International Institute for
Applied Systems Analysis
IIASA www.iiasa.ac.at

Techno-Economic Assessment of a Biomass-Based Cogeneration Plant with CO2 Capture and Storage

Uddin, N.

IIASA Interim Report
July 2004

International Institute for
Applied Systems Analysis
Schlossplatz 1
A-2361 Laxenburg, Austria

Tel: +43 2236 807 342
Fax: +43 2236 71313
E-mail: publications@iiasa.ac.at
Web: www.iiasa.ac.at

Interim Report **IR-04-034**

Techno-economic Assessment of a Biomass-based Cogeneration Plant with CO_2 Capture and Storage

Noim Uddin (noim.uddin@mh.se)

Approved by

Sten Nilsson
Deputy Director and Leader, Forestry Program

15 July 2004

Contents

1	**OBJECTIVE**	**1**
2	**INTRODUCTION**	**1**
	2.1 Background	**1**
	2.2 Complex Links between Energy and Environment	**3**
	2.3 Biomass-based Cogeneration (CHP)	**3**
3	**METHODOLOGY**	**6**
4	**MODELS AND ASSUMPTIONS**	**6**
	4.1 Plant Performance	**7**
	4.2 Specific Investment Costs	**8**
	4.3 Costs of Biomass Extraction	**9**
	4.4 Emissions of CO_2 and Cost of CO_2 Transportation and Storage	**11**
	4.5 Annual Operating Costs	**13**
	4.6 Cost of Electricity (COE)	**14**
5	**OPTIMAL SIZING OF BIOMASS-BASED COGENERATION**	**14**
6	**DISCUSSION**	**17**
REFERENCES		**17**

Abstract

Reduction of CO_2 emissions from energy systems could be achieved through: CO_2 capture and storage, energy savings, fuel switching among fossil fuels, increased use of renewable energy sources, and nuclear power. In addition, atmospheric CO_2 reduction could also be achieved through increasing the carbon stock in soils and standing biomass. The CO_2 capture and storage option for mitigating CO_2 emissions from biomass-based cogeneration plants, considering critical aspects such as future development of technologies, economies of scale, carbon price, site-specific analysis, and future energy systems has received little attention in scientific studies. With the overall objective of improved understanding of the potential scope for its large-scale implementation, a techno-economic assessment of biomass-based cogeneration plants with CO_2 capture and storage was carried out. Most of the above-mentioned critical aspects have been considered for the techno-economic assessment of cogeneration plants with CO_2 capture and storage technology.

The results show the optimal scale of the conversion systems with respect to cost of electricity (COE). The optimal size for steam turbine-based cogeneration (CHP-ST) technologies without CO_2 capture lies in the range 98–106 MWe (COE is 5.7 USD/MWh) when fueled by forest/logging residues, but the optimal size increases to 200–227 MWe for integrated gasification combined cycle based cogeneration (CHP-IGCC) (COE is 16.73 USD/MWh). The optimal size range increases considerably to 249–288 MWe (COE 15.70 USD/MWh) for Salix fueled CHP-ST technology without CO_2 capture and 441–504 MWe (COE 27.52 USD/MWh) for CHP-IGCC technology. With the additional feature of CO_2 capture, transport, and storage (here we assume 100 km CO_2 transport distance from the plant site) the unit capital cost for CHP-ST and CHP-IGCC technology increases around 70 and 30 percent, respectively.

If one considers revenues from trading emission quotas earned through negative emissions one can estimate a market price of CO_2 (PC) at which the COE becomes negative (i.e. all capital and operating costs are covered by revenues from heat and negative emissions delivered). Scale effects significantly influence the economic feasibility of CO_2 capture. According to the model calculation, the PC at which the COE becomes negative significantly drops from 75 USD/tCO_2 for 10 MWe CHP-ST plants to 32 USD/tCO_2 for 90 MWe CHP-ST plants when fueled by Salix. The PC drop from 65 USD/tCO_2 for 10 MWe CHP-ST plants to 25 USD/tCO_2 for 90 MWe CHP-ST plants when fueled by forest/logging residues. For CHP-IGCC plants, the PC decreases from 72.5 USD/tCO_2 for 30 MWe to 37.5 USD/tCO_2 for 170 MWe when fueled by Salix. When fueled by forest/logging residue, the PC decreases from 62.5 USD/tCO2 for 30 MWe plants to 30 USD/tCO_2 for 170 MWe.

The techno-economic assessment was based on electrical capacity of the plants and revenues from cogenerated heat and captured CO_2 were credited. In practice, the implementation of any cogeneration systems are limited by the heat sink, where the cogeneration systems should be optimized based on site-specific context.

Acknowledgments

I would like to express my profound gratitude, great appreciation and cordial thanks to Kenneth Möllersten for his invaluable advice, and experienced and insightful guidance in carrying out and completing this study at IIASA.

I would also like to express my sincere gratitude and thanks to Jill Jäger (ISTS, Harvard), Leif Gustavsson (Mid-Sweden University), Michael Obersteiner (Forestry Program, IIASA) and Leonardo Barreto (Environmentally Compatible Energy Strategies Program, IIASA) for their close cooperation with encouragement and guidance throughout the summer of 2003 at IIASA.

I have also benefited from the friendship and close cooperation with all the Forestry Program members and the 2003 Young Summer Scientist Program (YSSP) group, especially Joanna Horabik, Sharda Mahabir and Kentaro Aoki.

Thanks to all of my friends and colleagues of the 2003 YSSP and the Forestry Program for their moral support and encouragement during the research period and special thanks to Cynthia Festin and Shari Jandl for their kind cooperation.

Last but not least, my special thanks to the Swedish Research Council for Environment, Agricultural Sciences, and Spatial Planning (FORMAS) for awarding me the scholarship to pursue this research study at IIASA.

About the Author

Noim Uddin holds a Master of Science degree in Sustainable Energy Engineering from the Royal Institute of Technology (KTH) Sweden and a Bachelor of Science degree in Mechanical Engineering from Bangladesh. He has research and work experiences with the United Nations Economic and Social Commission for Asia and the Pacific; the Asian Institute of Technology, Thailand; University College Cork, Republic of Ireland; and the United Nations Framework Convention on Climate Change. His principle research areas broadly include energy-environment, climate change and flexibility mechanisms, energy efficiency and conservation, renewable energy resources, and mitigation of greenhouse gas emissions. At present he is continuing research work on the project 'Efficient Use of Forest Resource (EUFoR) — Biomass-based Energy Systems' at Mid-Sweden University.

Techno-economic Assessment of a Biomass-based Cogeneration Plant with CO_2 Capture and Storage

Noim Uddin

1 Objective

In Sweden, the use of biomass has doubled since the 1970s and today represents 16 percent of total primary energy use (SEA, 2003). The major fraction is used in forest-based industries (67 percent) and district heating systems (21 percent). Biomass utilization in the district-heating sector alone experienced a four-fold increase between 1990 and 1999, and notably the cost of forest fuel, such as logging residues, has been reduced by 50 percent since the mid 1980s. Cogeneration or combined heat and power production (CHP) is one way to reduce primary energy consumption and therefore be an effective option in retarding the environmental impacts. Here, a techno-economic assessment has been carried out for both CHP based on integrated gasification combined cycle (CHP-IGCC) and steam turbine technology (CHP-ST) technology when both systems are equipped with CO_2 capture and storage, which theoretically identify the biomass-based energy system as a negative CO_2 emitting system. The techno-economic assessment gives an overview of economic scale for biomass-based CHP-IGCC and CHP-ST conversion technology with CO_2 capture and storage facility with respect to the cost of electricity (COE).

