**Economic Evaluation of CO₂ Sequestration Technologies
Task 4, Biomass Gasification-Based Processing**

Final Technical Report

For the Period Ending May 30, 2002

**Martha L. Rollins (TVA), Les Reardon (TVA), David Nichols (TVA),
Patrick Lee (TVA), Millicent Moore (TVA), Mike Crim (TVA),
Robert Luttrell (TVA) and Evan Hughes (EPRI)**

June 2002

DE-FC26-00NT40937

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

ABSTRACT

Biomass derived energy currently accounts for about 3 quads of total primary energy use in the United States. Of this amount, about 0.8 quads are used for power generation. Several biomass energy production technologies exist today which contribute to this energy mix. Biomass combustion technologies have been the dominant source of biomass energy production, both historically and during the past two decades of expansion of modern biomass energy in the U. S. and Europe. As a research and development activity, biomass gasification has usually been the major emphasis as a method of more efficiently utilizing the energy potential of biomass, particularly wood. Numerous biomass gasification technologies exist today in various stages of development. Some are simple systems, while others employ a high degree of integration for maximum energy utilization. The purpose of this study is to conduct a technical and economic comparison of up to three biomass gasification technologies, including the carbon dioxide emissions reduction potential of each. To accomplish this, a literature search was first conducted to determine which technologies were most promising based on a specific set of criteria. The technical and economic performances of the selected processes were evaluated using computer models and available literature. Using these results, the carbon sequestration potential of the three technologies was then evaluated. The results of these evaluations are given in this final report

TABLE OF CONTENTS

Section	Title	Page
1.0	Introduction	5
2.0	Executive Summary	6
3.0	Experimental	18
4.0	Results and Discussion	20
4.1	Literature Survey	20
4.2	Comparison of Gasification Systems for Power, Fuel, and	34
	Chemical Production	
4.3	Cost of Avoiding Fossil CO ₂ Emissions	61
5.0	Conclusions	81
6.0	References	83
7.0	Bibliography	87
8.0	Appendix	133

1.0 INTRODUCTION

Biomass derived energy currently accounts for about 3 quads of total primary energy use in the United States. Of this amount, about 0.8 quads are used for power generation (EPRI 2001). Several biomass energy production technologies exist today which contribute to this energy mix. Biomass combustion technologies have been the dominant source of biomass energy production, both historically and during the past two decades of expansion of modern biomass energy in the U. S. and Europe. As a research and development activity, biomass gasification has usually been the major emphasis as a method of more efficiently utilizing the energy potential of biomass, particularly wood. Gasification technology was first commercialized using coal, however biomass resources such as wood have a unique environmental advantage over traditional fossil fuels in that the gasification of biomass has a mitigating effect on global warming, when a renewable biomass fuel is used instead of a fossil fuel. Also, biomass feedstocks are typically lower in sulfur and nitrogen than most coals.

Numerous biomass gasification technologies exist today in various stages of development. Some are simple systems, while others employ a high degree of integration for maximum energy utilization. “Integration” refers in a general way to obtaining heat and multiple products, in addition to electricity from the fuel or feedstock used. In a specialized way in gasification power systems, “integration” refers to use of the heat and steam flows from the gasification and gas cleaning steps in the process, for enhancement of the other parts of the process. One important example of such integration is the use of steam raised in syngas cooling as part of the steam flow into the steam power section of an IGCC power plant. (IGCC is an integrated gasification combined cycle).

Advanced biomass gasification offers the flexibility of producing a fuel gas with sufficient energy content to be utilized in advanced integrated combined cycle power systems. The higher energy content of the advanced biomass gasification processes also improves the capability for the biomass-derived gas to be further processed for chemical production.

The purpose of this study is to conduct a technical and economic comparison of up to three biomass gasification technologies, including the carbon dioxide emissions reduction potential of each. To accomplish this, a literature search was first conducted to determine which technologies were most promising based on a specific set of criteria. The technical and economic performances of the selected processes were evaluated using computer models and available literature. Evaluation methods developed by EPRI (the Electric Power Research Institute) were then used to determine the carbon dioxide reduction potential of the technologies. The results of this study are summarized in this final report.

2.0 EXECUTIVE SUMMARY

Biomass derived energy currently accounts for about 3 quads of total primary energy use in the United States. Of this amount, about 0.8 quads are used for power generation (Renewable Energy Assessment Guide—TAG-RE, 2001). Several biomass energy production technologies exist today which contribute to this energy mix. Biomass combustion technologies have been the dominant source of biomass energy production, both historically and during the past two decades of expansion of modern biomass energy in the U. S. and Europe. As a research and development activity, biomass gasification has usually been the major emphasis as a method of more efficiently utilizing the energy potential of biomass, particularly wood. Numerous biomass gasification technologies exist today in various stages of development. Some are simple systems, while others employ a high degree of integration for maximum energy utilization. The purpose of this study is to conduct a technical and economic comparison of up to three biomass gasification technologies, including the carbon dioxide emissions reduction potential of each. To accomplish this, a literature search was first conducted to determine which technologies were most promising based on a specific set of criteria. The technical and economic performances of the selected processes were evaluated using computer models and available literature. The carbon sequestration potential of the three technologies was then evaluated. The results of these evaluations are summarized in this report

2.1 Literature Review

The literature search was compiled from over 250 sources including websites, journals, conference proceedings, books, and personal communications. From these sources, 22 biomass gasification technologies were screened to identify and define various systems for heat and/or electrical power generation. These systems are shown in Table 1.

Table 1
Biomass Gasification Systems Evaluated

Biomass Gasification for Heat and/or Power Generation	Biomass Gasification for Advanced Power Cycles
BG Technologies USA, Inc.	Foster Wheeler Bioneer, atmospheric updraft gasifier
BIVKIN Gasification Technology	Foster Wheeler Pyroflow atmospheric circulating fluidized-bed gasifier
Brightstar Synfuels Co.	Foster Wheeler Bioflow pressurized circulating fluidized-bed gasifier
Cratech Gasification System	Battelle High Throughput Gasification Process, (FERCO)
Energy Products of Idaho	GTI RENGAS pressurized fluidized bed gasifier
Energem-Biosyn Gasification	Energy Farm Project in Di Cascian, Italy
PRM Energy Systems, Inc.	ARBRE Energy Project
Thermogenics	Brazil Biomass Integration Gasification-Gas Turbine Project
Thermoselect, S.A.	BioCoComb
TPS Termiska Processor AB	
Thermal Technologies, Inc.	
Etho Power Corporation	
Emery Gasification	

The technologies evaluated can be divided into two groups: simple systems suitable for developing countries which have large readily available biomass, and advanced systems needed for Western countries for power and combined heat/power generation. Advanced systems provide high efficiencies with reduced emissions to mitigate greenhouse gas emissions.

Each technology was evaluated based on the criteria described below.

- Efficiency
- Flexibility/Applicability/Fuel gas and synthesis gas
- Technical maturity
- Data availability
- Ease of operability
- Scalability
- High pressure for IGCC integration
- Feedstocks

- Industrial acceptance
- Size, footprint
- Simple system

Three technologies were identified for further evaluation based on their ability to best fulfill the rationale for concept selection, while representing a range of gasification technologies. These technologies are as follows: the GTI Renugas pressurized gasification technology, the Battelle High Throughput Gasification Process (FERCO), and the GTI Renugas atmospheric gasification technology.

A conceptual design was prepared for each of the three technologies selected. The design was used to compare the technical and economic feasibility of each technology. The process designs and the results of the comparison are given in the next section.

2.2 Comparison of Gasification Systems for Power, Fuel, and Chemical Production

Based on the results of the literature search, the pressurized Renugas process, the atmospheric Renugas process, and the atmospheric process developed by Battelle/FERCO were chosen for further evaluation. Using these three technologies, a base case power production scenario using an integrated combined cycle system was defined for each gasification technology. Two additional alternative scenarios were evaluated to compare the technical and economic feasibility of producing liquid fuel and chemicals from the product gases. Methanol and ammonia were chosen for evaluation as fuel and chemical products, respectively. The choice of methanol as a fuel was based on the potential to utilize methanol in combustion turbines for additional electricity production. Ammonia was chosen based on its abundance as a commodity chemical and on in-house expertise in the modeling of ammonia systems.

To determine the technical and economic feasibility of the scenarios described above, a base case power system design was developed for each gasification technology. ChemCad was used to model the Renugas gasification systems. Insufficient published data was available for the FERCO gasification system to allow the development of a ChemCad model within the time frame of this project. Instead, published information concerning the FERCO gas stream composition was used to develop a feed stream for the power, fuel, and chemical production models. The Battelle/FERCO process described in this study is derived from information published in the report entitled “Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems” (Craig and Mann, 1990). Modeling of the three gasification technologies is described below.

2.2.1 Pressurized and Atmospheric Renugas Gasification Models

The Renugas processes were modeled from detailed information provided by the developer for the pressurized version of the process. The initial model was constructed to almost exactly match the heat and material balance provided.

Figure 1 is a block flow diagram of the Renugas pressurized gasification process with integrated combined cycle power generation. Raw hardwood biomass containing 50 percent moisture is dried with low pressure steam to 20 percent moisture content. The partially dried biomass is fed via screw conveyor to the biomass gasifier. The gasifier operates at a pressure of 470 psia. A small amount of nitrogen (obtained by vaporizing liquid nitrogen) is fed to the conveyor to act as a seal against backflow of the pressurized hot gases from the gasifier. The biomass is partially oxidized with hot (>800°F) air in the gasifier. This air is obtained by extracting a portion of the air from the air compressor of the combustion turbine (CT) (about 10 percent of the CT air flow is extracted). The hot air from the CT's compressor is cooled and then compressed with a booster compressor to raise the pressure from nominally 350 psia to that of the gasifier, 470 psia. The CT air is partially cooled in an economizer, which rewarms the air from the booster compressor, thereby preserving most of the heat of compression in the CT compressor. The gasifier is operated at a temperature of 1600°F, which is set by controlling the rate of air extraction from the CT. Steam is also fed to the gasifier to promote carbon conversion. A carbon conversion of 99 percent is assumed based on the estimates of the Renugas process developer. Because there is no direct source of 470 psia steam in the process, steam is extracted from the high pressure (1150 psia) steam cycle.

Figure 1

Renugas Pressurized Gasification System

The gasifier operates at a pressure of 470 psia. A small amount of nitrogen (obtained by vaporizing liquid nitrogen) is fed to the conveyor to act as a seal against backflow of the pressurized hot gases from the gasifier.

The biomass is partially oxidized with hot (>800°F) air in the gasifier. This air is obtained by extracting a portion of the air from the air compressor of the combustion turbine (CT) (about 10 percent of the CT air flow is extracted). The hot air from the CT's compressor is cooled and then compressed with a booster compressor to raise the pressure from nominally 350 psia to that of the gasifier, 470 psia. The CT air is partially cooled in an economizer, which rewarms the air from the booster compressor, thereby preserving most of the heat of compression in the CT compressor.

The gasifier is operated at a temperature of 1600°F, which is set by controlling the rate of air extraction from the CT. Steam is also fed to the gasifier to promote carbon conversion. A carbon conversion of 99 percent is assumed based on the estimates of the Renugas process developer. Because there is no direct source of 470 psia steam in the process, steam is extracted from the high pressure (1150 psia) steam cycle.

turbine in the steam cycle. At the point of extraction from the turbine, the steam is superheated by about 180°F.

Rather than the booster compressor, which is no longer needed, extraction air from the CT is routed through an air expander to generate supplemental power.

2.2.2 Battelle/FERCO Gasification Model

Figure 3 is a block flow diagram of the FERCO gasification process with integrated combined cycle power generation. The FERCO gasification process was not modeled because of time constraints and because of a lack of detailed process information such as that provided by the developers of Renugas.

Figure 3

Battelle-FERCO Gasification System

Instead, the FERCO process was treated as a “black box,” with feedstock and gas production information derived from the open literature (Craig and Mann, 1990).

2.2.3 Gasification Plant Design

Using these models, a conceptual design was prepared for each of the base case systems and the methanol and ammonia scenarios. These designs are based on information found in the Craig and Mann report, internal TVA reports, and external contractor information. The following general premises were used to develop the conceptual designs:

- Wood as feedstock
- 1,000 ton per day nominal plant capacity
- 30 year plant life
- nth plant, minimal equipment redundancy
- 90.4% plant availability

The design consists of the following major plant areas: feedstock handling, feedstock drying, gasification, gas clean-up, combustion turbine, and HRSG.

2.2.4 Base Case Performance Summary

A summary of process data and system performance for the base case plant designs involving power production is given in Table 2.

Table 2

Process Data Summary and System Performance Results – Base Case CT System

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/daymtpd (tpd)	569 (626)	675 (743)	596 (656)
Air Flowrate, kg/hr (lb/h)	25,630 (56,500)	43,549 (96,000)	-
Steam Flowrate, kg/h (lb/h)	1,379(3,039)	1,649(3,626)	11,162 (24,600)
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	5,701 (12,569)	73,535 (162,100)	43,948 (96,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	5.79 (2491)	4.40 (1892)	14.6 (6279)
Power Island			
Gas Turbine	LM2500+	LM2500+	LM2500+
Power Production Summary			
Gas Turbine Output, MW	31.7	33.45	30.05
Steam Turbine Output, MW	11.36	12.18	8.43
Net System Output, MW	42.05	41.86	36.05
Net Plant eff, HHV Basis, %	40.6%	34.0%	32.3%

As shown in the table, wood flowrates varied slightly for each system based on the heating value of the gas produced. As mentioned earlier, a nominal plant size of 1,000 tpd was selected for the design. The flowrate shown in the table are at 20% moisture, after the incoming biomass has been dried.

2.2.5 Methanol and Ammonia Plant Designs

A plant design for the alternative scenarios involving methanol and ammonia was prepared. The plant would be almost identical to the base case design with the exception of the addition of an air separation unit for the Renugas systems and the addition of methanol and ammonia production systems. A cryogenic air separation unit was selected as the source of the 95 percent purity oxygen used in the production of methanol and ammonia. For methanol and ammonia production, the SMR units used in the designs are skid-mounted units manufactured by Hydro-Chem, a subsidiary of Linde AG. The units consist of a fired unit containing catalyst tubes.

2.2.6 Methanol Performance Summary

Process performance data for the methanol production scenario is shown in Table 3. For the methanol scenarios, the Renugas systems both use 95% oxygen during the gasification process as opposed to air used in the combustion turbine scenario.

Table 3

Process Data Summary and System Performance Results – Methanol

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/day (tpd)	569 (626)	675 (743)	596 (656)
Air Flowrate, kg/hr (lb/h)	5,217 (11,500)	7,374 (16,256)	-
Steam Flowrate, kg/hr (lb/h)	1,379 (3,039)	1,644 (3,626)	11,162 (24,600)
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	32,949 (72,632)	38,103 (83,995)	19,937 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	9.30 (3,997)	9.48 (4,076)	14.6 (6,279)
Power Production Summary			
Gas Turbine Output, MW	-	-	-
Steam Turbine Output, MW	1.25	1.77	-
Net System Output, MW	-4.21	-7.89	-2.99
Methanol Production Summary			
Methanol, tonnes/day (tpd)	283 (311)	325 (358)	291 (320)

As a result, the gas quantities produced by these two technologies are much smaller than in the combustion scenario.

2.2.7 Ammonia Performance Summary

Table 4 gives a summary of process performance for the ammonia production scenario. The gas streams for this scenario are the same as in the methanol scenario. In this scenario, a significant amount of electricity is produced through expansion in the process.

Table 4

Process Data Summary and System Performance Results – Ammonia

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/day (tpd)	569 (626)	675 (743)	596 (656)
95% Oxygen Flowrate, kg/hr (lb/h)	5,217 (11,500)	7,374 (16,256)	-
Steam Flowrate, kg/hr (lb/h)	1,379 (3,039)	1,644 (3,626)	-
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	32,949 (72,632)	38,103 (83,995)	19,937 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	9.3 (3,997)	9.48 (4,076)	14.6 (6,279)
Power Production Summary			
Gas Turbine Output, MW	-	-	-
Steam Turbine Output, MW	1.25	1.77	-
Net System Output, MW	-5.87	-7.09	-2.89
Ammonia Production Summary			
Ammonia, tonnes/day (tpd)	206 (227)	235 (259)	165 (181)

2.3 Economic Evaluation

An economic evaluation of the various integrated systems was conducted using conceptual designs described in the previous sections. The estimate is considered a “factored estimate” with much of the cost

information being derived from the study conducted by Craig and Mann and in-house TVA estimates. The Craig and Mann study uses 1990 as a reference year for cost estimating purposes. For the purpose of this study, a reference year of 2001 is used. Therefore, the costs as presented in the Craig and Mann study were corrected for capacity and cost year using a capacity factor of 0.6 and the Chemical Engineering Cost Index of 400. The balance of plant was based on 20% of the total for other plant costs.

Total capital investment and operating costs are summarized for the nine scenarios in Tables 5 and 6, respectively. As shown in Table 21, total capital investment for power production was essentially the same for the three processes. The least cost scenario was methanol production using the FERCO process.

Table 5

Total Capital Investment Summary

Technology	Power Production \$M/year	NH3 Production \$M/year	Methanol Production \$M/year
Pressurized Renugas	102.3	152.1	87.1
Atmospheric Renugas	103.7	162.3	87.4
FERCO	102.0	129.7	80.8

Operating costs for the systems ranged from \$6.42 million for power production using the pressurized Renugas system to \$10.76 million for the ammonia system using the FERCO gasification technology.

Table 6

Annual Operating Costs Summary

Technology	Power Production \$M/year	NH3 Production \$M/year	Methanol Production \$M/year
Pressurized Renugas	6.42	10.02	7.15
Atmospheric Renugas	6.77	8.18	8.93
FERCO	6.79	10.76	6.93

Revenue from each system is shown in Table 23. As shown, the atmospheric Renugas system for ammonia production had the highest revenue of the nine scenarios.

Table 7**Revenue Summary**

Technology	Power Production \$K/year	NH₃ Production \$K/year	Methanol Production \$K/year
Pressurized Renugas	13,321	14,982	12,410
Atmospheric Renugas	13,261	17,067	10,293
FERCO	11,421	11,946	12,796

A summary of the corresponding product quantities is shown in Table 8.

Table 8**Product Summary**

Technology	Power Production (MW)	NH₃ Production (T/D)	Methanol Production (TPD)
Pressurized Renugas	1009	227	311
Atmospheric Renugas	1005	259	358
FERCO	865	181	320

2.4 Cost Of Avoiding Fossil CO₂ Emissions

Using the three scenarios defined in the previous sections, the cost of carbon dioxide sequestration was evaluated. The cost of greenhouse gas mitigation using renewable energy technologies depends on both the difference between the generation costs of the renewable energy option--i.e., in these cases, the generation of electricity or the production of methanol or ammonia--and the low-cost alternative (e.g., coal or natural gas fuel or feedstock for electricity generation or methanol/ammonia production). The mitigation costs are usually expressed in units of the cost per unit fossil carbon emissions that are avoided, offset, captured, sequestered, etc.

The potential of each of the three biomass gasification systems to provide CO₂ emissions reduction was calculated. The three technologies were compared with three existing technologies: conventional coal-

fired power plants, advanced coal systems, and natural gas fired combined cycle systems. When compared with a conventional coal-fired plant, the cost in \$/tonne C for the high pressure Renugas, FERCO, and low-pressure Renugas was \$77.08, \$115.63, and \$154.17, respectively. For an advanced coal-fired plant, the emissions control costs in \$/tonne C were \$93.31, \$135.73, and \$178.14, respectively, for high pressure Renugas, FERCO, and low pressure Renugas. The emissions control costs for the natural gas combined cycle plant were \$218.81, \$312.61, and \$416.82, respectively for the high pressure Renugas, FERCO, and low pressure Renugas systems.

2.5 Conclusions

Based on the results of this study, it can be concluded that the two Renugas processes have the most potential to maximize power production via gasification. Ammonia and methanol production also tend to favor the Renugas processes, though the FERCO process produced slightly more methanol than the atmospheric Renugas system.

In order to show biomass gasification as among the lower cost, rather than higher cost, fossil carbon sequestration options, more ambitious R&D goals are necessary. These more ambitious goals would involve one or more or a combination of items such as better efficiency, lower cost fuel, lower O&M costs, and lower capital cost. The lower capital costs may be especially difficult to obtain, as the goals adopted in this report are already rather ambitious.

These ambitious goals are as follows: (1) a natural gas combined cycle at \$700/kW as applied at 100-MWe unit size as the power conversion option downstream of a biomass gasification system; (2) only \$300/kWe to construct the system that performs biomass gasification, gas cleanup and ash/char removal from the gasifier, and then sends clean gaseous fuel to the combined cycle power unit; and, (3) only \$100/kW for a system to receive, handle and feed solid biomass fuel (or “feedstock”) into the gasification/cleanup unit. It is possible that better efficiency, lower fuel cost and lower O&M costs are more likely to be achieved than are capital costs below the \$1100/kWe goal. A combination of all, plus added revenues from other bio-based products or environmental benefit revenues (such as waste disposal and water quality improvements) are also likely to be required in a system that becomes a low cost carbon sequestration option.

3.0 EXPERIMENTAL

The sources, techniques, and criteria used throughout the report to complete the literature search and the technical and economic evaluation of selected gasification technologies are described in this section.

3.1 Literature Search

The literature search was compiled from over 250 sources including websites, journals, conference proceedings, books, and personal communications. Examples of various sources include:

- DOE Information Bridge
- DOE Bibliographic Database
- Renewable Resources Data Center
- NREL Publications
- Gasification Company Websites
- EPRI publications
- Internal TVA reports
- Personal communications

A complete list of these sources is included in the bibliography section of this report. As stated in the introduction, the purpose of the literature search was to select up to three gasification technologies for technical and economic comparison. The specific set of criteria used is as follows:

- Efficiency
- Flexibility/Applicability/Fuel gas and synthesis gas
- Technical maturity
- Data availability
- Ease of operability
- Scalability
- High pressure for IGCC integration
- Feedstocks
- Industrial acceptance
- Size, footprint
- Simple system

3.2 Technical and Economic Comparison of Gasification Technologies

The technical and economic comparison of the three selected gasification technologies was prepared using published information. Depending on the level of data available for each process, the technical

performance of each gasification technology was determined using Chemcad. Literature values were used in areas where there was insufficient data available to prepare an actual model.

Economic values for the technologies were derived from in-house estimates, available literature, and personal communications. Standard cost estimating techniques from the EPRI Technical Assessment Guide were used to estimate capital and operating costs.

3.3 Carbon Sequestration Evaluation

“Carbon sequestration” usually refers to the avoidance of new additions of man-made carbon dioxide (CO₂) to the atmosphere. The specific way of avoiding CO₂ additions that is usually called “sequestration” is the capture and confinement (“sequestration”) of the CO₂ as it is generated in the combustion step in power or heat generation, thereby preventing what would otherwise be a new emission into the atmosphere of CO₂ from a carbon atom that had been locked in the earth’s surface in the form of a coal, oil or natural gas deposit.

In this study, biomass gasification technologies that can make power, steam, heat and chemical products from renewable biomass fuels, or “feedstocks,” are considered in terms of their ability to accomplish the same purpose as the usual “sequestration” technologies: namely, the avoidance of new emission of fossil carbon into the atmosphere. Biomass gasification accomplishes such avoidance by using as the feedstock carbon that was already in the atmosphere, so no new emission of a new carbon previously locked in the earth’s surface occurs. “Renewable” biomass feedstock is necessary to accomplish this. Unless the biomass used to make the electricity, heat, steam or other product is replaced by as much or more new growth of biomass to make more such feedstock the CO₂ that is put into the atmosphere upon combustion of biomass fuel—or combustion of the biomass gas or other product made from the biomass fuel—is not balanced by the taking of CO₂ from the atmosphere as the replacement biomass is grown. For this loop to be closed” in this way, all that matters is that an equal amount of biomass be grown somewhere in the world. Natural forests, man-made forests, and farms that grow energy crop fuels are all equally suitable as places where the replacement growth occurs. Here “equally suitable” means suitable for a balance of global carbon in the atmosphere: same amount pulled out of the atmosphere as is put in by the combustion to make energy or fuel or chemicals.

The method used here to evaluate biomass gasification technologies as carbon sequestration options is presented later in the report. In a word, the method is to estimate the cost of making electricity or chemicals via biomass gasification, subtract the cost of making the same product from fossil fuels or feedstocks, convert this “extra cost” into units of cost to “sequester carbon” as \$/tonne-C, and compare to other estimates of other ways to accomplish such carbon sequestration.

4.0 RESULTS AND DISCUSSION

The results of the literature survey and technical and economic evaluation are given in this section.

4.1 Literature Survey

Using the sources and methodology described in the previous section, 22 biomass gasification technologies were screened to identify and define various systems for heat and/or electrical power generation. These systems are shown in Table 9.

Table 9
Biomass Gasification Systems Evaluated

Biomass Gasification for Heat and/or Power Generation	Biomass Gasification for Advanced Power Cycles
BG Technologies USA, Inc.	Foster Wheeler Bioneer, atmospheric updraft gasifier
BIVKIN Gasification Technology	Foster Wheeler Pyroflow atmospheric circulating fluidized-bed gasifier
Brightstar Synfuels Co.	Foster Wheeler Bioflow pressurized circulating fluidized-bed gasifier
Cratech Gasification System	Battelle High Throughput Gasification Process, (FERCO)
Energy Products of Idaho	GTI RENUGAS pressurized fluidized bed gasifier
Enerkem-Biosyn Gasification	Energy Farm Project in Di Cascian, Italy
PRM Energy Systems, Inc.	ARBRE Energy Project
Thermogenics	Brazil Biomass Integration Gasification-Gas Turbine Project
Thermoselect, S.A.	BioCoComb
TPS Termiska Processor AB	
Thermal Technologies, Inc.	
Etho Power Corporation	
Emery Gasification	

The technologies evaluated can be divided into two groups: simple systems suitable for developing countries which have large readily available biomass, and advanced systems needed for Western countries

for power and combined heat/power generation. Advanced systems provide high efficiencies with reduced emissions to mitigate greenhouse gas emissions.

Much information on the various gasification technologies was obtained from the internet through company websites, news releases, and various interest groups. The report published by Juniper Consultancy Services Ltd. entitled "Technology and Business Review: Pyrolysis and Gasification of Waste – A Worldwide Technology and Business Review," Vol. 1 & 2, 2000 was also used extensively. This survey summarizes simple systems for heat and/or power generation (that are suitable when efficiency and emissions are not priority factors) and advanced systems for power and combined heat/power generation. An extensive report describing each system is presented in the appendix.

4.1.1 Simple Biomass Gasification Systems

Simple gasification systems produce syngas with a low heat content at atmospheric or low pressure. The fuel syngas can be used for operating gas engines for small-scale power production. Syngas from these simple gasification systems can also be used as boiler fuel or to add heat to a boiler. TVA and EPRI have investigated this approach for a possible cofiring operation at TVA's Allen Fossil Plant in Memphis. All these are applications where the syngas does not have to be as clean nor as high in heat and feedstock gas content as is considered necessary for use in a gas turbine or in a chemical production operation. In general, the syngas from simple gasification is not suitable for advanced turbines or chemical production. Fourteen simple systems were reviewed. Each is briefly described below.

4.1.1.1 BG Technologies USA, Inc.

BG Technologies USA, Inc., has licensed gasification technology from Ankur Scientific Energy Technologies PVT, LTD., of India for worldwide distribution (www.bgtechnologies.net and www.ankurscientific.com). Ankur Scientific has over 400 installations worldwide using this technology for processing wood chips, palm nut shells, cotton stalks, rice hulls, maize cobs, soy husks, coconut shells, and sawdust. The BG Technologies electric system consists of a biomass gasifier, gas cleaning and cooling equipment, and a diesel generator. The diesel generator is operated under dual fuel mode using diesel and producer gas from the gasifier which reduces diesel consumption by about 70%. The main objective of this system is to displace some of the fuel requirement for the diesel generator. Three systems are offered at 100, 250, and 400 kW_e capacities with conversion efficiencies ranging from 70-75%.

4.1.1.2 BIVKIN Gasification Technology

The Netherlands Energy Research Foundation (ECN) in Petten, Netherlands, developed and built a pilot circulating fluidized bed (CFB) gasification plant using the BIVKIN (Biomassa Vergassings Karakteriserings Installatie) process in cooperation with Novem, Afvalzorg, and Stork (Van den Broek, et al., 1997). The plant was initially used at the ECN location in Petten for the characterization of more than 15 different biomass species, including wood, sludge, grass, and manure. ECN has been conducting tests to improve the gas quality so that it can be used for

electrical generation in a gas engine. The CFB gasifier is integrated with a 500 kW_e internal combustion (IC) engine at the pilot plant.

4.1.1.3 Brightstar Synfuels Co./Brightstar Environmental

Brightstar Synfuels, Co., (BSC) developed a gasification concept in 1989 with tests in a 25-90 kg/h (55.1-198.4 lb/h) pilot plant. They subsequently scaled up to a commercial unit in 1994 at a particleboard plant. The plant had a capacity of 17,600 kg/h (38,801 lb/h) of sander dust. It was terminated in 1995 because of problems with the heat recovery equipment used in the gas cooling system. A free standing Commercial Demonstration Facility (CDF) was built near Baton Rouge, Louisiana, in 1996 with design throughput of 680 kg/h (1,499 lb/h). The facility was operated continuously to prove the concept and refine the process. This facility was considered a commercial scale facility because of the "tubular entrained flow" design. Multiple gasifiers would be used in larger capacities. Various feedstocks such as sawdust and sander dust, bark and wood chips, pulp and paper mill sludge, rice hulls, sugar cane bagasse, and sewage sludge were tested. Louisiana State University's Institute for Environmental Studies supported the demonstration plant in Louisiana.

4.1.1.4 Cratech Gasification System

Western Bioenergy funded Cratech in Tahoka, Texas, in 1998 to develop a gasification project for converting straw, grass, and shells (www.westbioenergy.com). A 1 MW unit was developed and tested. The Cratech gasifier is a pressurized, air-blown fluidized-bed reactor. Biomass is injected with a biomass pressurization and metering unit. The product gas is passed through a hot-gas cleanup system followed by injection into a turbine combustor. The system uses the higher practical thermodynamic efficiency of the Brayton cycle over the Rankin cycle.

4.1.1.5 Energy Products of Idaho

Energy Products of Idaho (EPI) of Coeur d'Alene, Idaho, claimed to design and build the first fluidized bed combustor for firing wood which also operates on 100% paper sludge (Inland Empire Paper Company, Spokane, WA) (www.energyproducts.com). EPI has designed and supplied more than 79 gasification plants worldwide since 1973. Their expertise is in atmospheric fluidized-bed (AFB) gasifiers. The bed material can be either sand or char or a combination of both. The fluidizing medium is usually air. Their AFB can process fuel with moisture contents up to 55% and high ash contents over 25%. Temperature is maintained below the fusion temperature between the ash and the slag which increases the utilization of the slagging fuels. The product gas is cleaned by cyclones. The heating content of the gas is about 7.4 MJ/scm (200 Btu/scf). The EPI website listed a total of 63 operating units in the world. These facilities process a wide variety of biofuels such as wood waste, bark and wood chips, RDF, hogged fuel, agricultural waste, urban wood waste, coal, polyethylene terephthalate, and polyvinylbutyryl.

4.1.1.6 Enerkem-Biosyn Gasification

The Enerkem-Biosyn gasification process has a long history of development in Canada. Many transformations have occurred over the past decades (<http://solstice.crest.org/renewables/bioenergy-list-archive/9612/msg00266.html>). Canadian

Industries Limited (CIL) was formed in the early 1970s as a wholly owned Canadian subsidiary of Imperial Chemical Industries (ICI). CIL initiated the OMNIFUEL program to develop a versatile fluidized-bed technology to convert its industrial wastes into useful syngas for either energy or chemical synthesis. A pilot plant was constructed in Kingston, Ontario. This was discontinued after CIL restructured. BBC Engineering was formed and installed a 10 metric ton/h demonstration gasifier coupled to a boiler at the Levesque sawmill in Hearst, Ontario. The economics did not favor the commercialization of the process despite its technical success.

4.1.1.7 PRM Energy Systems, Inc.

PRM Energy systems, Inc., founded in 1973, has many years of experience in biomass gasification for electricity and heat generation. Their website contains information on their various commercial and demonstration projects around the globe. The gasification technology was developed at Producers Rice Mill, Inc. (PRM). The first two gasifiers were installed in 1982 to gasify rice husks to produce process heat and steam for a large rice parboiling facility. Many biomass feedstocks were tested between 1984 and 1988 in a full-scale PRM gasifier. These include rice hulls, rice straw, chicken litter, green bark, sawdust and chips, peat, wheat straw, corn cobs and stubble, peanut hulls, RDF (fluff, flake, and pellet), petroleum coke, cotton-gin waste, cotton-seed hulls, and low-grade coal. The rice residue gasification has been in operation since 1982 in U.S., 1985 in Australia, 1987 in Malaysia, and 1995 in Costa Rica.

The PRM process is marketed by PRM Energy Systems itself as well as through Primenergy, Inc., for the U.S. and the Philippines. Grupo Guascor of Spain covers France, Italy, Spain, and Portugal (Juniper Consultancy Services Ltd, 2000). The PRM process is fully proven and has operated continuously at various scales.

4.1.1.8 Thermogenics

The Thermogenics gasifier is a directly heated, air-blown, continuous bottom fed, stratified updraft gasifier (Juniper Consultancy Services Ltd, 2000). It was designed specifically for processing MSW with a capacity of 0.5-3 metric ton/h (0.55-3.3 ton/h). The MSW is shredded and dried to a moisture content of 30% or less. It is introduced into the gasifier through the bottom. An external fuel source is used to heat the MSW to auto-thermal temperature. Gasification occurs around 980 °C (1,796 °F) at the bottom of the bed and 370 °C (698 °F) at the top. Char and particulates from the syngas are removed by a dust removal device and recycled to the gasifier. The syngas is cooled to condense the aerosols and passed through an electrostatic precipitator. The syngas can be used for power generation via gas engines or conventional boilers. The Thermogenics system has been reviewed favorably by NREL for MSW processing (Camp Dresser and McKee, 1996).

4.1.1.9 Thermoselect, S.A.

The development of the Thermoselect HTR (High Temperature Recycling) process began in 1989. A demonstration plant was built at Fondotoce in Italy and was operated for semi-commercial scale from 1994 to 1999. The process combines slow pyrolysis with fixed-bed oxygen-blown gasification and residue melting (Juniper Consultancy Services Ltd, 2000). The first stage of the process uses a high-pressure press to compact the feedstock to increase its bulk density, squeeze

out entrained air, and homogenize the material by dispersal of liquids. The second stage involves the pyrolysis of the compacted material by indirect heating while it flows down the pyrolysis channel.

4.1.1.10 TPS Termiska Processer AB

TPS Termiska Processer AB was established as a private company in 1992 to pursue the CFB for small- to medium-scale electricity production using biomass and RDF as feedstocks. TPS began work on the development of atmospheric pressure gasification for converting wood, peat, RDF, and other reactive solid fuels to energy in 1984. The gasification technology involves an air-blown circulating fluidized-bed (CFB) gasifier. It operates at 850-900 °C. The tarry product gas has a tar content of 0.5-2% of dry gas with a heating value of 4-7 MJ/Nm³ (107.4-187.9 Btu/scf). The system is favorable for fuel capacities greater than 10 MW_{th}.

4.1.1.11 Thermal Technologies, Inc.

A project at Camp Lejeune, North Carolina, was sponsored by the U.S. EPA and U.S. DOD Strategic Environmental Research and Development Program (Cleland, 1997). The Research Triangle Institute (RTI) is working under a Cooperative Agreement with EPA to complete the testing and demonstration. Other participants are the Marine Corps, North Carolina Department of Commerce, and Thermal Technologies, Inc. (TTI). The gasification technology used is the downdraft moving-bed gasifier from TTI.

4.1.1.12 Etho Power Corporation

Located in Kelowna, British Columbia, Canada, Etho Power developed a proprietary biomass electricity generating system that utilizes gasifiers, heat exchangers, and air turbines. It is claimed that the Etho system is more efficient, produces less emissions, and is less expensive than traditional biomass gasification systems. A demonstration system is located in Kelowna, British Columbia. The project is funded by the British Columbia provincial government, BC Hydro & Power Authority, and the National Research Council of Canada. Little information could be found on the gasification technology.

4.1.1.13 Emery Gasification

Emery Gasification is based in Salt Lake City, Utah. The company has developed a proprietary gasification technology for power production, chemical synthesis and industrial gases. Emery started the development in 1993. A 22.7-metric ton/day (25 ton/day) fixed-bed, air-blown gasifier was designed and built. The gasifier was operated for over 2,100 hours during a 20-month test period from late 1996 to the fall of 1998 with scrap tires as the principle feedstock. Biomass and MSW were also tested.

4.1.2 Advanced Biomass Gasification Systems

Advanced gasification systems generally involve integration with higher efficiencies and produce heat or combined heat/power generation. These systems are necessary for the high efficiencies and higher value products that enable companies in developed countries to use biomass at a large enough scale to help in controlling of greenhouse gas emissions. Seven companies that have advanced gasification systems are reviewed.

4.1.2.1 Foster Wheeler Gasification Technologies

Foster Wheeler owns several gasification patents and gasification technologies. A number of these were developed by Ahlstrom Pyropower (API). Foster Wheeler acquired API and has likewise acquired these gasification technologies. The different gasifiers are the atmospheric updraft gasifiers (Bioneer), atmospheric circulating fluidized-bed gasifiers (Pyroflow), and the pressurized circulating fluidized-bed gasifiers (Bioflow). These are described below.

4.1.2.1.1 Bioneer Atmospheric Updraft Gasifiers

Foster Wheeler developed the atmospheric updraft gasification technology for converting biomass to heat for small districts. These are known as the BIONEER gasifiers. A total of ten BIONEER gasifiers have been installed. The maximum plant size is 10 MW_{th} fuel input with most of the plants in the range of 3-8 MW_{th} input. These cannot be operated with sawdust or other smaller components because the feedstock is too fine to be effective in the process. These gasifiers are simple to operate, and the technology is well proven.

4.1.2.1.2 Pyroflow Atmospheric Circulating Fluidized-Bed Gasifiers

The next generation of gasifiers from Foster Wheeler is known as the Pyroflow gasifiers. They are atmospheric circulating fluidized-bed gasifiers (ACFB) developed in the 1980s.

4.1.2.1.3 Bioflow Pressurized Circulating Fluidized-Bed Gasifiers

The Swedish power company, Sydkraft AB, has constructed a co-generation plant at Värnamo, Sweden to demonstrate the integrated gasification combined cycle (IGCC) technology. Bioflow, Ltd., was formed as a joint venture between Ahlstrom and Sydkraft in 1992 to develop the pressurized air-blown circulating fluidized-bed gasifier. Foster Wheeler acquired a subsidiary of Ahlstrom that built the gasifier, and Bioflow became part of Foster Wheeler in 1995. The biomass integrated gasification combined cycle (BIGCC) plant in Värnamo was commissioned in 1993 and fully completed in 1996. It generates 6 MW_e and 9 MW_{th} for district heating in the city of Värnamo. This was the first complete BIGCC for both heat and power from biomass (Ståhl, 1997; Engström, 1999; and Ståhl, 1999).

4.1.2.2 Battelle High-Throughput Gasification Process (BHTGP) (FERCO)

Battelle Memorial Laboratory demonstrated high-throughput gasification through a cooperative effort involving the U.S. Department of Energy, the National Renewable Energy Laboratory (NREL), Burlington Electric Department, and the Future Energy Resources Corporation (FERCO) (Bain, 1996). Therefore, later in this report this technology is labeled “Battelle FERCO” or simply “FERCO”. The project for IGCC demonstration began in August 1994. The demonstration was located at the McNeil wood-fired power plant in Burlington, Vermont. The power plant has a capacity of 50 MW_e and was built in 1984. The capital cost of the plant was \$67 million (1984) and was \$13 million below budget. It is owned by the Burlington Electric Department, Central Vermont Public Services Corp., Green Mountain Power Corp., and the Vermont Public Supply Authority. A total of 77.1 metric ton/h (85 ton/h) of wood chips can be processed.

The Battelle High-Throughput Gasification Process (BHGTGP) system uses a low-pressure indirectly heated biomass gasifier. It has been demonstrated successfully in a 9.1 metric ton/day (10 ton/day) Process Research Unit (PRU) at Battelle's Columbus Laboratories in West Jefferson since 1980. This system was designed especially for biomass to take advantage of its high reactivity, low ash, low sulfur, and high volatile matter content. It has operated for over 22,000 hours. FERCO of Atlanta, Georgia, has licensed the technology from Battelle. The gasifier will be operated as an IGCC eventually and includes heat recovery and a condensing steam turbine. The plant is 20 times the scale of the pilot plant that can process 181.4 metric ton/h (200 ton/h) of woody feedstock. It accounts for about 30% of the plant's load (Bain, 1996).

The first phase of design and construction was completed in 1998 by Zurn NEPCO of Portland, Maine, and Redmond, Washington. The second phase includes the start-up and shake-down testing which began in 1998 and continued through 1999. The final phase involves long-term operation and testing. A gas turbine was designed and installed during the final phase in 2000. The other companies and agencies that are evaluating the technologies include Weyerhaeuser, General Electric, International Paper, Centerior Energy, the State of Iowa, New York State Energy Research and Development Authority, and the U.S. Environmental Protection Agency.

FERCO has trademarked the process SilvaGasTM (January 2001). The SilvaGasTM process uses two physically separated, circulating fluidized-bed reactors. One reactor acts as a gasification reactor to convert the biomass to gas and residual char. The second reactor is a combustion reactor which burns the char to provide heat for gasification.

4.1.2.3 GTI Pressurized Fluidized-bed Gasifier (Renugas[®])

GTI has developed the Renugas[®] biomass gasification technology based on their success in the U-Gas[®] coal gasification technology and holds US Patents 4,592,762 and 4,699,632. . Bagasse, wood chips, whole tree chips, hard and soft woods, willow, rice and wheat straw, alfalfa, highway chippings, mixture of bark and pulp sludge, and pelletized RDF were all tested with the 10.9 metric ton/day (12 ton/day) PDU at GTI in Chicago

4.1.2.4 Energy Farm Project in Di Cascina, Italy

A project on biomass-based IGCC was planned for Di Cascina, Italy (Beenackers, 1997 and www.bioelettrica.it). This project was one of three BIGCC demonstration projects funded by the European Commission within the framework of the THERMIE Programme. The joint-stock company, BIOELETTRICA S.p.A. will implement the project. The shareholders of the company are USF Smogless S.p.A., EDP-Electricidade de Portugal S.A., Energia Verde S.p.A., Lurgi Umwelt GmbH, and Fumagalli S.p.A. They were awarded the contract to supply the main systems for the plant in May 1997. The plant design and testing are underway and is expected to enter into commercial operation in 2001. This project will demonstrate the technical and economic feasibility of power-generation from biomass using the IGCC concept. The gasification system features the Lurgi atmospheric air-blown circulating fluidized-bed gasifier integrated with a 11.9 MW_e, single-shaft, heavy-duty gas turbine, suited to burn the low-calorific value syngas produced by the gasifier. The gasifier is supplied from Lurgi, and the turbine is from Nuovo Pignone. A heat-recovery steam-generator will provide steam to a 5 MW_e condensing steam turbine.

4.1.2.5 ARBRE Energy Project

The third BIGCC project funded by the European Commission was the ARBRE project (Arable Biomass Renewable Energy) to be located at the 2,000 MW_e Eggborough Power station in the Aire Valley, North Yorkshire of UK. This project will provide a net electrical output of 8 MW_e with an efficiency of 30.6%. The biofuel for this project contains about 80% short rotation forestry based on 2,600 ha (6,424.6 acres) of a mixture of willow and hybrid poplar. The coppice will be used throughout the year with onsite covered storage. The feedstock is dried to 10-20% moisture by the low-grade heat from the system. The gasification technology is supplied by TPS.

4.1.2.6 Brazil Biomass Integration Gasification-Gas Turbine

A Biomass Integration Gasification-Gas Turbine (BIG-GT) project was proposed by Eletrobrás (Brazilian Electric Power Co.) and CHESF (Companhia Hidro Elétrica do São Francisco) in April 1991. This involved building a 30 MW_e BIG-GT in the state of Bahia, Brazil, using wood or sugar cane bagasse as fuel. The project was named SIGAME (Wood Gasification Integrated System for Electricity Generation). The project was intended to confirm the technical and commercial viability of producing electricity from biomass using the integrated gasification combined cycle system. It was originally predicted that the commercial operation would begin in 2001. The proposed BIG-GT demonstration plant will produce about 40 MW_e and deliver about 32 MW of electricity to the grid.

