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COMMERCIALISATION BIVKIN-BASED GASIFICATION TECHNOLOGY

non-confidential version

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Acknowledgement/Preface

This report is the result of the project "Task Force commercialisation BIVKIN technology" with the objective to find out whether the BIVKIN-technology (developed by Stork, Afvalzorg, HoSt, ECN and Novem) can be commercialised. This project has been co-financed by Novem (project 355299/2130) and carried out by ECN, HoSt and Shell Renewables. The report is based on a confidential report (ECN-CX-00-50), the chapter describing technical improvements and their economic impact as well as the chapter dealing with the commercialisation programme has been omitted.

In the report, US$ has been used to indicate costs. For convenience, this has been abbreviated to \$. Where appropriate, an exchange rate of 2.2 Dutch guilders (*f*) per US$ has been used.

Key words

biomass, gasification, stand-alone, CHP, commercial exploitation

Colophon

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SUMMARY

In this report, the commercial viability of described BIVKIN-based biomass gasification technology in the range 5-15 MW_{th} has been assessed. The BIVKIN-based gasification technology is the system presently tested at ECN, consisting of a CFB-reactor (called BIVKIN), fuel gas cooler, wet scrubber with waste water cleaning section, saw dust filter and a gas engine. The assessment has been focussed on CHP-production (combined heat and power (=electricity)). Three scales have been considered. In the two smallest scales (5 and 12.5 MW_{th} input based on 10% wet fuel), the heat released during cooling of fuel gas, engine and flue gas is used for district heating. In the largest scale concept (14.7 MW_{th} input based on 10% wet fuel), the high temperature heat is used to generate steam for a steam turbine for extra electricity, the remaining heat is used for district heating.

From a market analysis, it is concluded that there is a potential market for BIVKIN-based biomass gasification plants of at least 2000 units in Europe in the coming 20 years. From an economic analysis for a business initiative selling the "BIVKIN-technology", it is concluded that such a business can be very profitable. It should be noted that during the first 4 years, the net cash flow will be negative for the turn-key supplier due to the need to realise demonstration plants and the assumption that the plant operator can exploit the plant profitably. Several possible demonstration projects have been described. The two closest to realisation are plants on the premises of ECN and HoSt respectively, illustrating the willingness to make the BIVKIN-technology a commercial product.

Based on estimated investment costs *without subsidies or tax-related profits*, it is concluded that the costs of produced electricity using clean and wet wood will generally be too high for an economically attractive exploitation of a BIVKIN-based gasification plant. However, if cheap (contaminated) biomass can be used, gasification CHP plants with a capacity in the upper range of the capacities considered (around 15 MW_{th} input) will become economically attractive. In this case the electricity production costs are 5 - 7 $ct/kWh (fuel price is 0 - 1.5 $/GJ) compared to 8 - 11 $ct/kWh when relatively expensive (2 - 4 $/GJ) clean and wet (40% moisture) biomass is used as fuel. Small-scale plants (5 MW_{th} input capacity) produce electricity for roughly 2 $ct/kWh more and therefore will generally not be economically viable (without subsidies and tax benefits) given the prices presently paid for green electricity in European countries. However, at this moment tax benefits alone can add up to a reduction of 1 $ct/kWh in The Netherlands.

The incorporation of a steam cycle in the BIVKIN-based plant does not make the exploitation more attractive. It is therefore not recommended for the relative small scales considered.

Several competing technologies for the BIVKIN-based business have been identified: combustion, fixed bed gasification and BIVKIN-resembling processes already on the market. In all cases, the BIVKIN-based gasification technology seems to have enough competing "strength" in the 1-5 MW_e scale. Combustion, being the most mature technology for the production of electricity, is relatively expensive. The difference of electricity production costs is generally around 2 $ct/kWh.

In order to be actually able to exploit a BIVKIN-based gasification plant successfully in the (near) future, it is necessary to focus on the tar problem. Tar has been identified as the main risk for the commercialisation of the integral technology. Tar-related problems have been estimated to add up to a maximum of 1.2 - 2.4 $ct/kWh increase of electricity production costs. Apart from this, the problems will result in a reduction of operational time. This not only results in an

extra increase of electricity production costs, it also reduces the reliability of the gasification plant since the non-operational time can generally not be planned. Reliability is of ultimate importance for new technologies like the one considered in this study. The tar problem therefore should get much attention.

In order to make the BIVKIN-technology economically feasible for relatively expensive (generally clean) biomass, the investment costs should be reduced.

The specific investment of the first commercial BIVKIN-based gasification plant, defined as the first plant built after realisation of two or three demonstration plants, is 3200 and 4400 $/kW$_e$ for the 12.5 and 5 MW$_{th}$ plant respectively when using wet fuel. A plant on dry fuel will cost 2800 and 3800 $/kW$_e$ respectively. This is high compared to fossil fuel powered systems. This results in relatively high electricity production costs since these costs are for 50-75% investment-related (partly caused by the wish to make profit on invested money; for the calculations an IRR of 9% is assumed). The estimated reduction of investment of the tenth plant will result in a reduction of costs of produced electricity of around 0.5 $ct/kWh.

Gas engines turn out to make up a significant part (up to 25%) of the total investment of a complete gasification CHP plant. At the same time, there seems to be “room” for reductions of the so-called de-rating of the engine when firing for low-calorific gas instead of natural gas. Quantitatively, the effect of engine de-rating is responsible for about 0.5 $ct/kWh of the electricity production costs. R&D on gas engines for low-calorific gases seems necessary and worthwhile when trying to make small-scale biomass CHP-units economically (more) attractive.

ECN and HoSt are willing to participate in an R&D-programme aiming at commercialising BIVKIN-gasification technology. Shell has no ambition to participate in the development. Shell however will consider acting as investor/owner of a BIVKIN-technology based gasification plant if this technology appears to be the best for the specific situation.

So as a final remark it can be stated that the success of commercial exploitation of the BIVKIN-technology depends on several main activities within the coming years:

- *Research and development related to the base case*: Several projects, presently carried out with the existing plant at ECN, will generate experimental results and knowledge of the system presented in this report as “BIVKIN-technology”.
- *Further research and development:* Some aspects have been mentioned in the report as subjects for further research in order to reduce the costs of produced electricity: solving several tar-related problems, increasing carbon conversion and improving gas-engine performance on low-calorific gases. The results of the R&D activities are essential for the specifications and engineering of the demonstration plants.
- *Demonstration*: The realisation of demonstration plants is necessary for successful commercialisation of the BIVKIN-technology. Two demonstration plants are planned on the premises of ECN and HoSt respectively.

1. INTRODUCTION

In 1996, ECN developed and built a circulating fluidized bed gasification process “BIVKIN” (Biomassa Vergassings Karakeriserings INstallatie) in co-operation with Novem, Afvalzorg and Stork. The plant was initially used at the ECN location in Petten for the characterisation of more than 15 different biomass species including wood, sludge, grass and manure. During this test work, it was discovered that BIVKIN was an ideal tool for gasification of such diverse biomass at various thermal outputs [1,2]. ECN has been conducting tests to improve the gas quality so that such fuel gas can be used for the generation of electricity by the use of a gas engine.

In order to bring the BIVKIN technology to the commercial market, ECN, Shell and HoSt performed a study to evaluate the engineering concept and cost of such a design in detail. With this study, co-financed by Novem, the commercial viability of the BIVKIN technology in the electrical output range of 1 to 5 MW_e is determined. For this relatively small scale, it is assumed that the extra positive cash flow due to selling the heat can compensate the higher investment per kW compared to large-scale systems where the produced heat generally cannot be used. This report is a reflection of the study to commercialise the BIVKIN technology. In this document, the BIVKIN-technology will be compared with alternative technologies commercially available for the power range under consideration. Both technical and economic evaluations will be presented.

HoSt is a Dutch engineering company interested in the marketing of the BIVKIN technology. However, for a commercial installation, HoSt would need to give a process guarantee. The complete BIVKIN installation would normally include a gas cleaning step and a gas engine for power generation. Such a design concept has not been demonstrated yet by ECN and thus process guarantee from HoSt would not be readily forthcoming. ECN and HoSt are therefore developing this total process concept for commercial applications. Since January 2000, a gas cleaning section has been added to the experimental facility. In May 2000, a gas engine (ABB-Zantingh) is coupled to complete the biomass-to-electricity research plant at ECN.

Shell Renewable has an interest in the BIVKIN technology if this can be marketed at a competitive price. Shell Renewable is at this moment evaluating projects where such a technology can be used in commercial projects.

Objective of the study

The objective of the study can be described as “to assess the commercial viability of an integral energy production system based on the BIVKIN-gasification technology”. Furthermore, a structure will be given as to how to commercialise the technology. The original assumption was that the total investment should be lower than 2000 $/kW_e$ in order to be economically attractive. During the project it has been recognised by the partners that this is not a relevant objective. The criteria to be used for the assessment have become:

- there is a market potential for BIVKIN-based biomass gasification plants
- the operation of the BIVKIN-based gasification plant is economically feasible
- the BIVKIN-based gasification plant is more attractive than the alternatives (combustion)

Activities

The activities defined are (and reported in underlying non-confidential report):

Assess the possibilities for the commercialisation of the BIVKIN-technology. Electricity production costs (assuming 9% IRR) will be calculated for the gasification process as well as the combustion process. In both cases, 3 scales will be considered between 1 and 5 MW_e. This will be done for a range of realistic fuel prices and with and without heat production. Also the potential market for BIVKIN-technology will be quantified.

2. BIVKIN TECHNOLOGY

The BIVKIN-technology comprises an air blown circulating fluidised bed gasifier in which a low calorific value fuel gas is produced from biomass. The fuel gas is cleaned in low temperature wet gas cleaning equipment, in order to make the fuel gas suitable for use in energy conversion equipment like boilers, gas turbines and gas engines.

As will be addressed in more detail in Chapters 3 and 5, the most promising market for the BIVKIN-technology is foreseen at a scale of 5 to 15 MW_{th} fuel input capacity. On this scale the technology is expected to be economically competitive with the alternatives such as combustion technology and fixed bed gasification technology, whilst there are no competitors with circulating fluidised bed technology at the moment.

Several applications for the produced fuel gas are possible. Fuel gas can be upgraded to Substitute Natural Gas (SNG), bio-diesel by Fischer-Tropsch synthesis, methanol, DME or the gas can be fired in gas turbines, gas engines, fuel cells or boilers to produce electricity and heat. Furthermore, several fuels can be considered, ranging from virgin fuels such as woody forest residues, residues from park trimmings and heavily contaminated (wood) waste fuels.

In this report, the perspectives of BIVKIN-technology are examined based on the use of relatively clean fuels and the use of fuel gas in gas engines to produce electricity and heat. This application of the fuel gas fits best the plans of the European Union directive (see Chapter 5, market). The choice for gas engines instead of gas turbines has been made because it is expected that small gas turbines suited for low calorific fuel gas will not be available on the short term. For this reason, only the application of gas engines has been considered in this report and it is anticipated that the BIVKIN technology will become available for commercial projects in 3 to 5 years time.

2.1 State of the art, experience

A 0.5 MW_{th} pilot plant has been realised at the premises of ECN, in order to be able to demonstrate and optimise the technology. Figure 2.1 shows a picture of the CFB-reactor. A process scheme of the pilot plant including the gas cleaning section is shown in Figure 2.2.

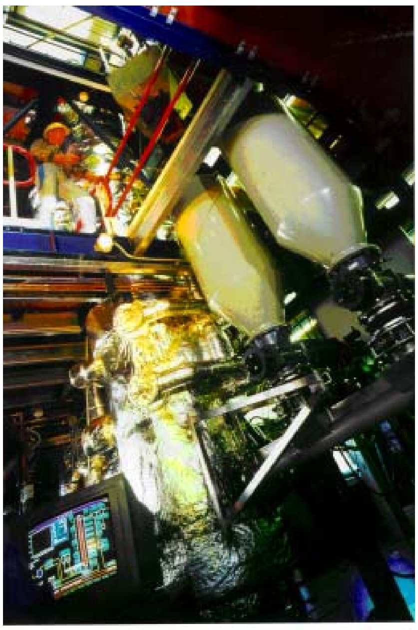

Figure 2.1 *Picture of test facility "BIVKIN" at ECN*

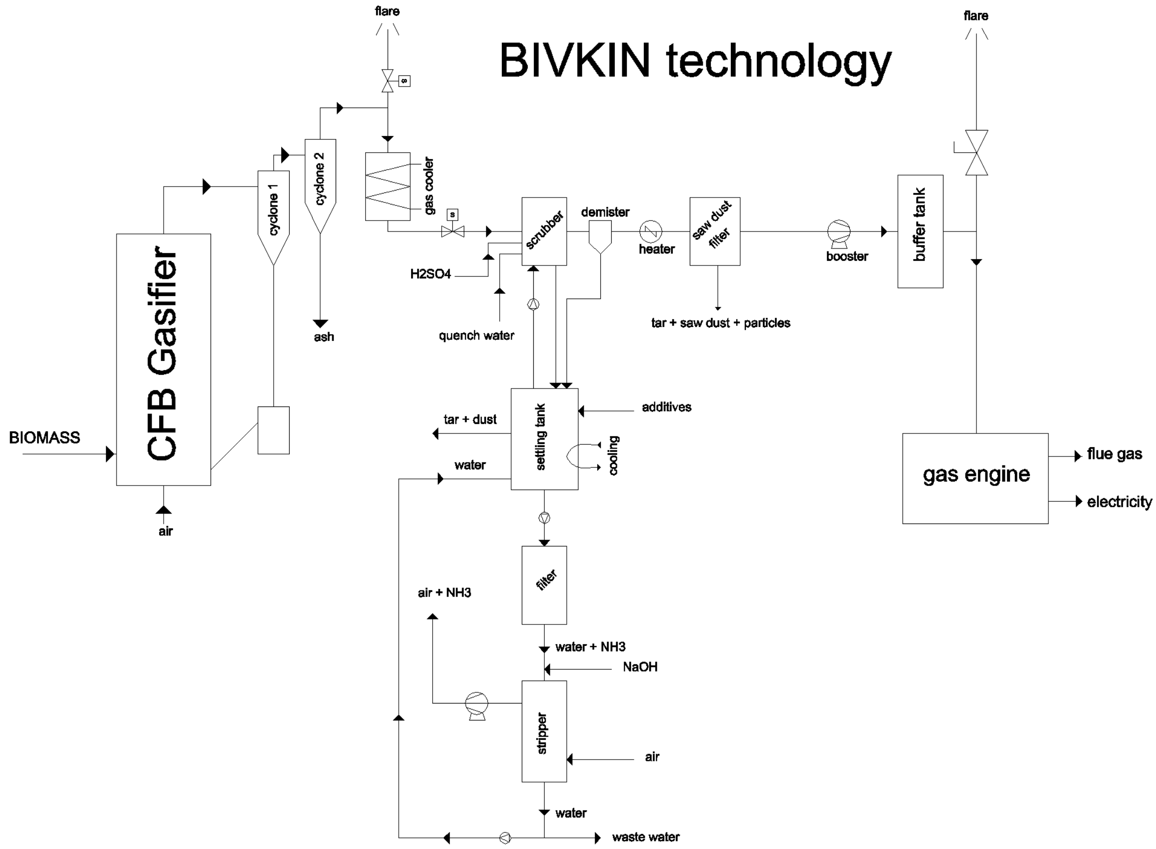

Figure 2.2 *Simplified process scheme of existing pilot plant at ECN*

The gasifier itself was operated for the first time in September 1996. Since then more than 500 hours of operation have been achieved with a broad range of feedstocks as fuel input. Several components of the gasifier have been modified and the gasifier as a whole has been optimised. Feeding systems where developed in order to be able to feed the different kind of feedstocks. Furthermore several procedures like heating up and cooling down of the gasifier have been automated to reduce the amount of manpower needed.