2 Introduction

2.1 Background

Energy is central to achieving the interrelated economic, social, and environmental aims of sustainable development. Present global primary energy use is, however, strongly linked to environmental and health issues, in particular climate change, as more than three-quarters of global primary energy use is based on fossil fuels, and three quarters of the anthropogenic emissions of CO_2 is due to the conversion of these fuels.

The consensus on reducing oil consumption, as a result of the oil crisis in the 1970s, triggered an increased use of modern biomass-based energy systems globally. In addition, the growing concern about the environmental impact of fossil fuels has increased the interest in renewable resources, such as biomass-based energy systems. In 2000, renewable energy accounted for 14 percent of the world's primary energy use, with an annual growth of 2 percent over the last 30 years (IEA, 2002b). A number of studies have assessed the potential contribution of biomass to the world's energy supply to be as much as 50 percent of the global energy demand in 2050, depending on land availability and future energy demand (Turkenburg, 2000). Hence, the potential reduction in greenhouse gas emissions is large when fossil fuels are replaced by sustainably produced biomass.[1] Although the risk of climatic impacts associated with fossil-based energy resources has been known for more than a century, the issue has only been in focus since the early 1990s.

Historically, forestry has played a major role in the economies of Northern Europe and particularly the Scandinavian countries. For example, the total export value of the forestry sector in Sweden amounted to around 10 billion USD in 1999 (FAO/UNCEC, 2001). About two-thirds of the total biomass supply in Sweden originates from forest-based industrial residues but logging residues, imported biomass, and domestic fuel wood are also important sources. Less than one percent of the total biomass supply originates from the agricultural sector. The energy potential of biomass in Sweden, apart from black liquors from the pulp and paper industry, is estimated to be around 125–175 TWh annually (SEA, 2003). Thus, the potential for increased use of biomass in Sweden is large, despite the fact that Sweden already uses more biomass for energy purposes than most other industrialized countries.

In Sweden, 65 percent of the total land area is covered with forest (compared to world average around 30 percent), of which 23 million hectares are classified as productive forest available for forestry. The timber resources within the sub-region of Northern Europe have developed steadily since the early 1900s (FAO/UNCEC, 2001), as a result of long-term silvicultural management and modest levels of felling. This is due to national forestry policies and forest acts, where the sustainable use of forests has been an important objective during most of the twentieth century. In Sweden, annual growth is currently about 100 million cubic meters, whereas felling accounts for only 70–75 million cubic meters. An estimate of the potential for biomass production from forest and arable land around 2015 is shown in Table 1 (Johansson, 1996).

Table 1: Estimated of biomass resources in Sweden by 2015.

Biomass resources	**Biomass potential, production conditions 2015 (TWh/yr)**
Energy crop alternatives	
Rape, seed and straw	4
Winter wheat, grain and straw	29
Reed canary-grass	36
Lucerne	45
Salix	59
Straw from food production	11
Forest/Logging residues	53–65
Industrial by-product	47–51

[1] Biomass, in broad terms, includes wood fuels, biomass-based industrial by-products, wood waste, and agricultural products but excludes municipal refuse and peat.

2.2 Complex Links between Energy and Environment

Environmental issues are strongly linked in complex and dynamic ways to production, distribution, conversion and use of energy carriers and have often been grouped into local, regional, and global problems. Historically, air pollution was seen as a local issue while acid rain, when recognized, was described as a regional problem. Climate change is one of the most well known global environmental issues. By using modern energy technologies, most of the local and regional impacts from fuel-based energy systems seem to be manageable. In contrast, climate change is a global, complex and multidimensional issue that must be addressed from a long-term perspective. Although the risk of climate change associated with the combustion of fossil fuels has been known for more than a century, the issue has only been in focus since the 1990s.

Implementation of the international agreements of United Nations Framework Convention on Climate Change (UNFCCC) in 1992 and the Kyoto Protocol of 1997 is an important first step in the reduction of greenhouse gas (GHG) emissions through international agreements. Although implementation of the Kyoto Protocol is complex, several possibilities exist for the reduction of GHG emissions. Reduction of CO_2 emissions from energy systems could be achieved through: CO_2 capture and storage, energy savings, fuel switching among fossil fuels, increased use of renewable energy sources, and nuclear power. Most of these options are applicable for stationary energy and industrial infrastructures. In addition, atmospheric CO_2 reduction could also be achieved through increasing the carbon stock in soils and standing biomass. Like most of the renewable energy resources, sustainably produced biomass will significantly reduce the specific long-term net CO_2 emissions, since the CO_2 released during the combustion of biomass is normally equal to the amount absorbed from the atmosphere by the forest over time. In addition, negative CO_2 emissions could be achieved from biomass systems through CO_2 capture and storage in large-scale biomass-based energy systems, such as large cogeneration (CHP) plans (Möllersten *et al.*, 2003).

Biomass-based energy systems include different conversion routes to produce heat, electricity and fuels. The implementation of biomass-based energy systems conversion technologies is site and country (rich in biomass resources) specific. Small-scale or traditional conversion technologies are fairly common in developing countries where conventional biomass or forest resources are usually sufficient to meet local energy demand. In some developed countries, environmentally sound energy systems are beginning to be common, and advanced biomass-based conversion technologies are evolving, especially in the area of heat and electricity production. New technologies, such as CO_2 capture and storage may change the preconditions of biomass-based energy systems strategies. Substituting biomass for fossil fuels in the electricity and heat sectors appears to be more cost efficient and provides a larger reduction per unit of biomass than would be the case if biomass were substituted for fossil fuels in the transportation sector (Gustavsson *et al.*, 1995).

2.3 Biomass-based Cogeneration (CHP)

Cogeneration or CHP are defined as the sequential generation of two different forms of useful energy from a single primary energy source, typically mechanical energy and thermal energy. CHP is possible with all heat machines and fuels from a few kW-rated to 1000 MW steam-condensing plants but the potential of CHP could be restricted due to the constraint of necessary heat demand. The biomass-based energy systems for heat and power production, in general, comprise either a single-step (such as large-scale cogeneration systems district heating system) or two-steps (such as combination of biomass-based power and heat-pump) conversion technologies (Karlsson, 2003). Excess electricity production from cogeneration would be supplied to electric utilities and credited. Moreover, a heat-distribution network is necessary.

The conversion technologies based on CHP and fueled by biomass include:

- Biomass-based Steam Turbine technology (CHP-ST); and
- Biomass-based Integrated Gasification Combined Cycle technology (CHP-IGCC).

Important technical parameters for cogeneration plants include: heat-to-power ratio, availability of fuels, quality of thermal energy needed, load patterns, systems reliability, grid dependent systems versus independent systems, retrofit versus new installation, electricity buy-back, and local environmental regulations (UNESCAP, 2000). Heat-to-power ratios and other parameters of cogeneration systems are given in Table 2.

Table 2: Heat-to-power ratios of cogeneration plants (UNESCAP, 2000).

