Expenses	
Fuel Cost ($/dry Mg)	49.5
Fuel Cost ($/kWh)e	0.0342
Labor Cost ($/kWh)	0.0104
Maintenance Cost ($/kWh)	0.0078
Insurance/Property Tax ($/kWh)	0.0073
Utilities ($/kWh)	0.0010
Ash Disposal ($/kWh)	0.0000
Management/Administration ($/kWh)	0.0010
Other Operating Expenses ($/kWh)	0.0021
Total Non-Fuel Expenses ($/kWh)	0.0296
Taxes	
Federal Tax Rate (%)	34
State Tax Rate (%)	9.6
Combined Tax Rate (%)	40.3
Production Tax Credit ($/kWh)	0.009
Production Tax Credit ($yr)	388,926
Escalation/Inflation	
General Inflation (%/y)	2.80
Escalation--Fuel (%/y)	2.80
Escalation--Other (%/y)	2.80

Income other than from electricity	
Capacity Payment ($/kW-y)	0
Interest Rate on Debt Reserve (%/y)	7
Price heat energy ($/kWh)th	0.01877
Annual Capacity Payment ($/y)	0
Annual Debt Reserve Interest ($/y)	0
Annual heat sales ($)	1,718,138
Annual heat sales ($/kWh)electricity	0.03976
Price for Ash ($/Mg)	5
Revenue from Ash sales ($/y)	2988
Revenue from Ash ($/kWh)e	0.00007
Financing	
Debt ratio (%)	85.00
Equity ratio (%)	15
Interest Rate on Debt (%/y)	6
Life of Loan (y)	15
Cost of equity (%/y)	15
Cost of Money (%/y)	7
Total Cost of Plant ($)	20,000,000
Total Equity Cost ($)	3,000,000
Total Debt Cost ($)	17,000,000
Capital Recovery Factor (Equity)	0.17102
Capital Recovery Factor (Debt)	0.10296
Annual Equity Recovery ($/y)	513,051
Annual Debt Payment ($/y)	1,750,367
Debt Reserve ($)	0
Depreciation Schedule	
5 Year MACRS	
Level Annual Cost (LAC)	
**Current $** Levelized COE ($/kWh)	**0.075**
**Constant $** Levelized COE ($/kWh)	**0.062**

Data collected by Robert Williams (insert contract dates); Source: Patel 2004

Table 3.4-2. Simple "Year 0" costs and revenues for the Carbona-Skive project

	($/kWh)	($/y)
Fuel Cost ($49.5/Mg)	0.0342	1,478,972
Labor	0.0104	448,562
Maintenance	0.0078	336,205
Insurance/Property Tax	0.0073	313,734
Utilities	0.0010	44,943
Ash Disposal	0.0000	0
Management/Admin	0.0010	44,943
Other Operating Exp.	0.0021	89,885
Total non Fuel Expenses	0.0296	1,278,271
Total Operating Expenses	0.0638	2,757,244
Debt & Equity Payment	0.0524	2,263,418
Heat Sales	0.0398	1,718,138
Revenue Requirement (simple calculation)*	0.0764	3,302,524

*Does not include effects of taxes, and inflation
Data collected by Robert Williams (insert contract dates); Source: Patel 2004

Revenues (other than from electricity)

Income from other than electricity sales include a nominal amount ($5/Mg or less than $3,000 per year) for sales of ash for land application and revenue from sale of heat (or offsetting purchase of heat that would otherwise be required). The revenue for heat is conservative and based on direct replacement of natural gas priced at $5.50/MMBtu ($0.55 per therm). The capacity factor for heat production is assumed the same as for power production (91%).

Revenue from heat sales in the base case analysis is significant. It amounts to nearly 4 cents/kWh of net electricity, essentially offsetting more than 60% of the fuel and O&M costs.

Financing

The base case assumes that 85% of the project is financed at 6% nominal annual interest with equity or investor financing for the remaining 15% of first costs. Rate of return (ROR) on equity is 15%/year. No debt reserve is held in escrow. The sensitivity analysis explores effects of changes in debt ratio and interest rate.

Tax treatment

The analysis assumes federal and state tax rates are 34% and 9.6%, respectively. Because the revenue requirements method specifies a rate of return (or interest on debt that must be met), taxes must be computed indirectly because revenues are not determined at this stage of the analysis. The five-year MACRS depreciation schedule is used, which typically credits the project with "negative" taxes in early years. In order to take advantage of this "credit," the company must be earning profits from other enterprises. This is assumed in the base case and all of the sensitivity analyses except for one case which does not allow negative taxes to credit the project.

Production tax credits (PTCs) should be available for this project, at least for five years.[124] For closed-loop biomass fuel (biomass not specifically grown for energy), the PTC is 0.9 cents/kWh. The base case analysis includes a $0.009/kWh PTC for the first five years. The absence of a PTC is treated in the sensitivity analysis.

Results and Sensitivity

For the base case, the COE or sales price needed in order to meet all expenses, pay debt and meet the required ROR, is 6.2 cents/kWh (constant dollars), or 7.5 cents/kWh (current dollars). The 7.5 cents/kWh is the amount that would have to be charged for electricity in each year of the project (with no escalation in the energy price for the entire 15 years) in order to pay all debts and expenses by the end of the project life (assuming base-case conditions and escalations for all costs). The 6.2 cents/kWh COE in constant dollars is the price of energy required for the first year but must escalate with inflation each year. The constant dollar amount can be used to compare to other alternatives in year zero dollars.

Table 3.4-3 shows selected results from the sensitivity analysis. As mentioned before, sales of heat contribute significantly to revenue. If no value for combined heat is credited to the project, the COE is more than 10 cents/kWh (a real project with no heat component would not need as much capital equipment and would have lower first costs). Lower capital, or fuel costs, with heat sales can yield a very attractive energy price of around 4 cents/kWh (see table below).

Graphs showing sensitivity of COE to changes in different variables appear below. A list of figures associated with the sensitivity analysis is provided here for convenience:

124. See footnote 121 on Section 45.

Figure (in text)	Description
3.4-1	Constant $ COE sensitivity analysis
3.4-2	Current $ COE sensitivity analysis
3.3-3	COE versus Fuel Cost
3.4-4	COE versus non-Fuel O&M Costs

Figure (in appendix)	Description
3.4-5	COE versus Debt Interest Rate
3.4-6	COE versus Equity Ratio
3.4-7	COE versus Electrical Efficiency
3.4-8	Company size and PTC effects on COE

The COE is about equally sensitive to relative changes from the base case of fuel, O&M, and capital cost. Changes in any of these three factors by ±10% will affect COE by about ±6%. Relative changes in interest rate on the loan (or ROR) influence the COE to a lesser extent than other costs. COE is equally although inversely sensitive to heat price changes.

Table 3.4-3. Selected results of economic model for Carbona-Skive project (bold type indicates change from base case)

Parameter	Units	Base Case	Low Fuel Price	High Fuel Price	w/o Heat Sales	Low Capital Cost	High Capital Cost	High Interest Rate Loan	Low Conversion Efficiency	Equity Ratio (30% with 15% ROI)	w/o PTC, Large Firm	Small Firm (no 'neg. tax')	Moderate Case (includes PTC-Large Firm)
Net District Heat Production (kW)th	(kWth)	11,482	11,482	11,482	**0**	11,482	11,482	11,482	11,482	11,482	11,482	11,482	11,482
Total Capital cost	($)	20,000,000	20,000,000	20,000,000	20,000,000	**12,000,000**	**30,000,000**	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	**16,264,000**
Capital Cost	($/kW)	3689	3689	3689	3689	2214	5534	3689	3689	3689	3689	3689	**3000**
Capacity Factor	(%)	91	91	91	91	91	91	91	91	91	91	91	**80**
Net Station Electrical Efficiency	(%)	25.7	25.7	25.7	25.7	25.7	25.7	25.7	**12.9**	25.7	25.7	25.7	25.7
Fuel Consumption Rate	(Mg/h)	3.7	3.7	3.7	3.7	3.7	3.7	3.7	**7.5**	3.7	3.7	3.7	3.7
Annual Fuel Consumption	(Mg/y)	29,878	29,878	29,878	29,878	29,878	29,878	29,878	**59,756**	29,878	29,878	29,878	26,267
Fuel Cost	($/Mg)	49.5	**24.8**	**74.3**	49.5	49.5	49.5	49.5	49.5	49.5	49.5	49.5	**39.6**
Labor Cost	($/kWh)	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	**0.0104**
Other O&M	($/kWh)	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	**0.0118**
Price heat energy	($/kWh-th)	0.019	0.019	0.019	**0.000**	0.019	0.019	0.019	0.019	0.019	0.019	0.019	**0.009**
Price heat energy	($/therm)	0.55	0.55	0.55	**0.00**	0.55	0.55	0.55	0.55	0.55	0.55	0.55	**0.28**
Interest Rate on Debt	(%)	6	6	6	6	6	6	**15**	6	6	6	6	**6**
Current $ Level Annual Revenue Requirements	(current $)	3,248,063	2,376,582	4,119,545	5,272,882	2,366,337	4,350,221	3,730,042	4,987,505	3,686,585	3,425,375	4,209,437	2,962,620
Constant $ Level Annual Revenue Requirements	(constant $)	2,681,040	1,961,695	3,400,384	4,352,381	1,953,239	3,590,791	3,179,783	4,116,822	3,061,797	2,827,398	3,474,584	2,445,427
Current $ LAC of Energy	(current $/kWh)	**0.075**	0.055	0.095	0.122	0.055	0.101	0.086	0.115	0.085	0.079	0.097	**0.078**
Constant $ LAC of Energy	(constant $/kWh)	**0.062**	0.045	0.079	0.101	0.045	0.083	0.074	0.095	0.071	0.065	0.080	**0.064**

Life of Project (loan/financing period)	(y)	15	Fuel Heating Value		20,260
Financed amount	(%)	85	Net Plant Capacity	(kWe)	5421
General inflation/Escalation	(%)	2.8	Combined Tax Rate (34 Fed, 9.6 State)	(%)	40.34

Data collected by Robert Williams (insert contract dates)

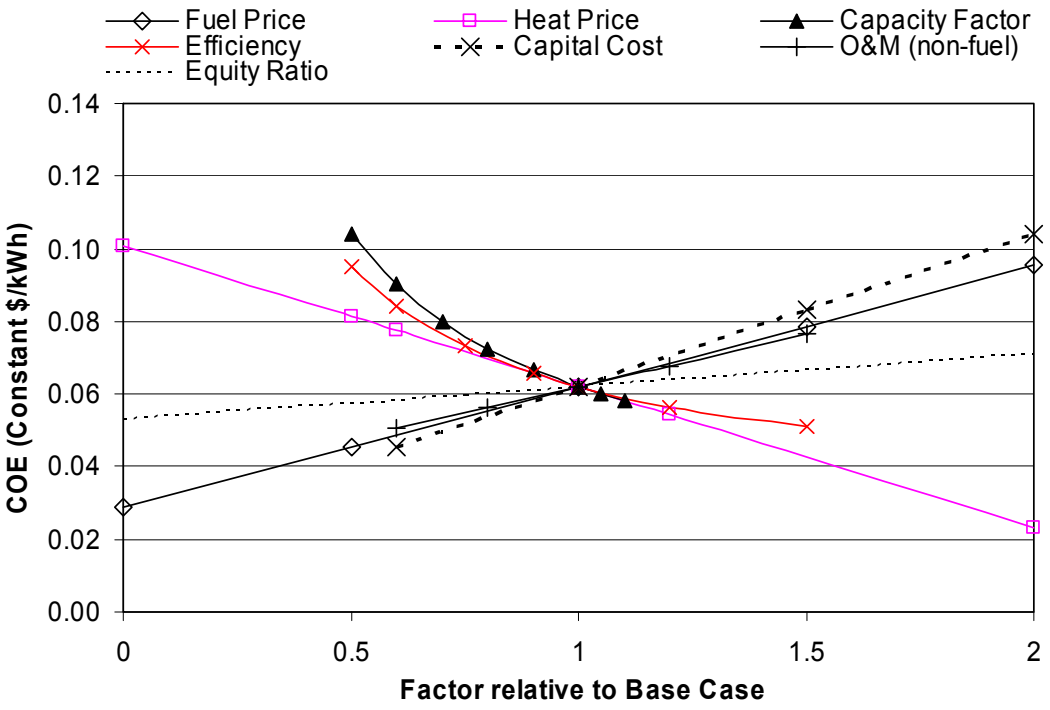

Figure 3.4-1. Constant $ COE sensitivity analysis (Carbona – Skive)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

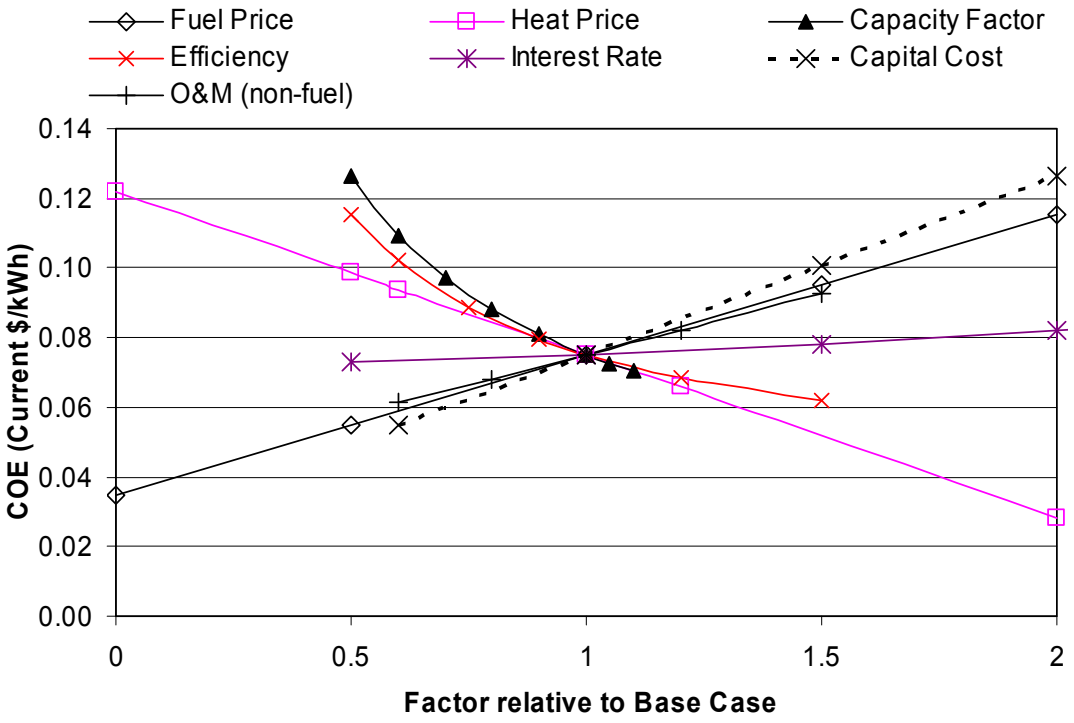

Figure 3.4-2. Current $ COE sensitivity analysis (Carbona – Skive)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

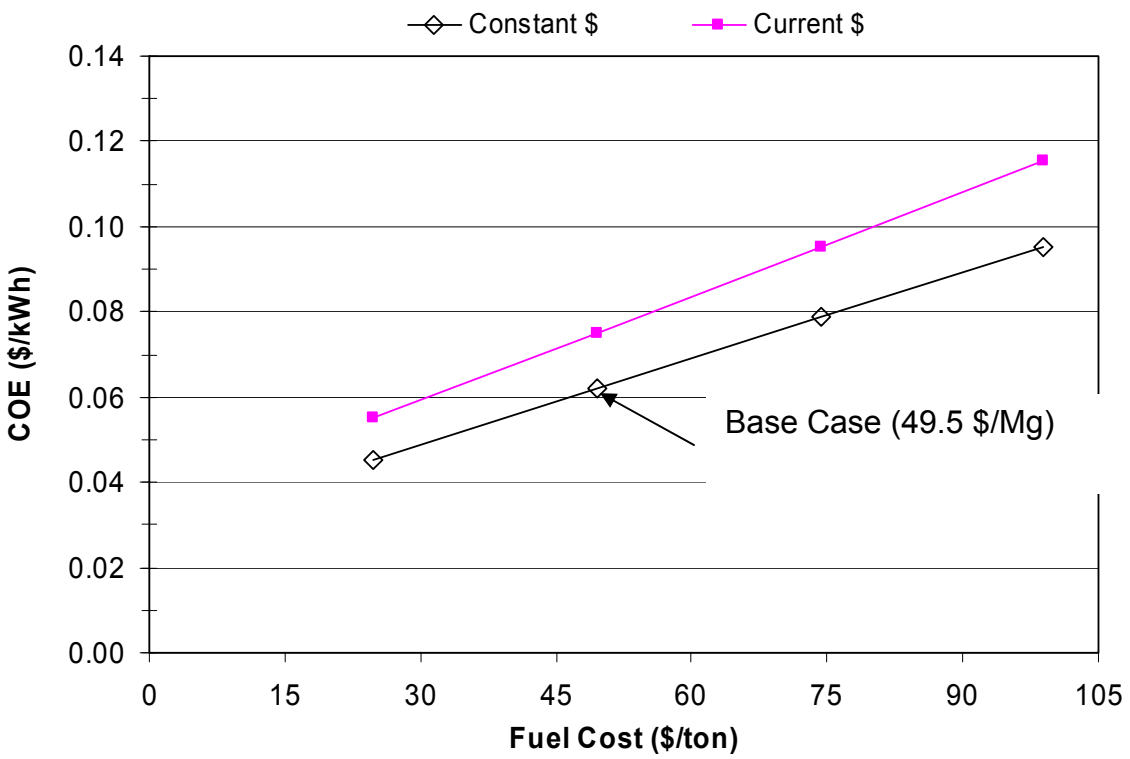

Figure 3.4-3. COE versus fuel cost (Carbona – Skive)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

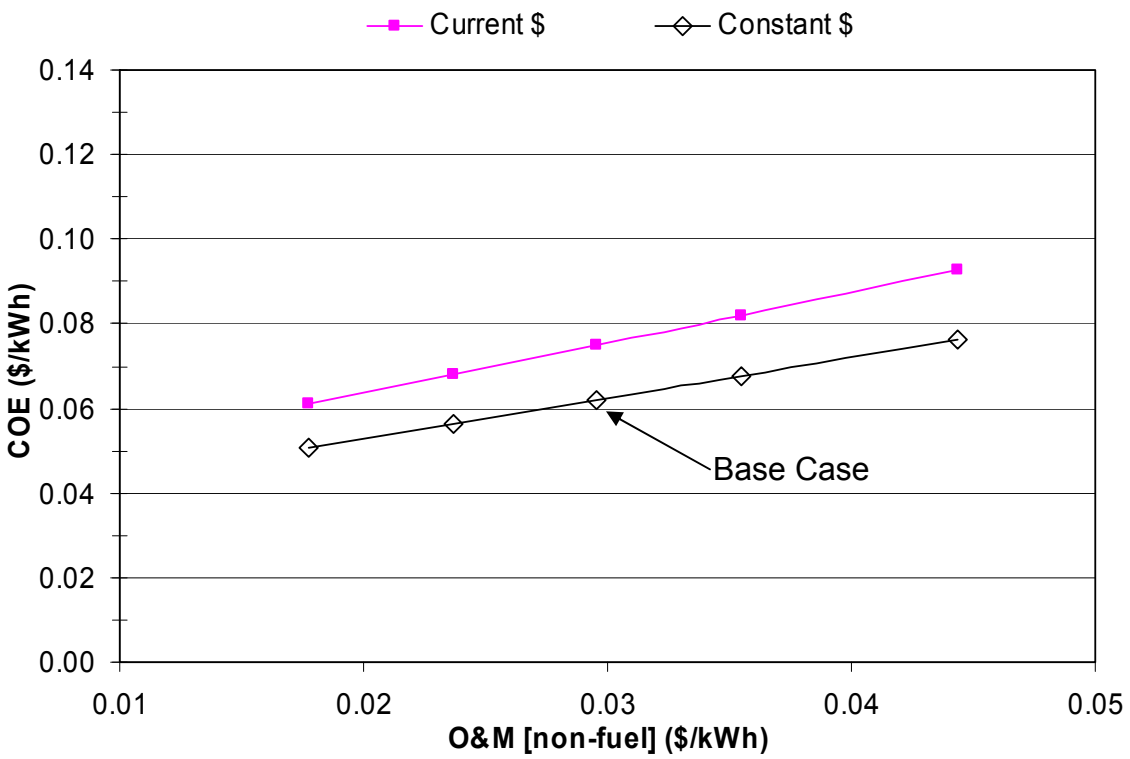

Figure 3.4-4. COE versus non-fuel O&M costs (Carbona – Skive)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

3.5. Fixed-Bed Gasifier- Carbona – Kokemäki, Finland CHP Plant

Assumptions (base case)

Table 3.5-1 shows the basic input parameters to the model for the base case (some of the values are calculated from the inputs). Capital cost is approximately $5.5 million, or nearly $3,000/kW installed including heat recovery equipment (Patel 2004).[125] Electric system capacity factor (here taken as availability) is 91% and station electrical efficiency is 30% (from the energy balance in Table 3.2-2). Fuel energy content, net efficiency, and capacity factor are used to calculate fuel consumption rate. The technical and economic life of the facility is assumed to be 15 years.

Costs

Base case fuel cost is assumed to be $30/dry short ton ($33/dry metric ton used in the model).[126] Fuel cost in terms of net electrical energy is 2 cents/kWh. Non-fuel operating and maintenance costs are assumed to be about 3 cents/kWh. The non-fuel operating expenses are default values appropriate for typical combustion boiler biomass facilities currently in operation in California. Table 3.5-2 shows first year costs and revenue requirement of the project. Total operating costs used in the base case amount to about 4.9 cents/kWh of electricity delivered. Depending on the level of automation that can be incorporated into this type of facility and maintenance requirements, operating costs may be lower than used in this analysis.

Revenues (other than from electricity)

Income from other than electricity sales include a nominal amount ($5/t, or less than $900 per year) for sales of ash for land application and revenue from sale of heat (or offsetting purchase of heat that would otherwise be required). The revenue for heat is conservative and based on natural gas price of $0.55 per therm ($5.50/MMBtu) and thermal energy capacity factor of 60%. Though the Kokemäki facility is sized to utilize all recoverable heat throughout the year (high heat utilization factor), the base case analysis here assumes a thermal energy capacity factor of 60%.

Revenue from heat sales in the base case analysis is significant. It amounts to about 2.1 cents/kWh of net electricity, offsetting more than 40% of the fuel and O&M costs.

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125. Note: Capital cost was given as 4.5 million Euros.
126. Fuel for this reactor does not require pelletizing as is the case for the CFB reactor specified in the Skive, Denmark, project. Fuel cost, therefore, does not include costs for pelletizing.

Table 3.5-1. Economic model base case parameters, Kokemäki, Finland, CHP Plant

Cost and Performance Assumptions	
Total Capital cost ($)	5,500,000
Capital Cost ($/kW)	2,996
Net Plant Capacity (kW)e	1,836
Net District Heat Production (kW)th	3,100
Capacity Factor-Power (%)	91
Capacity Factor-Heat (%)	60
Net Station Electrical Efficiency (%)	30.0
Fuel Heating Value (kJ/kg, dry basis)	20,260
Fuel Consumption Rate (dry Mg/h)	1.09
Fuel Ash Concentration (%)	2
Annual Production (kWh)e	14,635,858
Annual Production (kWh)th	16,293,600
Annual Fuel Consumption (dry Mg/y)	8,669
Annual Ash Disposal (Mg/y)	173
Annual Hours	7,972
Expenses	
Fuel Cost ($/dry Mg)	33
Fuel Cost ($/kWh)e	0.0195
Labor Cost ($/kWh)	0.0104
Maintenance Cost ($/kWh)	0.0078
Insurance/Property Tax ($/kWh)	0.0073
Utilities ($/kWh)	0.0010
Ash Disposal ($/kWh)	0
Management/Administration ($/kWh)	0.00104
Other Operating Expenses ($/kWh)	0.00208
Total Non-Fuel Expenses ($/kWh)	0.02958
Taxes	
Federal Tax Rate (%)	34
State Tax Rate (%)	9.6
Combined Tax Rate (%)	40.3
Production Tax Credit ($/kWh)	0.009
Production Tax Credit ($yr)	131,723
Escalation/Inflation	
General Inflation (%/y)	2.8
Escalation--Fuel (%/y)	2.8
Escalation--Other (%/y)	2.8

Income other than energy	
Capacity Payment ($/kW-y)	0
Interest Rate on Debt Reserve (%/y)	7.00
Price heat energy ($/kWh)th	0.0188
Annual Capacity Payment ($/y)	0
Annual Debt Reserve Interest ($/y)	0
Annual heat sales ($)	305,853
Annual heat sales ($/kWh)electricity	0.0209
Price for Ash ($/Mg)	5
Revenue from Ash sales ($/y)	867
Revenue from Ash ($/kWh)e	0.0001

Financing	
Debt ratio (%)	85
Equity ratio (%)	15
Interest Rate on Debt (%/y)	6
Life of Loan (y)	15
Cost of equity (%/y)	15
Cost of Money (%/y)	7.35
Total Cost of Plant ($)	5,500,000
Total Equity Cost ($)	825,000
Total Debt Cost ($)	4,675,000
Capital Recovery Factor (Equity)	0.17102
Capital Recovery Factor (Debt)	0.10296
Annual Equity Recovery ($/y)	141,089
Annual Debt Payment ($/y)	481,351
Debt Reserve ($)	0

Depreciation Schedule
5 Year MACRS

Level Annual Cost (LAC)	
**Current $** Levelized COE ($/kWh)	**0.068**
**Constant $** Levelized COE ($/kWh)	**0.056**

Data collected by Robert Williams (insert contract dates); Source: Patel 2004

Table 3.5-2. Simple "Year 0" costs and revenues for the Kokemäki CHP project

	($/kWh)	($/y)
Fuel Cost ($33/Mg)	0.0195	286,071
Labor	0.0104	151,920
Maintenance	0.0078	113,867
Insurance/Property Tax	0.0073	106,256
Utilities	0.0010	15,221
Ash Disposal	0.0000	0
Management/Admin	0.0010	15,221
Other Operating Exp.	0.0021	30,443
Total non Fuel Expenses	0.0296	432,929
Total Operating Expenses	0.0491	719,000
Debt & Equity Payment	0.0425	622,440
Heat Sales	0.0209	305,853
Revenue Requirement (simple calculation)*	0.0708	1,035,587

* does not include effects of taxes, and inflation
Data collected by Robert Williams (insert contract dates); Source: Patel 2004

Financing

As was done in the Carbona-Skive analysis, the base case assumes that 85% of the project is financed at 6% nominal annual interest with equity or investor financing for the remaining 15% of cost. ROR on equity is 15% per year. No debt reserve is held in escrow. The sensitivity analysis explores effects of changes in debt ratio and interest rate.

Tax Treatment

The analysis assumes federal and state tax rates are 34% and 9.6%, respectively. Taxes are computed indirectly by the revenue requirements method used here (see more explanation in the introduction of this section). The five-year MACRS depreciation schedule is used, which typically credits the project with "negative" taxes in early years. In order to take advantage of this "credit," the company must be earning profits from other enterprises. This is assumed in the base case and all of the sensitivity analyses except for one case which does not allow negative taxes to credit the project.

Production tax credits should be available for this project, at least for five years. For open-loop biomass fuel (biomass not specifically grown for energy), the PTC is 0.9 cents/kWh. The base case analysis includes the open-loop PTC. The absence of a PTC is treated in the sensitivity analysis.

Results

For the base case, the COE or sales price needed in order to meet all expenses, debt payments, and the required ROR for equity investment, is 7.1 cents/kWh (current dollars), or 5.8 cents/kWh (constant dollars). The 7.1 cents/kWh is the amount that would have to be charged for electricity in each year of the project (with no escalation in the energy price for the entire 15 years) in order to pay all debts and expenses by the end of the project life (assuming base-case conditions and escalations for all costs). The 5.8 cents/kWh COE in constant dollars is the price of energy required for the first year but must escalate with inflation each year. The constant dollar amount can be used to compare to other alternatives in today's (year zero) dollars. The resulting constant dollar COE ($0.058/kWh) is attractive for a small generator and can be improved if matched with a compatible heat client that can use more of the available heat than assumed in the base case.

Sensitivity

Table 3.5-3 shows selected results from the sensitivity analysis. As mentioned before, sales of heat contribute significantly to revenue. With no revenue from heat sales, the COE is about 7.9 cents/kWh. With improved heat capacity factor (to match electrical capacity factor), lower capital, or lower fuel costs (or a combination of factors), a COE below 5 cents/kWh can be achieved (see Table 3.5-3 below).

Figures 3.5-1 through 3.5-8 show relative sensitivity of COE to changes in different variables. The following is a list of the figures associated with the Kokemäki sensitivity analysis:

Figure	Description
3.5-1	Constant $ COE sensitivity analysis
3.5-2	Current $ COE sensitivity analysis
3.5-3	COE versus fuel cost
3.5-4	COE versus non-fuel O&M costs

Figure (in appendix)	Description
3.5-5	COE versus interest rate
3.5-6	COE versus Equity Ratio
3.5-7	COE versus net electric power efficiency
3.5-8	Variation of COE with tax consequences

The COE is most sensitive to changes in price of heat compared to changes in other factors (near the base case). This is illustrated by the steep slope of heat price curves in Figures 3.5-1 and 3.5-2, for example. COE is next most affected by relative changes in O&M costs. Relative changes in fuel price or capital costs affect COE about equally but to a lesser degree than heat price or O&M costs. Relative changes in interest rate on the loan (or ROR) influence the COE least compared to other factors. For example, ROR of 15% (instead of 6%) raises current dollars COE from 2.9 to 4 cents/kWh.

Table 3.5-3 also includes a case labeled "Moderate." This case gives results for moderate changes from the base case for several factors together including:

- Capacity factor reduced from 91% to 85%.
- Heat sales price reduced by half; from 0.68 to 0.34 $/therm.
- Small decrease in labor cost; from 0.0104 to 0.0100 $/kWh.
- PTC effects for a large or profitable firm.

The constant dollar COE resulting from the "Moderate" case is 5.5 cents/kWh, which may be acceptable for certain renewable energy markets. Reducing capacity factor and heat sales revenue will increase the electrical energy revenue requirements, while decreasing labor costs and including a PTC tend to decrease the required revenue.

Table 3.5-3. Selected results of economic analysis for Kokemäki CHP project (bold type indicates change from base case)

Parameter	Units	Base Case	Low Fuel Price	High Fuel Price	w/o Heat Sales	Improved Heat Capacity Factor (91%)	Low Capital Cost	High Capital Cost	High Interest Rate on Loan	Low Conversion Efficiency	Equity Ratio (25% with 15% ROI)	w/o PTC	Small Firm (no 'neg. tax')	Moderate Case (includes PTC-Large Firm)
Net Electrical Energy Production	(kWh)e	14,635,900	14,635,900	14,635,900	14,635,900	14,635,900	14,635,900	14,635,900	14,635,900	14,635,900	14,635,900	14,635,900	14,635,900	**12,866,688**
Net District Heat Production	(kWh)th	16,293,600	16,293,600	16,293,600	**0**	**24,711,960**	16,293,600	16,293,600	16,293,600	16,293,600	16,293,600	16,293,600	16,293,600	16,293,600
Total Capital cost	($)	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	**4,125,000**	**8,250,000**	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000
Capital Cost	($/kW)	2996	2996	2996	2996	2,996	**2247**	**4493**	2996	2996	2996	2996	2996	2996
Capacity Factor	(%)	91	91	91	91	91	91	91	91	91	91	91	91	**80**
Net Station Electrical Efficiency	(%)	30	30	30	30	30	30	30	30	**12**	30	30	30	30
Fuel Consumption Rate	(metric ton/h)	1.09	1.09	1.09	1.09	1	1.09	1.09	1.09	**2.72**	1.09	1.09	1.09	1.09
Annual Fuel Consumption	(metric ton/y)	8,669	8,669	8,669	8,669	8,669	8,669	8,669	8,669	**21,672**	8,669	8,669	8,669	**7,621**
Fuel Cost	($/t)	33	**16.5**	**66**	33	33	33	33	33	33	33	33	33	**26**
Labor Cost	($/kWh)	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104
Other O&M	($/kWh)	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	**0.0100**
Price heat energy	($/kWh-thermal)	0.019	0.019	0.019	**0.000**	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	**0.009**
Price heat energy	($/therm)	0.55	0.55	0.55	**0.00**	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	**0.28**
Interest Rate on Debt	(%)	6	6	6	6	6	6	6	**15**	6	6	6	6	6
Current $ Level Annual Revenue Requirements	(current $)	1,037,111	868,544	1,374,245	1,392,451	845,774	885,564	1,340,204	1,161,823	1,541,279	1,117,323	1,097,164	1,312,780	918,406
Constant $ Level Annual Revenue Requirements	(constant $)	856,060	716,920	1,134,339	1,149,367	698,125	730,969	1,106,241	990,430	1,272,214	926,080	905,629	1,083,605	758,077
Current $ LAC of Energy	(current $/kWh)	**0.071**	0.059	0.094	0.095	0.058	0.061	0.092	0.079	0.105	0.076	0.075	0.090	**0.071**
Constant $ LAC of Energy	(constant $/kWh)	**0.058**	0.049	0.078	0.079	0.048	0.050	0.076	0.068	0.087	0.063	0.062	0.074	**0.059**

Life of Project (loan/financing period)	(y)	15
Financed amount	(%)	Nominally 85
General inflation/Escalation	(%)	2.8

Data collected by Robert Williams (insert contract dates)

Fuel Heating Value	(kJ/kg)	20,260
Net Plant Capacity	(kWe)	1836
Combined Tax Rate (34 Fed, 9.6 State)	(%)	40.34

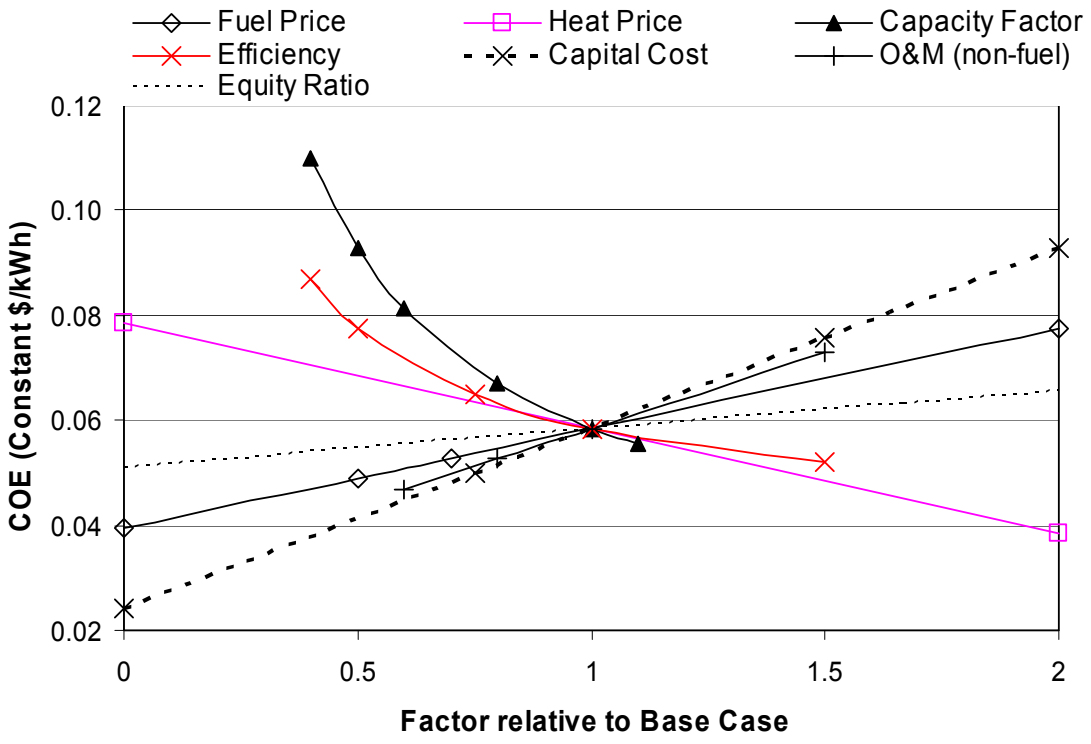

Figure 3.5-1. Constant $ COE sensitivity analysis (Kokemäki)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

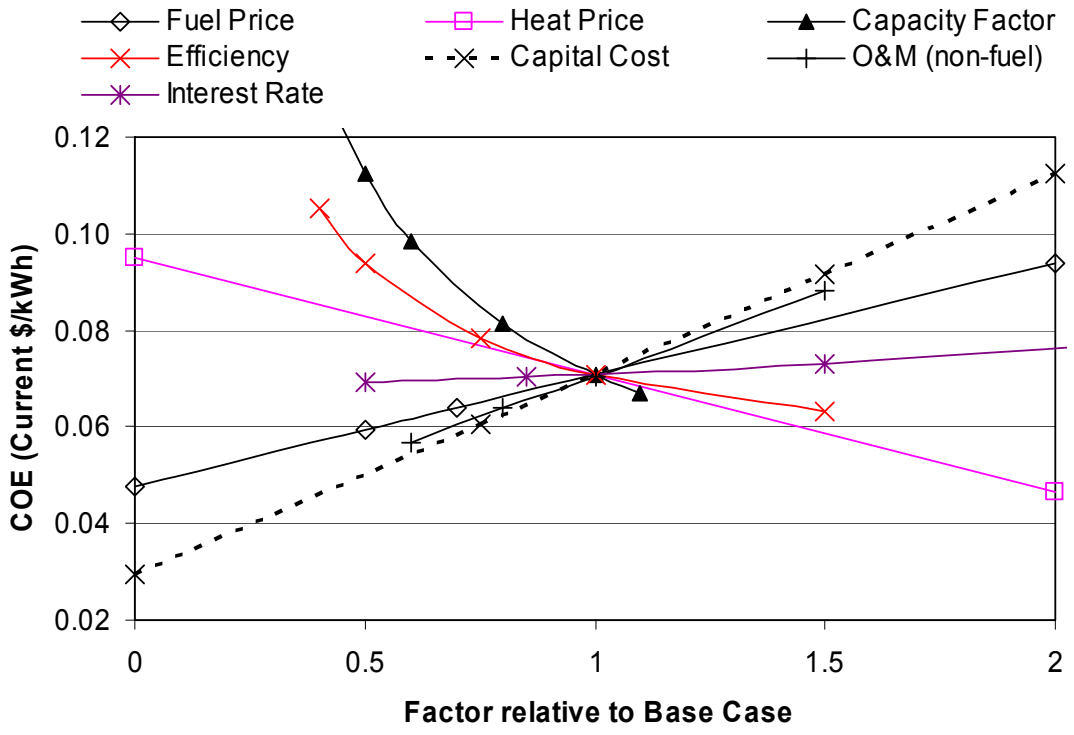

Figure 3.5-2. Current $ COE sensitivity analysis (Kokemäki)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

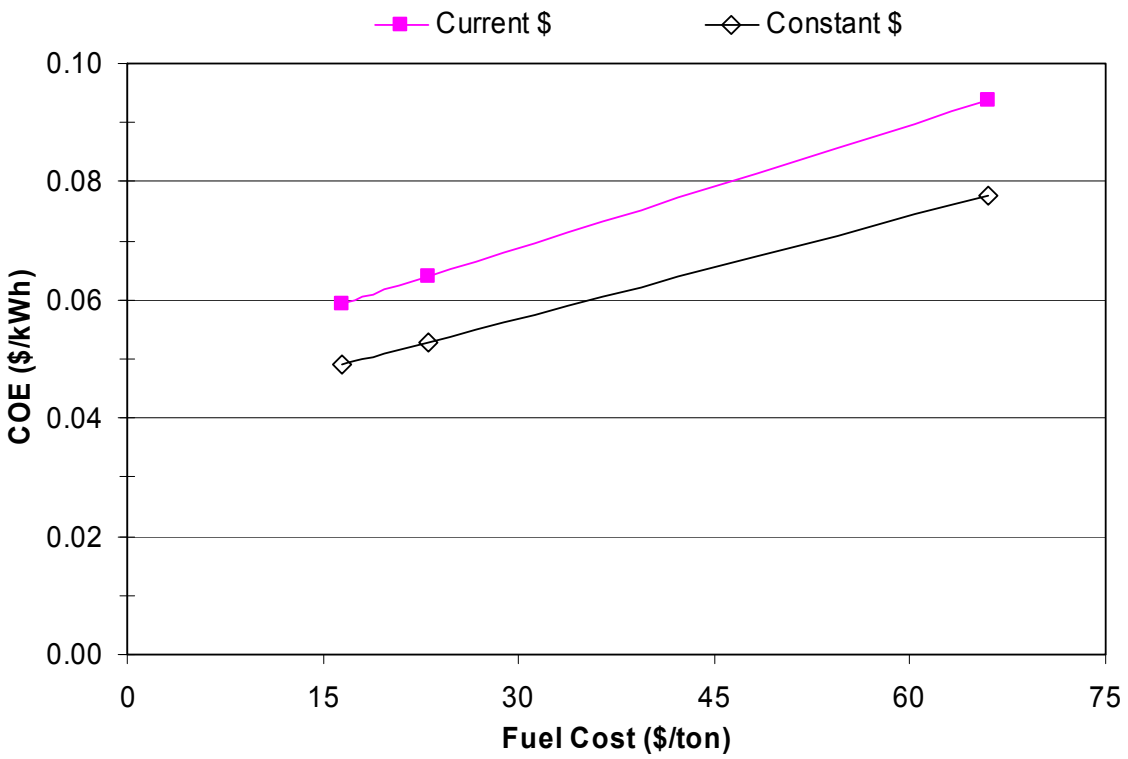

Figure 3.5-3. COE versus fuel cost (Kokemäki)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

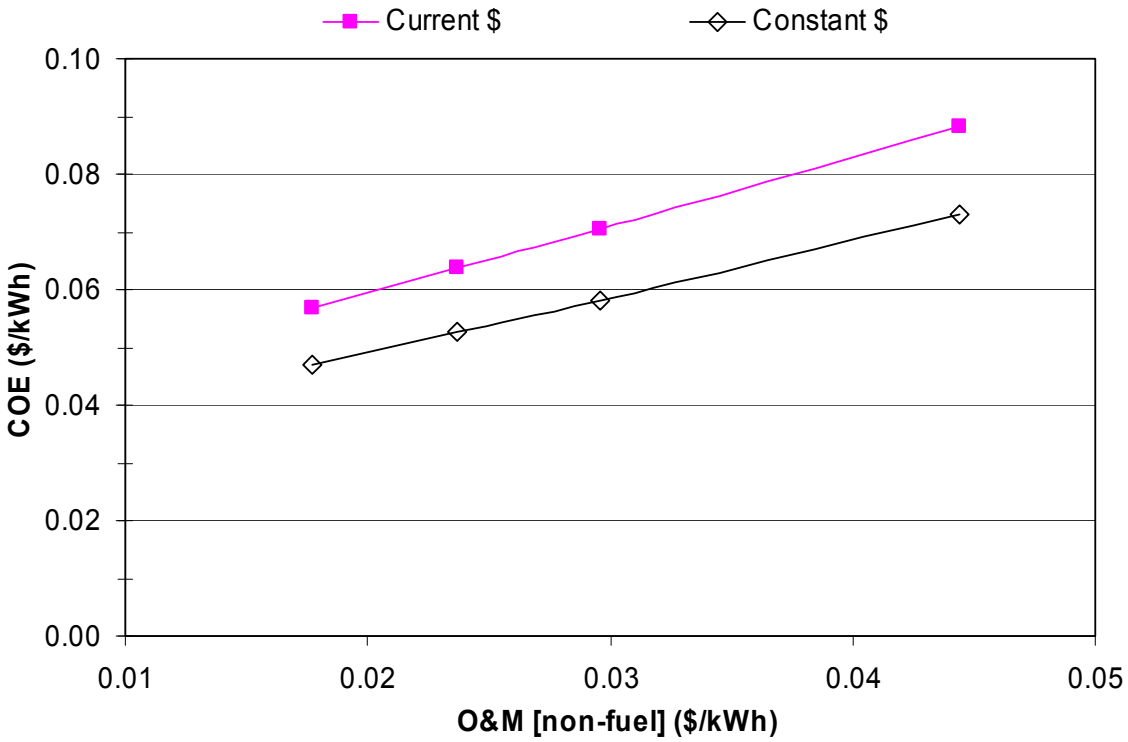

Figure 3.5-4. COE versus non-fuel O&M costs (Kokemäki)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

3.6. Carbona – India BIGCC

Assumptions (base case)

An economic analysis was performed on a BIGCC project in California, similar to the Carbona-India project (i.e., 12.5 MW). Figure 3.6-1 shows a schematic of the facility and Table 3-10 gives the basic parameters input to the model for the base case (some of the values are calculated from the inputs). The design specifies a Carbona-GTI pressurized circulating fluidized bed (CFB) reactor, warm-gas cleaning, two gas turbines (4.2 MW each), a heat recovery boiler, and steam turbine (about 4.2 MW). Fuel consumption is assumed to be 6.5 dry Mg/h, and net generating capacity of 12.5 MW. Electrical efficiency (HHV) is estimated at 34.3%.

For the first few installations in California, capital cost is assumed to be $2,800/kW installed ($35 million total installed cost). Capacity factor (here taken as availability) is 90% and station electrical efficiency is 34.3% (HHV basis). Fuel energy content, net efficiency, and capacity factor are used to calculate fuel consumption rate. The technical and economic life of the facility is assumed to be 20 years with profit, taxes, and production tax credits considered in the analysis.

