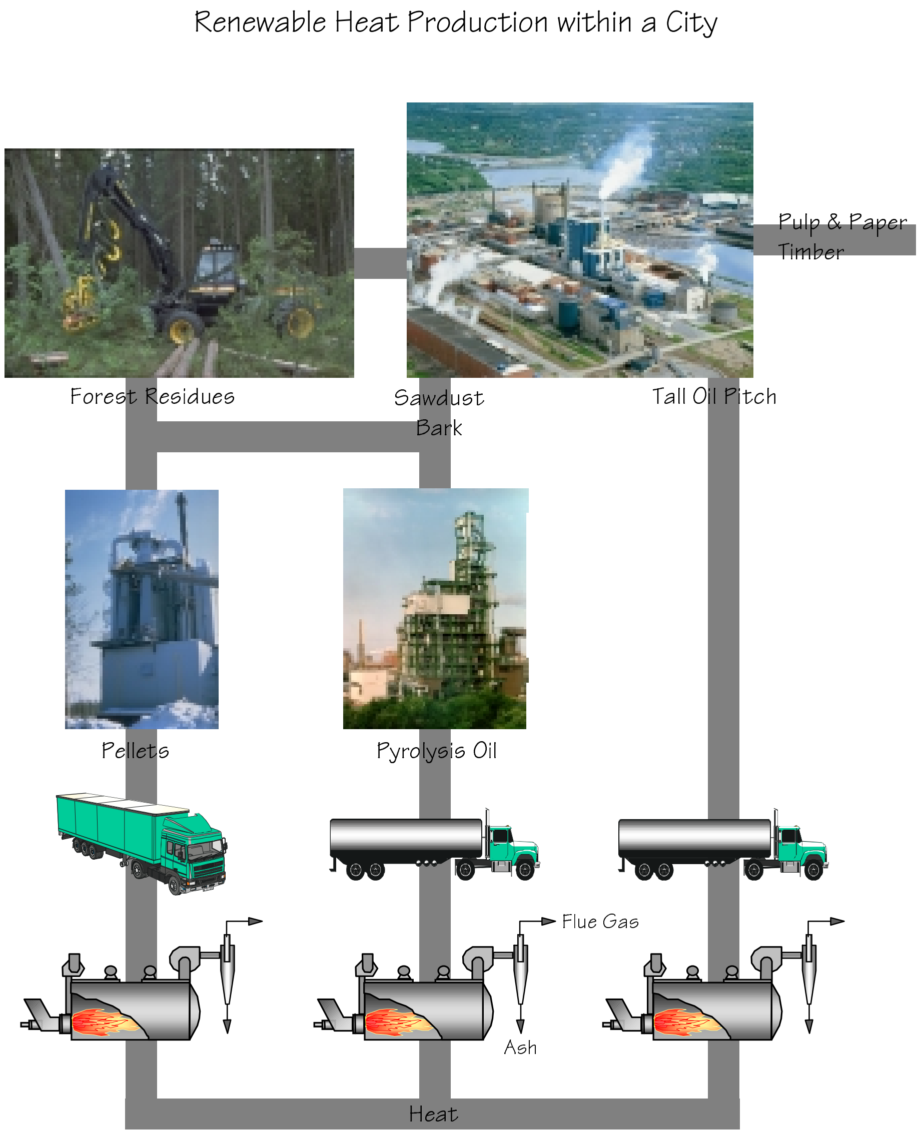
2024
VTT RESEARCH NOTES
VTT TIEDOTTEITA

Yrjö Solantausta, Erich Podesser, David Beckman, Anders Östman & Ralph P. Overend

IEA Bioenergy Task 22: Techno-economic assessment for bioenergy applications 1998–1999

Final report



TECHNICAL RESEARCH CENTRE OF FINLAND ESPOO 2000

VTT TIEDOTTEITA – MEDDELANDEN – RESEARCH NOTES 2024

IEA Bioenergy Task 22: Techno-economic assessments for bioenergy applications 1998–1999

Final report

Prepared for

International Energy Agency

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TECHNICAL RESEARCH CENTRE OF FINLAND
ESPOO 2000

ISBN 951–38–5655–0 (soft back ed.)
ISSN 1235–0605 (soft back ed.)

ISBN 951–38–5656–9 (URL: http://www.inf.vtt.fi/pdf/)
ISSN 1455–0865 (URL: http://www.inf.vtt.fi/pdf/)

JULKAISIJA – UTGIVARE – PUBLISHER

Valtion teknillinen tutkimuskeskus (VTT), Vuorimiehentie 5, PL 2000, 02044 VTT
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Cover photo: Kvaerner Pulping Oy, Fortum Corporation and Kemira Oyj

Technical editing Maini Manninen

Text preparing Arja Grahn

Otamedia Oy, Espoo 2000

Solantausta, Yrjö, Podesser, Erich, Beckman, David, Östman, Anders & Overend, Ralph P. IEA Bioenergy Task 22: Techno-economic assessment for bioenergy applications 1998–1999. Final report. Espoo 2000. Technical Research Centre of Finland, VTT Tiedotteita – Meddelanden – Research Notes 2024. 241 p.

Keywords biomass, conversion, feasibility, cogeneration, pyrolysis, flue gases, emissions, power generation, liquefaction, IEA

Executive summary

The objectives of the the IEA Bioenergy Tasks 22 were:

- to conduct analysis of bioenergy systems to support organisations working with products and services related to bioenergy
- to build and maintain a network for R&D organisations and industry
- to dissiminate data on biomass conversion technologies.

The IEA Bioenergy techno-economic resources have been maintained and improved since original studies in 1982. State-of-the-art, performance, and feasibility analysis of biomass for the following issues have been carried out:

- (heat and) electricity (CHP)
- liquid, gaseous, and solid fuel systems
- chemicals from biomass.

Technical and economic feasibility studies were carried out for several biomass power and fuel conversion technologies in Austria, Canada, Finland, Sweden and the United States over the years 1998–1999. Brazil was also contributing to the task. The core technologies analysed include:

- a flue gas condensing system for increased heat production integrated to a biomass boiler
- fast pyrolysis for slow release fertilizer
- small-scale steam boiler power plant compared to new concepts
- fast pyrolysis liquid production for district heat production within a city, and
- small modular biomass power systems.

Performance (mass and energy balances) of systems were determined rigorously, and the economic assessment was carried out with companies supplying or planning to use these systems. The companies, whose technologies or sites were considered, were selected by the funding agencies in the countries participating in this task.

Joanneum Research, Graz, Austria, has proposed an improved flue gas condensation concept, in which a larger fraction of the available condensing heat of flue gas is used for district heating than in current systems. Technical aspects with real site data are employed, together with economic and environmental aspects. Heat recovery from flue gas in biomass furnaces of district heat plants increases efficiency because of the high water content of wood chip and bark fuel. Due to the water content of the biofuel, the low heating value is commonly reduced to 50% of dry wood. However, if the flue gas is cooled to about 30 °C, large quantities of heat (30 to 50% of the furnace capacity) may be recovered by condensation. Preliminary analysis reveals that the proposed concept appears interesting coupled to co-generation plants. Experimental R&D work should be started to investigate and improve this special kind of heat pump technology.

Production of fertilisers from fast pyrolysis liquid is evaluated. **Resource Transforms International, RTI, of Waterloo, Canada**, has developed the patented process analysed in the task. In the analysis a comparison was made to conventional nitrogen-controlled release fertilizers. Preliminary results indicate that the concept appears interesting. More experimental R&D work should be carried out to supply data for further analysis. The results also emphasise the need for high value by-products with fast pyrolysis, as economic competitiveness in energy sector is otherwise difficult to reach without financial support.

The first BioPower Rankine co-generation power plant (0.9 MW power – 6 MW heat) suitable for sawmill and district heat operation, was commissioned by **Sermet Oy, Kiuruvesi, Finland**, in 1999. A comparison between the conventional steam boiler power plant and two new concepts proposed (gasification – gas engine, pyrolysis – diesel engine) is carried out to study the competitiveness of the BioPower concept. Due to the small scale, electricity costs are rather high in all the cases. Overall efficiencies for these systems are: the Rankine cycle 17.5%, gasification – gas engine 23.9%, and pyrolysis – diesel engine 24.7%. It is shown that the Rankine cycle is superior compared to the gasification gas engine and pyrolysis diesel engine with current cost data. Increasing fuel cost by 50% from the base value 45 FIM/MWh (2.3 US$/GJ) improves the competitiveness of new concepts, but the Rankine is continuously more economic over the whole annual operation time. It is concluded that especially the capital costs of the new power plant technologies should be reduced to be competitive compared to the Rankine cycle. Without such reductions it will be hard to compete with the Rankine cycle in small scale either in power-only or co-generation mode of operation.

Birka Energi Ab, Stockholm, Sweden, is currently using wood pellets and tall oil pitch as renewable fuels for district heating within the Stockholm city area. Pyrolysis liquid is a potential substitute for petroleum fuel oil. A technical, economic, and environmental assessment for the whole utilisation chain from forest residues to heat has been carried out. The assessment from raw material to hot water and flue gases yields a small preference to pyrolysis oil. However, this requires utilisation of by-product steam. Otherwise pellet production seems to be slightly advantageous since the energy efficiency of pyrolysis is lower. It is concluded that it is necessary to improve the quality of pyrolysis oil. There is no even-quality oil available today, and the oil cannot easily substitute for conventional fuel oil. In this respect, the pellets are superior. Preliminary results indicate that pyrolysis liquid may compete with wood pellets in heat production. However, there are a number of uncertain stages in the utilisation chain, which needs to adressed for the concept to reach industrial stage. For example, it should also be demonstrated that the the treatment of flue gas from the combustion of pyrolysis oil is not too difficult.

Working with industry (**Agrielectric Power, Inc., Lake Charles, Louisiana; Bechtel National Incorporated, San Francisco, California; Bioten General Partnership, Knoxville, Tennessee; Carbona Corporation, Atlanta, Georgia; Community Power Corporation, Aurora, Colorado; Energy and Environmental Research Center, Grand Forks, North Dakota; Niagara Mohawk Power Corporation, Syracuse, New York; Reflective Energies, Inc., Mission Viejo, California; STM Corporation, Ann Arbor, Michigan; SunPower, Inc., Athens, Ohio**), the U.S. Department of Energy's Small, Modular Systems Project is developing small biopower systems that are efficient and clean. The project consists of feasibility studies, prototype demonstrations, and proceeding to full system integration based on a business strategy for commercialization. Phase I of the three-phase project focused on the feasibility of developing cost-effective technologies and identifying the potential markets for each of the systems. In 1998, the National Renewable Energy Laboratory (NREL) in Golden, Colorado, and Sandia National Laboratories in Albuquerque, New Mexico, placed ten cost-shared contracts to develop small, modular biomass power systems. These contracts, which were the first phase of the Small Modular BioPower Initiative, were aimed at determining the feasibility of developing systems that are fuel-flexible, efficient, simple to operate, and whose operation will have minimum negative impacts on the environment. NREL and Sandia jointly managed procurement and monitored technical progress and oversight for the contracts.

The participants in the IEA Task have found the results of the first one and half years valuable, and have agreed to continue the task over the year 2000. Additional cases will be analysed during this year. The collaboration has proved to be a cost-effective way to generate necessary techno-economic base data to be used in supporting decision making in R&D.

Preface

IEA Bioenergy is an international collaboration within the International Energy Agency – IEA. IEA is an autonomous body within the framework of the Organisation for Economic Co-operation and Development (OECD) working with the implementation of an international energy programme.

The IEA Bioenergy "Techno-Economic Assessments for Bioenergy Applications" Task reported here, has several general objectives. The main objective is to make companies developing new systems within the bioenergy area and their products known in participating countries by carrying out pre-feasibility studies.

The objectives have been pursued 1998–1999 through carrying out studies in participating countries. Electricity, liquid fuel, and green chemical applications were studied. Studies were carried out in collaboration with companies developing new products or services from participating countries (Austria, Brazil, Canada, Finland, Sweden, and the United States of America) in the bioenergy field. The funding agents in each country were: Ministry of Science and Traffic, Austria; Natural Resources Canada (NRCan), CETC Division, Canada; National Technology Agency (Tekes), Finland; Energimyndigheten, Sweden, and the United States Department of Energy, U.S.A., respectively. The authors wish to acknowledge these organisations for supporting the work. We would also wish to acknowledge organisations and individuals, who contributed to the work: CEPEL and Marcos Vinicius (Brazil), RTI Ltd and Dr. Desmond Radlein (Canada), Sermet Oy and Dr. Juha Huotari (Finland), Birka Energi and Dr. Eva-Katrin Lindman (Sweden), Agrielectric Power, Inc., Bechtel National Incorporated, Bioten General Partnership, Carbona Corporation, Community Power Corporation, Energy and Environmental Research Center, Niagara Mohawk Power Corporation, Reflective Energies, Inc., STM Corporation, SunPower, Inc. (U.S.A).

The working group members were: Erich Podesser (Joanneum Research, Austria), Marcos Vinicius (Brazil), David Beckman (Zeton Inc., Canada), Yrjö Solantausta (coordination, VTT Energy, Finland), Anders Östman (Kemiinformation AB, Sweden), and Ralph P. Overend (National Renewable Energy Laboratory, U.S.A).

December 1999

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Contents

Part 1

Active flue gas condensation at a biomass district heating plant

Prepared for

International Energy Agency
IEA Bioenergy Task 22 – Techno-Economic assessments for bioenergy applications

IEA BIOENERGY T22: TECHNOECONOMICS: 1999:01

Erich Podesser & Henrike Bayer

Joanneum Research, Graz, Austria

Executive summary

Heat recovery from flue gas in biomass furnaces of district heat plants increases efficiency, because of the high water content of wood chip and bark fuels. Due to the water content of the biofuel, the lower heating value is normally about 50% of that of dry wood. However, if the flue gas is cooled down to about 30 °C, large quantities of heat (30 to 50% of the furnace capacity) may be recovered by condensation. When the flue gas temperature is lowered to 70 °C, the heat recovery is only 10%. If a heat pump is used, the low-temperature condensation heat – recovered from the flue gas – may be raised from 30 °C to the temperature of the district heat return level. For this purpose, a resorption heat pump with a mechanical compressor should be used due to the high coefficient of performance (COP). The mechanical compression unit is powered either by a grid-connected electric motor or by a flue gas powered bio-Stirling engine. Detailed calculation and design work of a resorption heat pump process, employing the Lorenz Process for heat recovery from flue gas, was carried out at Joanneum Research in 1997, because the number of biomass heating plants in Austria is 444 with an overall thermal output of 563 MW_{th}.

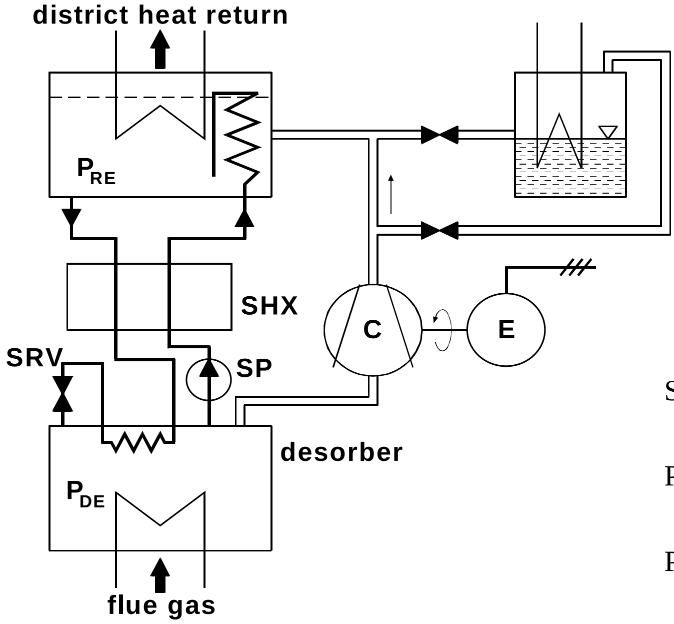
An analysis of different heat pump processes showed that a mechanically run resorption heat pump is the best option. The advantages evoked are as follows:

- High coefficient of performance (COP) due to the realisation of the Lorenz Process with temperature differences of all mass flows of more than 10 °C.
- High COP due to a low process pressure even at useful temperatures of 70–80 °C.
- Load control can be realised easily in principle.
- Since 1980, about 10 resorption heat pumps have been constructed and operated. The operational behaviour demonstrates the high COP.
- Biomass Stirling engines, developed at Joanneum Research, could be operated to drive the compressor and to generate electrical energy.

Some disadvantages have to be named too:

- There is no practical experience from resorption heat pumps in combination with a biomass-fired boiler.
- Some components of the resorption heat pump, like the “solution forwarding-processing” (Lösungsvorführung in German) of resorber and desorber are insufficiently known for a reliable design.
- Detailed control algorithms are insufficiently known.

Figure I shows the principle of the resorption heat pump.



SP	…	Working fluid pump
P_{RE}	…	Resorber pressure
P_{DE}	…	Desorber pressure

Figure I. Principle of a resorption heat pump process with a mechanic compressor; RS resorber, EG ...desorber.

Hot flue gas leaving the biomass-fired boiler powers the Stirling engine. Afterwards the flue gas enters the heat exchanger of the district heat system. After being cleaned in a cyclone the flue gas enters a further heat exchanger and is cooled down to 60 °C before entering the desorber EG of the resorption heat pump. As shown in Figure I, the resorption heat pump raises the temperature of waste heat to a suitable level for the district heating return.

In the framework of the Techno-Economic Assessments on the active condensation system proposed, data measured for an existing biomass district heat plant were used for the simulation of the technical behaviour of the plant. These data of 6-minute plant operation were extremely important for obtaining realistic results due to the partial load operation, which is the predominant case in practical operation. The results of the *technical calculations* showed that the COP lies in the range of 7 to 9 in all cases of partial load operation of the heat pump. These COP values are – with reference to other heat pump types – particularly high. Prerequisites for this excellent technical operation are technical maturity of apparatus design, plant control and optimised control algorithms. In partial load operation, the necessary compressor operation has to be controlled exactly by well-designed power electronics.

The *economical investigations* showed that due to the high COP the amortisation times of such plants could be in the range of 1–2 years depending on investment cost, water content and partial load factor. The investment costs were varied between 1 200 000 (specific cost of 2 400 ATS/kW_{th}) and 600 000 ATS, the water content in the range of 30–55% and the partial load factor 0.4–0.6.

Input data for economic calculation (1 EURO = 13.7603 ATS):

• specific net sales of heat	0.4 ATS/kWh_{th}
• specific cost of electricity supply	1.5 ATS/kWh_{el}
• fixed cost	6% of investment cost
• rate of interest	6%
• useful life of resorption heat pump	20 years
• resale value	equal to dismantling cost
• tax rate	34%
• Investitionsfreibetrag (a special Austrian tax exemption)	9%

The economic evaluation of an active condensation system with a resorption heat pump is based on the capital value and on the amortisation time. Regardless of investment cost and water content, the investment is economical for a partial load factor of 0.4 onwards (Figure II). For a partial load factor of 0.3, the water content should exceed 40% for an economical investment. Regarding an improvement in the economy, the water content is a more rigid parameter than the partial load factor. With regard to the capital value, the following limits can be found: For capital expenditures of ATS 1 200 000 and a partial load factor of 0.3, the water content must exceed 0.37. From a partial load factor of 0.4

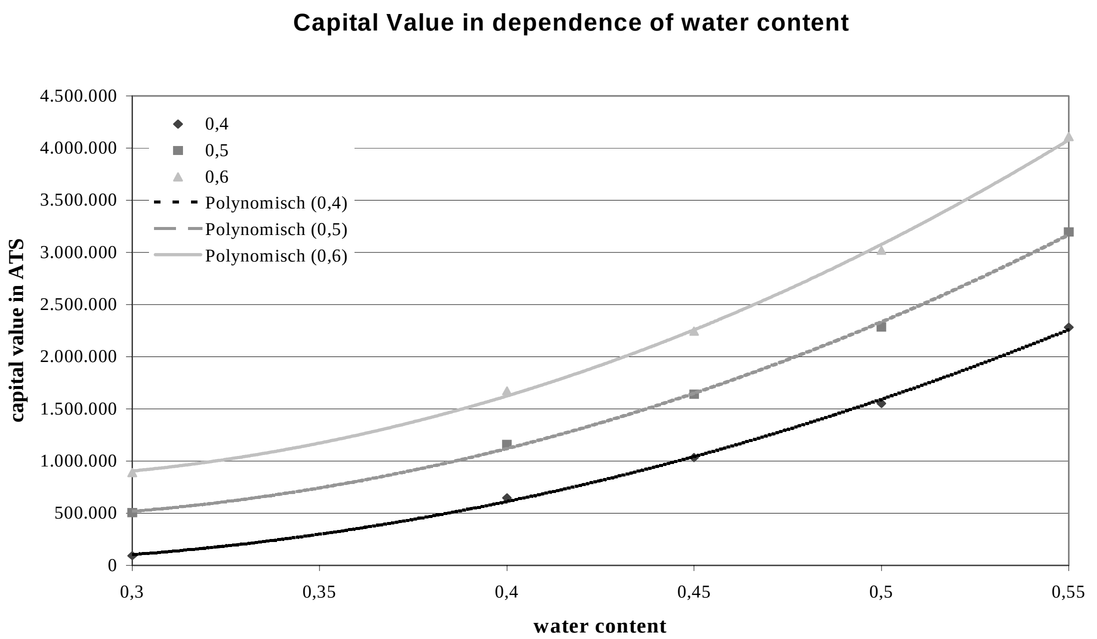


Figure II. Effect of partial load factor on the capital value, when no subsidies are granted.

onwards, there is no restriction concerning the water content. The lowest capital value of ATS 23 994 is reached for a water content of 0.24. As the capital value is higher than zero the investment is still feasible. When reducing investment cost to ATS 840 000 (30%) by means of subsidies or through cost cutting due to serial production, there is no limitation for the water content even at a partial load factor of 0.3.

For small water contents, an increase in partial load factor leads to a higher capital value than a rise in water content. For higher water contents just the opposite is true.

The rigid effect of water content can be seen when the amortisation time is taken as a decisive criterion. The payoff time is halved when the water content rises from 0.3 to 0.4, independently of the partial load factor (Figure III).

At a partial load factor of 0.3, the amortisation time exceeds the useful life of the resorption heat pump, when the investment cost of ATS 1 200 000 and the water content of 0.3 are taken into account. On the other hand, when the water content is 0.4 the partial load factor may fall to 0.2, and the investment is still feasible, even when capital expenditures were ATS 1 200 000. Although the partial load factor is a strict parameter, the effect of water content is the dominating feature in respect of the economy.

Because of these promising results, research and development work should be started to investigate and improve this special kind of heat pump technology.

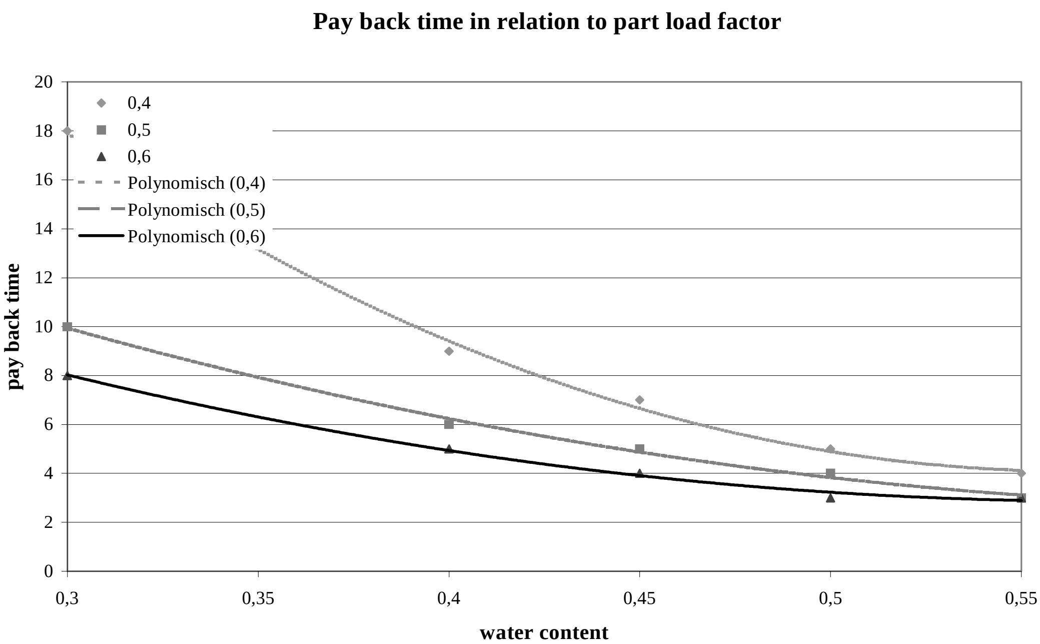


Figure III. Payback time in relation to a part load factor of 0.4 to 0.6.

Contents

1 Introduction

The focal point of the present study is the high water content of biofuels, e.g., wood chip and bark. Therefore the difference between the higher heating value (HHV) and the useful low heating value (LHV) is great, especially if bark is used as a fuel. Dry wood has a LHV of 5.2 kWh/kg, which is lowered by a 40% moisture content of wood fuel to 2.8 kWh/kg. The energy difference of HHV and LHV is used to evaporate the water of the biofuel in the furnace and leads to a high steam content of flue gas. That is why only the lower heating value is exploited to produce heat for the district heating system. Figure 1 indicates how much of the nominal boiler capacity can be recovered theoretically by condensing flue gas water. Assuming that the biofuel moisture is 45% (wet base) and the flue gas may be cooled to 30 °C, the waste heat available is 50% of the boiler capacity. Thus, a significant amount of the waste heat of the flue gas may be recovered (Table 1).

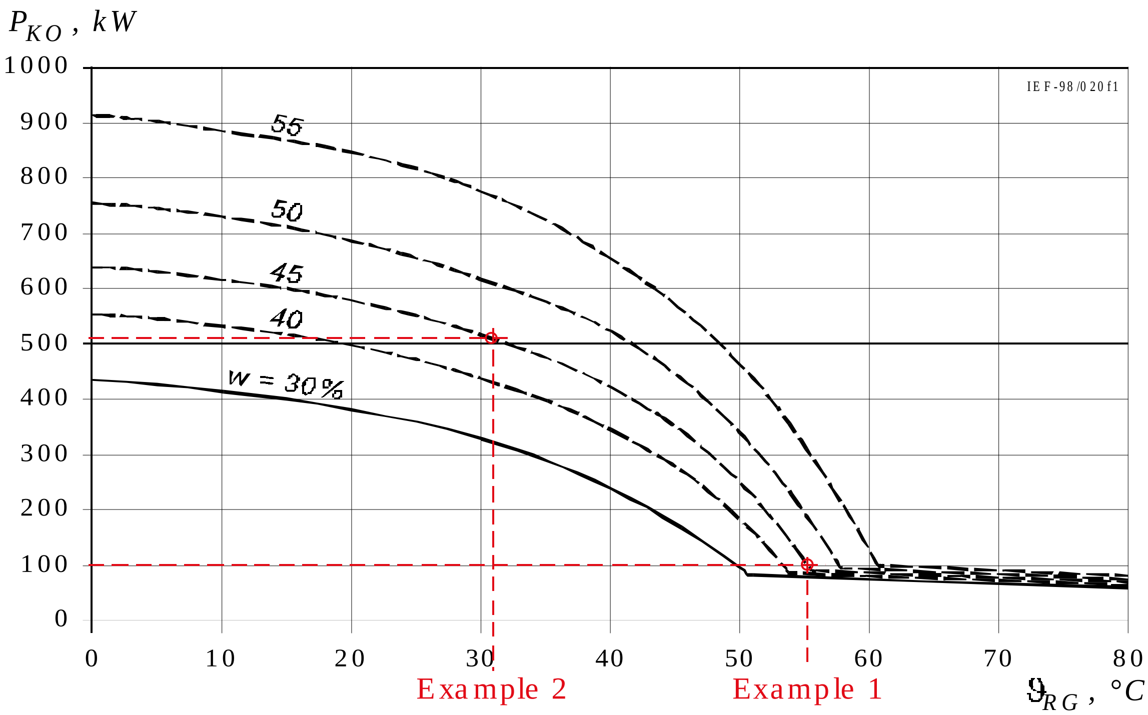


Figure 1. Relationship between flue gas temperature and condensation capacity. Parameters: biofuel water content, boiler capacity 1 000 kW_{th}, combustion air ratio 1.75, and flue gas temperature at boiler outlet 140 °C [1].

Table 1. Temperature, water content of biofuel and heat recovery rate of a conventional district heating system compared to that with active flue gas condensation.

Conditions		Example 1 (conventional)	Example 2 (active)
Flue gas temperature	°C	55	30
Water content of biofuel	%	45	45
Heat recovery ratio	%	10	50

2 Existing Austrian market

The number of biomass district heat plants in Austria was 444 in 1998, and their total nominal capacity was 563 MWth (Figure 2) [2].

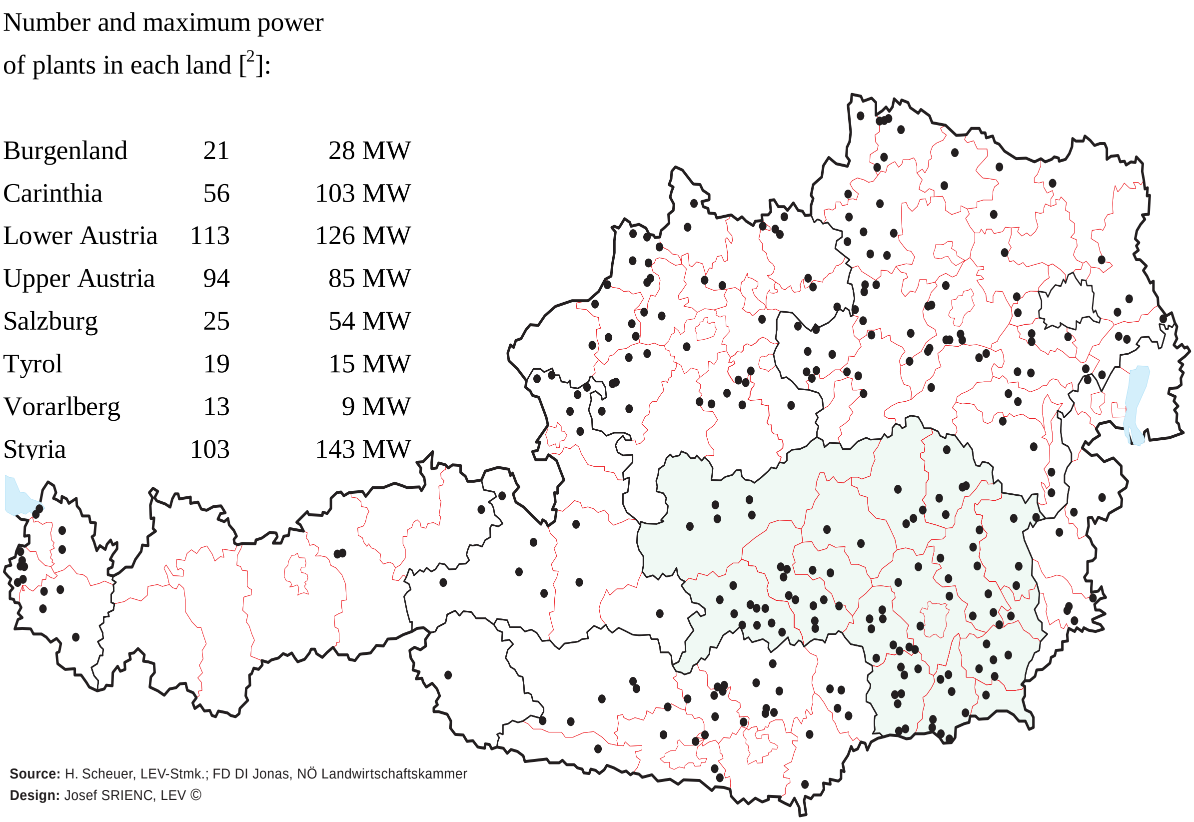


Figure 2. Biomass district heating plants in Austria.

Figure 3 indicates the energy flow diagram of a 1 MWth biomass boiler station equipped with a conventional flue gas condensation system. A wood fuel capacity of 1 130 kW_{th} is necessary to run the system under the design conditions. 838 kW_{th} are transferred to the district heat system by the DH/HE. 30, 18, and 12 kW_{th} are used for heating boiler indoor air and 30 kWth for preheating combustion air. 162 kW_{th} are recovered by the water-cooled flue gas condensation/heat recovery facility (FGC/HR) and added forward to district heat. The efficiency of the system shown in Figure 3 is 162 divided by 1 000 or 16% under optimised operating conditions.

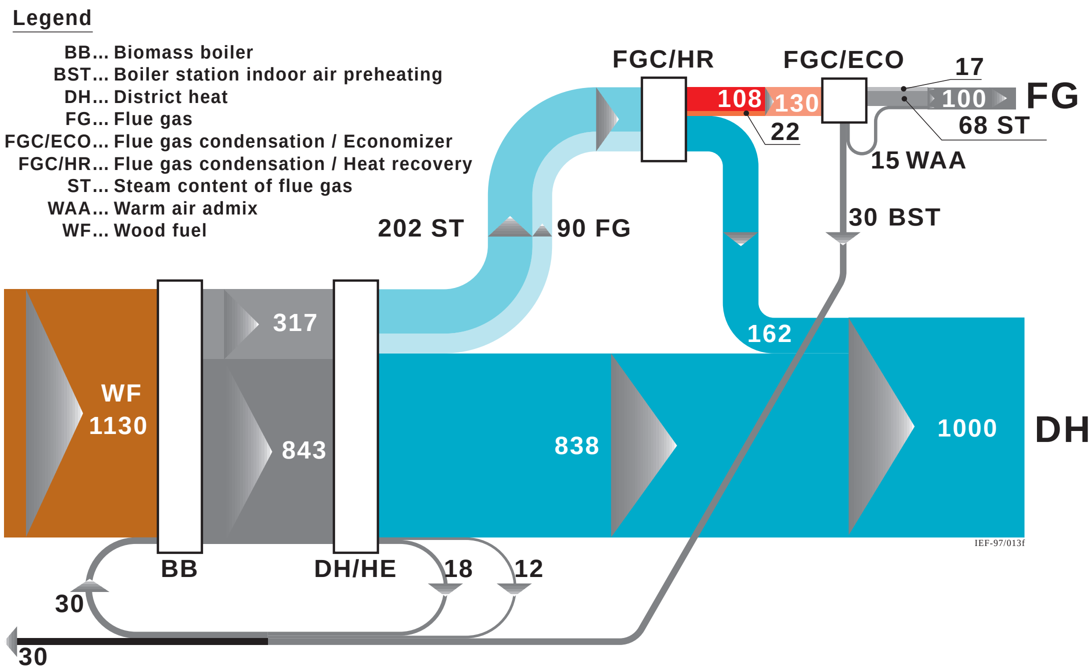


Figure 3. Energy flow diagram of a biomass district heating plant with flue gas condensation by district heat return.

3 Technical options

3.1 Possible processes

The following feasible technical heat pump processes were evaluated for the selection:

- absorption heat pump
- resorption heat pump with thermal compressor
- resorption heat pump with a mechanic compressor
- absorption heat transformer
- electrically driven compression heat pump.

3.2 Process selection

The heat pump processes mentioned above were investigated. Characteristic plant parameters were taken from references [3, 4, 5, 6, 7, 8, 9, 10, 11, 12]. It turned out that the resorption heat pump with a mechanic compressor is the best technical solution of current task setting. Its identified advantages are listed below:

- High coefficient of performance (COP) in the realisation of the Lorenz Process with > 10 °C temperature differences of all mass flows.
- High COP due to a low process pressure even at useful temperatures of 70–80 °C.
- Load control can be easily realised.
- Since 1980 about 10 resorption heat pumps have been manufactured and put into operation. The operational behaviour demonstrates the high COP.
- Biomass Stirling engines, which are developed at Joanneum Research could be used to operate the compressor and to generate electrical energy.

Some disadvantages should also be mentioned.

- There is no practical experience from the use of resorption heat pumps in biomass boiler stations.
- Some components of the resorption heat pump, like the "solution forward processing" (in German "Lösungsvorführung") of the resorber and desorber are insufficiently known for a reliable design.

4 Process design and plant configuration

A resorption heat pump with a thermal compressor can be designed by replacing the condenser in a single stage absorption heat pump by a resorber and the evaporator by a desorber, including a working fluid cycle (working fluid, heat exchanger, pump, and controlled pressure reduction valve). In the design of the resorption heat pump with a mechanical compressor, the thermal compressor of the resorption heat pump, consisting of an expeller, an absorber and a working fluid cycle, is replaced by a mechanic compressor. Figure 4 shows the principle of this type of heat pump.

A storage for refrigerant ammonia is added to the necessary components of the process to control the thermal load of the resorption heat pump. This storage is equipped with a heat exchanger for the condensation and evaporation of the refrigerant as shown in Figure 4.

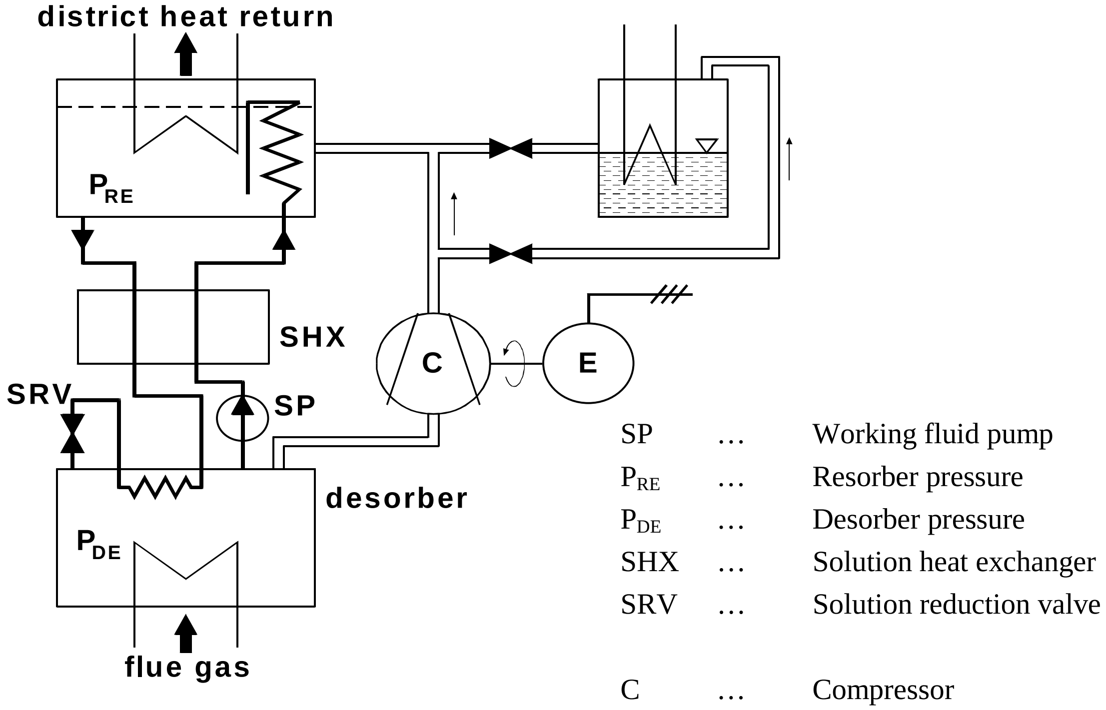


Figure 4. Principle of a resorption heat pump process with a mechanic compressor; RS ... resorber, EG ...desorber.

A principle design of a resorption heat pump plant with a mechanic compressor for condensing flue gas in a biomass boiler is shown in Figure 5. The furnace BMF produces hot flue gas, which powers the Stirling engine. After that the flue gas enters the heat exchanger of the district heating plant and is cleaned afterwards in a cyclone. A secondary heat exchanger cools the flue gas to about 60 °C before entering the desorber EG of the resorption heat pump. The temperature of the waste heat transferred, is elevated to the level suitable for heating up the district heat return, as Figure 5 indicates.

Compressor K is normally powered by the Stirling engine. If the shaft power of the Stirling engine is too low due to part-load operation, the electric generator operates as a motor providing the additional shaft power.

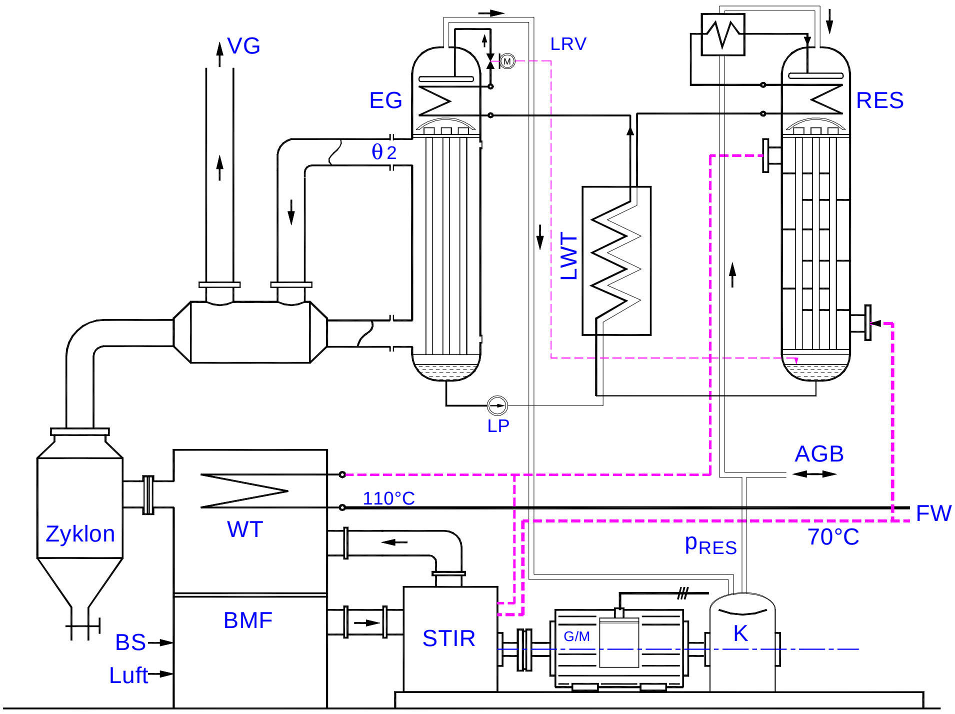


Figure 5. Biomass boiler plant with active flue gas condensation by a resorption heat pump with a mechanic compressor. FW = district heat, STIR = Stirling motor, BMF = biomass boiler, BS = biofuel, EG = desorber, G/M = generator/motor, K = compressor, VG = flue gas, STIR = Stirling engine, BMF = biomass furnace, AGB = compensator, LWT = solution heat exchanger, WT = heat exchanger.

In Figure 6, biomass BS is fed to a wood chip furnace that generates 1 000 kW of thermal energy for district heating. In order to gain the expected output of useful thermal energy, the energy content of the biofuel has to be 2 070 kW. According to the diagram, a thermal power amount of 1 070 kW leaves the furnace as steam in the flue gas and is led further to the heat pump. 500 kW of thermal power is recovered by the resorption heat pump and transferred to the district heat return. The resorption heat pump process needs 55 kW_m for driving the compressor K. Approximately 25% of the sensible energy content of the flue gas is transferred to the Stirling engine process for generating shaft power. The Stirling engine operates as a combined heat and power production unit. The heat rejected from the engine cooler to the district heat return is sold too.

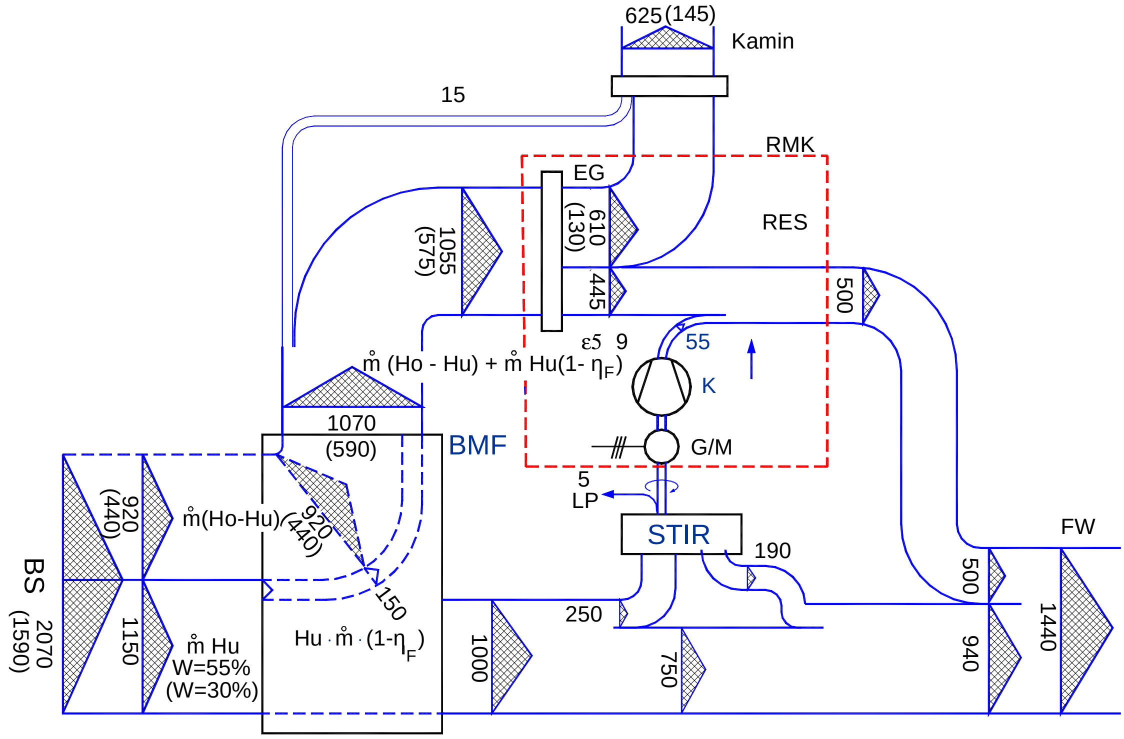


Figure 6. Energy flow diagram of a 1 000 kWth biomass boiler station with a 500 kW_{th} resorption heat pump with a mechanic compressor, numbers in kW. FW = district heat, STIR = Stirling motor, BMF = biomass boiler, BS = biofuel, EG = desorber, G/M = generator/motor, RMK = resorption heat pump with mechanic compressor, K = compressor. Simulation of the technical process with specific site data.

4.1 Site specification

The district heating plant "Pfarrwerfen" representing a typical biomass district heating site in Austria was chosen.

Address:	Hackgut- und Heizgenossenschaft Pfarrwerfen 5452 Pfarrwerfen 120, Austria
Location:	20 km south of the Province Capital Salzburg
Plant data:	Wood chip fired district heating (existing); an active flue gas condensation system with a mechanically driven resorption heat pump is simulated using the plant data.
Feedstock:	Debarked wood chips, wood chips (shredded), cut off wood chips, bark
Wood feed:	4 452 m^3/a (w = 0.32 to 0.55)

Land area required: 800 m^2 for the wood chip storage and district heating plant

Therm. capacity: 1 000 kW_{th} furnace, implemented (3 000 kW furnace planned)

Plant cost: ATS 23.7 mill. + 1.2 mill. (1 000 kW_{th} district heating and 500 kW_{th} resorption heat pump)

5 Calculation program for the technical process

5.1 General description

The process simulation of active flue gas condensation is executed in EXCEL 5 due to the 6-minute plant data available. The first step of the program concerns the program mask, which allows to read in the 6-minute plant data of a biomass district heating plant from the whole heating period from 1 September 1994 to 10 April 1995. The first step of the data treatment relates to the compression of the 6-minute data to daily data with the maximum, minimum and average values. With the aid of these compressed data the simulation of the resorption heat pump's (RHP) behaviour in an active flue gas condensing system (see Figure 6) of a biomass district heating plant is computed.

5.2 Description of important steps of the simulation

1	2	3	4	5

Compressed daily data from Sept. 1. 94 to Apr. 10. 95 (Kdab0994.XLS)

Date	Start	end	numbers	HGT20/12
1. Sept.	0: 6	0: 0	240	0.0
10. Jan	0: 6	0: 0	240	22.6
11. Jan	0: 6	0: 0	240	21.0
12. Jan	0: 6	0: 0	240	21.6
13. Jan	0: 6	0: 0	240	23.7
14. Jan	0: 6	0: 0	240	27.9
15. Jan	0: 6	0: 0	240	25.8
16. Jan	0: 6	0: 0	240	27.4
17. Jan	0: 6	0: 0	239	28.7
18. Jan	0: 6	0: 0	240	27.1
19. Jan	0: 6	0: 0	240	22.4
20. Jan	0: 6	0: 0	240	22.5
21. Jan	0: 6	0: 0	240	23.2
22. Jan	0: 6	0: 0	240	21.9
23. Jan	0: 6	0: 0	240	19.6
24. Jan	0: 6	0: 0	240	19.1
25. Jan	0: 6	0: 0	240	20.6
26. Jan	0: 6	0: 0	240	18.6
27. Jan	0: 6	0: 0	240	19.9
28. Jan	0: 6	0: 0	240	23.3
29. Jan	0: 6	0: 0	240	21.9
30. Jan	0: 6	0: 0	240	19.6
31. Jan	0: 6	0: 0	240	21.0

Column 1 Current date (compressed daily data set)
Column 2 Start of the first daily 6 minute measurement
Column 3 Start of the last daily measurement
Column 4 Numbers of 6-minute data sets of the day
Column 5 HTG (heating degree days)

1	6	7	8
	TMT050 Ambient temperature		
	°C	°C	°C
Date	Max	Min	mid
1. Sept.	24.4	14.0	18.0
10. Jan	1.0	-5.1	-2.4
11. Jan	0.8	-2.5	-1.6
12. Jan	2.7	-5.0	-2.0
13. Jan	-2.3	-6.2	-4.7
14. Jan	0.0	-10.5	-7.0
15. Jan	2.2	-9.4	-4.8
16. Jan	2.2	-11.4	-6.0
17. Jan	2.6	-11.8	-7.0
18. Jan	1.1	-11.6	-5.7
19. Jan	3.6	-6.0	-1.6
20. Jan	5.0	-6.0	-1.5
21. Jan	1.4	-5.6	-2.6
22. Jan	6.8	-5.7	-1.1
23. Jan	7.6	-2.3	1.3
24. Jan	4.7	-1.3	1.1
25. Jan	2.4	-2.8	-0.5
26. Jan	5.7	-0.2	2.0
27. Jan	2.5	-6.2	-0.5
28. Jan	5.3	-7.1	-2.7
29. Jan	4.9	-5.7	-1.2
30. Jan	7.4	-2.6	0.9
31. Jan	5.7	-7.6	-1.6

Columns 6, 7, 8 Outside temperatures (max., min. and average of the day)

1	9	10	11	12
		UT100 grid capacity		
	MW	MW	MW	MWh
Date	max	min	mid	work
1. Sept.	0.146	0.021	0.063	1.509
10. Jan	0.930	0.228	0.676	16.236
11. Jan	0.920	0.241	0.651	15.612
12. Jan	0.992	0.236	0.654	15.701
13. Jan	1.059	0.228	0.702	16.851
14. Jan	1.083	0.271	0.770	18.474
15. Jan	0.988	0.309	0.719	17.267
16. Jan	1.009	0.357	0.752	18.052
17. Jan	1.059	0.472	0.786	18.782
18. Jan	1.071	0.316	0.752	18.053
19. Jan	0.981	0.229	0.678	16.278
20. Jan	0.995	0.014	0.672	16.117
21. Jan	1.043	0.217	0.691	16.596
22. Jan	0.947	0.256	0.659	15.814
23. Jan	0.952	0.176	0.602	14.454
24. Jan	0.972	0.150	0.604	14.485
25. Jan	1.035	0.188	0.625	14.999
26. Jan	0.987	0.178	0.575	13.812
27. Jan	0.920	0.167	0.615	14.766
28. Jan	1.004	0.242	0.689	16.525
29. Jan	1.004	0.221	0.657	15.769
30. Jan	0.955	0.223	0.593	14.241
31. Jan	1.032	0.185	0.604	14.487

Columns 9, 10, 11 Net capacity (max., min. and average of the day)
Column 12 Thermal net work of the day

1	13	14	15	16	17
	UM200	**boiler part load (1MWth n.c.)**			**part load coeff.**
	MW	MW	MW	MWh	
Date	max	min	mid	work	mid
1. Sept.	0.614	0.019	0.104	2.497	0.104
10. Jan	0.942	0.050	0.613	14.711	0.613
11. Jan	0.739	0.051	0.555	13.312	0.555
12. Jan	0.997	0.042	0.550	13.210	0.550
13. Jan	0.936	0.041	0.595	14.270	0.595
14. Jan	1.077	0.088	0.704	16.894	0.704
15. Jan	0.860	0.339	0.674	16.187	0.674
16. Jan	1.010	0.334	0.701	16.827	0.701
17. Jan	0.995	0.130	0.708	16.930	0.708
18. Jan	0.975	0.360	0.691	16.592	0.691
19. Jan	1.001	0.047	0.598	14.354	0.598
20. Jan	1.078	0.048	0.597	14.318	0.597
21. Jan	1.208	0.048	0.622	14.917	0.622
22. Jan	0.899	0.142	0.606	14.554	0.606
23. Jan	0.960	0.054	0.610	14.651	0.610
24. Jan	1.143	0.078	0.709	17.018	0.709
25. Jan	1.056	0.243	0.717	17.213	0.717
26. Jan	1.029	0.047	0.519	12.468	0.519
27. Jan	0.796	0.039	0.528	12.661	0.528
28. Jan	1.045	-0.200	0.597	14.318	0.597
29. Jan	0.922	0.038	0.562	13.477	0.562
30. Jan	1.099	0.051	0.540	12.971	0.540
31. Jan	1.180	0.043	0.531	12.750	0.531

Column 13, 14, 15	Boiler thermal capacity (max., min. and average of the day)
Column 16	Boiler thermal work
Column 17	Part load number (average thermal capacity of the boiler divided by 24 hours)

1		18	19	20	21	22
Condenser capacity in kW in dependence of the water content of the bio fuel						
	Kond. kW	326	435	515	623	775
Date	w	0.3	0.4	0.45	0.5	0.55
1. Sept.		33.921	45.262	53.586	64.824	80.639
10. Jan		199.822	266.633	315.669	381.868	475.036
11. Jan		180.824	241.283	285.657	345.562	429.873
12. Jan		179.434	239.428	283.461	342.905	426.567
13. Jan		193.840	258.652	306.220	370.437	460.817
14. Jan		229.479	306.206	362.520	438.544	545.540
15. Jan		219.868	293.382	347.338	420.178	522.693
16. Jan		228.569	304.992	361.082	436.805	543.376
17. Jan		230.922	308.132	364.800	441.301	548.970
18. Jan		225.375	300.730	356.037	430.701	535.784
19. Jan		194.969	260.158	308.003	372.594	463.500
20. Jan		194.484	259.511	307.237	371.667	462.347
21. Jan		202.625	270.374	320.098	387.226	481.701
22. Jan		197.685	263.783	312.294	377.785	469.958
23. Jan		199.006	265.544	314.380	380.308	473.096
24. Jan		231.161	308.451	365.177	441.758	549.539
25. Jan		233.813	311.989	369.367	446.826	555.843
26. Jan		169.355	225.980	267.539	323.644	402.607
27. Jan		171.979	229.481	271.684	328.658	408.845
28. Jan		194.482	259.509	307.234	371.664	462.343
29. Jan		183.059	244.266	289.189	349.834	435.187
30. Jan		176.193	235.104	278.341	336.712	418.863
31. Jan		173.182	231.086	273.585	330.958	411.705

Column 18	Flue gas condensing capacity of a 1 000 kW_{th} furnace at a fuel water content of w = 30% (see specifications in Figure 1.
Column 19, 20, 21, 22	Flue gas condensing capacity (kW) of a 1 000 kW_{th} furnace at a fuel water content of w = 40, 45, 50, 55% (see specifications in Figure 1.

1	23	24	25	26	27
	Mass flow of the condensate in kg/h				
	Evaporation heat		0.6816	kWh/kg	
Date	0.3	0.4	0.45	0.5	0.55
1. Sept.	49.766	66.406	78.618	95.105	118.309
10. Jan	293.165	391.187	463.129	560.252	696.942
11. Jan	265.293	353.996	419.098	506.987	630.682
12. Jan	263.253	351.274	415.876	503.089	625.832
13. Jan	284.390	379.478	449.267	543.482	676.081
14. Jan	336.677	449.246	531.866	643.403	800.381
15. Jan	322.577	430.432	509.592	616.458	766.862
16. Jan	335.341	447.465	529.757	640.852	797.207
17. Jan	338.794	452.071	535.211	647.449	805.414
18. Jan	330.656	441.212	522.355	631.897	786.068
19. Jan	286.046	381.687	451.882	546.646	680.017
20. Jan	285.334	380.738	450.758	545.286	678.326
21. Jan	297.279	396.676	469.628	568.113	706.721
22. Jan	290.031	387.005	458.179	554.263	689.492
23. Jan	291.968	389.590	461.238	557.964	694.096
24. Jan	339.145	452.539	535.765	648.120	806.248
25. Jan	343.035	457.731	541.911	655.555	815.498
26. Jan	248.467	331.543	392.516	474.830	590.680
27. Jan	252.316	336.679	398.597	482.187	599.831
28. Jan	285.332	380.735	450.755	545.282	678.320
29. Jan	268.573	358.372	424.279	513.254	638.479
30. Jan	258.499	344.929	408.365	494.002	614.529
31. Jan	254.081	339.035	401.386	485.560	604.027

Column 23, 24, 25 26, 27 Mass flow of condensate (kg H_2O/h) for fuel water contents of 30, 40, 45, 50, 55%.