The state of the art of the gasification technology can be described best by the fact that testing of new feedstocks has become a somewhat boring routine for the involved operators. Stable operation of the gasifier is very easily achieved for long periods of times and interference of operators is reduced to a minimum. The complete automation of the gasifier seems possible. The most important item regarding gasification of new feedstocks often concerns the modification of the feeding system.

Up till now, successful gasification in the BIVKIN-gasifier has been demonstrated for the following feedstocks:

- willow
- waste wood (painted)
- particle board
- railway sleepers
- verge grass (pellets)
- straw (pellets)
- paper mill residue
- dried pig manure
- organic domestic waste
- beech
- bark
- sewage sludge/waste wood mixture
- cacao residue
- chicken manure
- hard wood from wood industry
- cellulose

A detailed description of the performance of the gasifier with the several feedstocks tested can be found in [1-3].

The low temperature wet gas cleaning and waste water treatment system has been realised during 1999. At this moment (March 2000), the gas cleaning and waste water treatment systems are still subject to further optimisation.

2.2 Evaluated system configurations

Within this report, the perspectives of BIVKIN-technology for use in three CHP power plant configurations, are evaluated in detail (capacities are based on fuel with 10% moisture):

1. 5 MW_{th} gasifier with gas engine for electricity production
2. 12.5 MW_{th} gasifier with gas engine(s) for electricity production
3. 14.7 MW_{th} gasifier with gas engine(s) and steam turbine for electricity production

The power plants are evaluated for the use of three different fuels:

a. clean biomass, 40% moisture
b. clean biomass, 10% moisture
c. contaminated biomass, 10% moisture

It should be noted here that in case of wet fuel (40% moisture), the input power decreases to 13.6, 11.6 and 4.6 MW_{th} (based on lower heating value). In this report however, the indicated capacity always refers to the dry (10% moisture) fuel into the gasifier, either 14.7 or 12.5 or 5 MW_{th}. In the next figure, this is illustrated. The increase of power is achieved by adding heat to the dryer. Hot flue gas usually is used.

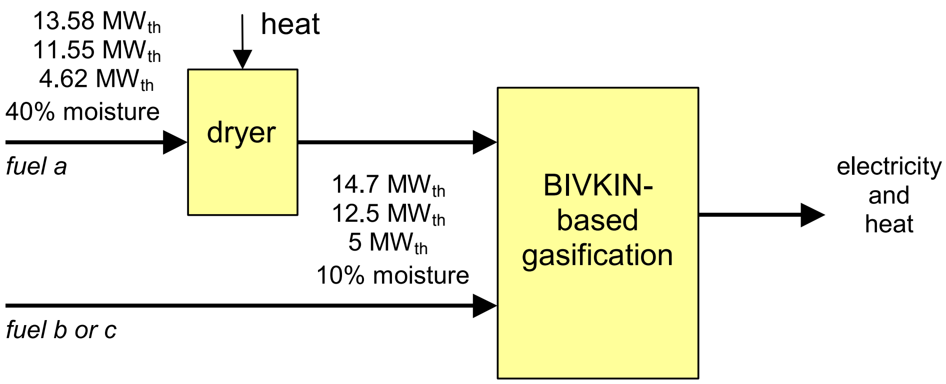

Figure 2.3 *Illustration of different scales and definition for dry and wet fuel*

In Appendix A, the main energy and heat flows of each of the above mentioned combinations are given. In this report, the emphasis will be on the use of clean biomass with 40% moisture. This is preferred by Shell. The other two fuels however will also be considered. The global schemes based on the use of dry fuel are presented in Figure 2.4 and 2.5.

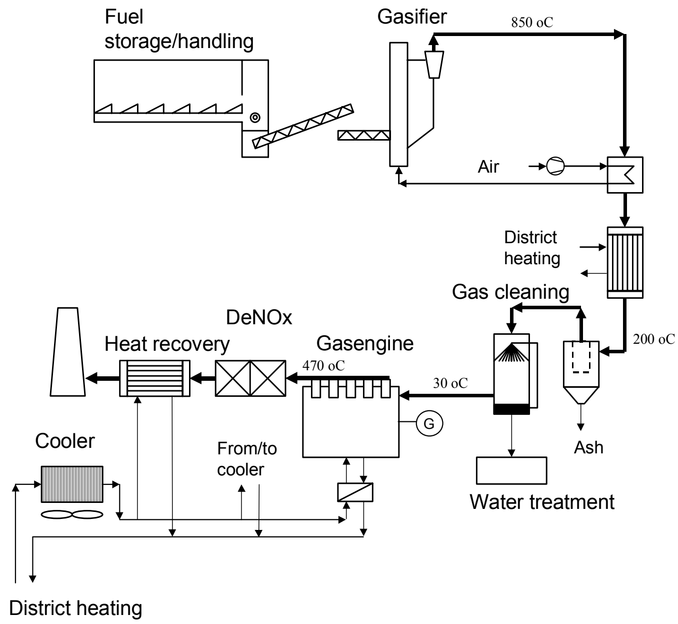

Figure 2.4 *Simplified scheme for BIVKIN-based power plants of 5 and 12.5 MW_{th}.*

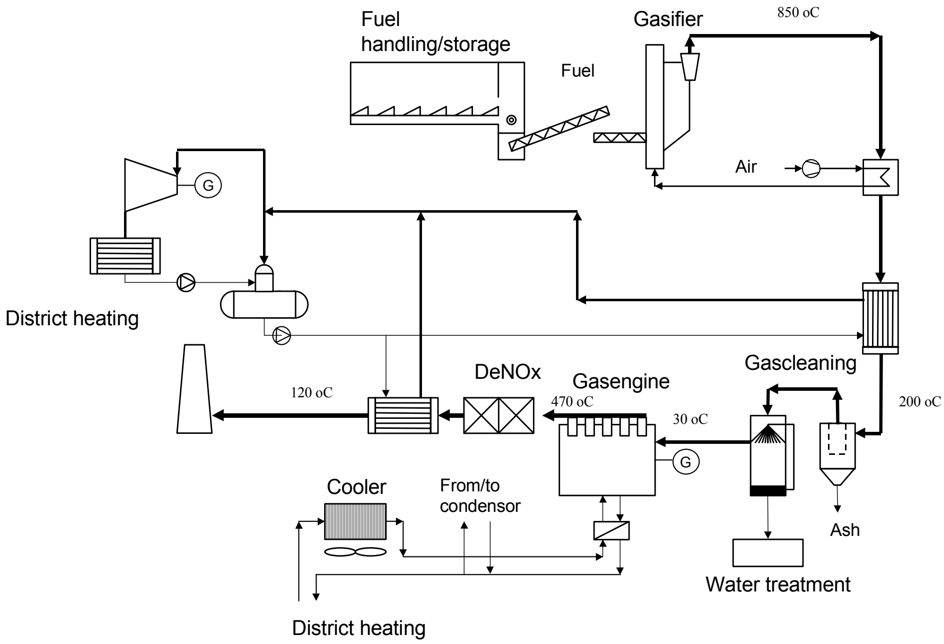

Figure 2.5 *Simplified scheme for BIVKIN-based 14.7 MW_{th} power plant*

Fuel storage and pre-treatment

The fuel is fed to the gasifier from a three-day storage equipped with moving floors. In case of wet fuels (40% moisture content), the fuel is dried to a moisture content of 10% in a rotary drum dryer, before the fuel is fed to the gasifier. The dryer is equipped with additional flue gas cleaning (cyclone and bag house filter) and is placed behind the heat exchanger, which recovers heat from the gas engine flue gases. The flue gas enters the dryer at a temperature of approximately 200°C. For this reason, the efficiency of heat production drops in case a dryer is part of the process. However, drying of wet fuel is beneficial to the economy of a power plant due to a higher electric efficiency and smaller size of the gasifier, gas cleaning and waste water treatment. Furthermore, integration of the gasifier with the gas engines is less critical due to a higher heating value of the produced fuel gas. For the gasification process itself, drying would not be necessary.

In calculations for dry and wet fuel, the LHV-based input in [MW_{th}] going into the gasifier is kept constant. This means that for wet fuel, the power input into the dryer reduces because the LHV reduces with increasing moisture content. For example: the 14.7 MW_{th} case for dry biomass (10% moisture) becomes a 13.58 MW_{th} input for wet biomass (40% moisture). For the latter case however, the fuel power after the dryer is 14.7 MW_{th} (the increase is achieved by using thermal energy from the flue gases). This means that the total plant for wet fuel is identical to the plant for dry fuel, except for the dryer and related energy-flows. NB: the efficiency is related to the energy content of the wet fuel[1].

Gasification
In the gasifier, fuel gas is produced by gasification with preheated air (400°C) at a temperature of approximately 850°C. The length of the riser is chosen to be 11 meter for the two largest systems (12.5 and 14.7 MW_{th} plant) and 7 meter for the 5 MW_{th}-system. The hot gas velocity is 6 m/s through the riser. The heat loss to the surroundings is assumed to be 2% of the thermal input. Carbon conversion is assumed to be 95%.

Gas cleaning and water treatment
The hot fuel gas is cooled by an air pre-heater and an additional heat exchanger to a temperature of 200°C, before the gas enters the gas cleaning system. The heat is delivered to the district heating system (5 and 12.5 MW_{th} power plants) or used for steam production (14.7 MW_{th} power plant). There's an option to "destroy" heat if heat cannot be used. The gas cleaning system consists of bag house filter followed by a two stage wet scrubber and sawdust filter for additional tar removal. The waste water produced is cleaned by a tar separation tank, active carbon filter and an ammonia stripper. Several waste streams like separated tars, ammonia, saw dust and the used active carbon are recycled to the gasifier and (partly) gasified/destroyed.

Gas engines
The cleaned fuel gas is fired in one or several gas engine(s) to produce electricity. A Jenbacher engine has been chosen for the several cases. It concerns a 1.9 MW_e engine on natural gas, modified for low calorific fuel gas. On fuel gas it will produce 1.2 MW_e with 35% efficiency. So, the so-called de-rating is assumed to be 40% when changing from natural gas to low calorific fuel gas. In the calculations, the amount of engines used for a certain scale is not limited to integer numbers.

Steam cycle and district heat
Part of the energy contained in engine cooling water, cooling oil and fuel gas can be delivered as heat for the district heating system. The hot flue gases from the engine are led through a $DeNO_x$ catalyst in order to reduce the NO_x emissions. For contaminated wood, also an oxy-cat is necessary to be able to meet the requirements (in The Netherlands). This catalytic converter is meant to reduce the fraction of mainly CO. The energy contained in the hot flue gases is recovered and used for steam production (14.7 MW_{th} power plant) or hot water production for the district heating system. In the 14.7 MW_{th} power plant configuration, the produced steam (28 bar, 415°C) in the fuel gas cooler and engine flue gas heat exchanger is led through a back pressure steam turbine for additional electricity production. The steam leaving the back-pressure steam turbine (90°C) is condensed in a heat exchanger in order to heat water for the district heating system. In the condensing systems (optimised for electricity), steam leaving the turbine is already condensed and about 30°C and not suitable for district heating. In any case, air-cooled systems are part of the system to "destroy" the heat if it is not needed temporarily.

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[1] Since efficiencies are generally calculated on LHV-base, with wet fuel electric efficiencies can be higher compared to the case where fuel is dry!

2.3 Investment costs

Performance and investment costs for a first commercial power plant were determined and the investment costs for a 10^{th} power plant were estimated. This was done in order to evaluate the proposed technology economically and compare the technology with alternatives like biomass combustion.

First commercial plant
In this report, the first commercial power plant is defined as the power plant that is built after one or two demonstration power plants. The costs of a demonstration power plant will be relatively high due to the high risks involved in building such a first of a kind power plant. The supplier will handle the risks for the supplier of the plant by 'safe' calculation of investment costs, and taking margins to compensate for possible late delivery and necessary modifications. The 'investment costs' heavily depend on agreed guarantees. Furthermore, engineering and commissioning costs will be excessive due to the fact that a lot of 'new' problems will come up and will have to be solved during actual design and first operation of the plant.

The first commercial power plant will be realised after having built one or possibly two demonstration power plants. The design and operation of this power plant is considered familiar and guarantees can be granted to an acceptable extent. Investment costs reflect the costs of equipment as well as engineering and other services, normally needed for realising unique plants, based on commercially available components.

The investment costs of a first commercial power plant have been determined by HoSt based on offers from suppliers for major equipment. Cost of items such as engineering, instrumentation, electric equipment, piping, civil works were determined based on detailed calculations for an 8 MW_{th} biomass combustion plant which has actually been built in Lelystad, The Netherlands. Experts of the formal HoSt mother companies, Stork and QtecQ, have been involved in determining the overall investment costs of the considered biomass gasification power plants. The investment costs reflect the costs of a turn-key delivered power plant including civil works, commissioning and connection to the electric grid and district heating infrastructure.

Tenth plant
The investment costs of the 10^{th} commercial power plant will be substantially lower than those of a first commercial plant due to a learning curve, as experienced by many other technologies.

HoSt has estimated the investment costs of a 10^{th} commercial power plant. The estimate was based on the assumption experienced in practice, that engineering costs of new components will decrease by 40% each time the amount of produced components is doubled. Furthermore is was assumed that manufacturing cost for new components will decrease by 5% every time the amount of produced components is doubled. The assumptions are regarded to be valid in case several biomass power plants are built during a year, and components are delivered by the same key-suppliers. For conventional components like the components of the steam cycle, fuel feeding screws and storage systems, it was assumed that investment costs will not decrease due to already achieved savings by a learning curve.

Investment
The calculated investment cost for a first and 10^{th} commercial power plant as well as the performances, are summarised in Table 2.1. NB: the 14.7 MW_{th} system includes a steam turbine contrary to the other two systems. In Appendix B the concepts for wet clean as well as dry clean and dry contaminated biomass are presented.

Table 2.1 *Investment for BIVKIN-based gasification systems for clean wet (40% moisture) biomass, both for first commercial and 10^{th} plant for indicated fuel input (MW_{th} LHV-base[2])*

		14.7	12.5	5
E (no heat)				
net electric output	MW_e	4.27		
first commercial plant				
investment	M$	13.6		
specific investment	$/kW$_e$	3180		
10^{th} plant				
investment	M$	12.2		
specific investment	$/kW$_e$	2860		
CHP				
net electric output	MW_e	4.06	3.20	1.27
net heat output	MW_{th}	4.17	4.45	1.79
first commercial plant				
investment	M$	13.2	10.2	5.6
specific investment	$/kW$_e$	3250	3190	4370
10^{th} plant				
investment	M$	11.8	8.9	4.6
specific investment	$/kW$_e$	2900	2770	3660

2.4 Calculated costs of produced electricity

In this chapter, the BIVKIN-based gasification plants will be economically evaluated. For different fuel prices and other parameters, the costs of produced electricity in [$ct/kWh] is calculated.

2.4.1 Assumptions and choices

In Appendix C the most important assumptions are given. Some assumptions are explained in more detail below.

Investment costs
The investment costs of the BIVKIN-based gasifier are covered in Chapter 2.3. It is assumed that no subsidies are granted and no tax-related profits apply. This is the worst case, in most countries some regulations exist. For example in The Netherlands, VAMIL and EIA regulations can effectively reduce the investment by 20-25%.

Biomass fuel
For the fuel, a clean and wet biomass is chosen for the base case. Table 2.2 gives the composition used for the calculations. It is the average composition of almost 300 clean biomass samples according to the public database Phyllis [4].

