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Biofuel policies for dynamic markets

Bioenergy strategies for Europe

Synergies and competition between the stationary and transportation sectors

Intelligent Energy Europe

Bioenergy strategies for Europe

Synergies and competition between the stationary and transportation sectors

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Table of contents

Executive summary

Biomass co-firing with coal represents an attractive near-term option for electricity generation from renewable energy sources (RES-E). In this report we have assessed the near-term technical potential for biomass co-firing with coal in the existing coal-fired power plant infrastructure in the EU27 Member States. This in order to indicate its possibility to be a stepping stone for the development of biofuels for transport. The total technical potential for RES-E from biomass co-firing amounts to approximately 50–90 TWh/yr, which requires a biomass supply of approximately 500–900 PJ/yr. The estimated co-firing potential in EU27 amounts to 20–35% of the estimated gap between current RES-E production and the RES-E target for 2010. However, for some member states the national co-firing potential is large enough to fill the national gap. The national biomass supply potential is considerably larger than the estimated biomass demand for co-firing for all member states. About 45% of the estimated biomass demand for co-firing comes from plants located close to the sea or near main navigable rivers and indicates the possibility for biomass import by sea transport. Thus, biomass co-firing has the potential to contribute substantially to the RES-E development in EU27.

Biomass gasification with subsequent synthesis to liquid or gaseous biofuels generates heat possible to use in district heating (DH) systems. In order to estimate the heat sink capacity of DH systems in the individual EU nations and assess the possibilities for biomass-gasification-based co-generation of synthetic biofuels for transportation and heat (biofuel/heat co-generation) for DH systems in the EU countries a model called the Euroheatspot model was developed. The possibilities are assessed (i) assuming different levels of competiveness relative to other heat supply options of biofuel/heat co-generation corresponding to the EU target for renewable energy for transportation for 2020 and (ii) assuming that the potential expansion of the DH systems by 2020 is met with biofuel/heat co-generation. In general, the size of the DH heat sinks represented by the existing national aggregated DH systems can accommodate biofuel/heat co-generation at a scale that is significant compared to the 2020 renewable transportation target. The possibilities for biofuel/heat co-generation also depend on its cost-competitiveness compared to, e.g., fossil-fuel-based CHP. The possible expansion of the DH systems by 2020 represents an important opportunity for biofuel/heat co-generation and is also influenced by the potential increase in the use of other heat supply options, such as, industrial waste heat, waste incineration, and CHP.

- *The analyses show that biomass might become scarce due to large demand for biomass in both transport and stationary energy sectors and therefore biomass prices may increase. Price impact analyses are less readily available but experience from countries with well established forest and bioenergy sectors shows that proactive early movers have grasped new opportunities for bioenergy products, even while the industry often has adopted defensive attitudes to policies stimulating bioenergy. Thus, several strategies seem to be available to exploit the synergies between different demand sectors, such as combined production of biofuels and heat.*

- *The **preliminary** results indicate that the influence of biofuel policies – claiming biomass resources for the production of biofuels for transport – on the situation for the stationary energy sector will very much depend on the development of options for carbon capture and storage (CCS) in the stationary energy sector. In short: if the implementation rate of CCS is slow, or if implementation starts late, then the*

stationary energy sector will look at biomass as a critical resource for meeting climate targets in line with longer term EU ambitions. The degree to which bioenergy will be demanded is dependent on many factors, biomass prices and prospects for other climate friendly energy options being among the most important. But it seem to be a robust conclusion that ambitious climate policies in combination with high ambitions for biofuels for transport can lead to strong competition for biomass between the stationary energy sector and transport sector, especially if CCS is not implemented on substantial scale. This shows that the assessment of impacts of biofuel policies require a comprehensive energy systems perspective, since the impacts are not only determined by the biofuel policies themselves but by the overall policy regime and development of a range of other energy technology options than those related to bioenergy.