28		29	30	31	32	33
			Fuel heat capacity			
m	dry mass		1.000	kg/s		
W	water content	0.3	0.4	0.45	0.5	0.55
mW	Water	0.429	0.667	0.818	1.000	1.222
mH	Fuel	1.429	1.667	1.818	2.000	2.222
Ho	kJ/kg	18500				
Conversion factor kJ/kWh		0.000278				
Upper heating value Ho...kWh/kg		5.139				
Evaporation heat r		0.6816				
Lower heating Value Hu kWh/kg		3.393	2.811	2.520	2.229	1.938
Q	fuel kWh/s	4.846775	4.684489	4.581216	4.457289	4.305822
Q	fuel kW	17448.39	16864.16	16492.38	16046.24	15500.96

Column 28 to 33 Interim calculation of heat capacity of wet fuel for a water content of 30, 40, 45, 50 and 55%

1	34	35	36	37	38
	Ratio of condensation heat to the fuel heat				
Date	0.3	0.4	0.45	0.5	0.55
1. Sept.	0.19	0.27	0.32	0.40	0.52
10. Jan	1.15	1.58	1.91	2.38	3.06
11. Jan	1.04	1.43	1.73	2.15	2.77
12. Jan	1.03	1.42	1.72	2.14	2.75
13. Jan	1.11	1.53	1.86	2.31	2.97
14. Jan	1.32	1.82	2.20	2.73	3.52
15. Jan	1.26	1.74	2.11	2.62	3.37
16. Jan	1.31	1.81	2.19	2.72	3.51
17. Jan	1.32	1.83	2.21	2.75	3.54
18. Jan	1.29	1.78	2.16	2.68	3.46
19. Jan	1.12	1.54	1.87	2.32	2.99
20. Jan	1.11	1.54	1.86	2.32	2.98
21. Jan	1.16	1.60	1.94	2.41	3.11
22. Jan	1.13	1.56	1.89	2.35	3.03
23. Jan	1.14	1.57	1.91	2.37	3.05
24. Jan	1.32	1.83	2.21	2.75	3.55
25. Jan	1.34	1.85	2.24	2.78	3.59
26. Jan	0.97	1.34	1.62	2.02	2.60
27. Jan	0.99	1.36	1.65	2.05	2.64
28. Jan	1.11	1.54	1.86	2.32	2.98
29. Jan	1.05	1.45	1.75	2.18	2.81
30. Jan	1.01	1.39	1.69	2.10	2.70
31. Jan	0.99	1.37	1.66	2.06	2.66

Columns 34, 35, 36, 37, 38 Ratio of condensing heat and fuel heat for the five fuel water contents

1	39	40	41	42	43
		NH_3-circuit: desorber kg/h			
	Q-Desorber	0.749	kWh		
Date	0.3	0.4	0.45	0.5	0.55
1. Sept.	45.288	60.430	71.544	86.547	107.663
10. Jan	266.784	355.985	421.454	509.837	634.227
11. Jan	241.420	322.141	381.385	461.365	573.929
12. Jan	239.564	319.664	378.453	457.817	569.516
13. Jan	258.799	345.330	408.839	494.576	615.243
14. Jan	306.380	408.820	484.005	585.506	728.358
15. Jan	293.549	391.699	463.735	560.985	697.854
16. Jan	305.165	407.199	482.086	583.184	725.469
17. Jan	308.307	411.391	487.049	589.187	732.938
18. Jan	300.901	401.509	475.350	575.035	715.332
19. Jan	260.306	347.340	411.219	497.455	618.825
20. Jan	259.658	346.476	410.196	496.218	617.286
21. Jan	270.528	360.980	427.367	516.990	643.126
22. Jan	263.933	352.180	416.949	504.386	627.447
23. Jan	265.695	354.532	419.733	507.755	631.637
24. Jan	308.626	411.817	487.553	589.798	733.697
25. Jan	312.167	416.541	493.147	596.564	742.114
26. Jan	226.108	301.708	357.195	432.102	537.526
27. Jan	229.611	306.383	362.729	438.796	545.854
28. Jan	259.656	346.474	410.193	496.214	617.280
29. Jan	244.405	326.123	386.100	467.068	581.024
30. Jan	235.237	313.890	371.617	449.549	559.230
31. Jan	231.217	308.526	365.266	441.866	549.673

Column 39, 40, 41, 42, 43 Desorber capacity for five different fuel water contents

44 45 46 47

Specific shaft power of the NH3-compressor after K. Linge [13]

wi	Indikatorwork	233 .067	Nm/kg
wi	Indikatorwork	65	Wh/kg
m	Coefficient of compression	1.25	
n	Coefficient of expansion	1.15	
epsilon o	Relative dead space	0.05	
p	Pressure of resorber	600 000	Pa
po	Pressure of desorber	100 000	Pa
delta p	Pressure loss outlet	30 000	Pa
delta po	Pressure loss inlet	5 000	Pa
vo	Volume of 1 kg NH_3 at po	1.32	m3/kg
eta mech FL	Mechanical COP	0.93	
Wkomp FL	Specific compressor shaft work	69.61	Wh/kg (NH_3)
	roughly	70	
PN	Name plate capacity of the compressor	70	kW

spec. shaft work: formula's part 1 and 2

part 1	part 2	part1–part2
229 376	52 810	176 566

$$wi := Vo\left[\frac{m}{(m-1)}\cdot(po-\Delta po)\cdot(1+\varepsilon o)\cdot\left[\left(\frac{p+\Delta p}{po-\Delta po}\right)^{\frac{(m-1)}{m}}-1\right]-\frac{n}{n-1}\cdot(p+\Delta p)\cdot\varepsilon o\cdot\left[1-\left(\frac{po-\Delta po}{p+\Delta p}\right)^{\frac{(n-1)}{n}}\right]\right]$$

w_i	indicator work for the compression of 1 kg ammonia	Nm/kg
p_o	NH_3-gas pressure above the boiling working fluid	N/m^2
Δp_o	pressure losses at the compressor inlet (valves, ducts, etc.)	N/m^2
p	NH_3-gas pressure above the resorbing working fluid	N/m^2
Δp	pressure losses at the compressor outlet (valves, ducts, etc.)	N/m^2
ε_o	relative dead volume	----
m	Compression coefficient (ammonia 1,25)	----
n	Back-expansion coefficient (Ammonia 1,15)	----
v_o	Volume of 1 kg ammonia gas at the compressor inlet	m^3/kg

Volume of 1 kg ammonia gas at the compressor inlet [13]

1	48	49	50	51	52

Necessary shaft power of the NH_3- compressor (kW)

Date	0.3	0.4	0.45	0.5	0.55
1. Sept.	5.005	5.985	6.705	7.676	9.043
10. Jan	19.556	25.331	29.569	35.291	43.344
11. Jan	17.890	23.115	26.951	32.129	39.416
12. Jan	17.768	22.953	26.759	31.898	39.129
13. Jan	19.031	24.633	28.745	34.296	42.108
14. Jan	22.157	28.789	33.657	40.228	49.476
15. Jan	21.314	27.668	32.332	38.628	47.489
16. Jan	22.077	28.683	33.531	40.076	49.288
17. Jan	22.283	28.957	33.855	40.468	49.774
18. Jan	21.797	28.310	33.091	39.545	48.628
19. Jan	19.130	24.765	28.900	34.483	42.341
20. Jan	19.088	24.708	28.834	34.403	42.241
21. Jan	19.802	25.658	29.956	35.758	43.924
22. Jan	19.368	25.082	29.275	34.936	42.903
23. Jan	19.484	25.236	29.457	35.155	43.176
24. Jan	22.304	28.985	33.888	40.508	49.824
25. Jan	22.537	29.294	34.254	40.949	50.372
26. Jan	16.884	21.778	25.370	30.220	37.045
27. Jan	17.114	22.084	25.732	30.657	37.588
28. Jan	19.088	24.708	28.833	34.402	42.240
29. Jan	18.086	23.376	27.259	32.501	39.879
30. Jan	17.483	22.575	26.313	31.358	38.459
31. Jan	17.219	22.224	25.898	30.857	37.836

Columns 48 to 52 Calculation of the part load compressor shaft power computed with plant data

53	54	55

Specific shaft work of the working fluid pump after R. Plank [14]

VL, m^3/h	6.5
delta P	6
eta LP	0.5
Vo, dm^3/kg	1.086
w LP, Wh	2.308	Wh/1 kg NH_3

Columns 53, 54, 55 Specific shaft work of the working fluid pump [14]

shaft power of the working fluid pump in kW

1	56	57	58	59	60
Date	0.3	0.4	0.45	0.5	0.55
1. Sept.	0.105	0.139	0.165	0.200	0.248
10. Jan	0.616	0.822	0.973	1.177	1.464
11. Jan	0.557	0.744	0.880	1.065	1.325
12. Jan	0.553	0.738	0.874	1.057	1.315
13. Jan	0.597	0.797	0.944	1.142	1.420
14. Jan	0.707	0.944	1.117	1.351	1.681
15. Jan	0.678	0.904	1.070	1.295	1.611
16. Jan	0.704	0.940	1.113	1.346	1.674
17. Jan	0.712	0.950	1.124	1.360	1.692
18. Jan	0.695	0.927	1.097	1.327	1.651
19. Jan	0.601	0.802	0.949	1.148	1.428
20. Jan	0.599	0.800	0.947	1.145	1.425
21. Jan	0.624	0.833	0.986	1.193	1.484
22. Jan	0.609	0.813	0.962	1.164	1.448
23. Jan	0.613	0.818	0.969	1.172	1.458
24. Jan	0.712	0.951	1.125	1.361	1.693
25. Jan	0.721	0.961	1.138	1.377	1.713
26. Jan	0.522	0.696	0.824	0.997	1.241
27. Jan	0.530	0.707	0.837	1.013	1.260
28. Jan	0.599	0.800	0.947	1.145	1.425
29. Jan	0.564	0.753	0.891	1.078	1.341
30. Jan	0.543	0.724	0.858	1.038	1.291
31. Jan	0.534	0.712	0.843	1.020	1.269

Columns 56 to 60 Shaft power of the working fluid pump at full load

1	61	62	63	64	65

Resorber capacity in dependence of part load and fuel water content

	(Qres	0,7	kWh/kg)		
Date	0.3	0.4	0.45	0.5	0.55
1. Sept.	31.701	42.301	50.081	60.583	75.364
10. Jan	186.749	249.190	295.018	356.886	443.959
11. Jan	168.994	225.499	266.970	322.955	401.750
12. Jan	167.695	223.765	264.917	320.472	398.661
13. Jan	181.159	241.731	286.187	346.203	430.670
14. Jan	214.466	286.174	338.804	409.854	509.850
15. Jan	205.484	274.189	324.615	392.689	488.498
16. Jan	213.616	285.039	337.460	408.229	507.828
17. Jan	215.815	287.974	340.934	412.431	513.056
18. Jan	210.631	281.056	332.745	402.524	500.733
19. Jan	182.214	243.138	287.853	348.219	433.177
20. Jan	181.761	242.534	287.137	347.353	432.100
21. Jan	189.369	252.686	299.157	361.893	450.188
22. Jan	184.753	246.526	291.864	353.070	439.213
23. Jan	185.987	248.172	293.813	355.428	442.146
24. Jan	216.038	288.272	341.287	412.858	513.588
25. Jan	218.517	291.579	345.203	417.595	519.480
26. Jan	158.276	211.196	250.037	302.471	376.269
27. Jan	160.728	214.468	253.910	307.157	382.098
28. Jan	181.759	242.531	287.135	347.350	432.096
29. Jan	171.083	228.286	270.270	326.948	406.717
30. Jan	164.666	219.723	260.132	314.684	391.461
31. Jan	161.852	215.968	255.686	309.306	384.771

Column 61 to 65 — Resorber capacity at part load with plant data and moisture contents of 35, 40, 45, 50 and 55%. Computing of the specific resorption heat pump work [15].

1	66	67	68	69	70

COP of the resorption heat pump

Date	0.3	0.4	0.45	0.5	0.55
1. Sept.	5.584	6.216	6.561	6.923	7.300
10. Jan	8.332	8.576	8.693	8.808	8.917
11. Jan	8.245	8.506	8.633	8.756	8.875
12. Jan	8.238	8.501	8.628	8.752	8.872
13. Jan	8.306	8.555	8.676	8.793	8.905
14. Jan	8.442	8.662	8.769	8.871	8.970
15. Jan	8.409	8.637	8.746	8.853	8.954
16. Jan	8.439	8.660	8.767	8.870	8.968
17. Jan	8.447	8.666	8.772	8.874	8.972
18. Jan	8.428	8.652	8.759	8.864	8.963
19. Jan	8.311	8.559	8.679	8.795	8.907
20. Jan	8.309	8.557	8.678	8.794	8.906
21. Jan	8.344	8.585	8.701	8.814	8.923
22. Jan	8.323	8.568	8.687	8.802	8.913
23. Jan	8.329	8.573	8.691	8.806	8.916
24. Jan	8.447	8.667	8.773	8.875	8.972
25. Jan	8.456	8.673	8.778	8.880	8.976
26. Jan	8.184	8.457	8.591	8.720	8.845
27. Jan	8.199	8.469	8.601	8.729	8.852
28. Jan	8.309	8.557	8.678	8.794	8.906
29. Jan	8.256	8.515	8.641	8.763	8.880
30. Jan	8.221	8.487	8.617	8.742	8.863
31. Jan	8.205	8.474	8.605	8.733	8.855

COP ... Coefficient of performance

Columns 66 to 70 — Coefficient of Performance (COP) for part load with the aid of the plant data for five several fuel water contents

6 Economic evaluation

In order to prove the economy of an investment in a resorption heat pump the following methods are applied:

- capital value
- dynamic payoff time.

The input data for the cost calculation are fixed and operating costs. As revenues, the surplus heat due to the resorption heat pump is considered.

6.1 Calculation scheme for capital value

The capital value is evaluated as the profit after taxes multiplied by the annual discounting factor (Table 2). The profit after taxes is based on the earnings before interest, taxes and depreciation (EBITD), which are the difference between the net sales and the annual costs.

$$EBITD_a = S_a - C_a \qquad (1)$$

$EBITD_a$ annual earnings before interest, taxes and depreciation
S_a annual net sales
C_a annual costs including imputed cost

After forming the EBIT, the earnings before interest and taxes, by adding the depreciation, the financial results are added, which leads to the profit/loss on ordinary activities. Considering taxes, the profit after taxes is gained. After sorting out the depreciation, the annual cash flow multiplied by the annual discounting factor leads to the discounted cash flow. The capital value is the sum of all annual discounting cash flows during the useful life.

The discounting factor equalises all payments and earnings to a certain time, as if all payments or earnings during the useful life were made at the same time. Hence, the highest number for a is that of the useful life, in our case 20 years (Table 2).

$$f_{D,a} = \frac{1}{(1+i)^a} \qquad (2)$$

$f_{D,a}$ annual discounting factor
n useful life
i rate of interest = 6%
a considered year in the range 1 to n

Balance sheet

Net sales
- Annual cost including imputed cost

Earnings before interest, taxes and depreciation
+ Imputed cost
- Depreciation

Earnings before interest and taxes
+ Financial result

Profit/loss on ordinary activities
- Taxes

Profit/loss after taxes
+ Depreciation

Cash flow (net working capital)
+/- Changes in current assets and short term accounts payable

Balance II
- Investment in fixed assets
- Loan redemption

Balance III
* Discounting factor

Discounted cash flow

Table 2. Annual discounting factor.

1. year	0.943396226
2. year	0.88999644
3. year	0.839619283
4. year	0.792093663
5. year	0.747258173
6. year	0.70496054
7. year	0.665057114
8. year	0.627412371
9. year	0.591898464
10. year	0.558394777
11. year	0.526787525
12. year	0.496969364
13. year	0.468839022
14. year	0.442300964
15. year	0.417265061
16. year	0.393646284
17. year	0.371364419
18. year	0.350343791
19. year	0.33051301
20. year	0.311804727

6.1.1 Investment cost

Capital expenditures comprise all devices of the resorption heat pump (Table 3) such as:

- resorber
- desorber
- compressor
- heat exchanger
- compensator
- piping system and fittings.

Besides the cost of the technical equipment (Table 3), the building costs as far as necessary are also included. No additional costs of planning activities are regarded.

Table 3. Lay-out parameters determining the investment costs.

Components	Capacity	Heat exchanger surface	Heat exchanger weight	Total equipment weight
	kW	m²	kg	kg
Desorber	535	50	1 159	1 333
Resorber	500	46	1 083	1 245
Solution heat exchanger	144	9	442	508
Auxiliary external heat exchanger R	199	40	1 200	1 380
Auxiliary external heat exchanger A	153	30	900	1 035
Compressor	50			
Solution pump	1.5			
Pipes				
Assembling				
Automation	0.5			

As the resorption heat pump is integrated in an existing district heating plant, neither the site cost nor the cost of developing the infrastructure are considered. There are no legal fees to be taken into account.

The total of investment cost is estimated for a nominal capacity of the resorption heat pump of 500 kW_{th}.

Investment costs are calculated on the basis of their weight and the materials chosen. In addition, the personnel costs related to manufacturing are taken into account (Table 4). The material chosen for all devices is 1.4301 due to the process temperature of 90 °C according to the return temperature of the district heating circuit of 70 °C.

Table 4. Economic data for determining the cost of investment.

Components	Specific material costs ATS/kg	Total material costs ATS	Specific manu-facturing costs ATS/kg	Total manu-facturing costs ATS	Total factory costs ATS
Desorber	40	53 314	60	79 980	133 294
Resorber	40	49 818	60	74 700	124 545
Solution heat ex-changer	40	20 332	60	30 480	50 812
Auxiliary external heat exchanger R	40	55 200	60	82 800	138 000
Auxiliary external heat exchanger A	40	41 400	60	62 100	103 500
Compressor					170 000
Solution pump					30 000
Pipes					80 000
Assembling					60 000
Automation					70 000
Sum					**960 151**
Additional fee 25%					240 038
Sum					**1 200 189**

By dividing 1.2 MATS by the thermal output of the resorption heat pump of 500 kW_{th}, the specific investment cost of 2 400 ATS/kW_{th} is obtained (Table 5).

Table 5. Capital expenditures.

Capital expenditures	Sum	Unit
Specific investment cost	2 400	ATS/kW_{th}
Thermal capacity	500	kW_{th}
Total investment cost (TIC)	1 200 000	ATS

6.1.2 Subsidies

A governmental grant of 30% and respectively 50% of the total investment cost is also discussed. Instead of subsidies the reduction of investment cost can as well be interpreted as a decrease in the factoring cost of the main devices of the resorption heat pump due to serial production.

6.1.3 Fixed costs

Insurance

The cost of taxes and insurance comprises 1% of the total capital expenditures. The insurance costs consist of fire protection, demolition of the plant due to stormy weather, hail, landslip, high-water, etc. In addition, any inconveniences due to a standstill of the plant are covered by this insurance.

6.1.4 Operating costs

Personnel cost

As no additional personnel are required for operating the resorption heat pump, the personnel costs are not considered.

Fuel cost

Analogous to the above, the additional fuel costs can be ignored.

Maintenance cost

The percentage of maintenance cost is set at 5% and includes all cost within the span of starting-up.

Cost of electricity demand

In Austria, the heating plants are of small business. Consequently, the specific costs of electricity supply are relatively high, 1.5 ATS/kWh. The electricity demand is dependent on the mechanical compressor (Table 6).

Table 6. Dependency of electricity cost on water content at a mean part load factor of 0.4.

Water content	0.30	0.40	0.45	0.50	0.55
Electricity demand, kWh/a	91 661	117 510	136 482	162 095	198 141
Electricity cost, ATS/a	137 491	176 265	204 723	243 142	297 213

6.1.5 Imputed cost

Imputed costs comprise depreciation, interest, imputed risk and salaries of firm owners (Table 7). In this particular case, the last two ones can be ignored.

$$d_{im} = \frac{IVC - RV}{n} \tag{3}$$

d_{im} imputed depreciation
IVC investment cost
RV Resale Value
n useful life

$$i_{im} = \frac{IVC + RV}{2} \cdot i \tag{4}$$

i_{im} imputed interest cost
i rate of interest

imputed cost = depreciation + interest.

Table 7. Depreciation and interest.

Investment cost	1 200 000	840 000	600 000
Depreciation	60 000	42 000	30 000
Interest	36 000	25 200	19 800
Total	96 000	67 200	49 800

Resale value

When the useful service life of the devices belonging to the resorption heat pump expires, a decision has to be made whether to reinvest in the plant to ensure safe operation for some more years, or to resale the plant. As the dismantling of the plant can be very cost-effective, the resale value is set equal to the dismantling cost. The resale value is used for evaluating the imputed depreciation and interest.

6.1.6 Total annual cost

The total annual costs comprise fixed cost, variable cost, such as cost of electricity supply, and imputed cost (Figure 7). The majority of costs are due to electricity supply.

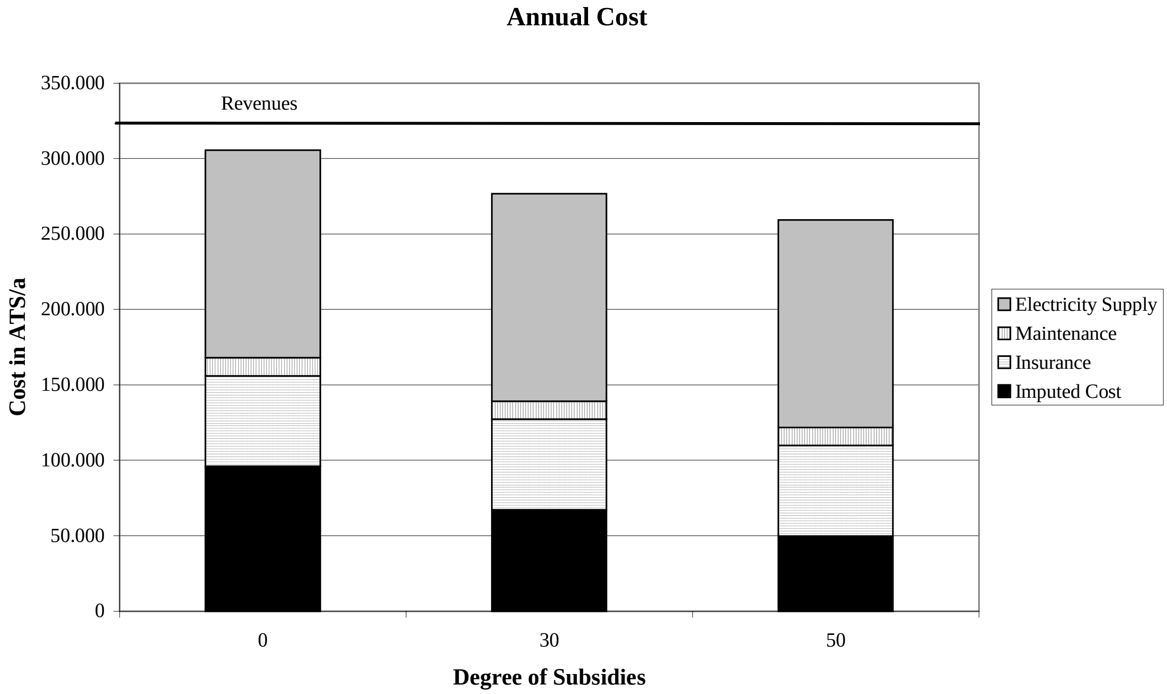


Figure 7. Annual costs in relation to the investment cost or degree of subsidies when the mean partial load factor is 0.4 and the water content is 30%.

6.1.7 Revenues

Revenues are achieved from the sales of heat to the district heating system. In Austria, the specific cost of 0.4 ATS/kWh_{th} is fairly common, and hence, this basis is chosen for further calculation.

The heat supply is dependent on the water content (Table 8). A rise in water content results in an increase in condensation heat that is supplied to the district heating system.

Table 8. Dependence of heat supply on water content at a part load factor of 0.4.

Water content	0.3	0.4	0.45	0.5	0.55
Q Resorber, kWh/a	807 141	1 077 013	1 275 084	1 542 481	1 918 816
Revenues, ATS/a	322 856	430 805	510 034	616 992	767 527

6.2 Discussion of results

In order to discuss the results, the first spreadsheet is shown in the following (Table 9). The water content of biomass is 30%. The mean part load factor is 0.4. No subsidies or reduction of investment cost are granted.

6.2.1 Earnings before interest, taxes and depreciation (EBITD)

Table 9. EBITD at a water content of 0.3 and a mean partial load factor of 0.4.

	Revenues	Electricity supply	Maintenance	Insurance	Imputed cost	EBITD
1. year	322 856	137 491	60 000	12 000	96 000	17 365
2. year	322 856	137 491	60 000	12 000	96 000	17 365
3. year	322 856	137 491	60 000	12 000	96 000	17 365
4. year	322 856	137 491	60 000	12 000	96 000	17 365
5. year	322 856	137 491	60 000	12 000	96 000	17 365
6. year	322 856	137 491	60 000	12 000	96 000	17 365
7. year	322 856	137 491	60 000	12 000	96 000	17 365
8. year	322 856	137 491	60 000	12 000	96 000	17 365
9. year	322 856	137 491	60 000	12 000	96 000	17 365
10. year	322 856	137 491	60 000	12 000	96 000	17 365
11. year	322 856	137 491	60 000	12 000	96 000	17 365
12. year	322 856	137 491	60 000	12 000	96 000	17 365
13. year	322 856	137 491	60 000	12 000	96 000	17 365
14. year	322 856	137 491	60 000	12 000	96 000	17 365
15. year	322 856	137 491	60 000	12 000	96 000	17 365
16. year	322 856	137 491	60 000	12 000	96 000	17 365
17. year	322 856	137 491	60 000	12 000	96 000	17 365
18. year	322 856	137 491	60 000	12 000	96 000	17 365
19. year	322 856	137 491	60 000	12 000	96 000	17 365
20. year	322 856	137 491	60 000	12 000	96 000	17 365

6.2.2 Earnings before interest and taxes (EBIT)

Depreciation according to balance sheet

This form of depreciation does ignore a salvage value and may have a useful life smaller than the actual one. This anticipated depreciation (Table 10) is used in order to allay the gain before taxes and therefore reduce the tax load.

$$a_{bal} = \frac{IVC}{n_{bal}} \quad (5)$$

n_{bal} useful life according to balance sheet

Table 10. Depreciation according to balance sheet.

Investment cost	1 200 000	840 000	600 000
Depreciation	60 000	42 000	30 000

In order to calculate the earnings before interest and taxes the imputed cost have to be sorted out of the EBITD. Changes in stock as well as the anticipated depreciation offer the base to form the EBIT.

6.2.3 Profit/loss from ordinary activities

The profit/loss from ordinary activities varies from the earnings before interest and taxes to financial gains and losses, such as selling financial assets, investment in a business, gains by participation of a business and interest income and expense (Tables 11–13).

Interest expense for loan capital

In order to evaluate the interest expense, the actual loan capital (debts) is multiplied by the rate of interest.

$Z_1 = K_0 * i$
$Z_2 = K_1 * i = [K_0 * (1 + i) – A] * i$
$Z_3 = K_2 * i = [K_1 * (1 + i) – A] * i$

etc., whereas

Z actual interest paid
K actual debt
A annuity
i rate of interest for loan capital

Table 11. Earnings before interest and taxes (EBIT) in ATS for a water content of 30%,the mean partial load factor of 0.4 and without subsidies.

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Operation results	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365	17 365
+ imputed cost	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000	96 000
+/- change in stocks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- neutral expense	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000
EBIT	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365

Table 12. Debts and interest repayments over the useful life, ATS.

Year	Debts	Interest repayments
0	1 200 000	
1	1 167 379	72 000
2	1 132 800	70 042
3	1 096 146	67 968
4	1 057 294	65 769
5	1 016 110	63 438
6	972 455	60 967
7	926 181	58 347
8	877 130	55 571
9	825 136	52 628
10	770 023	49 508
11	711 603	46 201
12	649 677	42 696
13	584 037	38 981
14	514 458	35 042
15	440 704	30 867
16	362 524	26 442
17	279 654	21 751
18	191 812	16 779
19	98 699	11 509
20	0	5 922

Table 13. Profit/loss from ordinary activities in ATS for a water content of 30%, a mean partial load factor of 0.4 and without subsidies.

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
EBIT	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365	53 365
+ Gains of participation																				
+ Interest received																				
+ Selling financial assets																				
- Investment in business																				
Depreciation of finan-cial assets																				
- Interest paid	-72 000	-70 043	-67 968	-65 769	-63 438	-60 967	-58 347	-55 571	-52 628	-49 508	-46 201	-42 696	-38 981	-35 042	-30 868	-26 442	-21 752	-16 779	-11 509	-5 922
Profit from ordinary activities	-18 635	-16 678	-14 603	-12 404	-10 073	- 7 602	- 4 982	-2 206	+ 737	+ 3 857	+ 7 164	+10669	+14382	+18323	+22497	+26923	+31613	+36586	+41856	+47443

6.2.4 Profit/loss after taxes

The corporation tax with a rate of 34% is calculated for the income from ordinary operation according to Table 13.

A certain percentage of the investment can be set aside as untaxed reserve (Table 14). It is usually 9% of the total investment cost. This mean of reducing the taxable earnings is applied only in Austria. The German word is "Investitionsfreibetrag".

Table 14. Untaxed reserves, ATS.

Investment cost	1 200 000	840 000	600 000
Untaxed reserves	108 000	75 600	54 000

When the loss can be brought forward from the previous year, only in the last two years of the useful life taxes have to be paid (Tables 15 and 16).

Table 15. Taxes in ATS for a water content of 30%, a mean partial load factor of 0.4 and without subsidies.

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Profit from ordinary activities	-18635	-16678	-14603	-12404	-10073	- 7602	- 4982	-2206	+ 737	+ 3857	+ 7164	+10669	+14382	+18323	+22497	+26923	+31613	+36586	+41856	+47443
+ Non-operating gains																				
- Non-operating expenses																				
+ Cancel an untaxed reserve fund																				
+ Cancel a capital reserve fund																				
+ Cancel a surplus fund																				
- Allocate an untaxed reserve	108000																			
- Allocate a surplus fund																				
- Loss carried forward		126635	143313	157916	170320	180393	187994	192977	195183	194446	190589	183425	172757	158372	140050	117552	90630	59016	22430	
Corporation tax																			6605	16131

Table 16. Profit/loss after taxes in ATS for a water content of 30%, a mean partial load factor of 0.4 and without subsidies.

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Profit from ordinary activities	-18635	-16678	-14603	-12404	-10073	- 7602	- 4982	-2206	+ 737	+ 3857	+ 7164	+10669	+14382	+18323	+22497	+26923	+31613	+36586	+41856	+47443
+ Non-operating gains																				
- Non-operating expenses																				
Taxes																			- 6605	-16131
Profit after taxes	-18635	-16678	-14603	-12404	-10073	- 7602	- 4982	-2206	+ 737	+ 3857	+ 7164	+10669	+14382	+18323	+22497	+26923	+31613	+36586	+35251	+31312

6.2.5 Discounted cash flow

Table 17. Discounted cash flow in ATS for a water content of 30%, a mean partial load factor of 0.4 and without subsidies.

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Profit after Taxes		-18635	-16678	-14603	-12404	-10073	- 7602	- 4982	-2206	+ 737	+ 3857	+ 7164	+10669	+14382	+18323	+22497	+26923	+31613	+36586	+35251	+31312
Not payable expenses		+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000	+60000
Not receivable returns																					
Cash Flow (net working capital)		+41365	+43322	+45397	+47596	+49927	+52398	+55018	+57794	+60737	+63857	+67164	+70669	+74384	+78323	+82497	+86923	+91613	+96586	+95251	+91312
Change in current assets																					
Balance II		+41365	+43322	+45397	+47596	+49927	+52398	+55018	+57794	+60737	+63857	+67164	+70669	+74384	+78323	+82497	+86923	+91613	+96586	+95251	+91312
Long-term deposits: Investment	-120000																				
Loan redemp-tion	120000	-32622	-34579	-36654	-38853	-41184	-43655	-46274	-49051	-51994	-55113	-58420	-61925	-65641	-69579	-73754	-78179	-82870	-87842	-93113	-98700
Balance III		+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743	+ 8743
Discounting factor	1	0,94	0,89	0,84	0,79	0,75	0,71	0,67	0,63	0,59	0,56	0,53	0,50	0,47	0,44	0,42	0,39	0,37	0,35	0,33	0,31
Discounted cash flow		+ 8249	+ 7782	+ 7341	+ 6926	+ 6534	+ 6164	+ 5815	+ 5486	+ 5175	+ 4882	+ 4606	+ 4345	+ 4099	+ 3867	+ 3648	+ 3442	+ 3247	+ 3063	707	-2303

6.2.6 Capital value

The capital value is the sum of all discounted cash flows during useful life:

$$CV = \sum_{a=1}^{n} DCF_a \tag{6}$$

CV capital value
DCF_a annual discounted cash flow

When the capital value is negative, the investment will not be economic. The capital value is calculated according to the above mentioned scheme for a water content of 30 to 55% and for subsidies of 0, 30 and 50%. The investment with the highest capital value is favourable.

The influence of the water content on the economic feasibility is shown in Figure 8.

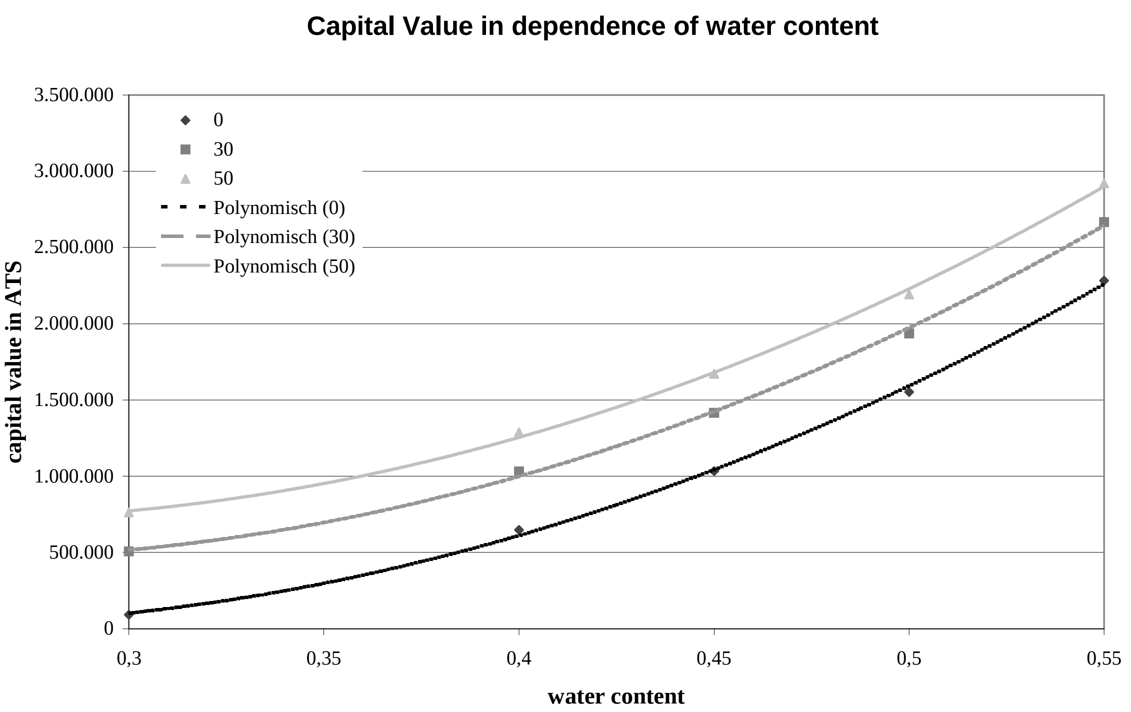


Figure 8. Influence of water content on the capital value at a mean partial load factor of 0.4.

Figure 8 shows that even at a water content of 30% the investment would be economic. Observing Table 9 the revenues from selling surplus heat due to the resorption heat pump are high enough to compensate for investment cost during useful life.

The dependency on the water content is as follows:

Subsidies in the range of 50%: CV = 24597085 w² – 12401669 w + 2280242

Subsidies in the range of 30%: CV = 24577653 w² – 12382962 w + 2020258

Subsidies in the range of 0%: CV = 23583848 w² – 11420468 w + 1406583

Increasing the partial load factor

An increase of 0.1 in the partial load factor shows a significant amelioration of the economy (Figure 9).

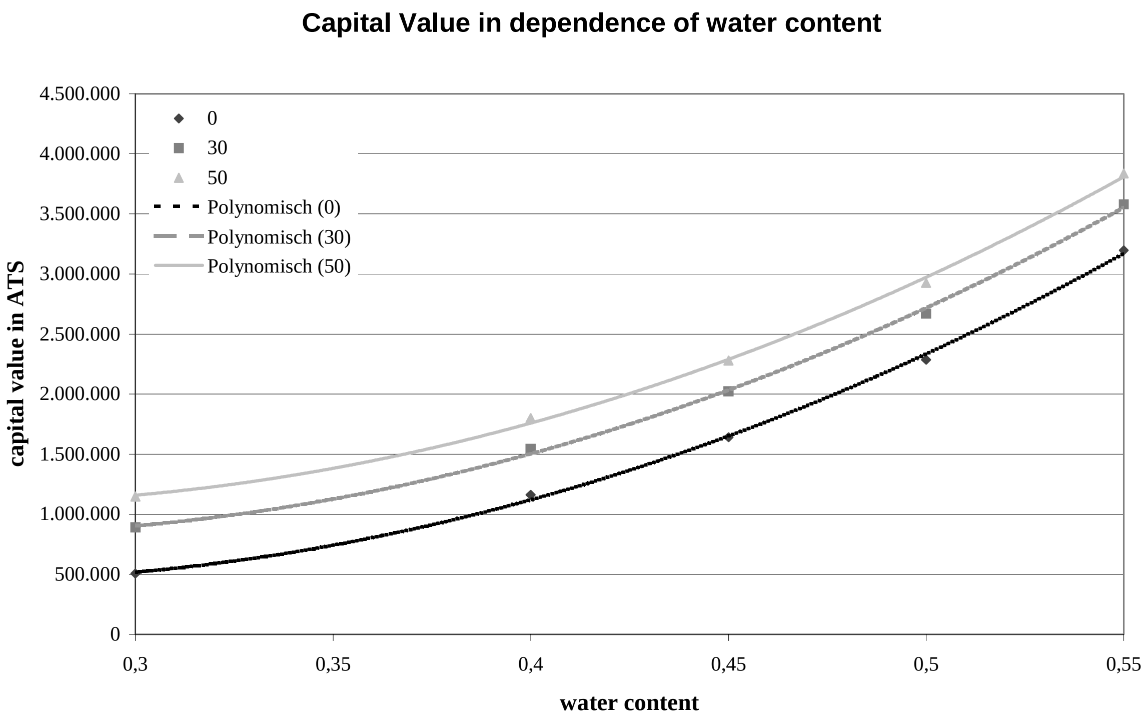


Figure 9. Effect of water content on the capital value, when the mean partial load factor is 0.5.

The effect of the water content can be expressed as follows:

Subsidies in the range of 50%: CV = 30658235 w² – 15457700 w + 3036647

Subsidies in the range of 30%: CV = 30658237 w² – 15457702 w + 2781108

Subsidies in the range of 0%: CV = 30586850 w² – 1538897 w + 2381469

Because of the strong tendency of improvement over the partial load factor, the mean partial load factor of 0.6 is discussed in the following (Figure 10).

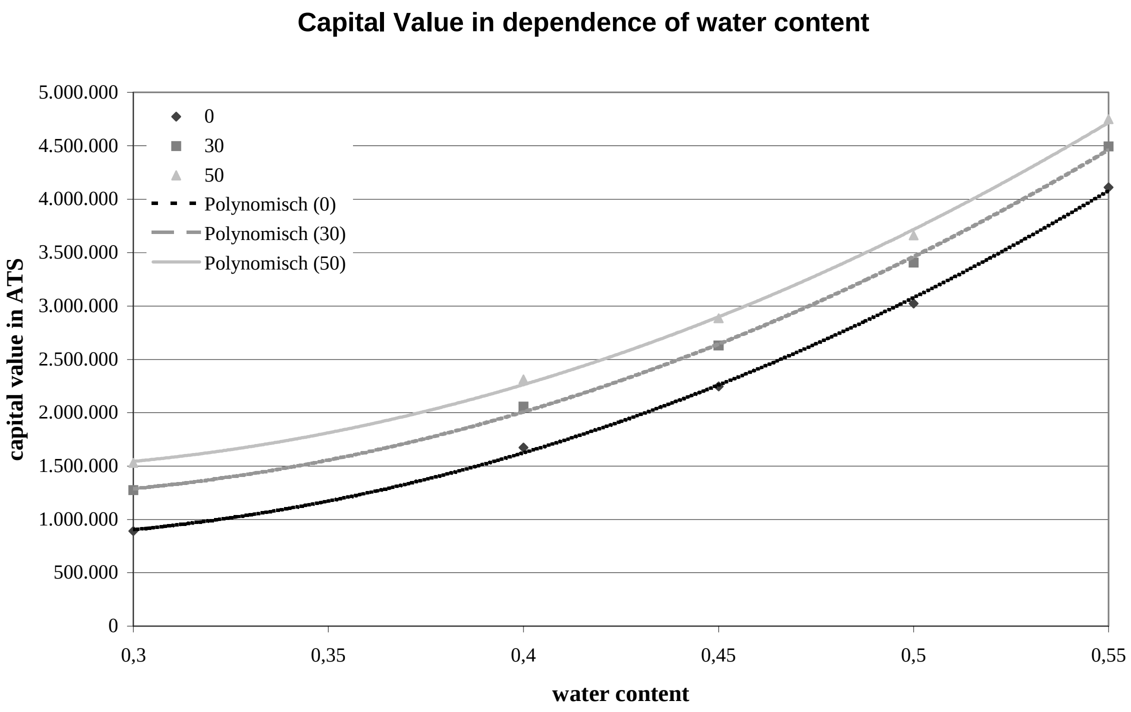


Figure 10. Effect of water content on the capital value, with the mean partial load factor of 0.6.

The gain in the capital value, dependent on the water content, is higher than with the mean partial load factor of 0.5. The increase of capital value relative to the water content is the higher the higher the water content. On the other hand, the increase at the partial load factor of 0.6 is higher than that with the partial load factor of 0.5, as soon as the water content exceeds 35%.

The effect of the water content can be expressed as follows:

Subsidies in the range of 50%: $CV = 36719309\, w^2 - 18513657\, w + 3793033$
Subsidies in the range of 30%: $CV = 36719311\, w^2 - 18513659\, w + 3537495$
Subsidies in the range of 0%: $CV = 36704310\, w^2 - 18499217\, w + 3150755$

In summary, the effect of the partial load factor is the crucial parameter when planning district heating with a resorption heat pump in order to utilise condensation heat.

Figure 11 shows that the gain in capital value is rigidly dependent on the partial load factor. On one hand, this means an economical operation at smaller water contents, on the other hand the higher the capital value, the shorter the payoff time, and the risk of investment decreases.

Part load factor 0.6: $CV = 36704310\ w^2 - 18499217\ w + 3150755$
Part load factor 0.5: $CV = 30586850\ w^2 - 15388976\ w + 2381469$
Part load factor 0.4: $CV = 23583848\ w^2 - 11420468\ w + 1406583$

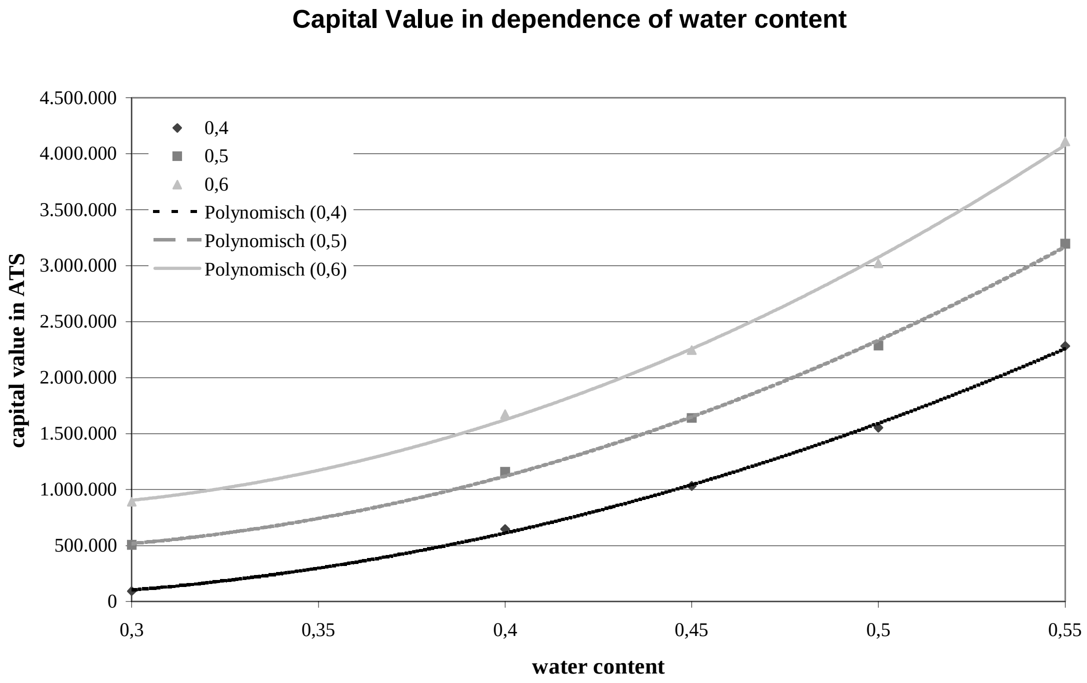


Figure 11. Effect of partial load factor on the capital value, when no subsidies are granted.

6.3 Payoff time

The payoff time is calculated as the point of time when the discounted difference of net sales and annual cost (imputed cost excluded) exceeds the investment cost.

$$\sum_{a=1}^{t}(S_a - C_a)\cdot f_{D,a} > IVC \qquad (7)$$

S_a annual net sales
C_a annual cost excluding imputed cost
$f_{D,a}$ annual discounting factor
IVC investment cost

The payoff time indicates a strong effect of reducing the investment cost. When the water content of 30% is discussed, a decline in investment cost halves the payoff time faster. Without any grant the amortisation time is 18 years, with a funding of 30% it is 11 years, and with 50% seven years, which is the half span (Figure 12).

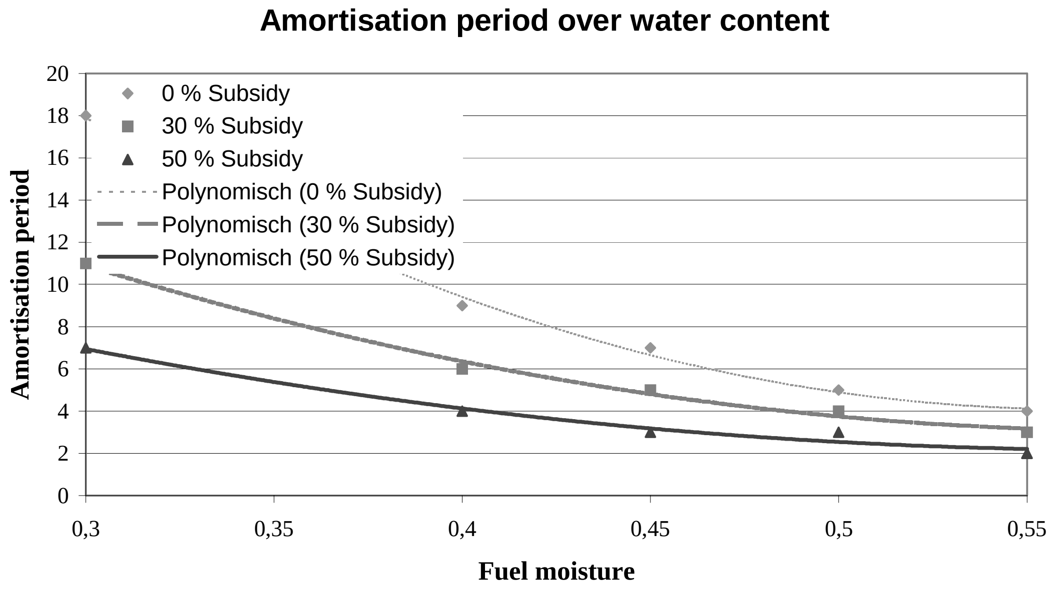


Figure 12. Amortisation time in relation to fuel moisture with a mean part load factor of 0.4.

The dependency of the pay back time on the water content is as follows:

Subsidies in the range of 50%: $t = 199\, w^2 - 244\, w + 67$
Subsidies in the range of 30%: $t = 97\, w^2 - 114\, w + 36$
Subsidies in the range of 0%: $t = 62\, w^2 - 71\, w + 23$

Increasing the partial load factor

The payoff time, within which the investment becomes economical, shows a payback time that is less than half of useful life even for a water content of 30%.

The dependency of the payback time on the water content is as follows (Figures 13 and 14):

Subsidies in the range of 50%: $t = 65\, w^2 - 82\, w + 29$
Subsidies in the range of 30%: $t = 31\, w^2 - 45\, w + 18$
Subsidies in the range of 0%: $t = 36\, w^2 - 42\, w + 14$
Subsidies in the range of 50%: $t = 34\, w^2 - 37\, w + 12$
Subsidies in the range of 30%: $t = 37\, w^2 - 48\, w + 17$
Subsidies in the range of 0%: $t = 69\, w^2 - 79\, w + 26$

We may conclude, that the highest gain in economy is obtained for small water contents when the partial load factor can be raised. The higher the water content the lower the decrease in payoff time (Figure 15).

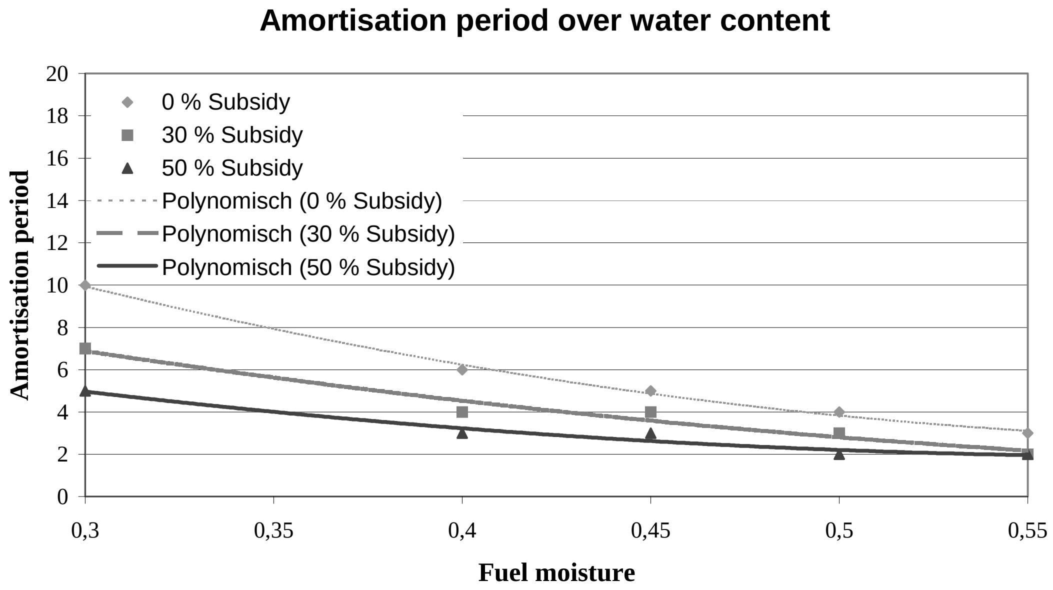


Figure 13. Dependency of amortisation time on water content when the mean partial load factor is 0.5.

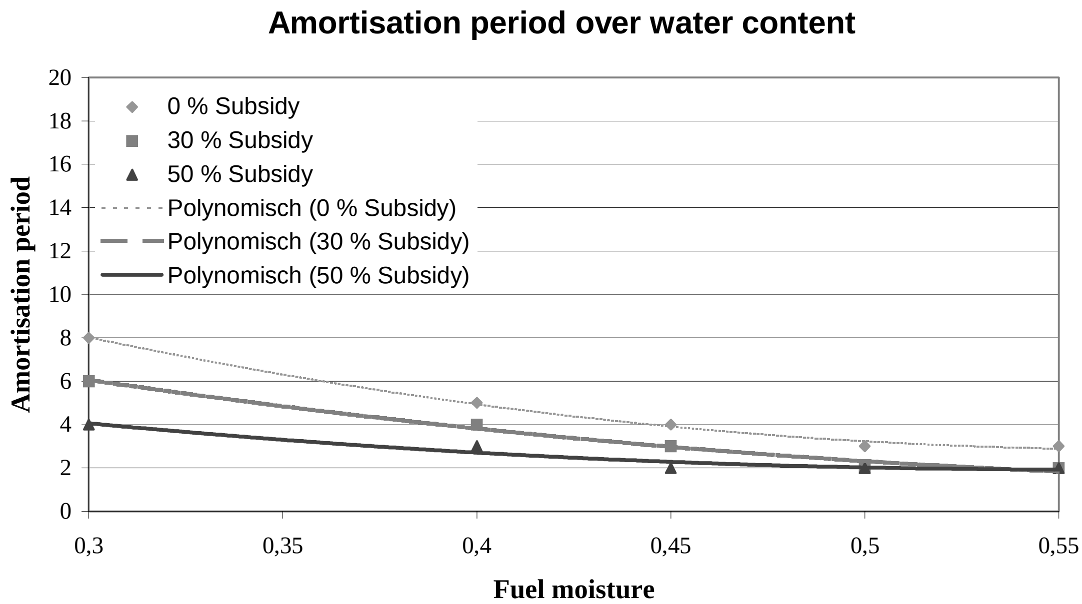


Figure 14. Dependency of amortisation time on water content when the partial load factor is 0.6.

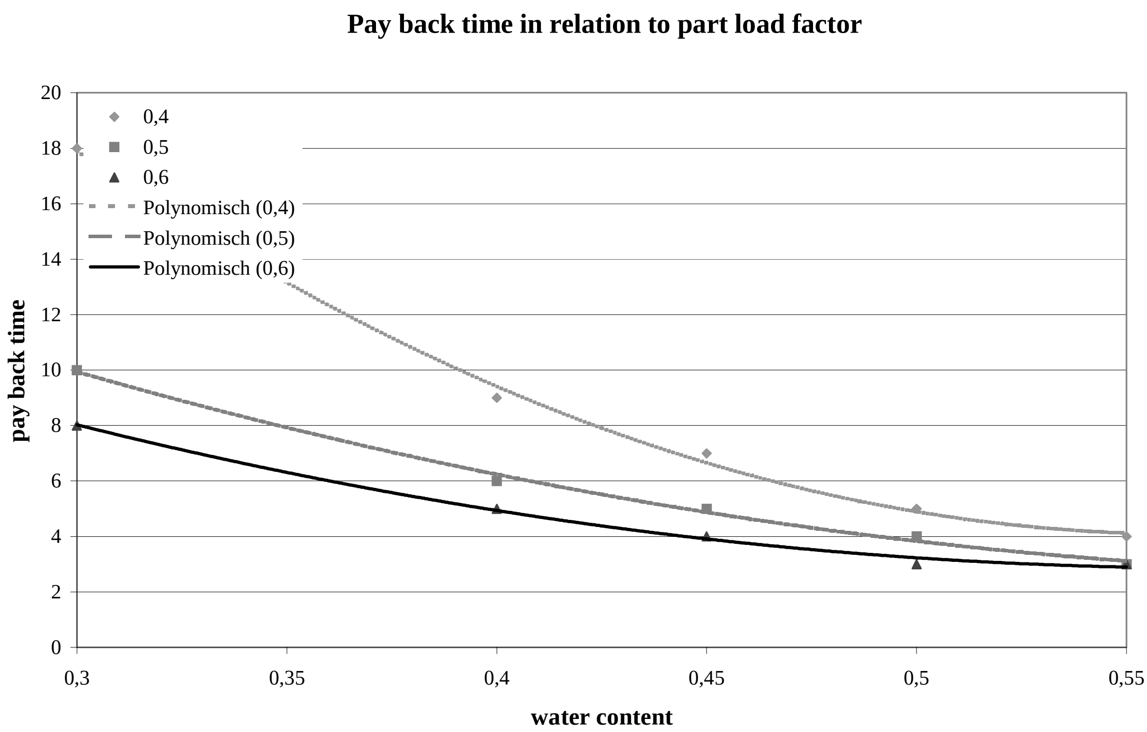


Figure 15. Payback time in relation to a part load factor of 0.4 to 0.6.

7 Technical uncertainties

7.1 Process design and calculation

The resorption process was designed by means of an enthalpy-concentration diagram for ammonia water solutions (i-ξ-diagram) of Merkel Bosnjakovic. The process was calculated with the data of this diagram step by step [16]. It is assumed that the process proposed – which is the basis for technical and economical evaluation, too – lies near the optimum. A better procedure of process definition and calculation could be reached with a computer program, e.g. Aspen$^+$, if a data bank for ammonia water solutions were available. With the aid of this computer program, a lot of process simulations could be carried out. This kind of calculation would ensure the attainment of the optimum design point.