Cogeneration systems	**Heat-to-power ratio (kWth/kWel)**	**Power output (as percent of fuel input)**	**Overall efficiency (percent)**
Back-pressure steam turbine	4–15	14–28	84–92
Extraction-condensing steam turbine	2–10	22–40	60–80
Gas turbine	1–2	24–35	70–85
Combined cycle	1–2	34–40	69–83
Reciprocating engine	1–3	33–53	75–85

Typical CHP-ST technologies include extraction/back pressure steam turbines, gas turbine with heat recovery steam generator (HRSG — with or without bottoming steam turbine), and reciprocating engines with HRSG. Typical CHP-IGCC systems are a set of integrated gasifier and gas turbine technology, which offers the potential of low unit capital costs and high thermodynamic efficiency at modest scales. The high efficiency of cogeneration (up to 90% or more) and efficient use of fuel compared with stand-alone power conversion systems results in a significant reduction of CO_2 emission and can therefore be an effective GHG mitigation option (IPCC, 2001). However, cogeneration can have environmental implications in the form of CO, SO_2 and NOx emissions to the atmosphere. The quantity of each of the pollutant generated depends largely on the type of fuel used and the characteristics of the cogeneration technology adopted.

Most of the existing Swedish cogeneration plants are CHP-ST technology and wood fueled. A detailed survey by Wahlund (2003) gives an overview of fourteen cogeneration plants in Sweden. The electrical capacity varies from 2 MWe to 39 MWe with the electrical efficiency of 20–30 percent and the systems configuration includes steam turbine with different combustion boilers (centrifugal fluidized, boiling fluidized bed, grate-fired type). The specific investment costs are much higher for smaller plants (typically USD 2390/kWe); whereas they are significantly lower for larger plants (typically USD 1690/kWe). Finland experienced the largest biomass-fired CHP-ST plant of 240 MWe with annual electricity and heat production of 700 GWh and 1300 GWh, respectively (Alholmens Kraft, 2002). Larson and Marrison (1997) reported ten or more BIG/GTCC commercially oriented demonstration projects worldwide. The development of efficient BIGCC is nearing commercial realization, several pilot and demonstration projects have been evaluated with varying degree of success (IPCC, 2001). Capital investment of a high pressure, direct gasification combined-cycle plant of the pilot and demonstration scale is estimated to fall from over USD 2000/kWe to around USD 1100/kWe by 2030 (IPCC, 2001). Sweden experienced the world's first cogeneration plant based on biomass integrated gasification combined cycle (BIGCC) technology in Värnamo with a 6MWe/9MW heat capacity in 1996 (Larson and Marrison, 1997). The United Kingdom experienced an air-blown circulating fluidized bed gasifier operating at atmospheric pressure will generate 10 MWe, the Arable Biomass Renewable Energy (ARBRE) project (VTT, 2001).

The large-scale conversion technologies considerably affect primary energy use, emissions and the cost of the energy systems to a certain extent. Scale effects within biomass-based energy systems are very significant for both their energetic and economic performance. Dornburg and Faaij (2001) concluded that at the scale ranges 0.1–300 MWth-input, the relative primary energy savings, i.e., the primary energy saved per unit of biomass energy input, generally improve with increasing scales and the total costs per unit of primary energy saved mostly decrease with increasing scale. The study by Larson and Marrison (1997), examined the BIG/GTCC power production facility in the US and Brazil and concluded that with pressurized BIG/GTCC, the optimum capacity ranges from 230–320 MWe. Here, the optimum capacity was defined as that which yields the minimum calculated cost of electricity (COE). For atmospheric pressure BIG/GTCC power production facility, optimum plant facility ranges from 110–142 MWe. Cameron *et al.* (2002) studied three different biomass resources and economic plant size with respect to power price in Western Canada and concluded that forest harvest residue have the smallest economic size of 137 MW and highest power costs USD 63/MWh. The optimum size for agricultural residues is 450 MW and the power cost is USD 50/MWh, and if it were possible to build a larger boiler, the optimum size for straw would be 628 MW, whereas the whole forest (see details in Cameron *et al.*, 2002) showed a very large optimal size up to 900 MW without considering nutrient replacement.

None of the above-mentioned studies have been carried out on cogeneration, where the selection of a cogeneration plant is based on the heat sink. Also, with an additional CO_2 capture and storage facility a theoretically carbon neutral biomass-based energy system would be a negative CO_2 emitting energy system. The capture of CO_2 from the flue gases of fossil fuels and its disposal, for example exhausted gas or oil wells, is being actively investigated in a number of countries. The use of CO_2 capture and storage technology will, however, lead to reduced energy efficiency and higher investment cost.

3 Methodology

The overall methodology for this techno-economic assessment followed the following steps:

- A review of literature on biomass-based CHP and the selection of different scales of conversion plants;
- Identifying parameters that will serve for the comparison of biomass-based energy systems with and without CO_2 capture and storage;
- Assessment of scale effects on specific investment costs, CO_2 capture and storage, biomass-supply needed, and related biomass cost with respect to transporting distances; and
- Assessment of electricity generating cost (COE), which is a function of specific investment cost, biomass-supply needed, biomass transportation distance, plant capacity factor, and heat-to-power ratio.

The methodology in the techno-economic work resembles a well-to-wheel approach of energy systems chain. The costs and resources use in every step of the energy chain (production, transportation and conversion) has been considered. In-terms of GHG emission only CO_2 emissions have been taken into consideration from the conversion processes. The modeling work begins with analyzing the supply of biomass to centrally located cogeneration plants, assessing the performance of alternative cogeneration plants; and ends with the determination of COE with and without the CO_2 capture option. The specific investment costs of CHP plants were estimated using literature data and a simple curve fitting method. The detailed calculations for optimal sizing of cogeneration systems are based on spreadsheet calculation, which is a linear and static modeling approach. The cost of biomass (production, transportation) was estimated from a literature review. Due to the unavailability of data on the cost of CO_2 capture, transport and storage, a model based on pipeline data was applied. The techno-economic assessment has been concluded by using spreadsheet calculations for estimating the COE when CHP plants were integrated with a CO_2 capture, transport and storage facility.

4 Models and Assumptions

The choice of biomass resource with its respective production, extraction, and transportation characteristics has implications for the suitable scale of biomass-based cogeneration systems. A large-scale system requires a higher biomass feedstock volume than smaller systems, which generally elevates the average cost of fuel transportation while a higher supply volume has lower transactional costs. In contrast, increasing scale reduces unit capital cost and the specific cost of CO_2 transportation and storage. In this techno-economic assessment, the conversion systems were assumed to be located near the heat load center and also to be centrally placed in a biomass production area. Salix and forest/logging residues were chosen as two biomass feedstock alternatives. Biomass transportation to the conversion plant was assumed to be carried out by truck. Data for fuel supply cost and cogeneration technologies' performance and capital costs were gathered from literature. The performance and capital cost of cogeneration plants with CO_2 capture were estimated using the Matlab code and literature data. The state-of-theart CHP technologies based on steam turbine (CHP-ST) and integrated gasification combined cycle (CHP-IGCC) have been considered. The analysis considers Salix and forest/logging residues as feedstock to a centrally located CHP plant and biomass transportation was by truck. A simple curve-fitting method was used to construct a model describing the specific capital cost of the analyzed cogeneration plants as a function of capacity. Alternative models for the calculation of CO_2 transportation and storage costs were assessed and one selected to be used in the present techno-economic evaluation. Finally, a model was developed for techno-economic assessment considering scale, fuel supply cost, specific investment costs and technical performance of cogeneration plants, and CO_2 transportation and storage costs. The models and assumptions applied are described in more detail below.