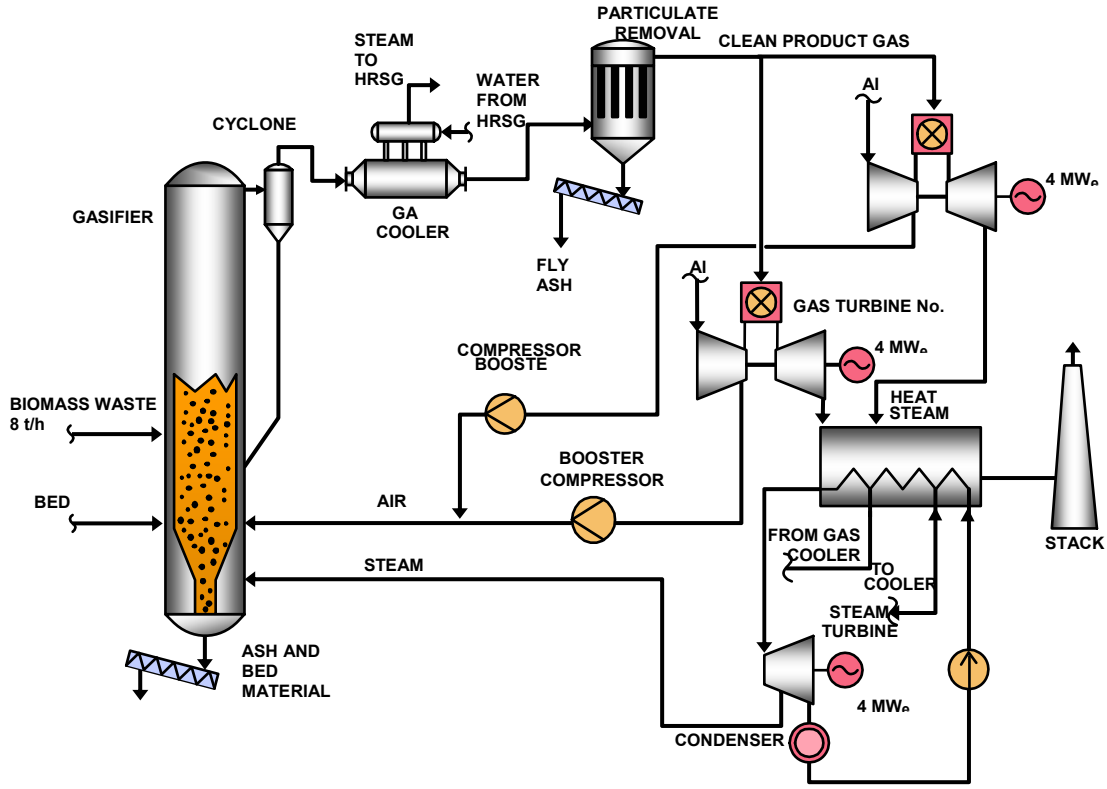

Figure 3.6-1. Schematic of Carbona-India BIGCC facility

Photo credit: Carbona Corporation

Costs

Base case fuel cost is assumed to be $30/dry short ton (assumes shredded or chipped fuel is acceptable; fuel price in the model is for a metric ton). Fuel cost in terms of net electrical energy is about 1.8 cents/kWh. Non-fuel operating and maintenance costs are assumed to be about 3 cents/kWh. The non-fuel operating expenses are default values appropriate for typical combustion boiler biomass facilities currently in operation in California (Morris 2000). Tables 3.6-1 and 3.6-2 show expenses in both $/kWh of net electrical energy and annual amounts. Total operating costs used in the base case amount to 4.8 cents/kWh of electricity delivered.

Revenues (other than from electricity)

Income other than from electricity sales include a nominal amount ($5/Mg or less than $6,000 per year) for sales of ash for land application. There is no combined heat production.

The base case assumes a capacity payment of $100/kWy ($1,250,000 annually). The current solid fuel combustion industry in California is receiving an average of $166/kWy (about $0.02/kWh) in capacity payment. Whether a new facility is able to obtain capacity payments will depend on how the power purchase agreement is structured.

Financing

The base case assumes that 85% of the project is bank financed at 6% nominal annual interest with equity or investor financing for the remaining 15% of first costs. Rate of return on equity is 15%/year. The technical and economic life of the facility is assumed to be 20 years. A debt reserve equal to one annual debt payment ($2.6 million) is held in escrow with earned simple interest returned to the project each year and the debt reserve effectively used as the final (year 20) debt payment.

Tax Treatment

The analysis assumes federal and state tax rates are 34% and 9.6%, respectively. Taxes are computed indirectly by the revenue requirements method used here (see more explanation in the Carbona-Skive section). The 10-year MACRS depreciation schedule is used, which typically credits the project with "negative" taxes in early years. In order to take advantage of this "credit," the company must be earning profits from other enterprises. This is assumed in the base case and all of the sensitivity analyses except for one dealing with PTC effects.

Production tax credits should be available for this project, at least for five years. For open-loop biomass fuel (biomass not specifically grown for energy), the PTC is 0.9 cents/kWh. PTC is included in the base case analysis. A case without PTC is calculated to show the effect on levelized COE (small because credit is assumed to only be available for the first five years). Small firms that cannot take advantage of the PTC because depreciation already reduces tax liability to zero (with negative taxes) are not allowed.

Results

Table 3.6-2 shows the results of the first year COE. The result in Table 3.6-2 does not account for effects of inflation, other cost escalations, and tax credits.

Using the revenue requirement model,[127] the base case COE is 7.6 cents/kWh (current dollars), or 6.0 cents/kWh (constant dollars). The 7.6 cents/kWh is the amount that would have to be charged for electricity in each year of the project in order to pay all debts and expenses by the end of the project life. The 6.0 cents/kWh COE in constant dollars can be used to compare to other alternatives in year zero dollars.

Table 3.6-1. Economic Base Case parameters for a BIGCC project in California

Cost and Performance Assumptions	
Total Capital cost ($)	35,000,000
Capital Cost ($/kW)	2800
Net Plant Capacity (kW)e	12,500
Net District Heat Production (kW)th	0
Capacity Factor (%)	90
Net Station Electrical Efficiency (%)	34.3
Fuel Heating Value (kJ/kg-dry basis)	20,260
Fuel Consumption Rate (dry Mg/h)	6.5
Fuel Ash Concentration (%)	2
Annual Production (kWh)e	98,550,000
Annual Production (kWh)th	0
Annual Fuel Consumption (dry Mg/y)	51,055
Annual Ash Disposal (Mg/y)	1021
Annual Hours	7884

Expenses	
Fuel Cost ($/dry Mg)	33
Fuel Cost ($/kWh)e	0.017096
Labor Cost ($/kWh)	0.01038
Maintenance Cost ($/kWh)	0.00778
Insurance/Property Tax ($/kWh)	0.00726
Utilities ($/kWh)	0.00104
Ash Disposal ($/kWh)	0
Management/Administration ($/kWh)	0.00104
Other Operating Expenses ($/kWh)	0.00208
Total Non-Fuel Expenses ($/kWh)	0.02958

Taxes	
Federal Tax Rate (%)	34
State Tax Rate (%)	9.6
Combined Tax Rate (%)	40.3
Production Tax Credit ($/kWh)	0.009
Production Tax Credit ($yr)	886,950

Escalation/Inflation	
General Inflation (%/y)	2.8
Escalation--Fuel (%/y)	2.8
Escalation--Other (%/y)	2.8

Income other than energy	
Capacity Payment ($/kW-y)	100
Interest Rate on Debt Reserve (%/y)	3
Price heat energy ($/kWh)th	0
Annual Capacity Payment ($/y)	1,125,000
Annual Debt Reserve Interest ($/y)	77,812
Annual heat sales ($)	0
Annual heat sales ($/kWh)electricity	0
Price for Ash ($/Mg)	5
Revenue from Ash sales ($/y)	5,105
Revenue from Ash ($/kWh)e	5.181E-05

Financing	
Debt ratio (%)	85
Equity ratio (%)	15
Interest Rate on Debt (%/y)	6
Life of Loan (y)	20
Cost of equity (%/y)	15
Cost of Money (%/y)	7.35
Total Cost of Plant ($)	35,000,000
Total Equity Cost ($)	5,250,000
Total Debt Cost ($)	29,750,000
Capital Recovery Factor (Equity)	0.1598
Capital Recovery Factor (Debt)	0.0872
Annual Equity Recovery ($/y)	838,748
Annual Debt Payment ($/y)	2,593,741
Debt Reserve ($)	2,593,741

Depreciation Schedule
10 year MACRS

Level Annual Cost (LAC)	
**Current $** Levelized COE ($/kWh)	**0.076**
**Constant $** Levelized COE($/kWh)	**0.060**

127. See http://faculty.enigineering.ucdavis.edu/jenkins/CBC/Calculator/cal.html

Data collected by Robert Williams

Table 3.6-2. Simple "Year 0" costs and revenues for the Carbona IGCC system

	($/kWh)	($/y)
Fuel Cost ($33/Mg)	0.0171	1,684,810
Labor	0.0104	1,022,949
Maintenance	0.0078	766,719
Insurance/Property Tax	0.0073	715,473
Utilities	0.0010	102,492
Ash Disposal	0.0000	0
Management/Admin	0.0010	102,492
Other Operating Exp.	0.0021	204,984
Total non Fuel Expenses	0.0296	2,915,109
Total Operating Expenses	0.0467	4,599,919
Debt & Equity Payment	0.0348	3,432,488
Capacity Payment	0.0114	1,125,000
Revenue Requirement (simple calculation)*	0.0701	6,907,407

* does not account for depreciation and tax affects, inflation and other cost escalations

Data collected by Robert Williams

Comparison to Other Estimates

The Energy Information Administration (EIA) publishes the Annual Energy Outlook, which includes projections of energy production and market penetration of technologies and energy sources. Table 3.6-3 shows some of the cost and performance assumptions used to prepare the EIA Annual Energy Outlook.

For modeling cost and performance of biomass, EIA assumes that a new biomass IGCC facility, first on-line in 2010 will have installed cost of $1,731/kW for a capacity of 80 MW. Overall conversion efficiency is assumed to be 38.2%. Non-fuel O&M costs are 0.94 cents/kWh.[128] Levelized COE using these cost and performance assumptions is 3.3 cents/kWh (constant dollars).[129] If no capacity payments are assumed, then COE would be 4.2 cents/kWh. This is lower than the BIGCC in California project reviewed in this report which has estimated COE of 6.0 and 6.9 cents/kWh with and without $100/kWy

128. Assumptions to the Annual Energy Outlook 2004 (U.S. DOE/EIA).

129. Assumes fuel costs of $30/bdt, 25% equity ratio (15% ROR) and 6% interest on debt, $100/kWy capacity payment, PTC of $0.009/kWh for five years, 10-year MACRS depreciation, and 20-year technical and economic life.

capacity payments. Non-fuel operating costs assumed for Carbona-India facility adapted to California are about 3 cents/kWh compared to the 0.94 cents/kWh assumed by EIA.

Craig and Mann (1996) compared projected levelized COE values for several BIGCC system designs. The constant dollar COE varied from 5.1 to 6.3 cents/kWh depending on the gasifier type and gas turbine. The low COE corresponded to a plant design specifying a low-pressure indirectly-heated gasifier with an advanced utility gas turbine with an installed cost of $1,108/kW and capacity of 122 MW. The high COE figure was for a plant utilizing a high-pressure direct fired air-blown gasifier and an aero-derivative gas turbine. The installed cost was $1,696/kW and capacity was 56 MW. The fuel cost in the study was $42 per dry ton and no capacity payments were assumed. These two differences account for the higher COE in the Craig and Mann (1996) study compared to that estimated in this report for the Carbona-India BIGCC project adjusted for California.

Table 3.6-3. Cost and performance parameters used by EIA (Adapted from U.S. DOE/EIA)

Technology	Size (MW)	Lead Time (y)	Contingency Factor	Optimism Factor[1]	Installed Cost[2] (2004 $/kWh)	Conversion Efficiency (%)
Adv Combustion Turbine	230	2	1.05	1	489	36.7
Conv Gas/Oil Comb Cycle	250	3	1.05	1	569	45.8
Adv Gas/Oil Comb Cycle (CC)	400	3	1.08	1	646	49.2
Distributed Generation -Base	2	3	1.05	1	854	36.3
Distributed Generation - Peak	1	2	1.05	1	1026	32.8
Wind	50	3	1.07	1	1066	33.2
ADV CC with Carbon Sequestration	400	3	1.08	1.04	1142	39.5
Scrubbed Coal New	600	4	1.07	1	1226	37.9
Coal IGCC	550	4	1.07	1	1452	42.7
MSW - Landfill Gas	30	3	1.07	1	1551	25.0
Biomass IGCC	80	4	1.07	1.02	1818	38.3
Advanced Nuclear	1000	6	1.1	1.05	2024	32.8
Coal IGCC with Carbon Sequestration	380	4	1.07	1.03	2192	35.5
Fuel Cells	10	3	1.05	1.1	2270	45.8
Geothermal [3]	50	4	1.05	1	2313	9.2
Solar Thermal	100	3	1.07	1.1	3062	33.2
Photovoltaic	5	2	1.05	1.1	4621	33.2

(1) The technological optimism factor is applied to the first four units of a new, unproven design. It reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
(2) Includes contingency and technical optimism factors. Does not include effect of investment tax credits
(3) Estimate for least expensive plant that could be built in the Northwest Power Pool region.

Sensitivity

Energy cost sensitivity was investigated by making changes to a single model input while holding all other variables at their base case values. Table 3.6-4 shows selected

results from the sensitivity analysis. For these conditions shown, the constant dollar COE falls between 5.2 and 8.8 cents/kWh.

The "Moderate Case" in Table 3.6-4 has three variables that have been changed from the Base Case. These are:

- Capacity Factor (availability) decreased from 90% to 70%.
- Equity ratio increased from 15 to 25%.
- Fuel Price decreased from $30 to $26 per ton ($33 to $28.6 per metric ton).

The first two changes above act to increase the COE while the lower fuel price reduces the COE.

Figures 3.6-1 through 3.6-9 show the sensitivity of COE to changes in model inputs (see list below and refer to Table 3.6-2 for Base Case parameters).

Figure	Description
3.6-2	Constant $ COE sensitivity analysis
3.6-3	Current $ COE sensitivity analysis
3.6-4	COE versus Fuel Cost
3.6-5	COE versus O&M Cost
Figure (in Appendix)	**Description**
3.6-6	COE versus Debt Interest Rate
3.6-7	COE versus Equity Ratio
3.6-8	COE versus Capacity Payment
3.6-9	COE versus Efficiency of Plant
3.6-10	Variation of COE with tax consequences

Figures 3.6-2 and 3.6-3 display changes in COE against relative changes from the Base Case for fuel price, capacity factor, plant efficiency, capital coast, non-fuel O&M costs, capacity payment, and equity ratio. Of these, relative changes in capacity payment and equity ratio have the least effect on COE; doubling the capacity payment reduces COE by about 15%, while eliminating the payment will increase COE by 15%. COE is most sensitive to relative changes in non-fuel O&M costs followed closely by capital cost sensitivity. A doubling of non-fuel O&M will increase COE by nearly 50%. Doubling the capital cost increases COE by approximately 40%. For the remaining variables, a relative change of ±50% in each will influence the COE by less than 30% from the Base Case value.

Table 3.6-4. Selected results of economic analysis for Carbona–India/California BIGCC project (bold type indicates change from base case).

Parameter	Units	Base Case	Low Fuel Price	High Fuel Price	Low Capital Cost	High Capital Cost	High Interest Rate on Loan	Low Conversion Efficiency	Zero Capacity Payment	High Capacity Payment	Equity Ratio (25% with 15% ROI)	w/o PTC, Large Firm	Small Firm (no negative taxes)	Moderate Case (also includes 25% equity ratio)
Net Electrical Energy Production	(kWh)e	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	**76,650,000**
Total Capital cost	($)	35,000,000	35,000,000	35,000,000	**26,250,000**	**70,000,000**	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000
Capital Cost	($/kW)	2800	2800	2800	**2100**	**5600**	2,800	2800	2,800	2800	2,800	2800	2800	2800
Capacity Factor	(%)	90	90	90	90	90	90	90	90	90	90	90	90	**70**
Capacity Payment	($/kW-y)	100	100	100	100	100	100	100	**0**	**166**	100	100	100	100
Net Station Electrical Efficiency	(%)	34.3	34.3	34.3	34.3	34.3	34	**13.7**	34.3	34.3	34.3	34.3	34.3	34.3
Fuel Consumption Rate	(metric ton/h)	6	6	6	6	6	6	**16.2**	6	6	6	6	6	6
Annual Fuel Consumption	(metric ton/y)	51,055	51,055	51,055	51,055	51,055	51,055	**127,637**	51,055	51,055	51,055	51,055	51,055	39,709
Fuel Cost	($/t)	33	**16.5**	**66**	33	33	33	33	33	33	33	33	33	**28.6**
Labor Cost	($/kWh)	0.0104	0.0104	0.0104	0.0104	0.0104	0	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104
Other O&M	($/kWh)	0.0192	0.0192	0.0192	0.0192	0.0192	0	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192
Interest Rate on Debt	(%)	6	6	6	6	6	**15**	6	6	6	6	6	6	6
Current $ Level Annual Revenue Requirements	(current $)	7,511,740	6,471,372	9,592,475	6,683,853	10,823,288	8,877,573	10,623,385	8,636,740	6,769,240	7,924,783	7,861,129	8,641,445	6,362,590
Constant $ Level Annual Revenue Requirements	(constant $)	5,916,727	5,097,267	7,555,647	5,264,630	8,525,114	7,377,726	8,367,658	6,802,849	5,331,887	6,286,630	6,191,928	6,806,555	5,011,583
Current $ LAC of Energy	(current $/kWh)	**0.076**	0.066	0.097	0.068	0.110	0.090	0.108	0.088	0.069	0.080	0.080	0.088	0.083
Constant $ LAC of Energy	(constant $/kWh)	**0.060**	0.052	0.077	0.053	0.087	0.075	0.085	0.069	0.054	0.064	0.063	0.069	0.065

Life of Project (loan/financing period)	(y)	20
General inflation/Escalation	(%)	2.8
Fuel Heating Value	(kJ/kg)	20,260

Net Plant Capacity	(kWe)	12500
Combined Tax Rate (34 Fed, 9.6 State)	(%)	40.34

Data collected by Robert Williams

Fuel cost and non-fuel O&M cost effects are illustrated in Figures 3.6-4 and 3.6-5, respectively.[130]

The effect of changes in debt interest rate is shown in Figure 3.6-6. Interest on debt has almost no effect on the current dollar COE and a very weak effect on the constant dollar COE.

Figure 3.6-7 depicts the change in COE due to changes in the equity ratio.[131] Increasing investment equity increases COE via two mechanisms, (1) the ROR for equity is higher than interest rate on debt (15% compared to 6% in the model) and (2) increased investment reduces tax deductions because of smaller loan interest payments. For this project, switching from borrowing 85% of the capital to financing with 100% equity (investment with 15% ROR) increases the COE by about 3.3 cents/kWh (or about 0.4 cents/kWh for each 10% increment of equity investment).

The effect of capacity payment on COE is illustrated in Figure 3.6-8. As mentioned earlier, changes in capacity payment have a fairly mild effect on COE (though stronger than interest on debt).

Changes in overall plant efficiency have a non-linear effect on the COE (see Figure 3.6-9). Increases in overall plant efficiency (all else being equal) obviously improve the economics of the facility but because the behavior is non-linear, continued increases in efficiency yield smaller improvements in COE. Conversely, a continuing decline in efficiency results in disproportional COE increases.

The effects of production tax credits and tax liability on the Base Case energy price are shown in Figure 3.6-10. Recall that the Base Case assumes the business has profits from other operations which allows the "negative" taxes (that result from the accelerated depreciation in the early years of the project) to be credited to the project. PTCs are also able to be credited in full to the project for these so called "large firms." "Small" firms may not be able to take "negative" taxes as a credit to the project and therefore do not enjoy the benefits of PTCs when there is no tax liability (such as when accelerated depreciation reduces tax liability to zero). In Figure 3.6-10, the left-most set of bars corresponds to the Base Case. PTC and small firm size each affect the COE by less than 15%.

130. Note: Figures 3.6-6 through 3.6-10 appear in the appendix.

131. Equity ratio is the fraction of capital costs covered by investment monies. Equity Ratio (%) = 100 – Debt Ratio (%), where Debt Ratio is the fraction of capital costs covered by borrowed funds.

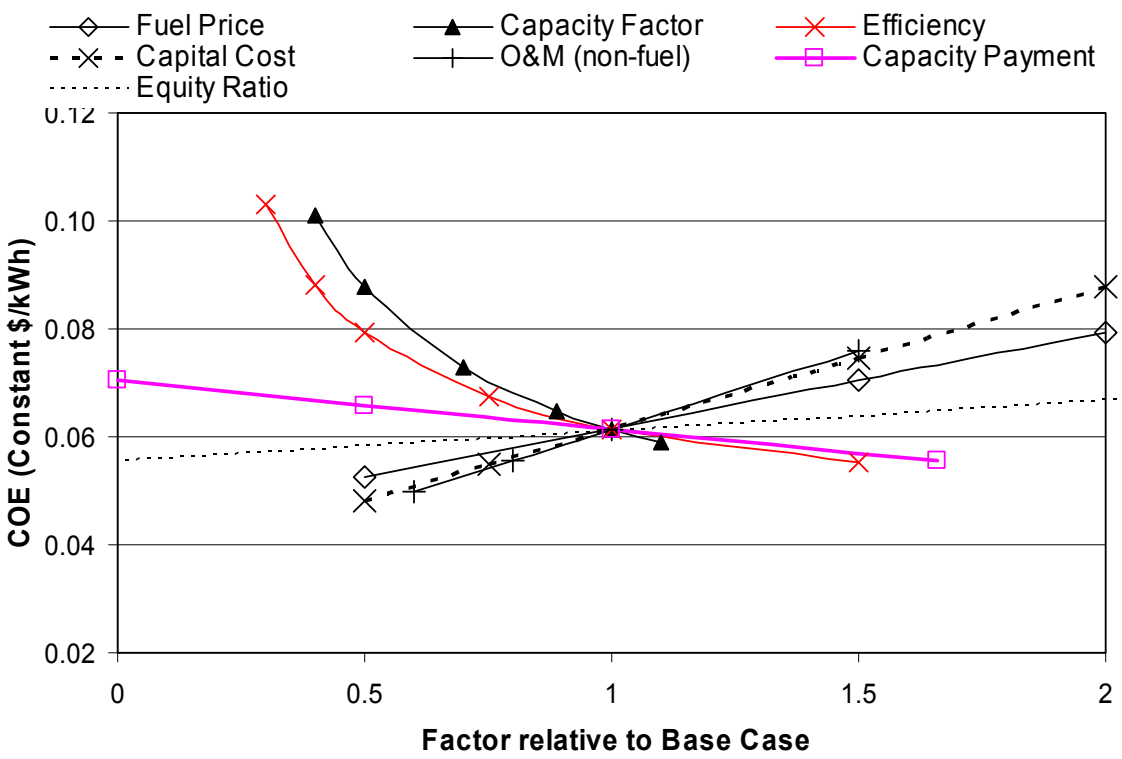

Figure 3.6-2. Constant $ COE sensitivity analysis (Carbona –India IGCC)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

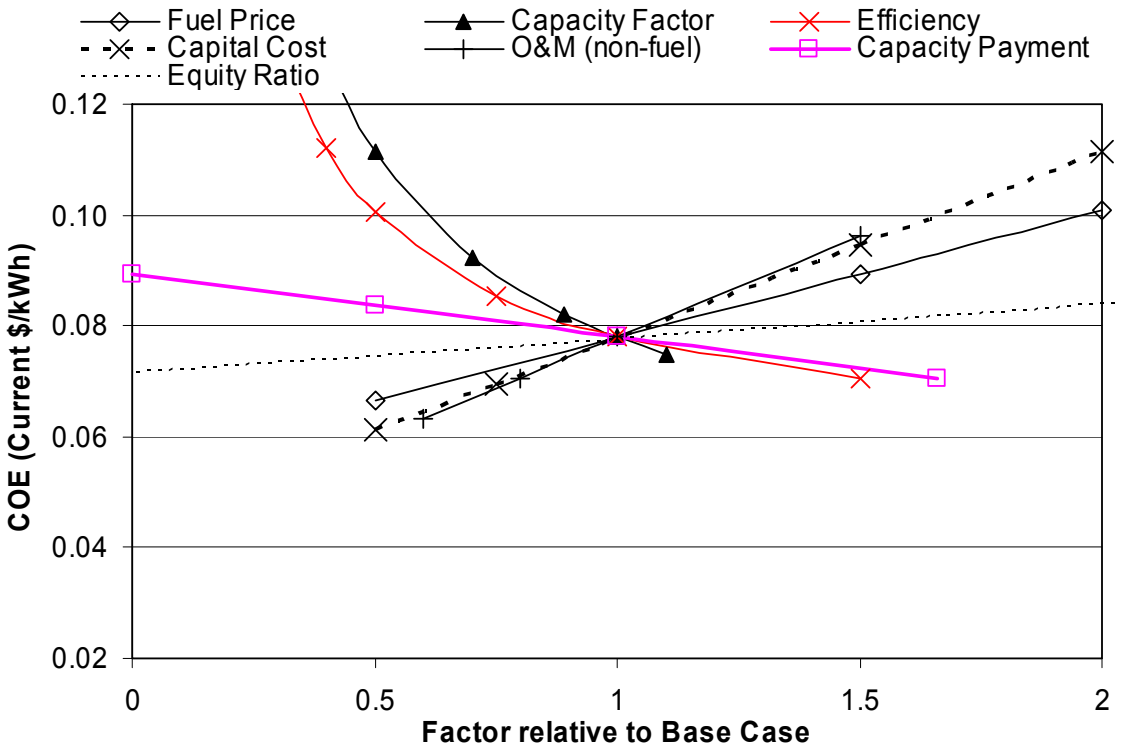

Figure 3.6-3. Current $ COE sensitivity analysis (Carbona –India IGCC)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

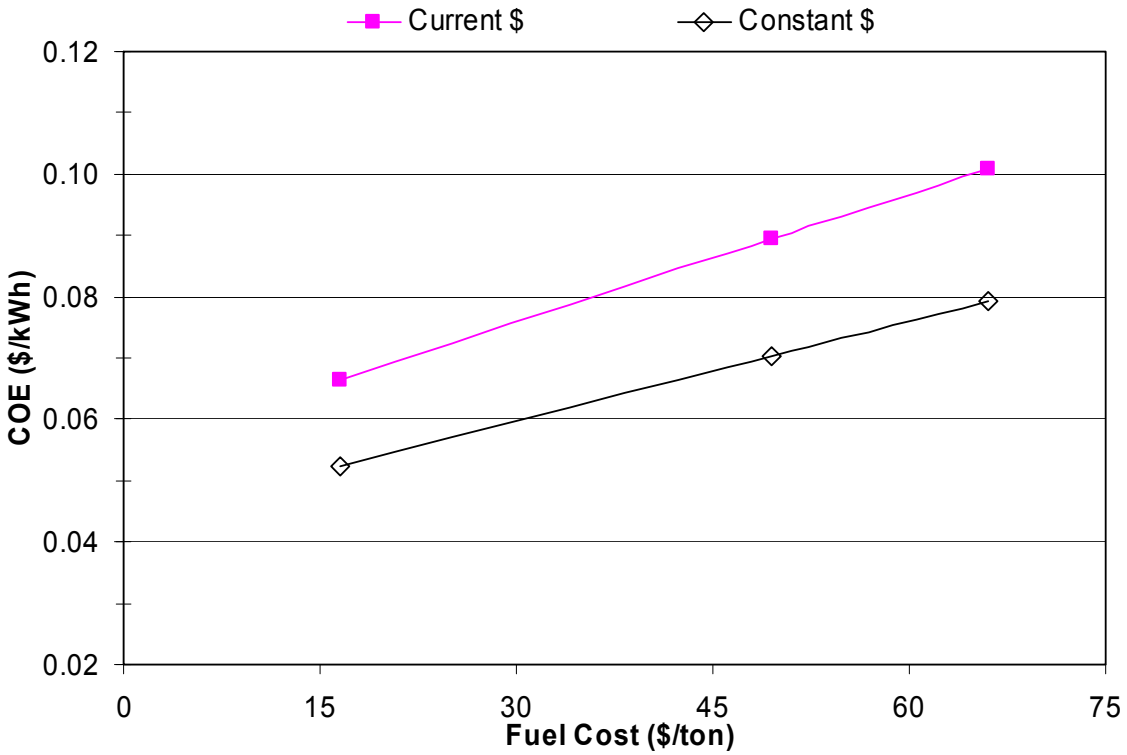

Figure 3.6-4. COE versus fuel cost (Carbona–India IGCC)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

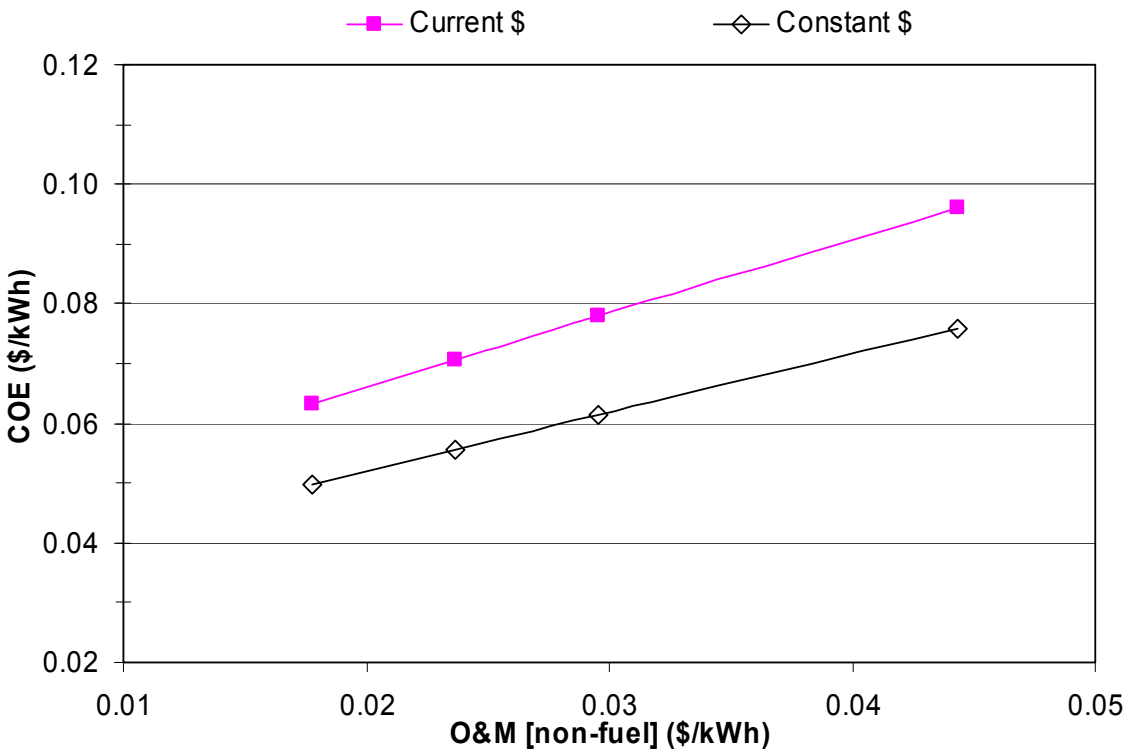

Figure 3.6-5. COE versus O&M cost (Carbona–India IGCC)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

3.7. Straw Combustion Facility

Assumptions (base case)

An economic analysis was done for the Ely power station design using rice straw fuel at delivered prices in California. The basic power plant energy revenue requirement calculator module was used. Table 3.7-1 displays the complete list of base case parameters used as well as levelized COE (model output). Some of the more significant base case assumptions are summarized here:

- $ 88 Million capital cost (using Ely, England, 2000 figures).
- Net capacity is 38 MW.
- No cogenerated heat sales.
- Capacity factor is 83% based on reported annual energy production at Ely (Newman 2003).
- Efficiency is 31.7 % based on calculation using Ely reported energy production and fuel usage (Ely report uses HHV [dry basis] for wheat straw which is about 17% greater than for rice straw, 18.2 MJ/kg for wheat straw, and 15.5 MJ/kg for rice straw) (Newman 2003).
- Delivered fuel price is $34/short ton and includes fuel processing. Price for California rice straw is discussed elsewhere (Bakker-Dhaliwal et al. 1999; Jenkins and Bakker-Dhaliwal et al. 2000; Haase 2003).
- The model standard for other operating costs is used except for ash disposal which is set to zero. This assumes disposal and handling costs are offset by sales of ash back to growers.
- Capacity payment of $100/kWy is used.
- Ash sales are zero, but assumes small income to offset handling mentioned above.
- Escalation and general inflation are 4%, except for PTC escalation, which is 3%.
- Equity ratio is 20%.
- Debt interest is 6%, equity return is 15%.
- Debt reserve of one annual payment is assumed, which earns interest at 4%/year.
- Analysis period is 20 years.
- MACRS depreciation schedule is 10 years
- PTC availability is five years.

- Able to take full credit from tax deductions (depreciation and PTC creating "negative" taxes, implies firm with profits in other areas).

Table 3.7-1. Economic Base Case parameters for a rice straw power plant

Capital Cost and Performance Assumptions	
Total Capital cost ($)	88,000,000
Capital Cost ($/kW)	2316
Net Plant Capacity (kW)e	38,000
Net District Heat Production (kW)th	0
Capacity Factor (%)	83
Net Station Electrical Efficiency (%)	31.7
Fuel Higher Heating Value (kJ/dry kg)	15,500
Fuel Consumption Rate (dry Mg/h)	27.8
Fuel Ash Concentration (%)	18
Annual Production (kWh)e	276,290,400
Annual Heat Production (kWh)th	0
Annual Fuel Consumption (dry Mg/y)	202,379
Annual Ash Disposal (Mg/y)	36,428
Annual Hours	7271

Expenses	
Fuel Cost ($/dry Mg)	37.4
Fuel Cost ($/kWh)e	0.0274
Labor Cost ($/kWh)	0.01038
Maintenance Cost ($/kWh)	0.00778
Insurance/Property Tax ($/kWh)	0.00726
Utilities ($/kWh)	0.00104
Ash Disposal ($/kWh)	0
Management/Administration ($/kWh)	0.00104
Other Operating Expenses ($/kWh)	0.00208
Total Non-Fuel Expenses ($/kWh)	0.02958

Escalation/Inflation	
General Inflation (%/y)	4
Escalation--Fuel (%/y)	4
Escalation--Other (%/y)	4
PTC escalation (%.y)	3

Taxes	
Federal Tax Rate (%)	34
State Tax Rate (%)	9.6
Combined Tax Rate (%)	40.3
Production Tax Credit ($/kWh)	0.009
Production Tax Credit ($yr)	2,486,614

Income other than energy	
Capacity Payment ($/kW-y)	100
Interest Rate on Debt Reserve (%/y)	4
Price heat energy ($/kWh)th	0
Annual Capacity Payment ($/y)	3,154,000
Annual Debt Reserve Interest ($/y)	245,512
Annual heat sales ($)	0
Annual heat sales ($/kWh)electricity	0
Price for Ash ($/Mg)	0
Revenue from Ash sales ($/y)	0
Revenue from Ash ($/kWh)e	0

Financing	
Debt ratio (%)	80
Equity ratio (%)	20
Interest Rate on Debt (%/y)	6
Life of Loan (y)	20
Cost of equity (%/y)	15
Cost of Money (%/y)	7.8
Total Cost of Plant ($)	88,000,000
Total Equity Cost ($)	17,600,000
Total Debt Cost ($)	70,400,000
Capital Recovery Factor (Equity)	0.1598
Capital Recovery Factor (Debt)	0.0872
Annual Equity Recovery ($/y)	2,811,802
Annual Debt Payment ($/y)	6,137,793
Debt Reserve ($)	6,137,793

Depreciation Schedule
10 year MACRS used

Level Annual Cost (LAC)	
**Current $** LAC of Energy ($/kWh)	**0.094**
**Constant $** LAC of Energy ($/kWh)	**0.067**

Data collected by Robert Williams (insert contract dates)

Results

Table 3.7-2 shows the results for the first year. This result does not account for effects of inflation, other cost escalations, and tax credits.

Table 3.7-2. Simple "Year 0" costs and revenues for the rice straw power plant

	($/kWh)	($/y)
Fuel Cost ($37.4/Mg)	0.0274	7,568,964
Labor	0.0104	2,867,894
Maintenance	0.0078	2,149,539
Insurance/Property Tax	0.0073	2,005,868
Utilities	0.0010	287,342
Ash Disposal	0.0000	0
Management/Admin	0.0010	287,342
Other Operating Exp.	0.0021	574,684
Total non Fuel Expenses	0.0296	8,172,670
Total Operating Expenses	0.0570	15,741,634
Debt Payment	0.0222	6,137,793
Equity Recovery	0.0102	2,811,802
Capacity Payment	(0.0114)	(3,154,000)
Revenue Requirement (simple calculation)*	0.0780	21,537,228

* does not account for depreciation and tax affects, inflation and other cost escalations
Data collected by Robert Williams (insert contract dates)

For the base case, the calculator yields a COE of 6.7 cents/kWh (constant dollar) or 9.4 cents/kWh (current dollars). The moderately high capital and fuel costs combine for a fairly high COE. Halving the fuel price reduces the COE to near 5 cents/kWh (constant dollar). Increasing capacity payment to the current industry average ($166/kWy) will reduce COE from 6.7 to 6.0 cents/kWh.

Sensitivity

The sensitivity of levelized COE was investigated by making changes to a single model input at a time (holding all other variables to their base case values Table 3.7-3 shows selected results from the sensitivity analysis. For the conditions shown, the constant dollar COE falls between 5.3 and 9.2 cents/kWh.

Figures 3.7-1 through 3.7-9 show sensitivity of COE to changes in several of the model inputs (refer to Table 3.7-1 for Base Case parameters).

Figure	Description
3.7-1	Constant $ COE sensitivity for a rice straw power plant
3.7-2	Current $ COE sensitivity for a rice straw power plant
3.7-3	COE versus Fuel Cost (rice straw plant)
3.7-4	COE versus non-fuel O&M Cost (rice straw plant)

Figure (in appendix)	Description
3.7-5	COE versus Debt Interest Rate (rice straw plant)
3.7-6	COE versus Equity Ratio (rice straw plant)
3.7-7	COE versus Capacity Payment (rice straw plant)
3.7-8	COE versus Efficiency of Plant (rice straw plant)
3.7-9	Effect of tax consequences on COE (rice straw plant)

Figures 3.7-1 and 3.7-2 show absolute changes in COE against relative changes from the Base Case for fuel price, capacity factor, plant efficiency, capital coast, non-fuel O&M costs, capacity payment, equity ratio, and debt interest rate. Of these, relative changes in capacity payment or equity ratio have the least effect on COE. Doubling the capacity payment reduces COE by about 11% (or 0.7 cents/kWh), while eliminating the payment will increase COE by 14%. A doubling of the equity ratio from 20% to 40% increases COE by about 0.6 cents/kWh (or some 9%).

COE is about equally sensitive to relative changes in non-fuel O&M costs, fuel price, and capital cost. A doubling of any of these three variables increases revenue requirements by about 40%. A 20% decrease in base case plant efficiency (to 25.4% net station efficiency) will increase COE by 10%, all else being equal, while a 20% boost in base case efficiency (38% net) lowers COE by 6.7%.

The effect of fully depreciating capital and applying production tax credits is displayed in Figure 3.7-9. A profitable firm that has tax liabilities from other enterprises can use these deductions to offset taxes from all of the company's businesses. A smaller firm with no other current business will not be able to credit the project with "negative" taxes and can use depreciation and tax credits up until tax liability reaches zero. This effective "small firm penalty" increases the project COE by nearly 1 cent/kWh (levelized for the length of the analysis, Figure 3.7-9).

Table 3.7-3. Selected results of economic analysis for the straw power plant (bold type indicates change from base case)

Parameter	Units	Base Case	Low Fuel Price	High Fuel Price	Low Capital Cost	High Capital Cost	High Interest Rate on Loan	Low Conversion Efficiency	Zero Capacity Payment	High Capacity Payment	100% Debt Ratio	Small Firm
Net Electrical Energy Production	(kWh)e	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000	98,550,000
Total Capital cost	($)	88,000,000	88,000,000	88,000,000	**66,000,000**	**176,000,000**	88,000,000	88,000,000	88,000,000	88,000,000	88,000,000	88,000,000
Capital Cost	($/kW)	2316	2316	2316	**1737**	**4632**	2316	2316	2,316	2316	2,316	2316
Capacity Factor	(%)	83	83	83	83	83	83	83	83	83	83	83
Capacity Payment	($/kW-y)	100	100	100	100	100	100	100	**0**	**166**	100	100
Net Station Electrical Efficiency	(%)	31.7	31.7	31.7	31.7	31.7	31.7	**22.0**	31.7	31.7	31.7	31.7
Fuel Consumption Rate	(metric ton/h)	28	28	28	28	28	28	**40.1**	28	28	28	28
Annual Fuel Consumption	(metric ton/y)	202,379	202,379	202,379	202,379	202,379	202,379	**291,612**	202,379	202,379	202,379	202,379
Fuel Cost	($/t)	37.4	**17.0**	**68.0**	37.4	37.4	37.4	37.4	37	37	37	37.4
Labor Cost	($/kWh)	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104	0.0104
Other O&M	($/kWh)	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192	0.0192
Interest Rate on Debt	(%)	6	6	6	6	6	**15**	6	6	6	6	6
Current $ Level Annual Revenue Requirements	(current $)	25,929,671	20,461,306	35,815,069	23,365,658	34,433,501	27,928,412	30,092,437	29,083,671	23,848,031	23,749,220	28,402,265
Constant $ Level Annual Revenue Requirements	(constant $)	18,436,416	14,548,320	25,465,094	16,613,361	24,482,777	21,347,872	21,396,210	20,678,961	16,956,336	16,535,783	20,194,470
Current $ LAC of Energy	(current $/kWh)	**0.094**	0.074	0.130	0.085	0.125	0.101	0.109	0.105	0.086	0.086	0.103
Constant $ LAC of Energy	(constant $/kWh)	**0.067**	0.053	0.092	0.060	0.089	0.077	0.077	0.075	0.061	0.060	0.073

Life of Project (loan/financing period)	(y)	20
General inflation/Escalation	(%)	4
Fuel Heating Value	(kj/kg)	15,500

Net Plant Capacity	(kWe)	38000
Combined Tax Rate (34 Fed, 9.6 State)	(%)	40.34

Data collected by Robert Williams (insert contract dates)

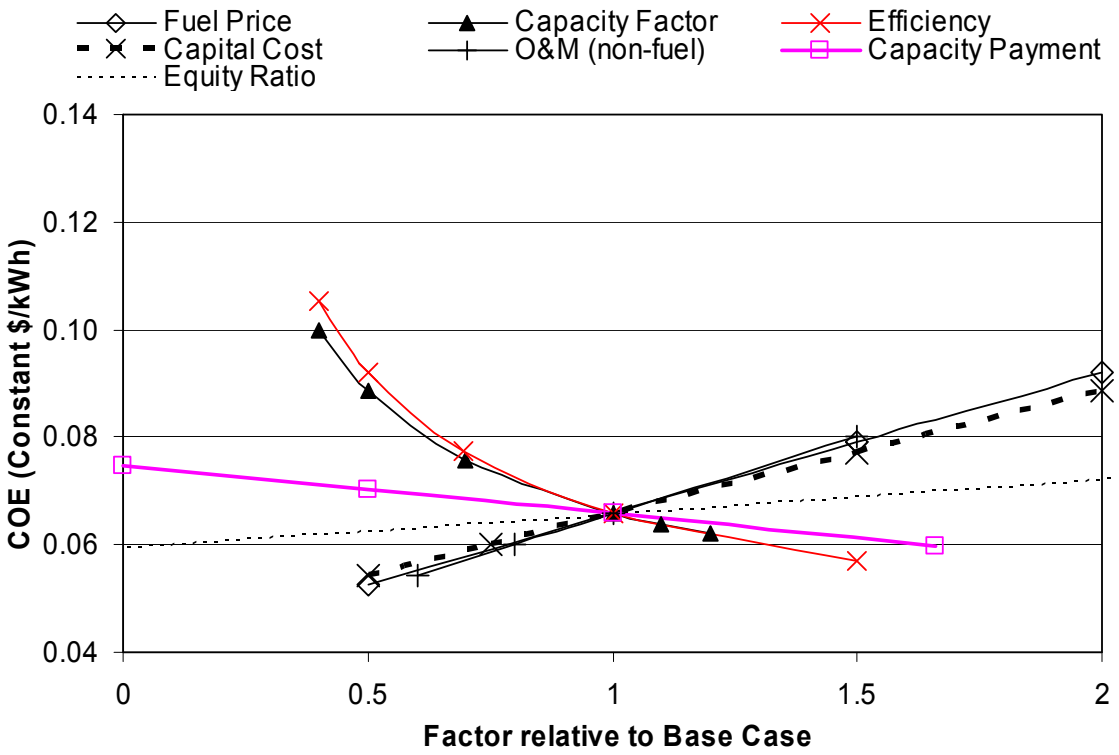

Figure 3.7-1. Constant $ COE sensitivity for a rice straw power plant

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

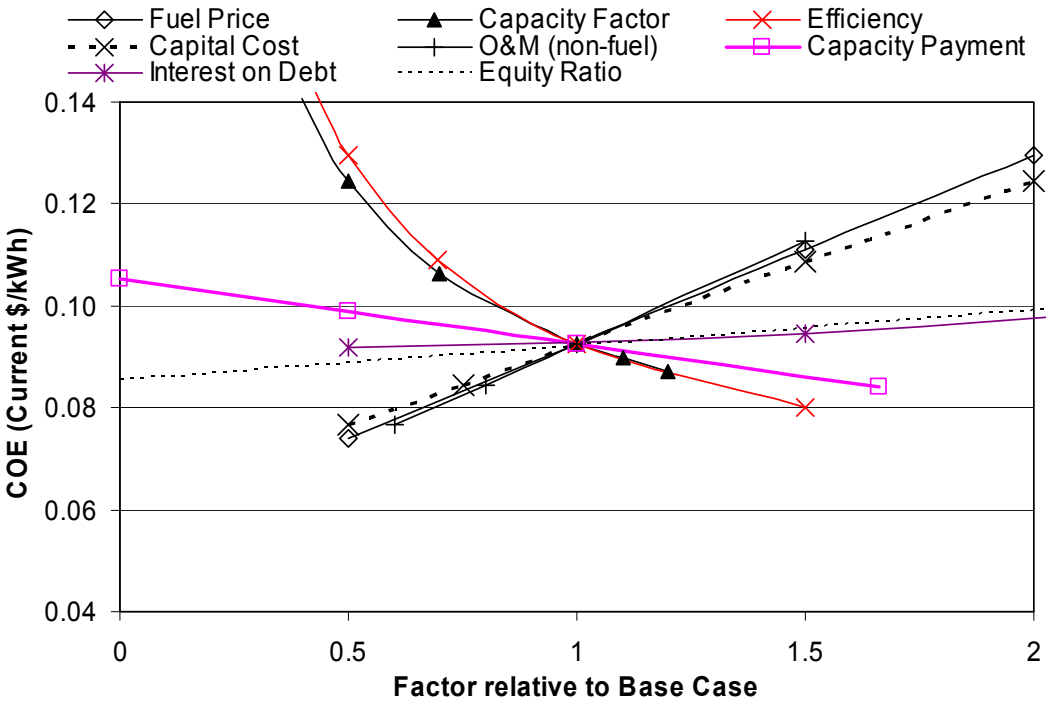

Figure 3.7-2. Current $ COE sensitivity (rice straw power plant)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

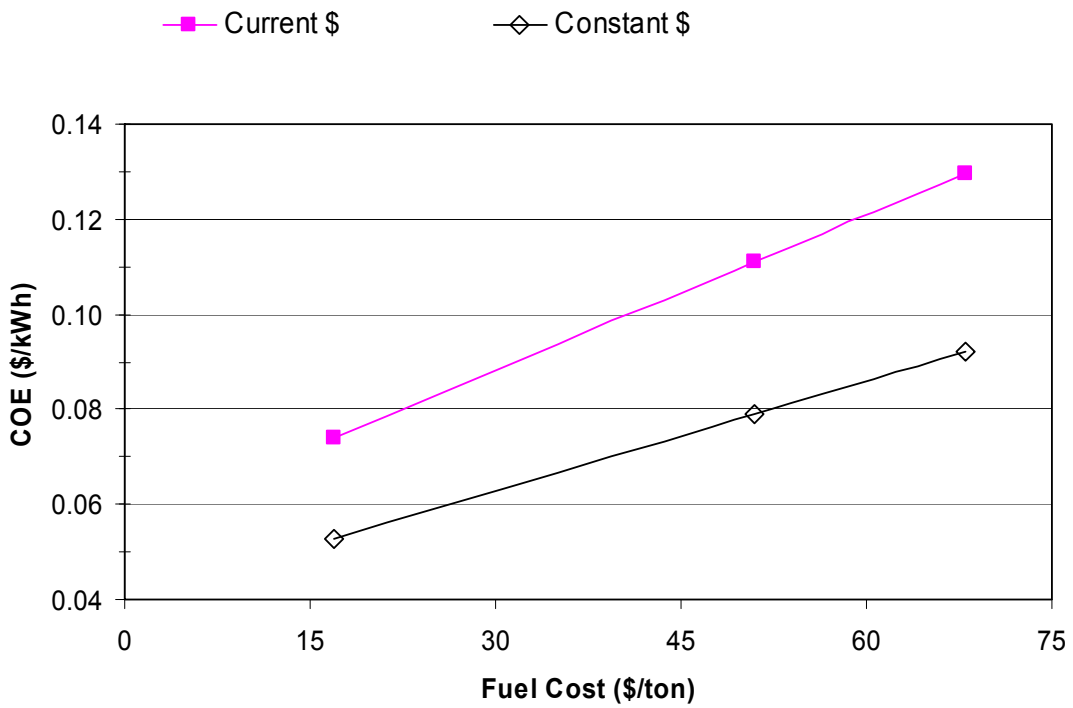

Figure 3.7-3. COE versus Fuel Cost (rice straw plant)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

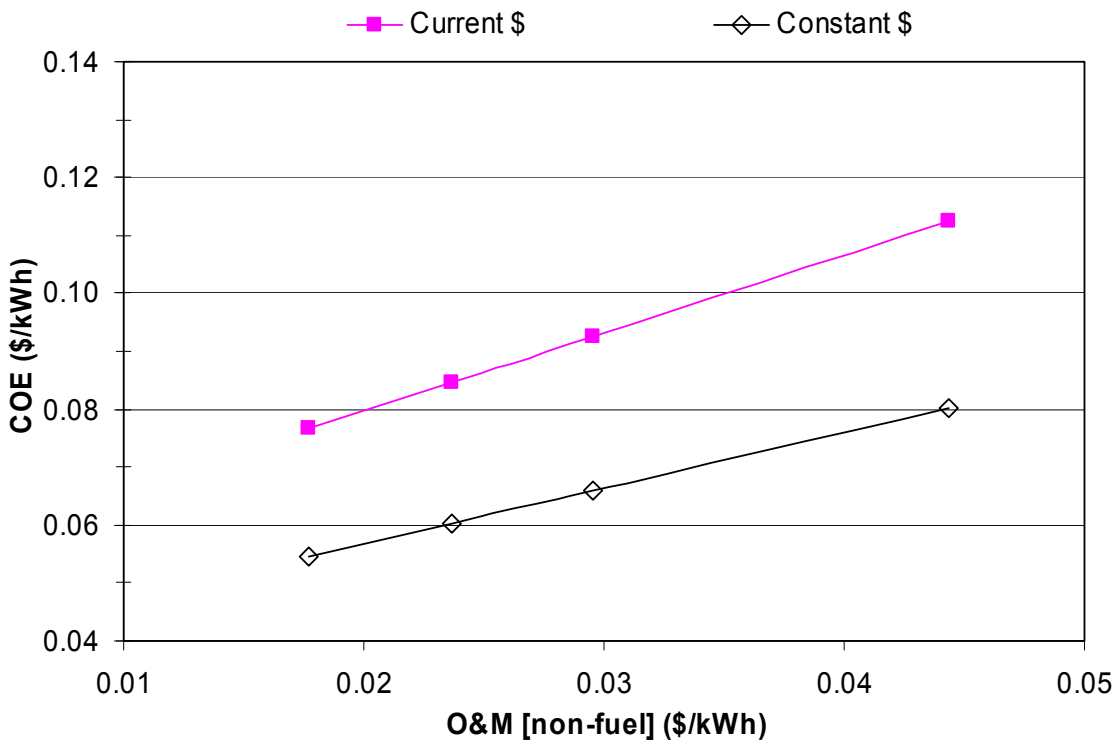

Figure 3.7-4. COE versus non-fuel O&M Cost (rice straw plant)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

3.8. MSW AD Systems

3.8.1 Review of Cost and Performance Data for Green Waste and MSW Digestion

Recent literature and reports were reviewed for cost and performance data of several MSW and green waste AD systems. Summaries of this information appear in Tables 3.8-1 and 3.8-2. This information was used to estimate some of the inputs to the economic model.