7.2 Apparatus design

The resorption process needs long trickle stretches that are responsible for the desorption or the resorption of the working gas ammonia. The sorption process proceeds under the same pressure but at sliding temperatures of the working solution. In addition to mass transfer, heat transfer should also be managed. The falling-film technology for mass and heat transfer was selected as the best technical option. In order to use apparatuses of relative small size, a grouping of vertical steel tubes with 12 mm inside diameter was used (a patent of Joanneum Research). The vertical falling films trickle down on the inside of the steel tube initialised and stabilised by suitable facilities. The cooling or heating medium flows outside of the steel tubes. The mass transfer depends on the temperature difference between the heating or cooling medium and the vertical falling film. In cases of high mass-transfer rates the ammonia gas flow inside the small steel tubes can disturb the stability of the falling film by generating stoppers.

7.3 Thermal pretreatment of working fluid

The working solution circle consists of the working fluid pump, the working fluid heat exchanger (WFHE) and an automatically controlled working-fluid pressure reduction valve. The WFHE´s task is to recover internal heat from the hot strong solution in the cold weak solution. Depending on the working point of the heat pump process the heat recovery may be not sufficient in all cases of operation. In some cases the suitable entrance temperature cannot be achieved by heat recovery only. Additional measures, like heat exchangers or a method called in German "Lösungsvorführung" (thermal pretreatment), have to be applied. Poor experiences have been obtained from thermal pretreatment, above all in facility design.

7.4 Process control

In the active recovery process of flue gas heat, the operation of the resorption heat pump is at first controlled by the temperature of the district heat return. Depending on condensable heat in the flue gas, the mass flow of the working fluid pump and of the ammonia compressor is controlled (speed control). There are poor experiences from the practical application of available resorption heat pumps. Control algorithms and control design of the heat pump system should be investigated and developed.

7.5 Economic calculation

In the economical calculations, the capital cost estimated for the whole active condensation plant is of significance. The costs of the main parts, e.g. apparatuses, piping, control system, necessary structural work, were calculated. The operation costs of the heat pump system are largely unknown. Therefore, the economic results like the capital value and the payback period are burdened with uncertainties. The economic calculations indicated that the results strongly depend on the partial load factor (PLF) of the district heating plant. For the factual calculation, the data measured with a real PLF was used. Largely unknown is the average PLF of the other 330 Austrian district heating plants, which are the main market for these applications proposed.

7.5.1 Investment cost

All components of the heat pump plant were roughly designed, and their size, weight, and cost of investment were determined. According to the results, the construction cost of a 500 kW – resorption heat pump amounted to ATS 960 000. An additional account was carried out shipment and manufacturer's revenue. The results indicated that the total costs of delivering a 500 kWth resorption heat pump to the site may amount to ATS 1 200 000. The investment in the Stirling engine is not included in this calculation.

7.5.2 Operation cost and revenues expected

The annual costs consist of imputed cost, maintenance cost and cost of electric power to operate the compressor. The imputed costs are calculated applying the interest of 6% and the lifetime of 20 years. The maintenance costs are estimated at 5% of the investment cost. The electricity cost of the 70 kW_{el} electric motor are calculated in respect of the partial load factor and specific cost for electric energy of 1.5 ATS/kWh_{el}. The heat recovered by the heat pump is also dependent on the water content and partial load factor. The specific revenues for the supplied heat are 0.4 ATS/kWh_{th} (net sales).

8 Environmental aspects

8.1 Reduction of emissions

The application of an active flue gas condensation plant at a biomass-fired boiler station reduces emissions of environmental pollutants. Measurements indicate that the dust content of the flue gas may be reduced from 720 to 105 mg/m^3 N at nominal power. In addition to dust, there are also other emissions, like CO, NO_2 and organic hydrocarbons, depending on the biofuel type. These emissions could be reduced to approximately 60% at a condensation plant [1].

8.2 Working fluid

A very important item in the discussion on heat pumps is the environmental benefit of the heat pump refrigerant. The refrigerant proposed, ammonia, is environmentally friendly, because it is a gas present in the atmosphere. Its Ozone Depletion Potential (ODP) is zero. The Global Warming Potential (GWP) is zero too. The third important key number of the refrigerant is the Indirect Global Warming Potential (I-GWP), which indicates the electric power consumption of the heat pump process. Because of the COP expected, the I-GWP of the resorption heat pump is low compared with other similar processes.

9 Conclusions

The primary goal of including an active condensation plant in a biomass boiler station is to utilise the high potential of heat recovery. The increase in the nominal capacity of the biomass furnace is estimated at 30 to 50 % if an active condensation plant is applied. In addition to this techno-economic advantage, the environmental aspects are of high interest. It was found that the dust content (ash) is reduced significantly and even CO, NO_2 and the organic hydrocarbons are reduced. Furthermore, the refrigerant used (ammonia) is a gas existing in the atmosphere and therefore environmentally friendly. A high COP of the heat pump may be expected due to the Lorenz process and the low pressures because of the resorption process. The compressor of the resorption heat pump could be powered by a biomass Stirling engine and/or an electric motor. The investment and operation costs of an 500 kW resorption heat pump plant were determined. The estimation of the annual revenue showed that an amortisation time of 4 to 6 years may be expected. Research and development work is necessary to improve the insufficiently known design of the plant and the heat pump components. A test plant at a biomass boiler site should be designed and constructed because of the lack of the experience.

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Part 2

Slow release fertilizer production plant from bio-oil
Technical-economic assessment

Prepared for

International Energy Agency
IEA Bioenergy Task 22 – Techno-Economic Assessments for Bioenergy Applications

IEA BIOENERGY T22: TECHNOECONOMICS: 1999:02

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Abstract

A techno-economic assessment has been completed for a slow release fertilizer production plant from bio-oil that is produced from the fast pyrolysis of biomass. The production of slow release fertilizers from biomass is based on patented technology developed by Resource Transforms International Ltd, of Waterloo, Canada.

This assessment was based on scaling up the technology to a production plant producing approximately 20,000 t/yr of solid fertilizer from whole bio-oil, containing 10% N. This size plant would process all of the bio-oil from a 200 t/d (wet, 50% moisture basis) bio-oil from wood production plant. The cost to produce slow release fertilizer from bio-oil is compared to the costs of conventional slow release and speciality fertilizers.

Mass and energy balances for the key operations of the plant, reactor and dryer, were determined using a steady-state simulation model developed using ASPEN Plus simulation software. The Bio-oil feed costs were determined from previous studies for similar sized plants completed by the IEA Techno-economic Analysis of Bioenergy Systems activity. Plant operating costs were based on operation at a site in Canada. Sensitivity analyses were studied for key process performance and cost parameters such as wood and bio-oil feedstock costs.

Contents

1 Introduction

This report is prepared as part of the IEA Bioenergy Techno-economic Analysis of Bioenergy Applications project. The overall objective of the project is to evaluate on a technical and economic basis the feasibility of applications of bioenergy. Slow release fertilizers are foreseen as a potential by-product of the production of bio-oil from biomass by fast pyrolysis. A techno-economic assessment was prepared for a slow release fertilizer production plant using bio-oil that is produced from the fast pyrolysis of biomass as the key raw material feed to the plant. The production of slow release fertilizers from biomass is based on patented technology developed by Resource Transforms International Ltd, of Waterloo, Canada [1]. This technology was developed as a method of using the chemicals contained in the whole bio-oil without requiring fractionation.

The production of bio-oil from wood by fast pyrolysis technology has been in a previous IEA Bioenergy study [2]. Two applications were studied: bio-oil production to produce electricity, and bio-oil production for combustion as a substitute boiler fuel.

2 Fertilizers from bio-oil

2.1 Chemical composition of bio-oil

The chemical components of bio-oil originate from the lignin as well as from the cellulosic and hemicellulosic polymers present in the feedstock and vary in size from simple low molecular weight compounds to large fragments with molecular weights over 1000. Meier and Scholze [3] found weight averaged molecular weights, M_w, in the range 500–800 and number averaged molecular weights, M_n, to be in the range 150–250 for a range of bio-oils from different processes. Their average polydispersity (M_w/M_n) was ~3.6. However, bio-oil is susceptible to aging reactions of a character, which leads to an increase in molecular weight over time.

2.1.1 Pyrolytic lignin

On addition of sufficient water, typically > 1:1, bio-oil separates into a water-soluble fraction and a denser very viscous phase, known as *pyrolytic lignin* (PL). The identification of the water insoluble component of bio-oil as principally, but not exclusively, lignin derived was made some time ago [4].

The bulk of PL is composed of higher molecular weight compounds. Based on gel permeation chromatography, the average molecular mass appears to be substantially lower than native or technical lignins. Components range from a few hundred up to several thousand Dalton. Meier and Scholze [3] found M_w ~ 800–2500, M_n ~ 130–280 and average polydispersity ~ 6.6 for PL separated from various bio-oils. For comparison, milled wood and organosolv lignins typically have molar masses M_w ~ 20,000 and ~ 2000–3000 respectively.

These data suggest that lignin derived components range from “monomers” through oligomers with degrees of polymerization ~ 10. The monomeric products include molecules derived from both syringyl and guaiacyl moieties with zero, one or two residual carbons groups arising from the propyl side chain. Extensive lists have been published by Faix et al [5]. While several of the monomers are of potentially high value, their individual concentrations are typically only around 1% by weight.

PL is also characterized by an increased abundance of phenolic hydroxyl relative to methoxyl groups. These presumably arise from the breaking of the characteristic β-O-4 ether linkages and perhaps as well as by partial loss of methoxyl groups by demethylation. Since, relative to phenolic groups, methoxyl groups deactivate the aromatic ring towards reactions with hydroxybenzyl alcohol [6], one might expect PL to be particularly suitable for use in phenol-formaldehyde resin applications where such reactions are a key part of the cross-linking process and where typical lignins from the common pulping processes have been ineffective. Other potential uses of lignins in general, many of which would also be applicable to PL, have been discussed [7, 8]. Some of the unique properties of PL, which could enhance its value in certain applications, include:

- purity – in particular freedom from carbohydrates and inorganic material,
- low molecular weight,
- possibly unusual functional group characteristics and
- solubility behaviour.

2.1.2 Water-soluble compounds

The most widely practiced routine quantitative analytical method for bio-oil is a water extraction followed by HPLC analysis on ion exchange columns. The method is very useful for obtaining data on the major compounds and a couple of typical analyses are shown in Table 1 for a softwood and a hardwood.

Unfortunately however, this method is not sensitive to several important compound classes; notice that together with PL only 60–70% of the organic fraction of bio-oil is quantified in this way.

Table 1. Typical composition of bio-oil (pyrolysis at 500 °C and ~0.5 s residence time).

Component	Wt% of bio-oil Eastern spruce	IEA-poplar
Formic acid/Formaldehyde	8.9	7.0
Hydroxyacetaldehyde	9.6	10.8
Acetic acid	4.8	3.7
Diacetyl	1.1	n.d.
Glyoxal	3.1	1.4
Acetol	1.5	2.8
Levoglucosan	4.9	2.3
Cellobiosan	3.1	1.2
Water	22.4	24.0
Pyrolytic lignin	24.2	28.3

In spite of this lack of detailed quantitative knowledge the excellent work of the group at the Institute of Wood Chemistry in Hamburg [9] has provided a fairly comprehensive qualitative picture. The identified compounds of carbohydrate origin may be divided essentially into the following classes:

- Hydroxy and oxo substituted low molecular weight (C_2–C_4) **linear aldehydes and ketones**
- Hydroxy, hydroxymethyl and/or oxo substituted (including lactones) **furans and furanones**
- Hydroxy, hydroxymethyl and/or oxo substituted (including lactones) **pyranones**
- **Anhydrosugars** (C_5–C_6)

Table 2 represents our best present estimate of the range of abundance of the various categories of compounds in hardwood or softwood bio-oil. Together with the monomeric lignin-derived aromatics, pyrolytic lignin and the specific compounds listed in Table 1 these classes appear to be able to account for most of bio-oil.

Table 2. Compound classes in bio-oil.

Compound class	Composition range (wt% of organic fraction of bio-oil)	Hydrophilicity (arbitrary scale 4 is highest)
C_1 compounds (formic acid, methanol and formaldehyde, CO_2)	5–10	4
C_2–C_4 linear hydroxyl and oxo substituted aldehydes and ketones (e.g. hydroxyacetaldehyde, acetol,…)	15–35	4
Hydroxyl, hydroxymethyl and/or oxo substituted oxygen heterocycles (C_5–C_6, e.g. furans, cyclic lactones,…)	10–20	3
Anhydrosugars incl. anhydro-Oligosaccharides (e.g. levoglucosan, cellobiosan,…)	6–10	4
Water-soluble carbohydrate-derived oligomeric and polymeric material of uncertain composition	5–10	4
Monomeric methoxyl substituted phenols (e.g. guaiacol, eugenols,…)	6–15	2
Pyrolytic lignin	15–30	1

2.1.3 Products from whole oil and its fractionation classes

Bio-oil is not easily separated into useful classes by the conventional distillation processes of petroleum refining. This is on account of its great thermal and chemical instability together with the very high boiling points of the abundant, highly polar oxygenates. Possibly fractionation by solvent extraction might prove to be more suitable. Unfortunately research in this field is rather limited and the best approaches are still not clear.

This fact suggests that applications of bio-oil as a whole or at most its solvent fractionation classes ought to be considered, at least in the initial stages of commercialization. From this point of view it is advantageous to take a simplified approach to bio-oil characterization by examining the distribution of its principal functional groups rather than individual compounds.

2.1.4 Functional groups

The distribution shown in Table 3 was obtained by Nicolaides some time ago [10] using chemical methods of analysis.

Table 3. Functional group distributions from various feedstocks.

Feedstock	Pyrolysis temperature °C	Moles functional groups /kg organic liquid				
		Carboxyl	Carbonyl	Hydroxyl	Phenolic	Methoxyl
Maple	480	2.1	5.7	0.92	2.8	2.1
Wheat straw	500	1.4	5.3	1.40	3.0	1.1
Poplar-aspen	450	2.1	6.2	0.77	2.8	1.6
"	500	1.6	6.9	0.87	2.8	1.5
"	550	1.7	6.6	0.77	2.8	1.2
Peat moss	520	1.2	3.0	1.30	1.8	0.7

The principal feature is the great abundance of carbonyl groups; in the best case these, together with carboxyl groups, account for over 7 moles/kg. This immediately suggests applications, which exploit their known chemical reactivity patterns, for example oxidations, reactions with active hydrogen compounds like amino and mercapto compounds and reactions with alcohols. No doubt the high chemical reactivity of these groups is at least partly responsible for the thermally instability and susceptibility to aging on storage.

The phenolic group, while not as reactive also suggests a variety of applications. The phenoxy and methoxyl content, if reasonably assumed to be associated with pyrolytic lignin, is quite consistent with the much more recently reported results of Meier & Scholze [3]. Phenolic groups are most abundant in the PL fraction, which also has the least concentration of carbonyl/carboxyl groups.

2.2 Fertilizers from bio-oil

A recent patent demonstrates how exploitation of the abundance of the reactive carbonyl functional groups in bio-oil can be turned to advantage [11]. By reacting with ammonia, urea or other sources of $-NH_2$ groups like manures, the nitrogen is converted to stable, biodegradable organic forms which can function as organic nitrogen slow release fertilizers. Based on the carbonyl content (Table 1) it may be estimated and was in fact verified that of the order of 10% N can be incorporated by direct reaction with aldehydic functional groups in bio-oil.

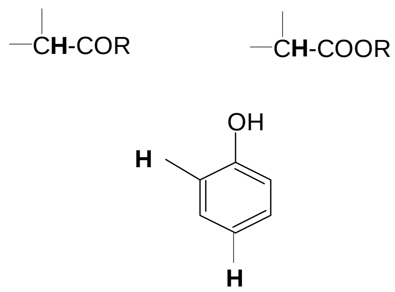
2.2.1 Chemistry of bio-oil reactions with nitrogen compounds

Carbonyl compounds and carboxylic acids in general undergo a great variety of complex reactions with amino and sulfide or mercapto compounds. The following reactions are not by any means exhaustive but illustrate some of the principal types of chemical reactions, which may be expected when such nitrogen and sulfur compounds react with bio-oil.

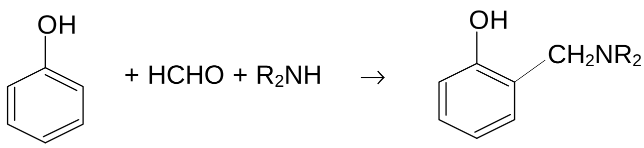
The Mannich reaction

An aldehyde condenses with ammonia in the form of its salt and a compound containing an active hydrogen to give a product known as a Mannich base. E.g.

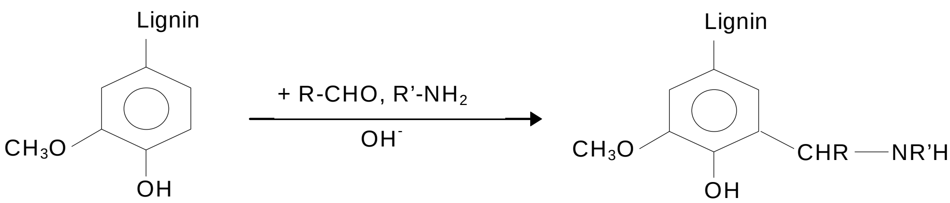
The Mannich base can then undergo further reaction with additional aldehyde and active hydrogen compound. Salts of amine and amide compounds also undergo the reaction. Many active hydrogen compounds give the reaction, including (active hydrogen in bold):



A variant of the Mannich reaction is the dialkylaminoalkylation of phenols by reaction with formaldehyde or other aldehyde with a secondary amine.



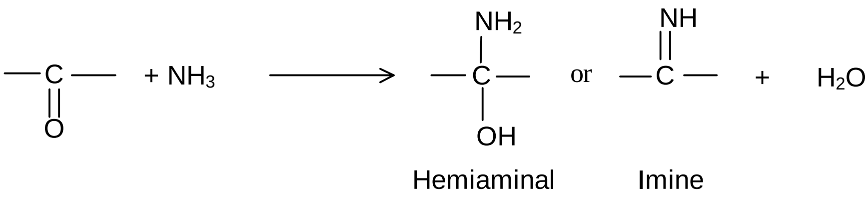
The use of lignin as a starting reaction for the Mannich reaction has been described [12], for example:



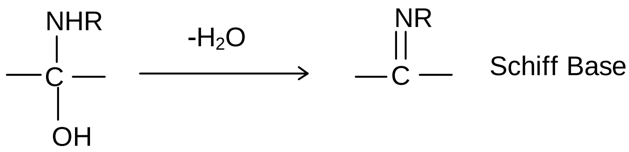
By exploiting other base catalyzed cross linking reaction with aldehydes, lignin molecules may be bound together to increase molecular weight of the product.

Formation of imines

It is very well known [13] that aldehydes and ketones react readily with ammonia and other primary amino compounds to give a variety of complex products. The initial product is usually either a hemiaminal or an imine.



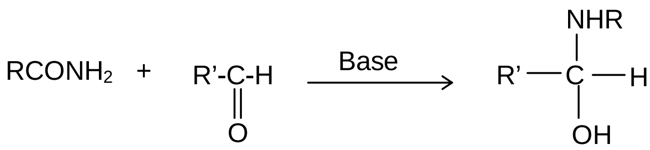
These compounds are generally unstable however and subsequently polymerize quite readily. If the reactant is an amine instead of ammonia similar reactions take place though the initial imines are usually more stable. When an aryl group is present, the initial hemiaminal can lose water to give a Schiff base.



From secondary amines the final product may be an enamine if the carbonyl compound contains a α-hydrogen.

Formation of amides

A further type of reaction, which may occur, is that between carboxylic acids and ammonia or amines to give salts which may subsequently decompose thermally to amides. Amides in turn can react with aldehydes in the presence of base to give acylated amino alcohols.



These may also dehydrate if a α-hydrogen is present.

2.3 Fertilizer properties

The principal benefits of nitrogen slow-release fertilizers are the more efficient use of nitrogen and the avoidance of nitrate and ammonium pollution of groundwater. However additional benefits can be cited.

Thus lignin is widely accepted to be a major precursor of humic matter in the soil. Indeed it has recently been demonstrated that typical lignin materials have a high degree of preservation in humic substances and that, furthermore, there is both chemical and morphological similarity between lignin and humic matter suggesting its use as a soil improvement agent [14]. Consequently the PL component of bio-oil may be expected to impart good soil conditioning properties. These properties of lignin has led to efforts to develop methods for chemical conversion of technical lignins into inexpensive fertilizers and soil improvement agents, e.g. by ammoniation [15] and by radical sulfonation and alkaline oxygenation [16].

Besides functioning as simple organic soil conditioners, the merits of humic substances for control of soil acidity [17], amelioration of the effects of excess Al and Fe [18], increasing availability of phosphate [19], and as crop stimulants [20], among other benefits, is well documented.

Finally lignins are excellent chelants or complexing agents for micronutrients trace metals like Mo, Fe, B, Zn, Mn and Cu. Functional groups also exist for binding other nutrients like Ca, K, and P. Thus the basic fertilizer product can be refined and tailored to precise agricultural requirements.

The future prospect of large-scale biomass energy plantations requires intensive agriculture and silviculture. This technology can contribute to "water-friendly" fertilization practices and at the same time provide a method for buffering carbon in the soil thereby reducing emissions of greenhouse gases like CO_2 and NH_3.

2.4 Production of fertilizer

Normally the production of slow-release fertilizers from carbonaceous sources like lignite requires ammoxidation [21], a high-pressure process in which the material is oxidized using air or oxygen to generate reactive oxygenated functional groups which simultaneously react with ammonia. On the other hand such groups occur naturally in bio-oil and this may be exploited by direct reaction with a suitable nitrogen source. Besides ammonia, alternative sources of N include urea and proteinaceous materials like manures, etc. It should also be emphasized here that if the market requires, fertilizers with up to 30% N can be obtained, at least from urea. In that case the excess urea over that required for stoichiometric reaction is bound as polyureas in analogy to the well-known urea-form process in which slow-release fertilizers are produced by co-polymerization of formaldehyde with urea.

Additional nutrients such as K and P can be added to the reactor. For example, P can be added as pulverized phosphate rock, which would be at least partially dissolved by the bio-oil. Thus the phosphorus is also expected to be available in slow-release form.

The conversion can be carried out on-condensed bio-oil or on-line during the pyrolysis process by injecting the nitrogen source before condensation. The final product may, as required, be produced in liquid form or as a solid by drying.

3 Fertilizer production plant

3.1 Design basis

The fertilizer production plant was sized to process the whole bio-oil produced from a 100 dry t/d wood feed fast pyrolysis plant, producing a solid product. The plant was designed to process this amount of bio-oil in a two shift per day, 16 h/d, operation at 330 days per year. This sizing was chosen to result in reasonable sized economy of scale for the process equipment. Table 4 summarizes the plant capacity. The capacity of the fast pyrolysis plant could be larger with 100 dry t/d off the overall wood feed dedicated to fertilizer production.

The slow release fertilizer from bio-oil is seen as a by-product, with the fertilizer production operation being part of a bio-oil facility that produces bio-oil for energy applications and other chemical products. For this reason the fertilizer production plant would operate within a larger bio-oil production facility as opposed to a stand alone plant. This permits some cost savings and efficiencies in terms of utilities integration and facilities sharing, such as steam production, buildings, land and administration. These cost savings are taken into account in this cost estimate.

Table 4. Fertilizer production plant summary.

	Units	
Annual operation	h/yr	5280 (2 shifts/day)
Bio-oil feed	t/d	72.3
Ammonia feed	t/d	4.2
Nitrogen content in fertilizer product	%	10
Fertilizer production	t/yr	19,230

3.2 Fertilizer production plant description

Figure 1 shows the flowsheet for the production of solid slow release fertilizer from bio-oil. Bio-oil and ammonia are reacted at 120 °C in continuous stirred reactor, operating at 50 Psig (3.5 barg). In the reactor condensation reactions with $–NH_2$ occur as described in Section 2 above together with polymerization. The product from the reactor is a homogeneous liquid that is pumped at approximately 100 °C to a spray dryer where it is dried to a 5% moisture content. The dried product is transferred by pneumatic conveyor to pelletizer for pelletizing and packaging.

The spray dryer operates at a gas inlet temperature of 300 °C, and a gas outlet temperature of 100 °C. The vapours from the dryer are condensed in a direct quench spray

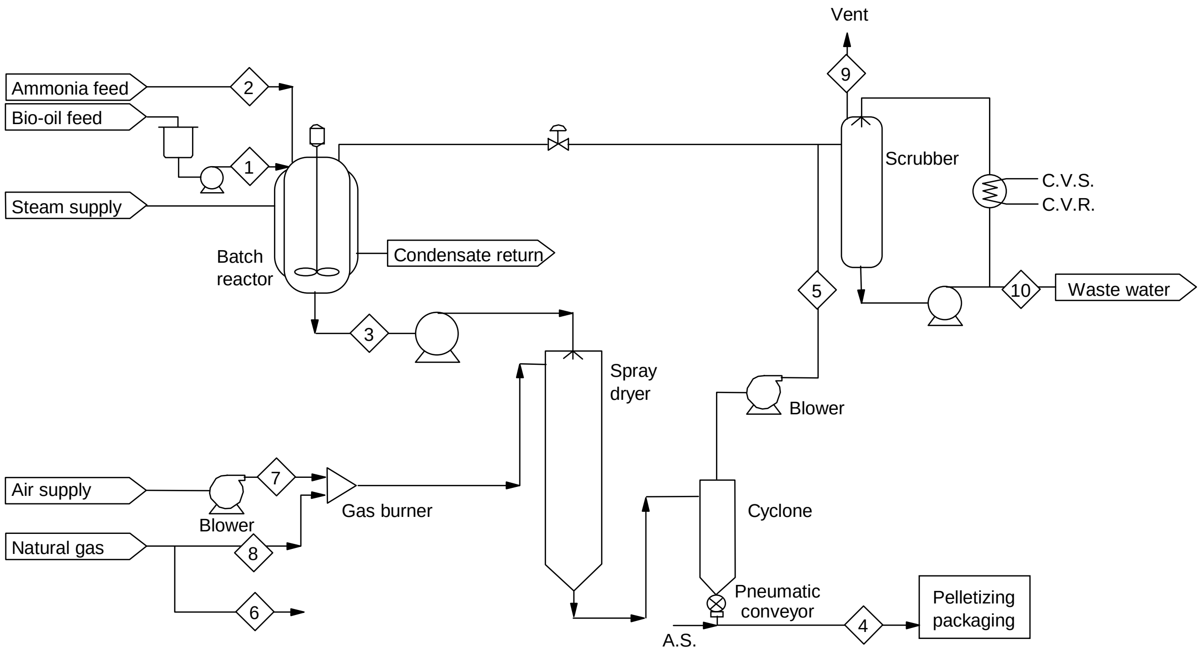


Figure 1. The flowsheet for the production of solid SRF from bio-oil.

condenser. Recirculating condensed water is used as the quench liquid. Any vapours vented through the reactor pressure control valve also pass through the scrubber. The scrubber produces a wastewater stream that is treated by aerobic treatment.

The design of the plant required process simulation of key steps in order to scale the process up from the laboratory scale experiments that the patent was based on. Key unknowns were the heat of reaction and the losses of light organic compounds in the spray dryer. ASPEN PLUS software was used to obtain an estimated heat of reaction for the reactor and to obtain a material balance for the spray dryer. In both cases model compounds and model reactions were used to simulate the wide mixture of components in the bio-oil and the different reactions taking place. The resulting material balance for the fertilizer plant is shown in Appendix 1.

3.3 Technical uncertainties

The basic process operations required to produce slow release fertilizer from bio-oil are conventional and scaling up this technology to commercial scale operation should not present major problems. Pilot testing of the drying step will be required to verify operating parameters and for sizing of the spray dryer. Most drying equipment manufacturers have pilot drying facilities available.

The uncertainties related to the production of bio-oil from wood by fast pyrolysis are discussed in a previous IEA report [2], which also discusses uncertainties related to bio-oil storage, corrosion and stability.

A key area of uncertainty is the actual performance of the slow release fertilizer produced from bio-oil compared to existing speciality fertilizers. Limited testing has been done with the fertilizer product on the growth of plant matter. The rate of release of the nitrogen from the bio-oil fertilizer is presently not known.

3.4 Material balance

The material balance for the slow release fertilizer plant was based on the Resource Transforms International patent [1], and on additional mass and energy balances determined for the reactor and dryer using ASPEN Plus simulation software. The reactor material balance used is shown in Table 5.

The material balance for the plant is shown in Appendix 1.

Table 5. Reactor material balance, basis 100 kg bio-oil feed.

REACTOR FEED	Mass, kg
Bio-oil	
Char	0.1
Water	22.3
Organics	77.6
Bio-oil total	100
Ammonia	5.8
Total feed	105.8
REACTOR PRODUCT	
Fertilizer	
Char	0.1
Water	28.5
Organics	77.2
Total product	105.8

3.5 Cost estimates

3.5.1 Capital costs

Capital costs for the plant were based on estimates and preliminary quotes for the major plant equipment. Consistent with the assumption that the fertilizer plant would be located as part of a larger bio-oil production facility, land, building and site preparation costs have not been included in the capital cost for the fertilizer plant. The total capital cost for the slow release fertilizer pilot plant, producing approximately 20,000 t/year, is CA$ 4.8 million Canadian dollars (US$ 3.36).

3.5.2 Operating costs

Appendix 2 contains the operating and product costs for the plant. The operating costs are based on a plant located in Canada. The following costs were used for the plant.

Labour costs

The average hourly labour cost including vacation and benefits costs is CA$ 60,000.00/year. The number of labourers per shift for the plant is estimated to be 2. Once operating experience is gained this could be reduced to one operator per shift with support from an adjacent bio-oil production plant.

The plant will be operated for two shifts per day, seven days per week with a total annual operation of 5 280 hours. This enables the production to be increased with product demand without incurring additional capital costs.

Electricity costs

Average cost: 0.04 CA$/kWhr

Bio-oil cost

The base case bio-oil cost used was CA$ 214/t (US$ 150.00/t). Since the cost of bio-oil can vary significantly depending on the cost of the biomass available and the capacity of the bio-oil production plant, sensitivity cases with bio-oil costs up to CA$ 429/t (US$ 300/t) were also evaluated.

Ammonia cost

324 CA$/t (226 US$/t)

Cooling water cost

A cooling water cost of 0.18 CA$/$m^3$ was used.

4 Economic results

4.1 Evaluation method

To evaluate the costs of producing slow release fertilizer from bio-oil, all the plant capital costs were assumed to be financed by a loan over a 20 year plant life at the cost of capital of 8%.

4.2 Results

The main factor influencing the cost of producing slow release fertilizer from bio-oil is the cost of the bio-oil, which is highly dependent on the cost of the biomass feed used. Therefore the cost of the slow release fertilizer was determined for several cases using different wood and related bio-oil costs. The results of these different cases are shown in Table 6. The bio-oil costs are for a 100 dry wood t/d capacity fast pyrolysis plant.

Table 6. Slow release fertilizer from bio-oil production costs, US$/t.

Wood cost, US$/t dry	Bio-oil cost, US$/t	Slow release fertilizer cost, US$/t
10	150	272
20	164	290
40	191	323

Figure 2 shows the cost of slow release fertilizer from bio-oil as a function of the cost of wood and the corresponding cost of bio-oil. As in Table 6, the bio-oil costs are based on a 100 dry t/d wood capacity. The difference between the fertilizer cost and the bio-oil cost for a given wood cost represents the value added to the bio-oil by producing a slow release fertilizer by-product.

Figure 3 shows the cost of the slow release fertilizer as a function of the bio-oil cost for a range of bio-oil costs from approximately US$ 100/t to US$ 300/t. This enables the estimation of the slow release fertilizer cost for a wide range of bio-oil costs.

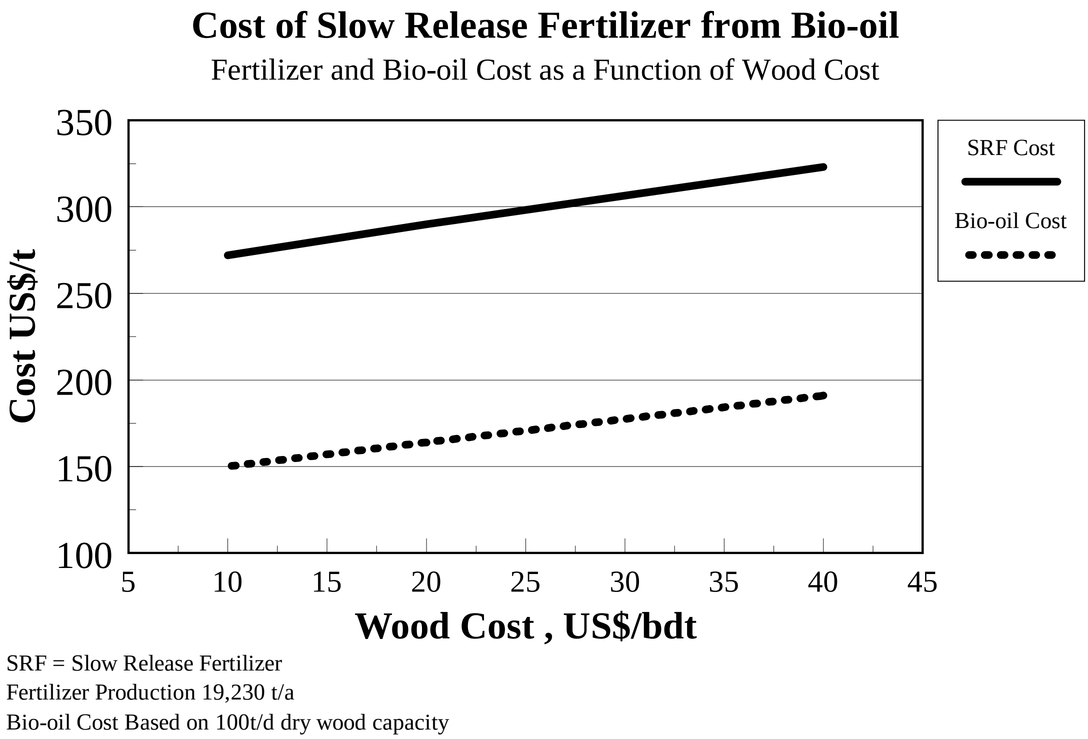


Figure 2. The cost of slow release fertilizer from bio-oil, US$/t

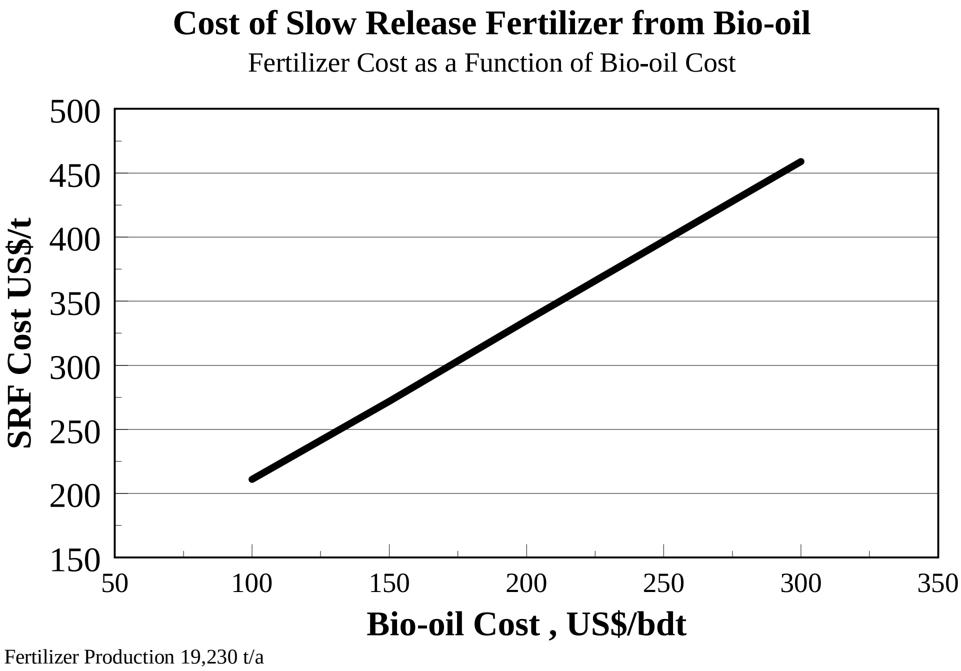


Figure 3. The cost of the SRF as a function of the bio-oil cost, US$/t .

4.3 Market for specialty fertilizers from bio-oil

The cost to produce slow release fertilizer from bio-oil appears to be competitive with conventional nitrogen controlled release fertilizers, which vary in price from US$250/ton for sulfur coated urea to $1250/ton for polymer coated fertilizers [22] Further discussion on of the types of markets for controlled release fertilizers can be found in reference [22].

It is envisaged that the bio-oil derived fertilizer product could be competitive in those market niches, which already use slow release fertilizers. These include golf courses, horticulture, greenhouse operations, etc. However a more interesting opportunity is its use in large-scale conventional farming operations especially in conjunction with the disposal of agricultural wastes and carbon sequestration opportunities. The product would produce added value for agricultural waste and at the same time synergistically enhance agricultural productivity. Additional possibilities in the future include fertilizers for agroforestry applications such as energy crops.

The overall value of the slow release fertilizer product will be determined by several factors. These include the sum of the replacement value of conventional N fertilizer, yield enhancement value due to humates, carbon dioxide sequestration credits and waste disposal credits for the biomass feedstock (if applicable).

5 Conclusions

1. The economics of producing slow release fertilizer from bio-oil appear to be promising. The cost of the bio-oil produced fertilizer is comparable with the value of existing specialty fertilizers currently available.
2. Testing of the slow release fertilizer on plant matter is needed to verify its performance compared to conventional specialty fertilizers.

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APPENDIX 1

Production of slow release fertilizers from bio-oil: material balances

Stream No.	1 Bio-oil feed	2 Ammo-nia feed	3 Product to dryer	4 Dried product	5 Vapours to scrubber	6 Natural gas for reactor	7 Air	8 Natural gas for dryer	9 Scrubber vent	10 Waste water
Mass flow, kg/h										
Non-condensible gases						50	640	35	675	
Organics	2 338		2 327	2 303	24					24
Water	672		858	121	737					737
Ammonia		175								
Char	4		4	4						
Total	3 014	175	3 189	2 428	761	50	640	35	675	761
Moisture, wt%	22.3		26.9	5.0						

APPENDIX 2

Operating and capital costs

Capital Cost		k$CA
Fixed capital investment FCI1		4 836
contingencies	10%	484
Fixed capital investment FCI2		5 319
start-up costs		532
working capital		266
interest during construction		340
Total capital requirement TCR		6 458
Capital to be depreciated		6 192

	kCA$/a	**CA$/t**
Fixed costs		
Operating labor	240	**13.0**
Maintenance labor	53	**2.9**
Overheads	88	**4.7**
Maintenance materials	160	**8.6**
Taxes, insurance	106	**5.7**
Others	53	**2.9**
Total	700	**37.8**
Variable costs		
Bio-oil Feed	2 387	**128.8**
Electricity	26	**1.4**
Ammonia Feed	464	**25.0**
Cooling Water	22.8	**1.2**
Total	2 900	**156.5**
Annual cost of capital	652	**35.2**
Product cost	4 252	**229**

Part 3

Power production from wood – comparison of the Rankine cycle to concepts using gasification and fast pyrolysis

Prepared for

International Energy Agency
IEA Bioenergy Task 22 – Techno-Economic Assessments for Bioenergy Applications

IEA BIOENERGY T22: TECHNOECONOMICS: 1999:03

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Abstract

A study of small scale power production from woody biomass was carried out within the IEA Bioenergy Task "Techno-Economic Assessments for Bioenergy Applications". The task had the following objectives:

- to compare the commercial steam boiler power plant (the Rankine cycle) to two alternative new power plant concepts
- to assess the uncertainties within these new concepts
- to estimate the development potential of these concepts.

The study was carried out comparing production of electricity at 2 MWe. The scale was selected to study

- how well the commercial steam boiler power plant competes with the new power plant concepts especially in the small scale
- what is the future estimates for cost and performance of the new concepts.

The systems compared were

- the Rankine steam boiler power plant
- the gas engine power plant using gasification fuel gas. The gasifier and the engine are integrated.
- the diesel power plant using fast pyrolysis liquid as a fuel. Liquid production and the power plant are de-coupled.

Overall efficiencies for these systems are: the Rankine cycle 17.5%, gasification – gas engine 23.9%, and pyrolysis – diesel engine 24.7%. Potential improved efficiencies for the three technologies are 23, 32.4, and 31.5%, respectively. Estimated specific investment costs for the base power plants are 2 300, 4 200, and 3 600 US$/kWe, respectively.

It is shown that the Rankine cycle is superior compared to the gasification gas engine and pyrolysis diesel engine with current cost data. Increasing fuel cost 50% from the base value FIM 45/MWh (USD 2.3/GJ) improves the competitiveness of new concepts, but the Rankine is continuously more economic over the whole annual operation time. At high fuel costs, the difference between the diesel and the Rankine is negligible below 4 000 h/a. In a very long-term operation time, the gas engine is not much more expensive than the Rankine power plant. Differences between the alternatives are fairly small over the whole range, where improvements for technologies are assumed valid. The range of variation with the Rankine and the least-cost new cycle is about 10%, which is not a significant difference within the accuracy of the study. It is shown that co-generation improves the economics of small-scale power production considerably. The Rankine cycle remains as the least-cost option in all cases studied.

It is concluded that for the new power plant technologies to be competitive compared to the Rankine cycle, especially capital costs have to be reduced. Without such reductions it will be hard to compete with the Rankine cycle in a small scale either in power-only or co-generation mode of operation.

Preface

IEA Bioenergy is an international collaboration within the International Energy Agency – IEA. IEA is an autonomous body within the framework of the Organisation for Economic Co-operation and Development (OECD) working with the implementation of an international energy programme.

The IEA Bioenergy "Techno-Economic Assessments for Bioenergy Applications" -Task reported here, has several general objectives. The main objective is to make companies developing new systems within the bioenergy area and their products known in participating countries by carrying out pre-feasibility studies.

The objectives have been pursued 1998–1999 through carrying out studies in participating countries. Electricity, liquid fuel, and green chemical applications were studied. Studies were carried out in collaboration with companies developing new products or services in the bioenergy field in the participating countries (Austria, Brazil, Canada, Finland, Sweden, and the United States of America). Small-scale power production concepts using woody biomass as fuel were compared in Finland. A study was carried out with Sermet Oy, whose contact information is shown below.

Yrjö Solantausta carried out the work at VTT Energy. Juha Huotari from Sermet Oy provided material and critical support for the work. The economic assessment was carried out using generic in-house data at VTT.

Espoo, December 1999

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Contents

1 Introduction

1.1 Electricity production

Solid, gaseous and liquid fuels are used for generating electricity in thermal power plants. Coal and natural gas dominate the market, although distillate fuels are also still used in many countries. Natural gas has been increasing its market share in the recent years, largely for economic reasons, but also because of environmental considerations. A combined-cycle power plant employing natural gas as fuel has a low specific investment and high efficiency. It also has a short construction period compared, for example, with coal-fired power plants. Natural gas produces less carbon dioxide per produced electricity unit than other fossil fuels due to a lower carbon-to-hydrogen ratio. Combined cycles also have low emissions of nitrogen and sulphur oxides, and low particulate emissions.

Electricity consumption is constantly increasing in the industrialised countries. All of the available large-scale production options have some complications: nuclear, which is neutral towards global warming and often the choice of the industry, is politically questionable and unacceptable in many countries; coal, although generally regarded as economical, is considered environmentally doubtful; and reserves of natural gas, although more environmentally satisfactory than its competitors, are limited.

Global warming may be a problem in the future [1]. Global warming is intensified by carbon dioxide (CO_2) and some other gases released, for example, during the combustion of fuels in electricity production. Most of the man-made CO_2 emissions are generated in power and heat production, and in the transportation sector. In addition, there are several more or less natural players in the greenhouse gas balance (water reservoirs, soil, peat bogs, human & animal wastes, etc.). Renewable energy sources like wind, hydro, solar photovoltaics, geothermal, and biomass are examples of alternatives that do not release net CO_2 into the atmosphere. In this work, the use of biomass for electricity production is investigated. Besides liquid fuels, electricity production is the largest market sector expected to employ biomass fuels.

However, there is a conflict between the electricity market demand, and the availability of biomass. Biomass is typically available in relatively limited amounts in one place, which suggests small unit sizes for logistical reasons to keep transportation costs of biomass low.

Sometimes relatively large amounts of biomass are available in one location. However, even then cost of biomass fuel increases considerably as the amount of fuel used at one site increases. An example of forest residue costs at a location in Finland as a function of the amount of fuel is shown in Figure 1. It may be seen, how the cost increases as the amount of fuel used increases from about FIM 40 to 70/MWh (USD 2.5 to 3.5/GJ). The site shown does not use the amounts indicated, but it is based on an estimate using real data for available forest residues from wood harvesting.

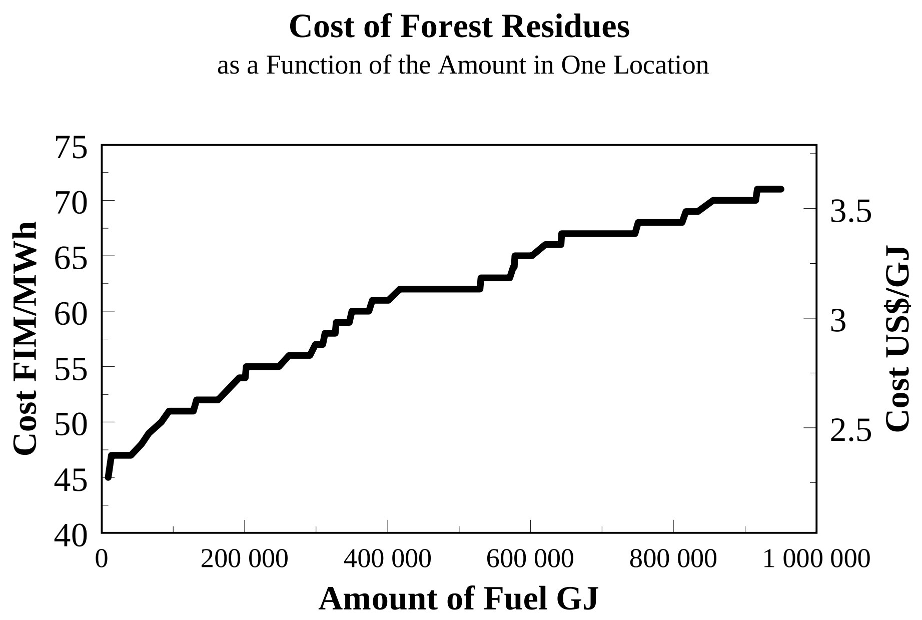


Figure 1. An example of the availability and cost of forest residue at a location in Finland.

However, although small biomass-fired power plants are preferable from the viewpoint of fuel supply, their specific investment costs are higher than those of large central power plants. Specific investment costs of power plants are compared in Figure 2. Two important issues may be seen:

- The scale has a considerable effect on the specific capital cost, which has a fundamental effect on power production costs
- Power plants using a solid fuel (wood, coal, and peat) a considerably more expensive than plants using a fluid fuel (natural gas, heavy fuel oil).

The higher specific investment cost of smaller power plants may partly be compensated by lower grid distribution costs, when power is produced at user site. In Figure 3 average market prices for electricity for two industrial users are compared. Grid transmission costs are a considerable share of cost of electricity, about one third and one fourth from the total cost for small and medium size industry, respectively.

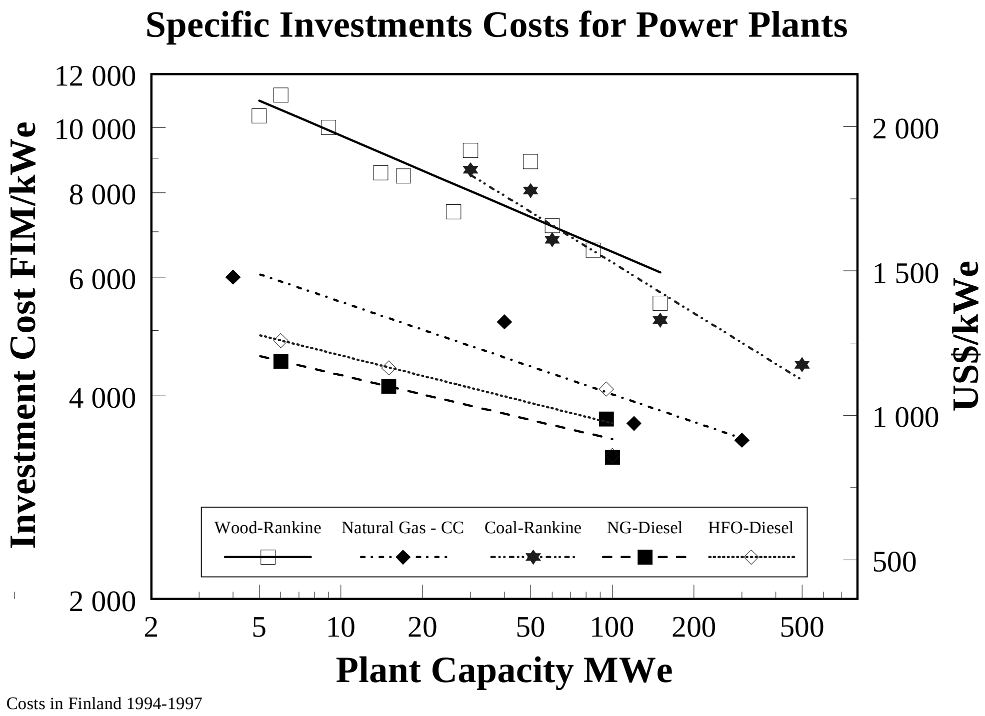


Figure 2. Specific investment costs of power plants. Costs shown for 1994–1997, both built and planned costs shown.

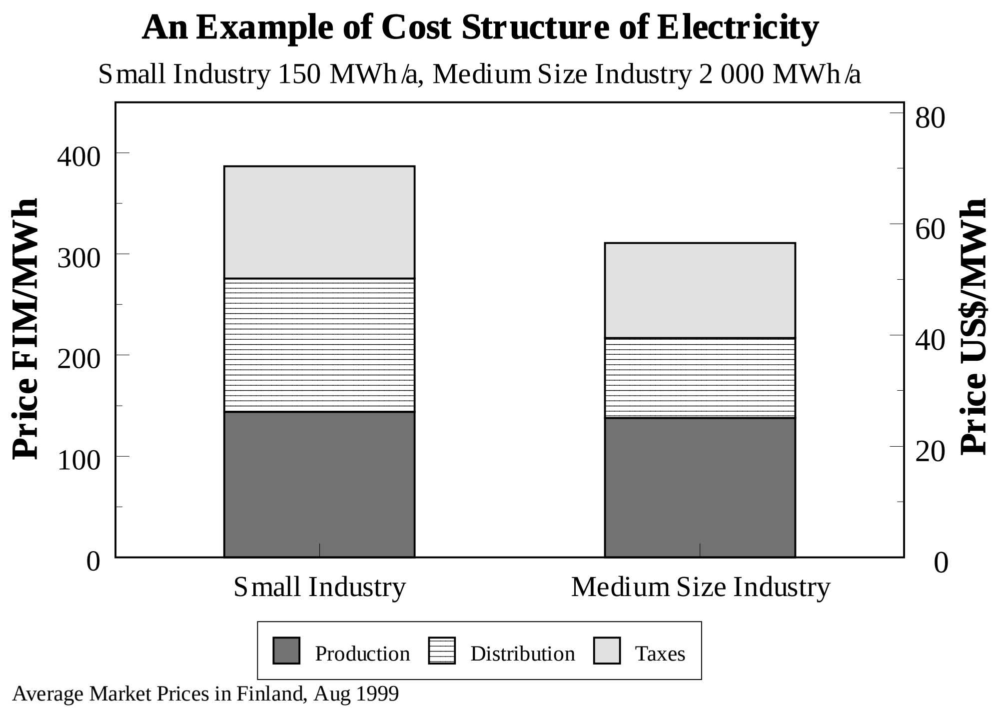


Figure 3. Average cost structures of electricity for small industrial users in 1999 in Finland.

A considerable market potential for biomass fired power plants have been proposed, for example, by Larson [2], and Keränen & Salo [3]. However, the power plant concepts considered in the references are suitable for large scale, and primarily suitable for pulp and paper industry.

Grassi [4] and Hislop & Hall [5] have also considered smaller power plant capacities. Hislop and Hall present a scenario, where a potential additional capacity for biomass power is given for 2025 in three capacity classes, 0.5, 7 and 40 MWe (Figure 4). According to Hislop and Hall, the scenario is not considered to require major changes in the present energy policies. Even if the smallest-size power plants were excluded as doubtful either technically or economically, the potential number remains considerable.

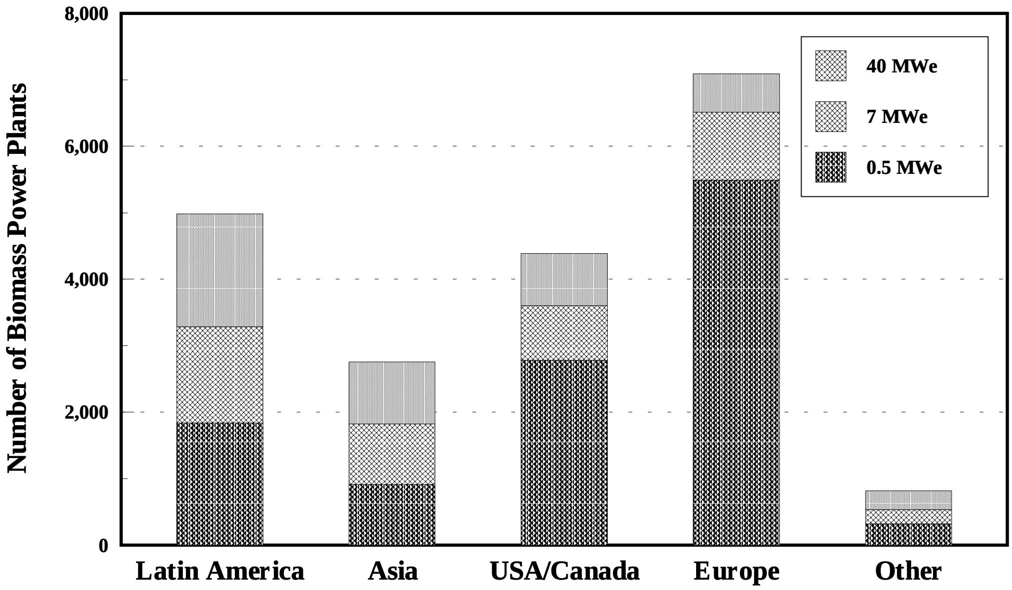


Figure 4. Global potential number of biomass power plants by 2025, published in [6], data from [5].

1.2 The biomass-fired Rankine cycle

The Rankine cycle continues to be the prime power plant technology, when biomass power plants are built. Although new technologies are being developed, practically all industrial plants employ the Rankine cycle.

A Rankine power plant has three main sections: fuel handling, boiler plant, and steam and power section. As an example, the boiler section of a fludised-bed boiler is shown in Figure 5.

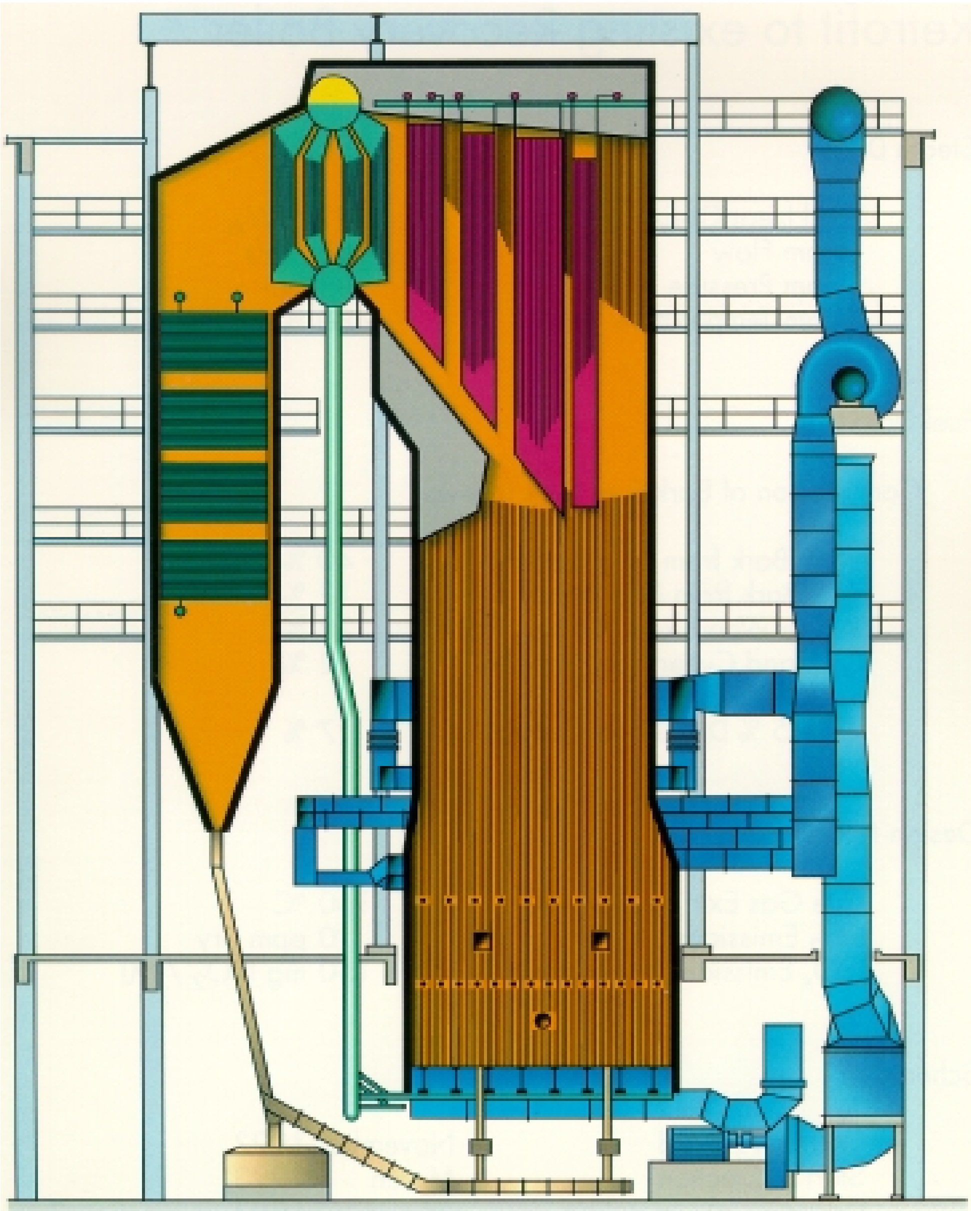


Figure 5. A boiler of a Rankine power plant.