4.1.2.7 BioCoComb Project

Biofuel for Co-Combustion (BioCoComb) is a project where syngas produced from biomass is co-combusted in a pulverized coal-fired power station. The project was supported by a European Community Thermie Fund and has been installed by Austrian Energy and Environment in Zeltweg, Austria. The power plant has a capacity of 137 MW of electricity from coal. The gasifier is capable of gasifying biomass such as bark, wood chips, and sawdust, and has a thermal capacity of 10 MW_{th}. The produced gas replaces about 3% of the coal fired in the boiler (Anderl, 1999).

4.1.3 Discussion of Literature Review

Each technology was evaluated based on the criteria described in section 2.0 “Experimental” and outlined again below:

- Efficiency
- Flexibility/Applicability/Fuel gas and synthesis gas
- Technical maturity
- Data availability
- Ease of operability
- Scalability
- High pressure for IGCC integration
- Feedstocks
- Industrial acceptance
- Size, footprint
- Simple system

Two measures of efficiency were included in the evaluation, cold gas efficiency and carbon conversion. Mature gasification technologies generally have a high cold gas efficiency and high carbon conversion. The moving bed gasifiers have the highest cold gas efficiency and highest carbon conversions. The fluidized-bed gasifiers have the lowest cold gas efficiency and lowest carbon conversion. High cold gas efficiency and carbon conversion do not necessarily result in the most economical technology. In the U.S., the Texaco gasification process, which has neither the highest cold gas efficiency or nor highest carbon conversion, has generally proven to be cost competitive with other gasification technologies (Takematsu 1991). This is accomplished through their development of auxiliary heat recovery systems, on-stream reliability and relative capital cost.

Fuel flexibility is obviously important for the production of both chemicals and heat and power. Air-blown gasifiers produce a fuel gas. Oxygen-blown gasifiers generally produce a gas suited for chemical synthesis. If the gasifier operates at atmospheric pressure, significant compression is usually required before the gas can be conditioned for synthesis. If the gasifier is operated at 400 psig or higher the gas is suited for all but the newest combustion turbines. Also, at 400 psig, no compression should be required before the gas is conditioned for chemical synthesis. Compression should only be required for the gas when it enters the synthesis loop. If the gasifier produces a syngas at elevated pressure that is low in inerts it is considered fully flexible.

In terms of maturity, the technology is considered mature and accepted by industry if there are commercial installations in operation. Several gasification technologies are in advanced states of demonstration and near-commercial. These include British Gas/Lurgi, H T Winkler, Shell and E-Gas (formerly known as Destec) (Simbeck 1993).

Assessments of size and footprint are based on gasifier pressure and whether the gasifier is air-blown or oxygen blown. Atmospheric gasifiers are relatively larger than pressurized systems and expected to be larger. Air-blown atmospheric gasifiers are expected to be even larger.

Factors identified during this review that significantly effect simplicity and ease of operation are the presence of tars and oils and the requirement for char recycle.

Using these criteria, the evaluation field was narrowed to include only advanced biomass gasification systems. Table 10 gives a comparison of these systems based on the evaluation criteria.

Table 10
Summary of Advanced Biomass Gasification Technologies

Process	Renugas®	TPS Termiska AB	Bioflow	SilvaGas®
Technology Owner(s)	GTI licensed to Carbona for licensed to PICHTR for Pacific Rim	TPS	Foster Wheeler	Battelle Columbus Laboratory, licensed to FERCO
Gasifier Type	Fluidized Bed	Circulating Fluidized Bed	Pressurized Fluidized Bed	Atmospheric Fluidized Bed
Feedstocks	Biomass	Biomass	Biomass	Biomass
Oxidant	Air/oxygen	Air	Air	Air
Ash	Ash	Ash		Ash
Operating Temperature, °C (°F)	(835) 1535	(850-900) 1562-1652	(950-1000) 1742-1832	(830) 1526
Maximum Operating Pressure, MPa (psig)	2.4 (333)	0.15 (21)	1.9 (262)	Atmospheric to low pressure
Efficiency: Cold Gas	Theoretical at over 76%, demonstration for the 100 tpd ranged from 55% to 77%.	not listed	not available	36% (estimate)
Efficiency: Electrical	30-35 % (estimate)	30.6%	32%	32% (net) (estimate)
Overall Efficiency	Not available	not found	83%	80% (estimate)
Carbon Conversion	over 95%	not found	over 90%	
Fuel Gas Heating Value, MJ/Nm ³ (Btu/ft ³)	10 (270)	4-7 (107-188)	5.3-6.3 (142-169)	15.5-17.3 (410-464)
Flexibility/Applicability/Fuel Gas & Synthesis Gas	The high pressure does not require compression. However, the presence of nitrogen lowers the heat content of the fuel gas even in the oxygen-blown mode. The low H ₂ /CO ratio may require extra shift reaction to increase the H ₂ /CO ratio for chemical production.	Fuel Gas, Syn Gas requires compression	It was demonstrate for fuel gas but not syn gas. The high pressure is suitable for syn gas and eliminates the need for compression.	Fuel Gas, Syn Gas requires compression
Technical Maturity, Industrial Acceptance	The operation under high pressure and oxygen-blown mode has not been demonstrated for sustained period of time. It may still be quite sometime before it	Yes and it is being demonstrated for IGCC.	It has been demonstrated successfully with many problems solved.	It is being demonstrated but it has not been demonstrated for a continual basis.
High Pressure for IGCC Integration	Yes but it hasn't been demonstrated.	Yes	Yes	No, the gas requires compression
Size, Footprint	Acceptable	Acceptable	Acceptable	Larger than single gasifier system
Simple System, Ease of Operability	The feed system may still need more development work for various biomass. The oxygen-blown mode has not been demonstrated at over 12 tpd.	not sure	Not sure	Yes
Scalability	Still need field verification; fully demonstrated at 12 tpd, it has been scaled up to 100 tpd at air-blown mode.	Fully	Fully	Fully

Table 10
Summary of Advanced Biomass Gasification Technologies

Process	Renugas®	TPS Termiska AB	Bioflow	SilvaGas®
Merits and Potential Challenges	The U-gas technology has been commercialized but the Renugas® technology still needs more developmental works.	It is being demonstrated in North Yorkshire U.K. for IGCC with hot gas cleanup and gas turbine. The net electric output is 8 MW _e .	It was demonstrated successfully at Värnamo, Sweden for both heat and power production.	It is being demonstrated at 250 tpd design capacity at Burlington, Vermont, U.S. It has not been demonstrated for IGCC yet.
Data Availability	Adequate	General information only.	limited	General information is available but specifics are not.

Table 10
Summary of Advanced Biomass Gasification Technologies (cont.)

Process	AFB	EPI	PRME
Technology Owner(s)	Foster Wheeler	Energy Products of Idaho	PRME Energy Corporation
Gasifier Type	Atmospheric Fluidized Bed	Atmospheric Fluidized Bed	Fluidized Bed
Feedstocks	Biomass	Biomass, petcoke, sewage and paper-mill sludge	Biomass
Oxidant	Air	Air	Air
Ash	Ash	Ash	Ash
Operating Temperature, °C (°F)	(800-1000) 1472-1832	(540-980) 1004-1796	Not available
Maximum Operating Pressure, Pa (psig)	Atmospheric to low pressure	Atmospheric to low pressure	Atmospheric to low pressure
Efficiency: Cold Gas	not available	not available	not available
Efficiency: Electrical	not available	not available	not available
Overall Efficiency	not available	not available	not available
Carbon Conversion	not available	not available	not available
Fuel Gas Heating Value, MJ/Nm ³ (Btu/ft ³)	not available	3.7-7.4 (100-200)	not available
Flexibility/Applicability/Fuel Gas & Synthesis Gas	Fuel Gas, Syn Gas requires compression	Suitable for low-BTU fuel gas but not suitable for chemical production via syngas. compression is needed for syn gas.	The system is designed for heat and power. It's probably not suitable for chemical conversion via syngas.
Technical Maturity, Industrial Acceptance	Many commercial plants built around the global mainly on pulp and paper mills.	Fully commercialized with several hundred tons of biomass per day plants.	Fully commercialized with several hundred tons of biomass per day plants.
High Pressure for IGCC Integration	not demonstrated, probably not suitable	Not suitable	The new plant in Italy that gasifies sansa will demonstrate the IGCC concept with gas cleanup system and an IC engine.
Size, Footprint	Acceptable	Acceptable	Acceptable
Simple System, Ease of Operability	Yes	Yes	Yes
Scalability	Fully	Fully	Fully
Merits and Potential Challenges	It is operational in Lahti, Finland to generate fuel gas for combustion in existing coal-fired boiler.	The gasification technology has been fully commercialized for heat and power production.	The gasification technology has been fully commercialized for heat and power production.
Data Availability	Limited	Limited, proprietary	Limited, propriety

4.1.4. Selected Biomass Gasification Systems

No one gasification technology satisfies all the factors previously identified as being preferred for concept selection. However, three technologies have been identified for further evaluation based on their ability to best fulfill the rationale for concept selection, while representing a range of gasification technologies. These technologies are as follows: the GTI Renugas pressurized gasification technology, the Battelle High Throughput Gasification Process (FERCO), and the GTI Renugas atmospheric gasification technology.

4.1.4.1 GTI Pressurized Renugas System

The pressurized Renugas technology was selected because of the following criteria:

- High cold gas efficiency
- High carbon conversion
- Flexibility (can produce either a low-btu gas in air-blown mode that is suited for a fuel gas or a medium-btu gas in oxygen-blown mode that can be conditioned to a synthesis gas for production of chemicals or fuels such as methanol and SNG)
- High pressure 3.14 mPa (435 psia) for IGCC integration
- Extensive operation at 1-ton per hour
- Industrial acceptance (selected by DOE for two large-scale projects)
- Simple system (gas produces low tars, pressurized syngas, minimal recycle)
- Tested with many biomass feedstocks
- Data is available
- The plant size is relative small because of the high pressure

4.2.1.2 GTI Atmospheric Renugas System

The atmospheric Renugas technology was selected because:

- High cold gas efficiency
- High carbon conversion
- Flexibility (can produce either a low-btu gas in air-blown mode that is suited for a fuel gas or a medium-btu gas in oxygen-blown mode that can be conditioned to a synthesis gas for production of chemicals or fuels such as methanol and SNG)
- Extensive operation at 1-ton per hour
- Industrial acceptance (selected by DOE for a large-scale project in Kentucky)
- Simple system (gas produces low tars, minimal recycle)
- Tested with many biomass feedstocks
- Data is available
- The plant has relatively low capital requirements because of its low pressure

4.1.4.3. Battelle Columbus Laboratory (FERCO) System

The Battelle Columbus Laboratory technology was selected based on the following criteria:

- Relative high cold gas efficiency
- High carbon utilization (char is combusted and the heat is recovered)
- Flexibility (produces a medium-btu gas that can be used either as a fuel gas or conditioned to a synthesis gas for production of chemicals or fuels such as methanol and SNG)
- Extensive operation at Battelle Laboratories and at Burlington Vermont.
- Industrial acceptance (FERCO project selected for sponsorship by DOE)
- Simple system (oxygen is not required to produce a medium-Btu gas, so an air separation plant can be avoided)
- Tested with several biomass materials
- Substantial operating history that should provide adequate data

A conceptual design has been prepared for each of the three technologies selected. The design was used to compare the technical and economic feasibility of each technology. The process designs and the results of the comparison are given in the next section.

4.2 Comparison of Gasification Systems for Power, Fuel, and Chemical Production

Based on the results of the literature search, the pressurized Renugas process, the atmospheric Renugas process, and the atmospheric process developed by Battelle/FERCO were chosen for further evaluation. Using these three technologies, a base case power production scenario using an integrated combined cycle system was defined for each gasification technology. Two additional alternative scenarios were evaluated to compare the technical and economic feasibility of producing liquid fuel and chemicals from the product gases. Methanol and ammonia were chosen for evaluation as fuel and chemical products, respectively. The choice of methanol as a fuel was based on the potential to utilize methanol in combustion turbines for additional electricity production. Ammonia was chosen based on its abundance as a commodity chemical and on in-house expertise in the modeling of ammonia systems.

To determine the technical and economic feasibility of the scenarios described above, a base case power system design was developed for each gasification technology. ChemCad was used to model the Renugas gasification systems. Insufficient published data was available for the FERCO gasification system to allow the development of a ChemCad model within the time frame of this project. Instead, published information concerning the FERCO gas stream composition was used to develop a feed stream for the power, fuel, and chemical production models.

4.2.1 Base Case Gasification Process Models

The methodology used to develop the Renugas gasification system process models is described in this section, along with the basis for and description of the Battelle/FERCO system. As mentioned earlier, the Battelle/FERCO gasification process was not modeled. The Battelle/FERCO process described in this study is derived from information published in the report entitled “Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems” (Craig and Mann, 1990). Modeling of the three gasification technologies is described below.

4.2.1.1 Pressurized and Atmospheric Renugas Gasification Models

The Renugas processes were modeled from detailed information provided by the developer for the pressurized version of the process. The initial model was constructed to almost exactly match the heat and material balance provided. The gasifier itself was modeled as a series of four reactors as follows:

- 1) A fixed-conversion type of reactor, which generated the major hydrocarbon species in the gas—benzene, ethylene, and naphthalene—as a proportion of the hydrogen in the feedstock. This same reactor generated ammonia by converting all nitrogen in the feedstock to ammonia.
- 2) A Gibbs free-energy reactor, which carried out all of the general reactions involving carbon, oxygen, and steam to equilibrium (i.e., simple gasification at equilibrium)

- 3) A second Gibbs reactor, which matched the predicted methane content of the gas by setting a temperature of approach to equilibrium for the methanation reaction.
- 4) A third Gibbs reactor, which matched the predicted shift reaction equilibrium by setting a separate temperature of approach.

Although an exact match of the developer's data was sought in the initial model, the methods employed by these reactors are sufficiently general in principle that the model is considered predictive, i.e. any changes in operating parameters such as feedstock, gasifier pressure and temperature, or oxidant type (air or oxygen), will result in a reasonably good estimate of the gasifier's new output and operation. Carbon conversion in the model was handled by simply bypassing some of the carbon around the reactors. Usually, carbon conversion in a gasifier is a function of physical mechanics (e.g. mixing or time of contact) within the reactor rather than a function of equilibrium or reaction chemistry.

Table 11 shows the feedstock analysis used for the Renugas process models (both pressurized and atmospheric versions). The feedstock was modeled as a non-conventional component series of solids which, collectively, have the same high heating value as the dry biomass.

Table 11

Analysis of Renugas Model Feedstock

Component	Ultimate Analysis (weight %, dry basis)
Carbon	48.51
Hydrogen	6.17
Nitrogen	0.12
Oxygen	44.22
Sulfur	0.04
Ash	0.94
HHV, Btu/lb (dry)	8472
Moisture, as received	50%

Figure 4 is a block flow diagram of the Renugas pressurized gasification process with integrated combined cycle power generation. Raw hardwood biomass containing 50 percent moisture is dried with low pressure steam to 20 percent moisture content. The partially dried biomass is fed via screw conveyor to the biomass gasifier.

Figure 4

Renugas Pressurized Gasification System

The gasifier operates at a pressure of 3.39 mPa (470 psia). A small amount of nitrogen (obtained by vaporizing liquid nitrogen) is fed to the conveyor to act as a seal against backflow of the pressurized hot gases from the gasifier.

The biomass is partially oxidized with hot 427°C (>800°F) air in the gasifier. This air is obtained by extracting a portion of the air from the air compressor of the combustion turbine (CT) (about 10 percent of the CT air flow is extracted). The hot air from the CT's compressor is cooled and then compressed with a booster compressor to raise the pressure from nominally 2.52 mPa (350 psia) to that of the gasifier, 3.39 mPa (470 psia). The CT air is partially cooled in an economizer, which rewarms the air from the booster compressor, thereby preserving most of the heat of compression in the CT compressor.

The gasifier is operated at a temperature of 871°C (1600°F), which is set by controlling the rate of air extraction from the CT. Steam is also fed to the gasifier to promote carbon conversion. A carbon conversion of 99 percent is assumed based on the estimates of the Renugas process developer. Because there is no direct source of 3.39 mPa(470 psia) steam in the process, steam is extracted from the high pressure 8.29 mPa (1150 psia) turbine in the steam cycle. At the point of extraction from the turbine, the steam is superheated by about 82°C (180°F).

The hot, 871°C (1600°F), raw gas leaving the gasifier is cooled to 538°C (1000°F) in a waste heat boiler. Saturated steam is produced at a pressure of 8.29 mPa (1150 psia) and is routed to

the high pressure steam cycle for superheating and subsequent power generation. The gas is filtered to remove entrained solids. Finally, the clean fuel gas is routed to the CT for firing and power generation in the combined cycle.

A simplifying assumption made for this study is that the CT burner system will have the capability of producing low NO_x emissions, even if the fuel gas contains some ammonia (about 0.08 percent, in this case). (Normally, ammonia converts directly to NO_x during conventional firing.) Burner systems of this type are currently under development, according to the Renugas process developer.

Because the fuel gas has a relatively low heat content compared with natural gas 6.11 mJ/Nm₃ (165 Btu/scf HVV, in this case, versus about 37.0 mJ/Nm₃ (1000 Btu/scf) for natural gas), and therefore a relatively high mass flow rate, air extraction from the CT is necessary to prevent a condition in which either the torque limit on the CT drive shaft is exceeded or the compressor goes into surge. Even with air extraction, however, the added mass loading through the CT expander increases the gross power output by about 11 percent to 31.7 MW from a base figure of 28.5 MW output on natural gas.

The hot exhaust from the CT enters a heat recovery steam generator (HRSG). For purpose of power production, the HRSG operates as a single pressure 8.29 mPa (1150 psia), non-reheat cycle (i.e., superheat only). Low pressure saturated steam .468 mPa (65 psia) was also generated for drying the biomass feedstock. Normally, two or three pressure steam generation for power generation would be used in a conventional natural gas-fired combined cycle. However, after generating steam at 8.29 mPa (1150 psia), there was only sufficient heat left in the exhaust to perform the needed biomass drying. It should be noted that the pressure selection of 8.29 mPa (1150 psia) and the configuration (non-reheat) was not optimized for maximum power output. However, this pressure and configuration was used consistently for all three gasification methods.

Figure 5 is a block flow diagram of the Renugas atmospheric-pressure gasification process with integrated combined cycle power generation. The gasification process is essentially the same as the pressurized version discussed above except that the gasifier operates at a pressure near atmospheric 180 kPa (25 psia). A compression step has been added to raise the pressure of the fuel gas to 3.39 mPa (470 psia) for firing in the CT. This step consists of an economizer heat exchanger (to cool the low-pressure gas by re-warming the compressed gas), a cooler, and a 5-stage intercooled compressor train.

Rather than the booster compressor, which is no longer needed, extraction air from the CT is routed through an air expander to generate supplemental power.

Figure 5

Renugas Atmospheric Gasification System

Steam for the gasifier is extracted at 180 kPa (25 psia) from the steam turbine. Since this extracted steam is low quality (about 2 percent condensate), it was heated in the HRSG to 249°C (480°F), which is the steam temperature used by Renugas in their models.

4.2.1.3 Battelle/FERCO Gasification Model

Figure 6 is a block flow diagram of the FERCO gasification process with integrated combined cycle power generation. The FERCO gasification process was not modeled because of time constraints and because of a lack of detailed process information such as that provided by the developers of Renugas.

Figure 6

Battelle-FERCO Gasification System

Instead, the FERCO process was treated as a “black box,” with feedstock and gas production information derived from the open literature (Craig and Mann, 1996). Table 12 gives the analysis of the feedstock used as the basis of the FERCO system.

Table 12

Analysis of FERCO Model Feedstock

Component	Ultimate Analysis (weight %, dry basis)
Carbon	50.88
Hydrogen	6.04
Nitrogen	0.17
Oxygen	41.9
Sulfur	0.09
Ash	0.92
HHV, Btu/lb (dry)	8722
Moisture, as received	50%

With indirect gasification, a pre-heated stream of sand (or some other solid medium) provides the heat input needed to gasify the biomass. In turn, char residue from this gasification step is

combusted in air in a separate char combustor vessel to provide the energy to heat the sand. Operation of both the char combustor and the gasifier is at near atmospheric pressure 180 kPa (25 psia). Because air never enters the gasifier, the fuel gas is not diluted with nitrogen and therefore has significantly higher heat content than gases from direct gasifiers. The fuel gas from the Ferco gasifier has sufficiently high heat content

13.5 MJ/Nm₃ (365 Btu/scf HHV) such that, when fired, no extraction of air from the CT is necessary and therefore the air expander found in the Renugas atmospheric gasification process is obviated.

Other than the elimination of the air expander, the integration of the gasifier with the combined cycle was similar to that for Renugas atmospheric gasification. There was one assumption made regarding internal process operation of the FERCO process. It was assumed that there was sufficient waste heat within the FERCO process to heat the fuel gas to 371°C (700°F) just prior to firing in the CT. This assumption is based on the statement in regarding indirect gasification that stated, “After compression, the syngas is heated indirectly to 371°C (700°F) with process heat from the quench and char combustor flue gas” (Craig and Mann, 1990).

4.2.2 Gasification Plant Design

Using these models, a conceptual design was prepared for each of the base case systems and the methanol and ammonia scenarios. These designs are based on information found in the Craig and Mann report, internal TVA reports, and external contractor information. The following general premises were used to develop the conceptual designs:

- Wood as feedstock
- 1,000 ton per day nominal plant capacity
- 30 year plant life
- nth plant, minimal equipment redundancy
- 90.4% plant availability

The design consists of the following major plant areas: feedstock handling, feedstock drying, gasification, gas clean-up, combustion turbine, and HRSG. Each section is described below.

4.2.2.1 Feedstock Handling and Preparation

Wood chips sized to about 5 cm (2 inches) would be delivered to the plant site by truck. The wood would be unloaded and moved to a storage yard. The wood yard would have sufficient storage area to store a one week supply. The plant is assumed to be located close to roads or railroad spurs which would be sufficient to allow adequate delivery of the feedstock. The moisture content of the as is chips is estimated at 50%. A rotary kiln dryer would be used to dry the chips to a moisture content of 20% prior to feeding. For the high pressure Renugas system, a feed lockhopper and pressurized feed hopper would be used to meter the feed into an injection screw that feeds the gasifier.

4.2.2.3 Gasification

The gasification systems have been described in the previous sections. The commercial designs for these systems were taken from the report by Craig and Mann.

4.2.2.4 Gas Clean-up

For the pressurized Renugas system, a primary cyclone is used to remove char and ash. Direct quench is used to condense the alkali species, followed by ceramic candle filters for alkali and particulate removal. For the atmospheric Renugas and FERCO systems, it was assumed that the fuel gas would enter a circulating fluidized tar cracking unit, followed by gas cooling, and particulate filtration.

4.2.2.5 Heat Recovery Steam Generator

Gas turbine exhaust would be fed to the heat recovery steam generator (HRSG). The HRSG would incorporate a superheater, high and low pressure boilers and economizers.

4.2.2.6 Steam Turbine

The steam turbine system consists of high and low pressure power turbines and a generator.

4.2.2.7 Combustion Turbine

The CT used in the design was a General Electric LM2500+, an aeroderivative-type CT which produces nominally 28.5 MW at a heat rate of about 9.5 mJ/kWh (9,000 Btu/kWh) when operated on natural gas at ISO conditions. The LM2500+ produces a desirable combination of good efficiency with moderate size.

In addition to the major process areas mentioned above, the plant design includes plant areas for cooling and potable water, instrumentation, waste treatment, and disposal, electrical, controls, piping, etc.

4.2.3 Base Case Process Plant Performance

The performance of each base case system design is described in this section. Primary inputs such as wood, air, and steam rates are given. The resulting fuel gas characteristics are also shown. Electricity production is given for the base case systems.

4.2.3.1 Fuel Gas Composition

A summary of the composition of the gas streams produced by each gasification technology is shown in Table 13. The Renugas systems are both air blown, resulting in fuel gas streams high in nitrogen. Because of the presence of nitrogen in the Renugas streams, the HHV is much less than that of the FERCO system. FERCO's HHV is 14.6 mJ/kg (6,279 Btu/lb) while the pressurized Renugas is 5.79 mJ/kg (2,491 Btu/lb) and the atmospheric Renugas is 4.40 mJ/kg (1,892 Btu/lb). However, because of the higher gas flow rates of the Renugas processes, the heat flow in MMBtu/h is higher for the Renugas than the FERCO system.

Table 13

**Summary of Fuel Gas Stream Compositions –
Base Case Combustion Turbine Scenario**

Item	Pressurized Renugas	Atmospheric Renugas	FERCO
Mol. Wt.	25.1	24.64	21.88
Temperature, °C (°F)	538 (1000)	538 (1000)	538 (1000)
Pressure, mPa (psia)	3.38 (470)	.180 (25)	.180 (25)
Composition, mol%			
Hydrogen	11.50%	14.22%	16.07%
Carbon monoxide	11.70%	12.74%	32.69%
Carbon dioxide	15.79%	13.14%	10.19%
Water	17.87%	16.90%	24.29%
Methane	7.52%	2.48%	11.99%
Benzene	0.24%	0.19%	0.00%
Ethylene	0.04%	0.03%	4.13%
Napthalene	0.08%	0.06%	0.30%
Nitrogen	34.75%	39.66%	0.00%
Argon	0.43%	0.50%	0.00%
Hydrogen sulfide	0.01%	0.01%	0.06%
Ammonia	0.08%	0.06%	0.28%
HHV, mJ/kg (Btu/lb)	5.79 (2491)	4.40 (1892)	14.6 (6279)
Heat flow (HHV), mJw (MMBtu/h)	295837 (280.4)	323585 (306.7)	291089 (275.9)
Cold gas efficiency, %	79.3%	73.1%	72.4%

Cold gas efficiencies are also shown in Table 5. The pressurized Renugas system has the highest cold gas efficiency at 79.3%. The FERCO and atmospheric Renugas are relatively close at 72.4% and 73.1%, respectively.

4.2.3.2 Base Case Performance Summary

A summary of process data and system performance for the base case plant designs involving power production is given in Table 14.

Table 14

Process Data Summary and System Performance Results

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/daymtpd (tpd)	569 (626)	675 (743)	596 (656)
Air Flowrate, kg/hr (lb/h)	25,630 (56,500)	43,549 (96,000)	-
Steam Flowrate, kg/h (lb/h)	1,379(3,039)	1,649(3,626)	11,162 (24,600)
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	5,701 (12,569)	73,535 (162,100)	43,948 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	5.79 (2491)	4.40 (1892)	14.6 (6279)
Power Island			
Gas Turbine	LM2500+	LM2500+	LM2500 +
Power Production Summary			
Gas Turbine Output, MW	31.7	33.45	30.05
Steam Turbine Output, MW	11.36	12.18	8.43
Net System Output, MW	42.05	41.86	36.05
Net Plant eff, HHV Basis, %	40.6%	34.0%	32.3%

As shown in the table, wood flowrates varied slightly for each system based on the heating value of the gas produced. As mentioned earlier, a nominal plant size of 909 tonnes/day (1,000 tpd) was selected for the design. The flowrate shown in the table are at 20% moisture, after the incoming biomass has been dried.

As shown in the table, air usage was 25,630 kg/hr (56,500 lb/hr) at 472 °C (882 °F) for the pressurized Renugas model and 43,549 kg/hr (96,000 lb/hr) at 182 °C (361 °F) for the atmospheric Renugas system. ISO starting conditions of 15 °C (59 °F) and 60% relative humidity were used for the air streams. Steam rates for the Renugas models were set at 0.15 wt./wt. carbon. The pressurized Renugas system was estimated to use 1,379 kg/hr (3,039 lb/hr) of steam at 3.39 MPa (470 psia) and 361 °C (682 °F). The atmospheric Renugas model required 1,645 kg/hr (3,626 lb/hr) at 180 kPa (25 psia) and 249 °C (480 °F). Steam for the FERCO system was estimated to be 11,162 kg/hr (24,600 lb/hr) based on information presented in the Craig and Mann study.

Electricity production ranged from a total of 38.48 MW for the FERCO system, up to 49.75 MW for the atmospheric Renugas system. Internal energy consumption is also shown in the table. Taking these loads into account, the net power production for the pressurized Renugas, FERCO, and the atmospheric Renugas system are 42.05 MW, 36.05 MW, and 41.86 MW, respectively. Heat rates and thermal efficiencies are also shown in the table. The pressurized Renugas system has the highest thermal efficiency at 40.6%. The FERCO system and the atmospheric Renugas system are close at 32.3% and 34.0%, respectively.

4.2.4 Methanol and Ammonia Process Models

For the purpose of studying chemical production (ammonia and methanol), the Renugas process was modeled as an oxygen-blown system. Chemical production from an air-blown gasifier is problematic because the nitrogen in the synthesis gas from the gasifier dilutes and retards the synthesis reactions. Models of oxygen-blown Renugas were constructed for both pressurized and atmospheric gasification. Gasifier pressures of 3.39 MPa and 180 kPa (470 and 25 psia) and an operating temperature of 871 °C (1600 °F) were the same as that assumed for the air-blown models.

4.2.4.1 Methanol Production Model

For methanol production, the reforming of the biomass syngas takes place in a single stage primary reformer integrated into a heat recovery unit (HRU). Steam reforming is an endothermic process and requires the HRU as a heat source to drive the reaction. Integrated steam reforming is a complex system that requires high temperatures, an external water source, and a complex flow scheme. Benefits include the inherent energy conservation of the HRU and the composition (maximized carbon monoxide content) of the synthesis gas after reforming.

Biomass syngas, is mixed with steam and fed into the primary reformer where it is decomposed into hydrogen, carbon monoxide, and carbon dioxide over a nickel catalyst. The ratios of the hydrogen, carbon monoxide, water, and carbon dioxide, once the water is removed, are sufficient for the methanol reaction. No further processing, either additional secondary reforming or shift reactions are needed, prior to methanol synthesis.

Heat is supplied to the reformer by firing the waste steam containing methane from the methanol separation section of the process and makeup biomass syngas. This provides all the heat necessary to drive the reformer reactions.

The fresh feed gas from the SMR unit is mixed with recycle gas. The mixed synthesis gas for the reforming system and the recycled is heated by the reactor effluent. It then passes through a zinc oxide guard bed for trace sulfur impurity removal (normally used with natural gas) before being sent to the methanol synthesis reactor. The catalyst remains in the reactor.

Part of the product methanol reactor exit gas is recompressed and recycled back to the reactor and the rest is sent to the methanol separation equipment. Preheating the reactor feed gas and the recycled crude methanol cools the crude methanol. Final cooling of the crude methanol is done with cooling water or refrigeration. The cooled crude methanol flows to a separator where the unconverted product gas and crude methanol are separated. The exhaust gas (or unreacted methane stream) is returned to the reformer where it is fired to generate the heat required for the steam methane reforming.

4.2.4.2 Ammonia Production Model

Ammonia can be produced from biomass syngas by using an SMR as with methanol production. Hydro-Chem, mentioned earlier as the methanol plant supplier, can also supply a skid-mounted NH_3 plant.

Feed gas from the SMR goes through a catalyzed three stage shift conversion where most of the carbon monoxide is converted to carbon dioxide resulting in additional hydrogen. The SMR gas contains sufficient water to drive the equilibrium conversion, and it is not necessary to add steam to supplement the shift reaction.

Equilibrium is favored by lower temperature but higher temperature is necessary to initialize and increase the shift reaction rate. Compression to 2.88 MPa (400 psia) increases the gas temperature to about 343 °C (650 °F), which is optimum for the initial stage. The model uses a three (3) stage shift with cooling after each stage. Medium pressure (MP) and low pressure (LP) steam is generated by cooling the gas between the high, medium, and the low temperature shift reactors. Final cooling prior to the hydrogen separation is with cooling water that lowers the gas temperature to about 43 °C (110 °F) for feed to a pressure swing adsorption (PSA) unit for H_2 purification. The process model used a slightly lower hydrogen purity because of the need for a methanator as explained below. Usually with lower purity comes higher recovery, but the same percent hydrogen recovery (76%) was used in the models to remain conservative.

A methanator is usually not needed after hydrogen purification. However, with slightly less hydrogen purity to coincide with the less pure nitrogen, a methanator is used in the process model to remove the oxygenated compounds. Oxygenated compounds (typically CO, CO_2 , or O_2) cause ammonia reactor temperatures to increase. Temperature excursions cause damage to

the ammonia catalyst and, therefore, oxygenated compounds need to be removed from the ammonia reactor feed gas. The nitrogen and hydrogen gases are mixed and compressed to the ammonia reactor feed pressure prior to the methanator. High pressure is not detrimental to methanation. This raises the gas temperature to about 316 °C (600 °F), which is normal for the methanation reaction.

Methane is an inert in the ammonia reactor and will build up to a certain extent in the recycle stream. Since most of the methane was removed from the SMR gas in the hydrogen PSA, the additional methane should not be a problem. Under the conditions of methanation, the oxygen, which enters with the nitrogen, is thought to react with hydrogen to form water. Some oxygen may react with carbon monoxide and be converted to carbon dioxide, but carbon dioxide is eliminated with the second reaction. Equilibrium conditions in the methanator favor the third reaction since there is an excess of H₂ as the driving force.

After methanation, the gas is cooled by generating MP and LP steam. Cooled recycle, at about a 3:1 weight ratio to the methanized feed, is mixed with the methanized feed. These mixing results in an ammonia reactor feed stream at 24 °C (75 °F), which condenses the water formed in the methanator. As previously mentioned, a controller makes sure the correct molar ration of hydrogen to nitrogen is at 3:1 by adjusting the air to the nitrogen PSA unit. This ratio is based on the combined recycle plus methanized feed.

The ammonia reactor exit stream is at 393 °C (740 °F) and is cooled by generating MP steam followed by pre-heating the ammonia reactor feed to 149 °C (300 °F). It is further cooled using cooling water followed by refrigerant cooling to drop the temperature to 6.7 °C (-20 °F). Liquid ammonia is separated from recycle gases in the recycle flash unit. Recycle flash operates just slightly below ammonia reactor operating pressure. A small amount of purge, set at 4.54 kg/hr (10 lb/hr), is removed from this recycle stream before it is re-compressed and mixed with the methanized feed. The ratio of recycle to methanized feed is about 3:1. This is fairly typical and depends on the amount of purge, the amount of impurities in the loop, and the amount of conversion obtained in the ammonia reactor.

A product flash unit, operating at about 1.08 MPa (150 psia), is used to remove most of the lighter entrained gases, concentrating the recycle flash bottoms from 98.3% to 99.3% ammonia. The resulting product is a 99.3% anhydrous ammonia.

4.2.5 Methanol and Ammonia Plant Designs

A plant design for the alternative scenarios involving methanol and ammonia was prepared. The plant would be almost identical to the base case design with the exception of the addition of an air separation unit for the Renugas systems and the addition of methanol and ammonia production systems. A cryogenic air separation unit was selected as the source of the 95 percent purity oxygen used in the production of methanol and ammonia. For methanol and ammonia production, the

SMR units used in the designs are skid-mounted units manufactured by Hydro-Chem, a subsidiary of Linde AG. The units consist of a fired unit containing catalyst tubes.

4.2.6 Methanol and Ammonia Process Plant Performance

The performance of each system for ammonia and methanol production is given in this section. Gas composition for chemical production is given along with primary process inputs and product outputs.

4.2.6.1 Methanol and Ammonia Gas Stream Composition

Table 15 gives the composition of the gas streams used for methanol and ammonia production. Because the Renugas systems are now oxygen-blown, the composition of the resulting fuel gas differs from original base case air-blown scenario, in that very little nitrogen is present.

Table 15
Summary of Fuel Gas Stream Compositions –
Methanol and Ammonia Production Scenarios

Item	Pressurized Renugas	Atmospheric Renugas	FERCO
Mol. Wt.	23.3	22.35	21.88
Temperature, °C (°F)	437 (818)	437 (819)	538 (1000)
Pressure, MPa (psia)	3.37 (468)	.166 (23)	.180 (25)
Composition, mol%			
Hydrogen	16.03%	22.20%	16.07%
Carbon monoxide	14.10%	20.63%	32.69%
Carbon dioxide	23.58%	20.66%	10.19%
Water	30.84%	25.40%	24.29%
Methane	12.73%	8.15%	11.99%
Benzene	0.34%	0.34%	0.00%
Ethylene	0.06%	0.06%	4.13%
Napthalene	0.11%	0.11%	0.30%
Nitrogen	1.70%	1.71%	0.00%
Argon	0.37%	0.43%	0.00%
Hydrogen sulfide	0.02%	0.01%	0.06%
Ammonia	0.11%	0.11%	0.28%
HHV, MJ/kg (Btu/lb)	9.3 (3997)	9.48 (4076)	14.6 (6279)
Heat flow (HHV), MJ/h (MMBtu/h)	306,282 (290.3)	361,145 (342.3)	291,089 (275.9)
Cold gas efficiency, %	82.1%	81.6%	72.4%

As expected, the lack of nitrogen in the Renugas scenarios caused an increase in the heat flow, HHV, and cold gas efficiencies as compared to the base case scenario. No changes were made in gasifier operation for the FERCO system, therefore the gas stream composition is the same in this scenario as in the base case FERCO system.

4.2.6.2 Methanol Performance Summary

Process performance data for the methanol production scenario is shown in Table 16. For the methanol scenarios, the Renugas systems both use 95% oxygen during the gasification process as opposed to air used in the combustion turbine scenario.

Table 16

Process Data Summary and System Performance Results – Methanol

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/day (tpd)	569 (626)	675 (743)	596 (656)
Air Flowrate, kg/hr (lb/h)	5,217 (11,500)	7,374 (16,256)	-
Steam Flowrate, kg/hr (lb/h)	1,379 (3,039)	1,644 (3,626)	11,162 (24,600)
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	32,949 (72,632)	38,103 (83,995)	19,937 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	9.30 (3,997)	9.48 (4,076)	14.6 (6,279)
Power Production Summary			
Gas Turbine Output, MW	-	-	-
Steam Turbine Output, MW	1.25	1.77	-
Net System Output, MW	-4.21	-7.89	-2.99
Methanol Production Summary			
Methanol, tonnes/day (tpd)	283 (311)	325 (358)	291 (320)

As a result, the gas quantities produced by these two technologies are much smaller than in the combustion scenario. As shown, the flowrates for the pressurized Renugas, FERCO, and atmospheric Renugas are 32,948 kg/hr (72,632 lb/hr), 19,937 kg/hr (43,948 lb/hr), and 38,103 kg/hr (83,995 lb/hr), respectively. As is expected, the HHV's for the Renugas processes are higher in this scenario than in the combustion turbine system. Based on the amount of power generated and the various parasitic loads, a net power requirement is realized

for all three systems. The pressurized and atmospheric Renugas processes require 4.21 MW and 7.89, respectively, and the FERCO system uses 4.96 MW. Methanol production for the pressurized Renugas system is 283 tonnes/day (311 tpd). The atmospheric Renugas and the FERCO processes are estimated to produce 325 tonnes/day (358 tpd) and 291 tonnes/day (320 tpd), respectively.

4.2.6.3 Ammonia Performance Summary

Table 17 gives a summary of process performance for the ammonia production scenario. The gas streams for this scenario are the same as in the methanol scenario. In this scenario, a significant amount of electricity is produced through expansion in the process.

Table 17
Process Data Summary and System Performance Results – Ammonia

	Pressurized Renugas	Atmospheric Renugas	FERCO
Gasifier Requirements			
Wood Flowrate, 20% moisture, tonnes/day (tpd)	569 (626)	675 (743)	596 (656)
95% Oxygen Flowrate, kg/hr (lb/h)	5,217 (11,500)	7,374 (16,256)	-
Steam Flowrate, kg/hr (lb/h)	1,379 (3,039)	1,644 (3,626)	-
Fuel Gas			
Fuel Gas Flowrate, kg/hr (lb/h)	32,949 (72,632)	38,103 (83,995)	19,937 (43,948)
Fuel Gas Heating Value, HHV, Wet Basis, MJ/kg (Btu/lb)	9.3 (3,997)	9.48 (4,076)	14.6 (6,279)
Power Production Summary			
Gas Turbine Output, MW	-	-	-
Steam Turbine Output, MW	1.25	1.77	-
Net System Output, MW	-5.87	-7.09	-2.89
Ammonia Production Summary			
Ammonia, tonnes/day (tpd)	206 (227)	235 (259)	165 (181)

The resulting net energy requirement for each system is as follows: 5.87 MW for the pressurized Renugas process, 4.86 MW for the FERCO system, and 10.85 MW for the atmospheric Renugas. Ammonia production for the pressurized and atmospheric Renugas

systems is 206 tonnes/day (227 tpd) and 235 tonnes/day (259 tpd), respectively. The FERCO system is estimated to produce 165 tonnes/day (181 tpd) of ammonia.

4.2.7 Economic Evaluation

An economic evaluation of the various integrated systems was conducted using conceptual designs described in the previous sections. The estimate is considered a “factored estimate” with much of the cost information being derived from the study conducted by Craig and Mann and in-house TVA estimates. The Craig and Mann study uses 1990 as a reference year for cost estimating purposes. For the purpose of this study, a reference year of 2001 is used. Therefore, the costs as presented in the Craig and Mann study were corrected for capacity and cost year using a capacity factor of 0.6 and the Chemical Engineering Cost Index of 400. The balance of plant was based on 20% of the total for other plant costs. Additional capital cost premises are listed below in Table 18.

Table 18

General Capital Cost Premises

Cost Category	Percent of Process Plant
General plant facilities	10
Engineering fees	15
Contingency	20
Start-up costs	4
Spare parts	1
Working capital	60 days operating cost

Operating costs are based on an average year of operation and include various direct costs such as raw materials and conversion costs, the premises of which are shown in Table 19.

Table 19

Direct Operating Cost Premises

Cost Category	Cost/unit
Wood	\$0.63/1000 MJ (\$0.66/million Btu)
Boiler feed water	\$0.66/cubic meter (\$2.50/1000 gallon)
Cooling water	
Ash disposal	\$8.80/tonne (\$8.00/ton)
Operating labor	\$15.00/hour
Supervision and clerical	25% of operating labor

Indirect costs are also included in the estimate and are derived from the premises shown in Table 20.

Table 20

Indirect Operating Cost Premises

Cost Category	Premise
Maintenance costs	4% of process plant cost
Insurance and local taxes	2% of process plant
Royalties	0.5% of electricity revenue

Selling price for the three products produced in these scenarios is shown in Table 21.

Table 21

Selling Price of Process Products

Product	Selling Price
Electricity	\$40/MWh
Methanol	\$133/tonne (\$121/ton)
Ammonia	\$220/tonne (\$200/ton)

Using these overall cost premises, capital and operating costs were estimated for the various integrated systems. These costs are described in the next section.

4.2.7.1 Capital Cost Estimate – Base Case CT System

Table 22 summarizes the capital costs for electricity production using the pressurized Renugas system, the atmospheric Renugas system, and the Battelle-FERCO system. As shown in the table, wood handling and drying costs are essentially the same for each system. The slight variations are based on the difference in feedrate for the three systems. As mentioned earlier, this difference in feedrate is due to the energy content of the gas produced by each system. For the purposes of this study, the size of the combustion turbine was held constant, therefore, the feedrate of wood to the gasifier varies for each system depending on the amount required to produce the desired energy content of the gas stream.