The economic model requires a factor for methane production per mass of input feedstock. Table 3.8-1 lists some recent literature values for methane production achieved in operating systems (i.e., the Dranco listings and the RW Beck report which contains a review of European facilities). Projected values for the APS–UCD digester and generic facilities are taken from recent reports, and an engineering thesis.

Table 3.8-1. Reported and projected average methane production for MSW-AD systems at 34% biogas to electricity conversion efficiency

Facility or Report	Source	Biogas Production (ft^3/ton input)	CH4 Production (m^3/Mg)	Biogas Energy per Ton Input (Gross)		
				(MMBtu)	(MJ)	(kWh)*
R. W. Beck-Iowa Report average	R. W. Beck (2004)	2208	42.1	1.31	1387	131
RIS Intl. Report to SMUD-Option 1	Kelleher (2005)	2900	49.8	1.56	1643	155
DRANCO - Brecht I	De Baere (2000)	3299	56.7	1.77	1869	176
APS - Channel Islands projections	McOuat and Gill (2004)	3081	57.7	1.80	1904	180
RIS Intl, Report to SMUD-Option 7	Kelleher (2005)	3544	60.9	1.90	2008	190
DRANCO – Brecht II	De Baere, (2000)	4003	68.8	2.15	2268	214
APS - UCD projections	Hartmann (2004)	3306	73.4	2.29	2418	228
DRANCO -Salzberg	De Baere, (2000)	4323	74.3	2.32	2449	231
DRANCO - Bassum	De Baere, (2000)	4708	80.9	2.53	2667	252
DRANCO - Kaiserslautern	De Baere, (2000)	5444	93.6	2.92	3084	291
	Averages	3697	66.8	2.10	2200	208

Capital Costs

Capital, labor, and other operating costs for MSW digester systems gathered from the literature are presented in Table 3.8-2. Capital cost estimates vary widely. Some of the differences are due to technology. Differences may also depend on how far along the "technological learning curve" the process developer was when the facility was built. A third explanation for capital cost differences reported in the literature is due to feedstock characteristics, degree of pretreatment required, and what portion of handling and post digestion stabilization infrastructure is attributed to the project. This last factor probably contributes most to capital cost differences among the comparisons.

Table 3.8-2. Cost Data used to determine base case model inputs.

Facility or Report	Capacity (kt/y)	Capital Cost			Labor ($/ton)	Digester O&M	Proportion of Installed Cost		Engine O&M ($/kWh)
		Total (M $)	($/ton capacity)	($/Mg capacity)		(% of installed cost)	Digester Plant (%)	Gen-set (%)	
Whyte & Perry (2001)	10	6.9	690*	761*					
Whyte & Perry (2001)	100	24.5	245	270					
Kompogas- Volketswil, Switzerland (2000) (Kelleher 2005)	5.5	2.1	382	421					
Kompogas (1998) (Edelmann et al. 2000)	10	5.5	550	607					
APS- UCD	11.5	2.3	200	221	in O&M	4.00	81.0	19.0	0.0150
APS- Channel Islands†	76	15.0	197	217	6.53	3.00	100	-	-
APS- Channel Islands w/power production	76	16.9	221*	244*	6.53*	3.00*	90.2*	9.8*	0.0150*
R. W. Beck small	36	7.4	206	227	3.55	2.25	87.7	12.3	0.0125
R. W. Beck large	69	12.8	186	205	2.88	2.25	87.5	12.5	0.0125
DRANCO-Bassum (1996)	15	3.9	260	287					
DRANCO-Kaiserslautern (1997)	22	11.3	514	567					
DRANCO - Rome (1999)	44	4.6	104*	115*					
DRANCO-Brecht II (1998)	55	16.8	305	336					
RIS - small	100	31.0	310	342	8.63	2.70	84.7	15.3	
RIS - large	200	55.0	275	303	6.12	2.70	83.3	16.7	
		Averages	307	339	5.57	2.83	85.23	14.8	0.0138

* Not used to calculate average
† Cost does not include power production

Capital costs for these facilities do enjoy economies of scale, most notably between 10 and 100,000 t/year capacities. In general, facilities below 20 to 25 thousand t/year capacity have installed costs between $400 and $700 per ton of capacity according to these data. The exceptions in this data set are the UCD-APS proposal for the UCD campus which has an estimated cost of $200/ton capacity and the Dranco Bassum facility which was installed for about $260/ton capacity (escalated to 2004 dollars). The value for the Dranco – Rome facility seems very low and probably does not include all associated costs. Facilities with capacity larger than 75,000 t/year are projected to have capital costs between about $200 and $300 per ton of capacity. RIS International Ltd. estimates capital costs of about $300 and $275 per ton of capacity for 100,000 and 200,000 t/year facilities and depending on whether the facility is built as an isolated unit or co-located with an existing waste handling facility (Kelleher 2005).

Interesting is the projected cost for the APS-Channel Islands design (capacity 76,000 t/year) at about $200 ton of capacity. The smaller APS proposal for UCD is also

estimated at $200 per ton of capacity. This is not an exhaustive review of cost data and further investigation is recommended. Figure 3.8-1 presents some of the capital cost information.

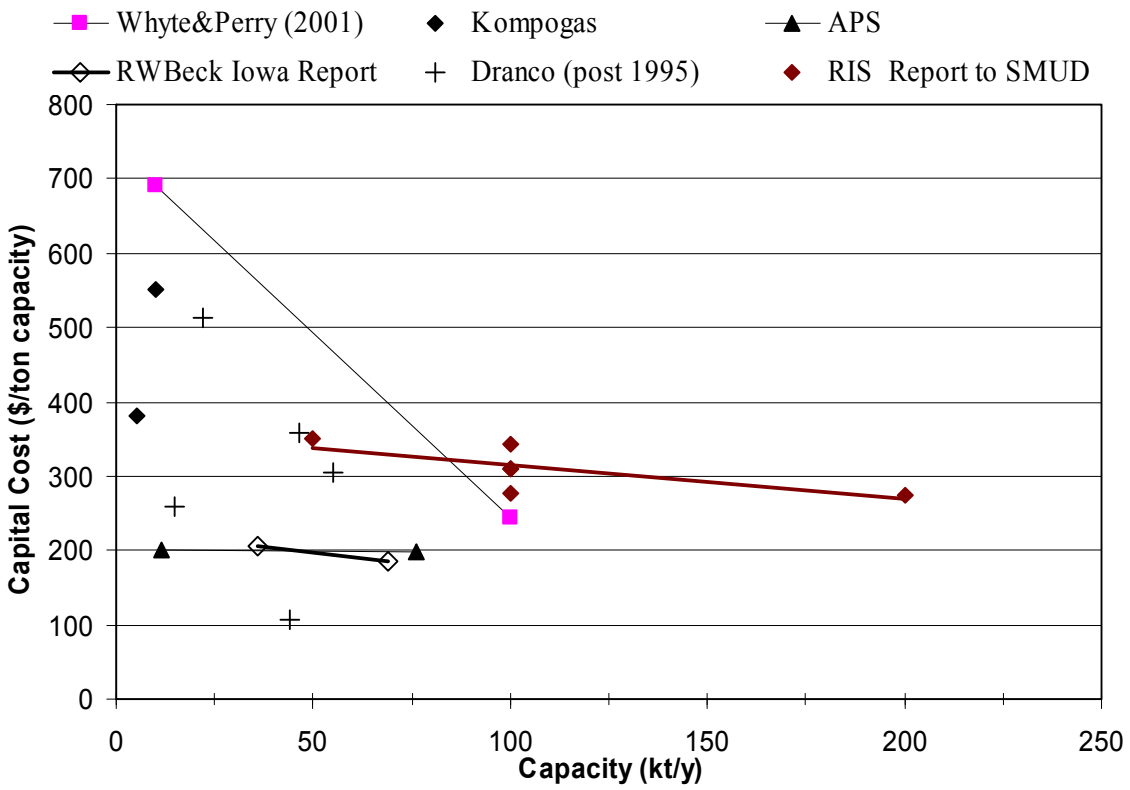

Figure 3.8-1. Capital costs vs. capacity for green waste and MSW AD systems
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Operating and Maintenance Costs

O&M costs include labor, building and plant maintenance and consumables, insurance and property taxes, and engine generator operations costs. Labor cost estimates vary from about $3 to more than $8.50 per ton processed. Differences depend on how support and administration costs are allocated and other assumptions used to derive the number of employees required to operate and manage the facility.

For example, in the economic evaluation section of the R. W. Beck-Iowa report, one manager and three laborers are assumed to operate a large facility (69,000 t/year), and a manager with two laborers for the smaller facility (36,000 t/year). The numbers in the R. W. Beck report work out to about one shift of 9 or 10 hours per day and six days per week (11,200 person-hours per year or about 5.6 full time employees (FTE) for the 69,000 ton facility). The year 1 labor values used in the R. W. Beck analysis is approximately $200,000, or about $3/ton processed. R. W. Beck based these numbers for units of labor on similarly sized facilities operating in Europe.

The HMH analysis of the APS-Channel Islands proposal uses 12 FTE for operations and 2 FTE for general services and administration. It is unclear how many shifts per day are assumed (it appears to be two or three), but mostly five-day weeks are used in their analysis (labor costs work out to be about $6.60/ton processed).

The RIS consultant report to SMUD estimates labor costs from $6 to $9 per ton processed depending on facility size and whether certain functions are shared with a co-located waste facility. The $6/ton-processed labor cost corresponds to a 200,000 t/year facility with 27 FTE employed (24 to operate, based on three shifts, and 3 FTE administration). The 100,000 t/year facility uses 16 FTE to operate with 3 FTE in administration (19 FTE total) and has a labor cost of $8.63/ton-processed. A 50,000 t/year facility is estimated to require 9 FTE (seven operational, two administration) based on two shifts per day costing $9/ton-processed in labor. Figure 3.8-2 plots per ton labor cost estimates.

Many of the facilities in Europe operate using a single shift of 8 to 12 hours per day during a six-day week. Material receiving and processing at these facilities is accomplished during the single daily shift, much like at an MRF or landfill. The digester itself does not need constant human attention and gas engines can operate unattended. Process monitoring at night is automated. During off hours, a technician is on-call and can be paged automatically by the process control and monitoring system if human intervention is required.

With that in mind, the number of FTE required in the APS-Channel Islands and the RIS analyses can likely be reduced once reliable operation is achieved.

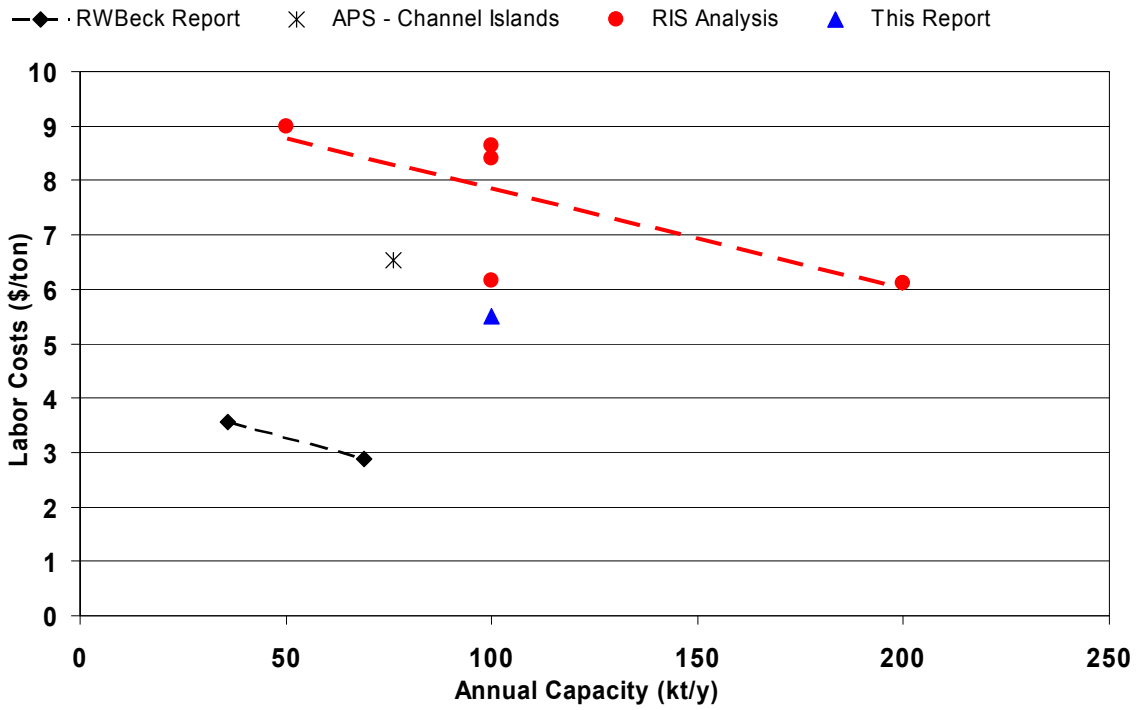

Figure 3.8-2. Digester plant labor costs from several sources

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Engine and Plant O&M

Reciprocating gas engine generator sets typically have operating costs between $0.01 and $0.015 per kWh of electricity generated. The digester and balance of plant have been assigned annual O&M costs between 2.3% and 4% of the digester installed cost (thus engine-generator and digester/balance of plant O&M costs are separated in the analysis). Table 3.8-2 (above) shows the split of total capital costs between the engine generator set and the digester plant. The digester plant accounts for between 81% and 88% of total capital (the average is 85% with the remaining allocated to the engine generator).

Balance of plant, building maintenance, utilities, taxes, etc. together has annual costs of between 3 and 5% of total installed capital (less engine generator capital cost).

3.8.2 Economic Analysis of Generic MSW AD System

A "generic" MSW AD process was modeled to determine annual revenue required to meet all debt, operating expense, and profit obligations. Two base case scenarios were considered: (1) a tipping fee was assumed and the level annual energy revenue (cost of energy or COE) was determined; and (2) an energy sales price was set and the required revenue from tipping fees was determined. Results of Scenarios 1 and 2 appear below.

Parameters for the base case of Scenarios 1 and 2 are found in Table 3.8-3. The facility is assumed to process 100,000 tons per year of mostly green waste material. Capital cost is assumed to be $275/ton-capacity. Methane production is 0.056 $m^{3/}$kg of feedstock (wet basis) and 10% of the produced biogas is consumed in the process for heating purposes and the remainder is converted to electricity at 34% efficiency (HHV basis). Thirty per cent of the generated electricity is consumed by the plant leaving 70% available for energy sales.

Base case expenses amount to $16.70 per wet ton of input. This includes labor costs of $5.50/ton, digester O&M of $6.90/ton, as well as engine-generator O&M, insurance, property tax, etc. The digester O&M is 2.9% of digester plant capital (excludes capital for engine). Engine generator O&M are $0.0138/kWh of gross generation. Insurance, property tax, and professional services are 0.5% of total capital. A 5% contingency is added to expenses.

The base case scenarios assume 85% of the capital cost ($23.4 million) is borrowed at an annual interest rate of 6% for a term of 20 years. The remaining 15% ($4.1 million) is financed by equity investment with a required ROR of 15%. This results in an effective cost of money (or effective interest rate) of 7.35%/year. The interest on the equity that is returned represents the profit for the facility. Annual debt and equity payments total $2.7 million per year, or $27/t. No debt reserve is used in the analysis.

Combined federal and state tax rate is 40.3% based on federal and state tax rates of 34% and 9%, respectively. A 0.9 cent/kWh PTC is applied to electricity sales for the first five years. The 10-year modified accelerated cost recovery system (MACRS) depreciation

schedule is used. The PTC and depreciation typically remove all income tax liability due to the project in early years and can reduce the company's tax liability further if the company has other profitable (taxable) enterprises. The economic analyses assume the business is profitable in other areas which allow "negative" taxes to be credited to the project (therefore reducing revenue requirements).

General inflation and price escalation rates are set at 2.1% per year. All expenses, the PTC, compost sales, tipping fee (in the case of COE determination), and electricity sales price (in the case of required tipping fee determination) escalate at this rate.

The solid residues are de-watered to 50% moisture content and sold for $5/Mg ($5.50/ton) as compost or soil amendment. Other income includes tipping fee revenue for the material received for processing and electricity sales. The value for each in the base case depends on the Scenario (1 or 2) and are discussed below (base case economic modeling assumptions and results are shown in Table 3.8-3 below).

Scenario 1-Generic MSW AD: COE Determination Given a Tipping Fee

For a levelized COE determination for the generic MSW AD system, a set tipping fee for the material processed is assumed. The tipping fee used is $26/ton of material, which is based on the published fee for self-haul material to the Kiefer landfill.[132] The full tipping fee is credited to the project and any preparation or processing costs are assumed to be accounted for in the plant O&M charge.

The resulting levelized COE for Scenario 1 is 10.1 cents/kWh and 8.4 cents/kWh (current dollar and constant dollar values respectively). See the Scenario 1 Results in Table 3.8-3.

Scenario 2-Generic MSW AD: Determination of Required Tipping Fee Given an Electricity Sales Price

For a determination of the levelized tipping fee required for the generic MSW AD system, an electricity sales price of 5.3 cents/kWh[133] was assumed (and allowed to escalate at 2.1% per year).

The required tipping fee for Scenario 2 is $34.7/t and $29.0/t (current dollar and constant dollar values respectively). See the Scenario 2 Results in Table 3.8-3.

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132. http://www.sacgreenteam.com/facilities/kieferrates.htm

133. This price approximates the effective price of electricity received by projects participating in the California Dairy Power Production Program that chose set energy price rather than capital cost buy-down.

Table 3.8-3. Generic MSW AD system economic assumptions and Scenario 1 & 2 results

Performance Assumptions		
Annual Wet Feedstock Consumption	(ton/y)	100,000
Methane Production	(m3/kg Wet Feedstock)	0.056
Fraction of biogas used for heat or steam	(%)	10
Gross Efficiency--Biogas to Electricity	(%)	34
Gross Electrical Capacity	(kWe)	1792
Fraction of Electricity consumed on site	(%)	30
Net Electrical Capacity	(kWe)	1254
Capacity Factor	(%)	100
Annual Gross Electricity Generation	(kWh)	15,696,049
Net Electricity available for sale (kWh/yr)	(kWh/yr)	10,987,234
Annual Sludge production	(t/y -50% moisture)	43,203
Liquid water, waste or re-use in process	(t/y)	43,818
Escalation/Inflation		
General Inflation	(%/y)	2.1
Escalation for Production Tax Credit	(%/y)	2.1
Escalation--Sludge sales	(%/y)	2.1
Escalation--Other	(%/y)	2.1
Taxes		
Federal Tax Rate	(%)	34
State Tax Rate	(%)	9.6
Production Tax Credit	($/kWh)	0.009
Combined Tax Rate	(%)	40.34
Income		
Sales price for Compostable Stream	($/t)	5
Annual Income from Compost Sales	($/y)	238,166
Tipping fee	($/t)	TBD
Annual Income from Tipping fee	($/y)	TBD
Energy Price	($/kWh)	TBD
Electricity sales	($/y)	TBD

Capital and Operating Costs		
Capital Cost	($/ton annual capacity)	275
Total Facility Capital Cost	($)	27,511,578
Labor Cost	($/y)	550,000
Digester Plant Op & Maintenance Cost	($/y)	686,139
Insurance/Property Tax/utilities/professional	($/y)	137,558
Engine Operating Expenses	($/y)	216,605
Contingency	(@5%)	79,515
Total O&M Expenses	($/y)	1,669,817
Total O&M Expenses	($/ton input)	16.7
Financing		
Debt ratio	(%)	85
Equity ratio	(%)	15
Interest Rate on Debt	(%/y)	6
Economic Life	(y)	20
Cost of equity	(%/y)	15
Cost of Money	(%/y)	7.35
Total Equity Cost	($)	4,126,737
Total Debt Cost	($)	23,384,841
Capital Recovery Factor	(Equity)	0.1598
Capital Recovery Factor	(Debt)	0.0872
Annual Equity Recovery	($/y)	659,294
Annual Debt Payment	($/y)	2,038,797
Debt Reserve	($)	0
Debt Payment and Equity Recovery	($/y)	2,698,091
Debt Payment and Equity Recovery	($/t)	27
Depreciation Schedule		
10 year MACRS used		

Scenario 1 Results					
If Tip Fee is set at:	($/t)	26	Required Electricity Sales Price (Levelized COE)	(Current $/kWh)	**0.101**
Then Tip Fee Income Generated is:	($/y)	2,600,000		(Constant $/kWh)	**0.084**

Scenario 2 Results					
If Electricity Sales Price is set at:	($/kWh)	0.053	Required Levelized Tip Fee	(Current $/ton)	**34.70**
Then Energy Income Generated is:	($/y)	582,323		(Constant $/ton)	**29.00**

Data collected by Robert Williams (insert contract dates)

Comparison with Other Studies

R.W. Beck estimated required tip fees for "revenue neutral" operation of a 70,000 t/year MSW AD facility to be only about $16/ton (no profit or tax implications in the analysis). The analysis assumed capital costs of about $200/ton-capacity, $3/input ton in labor, and $7.20/input ton for other O&M expenses. Revenue in the R.W. Beck analysis included $241,000 for electricity sales ($0.031/kWh or $3.50/input ton) and $485,000 for sludge or digestate sales (32,350 tons at $15/ton). The sludge sales amount to $7/ton of input to digester. R.W. Beck used a 20-year economic life, 3% annual inflation, and a 5% discount rate (or interest rate on debt) in their analysis. R.W. Beck assumed methane production of approximately 1,350 ft^3/input ton (or about 2,200 ft^3/input ton of biogas). Gross and net electricity generation was 9,000 and 7,770 MWh/year, respectively. This implies a facility parasitic load of only 14% which is lower than reported by others (See Table 3.8-4).

The lower capital and O&M costs and the higher value assumed for the residue and a possibly inflated net electricity value likely account for the low required tipping fee determined by R. W. Beck (Table 3.8-4).

The RIS International report to SMUD investigated several options that essentially differ in capital costs (high for green field site or moderate for co-location with existing waste handling facility), and whether the digestate is charged a fee for disposal (in the case of not co-located with and owning a compost facility) or zero fee/revenue (in the case of co-location with compost facility and compost processing equals its revenue).

Option 1 in the RIS estimates a much higher required tipping fee ($68/ton) for economic viability of AD of primarily green waste feedstock (at 100,000 tons per year) than the generic case analyzed in this report. It appears the analysis is before tax and depreciation consequences are considered and does not include owner profit. The RIS analysis assumes capital cost is $310/ton-capacity and uses $24.60/ton for O&M of which $8.60/ton is labor cost. Electricity is sold for $0.065/kWh and sludge or digestate is disposed at a cost of $25/ton. The economic life is 15 years using 6.4% interest on capital and a 2% rate of inflation.

The RIS Option 7 is an analysis of an AD system co-fed by greenwaste and food waste and collocated with an existing waste handling facility which allows capital and some operating costs to be shared. In addition, Option 7 does not charge digestate disposal fees to the project because composting occurs on site as an after treatment. The ratio of green to food waste was not given but gas production per input mass was increased by 22%. The Option 7 capital cost is $275/ton-capacity (amortized amount is equivalent to $29/ton input). The operating costs are $19/ton (of which $6.15/ton is labor). The required tipping fee (before tax consequences and owner profit) is $41 which assumes electricity is sold at $0.065/kWh. RIS Option 7 is more in line with the "generic MSW AD" analysis in this report which had a before-tax-and-profit required tip fee of $35/ton.

The two most significant assumption differences in the RIS analysis compared to that done in this report are the O&M costs and the value for treated digestate (see Table 3.8-4). Total O&M in the RIS analysis is 47% greater than that used in this report ($24.60/ton compared to $16.70/ton). The RIS analysis assumes the digestate and residual material incurs a disposal fee while this report and the R. W. Beck analysis assume the material has value and generates a stream of income.

O&M is composed of labor costs and equipment maintenance and consumables costs. The labor costs assumed by RIS tend to be high (Option 1 is about 55%/ton greater than those used in this report: $8.60/ton compared to $5.50/ton). The RIS analysis assumes around-the-clock staffing for seven days per week which may not be necessary. Waste pickup and deliveries usually occur during daytime hours only. Feedstock preparation and digester loading can also be done usually in a single shift per day. The digester and engine operation can be automated (alarm conditions can notify on call staff in case of emergencies). Facility staffing is also addressed above in the general O&M section.

The equipment, consumables, property tax, and insurance portion of the annual O&M charge is 5.2% of total capital in the RIS analysis while 4.2% is used in this report. This difference on a percent basis is magnified somewhat because of the higher capital cost assumed by RIS (The R.W. Beck analysis uses 3.6% of capital for non-labor O&M, which, when combined with the much lower capital cost, results in a relatively small O&M charge).

The RIS analysis (Option 1) assumed the AD facility was located and owned separately from a compost or landfill operation. Therefore, the residue/digestate is modeled as a waste product that re-enters the MSW/green waste market and is subject to a $25/ton tipping/hauling/processing charge. The analysis assumed 65% (mass basis) of the input feedstock winds up as either digestate or untreated residue. Effectively, the disposal costs are equivalent to an added fee of $16.25/ ton of input material (65% multiplied by $25/residue ton). The RSI Option 7 is more viable because it is collocated with a waste and compost facility which reduces capital and labor costs. The biggest contribution to the viability of Option 7 (compared to Option 1) comes from the ability to directly use (or dispose) the digestate in the collocated compost (or landfill) facility with no fee attached. This directly reduces the project required tip fee for the project by more than $16/ton.

This report assumed the AD facility is located with a compost facility owned and operated by the same organization. Therefore, the digestate/residue fraction had a value of $5/ton (representing the profit after undergoing aerobic stabilization). The income generated from sale of composted residue in this analysis amounts to about $2.40/ton of input feedstock.

Table 3.8-4. Comparison of performance and economic parameters used in three economic analyses of MSW AD systems

Parameter	Units	This Report (Generic system)	RWBeck	RIS Intl. Report to SMUD	
				Option 1- Mod. Capital cost, Residue Disposal fee	Option 7- Ave. Capital cost, No Disposal fee
Capacity	(tons per year)	100,000	69,000	100,000	100,000
Capital Cost	($/ton-capacity)	275	200	310	275
Analysis Period	(years)	20	20	15	15
Effective Interest Rate or Cost of Money	(%)	7.35	5.00	6.40	6.40
Annual Capital and Equity Payments	($ 000)	2,698	1,029	3,272	2,925
Capital and Equity Payment per input ton	($/ton)	26.98	14.91	32.72	29.25
Labor	($/ton)	5.50	3.00	8.60	6.15
Non - Labor O&M	($/ton)	11.20	7.20	16.00	12.90
Total O&M	($/ton)	16.70	10.20	24.60	19.05
Digestate or Residue	(tons)	52,504	32,364	65,000	70,000
Ratio of Digestate:Input	(-)	0.53	0.47	0.65	0.70
Digestate sales or disposal (negative)	($/ton)	4.54	15.00	(25.00)	0
Digestate Revenue (Disposal Cost) per ton input	($/ton)	2.38	7.04	(16.25)	0
Methane Production	(ft^3/ton)	1,793	1,347	1,595	1,950
Gross Electricity Generation	(MWh)	15,696	9,038	13,923	17,017
Parasitic Load	(%)	30	14	38	31
Net Electricity for Sale	(MWh)	10,987	7,767	8,588	11,700
Net Electricity per ton input	(kWh/ton)	110	113	86	117
Electricity Price	($/kWh)	0.053	0.031	0.065	0.065
Electricity Income	($/ton)	5.82	3.49	5.58	7.61
Pre-Tax Required Tip Fee	($/ton)	**35**	**15**	**68**	**41**
After Tax Required Tip Fee	(constant $/ton)	29	?	?	?

Data collected by Robert Williams (insert contract dates)

Sensitivity Analysis

Sensitivity analyses of the Scenario 1 and 2 results were done by varying a single input parameter while keeping all other inputs at the base case value. These results are discussed and displayed in a set of graphs which follow.

Figure 3.8-3 displays required tip fee versus electricity sales price for four different facility capital costs ($250, $275, $300, and $350/t of annual capacity). These curves were generated from the economic model using base case parameters discussed above and shown in Table 3.8-3 (base case capital cost is $275/t annual capacity).

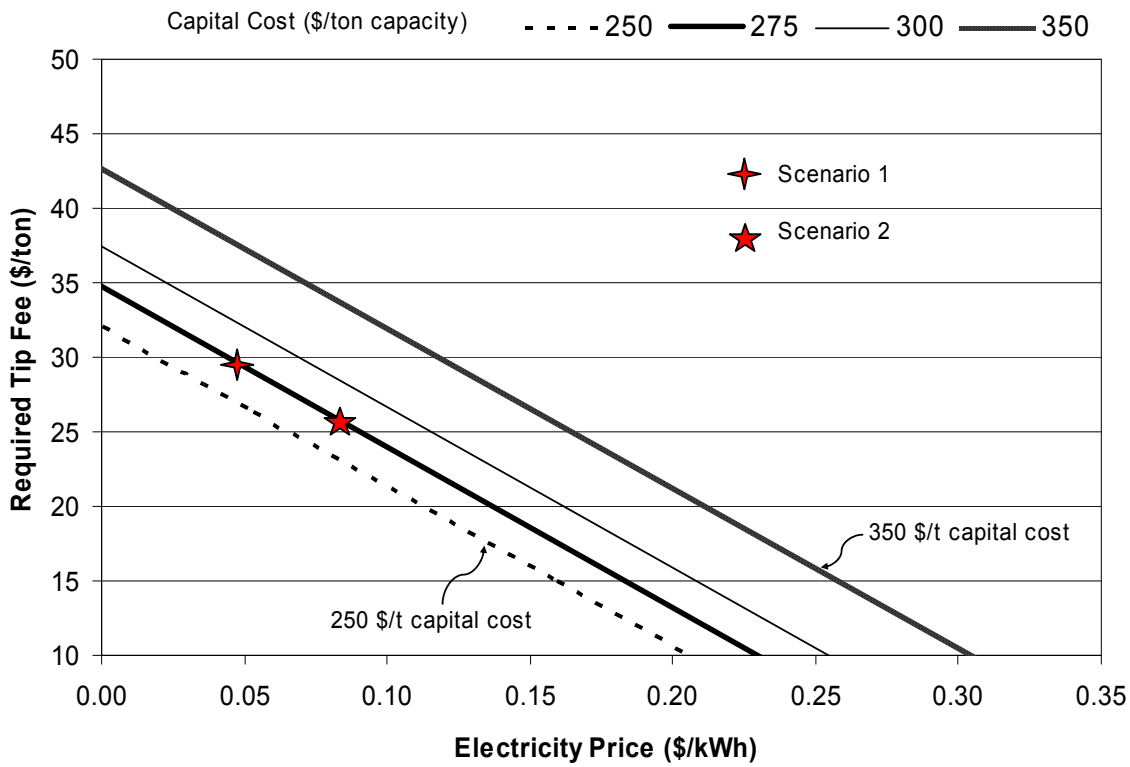

Figure 3.8-3. Required tip fee vs. electricity sales price for different capital costs of MSW AD systems

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Scenario 1 Sensitivity Analysis Discussion

For convenience, a list of the graphs displaying Scenario 1 cost of energy (COE) sensitivity results is provided:

Figure	Description
3.8-4	Constant $ COE sensitivity analysis (MSW AD Scenario 1)
3.8-5	Current $ COE sensitivity analysis (MSW AD Scenario 1)
3.8-6	COE versus Tipping Fee (MSW AD Scenario 1)
3.8-7	Current $ COE versus capital cost (MSW AD Scenario 1)
3.8-8	COE versus compost sales price (MSW AD Scenario 1)
3.8-9	COE and energy capacity vs. biogas production (MSW Scenario 1)
3.8-10	COE versus electric parasitic load (MSW AD Scenario 1)

Figure (in appendix)	Description
3.8-11	COE versus equity ratio (MSW AD Scenario 1)
3.8-12	COE versus interest rate on debt (MSW AD Scenario 1)
3.8-13	COE versus O&M costs (MSW AD Scenario 1)

The COE calculation is exceptionally sensitive to net tipping fee. The $26/ton tipping fee used in the calculation is the published value for self-haul rates to the public. Commercial waste haulers have likely negotiated lower tipping fees. A lower tipping fee

or a feedstock processing cost will significantly impact the COE. For example, with a $20/t tipping fee (instead of the $26/t used in the base case), the COE increases to 13.8 cents/kWh (constant dollar). This is an increase of more than 60% in COE for a 23% decrease in tipping fee. Note that at a tipping fee of approximately $35.50/t, the COE is zero (Figure 3.8-4).

COE is also quite sensitive to small relative changes in capital cost. A ±10% change in capital cost will impact COE by ±32%.[134] Sensitivity of required revenue to changes in O&M cost is lower than for tipping fee and capital costs, yet still significant. For example, a 10% change in O&M affects COE by about 18%. A reduction in O&M costs from the $16.70/t base case to about $7/t will reduce energy revenue requirements to zero (meaning tipping fee and compost sales are sufficient to meet financial obligations).

The COE is much less sensitive to changes in the other parameters used in the model. Refer to the figures below.

134. Changes in Capital Cost also affect the O&M charge in the model. The O&M charge is composed of two components that scale with capital cost (about 3% of digester plant capital) and electrical generation. O&M costs also include components that do not vary in the sensitivity analysis (e.g., wages, insurance, utilities, and property taxes). The largest single component of O&M is the digester plant O&M, which accounts for more than 40% of Base Case O&M.

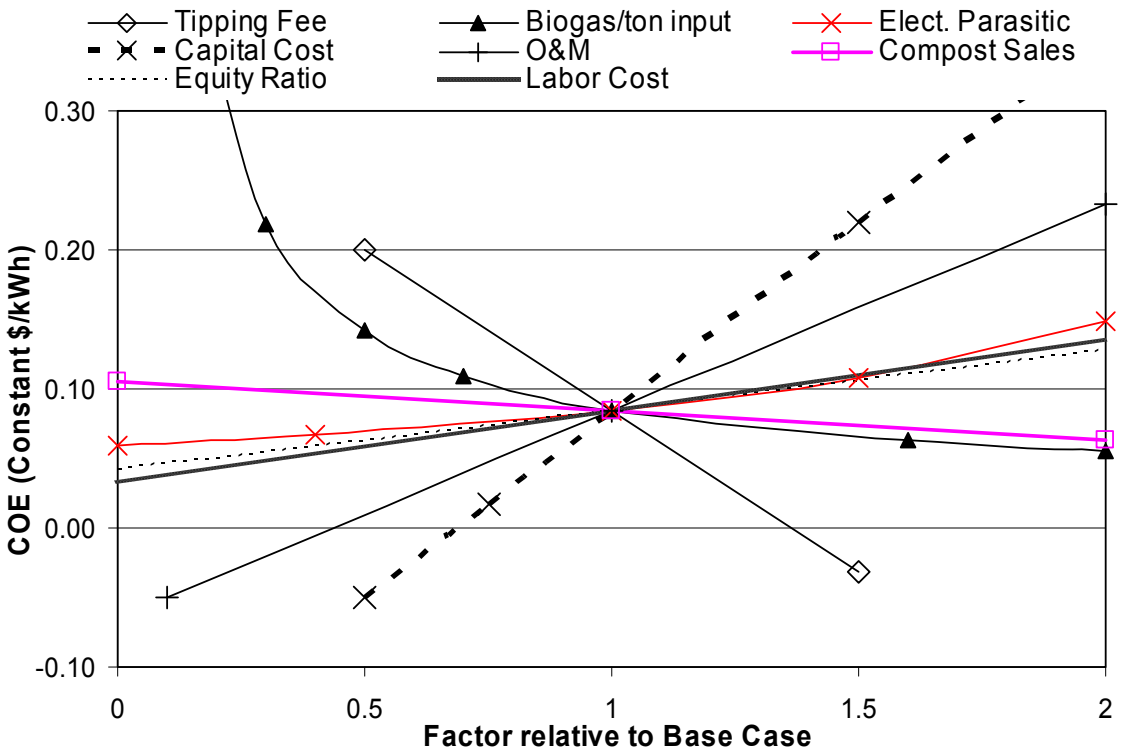

Figure 3.8-4. Constant $ COE sensitivity analysis (MSW AD Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

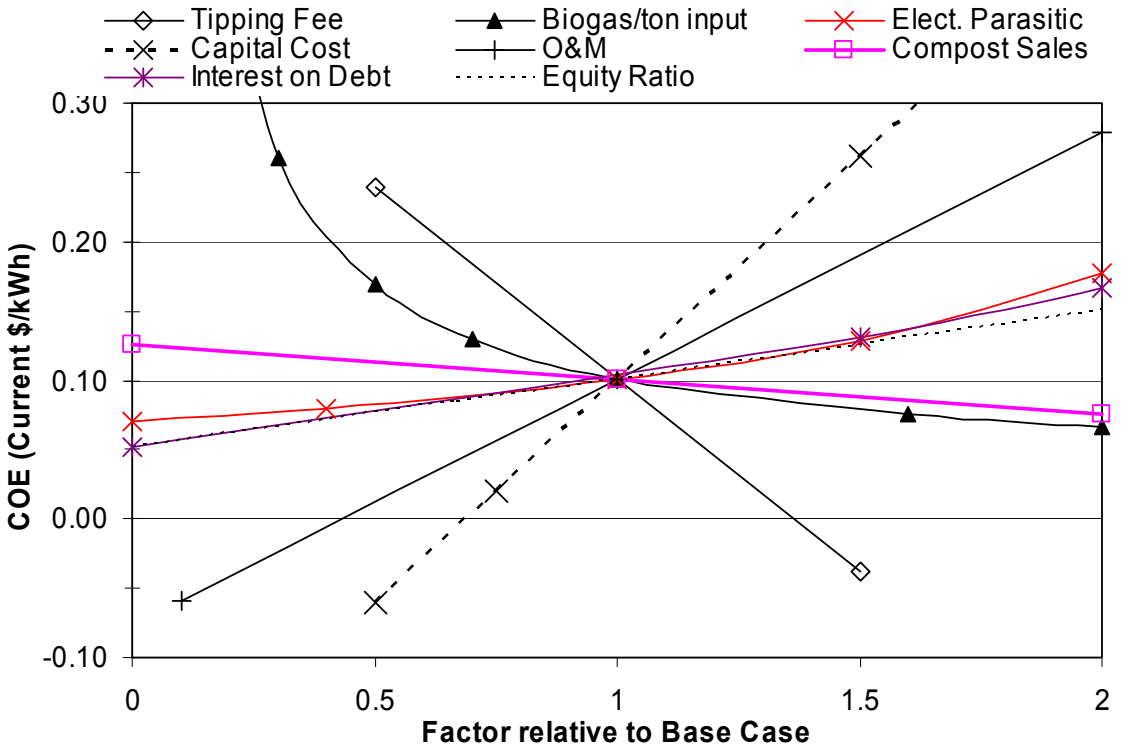

Figure 3.8-5. Current $ COE sensitivity analysis (MSW AD Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

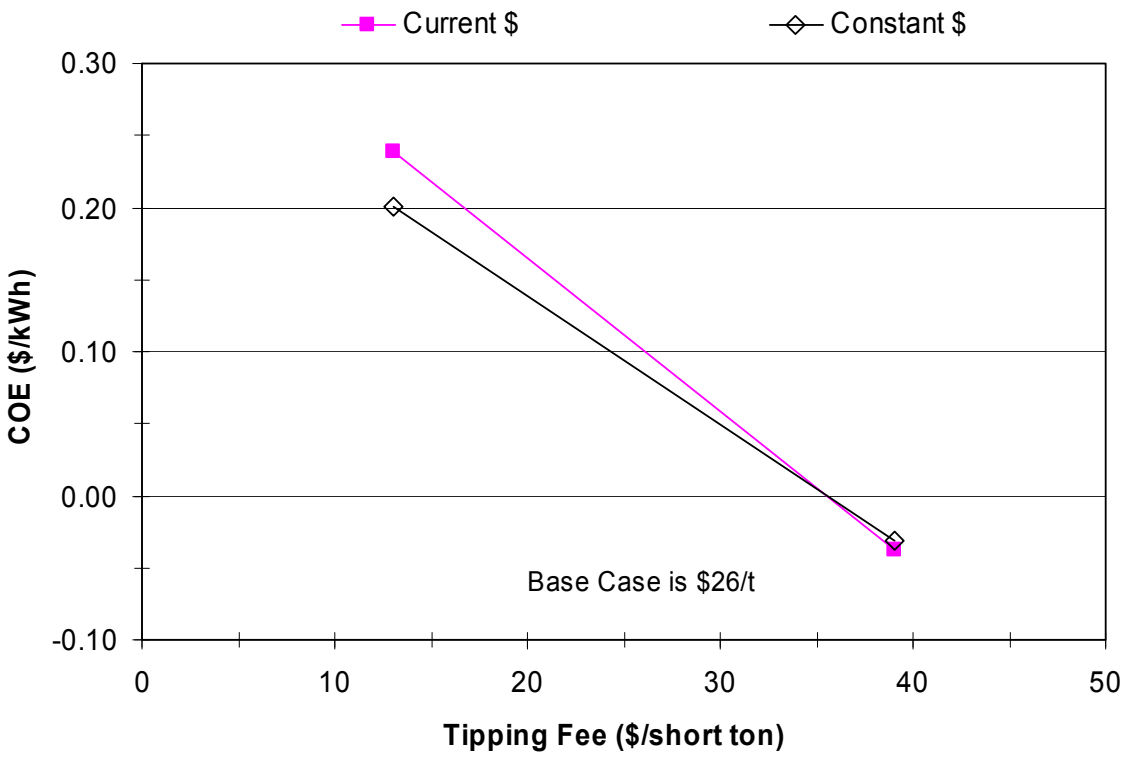

Figure 3.8-6. COE versus Tipping Fee (MSW AD Scenario 1)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