[2] fuel input based on dried fuel (10% moisture), see Figure 2.3, actual fuel input (40% moisture) is 13.6, 11.6 and 4.6 MW_{th} respectively.

Table 2.2 *Composition of biomass fuel used for economic evaluations*

	unit	value
moisture	wt% wet base	40
ash	wt% dry base	3
C	wt% dry and ash free	50.5
H	wt% dry and ash free	6.2
O	wt% dry and ash free	42.8

Biomass fuel price
The price of biomass feedstocks varies widely between countries. For example, virgin biomass in chipped form in Latin America can be purchased for 2 $/GJ, whereas in Denmark the cost of such feedstock can be as high as 4.5 $/GJ. Contaminated wood, however, can be purchased at reduced costs or sometimes even at negative costs i.e. the purchaser is paid for the off-take. This is because major European countries such as Germany are withholding landfill permits for contaminated wood, forcing companies to recycle such wood or use the wood for the production of heat and power. For the purpose of the study given in this report, feedstock prices range from 0 to 3.6 $/GJ. Realistic prices for clean biomass are between 2 and 4 $/GJ. For comparison: oil, natural gas and coal (for industrial use) cost 3.8, 2.6 and 1.8 $/GJ respectively in The Netherlands.

Heat price
The price of the heat, produced in CHP-units, varies widely between countries. Appendix D gives the price of natural gas for different countries both for industrial and private users. From these data, a realistic heat price (for industry) of 3.2 $/GJ is assumed for the calculations. In some countries however the heat price is considerably higher. Also in some countries “green” heat is given an extra price. In The Netherlands this is about 1.6 $/GJ. Therefore, a second option is used for the calculations: 4.5 $/GJ.

Electricity price
In the calculations, the cost of produced electricity is the result. This figure should be compared to the price that is actually paid in order to judge the economic perspective of the BIVKIN-based gasification technology. Electricity produced from fossil fuels is priced at different levels for industrial use and for domestic use, as shown in Appendix D. Also the amount of tax imposed on the electricity sales varies from country to country. More recently, some European governments have introduced carbon tax on the use of energy for domestic users. This way, governments hope that consumers would reduce the use of energy and thus help in the overall objectives of reducing the CO_2 emissions.

Electricity generated from biomass would, in general, not be competitive against electricity generated from fossil fuels. This is because investment costs are higher for biomass plants when compared with fossil fired plants. Also, economics of scale are difficult to realise due to the nature of biomass i.e. the heating value is low and the moisture content is high, giving logistic problems in moving large volumes of biomass for large-scale power plants.

Nevertheless, there is a drive by certain European governments to encourage the building of biomass heat and power plants by offering direct investment subsidies or by offering a tariff on the “standard” electricity price. Such a “green” tariff can be as much as 5 $ct/kWh.

From Appendix D it follows that the range is very broad. Realistic electricity prices (industrial users) are between 6 and 8 $ct/kWh. For any new technology to be commercially viable, the costs of electricity produced should not exceed 8 $ct/kWh.

Efficiency
The total efficiency (to heat and electricity) of the gasification-based CHP systems is assumed to be 70% and 65% for the gasification option without resp. with a steam cycle. Since the biomass has to be dried from 40% to 10% moisture, part of the heat produced has to be used within the plant. For this reason the total efficiency drops to 66% and 61% for the gasification systems without (5 and 12.5 MW_{th} input) resp. with a steam cycle (14.7 MW_{th} input).

2.4.2 Results [kWh-costs]

Table 2.3 presents the costs of produced electricity using wet (40% moisture) clean biomass for a BIVKIN-based gasification plant. In Appendix E, also the results for contaminated wood and dry clean wood are given.

Table 2.3 *Costs of produced electricity [$ct/kWh] for BIVKIN-based gasification plants running on clean biomass (40% moisture) as a function of fuel price [0.0 ... 3.6 $/GJ LHV-base]*

fuel input (MW_{th} LHV-base[3]) → fuel price [$/GJ] ↓	14.7	12.5	5
E (no heat)			
0.0	7.2		
0.9	8.2		
1.8	9.3		
2.7	10.3		
3.6	11.4		
CHP, H-price: 3.2 $/GJ			
0.0	6.2	5.7	8.5
0.9	7.3	6.9	9.7
1.8	8.4	8.1	10.9
2.7	9.5	9.3	12.1
3.6	10.6	10.5	13.3
CHP, H-price: 4.5 $/GJ			
0.0	5.7	5.0	7.9
0.9	6.8	6.2	9.0
1.8	7.9	7.4	10.2
2.7	9.0	8.6	11.4
3.6	10.1	9.8	12.6

Figure 2.6 shows the breakdown of the costs of electricity for several cases. From the figure it is clear that the fuel price and investment costs[4] (with maintenance and insurance as correlated costs) are responsible for the biggest part of the total costs of electricity. The profit by selling heat is considerable. It reduces the costs of electricity by about 15%. This is the main reason why small-scale systems can be economically attractive despite the relatively high investment costs due to the scale. The electricity costs from a gasifier where heat is sold is roughly equal to the situation where the investment is 30% lower and no heat is sold. In other words, compared to an electricity-plant a 30% higher CHP-plant investment is acceptable due to the extra income by heat use.

[3] fuel input based on dried fuel (10% moisture), see Figure 2.3, actual fuel input (40% moisture) is 13.6, 11.6 and 4.6 MW_{th} respectively.
[4] NB: The investment-related kWh-costs are partly resulting from the aim to make profit (assumption IRR=9%).

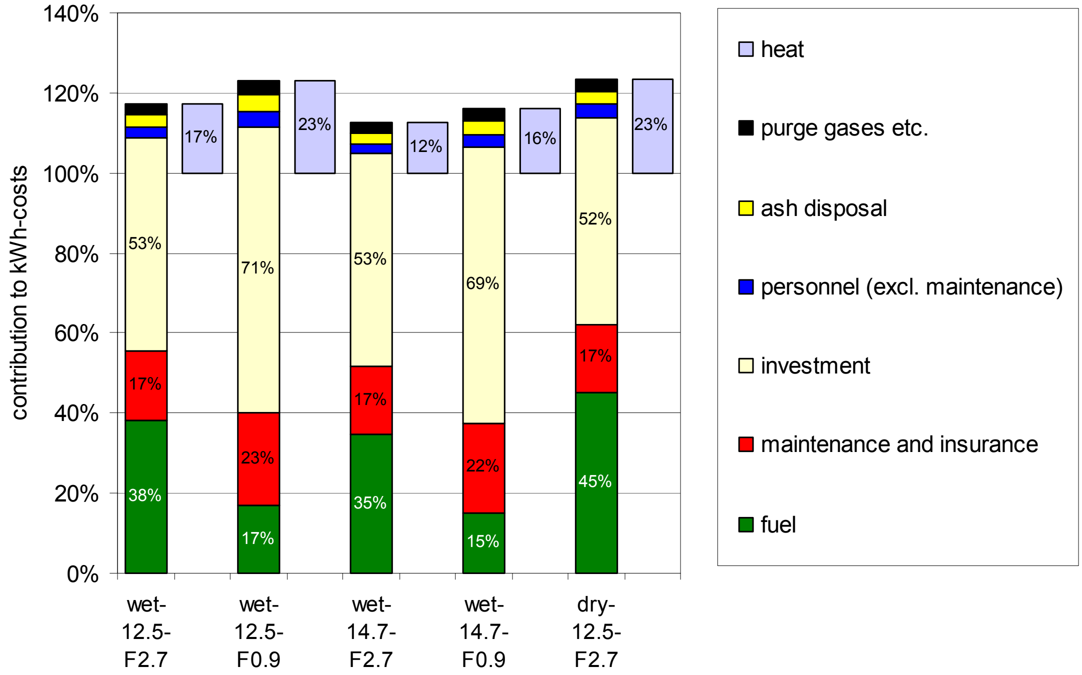

Figure 2.6 *Breakdown of costs of produced electricity in several gasification systems with different fuels with heat price of 3.2 \$/GJ; wet: clean biomass with 40% moisture, dry: clean biomass with 10% moisture, 12.5 and 14.7: fuel input capacity [MW_{th}], F0.9 and F2.7: biomass fuel price is 0.9 and 2.7 \$/GJ*

2.4.3 Sensitivity analysis

In this chapter, the influence of changing parameters will be discussed. For the calculations, the 12.5 MW_{th} CHP system running on wet biomass has been chosen. The main assumptions are given in Table 2.4. In Table 2.5, the effect of some changes is given, expressed as changes in the kWh-costs.

Table 2.4 *Base case for sensitivity analysis*

capacity: fuel input (LHV after dryer)	12.5 MW_{th}
fuel	clean biomass (40% moisture)
fuel price	2.7 $/GJ
heat price	3.2 $/GJ
total investment	10.2 M$
net electric efficiency	27.7%
net heat efficiency	38.5%
carbon conversion	95%
operation	8000 h/year
price of produced electricity (9% IRR, 15 years)	9.3 $ct/kWh

Table 2.5 *The effect on kWh-price of several changing parameters, base case see Table 2.4*

parameter	change	Δ kWh-price [$ct/kWh]
fuel	40% moisture → 10% moisture	- 1.0
fuel price	+ 25%	+ 0.9
heat price	- 25%	+ 0.4
learning curve (3rd → 10th plant)	-13% investment	- 0.8
total investment	+ 25%	+ 1.6
limited heat sold	8000 → 4000 hours/year	+ 0.8
carbon conversion	95% → 98%	- 0.4
operation	8000 → 6000 hours/year	+ 2.3
required profit of plant	IRR = 9% → 15% (15 years)	+ 1.9

2.5 Future development

In the coming years some developments will take place, apart from the own development programme, that might be relevant for the BIVKIN-technology and its commercial viability.

Gas engine
As presented earlier, the electricity is generated using one or more gas engines. For the larger scales, several gas engines will have to be used in parallel simply because no engines of sufficient capacity are available for low calorific fuel gas. However, larger engines might become available for fuel gas in the future. This will probably result in lower investment and slightly higher efficiency.

The so called "de-rating" of a gas engine when firing low-calorific fuel gas instead of natural gas (often the design fuel) is estimated to be 40% in this study. Together with some changes to be made (different compression ratio, ignition time, gas nozzles and mixer, …) the specific investment [$/kW$_e$] approximately doubles going from natural gas to fuel gas. Because the costs for the engine-section are about 25% of the total costs of a BIVKIN-based gasification plant, developments to reduce the de-rating do have significant effects on the economic performance of the electricity plant.

Gas turbine
Presently, gas turbines with 1-5 MW$_e$ capacity are not available for low calorific fuel gas. In the future this might change if there is a need for this technology. Gas turbines generally have a slightly lower efficiency than gas engines in the range up to 5 MW$_e$, but contrary to engines most of the remaining energy can be used to produce heat or steam (for e.g. steam cycle). Furthermore, gas turbines have less moving parts and probably have a longer life and less maintenance compared to gas engines.

Gas engines produce NO_x in quantities generally too high to meet (future) emission limits, even if all ammonia has been removed from the fuel gas. DeNO_x will be necessary. Gas turbines however, may produce flue gas with low NO_x concentrations. The removal of ammonia from the fuel gas may be sufficient to meet NO_x regulations. So, when using gas turbines, relative expensive deNO_x may be omitted.

Emission regulations
Emission limits for flue gases are subject to constant changes. Both European and national regulations on emission limits are changing due to new ideas and technological possibilities. This might result in a situation where the BIVKIN-based gasification plant, as presently considered, cannot satisfy new laws. In that case extra components should be included to clean

the gases to the desired level of contaminants. On the other hand, it might also be possible that e.g. small-scale CHP will be made more attractive because governments realise that small-scale units are the only way to reach national objectives in the field of renewable and sustainable energy supply or are essential for public acceptance.

2.6 Major technological risks and influence on costs

At the moment, the BIVKIN-technology exists only on a small scale at the premises of ECN. An important part of the commercialisation programme is the realisation of some demonstration plants with the objective of (1) to demonstrate the technology to potential customers, (2) to get to know the performance so as to give guarantees to future customers and (3) to identify weak points in the design in order to improve the concept. Because BIVKIN-technology demonstration plants are not yet realised and first tests with the integral test facility at ECN are just performed, certain technological risks are taken. Estimated costs of future plants may change as a result of this. In order to judge the impact of these risks on the commercialisation viability, the risks are analysed and the possible financial impact is estimated. In Table 2.6 a summary is given.

Biomass fuel handling and storage
The main technological risks taken in this part of the plant concern the transport sections and mainly the feeding of the biomass into the gasifier. It has been one of the major causes of delays in commissioning many new plants running on biomass fuel. The main reason for this is the limited experience in the field combined with the empirical character of the handling process. The solutions are often simple changes. In the worse case, a second feeding system should be installed. In the risk analysis, the maximum risk assumed is doubling the investment for the feeding unit.

Biomass fuel drying
Drying of the wet biomass with flue gas from the gas engine is rather mature and the risks involved are low.

Biomass fuel gasification
On the basis of the many tests performed with the test facility at ECN, the technological risks concerning the gasification are considered to be low. The only risk worth considering involves long-term effects like extensive erosion of refractory material. The solution might be to use different materials in the “danger zones”. The maximum extra investment involved is assumed to be half the costs of the refractory material. The practical problem of agglomeration and resulting loss of operational hours is not covered here since this problem is related to the fuel itself and can be solved by using different fuels.

Gas cleaning
Gas cleaning aims at reducing certain components in order to meet requirements (in a given country) of both engine and flue gas emissions. Presently, the system as used in the concepts given in Chapter 2.2 is tested at ECN. It does not work perfectly yet, but there are possibilities to improve the performance. Tar seems to be the major problem. Three different problems related to tar could be distinguished:

1. tar components condense in the fuel gas cooling section, resulting eventually in blockage of the pipes,
2. tar, separated from the gas, cannot be recycled to the gasifier resulting in a loss of energy and an extra waste stream,
3. after the cleaning section, the tar concentration in the gas is too high to be used in the engine.

For each of these problems, solutions can be described:
Ad 1. The hot fuel gas is cooled by water injection (quenching), thus avoiding cold spots. The maximum risk involved is that the energy stored as sensible heat cannot be used for district heating (5 and 12.5 MW_{th} systems) or steam production (14.7 MW_{th} system). At the same time, the amount of water to be disposed off increases.
Ad 2. The maximum risk involved here is that the energy content stored in the tars (approximately 3% of fuel input) is completely lost, resulting in a reduction of total efficiency and at the same time a waste stream (approximately 1 wt% of the fuel input is tar) is left for disposal. Because this is a highly carcinogenic substance, disposal costs are high. Furthermore, this tarry waste stream seriously damages the anticipated green image.
Ad 3. From experiences with commercial fixed bed gasification power plants realised at Schwarze Pumpe (formerly Eastern Germany), it can be stated that additional tar removal can be realised to a desired extent if needed, using additional low temperature methanol scrubbing equipment. The maximum risk is assumed to be doubling of the investment costs of the whole gas cleaning section.

As a possible solution for all three above-mentioned problems a thermal tar cracker may be implemented (either as a “simple” or regenerative or recuperative system). In this system, tar is cracked at high temperature. Oxygen (enriched air) can be used to compensate for the loss of calorific value of the fuel gas.

Waste water treatment

The wastewater treatment section contains mature components. The presence of tar in the water however, might result in certain problems. In the worst case, the wastewater cannot be disposed off as clean water. The maximum risk is assumed to be either increased disposal costs for the wastewater or an extra investment of half of the costs of the whole water treatment section.