A flowsheet of the steam and power section of another plant is shown in Figure 6. It shows a co-generation power plant producing 17 MWe of electricity and 48 MWth of district heat, which has been in operation in the city of Forssa in southern Finland since 1996. A description of the plant is given below.

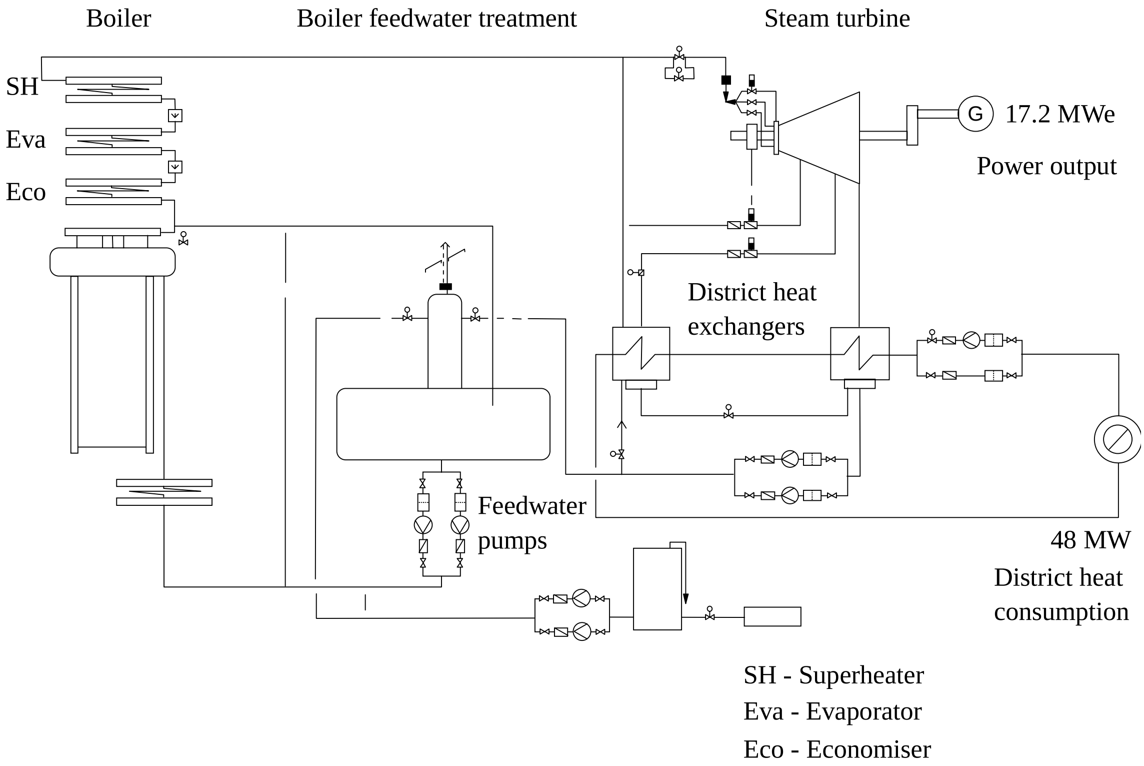


Figure 6. A steam and power section of a Rankine power plant.

Forest residue wood chips and wood wastes are used at this power plant. Wood chips are loaded from trucks into receiving bunkers. Belt conveyors carry fuel to metal separators and screens, and oversize pieces are introduced to a hammer mill. The fuel is further conveyed to the boiler, which is today typically either a bubbling or circulating fluidised-bed boiler (BFB or CFB, respectively). These boilers can burn several types of fuel, from coals to bio-sludges, which is the main reason for their popularity. Superheated steam (60 bar, 510 °C) is generated in the boiler. Steam is expanded through a steam turbine, which drives the generator. The turbine is a back-pressure unit, where the steam is condensed while generating steam (industrial CHP) or heating district heat water. The condensates are treated in the deaerator, and returned through the boiler feed-water pump to the boiler.

1.3 Small biomass-fired power plants

Small power plants rarely compete economically with large utility-scale production units, largely because of high specific investment costs. The personnel costs are also often high. An additional practical reason, why the small-scale production so far has been plagued with failures, is the error prone handling of heterogeneous biomass in small scale.

New small-scale power plant concepts (< 1–2 MWe) employing solid biomass as fuel include considerable technical and economic uncertainties. They rarely meet the reliability required from power plants connected to the grid. The technical feasibility of the smallest-size capacity is often questioned, and their economic viability is a larger uncertainty [7]. However, they have frequently been proposed [8], and development work on new small scale power production concepts is also supported by the EC DGXII [9, 10]. Two concepts are presented in section 1.5. These two concepts are then compared to the Rankine cycle in this report.

The Rankine cycle concept is also being developed further. The smallest viable plant size has been reduced from previous about 20 MWe to around 5 MWe in co-generation service, depending of course largely on local circumstances. An example of how the specific investment costs have been decreasing from around 1980 to the early 1990s is shown in Figure 7. The town of Pieksämäki was considering from the late 1970s of building a combined-heat and power plant. Several design studies were carried out between 1979 and 1990 before finally contracting the plant in 1991. All the costs have been converted to 1991 money. The first four data points are design values, and the last data point in 1991 corresponds to a real cost of a built power plant. A considerable decrease in cost may be seen.

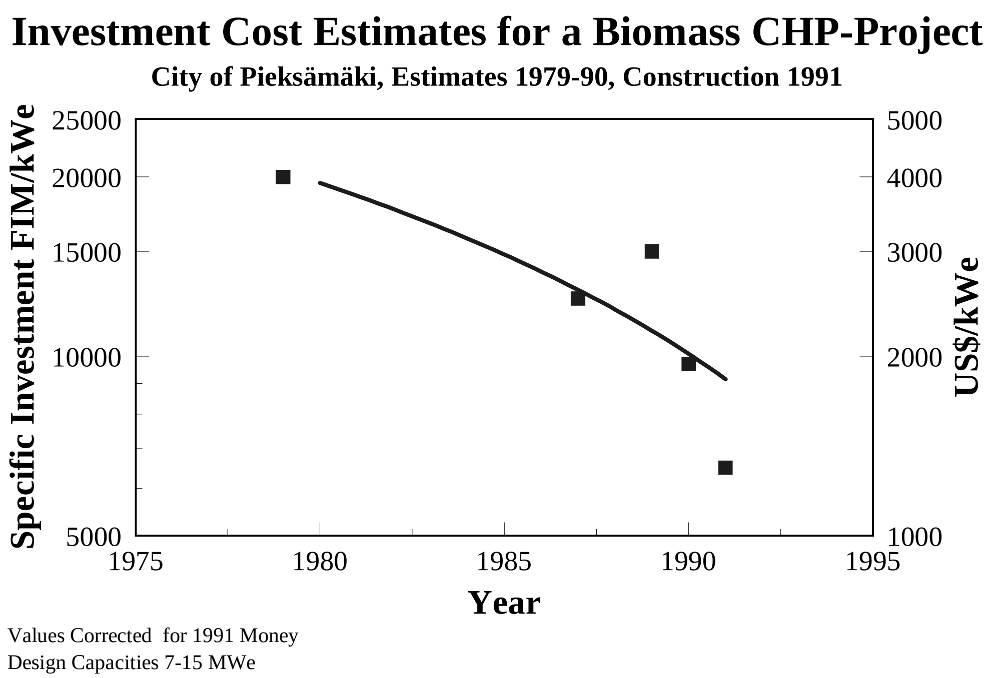


Figure 7. Reduction in the investment costs of Rankine power plants [11].

1.4 The small scale Rankine power plant by Sermet Oy

A Finnish company Sermet Oy is developing a small scale Rankine power plant concept, Sermet BioPower. The first plant was commissioned in 1999. In this report, the concept will be compared to new power plant concepts being developed.

Sermet Oy is presently the leading Finnish manufacturer and turnkey supplier of medium-sized boiler plants. Sermet was established in 1975 and is located in the town of Kiuruvesi in Central Finland. The operating management owns the company. The production comprises innovative boilers and boiler plants for utilisation of oil, gas and various biomasses or residuals for energy needs of industries and communities. The hot water or steam output range of a single boiler plant ranges from 1 to 120 MW. Since its foundation Sermet has delivered over 1 000 package, modular and stationary boiler plants, of which more than 350 to export markets.

Sermet has own grate, fluidized bed and pyrolysis combustion techniques that have been applied for biomass and residual fuels. Currently Sermet is the market and technology leader in Finland on sawmill boiler plant markets with the patented rotating grate combustion technology (Sermet BioGrate, Figure 8).

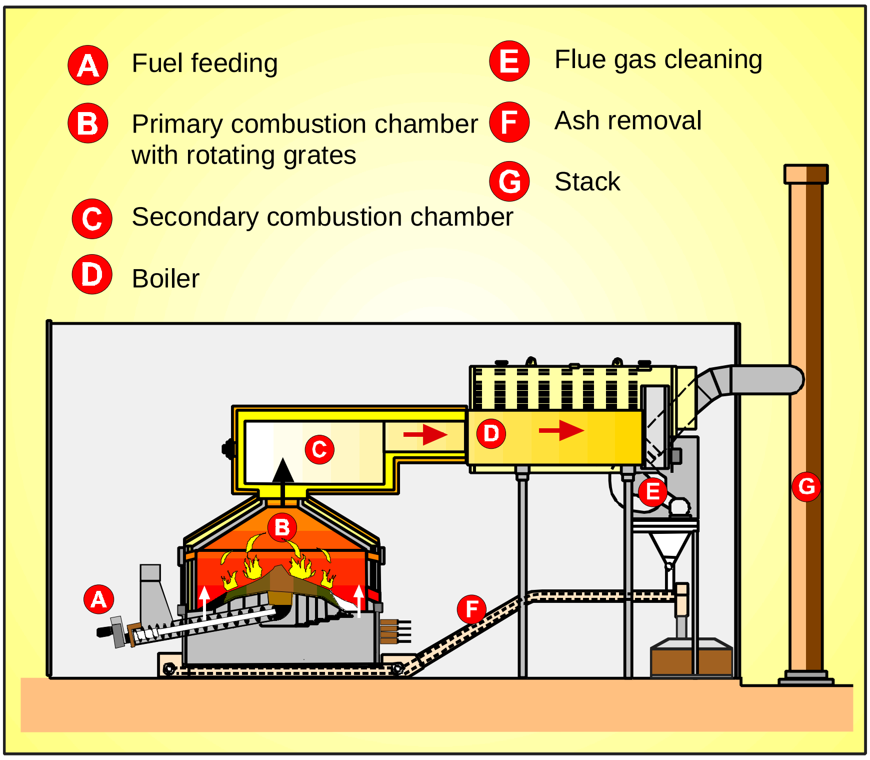


Figure 8. Sermet BioGrate boiler plant for capacities of 4–15 MW.

Sermet BioGrate development was initiated in 1990, and the concept was commercialised in 1994. Atotal of 40 units have been sold by 1999. Key features of this technology are:

- Suitable fuels are bark, sawdust and wood chips, and the moisture may be up to 65%
- Efficient combustion with low emissions
- Low operating and maintenance cost with fully automatic unmanned operation
- A patented process.

Based on the success of BioGrate combustion technology, the development of Sermet BioPower was initiated. The development was started in 1995, and the first plant whas commissioned in1999. Two flowsheets of Sermet BioPower are shown in Figures 9 and 10, one including a steam engine and the other a steam turbine.

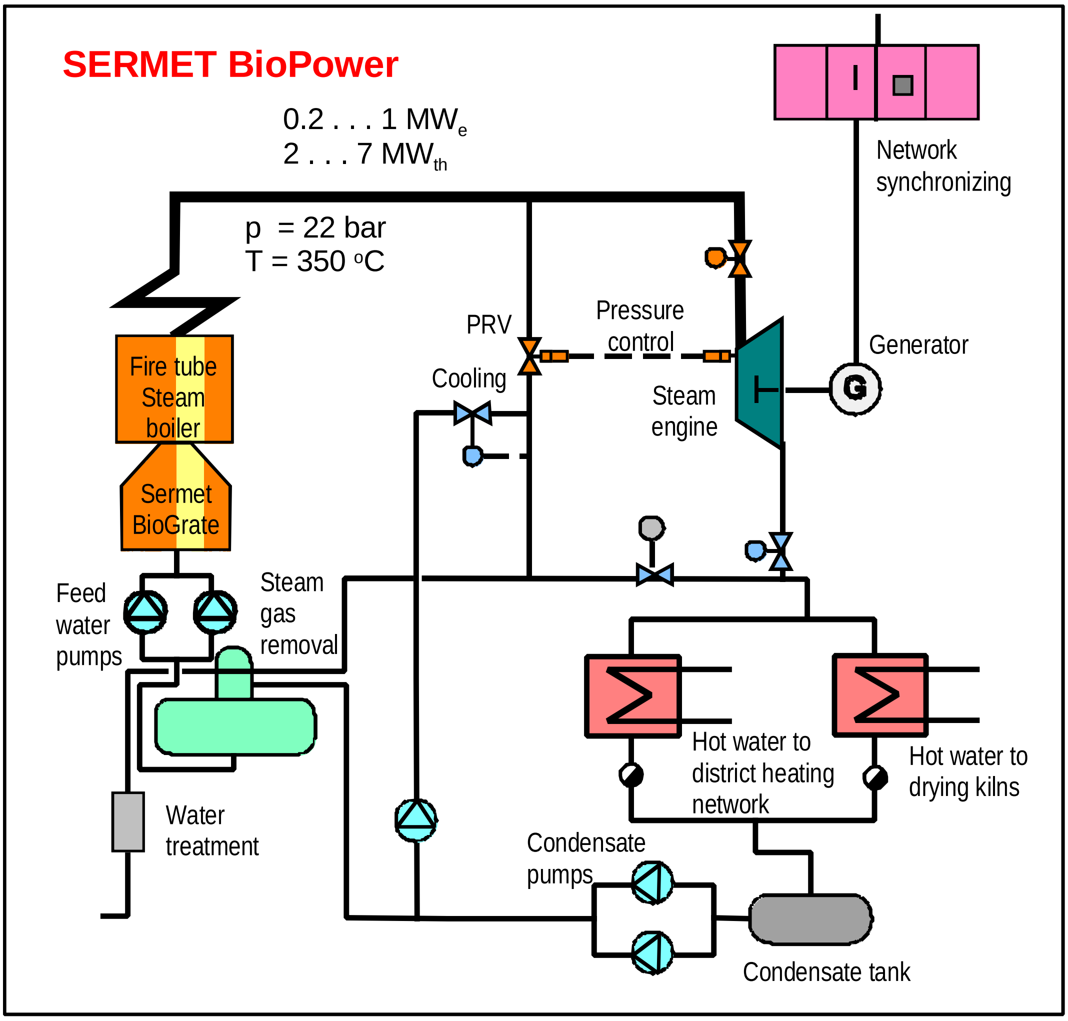


Figure 9. Sermet BioPower employing a steam engine.

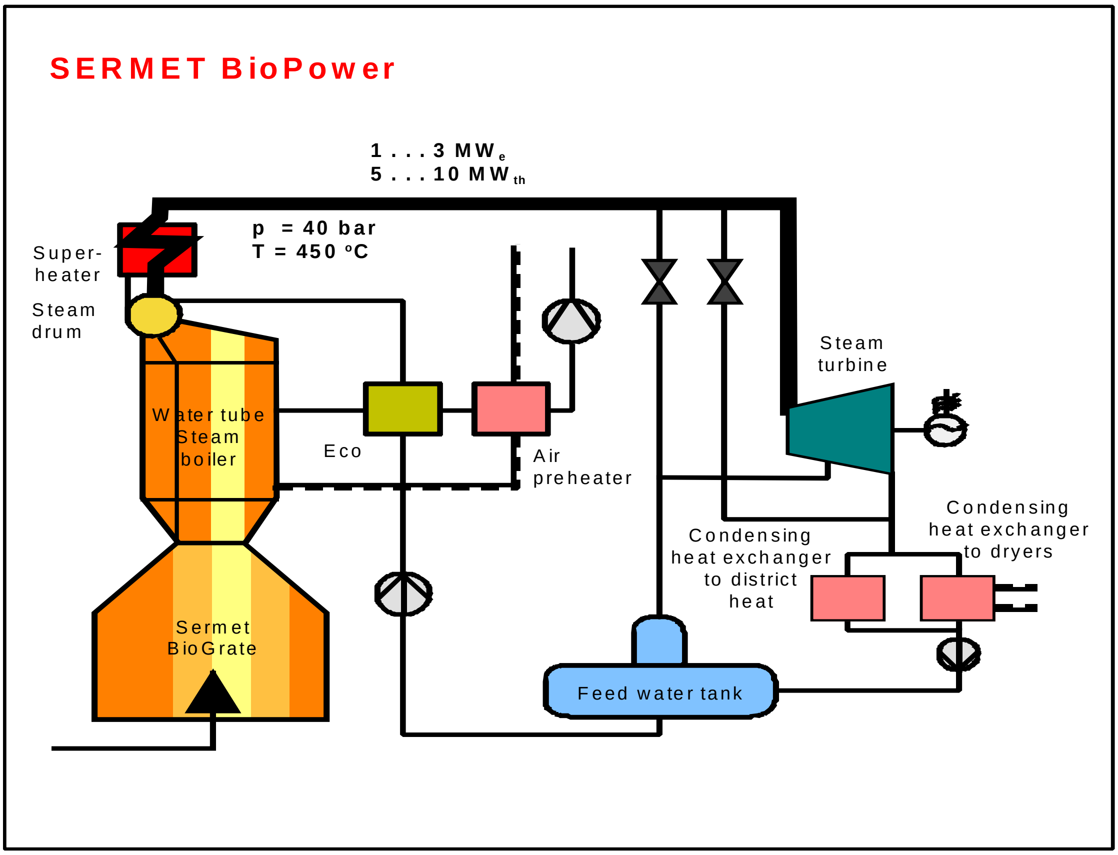


Figure 10. Sermet BioPower employing a steam turbine.

Technical features of this Rankine cycle power plant are:

- Steam boiler plant based on Sermet's BioGrate
- Turn key delivery
- Steam engine or turbine can be applied for electricity generation
- High-moisture biomass can be used as fuel
- Electricity to heat ratio around 15–25%
- Automatic operation and proven technology both for steam and electricity generation

Typical applications for the power plant are sawmills, other mechanical wood industries, and energy companies. Added value will be obtained for by-products (bark, sawdust, wood chips) by combined-heat and power (CHP) production. Purchased electricity consumption can be minimised, and extra savings will be generated by a reduction in electricity transmission costs.

2 Power plant concept compared

2.1 Introduction

A number of different power production concepts using biomass as fuel have been proposed and studied. Several different versions of systems employing gasification, pressurised combustion, fast pyrolysis, gas turbines, internal combustion engines, and Stirling engines, to name the most common, have been developed.

In this report, two alternative power production concepts are presented and compared to the Rankine cycle on a small scale, at 2 MWe. The concepts are shown in Figure 11.

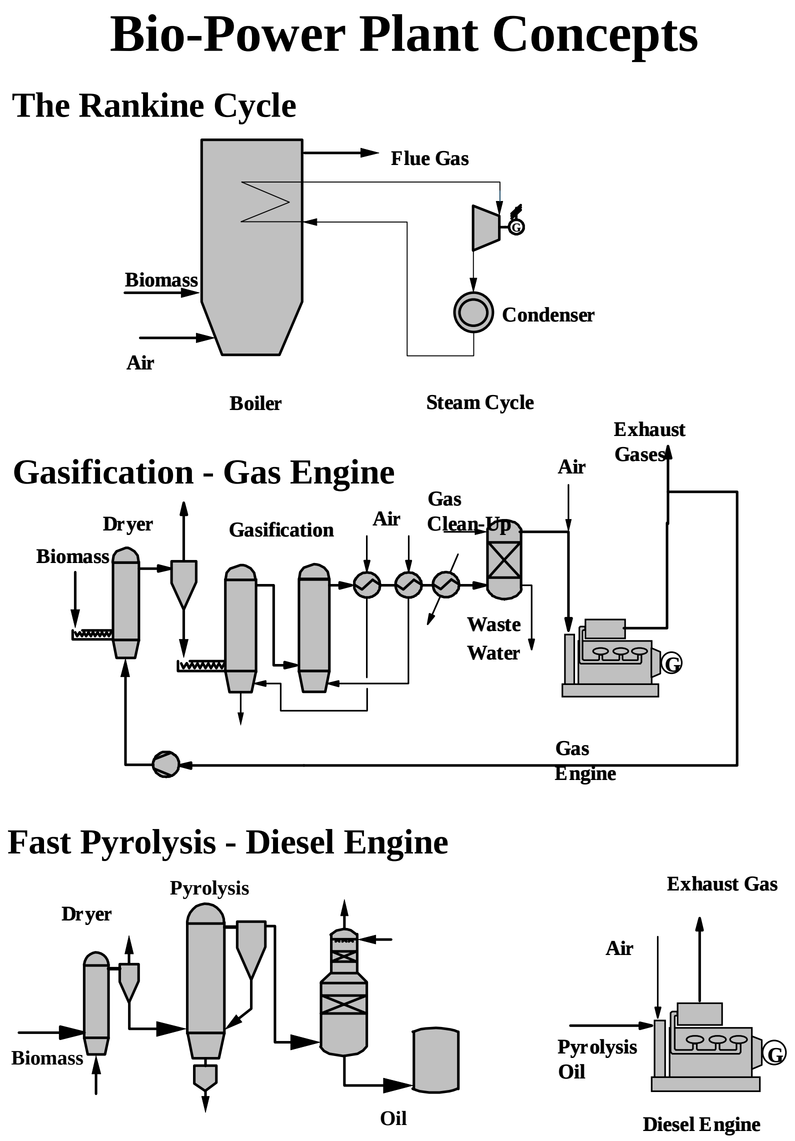


Figure 11. Power production concepts studied in the current work.

Wood chips are assumed as fuel in all cases (Table 1).

Table 1. Fuel properties, lower heating value (lhv).

Type		Whole-tree chips
Moisture content	wt%	45
Heating value (as received)	wt%	9.35
Ash content	wt%	1.5

The Rankine cycle concept was described a section 1.2 above. The characteristics of the two other power plant concepts are summarised below.

2.1.1 Gasification – gas engine

In this concept wood chips are first dried to about 20 wt% moisture. After drying the chips are fed to the fluidised-bed gasifier, in which fuel gas is produced from wood using air as the fluidisation medium. The fuel gas is led to a second reactor, where most of the tars present in the gas are converted in presence of dolomite to form more fuel gas components. The fuel gas is further cleaned and cooled in a water scrubber before compression for the engine injection. The fuel is fired in an Otto gas engine, which has been modified from a natural gas fired engine. Part of the engine exhaust gas is used for the energy demand of the dryer.

The potential gasification – gas engine concept (see section 2.3) is different in that it employs a fixed bed gasifier, a silo dryer, a catalytic gas cleaning stage, and an extensive heat recovery and integration [12].

2.1.2 Fast pyrolysis – diesel engine

This concept includes two distinctive separate plants: fast pyrolysis liquid production plant, and a diesel power plant. The two plants are operated independently. The scale of the pyrolysis plant should preferably be relatively large because of economics. However, the fuel delivery establishes obviously a limit to the plant size.

Wood is first dried in the flue gas dryer to less than 10 wt% and milled to a particle size of less than 6 mm. Dried wood is fed to the pyrolyser, where about 70 wt% of the wood is vaporised. The vapours are condensed by quenching with the recycle liquid, and the product liquid is drawn off. The liquid is stored in a tank. The product is transported to the power plant with a tank car. The liquid fuel is fired in a diesel power plant.

2.2 Analytical methods

The procedure employed in assessing system cost and performance is briefly summarised in this section. The work includes several stages. The technical data used in this assessment has been initially prepared within previous IEA Bioenergy activities and other collaborative projects with various industries. However, it should especially be noted that although Sermet Oy provided material for this report, the cost data used in the report also for the Rankine power plant was assessed at VTT.

As always with new technology, estimating the cost for the new systems is very challenging. In this work, the emphasis is on performance analysis and on assessing the technical uncertainties related to the new systems. Economic feasibility is also estimated, but it is recognised that more uncertainty is related to the cost estimation than to the performance estimation. It should be emphasised that uncertainties with the Rankine cycle cost and performance are minor compared those of to the new concepts.

The tasks related to the new power plant concepts were as follows:

1. Concept design. The pyrolysis liquid production concept has been defined and assessed within previous IEA projects [13, 14, 15]. Ensyn Technologies Inc. participated in one of the projects [15]. The gasification gas engine concept was analysed as part of a Finnish National Bioenergy Programme project [23].
2. Estimates had to be made by the IEA working group concerning the performance of units not yet demonstrated in industrial scale, and of the units applied outside their normal operating conditions. The estimates were carried out employing AspenPlus^{TM} [16] simulation software.
3. Flowsheet design based on analysing proposed concepts by developers. The working group prepared the final flowsheets for all the new concepts.
4. Performance analysis employing AspenPlus. Many leading chemical, petrochemical and related companies employ this program. The software is employed in deriving mass and energy balances for the new processes. Some studies concerning the Rankine cycle were also carried out with Aspen.
5. Sizing of the units based on normal engineering practises using estimated performances as basis.
6. Costing of the units based on data available from developers, from literature, and from the previous IEA projects [14, 15, 17]. It is not believed that the accuracy of cost estimates for new concepts is better than ±30%, and in some cases it may even be higher than this. However, the Rankine cycle estimate is within this range.
7. Economic analysis. Operating costs were estimated based on normal practises in process and power production industries. The annuity method was used for taking

capital costs into account in calculating cost of electricity. Product costs were calculated for pyrolysis liquid by taking average annual costs for capital costs.

8. Technical uncertainties. Technical uncertainties are evaluated and reported. Future work is suggested.

2.3 Performance

A summary of the performance of all power plants, including the Rankine cycle, is presented in Table 2. Two different performance evaluations are given:

- The first corresponding to a current industrial operation (the Rankine cycle), or current projection for an industrial operation (gasification and pyrolysis)
- The second corresponding to a future industrial operation (the Rankine cycle), or current projection for a potential industrial operation (gasification and pyrolysis).

Note that the two are not directly comparable, as there are currently no power plants in an industrial operation using gasification – gas engine or pyrolysis diesel engine. Note also that the performance of "future industrial operation" in the case of the Rankine cycle would be technically feasible already today. However, it is uneconomic to build a steam turbine with operational characteristics corresponding to such an efficiency on this scale. It is nevertheless important to bear in mind that technically it is also possible to increase the Rankine efficiency. Note that in the "future" pyrolysis case, in addition to liquid fuel production efficiency, the scale is also increased to suggest potential for improvement.

*Table 2. Performance of the power plant. * Efficiency indicated for overall efficiency including pyrolysis.*

	Rankine power plant		Gasification-gas engine		Pyrolysis diesel*		Pyrolysis liquid production	
	Base	Future	Base	Future	Base	Future	Base	Future
Wood input MWth	11.6	8.8	8.4	6.2			38.2	76.4
Pyr. liq. input MWth					5.0	4.7		
Power output MWe	2.0	2.0	2.0	2.0	2.0	2.0		
Power production efficiency %	17.5	23.0	23.9	32.4	24.7	31.5		
Liquid production MWth							24.8	56.0
Liquid fuel prod. efficiency %							65.0	73.3

Improvements in performance of these technologies are briefly summarised below. Overall efficiencies of these concepts are also compared in Figure 12, where base and future estimates are shown for each case.

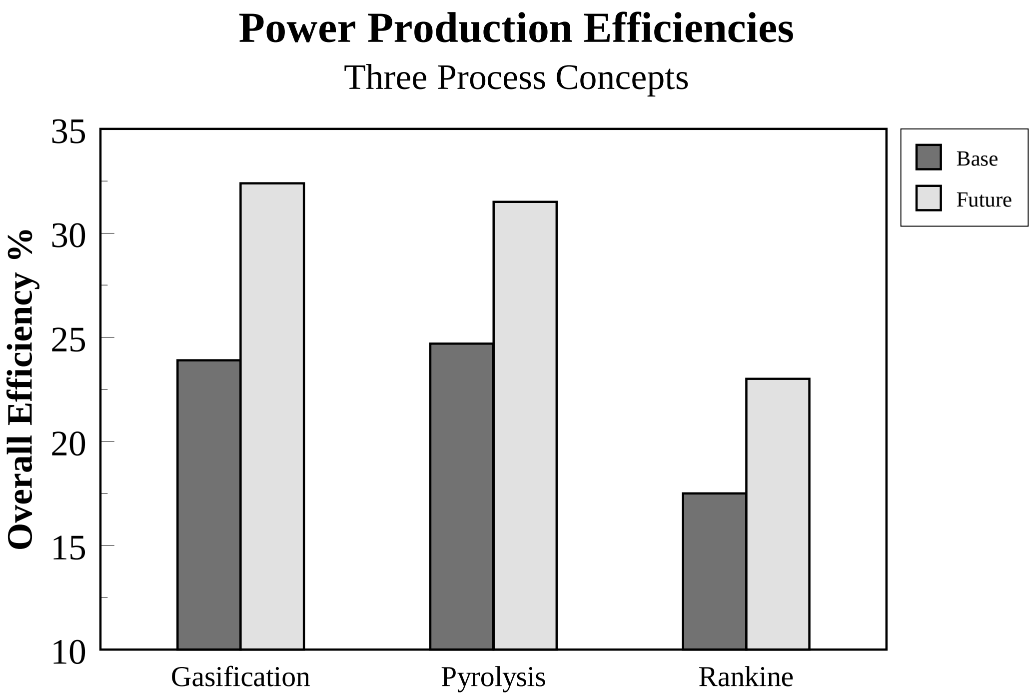


Figure 12. Overall power production efficiencies of the three biomass concepts indicating base and future estimates.

Measured emissions related to these technologies are presented in Table 3, in which data available in public domain for the two new concepts and manufacturers' data are summarised. It is clearly pointed out in the references concerning the emissions from the concepts under development (gasification, pyrolysis) that data for these cases is from experimental operation. Emissions for the new concepts have to be reduced to make it possible to operate the technologies industrially. In both cases high CO emissions are reported, which indicates incomplete combustion. It is also known that particulate emissions are relatively high in diesel engine combustion.

Table 3. Emissions from the three biomass power plant concepts. Rankine based on Huotari [18], Gasification gas engine by Herdin [19], and pyrolysis diesel engine by Bridgwater et al. [20]. NA = not available.

		Rankine Commercial	Gas engine Experimental	Diesel engine Experimental
Particulates (O_2 =6% db.)	mg / Nm_3	50	NA	NA
NO_X as NO_2	mg / MJ_{fuel}	120	60	230
CO	mg / MJ_{fuel}	100	1 920	1 210

2.3.1 Rankine cycle

The efficiency of the Rankine power plant may be improved from current industrial practise by using solutions with higher efficiencies than is economic today. Examples of these are shown in Figure 13, in which current industrial practise is shown together with estimated efficiencies, produced with a simulation model.

Three sets of improvement are studied:

- Increasing superheat steam values (temperature, pressure)
- Decreasing steam turbine back pressure
- Decreasing boiler flue gas temperature.

The results are presented together with what is believed to represent the current state of the art in each capacity range (shown as the industrial correlation in Figure 13). The steam data employed in producing the industrial correlation is summarised in Table 4.

It may be seen that the turbine back pressure has the greatest effect of the variables studied. It is believed that increasing the Rankine cycle efficiency from the present 17.5 to 23% is technically feasible, although economically not viable with current fuel prices.

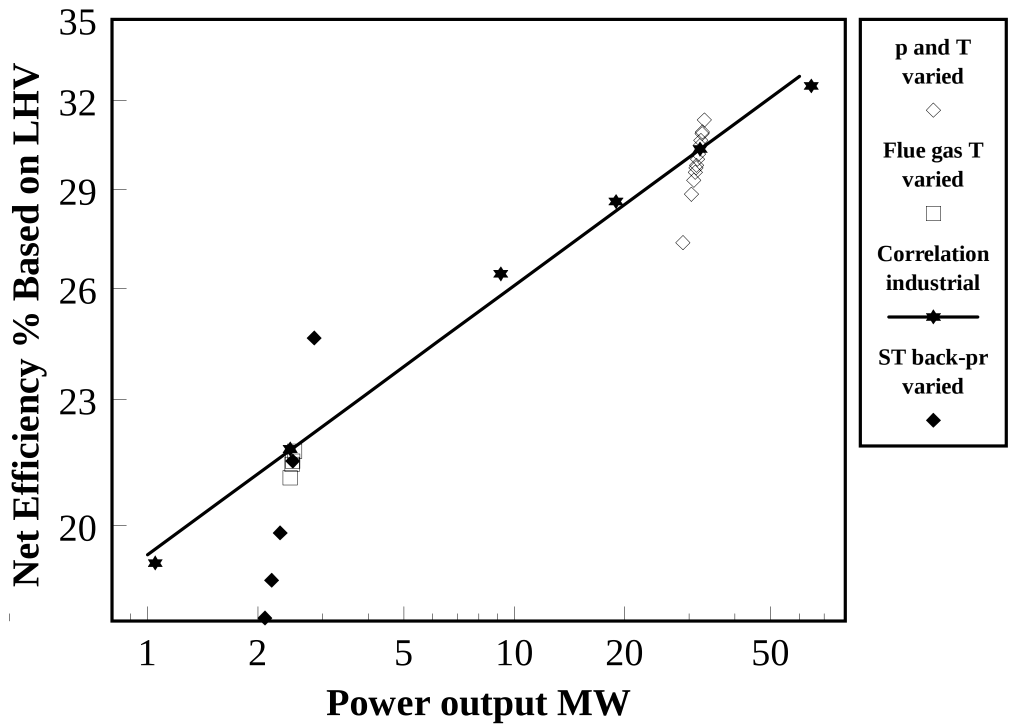


Figure 13. The Rankine power plant efficiency as a function of capacity, results from simulation compared to industrial practise.

Table 4. Steam data used in each capacity (Figure 12) for the industrial correlation.

Capacity MW_e	Steam pressure bar	Superheat temperature °C	Turbine back-pressure bar
60	100	540	0.04
30	90	530	0.06
20	80	520	0.08
10	60	510	0.1
2	40	480	0.2
1	40	450	0.3

2.3.2 Gasification – gas engine

The power plant concept has two integrated sections, which may also be reviewed separately. In the base case the cold gas efficiency (chemical energy in fuel gas / chemical energy in fuel wood) is gasification is 72.5%. Engine efficiency is lower than with natural gas (33% versus 40% based on fuel lhv), and the engine derating is 25% (power output decrease per cylinder, when LHV gas is used). In the future case a considerable improvement is expected both in gasification efficiency and in engine efficiency [12]. The derating is also expected to decrease. With these improvements in power plant component efficiencies, the overall efficiency is expected to improve from 23.9 to 32.4%. Note that the improvements suggested in [12] have not been fully used in this work.

2.3.3 Pyrolysis – diesel engine

This concept is the least developed of the concepts studied. The concept has two independent plants, whose efficiencies may be studied separately. In the base case the efficiency of liquid fuel production is estimated to be 65%, and the diesel engine efficiency 38%. In the future case an improvement in pyrolysis efficiency is expected, to 73%, and in engine efficiency, to 43%. No derating is expected when firing this liquid fuel. The respective overall efficiencies are 24.7 and 31.5%.

2.4 Investment and operating costs

Investment costs for these systems have been determined based on reports in the public domain. The reports used have been published by Ekono Energy [21], IEA Bioenergy [22] and VTT Energy [23]. Investment estimates are made for plants that are considered to be manufactured in industrial serial production. An industrial site in Western Europe, prepared for the power plant is assumed.

A summary of investment costs for the three systems studied are presented in Table 5. These costs refer to the "base" case concepts in Table 2 corresponding to commercially available power plant (the Rankine cycle), or estimates for what is believed to be available within 3 to 10 years from now (gasification and pyrolysis concepts).

A summary of operating costs of the power plants is presented in Table 6, and a summary of pyrolysis liquid production cost in Table 7. Capital costs were estimated with the annuity method using a service life of 20 years and a rate of interest of 10% corresponding to an annuity of 0.1175.

*Table 5. Investment costs for power plant concepts. * A corresponding share (5.3/24.8 note Table 2) of the pyrolysis liquid production plant investment has been allocated for pyrolysis diesel power plant.*

	Steam boiler plant	Gasification – gas engine	Pyrolysis diesel	Pyrolysis liquid production
Power output MW_e	2.0	2.0	2.0	
Fuel output MW_{th}				24.8
Power plant investment MUSD	4.6	8.5	2.6	
Milj. FIM	25	47	14	
Pyrolysis plant investment MUSD				21
Milj. FIM				120
Relative investment USD/kWe	2 300	4 200	3 600*	
FIM/kWe	12 500	23 300	20 000*	

Table 6. Operating costs of power plants. USD/MWh indicated for fuel (th) and electricity (e). Wood FIM 45/MWh, pyrolysis liquid FIM 220/MWh.

		Steam boiler plant	Gasification – gas engine	Pyrolysis diesel
Fuel		Wood	Wood	Pyrolysis liquid
Fuel cost	USD/MWhth	8.2	8.2	39.8
	USD/GJth	2.3	2.3	11.1
Service life	a	20	16	16
Maintenance and insurance	%/a	1.2	1.2	1.2
Personnel		2.5	2.5	1
Auxiliary oil firing	%	0	2	2
Other variable cost	USD/MWhe	0.5	0.7	2.1

Table 7. Summary of pyrolysis liquid production (39 000 t/a) costs. Fuel 45 FIM/MWh, 20 a of service life, rate of interest 10 %.

	USD/GJ	USD/MWh
FIXED OPERATING COST		
Operating labour	0.4	1.5
Maintenance labour	0.3	1.0
Overheads	0.6	2.0
Maintenance materials	0.8	3.0
Taxes, insurance	0.6	2.0
Others	0.3	1.0
Total	3.0	10.7
VARIABLE OPERATING COST		
Feedstock	3.2	11.5
Electricity	0.8	2.7
Total	4.0	14.2
CAPITAL CHARGES	4.1	14.9
PRODUCTION COST	11.1	39.8

The following availabilities are assumed for different power plants:

- the Rankine power plant 97% of the total nominal time
- the gas and diesel engine power plants 94%.

2.5 Technical uncertainties

Aspects related to the technical uncertainties in the new power plant concepts are summarised in this section. The Rankine cycle is discussed in Chapter 1.

2.5.1 Gasification – gas engine

Recently, Herdin [19] reported on the operation of a gas engine coupled to a gasifier. The overall power production efficiency reported was 26%. However, the size of the engine tested was not given, although it is believed to be around 200 to 500 kW_e. The test is important as it was carried out with a modern engine employing catalytic exhaust gas emission control devices. The tests confirm the gas cleaning problems previously encountered with this concept. Although NO_x emissions were acceptably low because of lean-burn combustion, CO emissions exceeded the German emission standard by a factor of 3 to 5. And when an oxidizing catalyst was employed for the exhaust gases, the catalyst was soon poisoned by contaminants in the fuel gas tar. It is concluded that the gas cleaning stage is not yet proven in continuous operation, and that emissions have not yet been reduced to a satisfactory level.

In addition to the problem of fuel gas contaminants and the associated challenges in gas cleaning, the second major issue related to IC engine operation with low heating value (LHV) gas is derating. This is the decreased maximum power output produced in an engine with an alternative fuel compared with that for which the engine was designed. Derating leads to an increased specific capital investment.

The derating is partially intrinsic because of the lower heating value of a stoichiometric mixture of LHV fuel gas and air compared with natural gas and air. The volumetric heating value of LHV gas from the air gasification of wood is typically about 10 to 15% of natural gas. However, the heating value of a stoichiometric mixture of LHV gas is only about 25% less than that of natural gas, and the intrinsic derating is thus about 25% [24].

Derating may be partly overcome by three alternative actions:

- increasing the engine compression ratio,
- pressurising the fuel gas by a turbo-charger, or
- using an additional fuel, i.e. dual-fuel operation.

The last alternative is technically most attractive.

LHV gas has a relatively high octane number and is hence more suitable for Otto engines than diesel engines. The octane number describes the anti-knock quality of the fuel that is required for high compression ratio spark-ignited Otto engines. Knocking is a sudden and jerky precombustion taking place during the compression stage before (spark) ignition. It leads to irregular combustion and may ultimately damage the engine. The octane number of LHV gas is highly dependent on the hydrogen content of the gas. The higher the hydrogen content, the less suitable the gas is for high compression ratio engines. Pressure ratios of at least 11:1 have successfully been employed for typical air gasification fuel gas [24].

Pressure charging increases the power output of the engine. However, there is very little experimental data available on turbo-charged engine operation with LHV gas. In principle, two alternatives are available for pressure-charging: LHV gas may be fed to the inlet of the engine combustion air compressor, or pressurised gasification may be applied to engine injectors (not reported in the open literature). In the latter case, part of the engine's turbo-charged compressor air may be used as the gasification air. However, both applications require modifications in existing engine configurations. The estimation of engine performance in such an operation is beyond the scope of this work. Such a system should be modelled with specific simulation modelling tool capable of predicting engine performance with different fuels.

Dual-fuel operation has been tested in diesel engines. Recently, as gas (Otto) engines have gained more popularity in LHV gas applications, dual-fuel operation has received less attention [24].

The fuel gas / air mixture heating value before ignition, which has been referred to above, is only one factor controlling the power output of an engine. Stassen points out [24] that it only fixes the limits of the maximum power output. Additional factors affecting the actual engine power output are the speed of flame propagation in the engine cylinders, mixture ignitability, and engine characteristics. The factors are interconnected [24].

Differences in the flame propagation speeds of LHV gas components, especially hydrogen (H_2), carbon monoxide (CO) and methane (CH_4), complicate engine operation. The flame propagation speed of hydrogen is ten times higher than that of CO and CH_4. At any rate, the speed of flame propagation for a fuel gas will always be different compared with that of a gasoline-air mixture. If the speed of flame propagation is low compared with the average piston speed, part of the fuel gas air mixture may burn during the exhaust stroke, causing engine damage and a drop in power output. For this reason, relatively low piston speeds are usually preferred, and consequently slow-speed engines yield the best performance. This is true for both diesel and Otto engines.

The tendency of an engine to knock is mainly dependent on the compression ratio and on the composition of LHV gas, largely on its hydrogen content. Knocking may be reduced by a number of engine characteristics, but many of them are contradictory to achieving the maximum engine power output and minimal derating [24]. An optimum choice with regard to ignition timing, air-fuel ratio, engine speed, engine load, and mixture temperature/pressure may be established in engine experiments. Recent developments in engine simulation and engine control techniques provide new means of optimising the performance. However, numerical simulation has not been widely applied to improving LHV gas utilisation in engines.

2.5.2 Pyrolysis – diesel engine

It has been shown by Scott and Piskorz [25] and later confirmed by others that the highest liquid yields from woody biomass can be produced with fast pyrolysis. An organic liquid yield of 60–75 wt% of dry wood was obtained. It has later been shown that the critical process features in maximising the liquid yield are a rapid heat-up period and a short vapour-phase residence time. However, the scale-up of such a system poses challenges.

Pyrolysis liquids are a complex mixture of organic compounds. They contain hundreds of individual substances belonging to several chemical classes. Typically 30–40 wt% of the compounds have been identified with quantitative GC.

Initially, the most important process development work in biomass fast pyrolysis was carried out in Canada. Two groups in particular, one at the University of Waterloo (Scott) and the other firstly at the University of Western Ontario and then later at Ensyn Technologies Inc. (Graham), developed systems, which may be applied in liquid fuel production. A bubbling fluidised bed is employed in the Waterloo Fast Pyrolysis Process (WFPP), whereas an entrained pyrolysis reactor is used in the Ensyn Rapid Thermal Process (RTP). In the USA a vortex reactor system was developed initially at the Solar Energy Research Institute (today the National Renewable Energy Laboratory) for fast pyrolysis biomass.

Ensyn has built the largest units presently in operation: two RTP reactors in the production of a food chemical with a feed capacity of 1 t/h [26]. However, in these plants the pyrolyser is not integrated into a char combustor, as envisioned in biofuel liquid production. There are no commercial biofuel liquid production plants on the energy market today. ENEL has operated an RTP pilot (500 kg/h) in Italy in 1996–1999. The Union Fenosa Waterloo Fast Pyrolysis Process (WFPP) plant (150 kg/h) was used in 1992–1998. Several PDU and laboratory-scale units are being operated both in Europe and in North America.

The adverse properties of a fast pyrolysis liquid as fuel are well known [27, 28, 29, 30, 31]. The properties of a fast pyrolysis liquid as a fuel liquid were initially reviewed by Elliott [27] in 1986, and several liquids were characterised in comparison with ASTM mineral oil specifications. Fuel specifications for pyrolysis liquids have more recently been discussed by Diebold et al [32].

The use of pyrolysis liquid in medium-size boilers designed for light mineral fuel oil appears to be promising in locations where heating oil is expensive. However, this application is probably technically less demanding than the power production concepts suggested. Technically easier but economically less attractive is the use of a pyrolysis liquid in a heavy oil boiler. Two large-scale combustion tests (40 and 20 tonnes) with a pyrolysis liquid have so far been carried out in 9 and 5 MW_{th} boilers [33].

Various companies are developing modified diesel and gas turbine engines. The engine sets even more severe requirements [34] for the fuel than the boiler applications, as the injection pressure is high. Two engine developers have studied the injection of pyrolysis liquids in diesel engines [35, 36]. In addition to these, there has been some laboratory-scale work with engines. A gas turbine has also been developed for pyrolysis liquid use [37].

3 Comparison of power production costs

3.1 Base cases

Comparison of projected power production costs is shown in Figure 14. The base assumptions used in this figure are presented in Table 6.

The Rankine cycle is superior over the whole operating time compared to the pyrolysis diesel and the gasification engine power plants. As would be expected, the cost of electricity (COE) is high due to the small scale of operation, for the wood Rankine about triple to that of COE from coal. The COE for industrial large-scale production is shown as a reference in Figure 15 for coal Rankine, natural gas combined-cycle, and natural gas diesel power plants.

Variation of some key parameters for the three small scale power plant concepts is carried out. Results from these studies on COE are shown in Figures 16 and 17.

Figure 16 depicts the effect of fuel cost variation on the COE. In both cases the Rankine cycle yields the lowest COE, but the Rankine is especially superior with low fuel cost. The Rankine cycle yields the lowest COE over the whole operation time studied. At high fuel costs, the difference between the diesel and the Rankine is negligible below 4 000 h/a. At very high operation time, the gas engine is not much more expensive than the Rankine power plant.

Figure 17 illustrates the effect of using different rates of interest in estimating the capital costs. Increasing the rate of interest corresponds to a situation, where the profit for an investor is taken into account in analysis. When the return on investment is low, the Rankine cycle is lowest cost above 3 000 h/a. When the return on investment requirement is raised to 15% (corresponding to an approximate effective profit of 10% on the investment), the competitiveness of the Rankine cycle improves even further.

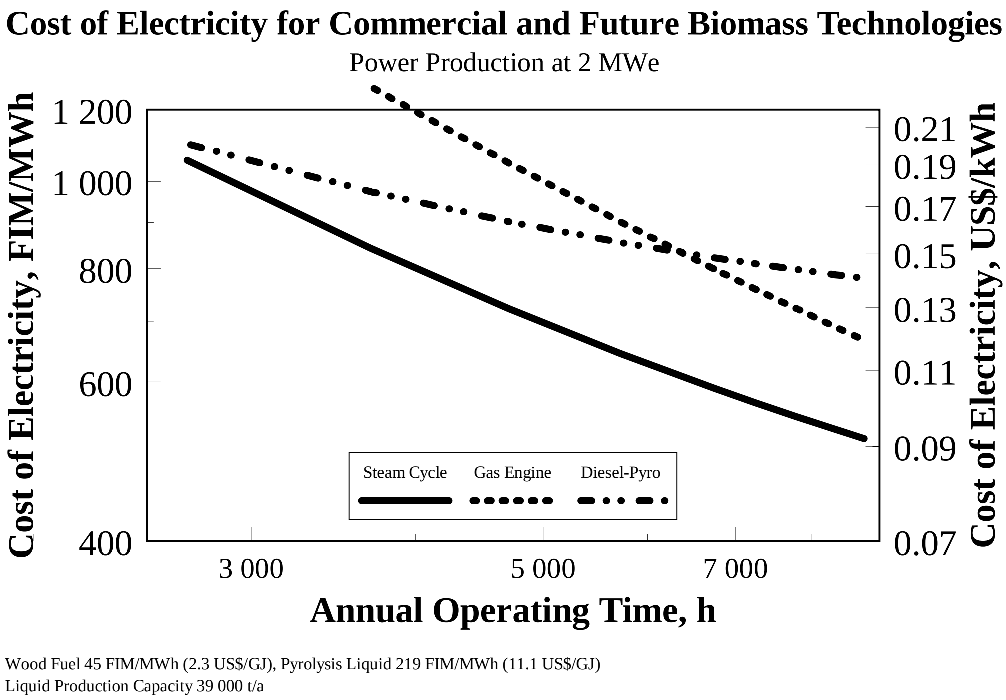


Figure 14. Cost of electricity for the three power plant concepts as a function of annual peak operating time. Service life shown in Table 5, rate of interest 10%.

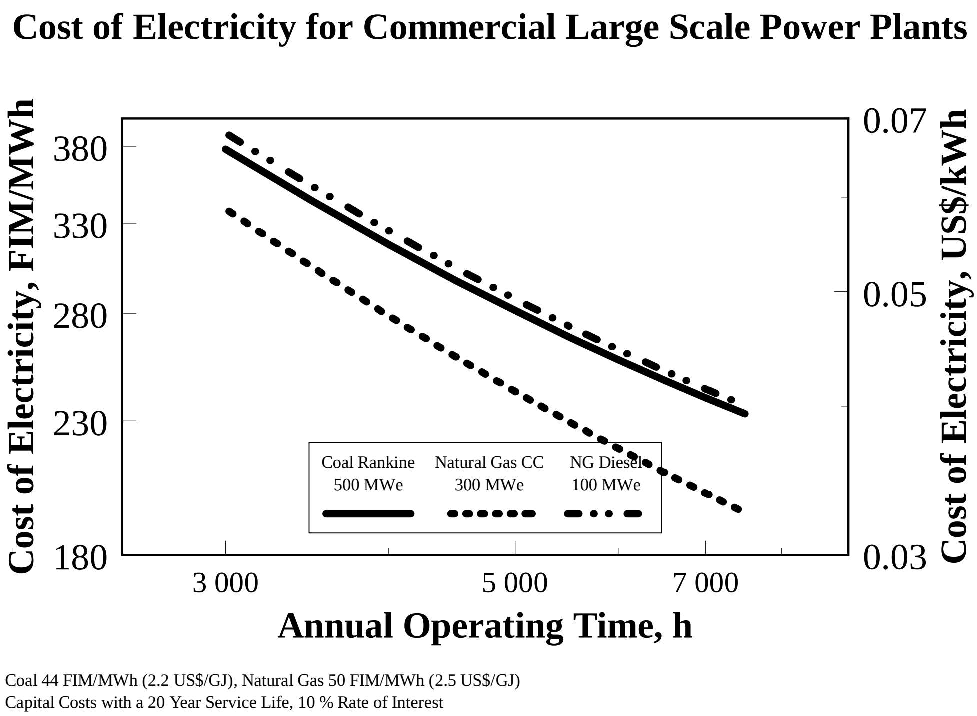
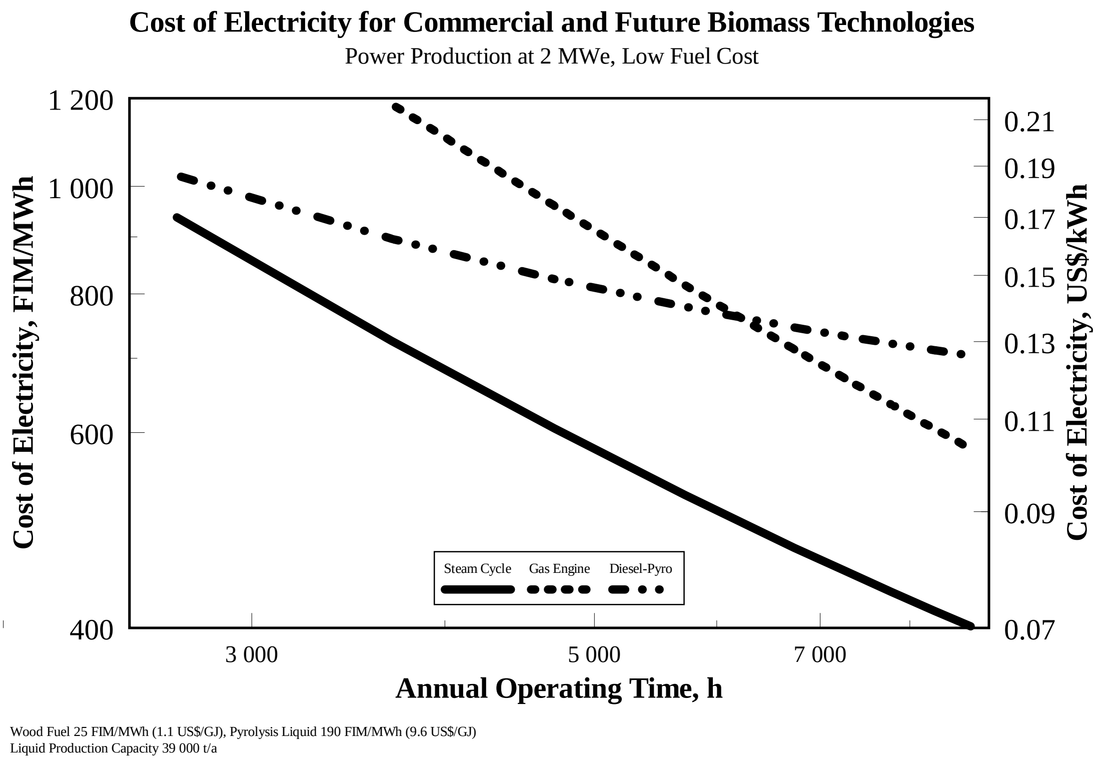


Figure 15. Cost of electricity for the three large scale power plants.