- *The analyses revealed that the biomass co-firing potential is substantial. This points to that when stimulating co-firing, policymakers in some member states may consider it a major opportunity for promoting a certain use of biomass. It is clear that some countries have considerable biomass import possibilities and waste and residues can meet a large part of the biomass demand for biomass co-firing with coal in many countries. This implies that if policymakers want to link co-firing to the use of lignocellulosic crops in order to stimulate the production of these crops to strengthen the link to the development of 2nd generation biofuels there might be a need for policies.*

- *The assessment of the present and prospective future DH systems in the individual EU countries show that it can offer a substantial heat sink for surplus heat from biofuels production using the biomass gasification route. The linking with district heating can serve the purpose of improving cost competitiveness of this biofuel option. However, the implementation potential depends on the cost-competitiveness of this heat supply option compared to, in particular, fossil-fuel-based CHP but also the future use of industrial surplus heat and heat from waste incineration.*

Introduction

The objective of work package (WP) 6 is to assess biofuel policy impacts in markets for lignocellulosic materials, focusing on the stationary energy sector and to discuss related policies. The aim is to draw qualitative conclusions about the interplay between the transport and stationary energy systems, and about stationary energy system development under different policy regimes and biomass availability.

WP6 include model-based analyses of possible developments of the EU stationary energy use (heat and power) in response to demand and constraints defined by relevant biofuel policy instruments and given the competing demand for biomass.

WP6 assesses two options for initiating markets and induce development and cost reductions in lignocellulosic supply and which thereby has the possibility to contribute to future more competitive production of second generation biofuels: (i) biomass co-firing with coal and (ii) the linking of district heating (DH) systems with biofuel production based on the gasification route. Recent work – building further on analyses made in the Refuel project – include GIS based assessment of biomass import possibilities and more detailed and policy related analysis of DH systems.

In response to stakeholder input collected during the Elobio stakeholder consultation process additional analyses have been included. These analyses aim at investigating possible food sector impacts of high paying capacity for biomass in the stationary energy sector – and how this paying capacity depends on policies and technology development relevant for the stationary sector. This adds a dimension to conventional views that competition with the food sector arises due to that the biofuel industry uses the same feedstocks as the food sector. The stationary sector competition rather concerns availability of productive lands, water, and other production functions.

Additional methodology development has been required for the extended analyses, which is less comprehensively described in this report.

Note that this report contains both deliverables D6.1 and D6.2. This means that this report presents both the Chalmers Powerplant Database and modelling toolbox as well as the results from the model analyses and policy assessment performed as part of WP 6.

Modelling toolbox and approach

There are many rationales behind the build-up of the Chalmers databases and energy system models. To put it brief and in general terms, modelling a complex system leads to a better understanding of that system and better understanding leads to better decision-making. Energy system model are useful for transforming a very complex reality into a simpler, yet representative, form that can be analyzed and thus lend insights about the energy system otherwise difficult to attain. Once a model has been established, it can be used to perform a multitude of sensitivity analyses on specific matters, in order to broaden the picture of results. This is a very efficient way of evaluating the robustness of model results.

Models can be used for exploring, i.e., perform a comprehensive but systematic search to uncover new or poorly known problems, linkages, and options. Models can also be used for mapping, i.e., a detailed charting of the new territory, unveiled for example by exploring models, to provide a reliable basis for such things as investment plans, legislation and regulation. Exploring models tend to take a long-term view and a broad perspective, while mapping models proceed stepwise and assume that most systems are stable.

Models can be used as a "filter" in order to evaluate consequences of certain policies that in reality may be difficult to relate to specific measures or policies due to "real-world noise". Using models specific actions or measures can be directly related to their consequences. The need to make forecasting studies is another common rationale for developing models, where energy system models include, for instance, electricity-market models where one of the objectives is to generate future prices of electricity with high precision.

A very comprehensive model of a complete system would be just as complex as that system itself and just as difficult to study and learn from: the art of model building is to know what to cut out. The choice between what to include and what to exclude in a model may have impact on the final results. These results may also be biased by the related assumptions included in the model. To tackle this, the modelling process should include feed back from different scientific disciplines as well as different business and activity areas. Such feedback can guide further modelling – not the least design of sensitivity analyses – to improve the understanding of the system under study.