Gas engine

The engine itself does not bring significant technological risks. The Austrian gas engine manufacturer Jenbacher has experience with low-calorific gas as fuel. The risks involved are either related to (1) the actual quality of the fuel gas compared to he design quality or (2) the emissions of CO and NO_x in the flue gas exiting the gas engine.
Ad 1. The first part is either directly related to the gas cleaning section, which is already covered above or has to do with the bulk composition of the gas (e.g. the H_2-content). In the last case this means that the compression ratio must be lowered. This does not significantly change the investment, but the electric efficiency drops. For this risk analysis an efficiency drop from 35% to 33% is assumed.
Ad 2. This implies a change of the flue gas cleaning section. In the worst case this means that this section has to be extended, for which the costs are assumed to be half of the costs of the flue gas section.

Steam cycle

The steam cycle brings about a very low risk. The main risk in this section involves the high temperature heat exchanger in the fuel gas. Because of high temperature corrosion and possibly erosion, the steam pressure should be lowered (reducing the electric efficiency of the steam cycle) or the heat exchanger should be replaced more often. In the worst case, a 10% (relative) decrease of the electric efficiency of the steam cycle is assumed.

Table 2.6 summarises the above mentioned risks for each section in the concept.

Table 2.6 *Analysis of technological risks during demonstration phase*

section	description of main technological risk	chance of risk	what should be done if risk becomes a fact
feeding	feeding system does not work properly	high	other/extra feeding system
fuel drying	mature	low	none
fuel gasification	extensive erosion of refractory material	medium	other (more expensive) refractory material
fuel gas cleaning	1. blockage of pipes by tar condensate	high	1. water quench: loss of useful heat
	2. tar recycling not possible	high	2. tar disposal: loss of energy and extra disposal costs
	3. insufficient tar removal	high	3. modified/new component (MeOH-scrubbing)
waste water treatment	waste water is not clean enough	medium	increased disposal costs or modified/extra components
gas engine	1. engine knocking because of high [H_2] or high compression ratio	medium	1. decrease compression ratio: electric efficiency decreases
	2. flue gas emissions do not meet regulations	medium	2. extra flue gas cleaning
steam cycle	extensive corrosion high-T heat exchanger	low	reduce steam temperature: electric efficiency steam cycle decreases

The analysis of technological risks as presented above is quantified for one case: 12.5 MW_{th} thermal input CHP-concept. In Table 2.7 the results are given. The chance that the identified risk actually happens and the financial impact are multiplied. The last column gives the net impact on the cost of electricity. This can be considered as the total risk involved by assuming the system described in Chapter 2.2 and presently tested at ECN works properly and can simply be scaled to the desired sizes.

Table 2.7 *Quantitative analysis of technological risks during demonstration phase. The effects are quantified for the 12.5 MW input CHP-option, 10.2 M\$ total investment, η_e = 27.7%, η_h = 38.5%. Base case: 2.7 \$/GJ fuel price, 3.2 \$/GJ heat price and 9.3 \$ct/kWh costs for electricity. Non-additional risks are printed in italics*

section	chance	maximum risk		net risk
	of risk	description	[$ct/kWh]	[$ct/kWh]
fuel feeding	80%	investment + 0.075 M$	+ 0.04	+ 0.03
fuel drying	20%	negligible	negligible	negligible
fuel gasification	50%	investment + 0.10 M$	+ 0.05	+ 0.02
fuel gas cleaning	80%	1. no use of fuel gas heat: reduction of heat output with 1.4 MW_{th}, if steam cycle is present*: loss of 0.2 MW_e and 1 MW_{th} after steam cycle	+ 0.5 or + 1.0	+ 0.4 or + 0.8
	80%	2. cold-gas efficiency drops with 3% and tar disposal costs are 120 $/ton	+ 0.4	+ 0.3
	80%	3. investment + 0.64 M$	+ 0.3	+ 0.2
waste water	50%	1. investment + 0.09 M$	+ 0.04	+ 0.02
treatment	50%	2. disposal cost wastewater + 60 $/ton	+ 0.7	+ *0.35*
gas engine	50%	η_e engine from 35 to 33%	+ 0.6	+ 0.3
	50%	investment + 0.28 M$	+ 0.14	+ 0.07
steam cycle	20%	net electric output drops with 0.03 MW_e*	+ 0.1	+ 0.02

* theoretical situation, the 12.5 MW_{th}-concept does not contain a steam cycle, the value is extrapolated from the 14.7 MW_{th} concept

From the table it appears that the total risk involved (sum of net risk mentioned in last column, excluding non-additional risks printed in italics) is 1.4 $ct/kWh or more if a steam cycle is part of the system. This so-called net risk is significantly lower than the difference between gasification and combustion (3.4 $ct/kWh for given case, see Chapter 3.3.2). In other words: the costs of electricity from a BIVKIN-based gasifier are lower than the costs of electricity from a combustion plant, even after a risk analysis of the BIVKIN-technology.

2.7 Conclusions

The addition of a steam cycle in a gasification plant (in this study the 14.7 MW_{th} fuel input option) does not result in a more economic situation. The extra electricity produced by the steam cycle is roughly cancelled out by the extra investment. The extra investment, the increase in complexity and the need for other competence of operators and maintenance personnel are good reasons for *not* adding an extra steam cycle to a BIVKIN-based gasification plant using gas engines and being not larger than 15 MW_{th} input. Furthermore, a risk analysis shows that tar problems have a relatively large impact on systems including a steam cycle.

The costs of produced electricity using a BIVKIN-based gasification CHP plant are 8 - 11 $ct/kWh for both a 12.5 and a 14.7 MW_{th} input system (without resp. with steam cycle) fuelled with clean and wet (40% moisture) biomass with a price of 2 - 4 $/GJ. For cheap contaminated fuel, the extra and more stringent flue gas emission limits will only slightly increase the total investment for the BIVKIN-based gasification plant. The electricity production cost reduces to 5 - 7 $ct/kWh for mentioned scale and (relatively low) biomass prices of 0 - 1.5 $/GJ. In Figure 2.7 the above effects are shown. All calculations have been performed with the assumption that no subsidies are granted and green tax profits do not apply. Especially for the near future, there will be financial regulations in many countries which make biomass CHP-plants more attractive. In The Netherlands so-called VAMIL and EIA regulations effectively can reduce the investment with 20-25%, corresponding to a reduction of up to 1 $ct/kWh of the electricity production costs.

In The Netherlands, electricity prices of about 7 $ct/kWh are given for green electricity. So here, using clean wood as a fuel for BIVKIN-based gasification plants for the 1-5 MW_e scale probably will not be economically attractive without subsidies and tax-profits. However, using demolition wood or other contaminated (and cheap) biomass can be attractive in the Netherlands.

The main risk taken, by assuming that the present test-facility at ECN (called BIVKIN-technology) can be simply scaled to commercial dimensions, is related to gas cleaning.

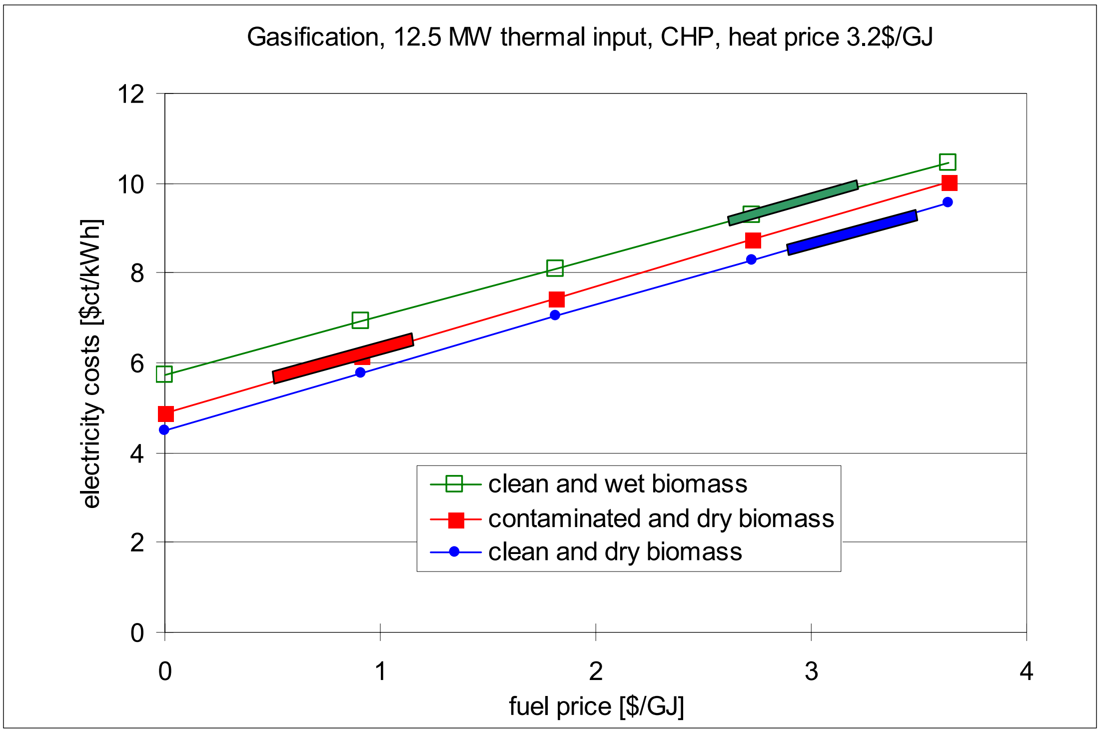

Figure 2.7 *Effect of fuels on costs of electricity. Shaded areas represent ranges of realistic fuel prices (in The Netherlands) for given fuels*

3. COMPETITIVE TECHNOLOGIES

From Chapter 2 it is concluded that under certain conditions, BIVKIN-based gasification technology can produce electricity with costs low enough to be economically attractive. In order to actually sell the technology, the results should also be compared to competing systems. In this chapter BIVKIN-technology is compared to other competitive technologies. For the plant sizes considered (5 to 15 MW_{th}), there is already commercial available combustion technology as well as other gasification technologies. It is assumed that these would be the main competitors of the BIVKIN-technology. In practice more technologies are present, such as technologies based on pyrolysis, digestion/fermentation and high-pressure decomposition. Due to very different characteristics of these technologies, it is foreseen by partners that those technologies will only be competitive on part of the market for electricity and heat production within the considered capacity range (specific feedstocks, need to store conversion product etc.).

3.1 Competing gasification technologies

The gasification technologies developed by competing suppliers of gasification power plants, are based either on fixed bed gasification or fluidized bed gasification. In both cases, a limited number of commercial running plants is present.

3.1.1 Fixed bed gasification

In fixed bed gasification reactors, the fuel is fed into the top of a vertical reactor. The fuel is transported downwards by gravity while undergoing the gasification reactions. Two types of fixed bed gasifiers can be principally distinguished by the direction the gasification air and produced fuel gas move through the reactor: updraft and downdraft gasifiers. Updraft gasifiers can be more easily scaled up compared to a downdraft gasifier but do produce more undesirable tars.

The comparison of BIVKIN-technology with fixed bed gasification technology is summarised in Table 3.1. Subsequently, the different aspects are described.

Table 3.1 *BIVKIN-based gasification versus fixed bed gasification (++: advantage BIVKIN, etc)*

aspect	score
fuel flexibility (fuel costs)	++
carbon conversion/residue production	+
electric efficiency	o
investment costs	+
development status	-

Fuel flexibility
One of the major advantages of BIVKIN-technology over fixed bed technology involves the superior fuel flexibility. BIVKIN-technology has been demonstrated to be suitable to handle a broad range of feedstocks with varying moisture content and physical shape. Fuels like sawdust and chicken manure have been gasified successfully, without any form of pre-treatment. Fixed bed gasifiers do require properly sized wood chips, briquettes or pellets[5] with a defined moisture content. In case of pellets, high quality standards are set regarding the mechanical strength of pellets at high temperatures. This mechanical strength would probably not be realised for all kinds of feedstock (verge grass, chicken manure).

Not only expensive pre-treatment steps can be omitted in the case of fluidized bed compared to fixed bed processes, also long-term contracts with fuel suppliers may not be necessary anymore since the fuel input is flexible. Furthermore, waste streams such as sawdust (for example from saw mills), can be mixed and will reduce the overall costs of fuel.

Carbon conversion and residues
One of the other advantages of BIVKIN-technology (or CFB gasification in general) involves a far better carbon conversion efficiency, resulting in a lower waste stream to dispose off, and less fuel consumption for a given electricity/heat output. The carbon efficiency of a commercial BIVKIN gasifier is estimated at 95% (conservative) to 98%, while the carbon conversion of fixed bed gasifiers amounts to only 90%.

Electric efficiency
The electric efficiency of a gasification plant is directly related to the cold gas efficiency of the gasifier[6]. This parameter is mainly determined by the carbon conversion, the heat loss of the reactor and the fuel gas temperature leaving the reactor. Fixed bed reactors generally show a lower carbon conversion but also have a lower exit temperature of the gas. The heat loss should be lower since the specific surface (m^2/m^3) is lower. The relatively high hydrogen-content in gas exiting a downdraft gasifier probably results in the necessity to lower the compression ratio of the gas engine due to knocking, resulting in a reduction of efficiency. The net effect is not clear beforehand.

Investment
The investment costs for BIVKIN-based power plants are expected to be slightly lower in the 5 to 15 MW_{th} scale compared to power plants based on fixed bed gasification technology:

- In the power plant size range from 5 to 15 MW_{th}, power plants based on fixed bed down draft gasification technology will need several reactors in parallel because of the limited scale-up possibilities. This means: several reactors in parallel, several fuel dosing/feeding systems, several ash discharge systems, several gasification control systems and increased instrumentation (temperature, pressure, gas analysis). In general, maintenance costs will increase. Fixed bed updraft gasifiers have the disadvantage of a high tar content making it inevitable to add an extra tar-reducing component in the gas cleaning section. Furthermore, CFB-reactors contain no moving parts in contrast to fixed bed gasifiers (rotating cone at high temperature).
- Because of a higher carbon efficiency, dimensions of fuel feeding/storage systems and fuel gas cleaning are reduced for a given output

Development status
Regarding development status, a number of fixed bed technologies have already accumulated several thousands hours of operation with a gas engine on a pilot plant scale. With the gas cleaning equipment installed at ECN in 1999, and the gas engine installed in March 2000, the

[5] pelletizing is expensive, approximately 1 $/GJ fuel LHV.
[6] cold gas efficiency: the lower heating value of the fuel gas related to the lower heating value of the biomass fuel.

main disadvantage of BIVKIN-technology compared to competing fixed bed technologies, involves the development status and the additional research that still is needed.

One argument often brought up in favour of fixed bed downdraft gasification involves a lower tar production of fixed bed downdraft gasifiers. For very small gasifiers (< 2 MW_{th}) equipped with a so called 'throat', indeed very low tar levels can be reached as required by gas engines without further tar removal, assuming very stable feedstock quality. However, even downdraft gasifiers sometimes do have extra tar removal units. For example the technology developed by Stork Thermeq incorporates a reverse flow catalytic tar reactor.

In case of fixed bed updraft technologies, suitable for use at larger scales, additional gas cleaning equipment has to be installed. Updraft fixed bed gasifiers produce huge amounts of tar [5] and tar removal is essential. The technology developed by Wellman incorporates an additional thermal/catalytic reactor at high temperature.