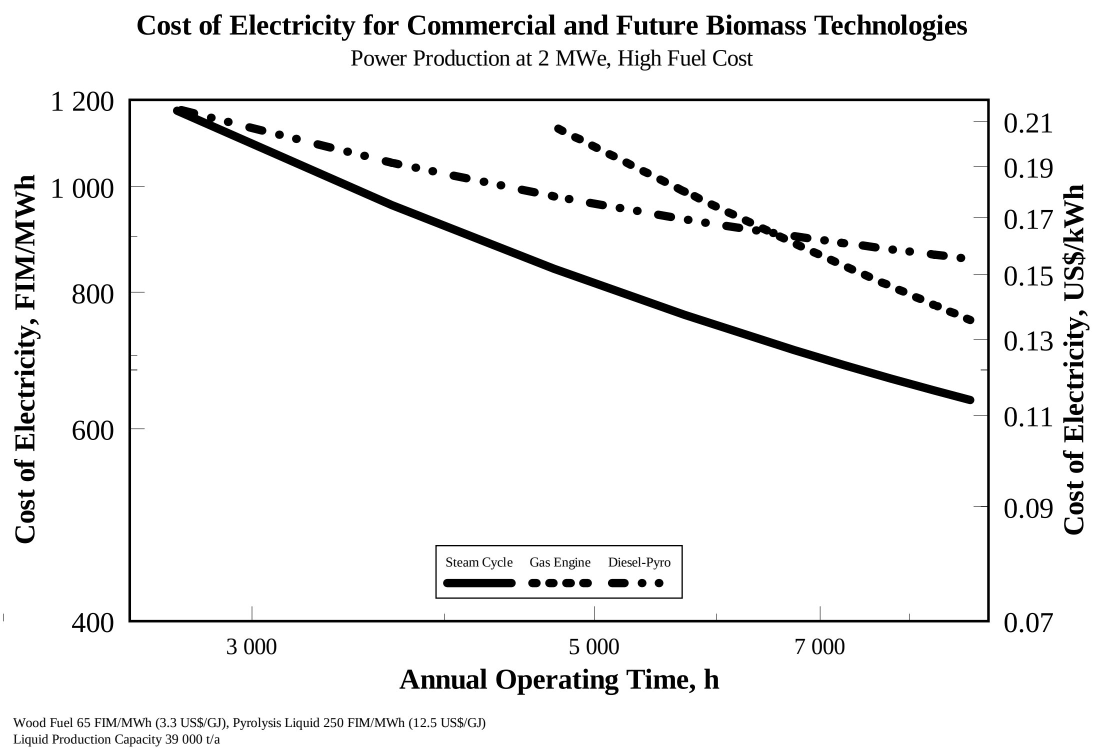
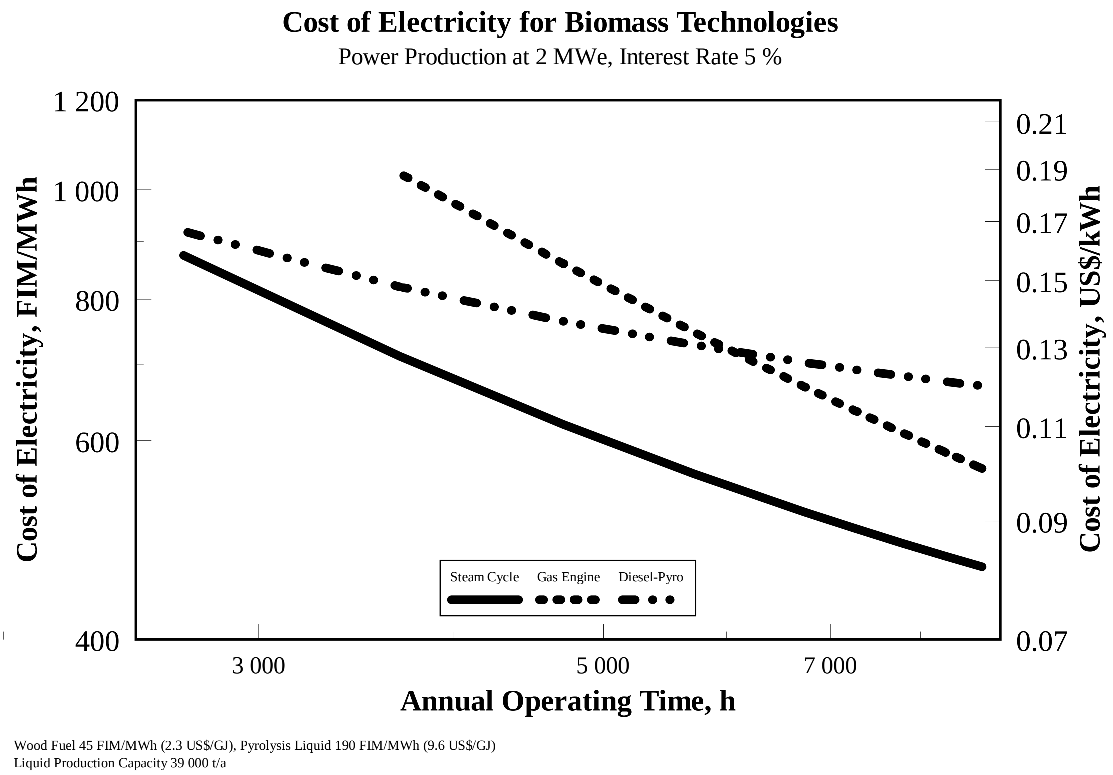


Figure 16. Cost of electricity for the three power plant concepts, low fuel cost of FIM 25/MWh (USD 1.1/GJ), and a high fuel cost of FIM 65/MWh (USD 3.3/GJ).



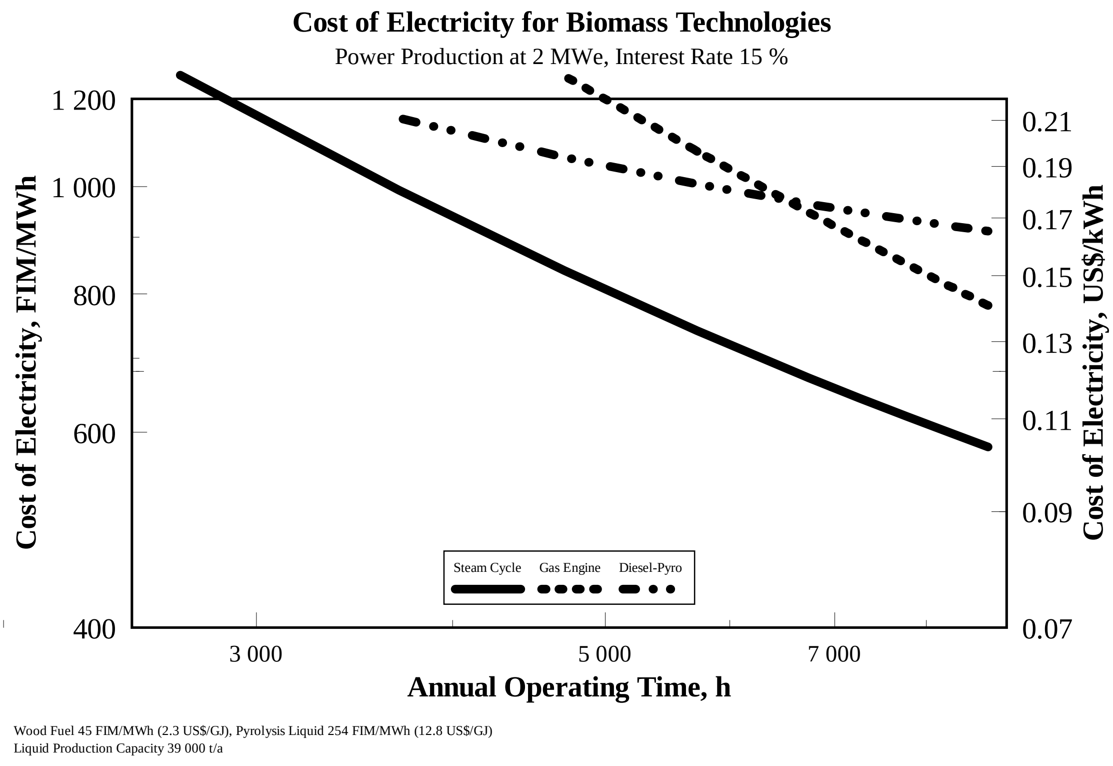


Figure 17. Cost of electricity for the three power plant concepts, capital costs estimated with a 5% (top) and 15% (bottom) rate of interest.

3.2 Sensitivity studies

Means of improving the feasibility of different power plant concepts is studied in this section. The objectives are

- to estimate, in which conditions the new alternatives (gasification and pyrolysis power plant concepts) may become competitive with the industrial alternative, the Rankine cycle power plant, and
- to estimate, to what extent the commercial alternative may be improved, if the concepts under development start to compete with the Rankine cycle.

Improvements are assumed for all technologies. The improvements are selected to represent, what is believed to be near-term potential developments. First, each improved technology is compared to other concepts with base values. Finally, all improvements are assumed valid simultaneously. The potential improvements assumed are summarised in Table 8. Note that for the future pyrolysis liquid production plant, double the feed capacity compared to base case is assumed.

Table 8. Summary of improvements assumed for the power plant concepts.

	Rankine power plant		Gasification – gas engine		Pyrolysis diesel	
	Base	Future	Base	Future	Base	Future
Power plant efficiency %	17.5	23.0	33.0	38.0	38.0	43.0
Gasification efficiency %			72.5	85.3		
Liquid prod. efficiency %					65.0	73.3
Overall efficiency %	17.5	23.0	23.9	32.4	24.7	31.5
Investment cost US$/kWe FIM/kWe	2 300 12 500	2 000 11 200	4 200 23 300	2 600 14 400	3 600 20 000	2 700 15 000

3.2.1 Rankine cycle

The performance of the Rankine cycle power plant was discussed in section 2.3. The assumed base value efficiency for the power plant is 17.5% (based on lower heating value of the fuel), and the base case specific investment is USD 2 300/kWe. It is assumed that an efficiency of 23% is technically feasible. Furthermore it is assumed that the specific capital investment may be reduced 10%, bringing a future plant cost down to USD 2000/kWe. If both of these improvements are realised, the competitiveness of the steam power plant is enhanced further compared to the new concepts with their base case assumptions. It may be seen be seen from Figure 18 that a considerable margin differentiates the Rankine cycle from the other two alternatives.

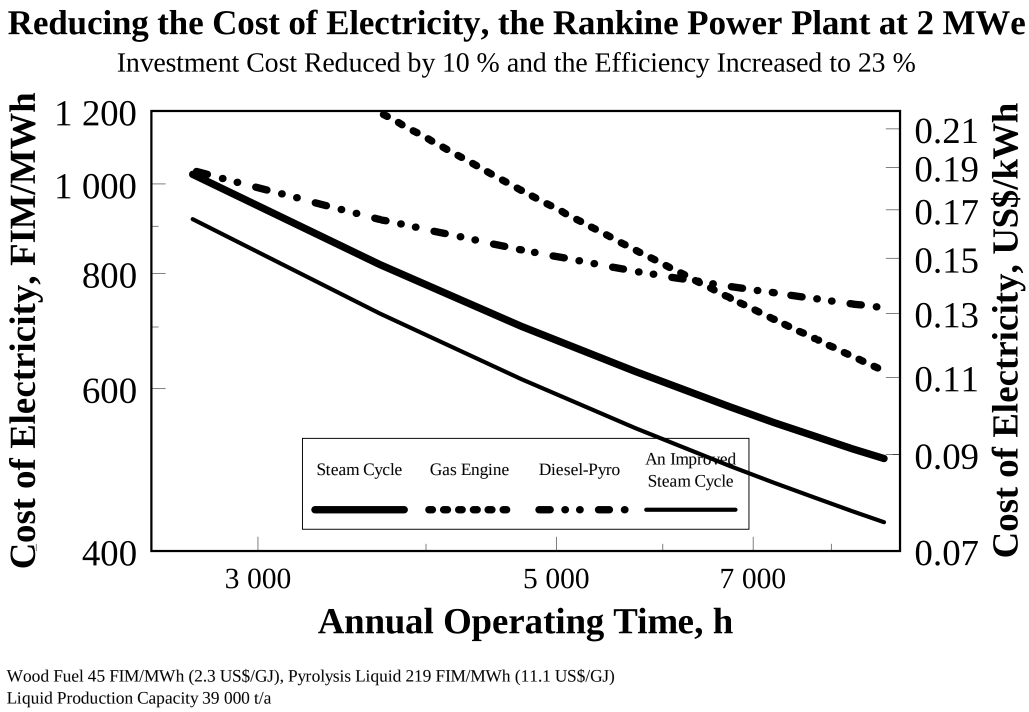


Figure 18. Improving the competitiveness of the Rankine cycle power plant.

3.2.2 Gasification gas engine

The assumed base value efficiency for the gasification gas engine power plant is 23.9% (based on lower heating value), and in the base case specific investment cost is USD 4 200/kWe. Assumption of improving both of these values may be made. A sensitivity study is carried out, how the COE from the new concept competes compared to other power plants (Figure 19). If the specific investment cost is reduced 40% to USD 2 600 /kWe, and the base efficiency may be increased to 32.4%, the new concept competes with the COE from the current Rankine cycle.

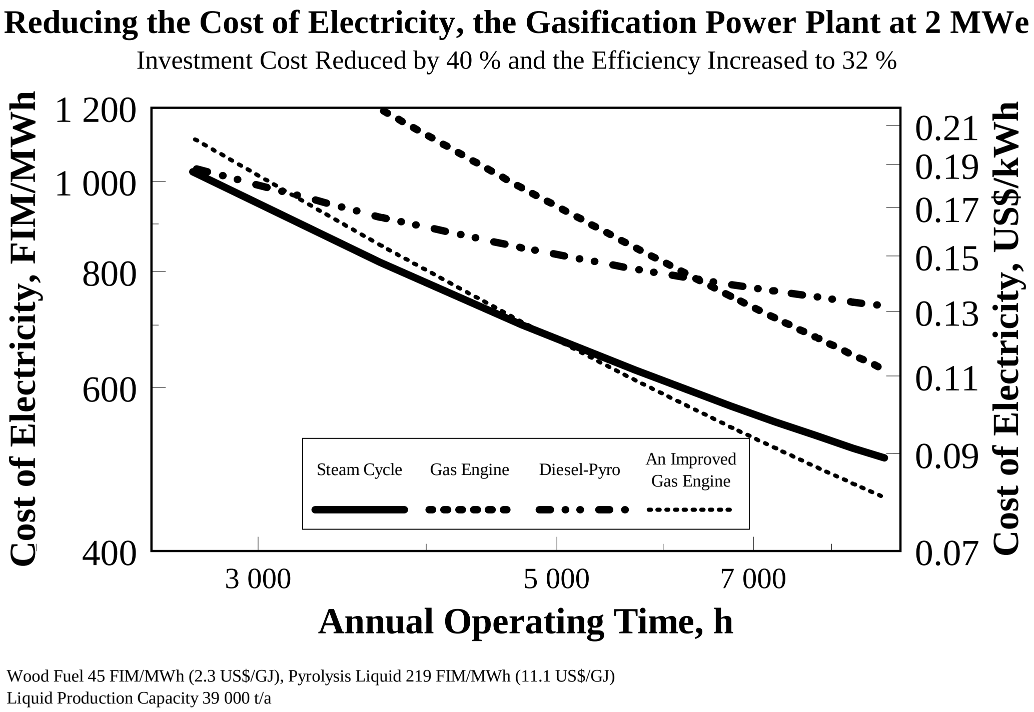


Figure 19. Improving the competitiveness of the gasification gas engine power plant.

3.2.3 Pyrolysis diesel engine

The pyrolysis diesel power plant includes the most technical and economic uncertainties of the concepts studied. Both its performance and cost are based on very limited amount of data, since no large-scale facilities are in operation.

Pyrolysis liquid is produced in a centralised plant serving multiple heat and power plants. Pyrolysis liquid production is a typical chemical process industry (CPI) plant. One of the significant features of CPI is the economics of scale, i.e. increasing the production capacity gives considerable cost benefits. There are probably similar opportunities for cost improvement within this power plant concept as with the Rankine and gasification power plants. However, because of the dominant nature of scale of liquid production with the concept, only the scale of pyrolysis liquid production is treated as a parameter in the sensitivity analysis. Efficiency is increased as the scale is increased.

The base capacity of pyrolysis liquid production is 39 000 t/a with an efficiency of 65%. The higher capacity considered in Figure 20 is 87 000 t/a with an efficiency of 73%. This corresponds to a reduction of pyrolysis liquid cost from USD 11.1 to 8.4/GJ using wood cost of USD 2.3/GJ.

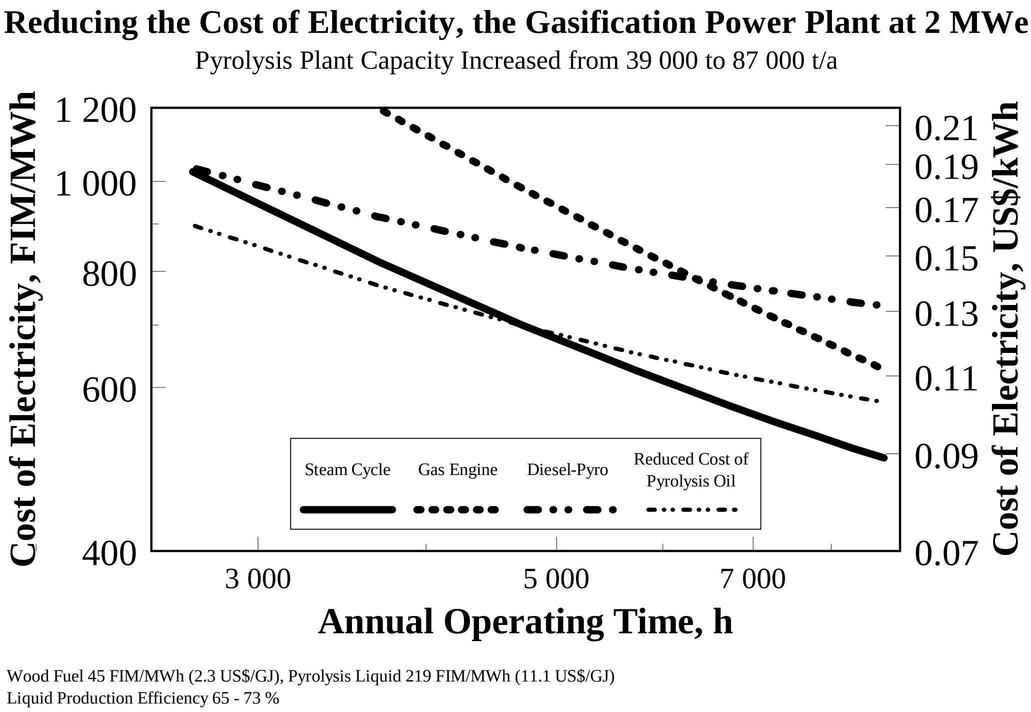
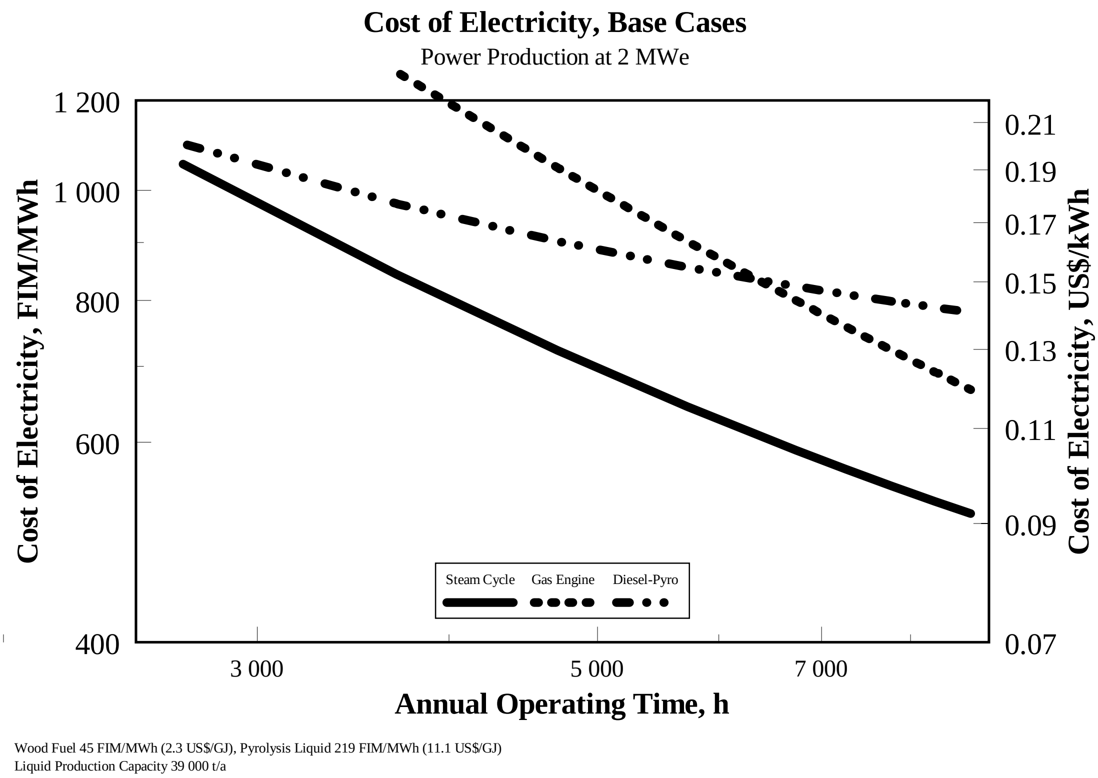


Figure 20. Improving the competitiveness of the Pyrolysis diesel power plant.

The reduction assumed for pyrolysis liquid cost has a considerable effect on the COE of the diesel power plant. Using the higher cost, the diesel concept appears competitive only at short annual operation times. However, if the larger capacity is assumed, the concept is competitive with the Rankine cycle over the whole operation time.

3.2.4 All potential improvements valid at the same time

The situation, where the potential improvements are all assumed valid at the same time is shown in Figure 21, in which the base values are also shown. It may be seen that differences between alternatives are fairly small over the whole range, when improvements for technologies are assumed valid. Above 6 500 h/a and below 4 000 h/a the range of variation with Rankine and the least cost new cycle is less than 10%, which is certainly not a significant difference within accuracy of the study.



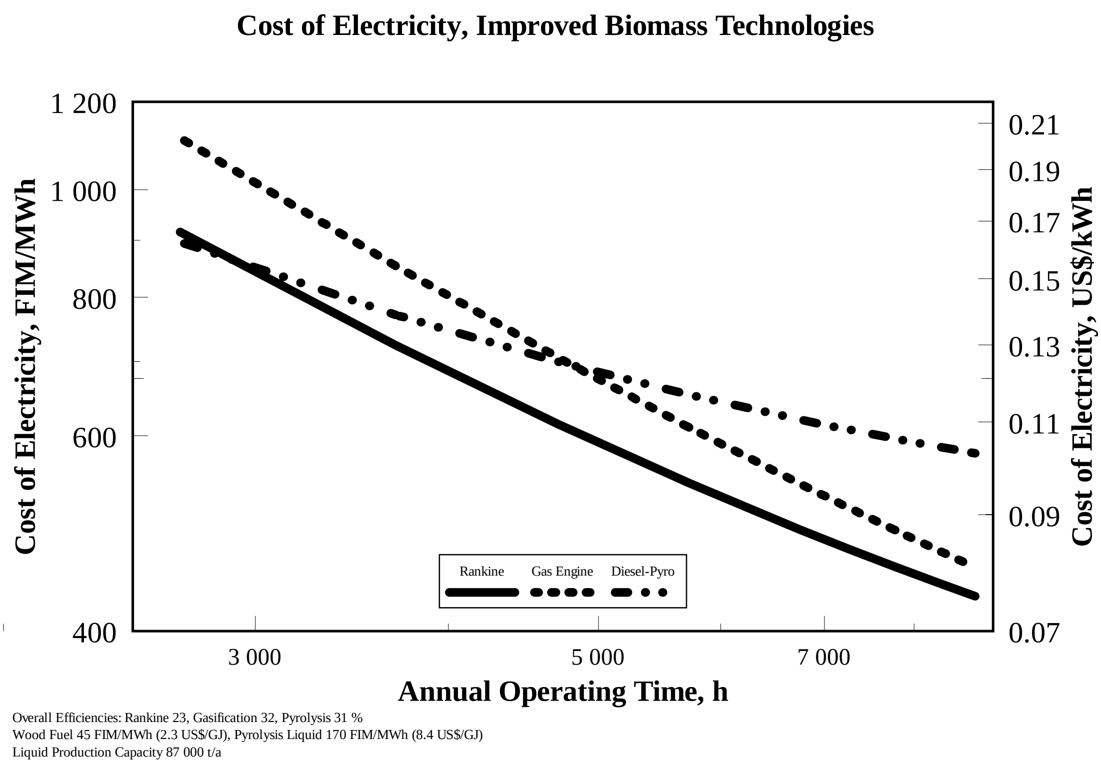


Figure 21. Potential improvements for all alternatives.

3.3 Combined heat and power production

The three technologies are also compared in co-generation (combined heat and power production, CHP, Figure 22). District heat production is assumed. The heat production capacity for each case is fixed at about 6 MWth, and the power production capacity is determined based on power-to-heat ratio of the individual technology. This approach for comparison is selected because the CHP plants are sized based on the heat demand.

The performances of the cases are summarised in Table 9. Again, improved future concepts are shown with performance values, which are believed to be feasible in the near future.

Table 9. Summary of the performance of the co-generation power plant concepts.

	Rankine power plant		Gasification – gas engine		Pyrolysis diesel	
	Base	Future	Base	Future	Base	Future
Power production MWe	2.0	2.0	5.0	5.0	6.2	6.2
Heat production MWth	6.8	5.8	6.0	5.7	6.5	6.5
Power production efficiency %	17.5	23.0	23.9	32.4	24.7	31.5
Overall efficiency %	88.0	90.0	85.0	90.0	58.5	66.0
Power-to-heat ratio	0.30	0.35	0.83	0.88	0.95	0.95

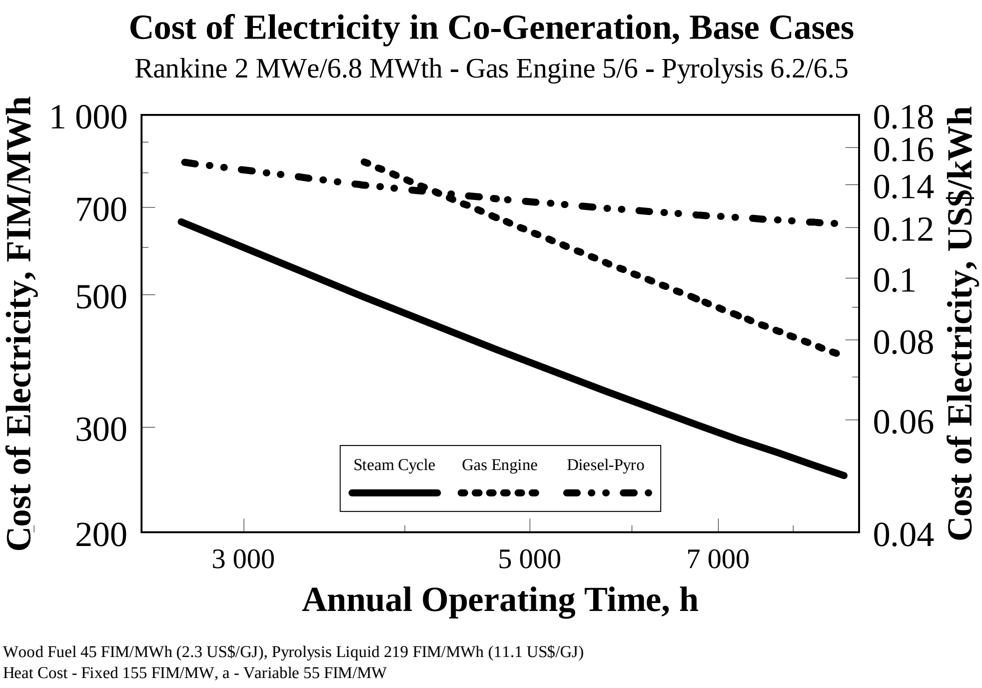
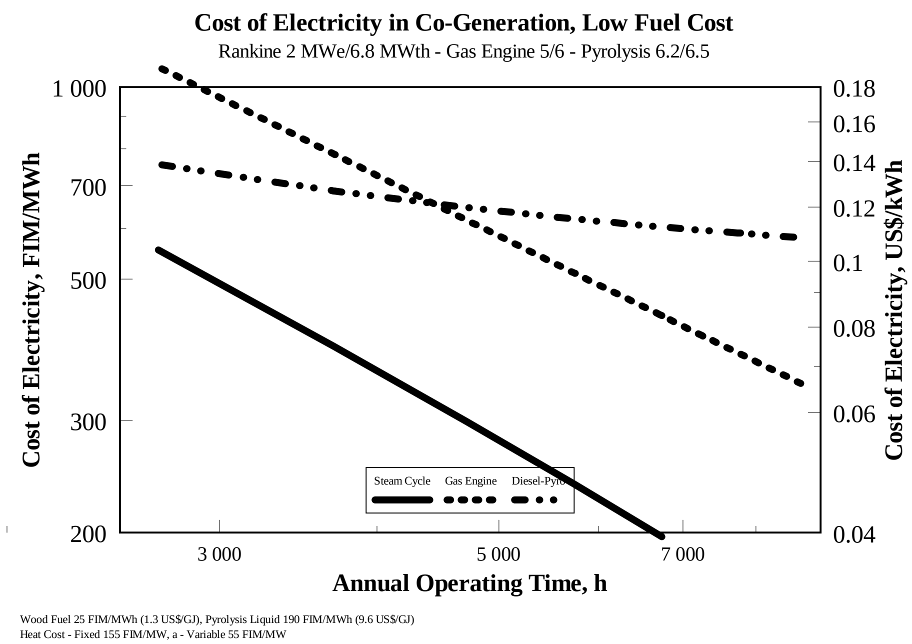


Figure 22. The three technologies compared in small scale co-generation.

It is seen that the Rankine cycle yields the lowest COE. Especially significant is the absolute COE of the Rankine co-gen plant at high operation time. Above 6 000 h/a operation time the COE is below USD 0.06/kWe, which should be compared to the COE for the conventional fossil plants. Although the wood fired Rankine still has a higher COE than the fossil plants, the reduction in COE due to co-generation is considerable.

Sensitivity of co-generation COE for the fuel cost is studied in Figure 23. It may be seen that when the fuel price is increased from USD 1.3 to 3.3/GJ, the difference between



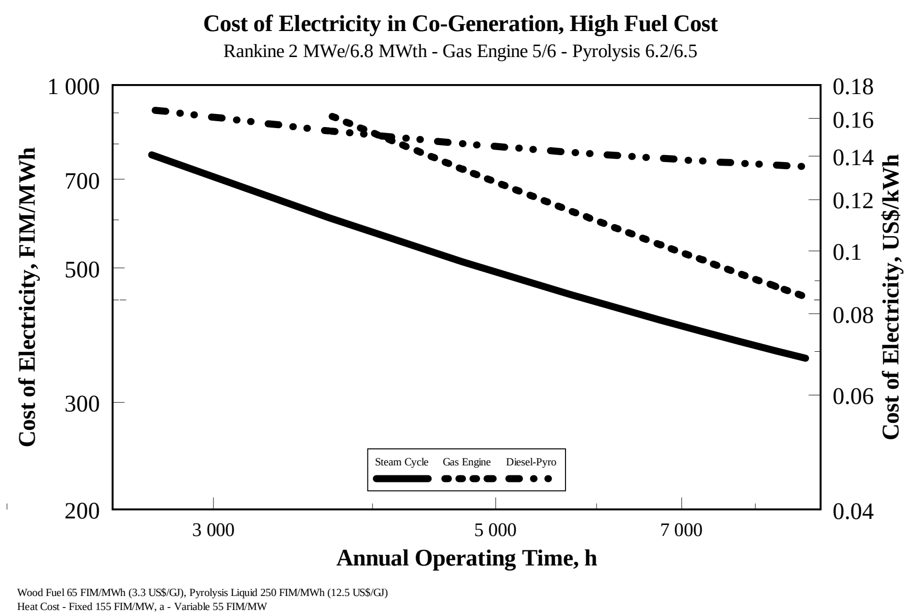
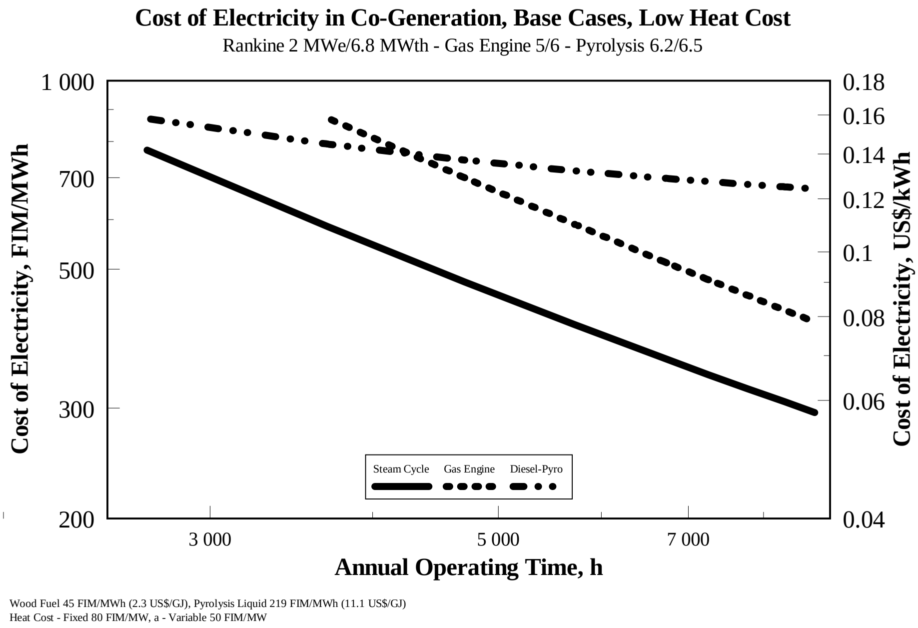


Figure 23. Variation of fuel cost in co-generation.

technologies is reduced. However, the Rankine cycle has clearly a lower COE over the whole range except below 2 500 h/a, which would be an uneconomic annual operation time in any case.

The sensitivity of COE for the cost of heat is depicted in Figure 24. It may be seen that the higher the cost of heat, the better the Rankine co-gen plant competes compared to new alternatives.



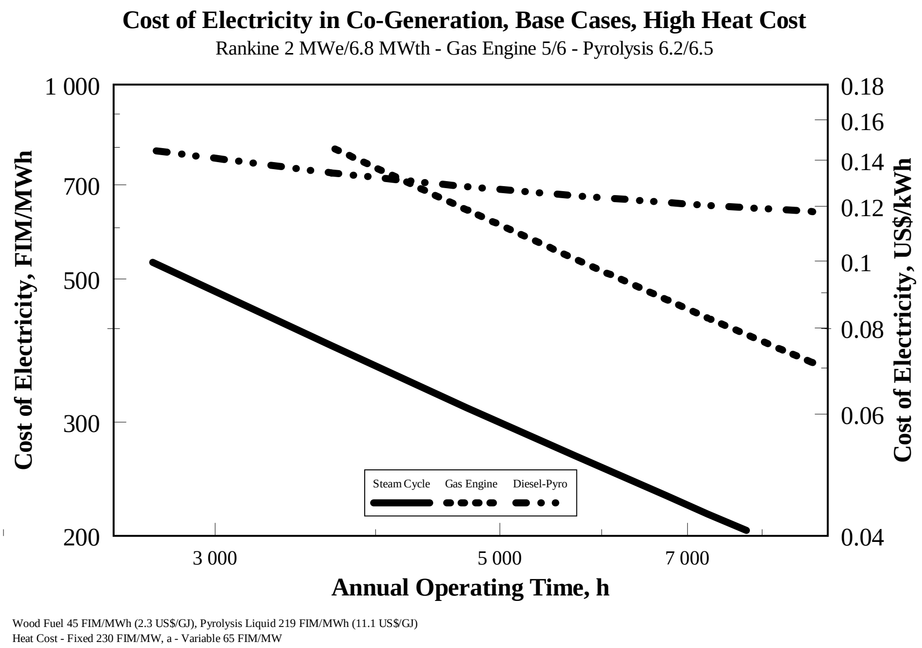
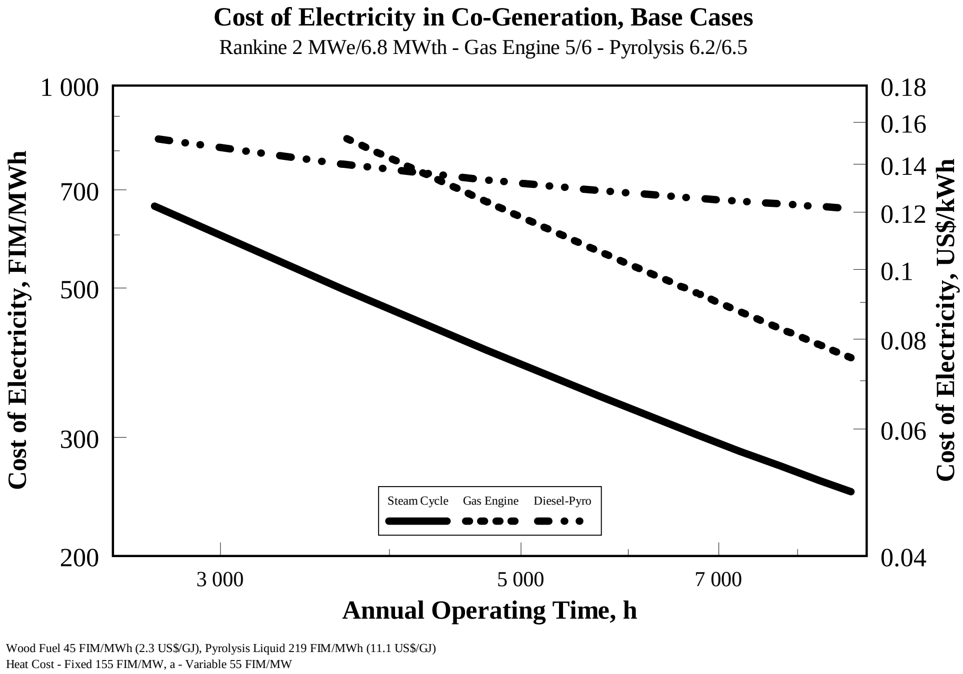


Figure 24. Variation of heat cost in co-generation.

Finally, the development potential of the technologies is compared in Figure 25. It is seen that the considerable difference between cases is reduced considerably, when assumptions for the development of technologies are used (Table 9). Differences between alternatives are practically negligible below 4 000 h/a, and even above this operation time only the COE from the diesel power plant is higher than the other COE.



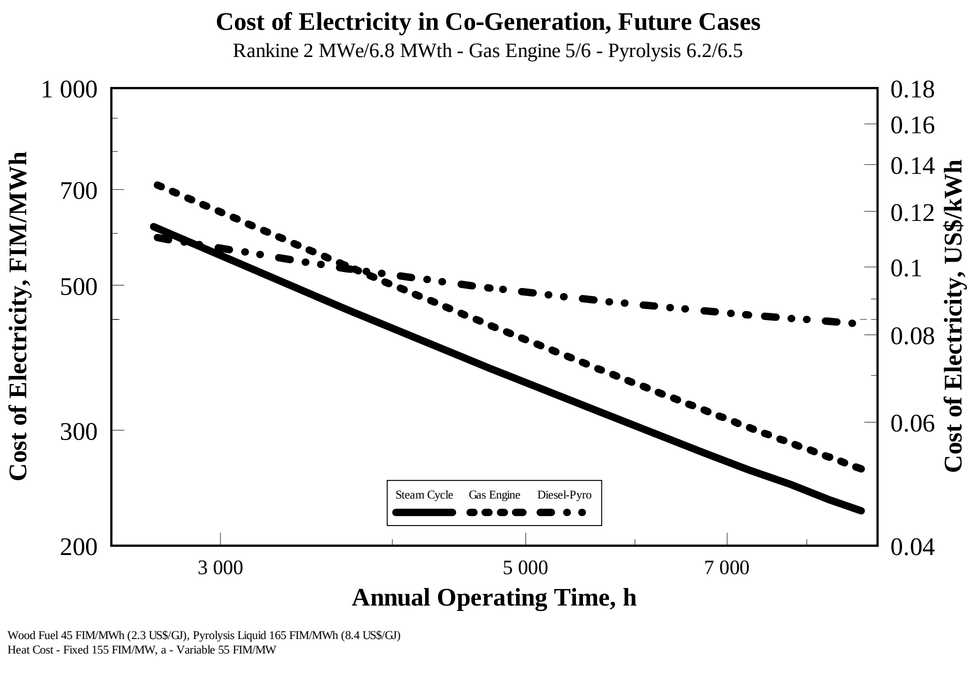


Figure 25. Development potential of technologies.

4 Conclusions

Three small-scale power production concepts were compared:

- The Rankine steam boiler power plant
- The gas engine power plant using gasification fuel gas. The gasifier and the engine are integrated.
- The diesel power plant using fast pyrolysis liquid as a fuel. Liquid production and the power plant are decoupled.

Overall efficiencies for the systems are: the Rankine cycle 17.5%, gasification – gas engine 23.9%, and pyrolysis – diesel engine 24.7%. Potential improved efficiencies for the three technologies are 23, 32.4, and 31.5%, respectively. It should be pointed out that the efficiencies used for both the potential new technologies are optimistic.

Estimated specific investment costs for the base power plants are USD 2 300, 4 200, and 3 600/kWe, respectively. It is estimated that these cost levels can currently be reached in industrial serial production of power plants. Estimated potential specific investment costs are USD 2 000, 2 600, and 2 700/kWe, respectively. It is believed that these costs are possible through R&D work and learning after construction of a number of these plants.

It is shown that the Rankine cycle is superior compared to the gasification gas engine and pyrolysis diesel engine with current cost data. Increasing fuel cost by 50% from the base value FIM 45/MWh (USD 2.3/GJ) improves the competitiveness of the new concepts, but the Rankine is continuously more economic over the whole annual operation time. At high fuel costs, the difference between the diesel and the Rankine is negligible below 4 000 h/a. At very high operation time, the gas engine is not much more expensive than the Rankine power plant. Differences between alternatives are fairly small over the whole range, when improvements for technologies are assumed valid. The range of variation with the Rankine and the least cost new cycle is about 10%, which is not a significant difference within the accuracy of the study. It is shown that co-generation improves the economics of small-scale power production considerably. The Rankine cycle remains as the least cost option in all cases studied.

It is concluded that for the new power plant technologies to be competitive compared to the Rankine cycle, especially capital costs have to be reduced. Without such reductions it will be hard to compete with the Rankine cycle on a small scale either in power-only or co-generation mode of operation.

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Part 4

Comparisons of alternative routes for biomass fuel
Biomass (pellets), pyrolysis oil and tall oil pitch

Prepared for

International Energy Agency
IEA Bioenergy Task 22 – Techno-Economic Assessments for Bioenergy Applications

IEA BIOENERGY T22: TECHNOECONOMICS: 1999:04

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Abstract

Upgraded wood fuels may be developed in several ways. Pellet manufacture and pyrolysis of wood into liquid fuel are two immediate routes where the latter tentatively may substitute fuel oil in existing boilers and heaters.

A techno-economic assessment and comparison of these routes has been carried out from the raw material to combustion in a boiler or heater. In the upgrading processes the unit operations and the equipment can be assumed to be to a large extent the same; receiving and storage of raw material, drying and milling. The key processes – pelletising and pyrolysis – are different, as well as transports of the products and the combustion technique.

In the comparison, data from existing pellet factories have to be related to estimated data for an assumed pyrolysis unit. This is handled by assessing the practical data as far as possible even for the pyrolysis process. For the investments these data cover some 2/3 of the total investment in a pyrolysis unit or 15 MUSD out of 22.

To achieve a consistency in the production costs, the pyrolysis unit is assumed to be equipped with a steam dryer to enable a by-product credit as is the case for most pellet units in Sweden. By means of this, the total energy efficiency is raised to about 90% in contrast to 70% which is usually assumed for the pyrolysis process. The pellet manufacture has an energy efficiency of almost 100% when by-product steam is considered.

Despite lower operating costs in the pyrolysis the production costs are still relatively higher (the absolute total production costs are not calculated). However, due to larger transport volumes (for the same amount of energy) and more complicated systems with the solid pellet fuel the difference is almost wiped out.

Although the combustion of pyrolysis oil has been demonstrated to be difficult due to the properties of the oil, estimates on the equipment required for firing still show lower investments than those for pellet combustion. In consequence, the assessment of the entire flow from raw material to “hot water” and flue gases gives a small preference to pyrolysis oil.

This, however, requires the by-product utilisation mentioned above. Otherwise pellet manufacture seems slightly advantageous, since the energy efficiency of pyrolysis is lower. Further, it should also be demonstrated that the flue gas treatment from combustion of pyrolysis oil is not too difficult.

Finally, it is concluded that a further development of the quality of pyrolysis oil is necessary. Today’s examples of oil are very uneven and cannot easily substitute conventional fuel oil. In this respect pellets are very superior.

Contents

1 Introduction

Renewable energy resources have been identified as a means for reducing net CO_2 contribution to the atmosphere. In Sweden and other countries, intensive work has been carried out during two decades to increase the utilisation of wood. Beside direct firing for heating purposes, efforts have been made to convert solid wood fuels into liquid and gaseous products that are more adapted to existing systems, i.e. crude oil products.

For liquefaction of wood some 5–10 process concepts under development were evaluated during the early 1980s. In the evaluations, pyrolysis techniques were pointed out as potentially advantageous, and since then only these have been commercialised to some extent.

Pyrolysis of wood yields solids (char and "ash"), gas and liquids. When carried out in a fluidised bed, the liquids (tar-like fluid) can be maximised to approximately 75% of the dry wood. The liquid product can be pumped and handled more or less like a conventional fuel oil even though it contains less energy per volume.

In consequence, this pyrolysis oil represents an alternate route to direct firing of solid wood. The advantage would be that pyrolysis oil might be readily introduced in the existing system whereas solid fuels require at least a different feeding device and a new burner. The cost for this adaptation of the fuel is the energy consumed in the conversion process, i.e. the pyrolysis.

Birka Energi in Stockholm is a public utility company serving, i.a., houses with district heating. Figure 1 gives an overview of the district heating system by Birka Energi.

The production of district heating is based on several techniques and fuels. In the main combustion units, heavy fuel oil is used as fuel in addition to wastes, wood pellets and tall oil pitch. Further, electric power is utilised; directly as well as in heat pumps (also installed on cleaned waste water). Co-production of power and heat is generated in a pressurised, fluidised bed combustion (PFBC) running on high sulphur coal.

Beside these larger heat stations, hot water is also produced in a number of small units (1–5 MW), at present fuelled with conventional light oil.

In total, the heat pumps contribute with some 25% of the heat, wastes with some 10%, wood pellets with some 15 and tall oil pitch with 5–10%. Light fuel oil is used to an extent of approximately 10–15%.

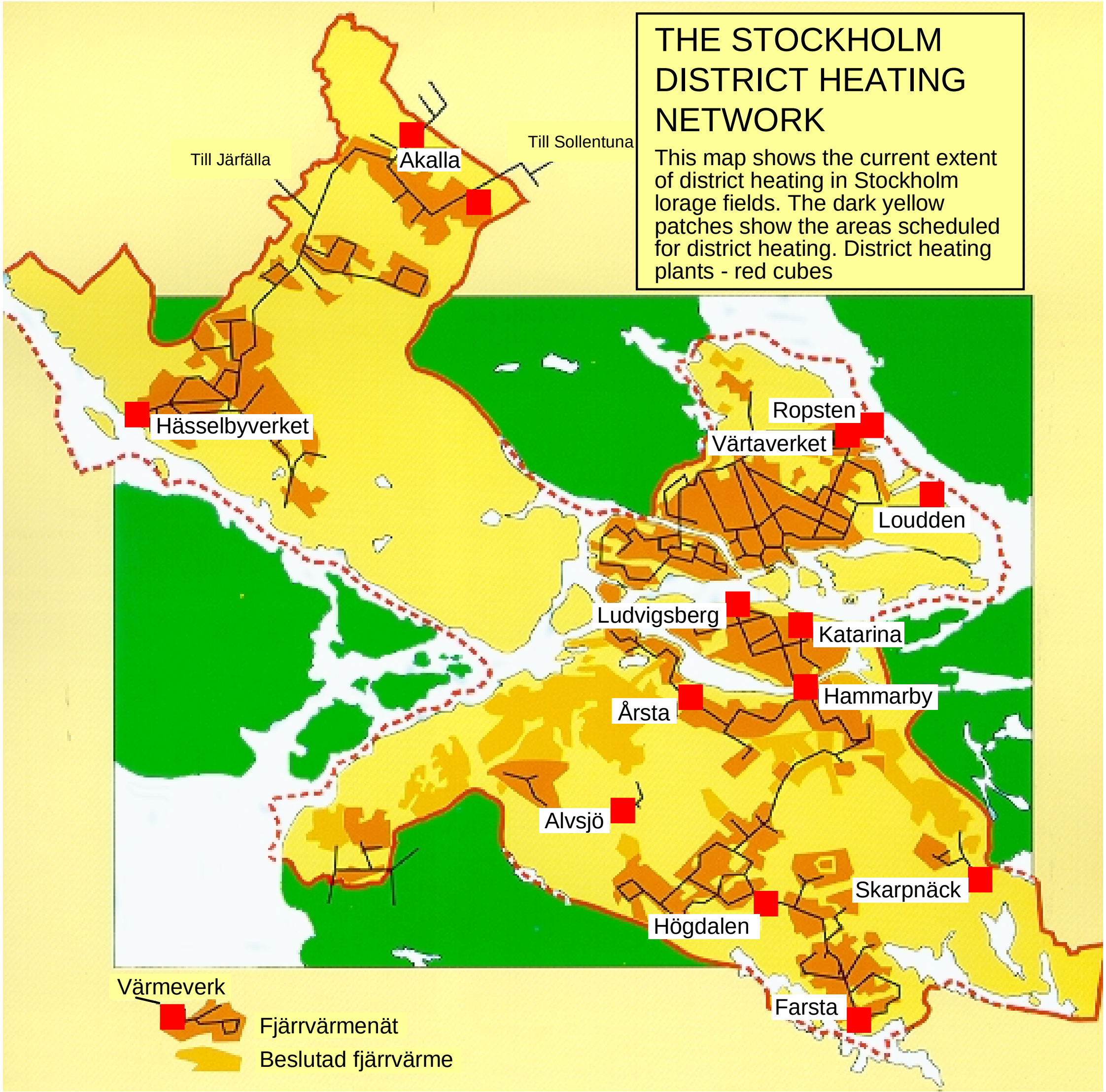

Figure 1. District heating in Stockholm supplied by Birka Energi.

To some extent the smaller units have been taken over from the house-owners and in due time they may be closed down. For these, an option at present exists to install new equipment for wood fuel (pellet) firing or substitute fuel oil with pyrolysis oil in – more or less – existing equipment.

The techno-economic assessment (TEA) below is based on these alternatives and related to the situation in Stockholm. As Birka Energi at present is using Tall pitch oil as well, this alternative is also incorporated but with less emphasis. Among the wood fuels, only pellets are considered. In general, wood chips and other wood fuels are regarded less attractive in small furnaces due to the investments in handling. (In private houses, wood chips, sawdust and logs are extensively used in Sweden – especially among farmers and other landowners (forests). This utilisation, however, requires a lot of manual work and is not considered here.)

The evaluation comprises investments and process costs for the three different routes for Biomass Fuel utilisation depicted on the next page (Figure 2); going from raw material (wood or forest residues) to produced heat and flue gas.

Although the origin of the Biomass Fuels lies in the forest in all three cases, different definitions have to be applied since tall oil pitch evolves as a by-product from the pulp industry. The costs for production of this by-product cannot be calculated as all the costs are charged the pulp and cannot be easily separated.

In effect, this route is left out for the time being and only compared in the end.

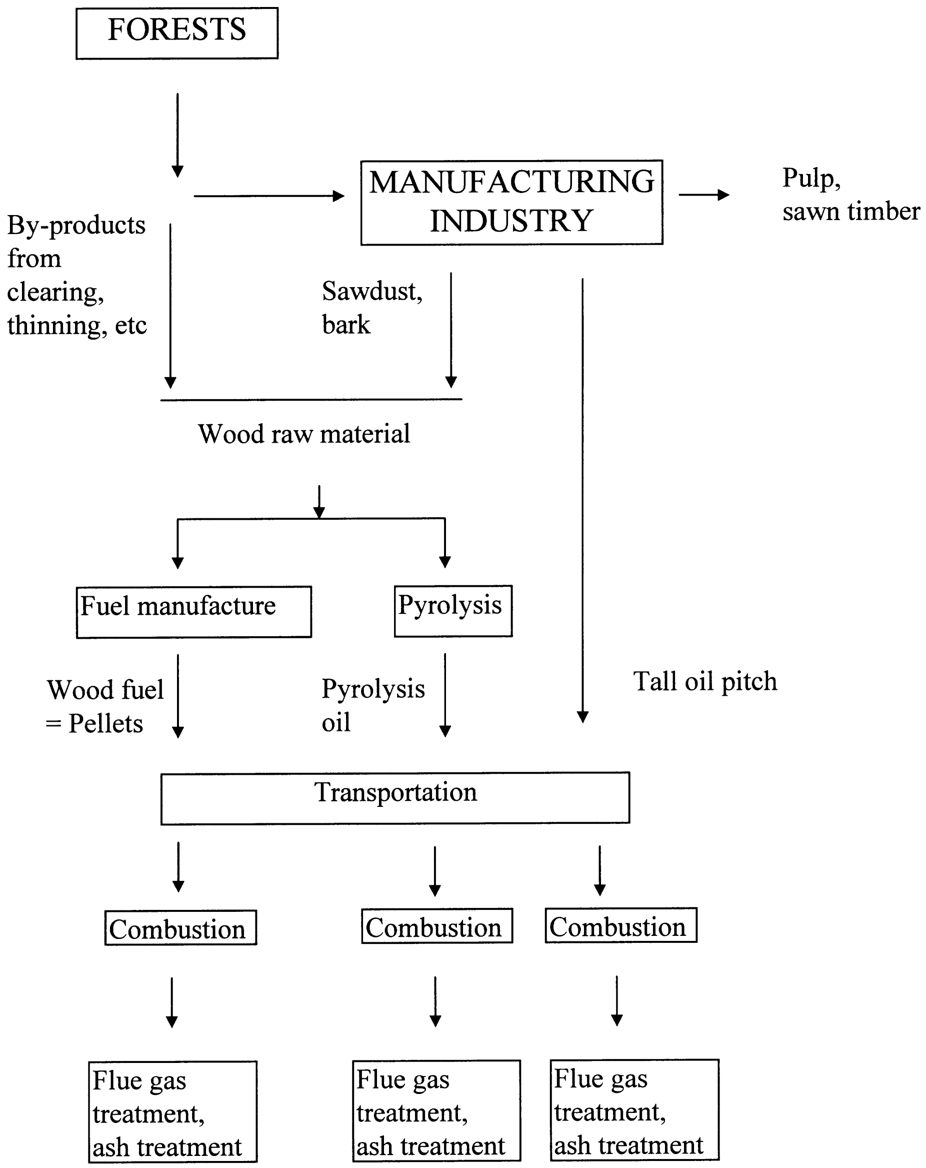

Figure 2. Biofuels from wood, evaluated in the report.

2 Assessment technique

The assessments are made on basis of 100.000 tons of DS raw material per year. Pellet production units have been built of almost this size in the last years and for the future – assuming a continued development – wood fuel manufacture should be of at least this capacity. In effect – by comparison reasons – the pyrolysis unit is given the same capacity although none of the existing units are of even near this size.

Swedish conditions are applied throughout the report. The costs are given in USD at a rate of exchange of 8 SEK/USD.

The capital costs are calculated as 15% annuity (8% rate of interest and 10 years lifetime) which is a common cost attributed to capital in Sweden in industrial ventures today.

The wood raw material has been assigned an LHV energy content of 5 MWh/ton DS and is assumed delivered with 50% moisture (as such containing ≈ 4.3 MWh/kg DS). The LHV energy content of the pellets is also 5 MWh/ton DS. For the pyrolysis oil the same energy content is assumed implying a water content of some 22%.

Power cost is set at 3.75 cents per kWh, an internationally low cost.

The base data have been collected from existing plants and activities as far as possible. In many cases internal figures on costs and consumptions have been provided and with respect to confidentiality they are not referenced with names; neither persons, nor companies. Preliminary versions of parts of the report have been communicated to people in the business for comments.

This technique of techno-economic assessment (TEA) differs from what is usually practised. Former evaluations have mostly been made through cost estimates on the equipment in smaller and larger units, to which costs for engineering, instalment, costs during construction, etc., have been added. This is preferably practised in situations where several process concepts under development are to be compared and secures an equal basis for comparison.

In this case, however, a process more or less under development is to be compared to existing plants. Further, the proposed technique has several unit operations in common with the established alternate process. In fact, as is demonstrated in overall flow sheets below, only the final unit operation carries a significant difference for the alternatives. In effect, a sounder basis for comparison is assumed if actual data from existing plants are used and only the significant difference is regarded.

This also implies that the comparisons do not need to be complete but only related to the significant difference. Additional costs for total production cost, such as interest during construction, costs for working capital, etc., can be set alike providing the no qualitative difference is at hand. Thus, the conclusions are based on differential costs and do not mirror the absolute magnitude of production costs.

It should also be stressed that several figures are average values and that the variations are large. For instance, a wood fuel (pellet) manufacturer located close to a pulp industry most certainly does not pay the raw material prices used in the assessment. Nor does a Biofuel producer pay the power and steam prices when located close to a utility company (using wood fuel). In these cases the coproduction is so intimate with backpressure steam, milling, etc., that it is hard to calculate even a rough figure on the specific costs.

The same conditions apply to investments in combustion equipment where storage tanks and feeders have been obtained at the most fluctuating costs depending on local circumstances.

In general, several figures on consumptions and costs have been collected. From these, mean values have been calculated or subjectively assessed.

3 Technical descriptions

3.1 Wood pellets manufacture

Wood pellets are manufactured from more or less selected material or selected mixtures of different wood residues. Raw wood is chipped and sieved before forwarding to a raw material storage along with, e.g., sawdust.

From the storage the material is milled and dried in an optional order depending on process design and equipment. At a moisture content of <15% the milled wood is fed to pelletisers, where it is compressed to pellets of 6–12 (25) mm in diameter.

The product is cooled in a cascade cooler and delivered in bags or bulk. The bulk density of the product is 650–700 kg/m^3 (Figure 3).