Table 22

Summary of Capital Costs for the Combustion Turbine System

Cost Category	Capital Costs, \$K (2001)		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Plant Section Description			
Wood Handling	2,749	3,046	2,826
Wood Drying	2,908	3,222	3,499
Gasification	21,555	24,541	9,110
Gas Cleanup	2,638	Inc w Gasif	12,452
Tar Cracker	Not Req'd	Inc w Gasif	292
Direct Quench	Not Req'd	Inc w Gasif	69
Boost Compressor	573	Inc w Gasif	3,655
Char Combuster System	Not Req'd	Inc w Gasif	Inc w Gasif
Combustion Turbine System	9,608	9,608	9,608
HRSG	4,137	4,137	4,137
Steam Cycle	8,155	8,504	6,819
Balance of Plant	11,210	11,355	11,173
Substation	3,728	3,718	3,399
Subtotal, Process plant cost	67,263	68,133	67,039
General Plant Facilities	6,726	6,813	6,704
Engineering Fees	10,089	10,220	10,056
Project Contingency	13,453	13,627	13,408
Prepaid Royalties	336	341	335
Startup Costs	2,691	2,725	2,682
Spare Parts	673	681	670
Working Capital	1,070	1,128	1,132
Land	0	0	0
Total Capital Requirement	102,301	103,667	102,025

Using the Craig and Mann study as a reference, the cost of the gasification system for the pressurized Renugas, the atmospheric Renugas and the Battelle-FERCO system was \$21.5, \$24.5 and \$9.1 million, respectively. Though the FERCO system appears to be the least cost option, the cost for gas clean-up given in the Craig and Mann study is fairly high at \$12.45 million. Gas-clean-up costs are included in the cost of gasification for the atmospheric Renugas process and are shown to be minimal (\$2.6 million) in the pressurized Renugas system. If the cost of clean-up was included in the gasification cost for both the pressurized Renugas and the Battelle FERCO system, the cost for the gasification systems would then be \$24.2 million for the pressurized Renugas, \$21.6 million for Battelle-FERCO, and \$24.5 million for atmospheric Renugas.

A tar cracker was used in the two low pressure systems to reduce the molecular weight of the larger hydrocarbons that may be present in the gas stream. The cost for this system was included in the atmospheric Renugas cost. The cost of tar cracking for the FERCO system was estimated at \$292,000.

No costs were included for land in each scenario. It was assumed that the facility would be located at an existing industrial site. Working capital for each scenario is based on 60 days of operating cost. The remaining capital costs are calculated as percentages of process plant cost as shown in Table 15. As summarized in Table 15, total capital investment costs for pressurized Renugas, FERCO, and atmospheric Renugas are \$102.3, \$102.0, and \$103.7 million, respectively.

4.2.7.2 Annual Operating Cost Estimate – Base Case CT System

Annual operating costs for the three systems are summarized in Table 23. Wood costs as shown are estimated to be \$0.63/1000 MJ (\$0.66/million Btu). The wood is estimated to have a Btu content of 19.7 MJ/kg (8,472 Btu/lb) for the Renugas systems. The FERCO system used the slightly higher energy content of 20.3 MJ/kg (8,722 Btu/lb) for Aspen as mentioned in the Craig and Mann report. As mentioned earlier, the plant size is based on a nominal 434 kg/d (1,000 lbs per day) of as is wood. However, based on the energy content of the gas produced by each system, the feed rate varies slightly for each system.

Table 23**Summary of Annual Operating Costs –Combustion Turbine Scenario**

Cost Category	Operating Costs, \$K/year		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood delivered, \$0.63/1000 MJ (\$0.66/million Btu), 19.7 MJ/kg (8472 Btu/lb) (dry)	1,849	2,194	1,936
BFW	77	21	73
Cooling Water	0	0	0
Ash disposal	19	22	326
Operating Labor	300	300	300
Supervision and Clerical	75	75	75
Maintenance Costs	2,691	2,725	2,682
Insurance and Local Taxes	1,345	1,363	1,341
Royalties	67	66	57
Other Operating Costs inc w Main Costs	0	0	0
Total Operating Costs before Cost of Capital and ROI	6,423	6,767	6,790

Ash is disposed of at a cost of \$8.80/tonne (\$8.00 per ton). Ash disposal costs are minimal for the Renugas systems, however, the FERCO process includes large disposal costs for the additional sand that is purged to prevent buildup of ash in the system. Operating labor is estimated at 20,000 hours per year at \$15.00 per hour for each system. Supervision and clerical were estimated as a percentage of operating labor. Maintenance and taxes and insurance costs were calculated using a percentage of the operating costs.

Royalties are based on revenue. In this scenario, all revenue is derived from the sale of electricity. As discussed earlier, the pressurized and atmospheric Renugas systems generate 42.05 and 41.86 MW, respectively. The FERCO system produces less electricity at 36.05 MW. Revenue from the sale of electricity produced by each system is based on a selling price of \$40 per MWh. Using this selling price, annual revenue for the pressurized Renugas, FERCO, and atmospheric Renugas was estimated to be \$13.3, \$11.4, and \$13.2 million, respectively. Total annual operating costs, excluding the cost of capital and return on investment (ROI), for the pressurized Renugas, FERCO, and atmospheric Renugas systems were estimated to be \$6.42 million, \$6.79 million, and \$6.77 million, respectively.

4.2.7.3 Capital Cost Estimate – Methanol Production System

Table 24 gives an estimate of capital costs for methanol production using the three gasification technologies for syngas production. As described in the design section of the report, for methanol production, 95% oxygen was used during gasification in the Renugas processes. Therefore, the flowrate of the resulting gas streams are smaller than those produced for combustion turbine operation (FERCO remained the same). This reduction in gas flowrate, resulted in smaller equipment sizes for the Renugas processes for the methanol production scenario. Capital costs for the Renugas gasifiers are therefore lower than in the combustion turbine scenario. As mentioned in the design section of this report, the methanol production system costs are based on a study conducted by TVA in 1999. The costs were corrected for capacity and inflation. Using the factors described earlier for the remaining plant costs, total capital investment costs for the methanol system using pressurized Renugas, FERCO, and atmospheric Renugas, were \$87.1 million, \$80.8 million, and \$81.4 million, respectively.

Table 24
Summary of Capital Costs – Methanol Production Scenario

Cost Category	Capital Costs, \$K (2001)		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood Handling	2,749	3,046	2,826
Wood Drying	2,908	3,222	3,499
Air Separation	5,384	6,626	Not Required
Gasification	17,370	17,539	9,110
Gas Cleanup	2,638	Inc w Gasif	12,452
Tar Cracker	Not Req'd	Inc w Gasif	292
Direct Quench	Not Req'd	Inc w Gasif	69
Boost Compressor	573	Inc w Gasif	3,655
Char Combuster System	Not Req'd	Inc w Gasif	Inc w Gasif
Combustion Turbine System	Not Req'd	Not Req'd	Not Required
HRSG	758	934	Not Required
Steam Recycle	1,076	1,325	Not Required
Methanol Production	13,568	12,128	13,820
Methanol Storage	815	728	830
Balance of Plant	7,114	6,713	6,380
Substation	0	0	0
Subtotal, Process Plant Cost	57,070	53,136	52,933
General Plant Facilities	5,707	5,314	5,293
Engineering Fees	8,560	7,970	7,940
Project Contingency	11,414	10,627	10,587
Prepaid Royalties	285	266	265
Total Capital at Mechanical Comp	83,036	77,313	77,017
Startup Costs	2,283	2,125	2,117
Spare Parts	571	531	529
Working Capital	1,192	1,489	1,155
Land	0	0	0
Total Capital Requirement	87,082	81,459	80,819

4.2.7.4 Annual Operating Costs – Methanol Production System

Annual operating costs for this scenario are shown in Table 25 and are similar to those calculated for the combustion turbine scenario. However, as described in the design section, because there is no combustion turbine, electricity must be purchased for each methanol production system. Electricity requirements vary considerably for each technology. Both Renugas processes require an air separation unit. The atmospheric Renugas process and the FERCO process also require fuel gas compression. As a result, the electricity costs for the pressurized Renugas, FERCO, and the atmospheric Renugas systems are \$1.33 million, \$0.95 million, and \$3.06 million, respectively. All other operating costs are estimated as discussed in the previous section.

Table 25

Summary of Annual Operating Costs – Methanol Production Scenario

Cost Category	Operating Costs, \$K/year		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood delivered, \$0.63/1000 MJ (\$0.66/million Btu), 19.7 MJ/kg (8472 Btu/lb) (dry)	1,849	2,194	1,936
BFW	42	3	58
Cooling Water	48	40	50
Electricity	1,334	3,060	947
Ash disposal	19	22	326
Operating Labor	300	300	300
Supervision and Clerical	75	75	75
Maintenance Costs	2,283	2,125	2,117
Insurance and Local Taxes	1,141	1,063	1,059
Royalties	62	51	64
Other Operating Costs inc w Main Costs	0	0	0
Total Operating Costs before Cost of Capital and ROI	7,152	8,934	6,932

Revenue from the technologies is based on the sale of methanol. Pressurized Renugas, FERCO, and atmospheric Renugas each produce 283 (311), 291 (320, and 235 tonnes/day (258 tons per day), respectively. At selling price of \$133/tonne (\$121 per ton), the annual revenue from using each technology is \$12.4 million for pressurized Renugas, \$12.8 million for FERCO, and \$10.3 million for atmospheric Renugas.

4.2.7.5 Total Capital Investment – Ammonia Production System

Table 26 gives a summary of capital costs for the ammonia production system. The costs are similar to those presented for the methanol production scenario. The costs shown for the ammonia production section were derived from in-house estimates based on production of ammonia from landfill gas.

Table 26

Summary of Capital Costs – Ammonia Production Scenario

Cost Category	Capital Costs, \$K (2001)		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood Handling	2,749	3,046	2,826
Wood Drying	2,908	3,222	3,499
Air Separation	5,384	6,626	Not Req'd
Gasification	17,370	17,539	9,110
Gas Cleanup	2,638	Inc w Gasif	12,452
Tar Cracker	Not Req'd	Inc w Gasif	292
Direct Quench	Not Req'd	Inc w Gasif	69
Boost Compressor	573	Inc w Gasif	3,655
Char Combuster System	Not Req'd	Inc w Gasif	Inc w Gasif
Combustion Turbine System	Not Req'd	Not Req'd	Not Required
HRSG	758	934	Not Required
Steam Recycle	1,076	1,325	Not Required
Ammonia Production	50,705	54,754	44,187
Ammonia Storage	815	728	830
Balance of Plant	7,114	6,713	6,380
Substation	0	0	0
Subtotal, Process Plant Cost	57,070	53,136	52,933
General Plant Facilities	5,707	5,314	5,293
Engineering Fees	8,560	7,970	7,940
Project Contingency	11,414	10,627	10,587
Prepaid Royalties	285	266	265
Total Capital at Mechanical Comp	83,036	77,313	77,017
Startup Costs	2,283	2,125	2,117
Spare Parts	571	531	529
Working Capital	1,192	1,489	1,155
Land	0	0	0
Total Capital Requirement	152,101	162,298	129,735

As shown in the table, total capital investment costs for the pressurized Renugas, atmospheric Renugas, and FERCO systems are \$152.1 million, \$162.3 million, and \$129.7 million, respectively.

4.2.7.6 Annual Operating Costs – Ammonia Production System

A summary of annual operating costs for the ammonia production scenario are shown in Table 27. As in the methanol case, electricity costs are significant for each gasification technology. The bulk of the electricity costs result from compression costs. In the atmospheric processes, the fuel gas stream must be compressed prior to ammonia production. There are also considerable power loads from refrigeration requirements.

Table 27

Summary of Annual Operating Costs – Ammonia Production Scenario

Cost Category	Operating Costs, \$K/year		
	Pressurized Renugas	Atmospheric Renugas	FERCO
Wood delivered, \$0.63/1000 MJ (\$0.66/million Btu), 19.7 MJ/kg (8472 Btu/lb) (dry)	1,849	2,194	1,936
BFW	38	46	19
Cooling Water	303	307	218
Electricity	1,860	2,246	916
Ash disposal	19	22	326
Operating Labor	300	300	300
Supervision and Clerical	75	75	75
Maintenance Costs	2,283	2,125	2,117
Insurance and Local Taxes	1,141	1,063	1,059
Royalties	62	51	64
Other Operating Costs inc w Main Costs	0	0	0
Total Operating Costs before Cost of Capital and ROI	10,018	10,760	8,177

All other costs are calculated as discussed in previous scenarios. As shown in the table, total annual operating costs for the Renugas and FERCO systems are \$10.02 million for pressurized Renugas, \$10.76 million for atmospheric Renugas and \$8.18 million for FERCO.

4.2.7.7 Summary of Economic Evaluation

Total capital investment and operating costs are summarized for the nine scenarios in Tables 28 and 29, respectively. As shown in Table 28, total capital investment for power production was essentially the same for the three processes. The least cost scenario was methanol production using the FERCO process.

Table 28**Total Capital Investment Summary**

Technology	Power Production \$M/year	NH3 Production \$M/year	Methanol Production \$M/year
Pressurized Renugas	102.3	152.1	87.1
Atmospheric Renugas	103.7	162.3	87.4
FERCO	102.0	129.7	80.8

Operating costs for the systems ranged from \$6.42 million for power production using the pressurized Renugas system to \$10.76 million for the ammonia system using the FERCO gasification technology.

Table 29**Annual Operating Costs Summary**

Technology	Power Production \$M/year	NH3 Production \$M/year	Methanol Production \$M/year
Pressurized Renugas	6.42	10.02	7.15
Atmospheric Renugas	6.77	8.18	8.93
FERCO	6.79	10.76	6.93

Revenue from each system is shown in Table 30. As shown, the atmospheric Renugas system for ammonia production had the highest revenue of the nine scenarios.

Table 30**Revenue Summary**

Technology	Power Production \$K/year	NH3 Production \$K/year	Methanol Production \$K/year
Pressurized Renugas	13,321	14,982	12,410
Atmospheric Renugas	13,261	17,067	10,293
FERCO	11,421	11,946	12,796

A summary of the corresponding product quantities is shown in Table 31.

Table 31**Product Summary**

Technology	Power Production (MW)	NH3 Production (T/D)	Methanol Production (T/D)
Pressurized Renugas	1009	227	311
Atmospheric Renugas	1005	259	358
FERCO	865	181	320

Based on the results of this portion of the study, it can be seen that the two Renugas processes appear to have the most potential to maximize power production via gasification. Ammonia and methanol production also tend to favor the Renugas processes, though the FERCO process produced slightly more methanol than the atmospheric Renugas system.

Process developments such as hot gas clean-up have the potential to improve the economics of biomass gasification. The effect of such improvements will be discussed in the next section along with the evaluation of the carbon sequestration potential of the three technologies.

4.3 Cost Of Avoiding Fossil CO2 Emissions

Using the three scenarios defined in the previous sections, the cost of carbon dioxide sequestration was evaluated. The cost of greenhouse gas mitigation using renewable energy technologies depends on both the difference between the generation costs of the renewable energy option--i.e., in these cases, the generation of electricity or the production of methanol or ammonia--and the low-cost alternative (e.g., coal or natural gas fuel or feedstock for electricity generation or methanol/ammonia production). The mitigation costs are usually expressed in units of the cost per unit fossil carbon emissions that are avoided, offset, captured, sequestered, etc. In this section, the extra costs of the renewable power generation technologies are converted into terms of cost per unit fossil carbon emission avoided.

It is known that several "greenhouse gases" contribute to humanity's effect on the radiation balance in the atmosphere and, hence, on potential global temperature and climate effects. They include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and certain chloro-fluorocarbons (CFCs). (The CFCs have become most widely known for their chemical effects in the stratosphere, reacting with and depleting the ozone layer. They also absorb infrared radiation and affect global heat balance. This occurs much lower than the stratosphere, down in the main mass of the atmosphere, i.e., the troposphere.) The relevant impacts of the greenhouse gases on the radiation balance vary between the greenhouse gases. Table 32 presents numbers that show this (Hughes 2000).

Table 32

Greenhouse Warming Strengths of the Key Gases

<u>Gas</u>	Lifetime in the <u>Atmosphere</u>	<u>Infrared absorbing strength relative to CO₂</u>		
		<u>20-year</u>	<u>100-year</u>	<u>500-year</u>
Carbon dioxide (CO ₂)	variable	1	1	1
Methane (CH ₄)	12 years (+-3)	56	21	7
Nitrous oxide (N ₂ O)	120 years	280	310	170
Chlorofluorocarbons (CFC)	not given	4900	3800	not given

Source: U.S. Dept. of Energy EIA, "Emissions of Greenhouse Gases in the US: 1996" Oct.1997.

In Table 32, different timeframes, as well as the four different gases, are shown because the non-CO₂ gases gradually are converted into CO₂ over the years and will eventually be at the same strength as CO₂, but not until well beyond the timeframes of interest here. In order to assess emission controls

applied to different gases on a common basis for global warming purposes, the emissions of the different greenhouse gases are normalized to a common basis by expressing them as equivalent CO₂ emissions. On a mass basis, and for a 100-year timeframe, methane (CH₄) absorbs 21 times as much of the earth's outgoing infrared radiation as carbon dioxide (CO₂). Therefore, we say that the mass of the equivalent CO₂ emission is 21x the mass of the methane put into the landfill gas energy system. In this section of the report the costs of greenhouse gas reduction will be expressed and compared on the basis of dollars per metric ton (tonne) of elemental carbon (\$/tonne C), based on the absorbing strength when that carbon atom is in a CO₂ molecule--the "CO₂ equivalent." When methane is the fuel, the carbon atom is in a CH₄ molecule. Hence, the factor per unit of energy will be less than the 21x. Here we use a factor of only 7.64, which is 21 x (16/44). The 16/44 is because each molecule of methane has a mass of 16, molecular weight, and goes into one atom of carbon in a carbon dioxide molecule of weight 44.

In addition to depending on the type of gas whose emission is reduced or avoided, the analysis leading to cost per unit weight of fossil CO₂ emissions avoided must take into account the type of fuel, technology and emitted gas that would otherwise have been used to generate the electricity replaced by the renewable technology. The amount of fossil carbon emission avoided by using a renewable resource instead of a fossil fuel power generation technology depends on the fossil fuel type that is "avoided" and on the conversion technology that would have been used to make the power from that fossil fuel. Table 33 shows the fuel effect, based on the carbon intensity of the various fuels, as measured in units of weight of carbon per unit of energy content of the fuel.

Table 33

Fuel Effect on Fossil Carbon Intensity

<u>Name of Fuel</u>	<u>Heat Content - HHV</u>		<u>Carbon Content</u>		<u>Fossil Carbon Intensity</u>	
	<u>(Btu/lb)</u>	<u>(MJ/kg)</u>	<u>(lb-C/lb)</u>	<u>(kg-C/kg)</u>	<u>(lb-C/MBtu)</u>	<u>(kg-C/MJ)</u>
Coal	13,700	31.798	0.78	0.78	56.9	24.5
Oil	18,000	41.778	0.85	0.85	47.2	20.3
Natural gas	23,800	55.240	0.76	0.76	31.9	13.8
Wood (dry)	8,000	18.568	0.45	0.45	Zero*	Zero*

*Note: "Fossil" carbon intensity is the measure relevant to greenhouse gas, and by this measure wood from renewable growth of trees is zero in carbon intensity. If the carbon in the fuel is put straight into the same formula used for the fossil fuels, then the carbon intensity for the wood is 54.2 lb-C/MBtu or 23.4 kg-C/MJ.

Next, Table 34 shows the effect of conversion technology, and, therefore, combines the effects of carbon intensity in the fuel with the efficiency of converting the fuel to electricity. Table 34 gives the emissions of carbon dioxide (or carbon) from present and future fossil fuel technologies, both coal-based and natural-gas-based.. Efficient pulverized coal units emit about 0.95 tons CO₂ per MWh of electricity generation, which is 0.26 tons C per MWh. Advanced IGCC technology will reduce these CO₂ emissions factors by about 20%. Advanced natural gas-combined cycle plants with efficiencies as high as 54% will emit about 0.37 tons CO₂ (0.10 tons C) per MWh. Therefore, to convert the extra cost of the renewable electricity, given in \$/MWh, into units of \$/tonne-C for the greenhouse gas reduction achieved, the \$/MWh is simply divided by the tonne-C/MWh of the fuel-technology combination that is considered to be the fossil technology replaced by the renewable one.

Table 34
Technology Effect on Fossil Carbon Intensity

Fuel - <u>Technology (HHV eff.)</u>	English units:	Carbon	Heat	<u>Fossil Carbon Emission</u>	
		Content <u>(lb/MBtu)</u>	Rate <u>(Btu/kWh)</u>	CO ₂ <u>(ton/MWh)</u>	C <u>(ton/MWh)</u>
Coal -					
Typical existing (0.341)		56.9	10,000	1.04	0.28
Pulverized, 95% scrubbed (0.376)		56.9	9,087	0.95	0.26
Advanced, IGCC (0.467)		56.9	7,308	0.76	0.21
Natural gas -					
Existing steam plant (0.331)		31.9	10,300	0.60	0.16
Advanced, CC (0.538)		31.9	6,350	0.37	0.10
Advanced, CT (0.427)		31.9	8,000	0.47	0.13
Advanced, fuel cell (0.637)		31.9	5,361	0.31	0.09
SI units:					
		Carbon <u>(kg/GJ)</u>	Heat Rate <u>(kJ/kWh)</u>	CO ₂ <u>(tonne/MWh)</u>	C <u>(tonne/MWh)</u>
Coal -					
Typical existing (0.341)		24.52	10,550	0.95	0.26
Pulverized, 95% scrubbed (0.376)		24.52	9,587	0.86	0.24
Advanced, IGCC (0.467)		24.52	7,710	0.69	0.19
Natural gas -					
Existing steam plant (0.331)		13.74	10,867	0.55	0.15
Advanced, CC (0.538)		13.74	6,699	0.34	0.09
Advanced, CT (0.427)		13.74	8,440	0.43	0.12
Advanced, fuel cell (0.637)		13.74	5,656	0.29	0.08

Source: EIA 1998 ("EIA Kyoto"), Tables 16, 17 (pages 73-75), U.S. DOE, October 1998.

4.3.1 Converting Power Costs into CO2 Reduction Costs

The results of applying this procedure are shown in Table 35. Examples of how Table 35 was calculated for several cases follow, with special emphasis on two cases that are somewhat different from the rest: biomass cofiring, and landfill gas. In biomass cofiring the fossil alternative is not a new fossil power plant, but, instead, is simply the operation of the existing coal-fired plant on 100% coal, with no biomass displacing any of the coal. In landfill gas, which here refers to landfill gas power generation, the burning of the biomass-derived methane gas avoids the emission by the landfill of a greenhouse gas 21 times as powerful, per unit weight, as the carbon dioxide in infrared absorbing and warming strength. Taking this greenhouse strength into account makes the cost of avoiding the CO2 equivalent much lower, by the 7.64 factor derived above.

Table 35

Conversions of Power Costs into CO2 Reduction Costs

<u>Renewable Technology</u>	<u>Extra Cost (\$/MWh)</u>	<u>Carbon Intensity Displaced</u>		<u>Cost of CO2 Reduction</u>	
		<u>Coal (tonne-C/MWh)</u>	<u>Natural Gas (tonne- C/MWh)</u>	<u>Coal (\$/tonne-C)</u>	<u>Natural Gas (\$/tonne-C)</u>
Biomass cofiring (low cost end of range)	\$ (5.00)*	0.264	not applicable	\$ (18.97)*	not applicable
Biomass cofiring (high cost end of range)	\$18.00	0.264	not applicable	\$68.28	not applicable
Biomass gasification or other advanced biomass	\$10.00	0.264	0.090	\$37.93	\$111.11
Wind	\$10.00	0.264	0.090	\$37.93	\$111.11
Geothermal	\$7.00	0.264	0.090	\$26.55	\$77.78
Solar Thermal	\$47.00	0.264	0.090	\$178.28	\$522.22
Solar PV	\$14.00	0.264	0.090	\$53.10	\$155.56
Landfill gas***	\$5.00	2.013	0.687	\$2.48	\$7.28

***The landfill gas conversion factors are based on the 21x stronger greenhouse warming effect of CH4 vs. CO2, and also the factor of 16/44 to convert from a weight basis to a mole basis.

The above results are taken from the EPRI report “Greenhouse Gas Reduction with Renewables” published in December 2000 as EPRI No. TR-113785 (Hughes 2000). They are shown here to provide further comparisons to the biomass gasification technologies that are the subject of this report. Further results from that earlier report by EPRI are presented in the subsection immediately below.

4.3.2 Total Supply Curve for Renewables

Table 36 shows the “supply curve” adopted in the EPRI report on renewables for greenhouse gas reduction (Hughes 2000) for the U.S.

Notice that solar PV residential has a high-cost **retail** value as the price of the fossil alternative: **\$100/MWh**, not \$42/MWh. Central station solar has the \$42/MWh as the alternative fossil price to be subtracted to derive the extra cost of the renewable option.

Biomass cofiring has zero as the cost of the fossil alternative, not \$42/MWh. As explained earlier, this is because, with the alternative being to run the coal plant on 100% coal, the costs were taken to be only the increment above the costs to build and operate the coal plant and to buy the coal fuel: \$0.25/MBtu extra for the biomass fuel, and capital and labor costs that are only the addition above the baseline existing plant and operating staff, plus extra maintenance only for the biomass equipment added to the plant. Because of the need for rapid payback on plant modifications paid out of the plant's annual capital improvement budget, capital recovery on biomass cofiring is at 33% per year, not 21%, on the capital cost of the biomass modifications.

Table 36
Supply Curve For All Renewables

Energy Source, Technology, and Other	Capacity GW	Annual Gen. TWh/year	Capital Cost \$/MWh	O&M Cost \$/MWh	Fuel Cost \$/MWh	Total Cost \$/MW	Alternative Cost \$/MWh	Extra Cost \$/MWh	Carbon Cost \$/tonne-C	Cumulative Generation TWh/year	Cum Carbon Reduction Mtonne-C/yr	Cum. Extra Cost \$Billion/year
Geothermal, hot low cost	2	15.0	29.00	7.40	0.00	36.40	42.00	-5.60	-23.69	15	3.6	(0.1)
Wind Class +5	9	35.0	33.50	6.60	0.00	40.10	42.00	-1.90	-8.04	50	13.0	(0.3)
Landfill Gas, 2 MW	4	24.0	38.30	10.00	6.50	54.80	42.00	12.80	7.10**	74	58.6**	(0.0)
Biomass, existing generation	7	45.0	0.00	20.00	24.00	44.00	42.00	2.00	8.46	119	70.3	0.1
Animal Wastes, 300 kW	4	24.0	52.30	20.00	0.00	72.30	42.00	30.30	16.80**	143	113.5**	0.8
Biomass Cofiring, blended*	3	20.0	2.40*	1.00*	2.80*	6.20	0.00	6.20	26.23	163	118.2	0.9
Geothermal, hot average cost	3	22.0	33.84	15.00	0.00	48.84	42.00	6.84	28.94	185	123.4	1.0
Geothermal, warm low cost	10	74.0	42.00	12.00	0.00	54.00	42.00	12.00	51.00	259	140.8	1.8
Biomass, advanced technology	40	260.0	35.60	10.20	11.40	57.20	42.00	15.20	64.50	519	202.2	5.8
Wind Class 4	16	48.0	43.10	8.50	0.00	51.60	42.00	9.60	40.62	567	213.5	6.3
Solar PV, residential good	10	27.5	108.70	5.20	0.00	113.90	100.00	13.90	58.81	595	220.0	6.9
Biomass Cofiring, separate*	4	27.0	9.80*	2.70*	2.80*	15.20	0.00	15.20	64.50	622	226.3	7.3
Wind Class 3	24	52.0	60.30	11.90	0.00	72.20	42.00	30.20	127.77	674	238.5	8.7
Geothermal, warm average cost	20	149.0	56.40	20.00	0.00	76.40	42.00	34.40	145.54	823	273.6	13.8
Solar PV, central good	10	23.0	79.50	1.20	0.00	80.70	42.00	38.70	163.73	846	279.0	14.7
Solar PV, residential average	12	22.0	140.30	6.40	0.00	146.70	100.00	46.70	197.58	868	284.2	15.7
Solar Thermal, 25 MW	10	27.0	79.20	10.20	0.00	89.40	42.00	47.40	200.54	895	290.6	17.0
Solar PV, central average	22	40.0	100.70	1.50	0.00	102.20	42.00	60.20	254.69	935	300.0	18.6

TOTALS 210 GWe 934.5 TWh Cost of last increment = \$254.69/tonne C Average cost = \$62.00/tonne C

* Biomass cofiring costs are incremental, i.e., costs above normal coal-fired operation, so fuel at \$0.25/MBtu is \$1.50/MBtu when coal is \$1.25. Capital is only the add-on to handle and fire the biomass, and O&M also is only the increment. Also, fast payback in these cases: 33% annual capital recovery rate, not just 21%.

**Animal wastes and landfill gas technologies eliminate a methane (CH₄) emission and therefore have a conversion to cost per tonne-C in CO₂ equivalents that is less by factor of (1/21) x (44/16), due to CH₄ being a stronger absorber of heat by 21x per unit weight. And, also, the CO₂-equivalent tonne-C/year of carbon reduction for the two technologies is a factor of 21 x (16/44) = 7.64 greater.

4.3.3 Sensitivity of Results

The costs of carbon reduction in Table 36 are derived from differences between the estimated future costs of the renewable technologies and the costs adopted for the fossil alternatives. The extra cost in \$/MWh are the same versus both fossil alternatives, because values for the cost of electricity from new, not existing, coal- and gas-fired power plants were selected to be the same, namely \$42/MWh. As discussed in the section above, the conversion from extra \$/MWh to cost in \$/tonne-C of fossil carbon emission avoided depends on the carbon intensity in tonne-C/MWh of the fossil power system whose emission is avoided. The carbon costs in \$/tonne-C in Table 36 are based on the coal case, which is 0.236 tonne-C/MWh. If natural gas in an efficient advanced combined cycle is the fossil option avoided, then the factor is 0.09 tonne-C/MWh, and the resulting carbon avoidance cost is higher by a factor of $0.236/0.09$, or 2.62. (The last three columns in Table 37 at the very end of this section show examples of extra cost in \$/MWh being converted to \$/tonne-C for both coal and natural gas as the advanced fossil power plant carbon emission avoided.)

Both the coal and the gas alternatives are estimated at essentially the same cost of 4.2¢/ kWh which is also \$42/MWh. A 15%, or 0.6¢/kWh, change in that 4.2¢/kWh cost will change the carbon reduction cost by \$6/MWh which converts to \$6 per 0.95 tonne of CO₂ or $(12/44) \times 0.95 = 0.26$ tonne of C, i.e., \$23/tonne-C. This uncertainty of \$23/tonne-C is equal to the total carbon reduction cost values near the low-cost end, and is in the range of 7% to 10% of the values at the high end of the carbon costs estimated in Table 36.

Of course, there is a similar uncertainty associated with the estimates of the costs of the renewable technologies themselves. The uncertainty of these will range from 15% of 4¢/kWh, i.e., 0.6¢/kWh or \$6/MWh, to values as large as 30% of high costs like 10¢ to 20¢/kWh at the high-cost, high-uncertainty end (i.e., 30% of costs as high as \$100/MWh to \$200/MWh). These translate into uncertainties in carbon reduction costs as large a proportion as $\pm 100\%$ of the cost at the low end of \$20/tonne-C, to values on the order of $\pm 30\%$ of some \$200 to \$500/tonne-C at the high-cost, high-uncertainty end.

4.3.3.1 Some Specific Sensitivities

Economic Parameters. The one dominant economic parameter is set the same for all the technologies, except for cofiring. This is the 21% “fixed charge rate,” or annual capital recovery factor, used in all except biomass cofiring. As explained in Section 4 and above, for cofiring this is set at a rate of 33%, because cofiring must compete with other near-term capital expenditures for improvements at existing coal-fired plants.

As also pointed out earlier, in all the above cases solar PV has been given the advantage of a \$100/MWh, which is 10¢/kWh, alternative price. Because the other

renewables are shown as competing against a \$42/MWh fossil alternative, this is nearly a \$60/MWh, or \$150/tonne-C, effect in favor of PV residential. However, the advantage is real, at least during the near- to mid-term while solar PV enters residential, commercial and remote location markets rather than bulk power markets. It reflects the actual and substantial retail versus wholesale generation price differential, and it reflects the fact that the best openings for solar PV will be where the sunlight itself is the distribution system and beats the cost of putting in the wires or bringing in high-cost diesel fuel.

Fuel Costs for Geothermal and Biomass. Biomass is the only renewable technology that pays for fuel as an ongoing operating cost. In some analyses, but not as done here, geothermal has a “fuel” input in the form of hot water flowing into the power plant. However, in this report and in the Technology Characterizations report (Hughes 2000), the cost to obtain this “geothermal fuel” is taken to be a capital expense, not a fuel cost. (The capital is spent to drill and complete the wells, and to buy and install the pipelines/pumps/etc. that bring hot water to the power plant and take the cooler water back from the plant into the injection wells, which inject it back into a cool part of the underground reservoir.) Therefore, for geothermal as done here, the non-capital costs are operating costs, not fuel costs. And, being for the most part fixed costs for payroll and maintenance, these operating costs are unlike fuel costs in that they are not tied closely to the plant heat rate nor to variations in the “fuel” flow rate, the rate of geothermal fluid flow to and from the plant.

Biomass. For biomass, fuel cost is very important in the economics. The fuel cost used for “advanced biomass” merits special comment, because energy crops are the fuel assumed when a potential capacity of 40 GWe is named in Table 36. Fuel cost of \$1.50/MBtu is the basis for the “advanced biomass” case, together with a high efficiency, i.e., the low heat rate of 7600 Btu/kWh, which corresponds to a higher heating value (HHV) efficiency of 45%. The \$1.50/MBtu is low compared to current estimates for energy crop costs when “dedicated biomass feedstock supply systems” are studied. A 1998 paper from the Oak Ridge National Laboratory (ORNL) on the price necessary to displace conventional farm crops gave \$2.50/MBtu and \$3.50/MBtu as the prices needed to bring millions of acres into energy crop production (Walsh 1998). The much lower price of \$1.50/MBtu is justified here for two reasons:

1. The energy crop could be the coproduct of a pulp/fiber farm, where a high-value fiber product is 70 to 80% of the mass grown and harvested and pays nearly all of the planting, cultivating and harvesting cost.
2. The fuel has a much lower cost of harvesting than that used in ORNL analysis (about \$5/dry ton, versus the \$20/dry ton apparently used in Walsh 1998).

These two measures to reduce costs are capable of reducing the total cost of energy crop fuel by \$1.00 to \$2.00/MBtu, having the effect of reducing a \$3 to \$4 per million Btu cost down to the \$1 to \$2 per million Btu range. These ways to reduce energy crop costs are discussed in a 1995 EPRI paper and a 1998 EPRI report (Hughes & Wiltsee 1995, Wiltsee 1998). The harvesting improvement is addressed in the first EPRI Whole Tree Energy report (EPRI 1993) and also in studies on energy from willows by Niagara Mohawk, DOE and EPRI (Wiltsee 1998, Niagara Mohawk & SUNY 1995).

The “existing biomass” category in the supply curve in Table 36 also uses a \$1.50/MBtu fuel cost, as does the separate feed biomass cofiring line. This \$1.50 is at the midpoint of a wide range of possible biomass fuel costs. Today, the wood-derived biomass that is the fuel for existing biomass power plants, and for most cofiring operations at coal-fired plants in the near-term future, comes at costs ranging from \$0.50/MBtu to \$2.50/MBtu. On a dry-weight basis the price range for biomass fuels both for today and for studies of future options is from a low of \$8 to a high of \$40, per dry ton. (Since normal green wood freshly cut is about 50% moisture, this range in dry weight costs is a range from \$4 to \$20 per “as-received” ton, at this 50% moisture value.) The low end, at \$0.50/MBtu, is enough to pay typical transportation costs to move the fuel some 30 to 70 miles (50 to 110 km) from source to power plant. Given such a large range in possible biomass fuel costs, the resulting range in carbon reduction costs is very large. Table 37 shows this. The range of biomass power plant efficiencies is also taken into account in Table 37. The low efficiency end of this range is that seen in some of today's high-heat-rate plants at 16,000 Btu/kWh (16.9 MJ/kWh, and 21% efficiency on a higher heating value, HHV, basis) to future advanced plants such as biomass gasification (IGCC) at 7500 Btu/kWh (7.9 MJ/kWh and 46% efficiency on an HHV basis).

Table 37**Sensitivity to Biomass Fuel Cost and Conversion Efficiency**

Case Identification (Fuel Cost, Heat Rate)	Biomass Fuel Cost (basis: 8300 Btu/lb. dry)		Heat Rate (Btu/kWh)	Result:	Result: Carbon Cost	
	\$/dry ton	\$/MBtu		Fuel	(\$/tonne-C)**	
				Cost	Coal at 0.236	Nat. gas at 0.09
				(\$/MWh)	tonne-C/MWh	tonne-C/MWh
Low cost, HR = 7,500	\$8.30	\$0.50	7,500	\$3.75	\$15.89	\$41.67
Low cost, HR = 10,000	\$8.30	\$0.50	10,000	\$5.00	\$21.19	\$55.56
Low cost, HR = 16,000	\$8.30	\$0.50	16,000	\$8.00	\$33.90	\$88.89
Mid-range, HR = 7,500	\$24.90	\$1.50	7,500	\$11.25	\$47.67	\$125.00
Mid-range, HR = 10,000	\$24.90	\$1.50	10,000	\$15.00	\$63.56	\$166.67
Mid-range, HR = 16,000	\$24.90	\$1.50	16,000	\$24.00	\$101.69	\$266.67
High cost, HR = 7,500	\$41.50	\$2.50	7,500	\$18.75	\$79.45	\$208.33
High cost, HR = 10,000	\$41.50	\$2.50	10,000	\$25.00	\$105.93	\$277.78
High cost, HR = 16,000	\$41.50	\$2.50	16,000	\$40.00	\$169.49	\$444.44

**Coal case is advanced pulverized coal plant with scrubber at a heat rate of 9087 Btu/kWh. Natural gas is an advanced combined cycle at a heat rate of 6350 Btu/kWh. These efficiencies are (HHV basis) 37.6% for the coal, and 53.7% for the natural gas. Emission factors are 519 lb-C/MWh or 0.236 tonne-C/MWh for the coal, and 201 lb-C/MWh or 0.09 tonne-C/MWh for the natural gas. Values from EIA Kyoto report (EIA 1998), pages 73 and 75.

4.3.4 Methodology in this Report for Biomass Gasification Technologies

The same approach as above was employed for the current report on biomass gasification as a CO₂ reduction measure. Details of the calculations are shown in Table 38.

Table 38

Electricity: CO2 Control Costs and Comparison of Technologies

<u>Issue/Item</u>	<u>Units</u>	<u>GTI</u> <u>Renu HP</u>	<u>Battelle</u> <u>FERCO</u>	<u>GTI</u> <u>Renu LP</u>
Efficiency				
Fuel input (mass, wet basis)	ton/24-hr-day	1002	1049	1189
Fuel moisture (wet basis)	%	50%	50%	50%
Heat content (HHV, dry)	Btu/lb	8472	8722	8472
Heat content (LHV, dry)	Btu/lb	7746	7996	7746
Fuel input (energy HHV)	Mbtu/hr	353.7	381.2	419.7
Fuel input (energy LHV)	Mbtu/hr	323.4	349.5	383.7
Net power output	MWe	42.05	36.05	41.86
Heat rate (HHV)	Btu/kWh	8,412	10,575	10,027
Efficiency (HHV basis)	%	40.6%	32.3%	34.0%
Efficiency (LHV basis)	%	44.4%	35.2%	37.2%
Carbon: fossil CO2				
Coal: C per unit energy	lb/Mbtu	57.1	57.1	57.1
Replace coal of 10,000 HR	tonCO2 / MWh	1.046	1.046	1.046
Coal in metric C (not CO2)	tonneC / MWh	0.259	0.259	0.259
Coal: C per unit energy	lb/Mbtu	57.1	57.1	57.1
Replace coal of 9087 HR	tonCO2 / MWh	0.951	0.951	0.951
Coal in metric C (not CO2)	tonneC / MWh	0.236	0.236	0.236
NG: C per unit energy	lb/Mbtu	31.7	31.7	31.7
Replace NG of 6,350 HR	tonCO2 / MWh	0.369	0.387	0.387
NG in metric C (not CO2)	tonneC / MWh	0.091	0.096	0.096
Capital cost				
Electricity capital req.	\$000	47,000	48,873	47,628
Electricity, cap. req. per kW	\$/kW	1,118	1,300	1,138
Electricity (per input biomass)	\$/ (ton/day)	\$46,906	\$46,590	\$40,057
Cost per tonne C				
Coal PC Coal conventional: \$/MWh	\$/MWh	\$42.00	\$42.00	\$42.00
Biomass option \$/MWh	\$/MWh	\$65.55	\$76.36	\$66.38
Extra \$/MWh vs coal	\$/MWh	\$23.55	\$34.36	\$24.38
C avoided vs coal conv	tonneC / MWh	0.259	0.259	0.259
Cost in \$/tonne C conv	\$ / tonneC	\$77.08	\$115.63	\$154.17
Coal adv.PC Coal advanced: \$/MWhr	\$/MWh	\$42.00	\$42.00	\$42.00
Biomass option \$/MWh	\$/MWh	\$65.55	\$76.36	\$66.38
Extra \$/MWh vs coal	\$/MWh	\$23.55	\$34.36	\$24.38
C avoided vs coal advncd	tonneC / MWh	0.236	0.236	0.236
Cost in \$/tonne C advncd	\$ / tonneC	\$93.31	\$135.73	\$178.14
NGCC adv.NG: \$/MWh	\$/MWh	\$42.00	\$42.00	\$42.00
Biomass option \$/MWh	\$/MWh	\$65.55	\$76.36	\$66.38
Extra \$/MWh vs NG	\$/MWh	\$23.55	\$34.36	\$24.38
C avoided vs NG	tonneC / MWh	0.091	0.091	0.091
Cost in \$/tonne C	\$ / tonneC	\$218.81	\$312.61	\$416.82

Table 38 (cont.)**Electricity: CO₂ Control Costs and Comparison of Technologies**

Plant characteristics:	Technology ==>	<u>Renu HP</u>	<u>FERCO</u>	<u>Renu LP</u>
Net power out, MWe	MWe	42.05	36.05	41.86
Annual gen, MWh/yr	MWh/yr	280,000	240,006	278,687
Capacity factor		0.760	0.760	0.760
Hours/year, hrs	Hours	6659	6658	6658
Total capital requirmt, \$000	\$000	47,000	48,873	47,628
Capital cost, \$/kW	\$/kW	1,118	1,300	1,138
HHV efficiency		40.6%	32.3%	34.0%
HHV heat rate	Btu/kWh	8412	10575	10027

Table 38 shows the cost and performance numbers that characterize the three biomass gasification technologies covered in detail in this report. The table steps through the calculation that converts \$/MWh of the biomass-based electricity into \$/MWh “extra”—meaning above the \$42/MWh adopted as the fossil-fuel-based alternative from new, not existing, coal-fired PC and advanced natural gas combined cycle (NGCC) power plants. Note that the \$42/MWh applies to the NGCC when demand for more natural gas -- to fuel 100 to 200 GWe or more of new power plants in the US -- has caused the price to be \$4.00/MMBtu instead of the \$2.50/MMBtu natural gas prices of most recent years. The \$ values are in 2001\$ but are intended to reflect future costs – the future costs still expressed as they would be in today’s dollars. The relevant concern here is with technologies that would be the commercial options some five to fifteen years in the future. The R&D and initial deployments have begun, and they will continue over the next five years.

Table 39 presents the technology “goal” cases that were used in Table 38. These goal cases have greatly reduced capital costs—on the order of \$1100/kWe rather than the “current” values derived in the detailed analysis of the tables presented prior to this section. The goal values of Table 38 were adopted to be consistent with the method described here and adopted in the “greenhouse gas report” EPRI TR-113785 (Hughes 2000). The lower portion of Table 39 shows the “current” cases, so that the reader can see how the “goal” cases differ. In general the goal cases are more “optimistic”—i.e., lower cost. However, there are two exceptions to this:

1. Biomass fuel costs are set at \$1.50/MMBtu, up from the \$0.66/MMBtu of the “current” cases. This is to allow for the use of larger amounts of more expensive residue fuels and also some energy crop fuels.

2. The “goal” capacity factor is set at 0.76 rather than 0.904. This is to be more consistent with capacity factors used in the earlier study, the “greenhouse gas report” (Hughes 2000).

The costs per metric ton (\$/tonne-C) in Tables 38 and 39 are unacceptably high to show biomass gasification as among the lower cost, rather than higher cost, fossil carbon reduction options. More ambitious R&D goals are probably needed. Better efficiency, lower cost fuel, and lower O&M costs are more likely to be achieved than are capital costs below the \$1100/kWe goal.