Existing plants
In Table 3.2 data related to some major competing fixed bed gasification technologies are summarised. The investment costs for power plants at a scale of approximately 5 MW_{th}/1 MW_e (small scale, only one reactor needed for fixed bed gasification) are between 3000 and 3500 US$/$kW_e$, based on communication with the suppliers. This seems to be within the same range as calculated for the BIVKIN-technology. As has been argued before, there is no reason for large deviations in investment costs of power plants based on fixed bed and small scale fluidized bed technology, if the same boundary conditions are applied. No plants based on fixed bed gasification have actually been built yet. Furthermore, no information is available on the scope of the estimates (civil works, degree of automation, commissioning, extent of waste water treatment, emission regulations: additional CO and NO_x reduction by catalysts). The calculations of the investment of the BIVKIN-technology have been performed "conservatively" with regard to items like civil works, engineering and costs for automation.

Table 3.2 *Summary of main characteristics of some fixed bed gasifier manufacturers, DD: downdraft ; UD : updraft*

technology	type	gas cleaning	capacity (single unit)	operational experience	environmental impact
Vølund	UD	cyclone, scrubbers	1 MW_e	only heat	scrubbing water
Wellman	UD	cyclone, thermal cracker, thermal oxidation, scrubber	2.5 MW_e	little on biomass much on coal	scrubbing water
Imbert	DD	cyclone, scrubber, charcoal filter (or ESP)	800 kW_e	more than 10 years ago	scrubbing water
Stork Thermeq	DD	cyclone, thermal catalytic cracker, fabric filter	1 MW_e	little in this power range	low due to dry gas cleaning
HTV-Juch	DD	cyclone, scrubber	850 kW_e	from pilot unit	scrubbing water

3.1.2 Fluidized bed gasification

In the field of fluidized bed gasification, several companies are developing gasification power plants. The major suppliers and some characteristics are summarised in Table 3.3 [6].

Table 3.3 *Circulating fluidized bed gasifiers for IGCC applications (integrated gasification combined cycle), A-BFB = atmospheric bubbling fluid bed, A-CFB = atmospheric circulating fluid bed, P-BFB = pressurised bubbling fluid bed, P-CFB = pressurised circulating fluid bed*

technology	name and location	gasifier	MW_e	MW_{th}	η_e	status	project costs [M$]	$/kW$_e$
Battelle	Vermont, USA	A-CFB[7] (2x)	15			operational, has run 100 hours	20	
IGT Renugas	BGF, Hawaii	P-BFB	5		30-35%	shut-down	11 (phase 1)	
TPS	ARBRE, UK	A-CFB	8			building	26	3300
Lurgi	Energy Farm, Italy	A-CFB	11.9		33%	design phase	37	3100
Carbona, Enviro-power	Finland	P-CFB		15		operational		
Foster Wheeler, Ahlstrom	Värnamo Sweden	P-CFB	6	9	32%	stopped	35	5700
TPS	BIG-GT, Brazil	A-CFB	32		41%	awaiting decision		
unknown	North-Holland	A-CFB	30		38%	tender stopped	105	3500

All existing fluidized bed gasifier suppliers are directing their development efforts towards power plants at a scale of at least 15 MW_{th} thermal capacity, and the produced fuel gas is used in gas turbines or existing large scale boilers. As such, those suppliers are not considered as competitors at this moment in the market where BIVKIN-technology is aiming at.

The possibility does exist that in the coming years one or more of the existing suppliers also wants to penetrate the lower scale market segment. However, the chances for this to happen are estimated as moderate because of several reasons:

- The largest market for gasification technology is most probably the market for large-scale power plants. This moment mentioned suppliers do need all available resources (money and engineering capacity) to get the technology ready for this market.
- Building gasification power plants on a smaller scale based on gas engines, does require substantial additional development efforts. The gasifier system has to be modified in terms of for example reduced reactor length, in order to become economically viable at a small scale. These modifications require extra evaluations and experiments so as to determine gasifier performance and dynamic behaviour. Also many small practical problems do ask for extra engineering capacity (for example the refractory can not be installed in the form of bricks by people standing in the reactor, but the material will have to moulded into gasifier sections because of a too small gasifier internal diameter). Furthermore, the integration of a gasifier with a gas engine asks for specific additional research and evaluations.
- As has been experienced in the past, existing suppliers are not willing to offer a gasifier for a small-scale power plant without substantial additional development activities. A gasifier power plant that is functioning badly will have a very negative impact on the supplier's reputation.
- Organisations of large companies like Lurgi and Foster-Wheeler are fully equipped and organised for handling large projects of tens millions of dollars. For those companies,

[7] IGCC in future, now: co-combustion

smaller scale projects are more difficult to handle economically, due to existing procedures and overheads.

In case existing suppliers keep on concentrating on the larger scale power plants in the coming three years, and HoSt is able to build a few demonstration power plants, it will probably be very difficult for mentioned suppliers to compete with demonstrated and optimised BIVKIN-technology.

3.2 Combustion technology

Combustion technology can be considered commercially available for a lot of biomass feedstocks. There are innumerable suppliers of furnace/boiler systems. Both grate fired boilers and fluidised bed boilers are suitable for power ranges up to 100 MW_e (300 MW_{th}). The upper limit is set mainly by anticipated fuel supply constraints.

Fluidised bed boilers are more compact than grate fired boilers. Furthermore, fluidised bed boilers are more effective in control of the more critical emissions, especially where low emission limits are specified. This advantage is the result of a better temperature control of the fluidised bed. Other operational characteristics such as availability are, in principle, similar. This also applies to fuel characteristics including fuel flexibility.

Because of the exothermal character of combustion processes, there is always a risk for temperature peaks locally or periodically. This not only may result in too high emissions of e.g. NO_x, it may also be a reason for agglomeration to occur [7]. This is an important difference with gasification, where the process is autothermal and the chance for temperature peaks to occur will generally be lower. If difficult fuels like grass and straw and other fast growing (generally cheap) fuels are available, one should realise that agglomeration is a serious problem and the choice of process is very important.

Although a lot of combustion power plants have been built in the capacity range considered (5 to 15 MW_{th}), very few combined heat and power plants have actually been realised. At these small capacities, specific investment costs rise very quickly and electric efficiencies are very low due to moderate efficiencies of steam turbines.

For three scales of biomass power plants, investment costs and performance were determined as a reference for comparison with gasification power plants (Chapter 3.3). The investment costs were determined by HoSt, together with specialists from QtecQ, who have actually been involved in building the 8 MW_{th} Lelystad biomass combustion power plant in the Netherlands. The results of the evaluation are given in Appendix A and Table 3.4 and are used for economical evaluation in Chapter 3.3. The total efficiency of the combustion-based CHP systems is assumed to be 80%.

Table 3.4 *Data on combustion CHP plants (for clean biomass, 40% moisture) used as a reference for evaluation*

	investment M$	electricity MW_e[8]	heat MW_{th}	electric efficiency[9]	specific investment $/$kW_{th}$ fuel input	specific investment $/$kW_e$
5 MW_{th}	4.4	0.62	3.1	13.5%	810	7100
12.5 MW_{th}	9.8	2.1	7.2	17.8%	720	4800
14.7 MW_{th}	10.9	2.4	8.5	17.8%	680	4500

[8] Based on condenser temperature of 80°C (hot water production at 75°C)
[9] Based on fuel input of wet material before dryer (4.6, 11.6 and 13.6 MW_{th} respectively), see Figure 2.3

In Figure 3.1 the investment costs of existing CHP plants are presented in \$ per kW_e. Also indicated are the calculated costs of the combustion plants considered in this report. Not visible from the figure is that the costs for large systems converge to values a little less than 2000 $\$/kW_e$. From the figure it becomes clear that (1) investment costs increase considerably with decreasing scale, (2) for a given scale, the difference between different plants can be as high as a factor of two and (3) the plants under consideration in this study are within the "cloud" of points.

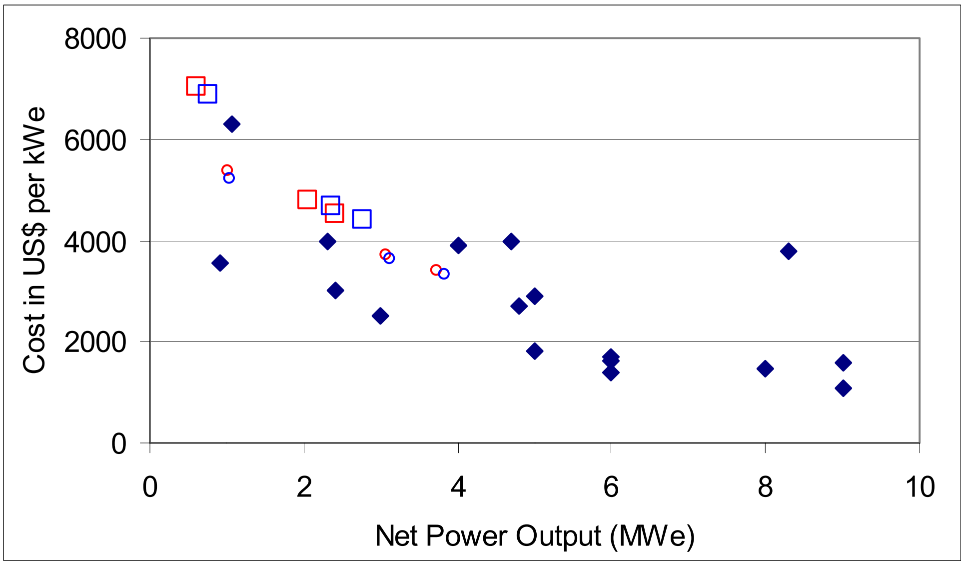

Figure 3.1 *Costs of existing CHP-units (expressed as $\$/kW_e$) based on combustion. Open symbols represent plants considered in this study (open squares: CHP, open circles: only electricity)*

3.3 BIVKIN-technology versus combustion

3.3.1 Efficiency

During combustion, all fuel is converted to a hot gas (flue gas), which can be used to generate steam in a boiler and subsequently generate electricity in a steam turbine/generator. The electric efficiency is mainly the result of the efficiency of the steam turbine.

By gasifying the fuel, a combustible fuel gas is produced. The gas can be combusted in a gas turbine or gas engine. The electric efficiency is the product of the efficiency of the gasifier (approx. 80%) and the turbine or gas engine (30-40%). A steam turbine can be coupled to convert "waste" heat to electricity.

In Figure 3.2 the electric efficiency is plotted against scale for both gasification and combustion processes. For gasifiers, the efficiency can be relatively high for small-scale systems. Only below about 0.1 MW_e (estimate) the efficiency drops due to a lower efficiency of both the gasifier and engine. At higher capacity (above 5 MW_e), combined cycles are possible. This is coupled with the availability of gas turbines for low calorific gas. In this case the heat from the (turbine) exhaust gas is used to generate extra electricity in a steam cycle. This can be as much as one-third of the total power produced, resulting is high electric efficiencies for these so called IGCC systems (integrated gasification combined cycle). For combustion however, the curve is rather different. Small-scale systems have very low efficiencies due to both low steam pressure and high losses in the steam turbine (isentropic or internal efficiency). Increasing scale will allow higher steam pressures and higher isentropic efficiencies resulting is higher electric efficiencies. In Figure 3.2, the above-presented trends are given in a graphic way together with the efficiency of some existing plants.

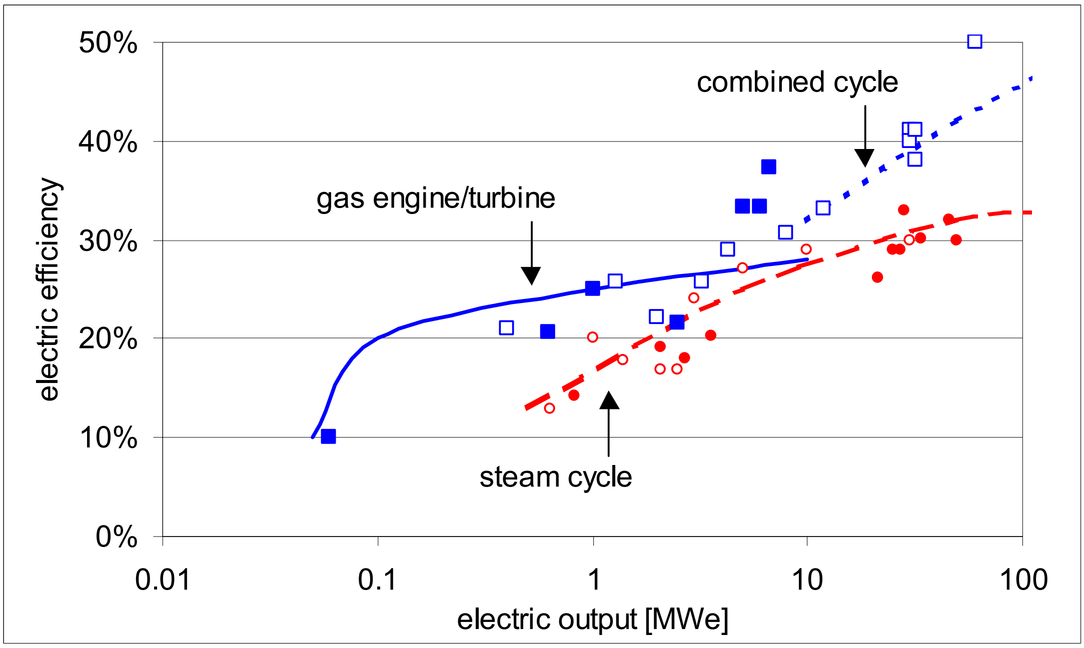

Figure 3.2 *Electric efficiency of biomass combustion (--, o and ●) and gasification (--, —, □ and ■) plants. Lines represent theoretical relations. Filled points represent actual plants (in most cases pilot plants), open points are calculated values both from this study and commercial plants still in the engineering or start-up phase*

From the theoretical lines in the figure above, there seems to be an incentive to market small-scale gasification systems (below 5 MW_e) as well as large scale IGCC-plants (above 20 MW_e). For these scales, gasification systems show significantly better electric efficiency than combustion systems. In practice a limit exists both for very small-scale systems due to increased costs (see also Figure 3.1) and for very large systems due to increasing costs for biomass fuel logistics. In this report, the subject is BIVKIN-based gasification systems producing 1-5 MW_e. From an electric efficiency point-of-view this seems to be an interesting range.

3.3.2 kWh-production costs

The economic performance of the BIVKIN-based gasification plant is compared with the most available and used technique: combustion. For both cases the cost of the electricity [$ct/kWh] is calculated using the assumptions given in Appendix C. Both CHP-production (electricity and heat) and electricity production without heat have been considered. As presented in Chapter 2.2 the CHP-option uses a back-pressure steam turbine (if any) and the option optimised for electricity has a condensing cycle.

Appendix E gives the costs of produced electricity both for combustion and BIVKIN-based gasification plants. In both cases, three scales are considered: 5, 12.5 and 14.7 MW_{th} based on the LHV of the fuel. From the figures it becomes clear that combustion produces electricity more expensively than gasification. In other words: gasification is economically more attractive than combustion when comparing the same scale based on fuel input. When comparing combustion and gasification producing the same heat (realistic when small-scale plants are dimensioned on heat demand), gasification is even more favoured. Figure 3.3 shows the different kWh-production costs for clean and wet (40% moisture) biomass for the CHP-option as indicated. The difference between gasification and combustion becomes small only for the combination of large scale (14.7 MW_{th} capacity) and very cheap fuel prices.