4.1 Plant Performance

Cogeneration plants were assumed to have constant performance regardless of size. Two cogeneration technologies were investigated; combined heat and power based on biomass boilers and steam turbine technology (CHP-ST) and biomass-integrated gasification combined cycle technology (CHP-IGCC), respectively. The steam turbine-based CHP systems were based on a biomass boiler producing super-heated high-pressure steam at 140 bar/540°C. The return temperature of the district heating water was assumed to be 70°C and the temperature of the hot water leaving the plant 100°C. In the case of steam turbine-based cogeneration, the analysis assumes post-combustion CO_2 capture by chemical absorption from flue gases. The heat consumption for regeneration of chemical absorbent was assumed to be 2.9 MJ/kgCO_2 captured. Table 3 presents the assumed performance of a steam turbine-based cogeneration plant.

Table 3: Performance of CHP-ST.

Plant type	**Electrical efficiency (%)**[a]	**Total efficiency (%)**[b]	**Carbon capture ratio (%)**[c]
Steam turbine CHP	30	90	0
Steam turbine CHP with post-combustion CO_2 capture	23	57	90

[a] Net electricity delivered/Fuel in.
[b] Net electricity delivered + Net heat delivered/Fuel in.
[c] Carbon captured/carbon in fuel.

The assumed technology for the studied CHP-BIGCC cases is pressurized, oxygen-blown gasification with an option for pre-combustion CO_2 capture. When the CO_2 capture option is applied in the BIGCC case, the producer gas undergoes a water-gas shift reaction in a CO-shift reactor downstream gasifier whereby CO is reacted with water to form CO_2 and H_2. The formation of additional CO_2 in the CO-shift reactor raises the fraction of the fuel's carbon content, which can be captured. CO_2 is separated from the shifted gas through physical absorption, which is a suitable process for gas streams at elevated pressures and CO_2 concentrations. Capture of CO_2 induces energy losses in the system and thus reduction in efficiency. Since the physical solvent is regenerated by pressure reduction, the main energy requirement for physical absorption is to pump physical absorbents. The work consumed for CO_2 absorption depends on the partial pressure of the CO_2 in the gas mixture. In this study the work required was assumed to be 0.14 MJ/kgCO_2 captured. In all cases with CO_2 capture, the CO_2 is compressed to 80 bars, which consumes 0.12 kWh_e/kgCO_2. The CO_2-lean syngas is used to fuel a combined cycle for power generation. Table 4 presents the assumed performance of a CHP-BIGCC cogeneration plant.

Table 4: Performance of CHP-BIGCC.

Plant type	Electrical efficiency (%)[a]	Total efficiency (%)[b]	Carbon capture ratio (%)[c]
CHP-BIGCC	43	86	0
CHP-BIGCC with pre-combustion CO_2 capture	37	81	90

[a] Net electricity delivered/Fuel in.
[b] Net electricity delivered + Net heat delivered/Fuel in.
[c] Carbon captured/carbon in fuel.

4.2 Specific Investment Costs

The total installed unit capital cost (UC in USD per unit capacity) for an energy conversion plant can be assumed to vary with capacity (Cap) as follows (based on Larson and Marrison, 1997):

$$UC = C + D * (Cap)^{E}$$

where C, D, and E are constant for a given configuration that is determined from available cost projections; E is a negative unit, i.e., unit cost falls with increasing capacity; and C corresponds to the unit cost that is reached asymptotically at a large scale.

The values of D and E are calculated based on the following equations:

$$D = (UnitCost_1 - C)/Capacity_1^{E}$$

where $E = \{\log([UnitCost_1 - C]/[UnitCost_2 - C])\}/\{\log(Capacity_1/Capacity_2)\}$; $Capacity_1$ and $Capacity_2$ are the two other plant sizes, and $UnitCost_1$ and $UnitCost_2$ are their respective unit costs.

The specific investment costs for the CHP-ST and CHP-IGCC plants with and without the CO_2 capture option were calculated based on the above mathematical expression. Data concerning biomass-based cogeneration plants with CO_2 capture were not available from the literature. Instead, data for conversion plants without CO_2 capture were combined with estimated costs for the additional components necessary. In the estimation of the capital cost for components in the plants with a CO_2 capture option it was necessary to adjust cost data from the literature for size. One typical way of doing this, which was followed in this work, is to assume that investment costs per unit is a function of scale is given by:

$$I_1 = I_0 * (C_1/C_0)^R$$

where I_k is the investment cost per unit; C is the capacity; Index 0 and 1 refer to two different plants; and R determines how fast the cost per unit increases with size (Remer, 1990; Jenkins, 1997). For R, the value 0.7 was used.

Table 5 presents the estimated capital costs of CHP-ST and CHP-IGCC with and without CO_2 capture and storage.

Table 5: Unit capital costs for selected cogeneration plants.

Plant Type and Capacity	Unit Investment Costs (USD/kWe) with out CO_2 capture, transport and storage	References	Estimated Unit Investment Costs (USD/kWe) with CO_2 capture
CHP-ST 10 MWe	2350	Energimyndigheten (2000)	4550
CHP-ST 30 MWe	1790	Energimyndigheten (2000)	3090
CH-ST 80 MWe	1330	Energimyndigheten (2000)	2330
CHP-BIGCC 30 MWe	2671	Naringsdepartementet, (1995); Lehtila and Tuhkanen (1999)	3300
CHP-BIGCC 60 MWe	1820	Gustavsson and Börjesson, (1998)	2300
CHP-BIGCC 136 MWe	1190	Craig *et al*. (1994)[a]	1600

[a] Craig *et al*. (1994) is based on a power plant. The data was used as the basis for calculations of a CHP plant.

4.3 Costs of Biomass Extraction

Suitable biomass resources for power and heat production are short-rotation forests such as Salix, forest/logging residues, reed canary grass, and straw. Larger plants require more biomass feedstock. Also, cogeneration or poly-generation facilities result in comparatively lower electrical efficiency and higher heating efficiency, which corresponds to higher biomass-feedstock input.

The productivity of perennial crops (willow, eucalyptus, switch grass) varies between 8 to 12 tons of dry mater (TDM) per year (Turkenburg, 2000). The potential biomass yield for Salix is high in Sweden as yields up to 30 dry ton/ha/year (480 GJ/ha/year) have been achieved from commercial Salix clones with optimized fertilization combined with irrigation. Energy yields and energy use for biomass production are given in Table 6 according to Börjesson and Gustavsson (1996).

Higher yields together with improved energy efficiency in the use of motor fuels and energy used in production of, e.g., seeds, fertilizers, pesticides and machinery, may result in a 30–45 percent lower primary energy use per unit biomass produced for fossil-based energy inputs by 2015.

Table 6: Energy yields and primary energy use for different biomass production.

Biomass resources	Energy yield GJ/ha, yr	Primary energy use GJ/ha, yr
Reed canary crops	110	8.9
Salix	150	6.3
Straw	30	1.1
Forest/Logging residues	13	0.51

The biomass production costs are thus assumed to be reduced in the future by 20–39 percent due to improved cultivation, and recovery methods resulting in, for example, lower labor, machinery; fuel, commercial fertilizer and pesticides requirements per GJ biomass produced. The production costs of different biomass in central Sweden by using fossil-fuel-based systems (all machinery used are running on diesel fuel) are in Table 7 according to Börjesson and Gustavsson (1996).