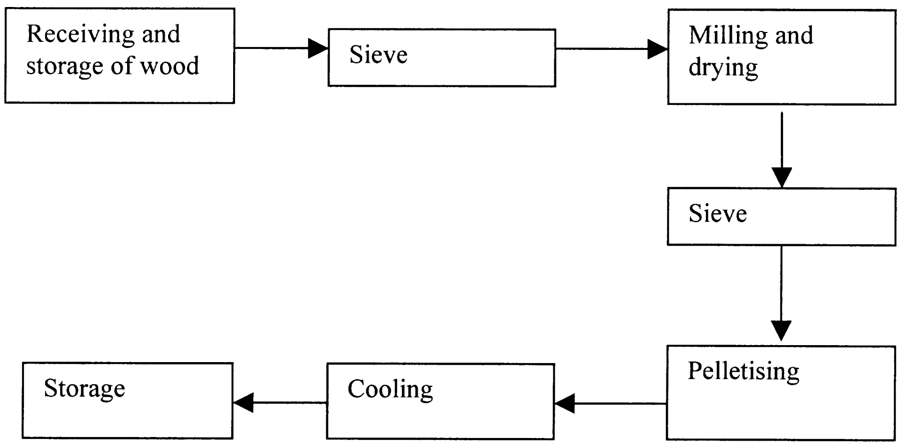

Figure 3. Principal flow sheet for pellet manufacture.

3.2 Production of pyrolysis oil

In pyrolysis the wood material is heated rapidly (flash heating) to about 500 ^{o}C, at which temperature the wood decomposes to a maximum amount of liquid product. At lower temperatures more char is formed and less liquid and gas and at higher ones the energy requirement is higher (= losses in a self-sustained process) without producing noticeably more liquid (Figure 4).

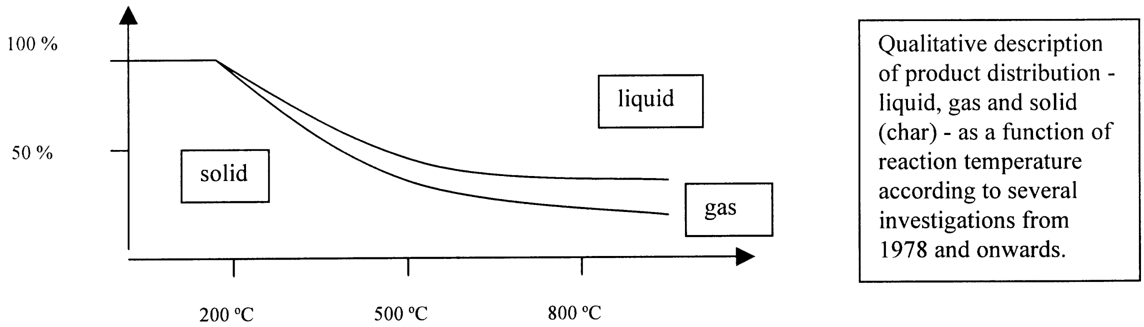

Figure 4. Principle yields of liquid, gaseous and solid product from fast pyrolysis, residence time around 0.5 s.

The pyrolysis process is carried out in a fluidised bed, where milled material is fed into bed and the product stream is condensed at temperatures between 100 and 200 ^{o}C. The char is usually separated before the condenser and used as fuel – along with gas – to provide heat to the fluidised bed (Figure 5).

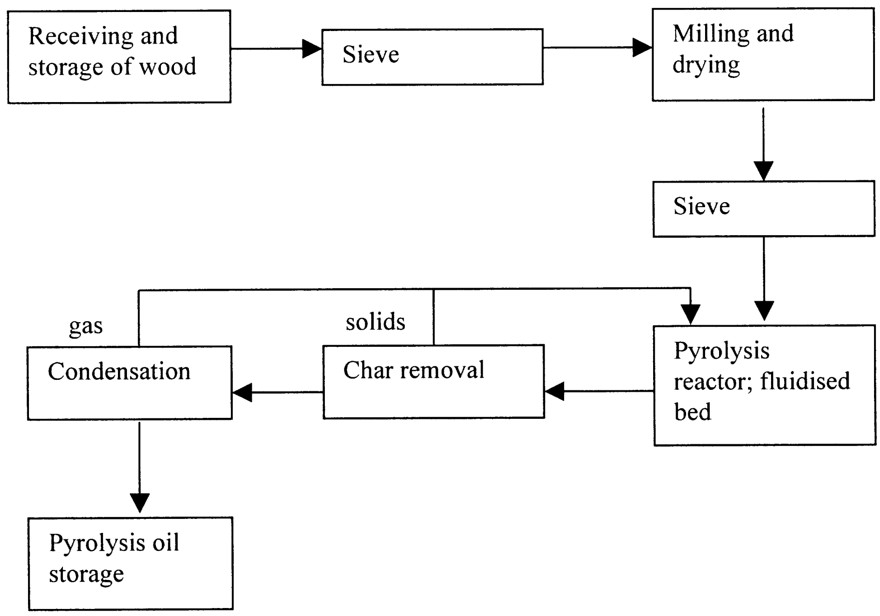

Figure 5. Principal flow sheet for production of pyrolysis oil.

The fluidised bed may be bubbling or circulating. In both cases a “fast pyrolysis” is obtained in contrast to slow pyrolysis, which usually yields lower amounts of liquids. An alternate process design is “Vacuum Pyrolysis”, which roughly is an intermediate design with slightly – but significantly – less liquid product than the fluidised bed produces.

3 Raw material costs

For the pellet manufacture as well as the pyrolysis unit a raw material intake of about 100 000 tons of DS wood per year is assumed (to cover the energy requirements in the dryer some extra raw material intake may be necessary). This amount is available within a transportation distance of 100 km in many places in Sweden.

At present most of wood fuel production is supplied with raw material from forest industries; pulp industry, saw mills, etc. Residues and waste products may be obtained in a range of prices and only a very minor part of the potential raw material from forestry is actually collected today.

To secure (or maintain) the availability of residues from the forest in the future, some companies actually pay an extra cost today for thinning and clearing material taken out of the forest. Unless a technique for this is established there is otherwise a risk to be dependent on industrial residues for the foreseeable future.

Depending on the circumstances the costs for this “extra” material today are estimated at 4.5–9 USD/MWh. Residues from felling are collected at lower costs; about 2 USD/MWh.

The average cost for transports is 0.79 USD/ton DS, km. Including the transports of forest residues (thinnings and clearings, etc.) from the forest to a road, the total raw material cost for these materials is estimated at least 10 USD/MWh. (pers. comm. Biofuel producers 1999, requested not to be quoted by name).

Saw dust is locally available at prices between 10 and 13 USD/MWh in 1998 in Sweden. However, the supply of sawdust varies strongly with the economic fluctuations and saw dust is unlikely to be guaranteed in required volumes over several years.

With reference to the fairly large consumption of raw material (100 000 tons of DS per year), an average price of 12.5 USD/MWh is assumed here.

This cost is considerably higher than what can be obtained in Finland, Canada and USA – simply because the utilisation of wood residues in these countries is comparatively smaller and that surplus still exist. In fact, raw material (and wood fuel products) is at present exported from these countries to Sweden. For small, occasional amounts in Sweden, lower prices are also feasible but the present comparison in general refers to an industrial, long-term activity. (The question about CO_2 taxation on fossil fuels in Sweden is here left out of the discussion although that, of course, forms the basis for the situation).

4 Cost evaluations for production of biofuel

As far as possible, the costs are quoted from data valid for today’s activities in Sweden. Some 20 plants for wood pellet manufacture three hundred thousand tons of biofuel for commercial use mainly in utility companies. The basis for this is the mentioned CO_2 tax in Sweden laid on all fossil fuels. (The total use of wood fuel in Sweden is about 1 million tons or 5 TWh, excluding the use of black liquor in the pulp industry and other similar utilisations).

A pyrolysis plant does not yet exist, and for this unit the costs are estimated from previous evaluations and prestudies of proposed units.

The pretreatment of the raw material – milling and drying – is the same or very similar for wood fuel manufacture and pyrolysis oil manufacture; in pellet production some 10–15% moisture content is accepted, whereas in pyrolysis the moisture content should preferably be <10% in the feed. Hence, the comparison of production costs basically can be focused on the actual pellet production vs. the pyrolysis process. On the general cost level, however, the receiving and pretreatment are evaluated as well.

4.1 Wood fuel (pellets) manufacture

In Sweden, wood pellets are increasingly used as wood fuel. The pellets are easier to handle in the transportation and they may be crushed before firing in “powder firing”. One of the main arguments for pellets is the storage function. There are restrictions in the storage of wood chips due to degradation, freezing risks and mould problems. Further, pellets are more homogenous in quality. For smaller boilers and heaters (30 kW (in family houses) to ≈5 MW) pellets are considered significantly advantageous.

Wood fuel production is often located in co-production with pulp industry or power/heating plants where steam from the other production is utilised in fuel production. Steam is required in the pelletising operation. In consequence, steam dryers are usually preferred and the low-pressure steam evolving from these may be used internally or for district heating (occasional flue gas dryers exist in plants not localised to other activities).

The use of steam dryers has so far been hampered by series of malfunctions, and consequently it is difficult to assess the general cost of drying. Recent figures for the total energy consumption, including power for the fans, etc indicate some 1.4 MWh/ton of water evaporated. Provided that the backpressure steam can be delivered as district heating or used otherwise, the net consumption is about 0.3 MWh/ton of dried feed, of which the majority is assumed to be power. Hence, drying from 50% moisture to about 15%, which might be suitable for pelletising, implies the cost of some 10–12 USD/ton DS or about 2 USD/MWh fuel product.

This process design implies that for the feed preparation some 25% extra wood raw material has to be combusted to generate medium-high pressure steam for the dryer. The majority of this cost, however, is reclaimed as district heat and is not added to the production costs. The investment in the steam production is assumed at some 2 MUSD equivalent with some 4 USD/MWh of pellet product.

The power consumption for milling in hammer mills, pellet compression, fans and conveyors is assumed at 20 kWh/MWh of pellets. At an average power cost of 3.75 cents/kWh this gives a cost of about 0.7 USD/MWh fuel product. Added to the power in the dryer, the total consumption thus is some 70 kWh/MWh of product.

Other specific operating cost items include gas and water treatment from the dryer and – for instance – additives for pellet formation. At the existing plants these installations are shared with other production and the specific costs are difficult to evaluate. Further, it seems that few additives are used at present.

The general operating costs include maintenance, insurance and labour costs. They are estimated at 1.4 USD/MWh, when the staff consists of some 10 people (the actual staff in co-production is difficult to specify). In comparison to the investment it should be commented that the maintenance is a mere 2% – a small number, especially considering that the process includes handling of solids.

The investments in the wood fuel plant have large variations depending on the local situation but in general given data fall within 20–30 (35) USD/MWh fuel product, year for existing plants; with the main parts falling on milling and drying (Steam dryers of this size are rare and the installations in fuel factories have been exceptionally expensive due to re-constructions. In the future, lower costs are expected). The higher figure would correspond to a green field localisation with a certain degree of infrastructure available (power, etc.) but including investments in receiving and storage of raw material. With a depreciation of 15% this implies capital costs of 3–4.5 USD/MWh fuel product.

Based on specific costs for dryers and other units, a new installation is rather judged to cost some 30–40 USD/MWh of product (see Table 1) resulting in corresponding capital costs of 4.5–6 USD/MWh of product.

Personal communications with wood fuel manufacturers indicate production costs of 6.2–8.7 USD/MWh on top of the raw material cost, which seems to roughly agree to the above estimates. A closer evaluation of this relation is impossible, since it requires information on specific revenues from the district heating, on annuities used, on internal prices of power, etc.

The cost features of wood pellet production with a capacity of 100 000 tons of raw material per year (500 GWh/year) are summarised in Table 1.

The material balance used in the economic evaluation is depicted in Figure 6.

Table 1. Characteristics of pellet manufacture.

Cost effecting item	Characterising figure	Comment
Energy efficiency	≈ 100 %	Providing backpressure steam can be sold as district heating (otherwise the energy efficiency is reduced to some 80%). Some losses are made in the dryer but they are neglected here.
Investments in receiving and storage of raw material	5–7.5 MUSD; 10–15 USD/MWh of product	Very much depending on local conditions
Investment in pretreatment	5–7.5 MUSD; 10–15 USD/MWh of product	The steam dryer is assumed at 7.5 USD/MWh and the milling some 5 USD/MWh.
Investment in pelletising	2.5–5 MSUD; 5–10 USD/MWh of product	Average 7.5 USD/MWh
Investment in additional steam generation	1.5–2.5 MUSD; 3–5 USD/MWh of product	"Theoretical" cost, since actual pellet production is mostly co-production where steam is available at lower costs.
Steam consumption	Small	Providing low pressure steam can be utilised elsewhere
Power consumption	70 kWh/MWh of product	At a price of 3.75 cents/kWh
Staff	10 people; 0.6 USD/MWh of product	Salaries are set about 30.000 USD/year, person
Cost capacity factor	Assumingly ≈ 0.8	For the steam dryer much less, for the rest higher.

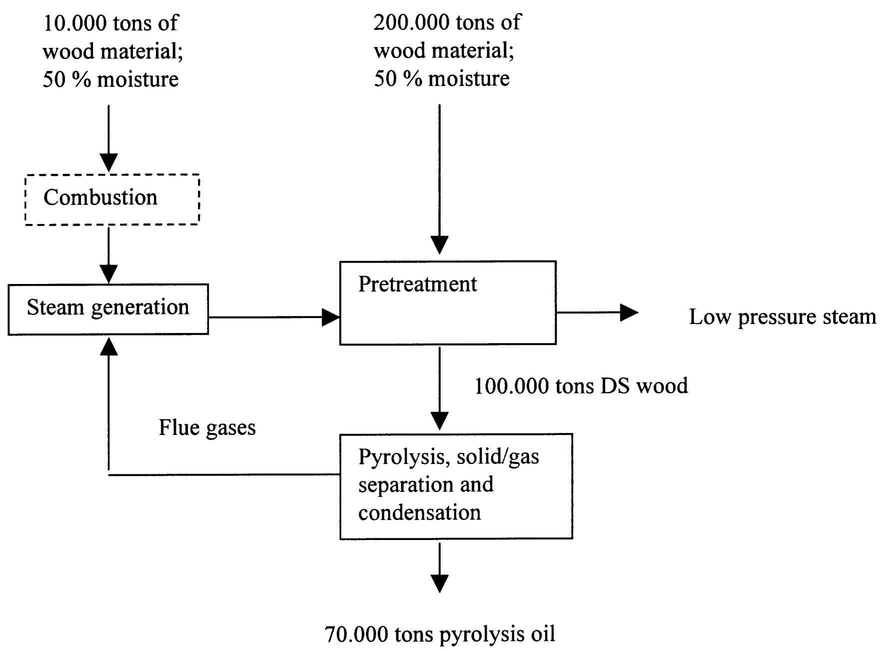

Figure 6. The material balance used in the economic evaluation.

4.2 Pyrolysis oil manufacture

In the pyrolysis oil production, steam is not used. Hence, flue gas dryers are preferred and assessed in most evaluations. Flue gas dryers – drum dryers or fluidised beds – are somewhat cheaper in investment (in the case studied some 6 USD/MWh raw material versus 8 for a steam dryer) but require a flue gas treatment after the dryer. The flue gas treatment most likely makes the investments about equal. In addition to a scrubber, or similar device, a waste water treatment has to be added.

For comparison reasons in this study, a steam dryer is assumed. To create analogous conditions, this also implies that the pyrolysis oil production is located where steam is available or at least low-pressure steam can be attributed a value.

As above, the extra fuel cost for drying is not incorporated in the production costs but only the investment cost is considered.

As is well-known, any pyrolysis unit has not yet been built for the capacity of 100 000 tons of DS per year (≈ 12.5 tons/h). However, previous cost estimates as well as practical data indicate quite a small cost capacity factor for the pyrolysis unit, < 0.65, effecting a comparatively much smaller specific investment for larger units. This is in agreement with the fast fluidised beds that have been installed elsewhere (for combustion and gasification).

For the rest of the equipment the cost capacity factor is assumed higher, ≈ 0.75, due to a substantial amount of solids handling (receiving, storage, milling).

For the intended production of pyrolysis oil in Sweden the magnitude of investment has been indicated to be 12–15 MUSD in a location, where some infrastructure is already available. This implies that the investment to a major part refers to receiving/storage, 50 000 tons of DS wood per year, i.e., half the size of the units evaluated in this study. This total investment effects a specific investment of 80–100 USD/MWh of product.

With an overall cost capacity factor of 0.7 the investment of 12–15 MUSD corresponds to 19–24 MUSD, of which some 5–7 MUSD fall on the receiving and storage of raw material and 12–19 MUSD are mainly referred to the pretreatment and pyrolysis units. At this capacity the specific investment is 55–70 USD/MWh of product.

Earlier investment cost estimates (e.g. IEA Bioenergy: T13: Technoeconomics: 1998:01 and Tony Bridgewater 1994) indicate that the pretreatment and pyrolysis units are roughly of the same magnitude in investments. In some studies the pretreatment (grinding and drying) is more costly, in others vice versa, which probably mirrors the development of dryers on one hand and the uncertainties of the pyrolysis unit on the other hand.

Receiving and storage as well as the pretreatment of pellets for production were assumed at 10–15 USD/MWh raw material (i.e. 5–7.5 MUSD in investment) each. This would leave some 7–12 MUSD for the intended pyrolysis unit and other facilities in the plant (steam production, waste water treatment, etc.). Using the same cost levels as in the “pellet case”, the indicated investment range for pyrolysis oil production seems reasonable and roughly in agreement with previous estimates (see Table 2).

A comparison may also be made with circulating fluidised beds in combustion and gasification. For a combustion unit, including a special feeding system but without condensation, the specific investment were about 15 USD/MWh at a capacity of some 50 000 tons of DS raw material per year. With the cost capacity factor of 0.65 this corresponds to about 12 USD/MWh at 100 000 tons/year.

A recent cost estimate for a gasification unit of 500 000 tons of DS wood per year, equipped with an advanced gas cleaning system, gave a specific investment of about 20 USD/MWh of feed. The unit was pressurised, which gives comparatively smaller dimensions but a more complicated feeding system. Scaled down to the size concerned, the implication is some 15 USD/MWh for the pyrolysis unit, when atmospheric pressure and a less advanced gas treatment are considered.

In conclusion, the information gathered implies magnitudes of about 15 (10–20) USD/MWh of raw material for the investment in the pyrolysis unit.

With dried raw material, the pyrolysis process is self-sufficient in energy and produces some excess energy (hot flue gas). The energy efficiency in the pyrolysis is about 70%.

The excess energy from the pyrolysis is used for steam generation in the steam dryer which requires an extra 5% of raw material for the energy production. As in the “pellet case”, the cost for this is assumed reclaimed from district heating or similar and only the investments in the steam generation are considered as a cost; 1.5–2.5 MUSD or 3–5 USD/MWh of raw material.

The extra addition of some 5% of raw material for the dryer, lowers the tentative total energy efficiency to 65%. However, with the assumed use of a steam dryer and the attribution of a sales value for district heat, the net losses of energy are restricted to cooling water from the condensing and “general losses”. These two factors are estimated at some 10% of the in-going energy effecting a practical total energy efficiency of about 90%; 70% being retrieved in the pyrolysis oil and 20% in the by-product steam.

Since the steam is largely produced by the pyrolysis, the production costs may be distributed over both products, i.e. the costs refer to a yield of 90% of the in-going energy, equally spread on pyrolysis oil and by-product steam. This statement is valid as long as the value of steam is higher than its total specific production costs.

The power consumption of the dryer and the pyrolysis is assumed at some 40 kWh/MWh of raw material to the pretreatment or about 45 kWh/MWh of products at 90% total energy efficiency. Accordingly, this implies 45 kWh/MWh of pyrolysis oil.

The capital costs of the investment and the raw material costs account for a major part of the production costs. Labour, maintenance, and insurance costs are assumed at 1.6 USD/MWh of raw material effecting 1.8 USD/MWh of pyrolysis oil.

The cost features of an assumed pyrolysis oil production at a capacity of 100.000 tons of raw material per year (500 GWh/year) are summarised in Table 2.

The material balance of the total pyrolysis process may be depicted as in Figure 7.

Table 2. Characteristics of pyrolysis oil manufacture.

Cost effecting item	Characterising figure	Comment
Energy efficiency	≈ 90 %	In the pyrolysis the efficiency is assumed at 75%. A flue gas dryer requires an extra 5% resulting in a total energy efficiency of ≈ 70%. By means of a steam dryer and assumed sales of district heat the practical energy efficiency is increased to some 90%.
Investments in receiving and storage of raw material	5–7.5 MUSD; 10–15 USD/MWh raw material; 11–16.5 USD/MWh of product	Very much depending on local conditions
Investment in pretreatment	5–7.5 MUSD; 10–15 USD/MWh raw material; 11–16.5 USD/MWh of product	The steam dryer is assumed at 7.5 USD/MWh and the milling some 5 USD/MWh.
Investment in pyrolysis	5–10 MUSD; 10–20 USD/MWh raw material; 11–22 USD/MWh of product	Average 16 USD/MWh of product.
Investment in additional steam generation	1.5–2.5 MUSD; 3–5 USD/MWh of product 3.5–5.5 USD/MWh of product	So far no pyrolysis units seem to have been evaluated with a steam dryer. Combustion of solids and gas is included in the pyrolysis unit and this cost refers to additional combustion and steam production.
Steam consumption	small	Providing low pressure steam can be utilised elsewhere
Power consumption	40 kWh/MWh raw material: 45 kWh/MWh of product	At a price of 3.75 cents/kWh
Staff	10 people	Salaries are set about 30 000 USD/year,person
Cost capacity factor	Assumingly ≈ 0.7	For the pyrolysis unit and the steam dryer less; for the rest higher.

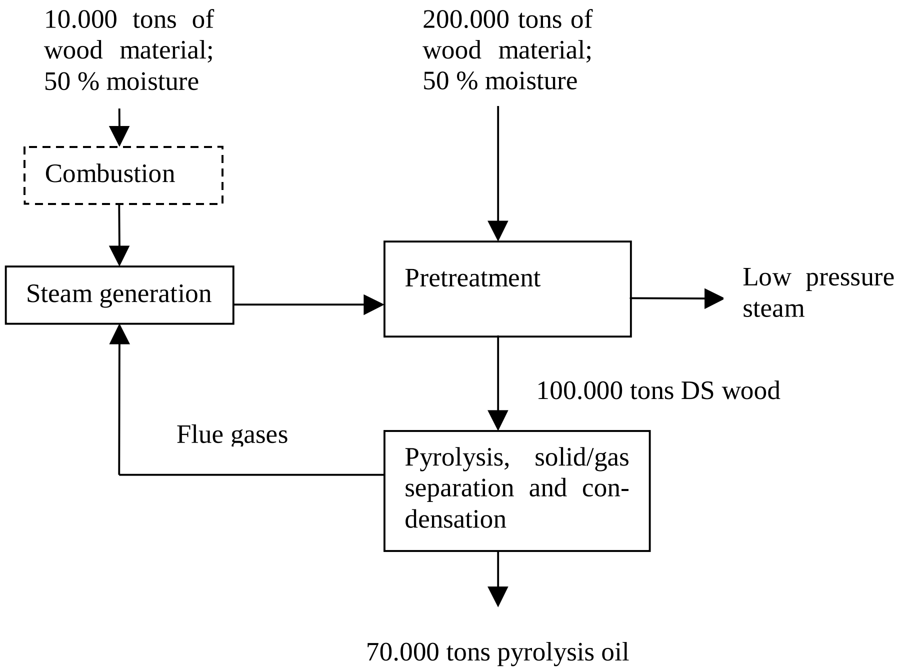

Figure 7. The material balance of the total pyrolysis process.

As seen in Table 2, the quoted and scaled up investment of 19–24 MUSD in the entire plant seems to be of reasonable magnitude. The mean value of the investments assessed in Table 2 and the mean value of 19–24 MUSD are almost the same. It should be noted, however, that Table 2 (as Table 1 above) does not cover the entire investment or required funding. Items like overall engineering, project management during construction, interest during construction and contingencies are not included and consequently the total funding will be larger.

With reference to this, the investment of 19–24 MUSD seems a little on the low side.

5 Transportation costs for fuel products

Providing that a "regular distribution" can be organised, the following cost relation between transportations of solid material like pellets and fluids like oil was obtained:

Over distances of 100 km, solid fuels may be distributed in Sweden at costs of 0.02–0.03 USD/km, MWh.

For liquid fuels such as pyrolysis oil, transportation is offered at costs of less than 0.01 USD/km, MWh, over 100 km providing that no special restrictions are made on the "oil".

The background for the different rates is to some extent that the liquid product is more easily loaded/unloaded. The possibility that the return trips are filled has been considered for the liquids but judged less likely. Mainly, the rate difference is an effect of differences in bulk densities, i.e. energy contents per m^3.

For a distance of 200 km these rates indicate the following cost levels:

for pellets	4	USD/MWh
for pyrolysis oil	2	"

These costs should not be taken too accurately, since transportations of this type are totally dependent on specific circumstances. Occasional loads may be an order of magnitude more expensive.

In this case, the cost levels – and the relation between solids and the liquid – are results of negotiations with two transportation companies; one specialised in oil transports and the other one dealing with solid materials (grains, wood chips, etc.). The conditions have been truck transports of 25 000–50 000 m^3/year evenly distributed over the time.

6 Summary of costs from raw material to combustion unit

The cost items above, i.e. significant cost factors from raw material to fuels delivered to a utility unit, may be summarised according to Table 4.

With respect to the reader the intervals used in Tables 1 and 2 are omitted and mean values given instead (Table 3). The cost interval is given within brackets in the end to indicate the accuracy of the cost estimates.

The investment and cost comparison for pellet manufacture and pyrolysis oil manufacture are summarised in Table 3.

The implication of the comparison in Table 3 is that the difference between pellet production and the assumed pyrolysis oil production is small – almost insignificant. This is not in agreement with what would usually be deducted from comparisons between the products.

As commented above (in section "Wood fuel (pellets) manufacture"), the present pellet producers indicate total production costs of 6.2–8.7 USD/MWh of product, whereas Table 3 indicates a higher cost; minimum ≈ 9.5 USD/MWh. Further, previous estimates on pyrolysis oil manufacture have arrived at production cost levels of >20 USD/MWh of product (for instance IEA Bioenergy: T13: Technoeconomics: 1998:01).

Table 3. Summary of the investments and costs for pellets and pyrolysis oil manufacture according to Tables 1 and 2. The quoted costs are not total production costs.

Cost item	Pellet manufacture		Pyrolysis oil manufacture	
Investments in MUSD and USD/MWh of product	MUSD	USD/MWh of product	MUSD	USD/MWh of product
Receiving and storage	6.25	12.5	6.25	13.75
Pretreatment	6.25	12.5	6.25	13.75
Key process	3.75	7.5	7.5	16.5
Combustion and steam production	2	4	2	4.5
Summary of investments concerned	18 (14–22.5)	36.5 (28–45)	22 (16.5–27.5)	48.5 (36.5–60.5)
Capital costs with 15% annuity on the investment, USD/MWh of product	5.5 (4.2–6.8)		7.3 (5.5–9.1)	
Power consumption and cost, USD/MWh of product	70 kWh/MWh of product 2.6		45 kWh/MWh of product 1.7	
Costs for labour, maintenance, etc., USD/MWh of product	1.4		1.8	
Sum of capital costs, power and labour / maintenance costs, USD/MWh of product	9.5 (8.2–10.8)		10.8 (9–12.6)	

Consequently, the usual comparisons would lead to at least double production costs for pyrolysis oil in comparison to pellets.

The costs summarised in Table 3 are not intended to be the total production costs. Hence, they should be lower than the actual costs. The reason why this is not the situation in pellet production is probably due to the fact that hardly any plant is installed as a stand-alone, green-field unit. As commented several times they are mostly built under special circumstances. This may explain the higher "production costs" for pellets in Table 3, effecting a somewhat smaller ratio between pellets and pyrolysis oil.

The main factor, however, lies in the provisions for the pyrolysis oil production with a steam dryer and a sales value of backpressure steam. In all previous evaluations of pyrolysis oil, the energy consumed for drying has been considered a loss, resulting in an overall energy efficiency of about 70%. This has a great impact on specific investments and operating costs in terms of labour, maintenance, etc.

In the present comparison, the overall efficiency is assumed to be 90% due to the steam dryer and the valuation of backpressure steam. The principal implication of this is that the raw material used for drying does not represent a loss but rather a parallel stream ending up as low-pressure steam for sale. The revenues from the steam assumingly pay for the costs of the "parallel stream".

In consequence, for the same feed the total costs are referred to 90% of the raw material in this case, whereas they are referred to only 70% when only pyrolysis oil is obtained. With a flue gas dryer all the costs in Table 3 would be about 30% higher, when by-product steam is not envisioned. This case is the one usually studied previously and with the figures in this evaluation it would lead to a "production cost" of minimum 12.5 USD/MWh (10.4–14.6) for pyrolysis oil or some 30% higher than for pellets.

Including raw material costs and transportation of the fuel to the combustion unit, the relation between pellets and pyrolysis oil is shown in Table 4.

Table 4. Cost comparisons for wood fuel, pyrolysis oil and tall oil pitch. Costs in USD/MWh.

Cost item	Wood fuel (pellets)	Pyrolysis oil	Tall oil pitch
Raw material (wood at 12.5 USD/MWh	12.5	13.9	
Significant production costs according to Table 3	9.5 (8.2–10.8)	10.8 (9–12.6)	
Sum of "production" costs	22 (20.7–23.3)	24.7 (22.9–26.5)	≈ 25
Transportation of fuel product, 200 km	4	2	2
Sum of evaluated costs for fuel delivered to a large customer	26 (24.7–27.3)	26.7 (24.9–28.5)	≈ 27

Again it is emphasised that the added cost items in Table 4 are not equivalent with the total production costs of pellets and pyrolysis oil. They cover only major costs for making comparisons, and the table is not intended as the total cost estimate.

The costs of pyrolysis oil in Table 4 may be compared with previous cost estimates. A client-specific evaluation by Kemiinformation in 1998 resulted in the total production cost of 34 USD/MWh of pyrolysis oil in a unit with the capacity of 140 GWh product per year (180 GWh of raw material). The referenced IEA Bioenergy: T13: Techno-economics: 1998:01 estimated the costs for a slightly smaller unit (165 GWh of raw material per year) at 43 USD/MWh of pyrolysis oil.

In the first evaluation the raw material price was set 20% lower, which resulted in some 2.5–3 USD/MWh lower cost in the production.

Both the units are about a third of the size of the one discussed here, which gives a higher specific investment; about 20% with a cost capacity factor of 0.7. The maintenance cost follows this relation and since the staff is about the same, regardless of the difference in production, some of the other specific costs (except steam, power, etc.) are also higher – approximately doubled.

Finally, the energy efficiency factor (70% energy efficiency in the quoted cost estimates versus 90% here) has an impact of about 2.5 and 3.5 USD/MWh, respectively, on the raw material costs.

These factors considered, the relation between the estimated costs is:

≈27 USD/MWh in this study (all costs not included)
≈30 USD/MWh in Kemiinformation's estimate 1998
≈32.5 USD/MWh in the IEA Bioenergy estimate

Since all costs are not included in this study, the agreement is acceptable and falls well within the accuracy of the estimates.

The costs of pellet production are basically estimated from information obtained from actual production. Despite this, the accuracy can be questioned for a new plant. Most of the existing plants are built in conjunction with other forest industries or erected in a former forest industry. In both cases savings in investments are obtained.

Selling prices of pellets have been noted up to about 27 USD/MWh in Sweden in 1998. Thus, the estimated significant costs of this product also seem to be acceptably evaluated.

The difference in capital costs for pellet and pyrolysis oil production alternatives in Table 3 is a little less than 2 USD/MWh. Out of this, the lower energy efficiency in the pyrolysis accounts for about 0.6 USD/MWh and the rest is attributed to the difference in key processes. The comparatively small difference in investments between the pelletising machinery (and cooler) and the pyrolysis unit has been discussed, but no further information can be obtained to verify other estimates (with a lower energy efficiency in the pyrolysis process the difference in specific investment of course increases).

7 Combustion costs

Pyrolysis oil is not yet used as a fuel in established combustion. Wood pellets have been a commercial fuel in Sweden since more than ten years but the use technique is not yet fully developed for very small units. As mentioned above, wood pellets are used preferably in boilers of 0.1–5 (10) MW. Larger units in Sweden fire lower-valued wood fuels (chips) and wastes, such as bark. For the lower-valued wood fuels the complexity of the equipment as well as maintenance requirements increase.

In the recent years, the pellet manufacturers have shown an increasing interest in developing the small-scale market, even down to heaters in private houses (about 30 kW). New systems for feeding and burning are constantly being demonstrated and according to news flashes a small but increasing number of boilers are refitted for pellet combustion.

For pyrolysis oil two strategies can be identified: One, where the oil is intended for boilers with 2–10 MW effect, and the other, where the pyrolysis oil is envisaged as a common fuel for units down to about 0.5 MW. The difference is that in the size class of 2–10 MW the production will be designated to a limited number of specific customers – 5 MW corresponds to the pyrolysis of some 5 000 tons of DS per year – whereas the smaller combustion units imply a commodity fuel. In both cases, however, the overall idea is that pyrolysis oil should substitute for the established oil in the existing heaters.

Depending on the market strategies, several cases have to be evaluated for the combustion cost comparisons. Large and small combustion units have different characteristics as well as – for instance – retrofitted and newly built units.

The cost evaluation for combustion is further complicated by different use patterns of the units.

However, the difference in the operating costs of combusting solid fuels in relation to liquid seems minor and the total cost is largely determined by the investments. Maintenance is partly proportional to the investment but evidently also governed by the type of system and the use pattern. At present the maintenance costs have to be more or less omitted due to the lack of long-time experience from pyrolysis oil (as well as wood pellets). There is a lot of experience from wood pellets but hardly in such a way that enables conclusive mean values, etc.

Hence, the present cost evaluation is more or less limited to the investments required for retrofitting conventional oil boilers into wood pellet fired boilers. The main idea is that whilst wood pellets firing requires retrofitting, pyrolysis oil can be directly used. At present, the latter seems not to be fulfilled, and the consequences are further discussed in the next section.

7.1 Wood pellets

Basically, wood pellets require a new burner for solid fuels, feeding systems, storage and automatic control.

In most cases the system is built up with a storage adapted to the transports. The pellets are delivered either in big bags or in bulk (small consumers) or in pressure vessels as, for instance, flour and cement. For very small heaters, the storage may be of only a few m^3. For larger units (hundreds of kW and upwards) silos of 50–100 m^3 are installed, which enable transports of 50 m^3 per truck.

From the storage the pellets are conveyed pneumatically or mechanically to a small storage before the feeder. A screw is usually used foro feeding the burner, and the latter may be of several designs (Figure 8).

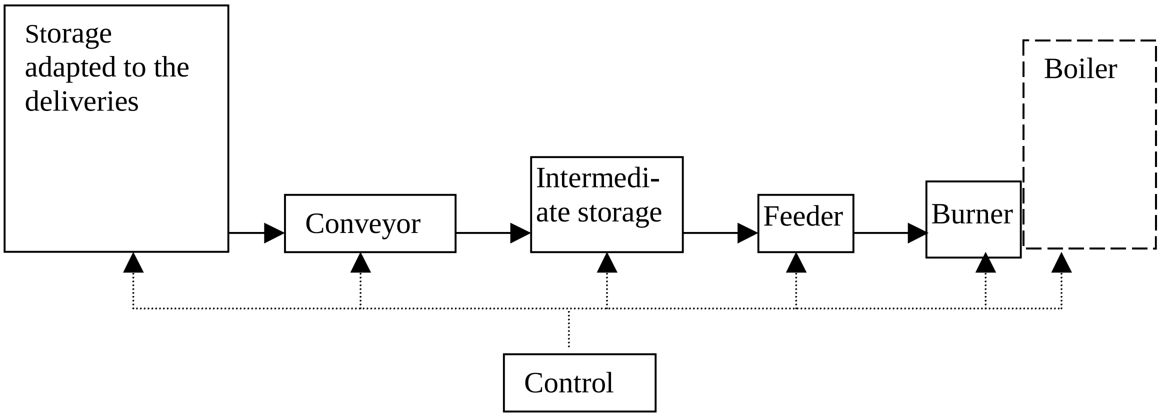

Figure 8. Principal flow sheet for combustion of pellets.

In a retrofitted boiler or heater rarely any reconstructions are made. The capacity may be lowered when the wood fuel substitutes for the fuel oil, but this is evaluated before the change. Sometimes an accumulation tank for hot water is installed to compensate for the lower capacity of the boiler (if the capacity may not be lowered the substitution is hardly feasible).

Equipment for real small-wood fired units (≈30 kW) is offered at about 150 USD/kW fuel. The price of the burner is some two thirds of this, and the automation is a minimum; temperature control, feeding rate, safety measures, etc.

Investments in units of ≈100 kW are of the magnitude of 100 USD/kW. At these capacities, manual work and attendance is still cost-effective and, consequently, the degree of automation and control systems is limited.

At 0.5 MW capacity, the recent investments have been of the order of 150–200 USD/kW. The increase in costs is to some extent due to a higher degree of automation, but mainly to the burners. In this size, the specific cost of the burner is almost doubled due to changes in construction.

The same type of burner is then used up to 5 MW (with multiple burners). From 1 MW to 5 the costs to an increasing extent are due to the storage (larger storages imply new constructions, foundations, etc.). At 1 MW the investments according to recent installations are about 250 USD/kW. At 5 MW the specific investment has decreased to 150 - 200 USD/kW – or even less (Table 5).

Table 5. Investments in combustion of pellets (wood fuel),USD/kW.

Item	≈30 kW	100 kW	1 MW	5 MW
Storage + conveyor	0–1.500	≈2.000	≈125 000	≈250 .000
Burner + feeder	≈2.500	≈8.000	≈100 000	≈450 000
Control	small	incl. in burner	≈25 000	≈50 .000

In conclusion, the specific investments for retrofitting a boiler or a heater for wood pellets are between 150 and 250 USD/kW fuel in the range of l 0.03–5 MW, with one extreme of 100 USD/kW at 100 kW.

At a depreciation of 15% and 2 000, 4 000 and 8 000 hours of duty per year this corresponds to capital costs of 11.3, 5.6 and 2.8 USD/MWh, respectively, at 150 USD/kW. With the higher investments of 250 USD/MW, the corresponding capital costs for these operating periods are 18.8, 9.4 and 4.7 USD/MWh.

An average cost for retrofitting a district heating boiler of 3 MW operating 4 000 hours per year can be about 7.5 USD/MWh.

7.2 Pyrolysis oil

As mentioned in the Background, one of the original ideas with pyrolysis oil was that it could substitute for fossil oil quite easily. Providing an existing fuel oil burner, the additional costs due to the substitution would be small. However, the present situation indicates that with today's qualities of pyrolysis oil this is not feasible.

Extensive testing has been carried out by Birka Energi with several types of pyrolysis oil (different raw materials) from various producers (pilot plants and similar) and of different age (= storing time). These results will be reported elsewhere but it can be stated that the products supplied to Birka Energi by no means can be directly or easily introduced into today's equipment. In relation to conventional fuel oils:

- the viscosities vary.
- ageing and chemical reactions occur in the pyrolysis oils.
- the constituents of the pyrolysis oil vary, effecting different burning properties.

- the ash-forming components are different from a fossil oil.
- solids and particles occur in the pyrolysis oil
- etc.

From the results it can at present be concluded that a reliable firing of pyrolysis oil requires some measures in an existing boiler. Providing this, however, the pyrolysis oil is judged feasible.

The required measures influence the oil as well as the boiler equipment and seem less likely to be applied on a small scale. For a 3 MW boiler a cost estimate can be made according to the following example:

coated tank to resist corrosion including stirrer, 50 m^3	40 000	USD
pump and feed piping in resistant material	12 000	“
new burner (modified design, with atomising)	25 000	“
possible reconstruction of furnace to to increase volume, lining	10 000–100 000	“
environmental and safety measures	50 000	“
Sum, including engineering and building	170 000–270 000	“

The investments indicate capital costs between 2.1 and 3.4 USD/MWh with a duty time of 4 000 hours/year (an average figure for a district heating boiler).

In addition to these equipment costs it seems probable that an addition of methanol to pyrolysis oil is beneficial or required. Other alcohols are also feasible but methanol would be the cheapest alternative. A 5% addition induces an extra cost of about 1 USD/MWh or a little less.

In summary, the likely costs of using today’s pyrolysis oils in existing boilers would be about 3.5 USD/MWh.

7.3 Tall oil pitch

Not included in this version.

7.4 Flue gas treatment

Firing of wood fuels, including pellets, is not without environmental problems. Badly performed, the flue gases can be a real environmental strain in terms of particles, hydrocarbons and fly ash. Larger units in Sweden are also equipped with a NO_x cleaning due to a special taxation system regarding NO_x.

Besides a thorough control of combustion, bag filters or similar are required in pellet fired boilers.

For pyrolysis oil, an evaluation of flue gases from the combustion tests is being carried out. From the immediate results it can be concluded, however, that any combustion of pyrolysis oil will require a flue gas treatment to be environmentally secure. Beside fly ash and particles on the filters in the test runs, the filters have been brownish coloured, probably resulting from lignin residuals.

In addition, the first results imply that the conventional flue gas cleaning may have problems with the pyrolysis oil flue gas. The gas is likely to contain sticky compounds and possibly even compounds that may polymerise, which can make bag filters and electrostatic filters impossible to use.

In conclusion, although the flue gases are not evaluated completely, in all probability the combustion of pyrolysis will require a flue gas cleaning of the same magnitude as that in pellet combustion. Hence, no significant difference between the two fuels can be identified at present and this factor is not further considered.

8 Summary and conclusions

The cost evaluations for the total use of wood pellets and pyrolysis oil may be summarised according to Table 6.

Table 6. Cost comparisons for wood pellets and pyrolysis from raw material to district heating in a 3 MW boiler. Costs in USD/MWh. All costs not included.

Cost item	Wood fuel (pellets)	Pyrolysis oil	Tall oil pitch
Production costs according to Table 4 (not complete)	22 (20.7–23.3)	24.7 (22.9–26.5)	≈ 25[1)]
Costs for transportation, 200 km	4	2	2
Costs in the boiler (retrofitting, reconstruction, etc)	7.5	3.5	3.5?
Sum of costs	33.5 (32.2–34.8)	30.2 (28.4–32)	30.5?

1) Price (not costs)

In Table 6, the total cost of using wood fuel as pellets in a 3 MW boiler for district heating is about 33 USD per MWh. The corresponding cost of pyrolysis oil is estimated a little lower (≈30 USD/MWh).

For comparison, fuel oil costs were some 40 USD/MWh in Sweden in 1998/98 for small consumers and some 30–40 USD for slightly bigger consumers, ≈ 0.1–1 MW. For the small boilers concerned – located in the middle of housing areas – only high quality oil is practically feasible at costs of this magnitude.

At present hardly any of the pellet producers pay the cost of 12.5 USD/MWh but rather 8–10 USD/MWh – if purchased externally. Consequently, the costs of established pellet production is lower than is estimated in Table 6.

The highest price paid by a utility company, noted in this study, was close to 29 USD/MWh.)

The difference between the costs of using wood pellets and the tentative costs of using pyrolysis oil is some 10%, which in general is well within the accuracy that can be expected. Thus, it cannot be stated a significant difference.

It must be stressed that the equivalence in costs is based on the assumption that the pyrolysis unit as well as the pellet production is equipped with a steam dryer enabling sales of low-pressure steam. In practice, this is today the situation for several pellet manufacturers, whereas none of the pyrolysis processes has been evaluated with this condition. Hence, if the present pellet production were compared to proposed pyrolysis oil production, the pellets would be advantageous by some 5–10 USD/MWh (pyrolysis oil some 5 USD more expensive and the present pellets 5–10 USD cheaper).

Some principal reasons point to the direction that the wood pellets could be less costly:

- The investment costs used in the study are based on actual figures for the production of pellets – although with large deviations – whereas the pyrolysis plant investment is a theoretical estimate, and these usually tend to underestimate the real costs.
- Further, an overview of the key process steps indicates that the pyrolysis unit is more complex than the pelletisers. The other parts of the complete processes are alike. In the investment cost estimate this is valued about 100% more for the pyrolysis – which, as commented before, seems a slightly small factor. We have no reason to question the estimate and cannot produce any more reliable data but at least the engineering part should imply a bit larger difference.
- Any upgrading of pyrolysis oil – to improve is applicability – will cost more money.

In the future, several factors may change. Most likely, further development of pyrolysis oil will improve the process as well as the properties of the product.

Secondly, the costs of firing both these fuels in boilers will probably decrease. This may not alter the relation between the fuels.

Thirdly, cheaper raw materials may appear. This will not affect the relation much, since the raw material share of the production costs is about the same. It might be easier to handle low-value raw materials in the pyrolysis as this includes a chemical breakdown of the material. Pelletising is to some extent sensitive to the structure of the wood. On the other hand, experiences have shown large variations in pyrolysis oil depending on raw material.

The overall conclusion is that pyrolysis oil may be produced and fired at the same cost level as pellets from wood. At present though, development work on pyrolysis oil has to secure an acceptable and even quality of the upgraded wood fuel as far as that of pellets.

Part 5

The U.S. Department of Energy's Small Modular Systems Project

Prepared for

International Energy Agency
IEA Bioenergy Task 22 – Techno-Economic Assessments for Bioenergy Applications

IEA BIOENERGY T22: TECHNOECONOMICS: 1999:05

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Abstract

Small, modular biopower systems have the potential to help in supplying electric power to the more than 2.5 billion people, who currently live without it in the world. The potential exists, because most of these people live in areas where large amounts of biomass are available for fuel. Small systems, those with rated capacities of 5 megawatts and smaller, could potentially provide power at the village level to serve many of these people.

Small biomass systems also have a great potential market in industrialized regions of the world in distributed applications. These applications consist of power generation attached to the transmission and distribution grid close to where the consumer uses electricity; some might be owned by the consumers themselves and would be connected to the power grid on the customer side of the electric meter. Both of these applications have large potential markets both inside the United States and abroad.

Working with industry, the U.S. Department of Energy's Small, Modular Systems Project is developing small biopower systems that are efficient and clean. The project consists of feasibility studies, prototype demonstrations, and proceeding to full system integration based on a business strategy for commercialization.

Phase I of the three-phase project focused on the feasibility of developing cost-effective technologies and identifying the potential markets for each of the systems.

Company	Technology
Agrielectric Power, Inc., Lake Charles, Louisiana	Fluidized-bed combustion with steam turbine
Bechtel National Incorporated, San Francisco, California	Gasification with spark ignition engine / generator, combustion turbine, or fuel cells
Bioten General Partnership, Knoxville, Tennessee	Direct-fired combustion turbine
Carbona Corporation, Atlanta, Georgia	Up-draft gasification with boiler/steam turbine
Community Power Corporation, Aurora, Colorado	Gasification with spark ignition engine / generator
Energy and Environmental Research Center, Grand Forks, North Dakota	Fluidized bed combustion, heat exchange fluid, steam generation, steam turbine
Niagara Mohawk Power Corporation, Syracuse, New York	Gasification with spark ignition engine / generator or combustion turbine / generator
Reflective Energies, Inc., Mission Viejo, California	Microturbine for biogas applications
STM Corporation, Ann Arbor, Michigan	Gasification with Stirling engine / generator
SunPower, Inc., Athens, Ohio	Combustion with Stirling engine / generator

Preface

IEA Bioenergy is an international collaboration within the International Energy Agency – IEA. IEA is an autonomous body within the framework of the Organization for Economic Co-operation and Development (OECD) working with the implementation of an international energy program.

The IEA Bioenergy "Techno-Economic Assessments for Bioenergy Applications" – Task reported here, has several general objectives. The main objective is to make companies developing new systems within the bioenergy area and their products known in participating countries by carrying out pre-feasibility studies.

The objectives have been pursued 1998-99 through carrying out studies in participating countries. Electricity, liquid fuel, and green chemical applications were studied. Studies were carried out in collaboration with companies developing new products or services from participating countries (Austria, Brazil, Canada, Finland, Sweden, and the United States of America) in the bioenergy field.

In 1998, the National Renewable Energy Laboratory (NREL) in Golden, Colorado, and Sandia National Laboratories in Albuquerque, New Mexico, placed ten cost-shared contracts to develop small, modular biomass power systems. These contracts, which were the first phase of the Small Modular BioPower Initiative, were aimed at determining the feasibility of developing systems that are fuel-flexible, efficient, simple to operate, and whose operation will have minimum negative impacts on the environment. NREL and Sandia jointly managed procurement and monitored technical progress and oversight for the contracts.

Through NREL, the executive summaries of the ten feasibility studies were made available to the IEA project.

Contents

Introduction

Small, modular biopower systems have the potential to help supply electric power to the more than 2.5 billion people in the world who currently live without it. The potential exists because most of these people live in areas where large amounts of biomass are available for fuel. Small systems, those with rated capacities of 5 megawatts and smaller, could potentially provide power at the village level to serve many of these people.

Small biomass systems also have a great potential market in industrialized regions of the world in distributed applications. These applications consist of power generation attached to the transmission and distribution grid close to where the consumer uses electricity; some might be owned by the consumers themselves and would be connected to the power grid on the customer side of the electric meter. Both of these applications have large potential markets both inside the United States and abroad.

Compared to small, modular power systems powered by fossil fuels that predominate in today's markets, biomass provides an alternative that is more environmentally acceptable. Furthermore, successful commercialization of small biopower systems completes the development of a biopower industry covering all ranges of expected power applications, including small systems for village power or distributed applications; combined heat and power systems for industrial applications; and cofiring, gasification, and advanced combustion for utility-scale power generation.

Working with industry, the U.S. Department of Energy's Small, Modular Systems Project is developing small biopower systems that are efficient and clean. The project consists of feasibility studies, prototype demonstrations, and proceeding to full system integration based on a business strategy for commercialization.

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Small modular systems have potential applications in both domestic and international markets. They have cost advantages in niche markets because of their modularity, standardized manufacture, and transport. Because they have simple connections, they will require a minimum of field engineering at customer sites. The intended power range for these systems is from 5 kilowatts to 5 megawatts.

Phase I of the three-phase project focused on the feasibility of developing cost-effective technologies and identifying the potential markets for each of the systems. Each of the companies participating shared at least 20% of the cost of the first phase; higher levels of participation by companies will be required in phases 2 and 3 of the project, which will be awarded on a competitive basis. The feasibility studies answered the following technical issues:

- System capacity (up to 5 MW)
- Load following ability
- System fuel consumption
- Fuel flexibility
- Number of operators and required training
- Life cycle costs
- Environmental impacts (feedstock related issues, and air, water, solid emissions)
- Safety
- Load profile (proposed hours of operation, etc.)
- Proposed fuel (including availability)
- Fuel handling/feeding system and method
- System transportability
- Maintenance schedule and costs
- Water consumption
- Capability for remote monitoring (unit performance and maintenance intervals).

The ten contracts were placed with the following companies, listed with their corresponding technologies:

Company	Technology
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STM Corporation, Ann Arbor, Michigan	Gasification with Stirling engine / generator
SunPower, Inc., Athens, Ohio	Combustion with Stirling engine / generator

The ten (10) Small Modular Biopower Initiative Phase 1 feasibility studies have been completed and the executive summaries are presented in the following chapters.

1 Agrilectric Power Incorporated

Subcontractor:	Agrilectric Power Incorporated P.0. Box 3716 Lake Charles, LA 70602
Contracting party:	Sandia National Laboratories
Subcontract title:	"Small Modular Biopower Project"
Subcontract No.:	SNL BC-0002D
Period of performance:	8 Jun 1999 through 30 Nov 1999
Subcontract contact:	Mr. H. Charles Weiss, Tel. (318) 421-6352

1.1 Introduction

Agrilectric Power, Inc., began the project with objectives that included identifying potential markets, defining system requirements, and reviewing technical issues requiring resolution. In addition, the goals included evaluating the environmental concerns while assessing the projected costs and developing strategic partnerships required to finance and complete the business development. The technology is an extension and refinement of that used at Lake Charles, Louisiana, to generate electric power by using rice hulls as fuel with the knowledge and experience gained during the operation of the facility. The specific study involved a family of rice hull-fired power generation units (PGUS) that would be deployed in emerging markets.

By working with a Japanese manufacturer of rice milling equipment the study identified the sizes of PGUs of 500 kW, 1500 kW, and 5 000 kW sizes, which closely matched production of rice hulls and power requirements for the operation of three line sizes of rice milling equipment. Once these capacities were identified, the quantity of hulls produced and the power requirements for mill operations set, the actual design sizes of the generating units were known. A design for each size was made based on the PGU being sited near a rice mill of the proper size. The economics of sizes and costs of the boiler and turbine required the economic choice of steam conditions for the best combination. A review of the expected emissions projected compliance with the regulations of these types of emissions.

Price projections have been made for these units based on U.S. equipment supplies, and discussion with vendors in other countries have shown possible significant reductions of total costs. The market for these units appears to be primarily outside the United States. The protective tariffs placed on imported goods by many countries causes the equipment to be more economically viable when purchased in the country of final use. This progress of unit size identification and cost estimates for import to other countries with rice production are major advances in implementing a development strategy.

1.2 Potential markets

The major market for this type of technology is outside the United States because of highly competitive fossil fuels, low power prices, and competing markets for rice hulls. The rice-producing areas in the United States can still dispose of rice hulls by landfilling when there is no market for the hulls such as bulk addition for animal feed. Changes in this capability that would increase the costs of disposal would increase the market potential for this technology.

Abroad, the primary rice-producing regions are Latin America, Southeast Asia, and the Pacific. Rice is also grown in parts of Egypt and Turkey, which could develop into market opportunity areas. In consideration of the current status of worldwide economies, the areas that appear to be prime, near-term market opportunities are Brazil, Uruguay, and Argentina. In Asia, Thailand, India, Malaysia, Indonesia, and China are the leading countries of market potential. The Philippines are also considered a high potential but, as with most countries, economic problems still impede full development.

The market for rice hull-fueled PGUs is thought to be small in terms of potential generation installed, but large in numbers of PGUS. The original estimate made at the beginning of the joint effort is shown in Table 1. This was based primarily in Asia. South America seems to be at least as large in potential.

Table 1. Original estimate.

Unit size	500 kW	1.5 MW	5 MW
Potential number	15 units	8 units	3 units

Table 2 lists the fuel available from a rice mill producing these hull quantities. The power consumption of the rice mill is based on the designs of the manufacturer.

Based on cost estimates of U. S. supplied equipment, Table 3 indicates the expected costs for a non-site specific site. Numerous factors are involved, which at this point are assumptions only. They can directly affect the final installed cost of the generating unit.

South America seems to be at least as large in potential. Further investigation in Brazil and China indicates that identifying manufacturers in countries that can produce the required equipment may reduce these costs. This does not address the concern of design confidentiality and the ability to control the release of design specifications to unauthorized parties.

Table 2. Fuel available from rice mill.

Unit size	500 kW	1.5 MW	5 MW
Fuel available	1 to 1.4 T/h	3 to 6 T/h	10 to 14 T/h
Total output kWh	480–600	1 400–1 800	4 800–6 000
Auxiliary use kWh	80–100	200–300	800–1 000
Net output kWh	400–500	1 200–1 500	4 000–5 000

Table 3. Expected unit costs.

Estimated unit cost	500 kW	1 500 kW	5 MW
First unit costs	$2,985/kW	$2,832/kW	$1,750/kW
Second unit costs	$2,835/kW	$2,690/kW	$1,663/kW

1.3 System design

The system design can burn rice hulls. Even though other fuels could be considered, the present effort is limited to the single fuel because the potential market is so large and applicable to so many areas of the world. The attached heat balance is for the 5000-kW design and shows all major equipment. The design significance is in the boiler and combustion system. The equipment outside this area is used in many installations around the world. The steam from the boiler is transported to the steam turbine where the energy is converted from mechanical to electrical in the generator. The spent steam is condensed back into water for pumping back to the boiler. The water from the cooling tower cools the condenser. The additional capability to use low-quality steam to dry rice or a parboiling of rice operation enhances the economics of this type of technology.

The rice hulls coming from the mill are ground by a hammermill and then transported to a storage or day bin. The feeders in the bottom of the bin control the amount of hulls or fuel being fed to the burners. As the feeder discharges the hulls, hot air is combined with the hulls in a venturi type device and transported to the burners. Two burners of equal capacity on the front of the boiler introduce the hulls into the furnaces. Because the hulls have been reduced in size, they are immediately combusted in the furnace while in suspension. There is no floor or grate in the furnace of the boiler. All combustion takes place before any ash falls from the gas stream. As the ash-laden gas flows through the system, hoppers at each device collect it. As the gas passes through the superheater, air heater, and economizer, its temperature decreases. When the gas enters the baghouse or fabric filter, the temperature is sufficiently low so that it will not harm the fabric bags. The gas passes through the cloth and the ash is collected on the outside of the bags and eventually falls into the hoppers for collection.

The ash formed by this process is a marketable product for various uses. Rice hulls combusted by other technologies may form a crystalline structure that is considered a respirable dust. In the amorphous form, the ash is considered benign. The ash produced by the suspension combustion is 99% amorphous. Uses include the steel industry for insulation material in the processing, filtration media, and combined with Portland cement for a superior concrete. Ash from this type of unit will add income from the ash sales rather than being a disposal cost.

The status of the design is conceptually complete. Sizing and general arrangement of the systems were made for all three (Table 4). Piping and instrument designs (electrical one lines) were developed and the control schemes were detailed for 5 000 kW. A review for the site-specific requirements will be necessary when a particular installation is chosen. Minimal work on the details of the generating system will be required.

Table 4. Heat rates.

500-kW heat rate	38,780 Btu/kWh or 9 772 kg-Cal/kWh
1 500-kW heat rate	24,200 Btu/kWh or 6 098 kg-Cal/kWh
5 000-kW heat rate	16,160 Btu/kWh or 4 052 kg-Cal/kWh

Although other systems and arrangements afford better heat rates, the overall goal must remain prominent in performing this design. The object is to use rice hulls in the most efficient manner without producing by-products that create problems. Efficiencies can be enhanced in this type of combustion system but at the cost of manufacturing an ash, which can be considered a hazard. Experience in the field with rice millers shows that the capital cost of these system's the largest concern. Use of rice hulls allows less efficient consumption if the price is justifiable and no additional problems are created by their use.