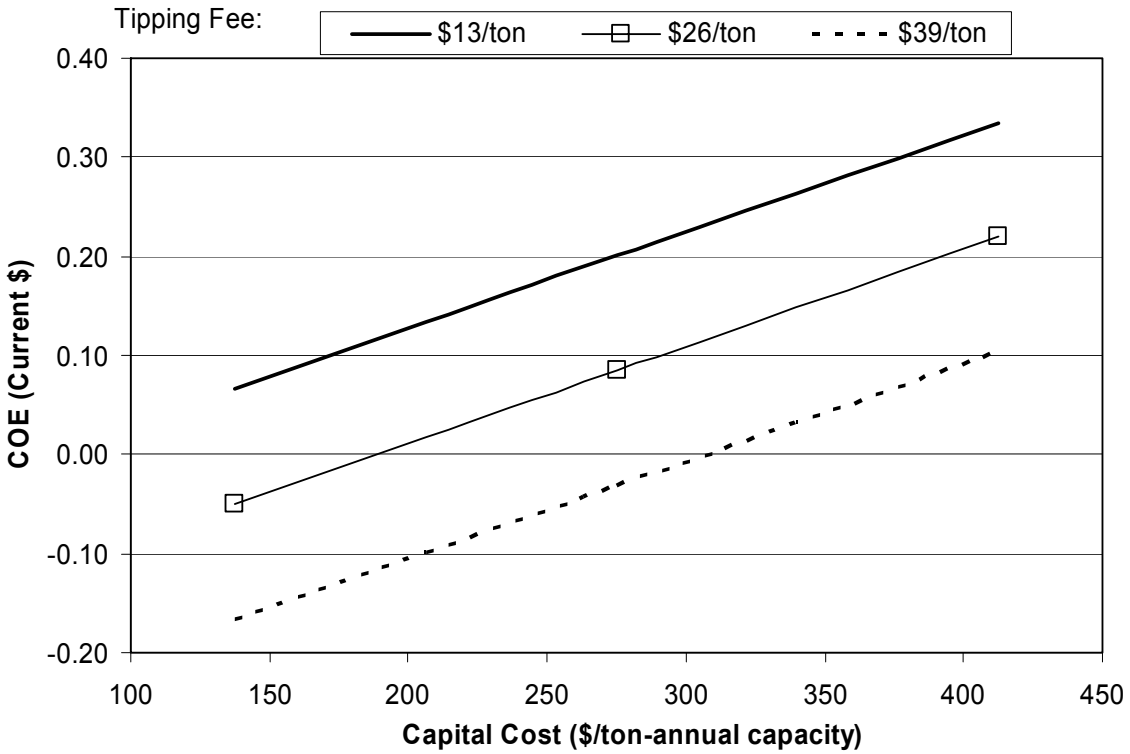

Figure 3.8-7. Current $ COE versus capital cost (MSW AD Scenario 1)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

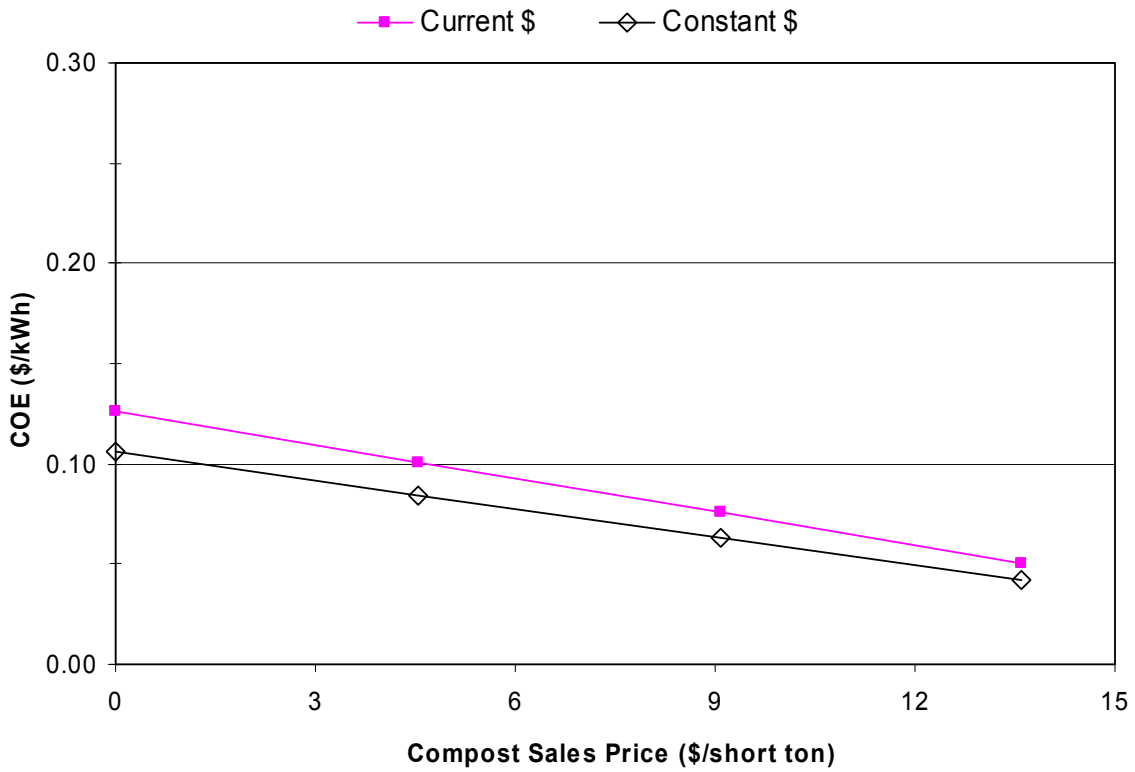

Figure 3.8-8. COE versus compost sales price (MSW AD Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

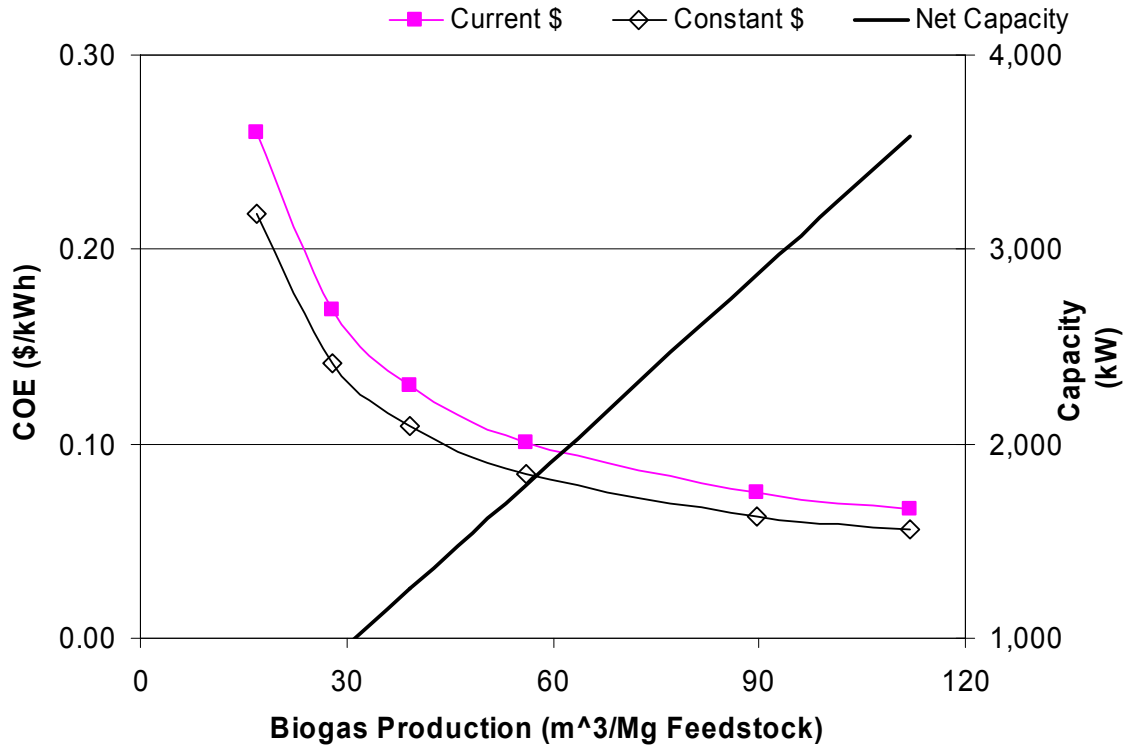

Figure 3.8-9. COE and energy capacity vs. biogas production (MSW AD Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

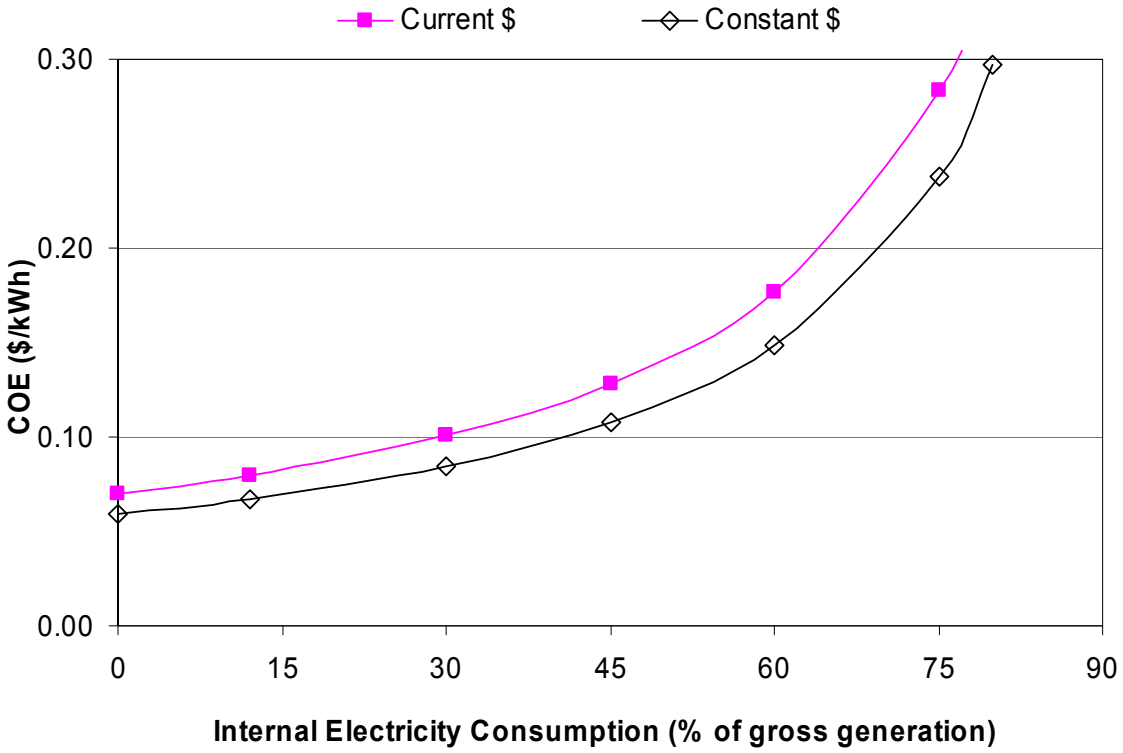

Figure 3.8-10. COE versus electric parasitic load (MSW AD scenario 1)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Scenario 2 Sensitivity Analysis Discussion

As with Scenario 1, a sensitivity analysis of required revenue was done by varying a single input parameter while keeping all other inputs at the base case value. The results are discussed and displayed in a set of graphs which follow. For convenience, a list of the graphs is provided:

Figure	Description
3.8-14	Constant $ Required Tip Fee sensitivity analysis (MSW AD scenario 2)
3.8-15	Current $ Required Tip Fee sensitivity analysis (MSW AD scenario 2)
3.8-16	Required Tip Fee vs. Electricity Price (MSW AD scenario 2)
3.8-17	Required Tip Fee vs. Capital Cost (MSW AD scenario 2)
3.8-18	Required Tip Fee vs. Compost Sales Price (MSW AD scenario 2)
3.8-19	Required Tip Fee & electrical capacity vs. biogas production (MSW AD scenario 2)
Figure (in Appendix)	**Description**
3.8-20	Required Tip Fee vs. Electrical Parasitic Load (MSW AD scenario 2)
3.8-21	Required Tip Fee vs. Equity Ratio (MSW AD scenario 2)
3.8-22	Required Tip Fee vs. Debt Interest Rate (MSW AD scenario 2)
3.8-23	Required Tip Fee vs. O&M Costs (MSW AD scenario 2)

The required tipping fee (given a set electricity price of 5.3 cents/kWh) is most sensitive to relative changes in capital cost. This is not surprising since capital repayment is the largest expense (the debt and equity Year 1 payment amount to $27.00/t and energy and

compost sales amount to only $8.20/t in the first year). A relative change in capital costs affects required tipping fee by the same relative amount (i.e., a ±1% change in capital costs changes required tipping fee by ±1% as well).

The second most significant factor affecting required revenue are O&M costs which amount to $16.70/t for the first year (see Figures 3.8-14 and 3.8-15). A relative change in O&M costs of ±1% affects required tipping fee by about ±0.6%.

The required tipping fee is fairly insensitive to the sales price of electricity. For example, doubling the sales price of electricity to 10.6 cents/kWh reduces required tipping fee by about 20% (to $23.30/t from the base case $29.00/t).

Tipping fee is even less sensitive to relative changes in the other variables investigated (equity ratio, biogas production, compost sales price, and debt interest rate) (see figures 3.8-14 and 3.8-15).

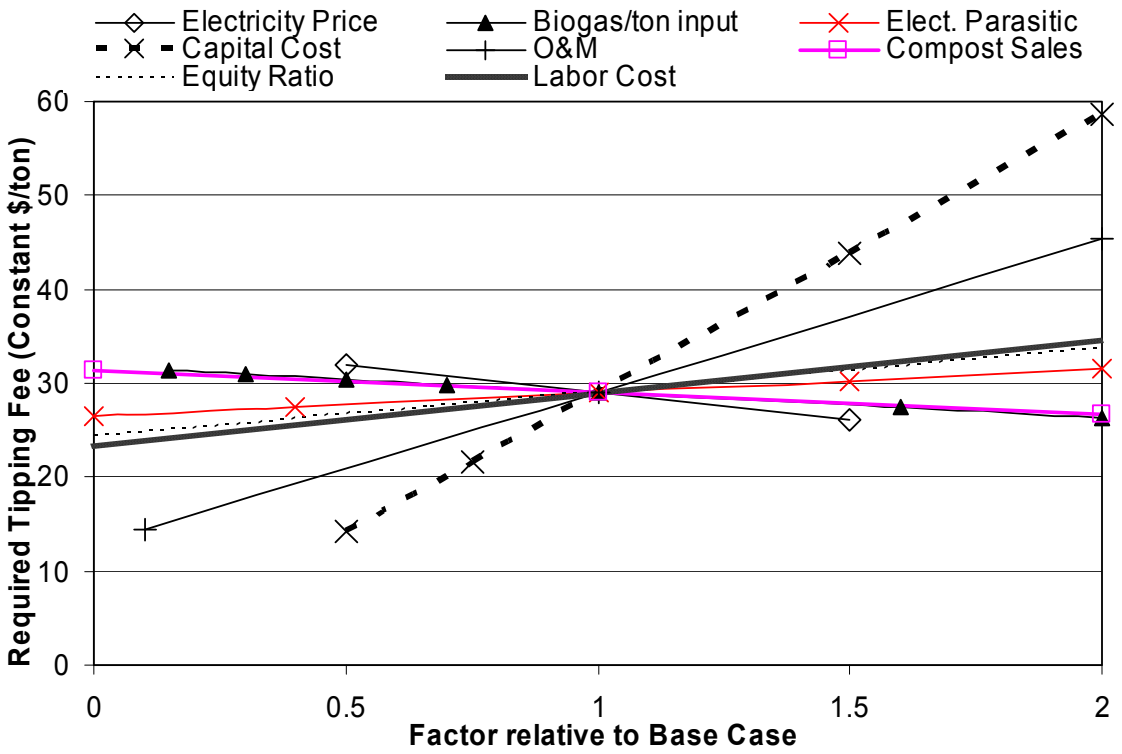

Figure 3.8-11. Constant $ required tipping fee sensitivity analysis (MSW AD Scenario 2)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

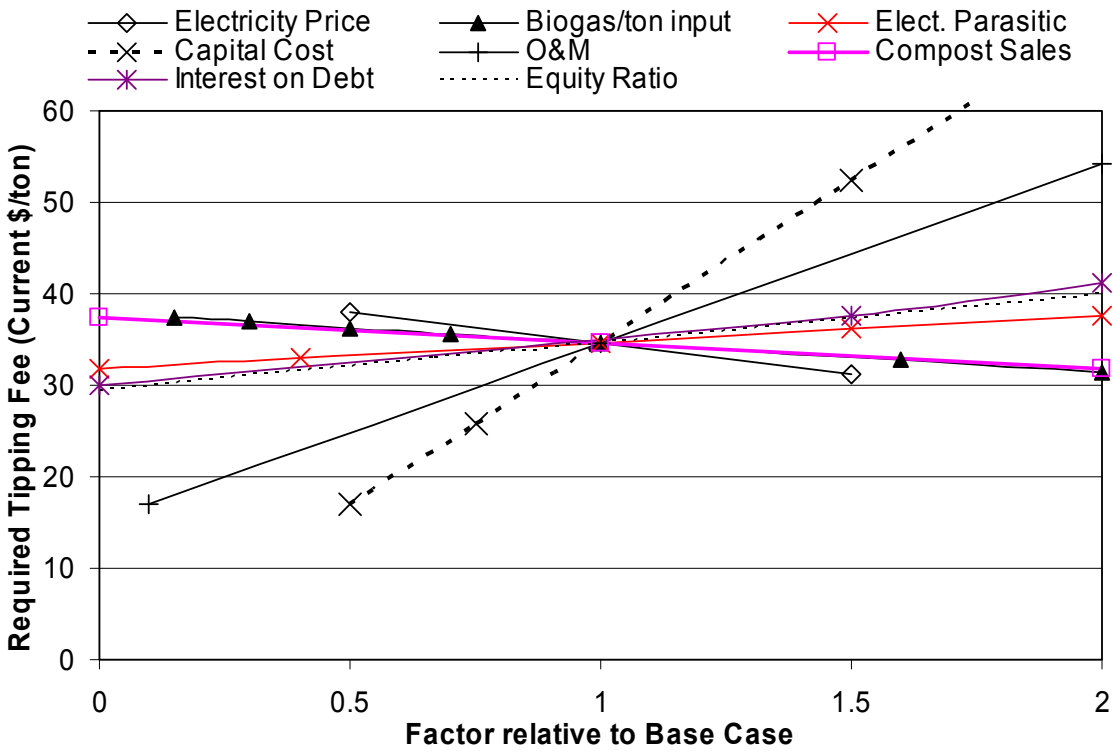

Figure 3.8-12. Current $ required tipping fee sensitivity analysis (MSW AD Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

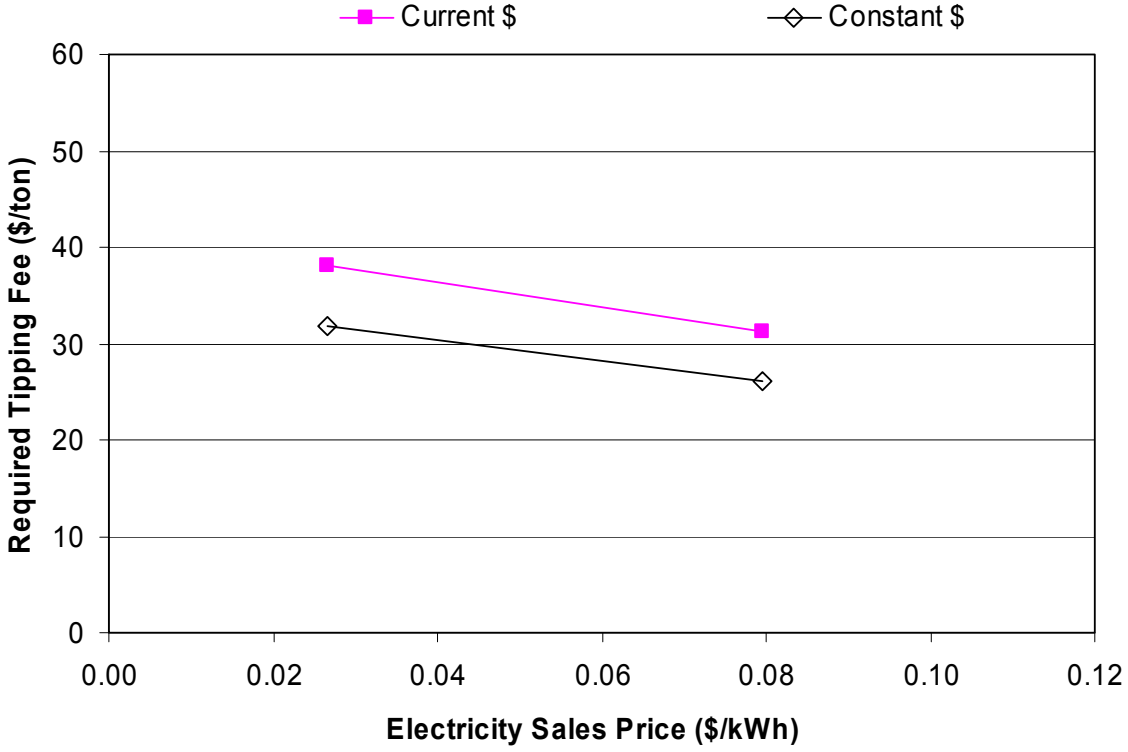

Figure 3.8-13. Required tipping fee vs. electricity price (MSW AD Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

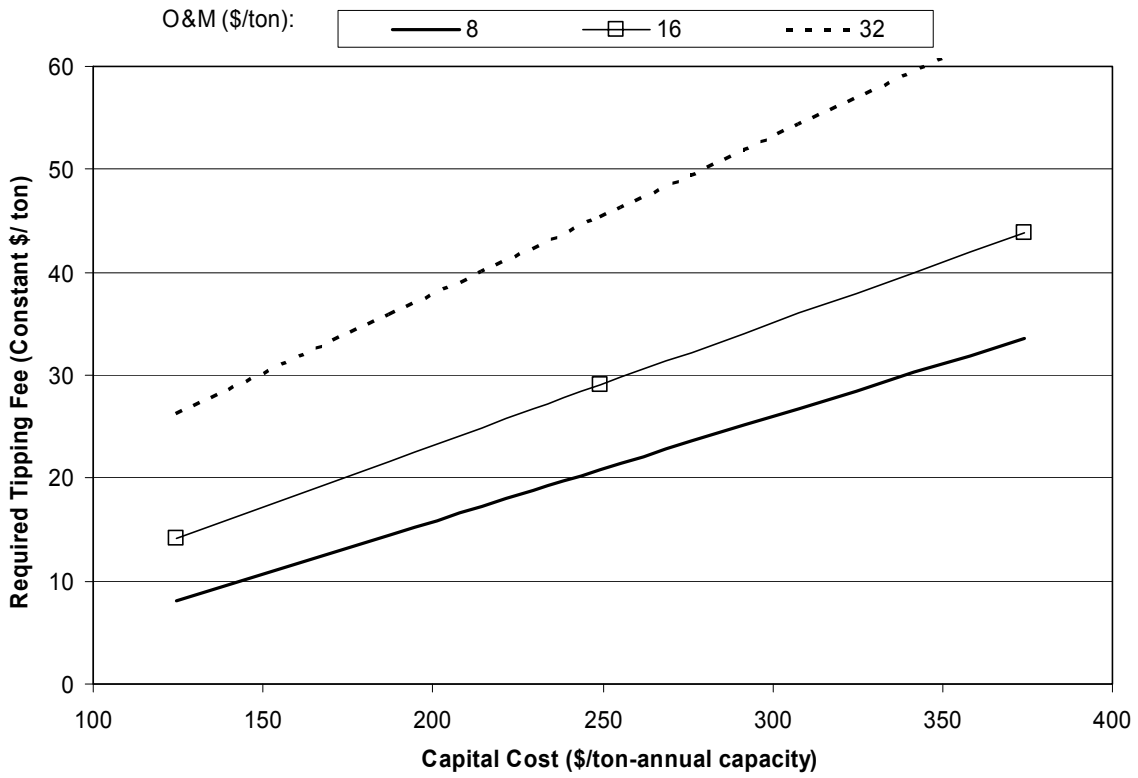

Figure 3.8-14. Required tipping fee vs. capital cost (MSW AD Scenario 2)

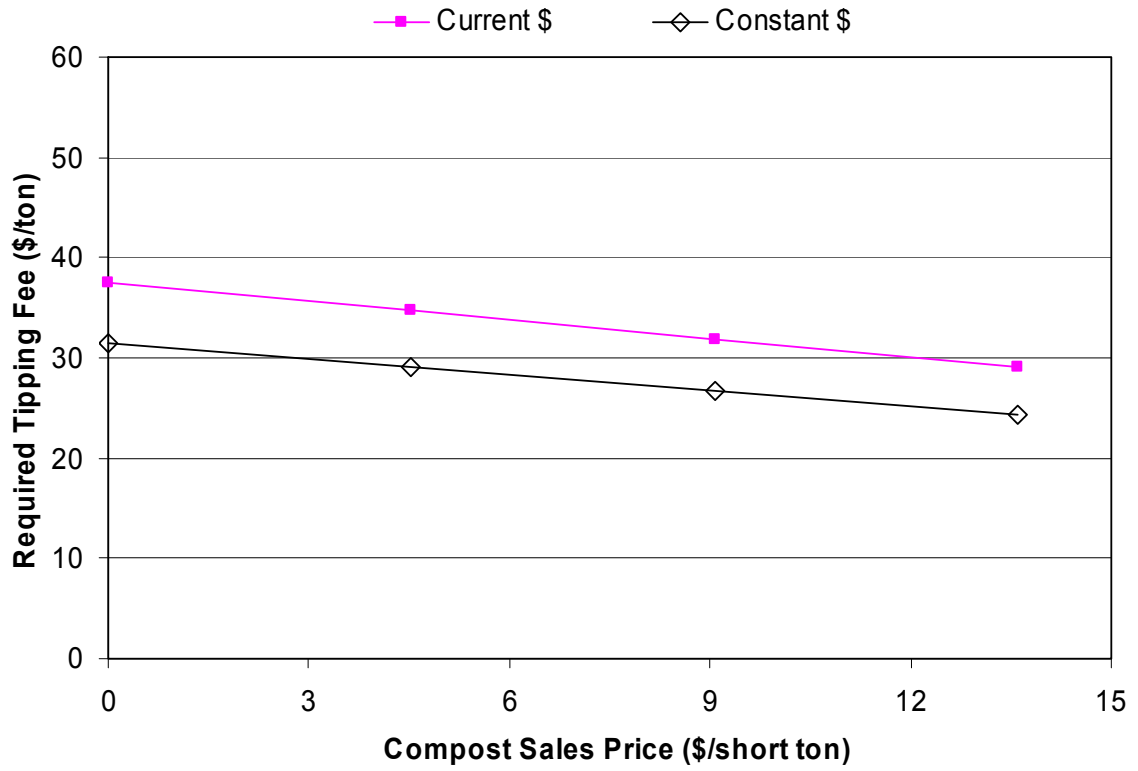

Figure 3.8-15. Required tipping fee vs. compost sales price (MSW AD Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

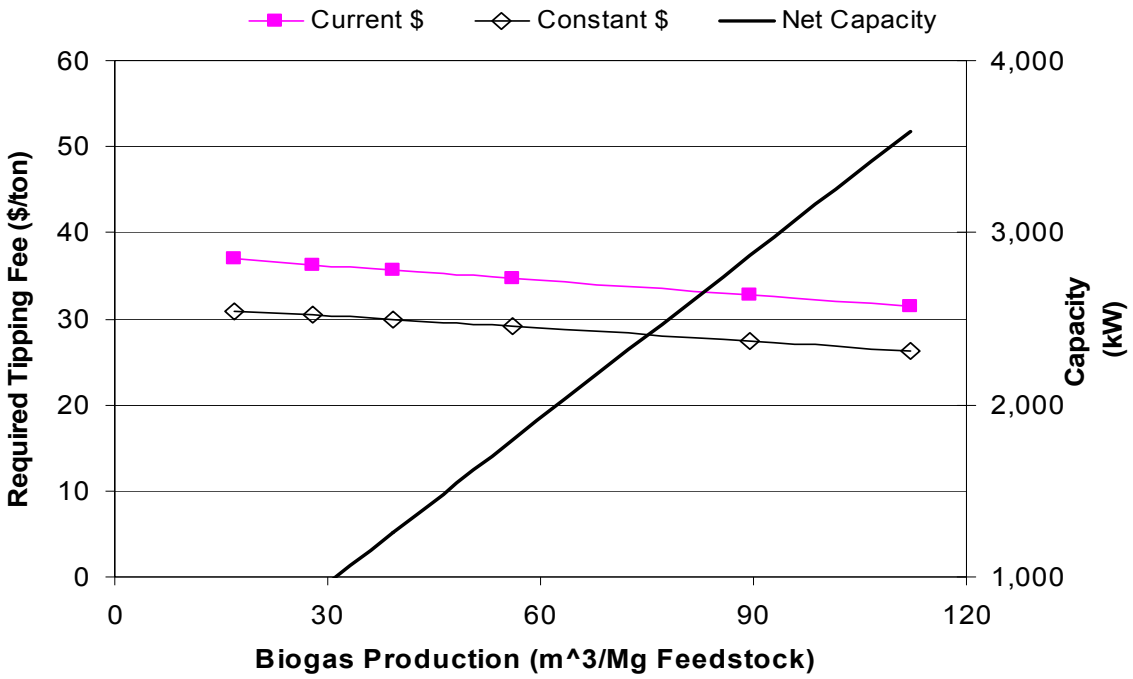

Figure 3.8-16. Required tipping fee & electrical capacity vs. biogas production (MSW AD Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

3.8.3 Anaerobic Phased Solids (APS) Digester

Assumptions

A preliminary economic analysis and risk assessment for the proposed CSU–Channel Islands APS digester facility was evaluated by HMH Energy Resources, Inc. (Larkspur, California) (McOuat and Gill 2004). The analysis concluded the project has a rate of return above the minimum required but the economics are very sensitive to changes in the assumptions (for example, tipping fee, capital costs, gas production). The recommendation by HMH was that CSU–Channel Islands should not pursue the project until satisfied with the performance of the 3 ton/day pilot plant nearing completion at the UCD campus.

Because the Channel Islands facility would sell biogas to another facility, economics of electricity generation were not included in the HMH review. For the most part, the analysis in this report uses the same economic and operational assumptions used in the HMH analysis, but instead, the biogas is used for fuel in reciprocating engine generators.

Adjustments and additions to the economic assumptions found in the HMH review in order to compute COE are given here:

- The capital and operating cost of generation equipment was added to the other costs detailed in the HMH review.

- Salaries and wages were reduced by 20%.
- Inflation and general escalation changed from 3% to 2.1%.
- A 20 -ear technical and economic life is used (instead of 15).
- A debt ratio of 85% (6% interest rate on debt and 15% ROR on equity).
- No water sales in the project.

These adjustments/additions are applicable to a more general situation rather than the specific conditions found at CSU–Channel Islands.

Using the same methane production per mass of feedstock (as in the HMH analysis), this facility should be able to generate about 1,560 kW (gross, capacity factor = 100%). The cost of generation equipment added to the $15.25 million digester plant is $1.66 million (based on a recent quote of $1.060/kW with $0.015/kWh O&M by Caterpillar Engine Company) (Zughbi 2005).

It was assumed that 80% of the gross generation is available for sale or use outside of the digester facility (i.e., 20% parasitic load).

Two scenarios were investigated: (1) the company is profitable with taxable income from other enterprises which allow the "negative" taxes generated in early years by depreciation and a $0.009/kWh PTC for five years to be credited to the project; and (2) the company is small, with perhaps this project being its only venture, and cannot utilize deductions and credits once tax liability reaches zero for any given year.

Results

Tables 3.8-5 and 3.8-6 show the assumptions and operational parameters for Scenarios 1 and 2, respectively. For Scenario 1, the levelized COE is $0.080/kWh (constant dollars). Scenario 2 has a levelized COE of $0.102/kWh (constant dollars). The ability to make full use of tax credits and capital depreciation (typically for larger firms), reduces electricity cost by $0.02/kWh. However, the COE for both scenarios are probably too high to compete on the open market, but may allow a project to be economical if the power is used on site to offset high retail electricity.

Base case cash flows appear in the appendix.

Sensitivity

Sensitivity analyses were done and the results are presented in Figures 3.8-24 through 3.8-27 for Scenario 1 and Figures 3.8-28 through 3.8-31 for Scenario 2.

As with other MSW AD systems, the COE is extremely sensitive to changes in tipping fee. A 10% change in tipping fee inversely changes the COE by more than 20%. In other words, an increase in tipping fee from the base case $27/ton to $30/ton will decrease the Scenario 1 COE from $0.08 to 0.062/kWh. Similarly, a reduction in tipping fee from $27 to 24/t increases COE from $0.08 to 0.098/kWh.

The COE is also quite sensitive to the capital costs. A 10% reduction in capital costs will reduce COE by more than 20%. Sensitivity of COE to O&M costs is about 1.5:1, or a 10% move in O&M costs changes COE by about 15%. COE is less sensitive to changes in sales of compostable digestate material.

The high degree of COE sensitivity to tipping fee, capital costs, and O&M costs is due to the relatively small energy production (and, therefore, electricity revenue) from AD systems. The revenue streams from tipping fee and compost sales are about twice that of the electricity. Together, the debt payment, equity recovery, and expenses amount to 3.3 times the revenue stream from energy. Changes in any of the major expense or non-energy revenue streams have a magnified effect on COE.

Table 3.8-5. APS digester Scenario 1 base case, (full use of tax reductions)

Capital Cost and Performance Assumptions	
Annual Wet Feedstock Consumption (Mg/y)	69,160
Annual Wet Feedstock Consumption (ton/y)	76,251
Digester Plant Cost ($)	15,250,276
Engine Generator Cost ($)	1,658,002
Total Facility Capital Cost ($)	16,908,278
Complete Cost ($/ton annual capacity)	222
Gross Electrical Capacity (kWe)	1564
Net Electrical Capacity (kWe)	1251
Parasitic Load (kWe)	313
Capacity Factor (%)	100
Methane Production (m3/kg Wet Feedstock)	0.0577
Annual Methane Production (m^3/y)	3,990,532
Fraction of biogas used for heat or steam (%)	0
Gross Efficiency--Biogas to Electricity (%)	34
Annual Gross Electricity Generation (kWh)	13,701,979
Net Electricity available for sale (kWh/yr)	10,961,583
Annual Sludge production (t/y -50% moisture)	32,420
Liquid water, waste or re-use in process (t/y)	33,963

Expenses	
Labor Cost ($/y)	497,921
Digester Plant Op & Maintenance Cost ($/y)	457,508
Insurance/Property Tax/utilities/professional ($/y)	84,541
Engine Operating Expenses ($/y)	205,530
Contingency	62,275
Total Expenses ($/y)	1,307,776
Total Expenses ($/ton input)	17.2

Escalation/Inflation	
General Inflation (%/y)	2.10
Escalation for Production Tax Credit (%/y)	2.10
Escalation--Sludge sales (%/y)	2.10
Escalation--Other (%/y)	2.10

Taxes	
Federal Tax Rate (%)	34.00
State Tax Rate (%)	9.60
Production Tax Credit ($/kWh)	0.009
Combined Tax Rate (%)	40.34

Data collected by Robert Williams (insert contract dates)

Income	
Electricity Capacity Payment ($/kW-y)	0
Electricity Sales Price ($/kWh)	Model Output
Electricity sales (or offset) $/y	Model Output
Interest Rate on Debt Reserve, if any (%/y)	2.0
Sales price for Compostable Material ($/Mg)	13.20
Net Tipping Fee ($/t) [after $9/ton processing cost]	18
Annual Capacity Payment ($/y)	0
Net Water sales price ($/100 gallons)	0
Annual Debt Reserve Interest ($/y)	0
Annual Income from Compost Sales	330,274
Annual Income from Tipping fee ($/y)	1,372,169
Income from Water sales ($/y)	0
Non-Energy Total Income ($/y)	1,702,458
Non-Energy Total Income ($/t wet feedstock)	22.3

Financing	
Debt ratio (%)	85.00
Equity ratio (%)	15.00
Interest Rate on Debt (%/y)	6.00
Economic Life (y)	20
Cost of equity (%/y)	15.00
Cost of Money (%/y)	7.35
Total Equity Cost ($)	2,536,242
Total Debt Cost ($)	14,372,036
Capital Recovery Factor (Equity)	0.1598
Capital Recovery Factor (Debt)	0.0872
Annual Equity Recovery ($/y)	405,194
Annual Debt Payment ($/y)	1,253,020
Debt Reserve ($)	0
Debt Payment and Equity Recovery ($/y)	1,658,213
Debt Payment and Equity Recovery ($/t)	21.7

Depreciation Schedule
10 year MACRS used

Levelized Required Energy Revenue	
Level Annual Revenue Required (current $)	1,043,733
Level Annual Revenue Required (constant $)	874,065

Revenue Requirement (COE)	
(Current $/kWh)	**0.095**
(Constant $/kWh)	**0.080**

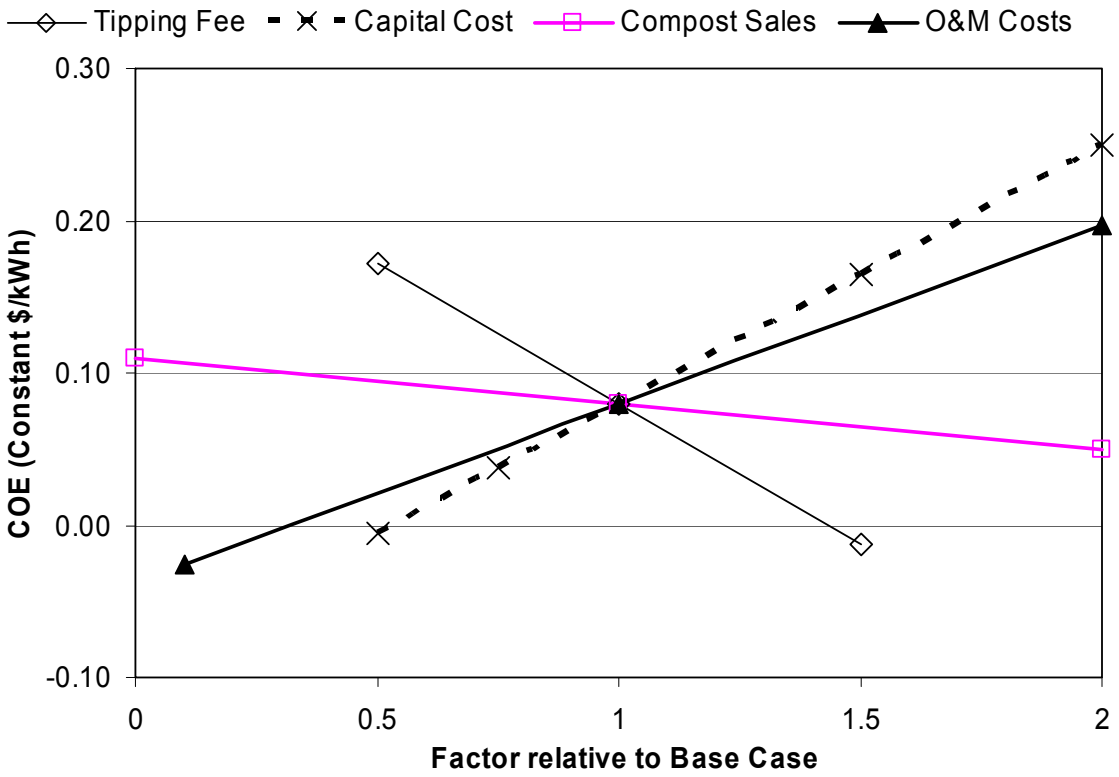

Figure 3.8-17. Constant $ COE sensitivity analysis (APS, Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

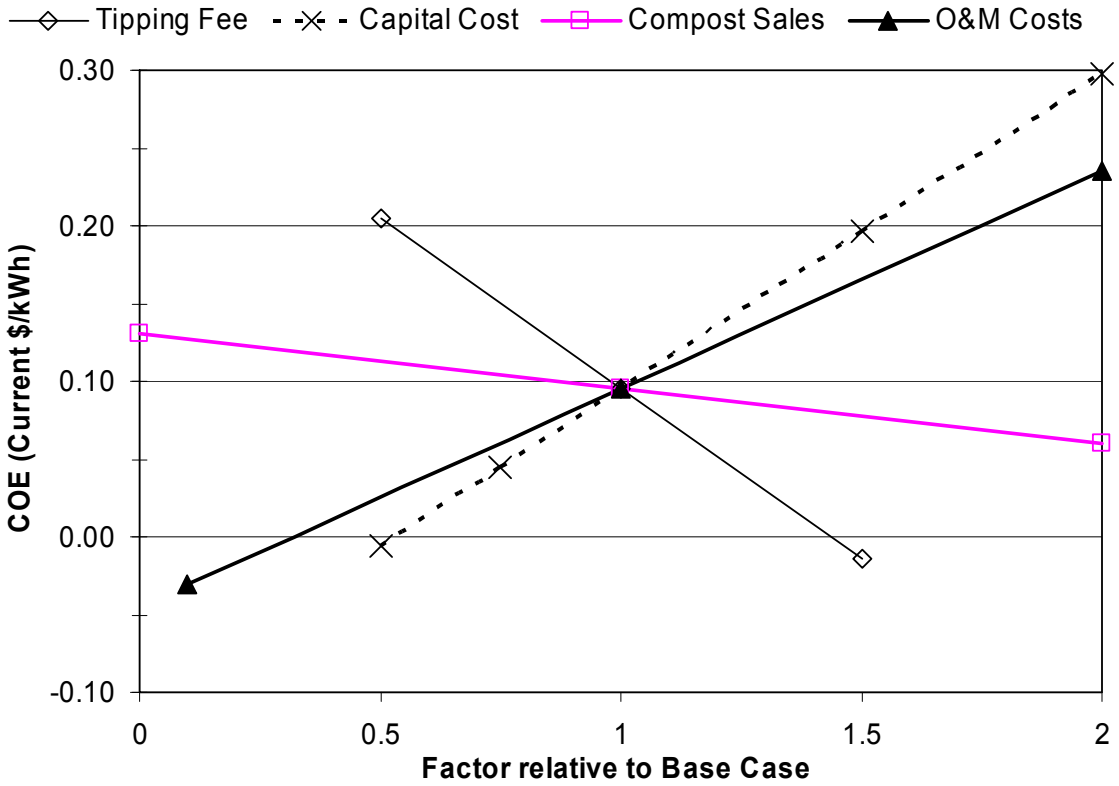

Figure 3.8-18. Current $ COE sensitivity analysis (APS, Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

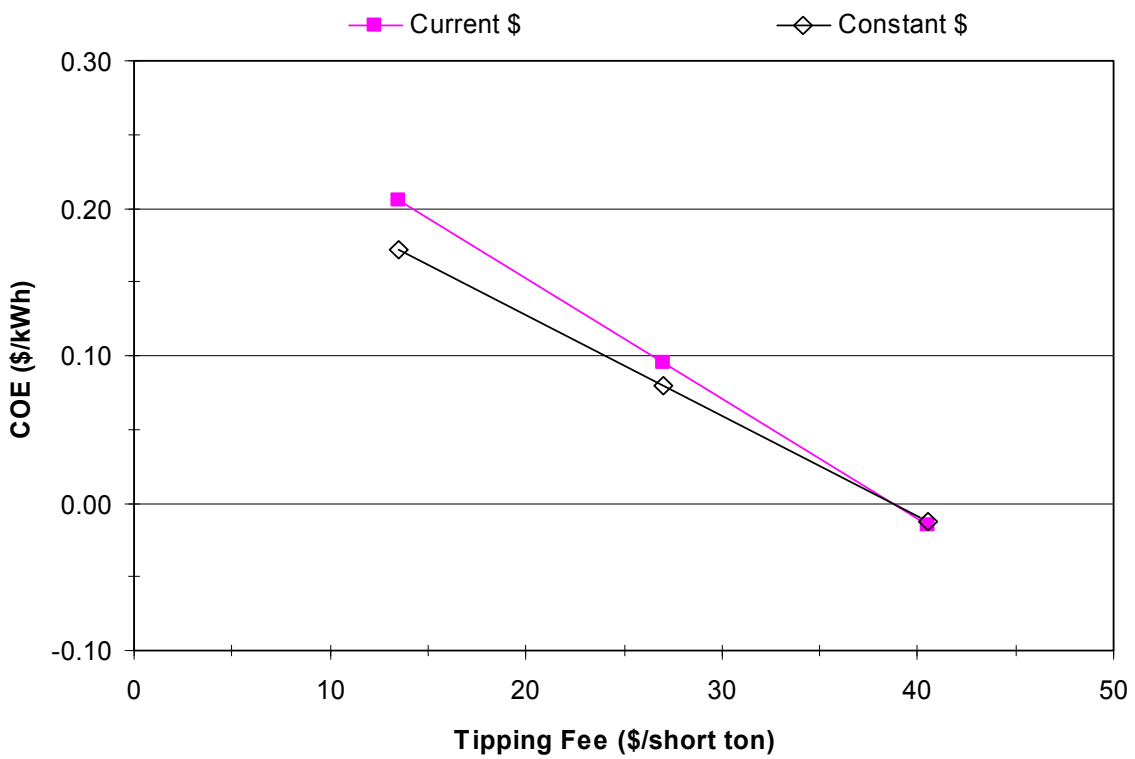

Figure 3.8-19. COE versus tipping fee (MSW AD, Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