2.1. Chalmers energy infrastructure database and related models

2.1.1 Chalmers databases

Chalmers databases provide for a highly detailed description of the current energy system with focus on power plants and other associated infrastructural limitations and possibilities. Even though the Chalmers databases are not actual models themselves, they will be used in the modeling process by generating a considerable share of the input that will be used in the models that are described here. The Chalmers databases consist of four databases designed to give a comprehensive description of the stationary European Energy system (see Figure 2.1.1). These are:

- **The Chalmers Power Plant database (CPPD)** which contains all power plants in EU plus Norway and Switzerland with a capacity of at least 10 MW plus cross-border transmission capacity (The Power grids/net database) and district-heat production from CHP stations (The District heating database). This means that the Power Plant database contains information for the majority of installed electricity-supply capacity in EU27, covering 97% of the total net capacity of plants in operation in the region (98% of the conventional thermal capacity) as given by Eurostat (2005). For more detailed information about the CPPD see (Kjärstad and Johnsson, 2007) and Section 2.2.

- **The Fuel database** which contains global field specific data on oil, gas and coal fields as well as data related to major transport facilities like pipelines, LNG and regasification terminals.

- **The CO_2 storage database** which contains all identified CO_2 storage reservoirs in Europe with a storage potential of 1 Mt CO_2 or more, i.e. gas and oil fields and aquifers.

- **The Member State database** which contains historic trends of key indicators like GDP and power generation as well as key national energy documents like Climate Change Strategy and Energy Strategy in EU.

The three first databases focus on supply issues while the fourth database primarily captures factors that affect the demand side. A vast part of the databases are ready to use. However all information will be continually updated by Chalmers. Although there exist some other databases on the power generation in EU, these are limited to either a specific technology (e.g. coal plants) or were established a number of years ago, resulting in that the recent development due to the deregulation of the power market is not included.

Today the gathered information at Chalmers is placed in access databases, named as described above. When using the databases, information is being transferred from the access databases into Excel, MARKAL etc for calculations and presentations or into GIS-programs for the combining of maps with the information. The database information can be compiled in numerous ways. For example in files, figures, maps, tables, diagrams, as input to simulations, aggregated national or European figures etc. A significant part of the data has been collected through direct contact with utilities, companies, responsible ministries etc. Where direct contact has been used, this will always serve as main source. Other sources are technical papers and reports made by ministries and IGOs. When written sources are being used the information must stem from the owner of the utility, else the information has to be checked with at least two other sources.

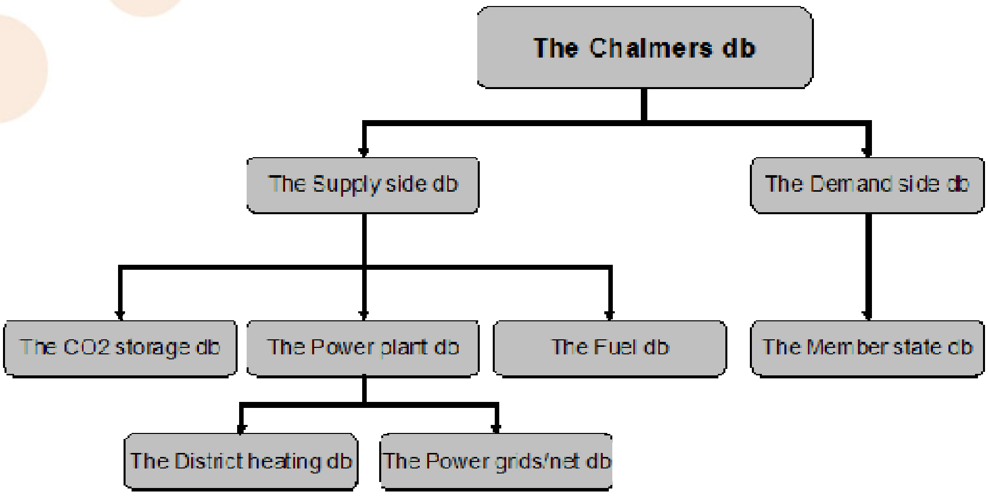

Figure 2.1.1 The Chalmers data bases of the energy infrastructure.