The Phase 1 work continued development into three sizes of units that will fit the mill capacities of rice milling equipment sizes; future work will require continuing efforts to reduce the initial capital costs. The possible assistance in this effort will be pursuing manufacturers in countries such as Brazil and China. Qualifications of boiler manufacturers will require the most strenuous effort to ensure the quality, detail design capability, business credibility, warranty assurance, and product support.

Other major engineered equipment although important to the success of the overall project, is less significant to the combustion/steam generation piece. Turbines, generators, condensers, pumps, feedwater heaters and the other equipment required is used in power plants with a great variety of fuels. Therefore, having greater variety of this type of equipment from several sources can ultimately reduce the overall costs of the project.

The expected environmental parameters are air emissions only and stated in Table 5. No significant differences are expected between unit sizes; therefore, applicable to all three designs. The particulate estimate is based on the assumption that a fabric filter will be used for control. Efficiencies of this device are matters of choice for particular locations and may not be included in the plant equipment. Other devices can be used with the penalty of additional emissions of particulate. If a market for this ash is developed, its recovery for sale may be an additional driving force to choose the more efficient collection device.

Table 5. Air emissions.

Oxides of nitrogen – NO, (lb/mmBtu)	0.05
Reactive organic compounds – ROC (lb/mmBtu)	0.001
Sulfur dioxide – $S0_2$ (lb/mmBtu)	0.05
Carbon monoxide – CO (lb/mmBtu)	0.159
Particulate – PM10 (gr/dscf)	0.01

1.4 Future development

Agrilectric Power, Inc., is marketing the technology as we develop the details of the design. There have been unsuccessful attempts to identify additional projects in the United States. The deregulation of the utility industry, combined with the abundance of natural gas in the rice-growing regions and additional markets developing for rice hulls, severely limit the capability of additional generation with rice hulls. In some regions, additional environmental compliance would open the reexamination of the potential. Deregulation by some states has included a renewable generation portfolio, which could bring about further development.

International development continues to be the most promising for this technology. Project development has been ongoing in South America, particularly Brazil. The rice industry in Brazil is strong and continues to grow in spite of recent economic problems. Manufacturers have been surveyed and some have been given the opportunity to demonstrate capability. The import duties on U.S. equipment is 25%, imposing a severe pricing disadvantage. Sources for all major equipment required for the power generating unit have been identified in Brazil with confidence that the standards used would provide a reliable system for this application.

Initial discussions have begun with manufacturers in China. Preliminary investigation indicated that the Chinese do not have detail design capability in the boiler manufacturer's organization. It was thought that the detailed design would have to be performed by design institutes that are fragmented into specialties and no one organization would be able to perform an overall design. This capability is a requirement because of the warranty serviceability requirements. Discussions with the manufacturers proved that they do have all the required capabilities and are very interested in pursuing this type of business arrangement. The design for the three units will have to be modified to coordinate with the turbine manufacturers in China who have chosen a different set of steam conditions for the common usage in small power generating plants.

Another effort to assemble a project in South America was made earlier this year when an engineering/construction company was asked for a cost proposal. The requirements of the project were to use U.S. equipment and package it into modules on the Texas Gulf coast. The equipment would then be shipped to South America for assembly on the plant site. This too, proved to be too expensive.

Future marketing and development efforts will continue to pursue international markets in the regions discussed earlier. The design concept discussed here provides a starting place for discussions and a realistic look at costs for this technology, but much work remains to reduce the costs to complete the marketing process. Agrilectric Power, Inc., and its partner Satake Corporation will continue to work with the Chinese, as that method appears to be the most likely road to success.

2 Bechtel National Incorporated

Subcontractor:	Bechtel National Incorporated 45 Fremont Street San Francisco, CA 94105-1895
Contracting party:	Sandia National Laboratories
Subcontract title:	"Small Modular Biopower Project"
Subcontract No.:	SNL BC-0002B
Period of performance:	26 May 1998 through 30 Nov 1999
Subcontract contact:	Mr. Babul Patel, Tel. (415) 768-1200

2.1 Introduction

This report represents the final product in response to the SNL contract to evaluate the feasibility of developing a small, modular biopower system. The effort supports the U.S. Department of Energy's (DOE) Biomass Power Program, whose goal is to develop small modular biopower systems that are fuel-flexible, create minimal impact on the environment, are efficient and simple to operate, and fall in the power generation range of 5 kW to 5 MW electric for domestic and international markets.

The study includes quantifying the domestic and international markets requiring industrial biomass power generation systems ranging between 800 kW and 1600 kW, identifying and quantifying the biomass fuels available in these markets, and evaluating these markets from economic and environmental standpoints. The preliminary system design expands on the present introductory design by identifying technical issues imposed by the market such as the appropriate system size, modularity requirements for transport, and local installation constraints. Further, the effort also included pursuing strategic partnerships with engine manufacturers to package an entire small modular biopower unit.

The Bechtel Technology and Consulting group of Bechtel National Inc. (BNI) led this effort with its subcontractor PRM Energy Systems, Inc. (PRME) of Hot Springs, Arkansas and its affiliate Primenergy of Tulsa, Oklahoma.

The basis for the small modular biopower system is the commercial KC gasifier. PRME owns the rights to the technology. PRME has been providing commercial KC gasifiers for industrial applications since the early 198Os. To date PRME has installed 18 of these gasifiers in a range of sizes from 8 MMBtu/h to 290 MMBtu/h. These installations provide process heat, process steam, electricity, and in many cases a combination of all three energy types.

2.2 Potential markets

A review of the present combustion turbine and reciprocating engine markets indicates that the largest market for distributed engine systems is in the 5- to 2000-kW size range. Sources indicate that most of the combustion turbines in 1996 to 1997 were shipped to the Far East, whereas the largest reciprocating engine markets appeared to be in North America and Europe.

Rice mills constitute a target market for the KC gasifier SMB system. Market studies show that Malaysia has more than 70 mills that could generate 800 kW or more, the Philippines and Thailand more than 100 mills each that could support an 800-kWe system. Information regarding the exact size of the mills in India and China was not obtained; however, the two countries produce more than 50% of the world's rice. Given that both countries have power shortages, they have potential markets for the SMB system.

The lumber industry also represents a unique market in which a waste resource could be used for power generation. Plywood factories normally require more power than sawmills and may support a 500- to 800-kWe system more readily in a captive power setting than would a sawmill. The Indonesian plywood factories studied require an average diesel system of 850 kWe. The waste residues from the factories can support 850 kWe to 1.5-MWe systems.

Most clients for the SMB system can maintain a system that requires operations and maintenance similar to a diesel generation system. The technical capabilities and spare parts will be considered in the SMB design. Load profiles for potential clients and typical industries, which indicate that a turndown ratio of 50% to 60% is required, were reviewed.

2.3 Fuel resources

Abundant resources exist for the SMB KC gasifier system in the form of crop or food processing residues. The KC gasifier can operate on 17 fuel sources, of which rice hulls, rice straw, wheat straw, lumber, corn cobs, and switchgrass residues were reviewed. Residues from the palm oil process were also estimated; however, empty fruit bunches (EFB) and palm nut shells have not been proven in the KC gasifier. The amount of residue and their subsequent potential power production were estimated based on crop production and independent studies. Table 6 summarizes the estimates of the total resource and power available. Electricity conversion efficiencies range from 18% to 22% depending on the resource, not taking into account the potential thermal energy available from the exhaust. The authors do not claim that the potential energy translates to market potential. The information indicates only the potential power production.

Table 6. Fuel resource quantities and energy production potential.

Crop/resource	1 000 tons	Potential, MWe
Rice hulls	106 900	5 580
Rice straw	534 700	33 743
Wheat straw	579 588	30 263
Corn cobs	633 600	112 540
Wood residue		45 000
Cotton gin trash	48 183	2 925
Switchgrass	84 400	8 346
Empty fruit bunches	7 440	402

2.4 Financial analysis

Financial analysis entails finding the new concern and determining the true costs of the SMB unit. Working capital requirements will be sought from a variety of sources including equity funds, potential strategic investors, and venture capitalists. These sources will be assessed, tested, and prioritized and the most advantageous working capital source will be chosen.

Detailed costs for the SMB unit based on manufacturing, assembly, installation, operations and management, and fuel costs have been established. The nominal delivered electricity cost for the units, under the scenario where there are no fuel costs, is approximately 4.9o/kWh for the 1600-kW unit and 8.0 O/kWh for the 800-kW unit. These prices assume a 7.5% interest rate for a 7-year term and 25% equity. According to published equipment prices for competing distributed energy technologies, when fuel prices exceed $2/MMBtu on combustion turbine units and $4/MMBtu with diesel generation systems, the 1.6-MW SMB unit has a lower levelized energy cost over a 15-year book life.

2.5 System design

The SMB system based on the KC gasifier has been designed in two sizes, 800 kWe and 1600 kWe. The model KC8 gasifier will be included in packaged systems, that require 800 kW or less, and be designated "Model KC8-800." The model KC 12 gasifier will be included in packaged systems that require 1600 kW or less and be designated "Model KC12-1600." The SMB systems consist of the gasifier system, producer gas cleanup, and a spark-ignited internal combustion engine (ICE).

The KC gasifier system typically includes the following equipment: fuel metering bin, continuous flow weigh meter, reactor/gasifier, refractory lined reactor gasifier, cooling water system, water-cooled ash discharge conveyors, multi-zoned air supply, rotary feeders, and instrumentation required to provide automatic control over the process. The entire gasification/combustion process, from metering to ash discharge, can be controlled manually or electronically.

In the producer gas cleaning system, the first preparatory step is cooling the producer gas from the evolution temperature. The initial cooling is accomplished by indirect heat exchange with air or water. Secondary cooling, ash, and initial tar are removed by direct liquid scrubbing. Exiting the liquid scrubber, the gas is finally mechanically scrubbed of tar, cooled in a heat exchanger with cooling water from external cooling tower, and slightly boosted in pressure. The clean producer gas is premixed with heated combustion air before being injected into the ICE.

The ICE is a V-16 with a dry turbo-compressor and electronic ignition. The engine is started with a 24-volt direct current starting motor. The engine is cooled by heat-exchanging internal cooling water with radiator cooling. All necessary pumps, exchangers, piping, and cooling water tower are included. Each engine is direct coupled to an electrical generator and each engine-driven generation set is mounted on a common frame.

The integration of the gasifier and gas cleanup system to produce a consistent quality producer gas to sustainably run an ICE has not been demonstrated. The future work and efforts should be directed toward demonstrating reliable power from the KC-8 system and tie-in with the grid.

Details regarding the producer gas production, process flow charts, and process flow diagrams are provided. A preliminary analysis of the gas produced from the KC gasifier indicates that the producer gas may be an acceptable fuel for a molten carbonate fuel cell with preprocessing of the gas. Fuel cells may be potential power generation sources in an SMB once the technology becomes fully commercial. They are not considered viable options at this time.

Both the model KC8-800 and the model KC 12-1600 have been designed so they can be packaged for export and transported by ship, rail, or truck in standard containers. Research indicates that infrastructure is present for most probable sites. The modules have been designed to maximize shop assembly and minimize field erection requirements.

2.6 Environment and safety

The SMB system based on the KC gasifier is designed to meet the World Bank General Environmental Guidelines. Initial tests indicate that the SMB unit will meet NO_x and SO_2 emission limits. Particulate, solid, and liquid waste limits will be tested in Phase 11. Design modifications will be made if necessary to meet the General Environmental Guidelines.

Impacts from manufacturing, shipping, installation, maintenance, operations, and decommissioning are similar to those of combustion turbine-, and diesel-generated power units of similar capacities. Operations have positive impacts on the environment by displacing fossil fuel with an agriculture residue. The agriculture residue is a sustainable, renewable resource. The CO_2 emitted during the conversion process is absorbed by subsequent crops grown.

The SMB unit based on the KC gasifier is designed with state-of-the-art instrumentation and built-in safety interlocks to provide automatic operation and protect personnel and equipment in the event of upset operating conditions.

2.7 Future development

KC-Systems is in an excellent position to capitalize on the vast market for SMB systems. The company's products are based on proven technology and its founders have a long track record of implementing successful biomass projects in the national and international marketplaces. The company's vision, mission, and goals are realistic, sound, and achievable.

The initial management team is made up of experienced professionals with positive and aggressive attitudes toward the success of this new venture. Several contacts with potential marketing and development partners are in place and require only further evaluation and negotiation. Supported by its parent companies, the new entity can start up and grow without additional capital; however, to expand rapidly and achieve its maximum potential, additional capital will likely be necessary.

KC-Systems' products are competitive in most markets. The company's initial system sizes will span approximately one-third of the total current market for competitive fossil fuel systems. The systems modularity and future scaled-up versions increase its coverage to more than one-half of the marketplace.

KC-Systems planned mode of production and operation is sound. The initial manufacturing of the gasification systems in Tulsa will ensure good quality control and efficient production. Adequate facilities are currently available for the first two years of production. The potential future procurement and manufacturing of portions of the systems on the local economy may provide opportunities for lowering costs.

The sales and distribution plans will provide for quick penetration into the target markets. The opening of dealerships within these markets will give immediate access to the dealers' current clients and provide for superior customer service.

The risks for this business venture are manageable.

KC-Systems presents a tremendous opportunity for its founders, partners, dealers, and suppliers to be the early leaders in the SMB field of renewable energy.

3 BIOTEN General Partnership

Subcontractor:	BIOTEN General Partnership 10330 Technology Drive Knoxville, TN 37932
Contracting party:	Midwest Research Institute, National Renewable Energy Laboratory Division
Subcontract title:	"Small Modular Biopower Project"
Subcontract No:	ACG-8-18073-04
Period of performance:	6 Jun 1998 through 31 Mar 1999
Subcontractor contact:	H.W. Arrowsmith, Tel. (423) 675-2130

3.1 Introduction

BIOTEN Corp. (BIOTEN) of Knoxville, Tennessee, is the corporate successor of BIOTEN Partnership ("BIOTEN GP"), a general partnership of BIOTEN, LLC ("LLC") and EUA BIOTEN, Inc. ("EUA"), a wholly owned subsidiary of Eastern Utilities Associates, Boston, Massachusetts.

BIOTEN has developed a generation system that produces electricity using biomass fuels directly fired in conjunction with a combustion turbine ("BIOTEN process"). The BIOTEN process utilizes the direct firing of biomass fuel in an offset, pressurized combustor whose combustion gases are cleaned in a cyclone filter and injected into the compressor turbine. BIOTEN modifies the combustion turbine by replacing the original fuel combustion chamber with a center section. The BIOTEN process is presented in Figure 1. The box labeled "Processed Fuel" represents a BIOTEN biomass fuel processing system designed to convert the raw "Biomass Fuel" into the "Dry Fuel" or "Fuel Dust" required for the BIOTEN combustion process. The BIOTEN combustion turbine system is composed of the components identified as "Combustor," "Cyclone Filter," "Gas Generator," and the "Power Turbine." The generation of electricity involves the component "Gear Box" and "Generator." The "Step-up Transformer" is part of the system to distribute the generated power to the power purchaser. The "Brake" is part of the safety systems built into the BIOTEN process to handle emergency situations.

The BIOTEN process has several environmental and economic advantages over the competing technologies:

- The BIOTEN process requires no process water because there is no steam cycle; thus, there is no water makeup or wastewater discharge. The process utilizes renewable biomass fuel, which is low in sulfur and nitrogen; thus, the SO_2 and NO_x emissions impacts are generally less than those of fossil fuels.

- The utilization of biomass fuels results in a zero net input of atmospheric CO_2 to the world greenhouse gases.
- The BIOTEN process can be installed in 10 months or less.
- The BIOTEN process has a low capital cost and an efficiency that results in very competitive production costs.

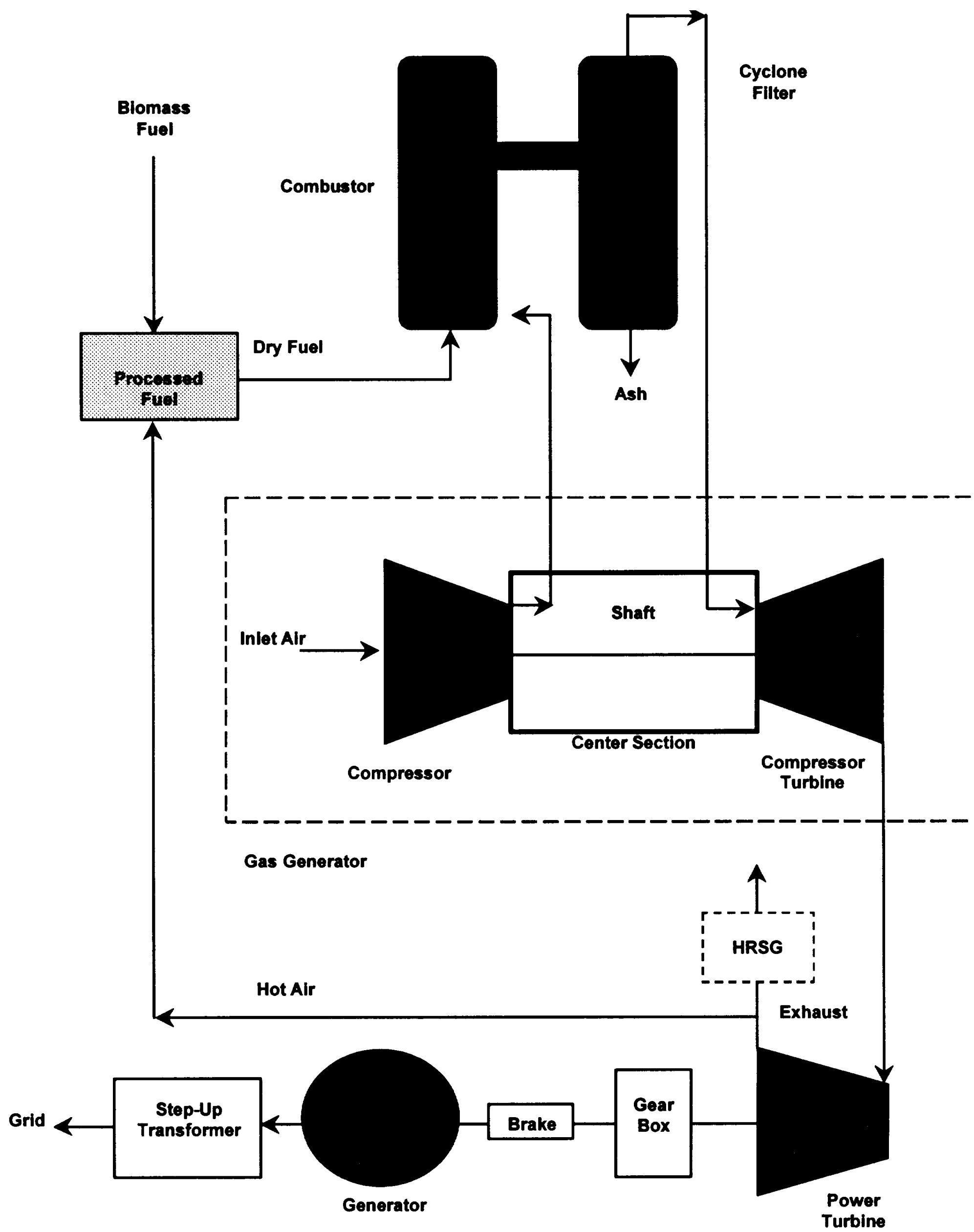

Figure 1. The BIOTEN Process.

3.2 Potential markets

This report analyzes the suitability of the BIOTEN process to be used in three countries or markets with distinctly different features. BIOTEN has performed significant research on India, the Philippines, and Canada in an effort to understand each country's market potential for applying the BIOTEN technology. We have contacted numerous prospective customers for our generating plants, including sugarmill owners, rice millers, lumber operations, paper and pulp facilities, waste disposal companies, and other biomass-related companies. The following are summaries of BIOTEN's market and resource assessments for the three countries studied.

A.SUMMARY OF MARKET ASSESSMENT			
	India	Philippines	Canada
1. Application of Bioten Process	• Simple cycle • Use of waste heat to enhance overall efficiency	• Simple cycle	• Simple cycle • Use of waste heat to enhance overall efficiency
2. Market size	3 500 MW	250 MW	1 000 MW
3. Module size	3–6 MW	5–6 MW 1–3 MW	5–6 MW
4. Competing technologies	NONE IN BIOTEN CAPACITY SIZE RANGE		
5. Permitting requirements	BIOTEN PLANT WILL SATISFY ALL KNOWN REQUIREMENTS		
B. SUMMARY OF RESOURCE ASSESSMENT			
1. Feedstock suitability	• Bagasse is acceptable	• Rice hulls are acceptable	• Sawdust, trimmings and bark are acceptable
6. Competitive uses	CHEMICAL COMPOSITION SUITABLE		
5. Properties	• Minimum to none	• None	• Minimum to none

Other features of these markets are:

India – Must import most of its liquid fossil fuel used to produce electricity. Laws have been passed in recent years to encourage the development of private power production. Sugarcane bagasse is a by-product of the sugar manufacturing process with a small- to medium-sized sugarmill capable of producing 5 to 10 MW of exportable electricity.

Philippines – Imports most of its fuel. There are large geothermal areas but energy costs are still very high. Laws affecting the disposal of rice hulls have not been enforced because of lack of disposal areas. Availability of rice hull burning plants would encourage enforcement. In many areas, three to ten rice mills produce enough rice hulls to supply a BIOTEN plant.

Canada – The country has extensive natural resources of energy; consequently, relatively low electricity rates. However, large quantities of sawmill waste are produced and environmental laws are forcing increased costs in disposal.

BIOTEN will focus on India to develop various strategies and business relationships needed to begin to penetrate this market and to develop a model for other international markets.

3.3 System design

BIOTEN has designed and constructed a net 5.0-MW commercial demonstration plant (CDP) located at Red Boiling Springs, Tennessee. The CDP is fueled by waste fresh-cut sawdust that is abundantly available in this part of Tennessee. The CDP has gone through several phases of testing and development during the past two years. The major components, including the fuel processor, turbines, pressurized suspension combustor, and cyclones, are based on technologies that are well known and have strong performance and maintenance records with tens of thousands of hours of in-service histories. The BIOTEN basic open cycle generation system design is characterized as a 5.0-MW net output plant operating at 1400'F and 120 psig with a mass flow of about 125 pounds per second while consuming approximately 10 tons per hour of biomass. The BIOTEN process plant may be obtained including all equipment requirements from fuel receiving and processing through the utility interconnection, as required by customer specification. The plant will fit on a 3-acre site or a parcel of land approximately 300 by 400 feet in size. The construction period is approximately 10 months.

The basic open cycle configuration provides three products. The primary product is electricity. The plant's net generation can be operated as a traditional base load generation plant. A secondary product is the plant's thermal discharge that may be used for drying and/or heating processes. The third product is an ash that contains potassium and other trace elements that support photosynthesis.

The basic fuel supply will normally be a waste stream. Thus, the BIOTEN process promotes the environmentally sound disposal of biomass waste products. The use of biomass fuels will help obtain the environmental targets established through the Kyoto, Japan Agreement. The agreement requires nations, especially industrialized ones, to effect significant reductions in greenhouse gases such as methane (CH_4) and CO_2. The BIOTEN process will greatly reduce the agricultural waste dumpings, major sources of CH_4 and CO_2 gases through the natural decomposition process of any biomass. Furthermore, burning biomass fuels does not generate the excess CO_2 associated with it burning fossil fuels because biomass consumes the same amount of CO_2 in its growth process as it generates when burned. Potential biomass fuel sources include waste products from lumber mills, forest and right-of-way clearing operations, pulp and paper mills, sugar-cane mills, rice mills, and agricultural waste such as wheat and corn stalks.

The BIOTEN process promotes the local environmental wellbeing by:

a. Disposing of waste residues while reducing greenhouse gas emissions and landfill requirements.
b. Reducing the need for fossil fuel by displacing some of the requirements with an inexpensive, locally generated renewable fuel source.
c. Providing electrical and thermal energy for the industrial and manufacturing complexes and the surrounding area and does not require a large transmission facilities infrastructure.
d. Generating a secondary product, an ash containing potassium and other trace elements, that is usable as the basis for a natural fertilizer and other commercial products. The use of an ash-based natural fertilizer will reduce the need for chemical-based fertilizers, another environmental benefit.

The CDP was sited under the State of Tennessee Environmental Siting Provisions. The Tennessee Environmental Protection Agency (EPA) mandates emission compliance levels that are either the same as or more stringent than the United States Federal EPA requirements.

3.4 Future development

BIOTEN has some remaining challenges that need to be satisfied to allow significant penetration into India or other world markets. The CDP will be used to prove the viability of the BIOTEN technology and demonstrate its performance characteristics. BIOTEN expects that sufficient data and operating results will be obtained and analyzed during the year 2000 to allow BIOTEN to offer a commercial product on a turnkey basis with reasonable commercial guarantees for availability, heat rate, and capacity. The CDP also allow BIOTEN to test and qualify additional biomass fuels besides sawdust including bagasse, rice hulls, and tree bark.

BIOTEN has developed an O&M plan to support the CDP, including operating procedures, preventative maintenance procedures, major overhaul schedules, and operator qualification and training programs. Additional run time at the CDP will allow BIOTEN to verify and fine tune these O&M procedures. These procedures will also provide the basis for developing the O&M support infrastructure required in foreign countries.

BIOTEN's vision of itself as a mature business focuses on providing customers worldwide with turnkey technology and customer services to support the development of renewable, clean, and economical electrical and thermal energy. To accomplish this, BIOTEN's services will include engineering, procurement and construction (EPC) services as well as financing support and O&M support services as defined by the customer.

To achieve these goals, BIOTEN has developed the following three sets of objectives:

A. Corporate objectives

1. Build a company recognized as a competent engineering and manufacturing firm that is recognized as a leader in the biomass power generation field.
2. Establish a reputation of quickly responding to potential business opportunities.
3. Operate the CDP on a financially sound and safe basis.
4. Use the CDP to develop approaches that improve the BIOTEN technology related to plant performance, efficiency, reliability, availability, and maintainability.
5. Collect data from CDP operations to optimize the commercial design of the BIOTEN process for as many biomass fuel sources as possible.
6. Develop and maintain a corporate staff that will support the company growth.

B. Business development objectives

1. Create and maintain an organization that provides the capability to address rapidly changing market and business opportunities.
2. Develop ongoing business relationships with renewable fuel producers, utilities, consultants, and EPC firms providing services to the electric generation market, power marketing groups, outside financial sources, and 0&M contractors to improve BIOTEN's possibility of expanding its business and satisfying customer's needs.

C. Financial objective

1. Obtain corporate revenue **stream** from unit sales and the associated ancillary functions that will continuously allow the company to grow.

BIOTEN's definition of success will be based on a combination of selling BIOTEN process systems worldwide while achieving the corporate, business development, and financial objectives previously discussed. BIOTEN recognizes most of its unit sales will be foreign.

The United States has a mature electrical generation and distribution system in place. The deregulation activities will not dismantle this structure but will realign it to provide more opportunities for competition. The generation opportunities will provide BIOTEN with the niche market for its products. In some regions of the United States biomass-fueled electric generation is not feasible. However, niche markets will be created for systems in the 5-MW to 10-MW range. This is BIOTEN's target market in the United States. This market will include the lumber and forestry industries, the municipal and landfill operators seeking ways to improve their management programs to extend the useful life of their assets, and some enterprising firms that will combine many resources for the mutual benefit of all parties involved.

Foreign countries that have agricultural foundations represent the largest market opportunity for any form of biomass energy generation. The BIOTEN process will help these countries develop their local infrastructures at feasible and economic rates. Developing nations have the desire to obtain the U.S. and Western European standard of living. However, they recognize this will not happen soon and will require both careful planning and financial support.

A successful BIOTEN will possess the engineering and manufacturing capabilities to satisfy all potential customers. Additionally, BIOTEN will have developed the necessary relationships to support any client with financing, EPC, and 0&M support issues as required. In terms of unit sales, a successful BIOTEN should be capable of delivering eight stand-alone units, six tandem units, four fuel processing systems, and the associate support functions per year.

4 Carbona Corporation

Subcontractor:	Carbona Corporation 4501 Circle 75 Parkway Suite E 5300 Atlanta, GA 30339
Contracting party:	Sandia National Laboratories
Subcontract title:	"Small Modular Biopower Project"
Subcontract No.:	SNL BC-0002E
Period of performance:	8 Jun 1998 through 30 Nov 1999
Subcontract contact:	Mr. Jim Patel, Tel. (770) 956-0601

4.1 Introduction

This report has been prepared by Carbona Corporation as part of DOE's SMB project. The feasibility study is Phase 1 of a three-phase program that will result in a demonstration of a small-scale biopower system.

The study is based on Carbona's updraft gasification technology, which is an atmospheric, fixed bed gasifier. Several plants based on this technology operate in Scandinavia. The power plant consists of a fuel handling section, gasifier, boiler, and a steam turbine generator.

The study has considered the feasibility of three sizes of power plants: 1, 3 and 5 MWe. All the plants are combined heat and electric power (CHP) producers. The preferred biomass fuel is woody biomass and the preferred markets are timber sawmills or district heating plants. The feasibility study includes a market and resource assessment, a preliminary design of the power plant, an environmental and cost analysis, and an integrated business and commercialization plan. The specific design is based on a 3-MWe power and 19 MMBtu/h heat producing biopower plant.

The results of the feasibility study show that in the markets evaluated such a biomass-based power plant can supply all the energy to a sawmill or to district heating (CHP) at attractive economics. Carbona and its partners propose to build and operate an updraft gasifier biopower (USB) plant either at a sawmill in Ghana or at a district heating plant in Denmark under Phase II of the SMB project.

4.2 Potential markets

The UGB system is a CHP plant. The biomass fuel for the UGB is wood waste either from forestry as wood chips or timber and sawmill operations. Therefore, the primary market for the UGB system is a sawmill or a community in a cold climate with a nearby forest industry or availability of wood residue. Both potential markets need electric power and some form of heat in the sawmill for drying and in the community for heating. Moreover, the planned size range of the UGB system – l, 3 and 5 MWe – is suitable for most of the market potential. Another requirement for the potential market for the community application is that it should be remotely located and therefore have no grid connection for electricity or that power price is very high. For both applications the price differential between wood waste and alternative fuels such as liquid petroleum and natural gas should be relatively large.

In the United States today the cost of electricity (COE) is very low (2–3 O/kWh), mainly because of low natural gas prices. Under these circumstances, the UGB system can not economically compete for new customers.

Remotely located communities near forestry industries are the only potential markets. However, several contacts with them have been unfruitful, mainly because of institutional barriers.

Therefore, the most attractive markets are international – in Scandinavia and the Baltic states and in developing countries within forest industries and where the alternative fuel prices are high. These countries are in Central and South America, West and East Africa, Asia-Pacific, Scandinavia, and the Baltic states. Some of the countries identified as promising potential markets in these regions are Brazil, Chile, Ghana, Kenya, India, China, Thailand, Denmark, Sweden, Latvia, and Estonia. The market and resource assessment in this study was for the two most promising areas: West Africa and Scandinavia.

The Danish government intends to continue the development of renewable energy at an average annual rate of 1%. This entails renewable energy increasing its share of the energy supply to about 3–5%. A gradual increase in the use of biomass at power plants should amount to 1.2 million tonnes of straw and 0.2 million tonnes of wood chips annually by 2000. Approximately 60 small towns should be converted to biomass-based district heating.

Data from the Food and Agriculture Organization of United Nations' database show that four African countries, which are all well-known for their large sawmill industries, have a market potential for at least 70 UGB plants of 3 MWe. These four countries are Ghana, Ivory Coast, Cameroon, and Nigeria.

The total investment cost of the 1, 3 and 5 MW UGB plants was estimated using standard costing practices. Because of the large size of the gasifier, for the UGB plant of 5 MW capacity two gasifiers will be assumed to supply gas to one gas boiler. The investment costs are summarized in Table 7.

Table 7. Investment costs.

Nominal capacity	Total investment cost
1 MW	\$3.88 million
3 MW	\$5.88 million
5 MW	\$8.52 million

The COE is 5–7 c/kWh depending on price of biomass fuel and heat.

4.3 System design

The power and heat generating power plant system described in this feasibility study is based on wood-based biomass. The fuel is gasified in an atmospheric pressure updraft gasifier. The low calorific value (LCV) product gas produced in the gasifier is burned directly in a boiler that generates high-pressure steam. Steam is utilized in a back-pressure steam turbine generating power and provides heat for district heating. The rest of the plant is a typical arrangement of conventional equipment.

The gasification plant (Figure 2) is to convert solid biomass fuel to product gas. The gasification plant is served by a fuel receiving station combined with covered fuel storage in addition to an open air fuel reclaim area. A conveyor transfers the fuel from the storage to the feeding system. The feeding system is piston type, gas-tight feeder located a top the gasifier. The gasifier is an air-blown updraft fixed bed gasifier. It comprises a refractory-lined shaft furnace and rotary grate. The fuel drops to the top of the fixed bed in the gasifier. First it will be dried by the upward product gas flow. In this drying process the product gas cools to about 480- 660 F (250–350 °C), the exit gas temperature of the gasifier. The dried fuel then moves downward in the fixed bed, countercurrent with the product gas, through the gasification zone of about 1800 F (1000 °C) temperature to the oxidation zone. The residual ash accumulates in this oxidation zone, near the grate. The gasifier ash is removed through the bottom of the gasifier by gravity through a valve system into the ash containers and is then landfilled.

The gasification air is fed through the rotating grate located in the bottom of the gasifier reactor to enable proper air distribution in the fixed bed. The air is preheated and humidified using steam before being fed into the gasifier. The steam is to control the gasification temperature (i.e., prevent ash sintering) in the lower bed area. The LCV product gas is generated in the gasification area. The product gas exiting the gasifier is directed to the gas boiler through the gas pipe. The gas pipe is short to minimize tar condensation. The gas is burned in a gas boiler equipped with a special gas burner suitable for LCV gas combustion.

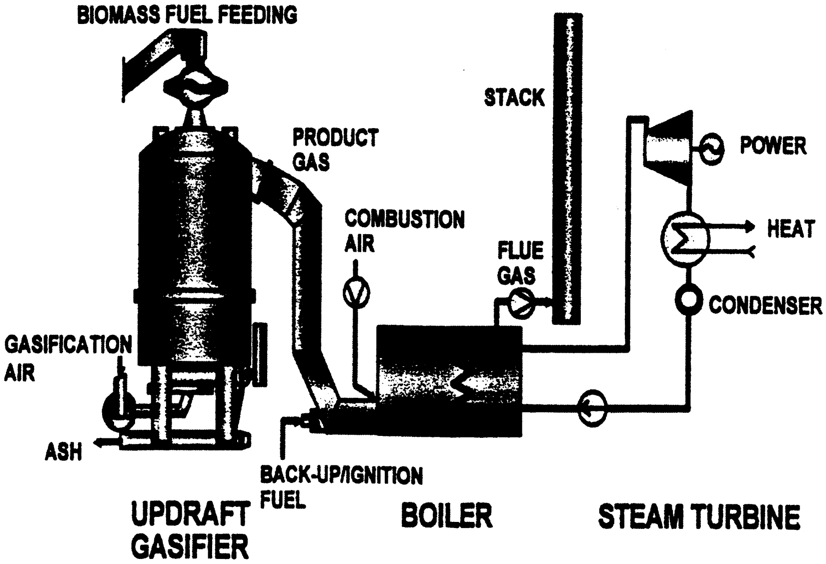

Figure 2. Updraft gasifier biopower system.

The emissions of UGB plant as compared with emission limits required by the World Bank are listed in Table 8.

Table 8. UGB plant emissions.

	Pollutant UGB plant	Emission rate World Bank limit
SO_2	0,009 tpd/MWe	0,2 tpd/MWe
NO_x	1 00 mg/MJ	260 mg/MJ
CO	25 mg/MJ	n/a
Particulate	10 mg/nm^3	50 mg/nm^3

The overall efficiencies of the three sizes of the UGB plants are shown in Table 9.

Table 9. Overall efficiencies of UGB plants.

Nominal capacity MW	Electric power MW	Heat MJ/s	Electric efficiency (LHV)	Overall efficiency (LHV)
1	1.0	3.66	18.6	82.0
3	3.0	8.37	21.9	82.7
5	5.0	13.6	22.4	83

4.4 Future development

Carbona intends to supply the UGB systems in the identified markets on a turnkey basis. To achieve this, strategic partnerships will be formed with a local company in each country. Carbona has the basic engineering and knowhow of the UGB system and has the background from experience in supplying UGB systems in Scandinavian countries through its sister company in Finland. There are 10 operating plants based on UGB principles, located mostly in Finland.

For Scandinavia and the Baltic states Carbona has entered into an alliance with FLS miljø a/s. Ultimately Carbona will solidify this agreement for delivering UGB plants on a turnkey basis in Europe. For Ghana, Carbona has already formed a cooperation with a company called Waypoint Ltd. Similarly, Carbona has also formed a cooperation with a company called EBIL Tech Limited in India for that market. A potential customer has also been identified in India for a demonstration project.

The short-term goal is to build and operate a demonstration plant for each of the two primary applications of the UGB system-sawmill and local community. Two commercial plants should be sold based on the results of the demonstration plants. In the midterm the goal is to build UGB Systems in four of the main potential market countries to establish a broad base for future business. Also during this period efforts will be made to improve the efficiency and cost competitiveness of the UGB System. One approach will be to develop gas cleanup techniques so the steam turbine power block can be replaced by a gas engine. Also, the feedstock base for the system will be expanded to include agricultural waste and retrieve derived fuel. In the long term for the business to be successful, at least five UGB systems should be sold annually, and the U. S. market for biomass-based power must be established. This will require innovative approaches in financing, project development, and new partnerships.

As part of the commercialization of the UGB system, an aggressive marketing plan will be implemented. An initial step has already been taken by signing up partners for sales and marketing efforts on a local level in Scandinavia, the Baltic states, Ghana, and India. Also, quickly establishing the demonstration plants to aid in the marketing effort whereby customers can inspect and evaluate the results of an operating unit is essential. Therefore, the initial marketing efforts will be concentrated in Scandinavia, the Baltic states, Ghana, and India.

5 Community Power Corporation

Subcontractor:	Community Power Corporation 5796 East Chenango Ave. Aurora, Colorado 80015
Contracting party:	Midwest Research Laboratory, National Renewable Energy Laboratory Division
Subcontract title:	"Small Modular Biopower Project"
Subcontract No:	NREL ACG-8-18073-01
Period of performance:	4 Jun 98 through 30 Sep 99
Subcontract contact:	Robb Walt, Tel. 303- 690-7869
Email:	robbcpc@aol.com

5.1 Introduction

Based on Community Power Corporation's (CPC) need for large numbers of small biopower systems for rural electrification projects in Indonesia and its inability to purchase a commercially proven system, in 1997 CPC formulated a strategy to develop a family of SMB systems to electrify off-grid communities. In January 1998, CPC created a new biopower division with the collaboration of Dr. Thomas B. Reed, an internationally recognized expert on gasifiers. Based on CPC's preliminary assessment of market requirements, Dr. Reed identified several necessary improvements to current state-of-the-art SMB systems. Compared to current power gasifiers, these improvements focused on developing a new modular "Turn Key, Tar Free" high-energy gasifier, much smaller in size, with fewer components, no liquid effluents or hazardous wastes, much lower capital and operating costs, reduced maintenance, minimal civil works, and greater load-following capability.

Under Phase 1 of the SMB project, CPC conducted market and biomass resource assessments for 12- to 25-kWe SMB systems in three countries: Indonesia, Brazil, and the Philippines. These field studies showed conclusively that there was a significant and growing rural electrification market for CPC's SMB system.

The objectives of Phase 1 were as follows:

1. Identify potential markets for CPC's proposed SMB system.
2. Define the characteristics of the system required by the markets.
3. Identify technical issues to be resolved for the systems to meet market requirements.
4. Identify and evaluate the environmental issues associated with the proposed system.
5. Investigate strategic partnerships required to finance the business development.

6. Develop a detailed engineering design study for the prototype SMB system.
7. Perform a preliminary hazard and operability study of the prototype.

The accomplishments during Phase 1 were as follows:

5.1.1 Market and pilot project identification

Conducted successful market assessment in Indonesia, Brazil, and the Philippines.

Identified community power and rural industries markets for (12 to 25kWe) SMB systems in the Philippines (2000), Indonesia (5000), Brazil (2000), and Alaska/United States (TBD).

Began preparing two specific pilot project sites to demonstrate CPC's SMB system in the Philippines.

Identified additional pilot project sites for CPC's SMB system in Indonesia and Brazil.

5.1.2 SMB system design and development

Developed a set of detailed market-driven specifications for CPC's new SMB system based on the comprehensive, on-the-ground market and customer surveys in three countries. Assembled a world-class design and engineering team to develop CPC's SMB prototype. Designed, fabricated, and tested a pre-prototype SMB power gasifier, including cleaning and cooling components, automated fuel feeder, and ash extraction system, and full instrumentation and data logging systems. At this time, 15 fully instrumented runs of the pre-prototype power gasifier have been conducted to determine the optimal design and operating parameters for a CPC "Turn Key, Tar Free" power gasifier during Phase 2. The pre-prototype system was demonstrated at NREL on September 14, 1999.

5.1.3 Strategic relationships

Established a formal strategic relationship with Shell Renewables (SR) to commercially develop CPC's SMB system and to apply the system in rural electrification projects.

In the Philippines, established formal relationships through MOUs and MOAs with two provincial governments, electric cooperatives, and the Philippines Coconut Authority for two SMB pilot projects. Established a relationship with the Development Bank of the Philippines to finance SMB system applications.

5.2 Potential markets

During Phase 1, CPC conducted field-based market studies for its SMB system in the Philippines, Indonesia, and Brazil. These studies showed conclusively that the primary market for CPC's SMB system is the electrification of off-grid communities. Two related markets were also identified for electrical and thermal energy for small-scale rural industries (agro-processing, crop drying, ice making, light manufacturing) and community needs for hot water and cooking.

There are more than 100,000 unelectrified communities in the Philippines, Indonesia, and Brazil. About 70,000 (70%) are in Indonesia, 20,000 (20%) in Brazil, and about 10,000 (10%) in the Philippines. About 50% or 50,000 are inaccessible because the lack of roads, do not have a sustainable biomass source, or are candidates for electrification by the utility during the next 10 years. Of the remaining 50,000 communities, about one half, or about 25,000 communities could pay for energy services from an SMB system. CPC's experience suggests that the potential sales of SMB systems in these countries over a 10-year period would be 2000 to 3000 systems or roughly 10% of the potential market. Of the three countries studied under Phase 1, the Philippines was selected as the most promising near-term market because of its stability, strong economic growth, abundant and appropriate agricultural residues (coconut shells and com cobs), and strong government support for private sector participation in rural electrification projects.

5.2.1 Philippines: Markets for CPC's SMB systems

With 70 million people, 7107 islands, a strong and growing economy, a stable government focused on sustainable rural development, and more than 4 million rural households without access to electricity, the Philippines offers a readily accessible $300 million annual market for renewable energy-based electricity services.

The same conditions that prohibit the use of conventional technologies make SMB systems ideal. The typical unelectrified region in the Philippines consists of hundreds of small clusters of 30 to 100 households surrounded by thousands of individual homes scattered throughout the countryside. In regions where coconut is the main crop, CPC's SMB systems are ideal for providing compact communities with 220-V accelerated current electricity services. Rural enterprises and community services such as water pumping, street lights, health clinics, schools, churches, community centers, stores, and workshops can also be served by CPC's 10- to 25 kWe SMB systems.

5.2.2 Indonesia: Markets for CPC's SMB systems

With 25 million unelectrified homes, mostly located in vast agricultural areas rich in biomass residues, Indonesia is an ideal market for SMB systems. CPC's 8 years of experience in Indonesia and field studies conducted under Phase 1 of the SMB project showed that more than half, or 12–15 million households (60,000 communities) are located in agriculturally rich and more prosperous agricultural regions. These rural households, which spend close to $1 billion each year for inferior and environmentally damaging energy services from kerosene and automobile and dry cell batteries, constitute CPC's primary target market for SMB power systems in Indonesia.

CPC will access this market for SMB systems through its joint venture in Indonesia, PT. Bakrie Renewable Energy Systems (PT.BRES). Working in concert with various market aggregating sponsors, CPC will use SMB pilot projects to create the opportunity to serve the nearly 3000 unelectrified agricultural communities that have been established during the past three decades. PT.BRES will also initiate sales of SMB systems to one of the Bakrie Group's largest and most profitable business entities, Bakrie Sumatra Plantations (PT.BSP). PT.BSP is a major owner, operator, and developer of plantations for palm oil and rubber wood. Hundreds of communities located on PT. BSP's many plantations are without access to electricity and represent an attractive potential market.

5.2.3 Brazil: Markets for CPC's SMB systems

CPC's field visit and market reconnaissance study in Brazil during Phase 1 showed that Brazil represents one of the world's largest potential markets for CPC's SMB power systems. However, because of the vastness of the country and a generally underdeveloped interior whose economy consists primarily of small-scale agriculture and forest products enterprises, supported by small, marginally accessible communities (typically with 20 to 50 homes), capturing and servicing this market presents a unique and difficult challenge. The typical household income in the target market communities is reported to be in the range of $200 per month, which suggests an excellent ability to afford a basic level of energy services.

The long legacy of government-supported and -controlled monopolies for generating and distributing electricity and high-cross subsidies for rural electrification, is a barrier to opening up the unserved markets (rural and isolated communities) to a market-driven supply of energy services. However, the ongoing privatization of state-owned utilities, changes in regulation policies, and a gradual breakdown of service territory monopolies, are opening up new opportunities for the commercial supply of renewable energy-based power systems and energy services to unserved communities. Another positive factor is that biomass-based power generation for off-grid rural enterprises and small communities is considered by key government agencies as an appropriate and necessary alternative, over the long-term, to diesel-based power systems.

5.2.4 Biomass resources in target markets

CPC's SMB system can be adapted to a variety of feedstock as dictated by the specific target market for electrical and/or thermal energy. In the case of Indonesia, CPC's target markets for its SMB system are thousands of unelectrified plantation communities that house workers and staff for large palm oil and rubber plantations. The feedstock in these communities is either palm nutshells (a residue from palm oil mills) or rubber wood from harvesting of non-productive trees. In the Philippines, CPC's initial target markets are off-grid communities located in regions where there is an abundance of coconut shells and corn cobs. In Brazil, CPC has identified markets in the Amazon basin and northeast regions where wood scraps and sawdust from small riverside sawmills, and nut shells (primarily ouricury and babasol) from local oil mills are plentiful local waste resources in thousands of communities.

The supply of relative small quantities of feedstock required by a community-based =1 electric service company to operate one of CPC's SMB systems is not considered a problem for the following reasons.

- Only those communities with a secure, long-term supply of feedstock will be selected as potential users of CPC biopower systems.
- Given the extremely large number of unelectrified communities already identified by CPC in Indonesia, the Philippines, and Brazil, there is an immense and growing pool of potential communities and customers.
- The relative small amount of power required each day (–300 kWh @ –20 kW peak) by communities in CPC's target markets requires a correspondingly small supply of feedstock (–300 kg/day/community).

5.2.5 Characteristics of feedstocks in target countries and markets

Indonesia

Indonesia is the world's second-largest producer of palm nut oil (more than 5 million tons/year from more than 200 mills) and a producer of more than 2 million tons of dry rubber and 60 million tons of rubber wood per year. Most production is located in CPC's target markets for the SMB system, so the selection of palm nut shells and non-productive rubber wood as the initial feedstocks was straightforward. Furthermore, CPC's joint venture partner, the Bakrie Group, is Indonesia's largest owner/operator of palm oil and rubber plantations and has just announced the startup of a $1 billion, 70,000-hectare palm oil plantation in Kalimantan.

CPC's field visits to both palm oil and rubber plantations in Sumatra and Kalimantan discovered a strong willingness of the owners to supply the relative small quantities of these residues to local communities to generate electricity. In virtually all cases, use of these residues by local communities was welcomed by the mill owners because it meant a higher quality of life for their employees (who live in the largely unelectrified communities) and an increase in the consumption of waste products, thus reducing the burden of disposal.

The Philippines

The Philippines has an abundant and varied supply of biomass resources that include crop residues, forest residues, and agro-industrial wastes. The most common and available residues for power generation and thermal processing are bagasse, rice husks, and coconut shells and husks. Wood and wood waste are the largest sources of fuel for home cooking; 61% of the total population and 84% of rural population cook with fuel wood. Countrywide, the largest quantities of biomass residues come from three sources: sugarcane (24 million tons/year), coconut (12 million tons/year) and rice (11 million tons/year).

Based on field visits to various regions and assessments of biomass resources, CPC has determined that the initial demonstration project will demonstrate the use of two agricultural residues: coconut shells and corn cobs. In both cases the supply of the feedstocks will be from the residue of the communities' commercial activities that produce corn and coconut oil.

Brazil

As a result of CPC's field mission to Brazil (August 1998), five significant markets for SMB systems in the 10- to 25-kWrange-including applications for village power, small sawmills and associated communities, small agricultural cooperatives, and a variety of rural industries in the Amazon Basin were identified. Biomass resources associated with these applications include wood scraps and sawdust residues from sawmills and residues from agricultural crops such as palm oil and cacao.

5.3 CPC's SMB system design

The CPC SMB gasifier design is based on a thorough knowledge of the thermodynamics and kinetics of pyrolysis and charcoal gasification reactions, as well as 25 years experience with many kinds of gasifiers. The new CPC gasifier has been designed using the following parameters:

- Maximum superficial velocity (SV) in pyrolysis zone of 1 m/s
- Fuel consumption of 10 kg/h fuel (dry, ash free basis, DAF)
- Fuel velocity in pyrolysis zone 10 cm/min for woody biomass, 3 cm/min for densified biomass
- Gas production = 25 m^3/h
- Energy content of gas @ 5 MJ/m^3 = 125 MJ/h
- Heat content/cooling load of gas (primarily N_2) at 1,000 °C = 1.3 MJ/m^3Y 32.5 MJ
- Gasifier efficiency = heat in gas/heat in fuel = 125/180 = 70%
- Gasification Air/Fuel (A/F) ratio – 1.5kg/kg, dry, ash-free fuel basis
- Total A/F ratio 6.0, DAF basis
- Pyrolytic gasifier diameter 10 cm
- Charcoal gasifier diameter 20 cm.

5.3.1 Description of CPC's SMB system

The CPC system employs a downdraft gasifier coupled to a spark ICE generator set. The gasifier design incorporates features that result in high levels of carbon conversion with low tar production. These design and operating features produce an ash with physical properties that make it easier to separate from the gas stream. The CPC SMB system uses a dry gas cleanup technology and operation principles that prevent formation of liquid condensates. CPC's prototype SMB is self-contained on a flat bed trailer having a footprint of 5 ft x 8 ft.

The CPC gasifier incorporates a flaming pyrolysis tube that generates charcoal centered in a larger plenum chamber, very well insulated at the bottom. A unique system of controlled injection of air for the final charcoal gasification process contributes to low tar and ash agglomeration. Agglomerated ash is automatically removed through a sealed opening in the base. Fuel is automatically fed to the gasifier. Figure 3 provides a simplified layout of CPC's SMB prototype system as of September 1999.

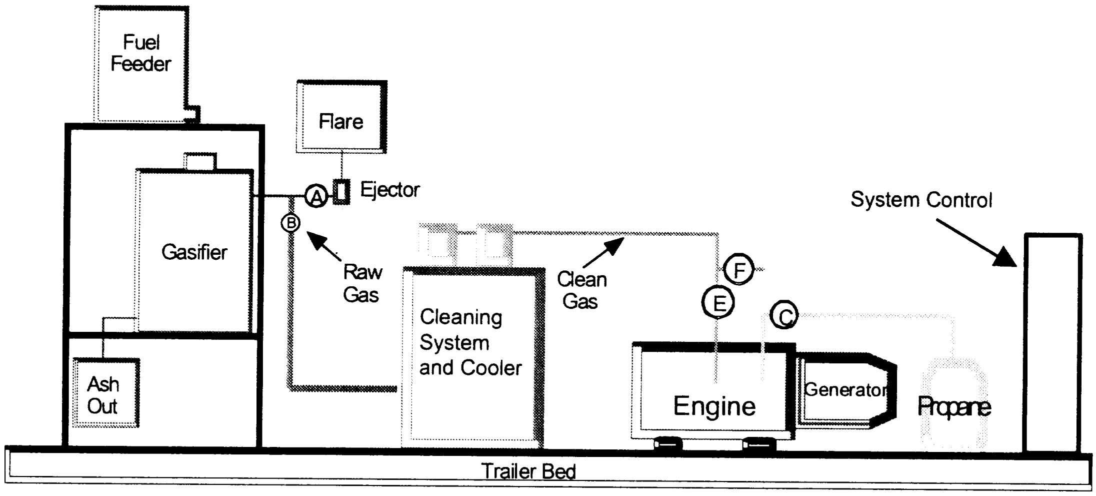

Figure 3. CPC's SMB prototype components.

5.4 Future development

In Phase 2, through collaboration with SR, CPC will use its new bioenergy development facility in Denver, Colorado, to prepare a pre-commercial SMB system for a series of field trails in the Philippines where both electrical and thermal energy will be provided to offgrid communities and rural enterprises.

In cooperation with SR, CPC will continue a long-term program to develop and supply a family of field-proven and commercially viable SMB systems to meet the growing global need for small, environmentally friendly, reliable, easily transportable and fully automated turnkey biopower systems.

6 Energy and Environmental Research Center

Subcontractor:	Energy and Environmental Research Center University of North Dakota P.O. Box 9018 Grand Forks, ND 58202
Contracting party:	Sandia National Laboratories
Subcontract title:	"Small Modular Biopower Project"
Subcontract No.:	SNL BC-0002C
Period of performance:	4 Jun 1998 through 30 Nov 1999
Subcontract contact:	Dr. Michael Mann, Tel. (701) 777-5193

6.1 Introduction

The Energy & Environmental Research Center (EERC) and its partners, King Coal Furnace Corporation and KJ Schwartz Engineering of Bismarck, North Dakota, have completed the preliminary design and feasibility of a modular fluid-bed biocombustor, which uses a bubbling fluid bed to burn biomass. Novel features of the system include the use of a thermal fluid for the in-bed and convective pass heat transfer, a new and novel steam engine to generate electricity, a combination biomass feed/drying system, and a modular package system developed by King Coal through its current stoker-fired business. The thermal fluid system will utilize Syltherm (polydimethyl-siloxane) to transfer the heat generated from the primary combustion system to a remote kettle boiler. By removing pressure parts from the boiler, manufacturing and operation become less costly, safer, and more flexible. A new steam engine being developed by Skinner Engine Company, Erie, Pennsylvania, offers higher efficiency and lower cost than its steam turbine counterpart. Ideal features for small remote applications, such as villages in Alaska, are the steam engine's simplicity and ease of service. The combined feed system/dryer represents a significant reduction over the use of a rotary or other dryer and offers the flexibility to handle fuels with moisture contents varying from 5% to more than 50%. The approach of packaging and delivering a complete system, including buildings, has allowed King Coal to keep system costs low so that its product can compete directly against low-cost gas- and oil-fired systems.

6.2 Market assessment

Based on an assessment of the small power market and biomass resource availability, King Coal has chosen to focus its marketing efforts on the lumber communities of the upper Midwest, including the states of Illinois, Indiana, Ohio, Michigan, Wisconsin, Minnesota, and the remote villages of Alaska. This assessment has further indicated that a 2-MW module would be an appropriate size for the upper Midwest market; 0.5 MW is more appropriate for the Alaskan and foreign markets. Forest residues are plentiful in both markets and represent a fuel that should perform well with minimal problems in the proposed design. Therefore, forest residues are targeted as the primary fuel for the system. Longer-range plans include incorporating design options into the fluid bed to allow operation using agriculture residues and urban wastes.

6.3 System design concept

The modular fluid-bed biocombustor, shown schematically in Figure 4, will use a fluid bed to combust biomass. The feed to the fluid bed will be predried in a unique feed storage bin design using heat recovered from the flue gas. Removing the moisture outside of the fluid bed eliminates the need to can-y that moisture through the system and significantly reduces the size of all system components. The dried fuel is conveyed to a live bottom feed hopper and from there metered to the fluid bed. The fluid bed is designed with a sparge tube-type distribution plate to allow tramp material to fall through to a bottom drain. The bed material will be selected based on concerns for agglomeration and the need for sulfur or chlorine capture. For most wood wastes, sulfur content is not needed, and local and inexpensive sand will be used as the bed material.

Preheated fluidizing air will be further heated to a design temperature of 1500 F by combusting the biomass in the fluid bed. Temperature and loads are controlled by varying the split of combustion air between the bed and freeboard and the amount and split of flue gas recirculation (FGR). This eliminates the need for locating heat-transfer surface in the freeboard area of the combustor. A special freeboard combustor design reduces both the required height of the combustor and the amount of ash carryover.