Table 7: Biomass production cost.

Biomass resource	Soil preparation and sowing	Fertilizing and pesticide application	Recovery and harvesting operations	Administration and compensation to land owner	Total USD/GJ
Reed canary grass	0.51	1.7	1.3	1.1	4.6
Salix	0.78	1.6	0.57	1.1	4.1
Straw	-	-	1.8	0.76	2.6
Forest/Logging residues	-	0.15	2.2	0.58	2.9

A biomass conversion facility accepting feedstock from a surrounding region may be shown to have an optimum size when the assumption of a positive economy of scale (decreasing cost with increasing size) in capital and non-fuel operating costs is combined with an increasing delivered fuel cost as the facility size increases. If the biomass conversion facility is centrally located in a rectangular space, the cost of biomass transportation is dependent on the maximum axial distances from conversion facility to biomass production site (Jenkins, 1997). For a centrally located biomass facility in a circular space, the transportation cost of biomass is directly proportional with the cubic power of the transportation distance (Nguyen and Prince, 1996). The cost of biomass delivery to a conversion plant site includes the cost of biomass production, and the cost of biomass transportation with the additional cost of biomass loading and unloading associated with transportation. The cost of biomass transportation depends on the transportation distance and the mode of transport. Costs for transportation of different biomass by different transportation mode are given in Table 8 based on Börjesson and Gustavsson (1996).

Based on different literature reviews, the cost function for biomass transportation in a centrally located plant were chosen from Börjesson and Gustavsson (1996) for Salix and forest/logging residues as biomass feedstock as given below. The transportation mode was considered for both cases by truck.

Table 8: Biomass transportation cost as function of transportation distance (d) in km.

Biomass resource	Tractor USD/TJ	Truck USD/TJ	Train USD/TJ	Boat USD/TJ
Reed canary grass	373+22*d	880+4.7*d	1900+0.71*d	1400+0.31*d
Salix	280+16*d	420+9.4*d	860+1.4*d	1000+0.63*d
Straw	520+29*d	1200+6.3*d	2700+0.90*d	2100+0.39*d
Forest/Logging residues	230+13*d	350+7.9*d	740+1.1*d	850+0.45*d

The cost function (USD/TJ) of Salix transportation by truck to a centrally located plant is:

$$420+9.4*d$$

where d is the transportation distance in km.

The cost function (USD/TJ) of forest/logging residues transportation by truck to a centrally located plant is:

$$350+7.9*d$$

where d is the transportation distance in km.

The transactional costs also have implications on biomass cost at a conversion facility site since a large-scale biomass conversion facility needs a higher volume of biomass-feedstock, which subsequently decreases the transactional costs. This component has not been considered in this techno-economic assessment.

4.4 Emissions of CO_2 and Cost of CO_2 Transportation and Storage

CO_2 emissions for a typical coal-fired power plant are in the range 130–260 kg CO_2/second (500–1000 MWe) and typical natural gas-fired power plants can be expected to emit half as much per second. A biomass-based conversion facility is often thought of as small-scale technology. Most of the biomass-based conversion facility in the world is currently used in traditional ways (for cooking), which is inherently very small-scale. One might expect small-scale uses to continue to be important, e.g., residential heating where the biomass is burnt as wood fuel or pellets. Under these conditions, scale considerations rule out CO_2 capture and storage from biomass because of high costs. However, there are larger sized operations in use, and these can be expected to become even more important in the future. Currently, pulp mills are major sources of CO_2, as are district heating plants and CHP plants (Möllersten *et al.*, 2003). For instance, a typical chemical pulp mill may produce 1500–3000 tons of pulp per day, which corresponds to 36–72 kg CO_2/second from biomass-based black liquor and bark. District heating plants, for example, would be the size of 10–100 MW, heat results with CO_2 emissions ranging from 1–10 kg CO_2/second at full capacity if fed with biomass. CO_2 capture and storage from natural-gas-based systems could reduce the CO_2 emission by about 70 percent, while in a biomass-based system the net CO_2 emission would be negative. Cogeneration could probably improve the economic feasibility of biomass energy with CO_2 capture and storage because multiple product systems raise the total biomass fuel feed and, thus, increase the CO_2 emissions rate.

Because of the large volumes of captured CO_2 from large-scale plants, pipelines are the leading option for the transportation of CO_2 to a storage location once it has been captured. Transportation of CO_2 can best be done in the supercritical state with pressures in the range of 80 to 140 bars. The compression and pipeline transportation of CO_2 is feasible and technically proven through several commercial enhanced oil recovery projects (Holloway, 2001). In addition, the use of large tankers might be economically attractive for long-distance transportation of compressed/liquefied CO_2 over water.

Models for estimating the cost of CO_2 transportation and storage have been presented by the IEA GHG R&D Program (IEA, 2002a) and Ogden (2002), respectively. The IEA model is a calculation tool, which estimates capital cost, fixed and variable operating costs for the pipelines and injection wells, as well as booster compressor requirements.[2] Ogden (2002) presents a cost function based on published pipeline data. The model represents the pipeline capital cost per unit length in terms of the flow rate Q and the pipeline length L with the equation:

$$C_{pipeline}\,(\text{USD/m}) = \text{USD } 700/\text{m} * (Q/Q_0)^{0.48} * (L/L_0)^{0.24}$$

where Q_0 = 16 000 t/day; L_0 = 100 km; and, furthermore, the installed capital cost per injection well with the equation :

$$C_{inj.\ well}\,(\text{USD/well}) = \text{USD 1.6 million} * \text{well depth (km)} + \text{USD 1.25 million.}$$

The economies of scale of CO_2 transportation and storage using the two models were investigated. The costs of transportation and storage were calculated for a set of CO_2 flow rates and transportation distances. CO_2 injection is assumed to take place in on-shore wells with negligible seepage back to the atmosphere and the depth of the injection wells was set to 1000 m. A practical upper limit on the injection rate per well was taken to be 50 kg CO_2/second. Capital costs were annualized using an interest rate of 8 percent and a plant life of 25 years. The IEA model enables the setting of geographical location of the project, which was selected to Europe, representing an average to high cost level in the model. Furthermore, the terrain was assumed to be cultivated land, representing an average cost level in the model. The results of the cost assessment are presented in Figure 1; showing costs normalized to USD/tCO_2 as a function of transportation distance. Costs calculated with the IEA (2002a) model are shown with a dotted line and the results from Ogden (2002) with a line. To be conservative in the techno-economic assessment in the present report the Ogden model was chosen to estimate the cost of CO_2 transportation and storage.

For a CO_2-generating facility in a coastal location Ekström *et al.* (1997) estimated the cost for CO_2 transportation and injection using a tanker at 17 USD/ton CO_2. A 700 km transportation distance, infrastructure for loading and intermediate storage of the CO_2,

[2] Booster compressors assure that the CO_2 stays in a liquid phase all the way along the pipeline.

and a CO_2 production rate of approximately 20 kg/second was considered. Since the cost of CO_2 transportation by tanker is quite insensitive to the transportation distance and the rate of CO_2 production, this value may be considered as a cap on the transportation and storage cost for projects allowing for transportation over water.