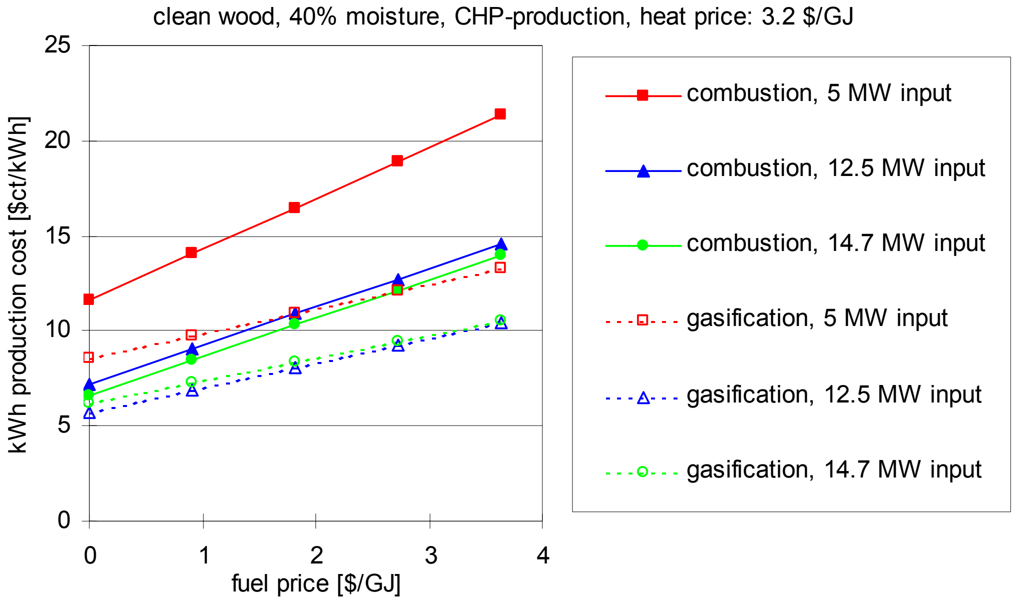

Figure 3.3 *Electricity production costs for combustion and gasification (BIVKIN-based technology) for clean wet biomass and CHP-production*

From the figure it becomes clear that the influence of the fuel price on electricity production cost is relatively large for combustion systems (higher slope in figure). This is the result of the relatively low efficiency for the combustion systems, in other words: a lot of fuel is needed to produce one kWh in combustion systems. This means that in a market where fuel prices will go up, gasification will become even more favourable in the capacity range considered.

The kWh-costs are the result of many factors of which fuel price and investment costs are the main. Figure 3.4 shows the breakdown of the costs of produced electricity both for the 12.5 MW_{th} fuel input gasification and combustion system.

Note that both electricity costs and heat costs influence the conclusions of an economic assessment. In The Netherlands the heat price is very low compared to what is paid for electricity. In Sweden this is just the other way around. In other words: conclusions from economic evaluations depend on local situations.

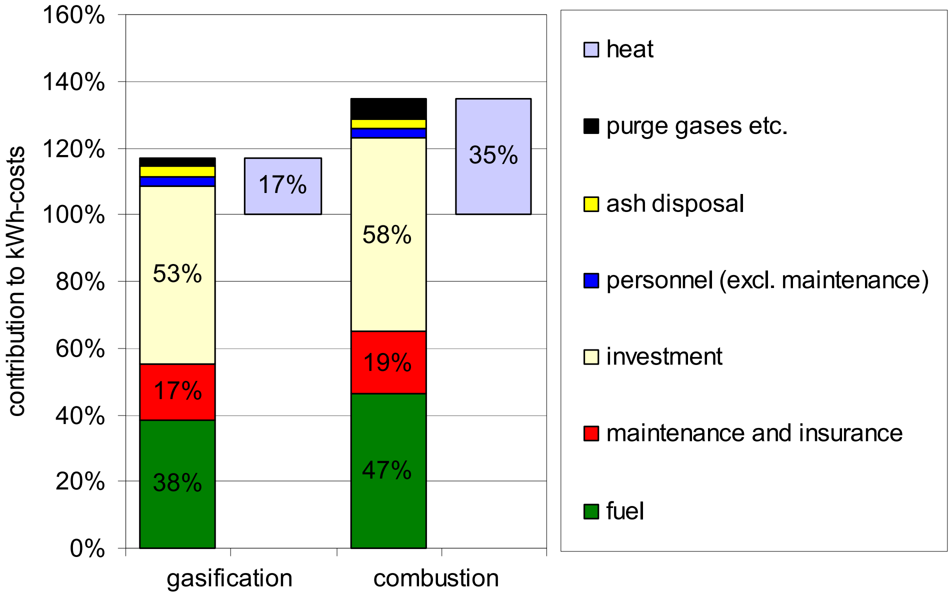

Figure 3.4 *Breakdown of kWh-costs of 12.5 MW_{th} fuel input system, the costs of electricity of each plant is normalised to 100%*

3.4 Conclusions

There are three possible competing technologies for the BIVKIN-based business: combustion, fixed bed gasification and BIVKIN-resembling processes already on the market. In all cases, the BIVKIN-based gasification technology seems to have enough competing "strength" in the 1-5 MW_e scale:

- BIVKIN-based gasification plants produce electricity considerably cheaper than combustion plants (strongly dependent on scale and fuel price, but the difference is roughly 2-3 $ct/kWh). The main reason for this is the relatively high electric efficiency of the gasification concept, especially in the range under consideration (up to 5 MW_e). Apart from the economic difference, also technical differences exist in favour of gasification. Combustion temperature, and especially temperature-homogeneity, is generally less easy to control because of the exothermal character of the reaction and the need to cool. Agglomeration risks are therefore greater and combustion processes are less suitable for fuels like grass and other fast growing (and therefore cheaper) biomass.
- Compared to fixed bed gasification systems, BIVKIN-based gasifiers show superior fuel flexibility. In practice this means a lower fuel price resulting in lower costs of produced electricity for a fluidized bed plant.
- Companies presently building power plants based on fluidized bed technology all are concerned with larger scale systems than is focussed on in this report, generally above 15 MW_{th} input capacity. The chance that these companies will try to go into the market for 1-5 MW_e systems is considered to be small. The risks are too high for these companies and new development is necessary.

4. IMPROVEMENT OPTIONS

Within the scope of the study, a few design modifications have been evaluated to check the possibility to improve the economical performance of gasification power plants (investment costs, operational costs, and electric output).

4.1 Oxygen enriched air

From thermodynamic calculations and published studies [8,9], it is clear that the use of oxygen (enriched air) instead of air results in a number of positive effects. The use of oxygen enriched air instead of normal air will in practice have the following impacts on a gasification power plant with a given thermal input based on LHV of fuel:

Advantages:
- the heating value of the product gas increases and the volume decreases, see Figure 4.1.
- the specific investment costs of the gasifier and the gas cleaning will be reduced due to a lower volume of fuel gas.
- the specific investment costs of the gas engine are reduced because of a lower de-rating of a gas engine running on a higher calorific value fuel gas
- the use of fuel gas in a gas engine will be less critical due to a higher calorific value (increasing reliability)
- the cold gas efficiency of the gasifier will increase: more energy is fed to the gas engine
- probably less tar will be produced because of the more reactive atmosphere resulting in a more easy gas cleaning and waste water treatment
- probably a higher carbon conversion for the same reason
- there is one extra parameter to control the process: oxygen-concentration (air/oxygen-ratio)

Disadvantages:
- the production of oxygen enriched air consumes electric power
- an oxygen enrichment plant will have to be built (increased investment costs)
- the sensitivity for fuel flow disturbances might increase
- air preheat temperature is limited due to corrosion

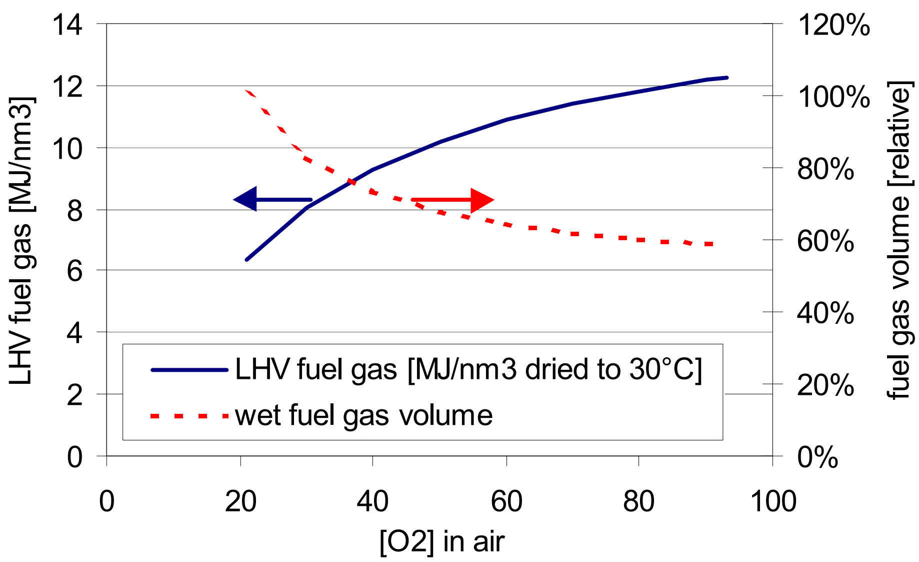

Figure 4.1 *Influence of oxygen content in gasification air on the calorific value of wet fuel gas (solid line, left axis) and fuel gas volume (dotted line, right axis) based on calculations*

The impact on investment costs, operational costs and power plant output has been calculated for a 14.7 MW_{th} gasifier power plant with gas engines and a steam cycle. The results are not discussed in this report due to the confidential character.

4.2 Oxygen enriched air plus thermal cracker

This chapter is omitted due to its confidential character.

4.3 Oxygen enriched air plus thermal cracker plus dry cleaning

This chapter is omitted due to its confidential character.

4.4 Other improvement options

This chapter is omitted due to its confidential character.

5. MARKET

In this chapter, the potential market for BIVKIN-based biomass gasification technology is identified and quantified where possible. This is done both from a process-demand point-of-view and a biomass fuel potential approach.

5.1 Requirements & Trends

Northern, Central and Eastern European countries (Germany, Austria, Denmark, Sweden, Finland, Poland, Hungary, Czech Republic, Slovakia and the Baltic States of Lithuania, Latvia and Estonia) have attractive environments for the development of commercial biomass Combined Heat and Power (CHP) units. In particular, most of these countries have already rural district heating (DH) installed and conversion of these units to CHP in the range 1 MW_e to 10 MW_e would offer ideal opportunities for the BIVKIN-technology if these could be made competitive with the existing technologies (such as grate combustion operated on a steam Rankine cycle).

Each of the national energy systems of the countries named above is quite distinct and each is undergoing continuous change and transformation. The rate of progress and the pace of change are greatest in Scandinavian countries and in Austria, where environmental imperatives such as CO_2 reduction have a strong influence on energy policy. The policies in these countries, combined with abundant biomass resources, have created a central role for bio-energy in the national energy profile. Conversion from fossil fuels to biomass at smaller scale decentralised facilities is well advanced. The strategy for market entry for BIVKIN-technology therefore would be enhanced if the cost of such technology were cost effective.

Customer Requirements
The customer (owner of the plant) generally has three requirements:
- To obtain competitively priced biomass conversion technologies for heat and power.
- To obtain an efficient, simple and flexible process system that can be operated continuously throughout the year without major maintenance or process downtime.
- To be able to produce heat and electricity under a “greener” profile produced from renewable resources in a sustainable manner.

Trends
There are three trends developing in the European energy market;
- A strong political will for the introduction of renewable energy sources to the market place (EU directive to have 10% of electricity from renewables by 2010)
- Kyoto promises to reduce CO_2 emissions from fossil fuels by 10% in 2010 (reference: 1990).
- Companies are seeking to improve their profile by securing a positive/least harmful impact on the environment by their production of goods and services. As a consequence of this and the incentives introduced by the new energy policy, there is a growing interest for renewables.

5.2 Market Potential

5.2.1 Factors influencing the market

The current heating market is influenced by several important factors such as decreasing market share of fossil fuels (CO_2-taxes), policies developing to avoid use of direct electric heating, growing environmental concerns and obtainable market advantages from demonstrating a “green production profile”.

In countries such as Denmark, there is active government encouragement via legislation to convert old coal fired or wood fired district heating systems to biomass operated CHP systems. Electricity produced from such units have guaranteed higher tariffs than that produced from fossil fuels. Such tariffs often compensate for higher investment costs that are incurred in building biomass CHP plants when compared to gas or oil fired CHP plants.

5.2.2 The market

In some of the European countries (Eastern Europe, Austria, Scandinavia), district heating is fairly common but the average size of units using biomass is very small. However, bio-energy has already become well established in Austria, Sweden, Finland and Denmark, see Appendix F. It is anticipated that the use of biomass will increase in Poland and Hungary at rates greater even than the overall energy market. Most of these countries have an extensive infrastructure for biomass supply. In addition, there is greater profile of agricultural by-products in the mix of bio-fuels that are available in these European countries, see also Appendix G.

There are two major trends in the district heating (DH) market. The first is the rate of installation of new capacity that will be more pronounced in some of the countries such as Finland and Hungary, although none will be growing very quickly. The other related trend is the refit of existing capacity.

CHP growth will be the explicit result of the push to refurbish ageing DH plants in all countries. It is anticipated that in Poland and Hungary there will be large-scale re-investment in gas-fired CHP. The smaller end of those markets, in rural areas where the gas pipelines do not reach, is open to alternatives such as biomass-fired units.

From EU-EuroHeat bureau fact sheets, the figures from Table 5.1 have been obtained. Note that most of the district heating plants are run on heavy fuel oil or natural gas. CHP units are mostly run on gas.

Table 5.1 *District heating (DH) facts for different European countries, n.a.: not available*

Country	DH share of heat market (%)	share of CHP in DH (%)
Austria	12	67
Czech Republic	32	n.a.
Denmark	50	73
Estonia	52	45
Finland	50	79
France	3.5	14
Germany	12	75
Hungary	17	24.9
Norway	3	n.a
Poland	34	48.5
Sweden	38	3

Austria
Most DH schemes are owned by either utilities or agricultural co-operatives comprised of local farmers who have direct access to biomass supply. There are about 447 DH plants of which 80% are under 2 MW_{th}. The vast majority of these plants is biomass-fired (90%), the remaining 10% are primarily conventional CHP plants (oil or gas).

Czech Republic
There is great non-exploited potential in DH & CHP in large villages and smaller towns.

Denmark
In Denmark, old coal fired DH plants were converted to operate on biomass after the first oil crisis in the 1970s. These in turn are ripe for conversion to biomass CHP. Over 400 DH companies exist of which about 140 are operated on biomass. The government is encouraging these companies to switch to CHP operation.

Estonia
DH continues to be economically competitive but uneconomical old systems need basic upgrading. Here there is a chance that some of these could be converted to biomass CHP.

Finland
About 250 communities in Finland (40% of the population) are serviced by DH. Biomass is used extensively in both municipal and industrial markets. CHP plants produce 80% of the DH energy. There's a growth in CHP fuelled by natural gas. Seven small-scale CHP units (<10MW_e) were built in the 1990s, each designed to operate on biomass. VTT estimates that a further 25 plants of this size could be built. There are 219 units (municipal CHP, DH, industrial CHP, small-scale CHP) that operate on biomass at various energy outputs.

France
There are 379 companies in the DH sector. There is very little potential for the development of biomass in France due to the dominance of cheap electricity form nuclear plants.

Germany
There are 232 DH companies in Germany. The amount of biomass used in generating heat for these plants is only 5% of the total fuel mix.

Hungary
109 DH units serve 20% of all residences. In major cities, the share of residences served by DH systems exceeds 75%.

Norway
Norway is for 98% dependent on hydro-energy. The government is encouraging DH for large buildings and these must operate on renewables.