2.1.2 Chalmers modelling toolbox

The Chalmers modelling toolbox contains a range of models. The models used specifically in this project will be described separately in detail in Section 2.2-2-4. Short descriptions of the other models are given in this section.

The PEEP model

The PEEP (Perspectives on European Energy Pathways) model minimizes the cost of the (major part of) the European energy and transport systems, which are described on a country level[1] under varying pre-defined dynamic constraints regarding availability and cost of energy resources and technologies, and also other constraints such as those defined by carbon abatement policies, the EC Biofuel Directive and other EU targets for promoting the introduction of alternative fuels for transport. The output of the PEEP model consist of energy (and transportation) sector development pathways that meet the energy demand at minimum cost given the constraints defined in relation to energy resources, technology and policies.

The energy system cost includes costs for fuel, capital, operation and maintenance, distribution and infrastructure. The timeframe considered is 2000-2050, and the model provides output for every decade. Thus, no annual load variation for e.g. electricity is included. The optimization algorithm represents the market mechanisms in an ideal market where all actors always have access to perfect information and act rationally. A graphic description of the model is presented in Figure 2.1.2.

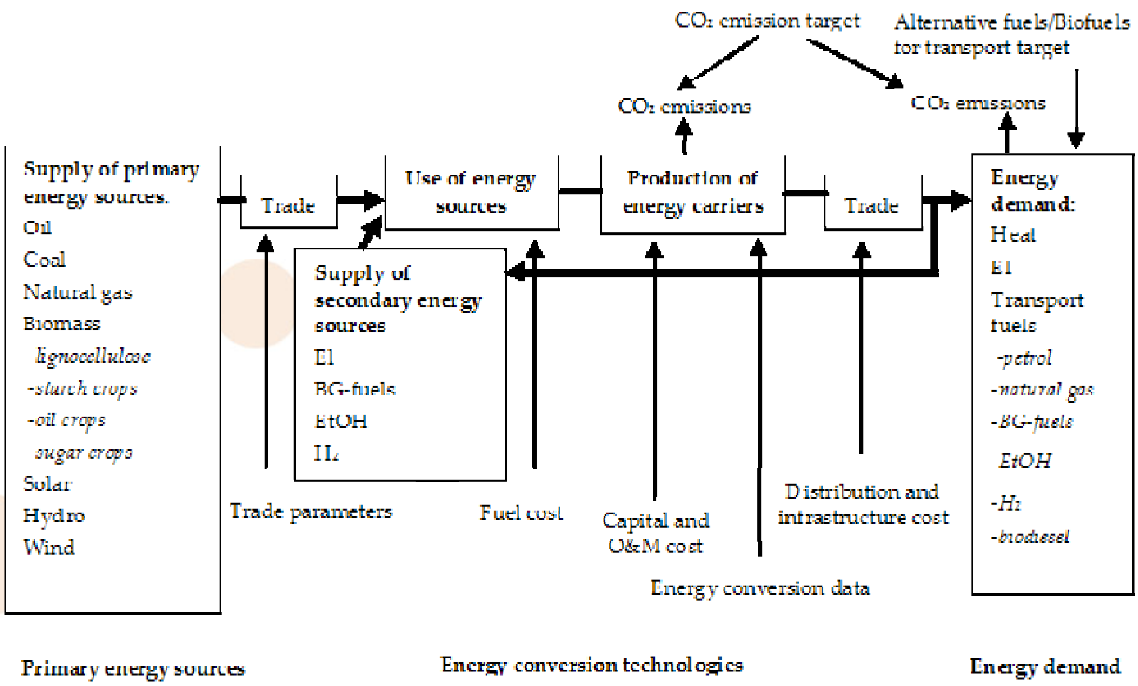

Figure 2.1.2. Graphic presentation of the model. The thick arrows represent energy flows within the model and the thin arrows represent exogenously given parameters. Also the energy demand (where heat represents heat and other energy use) and the supply of primary energy sources are given exogenously. Ligno-cellulose includes residues and energy crops from both forestry and agriculture. BGfuels denotes biofuels based on biomass gasification with subsequent synthesis (e.g., methanol, FT diesel). Petrol includes both diesel and gasoline.

The PEEP model can be used to analyze several issues under a varying context regarding European and world development in the transport and energy fields. The focus within the Pathways project will be on cost-effective bioenergy production, trade and use. For example the model can be used to analyze and assess:

- the implications of scenarios with high penetration of biofuels in transports, for the development of heat and power generation in EU25+

[1]The PEEP model includes all EU25 member states excluding Malta and Cyprus. The non-EU member state Romania is also included.

- in which sector biomass is most cost-effectively used, given externally defined policy regimes, development of mobility patterns and energy use, and development of relevant technologies and markets.
- the distribution of cost-efficient CO_2 reductions between different sectors, e.g. the stationary sector (industry and residents) and transports.
- an indication of an all-European tradable emission permit price for different CO_2-redcution targets.