Table 39

Goal Costs Adopted for the CO₂ Cost Analysis (Electricity)

	<u>"Goal" Cost Cases</u>			<u>"Goal" Cost Cases</u>		
	Renu HP	FERCO	Renu LP	Renu HP	FERCO	Renu LP
	<u>High Capac. Factor (90.4%)</u>			<u>"Low" Capac. Factor (76.0%)</u>		
Cap. Req.						
\$000	47,000	46,873	47,628	47,000	46,873	47,628
\$/kW	1,118	1,300	1,138	1,118	1,300	1,138
MWe	42.05	36.05	41.86	42.05	36.05	41.86
MWh	333,000	285,500	331,500	280,000	240,006	278,687
cap.fctr.	0.904	0.904	0.904	0.760	0.760	0.760
hours/yr	7919	7919	7919	6659	6658	6658
	<u>An.Oper.Cost</u>			<u>An.Oper.Cost</u>		
	High P	Atm.	Atm.	High P	Atm.	Atm.
	<u>Renu HP</u>	<u>FERCO</u>	<u>Renu LP</u>	<u>Renu HP</u>	<u>FERCO</u>	<u>Renu LP</u>
Fuel: \$1.50/ MMBtu	4,202	4,202	4,202	4,202	4,202	4,202
BFW	77	77	77	77	77	77
CW		0	0		0	0
Ash	19	19	19	19	19	19
30@70	2,100	2,100	2,100	2,100	2,100	2,100
4@70	280	280	280	280	280	280
3%	1,410	1,406	1,429	1,410	1,406	1,429
Ins./Tax.	800	800	800	800	800	800
Royal.	67	67	67	67	67	67
Other	0	0	0	0	0	0
Total of fuel+O&M	8,955	8,951	8,974	8,955	8,951	8,974
20% Capital	<u>9,400</u>	<u>9,375</u>	<u>9,526</u>	<u>9,400</u>	<u>9,375</u>	<u>9,526</u>
Tot. \$000	18,355	18,326	18,500	18,355	18,326	18,500
\$/MWh	55.12	64.19	55.81	65.55	76.36	66.38

Table 39 (cont.)

Goal Costs Adopted for the CO₂ Cost Analysis (Electricity)

<u>"Current" Cases</u> for Comparison:	<u>"Current" Cost Cases</u>			<u>"Current" Cost Cases</u>		
	Renu HP	FERCO	Renu LP	Renu HP	FERCO	Renu LP
	<u>High Capac. Factor (90.4%)</u>			<u>"Low" Capac. Factor (76.0%)</u>		
Cap. Req.						
\$000	102,301	102,025	103,667	102,301	102,025	103,667
\$/kW	2,433	2,830	2,477	2,433	2,830	2,477
MWe	42.05	36.05	41.86	42.05	36.05	41.86
MWh	333,036	285,516	331,531	280,000	240,006	278,687
cap.fctr.	0.904	0.904	0.904	0.760	0.760	0.760
\$/kW	2,433	2,830	2,477	2,433	2,830	2,477
MWe net output	42.05	36.05	41.86	42.05	36.05	41.86
	<u>Annual Costs, \$K (2001)</u>			<u>Annual Costs, \$K (2001)</u>		
Technology ==>	<u>Renu HP</u>	<u>FERCO</u>	<u>Renu LP</u>	<u>Renu HP</u>	<u>FERCO</u>	<u>Renu LP</u>
Wood delivered, \$0.66/million						
Btu, 8472 Btu/lb (dry)	1,849	1,936	2,194	1,849	1,936	2,194
BFW	77	73	21	77	73	21
Cooling Water	0	0	0	0	0	0
Ash disposal	19	326	22	19	326	22
Operating Labor	300	300	300	300	300	300
Supervision and Clerical	75	75	75	75	75	75
Maintenance Costs	2,691	2,682	2,725	2,691	2,682	2,725
Insur. and Local Taxes	1,345	1,341	1,363	1,345	1,341	1,363
Royalties	67	57	66	67	57	66
Other Operating Costs	0	0	0	0	0	0
Total Fuel + O&M	6,423	6,790	6,767	6,423	6,790	6,767
Capital at 20%/yr	<u>20,460</u>	<u>20,405</u>	<u>20,733</u>	<u>20,460</u>	<u>20,405</u>	<u>20,733</u>
Total	26,883	27,194	27,500	26,883	27,194	27,500
\$/MWh	80.72	95.25	82.95	96.01	113.31	98.68

4.3.5 Capital Cost Breakdown and Cost of Gas Cleanup

The cleanup or “conditioning” of the raw gas out of the gasifier is a critical part of the complete gasification system. For high-efficiency power and high-value fuels/chemicals, this cleanup step must achieve rather high purity as well as efficient use of energy. To investigate the cost of gas cleanup as a fraction of the total cost of building the biomass gasification system, Table 40 was prepared. The table is based on a proprietary cost analysis of a large pilot plant for gasification only – i.e., no gas turbine, no steam turbine and no generator and electricity export systems. If the plant had the turbines and boiler (HRSG), power generation, electrical substation, etc. added it would be a 15 MWe (net) system, assuming a 9000 Btu/kWh (net) heat rate. This gasification-only system, including feeding, drying, gasification, gas cleanup and ash handling, was estimated to cost \$577/kW, or \$8.6 million, in 2001 dollars. If the HRSG, turbines, etc. could be added at the cost of a pure natural gas (not biomass) combined cycle power plant at \$700/kW, this would be a \$1277/kW biomass gasification combined cycle (BGCC). At only about \$1300/kW at such a small size it would represent the achievement of the capital cost goal for biomass gasification power. This point is addressed further below.

On cost breakdown and the capital cost contribution of the gas cleanup system, Table 40 shows details that sum to 61.7 \$/kW for the gas cleanup, out of a total of 388/kW for the gasification system subtotal, before civil/structural, electrical and instruments/controls are included. After including such necessary scope, and distributing those items as shown in Table 40, the total is 91.7 out of the 577 \$/kW. Note that Table 40 assigns the ash handling system to the gasification proper, and does not include it in the gas cleanup. These results put the cost of gas cleanup as about 1/7 of the cost of the total biomass gasification “add-on” to make a simple natural gas combined power plant a biomass gasification CC instead.

Table 40

Cost Breakdown of Feeding, Drying, Gasification and Gas-Cleanup (Year 2001 \$)

<u>Component or Subsystem</u>	<u>\$M*</u>	<u>\$/kW</u>	<u>feed</u> <u>\$/kW</u>	<u>dryer</u> <u>\$/kW</u>	<u>gasif.</u> <u>\$/kW</u>	<u>clean</u> <u>\$/kW</u>	<u>total</u> <u>\$/kW</u>
Solid fuel input handling	0.25	14.6	14.6				14.6
Sludge input handling	0.21		[sludge dropped from scope]				0.0
Dryer output handling	0.36	21.0	21.0				21.0
Dryer and drying system	1.91	111.5		111.5			111.5
Flue gas duct from boiler, Plus air comp.,water, etc.	0.58	33.8	13.5	20.3			33.8
Misc. & undefined (10%)	<u>0.33</u>	<u>18.1</u>	<u>4.9</u>	<u>13.2</u>	<u>0.0</u>	<u>0.0</u>	<u>18.1</u>
Total for Biomass Fuel Handling (including drying 50% moisture to 20%)	3.64	199.0	54.1	145.0	0.0	0.0	199.0
Gasifier feed system	0.68	39.7			39.7		39.7
Gasifier and bed drain	0.29	16.9			16.9		16.9
Piping and insulation, including steam piping	0.12	7.0			7.0		7.0
Misc. & undefined (20%)	<u>0.22</u>	<u>12.8</u>			<u>12.8</u>		<u>12.8</u>
Total for Gasifier and Bed Drain	1.31	76.4			76.4		76.4

Table 40 (cont.)

Cost Breakdown of Feeding, Drying, Gasification and Gas-Cleanup (Year 2001 \$)

<u>Component or Subsystem</u>	<u>\$M*</u>	<u>\$/kW</u>	<u>feed</u>	<u>dryer</u>	<u>gasif.</u>	<u>clean</u>	<u>total</u>
			<u>\$/kW</u>	<u>\$/kW</u>	<u>\$/kW</u>	<u>\$/kW</u>	<u>\$/kW</u>
Cyclone (hot)	0.09	5.3				5.3	5.3
Heat out to steam/air (i.e., gas cooling)	0.30	17.4				17.4	17.4
Filter for cooled gas	0.29	16.9				16.9	16.9
Flare (50 ft high)	0.08	4.7			4.7		4.7
Major piping	0.26	15.2			6.1	9.1	15.2
Other pipe and insulation	<u>0.08</u>	<u>4.7</u>			<u>1.9</u>	<u>2.8</u>	<u>4.7</u>
Sub Total for Gas Handling	1.10	64.1			12.7	51.4	64.1
Ash handling	0.51	29.8			29.8		29.8
Burner/Boiler Mods	0.16		[burnr/boilr mods dropped from scope]				
Misc. & undefined (20%)	0.35	18.8			8.5	10.3	18.8
Total for Gas and Ash Handling	2.12	112.6			51.0	61.7	112.7
Sum: Feed, Dry, Gasify, Cleanup Gas and Handle Ash (basic equip- ment installation, without civil- structural, I&C and electrical)	388.0		54.1	145.0	127.4	61.7	388.2
Civil - Structural	0.85	49.6	6.9	18.5	16.3	7.9	49.6
Building (8400 ft2)	0.78	45.5	6.3	17.0	14.9	7.2	45.5
Misc. & undefined (10%)	0.16	9.3	1.3	3.5	3.1	1.5	9.3
Total for Civil/Struct./Building	1.79	104.5	14.5	39.0	34.3	16.6	104.5

Table 40 (cont.)

Cost Breakdown of Feeding, Drying, Gasification and Gas-Cleanup (Year 2001 \$)

<u>Component or Subsystem</u>	<u>\$M*</u>	<u>\$/kW</u>	<u>feed</u> <u>\$/kW</u>	<u>dryer</u> <u>\$/kW</u>	<u>gasif.</u> <u>\$/kW</u>	<u>clean</u> <u>\$/kW</u>	<u>total</u> <u>\$/kW</u>
Grounding, lighting and conduit	0.47	27.6	3.8	10.3	9.1	4.4	27.6
Power cables and terminations	0.03	1.6	0.2	0.6	0.5	0.3	1.6
Control cable and terminations	0.01	0.8	0.1	0.3	0.2	0.1	0.8
Instrument cable and terminations	0.02	0.9	0.1	0.3	0.3	0.1	0.9
Switch gear and transformer	0.08	4.7	0.7	1.7	1.5	0.7	4.7
Motor control center, plus local control stations	<u>0.09</u>	<u>5.3</u>	<u>0.7</u>	<u>2.0</u>	<u>1.7</u>	<u>0.8</u>	<u>5.3</u>
Sub Total - Electrical	0.70	40.8	5.7	15.2	13.4	6.5	40.8
Instruments and controls	0.67	39.1	5.4	14.6	12.8	6.2	39.1
Adjustment/correction	-0.06	-3.5	-0.5	-1.3	-1.1	-0.6	-3.5
Misc. & undefined (10%)	0.13	7.6	1.1	2.8	2.5	1.2	7.6
Total for Electrical + Inst./Controls	1.44	84.0	11.7	31.4	27.6	13.4	84.0
 Total for Entire Plant (2001\$)	 10.31*	 576.5	 80.3	 215.4	 189.3	 91.7	 576.6

* Note: The \$M column is for a 1.56 inflation adjustment from 1987. The other numbers are based on 1.35 and are \$/kWe (net), assuming a 9000 Btu/kWh (net) heat rate. Also, note that this "entire plant" is biomass gasification and clean-up, alone, with no generation of electricity. It is just the biomass gasification system that would have to be built in addition to a conventional natural gas combined cycle to make a complete power plant at the 9000 Btu/kWh heat rate.

4.3.6 Capital Cost Goal

The cost goal shown in the DOE-EPRI “RETC” report (NREL & EPRI 1997) was approximately \$1100/kW at 100-MW unit size. Table 42 displays costs at various unit sizes based on the \$1277/kW at the small size (15 MW) and scaling these costs with a 0.8 power law to 42, 50 and 100 MW sizes. At 100 MW the figure is \$870/kW, approximately 20% below the \$1100 cost goal of RETC (NREL & EPRI 1997).

Table 41 shows that a pilot plant of 15-MWe equivalent size that can be built for only \$8.6 million may be the equivalent of achieving a cost goal of only \$870/kWe (net) for a 100-MWe full power plant. On the 100-MWe plant the feeding/drying/gasification/gas-cleanup/ash-handling aspects of the plant would have to come to only \$329/kW, leaving \$541/kW as the cost of the basic gas-fired combined cycle power plant. Achieving such a goal would make a significant improvement in the cost of avoiding a tonne-C of fossil carbon emission. This is the cost goal that should be pursued in biomass gasification IGCC R&D.

Table 41

Scaling for Size

<u>Description</u>			
<u>Gasification-only Pilot Plant:</u>	<u>\$M</u>	<u>Size (MW)</u>	<u>\$/kW</u>
15-MWe size equivalent	8.6	14.73	576.6
Power law for scaling	0.7		
42-MWe size equivalent	17.9	42	426
50-MWe size equivalent	20.2	50	405
100-MWe size equivalent	32.9	100	329
<u>Whole BGCC Power Plant:</u>			
15-MWe size equivalent	18.8	14.73	1276.3
Power law for scaling	0.8		
42-MWe size equivalent	43.5	42	1035
50-MWe size equivalent	50.0	50	1000
100-MWe size equivalent	87.0	100	870

5.0 CONCLUSIONS

The costs of CO₂ avoidance or “sequestration” from the technologies described in this report are generally too high to justify the goals adopted in the calculations in Section 4.3. That section gives values for the three scenarios (or three biomass gasification technology options) as shown in Table 42 below.

Table 42

Summary of CO₂ Control Costs

Biomass Gasification Technology	CO₂ Control Cost Comparison (\$/tonne C)		
	Conventional Coal	Advanced Coal	Natural Gas Combined Cycle
GTI Renugas HP	\$77.08	\$93.31	\$218.81
Battelle FERCO	\$115.63	\$135.73	\$312.61
GTI Renugas LP	\$154.17	\$178.14	\$416.82

The renewable biomass source replacing a fossil fuel source is the equivalent of sequestration technology applied to a fossil fuel source. Rather than add cost to the fossil generation technology to perform operations to concentrate CO₂, capture that CO₂ and then transport and sequester it, the renewable biomass technologies simply generate the electricity from biomass whose carbon came from the atmosphere in the recent past and, thereby, avoid the addition of any new fossil carbon as CO₂ injected into the atmosphere. In effect, this method keeps the carbon in the ground in its “already sequestered” form, as coal, petroleum or natural gas.

Because the cost of this approach to sequestration depends on what fossil fuel source is avoided and on the efficiency and cost of the fossil fuel power generation technology that is avoided, the calculated sequestration costs in \$/tonne-C vary greatly even if the cost of applying the renewable electricity were to be fixed, i.e., held as a constant all at the same value.

Low cost carbon sequestration values are usually in the \$10 to \$30 per tonne of fossil carbon sequestered. Tables 38 and 39 are unacceptably high cost compared to such low cost carbon sequestration cases. In order to show biomass gasification as among the lower cost, rather than higher cost, fossil carbon sequestration options, more ambitious R&D goals are necessary. These more ambitious goals would involve one or more or a combination of items such as better efficiency, lower cost fuel, lower O&M costs, and lower capital cost. The lower capital costs may be especially difficult to obtain, as the goals adopted in Section 4.3 are already rather ambitious.

These ambitious goals are as follows: (1) a natural gas combined cycle at \$700/kW as applied at 100-MWe unit size as the power conversion option downstream of a biomass gasification system; (2) only \$300/kWe to construct the system that performs biomass gasification, gas cleanup and ash/char removal from the gasifier, and then sends clean gaseous fuel to the combined cycle power unit; and, (3) only \$100/kW for a system to receive, handle and feed solid biomass fuel (or “feedstock”) into the gasification/cleanup unit. It is possible that better efficiency, lower fuel cost and lower O&M costs are more likely to be achieved than are capital costs below the \$1100/kWe goal. A combination of all, plus added revenues from other bio-based products or environmental benefit revenues (such as waste disposal and water quality improvements) are also likely to be required in a system that becomes a low cost carbon sequestration option.

6.0 References

Anderl, Helmut; Mory, Andreas; and Zotter, Thomas (1999): BioCoComb Gasification of Biomass and Co-Combustion of the Gas in a Pulverized-Coal-Boiler. Proceedings of the 15th International Conference on Fluidized Bed Combustion, May 16-19, 1999. Savannah, Georgia.

Appel Consultants (November 1998) "Advanced Biomass Technology Characteristics, Status, and Lessons Learned," Report to EPRI by Appel Consultants, EPRI TR-111882.

Bain, Richard L.; Craig, Kevin C.; and Overend, Ralph P. (1997): Biomass Gasification - Commercialization and Development: The Combined Heat and Power (CHP) Option. Presented at the American Society of Mechanical Engineers. June 1997. Orlando, Florida.

Beenackers, A. A. C. M.; Maniatis, K. (1997): Gasification Technologies for Heat and Power from Biomass. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 24-51.

Blackadder, William H.; Lundberg, Henrik; Rensfelt, Erik; and Waldheim, Lars (1993): Heat and Power Production via Gasification in the Range of 5-50 MWe. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Glasgow, 449-475.

Czernik, S.; Koeberle, P. G.; Jollexz, P.; Bilodeau, J. F.; and Chornet, E. (1993): Gasification of Residual Biomass via the Biosyn Fluidized Bed Technology. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Glasgow, 423-437.

Cleland, J.; Purvis, C. R. (1997): Demonstration of a 1 MWe Biomass Power Plant at USMC Base Camp Lejeune. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 551-558.

Craig, Kevin R. and Mann, Margaret K, (1996), Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems. National Renewable

EIA (1996). "Greenhouse Gas Emissions in the United States 1995." Energy Information Administration (EIA), U.S. Department of Energy, October 1996.

EIA (1997). "Greenhouse Gas Emissions in the United States 1996," Energy Information Administration (EIA), U.S. Department of Energy, DOE/EIA-0573(96), October 1997.

EIA (1997a). "Greenhouse Gas Emissions in the United States 1995," Energy Information Administration, U.S. Department of Energy, August 1997.

EIA (1998), "Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity," Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC 20585. Report SR/OIAF/98-03, Distribution Category UC-950, October 1998.

EIA (1999). U.S. Dept. of Energy, Energy Information Administration, "Voluntary Reporting of Greenhouse Gases 1998." DOE/EIA-0608(98), December 1999.

Engström, Folke (1999): Overview of Power Generation from Biomass. Paper presented at 1999 Gasification Technologies Conference, San Francisco, CA. Oct. 19-20, 1999.

EPRI (1993a). "Strategic Analysis of Biomass and Waste Fuels for Electric Power Generation," EPRI Report TR-102773, December 1993.

EPRI (1993a). "Whole Tree Energy™ Design, Volume 1: Engineering and Economic Assessment." Final Report to EPRI by Research Triangle Institute, published as EPRI Report TR-101564 (Vol.2 Field Test Program, and Vol.3 Design for 100 MWe), Dec.1993.

EPRI (1993b). "Strategic Analysis of Biomass and Waste Fuels for Electric Power Generation," EPRI Report, TR-102773, December, 1993.

EPRI (1993c). "TAG™ - Technical Assessment Guide, Volume 1: Electricity Supply—1993," Revision 7, Electric Power Research Institute, Palo Alto, CA, EPRI/TR-102276-V1R7, 1993.

EPRI (1995). "BIOPOWER: Biomass and Waste-Fired Power Plant Performance and Cost Model," Electric Power Research Institute, EPRI Report TR-102774, March 1995.

EPRI (2001): Renewable Energy Assessment Guide—TAG-RE: 2000, EPRI, Palo Alto, CA, EPRI 1000574, Feb. 2001.

Hughes, Evan and Wiltsee, George (1995). "Comparative Evaluation of Fuel Costs from Energy Crops," presented at the Second Biomass Conference of the Americas, Portland, Oregon, 21-24 August 1995. Proceedings published by NREL, December 1995.

Hughes, Evan and Wiltsee, George (1995). "Review of Energy Crop Costs." Paper by Evan Hughes and George Wiltsee at the 2nd Biomass Conference of the Americas, Portland OR, August 1995. Proceedings published by NREL and Elsevier Press, 1995.

Hughes, Evan (2000). "Greenhouse Gas Reduction with Renewables" EPRI Report TR113785, EPRI staff report by Evan Hughes, December 2000.

Lindman, Nils (1993): Biomass Based Combined Cycles. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Glasgow, 511-521.

Lucero, A. J.; Klepper, R. E.; O'Keefe, W. M.; and Sethi, V. K. (2001): Development of a Process for Production of Mixed Alcohols from Synthesis Gas. Paper presented at 2001 ACS meeting.

Manurung, R. K.; Bennackers, A. A. C. M. (1993): Modeling and Simulation of an Open Core Down-Draft Moving Bed Rice Husk Gasifier. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 288-309.

Morris, Michael; Waldheim, Lars (2000): Efficient Power Generation from Wood Gasification. Paper Presented at Gasification for the Future, 11-13 April 2000, Noordwijk, The Netherlands.

NiagaraMohawk & SUNY (1995). "Economic Development through Biomass Energy Systems Integration: New York Willow Bioenergy Project." Final Report by the Salix Consortium and Niagara Mohawk Power Corporation to DOE, NREL, EPRI and the New York Energy State Research and Development Authority, EPRI Report TR-xxxxxx, December 1995.

NREL & EPRI 1997. "Renewable Energy Technology Characterizations," EPRI Report TR-109496, by NREL (for DOE) & EPRI, December 1997.

Paisley, M. A.; Irving, J. M.; and Overend, R. P. (2001): A Promising Power Option - The FERCO Silvagas Biomass Gasification Process - Operating Experience at the Burlington Gasifier. Proceedings of ASME Turbo Expo 2001 ASME Turb Expo Land, Sea, & Air 2001, June 4-7, New Orleans, Louisiana.

Peters, M. and Timmerhaus, K (1991). Plant Design and Economics for Chemical Engineers. 4th Edition. New York: McGraw-Hill.

Purvis, C. R.; Craig, J. D. (1998): A Small Scale Biomass Fueled Gas Turbine Power Plant. BioEnergy '98 - The Eighth Biennial National Bioenergy Conference, Oct. 4-8, 1998. Madison, WI.

Rensfelt, E. K. W. (1997): Atmospheric CFB Gasification - The Grève Plant and Beyond. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kalschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, UK, 139-159.

Ståhl, Krister; Neergaard, Magnus; and Nieminen, Jorma (1999): Progress Report: Värnamo Biomass Gasification Plant. Paper presented at 1999 Gasification Technologies Conference, San Francisco, CA. Oct. 19-20, 1999.

Ståhl, K.; Neergaard, M.; and Nilsson, P.-A. (1997): Pressurized CFB Gasification - The Värnamo Plant. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kalschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 160-171.

van der Drift, A.; de Kant, H. F.; and Rajai, J. B. (2000): Commercialization BIVKIN-Based Gasification Technology. The non-confidential version is available at ECN website. ECN-C-00-080.

Walsh, Marie et al (1998). "POLYSIS Analysis of Energy Crop Price and Production," paper in the Proceedings of BioEnergy '98, Madison, Wisconsin, 4-8 October 1998. U.S. Department of Energy, Great Lakes Regional Biomass Energy Program, Chicago, Illinois, October 1998.

Wiant, Benjamin; Bryan, Bruce; and Miles, Thomas, Jr. (1998): Hawaiian Biomass Gasification Facility: Testing Results and Current Status. BioEnergy '98: Expanding BioEnergy Partnership.

Wiltsee, George (1995). "Biomass Energy Fundamentals, Volume 2: Fuels and Technologies." Draft Final Report to EPRI by George Wiltsee of Appel Consultants, February 1995.

Wiltsee, George (1998). "Advanced Biomass Technology Characteristics, Status, and Lessons Learned," Final Report to EPRI by George Wiltsee of Appel Consultants, EPRI TR-111882, November 1998.

7.0 BIBLIOGRAPHY

BIOMASS POWER: HEAT AND POWER SYSTEMS

1. Ackermann, Thomas; Söder, Lennart (1999): Biomass Power Generation in Competitive Markets - The Impact of Instruments and Regulations. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
2. Bain, Richard L.; Overend, Ralph P.; and Craig, Kevin R. (1998): Biomass-Fired Power Generation. *Fuel Processing Technology* 54, 1-16.
3. Beenackers, A. A. C. M.; Maniatis, K. (1996): Gasification Technologies for Heat and Power from Biomass. Presented at The 1996 EuroSun Congress, Freiburg, Germany.
4. Bhattacharyya, Alakananda; Basu, Arunabha (1998): Process for Abatement of Nitrogen Oxides in Exhaust from a Turbine Power Generation. (to Amoco Corporation (Chicago, IL)) United States Patent 5,740,667, issued 21 April 1998.
5. Blackadder, William H.; Lundberg, Henrik; Rensfelt, Erik; and Waldheim, Lars (1993): Heat and Power Production via Gasification in the Range of 5-50 MWe. In: *Advances in Thermochemical Biomass Conversion*. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Glasgow, 449-475.
6. Bühler, R. (1997): Fixed Bed Gasification for Electricity Generation Application in Europe. In: *Biomass Gasification and Pyrolysis: State of the Art and Future Prospects*. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 117-128.
7. Cole, Jerald A. (1999): Autothermal Methods and Systems for Fuels Conversion. (to Energy and Environmental Research Corporation (Irvine, CA)) United States Patent 6,007,699, issued 28 December 1999.
8. Engström, Folke (1999): Overview of Power Generation from Biomass. Paper presented at 1999 Gasification Technologies Conference, San Francisco, CA. Oct. 19-20, 1999.
9. Ennis, Bernard; Cirrito, Anthony (1999): Method and Apparatus for Total Energy Fuel Conversion Systems. United States Patent 5,938,975, issued 17 August 1999.
10. Haavisto, Ilkka (1997): Fixed Bed Gasification for Heat Production. In: *Biomass Gasification and Pyrolysis: State of the Art and Future Prospects*. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 99-104.
11. Kallner, P.; Fredriksson, J.; and Kjellström, B. (1994): Wood Combustion and Ash Separation in A Cyclone for Gas Turbine Applications. In: *ASME Gogen Turbo Power*

- '94. 1994 ed. Vol. 9. (Eds: Kidd, H. Allan; Fransson, Torsten H.; Cooke, David H.; and Greitzer, Edward M.) ASME, New York, 523-531.
12. Lyon, Richard K. (1998): Methods and Systems for Heat Transfer by Unmixed Combustion. (to Energy and Environmental Research Corp. (Irvine, CA)) United States Patent 5,827,496, issued 27 October 1998.
 13. Manjunath, A.; Cotton, J.; Ekamabaram, A.; Sellakumar, K. M.; and Palonen, J. (unknown): Efficient and Clean Biomass Gasification and Combustion Technologies for Bagasse. Technical paper but source unknown; from www.fwc.com/publications/techpapers/powgen/bagasse3.cfm.
 14. Mukunda, H. S.; Dasappa, S.; Paul, P. J.; and Rajan, N. K. S. (1997): Fixed Bed Gasification for Electricity Generation. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 105-116.
 15. Prieto, Mario Sánchez; Sánchez, Caio Glauco (1999): Exergetic Considerations on the Use of Simulation in Fluidized Bed Reactor for Sugar Cane Bagasse. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
 16. Raiko, M.; Hulkkonen, S. (1997): Biomass-Fueled Power Plants In Finland. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 529-537.
 17. Romey, I.; Adorni, M.; and Wartmann, J. (1999): Innovative Components for Decentralised Combined Heat and Power Generation from Biomass Gasification. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
 18. Roy, C.; Morin, D.; Dube, F.; and Schwerdtfeger, A. E. (1997): Electricity Production from Biomass Using the Integrated Pyrocycling(TM) Combined Cycle Process. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 835-843.

CHEMICAL PRODUCTION FROM GASIFICATION AND SYNGAS

1. Adachi, Y.; Komoto, M.; Watanabe, I.; Ohno, Y.; and Fujimoto, K. (2000): Effective utilization of remote coal through dimethyl ether synthesis. *Fuel* 79, 229-234.
2. Anikeev, V. I.; Gudkov, A. V.; and Ermakova, A. (1996): Exergetic Analysis of Biomass Gasification for Co-Production of Methanol and Energy. *Theoretical Foundations of Chemical Engineering* 30(5), 461-468.
3. Aznar, Maria P.; Caballero, Miguel A.; Gil, Javier; Olivares, Ana; and Corella, Jose (1997): Hydrogen By Biomass Gasification with Steam-O₂ Mixtures and Steam Reforming and Co-Shift Catalytic Beds Downstream of the Gasifier. In: *Making a Business from Biomass in Energy, Environment, Chemicals, Fibers, and Materials: Proceedings of the 3rd Biomass Conference of the Americas*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon., 859-860.
4. Babu, S. P.; Onischak, M.; and Kosowski, G. (1982): Development of a Pressurized Fluidized-Bed Biomass Gasifier to Produce Substitute Fuels. In: *Biomass-to-Methanol Specialists' Workshop Proceedings*. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 193-204.
5. Beenackers, A. A. C. M.; Swaay, W. Van (1986): Introduction to the Biomass to Synthesis Gas Pilot Plant Programme of the C.E.C. and a First Evaluation of its Results. In: *Advanced Gasification: Methanol Production from Wood - Results of the EEC Pilot Programme*. Series E ed. Vol. 8. (Eds: Beenackers, A. A. C. M.; Swaay, W. P. M. Van) D. Reidel Publishing Company, Dordrecht, Holland, 2-27.
6. Black, J. W. (1982): The Pressurized Fluidized Bed Gasifier in the Synthesis of Methanol from Wood. In: *Biomass-to-Methanol Specialists' Workshop Proceedings*. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 231-238.
7. Chang, C. D.; Kuo, J. C. W.; Lang, W. H.; Jacob, S. M.; Wise, J. J.; and Silvestri, A. J. (1978): Process Studies on the Conversion of Methanol to Gasoline. *Ind. Eng. Chem. Process Des. Dev.* 17(3), 255-260.
8. Clough, Thomas J.; Grosvenor, Victor L.; and Pinsky, Naum (1993): Catalytic Process. (to Ensci Inc. (Santa Monica, CA)) United States Patent 5,266,204, issued 30 November 1993.
9. Coffman, J. A. (1995): Methanol from Biomass via Steam Gasification. *American Chemical Society. Division of Fuel Chemistry* 40(3), 725-728.
10. Coffman, John A. (1996a): Apparatus for Producing Methanol. (to Wright Malta Corporation (Ballston Spa, NY)) United States Patent 5,512,255, issued 30 April 1996.

11. Coffman, John A. (1996b): Method for Producing Methanol. (to Wright Malta Corporation (Ballston Spa, NY)) United States Patent 5,510,393, issued 23 April 1996.
12. Cohen, Laurence H.; Muller, Herman L. (1989): Methanol from Coal, Cost Projections. In: Encyclopedia of Chemical Processing and Design. Vol. 30. (Eds: McKetta, John J.; Cunningham, William A.) Marcel Dekker, Inc, New York, 1-24.
13. Diebold, J. P.; Elliott, D. C.; and Solantausta, Y. (1993): IEA Technoeconomic Analysis of the Thermochemical Conversion of Biomass to Gasoline by the NREL Process. In: Advances in Thermochemical Biomass Conversion. Vol. 2. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 1325-1342.
14. Faaij, Andre; Larson, Eric; Kreutz, Tom; and Hamelinck, Carlo (1999): Production of Methanol and Hydrogen from Biomass via Advanced Conversion Concepts. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 803.
15. Fiedler, Eckhard; Grossmann, Georg; Kerserbohm, Burkhard; Weiss, Günther; and Witte, Claus (1990): Methanol. In: Ullmann's Encyclopedia of Industrial Chemistry. Vol. A16. (Eds: Elvers, Barbara; Hawkins, Stephen; Schulz, Gail) VCH, Germany, 465-486.
16. Foley, Henry C.; Sonnichsen, George C.; Brake, Loren D.; Mariwala, Ravindra K.; and Lafyatis, David S. (1994): CMS/SiO sub 2/Al sub 2 O sub 3 catalysts for improved selectivity in the synthesis of amines from methanol and/or dimethyl ether and ammonia. (to University of Delaware, E. I. Du Pont de Nemours Company, Inc.) US Patent 5354893, issued 11 October 1994.
17. Foley, Henry C.; Sonnichsen, George C.; Brake, Loren D.; Mariwala, Ravindra K.; and Lafyatis, David S. (1995): CMS/SiO sub 2/Al sub 2 O sub 3 catalysts for improved selectivity in the synthesis of amines from methanol and/or dimethyl ether and ammonia. (to The University of Delaware, E. I. Du Pont de Nemours Company, Inc.) US Patent 5470814, issued 28 Nov 1995.
18. Foley, Henry C.; Sonnichsen, George C.; Brake, Loren D.; Mariwala, Ravindra K.; and Lafyatis, David S. (1996): CMS/SiO sub 2/Al sub 2 O sub 3 catalysts for improved selectivity in the synthesis of amines from methanol and/or dimethyl ether and ammonia. (to The University of Delaware, E. I. Du Pont de Nemours Company, Inc.) US Patent 5482909, issued 9 Jan 1996.
19. Fong, Wing-Chiu F.; Wilson, Raymond F. (1996): Gasification process combined with steam methane reforming to produce syngas suitable for methanol production. (to Texaco, Inc.) US Patent 5469859, issued 5 Mar 1996.

20. Fossum, Morten; Hustad, Johan E. (1993): Biomass Gasification for Industrial Production of Tar and Charcoal. In: *Advances in Thermochemical Biomass Conversion*. Vol. 2. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 1242-1256.
21. Frank, Marshall E. (1982): Chem Systems' Liquid Phase Methanol Process. In: *Biomass-to-Methanol Specialists' Workshop Proceedings*. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 27-32.
22. Fujimoto, Kaoru; Shikada, Tsutomu; Yamaoka, Kaoru; and Sumigama, Takashi (1995): Method of producing dimethyl ether. (to Fujimoto, Kaoru (NKK Corporation)) US Patent 5466720, issued 14 Nov 1995.
23. Graboski, Michael S. (1982): Comparison of Coal and Wood as Feedstocks for Methanol Manufacture. In: *Biomass-to-Methanol Specialists' Workshop Proceedings*. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 41-59.
24. Grady, James L.; Chen, Guang Jiong (1998): Bioconversion of Waste Biomass to Useful Products. (to Bioengineering Resources, Inc. (Fayetteville, AR)) United States Patent 5,821,111, issued 13 October 1998.
25. Haggin, Joseph (1982a): Methanol from biomass draws closer to market. *C&EN* 60(12 July), 24-25.
26. Haggin, Joseph (1982b): Methanol: Future fuel for electric utilities? *C&EN* 60(12 July), 41-42.
27. Hirano, A.; Hon-Nami, K.; Kunito, S.; Hada, M.; and Ogushi, Y. (1998): Temperature Effect on Continuous Gasification of Microalgal Biomass: Theoretical Yield of Methanol Production and Its Energy Balance. *Catalysis Today* 45, 399-404.
28. Hornig, A. W.; Theis, J. D. (1982): The Thagard High-Temperature Fluid-Wall Reactor for Syngas Generation from Biomass. In: *Biomass-to-Methanol Specialists' Workshop Proceedings*. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 205-218.
29. Jones, Michael David; Poole, Andrew David (1998): Process for the production of acetic acid by the carbonylation of dimethyl ether. (to BP Chemicals Limited) US Patent 5763654, issued 9 June 1998.
30. Kasem, A. (1979a): II-1 Fuel-Grade (Crude) Methanol. In: *Three Clean Fuels from Coal: Technology and Economics - Synthetic Natural Gas, Methanol and Medium Btu Gas*. (:) Mercel Dekker, Inc., New York, 57-81.

31. Kasem, A. (1979b): III-1 Medium Btu Gas Production. In: Three Clean Fuels from Coal: Technology and Economics - Synthetic Natural Gas, Methanol and Medium Btu Gas. (:) Mercel Dekker, Inc., New York, 97-109.
32. Kinoshita, Charles M.; Wang, Yue; and Takahashi, Patrick K. (1991): Chemical Equilibrium Computations for Gasification Of Biomass to Produce Methanol. *Energy Sources* 13, 361-368.
33. Klier, K. (1982): Methanol Synthesis. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 5-25.
34. Knifton, John F.; Gigsby, Robert A., Jr.; and Herbstman, Sheldon (1983): Alcohol/Ester Fuels from Synthese Gas. In: Catalytic Conversions of Synthesis Gas and Alcohols to Chemicals. (Ed: Herman, Richard G) Plenum Press, New York, 81-96.
35. Kochar, N. K.; Merims, R.; and Padia, A. S. (1981): Ethylene from Ethanol. *CEP* (June), 66-71.
36. Lapidus, Albert; Krylova, Alla; Paushkin, Yaroslav; Rathousky, Jiri; Zukal, Arnost; and Starek, Jindrich (1994): Synthesis of Liquid Fuels from Products of Biomass Gasification. *Fuel* 73(April), 583-590.
37. Larson, Eric D.; Jin, Haiming (1999): Biomass Conversion to Fischer-Tropsch Liquids: Preliminary Energy Balances. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 843-853.
38. Larson, Eric D.; Katofsky, Ryan E. (1993): Production of Hydrogen and Methanol via Biomass Gasification. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 495-510.
39. Lewnard, John J.; Hsiung, Thomas H.; White, James F.; and Bhatt, Bharat L. (1993): Liquid phase process for dimethyl ether synthesis. (to Air Products and Chemicals, Inc.) US Patent 5218003, issued 8 June 1993.
40. Mehrling, P.; Reimert, R. (1986): Synthetic Fuel from Wood via Gasification in the Circulating Fluid Bed. In: Advanced Gasification: Methanol Production from Wood - Results of the EEC Pilot Programme. Series E ed. Vol. 8. (Eds: Beenackers, A. A. C. M.; Swaaij, W. P. M. Van) D. Reidel Publishing Company, Dordrecht, Holland, 73-85.
41. Mudge, L. K.; Baker, E. G.; and Mitchell, D. H. (1982): Catalytic Generation of Methanol Synthesis Gas from Wood. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 179-192.

42. Othmer, Donald F. (1982): Advantages of Using Methanol. C&EN (30 Aug), 3.
43. Parkinson, Gerald (2000a): .. and Lurgi plans to build the world's largest methanol plant. CE (January), 17.
44. Parkinson, Gerald (2000b): Syngas process promises to cut costs for large-scale methanol production. CE (January), 17.
45. Parkinson, Gerald (2001): Lurgi will demonstrate its methanol-to-propylene process. CE (March), 15.
46. Peng, Xiang-Dong; Parris, Gene E.; Toseland, Bernard A.; and Battavio, Paula J. (1998): Use of aluminum phosphate as the dehydration catalyst in single step dimethyl ether process. (to Air Products and Chemicals, Inc.) US Patent 5753716, issued 19 May 1998.
47. Peng, Xiang-Dong; Wang, Andrew Wilson; and Toseland, Bernard Allen (2000): Single step synthesis gas-to-dimethyl ether process with methanol introduction. (to Air Products and Chemicals, Inc.) US Patent 6069180, issued 30 May 2000.
48. Pretzer, W. R.; Habib, M. M. (1983): Recent Advances in Alcohol Homologation: The Effect of Promoters. In: Catalytic Conversions of Synthesis Gas and Alcohols to Chemicals. (Ed: Herman, Richard G) Plenum Press, New York, 261-283.
49. Ptasinski, K. J.; Beenackers, A. A. C. M.; van Swaaij, W. P. M.; and Holstvoogd, R. (1986): Hydrogen Recovery from Gas Mixtures Using Metal Hydrides Suspended in Slurry. from The biomass Synthesis Gas Pilot Plant Programme of CEC ...
50. Reed, T. B.; Lerner, R. M. (1973): Methanol: A Versatile Fuel for Immediate Use. Science 182(4119, 28 December), 1299-1304.
51. Rezende, Maria Emília A.; Pasa, Vânia M. D.; and Lessa, Auro (1993): Continuous Charcoal Production - A Brazilian Experience. In: Advances in Thermochemical Biomass Conversion. Vol. 2. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 1289-1298.
52. Siwajek, Lawrence A.; Cook, W. Jeffrey; and Brown, William R. (1998a): Landfill gas recovery. (to Acrion Technologies, Inc.) Application: US. US Patent 5842357, issued 1 Dec 1998.
53. Siwajek, Lawrence A.; Cook, W. Jeffrey; and Brown, William R. (1998b): Landfill gas recovery. (to Acrion Technologies, Inc.) Application: US. US Patent 5681360, issued 28 Oct 1997.
54. Slaugh, Lynn H.; Ryan, Robert C. (1983): Dimethyl ether process. (to Shell Oil Company) US Patent 4417000, issued 22 Nov 1983.

55. Steinberg, Meyer; Dong, Yuanji (1996): Process and Apparatus for the Production of Methanol from Condensed Carbonaceous Material. United States Patent RE35,377, issued 12 November 1996.
56. Stucki, S.; Leuenberger, J.; and Kesselring, P. (1993): Methanol from Biomass - An Option for Switzerland. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Glasgow, 522-529.
57. Suppes, G. J.; Burkhart, M. L. (1999): Unified Approached Next Generation Biofuel - Fischer-Tropsch Fuel Blends. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 781-787.
58. Thiebaut, Daniel Marcel; Vidalin, Kenneth Ebenes (2001): Methanol plant retrofit. (to Acetex Limited) US Patent 6274096, issued 14 Aug 2001.
59. Tierney, John W.; Wender, Irving; and Palekar, Vishwesh M. (1995): Methanol Synthesis Using a Catalyst Combination of Alkali or Alkaline Earth Salts and Reduced Copper Chromite. (to University of Pittsburgh (Pittsburgh, PA)) United States Patent 5,384,335, issued 24 January 1995.
60. Topp-Jorgensen, Jorgen (1985): Process for the preparation of catalysts for use in ether synthesis. (to Haldor Topsoe A/S) US Patent 4536485, issued 20 Aug 1985.
61. Turn, S.; Kinoshita, C.; Zhang, Z.; Ishimura, D.; and Zhou, J. (1998): An Experimental Investigation of Hydrogen Production from Biomass Gasification. Int. J. Hydrogen Energy 23(8), 641-648.
62. van Dijk, Christiaan P. (1993a): Process for Producing and Utilizing an Oxygen Enriched Gas. (to Starchem Inc.) US Patent 5245110, issued 14 Sept 1993.
63. van Dijk, Christiaan P. (1993b): Process for Recovering Natural Gas in the Form of a Normally Liquid Carbon Containing Compound. (to Starchem Inc.) US Patent 5177114, issued 5 Jan 1993.
64. van Dijk, Christiaan P. (1998a): Dimethyl Ether Production and Recovery from Methanol. (to Starchem Inc.) US Patent 5750799, issued 12 May 1998.
65. van Dijk, Christiaan P. (1998b): Methanol Production Process Using a High Nitrogen Content Synthesis Gas with a Hydrogen Recycle. (to Starchem Inc.) US Patent 5472986, issued 5 Dec 1995.
66. Voss, Bodil; Joensen, Finn; and Hansen, John Bogild (1999): Preparation of fuel grade dimethyl ether. (to Haldor Topsoe A/S) US Patent 5908963, issued 1 June 1999.

67. Waldheim, L.; Rensfelt, E. (1982): Methanol from Wood and Peat. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 239-259.
68. Walsh, John H. (1993): The Synthesis of Atmospherically - Neutral Methanol Integrated with the Generation of Electricity in Processes Equipped for the Capture and Sequestering of Carbon Dioxide. *Energy Conv. Mgmt.* 34(9-11), 1031-1049.
69. Wentworth, Theodore O.; Stiles, Alvin B. (1980): Production of Methanol. US Patent 4235799, issued 25 Nov 1980.
70. Westerterp, K. R.; Kuczynski, M. (1989): Methanol Synthesis: Trickle Flow Reactor. In: *Encyclopedia of Chemical Processing and Design*. Vol. 30. (Eds: McKetta, John J.; Cunningham, William A.) Marcel Dekker, Inc, New York, 24-32.
71. Ying, W.; Fang, D.; and Zhu, B. (1994): Mathematical Simulation and the Analysis of Operating. *Chemical Reaction Engineering and Technology* 10(2), 152-160.