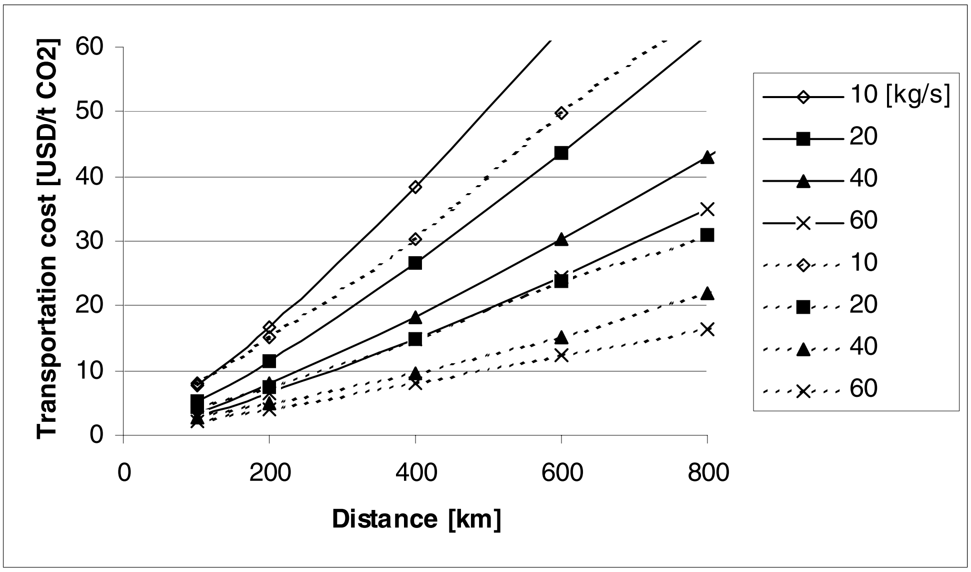

Figure 1: CO_2 transportation cost in varied distances.

An important consideration is that the cost assessment used in the present report assumes dedicated single pipelines for each project. If a CO_2 grid with trunk pipelines becomes a reality, similar to the case for natural gas, allowing numerous CO_2 emitting point sources to be connected to a CO_2 transport network, the average scale of the transportation system would increase thus decreasing the average cost. For example, the cost of transporting CO_2 5000 km in large-diameter pipelines has been estimated at 25 USD/ton CO_2 (IEA, 2002a).

4.5 Annual Operating Costs

The annual operating cost of a plant is a function of plant capacity, biomass requirement as feedstock of the conversion plants, biomass transportation distance, mode of biomass transportation, specific investment cost of the plant, annual capacity factor, heat-to-power ratio (2 for CHP-ST, and 1 for CHP-IGCC) since the price of produced heat were credited, and cost of CO_2 transportation and storage. A cost function, which expresses the annual operating costs of a plant, C (USD/year) would look like this:

C = annualized capital costs + annual operation and maintenance (O&M) costs + annual biomass costs – annual revenue of heat + annual sequestration costs of CO_2 – revenue from sequestrated CO_2.

The above equation could be presented as follows:

$C = (SCC)*(Cap)*0.11 + (SSC)*(Cap)*0.04 + (\alpha)*8760*(BM)*(P_{BM}) - H_{out}*P_H + C_{seq}*seq.cost - C_{seq}*PC$

where

SCC	is the specific capital cost, USD/kWe and the incremental capital costs were annualized by using 8 percent interest rate. And the incremental annual O&M cost is 4 percent of the incremental capital costs;
Cap	is the capacity of plant, kWe;
α	annual capacity factor;
8760	is the number of hours in one year;
0.11	is the annual capital charge factor;
BM	is the biomass requirement, kW;
P_{BM}	is the price of biomass, USD/kWh;
H_{out}	is the annual heat delivered, kWh;
P_H	is the price of heat, USD/kWh;
C_{seq}	is annually CO_2 put in storage, tCO_2/year;
seq.cost	is the cost of transporting and injecting the captured CO_2 to permanent storage, USD/tCO_2; and
PC	is the market price of CO_2, USD/tCO_2.

4.6 Cost of Electricity (COE)

Electricity generating cost is commonly used as an indicator for the calculation/evaluation of the expected economy of biomass-based energy systems with or without CO_2 capture and storage compared to conventional systems and/or among different combination technologies of biomass-based energy systems. The calculation of electricity generating costs is based on an annuity method. In operating a stationary energy generation facility different kinds of expenses are associated, which are dependent on capital, consumption, operation and further payments with periodically and non-periodically incurred costs. The COE is defined as:

$$COE = C \text{ (USD/year)} / E_{out} \text{ (MWh/year)}$$

where E_{out} is the annual electrical output (MWh).

5 Optimal Sizing of Biomass-based Cogeneration

The techno-economic assessments performed indicate the optimal scale of the conversion systems with respect to COE when the conversion systems integrated with CO_2 capture, transport and storage option. The optimal size of CHP-ST varies between the ranges of 98–106 MWe (COE is 5.7 USD/MWh) when fueled by forest/logging residues without CO_2 capture, transport, and storage, and 150 MWe (COE is 27.75

USD/MWh), when CO_2 is captured, transported 100 km and stored. The optimal size range considerably increases with Salix fueled CHP-ST from 249–288 MWe (COE is 15.70 USD/MWh) without CO_2 capture, transport, and storage and 310–330 MWe (COE is 37.24 USD/MWh) when CO_2 is captured, transported 100 km and stored. The optimal size for CHP-IGCC varies between the ranges of 200–227 MWe (COE is 16.73 USD/MWh) when fueled by forest/logging residues without CO_2 capture, transport, and storage, and 210 MWe (COE is 23.25 USD/MWh) when CO_2 is captured, transported 100 km and stored. The optimal size range considerably increases with Salix fueled CHP-IGCC from 441–504 MWe (COE is 27.52 USD/MWh) without CO_2 capture, transport, and storage and 410–450 MWe (COE is 29.81 USD/MWh) when CO_2 is captured, transported 100 km and stored.

If one considers revenues from trading emission quotas earned through negative emissions, one can estimate a market price of CO_2 (PC) at which COE becomes negative (i.e., all capital and operating costs are covered by revenues from heat and negative emissions delivered). Scale effect significantly influences that PC as shown in Figures 2, 3, 4, and 5. According to the model calculation, the PC significantly drops from 75 USD/tCO_2 for 10 MWe CHP-ST plants to 32 USD/tCO_2 for 90 MWe CHP-ST plants when fueled by Salix. The PC drops from 65 USD/tCO_2 for 10 MWe CHP-ST plants to 25 USD/tCO_2 for 90 MWe CHP-ST plants when fueled by forest/logging residues. For CHP-IGCC plants, the PC decreases from 72.5 USD/tCO_2 for 30 MWe to 37.5 USD/tCO_2 for 170 MWe when fueled by Salix. When fueled by forest/logging residue, the PC decreases from 62.5 USD/tCO2 for 30 MWe plants to 30 USD/tCO_2 for 170 MWe.