- the potential for cost-efficient biomass use in specific applications such as biomass co-firing with coal and biofuel/bioelectricity c-production with district heating.

The MARKAL-NORDIC model

The MARKAL (acronym for MARKet ALlocation) model generator is an optimizing linear-programming model generator with perfect foresight. In simple terms, MARKAL model generators satisfy, at the least possible cost[2], demand for energy through a complex combination of energy conversion modules, energy distribution chains and fuel-supply systems under a large number of constraints. Fuel switching, co-production of heat and power, and conservation and efficiency measures are considered, among other factors.[3]

Energy demand may be divided into an appropriate number of sub-sectors, for example demand for space heating or demand for electricity in the iron and steel industries. The division between sectors is based on nationality, sector (industry, residential housing and commerce etc.), and purpose of energy use (lighting, heating etc.). The annual load duration for electricity is divided into six periods, including diurnal representation of winter, summer and an intermediate season. The corresponding load duration for district heating is divided into only three periods, one for each season, while demand for all other energy carriers is expressed on an annual basis. The MARKAL model generator is dynamic in the sense that up to nine mutually interdependent time steps can be treated. Generally, the choice of time horizon for studies using the MARKAL model generator is between 20 and 50 years.

The MARKAL-NORDIC model includes a database describing the entire stationary energy system for the four Nordic countries Sweden, Norway, Finland and Denmark. Transports are included only as a simple bulk emission of CO_2 for each country. This means that CO_2 emissions from the transport sector are projected beforehand. All technologies in the model are described in terms of technical efficiency, availability, investment costs, operation and maintenance costs, fuel delivery costs, and life lengths. For existing technologies, capital costs are considered as sunk costs, and the time dependence of the residual capacity is expressed as an "age curve" based on estimations of remaining technical lifetime (assumed identical to the economic lifetime). Fuels are associated with exogenously given costs and potentials. For fossil fuels, potentials are unlimited, mimicking global markets. Natural gas is, however, supplied through a transmission and distribution grid associated with investment and O&M costs. Domestic fuels such as biomass are divided into several cost classes yielding a supply curve.

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[2] The objective function, which is to be minimized, is generally the total discounted system cost

[3] Technologies for energy supply are included on both the demand side and the supply side. Thus, *e.g.* heating of single-family houses may be achieved with, among other things, heating pumps, oil- and biofuelled furnaces or conservation measures. Correspondingly, on the supply side, *e.g.* district heating may be supplied by utilizing also heating pumps, oil- and biofuelled furnaces, and so forth.