Poland
DH networks supply heat and hot water to over 70% of all households in many cities. According to the Ministry of Agriculture, there are at least 1200 old fashioned rural DH units that are beyond repair and require replacement; these plants are currently fuelled by quality coal or heavy oil and their average thermal capacity is between 1 – 3 MW_{th}. A significant market exists for small to medium sized DH systems for cities in the 5 000 to 50 000 population range. Cities of these sizes do not purchase their thermal energy primarily from CHP plants but operate their own heat-only boilers. This market size is estimated at 675 cities.

Sweden

The number of wood fuel operated DH units is 53. There are 15 CHP plants on biomass.
From the above, it can be deduced that if the trend to convert old DH units to CHP units is encouraged by local and central authorities via fiscal measures or via direct subsidies, then a potential market for BIVKIN can be judged to be as indicated in Table 5.2.

Table 5.2 *Potential market for BIVKIN-based gasification plant based on figures on district heating units [16]*

Country	number of district heating units
Austria	400 +
Czech Republic	?
Denmark	250 +
Estonia	?
Finland	25 +
France	0
Germany	200 +
Hungary	100 +
Norway	?
Poland	1000 +
Sweden	50 +

There is thus a potential market of 2000 DH conversions that could be implemented in these countries over the next 20 years. If BIVKIN can capture 10% of this market than there is already a potential of 200 units that could be installed in the next 20 years.

5.3 Biomass resources and potential

In Europe, various biomass resources are available for energy production and a certain amount is already used. However, there remain resources unused. The main biomass resources that are widely used in Europe are fuel wood, wood residues from the wood processing industry, recovered wood products, pulping liquors and straw. The most relevant biomass resources hardly used are forest residues from timber production and thinning measures, residues from fruit plantations, public parks, road greenery, agricultural residues (olive oil or vegetable production), organic waste from industry and household and energy crops.

In this section, potentials of some of these biomass streams are given. All the data presented have been compiled from published literature. Only residues and energy crops are considered, whereas waste streams especially from households and industry remain unconsidered.

Appendix G gives land use of various European countries. These figures show that there is a large potential for sustainable biomass usage in some of the European countries. Appendix F gives the primary energy consumption of some of the European countries. Data show that Austria, Finland and Sweden have good percentage that is taken up by the use of biomass. Appendix H gives a detailed breakdown of the use of biomass in the EU. Also, primary energy consumption is listed and it shows that in the EU, about 3% of the total energy is obtained from biomass. Fossil fuels, hydro and nuclear still have a lion’s share of the energy used in EU.

In Europe, an area of about 116 million hectares is covered by forests. These forests are mainly cultivated for timber production. In Appendix I, estimates are made of the amount of additional biomass resources for energy. Results are summarised in the table below.

Table 5.3 *Summary of potential biomass resources available for energy purposes in Europe*

	PJ/year	% of 1995 fossil energy consumption
residual wood by-products	420	0.9
additional thinnings	500	1.1
road greenery, public parks	140	0.3
straw	560	1.2
agriculture/animal waste	110	0.2
energy crops	2600	5.6
total	4330	9.3

Based on the above explanations, it becomes clear that biomass contributes to the European energy supply to a limited extent. This share could be considerably higher. The average percentage of both the biomass already used and the currently unused biomass potential in Europe adds up to approximately 12.8% of the total primary energy consumption. It is obvious that biomass can be of great importance within the European energy system.

Appendix J gives an indication of the biomass potential in 2000 and 2020. From these studies, it appears that the biomass potential in Europe is 4600 PJ/year in 2000 and 6400 in the year 2020. It can be concluded that the biomass potential is much greater than the current use. The largest potential for bio-energy is in the Nordic and the Baltic countries.

5.4 Conclusions

From a study on existing fossil-fuelled CHP-units presently used for district heating purposes, it is estimated that the potential market for BIVKIN-based gasification plants is at least 2000 units in Europe. This market is created by the need to replace or refurbish existing plants combined with local or national targets with regard to the share of renewable sources in the energy supply. This will be encouraged by local or central authorities via fiscal measures and direct subsidies.

6. CONCLUSIONS

6.1 Main conclusions

The BIVKIN-technology for the production of electricity for scales up to 5 MW_e will produce electricity cheaper than when using combustion technology. Together with a great estimated market potential, it is concluded that the commercialisation of the BIVKIN-technology is economically attractive. However, some tar-related technical problems need to be solved first and a reduction of the investment per kW_e is desirable, especially when clean wet biomass is the fuel. Different options for improvement are available.

6.2 Extended conclusions

From a market analysis, it is concluded that there is a potential market for BIVKIN-based biomass gasification plants of at least 2000 units in Europe in the coming 20 years. From an economic analysis for a business initiative selling the "BIVKIN-technology", it can be concluded that such a business can be very profitable. It should be noted that during the first 4 years, the net cash flow will be negative for the turn-key supplier due to the need to realise demonstration plants and the assumption that the plant operator can exploit the plant profitable. Several possible demonstration projects have been identified. The two closest to realisation are plants on the premises of ECN and HoSt respectively, illustrating the willingness to make the BIVKIN-technology a commercial product.

Based on estimated investment costs *without subsidies or tax-related profits*, it is concluded that the costs of produced electricity using clean and wet wood will generally be too high for an economically attractive exploitation of a BIVKIN-based gasification plant. However, if cheap (contaminated) biomass can be used, gasification CHP plants with a capacity in the upper range of the capacities considered (around 15 MW_{th} input) will become economically attractive. In this case the electricity production costs are 5 - 7 \$ct/kWh (fuel price is 0 - 1.5 \$/GJ) compared to 8 - 11 \$ct/kWh when relatively expensive (2 - 4 \$/GJ) clean and wet (40% moisture) biomass is used as fuel. Small-scale plants (5 MW_{th} input capacity) produce electricity for roughly 2 \$ct/kWh more and therefore will generally not be economically viable (without subsidies and tax benefits) given the prices presently paid for green electricity in European countries.

There are several competing technologies for the BIVKIN-based business: combustion, fixed bed gasification and BIVKIN-resembling processes already on the market. In all cases, the BIVKIN-based gasification technology seems to have enough competing "strength" in the 1-5 MW_e scale. Combustion, being the most mature technology for the production of electricity, is relatively expensive. The difference of electricity production costs is generally around 2 \$ct/kWh.

In order to be actually able to exploit a BIVKIN-based gasification plant successfully in the (near) future, it is necessary to focus on the tar problem. Tar has been identified as the main risk for the commercialisation of the integral technology. Furthermore, in order to make the BIVKIN-technology economically feasible for relatively expensive (generally clean) biomass, the investment costs should be reduced. Both subjects therefore need further R&D-efforts.

ECN and HoSt are willing to participate in an R&D-programme aiming at commercialising BIVKIN-gasification technology. Shell has no ambition to participate in the development. Shell however will consider acting as investor/owner of a BIVKIN-technology based gasification plant if this technology appears to be the best for the specific situation.

Solving the tar-problems

Many different possible problems related to tar have been described: tar condensation and subsequent blockage in fuel gas pipes, tar recycling problems, insufficient tar removal from the fuel gas entering the gas engine, and insufficient waste water tar removal. These tar-related problems have been estimated to add up to a maximum of 1.2 – 2.4 $ct/kWh increase of electricity production costs. Apart from this, the problems will result in a reduction of operational time. This not only results in an extra increase of electricity production costs, it also reduces the reliability of the gasification plant since the non-operational time will generally be not planned. Reliability is of ultimate importance for new technologies like the one considered in this study. The tar problem therefore should get much attention.

Reducing the investment

The specific investment[10] of the first commercial BIVKIN-based gasification plant, defined as the first plant built after realisation of two or three demonstration plants, is 3200 and 4400 $/kW$_e$ for the 12.5 and 5 MW$_{th}$ input plant respectively when using wet fuel. A plant on dry fuel will cost 2800 and 3800 $/kW$_e$ respectively. This is high compared to fossil fuel powered systems. This results in relatively high electricity production costs since these costs are for 50-75% investment-related (partly caused by the wish to make profit on invested money; for the calculations an IRR of 9% is assumed). Reductions of investment can make the BIVKIN-based gasification technology (more) viable.

The specific investment of the system where part of the heat is used in a steam cycle to produce extra electricity (the 14.7 MW$_{th}$-concept) turns out to be roughly equal to the system where all the heat is used for district heating purposes. The incorporation of a steam cycle therefore is not a cost reducing option.

Simply making more plants and taking advantage of a learning effect and previous engineering efforts will result in a reduction of investment. The estimated reduction of investment of the tenth plant will be 400 and 700 $/kW$_e$ for the 12.5 and 5 MW$_{th}$ input systems respectively. This will result in a reduction of costs of produced electricity of around 0.5 $ct/kWh.

The costs of the gas engine(s) appear to be roughly 25% of the total investment of the plant. Based on limited experience and literature it is assumed that a gas engine only produces about 60% of its power if low-calorific gas is used as fuel instead of natural gas. Because also some technical changes are necessary due to the different air-to-fuel ratio and the presence of hydrogen in the fuel gas, the investment per kW$_e$ output roughly doubles going from natural gas to low calorific gas. The authors think that at least part of the reason of this very high so called de-rating is the limited R&D efforts in this field due to limited market. So, gas engines make up a significant part of the total investment of a complete gasification CHP plant and at the same time there seems to be “room” for reductions of specific investment costs for engines for low-calorific gases. Quantitatively, the effect of engine de-rating is responsible for about 0.5 $/kWh of the electricity production costs. So, R&D on gas engines for low-calorific gases seems necessary and worthwhile when trying to make small-scale biomass CHP-units economically (more) attractive.

So as a final remark it can be stated that the success of commercial exploitation of the BIVKIN-technology depends on several main activities within the coming years:

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[10] Investment in this study is defined as the total costs of the plant, including civil works, engineering, management, start-up, contingency and profit. It does not include interest during construction.

- *Research and development related to the base case*: Several projects, presently carried out with the existing plant at ECN, will generate experimental results and knowledge of the system presented in this report as “BIVKIN-technology”.
- *Further research and development:* Some aspects are identified as subjects for further research in order to reduce the costs of produced electricity: solving several tar-related problems, increasing carbon conversion and improving gas-engine performance on low-calorific gases. The results of the R&D activities are essential for the specifications and engineering of the demonstration plants.
- *Demonstration*: The realisation of demonstration plants is necessary for successful commercialisation of the BIVKIN-technology. Two demonstration plants are planned on the premises of ECN and HoSt respectively.

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APPENDIX A. EFFICIENCY AND INVESTMENT FOR DIFFERENT FUELS AND SYSTEMS

fuel		clean (10% moisture)						contaminated (10% moisture)						clean (40% moisture)					
technology		gasification			combustion			gasification			combustion			gasification			combustion		
fuel input (MW_{th} LHV-base[11])		14.7	12.5	5	14.7	12.5	5	14.7	12.5	5	14.7	12.5	5	14.7	12.5	5	14.7	12.5	5
electricity production only																			
E-production gas engine	MW_e	4.01			0	0	0	4.01			0	0	0	4.01			0	0	0
E-production steam engine	MW_e	0.77			3.82	3.13	1.03	0.77			3.82	3.13	1.03	0.53			3.74	3.07	1.01
E-use dryer	MW_e	0			0	0	0	0			0	0	0	0.05			0	0	0
E-use O2-plant	MW_e	0			0	0	0	0			0	0	0	0			0	0	0
E-use other	MW_e	0.22			0.29	0.25	0.13	0.22			0.29	0.25	0.13	0.22			0.29	0.25	0.13
net electric output	MW_e	4.56			3.53	2.88	0.90	4.56			3.53	2.88	0.9	4.27			3.45	2.82	0.88
net electric (=total) efficiency	%	31.0%			24.0%	23.0%	18.0%	31.0%			24.0%	23.0%	18.0%	31.4%			25.4%	24.4%	19.0%
investment	M$	12.3			11.8	10.5	4.7	12.7			12.6	11.3	5.2	13.6			11.8	10.5	4.7
specific investment	$/kW_e$	2692			3335	3646	5253	2792			3580	3930	5808	3184			3409	3727	5376
CHP-production																			
E-production gas engine	MW_e	4.01	3.42	1.37	0	0	0	4.01	3.42	1.37	0	0	0	4.01	3.43	1.37	0.00	0.00	0.00
E-production steam engine	MW_e	0.47	0	0	2.76	2.35	0.77	0.47	0	0	2.76	2.35	0.77	0.32	0	0	2.70	2.30	0.75
E-use dryer	MW_e	0	0	0	0	0	0	0	0	0	0	0	0	0.05	0.05	0.02	0	0	0
E-use O2-plant	MW_e	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E-use other	MW_e	0.22	0.19	0.08	0.29	0.25	0.13	0.22	0.19	0.08	0.29	0.25	0.13	0.22	0.19	0.08	0.29	0.25	0.13
net electric output	MW_e	4.26	3.23	1.29	2.47	2.10	0.64	4.26	3.23	1.29	2.47	2.1	0.64	4.06	3.20	1.27	2.41	2.05	0.62
net electric efficiency	%	29.0%	25.8%	25.8%	16.8%	16.8%	12.8%	29.0%	25.8%	25.8%	16.8%	16.8%	12.8%	29.9%	27.7%	27.5%	17.8%	17.8%	13.5%
H-production gross	MW_{th}	5.30	5.52	2.21	9.29	7.90	3.36	5.30	5.52	2.21	9.29	7.9	3.36	5.50	5.56	2.23	8.45	7.19	3.07
H-use dryer	MW_{th}	0	0	0	0	0	0	0	0	0	0	0	0	1.33	1.11	0.44	0	0	0
net heat output	MW_{th}	5.30	5.52	2.21	9.29	7.90	3.36	5.30	5.52	2.21	9.29	7.90	3.36	4.17	4.45	1.79	8.45	7.19	3.07
net heat efficiency	%	36.0%	44.2%	44.2%	63.2%	63.2%	67.2%	36.0%	44.2%	44.2%	63.2%	63.2%	67.2%	30.7%	38.5%	38.7%	62.2%	62.2%	66.5%
total efficiency	%	65.0%	70.0%	70.0%	80.0%	80.0%	80.0%	65.0%	70.0%	70.0%	80.0%	80.0%	80.0%	61%	66%	66%	80%	80%	80%
investment	M$	11.9	9.1	4.9	10.9	9.8	4.4	12.3	9.5	5.0	11.8	10.6	4.9	13.2	10.2	5.6	10.9	9.8	4.4
specific investment	$/kW_e$	2785	2813	3770	4417	4675	6889	2892	2940	3876	4785	5065	7670	3249	3188	4374	4520	4785	7053

[11] fuel input based on dried fuel (10% moisture), see Figure 2.3, actual fuel input for fuel containing 40% moisture is 13.6, 11.6 and 4.6 MW_{th} respectively

APPENDIX B. INVESTMENT OF BIVKIN-BASED GASIFICATION SYSTEMS

See also Appendix A for specifications of electric and heat output.

fuel		clean (10% moisture)			contaminated (10% moisture)			clean (40% moisture)		
fuel input (MW_{th} LHV-base[12])		14.7	12.5	5	14.7	12.5	5	14.7	12.5	5
E (no heat)										
net electric output	MW_e	4.56			4.56			4.27		
first commercial plant										
investment	M$	12.3			12.7			13.6		
specific investment	$/kW_e$	2690			2790			3180		
10th plant										
investment	M$	10.9			11.4			12.2		
specific investment	$/kW_e$	2390			2490			2860		
CHP										
net electric output	MW_e	4.26	3.23	1.29	4.26	3.23	1.29	4.06	3.20	1.27
net heat output	MW_{th}	5.30	5.52	2.21	5.30	5.52	2.21	4.17	4.45	1.79
first commercial plant										
investment	M$	11.9	9.1	4.9	12.3	9.5	5.0	13.2	10.2	5.6
specific investment	$/kW_e$	2790	2810	3770	2890	2940	3880	3250	3190	4370
10th plant										
investment	M$	10.4	7.8	3.9	10.9	8.2	4.1	11.8	8.9	4.6
specific investment	$/kW_e$	2450	2400	3060	2560	2530	3160	2900	2770	3660