THE CARBON CONNECTION-CO₂ REMOVAL, MITIGATION, SEQUESTRATION

1. DeLallo, Michael R.; Buchanan, Thomas L.; Holt, Neville A.; and Wolk, Ronald H. (2000): Evaluation of Innovative Fossil Cycles Incorporating CO₂ Removal. Paper Presented at 2000 Gasification Technologies Conference, San Francisco, CA, Oct. 8-11, 2000.
2. Edmonds, James A.; Dooley, James J. (1997): Appendix A: Workshop for the Preliminary Identification of Basic Science Needs and Opportunities For the Safe and Economical Capture and Sequestration of CO₂. Workshop Organized by above authors at Pacific Northwest National Laboratory.
3. Girouard, P.; Walsh, M. E.; and Becker, D. A. (1999): BIOCOST-Canada: A New Tool to Evaluate the Economic, Energy and Carbon Budgets of Perennial Energy Crops. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 85-90.
4. Holt, Neville; Booras, George; and Wolk, Ronald (2000): Analysis of Innovative Fossil Fuel Cycles Incorporating CO₂ Removal. Paper Presented at 2000 Gasification Technologies Conference, San Francisco, CA, Oct. 8-11, 2000.
5. Jungmeier, G.; Canella, L.; and Spitzer, J. (1999): Greenhouse Gas Emissions of Bioenergy Systems Compared to Fossil Energy Systems. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 437-444.

6. Mann, Margaret K.; Spath, Pamela L. (1999): The Net CO₂ Emissions and Energy Balances of Biomass and Coal-Fired Power Systems. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 379-385.
7. Smelser, S. C.; Booras, G. S. (1992): An Engineering and Economic Evaluation of CO₂ Removal from Fossil Fuel-Fired Power Plants. In: Proceedings: Ninth EPRI Conference on Gasification Power Plants. Vol. TR-100466s. (Ed: Holt, Neville A.) EPRI, Palo Alto, CA, 30-1 to 30-25.
8. Tolbert, V. R.; Joslin, J. D.; Thornton, F. C.; Bock, B. R.; Pettry, D. E.; Bandaranayake, W.; Tyler, D.; Houston, A.; and Schoenholtz, S. (1999): Biomass Crop Production: Benefits for Soil Quality and Carbon Sequestration. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 127-132.
9. Zan, C.; Fyles, J.; Girouard, P.; Samson, R.; and Doan, M. (1997): Carbon Storage in Switchgrass and Short-Rotation Willow Plantations. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 355-361.

LIFE CYCLE OF BIOMASS AND COAL IGCC

1. Anex, Robert; Velnati, Sasidhar; Meo, Mark; and Ellington, Rex (1998): Innovation and the Transformation to Clean Technologies: Life Cycle Management of Gas Turbine Systems. obtained from www.ou.edu/spp/turbine/paper.html.
2. Kaltschmitt, M.; Reinhardt, G. A.; and Stelzer, T. (1997): Life Cycle Analysis of Biofuels under Different Environmental Aspects. *Biomass and Bioenergy* 12(2), 121-134.
3. Mann, M. K.; Spath, P. L. (1997a): Summary of Results from a Life Cycle Assessment of a Biomass Gasification Combined-Cycle Power System. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1533-1543.
4. Mann, M. K.; Spath, P. L. (1997b): Technoeconomic Analysis and Life Cycle Assessment of an Integrated Biomass Gasification combined Cycle System Life Cycle Assessment of Biomass-To-Electricity. *Developments in Thermochemical Biomass Conversion* 2, 1567-1581.
5. Marano, J. J.; Rogers, S.; Spath, P. L.; and Mann, M. K. (1997): Life-Cycle Assessment of Biomass-Derived Refinery Feedstocks for Reducing CO₂ Emissions. In:

Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 325-337.

6. Rafaschieri, A.; Rapaccini, M.; and Manfrida, G. (1999): Life Cycle Assessment of Electricity Production from Poplar Energy Crops Compared with Conventional Fossil Fuels. *Energy Conv. Mgmt.* 40(14), 1477-1493.
7. Vaswani, Sudeep (2000): Development of Models for Calculating the Life Cycle Inventory of Methanol by Liquid Phase and Conventional Production Processes. MS Thesis, North Carolina State University.
8. Woods, J.; Hall, D. O. (1999): Producing a Life-Cycle Energy Balance for an Integrated Sweet Sorghum/Sugarcane System in the Semi-Arid Southeast Region of Zimbabwe. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 387-392.
9. Zemanek, G.; Reinhardt, G. A. (1999): First Total Evaluation of the Ecological Comparison: Biofuels Versus Conventional Fuels. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 393-426.

FEEDSTOCKS: EVALUATION, CHARACTERIZATION, AND DRYING

1. Bergstrom, R. (1997): The Use of Biomass in Sweden Today and for the Future. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1253-1262.
2. Brammer, J. G.; Bridgwater, A. V. (1999): Drying in a Biomass Gasification Plant for Power or Cogeneration. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 281-287.
3. Dai, Lin; Wang, Gehua; Su, Mingshan; Qu, Feng; and Liu, Xiaofeng (1999): Bioenergy Technologies in China: Their Development and Commercialization. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 193-201.
4. De Freitas, M. A. V.; Moreira, J. R. (1997): The Brazilian Renewable Energy Program: The Biomass National Plan. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1263-1271.
5. Faaij, Andre; van Doorn, Joep; Curvers, Toine; Waldheim, Lars; Olsson, Eva; van Wijk, Ad; and Daey-Ouwens, Cees (1997): Characteristics and Availability of Biomass Waste and Residues in the Netherlands for Gasification. *Biomass and Bioenergy* 12(4), 225-240.
6. Graham, Robin L.; Allison, Linda J.; and Becker, Denny A. (1997): ORECCL - Summary of a National Database on Energy Crop Landbase, Yields, and Costs. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 205-213.
7. Graham, R. L.; English, B. C.; Noon, C. E.; Jager, H. I.; and Daly, M. J. (1997): Predicting Switchgrass Farmgate and Delivered Costs: An 11 State Analysis. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 121-129.
8. Graham, R. L.; Liu, W.; Downing, M.; Noon, C. E.; Daly, M.; and Moore, A. (1997): The Effect Of Location and Facility Demand on the Marginal Cost of Delivered Wood Chips from Energy Crops: A Case of the State of Tennessee. *Biomass and Bioenergy* 13(3), 117-123.

9. Gullichsen, Johan (1999): The Kraft Pulp Mill - A Magnificent Producer of Bioenergy. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
10. Helynen, S. A. (1997): Bioenergy Production And Consumption In The Years 1992-2010 In Finland. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1273-1280.
11. Hewitt, William J.; English, Burton C.; Graham, Robin; and Daly, Mike (1997): Switchgrass as a Fuel Stock for Electric Power Generation in Tennessee. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1475-1480.
12. Hughes, E. E.; Augenstein, D. C.; and Benemann, J. R. (1997): Biomass Energy, Climate Change, and Electric Utility Restructuring. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1281-1282.
13. Komiyama, H.; Mitsumori, T.; Yamaji, K.; and Yamada, K. (2000): Assessment of Energy Systems by Using Biomass Plantation. Fuel 80, 707-715.
14. Li, Jingjing; Zhou, Aiming (1999): Biomass Resource Assessment for China. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 217-232.
15. McGowin, C.; Finney, K.; Peterson, T.; and Hughes, E. (2001): Renewable Energy Technical Assessment Guide - TAG-RE: 2000. Vol. 1000575. EPRI, Palo Alto, CA 94303.
16. McLaughlin, S.; Bouton, J.; Bransby, D.; Conger, R.; Ocumpaugh, W.; Parrish, D.; Taliaferro, C.; Vogel, K.; and Wulschleger, S. (1997): Evaluating and Improving Switchgrass as a Bioenergy Crop. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 137-143.
17. Morris, Gregory (1997): The California Biomass Industry Prepares Itself for a World of Competition. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1337-1344.

18. Olen, K. R. (1998): Opportunity Fuels Guidebook. Vol. TR-111487. EPRI, Palo Alto, CA 94303.
19. Rahmani, Mohammad; Hodges, Alan W.; Stricker, James A.; and Kiker, Clyde F. (1997): Economic Analysis of Biomass Crop Production in Florida. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 91-99.
20. Rooney, T. E.; Haase, S. G.; and Woselugel, A. E. (1999): Lignocellulosic Feedstock Resource Assessment. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 99-105.
21. Van Dyne, Donald L.; Blase, Melvin G. (1999): Crop Residues as Feedstocks of Choice for New Generation Cooperative Processing Plants. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 363-368.
22. Venendaal, R. (1997): European Energy Crops Overview - Utilisation for Power and Heat Generation and for the Production of Transport Fuels. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1291-1306.
23. Wood, John P.; Kinkelaar, Mark (1997): Municipal Solid Waste Biomass. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 101-108.
24. Wright, Lynn L.; Cushman, Janet H. (1997): A National Research & Development Strategy for Biomass Crop Feedstocks. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 109-118.
25. Yagodin, V.; Yudkevitch, Y.; and Svirin, L. (1999): Utilisation of Wood Waste. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.

GASIFICATION: BIOMASS

1. Androutsopoulos, George P.; Hatzilyberis, Kostas S. (2000): Allothermal Gasification of Lignite and/or Biomass: Design Aspects of an Indirect Heat Rotary Reactor Gasifier. Paper Presented at Novel Reactors and New Reactor Concepts I (AIChE Annual Meeting, Nov. 2000).
2. Antal, M. J. Jr; Allen, S. G.; Schulman, D.; Xu, X.; and Divilio, R. J. (2000): Biomass Gasification in Supercritical Water. *Ind. Eng. Chem. Res.* 39(11), 4040-4053.
3. Aznar, Maria O.; Caballero, Miguel A.; Gil, Javier; Olivares, Ana; and Corella, José (1997): Hydrogen by Biomass Gasification with Steam-O₂ Mixtures and Steam Reforming and Co-Shift Catalytic Beds Downstream of the Gasifier. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 859-860.
4. Aznar, Maria P.; Caballero, Miguel A.; Gil, Javier; Olivares, Ana; and Corella, Jose (1997): Hydrogen By Biomass Gasification with Steam-O₂ Mixtures and Steam Reforming and Co-Shift Catalytic Beds Downstream of the Gasifier. In: *Making a Business from Biomass in Energy, Environment, Chemicals, Fibers, and Materials: Proceedings of the 3rd Biomass Conference of the Americas*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon,, 859-860.
5. Aznar, M. P.; Corella, J.; Delgado, J.; and Lahoz, J. (1993): Improved Steam Gasification of Lignocellulosic Residues in a Fluidized Bed with Commercial Steam Reforming Catalysts. *Ind. Eng. Chem. Res.* 32(1), 1-10.
6. Aznar, M. P.; Gil, J.; Martin, J. A.; Frances, E.; Olivares, A.; Caballero, M. A.; Perez, P.; and Corella, J. (1996): Recent Advances in AFB Biomass Gasification Pilot Plant with Catalytic Reactors in a Downstream Slip Flow. *VTT Symposium* 163, 169-175.
7. Babu, Suresh P.; Anderson, Gerald L.; and Nandi, Satyendra P. (1986): Process for Gasification of Cellulosic Biomass. (to Institute of Gas Technology (Chicago, IL)) United States Patent 4,592,762, issued 2 August 1983.
8. Babu, Suresh P.; Anderson, Gerald L.; and Nandi, Satyendra P. (1987): Process for Gasification of Cellulosic Materials. (to Institute of Gas Technology (Chicago, IL)) United States Patent 4,699,632, issued 13 October 1987.
9. Bakhshi, N. N.; Dalai, A. K.; and Srinivas, S. T. (1999): Conversion of Various Biomass-Derived Chars to Hydrogen/High BTU Gas by Gasification with Steam. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 985-990.

10. Beenackers, A. A. C. M. (1999): Biomass Gasification in Moving Beds: A Review of European Technologies. *Renewable Energy* 16, 1180-1186.
11. Bentzen, Jens Dall; Henriksen, Ulrik; and Hansen, Claus Hindsgaul (1999): Investigations of a Two-Stage Gasifier. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
12. Chrysostome, Gérard; Lemasle, Jean-Michel (1982): Pressurized Oxygen Blown Fluidized Bed Gasification of Wood. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 303-311.
13. Corella, J.; Aznar, M.-P.; Gil, J.; and Caballero, M. A. (1999): Biomass Gasification in Fluidized Bed: Where To Locate the Dolomite to Improve Gasification? *Energy & Fuels* 13(6), 1122-1127.
14. Corella, J.; Orio, A.; and Toledo, J.-M. (1999): Biomass Gasification with Air in a Fluidized Bed: Exhaustive Tar Elimination with Commercial Steam Reforming Catalysts. *Energy & Fuels* 13(3), 702-709.
15. Courson, C.; Makaga, E.; Petit, C.; and Kiennemann, A. (2000): Development of Ni Catalysts for Gas Production from Biomass Gasification. Reactivity in Steam- and Dry-Reforming. *Catalysis Today* 63, 427-437.
16. Cousins, W. J. (1982): Oxygen-Blown Entrained-Flow Gasification of Wood. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 293-302.
17. de Jong, W.; Andries, J.; Hoppesteyn, P. D. J.; and Ünal, Ö. (1999a): Conversion of Biomass and Biomass-Coal Mixtures: Gasification, Hot Gas Cleaning and Gas Turbine Combustion. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1009-1016.
18. de Jong, Wiebren; Andries, Jans; Hoppesteyn, Peter; and Ünal, Ömer (1999b): Conversion of Biomass: Experimental Results from Pressurised Air-Blown Fluidised Bed Gasification and Hot Gas Cleanup. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
19. Devi, G. T.; Kannan, M. P. (2000): Gasification of Biomass Chars in Air - Effect of Heat Treatment Temperature. *Energy & Fuels* 14(1), 127-130.
20. Evans, R. J.; Knight, R. A.; Onischak, M.; and Babu, S. P. (1988): Development of Biomass Gasification to Produce Substitute Fuels. Prepared by Institute of Gas Technology for Pacific Northwest Laboratory under Contract DE-AC06-76RLO 1830 with the U.S. Department of Energy. March 1988.

21. Faaij, Andre; van Ree, Rene; Waldheim, Lars; Olsson, Eva; Oudhuis, Andre; van Wijk, A.; Daey-Ouwens, C.; and Turkenburg, W. (1997): Gasification of Biomass Wastes and Residues for Electricity Production. *Biomass and Bioenergy* 12(6), 387-407.
22. Garcia, L.; Salvador, M. L.; Arauzo, J.; and Bilbao, R. (1997): Steam Gasification of Biomass in Fluidized Bed Using a Ni-Al Coprecipitated Catalyst. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 373-382.
23. García, L.; Salvador, M. L.; Arauzo, J.; and Bilbao, R. (1999): Catalytic Steam Gasification of Pine Sawdust. Effect of Catalyst Weight/Biomass Flow Rate and Steam/Biomass Ratios on Gas Production and Composition. *Energy & Fuels* 13, 851-859.
24. Garcia, L.; Salvador, M. L.; Bilbao, R.; and Arauzo, J. (1999): CO₂ Gasification of Pine Sawdust Using a Coprecipitation Ni-Al Catalyst. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 947-952.
25. Gil, J.; Caballero, M. A.; Martin, J. A.; Aznar, M.-P.; and Corella, J. (1999): Biomass Gasification with Air in a Fluidized Bed: Effect of the In-Bed Use of Dolomite under Different Operation Conditions. *Ind. Eng. Chem. Res.* 38(11), 4226-4235.
26. Gounder, Ponnusami K. (1993): Combined Cycle Power Plant Incorporating Atmospheric Circulating Fluidized Bed Boiler and Gasifier. (to Ahlstrom Pyropower Corporation) Application: US. US Patent 5255507, issued 26 oct 1993.
27. Green, Alex E. S. (2000): Process and Device for Pyrolysis of Feedstock. United States Patent 6,048,374, issued 11 April 2000.
28. Hallgren, Anders; Andersson, Lars A.; and Bjerle, Ingemar (1993): High Temperature Gasification of Biomass in an Atmospheric Entrained Flow Reactor. In: *Advances in Thermochemical Biomass Conversion*. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 338-349.
29. Hauserman, W. B. (1994): High-Yield Hydrogen Production by Catalytic Gasification of Coal or Biomass. *Int. J. Hydrogen Energy* 19(5), 413-419.
30. Idem, R. O.; Katikaneni, S. P. R.; and Bakhshi, N. N. (1997): Potential of Producing High BTU Gas from Various Biomass - Derived Chars. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 383-390.

31. Johnssen, Wolf (2000): Method of Generating Electric Energy from Regenerative Biomass. (to Hannelore Binsmaier Nee Gallin-Ast (Erdweg-Grossberghofen, DE)) United States Patent 6,074,769, issued 13 June 2000.
32. Kannan, M. P.; Richards, G. N. (1990): Gasification Of Biomass Chars in Carbon Dioxide: Dependence of Gasification Rate on the Indigenous Metal Content. *Fuel* 69(June), 747-753.
33. Katikaneni, S. P. R.; Idem, R. O.; and Bakhshi, N. N. (1997): Steam Gasification of Biomass Chars: Potential of Producing High BTU Gas. In: *Biomass Gasification and Pyrolysis: State of the Art and Future Prospects*. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 191-196.
34. Lightner, Gene E. (2000): Production of Syngas from Biomass. United States Patent 6,133,328, issued 17 October 2000.
35. Miccio, F.; Moersch, O.; Spliethoff, H.; and Hein, K. R. G. (1999): Generation and Conversion of Carbonaceous Fine Particles during Bubbling Fluidised Bed Gasification of a Biomass Fuel. *Fuel* 78, 1473-1481.
36. Naber, J. E.; Goudriaan, F.; and Louter, A. S. (1997): Further Development and Commercialization of the Shell Hydrothermal Upgrading Process for Biomass Liquefaction. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials*. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1651-1659.
37. Naber, J. E.; Goudriaan, F.; van de Wal, S.; Zeevalkink, J. A.; and van de Beld, B. (1999): The HTU Process for Biomass Liquefaction: R&D Strategy and Potential Business Development. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 789-795.
38. Othmer, Donald F. (1981): Method for Producing SNG or SYN-Gas from Wet Solid Waste and Low Grade Fuels. United States Patent 4,251,227, issued 17 February 1981.
39. Pletka, R.; Brown, R.; and Smeenk, J. (1998): Indirectly Heated Fluidized Bed Biomass Gasification Using a Latent Heat Ballast. Presented at BioEnergy '98: Expanding BioEnergy Partnerships, Madison, Wisconsin. Oct. 4-8, 1998. P. 396-403.
40. Rapagna, S.; Nader, J.; and Foscolo, P. U. (1999): Catalytic Gasification of Biomass. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 977.

41. Reed, T. B.; Markson, M. (1982): The SERI High Pressure Oxygen Gasifier. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 151-174.
42. Ruottu, Seppo (1993): Process and Equipment for the Recocery of Energy and Chemicals in a Sulphate Process. (to Tampella Power Oy) Application: Tampere, FI. United States Patent 5,211,002, issued 18 May 1993.
43. Ruottu, Seppo; Kaariainen, Kari; and Hiltunen, Jyrki (2000): Method Based on a Fluidized-bed Reactor for Converting Hydrocarbons. United States Patent 6,045,688, issued 4 April 2000.
44. Schenk, E. P.; van Doorn, J.; and Kiel, J. H. A. (1997): Biomass Gasification Research in Fixed Bed and Fluidised Bed Reactors. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 129-139.
45. Stevens, Don J. (Ed.) (1994): Review and Analysis of the 1980-1989 Biomass Thermochemical Conversion Program. September 1994 ed. Vol. DE95000287. National Renewable Energy Laboratory, Golden, CO.
46. Storm, C.; Spliethoff, H.; and Hein, K. R. G. (2000): Generation of a Gaseous Fuel by Gasification of Biomass for Use as Reburn Gas in Coal-Fired Boilers. In: Fluidized Bed Combustion and Gasification. (:) VDI Verlag GmbH, Düsseldorf, Germany, 235-246.
47. Tiangco, V. M.; Jenkins, B. M.; and Goss, J. R. (1996): Optimum Specific Gasification Rate for Static Bed Rice Hull Gasifiers. Biomass and Bioenergy 11(1), 51-62.
48. Turn, Scott Q.; Ishimura, Darren M.; Kinoshita, Charles M.; and Masutani, Stephen M. (1996): Summary, Biomass Gasifier Facility Start-up Tests - October and December 1995. Prepared by Hawaii Natural Energy Institute for The Pacific International Center for High Technology Research. February 1996. (DOE/CH/10407-T1).
49. Wang, Y.; Kinoshita, C. M. (1002): Experimental Analysis of Biomass Gasification with Steam and Oxygen. Solar Energy 49(3), 153-158.
50. Wen, Harvey; Lausten, Connie; Pietruszkiewicz, Jon; DeLaquil, Pat; and Jain, B. C. (1999): Advances in Biomass Gasification Power Plants. Proceedings of The American Power Conference 61, 215-219.
51. Wiles, David; Suter, Richard; Ramsay, Bruce; Neufeld, Jake; Neufeld, George; and Burke, Helmut (1999): Biomass Gasification with a Difference. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1075-1078.

52. Wilson, H. T.; Gibbins, J. R. (1982): Biomass Gasification Developments. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 261-276.
53. Zamansky, V. M.; Jenkins, B. M.; Miles, T. R.; and Tiangco, V. M. (1999): Hybrid Combustion-Gasification Concept for Environmentally Safe Utilization of Biomass Energy. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1335-1340.
54. Zhou, Jiachun; Ishimura, Darren M.; and Kinoshita, Charles M. (1999): Effects of Injecting Steam on Catalytic Reforming of Gasified Biomass. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 991-997.

GASIFICATION: WASTE/PRODUCT CHARACTERIZATION

1. Abatzoglou, N.; Fernandez, J.-C.; Laramée, L.; Gassó, S.; and Chornet, E. (1997): The Biosyn Waste Biomass Gasification: Environmental Performances. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 259-268.
2. Bari, De I.; Barisano, D.; Cardinale, M.; Matera, D.; Nanna, F.; and Viggiano, D. (2000): Air Gasification of Biomass in a Downdraft Fixed Bed: A Comparative Study of the Inorganic and Organic Products Distribution. *Energy & Fuels* 14(4), 889-898.
3. Baskin, Evelyn; Lee, Chun Wai; and Natschke, David F. (1997): The U.S. EPA Biomass Fuel Analytical Laboratory. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 617-626.
4. Borduin, Leon C.; Fewell, Thomas; Gombert, Dirk; and Priebe, Steve (1998): Mixed Waste Focus Area Alternative Oxidation Technologies Development and Demonstration Program. Presented at Waste Management Symposium. March 1-5, 1998. Tucson, AZ.
5. Bransby, D. I.; Mullins, G. R.; and Bock, B. (1999): Agronomic Evaluation of Ash Following Gasification of Five Biomass Feedstocks. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 577-582.
6. Dayton, D. C. (1997): The Fate of Alkali Metal during Biomass Thermochemical Conversion. *Developments in Thermochemical Biomass Conversion* 2, 1263-1277.

7. Dayton, David C.; French, Richard J.; and Milne, Thomas A. (1995): Direct Observation of Alkali Vapor Release during Biomass Combustion and Gasification. 1. Application of Molecular Beam/Mass Spectrometry to Switchgrass Combustion. *Energy & Fuels* 9(5), 855-865.
8. Elliott, Douglas C. (1993): Evaluation of Wastewater Treatment Requirements for Thermochemical Biomass Liquefaction. In: *Advances in Thermochemical Biomass Conversion*. Vol. 2. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 1299-1313.
9. Fahlstrom, Per A. H. H.; Gorling, Karl G. (1982): Method for Recovering Oil and/or Gas from Carbonaceous Materials. (to Boliden Aktiebolag (Stockholm, SE)) United States Patent 4,345,990, issued 24 August 1982.
10. Fujimura, Hiroyuki; Hirayama, Yoshio; Fujinami, Shosaku; Nagato, Shuichi; Hirose, Tetsuhisa; Oshita, Takahiro; Irie, Masaaki; Takano, Kazuo; and Fukuda, Toshio (1999): Method for Treating Wastes by Gasification. United States Patent 5,900,224, issued 4 May 1999.
11. Greco, Nicholas P. (1984): Refining Lurgi Tar Acids. (to Koppers Company, Inc. (Pittsburgh, PA)) United States Patent 4,443,636, issued 17 April 1984.
12. Griselin, Nicolas; Bai, Xue-Song; and Fuchs, Laszlo (1999): Tracking of Particles in a Biomass Furnace. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
13. Holopainen, O. (1993): IGCC Plant Employing Heavy-Petroleum Residues. *Bioresource Technology* 46, 125-128.
14. Kinoshita, C. M.; Wang, Y.; and Zhou, J. (1994): Tar Formation under Different Biomass Gasification Conditions. *J. Anal. Appl. Pyrolysis* 29, 169-181.
15. Leppälahti, Jukka; Kurkela, Esa; Simell, Pekka; and Ståhlberg, Pekka (1993): Formation and Removal of Nitrogen Compounds in Gasification Processes. In: *Advances in Thermochemical Biomass Conversion*. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 160-174.
16. Li, Chun-Zhu; Tan, Li Lian (2000): Formation of NO_x and SO_x Precursors during the Pyrolysis of Coal and Biomass. Part III. Further Discussion on the Formation of HCN and NH₃ during Pyrolysis. *Fuel* 79, 1899-1906.
17. Milne, T. A.; Abatzoglou, N.; and Evans, R. J. (Eds.) (1998): Biomass Gasifier "Tars": Their Nature, Formation, and Conversion. NREL/TP-570-25357 ed. NREL, Golden, CO.

18. Milne, Thomas A.; Evans, Robert J.; and Abatzoglou, Nicolas (1997): Biomass Gasifier "Tars": Their Nature, Formation, Destruction, and Tolerance Limits in Energy Conversion Devices. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 729-738.
19. Moersch, O.; Spliethoff, H.; and Hein, K. R. G. (1997): A New System for Tar Sampling and Analysis. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 228-234.
20. Orr, Doug; Maxwell, David (2000): A Comparison of Gasification and Incineration of Hazardous Wastes. DCN 99.803931.02 ed. Radian International LLC, Austin, TX.
21. Padban, N.; Wang, W.; Ye, Z.; Bjerle, I.; and Odenbrand, I. (2000): Tar Formation in Pressurized Fluidized Bed Air Gasification of Woody Biomass. *Energy & Fuels* 14(3), 603-611.
22. Rosen, Carl; Mozaffari, Morteza; Russelle, Michael; and Nater, Edward (Eds.) (1997): Chemical Characterization of Ash Generated from Alfalfa Stem Gasification: Agricultural and Environmental Implications. Quarterly Report, July 1, 1997 - September 30, 1997. Vol. DE98005864. U.S. Department of Commerce, National Technical Information Service, Springfield, VA.
23. Roy, C.; Pakdel, H.; Zhang, H. G.; and Elliott, D. C. (1994): Characterization and Catalytic Gasification of the Aqueous By-Product from Vacuum Pyrolysis of Biomass. *The Canadian Journal of Chemical Engineering* 72(1), 98-105.
24. Smeenk, Jerod; Brown, Robert C.; and Eckels, Dave (1999): Determination of Vapor Phase Alkali Content during Biomass Gasification. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 961-967.
25. Talvitie, Maarit A.; Oksanen, Antti J.; and Miettinen, Markku J. (1999): Modelling of Nitric Oxide Formation in Saw Dust Combustion. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
26. Voelker, Gary E.; Steedman, William G.; and Chandran, Ravi R. (1996): Steam Reforming of Low-Level Mixed Waste. Presented at the DOE/FETC conference titled "Industry Partnerships to Deploy Environmental Technology," Morgantown, West Virginia.

GASIFICATION: COAL

1. Adlhoch, W.; Bellin, A.; Dehms, G.; Schumacher, H.-J.; and Schumacher, I. (Eds.)

- (1993): Gasification of Pittsburgh No. 8 in Rheinbraun's Pressurized High-Temperature Winkler Pilot Plant. Vol. TR-103367. EPRI, Palo Alto, CA.
2. Allis-Chalmers Corporation (1987): Carbon Conversion - Ash Agglomeration Study for the KILnGAS Coal Gasification Process. Vol. AP-5004. EPRI, Palo Alto, CA.
 3. Badger Plants (1978a): Conceptual Design of a Coal to Methanol Commercial Plant: Interim Final Report, July 16, 1976-February 15, 1978. Vol. I. Department of Energy, Washington, DC.
 4. Badger Plants (1978b): Conceptual Design of a Coal to Methanol Commercial Plant: Interim Final Report, July 16, 1976-February 15, 1978. Vol. II. Department of Energy, Washington, DC.
 5. Bellin, A.; Adlhoeh, W. (1992): Gasification of Pittsburgh No. 8 Coal in Rheinbraun's Atmospheric High-Temperature Winkler Process Development Unit. Vol. TR-100983. EPRI, Palo Alto, CA.
 6. Borghi, M.; Cantore, G.; Peretto, A.; and Spina, P. R. (1994): Cogeneration Combined Cycle Power Plants Fueled by Coal and Biomass GAs. In: ASME Gogen Turbo Power '94. 1994 ed. Vol. 9. (Eds: Kidd, H. Allan; Fransson, Torsten H.; Cooke, David H.; and Greitzer, Edward M.) ASME, New York, 589-598.
 7. Cascone, Ronald F.; Solomon, C. Ashley (1985): Method for the Production of Variable Amounts of Power from Syngas. (to The Halcon SD Group, Inc. (New York, NY)) United States Patent 4,524,581, issued 25 June 1985.
 8. CF Braun & Co. (1980): Conceptual Designs & Assessments of a Coal Gasification Demonstration Plant. Vol. 1. CF Braun & Co., Alhambra, CA.
 9. Crim, M. C.; Williamson, P. C. (Eds.) (1987): Coal Gasification Tests at TVA. Vol. AP-5047. EPRI, Palo Alto, CA.
 10. Dawkins, R. P.; Hughes, M. K.; Lamprecht, D. G.; Rao, A. D.; and Sander, M. T. (Eds.) (1985): Cost and Performance of Kellogg Rust Westinghouse-based Gasification-Combined-Cycle Plants. Vol. AP-4018. EPRI, Palo Alto, CA.
 11. delaMora, J. A.; Grisso, J. R.; Klumpe, H. W.; Musso, A.; and Roszkowski, T. R. (Eds.) (1985): Evaluation of the British Gas Corporation/Lurgi Slagging Gasifier in Gasification-Combined-Cycle Power Generation. Vol. AP-3980. EPRI, Palo Alto, CA.
 12. Department of Energy (1992a): First Annual Clean Coal Technology Conference Proceedings. Department of Energy, Washington, DC.
 13. Department of Energy (1992b): Ninth Annual International Pittsburgh Coal Conference Proceedings. Department of Energy, Washington, DC.

14. Dittus, Myles; Johnson, Dale (2001): The Hidden Value of Lignite Coal. Presented at the Gasification Technologies Conference, San Francisco, CA. October 7-10, 2001.
15. DOE (1999): Market-Based Advanced Coal Power Systems. Final Report, May 1999 ed. U.S. Department of Energy, Office of Fossil Energy, Washington, DC 20585. 374 pages.
16. Eustis, R. H.; Erbes, M. R.; and Phillips, J. N. (Eds.) (1987): Analysis of the Off-Design Performance and Phased Construction of Integrated-Gasification-Combined Cycle Power Plants. Vol. AP-5027. EPRI, Palo Alto, CA.
17. Foster Wheeler Corporation (1980): TVA Coal Gasification Commercial Demonstration Plant Project. Vol. 1. Foster Wheeler Corporation, Livingston, NJ.
18. Furimsky, E. (1998): Gasification of Oil Sand Coke: Review. Fuel Processing Technology 56, 263-290.
19. Giramonti, A. J.; Sadala, R. L. (1979): Concept Screening of Coal Gasification CAES Systems. Vol. EM-1077. EPRI, Palo Alto, CA.
20. Hamilton, S.; Garow, J.; and Lehman, S. J. (Eds.) (1980): Coal Gasification Combined-Cycle System Analysis. Vol. AP-1390. EPRI, Palo Alto, CA.
21. Hederman, William F., Jr. (1978): Prospects for the Commercialization of High-BTU Coal Gasification. Vol. R-2294-DOE. Rand, Santa Monica, CA.
22. Holt, Neville A. H. (2001): Coal Gasification Research, Development and Demonstration - Needs and Opportunities. Presented at the Gasification Technologies Conference, San Francisco, CA. October 10, 2001.
23. IEA (1995): Industry Attitudes to Steam Cycle Clean Coal Technologies: Survey of Current Status. OECD, Paris, France.
24. Jarzabek, R. L.; Matchak, T. A. (1989): Evaluation of a Dow-Based Gasification-Combined-Cycle Plant Low-Rank Coals. Vol. GS-6318. EPRI, Palo Alto, CA.
25. Kern, E. E.; Havemann, S. D.; and Chmielewski, R. G. (1992): Houston Lighting & Power Company's Evaluation of Coal Gasification Coproduction Energy Facilities. Vol. TR-101789. EPRI, Palo Alto, CA.
26. Kristiansen, Alice (Ed.) (1996): Understanding Coal Gasification. IEA Coal Research, London.
27. Leonard, Roxann; Rogers, Luke; Vimalchand, P.; Liu, Guohai; Smith, Peter V.; and Longanbach, James (2001): Development Status of the Transport Gasifier at the PSDF.

Presented at the Gasification Technologies Conference, San Francisco, CA. October 7-10, 2001.

28. Müller, Rainer (1991): Planning for Prenflo+ V64/3 IGCC demo plants. unknown source, copied from Chattanooga Library.
29. Oortwijn, Peter; Wentinck, Hendrik Martinus (1999): Process for Preparing Synthesis Gas. (to Shell Oil Company (Houston, TX)) United States Patent 5,931,978, issued 3 August 1999.
30. Peabody & Co. (1983): Updated Technical and Cost Sections for the North Alabama Coal Gasification Project. Peabody & Co., New York.
31. Penner, S. S.; Alpert, S. B.; Beer, J. M.; Denn, M.; Haag, W.; Magee, R.; Reichl, E.; Rubin, E. S.; Solomon, P. R.; Wender, I.; and Woodcock, K. (1987): Coal Gasification: Direct Applications and Syntheses of Chemicals and Fuels. Pergamon Journals Limited, Britain.
32. Phillips, J. N.; Kiszka, M. B.; Mahagaokar, U.; and Krewinghaas, A. B. (Eds.) (1993): Shell Coal Gasification Project. Vol. TR-100687. EPRI, Palo Alto, CA.
33. Schippers, K.; Wischnewski, R.; Keller, J.; Herbert, P. K.; and Sendelbeck, G. (1993): KoBra will demonstrate High Temperature Winkler IGCC. Modern Power Systems 13(2), 41-47.
34. Takematsu, Toshi'ichi; Maude, Chris (1991): Coal Gasification for IGCC Power Generation. IEA Coal Research, London.
35. van Heek, K. H. (2000): Progress of Coal science in the 20th Century. Fuel 79, 1-36.
36. Weston, Charles W.; Mandel, Frederick S. (1987): Sulfate Reduction Process Useful in Coal Gasification. (to Freeport-McMoRan Resource Partners, Limited Partnership (New Orleans, LA)) United States Patent 4,704,136, issued 3 November 1987.
37. Wheeldon, J. M. (1999): The Kellogg Brown & Root Transport Reactor: PSDF Test Results and Economic Evaluation. Vol. TR-114083. EPRI, Palo Alto, CA 94303.
38. Zhuo, Y.; Messenböck, R.; Collot, A.-G.; Megaritis, A.; Paterson, N.; Dugwell, D. R.; and Kandiyoti, R. (2000): Conversion of Coal Particles in Pyrolysis and Gasification: Comparison of Conversions in a Pilot-scale Gasifier and Bench-scale Test Equipment. Fuel 79, 793-802.

GASIFICATION: CO-FEEDING

1. Adlhoch, W.; Bellin, A.; Dehms, G.; Schumacher, H.-J.; and Schumacher, I. (Eds.) (1993): Gasification of Pittsburgh No. 8 in Rheinbraun's Pressurized High-Temperature Winkler Pilot Plant. Vol. TR-103367. EPRI, Palo Alto, CA.

2. Allis-Chalmers Corporation (1987): Carbon Conversion - Ash Agglomeration Study for the KILnGAS Coal Gasification Process. Vol. AP-5004. EPRI, Palo Alto, CA.
3. Andries, J.; de Jong, W.; and Hein, K. R. G. (1997a): Co-Gasification of Biomass and Coal in a Pressurised Fluidised Bed Gasifier. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 172-181.
4. Andries, J.; De Jong, W.; and Hein, K. R. G. (1997b): Co-Gasification of Biomass and Coal in a Pressurized Fluidized Bed Gasifier. VDI Berichte 1314, 211-213.
5. Badger Plants (1978a): Conceptual Design of a Coal to Methanol Commercial Plant: Interim Final Report, July 16, 1976-February 15, 1978. Vol. I. Department of Energy, Washington, DC.
6. Badger Plants (1978b): Conceptual Design of a Coal to Methanol Commercial Plant: Interim Final Report, July 16, 1976-February 15, 1978. Vol. II. Department of Energy, Washington, DC.
7. Bellin, A.; Adlhoch, W. (1992): Gasification of Pittsburgh No. 8 Coal in Rheinbraun's Atmospheric High-Temperature Winkler Process Development Unit. Vol. TR-100983. EPRI, Palo Alto, CA.
8. Borghi, M.; Cantore, G.; Peretto, A.; and Spina, P. R. (1994): Cogeneration Combined Cycle Power Plants Fueled by Coal and Biomass GAs. In: ASME Gogen Turbo Power '94. 1994 ed. Vol. 9. (Eds: Kidd, H. Allan; Fransson, Torsten H.; Cooke, David H.; and Greitzer, Edward M.) ASME, New York, 589-598.
9. Brown, Robert C.; Liu, Qin; and Norton, Glenn (1997): Catalytic Effects Observed During the Co-Gasification of Coal and Switchgrass. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 651-661.
10. Cascone, Ronald F.; Solomon, C. Ashley (1985): Method for the Production of Variable Amounts of Power from Syngas. (to The Halcon SD Group, Inc. (New York, NY)) United States Patent 4,524,581, issued 25 June 1985.
11. CF Braun & Co. (1980): Conceptual Designs & Assessments of a Coal Gasification Demonstration Plant. Vol. 1. CF Braun & Co., Alhambra, CA.
12. Chen, Guanxing; Yu, Qizhuang; Brage, Claes; Rosén, Christer; and Sjöström, Krister (1997): Cogasification of Birch Wood and Daw Mill Coal in Pressurized Fluidized Bed Reactor. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects.

(Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 182-196.

13. Chen, Guanxing; Yu, Qizhuang; Brage, Claes; Rosén, Christer; and Sjöström, Krister (1999): Biomass Co-gasification with Coal: The Process Benefit Due to Positive Synergistic Effects. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1017-1023.
14. Collot, A.-G.; Zhuo, Y.; Dugwell, D. R.; and Kandiyoti, R. (1999): Co-pyrolysis and Co-gasification of Coal and Biomass in Bench-scale Fixed-bed and Fluidised Bed Reactors. *Fuel* 78, 667-679.
15. Crim, M. C.; Williamson, P. C. (Eds.) (1987): Coal Gasification Tests at TVA. Vol. AP-5047. EPRI, Palo Alto, CA.
16. Dawkins, R. P.; Hughes, M. K.; Lamprecht, D. G.; Rao, A. D.; and Sander, M. T. (Eds.) (1985): Cost and Performance of Kellogg Rust Westinghouse-based Gasification-Combined-Cycle Plants. Vol. AP-4018. EPRI, Palo Alto, CA.
17. DeJong, W.; Andries, J.; and Hein, K. R. G. (1997): Co-Gasification of Biomass and Biomass-Coal Mixtures in a Bubbling Pressurised Fluidized Bed Reactor Using Air and Steam. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 559-570.
18. delaMora, J. A.; Grisso, J. R.; Klumpe, H. W.; Musso, A.; and Roszkowski, T. R. (Eds.) (1985): Evaluation of the British Gas Corporation/Lurgi Slagging Gasifier in Gasification-Combined-Cycle Power Generation. Vol. AP-3980. EPRI, Palo Alto, CA.
19. Department of Energy (1992a): First Annual Clean Coal Technology Conference Proceedings. Department of Energy, Washington, DC.
20. Department of Energy (1992b): Ninth Annual International Pittsburgh Coal Conference Proceedings. Department of Energy, Washington, DC.
21. DOE (1999): Market-Based Advanced Coal Power Systems. Final Report, May 1999 ed. U.S. Department of Energy, Office of Fossil Energy, Washington, DC 20585. 374 pages.
22. Eustis, R. H.; Erbes, M. R.; and Phillips, J. N. (Eds.) (1987): Analysis of the Off-Design Performance and Phased Construction of Integrated-Gasification-Combined Cycle Power Plants. Vol. AP-5027. EPRI, Palo Alto, CA.
23. Foster Wheeler Corporation (1980): TVA Coal Gasification Commercial Demonstration Plant Project. Vol. 1. Foster Wheeler Corporation, Livingston, NJ.

24. Furimsky, E. (1998): Gasification of Oil Sand Coke: Review. *Fuel Processing Technology* 56, 263-290.
25. Giramonti, A. J.; Sadala, R. L. (1979): Concept Screening of Coal Gasification CAES Systems. Vol. EM-1077. EPRI, Palo Alto, CA.
26. Hamilton, S.; Garow, J.; and Lehman, S. J. (Eds.) (1980): Coal Gasification Combined-Cycle System Analysis. Vol. AP-1390. EPRI, Palo Alto, CA.
27. Hederman, William F., Jr. (1978): Prospects for the Commercialization of High-BTU Coal Gasification. Vol. R-2294-DOE. Rand, Santa Monica, CA.
28. IEA (1995): Industry Attitudes to Steam Cycle Clean Coal Technologies: Survey of Current Status. OECD, Paris, France.
29. Jarzabek, R. L.; Matchak, T. A. (1989): Evaluation of a Dow-Based Gasification-Combined-Cycle Plant Low-Rank Coals. Vol. GS-6318. EPRI, Palo Alto, CA.
30. Kern, E. E.; Havemann, S. D.; and Chmielewski, R. G. (1992): Houston Lighting & Power Company's Evaluation of Coal Gasification Coproduction Energy Facilities. Vol. TR-101789. EPRI, Palo Alto, CA.
31. Kristiansen, Alice (Ed.) (1996): Understanding Coal Gasification. IEA Coal Research, London.
32. Matsumura, Y.; Nonaka, H.; Yokura, H.; Tsutsumi, A.; and Yoshida, K. (1999): Co-liquefaction of Coal and Cellulose in Supercritical Water. *Fuel* 78, 1049-1056.
33. Müller, Rainer (1991): Planning for Prenflo+ V64/3 IGCC demo plants. unknown source, copied from Chattanooga Library.
34. Oortwijn, Peter; Wentinck, Hendrik Martinus (1999): Process for Preparing Synthesis Gas. (to Shell Oil Company (Houston, TX)) United States Patent 5,931,978, issued 3 August 1999.
35. Pan, Y. G.; Velo, E.; and Puigjaner, L. (1995): Thermogravimetric Study on Pyrolysis for Fluidized Bed Gasification of Biomass/Poor Coal Blends. *Coal Science and Technology* 1(24), 981-984.
36. Pan, Y. G.; Velo, E.; Roca, X.; Manyá, J. J.; and Puigjaner, L. (2000): Fluidized-Bed Co-Gasification Of Residual Biomass/Poor Coal Blends For Fuel Gas Production. *Fuel* 79, 1317-1326.
37. Peabody & Co. (1983): Updated Technical and Cost Sections for the North Alabama Coal Gasification Project. Peabody & Co., New York.