By using the MARKAL-NORDIC model the Nordic countries may act as a test arena for several of the research issues that will be addressed in the project and that may not be as thoroughly investigated for other regions where the regional modeling lacks the corresponding high resolution as is included in MARKAL-NORDIC for the Nordic countries. Some of the research questions addressed are, among others:

- The interrelationship between policy measures, e.g. tradable emission permits, tradable green certificates (electricity certificates) and CO_2 and energy taxes.
- The future development of the energy system and the role of different energy carriers such as electricity, district heating, gas and biofuels.
- Costs for meeting specific climate-policy targets
- The impact of climate and energy policy on energy markets
- The distribution of cost-efficient climate-policy measures between different stationary energy sectors, e g residential, service and industrial sectors, and Nordic countries

The Martes model

Martes is a detailed simulation model for analysis of municipal district heating systems where production of district heating, electricity and steam may be described. The model is built around two annual load curves (one for district heating and one, if applicable, for industrial steam) each divided into 730 periods, i.e. day and night. Different production units, e.g. heat stations, heat accumulators, steam generators, combined heat and power stations and heating pumps are assigned to each heat and steam load. Exchange capacities between different local heat systems may also be included.

For a given heat load, all included production units are dispatched according to a least-cost order of merit and according to the restrictions related to each unit, i.e. availability, minimum load, prioritized dispatch and so forth. Thus, the objective of a Martes model run is to simulate real-life operation of district-heating supply a description of how district heating plants are operated in reality. Furthermore, a Martes run may be formulated as a mixed-integer optimization problem, including start and stop decisions and minimum load restrictions of single units. Output parameters from a Martes model run are, among others, production by fuel and technology, emissions, costs and utilization times.

Martes keeps track of all emissions specified by the user. This, generally, applies to CO_2, SO_x and NO_x. The model user may also include taxes on carbon and energy, subsidies and other policy measures that have an impact on the district-heating production.

Research questions that will be addressed by the Martes model are for instance:

- what are the consequences of different policy measures (European and national) on the district heating supply system in terms of e g emissions, costs and dispatch?
- what is the possible and/or cost-efficient contribution from electricity produced in combined heat and power schemes?
- how will different key technologies, such as waste and biomass incineration, change the terms for producing district heating.
- to improve the knowledge and description of how local (and small scale) markets such as district heating systems can be linked to a wider European context.

The EPOD model

The development of the EPOD (Electric POwer Dispatch) model is still at early stage. The objective of this model is to use the output from the ELIN model (ELectrcity-INvestment model, see Section 2.4), namely the electricity capacities for a specific year, and to use these capacities in order to supply a given electricity demand with seasonal variation (preferably day and night resolution) to the least possible cost under a variety of restrictions (e.g. plant availability). The aim is to cover at least Northern and Western Europe.

Research questions that will be dealt with by the EPOD model are for example:

- the impact of new investments on power dispatch.
- features of a future electricity supply system in terms of e g marginal costs for producing electricity, cross-border trade between European countries and CO2 emissions.

2.2. Modelling the biomass co-firing potential

2.2.1 Approach

The near-term technical potential for biomass co-firing with coal in the EU27 member states is estimated as the maximum amount of biomass-based electricity that can be produced from biomass co-firing in the existing coal-fired power plant infrastructure as well as the corresponding amount of biomass required, applying previous co-firing experience from various power plant types. The main focus is on existing plants, but we will also determine the technical potential for biomass co-firing with coal for EU27 plants under construction or that is planned.

The required data for existing coal-fired power plants in operation (as well as those being planned and under construction) and adherent boiler capacities assumed available for co-firing are obtained from the Chalmers Power Plant Database (CPPD). The CPPD includes parameters such as the name, position, fuel type, net power capacity, and age of power plants.