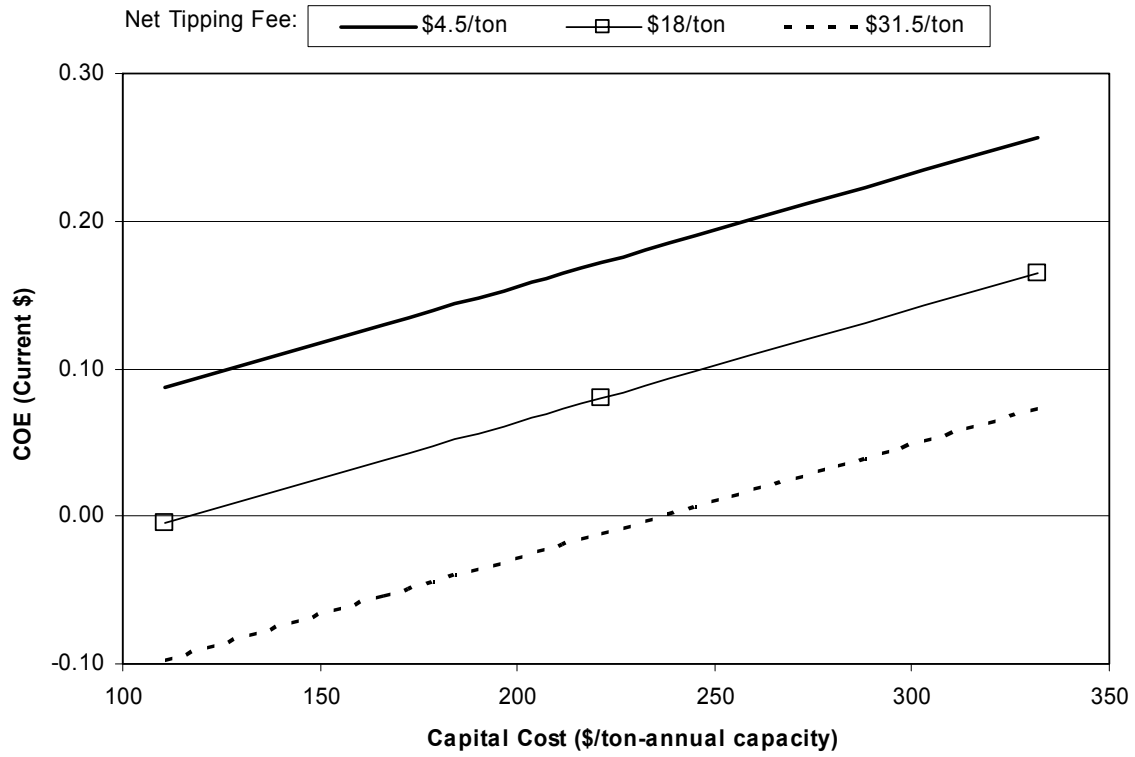

Figure 3.8-20. Current $ COE versus capital cost (MSW AD, Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Table 3.8-6. APS digester Scenario 2 base case, (no "negative" taxes)

Capital Cost and Performance Assumptions	
Annual Wet Feedstock Consumption (Mg/y)	69,160
Annual Wet Feedstock Consumption (ton/y)	76,251
Digester Plant Cost ($)	15,250,276
Engine Generator Cost ($)	1,658,002
Total Facility Capital Cost ($)	16,908,278
Complete Cost ($/ton annual capacity)	222
Gross Electrical Capacity (kWe)	1564
Net Electrical Capacity (kWe)	1251
Parasitic Load (kWe)	313
Capacity Factor (%)	100
Methane Production (m3/kg Wet Feedstock)	0.0577
Annual Methane Production (m^3/y)	3,990,532
Fraction of biogas used for heat or steam (%)	0
Gross Efficiency--Biogas to Electricity (%)	34
Annual Gross Electricity Generation (kWh)	13,701,979
Net Electricity available for sale (kWh/yr)	10,961,583
Annual Sludge production (t/y -50% moisture)	32,420
Liquid water, waste or re-use in process (t/y)	33,963

Expenses	
Labor Cost ($/y)	497,921
Digester Plant Op & Maintenance Cost ($/y)	457,508
Insurance/Property Tax/utilities/professional ($/y)	84,541
Engine Operating Expenses ($/y)	205,530
Contingency	62,275
Total Expenses ($/y)	1,307,776
Total Expenses ($/ton input)	17.2

Escalation/Inflation	
General Inflation (%/y)	2.10
Escalation for Production Tax Credit (%/y)	2.10
Escalation--Sludge sales (%/y)	2.10
Escalation--Other (%/y)	2.10

Taxes	
Federal Tax Rate (%)	34.00
State Tax Rate (%)	9.60
Production Tax Credit ($/kWh)	0.009
Combined Tax Rate (%)	40.34

Data collected by Robert Williams (insert contract dates)

Income	
Electricity Capacity Payment ($/kW-y)	0
Electricity Sales Price ($/kWh)	Model Output
Electricity sales (or offset) $/y	Model Output
Interest Rate on Debt Reserve, if any (%/y)	2.0
Sales price for Compostable Material ($/Mg)	13.20
Net Tipping Fee ($/t) [after $9/ton processing cost	18
Annual Capacity Payment ($/y)	0
Net Water sales price ($/100 gallons)	0
Annual Debt Reserve Interest ($/y)	0
Annual Income from Compost Sales	330,274
Annual Income from Tipping fee ($/y)	1,372,169
Income from Water sales ($/y)	0
Non-Energy Total Income ($/y)	1,702,458
Non-Energy Total Income ($/t wet feedstock)	22.3

Financing	
Debt ratio (%)	85.00
Equity ratio (%)	15.00
Interest Rate on Debt (%/y)	6.00
Economic Life (y)	20
Cost of equity (%/y)	15.00
Cost of Money (%/y)	7.35
Total Equity Cost ($)	2,536,242
Total Debt Cost ($)	14,372,036
Capital Recovery Factor (Equity)	0.1598
Capital Recovery Factor (Debt)	0.0872
Annual Equity Recovery ($/y)	405,194
Annual Debt Payment ($/y)	1,253,020
Debt Reserve ($)	0
Debt Payment and Equity Recovery ($/y)	1,658,213
Debt Payment and Equity Recovery ($/t)	21.7

Depreciation Schedule
20 year Straight-Line used

Levelized Required Energy Revenue	
Level Annual Revenue Required (current $)	1,324,195
Level Annual Revenue Required (constant $)	1,108,936

Revenue Requirement (COE)	
(Current $/kWh)	0.121
(Constant $/kWh)	0.101

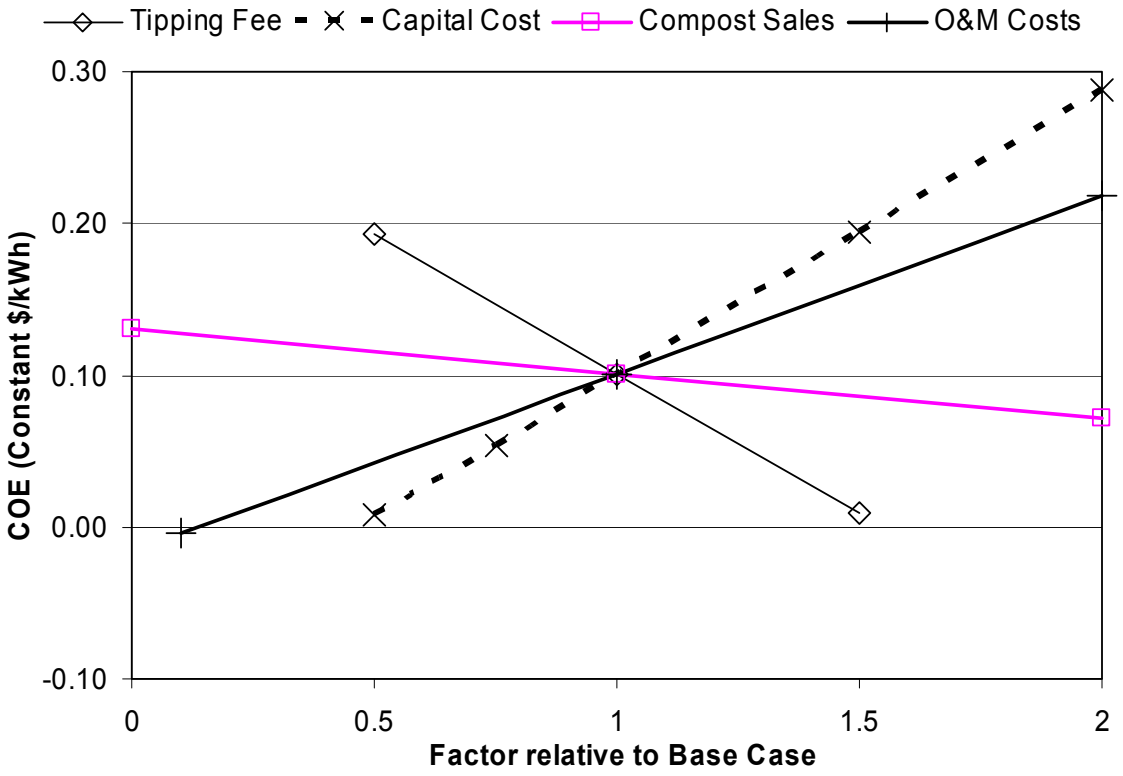

Figure 3.8-21. Constant $ COE sensitivity analysis (APS, Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

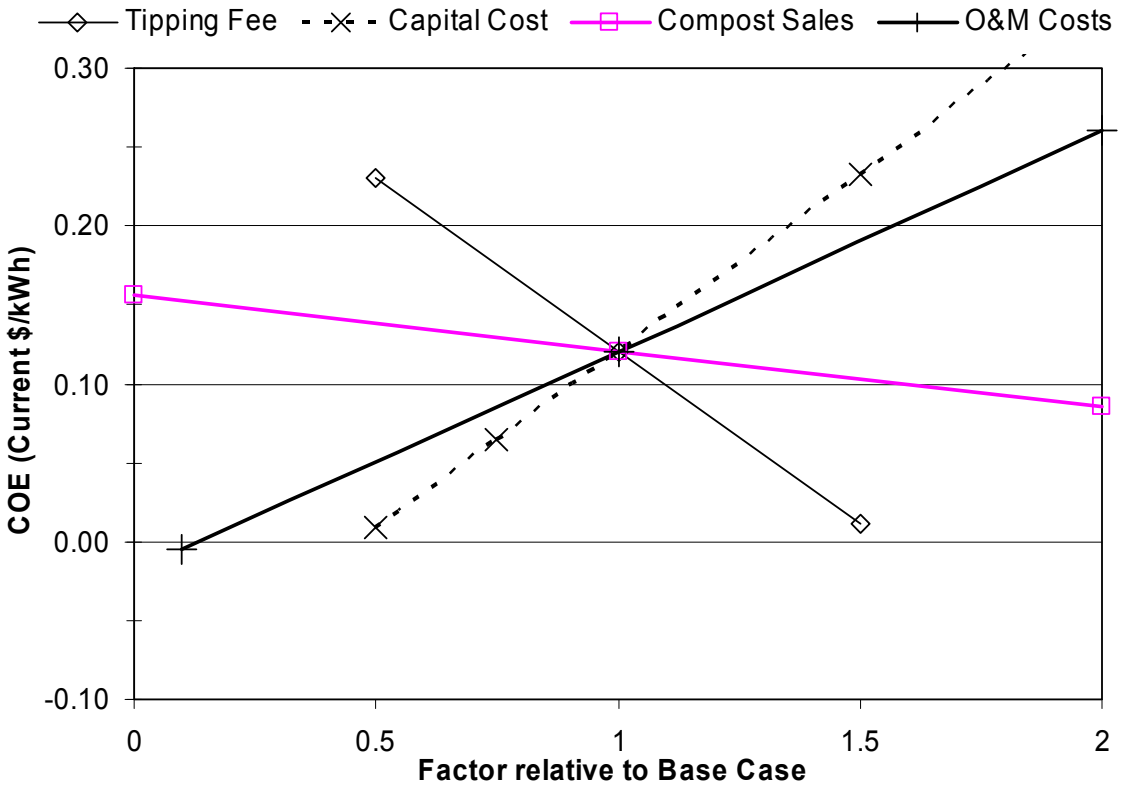

Figure 3.8-22. Current $ COE sensitivity analysis (APS, Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

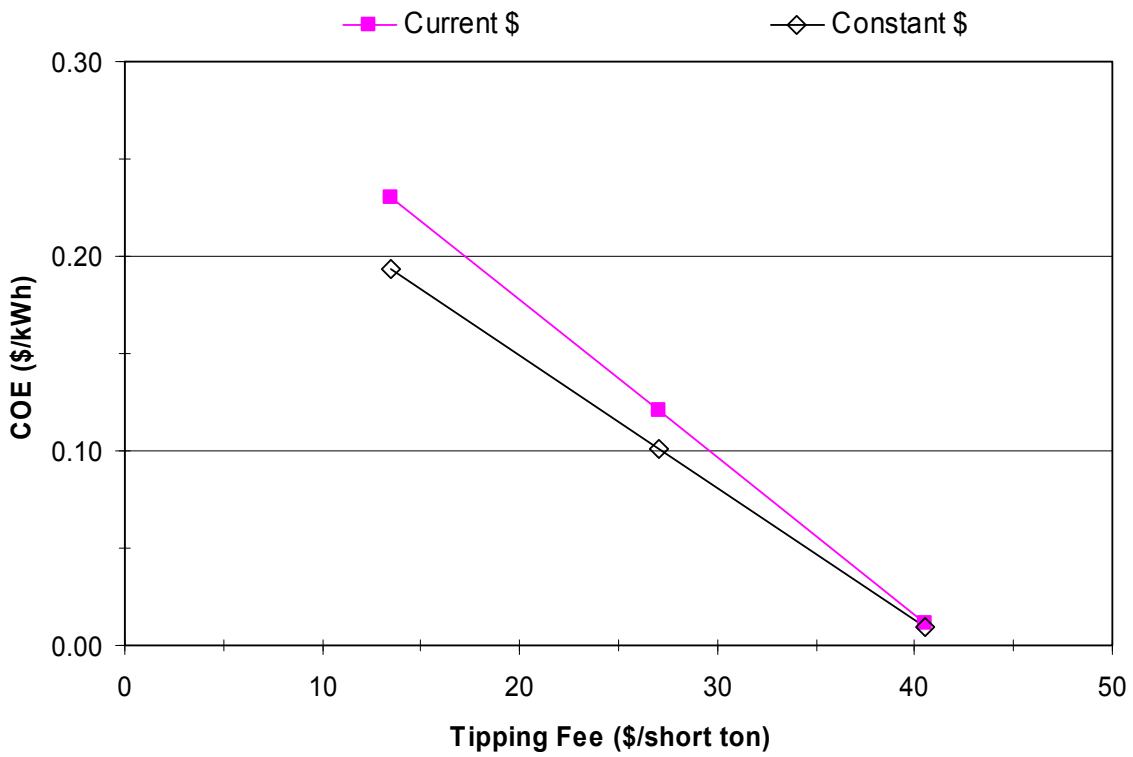

Figure 3.8-23. COE versus tipping fee (MSW AD, Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

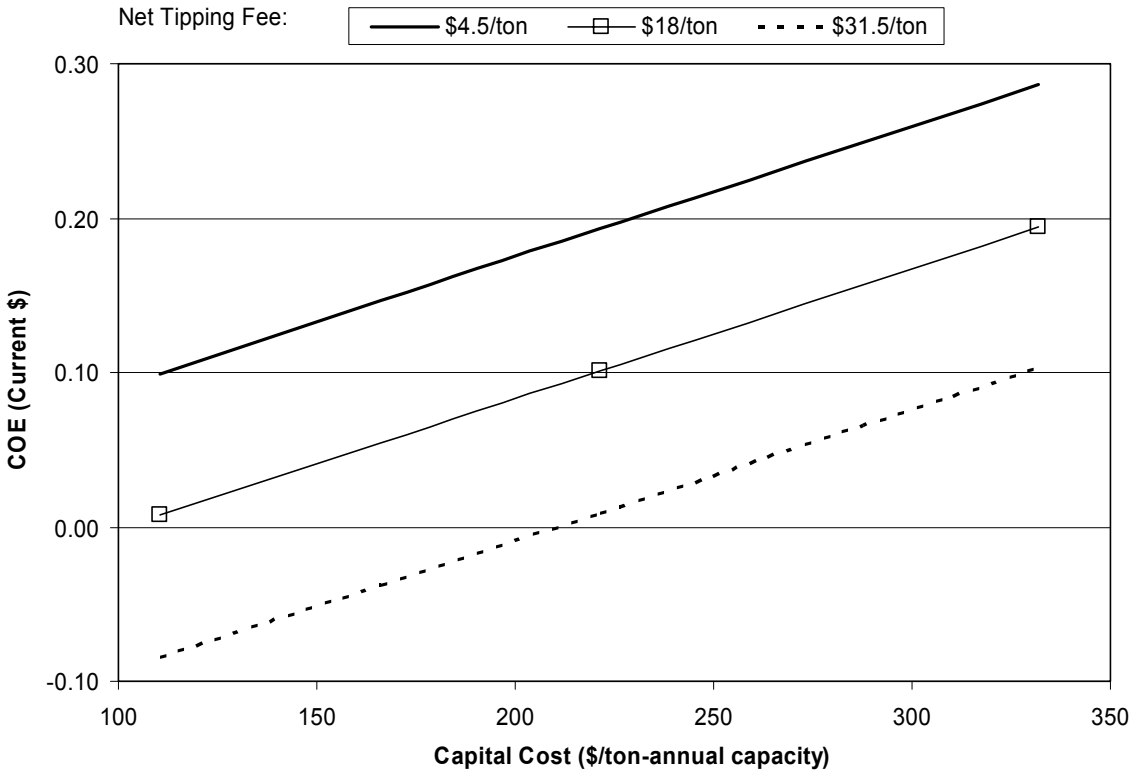

Figure 3.8-24. Current $ COE versus capital cost (MSW AD, Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

3.9. Dairy Manure Power Systems

Background

Recent legislation (SB 5X) appropriated monies for assisting dairies in California in the installation of systems to create power from dairy wastes. This led to the establishment of the Dairy Power Production Program by the California Energy Commission in order to encourage the development of biologically based anaerobic digestion and gasification ("biogas") electricity generation projects in the State. Objectives include developing commercially proven biogas electricity systems to help California dairies offset the purchase of electricity, and providing environmental benefits through reduction of air and ground water pollutants associated with storage and treatment of livestock wastes. Approximately $10 million was available including program administration costs.

Western United Resource Development, Inc. (WURD) was selected by the Energy Commission to manage the program. The program can provide two types of assistance for qualifying dairy biogas projects: (1) buy-down grants that cover a percentage of the capital costs of the proposed biogas system; or (2) incentive payments for generated electricity. In general, buy-down grants cover a maximum of up to 50% of the capital costs of the biogas system based on estimated power production, not to exceed $2,000/kW installed, whichever is less. Electricity generation incentive payments are based on 5.7 cents/kWh of electricity generated by the dairy biogas system paid out over a maximum of five years. The total cumulative payments under the incentive payment route are intended (after five years) to equal the amount of funding that would be provided for an equivalently sized digester-to-electricity system under the buy down approach.

3.9.1 Determining Costs

Actual costs for these projects are not yet documented. The costs were estimated in the grant proposals which served as the basis for determining the award amount. Grant payments are subject to invoices to be submitted by the project owners. Complete invoices are not yet available for review.

The estimated costs, generation capacities and other information for the projects in the DPPP are listed in Table 3.9-1. The estimated capital costs range is $1,470 to 6,000/kW. The value of $1,470/kW seems low since engine generator sets alone cost between $600 and $1,200 (or more)/kW depending on size, heat recovery and emission control equipment, etc. The cost on a "per head" basis is $180 to $860 per lactating cow. The costs per kW capacity do not correlate with the costs per animal because not all of the information is believed to be consistent. For example, some of the design capacities are based on a future projected herd size and/or not all of the existing lactating cows at the dairy are necessarily served by the digester system.

Table 3.9-1. California Dairy Power Program estimated costs and capacities

Number of Lactating Cows	System Type	Estimated Capacity (kW)	Estimated Costs		Grant Amount	Estimated Total Cost
			($/kW)	($/animal)		
175	Cov'd lagoon	30	2500	429	$37,500	$75,000
237	Cov'd lagoon	75	1811	573	$67,900	$135,800
1050	Cov'd lagoon	120	3017	345	$181,000	$362,000
1258	Cov'd lagoon	150	1530	182	$114,779	$229,557
1600	Cov'd lagoon	160	4831	483	$320,000	$772,925
6000	Cov'd lagoon	250	6000	250	$500,000	$1,500,000
5081	Cov'd lagoon	300	4298	254	$600,000	$1,289,520
1100	Mixed	100	5820	529	$200,000	$582,000
600	Plug flow	130	3764	815	$244,642	$489,284
770	Plug flow	150	4413	860	$300,000	$661,923
1900	Plug flow	160	3281	276	$262,449	$524,898
1500	Plug flow	260	1469	255	$190,925	$381,850
4700	Plug flow	563	2747	329	$773,175	$1,546,350
7200	PF -2 stage	1000	4565	634	$2,000,000	$4,565,000
	Averages	246	3575	444	$413,741	$936,865
				Totals	$5,792,370	$13,116,107

PF = Plug Flow
Data collected by Robert Williams (insert contract dates)

More specific operational and better cost data are needed in order to do a detailed analysis. Recent progress reports with updated cost and three months of performance data are available from the Energy Commission.[135] Three of the facilities discussed in the report utilize a covered lagoon for the digester and one facility is a plug-flow system. The dairy sizes range from 250 to 5,350 average numbers of lactating cows. Two facilities estimate gas production is about twice what the installed engine can consume and are in the process of or are considering adding engine-generator capacity. If more engine capacity is added, the estimated total installed cost for these four systems is $3,000 to $4,500/kW. Table 3.9-2 displays some of the cost and performance information in the recent progress reports.

135. DPPP 90-day evaluation reports (Publication Nos. CEC-500-2005-114, -115, -116, and -117. Available at: http://www.energy.ca.gov/pier/renewable/finalreports.html

Table 3.9-2. Updated cost and performance information from four DPPP dairies

DPPP Dairy	Ave. number lactating cows	HRT (days)	Capacity (kWe)	Ave Power (kW)	Engine eff.	Est. Gas Prodn. (ft^3/cow/d)	Est. Power/cow (Kw/cow)	Final Capital Cost ($)	Installed Cost ($/kW)	Operating Cost ($/kWh)	Installed Cost -w/ sufficient capacity ($/kW)
Cotton-wood	5,351	34	300	255	0.32	41	0.05	2.7 M	**9,000**	0.027	**4,351**
Castel. Bros.	1,608	40	160	129	0.25	88	0.08	800,000	**5,000**	0.006	**2,932**
Meadow-brook	2,133	19	160	106	0.21	32	0.05	800,000	5,000	0.007	5,000
Blakes Landing	247	34	75	26	0.24	60	0.11	336,362	4,485	0.005	4,485

Data collected by Robert Williams (insert contract dates)

There is readily available information for dairy digesters planned and operating in the upper Midwest (Kramer 2004). The "Biogas Casebook" by Kramer contains information on a number of digester facilities designed for animal manure in the Great Lakes region. Most of the facilities are dairies, but swine and poultry manure digesters are included as well. Table 3.9-3 contains a summary of information for most of the operating or planned dairy digester systems in the Case Book. The cost information is reported by the project developer or estimated by Kramer. The costs for these facilities range from about $2,400 to $5,900/kW and about $400 to $1,100 per lactating cow.

Table 3.9-3. Estimated costs and capacities for dairy digester systems in the Midwest (Kramer 2004).

Number of Lactating Cows	System Type	No. of Stages	Estimated Capacity (kW)	Estimated Costs ($/kW)	Estimated Costs ($/animal)	Estimated Total Cost
840	PF	1	135	2630	423	$355,000
1,000	PF	1	140	3571	500	$500,000
675	PF	1	130	3858	743	$501,500
1,400	PF	1	260	5869	1090	$1,526,000
875	PF	2	135	3852	594	$520,000
1,100	PF	2	200	3500	636	$700,000
3,400	PF	2	700	2429	500	$1,700,000
900	M		750	-	-	NA
910	M		750	-	-	NA
1,000	PF	2	200	-	-	NA
1,000	PF	2	200	-	-	NA
2,400	M		375	-	-	NA
3,200	VPF		750	-	-	NA
3,750	PF	2	600	-	-	NA
			Averages	3673	641	$ 828,929

PF = Plug Flow, VPF = Vertical Plug Flow, M = Mixed tank
NA = Not Available
*Figures 3.9-1 through 3.9-4 display some of the information in Tables 3.9-1 and 3.9-2.
Data collected by Robert Williams (insert contract dates)

Figure 3.9-1 shows estimated costs ($/kW) versus design or estimated capacity. There does not appear to be an economy of scale if all digester types are lumped together. For the covered lagoon designs in California, it appears that cost per installed kW increases with capacity, contrary to expectations. A review of the actual cost data when available is recommended before any conclusions can be made regarding this apparent trend. Plug flow designs (PF) in the Midwest have a similar cost trend, but again, further investigations are warranted. California PF designs, and Midwest two-stage PFs do seem to trend to lower cost with larger capacity (Figure 3.9-1), but again, because of the uncertainty in the data the small number of facilities in the data set, and the relatively narrow ranges of sizes built, no conclusions can be made at this time.

Figure 3.9-2 shows cost on a per animal basis versus number of animals at the facility. The data are somewhat less scattered but there seems to be a trend towards lower cost with increasing herd size.

Figure 3.9-3 displays total capacity versus number of animals. As expected, capacity increases with number of animals. Figure 3.9-4 shows the per-animal capacity (kW/animal) compared with herd size. There appears to be a weak trend to lower kW/animal with larger herd size which is also counter-intuitive. One might expect better manure collection efficiency with larger operations. The weak trend in Figure 3.9-4 might reflect specification of over sized generating capacities in anticipation of increasing herd size sometime in the future.

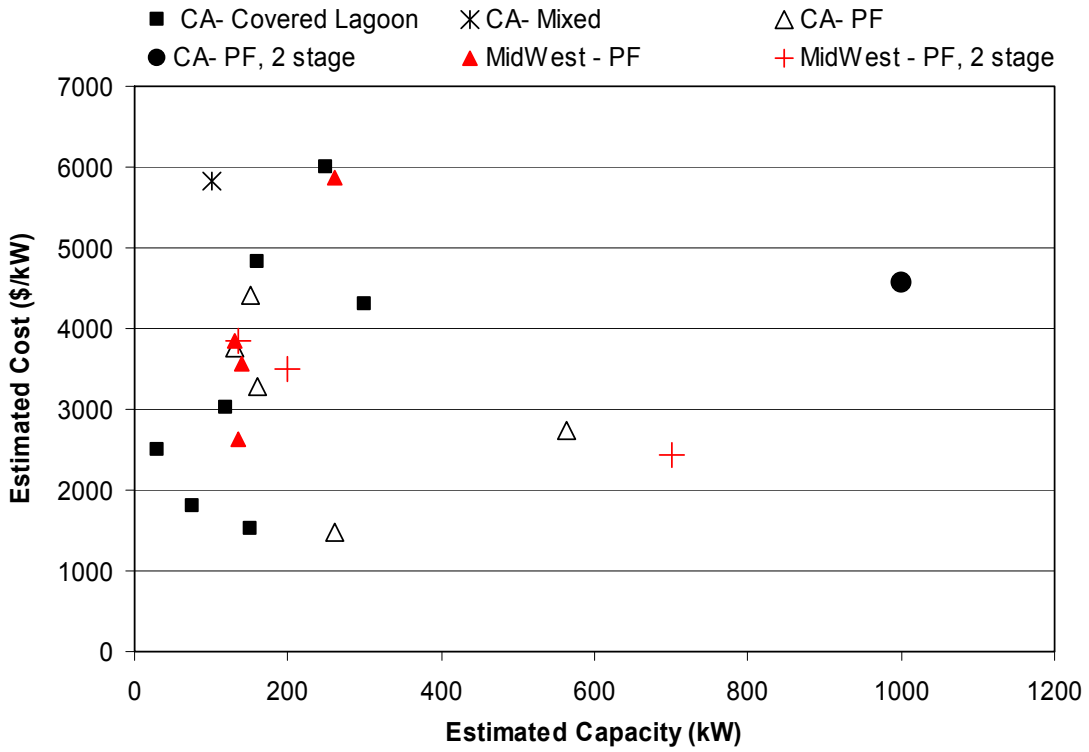

Figure 3.9-1. Estimated installed costs versus capacity for California and Midwest dairy digesters

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

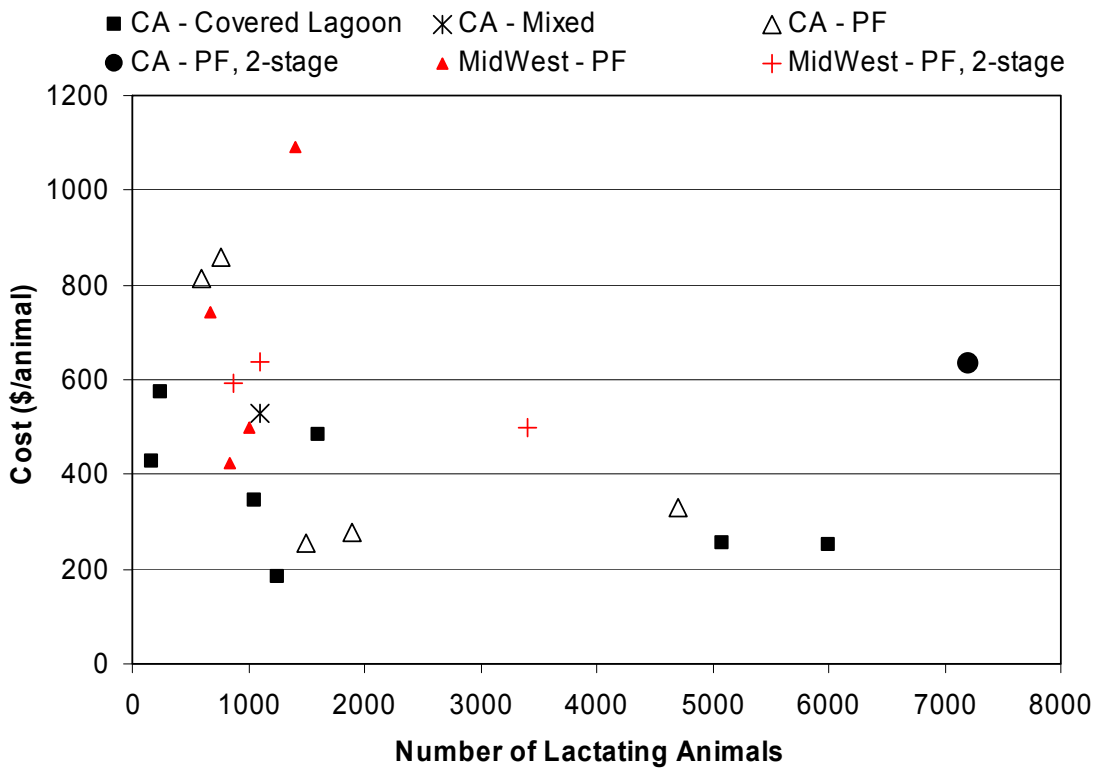

Figure 3.9-2. Dairy digester costs versus number of animals

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

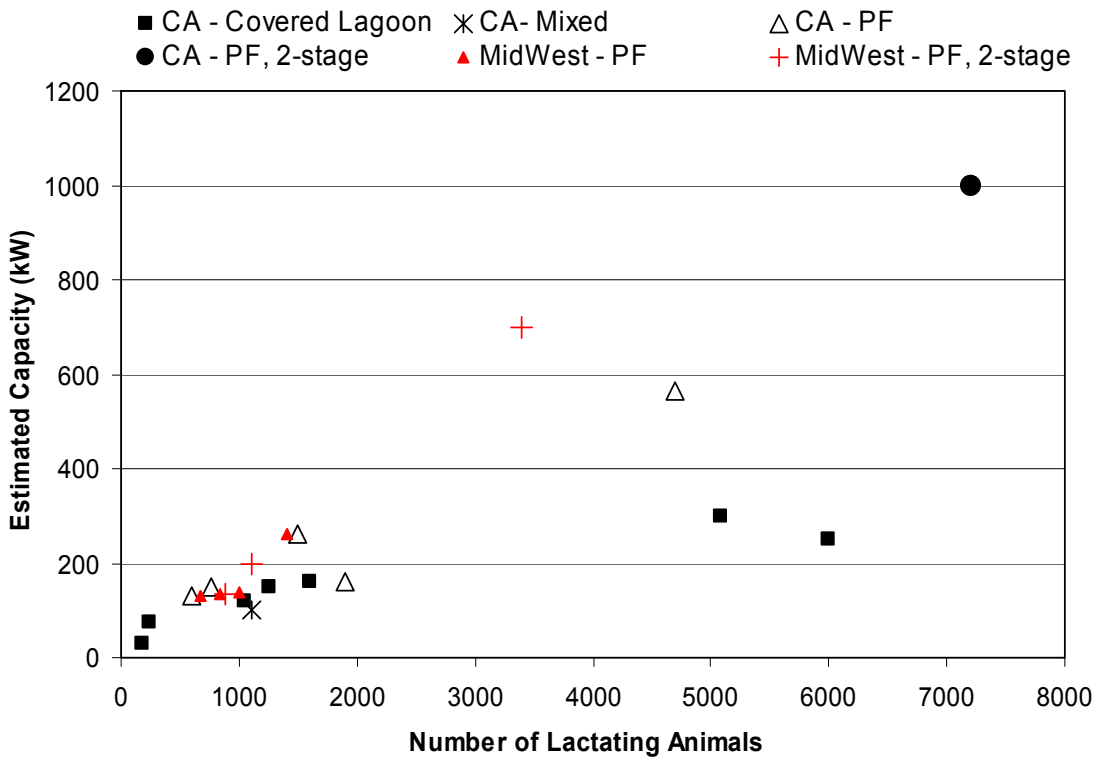

Figure 3.9-3. Estimated total capacity versus number of animals for dairy digesters

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

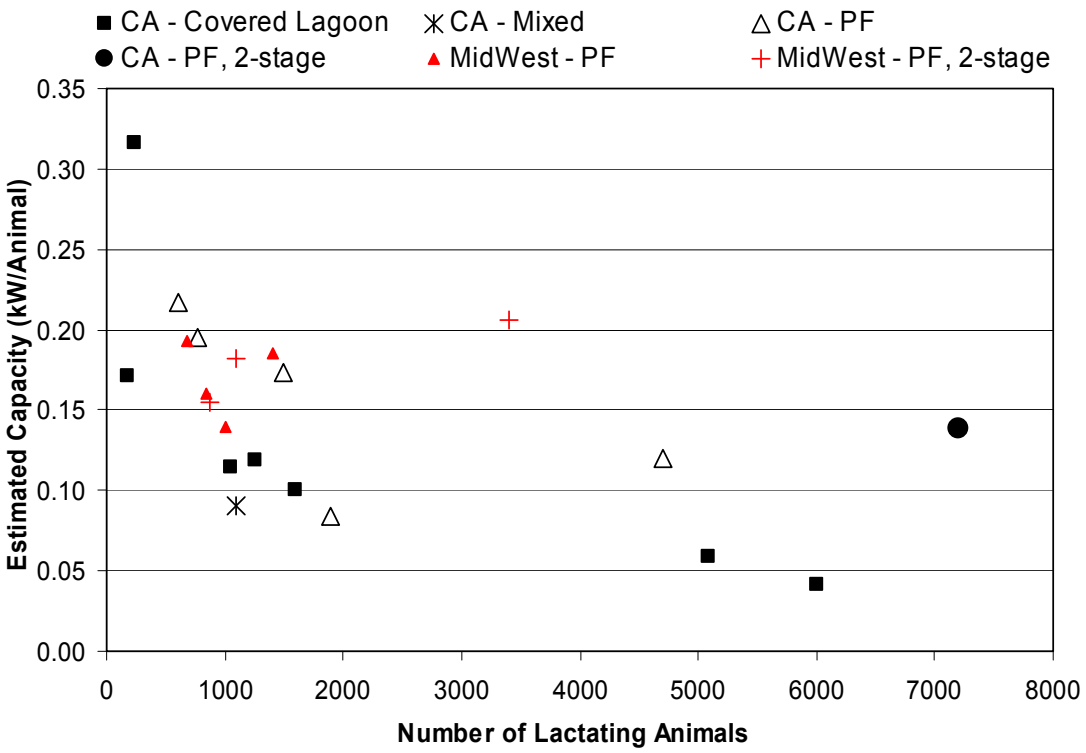

Figure 3.9-4. Estimated capacity per animal versus number of animals for dairy digesters
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

DPPP COE Estimates

Cost of energy estimates for the California DPPP projects with the highest ($6,000/kW) and lowest ($1,469/kW) capital cost estimates were made. The assumptions include 85% percent capacity factor, 25% equity ratio, 6% loan interest rate, 15% return on equity, 15 year economic life, and a $0.009/kWh production tax credit for the first five years.

O&M costs are assumed to be $0.02/kWh. This includes engine generator costs of $0.015/kWh. For each scenario, the total O&M costs are about $37,200 for the first year.

The five-year MACRS depreciation schedule was used and the "negative taxes" from depreciation and debt interest are allowed or credited to the project. Combined state and federal tax rate is 40.34%.

Though the economic life (and technical life) was assumed to be 15 years, estimates were made for two loan repayment periods: one at 10 years and another at 15 years. Also included are the results for COE using a five-year loan and investment recovery period which approximates revenue required for a five-year simple payback.

Results

For the low capital cost scenario, the constant dollar COE ranged from 3.5 cents/kWh (for the low capital cost amortized over 15 years) to 10.0 cents/kWh for the large capital cost case with a 10-year loan repayment period. For the midlevel capital cost ($3600/kWh), COE was about 6.4 cents/kWh (Table 3.9-4).

If 40% of the engine exhaust and cooling water heat are recovered (annual basis), then COE is lowered by roughly 1.5 cents/kWh (assuming displacement of natural gas priced at $5.50/MMBtu.

For recovery of all investment and loan amounts after 5 years, the levelized COE is approximately 6, 13, and 21 cents/kWh for the low, midlevel, and high capital cost cases, respectively (Table 3.9-4).

Figure 3.9-5 displays the relationship of COE to capital cost using different loan periods and project lifetimes. For projects with simple payback period of five years (i.e., five-year loan and revenues sufficient to pay loan and operating costs in the first five years), the COE is quite sensitive to capital cost,

Table 3.9-4. Economic parameters for California DPPP for highest, lowest, and mid-priced project

Parameter	Units	Inputs and Results					
Capital Cost	($/kW)	**1469**		**3600**		**6000**	
Net Estimated Capacity	(kW)	250					
Capacity Factor	(%)	85					
"	(hours)	7446					
Energy Production	(kWh)	1,861,500					
O&M	$/kWh	0.02					
Debt ratio	(%)	75					
Equity ratio	(%)	25					
Interest Rate on Debt	(%)	6					
Cost of Equity	(%)	15					
General inflation/escalation	(%)	2.8					
Total Cost of Plant	($)	**367,250**		**900,000**		**1,500,000**	
Total Equity Cost	($)	**91,813**		**225,000**		**375,000**	
Total Debt Cost	($)	**275,438**		**675,000**		**1,125,000**	
Depreciation		5 yr MACRS					
Production Tax Credit	($/kWh)	0.009					
Combined Tax Rate	(%)	40.34					
Economic Life	(y)	15					
Loan Repayment Period	(y)	**15**	**10**	**15**	**10**	**15**	**10**
Results							
Current $ LAC of Energy	($/kWh)	**0.042**	**0.044**	**0.075**	**0.080**	**0.112**	**0.120**
Constant $ LAC of Energy	($/kWh)	**0.035**	**0.036**	**0.062**	**0.066**	**0.093**	**0.100**
Equity and Loan Repayment - 5 yrs, Analysis period 6 yrs to capture depreciation:							
Current $ COE	($/kWh)	**0.068**		**0.144**		**0.230**	
Constant $ COE	($/kWh)	**0.063**		**0.133**		**0.212**	

Assumes negative taxes are credited to the project.

Data collected by Robert Williams (insert contract dates)

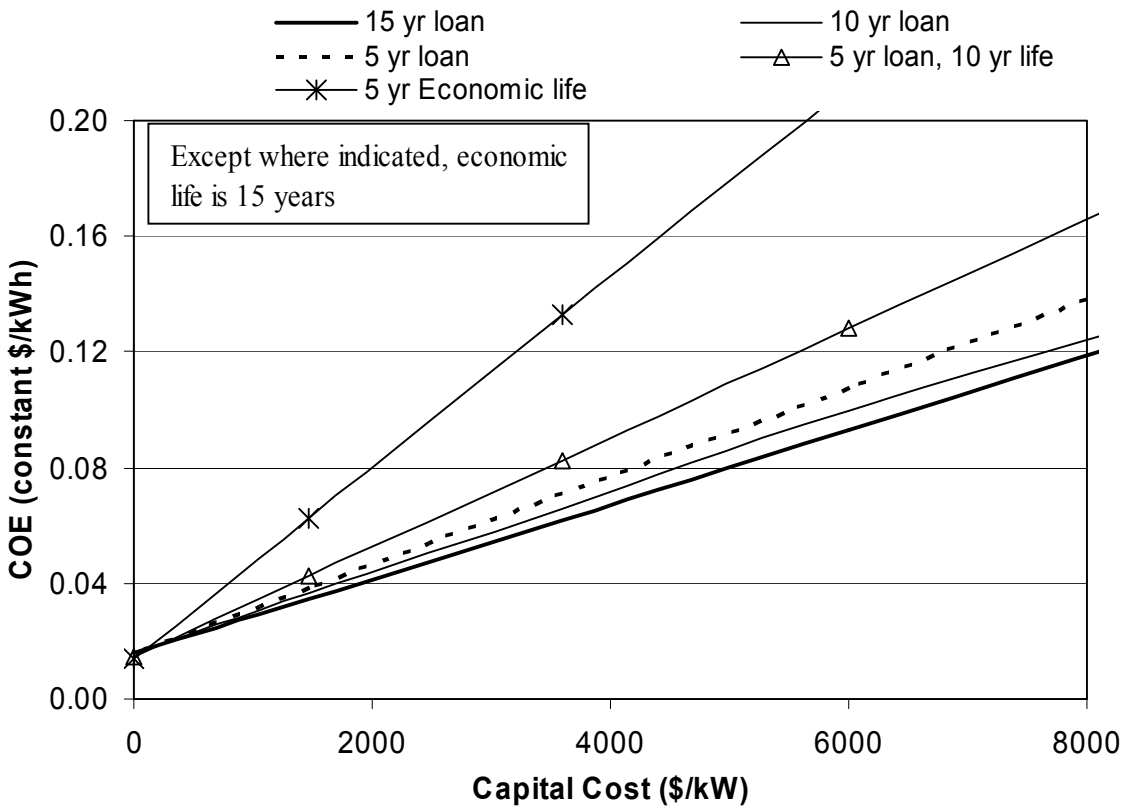

Figure 3.9-5. COE vs. capital cost for several loan periods or economic lifetimes for dairy digester power systems

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Discussion

Dairy digesters can be costly and require moderate energy prices if financed solely by electricity sales. There are likely cases where the systems are financially viable on energy revenue if the facility is a large electricity consumer and the on-site generation can offset retail electricity prices. Delivered power to dairies in the San Joaquin Valley air district varies between 8 and nearly 16 cents/kWh depending on utility and time of year (see Table 3.9-5). Heat recovery for beneficial use is almost always financially attractive if there is a convenient heat client, such as nearby food or cheese processing facility. Co-digestion of food or industrial wastes and/or sillage material is likely to be of advantage economically because of increased gas production and (in the case of food/industrial waste) the possibility of receiving a disposal or tipping fee.

Table 3-9-6. Retail power rates[136]

Power Delivery Service Rates			
Name	Winter ($/kW-hr)	Summer ($/kW-hr)	Average ($/kW-hr)
SCE	0.1027	0.1580	0.1304
PG&E	0.1577	0.1577	0.1577
TID	0.0873	0.0934	0.0904
MID	0.0799	0.0931	0.0865
Total			0.1163

SCE = Southern California Edison
PG&E = Pacific Gas and Electric Company
TID = Turlock Irrigation District
MID = Modesto Irrigation District

136. BACT Cost-Effectiveness for Digester, San Joaquin Valley APCD, 2004.

4.0 Conclusions and Recommendations

Environmental and energy policies in Europe and Japan have created a vibrant biomass power industry and research and development sector. These policies create high feed-in tariffs for renewable energy while simultaneously imposing high landfill costs that enable MSW conversion technology development and deployment.

In California, no new solid fuel combustion facilities have been commissioned since 1992 and several facilities have shut down or converted to natural gas fuel as a result of poor economic conditions including coincident loss of associated industries such as sawmills supplying fuel to cogeneration facilities. Recent biomass power related activity in California has largely been driven by environmental concerns over manure from confined animal operations such as dairies and opportunities for greater use of landfill gas and sewage digester gas. California's renewable portfolio standard (RPS) now provides one of the primary mechanisms for long term contracting for renewable energy, but higher generation costs associated with many biomass technologies in competition with lower-cost wind and geothermal resources have so far restricted biomass entry into this market. Increasing interest in renewable transportation fuels is creating market opportunities for biomass, but power generation will remain a key industry for further biomass development, including an integral part of biorefineries.

Some of the successfully demonstrated or operating systems in Europe could compete in California while others would need some level of support before achieving commercial status. Mechanisms that internalize the external benefits of sustainable biomass power systems are recommended, such as carbon trading, carbon emissions taxes, or renewable energy credits.

One of the hurdles facing transfer of the technology to the United States is the high risk perceived by financiers due to the lack of demonstrated facilities operating in California and satisfying permit requirements. To address these issues of technology transfer, SMUD may wish to consider various development alternatives, including the following:

- Form a public-private partnership to demonstrate advanced thermochemical conversion (i.e., BIGCC) and other technologies in California using pilot or commercial scale designs.
- Increase the biomass power portfolio. SMUD is already involved in the development of biomass power projects that enhance local waste management (i.e., green and food waste and manure).The large resource in the region composed of forest and agricultural thinnings and residues represent an opportunity for SMUD to significantly increase its biomass power portfolio. Specific project recommendations are:
    - Transfer existing biomass CHP technology (500 kW to 2 MW) to a suitable heat client in the Sacramento region (heat clients include absorption cooling applications).

  - Exploit the fuel potential in the region's rice straw and other crop residues with transfer of existing technology.