38. Penner, S. S.; Alpert, S. B.; Beer, J. M.; Denn, M.; Haag, W.; Magee, R.; Reichl, E.; Rubin, E. S.; Solomon, P. R.; Wender, I.; and Woodcock, K. (1987): Coal Gasification: Direct Applications and Syntheses of Chemicals and Fuels. Pergamon Journals Limited, Britain.
39. Phillips, J. N.; Kiszka, M. B.; Mahagaokar, U.; and Krewinghaas, A. B. (Eds.) (1993): Shell Coal Gasification Project. Vol. TR-100687. EPRI, Palo Alto, CA.
40. Schiffer, H. P.; Adlhock, W. (1996): Gasification Experience with Biomass and Wastes. VTT Symposium 164, 67-82.
41. Schippers, K.; Wischnewski, R.; Keller, J.; Herbert, P. K.; and Sendelbeck, G. (1993): KoBra will demonstrate High Temperature Winkler IGCC. Modern Power Systems 13(2), 41-47.
42. Takematsu, Toshi'ichi; Maude, Chris (1991): Coal Gasification for IGCC Power Generation. IEA Coal Research, London.
43. van Heek, K. H. (2000): Progress of Coal science in the 20th Century. Fuel 79, 1-36.
44. Weston, Charles W.; Mandel, Frederick S. (1987): Sulfate Reduction Process Useful in Coal Gasification. (to Freeport-McMoRan Resource Partners, Limited Partnership (New Orleans, LA)) United States Patent 4,704,136, issued 3 November 1987.
45. Wheeldon, J. M. (1999): The Kellogg Brown & Root Transport Reactor: PSDF Test Results and Economic Evaluation. Vol. TR-114083. EPRI, Palo Alto, CA 94303.
46. Williams, A.; Pourkashanian, M.; Jones, J. M.; and Skorupska, N. (2000): Chapter 7: Two-Component Coal Combustion. In: Combustion and Gasification of Coal. (:) Taylor & Francis, New York, 187-209.
47. Yu, Q.; Brage, C.; Chen, G.; and Sjöström, K. (1999): Synergistic Effect on Tar Formation in Co-gasification of Energy Crops and Coal. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1033-1040.
48. Zhuo, Y.; Messenböck, R.; Collot, A.-G.; Megaritis, A.; Paterson, N.; Dugwell, D. R.; and Kandiyoti, R. (2000): Conversion of Coal Particles in Pyrolysis and Gasification: Comparison of Conversions in a Pilot-scale Gasifier and Bench-scale Test Equipment. Fuel 79, 793-802.

GASIFICATION: FUNDAMENTALS

1. Barrio, M.; Hustad, J. E. (unknown): CO₂ Gasification of Birch Char and the Effect of CO Inhibition on the Calculation of Chemical Kinetics. unknown source.

2. Blander, Milton (1997): Calculations of the Presence of Fouling and Corrosive Liquids in the Combustion and Gasification of Biomass. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 365-371.
3. Chen, Guanzing; Yu, Qizhuang; Sjöström, Krister; and Björnbom, Emilia (1993): Pyrolysis/Gasification of Biomass in Presence of Dolomite in a Pressurized Fluidized Bed. In: Advances in Thermochemical Biomass Conversion. Vol. 2. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 1197-1204.
4. Colomba, D. B.; Signorelli, G.; and Portoricco, G. (1999): Countercurrent Fixed-Bed Gasification of Biomass at Laboratory Scale. *Ind. Eng. Chem. Res.* 38(7), 2571-2581.
5. Dayton, David C.; Evans, Robert J. (1997): Laboratory Gasification Studies Via Partial Oxidation of Biomass Pyrolysis Vapors. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 673-682.
6. Esperanza, E.; Aleman, Y.; Arauzo, J.; and Gea, G. (1999): Fluidized Bed Gasification of Sugar Cane Bagasse. Influence on Gas Composition. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
7. Ethington, Don; Riley, Ray J.; and Tock, Richard W. (1987): Method for Gas Synthesis. (to AL-CHEM Fuels, Inc. (Dimmitt, TX)) United States Patent 4,690,743, issued 1 September 1987.
8. Evans, Robert J.; Elam, Carolyn C.; Looker, Michael; and Nimlos, Mark (1999): Formation of Aromatic Hydrocarbons due to Partial Oxidation Reactions in Biomass Gasification. Reprint from Symposium - Div. Fuel Chem. American Chemical Society, p. 256-260.
9. Gafernäs, Leena; Sipilä, Kai; and Ekman, Rainer (1993): Behaviour of Organic Compounds in Biomass Drying. In: Advances in Thermochemical Biomass Conversion. Vol. 2. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 1533-1544.
10. Geyer, Wayne A.; DeWyke, Jon; and Walawender, Walter P. (2000): Biomass and Gasification Properties of Young Populus Clones. *Wood and Paper Science* 32(3), 375-384.
11. Geyer, Wayne A.; Walawender, Walter P. (1997): Biomass Properties and Gasification Behavior of Young Silver Maple Trees. *Wood and Fiber Science* 29(1), 85-90.

12. Guzdar, A. R.; Harvey, A. C. (1982): Feeding Coal and Biomass into High Pressure Reactors. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 119-149.
13. Hallgren, A. L. (1997): Improved Technologies for the Gasification of Energy Crop Fuels. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 571-576.
14. Hauserman, William B. (1997): Relating Catalytic Coal or Biomass Gasification Mechanisms to Plant Capital Cost Components. *Int. J. Hydrogen Energy* 22(4), 409-414.
15. Jenkins, B. M.; Baxter, L. L.; Miles, T. R. Jr; and Miles, T. R. (1998): Combustion Properties of Biomass. *Fuel Processing Technology* 54, 17-46.
16. Kallstrom, R. (1994): Corrosion During Gasification of Biomass and Waste. *Journal De Physique IV* 3(9), 751-761.
17. Kato, Yoshitaka; Yoshikawa, Kunio (2000): Gasification Performance of a Pebble Bed Gasifier Using High Temperature Air and Steam. *Proceedings of 2000 International Joint Power Generation Conference*, Miami Beach, Florida, July 23-26, 2000.
18. Liu, Ping; Guo, Xiaofen; Wu, Chuangzhi; Chen, Yong; and Arai, Norio (2000): Gasification Characteristics of Biomass Wastes in Fluidized Bed Gasifier. *Journal of Propulsion and Power* 16(4), 606-608.
19. Moilanen, A.; Kurkela, E. (1995): Gasification Reactivities of Solid Biomass Fuels. *American Chemical Society. Division of Fuel Chemistry* 40(3), 688-693.
20. Olivares, Ana; Aznar, Maria P.; Caballero, Miguel A.; Frances, Eva; and Corella, Jose (1997): Improving the Product Distribution and Gas Quality in Biomass Gasification by In-Bed Use of Dolomite. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 745.
21. Reed, Thomas B. (1982): Oxygen Production for Biomass Gasification. In: *Biomass-to-Methanol Specialists' Workshop Proceedings*. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 79-82.
22. Scala, C. Von; Struis, R.; and Stucki, S. (1997): The Influence of Chlorine on the Gasification of Wood. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and*

Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 415-421.

23. Schmieder, H.; Abeln, J.; Boukis, N.; Dinjus, E.; Kruse, A.; Kluth, M.; Petrich, G.; Sadri, E.; and Schacht, M. (2000): Hydrothermal Gasification of Biomass and Organic Wastes. *The Journal of Supercritical Fluids* 17(2), 145-153.
24. Spangler, Michael J. (1995): Method for Producing Synthesis Gas. (to Amoco Corporation (Chicago, IL)) United States Patent 5,478,370, issued 26 December 1995.
25. Turn, S. Q.; Kinoshita, C. M.; Ishimura, D. M.; and Jenkins, B. M. (1997): Removal of Inorganic Constituents of Fresh Herbaceous Fuels: Processes and Costs. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials*. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 401-414.
26. Vriesman, P.; Heginuz, E.; and Sjoström, K. (2000): Biomass Gasification in a Laboratory-Scale AFBG: Influence of the Location of the Feeding Point on the Fuel-N Conversion. *Fuel* 79, 1371-1378.
27. Wang, Y.; Kinoshita, C. M. (1991): Temperature Field and Reaction Zones in Biomass Gasification. *Journal of Solar Energy Engineering* 113(4), 224-227.
28. Wilen, C.; Rautalin, A. (1993): Handling and Feeding Of Biomass to Pressurized Reactors: Safety Engineering. *Bioresource Technology* 46, 77-85.
29. Williams, Paul T.; Besler, Serpil (1993): Thermogravimetric Analysis of the Components of Biomass. In: *Advances in Thermochemical Biomass Conversion*. Vol. 2. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 771-783.
30. Zhou, Jiachun; Masutani, Stephen M.; Ishimura, Darren M.; Turn, Scott Q.; and Kinoshita, Charles M. (2000): Release of Fuel-Bound Nitrogen During Biomass Gasification. *Ind. Eng. Chem. Res.* 39(3), 626-634.

GASIFICATION: KINETICS & MODELING

1. Bechtel (1998): Aspen Process Flowsheet Simulation Model of a Battelle Biomass-Based Gasification, Fischer-Tropsch Liquefaction and Combined-Cycle Power Plant. Work Performed Under Contract No.: DE-AC22-93PC91029, for US Department of Energy, Office of Fossil Energy. Topical Report May 1998.
2. Bettagli, N.; Desideri, U.; and Fiaschi, D. (1995): A Biomass Combustion-Gasification Model: Validation and Sensitivity Analysis. *Journal of Energy Resources Technology* 117, 329-336.

3. Bilodeau, J.-F.; Therien, N.; Proulx, P.; Czernik, S.; and Chornet, E. (1993): A Mathematical Model of Fluidized Bed Biomass Gasification. *The Canadian Journal of Chemical Engineering* 71(8), 549-557.
4. Bingyan, X.; Chuangzhi, W.; Zhengfen, L.; and Xi Guang, Z. (1992): Kinetic Study on Biomass Gasification. *Solar Energy* 49(3), 199-204.
5. Blasi, Colomba Di (1997): Dynamic Models of Fixed-Bed Biomass Gasification Reactors. In: *Biomass Gasification and Pyrolysis: State of the Art and Future Prospects*. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 197-206.
6. Corella, J.; Aznar, M. P.; Gil, J.; Caballero, M. A.; and Martin, J. A. (1999): Modelling a Fluidized-Bed Gasifier of Biomass in Stationary State with In-Bed Use of Dolomite: Abrasion, Erosion and Carry Over of the Dolomite. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1049-1050.
7. Depew, C.; Martinez, A.; and Collodi, G. (1998): Dynamic Simulation for IGCC Process and Control Design. *Hydrocarbon Processing (International Edition)* 77(Jan), 107-110.
8. Frey, H. Christopher; Bharvirkar, Ranjit (1998): Desktop Modeling of the Performance, Emissions, and Cost of Gasification Systems. *Proceedings of the 91st Annual Meeting, Air and Waste Management Association*, 1-14.
9. Gea, G.; Murillo, M. B.; and Arauzo, J. (1999): Kinetics of CO₂ Gasification of Black Liquors from Alkaline Pulping of Straw. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 969-975.
10. Gobel, B.; Bentzen, J. D.; Henriksen, U.; and Houbak, N. (1999): Dynamic Modelling of the Two-Stage Gasification Process. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products*. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1025-1031.
11. Guo, Bing; Li, Dingkai; Cheng, Congming; Lü, Zi-an; and Shen, Youting (2001): Simulation of Biomass Gasification with a Hybrid Neural Network Model. *Bioresource Technology* 76, 77-83.
12. Henrich, E.; Bürkle, S.; Meza-Renken, Z. I.; and Rumpel, S. (1999): Combustion and Gasification Kinetics of Pyrolysis Chars from Waste and Biomass. *J. Anal. Appl. Pyrolysis* 49, 221-241.

13. Kayal, T. K.; Chakravarty, M.; and Biswas, G. K. (1994): Mathematical Modelling of Continuous Updraft Gasification of Bundled Jute Stick - A Low Ash Content Woody Biomass. *Bioresource Technology* 49, 61-73.
14. Kayal, T. K.; Chakravarty, M.; and Biswas, G. K. (1997): Mathematical Modelling of Steady State Updraft Gasification of Jute Particles Of Definite Sizes Packed Randomly - An Analytical Approach. *Bioresource Technology* 60, 131-141.
15. Korving, Arie; Schoen, Peter (1995): Dynamic Balance-of-Plant Model for a Coal Gasification Combined-Cycle Plant. *SAMS* 21, 267-278.
16. Li, X.; Grace, J. R.; Watkinson, A. P.; Lim, C. J.; and Ergüdenler, A. (2001): Equilibrium Modeling of Gasification: A Free Energy Minimization Approach and Its Application to a Circulating Fluidized Bed Coal Gasifier. *Fuel* 80(2), 195-207.
17. Manurung, R. K.; Bennackers, A. A. C. M. (1993): Modeling and Simulation of an Open Core Down-Draft Moving Bed Rice Husk Gasifier. In: *Advances in Thermochemical Biomass Conversion*. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 288-309.
18. Orfao, J. J. M.; Antunes, F. J. A.; and Fiueiredo, J. L. (1999): Pyrolysis Kinetics of Lignocellulosic Materials - Three Independent Reactions Model. *Fuel* 78, 349-358.
19. Pickett, Mathew Michael Russell (2000): Modeling the Performance and Emissions of British Gas/Lurgi-Based Integrated Gasification Combined Cycle Systems. MS Thesis, North Caroline State University.
20. Schuster, G.; Loffler, G.; Weigl, K.; and Hofbauer, H. (2001a): Biomass Steam Gasification - An Extensive Parametric Modeling Study. *Bioresource Technology* 77, 71-79.
21. Schuster, G.; Loffler, G.; Weigl, K.; and Hofbauer, H. (2001b): Biomass Steam Gasification - An Extensive Parametric Modeling Study. *Bioresource Technology* 77, 71-79.
22. Srivastava, Ajit K.; Posselius, John H. (1981): Dimensional Analysis and Similitude Modelling of the Gasification Process. In: 1981 Winter Meeting American Society of Agricultural Engineers, Palmer House, Chicago, Illinois, Dec. 15-18, 1981. 1981 ed. Vol. Paper no. 81-3588. (:) ASAE,, .
23. Uil, H. den; Mozaffarian, M.; Hemmes, K.; and Bracht, M. (1999): New and Advanced Processes for Biomass Conversion Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.

24. Walter, Arnaldo C.; Bajay, Sergio V.; and Nogueira, Luiz A. H. (1994): A Simulation Methodology to Evaluate BIG-STIG Systems in Sugar and Alcohol Plants. In: ASME Gogen Turbo Power '94. 1994 ed. Vol. 9. (Eds: Kidd, H. Allan; Fransson, Torsten H.; Cooke, David H.; and Greitzer, Edward M.) ASME, New York, 655-661.
25. Wang, Y.; Kinoshita, C. M. (1993): Kinetic Model of Biomass Gasification. Solar Energy 51(1), 19-25.

GASIFICATION: WASTES AND NON-BIOMASS

1. Borduin, Leon C.; Fewell, Thomas; Gombert, Dirk; and Priebe, Steve (1998): Mixed Waste Focus Area Alternative Oxidation Technologies Development and Demonstration Program. Presented at Waste Management Symposium. March 1-5, 1998. Tucson, AZ.
2. Fujimura, Hiroyuki; Hirayama, Yoshio; Fujinami, Shosaku; Nagato, Schuichi; Hirose, Tetsuhisa; Oshita, Takahiro; Irie, Masaaki; Takano, Kazuo; and Fukuda, Toshio (1999): Method for Treating Wastes by Gasification. United States Patent 5,900,224, issued 4 May 1999.
3. Holopainen, O. (1993): IGCC Plant Employing Heavy-Petroleum Residues. Bioresource Technology 46, 125-128.
4. Orr, Doug; Maxwell, David (2000): A Comparison of Gasification and Incineration of Hazardous Wastes. DCN 99.803931.02 ed. Radian International LLC, Austin, TX.
5. Voelker, Gary E.; Steedman, William G.; and Chandran, Ravi R. (1996): Steam Reforming of Low-Level Mixed Waste. Presented at the DOE/FETC conference titled "Industry Partnerships to Deploy Environmental Technology," Morgantown, West Virginia.

Gasification: Projects

1. Anderl, Helmut; Mory, Andreas; and Zotter, Thomas (1999): BioCoComb Gasification of Biomass and Co-Combustion of the Gas in a Pulverized-Coal-Boiler. Proceedings of the 15th International Conference on Fluidized Bed Combustion, May 16-19, 1999. Savannah, Georgia.
2. Babu, S. P. (1995): Thermal Gasification of Biomass Technology Developments: End of Task Report for 1992 to 1994. Biomass and Bioenergy 9(1-5), 271-285.
3. Babu, Suresh P.; Bain, Richard L.; and Craig, Kevin R. (1996): Thermal Gasification of Biomass Technology Development in the U.S.A. VTT Symposium 164, 55-65.
4. Bain, Richard L.; Craig, Kevin C.; and Overend, Ralph P. (1997): Biomass Gasification - Commercialization and Development: The Combined Heat and Power (CHP) Option.

Presented at the American Society of Mechanical Engineers. June 1997. Orlando, Florida.

5. Bain, R. L.; Overend, R. P. (1996): New Gasification Technology Offers Promise for Biomass Plants. *Power Engineering* 100(8, August), 32-39.
6. Barducci, GianLuca; Daddi, Paolo; Polzinette, GianCarlo; and Ulivieri, Piero (1995): Thermic and Electric Power Production and Use from Gasification of Biomass and RDF: Experience at CFBG Plant at Greve in Chianti. In: *Proceedings Second Biomass Conference of the Americas: Energy, Environment, Agriculture, and Industry.* (:) NREL, Golden, Colorado, 565-575.
7. Beenackers, A. A. C. M. (1993): Biomass Gasification: Implementation and Research in Europe. *Int. J. Solar Energy* 13(4), 249-260.
8. Beenackers, A. A. C. M.; Maniatis, K. (1997): Gasification Technologies for Heat and Power from Biomass. In: *Biomass Gasification and Pyrolysis: State of the Art and Future Prospects.* (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 24-51.
9. Belval, R. P.; Paisley, M. A.; Simpkins, E.; and Farris, G. (1997): The New Millennium Biomass Power Cycle Program. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials.* Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1407-1413.
10. Bilbao, R.; Garcia-Bacaicoa, P.; Uson, C.; and Seare, K. (1997): A Gasifier Integrated in a Hybrid Wind-Biomass System. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials.* Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1425-1434.
11. Brammer, J. G.; van de Beld, L.; Bridgwater, A. V.; and Assink, D. (1999): Development of a NOvel Reverse-Flow Slagging Gasifier for Small-Scale Cogeneration Applications. In: *Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products.* Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1119-1125.
12. Burr, Michael (1999): Biogas Rising. *Independent Energy* 6(Jul/Aug), 29-30.
13. Cleland, J.; Purvis, C. R. (1997): Demonstration of a 1 MWe Biomass Power Plant at USMC Base Camp Lejeune. In: *Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials.* Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 551-558.

14. Cleland, John G.; Purvis, Carol R. (1999): Camp LeJeune Energy from Wood (CLEW) Project. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1067-1073.
15. Czernik, S.; Koeberle, P. G.; Jollexz, P.; Bilodeau, J. F.; and Chornet, E. (1993): Gasification of Residual Biomass via the Biosyn Fluidized Bed Technology. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Glasgow, 423-437.
16. de Lange, H. J.; Barbucci, P. (1999): The Realisation of a Biomass-Fuelled IGCC Plant in Italy. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1079-1085.
17. de Lange, H. J.; Barbucci, P. (unknown): The Realisation of a Biomass-Fuelled IGCC Plant in Italy. obtained from Bioelettrica website: www.bioelettrica.it.
18. Elliott, P.; Booth, R. (1996): Biomass Energy for the Twenty First Century Commercial Demonstration of a Modern Biomass Power System Based on Gasification-Combined Cycle Tehnology. *Energy & Environment* 7(2), 191-208.
19. Farris, S. G. (1996): Commercial Demonstration of Biomass Gasification. Presented at TAPPI 1996 Engineering Conference; p. 567-596.
20. Harvey, Simon (1999): High Efficiency Steam Reforming of Biomass as a Means to Reduce Costs and Emissions of Heat Production in District Heating Systems. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
21. Kinoshita, Charles M.; Turn, Scott Q.; Overend, Ralph P.; and Bain, Richard L. (1997): Power Generation Potential of Biomass Gasification Systems. *J. Energy Eng.* 123(3, December), 88-99.
22. Koljonen, Jorma; Kurkela, Esa; and Wilen, Carl (1993): Peat-Based HTW-Plant at Oulu. *Bioresource Technology* 46, 95-101.
23. Larson, Eric D.; Consonni, Stefano (1997): Performance of Black Liquor Gasifier/Gas Turbine Combined Cycle Cogeneration in the Kraft Pulp and Paper Industry. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1495-1512.
24. Larson, E. D.; Kreutz, T. G.; and Consonni, S. (1997): Biomass And Black Liquor Gasifier/Gas Turbine Cogeneration at Pulp And Paper Mills. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy,

Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1321-1335.

25. Lindman, Nils (1993): Biomass Based Combined Cycles. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Glasgow, 511-521.
26. Lundqvist, R. G. (1993): The IGCC Demonstration Plant at Värnamo. Bioresource Technology 46, 49-53.
27. Oster, L. A.; Michaels, H. J. (1982): Peat as a Feedstock of the KBW Gasification Process. In: Biomass-to-Methanol Specialists' Workshop Proceedings. (Eds: Reed, Thomas B.; Graboski, Michael) Solar Energy Research Institute, CO, 61-77.
28. Overend, R. P.; Onischak, M.; Trenka, A.; and Kinoshita, C. (1993): The U.S. Department of Energy and The Pacific International Center for High Technology Research Pressurized Oxygen-Air Fluidized Bed Biomass Gasification Scaleup. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Glasgow, 438-448.
29. Paisley, Mark A.; Farris, Glenn; Slack, William; and Irving, John (1997): Commercial Development of the Battelle/FERCO Biomass Gasification Process - Initial Operation of the McNeil Gasifier. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 579-588.
30. Paisley, Mark A.; Farris, Milton C.; Black, John; Irving, John M.; and Overend, Ralph P. (1999): Commercial Demonstration of the Battelle/FERCO Biomass Gasification Process: Startup and Initial Operating Experience. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1061-1066.
31. Paisley, M. A.; Farris, M. C.; Black, J. W.; Irving, J. M.; and Overend, R. P. (2000): Preliminary Operating Results from the battelle/FERCO Gasification Demonstration Plant in Burlington, Vermont, USA. Presented at 1st World Conference and Exhibition on Biomass for Energy and Industry in Seville, Spain. May 2000.
32. Paisley, M. A.; Irving, J. M.; and Overend, R. P. (2001): A Promising Power Option - The FERCO Silvagas Biomass Gasification Process - Operating Experience at the Burlington Gasifier. Proceedings of ASME Turbo Expo 2001 ASME Turb Expo Land, Sea, & Air 2001, June 4-7, New Orleans, Louisiana.

33. Rensfelt, E. K. W. (1997): Atmospheric CFB Gasification - The Grève Plant and Beyond. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kalschmitt, M.; Bridgewater, A. V.) CPL Scientific Limited, UK, 139-159.
34. Roque, P.; Ponce, F.; Lopez, P.; Rubio, A.; and Perez, R. (1997): Demonstration BIG/GT/CC Plant Working on Sugar Cane Biomass. General Considerations. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1379-1387.
35. Schenkel, Y.; Grulois, C.; Martin, J.; Bourgois, F.; Jossart, J.-M.; and Meekers, E. (1997): SRC-Gazel: A Full-Scale Pilot Project. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 465-476.
36. Ståhl, K.; Neergaard, M.; and Nilsson, P.-A. (1997): Pressurized CFB Gasification - The Värnamo Plant. In: Biomass Gasification and Pyrolysis: State of the Art and Future Prospects. (Eds: Kalschmitt, M.; Bridgewater, A. V.) CPL Scientific Limited, Newbury, UK, 160-171.
37. Van Den Broek, R.; De Miranda, R. C.; and Van Wijk, A. (1997): Combined Heat and Power Generation from Bagasse and Eucalyptus by Sugarmills In Nicaragua. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1389-1400.
38. van der Drift, A.; de Kant, H. F.; and Rajai, J. B. (2000): Commercialization BIVKIN-Based Gasification Technology. The non-confidential version is available at ECN website. ECN-C-00-080.
39. Weeks, Sim T.; Rohrer, John W. (1997): Commercial Demonstration of Biomass Gasification. TAPPI 80(5), 147-152.
40. Wiant, B.; Larkin, J.; and Onischak, M. (1997): Hawaiian Biomass Gasification Commercialization Program. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. Addendum. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, .
41. Wiltsee, G. (1998): Advanced Biomass: Technology Characteristics, Status and Lessons Learned. Vol. TR-111882. EPRI, Palo Alto, CA 94303.
42. Wiltsee, G. A. (1999): Lessons Learned from Existing Biomass Power Plants. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in

Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 79-84.

SYSTEM INTEGRATION: CONCEPTS

1. Abatzoglou, N.; Fernandez, J.-C.; Laramée, L.; Jollez, P.; and Chornet, E. (1997): Application of Gasification to the Conversion of Wood, Urban and Industrial Wastes. *Developments in Thermochemical Biomass Conversion* 2, 960-972.
2. Amos, Wade A. (Ed.) (1998): Analysis of Two Biomass Gasification/Fuel Cell Scenarios for Small-Scale Power Generation. NREL/TP-570-25886 ed. NREL, Golden, CO.
3. Arrieta, Felipe Raúl Ponce; Sánchez, Caio Glauco (1999): BIG-GT and CEST Technologies for Sugar Cane Mill. Thermodynamic and Economic Assessments. Presented at 2nd Olle Lindström Symposium on Renewable Energy, Bioenergy, 9-11 June, 1999 at Royal Institute of Technology, Stockholm, Sweden.
4. Campbell, P. E.; MuMullen, J. T.; and Williams, B. C. (2000): Concept for a Competitive Coal Fired Integrated Gasification Combined Cycle Power Plant. *Fuel* 79, 1031-1040.
5. Dong, Ynanji; Cole, Edward (1996): Evaluation of Biomass Reactivity in Hydrogasification for the Hynol Process. United States Environmental Protection Agency, EPA/600/SR-96/071 Oct. 1996.
6. Hanrahan, Robert J.; Parker, Robin Z.; and Heaton, Harley L. (2000): Comprehensive System for Utility Load Leveling, Hydrogen Production, Stack Gas Cleanup, Greenhouse Gas Abatement, and Methanol Synthesis. (to Solar Reactor Technologies, Inc.) US Patent 6093306, issued 25 July 2000.
7. Janda, Gary F.; Kuechler, Keith H.; Guide, John J.; Mittricker, Frank F.; and Roberto, Frank (1999): High efficiency reformed methanol gas turbine power plants. (to Exxon Chemical Patents Inc.) Application: US. US Patent 5927063, issued 27 July 1999.
8. Kaltschmitt, M.; Bridgwater, A. V. (1997): Research, Development and Demonstration Needs for Biomass Gasification and Pyrolysis. In: *Biomass Gasification and Pyrolysis: State of the Art and Future Prospects*. (Eds: Kaltschmitt, M.; Bridgwater, A. V.) CPL Scientific Limited, Newbury, UK, 537-550.
9. Larson, Eric D. (1999): Advanced Technologies for Biomass Conversion to Energy. see ref #311.
10. Neathery, J.; Gray, D.; Challman, D.; and Derbyshire, F. (1999): The Pioneer plant Concept: Co-production of Electricity and Added-value Products from Coal. *Fuel* 78, 815-823.

11. Schmid, Christoph; Mühlen, Heinz-Jürgen (1999): Staged-Reforming - A Thermal Conversion Process Specifically Developed for Biomass. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
12. Schmidt, D. D.; Pavlish, J. H.; Mann, M. D.; and Robb, M. F. (1999): An Advanced Modular Fluid-Bed Combustion Concept for Biomass Utilization. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1475-1480.
13. Sethi, Prab; Chaudhry, Shahid; and Unnasch, Stefan (1999): Methanol Production from Biomass Using the Hynol Process. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 833-836.
14. Silveira, José Luz; Martins, Elisângela; Gomes, Lincoln Alex; and Ragonha, Luiz Fernando Jr (1999): Study of a Fuel Cell Cogeneration System: Energetic, Exergetic and Economic Analysis. Presented at 2nd Olle Lindström Symposium on renewable Energy, Stockholm, Sweden, June 9-11, 1999. P. 190-196.
15. Solantausta, Y.; Bridgwater, A. T.; and Beckman, D. (1995): Feasibility of Power Production with Pyrolysis and Gasification Systems. Biomass and Bioenergy 9(1-5), 257-269.
16. Solantausta, Yrjö; Mäkinen, Tuula; McKeough, Paterson; and Kurkela, Esa (1993): Performance of Cogeneration Gasification Combined-Cycle Power Plants Employing Biomass As Fuel. In: Advances in Thermochemical Biomass Conversion. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 476-494.
17. Steinberg, Meyer (1997): The Carnol Process System for CO₂ Mitigation and Methanol Production. Energy - The International Journal 22(2), 143-149.
18. Steinberg, Meyer (unknown): The Carnol System for Methanol Production and Comitigation from Coal Fired Power Plants and The Transportation Section. Brookhaven National Laboratory, Upton, N.Y. 11973.
19. Unnasch, Stefan (1996): Hynol Process Engineering: Process Configuration, Site, Plan, and Equipment Design. United States Environmental Protection Agency, Research and Development, May 1996. EPA/600/SR-96/006.
20. Yamada, K.; Konishi, K.; Okada, O.; and Steinberg, M. (1992): Evaluation of Hydrocarb Process for CO₂ Removal. Energy Conv. Mgmt. 33(5-8), 437-441.
21. Yamauchi, Yasuhiro; Tokita, Yuuji; Murakami, Nobuaki; Takita, Katsuhiko; Muraishi, Kensuki; Kaneko, Shozo; Uchida, Satoshi; Ukeguchi, Nobuhiro; and Shirakawa,

Seiichi (1994): Method for producing methanol by use of nuclear heat and power generating plant. (to Mitsubishi Jukogyo Kabushiki Kaisha) Application: Japan. US Patent 5312843, issued 17 May 1994.

22. Zysin, L. V.; Koshkin, N. L. (1993): Utilization of Biomass Based on Thermochemical Gasification for Power Generation. *Thermal Engineering* 40(4), 281-284.

SYSTEM INTEGRATION: ECONOMICS

1. Barker, S. N. (1996): Gasification and Pyrolysis - Routes to Competitive Electricity Production from Biomass in the UK. *Energy Conv. Mgmt.* 37(6-8), 861-866.
2. Bridgwater, Anthony V.; Anders, Mark (1991): Economics of Liquid Fuels Production by Coal Gasification. *Fuel* 70, 1193-1207.
3. Brown, R. E.; Delaney, R. C.; Hsu, W. W.; Ravikuma, R. H.; Smelser, S. C.; and Stock, R. M. (Eds.) (1982): Economic Evaluation of the Coproduction of Methanol and Electricity with Texaco Gasification-Combined-Cycle Systems. Vol. AP-2212. EPRI, Palo Alto, CA.
4. Chick, A. P.; Picken, D. J. (1996): The Economics of Short Rotation Coppicing for Gasification and Electricity Production on Site. *International Journal of Ambient Energy* 17(4), 207-211.
5. Craig, Kevin R.; Mann, Margaret K. (Eds.) (1996): Cost and Performance Analysis of Biomass-Based Integrated Gasification Combined-Cycle (BIGCC) Power Systems. NREL/TP-430-21657 ed. NREL, Golden, CO.
6. DeLong, Max M. (1995): Economic Development Through Biomass System Integration: Summary Report. NREL/TP-430-20517 ed. Vol. 1-4 and Summary. NREL, Golden, CO.
7. Graig, Kevin R.; Mann, Margaret K.; and Bain, Richard L. (1994): Cost and Performance Potential of Advanced Integrated Biomass Gasification Combined Cycle Power Systems. In: *ASME Gogen Turbo Power '94*. 1994 ed. Vol. 9. (Eds: Kidd, H. Allan; Fransson, Torsten H.; Cooke, David H.; and Greitzer, Edward M.) ASME, New York, 641-654.
8. McConnell, Chuck; Drnevich, Ray; and Simbeck, Dale (2000): Gasification Project Economics and Critical Success Factors to Complete in the Marketplace. Paper Presented at 2000 Gasification Technologies Conference, San Francisco, CA, Oct. 8-11, 2000.
9. Tanaka, K.; Wen, C.; and Yamada, K. (2000): Design and Evaluation of Combined Cycle System with Solid Oxide Fuel Cell and Gas Turbine. *Fuel* 79, 1493-1507.

10. Vivenzio, T. A.; Shectman, D. L.; and Wells, P. D. (1995): Performance and Cost of an IVOSDIG Biomass Gasification Combined Cycle System. Vol. TR-105356. EPRI, Palo Alto, CA.
11. Weyerhaeuser (1996): New Bern Biomass to Energy Feasibility Study. Vol. TR-106062. EPRI, Palo Alto, CA 94304.

SYSTEM INTEGRATION: POWER GENERATION AND BIOFUELS

1. Anikeev, V. (1999): Modern Technologies of the Biomass Conversion for Chemicals, Carbon Sorbents, Energy, Heat and Hydrocarbon Fuels Production. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 563-569.
2. Cipollone, Roberto; Cocco, Daniele; and Bonfitto, Emanuele (1999): Integration between Gas Turbine Plants and Biomass Drying Processes. In: Proceedings of the 4th Biomass Conference of the Americas: A Growth Opportunity in Green Energy and Value-Added Products. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 291-298.
3. Easterly, James L. (1997): Economics of Integrated Ethanol and Electricity Production. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1641-1649.
4. Haavisto, I. (1996): Fixed Bed Gasification of Solid Biomass Fuels. VTT Symposium 164, 127-132.
5. Holt, Neville A. H. (2001+): Integrated Gasification Combined Cycle Power Plants. to be published in Encyclopedia of Technology.
6. Hughes, Wendy E. M.; Larson, Eric D. (1995): Performance Prediction of Potential First-Generation Commercial Biomass-Gasifier/Gas Turbine Power Plants. Presented at The 1995 Harare Solar World Congress, Harare, Zimbabwe.
7. Joshi, Medha M.; Lee, Sunggyu (1996): Integrated Gasification Combined Cycle - A Review of IGCC Technology. Energy Sources 18, 537-568.
8. Karg, Jürgen; Haupt, Günther; and Zimmermann, Gerhard (2000): Optimized IGCC Cycles for Future Applications. Paper Presented at 2000 Gasification Technologies Conference, San Francisco, California, October 8-11, 2000.
9. Larson, E. D. (1992): Biomass-Gasifier/Gas-Turbine Applications in the Pulp and Paper Industry: An Initial Strategy for Reducing Electric Utility CO₂ Emissions. In: Proceedings: Ninth EPRI Conference on Gasification Power Plants. Vol. TR-100466s. (Ed: Holt, Neville A.) EPRI, Palo Alto, CA, 31-1 to 31-21.
10. Larson, Eric D. (1999): Advanced Technologies for Biomass Conversion to Energy. (presented at 2nd Olle Lindström Symposium on Renewable Energy: Bioenergy; Royal Institute of Technology; Stockholm, Sweden; p. 1-10)

11. Larson, Eric D.; Consonni, Stefano (1997): Performance of Black Liquor Gasifier/Gas Turbine Combined Cycle Cogeneration in the Kraft Pulp and Paper Industry. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1495-1512.
12. Lindman, Nils (1992): Biomass Based Combined Cycles. Advances in Thermochemical Biomass Conversion 1, 511-521. (3rd International Conference on Advances in Thermochemical Biomass Conversion; May 1992, Intelken, Switzerland)
13. Manderbach, M. (1997): Wood and Biomass Firing - A State-of-the-Art of Technologies. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 519-527.
14. Morris, Michael; Waldheim, Lars (2000): Efficient Power Generation from Wood Gasification. Paper Presented at Gasification for the Future, 11-13 April 2000, Noordwijk, The Netherlands.
15. Perka, Alan T.; Hsiung, Thomas T.; Klosek, Joseph; and Moore, Robert B. (1990): IGCC process with combined methanol synthesis/water gas shift for methanol and electrical power production. (to Air Products and Chemicals, Inc.) Application: US. US Patent 4946477, issued 7 Aug 1990.
16. Pitcher, K.; Lundberg, H. (1997): The Development of a Wood Fuel Gasification Plant Utilizing Short Rotation Coppice and Forestry Residues, Project ARBRE. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1367-1378.
17. Porter, Kevin; Wiser, Ryan (2000): Biomass Power and State Renewable Energy Policies Under Electric Utility Industry Restructuring. Paper Presented at Bioenergy 2000, Buffalo, New York. October 15-19, 2000.
18. Raymond, Delmar; Kieffer, Judith (1999): Biomass Gasification Combined Cycle - A Shared Opportunity for the Nation and Industry. TAPPI Pulping Conference 3, 883-901.
19. Reed, Thomas B. (1997): World State of Gasification. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemical, Fibers and Materials. Vol. 1. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 589-595.
20. Shellhorse, V. H.; Garstang, J. H.; Herbert, P. K.; and Kluttz, D. E. (1995): Repowering Applications Using the British Gas/Lurgi Fixed-Bed Gasification Process. Proceedings of The American Power Conference 57, 70-77.

21. Smeenk, J.; Steinfeld, G.; Brown, R. C.; Simpkins, E.; and Dawson, R. M. (1997): Evaluation of an Integrated Biomass Gasification/Fuel Cell Power Plant. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. Vol. 2. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1353-1361.
22. de Souza-Santos, Marcio L. (1999): A Feasibility Study of an Alternative Power Generation System Based on Biomass Gasification/Gas Turbine Concept. *Fuel* 78, 529-538.
23. Sipilä, Kai; Kurkela, Esa; and Solantausta, Yrjö (1993): New Options for Biomass-Based Power Production by IGCC. A Finnish National Research Programme - JALO. In: *Advances in Thermochemical Biomass Conversion*. Vol. 1. (Ed: Bridgwater, A. V.) Blackie Academic & Professional, Cambridge, UK, 77-91.
24. Stanzel, W. C.; Boncimino, G. J. (2000): Combined Cycle Plant Optimization Studies: Evaluations of Heat Recovery Steam, Generator Design, Duct Firing and Combustion Turbine Inlet Air Cooling Options. Vol. 1000684. EPRI, Palo Alto, CA 94303.
25. Sterzinger, George (1995): Making Biomass Energy a Contender. *Technology Review* 98(October), 34-40.
26. Stricker, J. A.; Tuohy, P. G.; Rahmani, M.; and Hodges, A. W. (1997): Scale-Up of a Dedicated Biomass Feedstock System for Production of Ethanol and Electricity. In: Proceedings of the 3rd Biomass Conference of the Americas: Making a Business from Biomass in Energy, Environment, Chemicals, Fibers and Materials. (Eds: Overend, Ralph P.; Chornet, Esteban) Pergamon, Great Britain, 1093-1101.
27. Tait, K. M.; McDonald, M. M. (1994): Recent developments in IGCC Technology. *CIM Bulletin* 87, 27-35.
28. Waldheim, L.; Morris, M. (2000): Biomass Power Generation: Sugar Cane Bagasse and Trash. Paper Presented at Progress in Thermochemical Biomass Conversion, 17-22 September 2000, Tyrol, Austria.

8.0 APPENDIX

Literature Survey of Biomass Gasification Technologies

TABLE OF CONTENTS

1	LITERATURE SURVEY OF BIOMASS GASIFICATION TECHNOLOGIES	138
1.1	BIOMASS GASIFICATION TECHNOLOGIES.....	138
1.1.1	<i>Simple Biomass Gasification Systems</i>	<i>138</i>
1.1.1.1	BG Technologies USA, Inc.	138
1.1.1.2	BIVKIN Gasification Technology	139
1.1.1.3	Brightstar Synfuels Co./Brightstar Environmental	142
1.1.1.4	Cratech Gasification System.....	145
1.1.1.5	Energy Products of Idaho.....	145
1.1.1.6	Enerkem-Biosyn Gasification.....	146
1.1.1.7	PRM Energy Systems, Inc.....	148
1.1.1.8	Thermogenics	149
1.1.1.9	Thermoselect, S.A.	150
1.1.1.10	TPS Termiska Processer AB	152
1.1.1.11	Thermal Technologies, Inc.	156
1.1.1.12	Etho Power Corporation.....	157
1.1.1.13	Emery Gasification	157
1.1.1.14	Other Biomass Gasification Developments.....	158
1.1.2	<i>Advanced Biomass Gasification Systems.....</i>	<i>160</i>
1.1.2.1	Foster Wheeler Gasification Technologies	160
1.1.2.1.1	Bioneer Atmospheric Updraft Gasifiers.....	160
1.1.2.1.2	Pyroflow Atmospheric Circulating Fluidized-Bed Gasifiers	160
1.1.2.1.3	Bioflow Pressurized Circulating Fluidized-Bed Gasifiers	163
1.1.2.2	Battelle High-Throughput Gasification Process (BHTGP).....	166
1.1.2.3	GTI Pressurized Fluidized-bed Gasifier (Renugas®).....	170
1.1.2.3.1	Renugas® Hawaii Biomass Gasifier Project	171
1.1.2.3.2	Renugas® Pilot Plant in Tampere, Finland	174
1.1.2.3.3	Renugas® VEGA IGCC Demonstration Project.....	178
1.1.2.3.4	Biocycle Project in Denmark	179
1.1.2.3.5	Renugas® MnVAP IGCC Demonstration Project	180
1.1.2.4	Energy Farm Project in Di Cascina, Italy	180
1.1.2.5	ARBRE Energy Project	182
1.1.2.6	Brazil Biomass Integration Gasification-Gas Turbine	184
1.1.2.7	BioCoComb Project	185
1.1.2.8	Summary of Advanced Biomass Gasification Systems.....	187
2	REFERENCES	ERROR! BOOKMARK NOT DEFINED.
3	BIBLIOGRAPHY	ERROR! BOOKMARK NOT DEFINED.
	BIOMASS POWER: HEAT AND POWER SYSTEMS.....	ERROR! BOOKMARK NOT DEFINED.
	CHEMICAL PRODUCTION FROM GASIFICATION AND SYNGAS.....	ERROR! BOOKMARK NOT DEFINED.
	THE CARBON CONNECTION-CO ₂ REMOVAL, MITIGATION, SEQUESTRATION.....	ERROR! BOOKMARK NOT DEFINED.
	LIFE CYCLE OF BIOMASS AND COAL IGCC.....	ERROR! BOOKMARK NOT DEFINED.
	FEEDSTOCKS: EVALUATION, CHARACTERIZATION, AND DRYING.....	ERROR! BOOKMARK NOT DEFINED.
	GASIFICATION: BIOMASS	ERROR! BOOKMARK NOT DEFINED.
	GASIFICATION: WASTE/PRODUCT CHARACTERIZATION.....	ERROR! BOOKMARK NOT DEFINED.
	GASIFICATION: COAL	ERROR! BOOKMARK NOT DEFINED.
	GASIFICATION: CO-FEEDING	ERROR! BOOKMARK NOT DEFINED.
	GASIFICATION: FUNDAMENTALS.....	ERROR! BOOKMARK NOT DEFINED.
	GASIFICATION: KINETICS & MODELING.....	ERROR! BOOKMARK NOT DEFINED.
	GASIFICATION: WASTES AND NON-BIOMASS	ERROR! BOOKMARK NOT DEFINED.
	SYSTEM INTEGRATION: CONCEPTS.....	ERROR! BOOKMARK NOT DEFINED.
	SYSTEM INTEGRATION: ECONOMICS.....	ERROR! BOOKMARK NOT DEFINED.
	SYSTEM INTEGRATION: POWER GENERATION AND BIOFUELS.....	ERROR! BOOKMARK NOT DEFINED.