[12] fuel input based on dried fuel (10% moisture), see Figure 2.3, actual fuel input for fuel containing 40% moisture is 13.6, 11.6 and 4.6 MW_{th} respectively

APPENDIX C. ASSUMPTIONS USED FOR ECONOMIC EVALUATIONS

	unit	value
operation	hr/year	8000
HHV fuel	MJ/kg daf	20
[H] in fuel	wt% H daf	6.2
[C] in fuel	wt% daf	51
[ash] in clean fuel	wt% dry	3
[ash] in contaminated fuel	wt% dry	5
heat loss of reactor	% of thermal input	2
HHV of C in ash	MJ/kg C	32
depreciation	year	15
maintenance and insurance	% of total costs	4
requested internal rate of return (IRR)	% of total investment	9
personnel (1 man-year/year in all cases)	\$/year	68.2
deposit costs ash/sand	\$/tonne	59
deposit costs condensate	\$/tonne	0.7
price of purge nitrogen	$\$/m_n^3$	0.14
price of bed material	\$/tonne	57
price of ammonia (25%)	\$/tonne	136
price of $Ca(OH)_3$	\$/tonne	91
price of NaOH	\$/tonne	318
price of activated carbon	\$/tonne	227
price of cooling water	\$/tonne	0.5

	unit	value	
		gasification	combustion
condensate production	kg / kg fuel (daf)	0.15	0
gas/water cleaning residue production	kg / kg fuel (daf)	0.02	0.01
purge nitrogen	m_n^3 / kg fuel daf	0.01	0.01
bed material (sand)	kg / kg fuel (daf)	0.005	0.005
ammonia	kg / kg fuel (daf)		0.02
$Ca(OH)_3$	kg / kg fuel (daf)		0.01
NaOH	kg / kg fuel (daf)	0.0006	
activated carbon	kg / kg fuel (daf)	0.0006	
cooling water (for condensing steam turbine)	kg / kg fuel (daf)	1	1
total efficiency (CHP)	%	70	80
total efficiency, with steam cycle (CHP)	%	65	
carbon conversion	%	95	99
gross electric efficiency gas engine[13]	%	35	-
steam cycle efficiency[14]	%	11/18	[15]

[13] LHV of fuel gas to electricity
[14] for 14.7 MW-option for back-pressure and condensing cycle respectively
[15] see Appendix A

APPENDIX D. PRICES OF NATURAL GAS AND ELECTRICITY IN DIFFERENT COUNTRIES (1998)

Natural gas price in [$/GJ]

	industry	private
Austria	4.44	8.83
Belgium	2.56	8.83
Denmark		13.75
Finland	2.92	3.56
France	3.19	8.78
Germany	4.25	8.53
Ireland	6.03	8.94
Italy	3.64	14.39
Netherlands	2.61	7.61
Spain	2.94	11.36
Sweden	5.25	13.67
UK	2.25	7.06
USA	2.56	5.61

Electricity price [$ct/kWh]

	industry	private
Austria	6.7	14.5
Belgium	6.1	16.9
Denmark	6.1	19.0
Finland	4.5	8.7
France	5.2	12.4
Germany	7.5	15.6
Ireland	5.3	11.0
Italy	8.4	14.3
Netherlands	5.6	11.4
Norway		6.0
Portugal	8.1	13.6
Spain	5.7	14.3
Sweden	3.6	9.9
UK	5.7	10.8

APPENDIX E. COSTS OF ELECTRICITY [$CT/KWH] FOR DIFFERENT SYSTEMS

fuel		clean (10% moisture)						contaminated (10% moisture)						clean (40% moisture)					
technology		gasification			combustion			gasification			combustion			gasification			combustion		
fuel input[16] (MW_{th} LHV-base)		14.7	12.5	5	14.7	12.5	5	14.7	12.5	5	14.7	12.5	5	14.7	12.5	5	14.7	12.5	5
electricity production only																			
net electric (=total) efficiency	%	31.0%			24.0%	23.0%	18.0%	31.0%			24.0%	23.0%	18.0%	31.4%			25.4%	24.4%	19.0%
investment	M$	12.3			11.8	10.5	4.7	12.7			12.6	11.3	5.2	13.6			11.8	10.5	4.7
fuel price:	0.0$/GJ	6.1			7.8	8.5	12.6	6.4			8.4	9.1	13.9	7.2			7.9	8.7	12.9
	0.9$/GJ	7.1			9.1	9.9	14.4	7.5			9.7	10.6	15.7	8.2			9.2	10.0	14.6
	1.8$/GJ	8.2			10.5	11.3	16.2	8.5			11.1	12.0	17.6	9.3			10.5	11.3	16.3
	2.7$/GJ	9.3			11.8	12.7	18.0	9.6			12.5	13.5	19.5	10.3			11.8	12.7	18.1
	3.6$/GJ	10.3			13.2	14.1	19.9	10.7			13.9	15.0	21.3	11.4			13.1	14.0	19.8
CHP-production																			
net electric efficiency	%	29.0%	25.8%	25.8%	16.8%	16.8%	12.8%	29.0%	25.8%	25.8%	16.8%	16.8%	12.8%	29.9%	27.7%	27.5%	17.8%	17.8%	13.5%
net heat efficiency	%	36.0%	44.2%	44.2%	63.2%	63.2%	67.2%	36.0%	44.2%	44.2%	63.2%	63.2%	67.2%	30.7%	38.5%	38.7%	62.2%	62.2%	66.5%
total efficiency	%	65%	70%	70%	80%	80%	80%	65%	70%	70%	80%	80%	80%	61%	66%	66%	80%	80%	80%
investment	M$	11.9	9.1	4.9	10.9	9.8	4.4	12.3	9.5	5.0	11.8	10.6	4.9	13.2	10.2	5.6	10.9	9.8	4.4
H-price in $/GJ3.2																			
fuel price:	0.0$/GJ	4.9	4.5	6.8	6.0	6.5	10.6	5.2	4.9	7.2	6.9	7.5	12.4	6.2	5.7	8.5	6.6	7.2	11.6
	0.9$/GJ	6.0	5.8	8.1	7.9	8.5	13.1	6.3	6.2	8.5	8.9	9.5	15.0	7.3	6.9	9.7	8.5	9.1	14.0
	1.8$/GJ	7.1	7.0	9.4	9.9	10.5	15.7	7.5	7.4	9.7	10.9	11.5	17.6	8.4	8.1	10.9	10.3	10.9	16.5
	2.7$/GJ	8.2	8.3	10.6	11.8	12.4	18.3	8.6	8.7	11.0	12.9	13.5	20.2	9.5	9.3	12.1	12.1	12.7	18.9
	3.6$/GJ	9.4	9.6	11.9	13.7	14.3	20.8	9.8	10.0	12.3	14.8	15.5	22.8	10.6	10.5	13.3	14.0	14.6	21.4
H-price in $/GJ4.5																			
fuel price:	0.0$/GJ	4.3	3.7	6.0	4.1	4.7	8.0	4.5	4.0	6.3	5.0	5.7	9.8	5.7	5.0	7.9	4.9	5.5	9.2
	0.9$/GJ	5.4	4.9	7.3	6.0	6.7	10.6	5.7	5.3	7.6	7.0	7.6	12.4	6.8	6.2	9.0	6.7	7.3	11.6
	1.8$/GJ	6.5	6.2	8.5	8.0	8.6	13.1	6.8	6.6	8.9	9.0	9.6	15.0	7.9	7.4	10.2	8.6	9.2	14.0
	2.7$/GJ	7.6	7.5	9.8	10.0	10.5	15.7	8.0	7.9	10.2	11.0	11.6	17.6	9.0	8.6	11.4	10.4	11.0	16.5
	3.6$/GJ	8.8	8.7	11.1	11.9	12.5	18.2	9.2	9.2	11.5	13.0	13.6	20.3	10.1	9.8	12.6	12.3	12.9	18.9

[16] fuel input based on dried fuel (10% moisture), see Figure 2.3, actual fuel input for fuel containing 40% moisture is 13.6, 11.6 and 4.6 MW_{th} respectively

APPENDIX F. PRIMARY ENERGY CONSUMPTION (1996)

Source: IEA

	M t o e / a [17]	renewable energy (excluding hydro)
Austria	27	8.6 %
Denmark	23	6.6 %
Finland	32	16.9 %
France	254	4.2 %
Germany	350	1.2 %
The Netherlands	76	0.9 %
Norway	23	5.4 %
Sweden	53	14.7 %
UK	235	0.5 %

[17] M t o e / a = million tonnes of oil equivalent per year
Conversion : 1 M t o e is the same as :
- 11.6 TWh (= 1600 MWe @ 85 % capacity factor)
- 41.9 PJ (= 3300 MWth @ 3500 h capacity factor)

APPENDIX G. LAND USE OF EUROPEAN COUNTRIES

Reference: [10]

	total land area (km^2)	arable land (%)	permanent crops (%)	meadows & pastures (%)	forest and woodland (%)	other (%)
Austria	82700	17	1	24	45	13
Belgium	30230	24	1	20	21	34
Bulgaria	111000	34	3	18	35	10
Czech Rep.	78600					
Estonia	43200	22		11	44	23
France	545630	32	2	23	27	16
Germany	349520	34	1	16	30	19
Greece	130800	23	8	40	20	9
Hungary	92000	51	6	13	18	12
Ireland	68890	14	0	71	5	10
Italy	294020	32	10	17	22	19
Latvia	64600	27	0	13	42	18
Lithuania	65200	49	0	22	16	13
Poland	304500	46	1	13	28	12
Portugal	88930	45			36	19
Romania	230000	43	3	19	28	7
Slovakia	48800					
Slovenia	20300	10	2	20	45	23
Spain	499400	31	10	21	31	7
Sweden	449964	7	0	2	64	27
UK	241590	29	0	48	9	14

APPENDIX H. CURRENT USE OF BIOMASS IN EUROPE

Sources:

- Eurostat: Renewable energy sources statistics. The statistical office of the European communities, Luxembourg 1995
- European timber trends and prospects into 21st century, ECE/TIM/SP/11, UN, 1996
- BP statistical review of world energy

Data in PJ/year

	biomass energy					prim. energy consumption in Europe 1995		
	house-holds	district heating	industry	power generation	total	total fossil fuels	total hydro+nuclear	total non-biomass
Germany	92	0	11	22	125	12334	1742	14076
Belgium & Luxembourg	8	0	0	2.5	10	1922	427	2349
Denmark	15	9.3	6	2.2	33	842	0	842
France	299	0	59	4.9	364	5510	4346	9856
Greece	54	0	5	0.1	58	1068	13	1081
UK	7	0	2.4	0	10	8177	984	9161
Ireland	1.7	0	5	0	7	415	4	419
Italy	94	0	40	2.9	137	6238	151	6389
The Netherlands	13	0	1.4	0	15	3396	42	3438
Portugal	61	0	32	5.8	99	703	29	732
Spain	88	0	42	26	156	3450	687	4137
Finland	45	2.9	0.8	153	202	712	251	963
Austria	130	0	0	0	130	821	142	963
Sweden	276	0	0	0	276	833	967	1800
TOTAL	1185	13	204	220	1622	46419	9785	56204

APPENDIX I. BIOMASS RESOURCE POTENTIAL FOR ENERGY

Following estimate has been made if various additional biomass streams can be used as the energy source [12]:

- Residual wood that is currently produced as a by-product can be estimated based on the timber wood production carried out throughout Europe. The European timber wood production from hardwood and softwood is in the range of about 70 and 165 million m^3 respectively. This adds up to 235 million m^3 of wood of which 23% is produced in Sweden, 19% in France, 17% in Finland and 12% in Germany, whereas the other EU-countries contribute to less than 10% each. Assuming a share of residual wood from timber production of 15% for softwood and 20% for hardwood, an energy potential from softwood and hardwood of 182 and 233 PJ/year respectively is available in Europe. These *420 PJ/year* are a share of 0.9% of the overall energy consumption of fossil energy carriers in Europe in 1995.
- Since the wood price is presently on a very low level, thinning is only carried out to a limited extent. Assuming additional thinning to assure an optimal cultivation of the forests for wood production, the corresponding energy potential can be estimated (UN data): approximately 0.4 m^3/ha/year additional wood production in Europe Based on this, an energy potential in the range of *500 PJ/year* can be calculated. This is a share of just 1.1% in relation to the overall fossil energy consumption in Europe in 1995.
- Additionally, wood residues are available from road greenery, public parks, fruit or olive plantations, viticulture, private gardens, etc. There are no reliable figures but a rough estimate of 15% of the wood residues produced during timber production in the forests can be taken as a guide. This adds up to *140 PJ/year* (i.e. 0.3% in relation to the overall fossil energy production in Europe in 1995).

All these different potentials add up to 1050 PJ/year in Europe or 2.3% of the overall consumption of fossil energy carriers in Europe in 1995. However, additional sources of biomass that can displace fossil fuels are:

- Straw: assuming that only 20% of the straw is available for energy production and calculating with a straw-to-grain ratio of 1, the amount of available straw adds up to about *560 PJ/year,* which is a share of 1.2% of the overall consumption of fossil energy carriers in Europe in 1995.
- Other organic residues (olive pit, shells, husks, etc.) and animal waste are difficult to estimate due to lack of data but it can be assumed that such residues amount to one fifth of the energy potential from straw. This adds to about *110 PJ/year* (0.24% of 1995 primary energy).
- Energy crops: assume that 15% of the overall agricultural land currently used in Europe (145 million ha including grasslands) could be used for the production of energy crops. Assuming an average yield of the annual and perennial crops grown on this land area in the range of 80% of the yield of currently achieved yields by growing cereals, an energy potential in the range of *2600 PJ/year* (5.6% of the 1995 primary energy) can be calculated for the EU-countries.

APPENDIX J. BIOMASS POTENTIAL 2000 AND 2020

Reference: [11]

	TPER 1990 (PJ)	Biomass potential 2000 (PJ)	SSR 2000	Biomass potential 2020 (PJ)	SSR 2020
Austria	1048	112	11%	154	15%
Belgium	1973	6	0 %	101	5 %
Czech & Slovak Rep.	2991	180	6 %		
Denmark	762	55	7 %	103	14 %
Estonia	398	72	18 %		
Finland	1179	479	41 %	646	55 %
France	9244	643	7 %	1067	12 %
Germany	15327	459	3 %	840	5 %
Greece	918	112	12 %	216	24 %
Hungary	1212	121	10 %		
Ireland	428	16	4 %	59	14 %
Italy	6433	486	8 %	566	9 %
Latvia	318	75	24 %		
Lithuania	763	86	11 %		
Luxembourg	149	-1	- 1 %	6	4 %
Norway	966	114	12 %	257	27 %
Poland	4128	349	8 %		
Portugal	745	140	19 %	124	17 %
Spain	3730	285	8 %	729	20 %
Sweden	1953	614	31 %	687	35 %
Switzerland	1062	53	5 %	92	9 %
UK	8833	193	2 %	724	8 %

TPER = total primary energy requirement
SSR = self sufficiency rate : biomass potential 2000 (or 2020) as percentage of TPER 1990