- Increase research and development funding and activity to obtain more detailed and more reliable operating, economic, and environmental data for new anaerobic digestion and other facilities and participate in or motivate related state efforts to enhance the overall quality of information available on biomass systems.
- Work with the state and federal governments to increase research and demonstration activity on concepts to improve technology and reduce emissions from biomass conversion, including:
  - Investigate advanced reburning using biomass fuels to reduce NOx emissions for retrofit or new facility design.
  - Evaluate SCR and regenerative SCR (RSCR) NOx control techniques.
  - Investigate ozone injection to assess feasibility as a NOx control technique for solid-fueled and other biomass systems.
- Improve emissions performance of reciprocating engines, including:
  - Improve fuel gas cleaning.
  - H_2S and siloxane from biogas to enable greater use of catalytic after-treatment of combustion gases and other control measures.
  - Reduce nitrogen compounds (NH_3, HCN) in producer gas from thermal gasification systems.
- Continue development of hydrogen enriched fuel gas for improved lean burn engine performance.
- Improve efficiency of micro-turbines.
- Reduce costs of stationary fuel cell power systems.

Ongoing and new demonstration or "first commercial" biomass gasification with CHP facilities overseas present a timely opportunity for observing and monitoring these facilities. Further development of existing association with the project developers in order to facilitate exchange of information is recommended. In addressing the greater use of biomass within its territory and surrounding region for renewable generation and improved environmental quality, SMUD will serve as a model for development in the rest of the state. SMUD actions can help shift state waste management policies to more appropriate resource management strategies.

Commercialization Potential and Benefits to California

There has not been any substantial increase in biopower generating capacity in California since the early 1990s. In order for biomass power to make a significant contribution to the supply of renewable electricity in California, the aging fleet of biomass facilities will need to be repowered and large amounts of new capacity must be developed. If this is to occur, new strategies for utilization of biomass resource will be required, including increasing the range of feedstocks used, newer and updated conversion technologies, and a more consistent policy approach.

Because of extensive research and development overseas, advanced biomass power systems that are built in California will likely be imported technologies and designs.

With the higher natural gas prices recently experienced, automated biomass CHP systems are commercially viable if a suitable client for the heat is available. Without heat co-product, the economics of advanced (as well as the standard stoker or circulating fluidized bed boilers) biopower systems are marginal at current electricity market prices.

Depending on which set of RPS goals are pursued (20% renewables by 2017, or 33% by 2020), new renewable generation capacity will be required at the rate of 3,200 to 5,000 MW each year. Current biopower capacity is approximately 1,000 MW and biomass contributes about 2% of total or 25% of renewable power consumed in the state. If biomass power were to continue to provide ¼ of non-hydro renewable generation under the RPS, then new biopower capacity would need to be added at the rate of 800 to more than 1,200 MW each year.

The descriptions, problem identification, and analysis in the report, as well as the contact database can be used to help define a strategy for building increased biopower capacity in California. Increasing biopower production benefits California by increasing the renewable content in the electricity portfolio, generates economic activity in the fuel supply and logistics sector, provides a number of stable jobs at the generating facility, and utilizes some of the vast biomass resource in the state that otherwise would be consumed in prescribed burns or wildfires, disposed in landfills, or left in field or forest for eventual decay.

The information and analysis in this report addresses advanced biopower technologies and includes recommendations for moving forward. This report can serve as a technology reference and information source for those involved in mapping a state biomass power strategy that contributes to the RPS. Used in this way, the report (and project) will save the Energy Commission, or other state agencies, time and money.

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Glossary

AD	Anaerobic digestion
ADC	Alternative daily cover
AF	Air to Fuel Ratio (mass basis)
AF_{stoich}	Stoichiometric Air to Fuel Ratio (mass basis)
AMBR	Anaerobic Moving Bed Reactor
APCD	Air Pollution Control District
APS	Anaerobic Phased Solids
AQMD	Air Quality Management District
ASR	Automobile shredder residue
ATDC	After top-dead-center
BACT	Best Available Control Technology
BDT	Bone Dry Ton
BFB	Bubbling fluidized bed
BGL	British Gas- Lurgi
BIGCC	Biomass integrated gasifier combined cycle
BTU	British Thermal Unit
C&D	Construction and demolition
C/N	Carbon/nitrogen ratio
ca	Capita
CADDET	Centre for Analysis and Dissemination of Demonstrated Energy Technologies
CARB	California Air Resources Board
CC	Combined Cycle
CDFFP	California Department of Forestry and Fire Protection
CEC	California Energy Commission
CENBIO	The Reference Center on Biomass (Brazil)
CEQA	California Environmental Quality Act
CFB	Circulating fluidized bed
CH_4	Methane
CHP	Combined Heat and Power
CI	Compression Ignited
CIWMB	California Integrated Waste Management Board
CNG	Compressed Natural Gas
COE	Cost of energy
CPUC	California Public Utilities Commission
CSTR	Continuously stirred tank reactor (complete mix reactor)
d	Day
DOE	US Department of Energy
DPPP	Dairy Power Production Program
EC	European Community

EGR	Exhaust gas recirculation
EIA	US Energy Information Agency
EISG	Energy Innovation Small Grant (a CEC program)
EJ	10^{18} joules (exajoule)
EPA	Environmental Protection Agency
EPR	Extended Producer Responsibility
ESP	Electrostatic precipitator (for PM control)
EU	European Union
FERC	Federal Energy Regulatory Commission
FOG	Fats, Oils, and Grease
FT	Fischer-Tropsch
GAIA	Global Anti-Incinerator Alliance
GHG	Greenhouse gas
GPD	Gallons per day
GTCC	Gas turbine combined cycle
GWh	Gigawatt-hour (10^9 watt-hours)
h	Hour
HALO	Hydrogen assisted lean operation
HHV	Higher heating value
HRSG	Heat recovery steam generator
HRT	Hydraulic Retention Time
HS	High solids
IEA	International Energy Agency
IGCC	Integrated Gasifier Combined Cycle
IRR	Internal Rate of Return
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-hour
LFG	Landfill gas
LFGTE	Landfill gas to energy
LHV	Lower Heating Value
LS	Low solids
MACT	Maximum Available Control Technology
MBT	Mechanical biological treatment
MJ	10^6 joules (megajoule)
MMBTU	Million BTU
MNES	The Ministry of Non-conventional Energy Sources (India)
MRF	Material recovery facility
MS	Multi-stage
MSW	Municipal Solid Waste
Mt	Million short tons
MW	Megawatt
MWh	Megawatt-hour

MWth	Megawatt of heat or thermal energy
NETL	National Energy Technology Laboratory
NREL	National Renewable Energy Laboratory
NSCR	Nonselective Catalytic Reduction
PIER	Public Interest Energy Research
PM	Particulate Matter
POTW	Publicly owned treatment works
PPA	Power purchase agreement
PTC	Production tax credit
PURPA	Public Utilities Regulatory Policy Act
RDDD	Research, development, demonstration, and deployment
RDF	Refuse derived fuel
REC	Renewable Energy Credit
RFP	Request for proposal
ROG	Reactive Organic Gases. Precursor to ground level ozone formation.
ROR	Rate of return
RPS	Renewable Portfolio Standard
RSCR	Regenerative SCR
SBIR	Small business innovation research
SCR	Selective Catalytic Reduction
SI	Spark Ignited
SNCR	Selective Non-Catalytic Reduction
SO4	Standard Offer 4
SRAC	short-run avoided cost
SRT	Solids Retention Time
t	Ton
TEQ	Toxic Equivalent
TOC	Total Organic Compound
TPD	Tons per day
TS	Total Solids
UASB	Upflow Anaerobic Sludge Blanket
USDA	US Department of Agriculture
VOC	Volatile Organic Compounds (sometimes referred to as ROG). Precursor to ground level ozone formation
VS	Volatile Solids
W	Watt (Nms-1)
WWTP	Waste water treatment plants
y	Year

Acidogenic	Acid-forming; used to describe microorganisms that break down organic matter to acids during the anaerobic digestion process
Aerobic	With or in the presence of oxygen.
Anaerobic	Without oxygen
Biogas	A naturally occurring gas produced from anaerobic digestion. Biogas is composed primarily of methane (typically 55–70% by volume) and carbon dioxide (typically 30–45%). Biogas may also include smaller amounts of hydrogen sulfide (typically 50–2,000 parts per million [ppm]), water vapor (saturated), oxygen (trace), siloxanes (if gas is produced from a landfill or waste water treatment plant) and various trace hydrocarbons.
Carbonization	A low temperature and high residence time pyrolytic process designed to produce the maximum quantity of char. Typically used to make char coal from wood.
Cellulose	A complex carbohydrate, $(C_6H_{10}O_5)n$, that is composed of glucose units. Cellulose forms the main constituent of the cell wall in most plants.
Co-digestion	The simultaneous digestion of a mixture of two or more feedstocks. Co-digestion is sometimes employed to balance nutrient requirements of the process, improve gas production rate, as well as to process wastes from multiple sources.
Combustion	A rapid conversion of chemical energy into thermal energy. The reaction is exothermic. Organic matter is oxidized with sufficient air (or oxygen) for reactions to go to completion. The carbon and hydrogen are oxidized to carbon dioxide and water, respectively.
Conventional pollutants	As specified under the Clean Water Act, conventional pollutants include suspended solids, coliform bacteria, biochemical oxygen demand, pH, oil and grease.
Criteria air pollutants	The six criteria pollutants are ozone (O_3). carbon monoxide (CO), particulate matter (PM_{10}), sulfur dioxide (SO_2), lead (Pb), and oxides of nitrogen (NO_x).
Digestion	Either in the presence of oxygen (aerobic) or in an oxygen-depleted atmosphere (anaerobic), the process in which microbes digest biogenic carbonaceous materials and emit any number of energetic, inert gases and liquids.
Elutriation	The separation of finer lighter particles from coarser heavier particles in a mixture by means of a usually slow upward stream of fluid so that the lighter particles are carried upward:
Entrain	To carry (suspended particles, for example) along in a current.
Extended Producer Responsibility (EPR)	As it relates to solid waste management, refers to responsibility placed on waste producers for disposal or mitigation of their own waste. 'Producer pays' or 'take-back' laws are examples of implementing EPR.
Fermentation	The use of microorganisms such as yeast, bacteria, and fungi to convert substrates such as sugar into products. In the absence of oxygen, these products can include ethanol, methane, and carbon dioxide plus some increase in cell mass. When oxygen is present, the increase in cell mass is generally much greater with water and carbon dioxide usually the primary products.
Fischer-Tropsch	A synthesis process for producing mainly straight-chain paraffinic hydrocarbons from a synthesis gas having the correct mixture of CO and H_2. Catalysts are usually employed. Typical operating conditions for FT synthesis are temperatures of 390-660 °F and pressures of 15-40 atmospheres depending on the desired products. The product range includes the light hydrocarbons methane (CH_4) and ethane (C_2), LPG (C_3-C_4), gasoline (C_5-C_{12}), diesel (C_{13}-C_{22}), and waxes (>C_{23}). The distribution of the products depends on the catalyst and the process conditions (temperature, pressure, and residence time). The synthesis gas should have low tar and particulate matter content to avoid progressive contamination of the catalysts. Biomass derived synthesis gas for

	FT liquid production is pre-commercial. However, it may be more easily commercialized than coal since it has smaller quantities of contaminants to remove in the synthesis gas cleaning process.
Gasification	Production of energetic gases from solid or liquid organic feedstocks usually by partial oxidation. Primary energetic gases produced are hydrogen, carbon monoxide, and methane, along with an inorganic ash residue.
Hydraulic retention time (HRT)	The average time a 'volume element' of fluid resides in a reactor. It is computed from liquid-filled volume of an anaerobic digester divided by the volumetric flow rate of liquid medium.
Hydrogasification	Gasification using hydrogen gas to react with the carbon in organic materials to produce a methane rich gas effluent, and provide heat for the process. Any pyrolytic products present are usually converted into methane. Steam pyrolysis is often used as a precursor process that can enhance the hydrogen reaction kinetics, despite the presence of water in the feed. Since oxygen is not intentionally introduced, carbon oxides are reduced and methane increased as the hydrogen pressure is increased. Toxic hydrocarbons, like furans and dioxins, are chemically reduced by hydrogasification to less hazardous chemical compounds.
Hydrolysis	A chemical or biological process in which water is added to other molecules (the conditions are wide ranging and many molecules can be hydrolyzed). Hydrolysis is a pre-treatment or preliminary step in fermentation processes that ultimately yield biogas or ethanol. For cellulose and hemicellulose, a variety of hydrolysis methods can be used to break down the long chain polymer into simple glucose molecules, Efficiencies of hydrolysis vary among methods and feedstocks.
Integrated Gasifier Combined Cycle (IGCC)	Combined cycle systems that incorporate a gasifier for the purposes of converting the solid fuel to a fuel gas for combustion in a gas turbine using the Brayton cycle. Combined cycle (CC) power systems can extract more useful energy from a given amount of input energy or fuel by utilizing two power cycles in sequence: 1) a gas turbine Brayton cycle and 2) a steam Rankine cycle utilizing heat rejected in the gas turbine exhaust. In such systems, the steam boiler is conventionally referred to as a heat recovery steam generator (HRSG). Gas turbines require a clean, particle free exhaust gas for expansion through the turbine. Using the effluent gases from gasified biomass or coal as a turbine fuel requires cleanup before introduction to the combustion chamber of the turbine, similar to those present in commercially cleaned natural gas. Gasification of coal for IGCC is being done in over 20 facilities worldwide.
Incineration	A generic term in the industry that connotes any process that combusts waste. Combustion of solid wastes that have had no sorting or pre-treatment applied to the whole solid waste 'mass' used as feedstock. Heat and power may or may not be recovered.
Ligno-cellulosic	Consisting of cellulose intimately associated with lignin, an amorphous polymer related to cellulose that has strength and rigidity. Wood is the most abundant ligno-cellulosic material .though almost all plant biomass contains lignin. Lignin does not degrade anaerobically (and is the most recalcitrant component of biomass for aerobic decomposition). Because of the structural nature of ligno-cellulosic material, much of the cellulose is difficult to access for anaerobic digestion.
Mesophilic	One of two optimal temperature ranges for microorganisms involved in anaerobic digestion. Mesophilic temperature is around 95° F (35° C).
methane	Methane is the main component of natural gas and biogas. It is the simplest hydrocarbon consisting of one carbon atom and four hydrogen atoms (CH_4). The heat content of methane is approximately 1,000 BTU/scf (standard cubic feet). Methane is a greenhouse gas with 21 times the global warming potential of carbon dioxide by weight.
Nonselective	The typical automotive '3-way' catalytic converter. Usually, the catalyst

Catalytic Reduction (NSCR)	sequentially reduces NOx compounds and oxidizes CO and unburned HC. It operates in a very narrow (and low) oxygen concentration range requiring a exhaust oxygen sensor and air/fuel controller. This is not compatible with lean-burn engines because exhaust oxygen concentration is too high. The catalyst is subject to damage by sulfur compounds in the exhaust.
Organic	Material containing carbon and hydrogen. Organic material in MSW includes the biomass components of the waste stream as well as hydrocarbons usually derived from fossil sources (e.g., most plastics, polymers, the majority of waste tire components, and petroleum residues).
Priority (toxic) pollutants	Pollutants that are particularly harmful to animal or plant life. They are grouped primarily into organics (including pesticides, solvents, polychlorinated biphenyls [PCBs], and dioxins) and metals (including lead, silver, mercury, copper, chromium, zinc, nickel, and cadmium).
Pyrolysis	A thermal degradation of carbonaceous material in an oxygen-free reactor. Pyrolytic oils, fuel gas, chars and ash are produced in quantities that are highly dependent on temperature, residence time and the amount of heat applied.
Rankine cycle	The most widely used thermal cycle for electrical power generation throughout the world. It is commonly called a 'steam cycle' when the working fluid is water. It consists of a boiler where heat is added to liquid phase pressurized working fluid (water) to create a high temperature and pressurized vapor (steam if the working fluid is water). The high-pressure steam is expanded through a turbine, which turns a generator creating electrical power. The low-pressure steam coming out of the turbine is condensed to liquid by cooling after which the pressure of the relatively low temperature liquid is raised by a boiler feed pump or pumps to repeat the cycle. Rankine cycle efficiencies depend on plant size, fuel, and design and typically vary from about 10% for very small (<1 MW_e) solid-fueled systems to greater than 40% for large (>500 MW_e) supercritical units. Typical solid-fueled biomass and waste fired power plants (~10-100 MW_e) have net efficiencies of about 17-25%.
Reactive organic gases	A term equivalent to volatile organic compounds that is used by the California Air Resources Board. Reactive organic gases (ROG) are precursors to photochemical smog.
Regenerative SCR (RSCR)	Also called 'Tail-end' SCR, an SCR system placed downstream of gas cleaning and cooling operations in order to reduce catalyst fouling by sulfur and other inorganic compounds in the exhaust gas. Because the gas has been cooled, it must be re-heated (regenerated) to a high enough temperature for the catalyst to function. In large coal facilities with RSCR, the energy penalty for reheating the flue gas to 300° C (570° F) is about 3% of plant output.
Selective Catalytic Reduction (SCR)	Selectively reduces NOx by the injection of ammonia or urea reagent upstream of a precious metal oxide catalyst. This requires some oxygen in the exhaust stream and therefore, as pertains to reciprocating engines, is only applicable to lean burn SI, CI, and Dual-fuel CI engines. SCR is used in stationary gas turbine applications and regenerative SCR systems are utilized in coal and MSW combustion systems. The catalyst is also susceptible to sulfur and volatile inorganic compounds adsorption rendering sites inactive. A certain amount of ammonia passes through unreacted which requires monitoring in order to meet ammonia slip limits. An SCR system consists of reagent storage, feed and injection system, catalyst, and monitoring equipment for use in controlling ammonia slip. Predictive mapping and monitoring of engine parameters can be used for reagent flow control instead of exhaust monitoring. SCR for solid fuel biomass combustion systems is developmental due to gas cleaning requirements.
Selective Non-Catalytic Reduction (SNCR)	Utilizes ammonia, urea, or other suitable amine based compounds that react selectively with NOx in a flue gas in the presence of oxygen to reduce oxides of nitrogen to N_2. The reactions proceed at fairly high temperature and the temperature range for the reactions to occur is rather narrow at 1600 – 2100 °F

	(900-1150 °C) which is why the technique is also known as 'thermal de-NOx' Typically, more than stoichiometric amounts of ammonia or urea are injected in order to sufficiently drive the NOx reduction reactions which leads to certain amounts of ammonia passing unreacted through the system (so-called ammonia slip). SNCR is used extensively in industrial and utility boilers and furnaces, including biomass boilers. SNCR is a component of BACT for biomass boilers in California.
Short-run avoided cost	Marginal cost to generate or procure the next increment of electricity. For example, SRAC is used to set energy prices for qualifying facilities as defined by PURPA
Standard Offer No. 4 (SO#4)	The Interim Standard Offer No. 4 (SO#4) were contracts made available to independent biomass power developers by PG&E and SCE. Available for signing in 1984 and 1985 with a 5 year window to bring projects on-line, the SO#4 guaranteed firm energy prices for 10 years based on the relatively high SRAC rates in effect at that time ($0.05-0.06/kWh) and escalating to above $0.12/kWh. At the end of the 10-year fixed rate portion, generators would receive the current market SRAC which had significantly declined by the late 1990's.
Starved air incineration	This process is usually two fold. In the first stage, the reactor is fed with sub-stoichiometric levels of oxygen, which creates a reducing environment, driving the organic components into the gas phase and leaving the inorganic material as ash residue. The next stage thermally oxidizes the organic gases by mixing with excess oxygen.
Steam pyrolysis	A thermally driven decomposition of organic material in a high pressure superheat steam reactor. The steam produces more gas products and less pyrolytic oil than dry pyrolysis. The pyrolytic char formed is highly porous and is often used to make activated carbon from waste biomass. The activation of the char, enhances the reactivity of the gasification process, especially when using hydrogen.
Steam reforming	An endothermic chemical conversion process used to make hydrogen and carbon monoxide from superheat steam and hydrocarbon gases such as methane using a nickel based catalyst.
Stoichiometry	Generally the molar or mass relationships among reactants and products of a chemical reaction. In any combustion reaction, for example, there is a specific molar or mass ratio of oxygen or air (contains 21% oxygen by volume) to fuel that is required for complete combustion to occur (fuel fully oxidized to carbon dioxide and water). This ratio is called the stoichiometric ratio or the stoichiometric air-fuel ratio. The inverse ratio is referred to as the stoichiometric fuel-air ratio. If excess oxygen or air is supplied, the combustion occurs under fuel-lean conditions. If insufficient oxygen or air is supplied, the combustion is fuel-rich. The ratio of the stoichiometric air-fuel ratio to the actual air-fuel ratio is called the equivalence ratio (f), so that fuel-lean conditions occur at equivalence ratios less than 1, and fuel-rich conditions occur at equivalence ratios greater than 1. An equivalence ratio equal to 1 specifies the stoichiometric air-fuel ratio. The inverse of the equivalence ratio is the air- or lambda-factor (l). Combustion conditions are commonly described by the equivalence ratio, while gasification conditions (extremely fuel rich) are commonly described by the air-factor.
Synthesis gas	A mixture of carbon dioxide, carbon monoxide and hydrogen gas formed via gasification for the express purpose of synthesizing products.
Technical availability	Related to biomass resource, it is the amount of resource estimated to be practically and economically obtainable
Thermal oxidation	A high temperature oxidative process that uses excess oxygen to convert gaseous organic matter into carbon dioxide and water vapor.
Total Solids	Used to characterize digester systems input feedstock. Total solids (TS) means the dry matter content, usually expressed as % of total weight, of the prepared feedstock. By definition, TS = 100 – moisture content of a sample. Also, TS =

	VS plus ash content.
Volatile organic compounds	VOCs are non-methane, non-ethane, photoreactive hydrocarbon gases that vaporize at room temperature (methane and ethane are not photoreactive). The quantity of VOC is sometimes determined by measuring non-methane non-ethane organic compounds. When combined with NO_x and sunlight, VOCs produce ozone, a criteria air pollutant. Anthropogenic sources of VOCs include products of incomplete combustion, evaporation of hydrocarbon fuels, fugitive emissions from oil refineries and petro-chemical plants, fermented beverage manufacturing, large animal feeding operations and feed ensiling. However, natural VOC emissions account for the majority of VOC emissions (approximately 60% of the US VOC emission inventory). Vegetation, especially hardwood and pine trees account for most of the natural VOC emissions. They are also an intermediate product in the creation of methane during anaerobic digestion and are produced during enteric fermentation.
Volatile Solids	Used to characterize digester systems input feedstock, volatile solids (VSs) are the organic (carbon containing) portion of the prepared reactor feedstock. Usually expressed as a fraction of total solids, but sometimes expressed as a fraction of total sample (wet) weight. The amount of VS in a sample is determined by an analytical method called "loss on ignition." It is the amount of matter that is volatilized and burned from a sample exposed to air at 550 ºC for 2 hours. The inorganic (ash) component of total solids remains after the loss on ignition procedure. VS + ash = TS. Not all of the VS component of a feedstock is digestible.

Appendix A

Supplemental Figures from Chapter 3 (Economic Analysis)

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Figure 3.8-22. Required Tip Fee vs. Debt Interest Rate (MSW AD scenario 2) A-15
Figure 3.8-23. Required Tip Fee vs. O&M Costs (MSW AD scenario 2) A-16

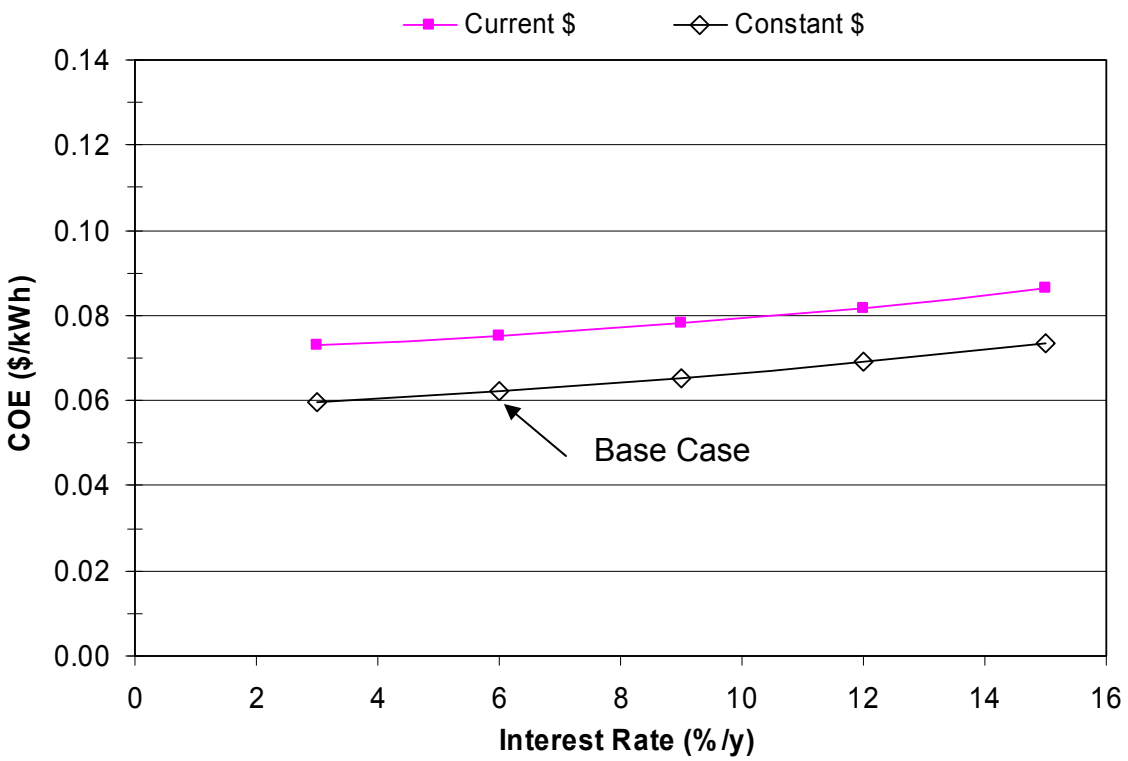

Figure 3.4-5. COE versus debt interest rate (Carbona – Skive)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

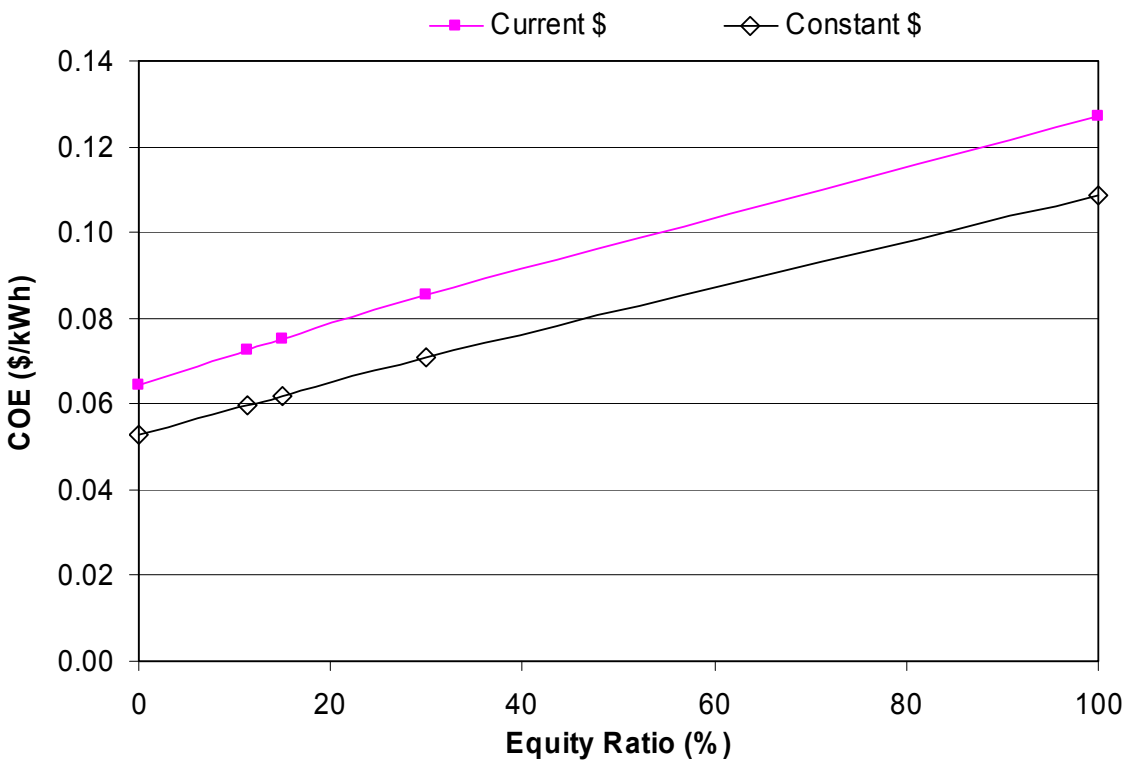

Figure 3.4-6. COE versus equity ratio (Carbona – Skive)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

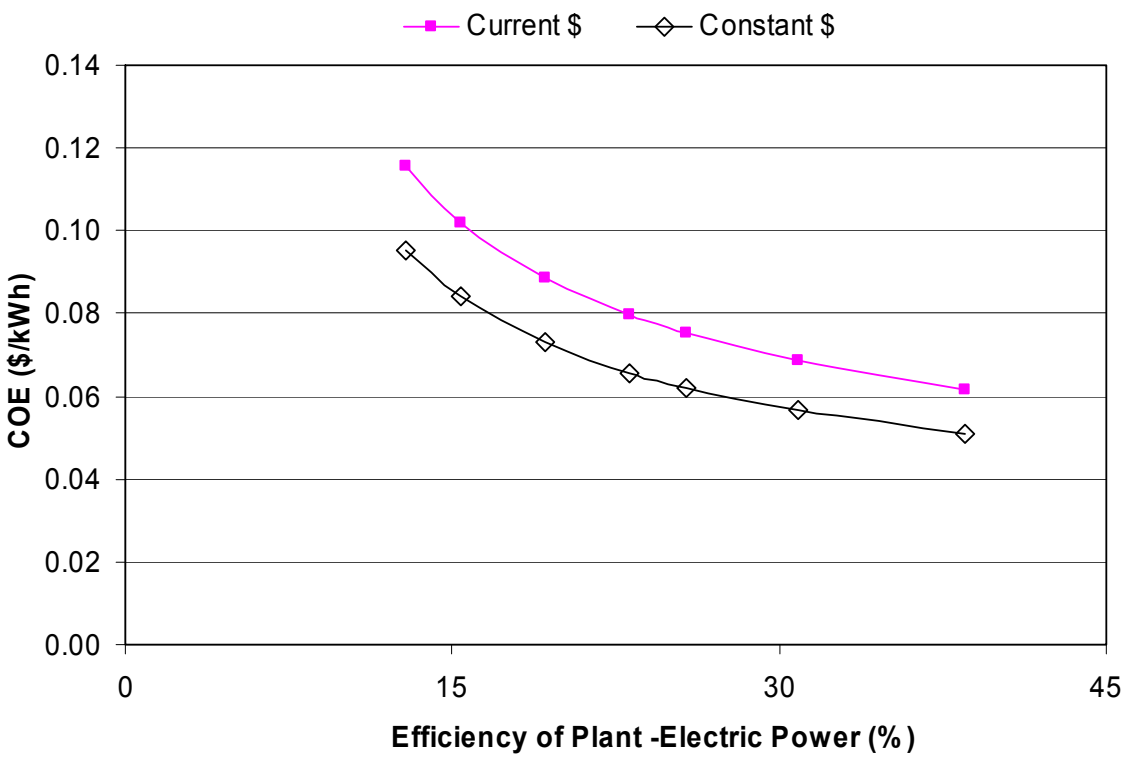

Figure 3.4-7. COE versus electrical efficiency (Carbona – Skive)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

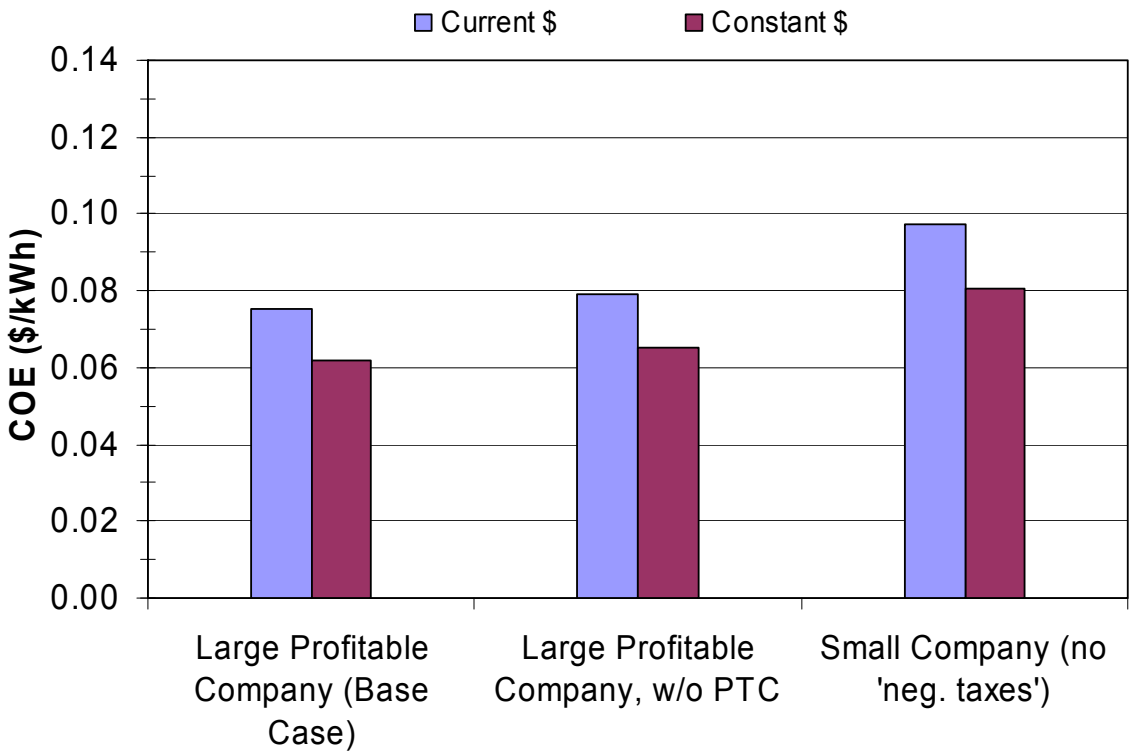

Figure 3.4-8. Company size and PTC effects on COE (Carbona – Skive) Photo credit: UC Davis Research Team; Photo credit: Robert Williams

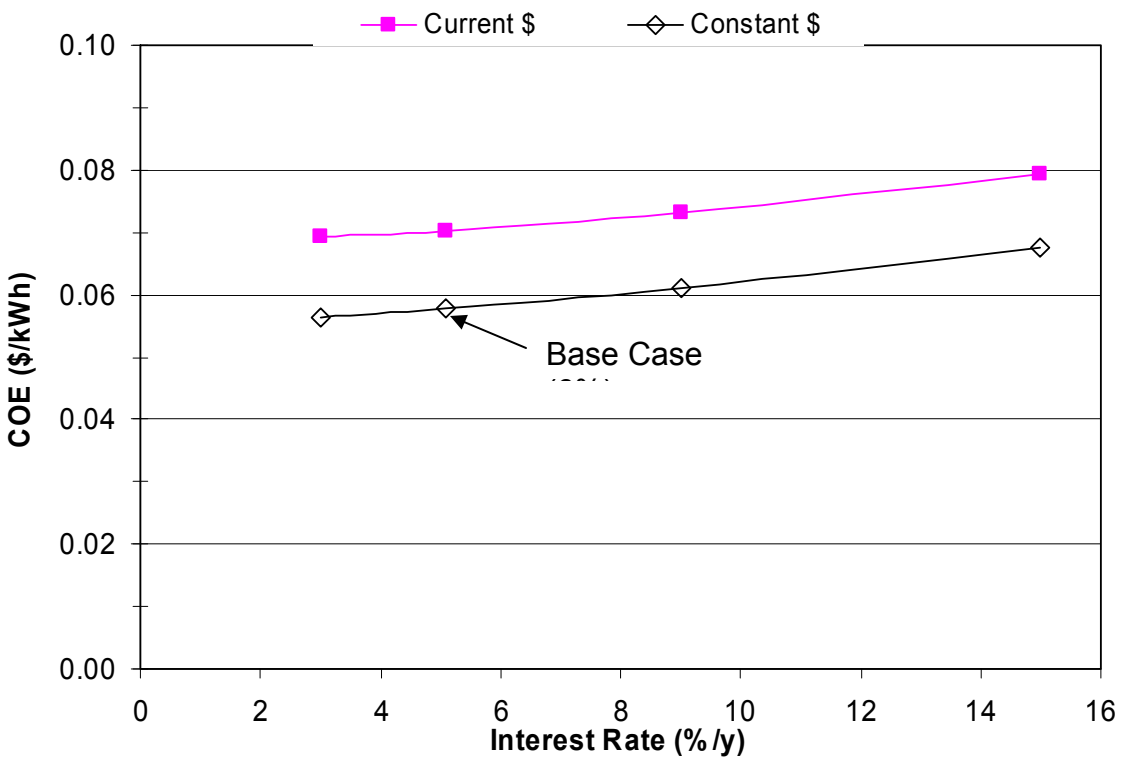

Figure 3.5-5. COE versus interest rate (Kokemäki)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

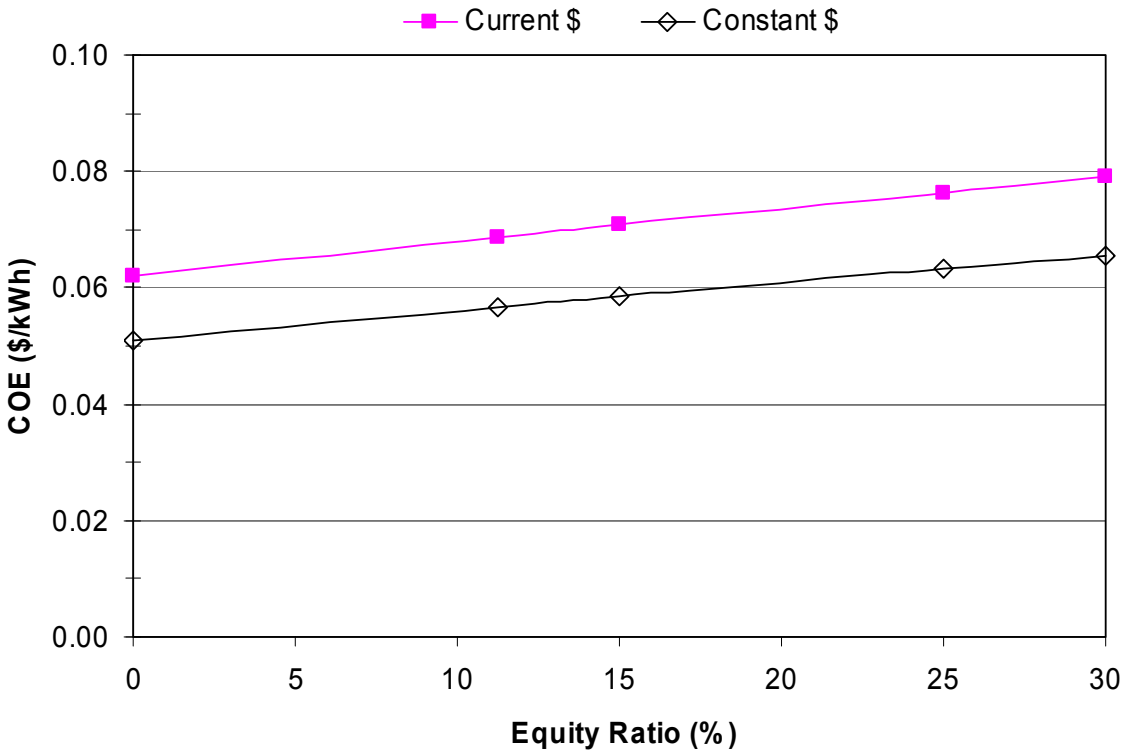

Figure 3.5-6. COE versus equity ratio (Kokemäki)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

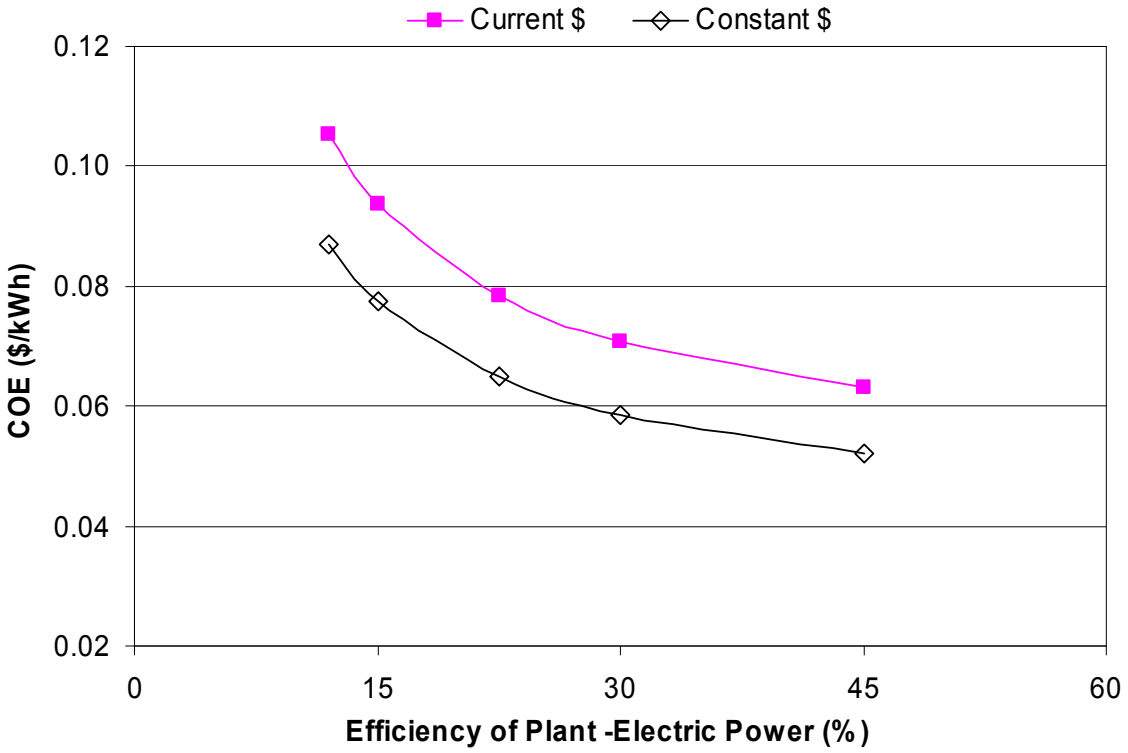

Figure 3.5-7. COE versus net electric power efficiency (Kokemäki)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

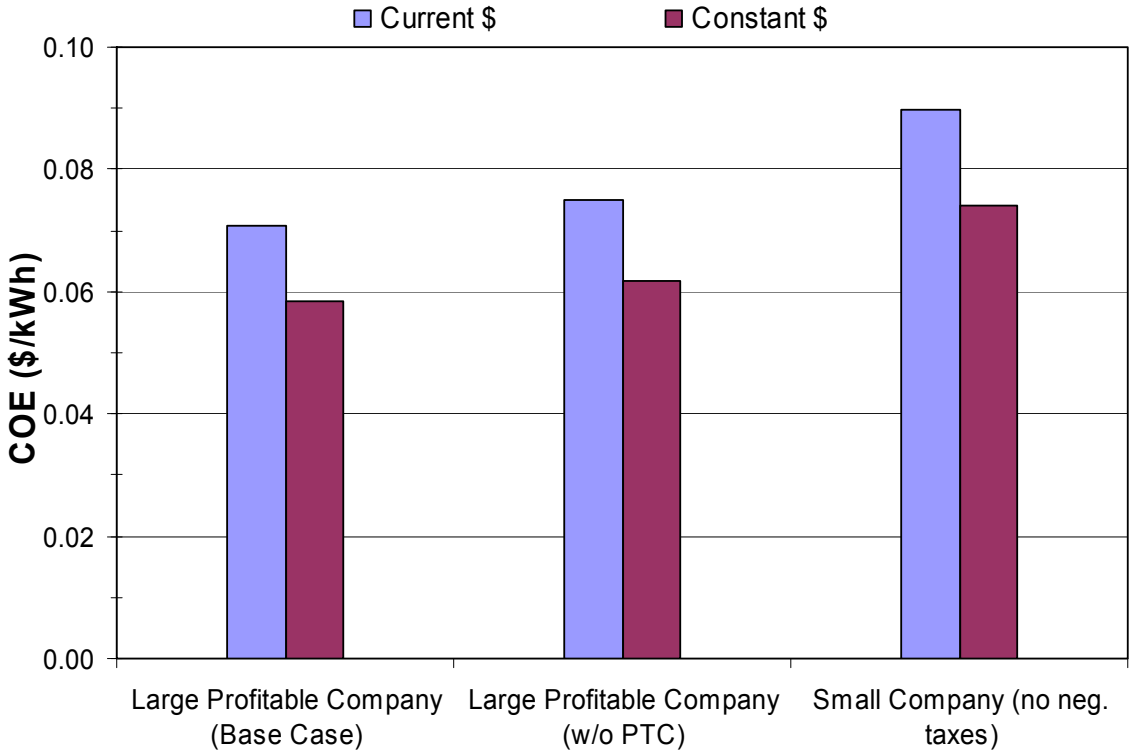

Figure 3.5-8. Variation of COE with tax consequences (Kokemäki)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