Heat is transferred from the bed and convective pass to heat a thermal fluid from 300 to 650 F. Syltherm, a silicon-based fluid marketed by Dow Chemical was chosen for the thermal fluid because of its low freezing point (–40 F), high boiling point (750 F), and its noncombustible nature. The thermal fluid then transfers its heat external to the boiler in a heat exchanger to generate steam to drive a steam engine for the smaller 0.5-MW system and a steam turbine for the larger 2-MW unit. The steam engine is an excellent choice for these applications because of its relatively high thermal efficiency, low cost, and ability to utilize low-quality (wet) steam. Its size is limited to approximately 0.5 MW; therefore, prototype testing will be performed using both a 2-MW turbine and a 0.5-MW steam engine. This will allow a comparison of the benefits of using multiple steam engines versus a single steam turbine for the larger (2-MW) system. Multiples of the 0.5- or 2-MW unit will be used for electricity generation in the anticipated range of 500 kW to 5 MW.

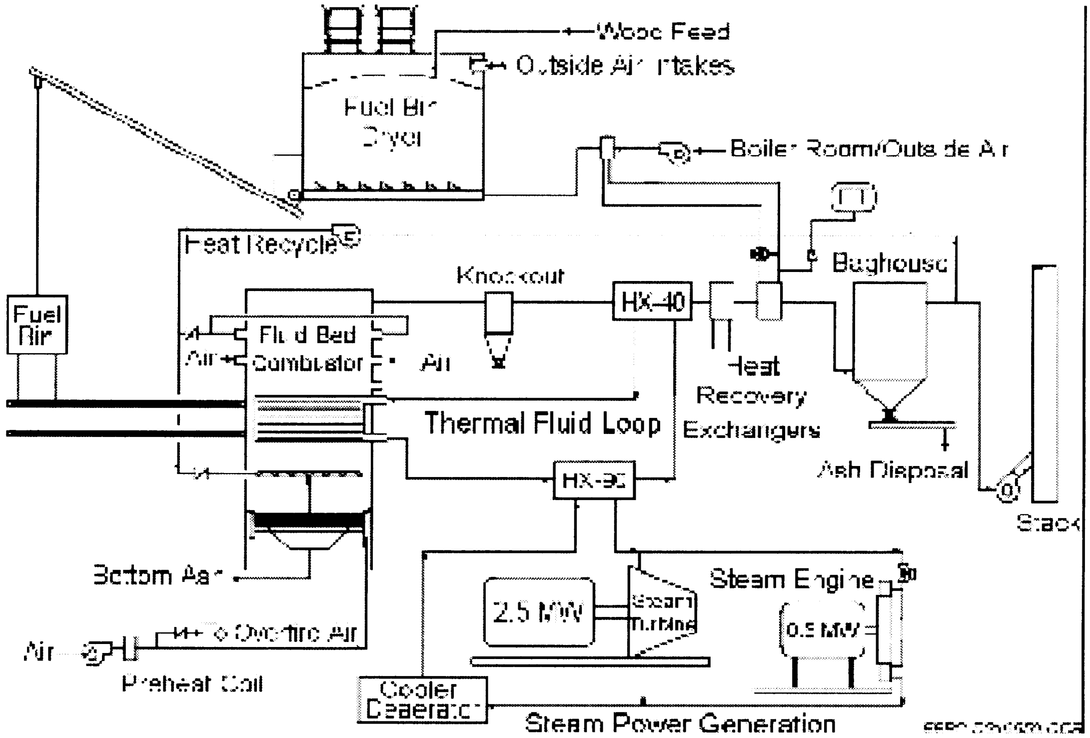

Figure 4. Modular fluid-bed combustor.

Flue gases are cooled to 500 F by the thermal fluid heat exchanger. Particulates will be removed using a multi-cyclone before recovered heat from the hot flue gases is used to dry the fuel. The flue gas is cooled to approximately 120 F while drying the fuel from 50% to 15% moisture. The dryer makes good use of low-level heat from the flue gas that is normally wasted out the stack.

6.4 Operating characteristics for niche markets

The modular fluid bed has a simple design. King Coal has manufactured and marketed stoker systems for 20 years, with installations in schools and other public buildings, greenhouses, livestock operations, lumber mills, and other locations that lack skilled labor. In all cases, the system is designed to be operated by a janitor, maintenance worker, or other unskilled laborer. The current system will be designed using the same concept, which will allow the fluid bed to be installed in any community.

The proposed design is for a self-contained power generating system. No external electricity will be required during system operation. The system is not dependent on a power grid and can operate as a stand-alone generation system to supply power to a given facility or community. For communities such as those in Alaska where a village is currently being serviced by diesel engines, the modular fluid-bed biocombustor would replace the diesel engine as the primary power source, but would keep the diesel engine on-line as backup.

A major market for the proposed system consists of sites that require both electricity and thermal heat, either as steam or hot water. For those systems, a steam delivery system will need to be added to facilitate delivery to the thermal host. The complexity and cost of the installation of the required infrastructure will depend on the proximity of the host to the power plant and the availability of infrastructure. The delivery of the thermal load needs to be considered as a part of the preliminary plant siting.

For other applications, such as greenhouses, public buildings, agriculture processing plants, and other locations that are currently connected to the power grid and are using fossil fuels for the thermal load, the proposed system will be tied into the current infrastructure.

The cost of power in the current markets is quite variable, depending on the market site. In remote locations such as Alaska, power costs are 100 to 400 cents/kWh. In other locations in the lower 48 states, the cost of gas or oil as a source of heat is the driving force that makes conversion to biomass fuels attractive. Because the modular fluid-bed combustor has a broad market base, it must be able to match the price of alternative energy sources for any niche it is to fill. Generally speaking, that means electricity in the price range of 2.50 to 7.5 c/kWh. Several companies have considered, or are considering, selling "green power" at prices in this range. King Coal and its partners have estimated the breakeven power cost at approximately 6 c/kWh for the proposed installation at Cass Lake, Minnesota.

6.5 System applications

The modular fluid-bed biocombustor is designed to generate electricity alone, electricity and thermal energy, or thermal energy alone. The primary market for the system will be markets requiring either electricity alone or both electrical and thermal demands. A system range of 0.5 to 5 MW is thought to best match the availability of the centrally located biomass for a given area and the needs for the primary users of the system.

The demand placed on the system will vary as a function of application. For example, for remote sites in Alaska, the load will have a daily peak during the day as well as a seasonal peak during the winter. Greenhouses and farming operations typically have a winter peak for heat and electricity. However, some greenhouses use special lighting to promote plant growth and have a fairly even year-round electrical demand. Other sites, such as agriculture processing plants (ethanol plant, straw board plant, etc.), will have a steady load 24 hours a day, 7 days a week, 320 to 350 days a year. The sites with the constant baseload demand are optimal locations for the proposed system. However, the modular fluid-bed biocombustor is applicable to situations with all the loads described. The steam engine by itself or in multiples is very applicable to the varying demand (load following) approach.

The small size of the proposed system exempts it from most federal emission standards. Particulate and sulfur emissions will be regulated for systems on the larger end of the scale, with no requirements for those on the smaller end. Even though emission requirements are minimal, the modular fluid-bed biocombustor will have low emissions. Biomass typically has low sulfur, minimizing SO_2 emissions. Limestone can be added to control sulfur emissions for a fuel with higher sulfur levels. The fluid bed typically generates low NO_x emissions, and further reductions will be obtained with air staging and FGR. Particulate control will be met with a baghouse; CO levels are expected to be below 200 ppm. This should allow operation in most states and foreign countries well within the current regulatory emission levels. For states such as California with extremely low emission levels rather expensive control systems may be required. This could preclude operation in the most sensitive areas of the country.

The prime competition for the proposed system will be electricity from the grid, steam or process heat from coal-fired stokers or gas-fired systems, and diesel generators. With regard to the use of biomass, competition will come from stoker-fired systems, gasifiers coupled to ICEs or microturbines, and sterling engines. Other competition could come from other renewables such as small hydroelectric and wind generators.

6.6 Future development

King Coal's approach for further developing this product is to build a fully operational prototype at an industrial park in Cass Lake. This approach allows operating revenue to be generated, which will offset the cost of operating the system during the testing and evaluation phases. It also provides the opportunity to test the various developmental components in a realistic setting. The data generated on system reliability and maintainability will be needed to help market a demonstration in Alaska. The system will be equipped with both a 2-MW steam turbine and a 0.5-MW steam engine. The steam turbine should allow for long-term stable operation and provide the flexibility to focus developmental efforts on the steam engine. In addition, long-term operation will offer the opportunity to gather design information under a variety of conditions for the dryer/feeder and the thermal fluid heat exchanges. Several iterations of these designs will likely need to be tested before determining the final specification to be included as part of the standard package. Long-term operation of these two subsystems is also crucial to demonstrating their safety.

7 Niagara Mohawk Power Corporation

Subcontractor:	Niagara Mohawk Power Corporation 300 Erie Boulevard West Syracuse, NY 13202
Contracting arty:	Midwest Research Institute, National Renewable Energy Laboratory Division
Subcontract title:	"Small Modular Biopower Project"
Subcontract No:	ACG-8-18073-05
Period of performance:	30 Jun 98 through 31 Dec 98
Subcontractor contact:	Dr. Peter K. Strangway, Tel. (315) 428-6532

7.1 Background

Niagara Mohawk Power Corporation (NMPC) will invest nearly $2 million during 1999 to retrofit its Dunkirk Steam Station to co-fire approximately 10 MW of biomass with coal. Co-firing has long been a goal for the Dunkirk Station owners and is seen by the new plant manager as an important added value capability as the station is transferred from NMPC to NRG in the summer of 1999. As the lead organization for the Salix Consortium, NMPC works with 20 organizations in the Northeast to scaleup and demonstrate the viability of willow energy crops. This is the second leg of the NMPC program to demonstrate sustainable future energy supplies of biomass for power generation. The third leg of NMPC plans for biomass is the development of viable distributed power systems to support the grid where load growth and biomass resources converge. The proposed objective of this feasibility study was to develop a system (components and configuration) from commercially available technologies and to evaluate costs and benefits of operating the system in NMPC's service area.

In Phase I, we proposed to explore the feasibility of biomass gasifiers for two potential near-term markets: 1) grid support for power distribution in rural locations, and 2) co-location at large-scale power generation facilities to provide NO_x control and fuel flexibility. After preliminary work, the focus of the effort became grid support, or distributed generation, applications. The distributed generation systems in remote areas would be a better fit with NMPC's role in the restructured electricity market. It also appears to be a lower risk application with very near-term applicability.

7.2 Rural service markets for biomass support to transmission and distribution

A distributed generation facility located at the end of the grid may be able to deliver power competitively using locally available biomass resources. In the not-too-distant future, remote customers may have to bear more of the cost of service than they do today as the electric markets are deregulated. A distributed generation system will not have to be burdened with the full charge for transmission. Biomass distributed generation may become more competitive under these circumstances, even though much cheaper power may be available at power exchanges.

The area selected by NMPC for a site-specific evaluation of the market for biomass-fueled gensets is representative of many of the rural areas bordering the Appalachian chain In the opinion of CT Donovan Associates and Tim Volk, State University of New York Environmental Services and Forestry, the volume of resources in this region can be replicated in many areas of Pennsylvania, New York, Verrnont, New Hampshire, and Maine. In the northern tier of this region a number of biomass-fueled generating plants built during the 1970s helped establish an infrastructure for biomass energy supplies. The retirement of some of these stations is creating a situation in which fuel suppliers will need to find buyers or close their operations. This situation has created near-term opportunities to acquire fuels for new projects at very competitive prices. The opportunity to pick up the slack in business will fade as suppliers adjust to the market.

The cost of upgrading transmission and distribution to communities served by radial feeders in the Adirondack area is $4 to $8 million. A generation system using local fuels would be an attractive alternative to reconducting the transmissions lines if capital requirements were the same or less, and the (levelized) COE was competitive. The use of reliable distributed generation technology would mean that the needed capacity could be added without disrupting service during construction. System reliability would improve because these rural customers could be served by two independent sources much the same way that transmission loops often provide two routes to reach the customer.

7.3 Technology and application economics for grid support applications

Although this study discovered significant outstanding technical issues with gasification and its use with engine systems, the design and costing of a system was undertaken to understand the economics of a 5-MW biomass power plant built with currently available equipment. The power plant would be composed of the gasifier, gas turbine and generator, wood receiving facility, a stockyard, sizing equipment, a rotary wood dryer, storage silo, and a substation. The plant is assumed to be located somewhere in the Adirondack Park region in one-half mile of a distribution substation.

This plant is intended for base load duty to maximize utilization and thus lower costs. The system design began with the premise of generating a nominal 5 MW, capacity. The net output of the plant turned out to be 4.27 MW after plant parasitic uses. As a base loaded plant, the capacity utilization was assumed to be 90% or better.

The Primenergy gasifier is used as the basis of the system (Table 10). This system requires that the wood feed have a moisture content (MC) of 20% or less. Because a large portion of the wood supply will be whole green chips and bark, a dryer is required. A gas turbine generator was chosen over a spark ignition reciprocating engine generator because it has lower capital and operating costs. A Solar Turbine's Taurus 60, rated at 5,200 kW ISO base load, was chosen as a representative model. To complete the plant, a substation is required to step up the voltage to tie into the distribution system. Total capital requirements are an estimated $15 million.

Table 10. NMPC plant specification.

Gross output	5.2 MW
Net output	4.27 MW
Annual net output	33,633 MWh
Capacity utilization	90%
Annual operating hours	7884
Fuel	Wood residues
Fuel consumption	103,000 green tons/yr

At this point, NMPC realized that building a modular 5-MW system for stand-alone electricity service from today's off-the-shelf equipment would not be cost competitive with the line upgrade alternative. Given the significant technical issues with gasifiers of that capacity and their coupling with a turbine or reciprocating engine, a successful demonstration of this scale of application could be undertaken within the next 5 years seemed unlikely. A major technical development and demonstration effort would have to be mounted to build a system in the near term that would satisfy NMPC standards for service.

Despite this conclusion, a financial analysis was conducted to complete the feasibility study. A levelized revenue requirement calculation was performed for the base case (building in the near term with currently available equipment with current wood prices). Several scenarios were run from the base case to illustrate the impact of capacity utilization, wood cost, and total capital requirements. Finally, an analysis was performed to establish cost and performance goals for future systems. A best case system was developed by optimistically cutting costs and improving performance in every area available.

The calculated COE for the base case is 16.28o/kWh, mostly because of the high costs of handling, sizing, and drying the wood. Because of the labor required and the maintenance of the equipment, the O&M costs comprise more than half the COE.

The COE for the future system design is 8.20/kWh with $14.00/green ton wood, of 5.90 with zero cost wood. A capital investment of $10.5 million is required. This is considerably closer to providing an alternative to the line upgrade option. However, capital requirements still exceed the transmission line upgrade, and the COE exceeds, albeit slightly, the rates established for the Adirondack Park region. Lastly, achieving this level of cost with the attendant expectation of higher performance and high reliability and availability is likely to be a large undertaking.

7.4 Conclusions

NMPC remains very interested in the development of an advanced, cost-effective biomass modular generation technology that uses local resources. The cost of upgrading radial feeders in rural, environmentally sensitive areas will require significant company investment during the next 10 years. However, we have concluded that biomass gasification systems are not technically or economically ready to provide a viable alternative to reconducting. The efficiency of the gasifiers must be improved and their reliability demonstrated before these systems can be considered ready for service. Much of the required work is underway, and we hope that DOE can continue to support these efforts.

Although NMPC is not prepared to assume a primary R&D role at this juncture, we would be open to partnering with a technology developer and others when the technology is ready for a pre-commercial demonstration.

8 Reflective Energies

Subcontractor:	Reflective Energies 22922 Tiagua Mission Viejo, CA 92692-1433
Contracting party:	Midwest Research Institute, National Renewable Energy Laboratory
Subcontract title:	"Small Modular Biopower Project"
Subcontract No.:	NREL ACG-8-18073-03
Period of performance:	6 Jun 98 through 31 Dec 99
Subcontract contact:	Edan Prabhu, Tel. (714) 380-4899

8.1 The Flex-Microturbine™, running on low-pressure, low-energy gases

Reflective Energies is developing a new business that will convert enormous quantities of previously unusable waste into electricity at very low cost. The key technology for the new business is a small, reliable, microturbine electric power plant, the Flex-Microturbine™. The Flex-Microturbine™ will be able to run on fuel gases that are today considered too low in pressure or energy content to produce electric power. It will be able to tap many sources of renewable energy. Flex-Microturbines™ will accept a wide range of low-grade fuel gases while producing lower emissions than "traditional" microturbines. The Flex-Microturbine™ will run on the waste gas now flared from landfill operations, from animal waste and on low-energy gas from the gasification of biomass in addition to waste gases from petroleum and coal production operations. The EPA considers each one of these streams a major environmental hazard and has specific programs for mitigating emissions from each such operation.

Reflective Energies is partnered with Capstone Turbine Corporation, maker of the world's first commercial microturbine power plant and the first to obtain UL approval for the entire power plant. The Flex-Microturbine™ will be adapted from the commercial Capstone Micro-Turbine™ line, and will be produced, marketed, and serviced by Capstone.

The Flex-Microturbine™ will create markets not currently available to other microturbines, which require pressurized, high-Btu fuel or expensive fuel gas compressors. By using low-grade fuel that is now going to waste, these plants will produce electricity at significantly lower costs than larger plants. They would also provide major environmental and social benefits, converting damaging waste into electricity. In many cases, the environmental or renewable energy benefits will qualify for subsidies from governments and multilateral institutions pledged to support renewable energy and to combat global warming.

Flex-Microturbines^{TM} will be also run on low-Btu biomass gas from waste wood and crop residues. It will run on fuels well below 100 Btu/scf with no other fuel present. These are important fuels for many developing countries with desperate shortages of power and large quantities of underutilized or destroyed biomass.

Portable plants coupled to small wood gasifiers will be developed and fitted onto flatbed trailers. Instead of moving the fuel to the plant, these plants will be moved from site to site to consume local fuel. This will be especially valuable in the western United States where decades of dying trees and brush pose threats of catastrophic fires, and where huge quantities of unwanted crop and orchard residues are mounting.

In addition to its enormous renewable energy applications, the Flex-Microturbine^{TM} will also be the practical low-cost technology for low-pressure natural gas. The ultra-low emissions and the elimination of the fuel gas compressors will offer compelling advantages over traditional microturbines. Whereas emissions limit the use of certain natural gas engines, the Flex-Microturbine^{TM} will meet the most stringent emissions requirements anywhere.

The Flex-Microturbine^{TM} creates a fundamental increase in the usefulness of microturbines, and will enhance the quality of life for people all over the world.

8.2 The market

The world market for the Flex-Microturbine^{TM}, using only fuels presently wasted, is several hundred thousand megawatts. The projected annual sales for the Flex-Microturbine^{TM} are presented in Table 11. The figures assume that only 1% of the total potential market will be achieved each year.

8.3 Market drivers

There are several reasons why customers will select the Flex-Microturbine^{TM} to generated electricity. Where fuel is a free by-product, electricity will simply be sold for a profit. Renewable energy incentives will enhance the economics. Some customers will even run the Flex-Microturbine^{TM} on low-pressure natural gas to offset high retail electricity costs and to enhance the security of electric supply. President Clinton's Executive Order calling for a threefold increase in bioenergy by 2010 will accelerate the market.

Table 11. The Flex-Microturbine™ market potential.

Market	Fuel source	Potential MW	No. of units 100% of market	Units per year 1% of market/yr	Revenue @ $400/kW Annual gross rev.
California	Wood/crop residue	1,000	33,000	330	4,000,000
	Landfill gas	500	16,500	165	2,000,000
	Animal manure	100	3,300	33	400,000
	Other waste gas	1,000	33,000	330	4,000,000
	Total California	**2,600**	**85,800**	**858**	**10,400,000**
U.S.	Wood/crop residue	10,000	330,000	3,300	40,000,000
	Landfill gas	10,000	330,000	3,300	40,000,000
	Animal manure	1,000	33,000	330	4,000,000
	Other waste gas	10,000	330,000	3,300	40,000,000
	Total U.S.	**31,000**	**1,023,000**	**10,230**	**124,000,000**
Wordwide	Wood/crop residue	100,000	3,300,000	33,000	400,000,000
	Landfill gas	25,000	825,000	8,250	100,000,000
	Animal manure	20,000	860,000	6,600	80,000,000
	Other waste gas	100,000	3,300,000	33,000	400,000,000
	Total worldwide	**245,000**	**8,085,000**	**80,850**	**980,000,000**

Figure 5 compares the cost of generating electricity from the Flex-Microturbine™ to the cost of wholesale and retail electricity. For low-grade fuel applications the Flex-Microturbine™ beats retail power prices even with natural gas as the fuel. Figure 5 does not take credit for any renewable energy subsidies, buydowns, green power portfolio standards, and pricing. Such subsidies, available in the United States and worldwide, will further enhance the economics.

Even without subsidies, the capital payback period for many of the applications will be between one and three years. This payback will be quickest where fuel is essentially free for the taking, such as in numerous landfill operations today, or where labor is inexpensive.

8.4 Current status and plans

The critical technical development work is now complete, supported by important funding from DOE and NREL. Successful safety testing of the new concept performed at the University of California Combustion Laboratory in Irvine. Key partnerships have been established. A development agreement with the EERC, Grand Forks, is underway.

Funds for demonstration testing are expected from the DOE and the State of California's PIER program. The first demonstration units are expected in early 2000 with commercial units available in early 2001. Demonstration units will be run on "producer" gas from wood gasifiers, landfill gas, and on digester and petroleum production gases currently being flared.

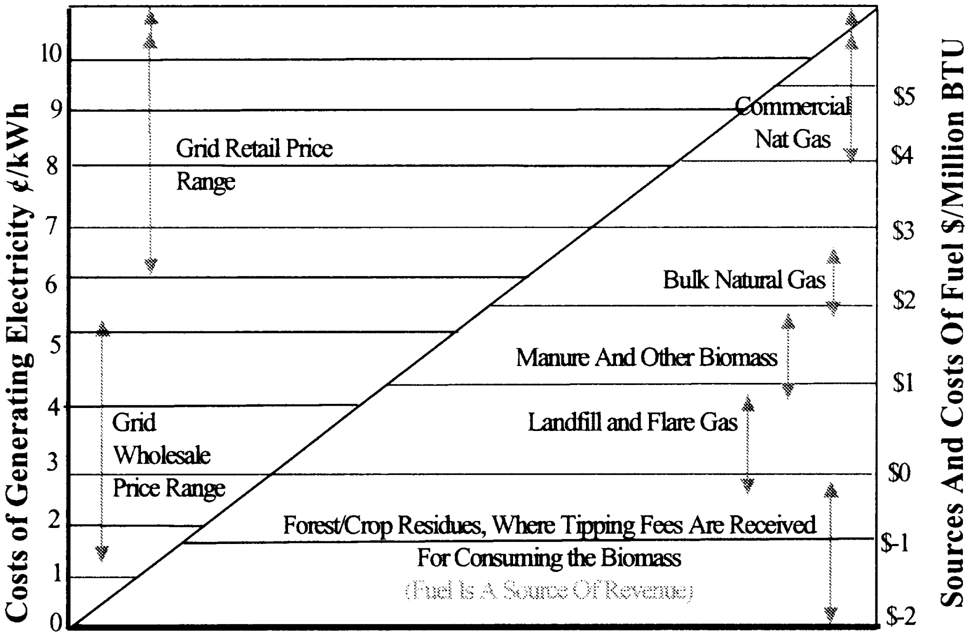

Figure 5. Microturbine generating costs for various fuels compared to traditional generation costs.

8.5 Business strategy

Following development of the Flex-Microturbine™ and hand-over of manufacture and marketing to Capstone, Reflective will focus on developing high-value, high-visibility projects for the Flex-Microturbine™ in the United States and elsewhere. There is already a strong market pull for this product, with a large backlog of potential buyers. Interested parties include DOE, the Los Angeles County Sanitation District, the California Department of Forestry, Dane County Landfill in Madison, Wisconsin, NISource, and other landfill and animal digesters around the nation. In addition, the World Bank, the Global Environment Facility, United States Agency for International Development, the United Nations Development Program, the International Finance Corporation, and others have expressed interest in such a dependable renewable energy system that is easily installed, uses local fuel, and creates local jobs. As in the United States, Reflective will develop high-visibility international projects, seeding the market for rapid growth.

9 STM Corporation

Subcontractor:	STM Corporation 275 Metty Drive Ann Arbor, Ml 48103
Contracting party:	Sandia National Laboratories
Subcontract title:	"Small Modular Biopower Project"
Subcontract No.:	SNL BC-0002A
Period of performance:	19 May 1998 to 30 Nov 1999
Subcontract contact:	Dr. Benjamin Ziph, Tel. (834) 995-1755

9.1 Introduction

Pursuant to SNL's contract #BC-0002A, STM Corporation has been developing an SMB system based on STM's 25-kW Stirling-cycle engine: the STM4-120[1]. The Stirling-cycle engine is externally heated and thus requires merely a sufficiently hot flow of combustion gases through its heat exchanger to produce power. A Stirling-based biopower system can then be implemented simply by directing the gaseous products of the combustion of solid biomass fuel through the heat exchanger of the engine, in contrast with ICE-based systems that require the solid biomass fuel to first be converted into cool and clean gaseous fuel.

The objectives of Phase 1 have been to develop technical and business strategies for incorporating the STM 4-120 engine with a solid biomass combustion system, into an SMB system and to commercially introduce this system into suitable markets. The approach to the Phase 1 study was based on the recognition that commercial introduction will be strongly facilitated by employing a developed engine that will be mass-produced for a number of applications.

STM engaged the Antares Group to conduct a market assessment study and a biomass resource assessment study. Inputs from these studies were used to design a complete biopower system made up of the STM 4-120 Stirling engine close-coupled to a commercial updraft sawdust gasifier and equipped with an induction generator to produce grid-connected electric power. The design was then used to assess the performance, costs, safety, and environmental impacts of the system. Finally, all this information was taken into consideration in developing a preliminary business plan and commercialization strategy.

9.2 Potential markets

The domestic market potential was based on the estimated amount of sawdust available. Previous analyses showed that sawdust presents the most viable biomass feedstock for the BioStirling system because of its abundance and physical characteristics. Sawdust is generated by both primary and secondary wood processing facilities. Residue that is disposed of at no higher value to the mill was considered to be "available" for use as feedstock. This category includes residue that the mill gives away, pays to have removed, stockpiles onsite, incinerates onsite, landfills, or scraps in any other way. The market is the number of STM units that can be supported annually multiplied by available sawdust. The total revenue was arrived at by assuming STM captured 100% of this market. The price per 25-kW unit was assumed to be $40,000, and each unit needs to be fueled by 457 tons of sawdust per year. For the primary mills market, the analysis shows that STM has the potential to sell 4040 units and collect $161 million in revenue. For the secondary mills market, STM has the potential to sell 1258 units and collect $50 million in revenue, across the United States.

Table 12 outlines some key assumptions.

Table 12. Summary of domestic market potential assumptions. Table results expressed in cents/kWh.

Variable	Value
System size	25 kWe
System cost	$1,600/kW
System efficiency (electrical)	29,246 Btu/kWh
Operating hours	7000 h/yr
Fuel HHV (@ 30% MC)	5600
Sawdust required/Unit	457 tons/yr
Secondary mill residues/Primary mill residues	0.31 ton/ton
Avail. sawdust/Total avail. residues	0.39 ton/ton

A first approximation was made of the international market potential for each country analyzed in this report. Results showed that if it captures 100% of the market, STM has the potential to sell 9371 units and collect $375 million in revenue across the 21 countries in this analysis.

The economic benefit of the BioStirling system to the end user will be the key to its success. This will rely on demonstrating the value of producing on-site electricity/heat and the waste disposal avoidance benefits of this system. A simple tool was developed that provides some perspective on the market conditions that must exist to make the BioStirling system attractive. Table 13 summarizes the analysis in a cross-tabulated matrix. The analysis relies on the following assumptions:

- Overall thermal efficiency of the BioStirling system is 82%.
- Heating fuel is displaced at $2.00-$4.50/MMBtu via heat recovery.
- Tipping fees paid for waste wood removal range from $0.00 to $40.00/ton.

Table 13. STM system benefits (cents/kWh). Accrued through avoided residue disposal costs and heating fuel offsets.

Disposal costs*, $/ton)

Fuel $/MMBtu	-	2.00	5.00	10.00	15.00	20.00	25.00	30.00	40.00
-	-	0.52	1.31	2.61	3.92	5.22	6.53	7.83	10.44
2.00	4.13	4.66	5.44	6.74	8.05	9.36	10.66	11.97	14.58
2.25	4.65	5.17	5.96	7.26	8.57	9.87	11.18	12.48	15.09
2.50	5.17	5.69	6.47	7.78	9.08	10.39	11.69	13.00	15.61
2.75	4.65	5.17	5.96	7.26	8.57	9.87	11.18	12.48	15.09
3.00	5.17	5.69	6.47	7.78	9.08	10.39	11.69	13.00	15.61
3.50	5.68	6.21	6.99	8.29	9.60	10.91	12.21	13.52	16.13
4.00	6.20	6.72	7.51	8.81	10.12	11.42	12.73	14.03	16.64
4.50	7.23	7.76	8.54	9.84	11.15	12.46	13.76	15.07	17.68

* *includes tipping fees and other removal costs*

Under these assumptions, the value of offsetting tipping fees and heating fuel costs can exceed 170/kWh. 'Me effect' of this is illustrated in the following example.

A facility is currently paying $5/ton disposal costs for waste wood. The facility will also be able to use the waste heat from the BioStirling system and currently pays $3.00/MMBtu for heating fuel. Therefore, the avoided cost benefit of the STM system is 6.5 c/kWh. The significance of this benefit is illustrated as follows:

Sawmill's current electricity costs as purchased from the grid	5.5 c/kWh
Less BioStirling electricity generation (capital plus O&M, fuel is free)	– 4.8 c/k)"
Savings in electricity cost	± 0.7 c/kWh
Benefit of avoiding heat and disposal costs	6.5 c/kWh
Net benefit realized through BioStirling utilization	7.2 c/kWh
Annual generation	175,200 c/kWh
Net Annual Benefit (rounded)	**$12,600**

The net annual benefit appears attractive and translates into a 3-year simple payback on the investment. This analysis also suggests that the benefits of avoiding disposal and heating fuel costs will far outweigh the benefits of on-site electrical generation unless the facility is paying very high electricity costs.

Two other considerations enhance the market projection but are not included in the reference case:

- Some states grant a $5/ton credit for the conversion of sawdust into an "economically valuable product," which can include electricity. This credit would add to the overall economic benefit of an end user.
- The system described herein presumes sawdust as the feedstock of choice. Not included in the market projections is that the BioStirling system may also employ, without change, other compatible feedstocks – primarily agricultural wastes.

9.3 System design

Figure 6 shows a schematic of the biopower system. The biomass feedstock is combusted in two stages: The first is a sub-stoichiometric, sub-atmospheric gasification using Chiptec Wood Energy Systems' C-1 updraft sawdust gasifier. The second stage – complete combustion of the gas from the first stage – takes place in a continuous combustor equipped with a jet pump flow inducer. A combustion blower supplies the secondary air to the combustor. The secondary air creates suction at the jet pump throat to induce atmospheric airflow into the gasifier and producer gas flow out through the ash separator and to the secondary combustor where it burns with the secondary air. The combustion gases then flow through the engine heat exchanger, give up its heat to the engine and are exhausted or delivered to an application-specific consumer heat load. Between the gasifier and the secondary combustor are disposed a cyclone fly-ash separator and a bypass system that is activated only upon startup and shutdown of the system. The engine drives an induction generator to produce grid-connected electric power.

The technical specifications of the system are summarized in Table 14.

The BioStirling design concept addresses the following technical issues:

- Fouling and corrosion
- Safety and environmental pollution
- Durability and economical operation.

Benefits of avoiding disposal and heating fuel costs will far outweigh the benefits of on-site electrical generation.

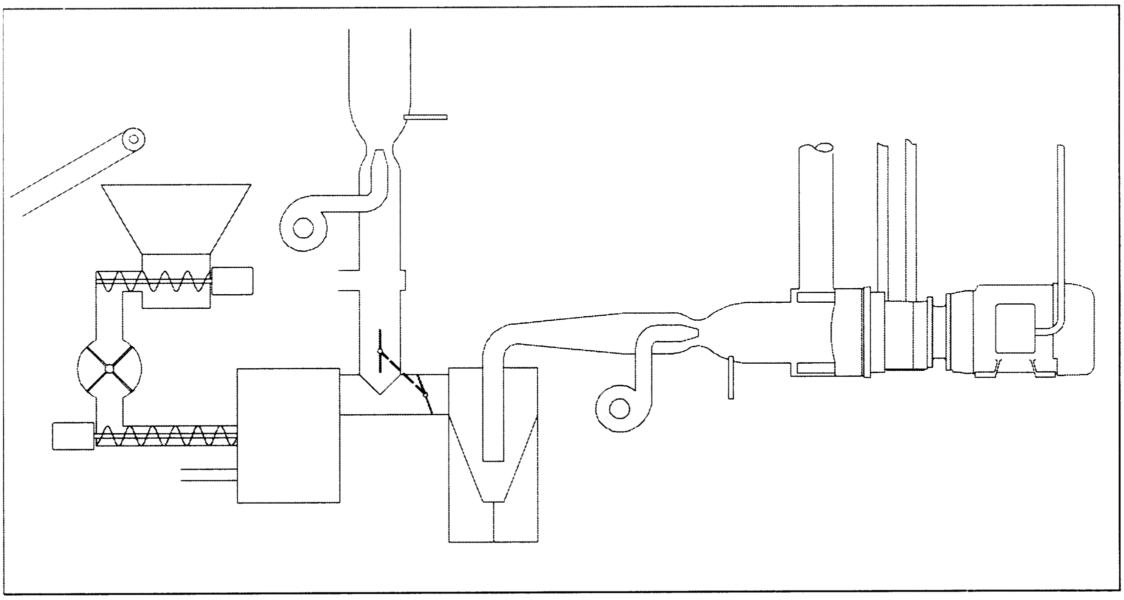

Figure 6. BioStirling system schematic.

Table 14. BioStirling system specifications.

Primary feedstock	Sawdust
Feedstock consumption	59 kg/h
Air flow Primary Secondary Total	24 g/s 108 g/s 132 g/s
Electric power	25 kWe
Heat to consumer	140 kWth at 813 ºC
Coolant heat	41 kWth at 60 ºC
Energy utilization efficiency	86.5%
Exhaust heat	29 kWth at 200 ºC
Installation size (LxWxH)	5.66 x 2.87 x 3.66 m
Emission indexes (g/kg) CO NO_x	1.0 2.5
Design life	50,000 h

9.4 Future development

The BioStirling system will be introduced to the market via selective demonstration programs involving commercial organizations or parties affiliated with commercial entities that need the system and that are known high-exposure participants in the biomass market.

- A joint venture with a major industrial partner is now in the process of being formed

- The bulk of marketing (sales-service-distribution) will be the responsibility of the industrial partner
- STM shall remain the technology provider to the joint venture and assume some manufacturing functions for the production of Stirling-specific components
- Future development and deployment funding is envisioned from a variety of sources, depending on the market and dominant pacing items involved
- Internal R&D funds from the joint venture
- Agencies with dedicated biomass programs resolving environmental concerns connected to biomass
- Multinational aid and funding organizations
- Revenues from commercial sales.

10 Sunpower, Inc.

Subcontractor:	Sunpower, Inc. 182 Mill Street Athens, OH 45701
Contracting party:	Midwest Research Institute, National Renewable Energy Laboratory Division
Subcontract title:	"Small Modular Biopower Project"
Subcontract No:	ACG-8-18073-03
Period of performance:	6 Jun 98 through 30 Sep 99
Subcontractor contact:	Elaine Mather, Tel. (740) 594-2221 mather@sunpower.com

10.1 Introduction

The subject of this SMB project is a system that burns biomass fuels and converts the resulting heat to electric power by means of a free-piston Stirling engine. The first systems to be commercialized through this project are designed to burn wood fuels, because at present those fuels are widely used by a large, initial target market: homeowners who burn wood for heat. Later products will be designed to burn other types of biomass fuels as they become commercially available.

The overall objective of this SMB project is to develop SMB systems that are fuel-flexible, efficient, simple to operate, whose operation has minimum negative impacts on the environment, and which that provide power in the range of electrical generation sizes smaller than 20 kW for domestic and international markets. The Phase 1 objective was a feasibility study that includes a market assessment, resource assessment, preliminary system design, assessment of relevant environmental and safety considerations, evaluation of financial and cost issues, and preliminary business plan and commercialization strategy.

This project achieved all Phase 1 objectives with respect to the first product in a line of SMB systems. That product is a system that cogenerates as much as 1 kW of electrical power together with heat for water and space heating in single-family dwellings. Later products will have electrical output capacities as high as 20 kW for larger residential, commercial, and agricultural applications.

10.2 Potential markets

10.2.1 The market

The target market for these products is in individual residential, small commercial, and farm buildings worldwide wherever low-cost biomass fuel is abundantly available and electric power is unavailable, unreliable, or expensive. These products will he sold in three market segments: remote homes in developed countries, off-grid rural electrification in developing countries, and on-grid distributed power production worldwide.

Near-term sales opportunities for these products are in the forested territories of the higher latitudes where wood is burned extensively as a fuel. The aggregate sizes for all single-family residences in North America, Europe, and developing countries are estimated to be $200 billion, $230 billion, and $150 billion, respectively.

10.2.2 The biomass fuels

The initial models of these residential cogeneration products will burn wood pellets and fuel wood. Most wood pellets used for residential heating are made from sawdust and ground wood chips, which are waste materials from trees used to make furniture, lumber, and other products. Pellet fuels graded by The Pellet Fuels Institute must meet tests for density, dimensions, fines, chlorides, and alkali content. These physical and chemical properties are ideal for biomass combustion, but the processing that contributes these virtues also makes pellets the most expensive form of biomass fuel. Because they are densified, pellets can be profitably transported to distant markets.

Fuel wood is harvested as a fuel source rather than as lumber or for other purposes. Production is highest in the forested territories of the northern and central latitudes. The United States produces the most fuel wood in North America. Russia produces the most fuel wood in Europe, but per capita fuel wood production is much greater in the Scandinavian and Baltic countries, especially in Finland.

10.2.3 Competing demand for these biomass fuels

The primary competing demand for these biomass fuels is residential heating. The new residential biomass cogeneration products will not change this usage for the initial target market of homeowners who already burn wood for heat. Later the market will be expanded to displace expensive and polluting residential electric and fossil fuel heat sources, which will increase the demand for biomass fuels.

10.2.4 The optimum size for this technology

Historically, Stirling engines have been fabricated in capacities from 1 W to more than 1 MW. The optimum size for this technology is an economic issue relative to competing technologies for the same application, and it has not yet been determined in the marketplace. Stirling engines work by sensible heat transfer into and out of the engines, so they are believed to be most competitive as their size is reduced and their surface-to-volume ratio increases. Therefore, free-piston Stirling engines are generally believed to be most economically competitive with other technologies at power levels less than 20 kW; this advantage is believed to increase as size is further reduced. This favors an economy of scale based on high-volume manufacturing rather than on high unit capacity.

10.2.5 The demand for this type of power

Such a low power range has a major economic advantage over larger biopower technologies that compete with other large generating technologies in a wholesale deregulated electric power market. Residential biomass cogeneration systems can compete on the retail market where competing prices are highest. This creates opportunities for higher margins and smaller financial risks. Furthermore, avoidance of a separate heating bill also creates a large economic incentive for homeowners to convert from expensive electric heat to biomass cogeneration.

For example, for the 1 million off-grid homes in North America, the competing prices of electricity range as high as $0.75/kWh or more and the primary heat source for many of these homes is wood. In North America, 15 million homes burn wood for heat, including 5 million in the Northeastern states (where homeowners pay the highest electric utility rates in North America). In addition, 9 million homes are heated by electricity.

Of the countries with the highest average household electric utility rates, all but Korea and Japan are in Europe. In Europe, too, many are heated by wood, including 1.3 million in Scandinavia, 600,000 in Austria, and 2.5 million in France. Many more homes, including 2.5 million in Scandinavia, 300,000 in Austria, and 9 million in France, are heated by electricity.

10.2.6 Fit of the optimum size to the demand

In middle-class, single-family residences in developed countries, the average annual electrical load for purposes other than space heating and cooling is 1 kW. The average daily peak electrical load is -1.5 kW and momentary surge loads can be as great as 6 kW as motors in home appliances start up. The peak load exceeds 1 kW for only a few hours per day, however, and surge loads occur for only a few minutes per day.

Sunpower believes that the greatest home economy will be achieved by residential co-generation systems that serve the average annual electrical load and use other sources of electrical power, such as an electrical utility grid or a battery bank and an inverter, to serve peak and surge loads. Thus, the optimum size of free-piston Stirling engines fits especially well with the average annual electrical demand of the single-family residential market.

10.2.7 Biomass requirement and availability

A 1 kW residential biomass cogeneration system for markets in northern latitudes may be designed to burn the least fuel required for the system's electric generating capacity, or to burn more wood to serve the full residential space heating requirement. For the 1 kW electrical generating capacity, a residential biomass cogeneration system will burn ~1.5 kg of wood pellets per hour. This projects to ~6.5 tons of wood pellets per year (the corresponding amount of fuel wood depends on the moisture content of the fuel). This amount is similar to the amount burned by homes in Sweden that use pellet furnaces as their primary heat sources.

Wood pellets are widely available for retail sale in North America and northern Europe. They are delivered directly to homes throughout Sweden south of the 60^{th} parallel, where more than 80% of the population lives. Self-cut fuel wood is commonly cut on the homeowner's own woodlot. Purchased fuel wood is delivered by the retail vendor, usually an individual entrepreneur.

10.2.8 Projected system capital cost

Because SMB systems can be targeted at high margin markets where the competing COE is highest, entry prices for these systems can be unusually high. The cost of a competing residential solar photovoltaic electric generator system capable of providing the same 24 kWh/day every day of the year in northern forested territories (where insolation is low) ranges from $50,000 to $100,000. An international distributor of renewable energy systems believes that the North American remote home market will pay $10,000 for 1-kW residential biomass cogeneration systems, i.e., $10,000/kW.

To open larger markets, prices will need to be reduced, but Sunpower believes this will be achievable as manufacturing volume increases. For sale to on-grid markets, prices may be reduced to $3,500/kW or lower. The target high volume system manufacturing cost is $1,000/kW.

10.2.9 The cost of electricity for the proposed market

The economics of the cogeneration of electricity and heat differs fundamentally from those of electric generation, which is critical in enabling residential biomass cogeneration products to compete aggressively against all electric generating technologies. In both electric generation and cogeneration, the COE increases with the system capital cost, the cost of fuel, and the O&M costs. In cogeneration, however, this cost is reduced by the market value of the heat that is cogenerated and that does not have to be purchased separately from another heat source. Furthermore, the effective cost of cogenerated electricity decreases as the avoided market value of the heat increases. Therefore, the very same cogeneration system produces electricity at different prices, depending on the values of the avoided cost of heat.

Thus, even at entry market prices for equipment, when it displaces heat from a wood stove, a 1-kW residential biomass cogeneration system in a home in a northern latitude cuts the COE in half. When the competing heat source is a more expensive oil furnace, the reduction in the effective cost of cogenerated electricity is greater, and when the competing heat source is electricity, the reduction is so great that the effective cost of cogenerated electricity actually becomes negative! Furthermore, it becomes most negative where competing electric rates are highest. In France, for example, where the household electric utility rate is $0.17/kVlh, a 1 kW residential biomass cogeneration system sold for $9,500 would cogenerate electricity at –$0. 10/kWh when it displaces heat from an electric heating system. Only through cogeneration can the effective COE be negative.

10.3 System design

As shown in Figure 7, in the residential biomass cogeneration systems being developed, fuel is first pyrolyzed at –55 °C and then mixed with recuperatively preheated secondary air for combustion at ~1400 °C. The resulting exhaust gas is channeled over the head of the free-piston Stirling engine as required by the electrical load, or diverted past the engine to the recuperator. Approximately three-quarters of the heat absorbed by the engine at 550 °C is rejected into the engine's coolant fluid, which is circulated to the thermal load by an inertia water pump driven by the vibration of the engine body. The rest of the energy absorbed by the engine appears as electric power generated by the linear altenater mechanically linked to the engine's piston.

The combustion exhaust gas leaves the engine at –700 °C; additional sensible heat is then recuperated into the combustion air to reduce the amount of biomass fuel required to maintain the engine's head temperature. An optional condensing heat exchanger may be employed to recover the latent heat in the exhaust.

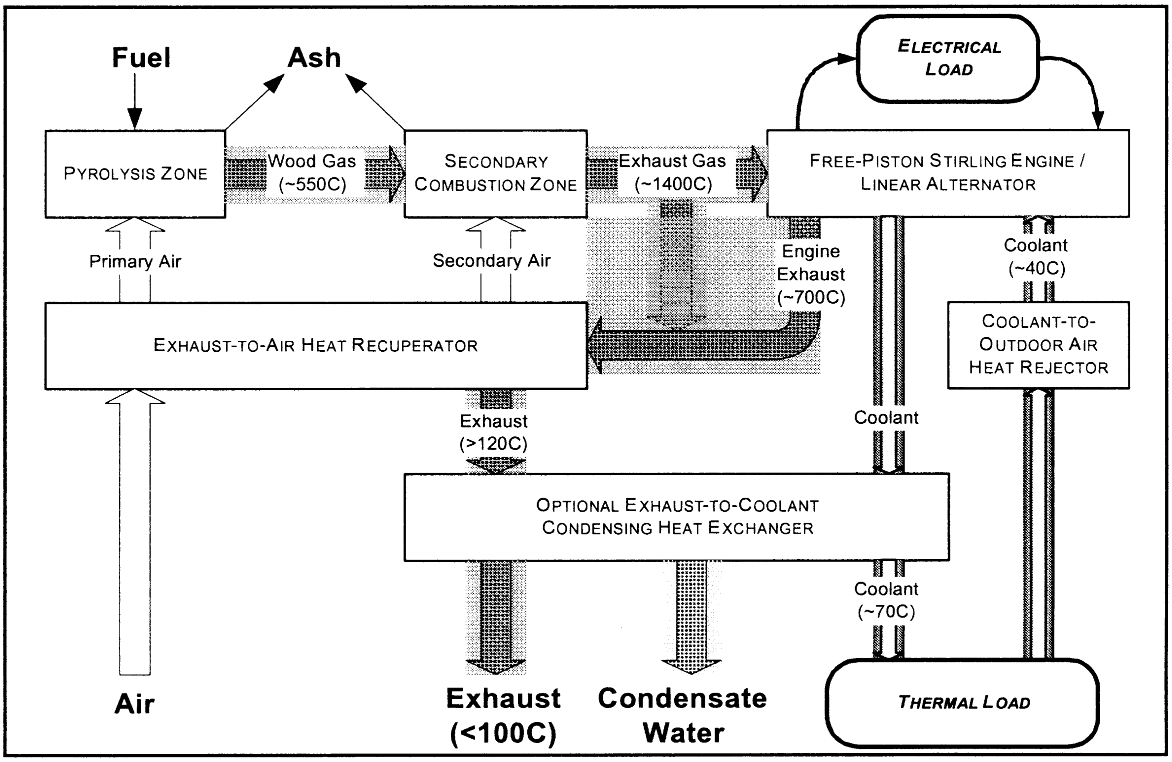

Figure 7. Residential biomass cogeneration system.

The thermal load is composed of parallel loops for domestic hot water, space heating, and system heat rejection. When hot water and space heating loads do not demand all the heat cogenerated with the electrical power, that excess heat must be rejected from the system to the environment.

Several such proof-of-concept prototype systems have been fabricated and their electrical and thermal performances have been confirmed. Further testing is required to determine whether the design requires improvements to reduce cost, increase reliability, and verify compliance with safety and environmental regulations.

10.3.1 System specifications

On the basis of experience with similar biomass burners and engines, as well as proof-of-concept prototype residential biomass cogeneration systems, the following specifications for the first residential biomass cogeneration system products are forecast:

Size	102.0 cm H x 76.2 cm W x 56.0 cm D
Dimensions	
Electrical output power	1 kW
Thermal output	3.8 kW (without supplementary combustion)

Efficiency	
Electrical	15%
Thermal	68%
Overall	83%
Reliability	
Engine maintenance	None
Burner maintenance	Fueling and ash removal
Mean time to replacement	80,000 h
Environmental emissions	
Particulates	<1 g/h
CO	<10 ppm
NO_x	<100 ppm
SO_2	nondetectable
Total VOC	<20 mg/m^3
PAH	100 mg/h

10.3.2 Current use of this technology

The biomass combustion and free-piston Stirling engine technologies in the SMB systems under development are new technologies. Several biomass burners like the ones in proof-of-concept prototypes developed by Sunpower have been fabricated by the original developer and independently tested. Some are in use as residential furnaces and cookstoves. Several dozen free-piston Stirling engines have been fabricated by Sunpower and independently tested. Neither technology has been commercialized in manufactured products.

10.3.3 Technical issues resolved in Phase 1

During Phase 1, system issues concerning the interface of a residential biomass cogeneration unit to residential thermal and electrical loads were resolved. It was decided, for example, to configure domestic water and space heating thermal loads in parallel with the Stirling engine's heat rejection system. It was also decided to size the engine to serve the average annual electrical load rather than the peak and surge loads.

A preliminary estimate of manufacturing costs was also made to identify parts and assembly steps on which to focus additional manufacturing engineering to further reduce manufacturing cost.

Under separate internal funding concurrent with Phase 1, Sunpower also fabricated several proof-of-concept residential biomass cogeneration systems. These prototypes confirmed that small biomass combustion systems can be thermally linked to a free-piston Stirling engine, that the engine can respond to changing electrical loads over the full range of its electrical output capacity, and that the heat rejected by the engine can be transferred to a hot water circulation system.

10.3.4 Remaining technical issues

The major technical issues remaining to be resolved relate to manufacturing cost and quality and to the confirmation of expectations about performance and compliance with various safety and environmental regulations. With respect to manufacturing, repeatable, reliable, low-cost manufacturing processes remain to be developed in the factory in which they are to be performed. The performance and compliance of units coming off the factory's production line remain to be confirmed through laboratory tests and field trials.

10.3.5 Environmental effects of using or harvesting biomass

Of course, the harvesting of biomass may or may not be conducted in a sustainable manner, and local populations will need to discipline themselves to do so. The raw materials for pellet fuel production would often otherwise make their way into the municipal solid waste system; however, the widespread commercialization of residential biomass cogeneration systems may have a beneficial impact on municipal solid waste streams. Furthermore, if large numbers of homeowners use these products to convert their homes from fossil fuel or electric heating systems, these systems will have beneficial impacts on global warming and acid rain.

10.3.6 Air emissions

On the basis of independent measurements of air emissions from a similar two-stage biomass burner fabricated by the original developer, extremely clean emissions performance satisfying the strictest local regulations is expected. The forecast particulate emissions specified are as low as the best pellet and catalytic wood stoves, and the CO emissions are only 25% of the gas industry standard for CO-free combustion.

10.3.7 By-products

The most economically significant by-product of electrical generation in the SMB systems under development is heat. This cogeneration of heat enables these systems to compete aggressively with other sources of electrical power. In most localities, the ash produced by the planned residential biomass cogeneration systems will be a beneficial soil amendment in homeowners' gardens. One exception is a region in northern Sweden that was contaminated by the Chernobyl nuclear accident. The ash from wood harvested in this region is classified as nuclear waste by Swedish authorities, who forbid its disposal by return to the forest.

10.4 Future development

10.4.1 Partnerships

In 1994, Sunpower licensed its free-piston Stirling engine technology to Wood-Mizer Products, Inc. Wood-Mizer manufactures portable sawmills and distributes them in 104 countries worldwide. In 1996, Wood-Mizer assigned its free-piston Stirling engine rights to External Power, LLC, a new firm created by Wood-Mizer to focus on the commercialization of these engines. External Power plans to manufacture free-piston Stirling engines in various kinds of products. External Power plans to distribute residential biomass cogeneration systems through Wood-Mizer's worldwide network and through other distribution channels.

External Power has also formed a strategic partnership with Energidalen, a biomass energy research center and business incubator in Sollefteå, Sweden. Energidalen will perform market analyses for External Power's products in Europe, develop distribution channels, and recruit European investors. Energidalen will also test External Power products to facilitate their approval for sale in the European Union. In addition, Energidalen will make joint proposals with External Power to the European Commission for financial assistance to promote the commercialization of these products throughout the European Union.

To bring residential biomass cogeneration systems to market widely, External Power plans to recruit strategic corporate partners in various industries involved in the biomass energy chain, including forestry, pellet fuels, electric power, residential heating, and white goods.

External Power also plans to recruit other strategic corporate partners and to sell engines to them as original equipment manufacturers for other commercial applications of free-piston Stirling engines. One such application is expected to be natural gas- and propane-fueled residential cogeneration systems.

10.4.2 Sources of financing for future development and deployment

External Power plans to finance the development of its first residential biomass cogeneration products and the first factory to produce them by means of a 50% cost-shared Phase 2 project in the DOE Small Modular Biopower Program. Half the cost of this project will be guaranteed by Wood-Mizer Products, Inc. Subsequently, External Power will seek to finance widespread field trials of these products in North America and Europe by means of a Phase 3 project in the same program, with cost equally shared by External Power, DOE, and the European Commission. Financing for the startup and expansion of full-scale production distribution, sales, and service will be sought from banks, strategic corporate partners, venture capitalists, and private and public offerings of stock, as well as from retained earnings on early sales in high margin markets.

10.4.3 Marketing and original equipment strategy

External Power is still developing its marketing and distribution strategy, but expects to distribute residential biomass cogeneration systems to homeowners through various distribution channels, including Wood-Mizer's worldwide distribution network, pellet fuel distributors, heating equipment distributors, and electric utilities as well as through direct sales via electronic commerce. Where appropriate, External Power also plans to sell free-piston Stirling engines to original equipment manufacturers for inclusion in cogeneration and electrical generation systems sold under their labels and brand names.

10.4.4 Market entry and growth strategy

Directly and through strategic partners, External Power plans to offer residential biomass cogeneration products first to the off-grid market in the forested territories of northern North America where the competing COE is very high. In this region homes have a substantial thermal load and homeowners are accustomed to burning wood for heat. External Power then plans to expand sales to northern Europe where similar conditions prevail, except that few homes are off-grid but the competing COE from electric utilities is much higher than in North America. Only later will External Power attempt to enter on-grid markets in North America, probably first in the Northeastern States and in high-cost rural load pockets of electric utilities elsewhere.

External Power products will be marketed first to homeowners who are already accustomed to burning wood for heat, and later to homeowners who wish to glean the large economic and environmental benefits of converting their homes from oil and electric to biomass heat sources.

In parallel, External Power will distribute residential biomass cogeneration systems in developing countries through Wood-Mizer's worldwide network of distributors. Through other strategic partners, External Power will expand operations in these countries as their markets mature.

As other biomass fuels become commercially available for residential use, External Power will develop new products to burn those fuels. Possible future commercial biofuels include herbaceous crops and wastes, biodiesel oil, and ethanol.

Finally, External Power also plans to develop products with electrical capacities as high as 20 kW or more for larger residential, small commercial, and agricultural markets.

Published by

Vuorimiehentie 5, P.O.Box 2000, FIN-02044 VTT, Finland
Phone internat. +358 9 4561
Fax +358 9 456 4374

Series title, number and report code of publication

VTT Research Notes 2024
VTT–TIED–2024

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Title

IEA Bioenergy Task 22: Techno-economic assessments for bioenergy applications 1998–1999

Final report

Abstract

In the IEA Bioenergy Tasks 22 the objectives were:

- to conduct analysis of bioenergy systems to support organisations working with products and services related to bioenergy
- to build and maintain a network for R&D organisations and industry
- to disseminate data on biomass conversion technologies.

The IEA Bioenergy techno-economic resources have been maintained and improved since original studies in 1982. State-of-the-art, performance, and feasibility analysis of biomass to

- (heat and) electricity (CHP)
- liquid, gaseous, and solid fuel systems
- chemicals from biomass

have been carried out.

Technical and economic feasibility studies were carried out for several biomass power and fuel conversion technologies in Austria, Canada, Finland, Sweden and the United States during 1998–1999. Brazil was also a participant in the task. The core technologies analysed include:

- a flue gas condensing system for increased heat production integrated to a biomass boiler
- the production of slow release fertilizers from fast pyrolysis liquids
- small-scale steam boiler power plant compared to new concepts
- fast pyrolysis liquid production for district heat production within a city, and
- small modular biomass power systems.

Performance (mass and energy balances) of systems are determined rigorously, and the economic assessment will be carried out with companies supplying or planning to use these systems. The companies, whose technologies or sites are considered, have been selected by the funding agencies in the countries participating in this task.

The participants have found the results of the first one and half years valuable, and have agreed to continue the task during the year 2000. Additional cases will be analysed during year 2000. The collaboration has proved to be a cost effective way to generate necessary techno-economic base data to be used in supporting decision making in R&D.

Keywords
biomass, conversion, feasibility, cogeneration, pyrolysis, flue gases, emissions, power generation, liquefaction, IEA

Activity unit
VTT Energy, New Energy Technologies, Biologinkuja 3–5, P.O.Box 1601, FIN–02044 VTT, Finland

ISBN
951–38–5655–0 (soft back edition)
951–38–5656–9 (URL: http://www.inf.vtt.fi/pdf/)

Project number
N8SU00253

Date	Language	Pages	Price
March 2000	English	241 p.	E

Name of project
IEA Bioenergy Task 22 – Techno-economic assessments for bioenergy applications

Commissioned by
International Energy Agency (IEA)

Series title and ISSN
VTT Tiedotteita – Meddelanden – Research Notes
1235–0605 (soft back edition)
1455–0865 (URL: http://www.inf.vtt.fi/pdf/)

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