TABLE OF TABLES

TABLE 1. INVESTMENT FOR BIVKIN-BASED GASIFICATION SYSTEMS.....	141
TABLE 2. SUMMARY OF EMISSIONS FOR WHYTES GULLY SITE.....	144
TABLE 3. COMPOSITION OF ECALENE™ (POWER ENERGY FUELS)	149
TABLE 4. CURRENT DEVELOPMENTS ON BIOMASS GASIFICATION FOR HEAT AND/OR POWER GENERATION (BTG)	159
TABLE 5. SPECIFICATIONS OF THE GASIFICATION PLANT AT LAHTI, FINLAND.....	163
TABLE 6. TECHNICAL DATA FOR VÄRNAMO BIGCC PLANT (STÅHL, 1997)	165
TABLE 7. PRODUCT GAS COMPOSITION FROM THE BIGCC AT VÄRNAMO, SWEDEN.....	166
TABLE 8. BENZENE AND LIGHT TARS CONCENTRATIONS.....	166
TABLE 9. STATISTICS OF THE BURLINGTON BIOMASS GASIFICATION PLANT.....	168
TABLE 10. COMPARISON OF DATA FROM THE PRU AND MCNEIL STATION (PAISLEY, 2001).....	169
TABLE 11. OPERATING CONDITIONS OF RENUGAS® PDU GASIFIER.....	170
TABLE 12. TEST RESULTS OF RENUGAS® GASIFIER (GTI).....	174
TABLE 13. OPERATING CONDITIONS OF THE DEMONSTRATION GASIFICATION PLANT IN TAMPERE	176
TABLE 14. FEEDSTOCK TESTED AT DEMONSTRATION PLANT IN TAMPERE	177
TABLE 15. COMPOSITION OF GAS PRODUCED FROM DEMONSTRATION PLANT IN TAMPERE.....	177
TABLE 16. CALCULATED GAS COMPOSITION AT 55% MOISTURE.....	187
TABLE 17. ADVANCED GASIFICATION DEMONSTRATION (ADAPTED FROM BEENACKERS, 1997).....	189

TABLE OF FIGURES

FIGURE 1. PROCESS DIAGRAM OF THE BIVKIN GASIFICATION TECHNOLOGY (VAN DER DRIFT ET AL., 2000)	139
FIGURE 2. PICTURES OF THE BIVKIN-BASED GASIFICATION SYSTEM PILOT PLANT (ECN)	140
FIGURE 3. FLOW SHEET OF THE 5 AND 12.5 MW _{TH} BIVKIN-BASED POWER PLANT	141
FIGURE 4. FLOW SHEET OF THE 14.7 MW _{TH} BIVKIN-BASED POWER PLANT	142
FIGURE 5. SCHEMATIC DIAGRAM OF THE SWERF TM TECHNOLOGY	143
FIGURE 6. AERIAL PHOTO OF THE WHYTES GULLY FACILITY IN WOLLONGONG	144
FIGURE 7. CRATECH GASIFICATION SYSTEM (PURVIS AND CRAIG, 1998)	145
FIGURE 8. BIOSYN PDU AT UNIVERSITÉ DE SHERBROOKE (CZERNIK, 1993)	147
FIGURE 9. FLOW DIAGRAM OF THE 500-GPD FACILITY AT WRI (LUCERO, 2001)	150
FIGURE 10. THERMOSELECT HTR GASIFIER (JUNIPER CONSULTANCY SERVICES LTD, 2000)	151
FIGURE 11. THE MINO GASIFICATION PROCESS	152
FIGURE 12. TPS ACFB GASIFIER	153
FIGURE 13. TPS PILOT PLANT WITH TAR CRACKER	154
FIGURE 14. FLOW DIAGRAM OF THE TPS GASIFICATION SYSTEM FOR RDF IN GRÈVE-IN-CHIANTI, ITALY	154
FIGURE 15. TPS BIGCC CONCEPT (MORRIS, 2000)	155
FIGURE 16. CAMP LEJEUNE ENERGY FROM WOOD (CLEW) PROJECT	156
FIGURE 17. EMERY'S 25 TON/DAY GASIFIER	158
FIGURE 18. FOSTER WHEELER'S PYROFLOW ACFB GASIFIER	161
FIGURE 19. FLOW DIAGRAM FOR THE CFB GASIFIER AT LAHTI, FINLAND	162
FIGURE 20. THE CFB GASIFICATION PLANT AT LAHTI, FINLAND	162
FIGURE 21. BIGCC AT VÄRNAMO, SWEDEN BASED ON THE BIOFLOW GASIFIER (STÅHL, 1999)	164
FIGURE 22. FERCO'S SILVA GAS TM PROCESS AT BURLINGTON, VERMONT	167
FIGURE 23. FLOW DIAGRAM OF THE BATTELLE/FERCO IGCC AT MCNEIL GENERATING STATION	168
FIGURE 24. ISOMETRIC VIEW OF THE 12 TPD GTI PDU	170
FIGURE 25. GTI DEMONSTRATION PLANT GASIFIER	172
FIGURE 26. RENUGAS [®] DEMONSTRATION PLANT IN PAIA, HAWAII	172
FIGURE 27. COAL/BIOMASS DEMONSTRATION PLANT AT TAMPERE, FINLAND (COURTESY OF CARBONA)	175
FIGURE 28. GASIFICATION DEMONSTRATION PLANT AT TAMPERE, FINLAND (COURTESY OF CARBONA)	176
FIGURE 29. PICTURE OF THE GASIFICATION DEMONSTRATION PLANT IN TAMPERE, FINLAND (COURTESY OF CARBONA)	178
FIGURE 30. FLOW DIAGRAM OF THE PROPOSED VEGA BIOMASS IGCC IN SWEDEN (LINDMAN, 1993)	179
FIGURE 31. BIOCYCLE PROJECT IN FINLAND	180
FIGURE 32. FLOW DIAGRAM OF THE ENERGY FARM PROJECT IN ITALY	181
FIGURE 33. ARBRE PROJECT IN YORKSHIRE, UK	182
FIGURE 34. PROJECT ARBRE SITE AT YORKSHIRE, UK AS OF DECEMBER, 1999	183
FIGURE 35. GASIFICATION SECTION OF PROJECT ARBRE PLANT	183
FIGURE 36. CFB GASIFIER USED AT THE BIOCoCoMB PROJECT IN AUSTRIA	186

1 LITERATURE SURVEY OF BIOMASS GASIFICATION TECHNOLOGIES

1.1 BIOMASS GASIFICATION TECHNOLOGIES

Biomass gasification has a long development history. Numerous systems have been developed and commercialized in the past to supply thermal energy and fuel gas or synthesis gas (syngas) for industrial and transportation applications. Simple gasification systems are still available today that are suitable for developing countries where large quantities of easily accessible biomass are available. These systems are generally low efficiency and produce either heat or electrical power. Advanced systems are needed for western countries for power and combined heat/power generation. Advanced systems provide high efficiencies with reduced emissions to mitigate greenhouse gas emissions. A literature review was conducted to identify and define various gasification systems for heat and/or electrical power generation. Much information was obtained from the internet through company websites, news releases, and various interest groups. The report published by Juniper Consultancy Services Ltd. ("Technology and Business Review: Pyrolysis and Gasification of Waste – A Worldwide Technology and Business Review," Vol. 1 & 2, 2000) was also used extensively. This literature survey summarizes simple systems for heat and/or power generation (that are suitable when efficiency and emissions are not priority factors) and advanced systems for power and combined heat/power generation.

1.1.1 Simple Biomass Gasification Systems

Simple gasification systems produce syngas with a low-heating content at atmospheric or low pressure. The fuel syngas can be used for operating gas engines for small-scale power production. In general, the syngas is not suitable for advanced turbines or chemical production. Over 14 of these simple systems are reviewed.

1.1.1.1 BG Technologies USA, Inc.

BG Technologies USA, Inc., has licensed gasification technology from Ankur Scientific Energy Technologies PVT, LTD., of India for worldwide distribution (www.bgtechnologies.net and www.ankurscientific.com). Ankur Scientific has over 400 installations worldwide using this technology for processing wood chips, palm nut shells, cotton stalks, rice hulls, maize cobs, soy husks, coconut shells, and sawdust. The BG Technologies electric system consists of a biomass gasifier, gas cleaning and cooling equipment, and a diesel generator. The diesel generator is operated under dual fuel mode using diesel and producer gas from the gasifier which reduces diesel consumption by about 70%. The main objective of this system is to displace some of the fuel requirement for the diesel generator. Three systems are offered at 100, 250, and 400 kW_e capacities with conversion efficiencies ranging from 70-75%. The typical composition of the syngas is 19±3% CO, 10±4% CO₂, 50% N₂, 18±2% H₂, and up to 3% of CH₄.

1.1.1.2 BIVKIN Gasification Technology

The Netherlands Energy Research Foundation (ECN) in Petten, Netherlands, developed and built a pilot circulating fluidized bed (CFB) gasification plant using the BIVKIN (Biomassa Vergassings Karakteriserings Installatie) process in cooperation with Novem, Afvalzorg, and Stork (Van den Broek, et al., 1997). The plant was initially used at the ECN location in Petten for the characterization of more than 15 different biomass species, including wood, sludge, grass, and manure. ECN has been conducting tests to improve the gas quality so that it can be used for electrical generation in a gas engine. The CFB gasifier is integrated with a 500 kW_e internal combustion (IC) engine at the pilot plant. A diagram of the BIVKIN process is shown in Figure 1.

Figure 1. Process Diagram of the BIVKIN Gasification Technology (Van der Drift et al., 2000)

Operation of the pilot plant was initiated in 1996. It had operated for more than 500 hours with various fuels as of August 2000. The operation of the gasifier is very stable, and complete automation of the gasifier is possible. Pictures of the BIVKIN-based gasification plant in Petten, Netherlands, are shown in Figure 2.

Figure 2. Pictures of the BIVKIN-based Gasification System Pilot Plant (ECN)

ECN, Shell, and HoSt (with co-financing from Novem) performed a study to evaluate the engineering concept and cost for a commercial-scale facility using the BIVKIN technology in the electrical output range of 1 to 5 MW_e. A non-confidential version of the report is available from ECN (Van der Drift et al., 2000). The study evaluated three different sizes with the following scenarios: 5 MW_{th} gasifier with gas engine for electricity production, 12.5 MW_{th} gasifier with gas engine for electricity production, and 14.7 MW_{th} gasifier with gas engine and steam turbine for electricity production. The fuels evaluated were clean biomass at 40% moisture, clean biomass at 10% moisture, and contaminated biomass at 10% moisture. For the wet biomass (40%), the fuel inputs were adjusted to 4.62, 11.55, and 13.58 MW_{th} to compensate for the additional water. A dryer is required to remove the excess water to provide the stated fuel input to the gasifier. The schemes for these are shown in Figure 3 and Figure 4. Costs of items such as engineering, instrumentation, electric equipment, piping, and civil were determined based on detailed calculations for an 8 MW_{th} biomass combustion plant that was actually built in Lelystad, Netherlands. A summary of the investment for these scenarios is shown in Table 1.

Table 1. Investment for BIVKIN-based Gasification Systems

Fuel Input		14.7	12.5	5
Electricity (no heat)				
Net electricity output	MW _e	4.27		
1 st Commercial plant investment	M\$	13.6		
	\$/kW _e	3180		
10 th Plant investment	M\$	12.2		
	\$/kW _e	2860		
Combined Heat and Power				
Net electricity output	MW _e	4.06	3.20	1.27
Net heat output	MW _{th}	4.17	4.45	1.79
1 st Commercial plant investment	M\$	13.2	10.2	5.6
	\$/kW _e	3250	3190	4370
10 th Plant investment	M\$	11.8	8.9	4.6
	\$/kW _e	2900	2770	3660

Figure 3. Flow sheet of the 5 and 12.5 MW_{th} BIVKIN-based power plant

Figure 4. Flow sheet of the 14.7 MW_{th} BIVKIN-based power plant

The capital investment estimates for these scenarios are similar or better than other similarly sized gasification processes under development (as shown later in Table 4). The total efficiency of the plant is assumed to be 70% and 65% with and without the steam turbine, respectively. The efficiency drops to 66% and 61%, respectively, with the 40% moisture biomass. One of the conclusions that can be drawn is that the added steam turbine does not warrant the extra investment at these scales. The cost of the electricity ranges from 5-7¢/kWh when the fuel cost is \$0-1.5/GJ (\$0-1.58/Btu) and 8-11¢/kWh when the fuel cost is \$2-4/GJ (\$2.11-\$4.22/Btu) (clean biomass).

1.1.1.3 Brightstar Synfuels Co./Brightstar Environmental

Brightstar Synfuels, Co., (BSC) developed a gasification concept in 1989 with tests in a 25-90 kg/h (55.1-198.4 lb/h) pilot plant. They subsequently scaled up to a commercial unit in 1994 at a particleboard plant. The plant had a capacity of 17,600 kg/h (38,801 lb/h) of sander dust. It was terminated in 1995 because of problems with the heat recovery equipment used in the gas cooling system. A free standing Commercial Demonstration Facility (CDF) was built near Baton Rouge, Louisiana, in 1996 with design throughput of 680 kg/h (1,499 lb/h). The facility was operated continuously to prove the concept and refine the process. This facility was considered a commercial scale facility because of the "tubular entrained flow" design. Multiple gasifiers would be used in larger capacities. Various feedstocks such as sawdust and sander dust, bark and wood chips, pulp and paper mill sludge, rice hulls, sugar cane bagasse, and sewage sludge were tested. Louisiana State University's Institute for Environmental Studies supported the demonstration plant in Louisiana. The syngas produced from the system had the following composition: 30-40% H₂, 20-30% CO, 10-15% CH₄, 15-20% CO₂, 1% C₂H₄, 6% water, and 1% N₂.

The major steps in the Brightstar process are:

1. Delivery of biomass to a metering bin from which it is conveyed with recycled syngas or steam without air or oxygen into the gasifier.
2. Reforming of material into hot syngas that contains the inorganic (ash) fraction of the biomass and a small amount of unreformed carbon.
3. Recovery of sensible heat in the hot syngas to produce heat for the reforming process.
4. Cleaning of the cool syngas through a filter and removal of the particulate in the syngas to produce a dry, innocuous waste. Clean syngas is then available for combustion in engines, turbines, or standard natural gas burners with minor modifications.

Brightstar entered a license agreement and strategic alliance with Energy Developments Limited (EDL) of Australia to commercialize the Brightstar process in Australia for municipal solid waste (MSW) feedstock. EDL became a major shareholder in Brightstar (Juniper Consultancy Services Ltd, 2000). BSC became a subsidiary for EDL as Brightstar Environmental.

The waste-to-energy concept that is being developed in Australia is called SWERFTM (Solid Waste Energy and Recycling Facility). A schematic diagram of the SWERFTM technology is shown in Figure 5 (www.brightstarencvironmental.com).

Figure 5. Schematic Diagram of the SWERFTM Technology

The facility initially converts green wood waste to electricity using the Brightstar gasification process. The first plant is built near Wollongong City Council's Whytes Gully landfill site in New South Wales, Australia (www.wollongong.nsw.gov.au). The site was commissioned on May 18, 2000. It was designed to process green organic materials such as urban tree toppings at 20,000 metric ton/a (22,046 ton/a). The syngas is burned with natural gas to produce electricity. The second phase will extend this to process 150,000 metric ton/a (165,345 ton/a) (of MSW to generate 120 GWh/a of electricity). The final design would consist of four gasifiers and eight generator modules. The plant was completed and opened in 2001. During the test period the plant was ramped up to a throughput level equating to about 60% of the nameplate capacity measured at the primary gasifier. One of the problems from the system was the carry over of fine char particles from the gasifier vessel with the gas stream. The other systems have performed to expectations. Modifications to the char gasifier are planned to prevent the aforementioned problem. Brightstar is planned to complete the nameplate capacity late this year before the start of the next SWERFTM projects (www.planktark.org/dailynewsstory.cfm/newsid/14214/story.htm). An aerial photo of

the Whytes Gully facility is shown in Figure 6
(www.brightstarensvironmental.com/html/News/newstext.htm).

Figure 6. Aerial Photo of the Whytes Gully Facility in Wollongong

The key air emissions for the Whytes Gully site is summarized in Table 2
(<http://www.brightstarensvironmental.com/html/env%20frame%20set/tables.htm>)

Table 2. Summary of Emissions for Whytes Gully Site

Emissions	License Limit, mg/Nm ³	Engine, mg/Nm ³	Reformer, mg/Nm ³
Acid gases of chlorine (HCl)	41	0.02	0.01
Dioxins and furans (TEQ)	9.3	<0.03	<0.03
Oxides of Nitrogen (NO _x)	308	152-208	24-68
Sulphur Dioxide (SO ₂)	86	20.5	<30
Particulate Matter (PM)	24	2.6	Not tested
Cadium and Tellurium (Cd and Ti)	0.02	0.005	0.0005
Mecury (Hg)	0.02	0.0056	0.0056
Lead (Pb)	0.20	<0.0009	<0.0009
Hydrogen Sulphide (H ₂ S)	No level assigned	0.001	0.001

Brightstar Environmental has signed a contract with Derby City Council in Britain to recycle and recover resources from the waste in and around Derby (www.brightstarensvironmental.com/derby/text.htm). This facility will process 50,000 metric ton/a (55,116 ton/a) of waste and generate around 5 MW of electricity. The SWERFTM facility will be build at Sinfin Lane, on a site formerly occupied by a tannery. The construction is expected to start in 2002 with plant opening in late 2002. Brightstar is also in the early stages of developing the SWERFTM facility in Kent in conjunction with Brett Waste Management in Britain.

1.1.1.4 Cratech Gasification System

Western Bioenergy funded Cratech in Tahoka, Texas, in 1998 to develop a gasification project for converting straw, grass, and shells (www.westbioenergy.com). A 1 MW unit was developed and tested. The Cratech gasifier is a pressurized, air-blown fluidized-bed reactor. Biomass is injected with a biomass pressurization and metering unit. The product gas is passed through a hot-gas cleanup system followed by injection into a turbine combustor. The system uses the higher practical thermodynamic efficiency of the Brayton cycle over the Rankin cycle. A flow diagram of the Cratech process is shown in Figure 7 (Purvis and Craig, 1998).

Figure 7. Cratech Gasification System (Purvis and Craig, 1998)

The maximum design pressure of the Cratech system is 1,353 kPa (202.8 psi) at a feed rate of 1,996 kg/h (2.2 ton/h) of wood at temperatures below 730 °C. The syngas is cleaned by a hot-gas filter and is directed to the combustion chamber of a gas turbine engine. Wet scrubbers are not used. Catalysts and higher temperatures are not needed for tar destruction before combustion. The composition of the syngas is 10.4% H₂, 3% CH₄, 17% CO, 15.3% CO₂, 41% N₂, 12% H₂O, 1 % C₂H₄, and 0.3% C₂H₆. The lower heating value of the syngas is 5.18 MJ/scm (139 Btu/scf). The Cratech system can fuel a turbine of 1.5 MW_e with a maximum pressure ratio of about 11.0. The initial gas turbine combustion test was performed with a Solar Spartan turbine rated at 225 kW_e with a pressure ratio of 4.0. An EGT Typhoon gas turbine was designed to operate on the low heating value syngas.

1.1.1.5 Energy Products of Idaho

Energy Products of Idaho (EPI) of Coeur d'Alene, Idaho, claimed to design and build the first fluidized bed combustor for firing wood which also operates on 100% paper sludge

(Inland Empire Paper Company, Spokane, WA) (www.energyproducts.com). EPI has designed and supplied more than 79 gasification plants worldwide since 1973. Their expertise is in atmospheric fluidized-bed (AFB) gasifiers. The bed material can be either sand or char or a combination of both. The fluidizing medium is usually air. Their AFB can process fuel with moisture contents up to 55% and high ash contents over 25%. Temperature is maintained below the fusion temperature between the ash and the slag which increases the utilization of the slagging fuels. The product gas is cleaned by cyclones. The heating content of the gas is about 7.4 MJ/scm (200 Btu/scf). The EPI website listed a total of 63 operating units in the world. These facilities process a wide variety of biofuels such as wood waste, bark and wood chips, RDF, hogged fuel, agricultural waste, urban wood waste, coal, polyethylene terephthalate, and polyvinylbutyryl. Most of these plants produce heat and steam. Several plants produce electricity in the range of 25 to 50 MW_e. One plant was scheduled for start up October 2001 in Verzuolo, Italy, for heat and steam production using paper sludge and wood waste feedstocks. Another system is scheduled for start up in the fall of 2002 at Trus Joist Weyerhaeuser in Northwest Ontario, Canada, for heat and steam generation.

1.1.1.6 Enerkem-Biosyn Gasification

The Enerkem-Biosyn gasification process has a long history of development in Canada. Many transformations have occurred over the past decades (<http://solstice.crest.org/renewables/bioenergy-list-archive/9612/msg00266.html>). Canadian Industries Limited (CIL) was formed in the early 1970s as a wholly owned Canadian subsidiary of Imperial Chemical Industries (ICI). CIL initiated the OMNIFUEL program to develop a versatile fluidized-bed technology to convert its industrial wastes into useful syngas for either energy or chemical synthesis. A pilot plant was constructed in Kingston, Ontario. This was discontinued after CIL restructured. BBC Engineering was formed and installed a 10 metric ton/h demonstration gasifier coupled to a boiler at the Levesque sawmill in Hearst, Ontario. The economics did not favor the commercialization of the process despite its technical success.

Canertech was created in the late 1970s by the Canadian government to promote alternate energy sources. Nouveler, a subsidiary of HydroQuebec, formed a joint venture, Biosyn Inc., with Canertech to demonstrate the gasification of biomass and the conversion of the syngas to methanol. A 10 metric ton/h (11.0 ton/h) gasification plant was designed and erected by SNC, a Montreal-based engineering firm, and BBC Engineering at St. Juste de la Bretonniere, Quebec. The gasifier was a pressurized reactor with maximum pressure of 1,600 kPa (232 psi). The demonstration proceeded from 1984 to 1986. Over 1,600 hours were operated in the gasification mode and over 600 hours were operated with coupling to a 750 kVA Alstrom generator. Canertech was dissolved in 1984, and Nouveler became the sole owner of Biosyn, Inc. Biodev, Inc., was a joint venture between Nouveler and SNC to commercialize the Biosyn technology. A demonstration project was secured in Guyane, France, to produce 7.5 MW of electricity. The plant was constructed and briefly operated. It was abandoned in the late 1980s, and Biodev was dismantled. Biothermica Ltd., was formed as an independent company to continue to pursue the commercialization of the licensed Biosyn technology. The gasification plant

and the sawmill at St. Juste were sold to a sawmill company, BECESCO, in 1989. The gasification plant remained at the sawmill.

The intellectual property generated by Biosyn was transferred to Centre Quebecois de Valorisation de la Biomasse (CQVB) in 1989. CQVB, a provincial corporation, launched a program to use the gasification technology to process forest waste, agricultural waste, MSW and RDF, and industrial wastes. A research program was started in 1990 at Université de Sherbrooke. Research was carried out using a 50 kg/h (110 lb/h) gasifier that was built by IREQ. It was then transferred to Sherbrooke, and a PDU facility was built around the gasifier. A flow diagram of the PDU is shown in Figure 8.

Figure 1. Process flow diagram of the gasifier installation having a nominal capacity of 500 kg/h of biomass.

Figure 8. Biosyn PDU at Université de Sherbrooke (Czernik, 1993)

A partnership between Université de Sherbrooke and National Research Council of Canada led to the creation of the Groupe de Recherche sur les Technologies et Procédés de Conversion (GRTPC) for fundamental and applied research in biomass conversion. Kemestrie, Inc., was formed in 1993 as a spin-off company from Sherbrooke to advance the commercialization efforts. A 100-kg/h (220 lb/h) unit was installed at a metallurgical plant in Quebec to recycle aluminum from post-consumer packaging. The environmental division of Kemestrie, Inc, Enerkem Technologies Inc., was established in 1998 to commercialize the environmental energy and coproducts technologies. Biothermica continues to focus on the larger capacity energy conversion markets. A demonstration unit is also located at Alcan in Arvida, Quebec, in addition to the PDU at Sherbrooke.

The Biosyn technology is a bubbling fluidized-bed gasifier with cold or hot syngas purification system. The biofuel is limited to a maximum of 5 cm (1.96 inch) with a maximum moisture content of 20-25%. Gasification occurs at temperatures between 700 and 900 °C (1,292 and 1,652 °F). Average high heating content of the syngas is 6 MJ/Nm³, and a higher heating content of 12 MJ/Nm³ can be obtained with oxygen injection. The syngas is cleaned by a cyclone system to remove 90-95% of the solid particles. Both the washing and filtration system can be used to purify the gas further. The typical composition of the syngas by volume is 16% CO₂, 12-30% CO, 2-10% H₂, and 55% N₂. The syngas also contains small percentages of light hydrocarbons, oxygen, solid particles, tar, and other elements. The estimated cost of the system when coupled to energy production varies from \$1,500 to \$2,000/kW (www.enerkem.com).

1.1.1.7 PRM Energy Systems, Inc.

PRM Energy systems, Inc., founded in 1973, has many years of experience in biomass gasification for electricity and heat generation. Their website contains information on their various commercial and demonstration projects around the globe. The gasification technology was developed at Producers Rice Mill, Inc. (PRM). The first two gasifiers were installed in 1982 to gasify rice husks to produce process heat and steam for a large rice parboiling facility. Many biomass feedstocks were tested between 1984 and 1988 in a full-scale PRM gasifier. These include rice hulls, rice straw, chicken litter, green bark, sawdust and chips, peat, wheat straw, corn cobs and stubble, peanut hulls, RDF (fluff, flake, and pellet), petroleum coke, cotton-gin waste, cotton-seed hulls, and low-grade coal. The rice residue gasification has been in operation since 1982 in U.S., 1985 in Australia, 1987 in Malaysia, and 1995 in Costa Rica.

The PRM gasifier is a vertical cylindrical steel shell with reduced diameter in the upper section. The inside is lined with refractory material that can withstand temperatures as high as 1,560 °C (2,840 °F). The feed rate of the fuel and the out feed conveyor for ash are controlled by the preset temperature of the gasifier. Gasification is carried out with the addition of 10-12% of the stoichiometric air requirement. Partial combustion of the fixed carbon occurs in the gasification zone. Gases are burned in the combustion tube and chamber which also promotes thermal cracking of tars and hydrocarbons. The clean, low BTU content gas can be used for drying applications or in the radiant section of the boiler.

A gasification plant was installed in Greenville, Mississippi, in 1995 with a thermal and net electric output of 17.5 MW_{th} and 6.5 MW_e, respectively, using rice husk feedstock. Another system was installed in 1996 in Stuttgart, Arkansas with 63 MW_{th} and 12 MW_e output also with rice husk feedstock (Biomass Technology Group: www.btgworld.com).

A gasification plant which includes a cleanup system and IC engine/generation was scheduled for completion in 2001 for Rossano Energia, SpA in the south of Italy for processing olive residue (sansa). It is expected to generate approximately 4.05 MW_{th} (gross) of electricity from 4,500 kg/h (9,920 lb/h) of sansa (www.prmenergy.com).

The PRM process is marketed by PRM Energy Systems itself as well as through Primenergy, Inc., for the U.S. and the Philippines. Grupo Guascor of Spain covers France, Italy, Spain, and Portugal (Juniper Consultancy Services Ltd, 2000). The PRM process is fully proven and has operated continuously at various scales.

1.1.1.8 Thermogenics

The Thermogenics gasifier is a directly heated, air-blown, continuous bottom fed, stratified updraft gasifier (Juniper Consultancy Services Ltd, 2000). It was designed specifically for processing MSW with a capacity of 0.5-3 metric ton/h (0.55-3.3 ton/h). The MSW is shredded and dried to a moisture content of 30% or less. It is introduced into the gasifier through the bottom. An external fuel source is used to heat the MSW to auto-thermal temperature. Gasification occurs around 980 °C (1,796 °F) at the bottom of the bed and 370 °C (698 °F) at the top. Char and particulates from the syngas are removed by a dust removal device and recycled to the gasifier. The syngas is cooled to condense the aerosols and passed through an electrostatic precipitator. The syngas can be used for power generation via gas engines or conventional boilers. The Thermogenics system has been reviewed favorably by NREL for MSW processing (Camp Dresser and McKee, 1996).

Thermogenics is cooperating with Power Energy Fuels, Inc., (PEFI) based in Lakewood, Colorado, to produce EcaleneTM as oxygenate for transportation. EcaleneTM is a mixture of ethanol and higher alcohols with a composition as shown in Table 3.

Table 3. Composition of EcaleneTM (Power Energy Fuels)

Component	Percent (by wt)
Methanol	0
Ethanol	75
Propanol	9
Butanol	7
Pentanol	5
Hexanol and Higher Alcohols	4

The EcaleneTM is produced by passing the syngas through a proprietary molybdenum sulfide catalyst. The molybdenum sulfide catalyst is developed at PowerEnerCat, Inc. Both of these companies shared the same C.E.O., G.R. Jackson. Furthermore, development of the catalytic conversion of syngas to EcaleneTM is currently underway at Western Research Institute (WRI) located in Laramie, Wyoming. WRI is testing the catalyst for natural gas and landfill gas using a 1.89 m³/day (500 gal/day) pilot (Lucero, 2001). This catalyst was first studied at Dow and Union Carbide for alcohol production. A schematic diagram showing the bench-scale facility at WRI is shown in Figure 9.

Figure 9. Flow Diagram of the 500-gpd Facility at WRI (Lucero, 2001)

It is not clear at this time whether Thermogenics is still working with PEFI to use the Thermogenics gasifier for the production of syngas for EcaleneTM production. PEFI is currently developing their own syngas from natural gas to produce the EcaleneTM. A commercial demonstration facility is under development for this effort and is being fabricated by FabPro, LLC, in Denver, Colorado, for siting at WRI.

1.1.1.9 Thermoselect, S.A.

The development of the Thermoselect HTR (High Temperature Recycling) process began in 1989. A demonstration plant was built at Fondotoce in Italy and was operated for semi-commercial scale from 1994 to 1999. The process combines slow pyrolysis with fixed-bed oxygen-blown gasification and residue melting (Juniper Consultancy Services Ltd, 2000). The first stage of the process uses a high-pressure press to compact the feedstock to increase its bulk density, squeeze out entrained air, and homogenize the material by dispersal of liquids. The second stage involves the pyrolysis of the compacted material by indirect heating while it flows down the pyrolysis channel. The temperature varies from 100-200 °C (221-392 °F) at the entrance to over 800 °C (1,472 °F) at the transition point from the pyrolysis channel to the gasification reactor. A residence time of 1-2 hours is needed to convert the material to syngas and char.

Further reaction takes place in the gasification reactor with a residence time of 2-4 seconds and a syngas discharge temperature of 1,200 °C (2,192 °F). Oxygen is fed to the gasification reactor at a pressure of 100 kPa (14.5 psi). All the carbon char is converted to syngas comprising mostly H₂ and CO. The inorganic components such as metals and mineral materials are maintained in a molten stage between 1600-2000 °C (2912-3632 °F) with additional fuel gas. Slag in molten state is water quenched to form mineral chip and iron rich metal pellets for recycling.

The syngas from the gasification reactor is water quenched to below 70 °C (158 °F). Acid gases such as HCl and HF are removed by conventional scrubbing while H₂S is converted catalytically to elemental sulfur. The syngas is further processed to remove water vapor and passed through an activated carbon filter to comply with regulatory limits. The syngas can be used as a fuel source for power generation. A schematic diagram of the Thermoselect HTR process is shown in Figure 10.

Figure 10. Thermoselect HTR Gasifier (Juniper Consultancy Services Ltd, 2000)

Many improvements have been made to the Thermoselect gasifier including increased throughput from 9.1 metric ton/h (10 ton/h) to 1.4 metric ton/h (12.5 ton/h), improved efficiency from the Jenbacher gas engines to 38.5%, preheating of the pyrolysis channel with waste heat, and increased energy efficiency of 41% when coupled to a combined heat cycle element employing an Organic Rankine Cycle (Juniper Consultancy Services Ltd, 2000).

The Thermoselect process is designed for specific needs at different locations. The plant at Karlsruhe, Germany (1999) uses three trains of the Thermoselect system to process 204,119 metric ton/a (225,000 ton/a) of MSW and produce 50 MW_{th} of heat for the district heating network. The plant at Ansbach, Germany (2000), has one train to process 75,000 ton/a of MSW, and a second train is scheduled to be added later. The thermal-to-electrical conversion efficiency is claimed to be 38.5%. The Thermoselect plant at Hanau, Germany, uses two trains to process 91,647 metric ton/a (90,000 ton/a) of MSW. The syngas is used for offsite power generation of 10.3 MW_e. A facility was built in Chiba, Japan, in 1999 with two trains to process 136.1 metric ton/day (150 ton/day) of MSW.

Interstate Waste Technologies, Inc. (IWT), has agreed to represent Thermoselect in the Western Hemisphere (PRNewswire, July 21, 2000). Some other developments can be found at IWT's website at www.interstatewastetechnologies.com. Thermoselect is the current leader in MSW processing in Europe. A detail report is provided by the publication by Juniper Consultancy Services Ltd (Juniper Consultancy Services Ltd, 2000). Camp Dresser and McKee has compared the Thermoselect process with six other MSW processing technologies for NREL under a DOE contract (Camp Dresser Report, 1996). They found that the Thermoselect facility is the most capital intensive at about \$237 million for a 1,440 Mg/day (1,587 ton/day) plant and also has the highest operating cost at \$94.92/Mg (\$86.11/ton). On the other hand, it has the highest net heat rate at 13.55 MJ/kWh (12,843 Btu/kWh).

1.1.1.10 TPS Termiska Processer AB

In the 1970s, Studsvik of Sweden diversified into other areas of energy development aside from nuclear. The Thermal Engineering Laboratory assumed the responsibility of the circulating fluidized-bed gasification technology called the MINO process (Juniper Consultancy Services Ltd, 2000). Studsvik operated the MINO 2.5-MW pilot plant at up to 2,027 kPa (294 psi) from 1979-1986 (Blackadder, 1993). Figure 11 shows the MINO process with a high-temperature filter. The integrated gasification combined cycle (IGCC) concept failed because of the lack of interest from the Swedish government.

Figure 11. The MINO Gasification Process

TPS Termiska Processer AB was established as a private company in 1992 to pursue the CFB for small- to medium-scale electricity production using biomass and RDF as

feedstocks. TPS began work on the development of atmospheric pressure gasification for converting wood, peat, RDF, and other reactive solid fuels to energy in 1984. The gasification technology involves an air-blown circulating fluidized-bed (CFB) gasifier. It operates at 850-900 °C. The tarry product gas has a tar content of 0.5-2% of dry gas with a heating value of 4-7 MJ/Nm³ (107.4-187.9 Btu/scf). The system is favorable for fuel capacities greater than 10 MW_{th}. The characteristics of the TPS system are good fuel flexibility, compactness and cost-effective large-scale construction, good controllability and low-load operation characteristics, uniform process temperature due to highly turbulent movement of solids, optimum gas quality (high carbon conversion), no extensive fuel treatment required, and fines recycling from a secondary solids separator (Rensfelt, 1997).

The 2 MW_{th} CFB pilot plant at TPS was erected in 1986. A schematic diagram of the CFB gasifier is shown in Figure 12.

Figure 12. TPS ACFB Gasifier

Feedstocks such as bark, wood/PVC mixture, and RDF were tested in late 1986 and 1987. A variety of other feedstocks were also tested in subsequent years of development. In 1987, a dolomite-containing CFB tar cracker, a cold-gas filter, a wet scrubber, and a modified 500-kW shaft-powered, turbo-charged, eight-cylinder, dual-fuel, diesel engine were installed at the pilot plant. Extensive research has been done using a second reactor as a tar cracker. Figure 13 shows the flow diagram of the process at the pilot scale. The tars in the syngas are cracked catalytically by dolomite in a separate vessel at about 900 °C (1,652 °F) immediately downstream of the gasifier.

Figure 13. TPS Pilot Plant with Tar Cracker

The CFB license was sold to Ansaldo Aerimpianti SpA for the construction of a waste-fueled gasification plant in Grève-in-Chianti, Italy (Rensfelt, 1997). The plant was commissioned in 1992 and has a total capacity of 200 metric tons (220.5 tons) of RDF per day using two 15-MW_{th} CFB gasifiers. The gasifiers operate at close to atmospheric pressure at about 850 °C (1,562 °F) using air as the gasification/fluidizing agent. A process flow sheet is shown in Figure 14.

Figure 14. Flow Diagram of the TPS Gasification System for RDF in Grève-in-Chianti, Italy

The raw syngas passes through two stages of solids separation before being fed to a furnace/boiler. The flue gas is cleaned in a three-stage dry scrubber system before being exhausted through the stack. The steam produced in the boiler is used to drive a 6.7 MW_e steam condensing turbine. The tar cracker was not installed at the Grève-in-Chianti plant, and an additional line was planned which will incorporate a CFB tar cracker (Juniper Consultancy Services Ltd, 2000).

TPS started to promote the use of the ACFB system for biomass integrated gasification combined cycle (BIGCC) application in 1990 after extensive evaluation of the technology. TPS was chosen to supply the gasifiers for the BIG-GT project in Brazil and the ARBRE Energy project in the UK. The ARBRE project was scheduled for operation in 2001 (Biomass Technology Group) using hot-gas clean up technology developed at TPS (Morris, 2000). The major activities of the \$100 million BIG-GT project in Brazil were started in 2000 (TPS Newsletter, May 2000). The BIGCC concept that is offered by TPS is shown schematically in Figure 15.

Figure 15. TPS BIGCC Concept (Morris, 2000)

The system generates low heating value fuel gas at about 6-7 MJ/Nm³ (161-187.9 Btu/scf). The tars are cracked in a tar cracker with dolomite at 900 °C (1,652 °F). The fuel gas is cleaned by a filter and wet scrubbing. In addition, the ammonia is dissolved in water to reduce NO_x formation from fuel nitrogen. According to TPS, the advantages of the atmospheric pressure BIGCC technology over pressurized technology are:

1. less required development and reliable operation,
2. simpler fuel and ash handling systems,
3. more reliable gas purification – use of gas scrubber ensures that the product gas is of sufficient quality for gas turbine operation,
4. higher heating value of the product gas,
5. supplementary firing of the heat recovery steam generator allows plant output to be boosted,

5% CH₄, and 44% N₂. Wood residues within short distance are used as feedstock. Large wood particles for this system reduce fuel requirements for the drying. The system requires simple controls and minimum labor. The installed cost for this system is estimated to be \$760/kW because of the reduced equipment investment.

1.1.1.12 Etho Power Corporation

Etho Power Corporation is a privately owned company located in Kelowna, British Columbia, Canada. Etho Power developed a proprietary biomass electricity generating system that utilizes gasifiers, heat exchangers, and air turbines. It is claimed that the Etho system is more efficient, produces less emissions, and is less expensive than traditional biomass gasification systems. A demonstration system is located in Kelowna, British Columbia. The project is funded by the British Columbia provincial government, BC Hydro & Power Authority, and the National Research Council of Canada. Little information could be found on the gasification technology.

Maxim Power Corporation announced on January 18, 2001, that it has entered an agreement with Etho Power. Under the agreement, Maxim will have an exclusive license for the utilization of the biomass-to-electricity and/or thermal recovery technology in Mexico, the Caribbean, and Central and South America. Maxim will also co-market with Etho Power globally as a provider of "Build, Own Operate" services for purchasers of the Etho Power Systems (Maxim Power Corp., News Release 1/18/01).

Etho has completed commissioning of its first commercial gasification system at Princeton Wood Preservers, Ltd. (British Columbia). Waste wood is gasified to produce thermal energy to substitute for natural gas at the plant. A second commercial gasification system was delivered to Visy Paper Pty. in Australia in 2001. Waste paper and plastics are scheduled to be gasified at this plant to produce thermal energy to offset natural gas consumption. The gasification system costs about \$1,800,000. Etho and Visy have entered a four-year agreement worth an estimated \$25 million dollars to supply six gasifiers or gasification-to-electricity power plants in Australia and United States. A demonstration plant funded by the Illinois-based Coaltec Energy will be used to demonstrate the gasification of waste coal tailings. Coaltec has secured \$2,000,000 from the Illinois Clean Coal Review Board to support the project. Approximately \$540,000 will be spent on building and operating the gasifier. The remaining monies will be used to fund a portion of the capital cost for the first commercial gasification-to-electricity installation (Maxim Power Corp., News Release 10/9/01).

1.1.1.13 Emery Gasification

Emery Gasification is based in Salt Lake City, Utah. It has developed a proprietary gasification technology for power production, chemical synthesis and industrial gases. It started the development in 1993. A 22.7-metric ton/day (25 ton/day) fixed-bed, air-blown gasifier was designed and built. It has been operated for over 2,100 hours during a 20-month test period from late 1996 to the fall of 1998 with scrap tires as the principle feedstock. Biomass and MSW were also tested. A picture of the gasifier is shown in Figure 17.

Figure 17. Emery's 25 ton/day Gasifier.

Emery Gasification technologies are covered by patents 5,573,559 and 5,787,822. Emery is also developing a novel multi-pollutant control process that removes the pollutants from the flue gas stream of coal-fired power plants at high efficiencies (www.emerygas.com).

In 2001, Emery formed a relationship with Idaho National Energy and Environmental Laboratory (INEEL) and successfully obtained a grant from the Department of Energy in to develop an advanced biomass gasification/power system. Additional partners are Combustion Resources, LLC, Biomass Energy Foundation, and the Southeastern Public Service Authority (SPSA). Emery is actively pursuing other funding opportunities to further develop their biomass- and coal-based gasification systems.

1.1.1.14 Other Biomass Gasification Developments

Several other developments in biomass gasification for heat and power are summarized in Table 4. These are found at the website of Biomass Technology Group.

Table 4. Current Developments on Biomass Gasification for Heat and/or Power Generation (BTG)

Location	Year Installed	Plant Owner	Manufacturer	Gasification Technology	Electric Output, MW _e		Thermal Output, MW _{th}	Feedstock	Gas Treatment	Capital Cost
					(Gross)	(Net)				
Harboøre, Denmark	1994	Ansaldo Vølund	Babcock Wilcox Vølund	Vølund R&D Centre, updraft counter-current fixed bed gasifier	1.5	1.0	3.2	Wood chips, 1-8 cm (0.39-3.15 in), 30-55% water	cooler, cyclone, wet electrostatic precipitator, wet scrubber	\$5.5 million
Elsterwerda, Germany	2000/2001	Elbe-Elster Holzkraft AG	PPS Pipeline Systems GmbH	PPS Pipeline Systems, downdraft co-current fixed bed gasifier	4.5	3.9	7.5	Clean wood, demolition wood, waste wood, and wood chips, 2-20 cm (0.79-7.9 in), <35% water	cooler, cyclone	\$15 million
Siebenlehn, Germany	1999	Sachsenholz, AG	PPS Pipeline Systems GmbH	PPS Pipeline Systems GmbH	2.3-2.4	1.8-2.0	4.5	Clean wood, demolition wood, waste wood, and wood chips, 2-20 cm (0.79-7.9 in), <35% water	cooler, cyclone	\$10 million
Eye, Suffolk, UK	2001, under construction	unknown	unknown	unknown		5.228	na	Short rotation coppice, wood chips	unknown	
Cricklade North Wiltshire, UK	2001, under construction	unknown	unknown	unknown		5.528	na	Short rotation coppice, wood chips	unknown	

1.1.2 Advanced Biomass Gasification Systems

Advanced gasification systems generally involve integration with higher efficiencies and produce heat or combined heat/power generation. These systems are necessary for the Western countries for controlling of greenhouse gas emissions. Seven companies that have advanced gasification systems are reviewed.

1.1.2.1 Foster Wheeler Gasification Technologies

Foster Wheeler owns several gasification patents and gasification technologies. Some of these were developed by Ahlstrom Pyropower (API). Foster Wheeler acquired API and has likewise acquired these gasification technologies. The different gasifiers are the atmospheric updraft gasifiers (Bioneer), atmospheric circulating fluidized-bed gasifiers (Pyroflow), and the pressurized circulating fluidized-bed gasifiers (Bioflow). These are described below.

1.1.2.1.1 Bioneer Atmospheric Updraft Gasifiers

Foster Wheeler developed the atmospheric updraft gasification technology for converting biomass to heat for small districts. These are known as the BIONEER gasifiers. A total of ten BIONEER gasifiers have been installed. The maximum plant size is 10 MW_{th} fuel input with most of the plants in the range of 3-8 MW_{th} input. The can not be operated with sawdust or other smaller components because the feedstock is too fine to be effective in the process. These gasifiers are simple to operate, and the technology is well proven.

1.1.2.1.2 Pyroflow Atmospheric Circulating Fluidized-Bed Gasifiers

The next generation of gasifiers from Foster Wheeler is known as the Pyroflow gasifiers. They are atmospheric circulating fluidized-bed gasifiers (ACFB) developed in the 1980s by API as shown in Figure 18.

Figure 18. Foster Wheeler's Pyroflow ACFB Gasifier

The first commercial installation by Foster Wheeler Energia Oy in 1983 was to Wisaforest Oy pulp and paper plant in Pietarsaari, Finland, with a 35 MW capacity (Engström, 1999). Two more units were installed in two pulp mills in Sweden (Norrundet Bruk Ab, Norrsundet, Sweden and ASSI, Karlsborgs Burk, Sweden) in 1985 and 1986, both 27 MW. Another 17 MW unit was installed at Portucell pulp mill in Rodao Mill, Portugal, in 1986. A fifth installation in 1998 was at Kymijärvi Power Station in the city of Lahti in southern Finland. This plant is operated by Lahden Lämpövoima Oy. A flow diagram of the gasification process for heat and power at Lahti is shown in Figure 19. A picture showing the site of the gasification plant is shown in Figure 20.