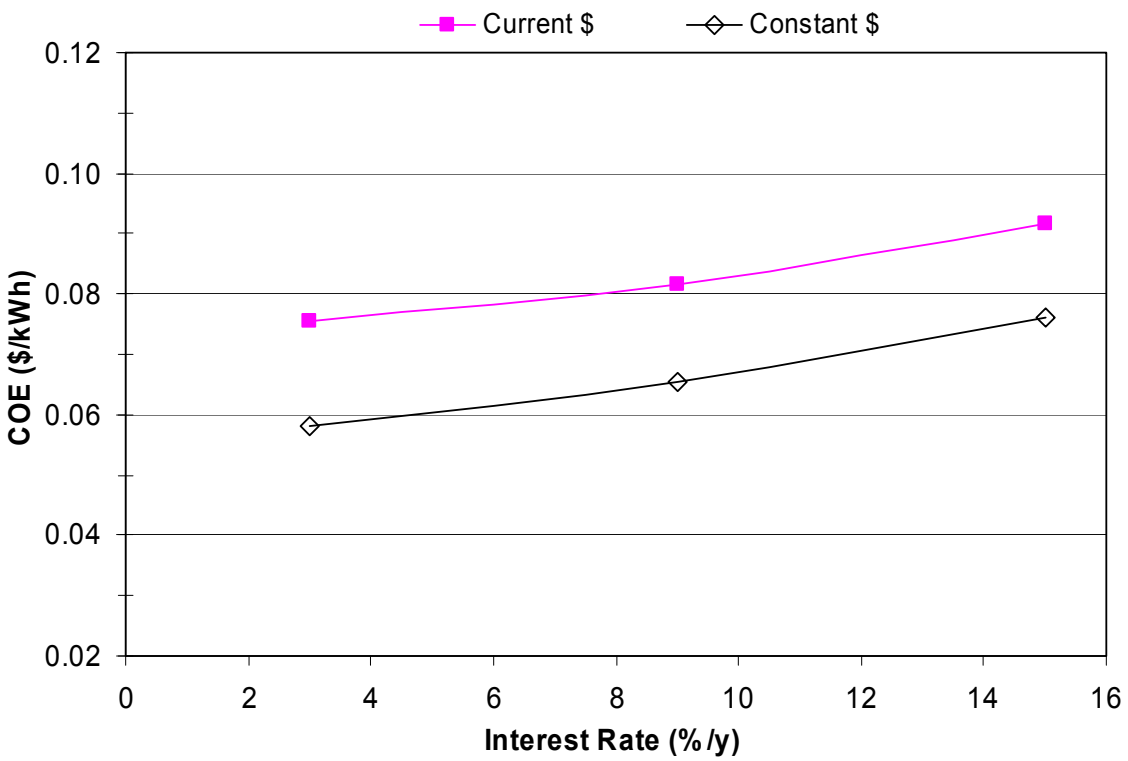

Figure 3.6-6. COE versus debt interest rate (Carbona –India IGCC)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

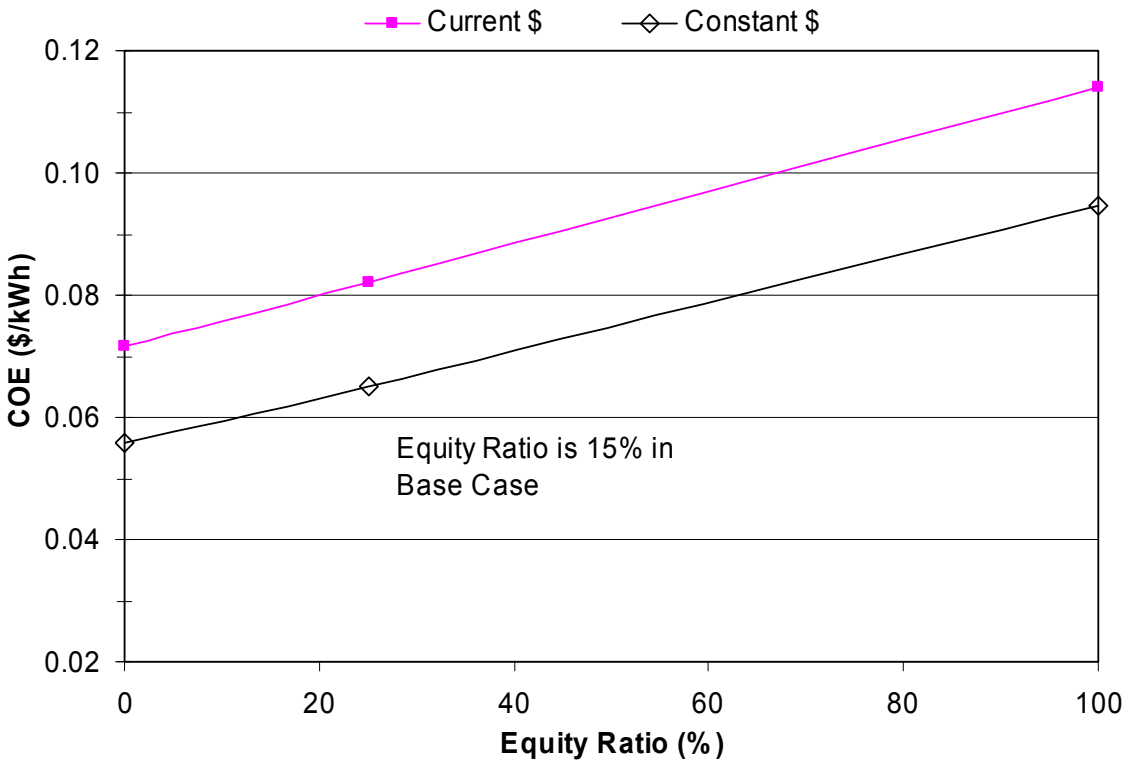

Figure 3.6-7. COE versus equity ratio (Carbona–India IGCC)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

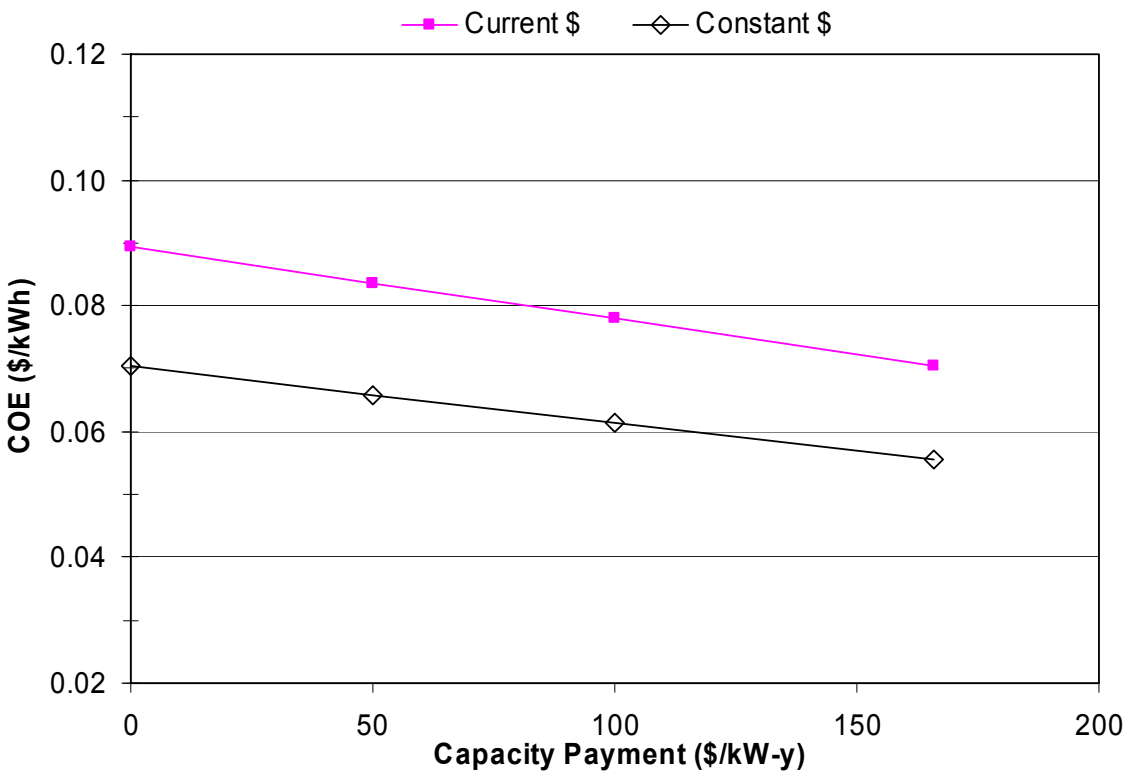

Figure 3.6-8. COE versus capacity payment (Carbona –India IGCC)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

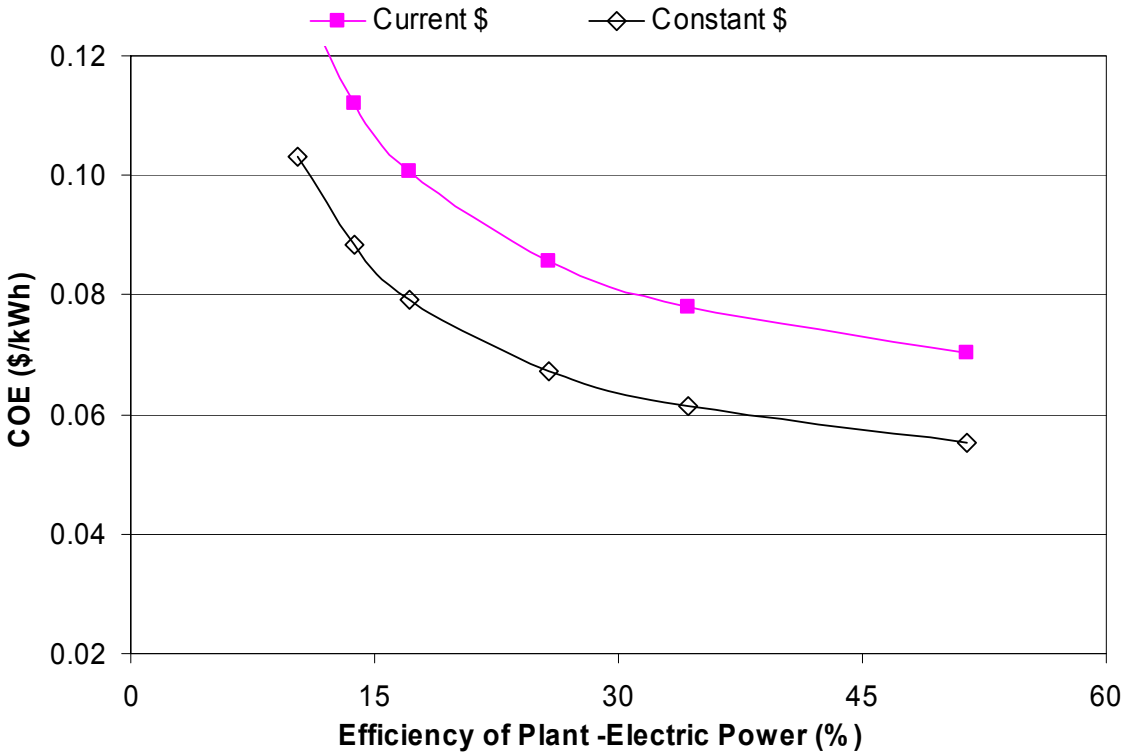

Figure 3.6-9. COE versus efficiency of plant (Carbona –India IGCC)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

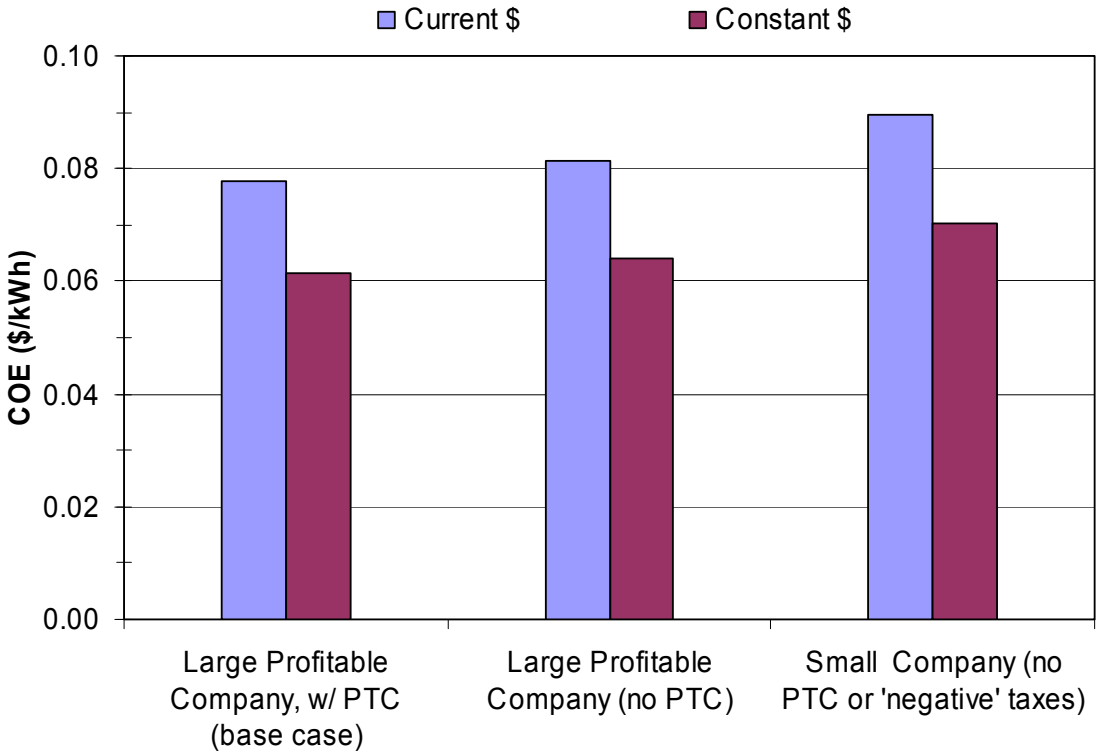

Figure 3.6-10 Variation of COE with tax consequences (Carbona –India IGCC)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

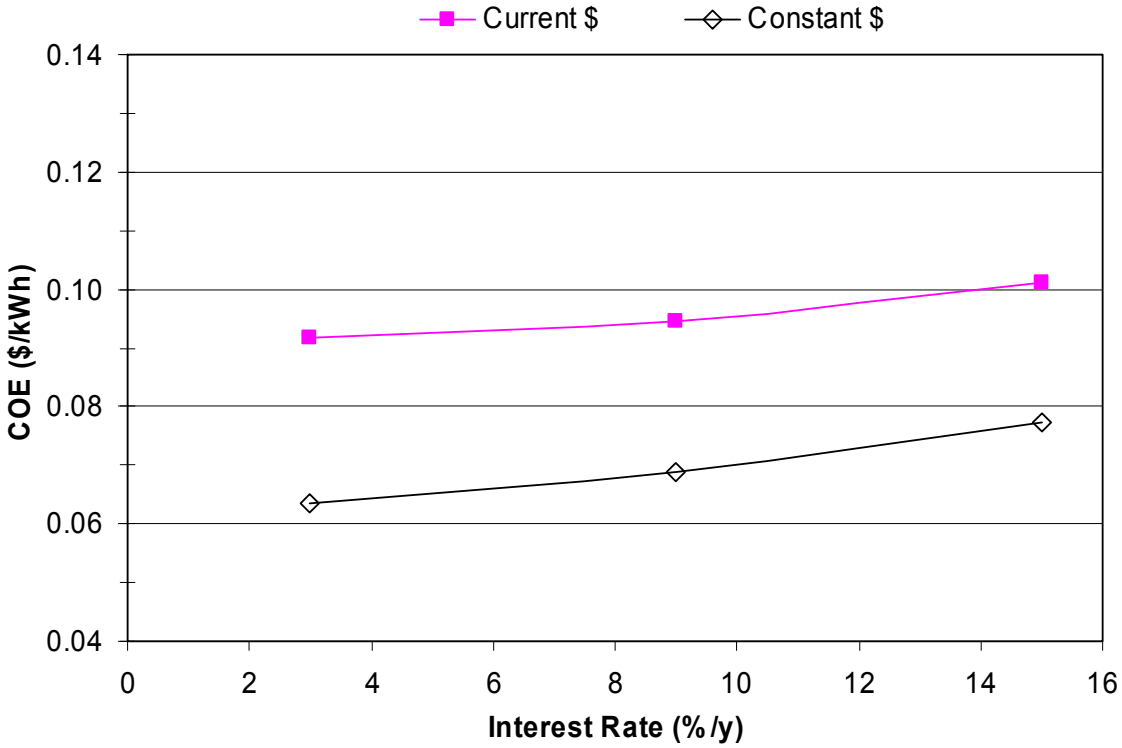

Figure 3.7-5. COE versus debt interest rate (rice straw plant)
Photo credit: UC Davis Research Team; Photo credit: Robert Williams

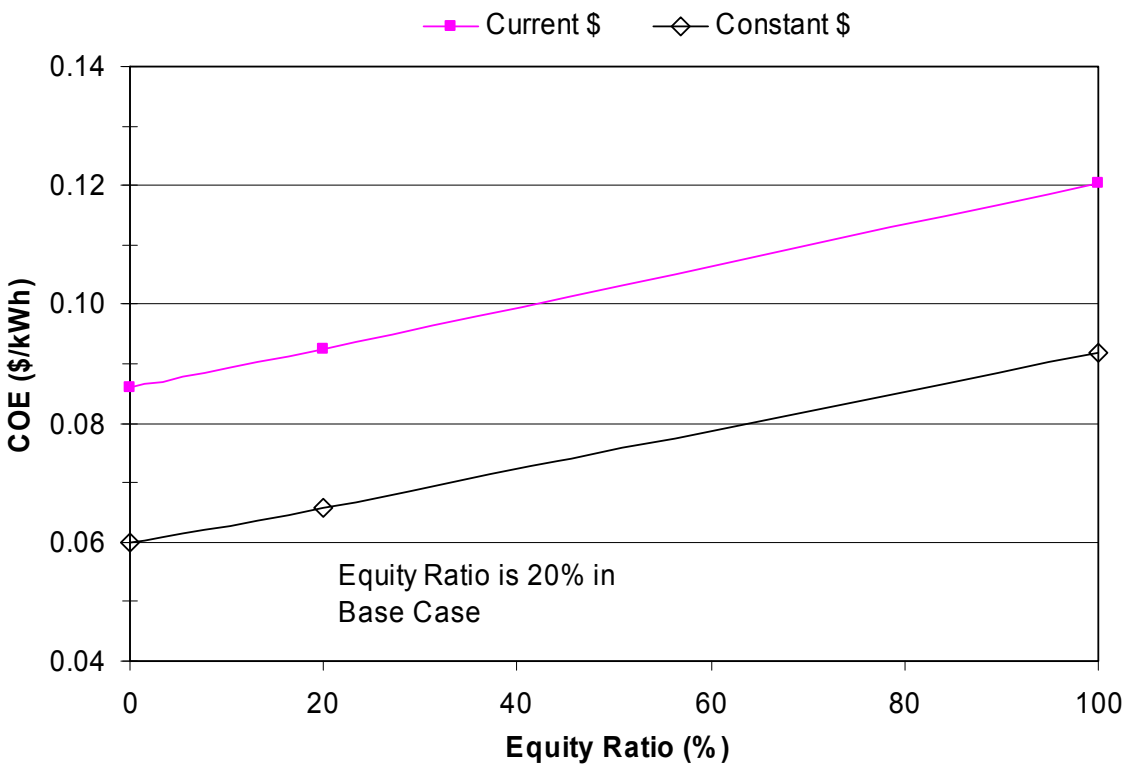

Figure 3.7-6. COE versus equity ratio (rice straw plant)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

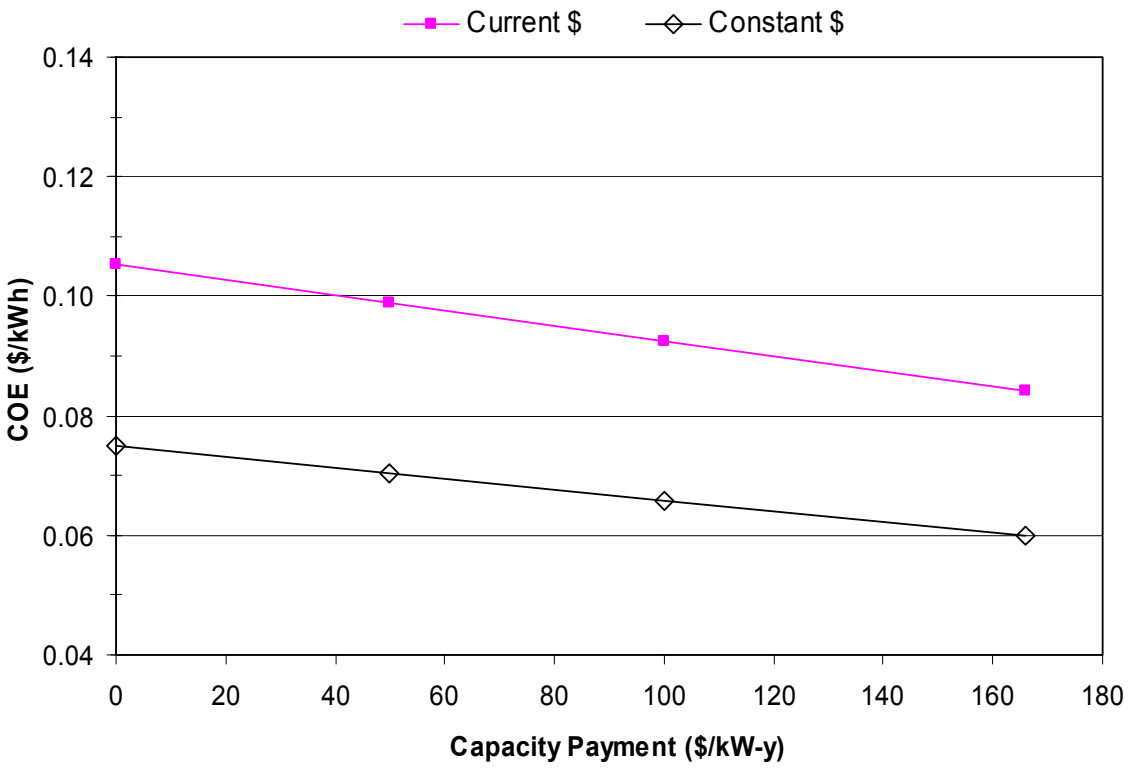

Figure 3.7-7. COE versus capacity payment (rice straw plant)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

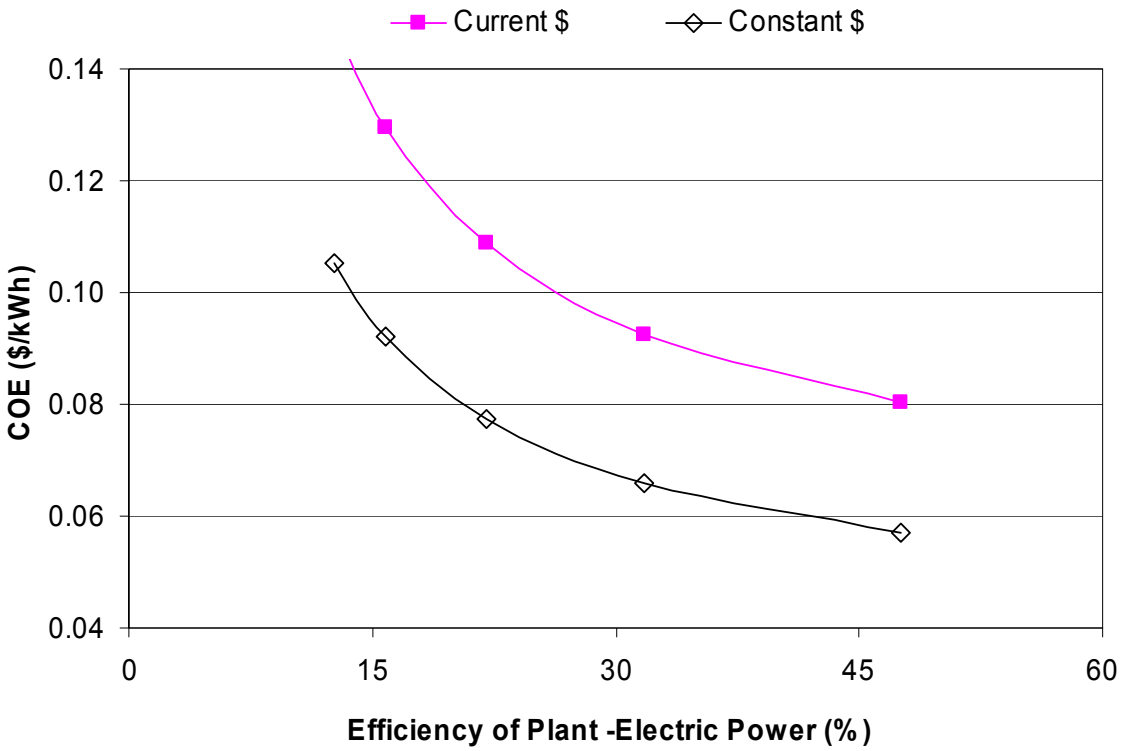

Figure 3.7-8. COE versus efficiency of plant (rice straw plant)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

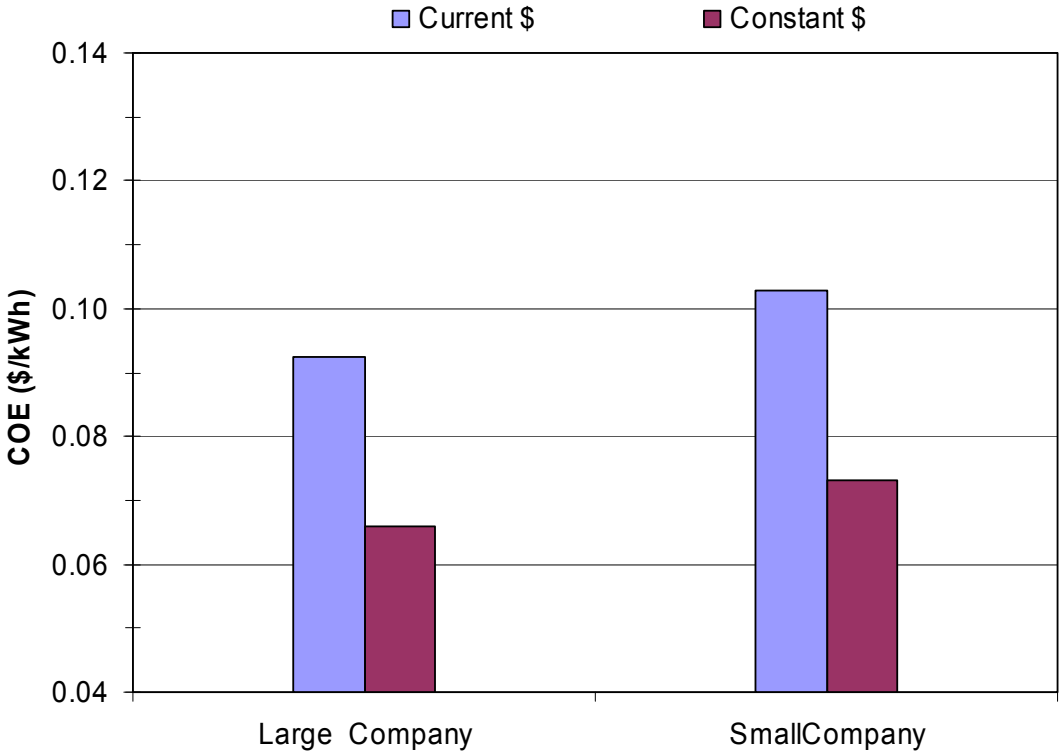

Figure 3.7-9. Effect of tax consequences on COE (rice straw plant)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

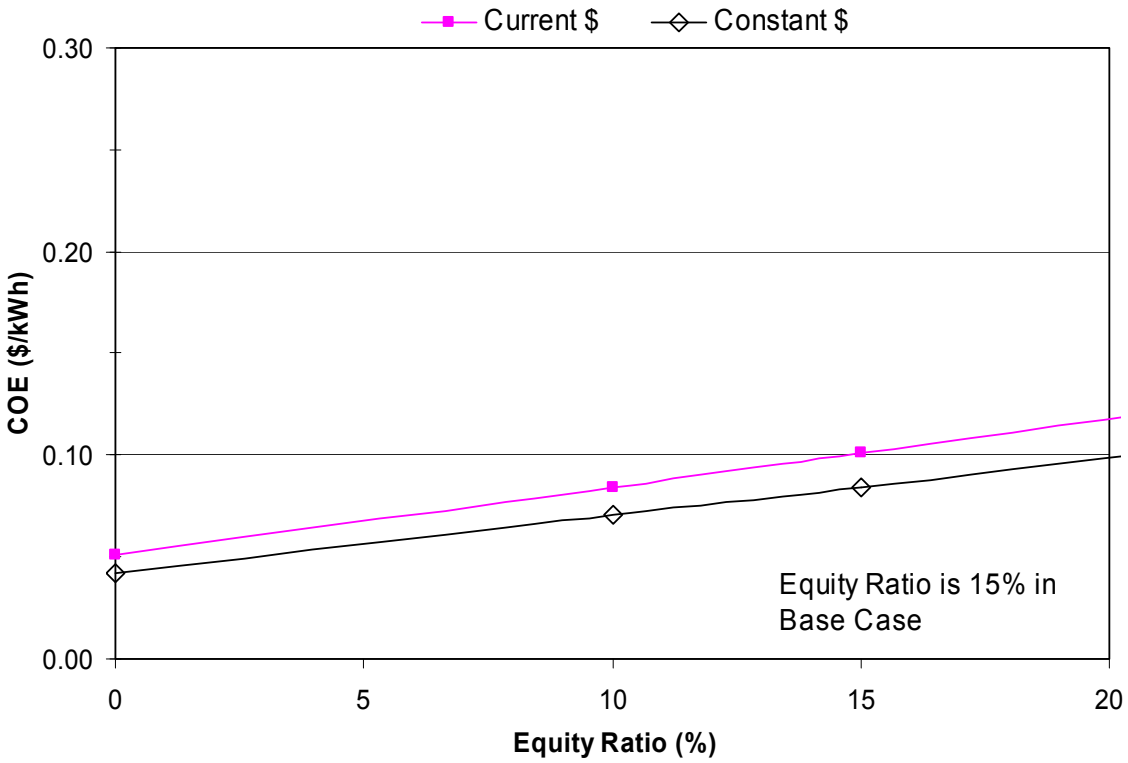

Figure 3.8-11. COE versus equity ratio (MSW AD Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

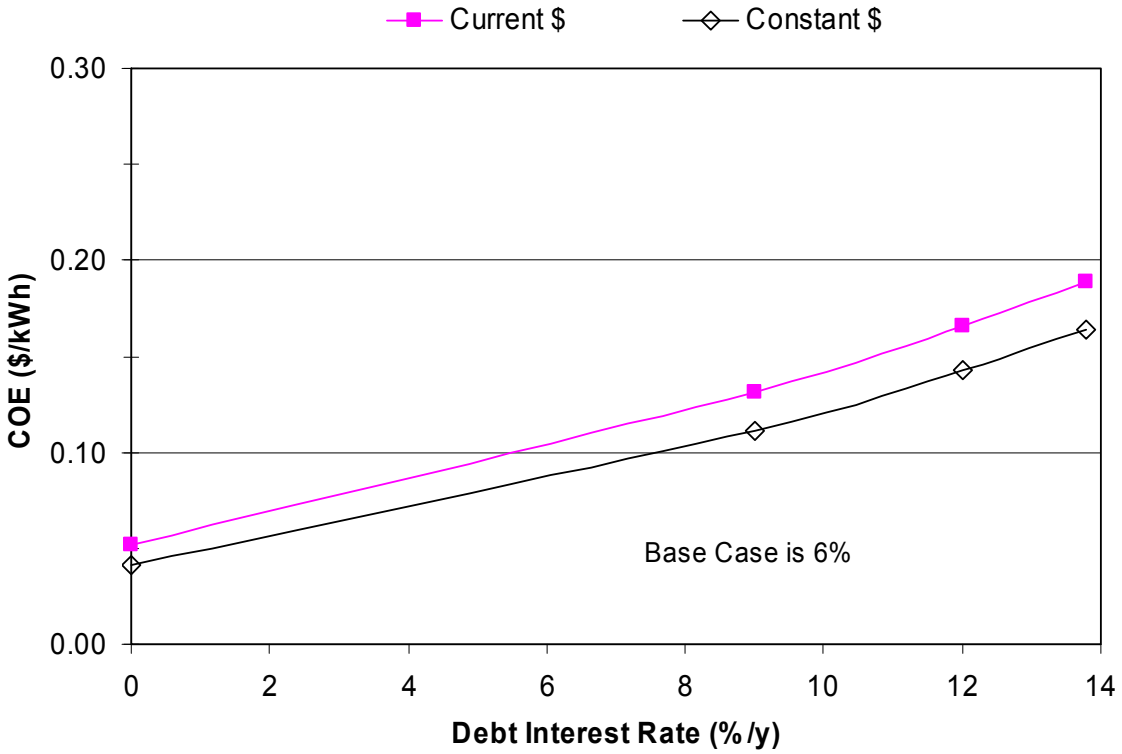

Figure 3.8-12. COE versus interest rate on debt (MSW AD Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

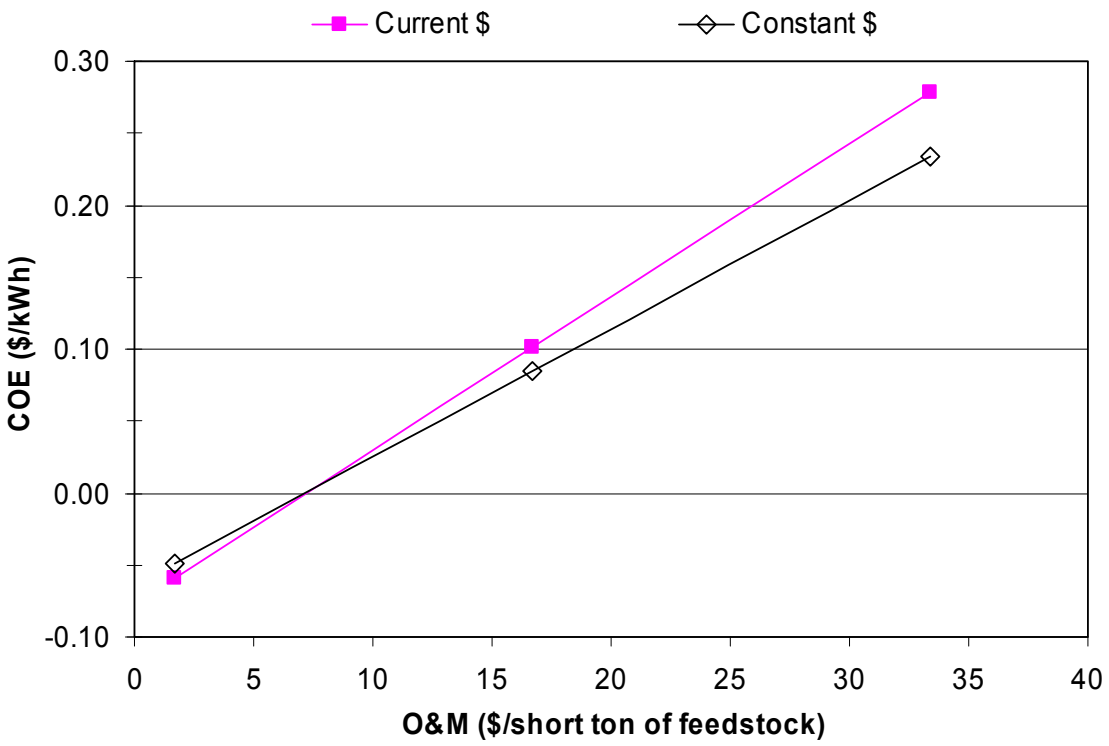

Figure 3.8-13. COE versus O&M costs (MSW AD Scenario 1)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

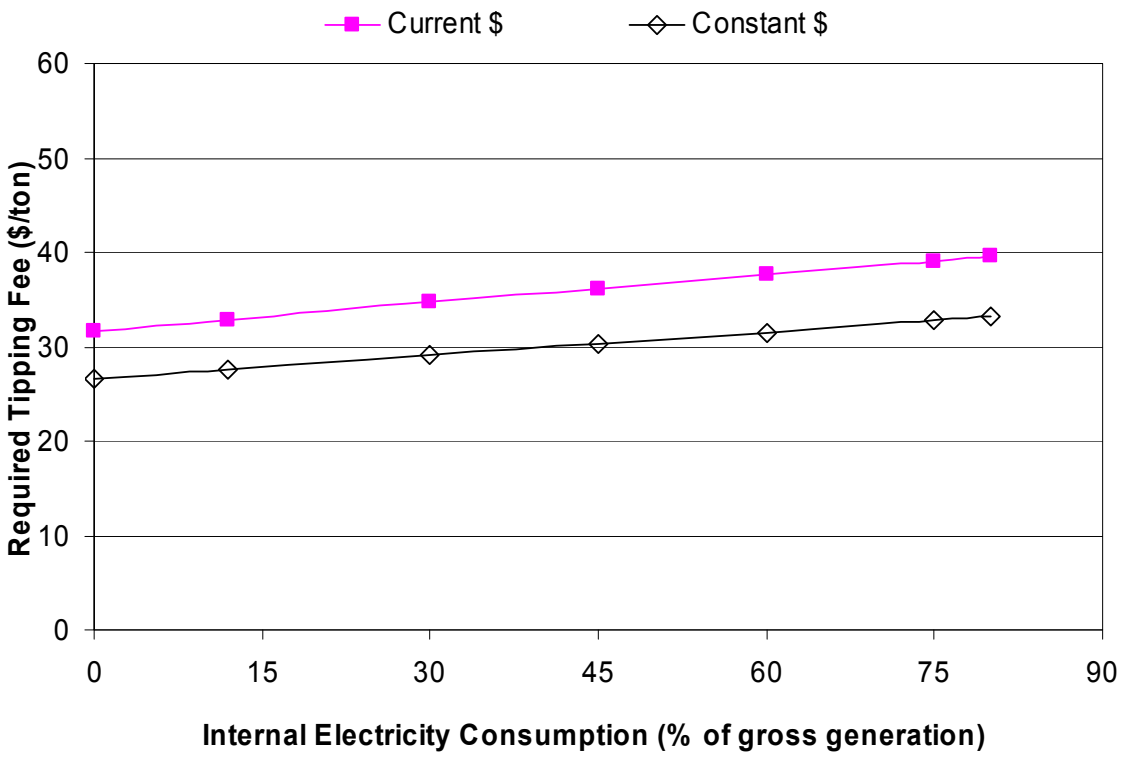

Figure 3.8-20. Required tipping fee vs. electrical parasitic load (MSW AD Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

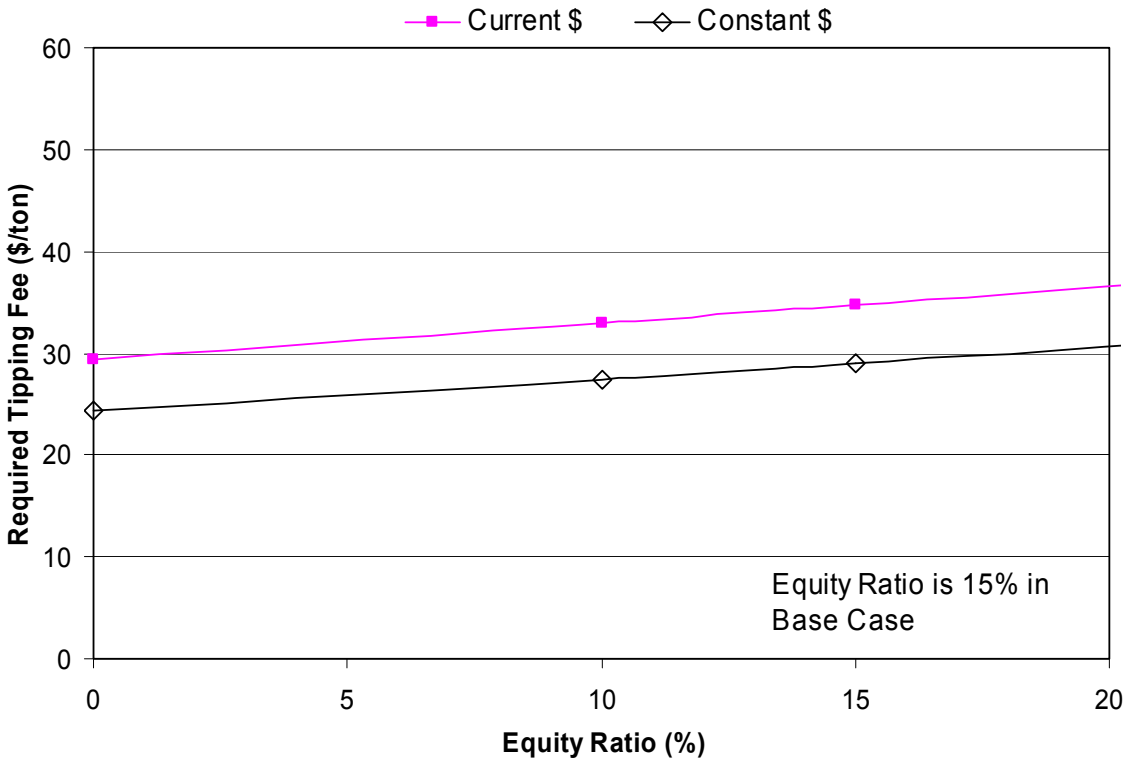

Figure 3.8-21. Required tipping fee vs. equity ratio (MSW AD Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

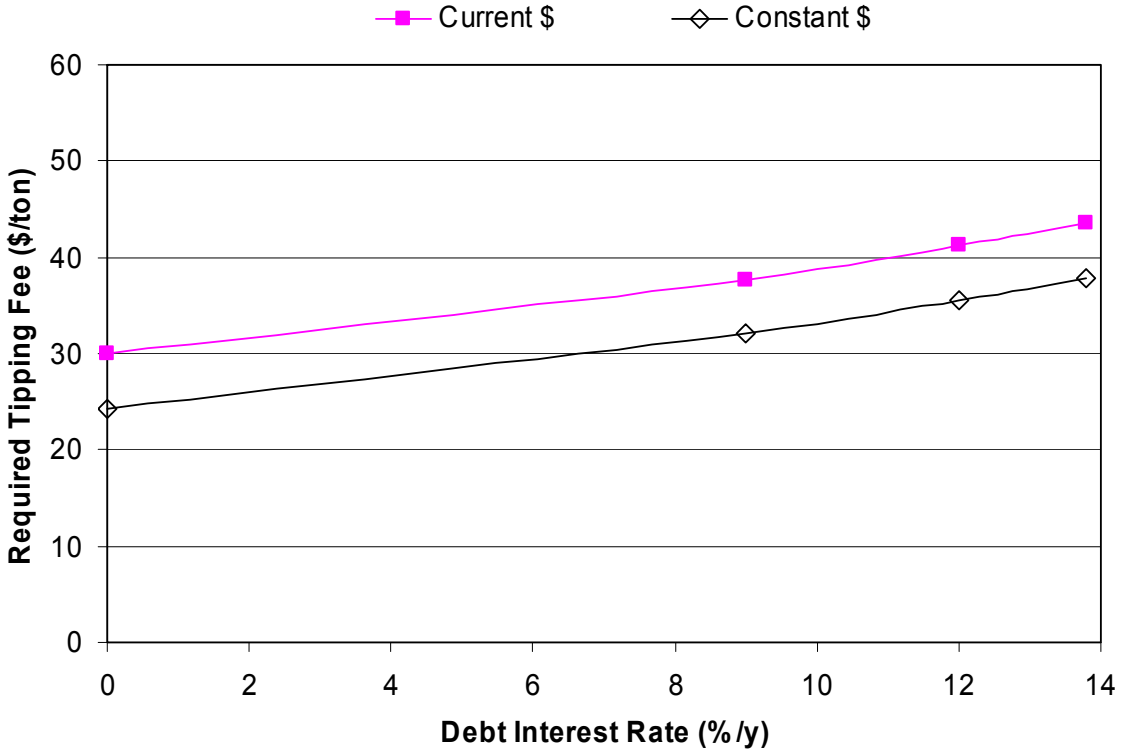

Figure 3.8-22. Required Tipping fee vs. debt interest rate (MSW AD Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

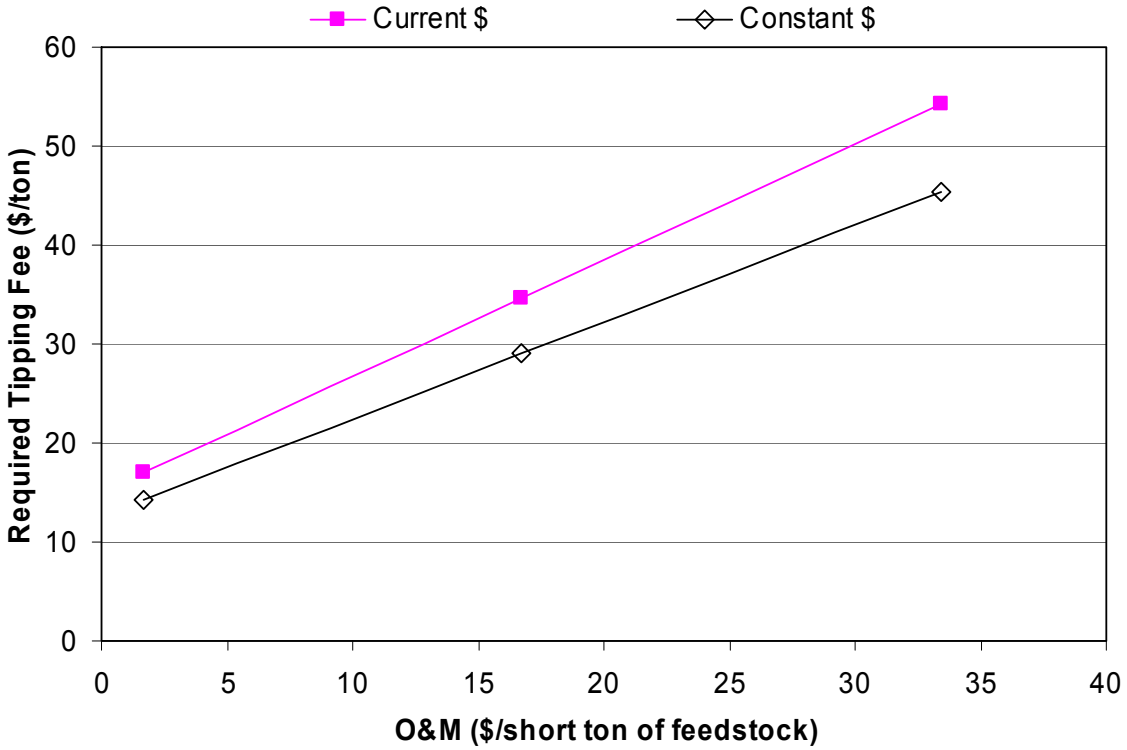

Figure 3.8-23. Required tipping fee vs. O&M costs (MSW AD Scenario 2)