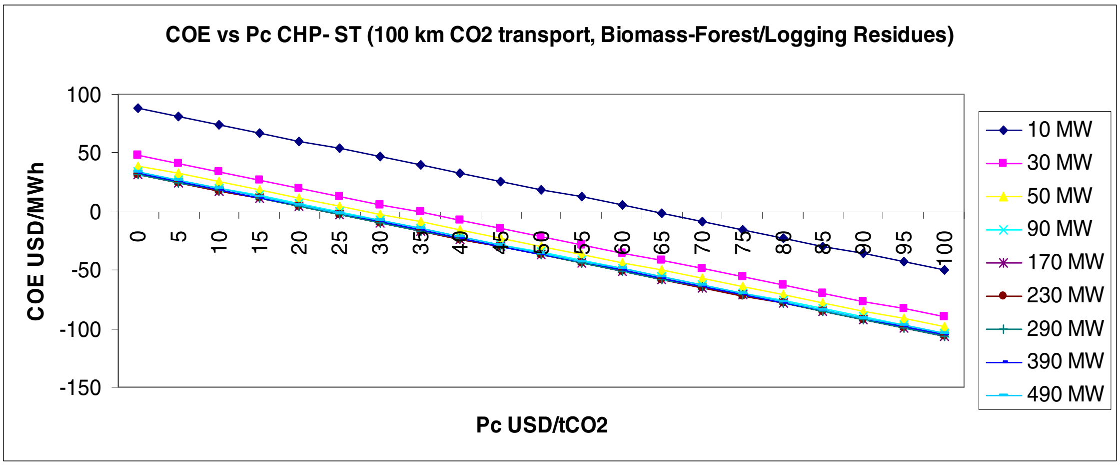

Figure 2: COE vs PC (CHP-ST, 100 km transport of CO_2 and biomass forest/logging residues).

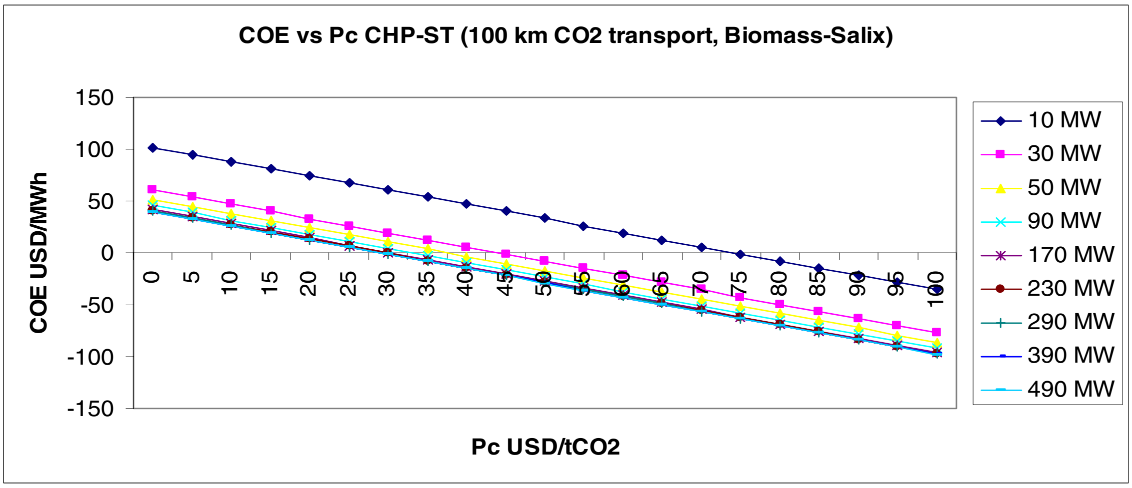

Figure 3: COE vs PC (CHP-ST, 100 km transport of CO_2 and biomass Salix).

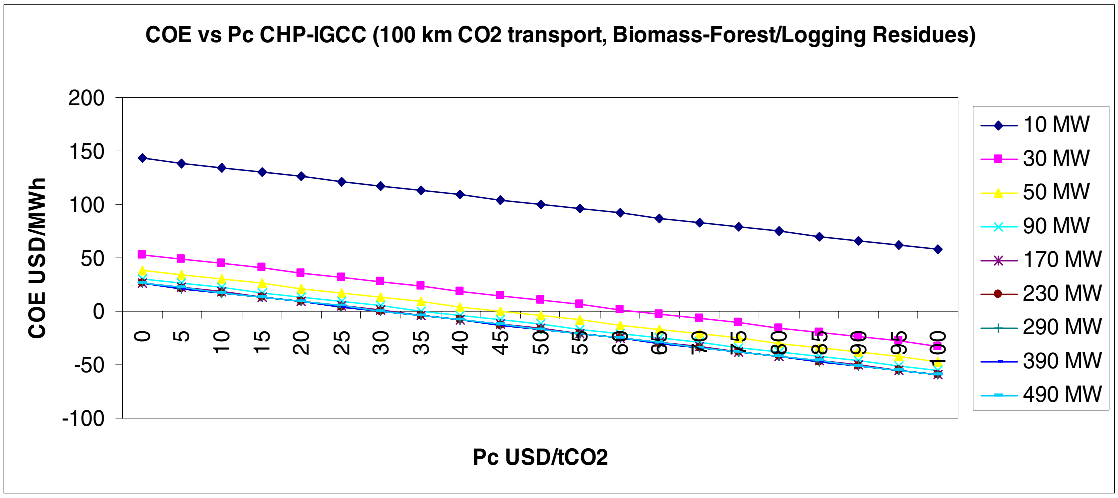

Figure 4: COE vs PC (CHP-IGCC, 100 km transport of CO_2 and biomass forest/logging residues).

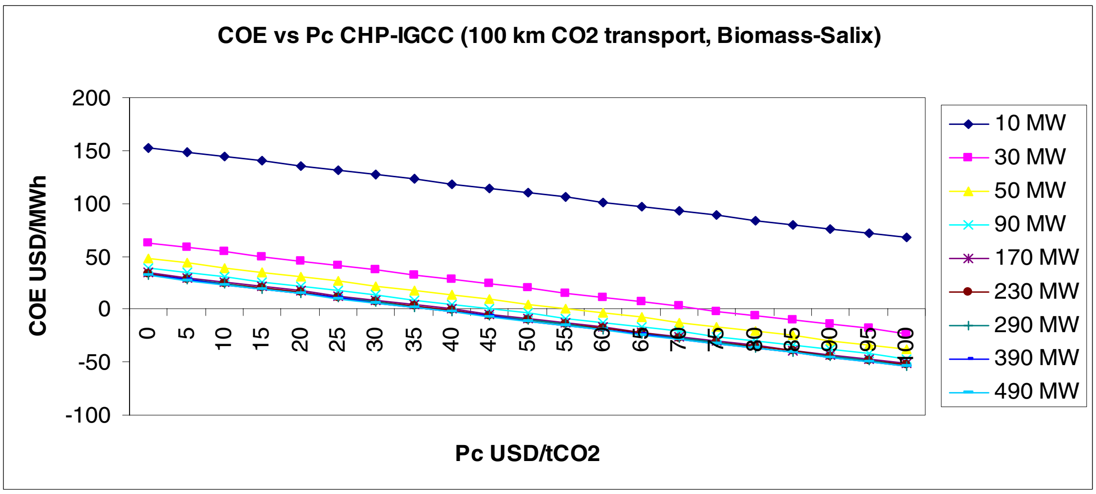

Figure 5: COE vs PC (CHP-IGCC, 100 km transport of CO_2 and biomass Salix).