Kymijärvi Power Plant, Lahti, Finland

Figure 19. Flow Diagram for the CFB gasifier at Lahti, Finland

Figure 20. The CFB gasification plant at Lahti, Finland

The power plant was constructed in 1976 with a maximum power capacity of 167 MW_e and maximum district heat production of 240 MW_{th} with oil-firing. It was modified in 1982 for coal firing. A gas turbine was added in 1986 with a maximum output of 40 MW_e (at -25 °C or -77 °F). The feed rate to the plant was 163,295 metric ton/a (180,000 ton/a) (1,200 GWh/a) of coal and 800 GWh/a of natural gas.

The construction of the Lahti gasification plant was started in 1997 to replace about 15% of the total fuels burned in the main boiler with biofuels. The first switchover took place on January 14, 1998. Some specifications for this plant are shown in Table 5. The CFB gasifier produces low-Btu gas to burners in a coal-fired boiler. Hence, the fuel gas is not used directly for heat and power generation, but is rather a co-combustion process similar to the BioCoComb process under development in Austria. The boiler is a Benson-type

once-through boiler with steam conditions of 125 kg/s (275.6 lb/s), 540 °C (1004 °F)/17,000 kPa (2,466 psi) and 540 °C (1004 °F)/4,000 kPa (580 psi) reheat.

Table 5. Specifications of the Gasification Plant at Lahti, Finland

Design Capacity	Boiler	167 MW _e
		240 MW _{th}
	Gasifier	45 MW _{th}
Fuels (GWh/a thermal)	Coal	1200
	Natural Gas	800
	Biomass	ca. 300

The goal of the integrated gasification plant was to demonstrate the commercial scale of direct gasification of wet biofuel and the use of hot, raw and very low caloric gas directly in the existing coal-fired boiler. The gasifier is an atmospheric circulating fluidized-bed (CFB) gasification system. The biofuel contains 20-60% water with 40-80% combustibles and 1-2% ash. Feedstocks include biomass (wood chips, bark, sawdust), REF (recycled refuse), railway sleepers (chipped onsite), shredded tires, plastics, etc. The biofuels are not dried, and this reduces the investment costs and simplifies the overall system.

The operating temperature in the reactor varies from 800 to 1,000 °C (1,472-1,832 °F) depending on the biofuel and application. The primary reaction is pyrolysis of the biofuel followed by a secondary homogeneous reaction taking place in the gas phase. Most of the solids in the system are separated in the cyclone and returned to the lower part of the gasifier reactor.

During the first year of operation, about 230 GWh of energy was generated from biomass. A total of 4,730 hours of operation was performed in the gasification mode in 1998. The highest monthly availability was 93%, and the average availability was 82%. A 5-10% reduction of NO_x (10 mg/MJ or 0.0236 lb/mmBtu) and 20-25 mg/MJ (0.0465-0.0582 lb/mmBtu) in SO_x were obtained. However, an increase of about 5 mg/MJ (0.0118 lb/mmBtu) of HCl was obtained because of the presence of chlorine in the REF. The trace metals were also increased in the emission. There were no major problems reported with the operation of the gasification plant (Ståhl, 1999).

1.1.2.1.3 Bioflow Pressurized Circulating Fluidized-Bed Gasifiers

The Swedish power company, Sydkraft AB, decided in June 1991 to build a co-generation plant at Värnamo, Sweden to demonstrate the integrated gasification combined cycle (IGCC) technology. Bioflow, Ltd., was formed as a joint venture between Ahlstrom and Sydkraft in 1992 to develop the pressurized air-blown circulating fluidized-bed gasifier. Foster Wheeler acquired the part of Ahlstrom that built the gasifier and Bioflow became part of Foster Wheeler in 1995. The biomass integrated gasification combined cycle (BIGCC) plant in Värnamo was commissioned in 1993 and fully completed in 1996. It generates 6 MW_e and 9 MW_{th} for district heating in the city

of Värnamo. This was the first complete BIGCC for both heat and power from biomass (Ståhl, 1997; Engström, 1999; and Ståhl, 1999).

The flow diagram of the Bioflow IGCC at Värnamo is shown in Figure 21.

Figure 21. BIGCC at Värnamo, Sweden based on the Bioflow Gasifier (Ståhl, 1999)

In this process, the wood fuel is dried to 10-20% moisture in a separate fuel preparation plant using a flue gas dryer. It is pressurized in a lockhopper system and fed to the gasifier by screw feeders a few meters above the bottom. The operating pressure and temperature of the gasifier are 2,000 kPa (290 psi) and 950-1,000 °C (1,742-1,832 °F), respectively. The gasifier consists of the fluidized-bed reactor, cyclone, and cyclone return leg, all totally refractory lined. The gas produced from the system flows to a gas cooler and a hot gas filter after passing through the cyclone. The gas cooler lowers the gas temperature to 350-400 °C (662-752 °F) before it enters the ceramic filter system. The gas is burned in the combustion chambers and expands through the gas turbine generating 4 MW_e. The gas turbine is a single-shaft industrial gas turbine supplied by Alstom Gas Turbine (Typhoon). The system was designed for low heating value gas (5 MJ/Nm³ or 134 Btu/scf). Heat is recovered by the heat recovery steam generator (HRSG) to produce an additional 2 MW of electricity.

Table 6 shows the technical data from the Värnamo BIGCC plant (Ståhl, 1997).

Table 6. Technical Data for Värnamo BIGCC Plant (Ståhl, 1997)

Component	Specification
Power Generation	6 MW _e
Heat Generation	9 MW _{th}
Fuel Input	18 MW (85% ds)
Fuel	Wood Chips
Net Electrical Efficiency (LCV)	32%
Total Net Efficiency (LCV)	83%
Gasification Pressure	2,000 kPa (290 psi)
Gasification Temperature	950-1,000 °C (1,742-1,832 °F)
Lower Calorific Value of Product Gas	5 MJ/Nm ³ (134 Btu/scf)
Steam Pressure	4,000 kPa (580 psi)
Steam Temperature	455 °C (851 °F)
Plant Owner	Sydskraft AB

The commissioning of the feed preparation plant was in late 1992. The first gasification test on wood chips at low pressure was performed in June 1993. The start-up phase was completed during spring 1996. As of August 1999, a total of 8500 hours of gasification runs had been performed with about 3,500 hours of operation as a fully integrated plant. Feedstocks such as wood chips, forest residue (bark, branches, etc), sawdust and bark pellets, willow (salix), straw and pelletized RDF have been processed at the plant. They all showed good results without deposits or sinter in the systems. The bed material of the gasifier is magnesite (MgO) which performed well. Other materials could be tested to further optimize the gasification process.

The hot-gas cleanup was originally carried out with a ceramic filter that was supplied by Schumacher GmbH. The filter candles were arranged in six groups, with separate backpulsing. Initially, the ceramic filter showed good filter efficiency with stable pressure drop. However, two ceramic candles broke after more than 1,200 hours of trouble-free operation. The reason for the breakage was never identified by the manufacturer. A new design of ceramic filters was installed, but one of the new candles broke only after 350 hours of operation. Several modifications were made, and a metallic police filter was installed downstream of the main filter. The main filter failed soon after the modifications. The ceramic filter candles were replaced by metallic filter candles during the summer of 1998. The metallic filter was supplied by Mott Corporation. The new metallic filter has been operated more than 2,200 hours as of 1999 without any breakage or other damage during normal operation (Ståhl, 1999).

The dry gas composition of the product gas is shown in Table 7. The gas quality regarding hydrogen was lower than expected. The gas heating value was in the range of 5.3-6.3 MJ/Nm³ (142-169 Btu/scf). The benzene and light tars concentrations for bark and pine chips are shown in Table 8. The benzene and light tars were lower with bark as compared to pine chips.

Table 7. Product Gas Composition from the BIGCC at Värnamo, Sweden

Gas Component	Concentration (vol. %)
CO	16-19%
H ₂	9.5-12%
CH ₄	5.8-7.5%
CO ₂	14.4-17.5%
N ₂	48-52%

Table 8. Benzene and Light Tars Concentrations

Fuel	Benzene, mg/Nm ³	Light Tars, mg/Nm ³
Bark (60%), Forest Residues (40%)	5,000-6,300	1,500-2,200
Pine Chips	7,000-9,000	2,500-3,700

The thermal NO_x was low due to the relatively low combustion temperature in the gas turbine combustors. The level is a direct function of the level of nitrogen content in the feedstock. With high nitrogen content fuel such as bark, the NO_x level was around 130 ppm. A NO_x level of 40 ppm was recorded from low nitrogen content fuel. The NO_x level can be reduced by developing new combustors, and the use of selective catalytic oxidation (SCO) can further reduce the emissions from ammonia and HCN. The recorded levels of alkalines were below 0.1 ppm (wt.) (Ståhl, 1999).

1.1.2.2 Battelle High-Throughput Gasification Process (BHTGP)

Battelle Memorial Laboratory demonstrated high-throughput gasification in cooperation between the U.S Department of Energy, the National Renewable Energy Laboratory (NREL), Burlington Electric Department, and the Future Energy Resources Corporation (FERCO) (Bain, 1996). The project for IGCC demonstration began in August 1994. The demonstration was located at the McNeil wood-fired power plant in Burlington, Vermont. The power plant has a capacity of 50 MW_e and was built in 1984. The capital cost of the plant was \$67 million (1984) and was \$13 million below budget. It is owned by the Burlington Electric Department, Central Vermont Public Services Corp., Green Mountain Power Corp., and the Vermont Public Supply Authority. A total of 77.1 metric ton/h (85 ton/h) of wood chips can be processed.

The Battelle High-Throughput Gasification Process (BHTGP) system uses a low-pressure indirectly heated biomass gasifier. It has been demonstrated successfully in a 9.1 metric ton/day (10 ton/day) Process Research Unit (PRU) at Battelle's Columbus Laboratories in West Jefferson since 1980. This system was designed especially for biomass to take advantage of its high reactivity, low ash, low sulfur, and high volatile matter content. It has operated for over 22,000 hours. FERCO of Atlanta, Georgia, has licensed the technology from Battelle. The gasifier will be operated as an IGCC eventually and includes heat recovery and a condensing steam turbine. The plant is 20 times the scale of the pilot plant that can process 181.4 metric ton/h (200 ton/h) of woody feedstock. It accounts for about 30% of the plant's load (Bain, 1996).

The first phase of design and construction was completed in 1998 by Zurn NEPCO of Portland, Maine, and Redmond, Washington. The second phase includes the start-up and shake-down testing which began in 1998 and continued through 1999. The final phase involves long-term operation and testing. A gas turbine was designed and installed during the final phase in 2000. The other companies and agencies that are evaluating the technologies include Weyerhaeuser, General Electric, International Paper, Centerior Energy, the State of Iowa, New York State Energy Research and Development Authority, and the U.S. Environmental Protection Agency.

FERCO has trademarked the process SilvaGasTM (January 2001). The SilvaGasTM process uses two physically separated, circulating fluidized-bed reactors. One reactor acts as a gasification reactor to convert the biomass to gas and residual char. The second reactor is a combustion reactor which burns the char to provide heat for gasification. Figure 22 shows a schematic diagram of the gasification system.

Figure 22. FERCO's SilvaGasTM Process at Burlington, Vermont

One system was installed at McNeil generating station in Burlington, Vermont. The flow diagram of the Battelle/FERCO IGCC at McNeil generating station is shown in Figure 23. Some plant statistics for the Burlington installation are shown in Table 9.

Figure 23. Flow Diagram of the Battelle/FERCO IGCC at McNeil Generating Station.

Table 9. Statistics of the Burlington Biomass Gasification Plant

Component	Specification			
Design Capacity, MW _e	50			
Configuration	Traveling grate stoker boiler			
Fuels	Wood wastes: forest, mill, and urban residues, Natural Gas (when economical)			
Year	1995	1996	1997	1998*
Net generation, MWh/a	136,000	137,000	155,000	155,000
Annual capacity factor, %	31.0	31.1	35.4	35.4
Net heat rate, MJ/kWh (Btu/kWh)	14.47-14.9 (13,714-14,125)			
Thermal Efficiency, HHV, %	24.-24.9			
* Projected in 1998				

In the FERCO process, the wood is heated to about 830 °C (1,526 °F) by hot sand circulating between two chambers. The gas has a medium heat content of about 18.6 MJ/m³ (500 Btu/ft³). This can be used as fuel for unmodified gas turbine. Since this gasifier does not require pure oxygen feed and produces medium heat-content gas, it is less costly to build and operate according to FERCO. The gasifier design has a high throughput of 3,000 lb biomass/h per ft² of cross sectional area of the reactor compared to about 200 lb/h-ft² for a conventional gasifier. The gasifier has a diameter of 1.07 m (3.5 ft) with a design capacity of 181.4 metric ton/day (200 ton/day) dry wood. The plant tested two gas conditioning systems for tar removal. The first system was a conventional scrubbing system with a venturi scrubber followed by a spray tower scrubber which removed most of the tars. The second system was a fluidized-bed catalyst chamber

employing a new catalyst called DN-34. This essentially eliminated all tars from the gas. The gas was conditioned and pressurized to 100 psig to fire a gas turbine. A pilot test demonstrated the operation of a Solar Turbine 200 kW conventional gas turbine-generator with an unmodified gas turbine for gasification. A comparison of the gas quality is shown in Table 10.

Table 10. Comparison of Data from the PRU and McNeil Station (Paisley, 2001)

Component	Volume Percent	
	PRU Data	McNeil Station Data
H ₂	17.5	22.0
CO	50.0	44.4
CO ₂	9.4	12.2
CH ₄	15.5	15.6
C ₂ H ₄	6.0	5.1
C ₂ H ₆	1.1	0.7
HHV, MJ/Nm ³ (Btu/scf)	18.5 (499)	17.3 (468)

The gasification demonstration plant has not operated continuously for a sustained period of days or weeks for the 18 months after the completion of the construction. One major change was made to the gasifier in late 1998; however, the specific problems have not been disclosed. The Salix project with planting of 5,000 short rotation energy crop trees to supply the power plant at McNeil site was uncertain. The first lesson learned from the project was a siting problem because of its urban setting. The second problem was the long-term fuel contracts resulting in a pile up of wood at the site and deterioration of the wood when the plant was not operated (www.westbioenergy.org).

The latest data presented at the ASME conference in New Orleans reported that the throughput of the gasifier was in excess of 317.5 metric ton/day (350 ton/day) over the design capacity of 181.4 metric ton/day (200 ton/day) of the plant. The FERCO website has claimed a throughput of 408.2 metric ton/day (450 ton/day). The planning for the next 12 months will further evaluate the gas conditioning, design and implementation of advanced power generation, and the options of biomass drying at the site (Paisley, 2001). The capital investment for a conceptual 56 MW_e plant is \$1,307/kW (1996 dollars) according to FERCO.

FERCO was reorganized and refinanced in 1999 with the addition of the Turner Foundation as a shareholder (Paisley, 2001). Turner Foundation and private investors have provided \$16 million to FERCO to commercialize FERCO's biomass gasification technology (Electric Light & Power 78, no. 4, p. 26, Apr. 2000).

The Battelle/FERCO gasification plant was scheduled for start up during the summer of 2001 with additional analytical support from NREL (person communication with Ed Wolfrum).

1.1.2.3 GTI Pressurized Fluidized-bed Gasifier (Renugas®)

GTI has developed the Renugas® biomass gasification technology based on their success in the U-Gas® coal gasification technology and holds US Patents 4,592,762 and 4,699,632. The PDU gasifier has a dimension of 0.91-m O.D. x ~6.7-m (3-foot O.D. x ~22-foot) height and has a Incoloy 800H metal liner. The fluidization section is about 1.8-2.3 m (6-7.5 ft) in height. An isometric view of the 12 ton/day PDU is shown in Figure 24.

Figure 24. Isometric View of the 12 tpd GTI PDU

Bagasse, wood chips, whole tree chips, hard and soft woods, willow, rice and wheat straw, alfalfa, highway chippings, mixture of bark and pulp sludge, and pelletized RDF were all tested with the 10.9 metric ton/day (12 ton/day) PDU at GTI in Chicago. The conditions of the gasifier are summarized in Table 11.

Table 11. Operating Conditions of Renugas® PDU Gasifier

Parameter	Conditions
Temperature, °C (°F)	748-982 (1,380-1,800)
Pressure, kPa (psi)	up to 2,413 (350)
Feed Rate, kg/h (lb/h)	181-472 (400-1,040)
Feed Moisture, %	5-27
Steam Input, lb/lb feed	0-1.2
Fluidized Bed Height, m (ft)	1.83-2.29 (6-7.5)

Superficial Gas Velocity, m/s (ft/s)	0.46-1.37 (1.5-4.5)
--------------------------------------	---------------------

1.1.2.3.1 Renugas[®] Hawaii Biomass Gasifier Project

The objective of the Hawaii Biomass Gasifier Project is to scale-up the pilot 10.9 metric ton/day (12 ton/day) GTI's Renugas[®] pressurized air/oxygen gasifier to 45.4-90.7 metric ton/day (50-100 ton/day) using bagasse and wood as fuel. This would demonstrate the near-term integration gasification and hot-gas cleanup (HGCU) system with gas turbines for power and heat generation.

The participants of this projects are Westinghouse Electric Corporation, the Pacific International Center for High Technology Research (PICHTR), the Hawaii Natural Energy Institute (HNEI), the Hawaii Commercial and Sugar Company (HC&S), the Ralph M. Parsons Company, and the National Renewable Energy Laboratory.

The biomass gasification demonstration plant is located at a site adjacent to the Hawaiian Commercial and Sugar Company (HC&S) on the island of Maui. The Renugas[®] gasifier was designed to operate with either air or oxygen at pressures up to 2,068 kPa (300 psia) with typical temperatures of 850 to 900 °C (1,562-1,652 °F). Phase one of the project included the design, construction, and preliminary operation of the gasifier. Phase two of the project would operate the gasifier at a feed rate of 45.4 metric ton/day (50 ton/day) at a maximum pressure of 1,034 kPa (150 psia). A slip-stream HGCU unit would be installed to provide long-term evaluation of its performance. A full-scale HGCU would be designed, and a gas turbine would be added to the system to generate 3-5 MW of electricity at 91.7 metric ton/day (100 ton/day) capacity. Phase three of the project would operate the gasifier in oxygen-blown mode to produce a syngas for methanol synthesis in addition to electricity generation.

A schematic diagram of the Renugas[®] gasifier is shown in Figure 25, and the schematic diagram of the demonstration plant is shown in Figure 26.

Figure 25. GTI Demonstration Plant Gasifier

Figure 26. Renugas® Demonstration Plant in Paia, Hawaii

The Renugas® demonstration gasifier has a dimension of 1.4 m I.D. x 7.0 m (4.6 feet I.D. x 23 feet) in height. The lower fluidized-bed section has an internal diameter of 0.914 m (3 ft). The overhead expansion zone has an internal diameter of 1.4 m (4.6 ft). The gasifier was packed with fiber insulation in order to operate it at adiabatic condition.

Spherical alumina beads were used to provide good heat transfer and fluidization. The biomass was fed at the lowest part of the fluidized-bed reactor.

The bagasse was reduced to approximately ½- to 1-inch lengths to achieve bulk density of about 0.11-0.13 kg/L (7-8 lb/ft³). Bagasse is pneumatically conveyed to a cyclone which feeds the propane-fired rotary drum dryer that reduces moisture content from an average of 43% to 15-20%. It is then fed pneumatically to a disengaging cyclone above the gasifier structure and conveyed to the gasifier feed system (Wiant, 1998).

The feed system consists of the day bin, weigh bin, lockhopper and lockhopper valves, metering bin, collector screw, and gasifier injector screw. The day bin holds about 40 minutes of prepared bagasse. It automatically refills the weigh bin to a selected batch weight. The two live-bottom screws in the weigh bin discharged the bagasse into the lockhopper. The lockhopper cycles bagasse from atmospheric to operating pressure. Nitrogen or propane is used to pressurize the lockhopper to above the operating pressure of gasifier to provide a positive pressure in the lockhopper. The bagasse was conveyed to the gasifier via a collector screw and injection screws (Wiant, 1998).

The design of the gasification system allowed about 90% of the gas flow to the hot gas cyclone and 10% to the HGCU system slipstream. The HGCU used ceramic candle filters for removal of entrained ash at 700 °C (1,292 °F) or less. Both product gas streams were delivered to the combustion flare at near atmospheric pressure.

Fluidized velocities were maintained to entrain ash with product gases. Recycling of carryover was not needed due to high carbon conversion. The non-entrained inerts are periodically discharged from the reactor bottom. Some test results comparing to the 12 ton/day PDU at GTI are shown in Table 12.

Table 12. Test Results of Renugas[®] Gasifier (GTI)

Parameters	Demonstration Tests			PDU Test
	Oct. 95, no steam	Dec. 95, no steam	Dec. 95 with steam	1992 with steam
Temperature, °C (°F)	841 (1,545)	835 (1,535)	859 (1,575)	853 (1,568)
Pressure, kPa (psig)	296 (43)	421 (61)	503 (73)	2,137 (310)
Feed Rate, kg/h (lb/h)	1,048 (2,310)	1,714 (3,779)	1,561 (3,441)	254 (560)
Moisture of Bagasse, %	26	31	17	18
Dry inert-free gas composition (% by volume)				
Hydrogen	12.0	12.1	18.4	18.1
Carbon monoxide	27.0	29.1	26.2	26.1
Carbon dioxide	49.9	45.6	39.0	37.6
Methane	9.0	10.4	14.9	17.3
C ₂ species	1.4	1.9	1.5	0.5
C ₃ species	0.8	0.7	--	0.3
HHV, MJ/m ³ (Btu/ft ³)	9.95 (267)	10.9 (292)	11.4 (307)	12.6 (338)
Carbon Conversion, %	95	96	98	96

The tests from the demonstration plant were performed at lower pressure than the PDU. The heating value of the fuel gas is lower than the results from the PDU.

Stable operation of the hot-gas cleanup was achieved at 704 °C (1,300 °F), 172-862 kPa (25-125 psi), 2-40 min pulse cycles, and 318-499 kg/h (700-1,100 lb/h). There was no evidence of ash penetration and ash bridging. In addition, no filter candles were broken during operation. The oils and tars contained very small quantities of reactive components that were susceptible to cracking and carbon deposition on the filter surface. They did not affect filter operation, and they could be completely consumed in gas turbine combustors.

The Renugas[®] gasification plant demonstrated continuous operation with bagasse and integrated operation of the gasifier and HGCU. The major problem in the operation was the low-bulk density of the bagasse which led to difficulty in feeder operation. Furthermore, the residual sugars in the bagasse dust interrupted the lockhopper operation. The demonstration in Hawaii has been discontinued due to lack of funds.

1.1.2.3.2 Renugas[®] Pilot Plant in Tampere, Finland

The Renugas[®] technology was licensed to Tampella Power of Finland in 1989. A 27.2 metric ton/day (30-ton/day) plant based on coal and 90.7 metric ton/day (100 ton/day) plant based on biomass were built and commissioned in 1993 by Tampella's subsidiary, Enviropower, in Tampere, Finland, to further the development for IGCC applications. The gasification demonstration plant in Tampere, Finland, was designed for a maximum pressure of 2,413 kPa (350 psi) and a maximum temperature of 982 °C (1,800 °F). It was originally designed for coal at 27.2 metric ton/day (30 ton/day), but can also handle biomass at 90.7 metric ton/day (100 ton/day). The plant was designed to evaluate the HGCU and clean fuel gas production for IGCC applications. It was integrated with an on-

site co-generation plant. In 1997, Carbona, Inc. was formed as a result of the restructuring of Enviropower, and it maintains the exclusive license of the Renugas[®] technology from GTI for development in Europe, Canada, Brazil, and South Africa. The license for the development in the Pacific Rim and Pacific Basin was awarded to PICHTR. The demonstration plant is now owned and operated by Carbona, Inc. It now serves as a test facility, and it will not operate in the summer from June to September because heat is not needed by the city district heating system. The flow diagram of the demonstration plant is shown in Figure 27.

Figure 27. Coal/Biomass Demonstration Plant at Tampere, Finland (Courtesy of Carbona)

The plant has separate coal and biomass feed systems. Sulfur removal is needed only for coal gasification. The sorbent was developed in collaboration with Research Triangle Park (RTI) in the U.S. Figure 28 is the schematic diagram of the gasification system. The operating conditions of the demonstration plant are shown in Table 13.

Figure 28. Gasification Demonstration Plant at Tampere, Finland (Courtesy of Carbona)

Table 13. Operating Conditions of the Demonstration Gasification Plant in Tampere

Parameter	Condition	
Pressure	7-22 bar(g)	100-325 psig
Temperature	700-950 °C	1,290-1,740 °F
Feed Rate	0.38-1.12 kg/s	3,016-9,186 lb/h
Thermal Input	5.0-17.0 MJ/s	17.1-58.2 MMBtu/h
Air Feed Rate	0.60-1.63 kg/s	4,762-12,940 lb/h
Steam Feed Rate	0.04-0.26 kg/s	320-2,090 lb/h
Superficial Gas Velocity	0.5-1.2 m/s	1.6-3.9 ft/s
Filter Temperature	450-570 °C	840-1,060 °F

The various feedstocks and their quantity tested at the GASPI plant are shown in Table 14. All of these fuels were tested under air-blown conditions. The composition of the gas produced from the GASPI plant using wood waste is shown in Table 15.

Table 14. Feedstock Tested at Demonstration Plant in Tampere

Fuel	Quantity, metric ton (ton)
Wood Chips	1,630 (1,797)
Forest Residue	1,750 (1,929)
Paper Mill Waste (bark, paper, sludge)	1,180 (1,300)
Willow	400 (441)
Straw with coal	20 (+ 120 metric ton of coal) (22 + 132)
Alfalfa	300 (331)

Table 15. Composition of Gas Produced from Demonstration Plant in Tampere

Gas Component	Concentration (vol. %)
CO	18.7
H ₂	14.5
CH ₄	4.2
CO ₂	11.0
H ₂ O	10.0
N ₂	41.6
C _x H _y (light tars), ppmv	<6,000
Heavy tars, ppmv	<100
NH ₃ , HCN, ppmv	400-2,000
H ₂ S, COS, ppmv	<100
Alkalines (Na+K),ppmv	<0.1
HCl, ppmv	<10
Dust, ppmv	<5
LHV, kJ/Nm ³ (Btu/scf)	5,530 (138)

A picture of the demonstration plant is shown in Figure 29. The tall building in the middle houses the gasification system with the 2nd stage cyclone located on top of the building. The building is about 36.6 m (120 ft) tall with the cyclone extended another 9.1 m (30 ft) into the atmosphere. The structure to the right hand side of the building is the fuel preparation and storage area. The building behind the gasification building houses the heat generation system. The detached building to the left of the plant consists of the office facility. The air, nitrogen, and propane (for startup) tanks are located near the front of the picture.

Figure 29. Picture of the Gasification Demonstration Plant in Tampere, Finland (Courtesy of Carbona)

1.1.2.3.3 Renugas® VEGA IGCC Demonstration Project

Vattenfall AB started the evaluation of the VEGA IGCC project in Sweden in 1989. The IGCC plant generated 60 MW_e and 65 MW_{th} with 140 MW fuel input using the Tampella process (Renugas®). The overall efficiency of the plant was estimated to be above 40% (Lindman, 1993). Air-blown gasification was selected because of the significant investment in the air separation unit. The location of the IGCC plant was in the city of Eskilstuna, Sweden. The demonstration was planned for 1996. A flow diagram of the biomass IGCC is shown in Figure 30.

Figure 31. Biocycle Project in Finland

1.1.2.3.5 Renugas[®] MnVAP IGCC Demonstration Project

In 1998, the Renugas[®] technology was selected for a proposed IGCC project by the Minnesota Valley Alfalfa Produces (MnVAP) in Granite Falls, Minnesota, to provide 75-103 MW_e. The estimated cost of the project was about \$1,643/kW. The IGCC plant would consume 997.9 metric ton/day (1,100 ton/day) of alfalfa stem for power production. Extensive testing of the alfalfa was performed at Carbona's pilot plant in Finland. DOE announced that it would no longer participate in the cooperative agreement with MnVAP project and decided not to fund the construction of the power plant and the associated processing facilities (Federal Register: September 20, 1999).

1.1.2.4 Energy Farm Project in Di Cascina, Italy

A project on biomass-based IGCC was planned for Di Cascina, Italy (Beenackers, 1997 and www.bioelettrica.it). This project was one of three BIGCC demonstration projects funded by the European Commission within the framework of the THERMIE Programme. The joint-stock company, BIOELETTRICA S.p.A. will implement the project. The shareholders of the company are USF Smogless S.p.A., EDP-Electricidade de Portugal S.A., Energia Verde S.p.A., Lurgi Umwelt GmbH, and Fumagalli S.p.A. They were awarded for the supply of the main systems for the plant in May 1997. The plant design and testing are underway and is expected to enter into commercial operation in 2001.

This project will demonstrate the technical and economic feasibility of power-generation from biomass using the IGCC concept. The gasification system features the Lurgi atmospheric air-blown circulating fluidized-bed gasifier integrated with a 11.9 MW_e,

single-shaft, heavy-duty gas turbine, suited to burn the low-calorific value syngas produced by the gasifier. The gasifier is supplied from Lurgi, and the turbine is from Nuovo Pignone. A heat-recovery steam-generator will provide steam to a 5 MW_e condensing steam turbine. The plant's net thermal efficiency is about 33 %. A process flow sheet is shown in Figure 32.

Figure 32. Flow Diagram of the Energy Farm Project in Italy

The fuel will consist not only of short rotation forestry (SRF), but also of forestry and agricultural residues. The wood species will include poplar, robinia, willow, and chestnut, whereas the agricultural residues will comprise olive stones and grape-seed flour.

In this process, wet wood will be shredded to chips (30x30x6 mm or 1.18x1.18x0.236 inch) before mixing with the agricultural residues. Flue gases from the heat-recovery steam-generator (HRSG) are used to dry the biofuel to the desired moisture content (8-10%). The dried fuel is gasified in the CFB gasifier supplied by Lurgi to produce the syngas. The gasification takes place at about 800 °C (1,470 °F) and 140 kPa. This syngas is cooled in two stages during which syngas is cooled from 800 to 600 °C (1,472-1,112 °F) while the gasification air is preheated to 500 °C (932 °F). The syngas is cooled in the second stage to 240 °C (464 °F) in the waste heat boiler for steam production. The char and particulates are removed by passing syngas through a cyclone and a bag filter. The syngas is washed in a wet-scrubber and cooled to 45 °C (113 °F). Then it is compressed in several inter-cooled stages and delivered to a PGT10 B/1 gas turbine.

It was found that this project has faced difficulties because of the change of supplier for the gasification technology (Henk de Lange at Bioelettrica, personal communication). The problem seems to have been resolved. The new supplier of the gasification technology has not been identified, however. Public information will be announced around September 2001 according to Giuseppe Neri at Bioelettrica (personal communication).

1.1.2.5 ARBRE Energy Project

The third BIGCC project funded by the European Commission was the ARBRE project (Arable Biomass Renewable Energy) to be located at the 2,000 MW_e Eggborough Power station in the Aire Valley, North Yorkshire of UK. This project will provide a net electrical output of 8 MW_e with an efficiency of 30.6%. The process flow sheet is shown in Figure 33 (www.arbre.co.uk).

Figure 33. ARBRE Project in Yorkshire, UK

The biofuel for this project contains about 80% short rotation forestry based on 2,600 ha (6,424.6 acres) of a mixture of willow and hybrid poplar. The coppice will be used throughout the year with onsite covered storage. The feedstock is dried to 10-20% moisture by the low-grade heat from the system. It is expected that the drying will take up to 2 days to complete. The gasification technology is supplied by TPS. The details of the TPS gasification system can be found in the TPS section. The plant was partially completed by the end of 1999. A picture of the plant is shown in Figure 34 and a picture of the gasification section is shown in Figure 35 (Morris, 2000).

Figure 34. Project ARBRE site at Yorkshire, UK as of December, 1999

Figure 35. Gasification Section of Project ARBRE Plant

The construction of the BIGCC plant should have been completed by now and should be undergoing startup testing.

1.1.2.6 Brazil Biomass Integration Gasification-Gas Turbine

A Biomass Integration Gasification-Gas Turbine (BIG-GT) project was proposed by Eletrobrás (Brazilian Electric Power Co.) and CHESF (Companhia Hidro Elétrica do São Francisco) in April 1991. This involved building a 30 MW_e BIG-GT in the state of Bahia, Brazil, using wood or sugar cane bagasse as fuel. The project was named SIGAME (Wood Gasification Integrated System for Electricity Generation). This was intended to confirm the technical and commercial viability of producing electricity from biomass using the integrated gasification combined cycle system. It was originally predicted that the commercial operation would begin in 2001.

Global Environment Facility (GEF) and the World Bank considered funding the pilot demonstration project because of its potential for efficient and fuel-flexible use of biomass for power production. The GEF was formed in 1990 and is administered by the World Bank. Its task is to fund environmental conservation projects, mainly in the Third World. The project was initialized in 1993. The short-term objective of the BIG-GT project is to establish a globally-replicable prototype unit on a commercial scale for the cogeneration of electricity based on the gasification of wood chips or sugarcane bagasse. The long-term objective of this project is to reduce global warming by lowering CO₂ emissions from fossil fuels.

Two gasification systems in combination with the General Electric LM-2500 aeroderivative gas turbine were chosen for final evaluation. The first technology was from TPS Termiska Processor AB. It was an atmospheric fluidized-bed gasifier where the product gas is cleaned with cold quench wet scrubbing. The second gasification technology was the pressurized fluidized-bed reactor offered from Bioflow (now Foster Wheeler). Hot-gas clean-up with ceramic filters were used in this system. TPS has finished all the gasification testing with bagasse in their gasifier in late 1994. The gasification testing by Bioflow at the Värnamo plant in Sweden was uncertain at that time. Phase I of the project resulted in the selection of the TPS system. Phase II of the project involved the World Bank contracting with EPRI to perform an economic and risk evaluation of the Brazil BIG-GT project based on EPRI's model ("BIOPOWER: Biomass and Waste Fuel Power Plant Performance and Cost Model," EPRI TR-101774, March 1985). An economic study using the two gasification technologies for the BIG-GT in Brazil was finished and published ("BIOPOWER: Biomass and Waste Fuel Power Plant Performance and Cost Model, Version 1.01," EPRI TR-101774, Rev. March 1996).

The proposed BIG-GT demonstration plant will produce about 40 MW_e and deliver about 32 MW of electricity to the grid. The wood will be chipped and dried onsite with waste heat from the system and then gasified inside the atmospheric fluidized-bed gasifier. The syngas is subjected to a series of conditioning steps for removal of tars, ammonia, and fine particulates. The BIG-GT is expected to have a high heating value (HHV) of 38.0 % and net heat rate of 9473 kJ/kWh (8982 Btu/kWh) on a HHV basis. The consumption of biomass fuel will be 115,562 dry metric ton/a (127,385 ton/a).

EPRI used their BIOPOWER spreadsheet model for sensitivity analyses to determine the parameters most critical in determining the economics and risks associated with the BIG-

GT project. It was found that the most critical parameters are total plant cost, discount rate, and availability/capacity factor. The funding of the demonstration project by the World Bank would contribute significantly to Brazil's capability to deploy biomass gasification power plants in Brazil after year 2010 and would reduce the delivered cost of electricity from the plants.

This project was postponed and scheduled for 2000 (Juniper Consultancy Services Ltd, 2000). However, it was found on the World Bank website that the project was dropped (June, 2001). Hence, the future of this BIG-GT is not clear.

1.1.2.7 BioCoComb Project

Biofuel for Co-Combustion (BioCoComb) is a project where syngas produced from biomass is co-combusted in a pulverized coal-fired power station. The project was supported by a European Community Thermie Fund and has been installed by Austrian Energy and Environment in Zeltweg, Austria. The power plant has a capacity of 137 MW of electricity from coal. The gasifier is capable of gasifying biomass such as bark, wood chips, and sawdust, and has a thermal capacity of 10 MW_{th}. The produced gas replaces about 3% of the coal fired in the boiler (Anderl, 1999).

The major advantages of the BioCoComb concept are:

1. low gas quality sufficient for co-firing,
2. no hot-gas cleaning or cooling,
3. no predrying or milling of the biomass,
4. relatively low temperatures in the gasifier to prevent slagging,
5. favorable effects on power plant emissions (CO₂, NO_x),
6. no severe modifications of the existing coal-fired boiler,
7. high flexibility in arranging and integrating the main components into existing plants, and
8. reduction of ammonia water consumption from the re-burning in the coal boiler.

In this process, the biomass is converted to low calorific value (LCV) syngas in a separate gasification reactor. The syngas is fed to a conventional coal boiler where it is burned with the coal. This concept offers the highest flexibility in integrating the main components into the existing plants.

The Zeltweg power plant has been operated since 1962. Lignite was initially used as fuel, but was switched to hard coal 20 years later. Main steam data (HP/reheat) are 185 bar/44 bar (2,683/638 psi) at 535 °C (995 °F). The flue gas cleaning systems were renewed. NO_x removal is achieved by a selective non-catalytic reactor (SNCR) system with ammonia injection, and SO₂ removal is performed in a CFB-desulfurization reactor.

In the external circulating fluidized-bed gasifier, the biomass is combusted in a sub-stoichiometric atmosphere through an auto-thermal method. Predrying or milling of the biomass is not necessary. The size of the biomass is limited to 30x30x100 mm (1.18x1.18x3.94 inch). Low calorific value (LCV) gas is produced from incomplete

combustion due to the lack of oxygen. The gasification temperature is maintained at about 800-850 °C (1,472-1,562 °F) which is below the critical ash melting points. Mechanical attrition inside the gasifier produces very fine char particles. The larger particles are separated by cyclones and recycled back to the gasifier. The fine particles leave the gasifier and are combusted in the furnace of the power plant. Hot gas or cool gas cleaning is not necessary with this system. Re-burning of the produced gas occurs in the boiler when the unburned hydrocarbons are cracked to create radicals which attack the NO_x and decompose it to nitrogen and oxygen again. This was known only with natural gas in the past. A schematic diagram showing the gasification system is shown in Figure 36.

Figure 36. CFB Gasifier Used at the BioCoComb Project in Austria

The CFB gasifier is constructed using steel with a brick and concrete refractory lining. The gasification chamber is a vertical tube without internal mechanical components or heat exchangers. Compressed air is injected into the gasifier via an open nozzle grid located at the bottom of the gasifier. The air is taken from the recuperator of the coal

boiler at about 270 °C (518 °F). The bed material is a fine sand of a defined particle fraction. A startup burner is employed to heat up the reactor and for emergencies. The reaction temperature and bed behavior are the main parameters controlled by varying the air flow. A water-cooled screw conveyor is located at the bottom of the gasifier to allow discharge of bed material and incombustible parts. The ash is expected to be very fine and will leave the gasifier with the gas.

The BioCoComb concept was started in 1993, and the detailed planning phase began September 1996. Construction began in May 1997 with commissioning taking place in November. First gasification was achieved on December 10, 1997. More than 1,905 metric tons (2,100 tons) of biomass was gasified during the first two months of operation. The main fuel was spruce bark with a moisture content of approximately 50-55% (open storage). Chopped wood and sawdust from larch trees were also used. The operation of the gasifier was very successful with complete biomass conversion. The discharge bed material contained less than 0.4% of carbon. Homogenous temperatures were recorded throughout the gasifier. The power range of the gasifier was varied between 5 and 13 MW_{th}. The quality of the product was similar to that expected, and its composition is shown in Table 16.

Table 16. Calculated Gas Composition at 55% Moisture

Component	Mole %
O ₂	0.00
N ₂	38.44
CO	4.55
CO ₂	12.31
CH ₄	0.00
H ₂	10.54
H ₂ O	34.15
Lower Heating Value, MJ/kg df (Btu/lb)	1.61 (692)

The combustion of the produced gas in the boiler worked without problems. The re-burning effects in the boiler reduced the ammonia water consumption by 10-15%. There was no detectable damage to the gasifier after inspection. There was no deposition of tars in the system, especially in the hot-gas duct. The furnace walls of the boiler did not show more slagging than usual. The problems associated with the biomass feed system such as bridging in the dosing silo, slipping of frozen biomass on inclined belts, or blocking on the rotating disc separator were more or less all solved. The first demonstration of this concept is at the Lahti gasification plant in Finland.

1.1.2.8 Summary of Advanced Biomass Gasification Systems

Of the seven biomass integrated gasification combined cycle projects, the Bioflow gasification plant in Värnamo has proven that converting the biomass to heat and power is feasible. The Energy Farm project in Italy is undergoing some changes and will proceed in the near future. The other two demonstrations that are operating are the

ARBRE plant in U.K. and the Burlington plant in the U.S. The proposed BIGCC demonstration projects are summarized in Table 17.

Table 17. Advanced Gasification Demonstration (adapted from Beenackers, 1997)

PROJECT TITLE	BIOFLOW	FERCO SilvaGas®	Hawaii I
LOCATION	Värnamo, Sweden	Burlington, Vermont, USA	Paia, Hawaii,
CONSORTIUM	Ahlstrom, Fi; Sydkraft, and Foster Wheeler from Sweden	FERCO, Battelle, Burlington Electric, and ZURN NEPCO, all of USA	HICHTR, Sta HC&S, Ralpl GTI, NREL, ,
STATUS	The plant was shutdown in Oct. 1999*	In Operation - discontinuous	Terminated
TECHNOLOGY			
Gasification Process	IGCC	Gasification/Gas Turbine	IGCC/Metha
Gasifier	Press. CFB	Atm. Indirectly Heated	Press. FB
Gasifier Supplier	Ahlstrom (Bioflow)	Battelle	GTI (RENUC
Tar Removal	Hot gas cleanup	Catalytic – DN-34	Hot gas clean
Operating Conditions, °C/bar(g) (°F/psi)	950-1000/22 (1472-1832/319)	650-760/1.01 (1202-1400/14.6)	835/5 (1535/7
Gas Cleaning	Ceramic filter	wet scrubber	Ceramic filter
Gas Turbine	EGT/Typhoon	not specified	
Steam Turbine	Nadrowski	not specified	
CAPACITY			
Installed Capacity, MW _e /MW _{th}	6/9	15	3-5
Net Electric Output, MW _e	6	NA	5.0
Net Heat Output, MW _{th}	9	NA	NA
Thermal Efficiency, %		36 (estimated)	up to 80%
Electric Efficiency, %	32	32 (net), 34.5 (gross) (estimated)	30-35 (estim
Overall Efficiency, %	83	80 (estimated)	NA
Heating value of syngas, MJ/Nm ³ (Btu/scf)	5.3-6.3 (153-182)	15.5-17.3 (450-500)	10 (289)
FEEDSTOCK			
Source	Wood waste	Wood	Bagasse
Feedstock requirement, metric ton/day (ton/day) (MW)	90.7 (100) (18)	181 ¹ (200 ¹), 318 ² (350 ²)	90.7 (100)

* Biomass Technology Group (www.btgworld.com); NA – not available; 1 – design throughput; 2 – actual throughput

Table 17. Advanced Gasification Demonstration (Cont'd)

PROJECT TITLE	BIOCYCLE	SIGAME/BIG-GT	Energy Farm
LOCATION	Relocated to Finland	Bahia, Brazil	Di Cascina, Italy
CONSORTIUM	ELSAM, ELKRAFT, and VEAG from Denmark, and TRACTEBEL, BE	Electrobrás, CHESF, and Shell from Brazil	ENEL, LURGI, LE RENE ,IT; SWP and EGT of UK, and EDP, PO
STATUS	Terminated	Not funded	Change of Gasification Technology
TECHNOLOGY			
Gasification Process	IGCC	IGCC	IGCC
Gasifier	Press. CFB	Atm. CFB	Atm. CFB
Gasifier Supplier	Carbona	TPS	Lurgi (original supplier)
Gas Cleanup	Dolomite – Hot gas cleanup	Catalytic – Dolomite	Water Scrubbing
Operating Conditions, °C/bar (°F/psi)	850-950/22 (1562-1742/319)	850-900/1.5 (1562-1652/21.8)	800/1.4 (1472/20.3)
Gas Cleanup	Ceramic filter	Bag filter/scrubbing	Bag Filter
Turbine	EGT/Typhoon	GE LM2500	EGT/Typhoon
Gas Turbine			
CAPACITY			
Rated Capacity, MW _e /MW _{th}	7.9	40	14.3
Electric Output, MW _e	7.2	32	11.9
Heat Output, MW _{th}	6.78	NA	0
Electric Efficiency, %	39.9	41	33
Overall Efficiency, %	77.3	NA	NA
FEEDSTOCK			
Feedstock	Wood – SRC/Forest	<i>Eucalyptus</i> plantation	Wood – SRC/Forest
Feedstock requirement, metric ton/day (day)	76 (84)	463 (510)	134 (148)