Photo credit: UC Davis Research Team; Photo credit: Robert Williams

Appendix B

Base Cash Flows

Annual Cash Flows-Carbona Skive

Year	1	2	3	4	5	6	7	8	9	10
Equity Recovery	513,051	513,051	513,051	513,051	513,051	513,051	513,051	513,051	513,051	513,051
Equity Interest	450,000	440,542	429,666	417,158	402,774	386,233	367,210	345,334	320,176	291,245
Equity Principal Paid	63,051	72,509	83,385	95,893	110,277	126,818	145,841	167,717	192,875	221,806
Equity Principal Remaining	2,936,949	2,864,440	2,781,055	2,685,162	2,574,885	2,448,067	2,302,225	2,134,508	1,941,633	1,719,827
Debt Recovery	1,750,367	1,750,367	1,750,367	1,750,367	1,750,367	1,750,367	1,750,367	1,750,367	1,750,367	1,750,367
Debt Interest	1,020,000	976,178	929,727	880,488	828,295	772,971	714,327	652,165	586,273	516,427
Debt Principal Paid	730,367	774,189	820,640	869,879	922,071	977,396	1,036,040	1,098,202	1,164,094	1,233,940
Debt Principal Remaining	16,269,633	15,495,444	14,674,804	13,804,925	12,882,853	11,905,458	10,869,418	9,771,216	8,607,122	7,373,183
Fuel Cost	1,478,972	1,520,384	1,562,954	1,606,717	1,651,705	1,697,953	1,745,495	1,794,369	1,844,612	1,896,261
Non-fuel Expenses	1,278,271	1,314,063	1,350,857	1,388,681	1,427,564	1,467,536	1,508,627	1,550,868	1,594,292	1,638,933
Debt Reserve	0	0	0	0	0	0	0	0	0	0
Depreciation	4,000,000	6,400,000	3,840,000	2,304,000	2,304,000	1,152,000	0	0	0	0
Capacity Income	0	0	0	0	0	0	0	0	0	0
Annual heat sales ($)	1,718,138	1,766,246	1,815,701	1,866,541	1,918,804	1,972,530	2,027,761	2,084,538	2,142,906	2,202,907
Annual Ash sales ($)	2,988	3,071	3,157	3,246	3,337	3,430	3,526	3,625	3,726	3,831
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0
Taxes	-1,863,594	-3,456,494	-1,694,396	-622,692	-587,407	228,808	1,047,267	1,089,292	1,133,838	1,181,058
Tax Credit	388,926	388,926	388,926	388,926	388,926	0	0	0	0	0
Taxes With PTC	-2,252,521	-3,845,421	-2,083,323	-1,011,618	-976,333	228,808	1,047,267	1,089,292	1,133,838	1,181,058
Energy Revenue Required	1,047,015	-516,874	1,275,048	2,377,411	2,444,213	3,681,754	4,533,520	4,609,784	4,689,529	4,772,932

Current $ Level Annual Cost (LAC)

Cost of Money	0.0735									
Present Worth (time 0)	975,329	-448,518	1,030,672	1,790,178	1,714,466	2,405,706	2,759,441	2,613,751	2,476,913	2,348,360
Total Present Worth	28,940,052									
Capital Recovery Factor (current)	0.1122									
Current $ Level Annual Revenue Requirements ($/y)	3,248,063									
Current $ LAC of Energy ($/kWh)	**0.0752**									

Constant $ Level Annual Cost (LAC)

Real Cost of Money (inflation adjusted)	0.0443
Capital Recovery Factor (constant)	0.0926
Constant $ Level Annual Revenue Req	2,681,040
Constant $ LAC of Energy ($/kWh)	**0.0620**

Annual Cash Flows-Carbona Skive **Continued**

	11	12	13	14	15	16	17	18	19	20
Equity Recovery	513,051	513,051	513,051	513,051	513,051	513,051	513,051	513,051	513,051	513,051
Equity Interest	257,974	219,712	175,712	125,111	66,920	0	-76,958	-165,459	-267,236	-384,279
Equity Principal Paid	255,077	293,339	337,339	387,940	446,131	513,051	590,009	678,510	780,287	897,330
Equity Principal Remaining	1,464,750	1,171,411	834,072	446,131	0	-513,051	-1,103,060	-1,781,570	-2,561,857	-3,459,187
Debt Recovery	1,750,367	1,750,367	1,750,367	1,750,367	1,750,367	0	0	0	0	0
Debt Interest	442,391	363,912	280,725	192,547	99,077	0	0	0	0	0
Debt Principal Paid	1,307,976	1,386,455	1,469,642	1,557,820	1,651,290	0	0	0	0	0
Debt Principal Remaining	6,065,206	4,678,752	3,209,110	1,651,290	0	0	0	0	0	0
Fuel Cost	1,949,356	2,003,938	2,060,048	2,117,730	2,177,026	0	0	0	0	0
Non-fuel Expenses	1,684,823	1,731,998	1,780,494	1,830,348	1,881,597	0	0	0	0	0
Debt Reserve	0	0	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	0	0	0	0	0	0
Capacity Income	0	0	0	0	0	0	0	0	0	0
Annual heat sales ($)	2,264,588	2,327,997	2,393,181	2,460,190	2,529,075	0	0	0	0	0
Annual Ash sales ($)	3,938	4,048	4,162	4,278	4,398	0	0	0	0	0
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0
Taxes	1,231,110	1,284,166	1,340,405	1,400,018	1,463,208	346,850	346,850	346,850	346,850	346,850
Tax Credit	0	0	0	0	0					
Taxes With PTC	1,231,110	1,284,166	1,340,405	1,400,018	1,463,208					
Energy Revenue Required	4,860,181	4,951,475	5,047,023	5,147,045	5,251,777	859,901	859,901	859,901	859,901	859,901

	2,227,562	2,114,024	2,007,283	1,906,906	1,812,490	276,449	257,521	239,890	223,465	208,165

Annual Cash Flows - Kokemaki, Finland

Year	1	2	3	4	5	6	7	8	9	10
Equity Recovery	141,089	141,089	141,089	141,089	141,089	141,089	141,089	141,089	141,089	141,089
Equity Interest	123,750	121,149	118,158	114,719	110,763	106,214	100,983	94,967	88,048	80,092
Equity Principal Paid	17,339	19,940	22,931	26,371	30,326	34,875	40,106	46,122	53,041	60,997
Equity Principal Remaining	807,661	787,721	764,790	738,420	708,093	673,218	633,112	586,990	533,949	472,952
Debt Recovery	481,351	481,351	481,351	481,351	481,351	481,351	481,351	481,351	481,351	481,351
Debt Interest	280,500	268,449	255,675	242,134	227,781	212,567	196,440	179,345	161,225	142,018
Debt Principal Paid	200,851	212,902	225,676	239,217	253,570	268,784	284,911	302,006	320,126	339,333
Debt Principal Remaining	4,474,149	4,261,247	4,035,571	3,796,354	3,542,785	3,274,001	2,989,090	2,687,084	2,366,959	2,027,625
Fuel Cost	286,071	294,081	302,315	310,780	319,482	328,427	337,623	347,077	356,795	366,785
Non-fuel Expenses	432,929	445,051	457,512	470,322	483,491	497,029	510,946	525,253	539,960	555,078
Debt Reserve	0	0	0	0	0	0	0	0	0	0
Depreciation	1,100,000	1,760,000	1,056,000	633,600	633,600	316,800	0	0	0	0
Capacity Income	0	0	0	0	0	0	0	0	0	0
Annual heat sales ($)	305,853	314,416	323,220	332,270	341,574	351,138	360,970	371,077	381,467	392,148
Annual Ash sales ($)	867	891	916	942	968	995	1,023	1,052	1,081	1,111
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0
Taxes before PTC	-512,488	-950,536	-465,959	-171,240	-161,537	62,922	287,998	299,555	311,806	324,791
Tax Credit	131,723	131,723	131,723	131,723	131,723	0	0	0	0	0
Taxes With PTC	-644,211	-1,082,259	-597,682	-302,963	-293,260	62,922	287,998	299,555	311,806	324,791
Energy Revenue Required	390,509	-35,995	460,450	767,368	789,612	1,158,686	1,397,015	1,422,196	1,448,452	1,475,835

Current $ Level Annual Cost (LAC)										
Cost of Money	0.0735									
Present Worth (time 0)	363,772	-31,234	372,200	577,824	553,864	757,100	850,328	806,386	765,043	726,135
Total Present Worth	8,863,591									
Capital Recovery Factor (current)	0.1122									
Current $ Level Annual Revenue Requirements ($/y)	994,798									
Current $ LAC of Energy ($/kWh)	**0.071**									

Constant $ Level Annual Cost (LAC)	
Real Cost of Money (inflation adjusted)	0.0443
Capital Recovery Factor (constant)	0.0926
Constant $ Level Annual Revenue Requirements ($/y)	821,133
Constant $ LAC of Energy ($/kWh)	**0.058**

Annual Cash Flows - Kokemaki, Finland	(Continued)					
Year	11	12	13	14	15	16
Equity Recovery	141,089	141,089	141,089	141,089	141,089	0
Equity Interest	70,943	60,421	48,321	34,405	18,403	0
Equity Principal Paid	70,146	80,668	92,768	106,684	122,686	0
Equity Principal Remaining	402,806	322,138	229,370	122,686	0	0
Debt Recovery	481,351	481,351	481,351	481,351	481,351	0
Debt Interest	121,658	100,076	77,199	52,950	27,246	0
Debt Principal Paid	359,693	381,275	404,152	428,401	454,105	0
Debt Principal Remaining	1,667,932	1,286,657	882,505	454,105	0	0
Fuel Cost	377,055	387,613	398,466	409,623	421,093	0
Non-fuel Expenses	570,621	586,598	603,023	619,907	637,265	0
Debt Reserve	0	0	0	0	0	0
Depreciation	0	0	0	0	0	0
Capacity Income	0	0	0	0	0	0
Annual heat sales ($)	403,128	414,416	426,020	437,948	450,211	0
Annual Ash sales ($)	1,143	1,175	1,207	1,241	1,276	0
Interest on Debt Reserve	0	0	0	0	0	0
Taxes before PTC	338,555	353,146	368,611	385,005	402,382	0
Tax Credit	0	0	0	0	0	
Taxes With PTC	338,555	353,146	368,611	385,005	402,382	
Energy Revenue Required	1,504,400	1,534,206	1,565,313	1,597,786	1,631,693	0
	689,511	655,027	622,550	591,957	563,129	0

Annual Cash Flows -Carbona IGCC

Year	1	2	3	4	5	6	7	8	9
Equity Recovery	838,748	838,748	838,748	838,748	838,748	838,748	838,748	838,748	838,748
Equity Interest	787,500	779,813	770,973	760,806	749,115	735,670	720,209	702,428	681,980
Equity Principal Paid	51,248	58,935	67,775	77,941	89,633	103,077	118,539	136,320	156,768
Equity Principal Remaining	5,198,752	5,139,817	5,072,042	4,994,101	4,904,468	4,801,391	4,682,852	4,546,532	4,389,764
Debt Recovery	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741
Debt Interest	1,785,000	1,736,476	1,685,040	1,630,518	1,572,724	1,511,463	1,446,527	1,377,694	1,304,731
Debt Principal Paid	808,741	857,265	908,701	963,223	1,021,016	1,082,277	1,147,214	1,216,047	1,289,010
Debt Principal Remaining	28,941,259	28,083,994	27,175,294	26,212,071	25,191,054	24,108,777	22,961,563	21,745,516	20,456,507
Fuel Cost	1,821,204	1,872,198	1,924,619	1,978,509	2,033,907	2,090,856	2,149,400	2,209,583	2,271,452
Non-fuel Expenses	2,915,109	2,996,732	3,080,641	3,166,898	3,255,572	3,346,728	3,440,436	3,536,768	3,635,798
Debt Reserve	2,593,741	0	0	0	0	0	0	0	0
Depreciation	3,500,000	6,300,000	5,040,000	4,032,000	3,227,000	2,579,500	2,292,500	2,292,500	2,292,500
Capacity Income	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000
Annual heat sales ($)	0	0	0	0	0	0	0	0	0
Annual Ash sales ($)	5,519	5,673	5,832	5,995	6,163	6,336	6,513	6,696	6,883
Interest on Debt Reserve	77,812	77,812	77,812	77,812	77,812	77,812	77,812	77,812	77,812
Taxes before PTC	-1,252,395	-3,112,537	-2,225,938	-1,507,617	-924,323	-445,164	-207,236	-160,701	-111,375
Tax Credit	886,950	886,950	886,950	886,950	886,950	0	0	0	0
Taxes with PTC	-2,139,345	-3,999,487	-3,112,888	-2,394,567	-1,811,273	-445,164	-207,236	-160,701	-111,375
Energy Revenue Required	7,414,866	3,093,445	4,116,216	4,974,521	5,701,718	7,215,760	7,605,763	7,808,631	8,018,668

Current $ Level Annual Cost (LAC)

Cost of Money	0.0735								
Present Worth (time 0)	6,907,187	2,684,345	3,327,300	3,745,787	3,999,406	4,714,871	4,629,440	4,427,499	4,235,296
Total Present Worth	79,191,558								
Capital Recovery Factor (current)	0.0970								
Current $ Level Annual Revenue Requirements ($/y)	7,679,676								
Current $ LAC of Energy ($/kWh)	**0.078**								

Constant $ Level Annual Cost (LAC)

Real Cost of Money (inflation adjusted)	0.0443
Capital Recovery Factor (constant)	0.0764
Constant $ Level Annual Revenue Requirements ($/y)	6,049,004
Constant $ LAC of Energy ($/kWh)	**0.061**

Annual Cash Flows -Carbona IGCC **(Continued)**

Year	10	11	12	13	14	15	16	17	18	19	20
Equity Recovery	838,748	838,748	838,748	838,748	838,748	838,748	838,748	838,748	838,748	838,748	838,748
Equity Interest	658,465	631,422	600,323	564,560	523,431	476,134	421,742	359,191	287,257	204,534	109,402
Equity Principal Paid	180,283	207,326	238,424	274,188	315,316	362,614	417,006	479,557	551,490	634,214	729,346
Equity Principal Remaining	4,209,481	4,002,155	3,763,731	3,489,543	3,174,226	2,811,612	2,394,607	1,915,050	1,363,560	729,346	0
Debt Recovery	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741	2,593,741
Debt Interest	1,227,390	1,145,409	1,058,510	966,396	868,755	765,256	655,547	539,255	415,986	285,321	146,816
Debt Principal Paid	1,366,350	1,448,331	1,535,231	1,627,345	1,724,986	1,828,485	1,938,194	2,054,485	2,177,755	2,308,420	2,446,925
Debt Principal Remaining	19,090,156	17,641,825	16,106,594	14,479,249	12,754,264	10,925,779	8,987,585	6,933,100	4,755,345	2,446,925	0
Fuel Cost	2,335,052	2,400,434	2,467,646	2,536,740	2,607,769	2,680,786	2,755,848	2,833,012	2,912,336	2,993,882	3,077,711
Non-fuel Expenses	3,737,600	3,842,253	3,949,836	4,060,431	4,174,123	4,290,999	4,411,147	4,534,659	4,661,629	4,792,155	4,926,335
Debt Reserve	0	0	0	0	0	0	0	0	0	0	-2,593,741
Depreciation	2,292,500	1,151,500	0	0	0	0	0	0	0	0	0
Capacity Income	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000	1,125,000
Annual heat sales ($)	0	0	0	0	0	0	0	0	0	0	0
Annual Ash sales ($)	7,076	7,274	7,478	7,687	7,902	8,124	8,351	8,585	8,825	9,072	9,326
Interest on Debt Reserve	77,812	77,812	77,812	77,812	77,812	77,812	77,812	77,812	77,812	77,812	77,812
Taxes before PTC	-59,088	767,711	1,604,934	1,667,208	1,733,218	1,803,189	1,877,358	1,955,978	2,039,314	2,127,651	2,221,288
Tax Credit	0	0	0	0	0	0	0	0	0	0	0
Taxes with PTC	-59,088	767,711	1,604,934	1,667,208	1,733,218	1,803,189	1,877,358	1,955,978	2,039,314	2,127,651	2,221,288
Energy Revenue Required	8,236,164	9,232,800	10,244,615	10,486,369	10,736,884	10,996,527	11,265,679	11,544,740	11,834,131	12,134,291	9,851,943

	4,052,327	4,231,661	4,373,922	4,170,600	3,977,861	3,795,114	3,621,801	3,457,398	3,301,410	3,153,374	2,384,959

Annual Cash Flows - Straw Facility

Year	1	2	3	4	5	6	7	8	9	10
Equity Recovery	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802
Equity Interest	2,640,000	2,614,230	2,584,594	2,550,513	2,511,319	2,466,247	2,414,414	2,354,805	2,286,256	2,207,424
Equity Principal Paid	171,802	197,572	227,208	261,289	300,483	345,555	397,388	456,996	525,546	604,378
Equity Principal Remaining	17,428,198	17,230,626	17,003,418	16,742,129	16,441,646	16,096,091	15,698,703	15,241,707	14,716,161	14,111,783
Debt Recovery	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793
Debt Interest	4,224,000	4,109,172	3,987,455	3,858,435	3,721,673	3,576,706	3,423,041	3,260,156	3,087,498	2,904,480
Debt Principal Paid	1,913,793	2,028,620	2,150,338	2,279,358	2,416,119	2,561,086	2,714,752	2,877,637	3,050,295	3,233,313
Debt Principal Remaining	68,486,207	66,457,587	64,307,249	62,027,891	59,611,772	57,050,686	54,335,934	51,458,297	48,408,002	45,174,689
Fuel Cost	7,568,964	7,871,722	8,186,591	8,514,055	8,854,617	9,208,802	9,577,154	9,960,240	10,358,649	10,772,995
Non-fuel Expenses	8,172,670	8,499,577	8,839,560	9,193,142	9,560,868	9,943,303	10,341,035	10,754,676	11,184,863	11,632,258
Debt Reserve	6,137,793	0	0	0	0	0	0	0	0	0
Depreciation	8,800,000	15,840,000	12,672,000	10,137,600	8,113,600	6,485,600	5,764,000	5,764,000	5,764,000	5,764,000
Capacity Income	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444
Annual heat sales ($)	0	0	0	0	0	0	0	0	0	0
Annual Ash sales ($)	0	0	0	0	0	0	0	0	0	0
Interest on Debt Reserve	245,512	245,512	245,512	245,512	245,512	245,512	245,512	245,512	245,512	245,512
Taxes before PTC	-2,754,512	-7,436,293	-5,212,271	-3,411,659	-1,950,871	-752,252	-160,526	-50,407	66,319	190,048
Tax Credit	2,486,614	2,561,212	2,638,048	2,717,190	2,798,706	0	0	0	0	0
Taxes with PTC	-5,241,126	-9,997,505	-7,850,319	-6,128,849	-4,749,576	-752,252	-160,526	-50,407	66,319	190,048
Energy Revenue Required	21,837,939	11,573,433	14,375,470	16,777,987	18,865,547	23,599,491	24,957,301	25,864,147	26,809,470	27,794,940

Current $ Level Annual Cost (LAC)

Cost of Money	0.0780									
Present Worth (time 0)	20,257,829	9,959,205	11,475,346	12,424,096	12,959,123	15,038,000	14,752,523	14,182,346	13,637,017	13,115,297
Total Present Worth	254,922,879									
Capital Recovery Factor (current)	0.1003									
Current $ Level Annual Revenue Requirements ($/y)	25,579,227									
Current $ LAC of Energy ($/kWh)	**0.0926**									

Constant $ Level Annual Cost (LAC)

Real Cost of Money (inflation adjusted)	0.0365
Capital Recovery Factor (constant)	0.0713
Constant $ Level Annual Revenue Requirements ($/y)	18,187,244
Constant $ LAC of Energy ($/kWh)	**0.0658**

Year	11	12	13	14	15	16	17	18	19	20
Equity Recovery	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802	2,811,802
Equity Interest	2,116,767	2,012,512	1,892,619	1,754,741	1,596,182	1,413,839	1,204,145	962,997	685,676	366,757
Equity Principal Paid	695,034	799,290	919,183	1,057,060	1,215,620	1,397,962	1,607,657	1,848,805	2,126,126	2,445,045
Equity Principal Remaining	13,416,749	12,617,459	11,698,276	10,641,216	9,425,596	8,027,634	6,419,977	4,571,171	2,445,045	0
Debt Recovery	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793	6,137,793
Debt Interest	2,710,481	2,504,843	2,286,866	2,055,810	1,810,891	1,551,277	1,276,086	984,384	675,179	347,422
Debt Principal Paid	3,427,311	3,632,950	3,850,927	4,081,983	4,326,902	4,586,516	4,861,707	5,153,409	5,462,614	5,790,371
Debt Principal Remaining	41,747,378	38,114,428	34,263,501	30,181,518	25,854,616	21,268,100	16,406,394	11,252,984	5,790,371	0
Fuel Cost	11,203,915	11,652,072	12,118,155	12,602,881	13,106,996	13,631,276	14,176,527	14,743,588	15,333,332	15,946,665
Non-fuel Expenses	12,097,548	12,581,450	13,084,708	13,608,096	14,152,420	14,718,517	15,307,258	15,919,548	16,556,330	17,218,583
Debt Reserve	0	0	0	0	0	0	0	0	0	-6,137,793
Depreciation	2,895,200	0	0	0	0	0	0	0	0	0
Capacity Income	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444	3,504,444
Annual heat sales ($)	0	0	0	0	0	0	0	0	0	0
Annual Ash sales ($)	0	0	0	0	0	0	0	0	0	0
Interest on Debt Reserve	245,512	245,512	245,512	245,512	245,512	245,512	245,512	245,512	245,512	245,512
Taxes before PTC	2,260,661	4,356,991	4,504,355	4,660,561	4,826,139	5,001,652	5,187,695	5,384,901	5,593,940	5,815,521
Tax Credit	0	0	0	0	0	0	0	0	0	0
Taxes with PTC	2,260,661	4,356,991	4,504,355	4,660,561	4,826,139	5,001,652	5,187,695	5,384,901	5,593,940	5,815,521
Energy Revenue Required	30,761,763	33,790,152	34,906,856	36,071,177	37,285,194	38,551,083	39,871,118	41,247,676	42,683,240	38,042,614

	13,464,953	13,720,344	13,148,217	12,603,688	12,085,232	11,591,414	11,120,888	10,672,393	10,244,740	8,470,229

Annual Cash Flows Generic MSW AD (COE Calculation)										
Year	1	2	3	4	5	6	7	8	9	10
Equity Recovery	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294
Equity Interest	619,010	612,968	606,019	598,028	588,838	578,270	566,116	552,140	536,067	517,583
Equity Principal Paid	40,283	46,325	53,274	61,265	70,455	81,024	93,177	107,154	123,227	141,711
Equity Principal Remaining	4,086,454	4,040,128	3,986,854	3,925,588	3,855,133	3,774,110	3,680,933	3,573,779	3,450,552	3,308,842
Debt Recovery	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797
Debt Interest	1,403,090	1,364,948	1,324,517	1,281,660	1,236,232	1,188,078	1,137,035	1,082,929	1,025,577	964,784
Debt Principal Paid	635,707	673,849	714,280	757,137	802,565	850,719	901,762	955,868	1,013,220	1,074,013
Debt Principal Remaining	22,749,134	22,075,285	21,361,006	20,603,869	19,801,304	18,950,585	18,048,823	17,092,956	16,079,736	15,005,723
Fuel Cost	0	0	0	0	0	0	0	0	0	0
Non-fuel Expenses	1,669,817	1,704,883	1,740,686	1,777,240	1,814,562	1,852,668	1,891,574	1,931,297	1,971,855	2,013,263
Debt Reserve	0	0	0	0	0	0	0	0	0	0
Depreciation	2,751,158	4,952,084	3,961,667	3,169,334	2,536,567	2,027,603	1,802,008	1,802,008	1,802,008	1,802,008
Income--Capacity	0	0	0	0	0	0	0	0	0	0
Income - Electricity sales	0	0	0	0	0	0	0	0	0	0
Income--Heat	0	0	0	0	0	0	0	0	0	0
Income--Compost Material	238,166	243,167	248,274	253,488	258,811	264,246	269,795	275,461	281,245	287,152
Income-- Tipping Fee	2,599,326	2,653,912	2,709,644	2,766,546	2,824,644	2,883,961	2,944,525	3,006,360	3,069,493	3,133,953
Income - Sales of waste water	0	0	0	0	0	0	0	0	0	0
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0
Taxes w/o credit	-984,439	-2,446,595	-1,749,687	-1,185,055	-726,560	-349,919	-162,897	-126,319	-87,546	-46,446
Tax Credit	98,885	144,231	147,260	150,352	153,510	0	0	0	0	0
Taxes	-1,083,324	-2,590,826	-1,896,947	-1,335,407	-880,070	-349,919	-162,897	-126,319	-87,546	-46,446
Revenue Required	447,092	-1,084,931	-416,089	119,889	549,129	1,052,633	1,212,448	1,221,249	1,231,661	1,243,804
Current $ Level Annual Cost (LAC)										
Cost of Money	0.0735									
Present Worth (time 0)	416,480	-941,452	-336,341	90,276	385,180	687,804	737,987	692,449	650,538	611,972
Total Present Worth	11,427,406									
Capital Recovery Factor (current)	0.0970									
Current $ Level Annual Revenue Requirements ($/y)	1,108,183									
Current $ LAC of Electrical Energy ($/kWh)	**0.101**									
Constant $ Level Annual Cost (LAC)										
Real Cost of Money (inflation adjusted)	0.0514									
Capital Recovery Factor (constant)	0.0812									
Constant $ Level Annual Revenue Requirements ($/y)	928,039									
Constant $ LAC of Electrical Energy ($/kWh)	**0.084**									

Annual Cash Flows Generic MSW AD (COE Calculation) ***(Continued)***

Year	11	12	13	14	15	16	17	18	19	20	Total
Equity Recovery	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	13,185,870
Equity Interest	496,326	471,881	443,769	411,441	374,263	331,508	282,340	225,797	160,773	85,995	9,059,134
Equity Principal Paid	162,967	187,412	215,524	247,853	285,031	327,785	376,953	433,496	498,521	573,299	4,126,737
Equity Principal Remaining	3,145,874	2,958,462	2,742,938	2,495,085	2,210,054	1,882,269	1,505,316	1,071,819	573,299	0	--
Debt Recovery	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	40,775,940
Debt Interest	900,343	832,036	759,631	682,881	601,526	515,289	423,879	326,984	224,275	115,404	17,391,099
Debt Principal Paid	1,138,454	1,206,761	1,279,166	1,355,916	1,437,271	1,523,508	1,614,918	1,711,813	1,814,522	1,923,393	23,384,841
Debt Principal Remaining	13,867,270	12,660,509	11,381,342	10,025,426	8,588,155	7,064,647	5,449,729	3,737,915	1,923,393	0	--
Fuel Cost	0	0	0	0	0	0	0	0	0	0	0
Non-fuel Expenses	2,055,542	2,098,708	2,142,781	2,187,780	2,233,723	2,280,631	2,328,524	2,377,423	2,427,349	2,478,324	40,978,633
Debt Reserve	0	0	0	0	0	0	0	0	0	0	0
Depreciation	905,131	0	0	0	0	0	0	0	0	0	27,511,578
Income--Capacity	0	0	0	0	0	0	0	0	0	0	0
Income - Electricity sales	0	0	0	0	0	0	0	0	0	0	
Income--Heat	0	0	0	0	0	0	0	0	0	0	0
Income--Compost Material	293,182	299,339	305,625	312,043	318,596	325,286	332,117	339,092	346,213	353,483	5,844,779
Income-- Tipping Fee	3,199,766	3,266,961	3,335,567	3,405,614	3,477,132	3,550,151	3,624,705	3,700,823	3,778,541	3,857,890	63,789,512
Income - Sales of waste water	0	0	0	0	0	0	0	0	0	0	
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0	0
Taxes w/o credit	603,455	1,261,551	1,310,501	1,362,388	1,417,388	1,475,688	1,537,487	1,602,993	1,672,429	1,746,032	6,124,450
Tax Credit	0	0	0	0	0	0	0	0	0	0	694,238
Taxes	603,455	1,261,551	1,310,501	1,362,388	1,417,388	1,475,688	1,537,487	1,602,993	1,672,429	1,746,032	5,430,213
Revenue Required	1,864,141	2,492,050	2,510,181	2,530,601	2,553,474	2,578,972	2,607,280	2,638,592	2,673,116	2,711,073	30,736,364
	854,390	1,063,977	998,340	937,551	881,253	829,113	780,823	736,097	694,671	656,297	

Annual Cash Flows - Generic MSW AD (Required Tipping Fee Determination)

Year	1	2	3	4	5	6	7	8	9	10
Equity Recovery	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294
Equity Interest	619,010	612,968	606,019	598,028	588,838	578,270	566,116	552,140	536,067	517,583
Equity Principal Paid	40,283	46,325	53,274	61,265	70,455	81,024	93,177	107,154	123,227	141,711
Equity Principal Remaining	4,086,454	4,040,128	3,986,854	3,925,588	3,855,133	3,774,110	3,680,933	3,573,779	3,450,552	3,308,842
Debt Recovery	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797
Debt Interest	1,403,090	1,364,948	1,324,517	1,281,660	1,236,232	1,188,078	1,137,035	1,082,929	1,025,577	964,784
Debt Principal Paid	635,707	673,849	714,280	757,137	802,565	850,719	901,762	955,868	1,013,220	1,074,013
Debt Principal Remaining	22,749,134	22,075,285	21,361,006	20,603,869	19,801,304	18,950,585	18,048,823	17,092,956	16,079,736	15,005,723
Fuel Cost	0	0	0	0	0	0	0	0	0	0
Non-fuel Expenses	1,669,817	1,704,883	1,740,686	1,777,240	1,814,562	1,852,668	1,891,574	1,931,297	1,971,855	2,013,263
Debt Reserve	0	0	0	0	0	0	0	0	0	0
Depreciation	2,751,158	4,952,084	3,961,667	3,169,334	2,536,567	2,027,603	1,802,008	1,802,008	1,802,008	1,802,008
Income--Capacity	0	0	0	0	0	0	0	0	0	0
Income - Electricity sales	582,323	594,552	607,038	619,786	632,801	646,090	659,658	673,511	687,654	702,095
Income--Heat	0	0	0	0	0	0	0	0	0	0
Income--Compost Material	238,166	243,167	248,274	253,488	258,811	264,246	269,795	275,461	281,245	287,152
Income-- Tipping Fee	0	0	0	0	0	0	0	0	0	0
Income - Sales of waste water	0	0	0	0	0	0	0	0	0	0
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0
Taxes w/o credit	-984,439	-2,446,595	-1,749,687	-1,185,055	-726,560	-349,919	-162,897	-126,319	-87,546	-46,446
Tax Credit	98,885	144,231	147,260	150,352	153,510	0	0	0	0	0
Taxes	-1,083,324	-2,590,826	-1,896,947	-1,335,407	-880,070	-349,919	-162,897	-126,319	-87,546	-46,446
Revenue Required	2,464,094	974,429	1,686,517	2,266,650	2,740,971	3,290,504	3,497,315	3,554,098	3,613,500	3,675,661
Current $ Level Annual Cost (LAC)										
Cost of Money	0.0735									
Present Worth (time 0)	2,295,383	845,563	1,363,279	1,706,775	1,922,624	2,150,058	2,128,729	2,015,176	1,908,577	1,808,485
Total Present Worth	35,752,933									
Capital Recovery Factor (current)	0.0970									
Current $ Level Annual Revenue Requirements ($/y)	3,467,174									
Current $ LA Tipping fee Requirement ($/Mg)	38.227									
($/short ton)	**34.7**									
Constant $ Level Annual Cost (LAC)										
Real Cost of Money (inflation adjusted)	0.0514									
Capital Recovery Factor (constant)	0.0812									
Constant $ Level Annual Revenue Requirements ($/y)	2,903,555									
Constant $ LA Tipping fee Requirement ($/Mg)	32.013									

Annual Cash Flows - Generic MSW AD (Required Tipping Fee Determination) ***Continued***

	11	12	13	14	15	16	17	18	19	20	Total
Equity Recovery	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	659,294	13,185,870
Equity Interest	496,326	471,881	443,769	411,441	374,263	331,508	282,340	225,797	160,773	85,995	9,059,134
Equity Principal Paid	162,967	187,412	215,524	247,853	285,031	327,785	376,953	433,496	498,521	573,299	4,126,737
Equity Principal Remaining	3,145,874	2,958,462	2,742,938	2,495,085	2,210,054	1,882,269	1,505,316	1,071,819	573,299	0	--
Debt Recovery	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	2,038,797	40,775,940
Debt Interest	900,343	832,036	759,631	682,881	601,526	515,289	423,879	326,984	224,275	115,404	17,391,099
Debt Principal Paid	1,138,454	1,206,761	1,279,166	1,355,916	1,437,271	1,523,508	1,614,918	1,711,813	1,814,522	1,923,393	23,384,841
Debt Principal Remaining	13,867,270	12,660,509	11,381,342	10,025,426	8,588,155	7,064,647	5,449,729	3,737,915	1,923,393	0	--
Fuel Cost	0	0	0	0	0	0	0	0	0	0	0
Non-fuel Expenses	2,055,542	2,098,708	2,142,781	2,187,780	2,233,723	2,280,631	2,328,524	2,377,423	2,427,349	2,478,324	40,978,633
Debt Reserve	0	0	0	0	0	0	0	0	0	0	0
Depreciation	905,131	0	0	0	0	0	0	0	0	0	27,511,578
Income--Capacity	0	0	0	0	0	0	0	0	0	0	0
Income - Electricity sales	716,839	731,893	747,262	762,955	778,977	795,336	812,038	829,090	846,501	864,278	
Income--Heat	0	0	0	0	0	0	0	0	0	0	0
Income--Compost Material	293,182	299,339	305,625	312,043	318,596	325,286	332,117	339,092	346,213	353,483	5,844,779
Income-- Tipping Fee	0	0	0	0	0	0	0	0	0	0	0
Income - Sales of waste water	0	0	0	0	0	0	0	0	0	0	
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0	0
Taxes w/o credit	603,455	1,261,551	1,310,501	1,362,388	1,417,388	1,475,688	1,537,487	1,602,993	1,672,429	1,746,032	6,124,450
Tax Credit	0	0	0	0	0	0	0	0	0	0	694,238
Taxes	603,455	1,261,551	1,310,501	1,362,388	1,417,388	1,475,688	1,537,487	1,602,993	1,672,429	1,746,032	5,430,213
Revenue Required	4,347,067	5,027,118	5,098,485	5,173,260	5,251,629	5,333,788	5,419,947	5,510,325	5,605,155	5,704,685	80,235,200
Present Worth (time 0)	1,992,387	2,146,320	2,027,751	1,916,618	1,812,439	1,714,759	1,623,156	1,537,235	1,456,628	1,380,991	
											69,343,487
											69,343,487

Table APS-2. Base Case Cash Flow, APS Scenario 1 (Full tax deductions)

Year	1	2	3	4	5	6	7	8	9	10
Equity Recovery	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194
Equity Interest	380,436	376,723	372,452	367,541	361,893	355,398	347,928	339,338	329,460	318,100
Equity Principal Paid	24,757	28,471	32,742	37,653	43,301	49,796	57,265	65,855	75,734	87,094
Equity Principal Remaining	2,511,484	2,483,013	2,450,271	2,412,618	2,369,318	2,319,521	2,262,256	2,196,401	2,120,667	2,033,573
Debt Recovery	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020
Debt Interest	862,322	838,880	814,032	787,693	759,773	730,178	698,808	665,555	630,307	592,945
Debt Principal Paid	390,697	414,139	438,988	465,327	493,247	522,841	554,212	587,464	622,712	660,075
Debt Principal Remaining	13,981,339	13,567,199	13,128,212	12,662,885	12,169,638	11,646,797	11,092,585	10,505,121	9,882,408	9,222,333
Fuel Cost	0	0	0	0	0	0	0	0	0	0
Non-fuel Expenses	1,307,776	1,335,239	1,363,279	1,391,908	1,421,138	1,450,982	1,481,453	1,512,563	1,544,327	1,576,758
Debt Reserve	0	0	0	0	0	0	0	0	0	0
Depreciation	1,690,828	3,043,490	2,434,792	1,947,834	1,558,943	1,246,140	1,107,492	1,107,492	1,107,492	1,107,492
Income--Capacity	0	0	0	0	0	0	0	0	0	0
Income - Electricity sales	0	0	0	0	0	0	0	0	0	0
Income--Heat	0	0	0	0	0	0	0	0	0	0
Income--Compost Material	330,274	337,210	344,291	351,521	358,903	366,440	374,136	381,992	390,014	398,205
Income-- Tipping Fee	1,372,169	1,400,985	1,430,405	1,460,444	1,491,113	1,522,426	1,554,397	1,587,040	1,620,368	1,654,395
Income - Sales of waste water	0	0	0	0	0	0	0	0	0	0
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0
Taxes w/o credit	-605,024	-1,503,647	-1,075,336	-728,320	-446,535	-215,056	-100,114	-77,634	-53,804	-28,545
Tax Credit	98,654	125,907	128,552	131,251	134,007	0	0	0	0	0
Taxes	-703,678	-1,629,555	-1,203,888	-859,571	-580,542	-215,056	-100,114	-77,634	-53,804	-28,545
Revenue Required	559,868	-374,296	42,908	378,585	648,793	1,005,273	1,111,019	1,124,110	1,138,354	1,153,826

Current $ Level Annual Cost (LAC)

Cost of Money	0.0735									
Present Worth (time 0)	521,535	-324,797	34,684	285,072	455,088	656,858	676,250	637,371	601,255	567,701
Total Present Worth	10,762,802									
Capital Recovery Factor (curren	0.0970									
Current $ Level Annual Revenue	1,043,733									
Current $ LAC of Electrical En	**0.095**									

Constant $ Level Annual Cost (LAC)

Real Cost of Money (inflation ad	0.0514
Capital Recovery Factor (consta	0.0812
Constant $ Level Annual Reven	874,065
Constant $ LAC of Electrical E	**0.080**

Table APS-2. (Continued) Base Case Cash Flow, APS Scenario 1 (Full tax deductions)

Year	11	12	13	14	15	16	17	18	19	20	Total
Equity Recovery	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	8,103,874
Equity Interest	305,036	290,012	272,735	252,866	230,017	203,741	173,523	138,772	98,809	52,851	5,567,632
Equity Principal Paid	100,158	115,181	132,459	152,327	175,176	201,453	231,671	266,421	306,385	352,342	2,536,242
Equity Principal Remaining	1,933,416	1,818,234	1,685,776	1,533,449	1,358,272	1,156,819	925,148	658,727	352,342	0	--
Debt Recovery	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	25,060,392
Debt Interest	553,340	511,359	466,860	419,690	369,690	316,690	260,511	200,960	137,837	70,926	10,688,356
Debt Principal Paid	699,680	741,660	786,160	833,330	883,329	936,329	992,509	1,052,059	1,115,183	1,182,094	14,372,036
Debt Principal Remaining	8,522,654	7,780,993	6,994,833	6,161,504	5,278,174	4,341,845	3,349,336	2,297,277	1,182,094	0	--
Fuel Cost	0	0	0	0	0	0	0	0	0	0	0
Non-fuel Expenses	1,609,870	1,643,677	1,678,194	1,713,436	1,749,419	1,786,156	1,823,666	1,861,963	1,901,064	1,940,986	32,093,853
Debt Reserve	0	0	0	0	0	0	0	0	0	0	0
Depreciation	556,282	0	0	0	0	0	0	0	0	0	16,908,278
Income--Capacity	0	0	0	0	0	0	0	0	0	0	0
Income - Electricity sales	0	0	0	0	0	0	0	0	0	0	
Income--Heat	0	0	0	0	0	0	0	0	0	0	0
Income--Compost Material	406,567	415,105	423,822	432,722	441,809	451,087	460,560	470,232	480,107	490,189	8,105,189
Income-- Tipping Fee	1,689,138	1,724,609	1,760,826	1,797,804	1,835,557	1,874,104	1,913,460	1,953,643	1,994,670	2,036,558	33,674,111
Income - Sales of waste water	0	0	0	0	0	0	0	0	0	0	
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0	0
Taxes w/o credit	370,876	775,334	805,418	837,307	871,109	906,940	944,920	985,180	1,027,855	1,073,090	3,764,012
Tax Credit	0	0	0	0	0	0	0	0	0	0	618,372
Taxes	370,876	775,334	805,418	837,307	871,109	906,940	944,920	985,180	1,027,855	1,073,090	3,145,640
Revenue Required	1,543,255	1,937,510	1,957,177	1,978,431	2,001,374	2,026,118	2,052,779	2,081,480	2,112,355	2,145,543	26,624,460
Present Worth (time 0)	707,319	827,217	778,401	732,980	690,713	651,376	614,762	580,678	548,944	519,393	
											20,874,658
											20,874,658

Table APS-4. Base Case Cash Flow, APS Scenario 2 (no ‘negative’ taxes).

Year	1	2	3	4	5	6	7	8	9	10
Equity Recovery	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194
Equity Interest	380,436	376,723	372,452	367,541	361,893	355,398	347,928	339,338	329,460	318,100
Equity Principal Paid	24,757	28,471	32,742	37,653	43,301	49,796	57,265	65,855	75,734	87,094
Equity Principal Remaining	2,511,484	2,483,013	2,450,271	2,412,618	2,369,318	2,319,521	2,262,256	2,196,401	2,120,667	2,033,573
Debt Recovery	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020
Debt Interest	862,322	838,880	814,032	787,693	759,773	730,178	698,808	665,555	630,307	592,945
Debt Principal Paid	390,697	414,139	438,988	465,327	493,247	522,841	554,212	587,464	622,712	660,075
Debt Principal Remaining	13,981,339	13,567,199	13,128,212	12,662,885	12,169,638	11,646,797	11,092,585	10,505,121	9,882,408	9,222,333
Fuel Cost	0	0	0	0	0	0	0	0	0	0
Non-fuel Expenses	1,307,776	1,335,239	1,363,279	1,391,908	1,421,138	1,450,982	1,481,453	1,512,563	1,544,327	1,576,758
Debt Reserve	0	0	0	0	0	0	0	0	0	0
Depreciation	845,414	845,414	845,414	845,414	845,414	845,414	845,414	845,414	845,414	845,414
Income--Capacity	0	0	0	0	0	0	0	0	0	0
Income - Electricity sales	0	0	0	0	0	0	0	0	0	0
Income--Heat	0	0	0	0	0	0	0	0	0	0
Income--Compost Material	330,274	337,210	344,291	351,521	358,903	366,440	374,136	381,992	390,014	398,205
Income-- Tipping Fee	1,372,169	1,400,985	1,430,405	1,460,444	1,491,113	1,522,426	1,554,397	1,587,040	1,620,368	1,654,395
Income - Sales of waste water	0	0	0	0	0	0	0	0	0	0
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0
Taxes w/o credit	-33,480	-17,632	-833	16,973	35,849	55,856	77,064	99,545	123,374	148,633
Tax Credit	98,654	125,907	128,552	131,251	134,007	0	0	0	0	0
Taxes	0	0	0	0	0	55,856	77,064	99,545	123,374	148,633
Revenue Required	1,263,546	1,255,258	1,246,796	1,238,156	1,229,335	1,276,185	1,288,197	1,301,289	1,315,533	1,331,005

Current $ Level Annual Cost (LAC)

Cost of Money	0.0735									
Present Worth (time 0)	1,177,034	1,089,253	1,007,835	932,325	862,303	833,876	784,094	737,832	694,837	654,876
Total Present Worth	13,654,883									
Capital Recovery Factor (curren	0.0970									
Current $ Level Annual Revenu	1,324,195									
Current $ LAC of Electrical En	**0.121**									

Constant $ Level Annual Cost (LAC)

Real Cost of Money (inflation ad	0.0514
Capital Recovery Factor (consta	0.0812
Constant $ Level Annual Reven	1,108,936
Constant $ LAC of Electrical E	**0.101**

Table APS-4. (Continued) Base Case Cash Flow, APS Scenario 2(no 'negative' taxes).

Year	11	12	13	14	15	16	17	18	19	20	Total
Equity Recovery	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	405,194	8,103,874
Equity Interest	305,036	290,012	272,735	252,866	230,017	203,741	173,523	138,772	98,809	52,851	5,567,632
Equity Principal Paid	100,158	115,181	132,459	152,327	175,176	201,453	231,671	266,421	306,385	352,342	2,536,242
Equity Principal Remaining	1,933,416	1,818,234	1,685,776	1,533,449	1,358,272	1,156,819	925,148	658,727	352,342	0	--
Debt Recovery	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	1,253,020	25,060,392
Debt Interest	553,340	511,359	466,860	419,690	369,690	316,690	260,511	200,960	137,837	70,926	10,688,356
Debt Principal Paid	699,680	741,660	786,160	833,330	883,329	936,329	992,509	1,052,059	1,115,183	1,182,094	14,372,036
Debt Principal Remaining	8,522,654	7,780,993	6,994,833	6,161,504	5,278,174	4,341,845	3,349,336	2,297,277	1,182,094	0	--
Fuel Cost	0	0	0	0	0	0	0	0	0	0	0
Non-fuel Expenses	1,609,870	1,643,677	1,678,194	1,713,436	1,749,419	1,786,156	1,823,666	1,861,963	1,901,064	1,940,986	32,093,853
Debt Reserve	0	0	0	0	0	0	0	0	0	0	0
Depreciation	845,414	845,414	845,414	845,414	845,414	845,414	845,414	845,414	845,414	845,414	16,908,278
Income--Capacity	0	0	0	0	0	0	0	0	0	0	0
Income - Electricity sales	0	0	0	0	0	0	0	0	0	0	
Income--Heat	0	0	0	0	0	0	0	0	0	0	0
Income--Compost Material	406,567	415,105	423,822	432,722	441,809	451,087	460,560	470,232	480,107	490,189	8,105,189
Income-- Tipping Fee	1,689,138	1,724,609	1,760,826	1,797,804	1,835,557	1,874,104	1,913,460	1,953,643	1,994,670	2,036,558	33,674,111
Income - Sales of waste water	0	0	0	0	0	0	0	0	0	0	
Interest on Debt Reserve	0	0	0	0	0	0	0	0	0	0	0
Taxes w/o credit	175,408	203,789	233,873	265,763	299,565	335,396	373,376	413,635	456,310	501,546	3,764,012
Tax Credit	0	0	0	0	0	0	0	0	0	0	618,372
Taxes	175,408	203,789	233,873	265,763	299,565	335,396	373,376	413,635	456,310	501,546	3,763,135
Revenue Required	1,347,787	1,365,966	1,385,633	1,406,886	1,429,830	1,454,574	1,481,234	1,509,936	1,540,811	1,573,998	27,241,955
Present Worth (time 0)	617,730	583,197	551,089	521,231	493,462	467,631	443,597	421,232	400,415	381,034	
											26,483,902
											26,483,902