6 Discussion

For the different conversion systems a comparison of three important parameters, costs, environmental impacts, and resource use should be considered; here, the analysis is based on cost parameter. Here, a 100 km distance from the plant site was chosen for CO_2 transportation and storage. A similar assessment should also been carried out for a range of CO_2 transport from 100–1000 km. The feedstock — Salix productions were based on sustainable cultivation and forest/logging residues from sustainably managed forest. The techno-economic assessment was based on the electrical capacity of the plants and revenues from cogenerated heat and captured CO_2 were credited. In practice, the implementation of any cogeneration system is limited by the heat sink, where the cogeneration systems should be optimized based on site-specific context. A further study would be called for taking into consideration the transactional costs for feedstock handling related to large biomass-based cogeneration facility; comparison of electricity prices when comparing two different technologies that do not have the same magnitude of heat output because of different heat-to-power ratio; several possible CO_2 transportation distances, mode of transport and storage options; and also possibilities of other feedstock.

References

Alholmens Kraft (2002). Power from Biomass. Information Brochure, Alholmens Kraft, Finland.

Börjesson, P. and L. Gustavsson (1996). Regional Production and Utilization of Biomass in Sweden. *Energy*, Vol. 21, No. 9, pp. 747–764.

Cameron, J., A. Kumar and P. Flynn (2002). Optimizing Technology for Biomass Usage for Power Generation. In: Proceedings of the Twelfth European Biomass Conference "Biomass for Energy, Industry and Climate Protection", 17–21 June 2002, Amsterdam, Netherlands, Volume 1, pp. 123–126. Published by ETA-Florence, Plazza Savanarosa, 10, I-50132 Florence, Italy, ISBN 88-900442-5-X and 3-936338-10-8.

Craig, K.R., M.K. Mann and R.L. Bain (1994). Cost and Performance Potential of Advanced Integrated Biomass Gasification Combined Cycle Power Systems. In: Proceedings of the ASME Cogen Turbo Power '94, 25–27 October 1994, Portland, Oregon, USA. 8th Congress and Exposition on Gas Turbines in Cogeneration and Utility, Industrial and Independent Power Generation, ISBN 07918-1213-8.

Dornburg, V. and A.P.C. Faaij (2001). Efficiency and Economy of Wood-fired Biomass Energy Systems in Relation to Scale Regarding Heat and Power Generation Using Combustion and Gasification Technologies. *Biomass and Bioenergy*, Vol. 21, pp. 91–108.

Ekström C, M. Blumer, A. Cavani, M. Hedberg, A. Hinderson, C.-G. Svensson, M. Westermark, M. Erlström and S. Hagenfeldt (1997). Technologies and Costs in Sweden for Capture and Storage of CO_2 from Combustion of Fossil Fuels for Production of Power, Heat and/or Transportation Fuels. Vattenfall Utveckling AB, Stockholm, Sweden (in Swedish).

Energimyndigheten (2000). Energi och klimat i Sverige, Scenarier 2010. EB 4:2000, Eskilstuna, Sweden (in Swedish).

FAO/UNCEC (2001). Global Forest Resources Assessment Report 2000. United Nations Food and Agriculture Organization (FAO), Rome, Italy.

Gustavsson, L. and P. Börjesson (1998). CO_2 Mitigation Cost — Bioenergy Systems and Natural Gas Systems with Decarbonisation. *Energy Policy*, Vol. 26, No. 9, pp. 699–713.

Gustavsson, L., P. Börjesson, B. Johansson and P. Svenningsson (1995). Reducing CO_2 Emissions by Substituting Biomass for Fossil Fuels. *Energy*, Vol. 20, No. 11, pp. 1097–1113.

Holloway, S. (2001). Storage of Fossil Fuel-derived Carbon Dioxide Beneath the Surface of the Earth. *Annual Review Energy Environment*, Number 26, pp. 145–166.

IEA (2002a). Transmission of CO_2 and Energy. Report No. PH4/6. Greenhouse Gas R&D Programme, International Energy Agency (IEA), Stoke Orchard, UK.

IEA (2002b). Renewables in Global Energy Supply — An IEA Fact Sheet. International Energy Agency (IEA), Paris, France.

IPCC (2001). Climate Change 2001 — Mitigation. Intergovernmental Panel on Climate Change (IPCC), Cambridge University Press, UK.

Jenkins, B.M. (1997). A Comment on the Optimal Sizing of a Biomass Utilization Facility Under Constant and Variable Cost Scaling. *Biomass and Bioenergy*; 13(1–2), pp. 1–9.

Johansson, B. (1996). Transportation Fuels from Swedish Biomass — Environmental and Cost Aspects. *Transportation Research and Development*, Vol. 1, No. 1, pp. 47–62.

Karlsson, Å. (2003). Comparative Assessment of Fuel-Based Systems for Space Heating. Ph.D. Dissertation, Lund University, Sweden.

Larson, E.D. and C.I. Marrison (1997). Economic Scales for First-Generation Biomass-Gasifier/Gas Turbine Combined Cycles Fueled from Energy Plantation. *Journal of Engineering for Gas Turbine and Power*, Vol. 119, pp. 285–290.

Lehtilä, A and S. Tuhkanen (1999). Integrated Cost-effectiveness Analysis of Greenhouse Gas Emission Abatement — The Case of Finland. Technical Research Center of Finland (VTT), Espoo, Finland.

Möllersten, K., J. Yan J. and J.R. Moreira (2003). Potential Market Niches for Biomass Energy with CO_2 Capture and Storage — Opportunities for Energy Supply with Negative CO_2 Emissions. *Biomass and Bioenergy,* 25(3), pp. 273–285.

Näringsdepartementet (1995). Omställning av energisystemet. SOU 1995:140, Stockholm, Sweden (in Swedish).

Nguyen, M.H. and R.G.H. Prince (1996). A Simple Rule for Bioenergy Conversion Plant Size Optimization: Bioethanol from Sugarcane and Sweet Sorghum. *Biomass and Bioenergy*, Vol. 10, No. 5/6, pp. 361–365.

Ogden, J.M. (2002). Modeling Infrastructure for a Fossil Hydrogen Energy System with CO_2 Sequestration. In: Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies (GHGT6), 1-4 October 2002), Kyoto, Japan. J. Gale and Y. Kaya (eds.), Pergamon, Oxford, UK.

Remer, D.S. (1990). Design Cost Factors for Scaling-up Engineering Equipment. *Chemical Engineering Progress*, August, pp. 77–82.

SEA (2003). Biomass Survey in Europe — Country Report of Sweden. EUBIONET, EC-Altener, Swedish Energy Agency (SEA), Stockholm, Sweden.

Turkenburg, W.C. (2000). Renewable Energy Technologies. In: *UNDP, UNDESA, WEC, World Energy Assessment,* Chapter 7, New York, USA, pp. 220–272.

UNESCAP (2000). Cogeneration. United Nations Economic and Social Commission for Asia and the Pacific (UNESCAP), New York, USA.

VTT (2001). Biomass CHP Technologies — Future COGEN. Energy Report 7/2001, Technical Research Center of Finland (VTT), Espoo, Finland.

Wahlund, B. (2003). Regional Bioenergy Utilization in Energy Systems and Impacts on CO_2 Emission. Ph.D. Dissertation, Royal Institute of Technology, Sweden.