We assume that all types of coal-fired boilers in operation are available for co-firing but the age of the power plant is assumed to influence the availability for co-firing since old boilers in general have lower efficiency, are likely to remain in operation a shorter time and therefore are less interesting for upgrading to support co-firing. 2007 is used as reference year and two cases are considered:

- Case 1, where boilers commissioned in 1967 or later (i.e., those ≤40 years old) are assumed available for co-firing,
- Case 2 where boilers commissioned in 1977 or later (i.e., those ≤30 years old) are assumed available for co-firing.

Case 1 includes the major part of the capacity of the existing EU27 coal-fired power plant infrastructure (about 90%) and Case 2 assumes the use of about 50% of the installed capacity. The technical biomass co-firing potential depends on the share of biomass that is possible to blend in the fuel mix in the available boilers. In this study we use two different biomass fuel shares in order to reflect that there is a difference in possible co-firing share between fluidised bed (FB) boilers and pulverized coal-fired (PC) and grate-fired (GF) boilers, where the former generally allows a higher share of biomass than the latter. We assume that:

- Biomass can replace 15% of coal (in terms of energy) in FB boilers and 10% of coal in PC and GF boilers.

These assumed biomass fuel shares are based on the technical assessment of co-firing possibilities for different boiler types made by Berggren et al. (2008). Their assessment is based on co-firing in Europe and the US, with special attention to the Swedish experience. It should be noted that there are commercial co-firing applications with higher co-firing shares than those suggested by Berggren et al; e.g., a 20% biomass fuel share is applied in plants in Denmark (IEA Bioenergy, 2007). Thus, future co-firing levels might be higher, but the chosen values are judged as representative of the present levels and are considered low-risk, i.e. do not pose significant technical problems.

The following assumptions are made regarding conversion efficiency:

- Due to the relatively low share of biomass in the fuel mix the introduction of biomass is not assumed to change the efficiency (or the capacity) of the plants.
- All coal plants are assumed to have the following age-dependent electricity conversion efficiencies: 31-40 years, 30%; 21-30 years, 35%; 11-20 years, 37%; 0-10 years, 40% and plants under construction and planning, 45%.

The net power capacities reported in the CPPD are converted to gross power capacities by assuming that losses and energy for internal use correspond to 5% of the gross capacity. The annual technical biomass co-firing potential also depends on the operating time or load factor of the plants.

- The load factor was estimated on a nation by nation basis and for plants using lignite and hard coal separately. This was done by using the 2004 annual national power generation by fuel (Eurostat, 2006) and the national total power capacity (except reserve capacity) for the two types of coal, from CPPD. The calculated average load factors are presented in Table 2.2.1.

Table 2.2.1 Estimated average national load factors for electricity production in the EU27 MS based on national production of electricity in 2004 (Eurostat, 2006) and the total national power capacity (CPPD).

	Load factor (hours/year)	
Member State[1]	**Hard coal**	**Lignite**
Austria (A)	4707	2529
Belgium (B)	3416	-
Bulgaria (BU)	1780	4545
Czech Republic[1] (CZ)	4693	4693
Denmark (DK)	3542	-
Estonia (EE)	-	3175
Finland (FIN)	4751	-
France (F)	3433	-
Germany (D)	4860	7740
Greece (EL)	-	7263
Hungary (HU)	-	5640
Ireland (IRL)	7285	-
Italy (I)	6341	-
Netherlands (NL)	5410	-
Poland (PL)	4208	6553
Portugal (P)	8366	-
Romania[1] (RO)	3344	3344
Slovakia (SK)	4279	4515
Slovenia (SI)	2392	6832

Spain (E)	7253	3018
Sweden (S)	1667	-
United Kingdom (UK)	4540	-

[1] The same load factor is used for lignite and hard coal in both the Czech Republic and Romania, due to differences in the reporting of coal use in the sources.

The technical potential for RES-E generation from co-firing biomass with coal in existing power plants is calculated for each EU27 MS using the available boiler capacity for co-firing, the estimated load factor, and the assumed maximum biomass share in the fuel mix for the different boiler types included in the database. This RES-E production is compared to the remaining amount of RES-E needed to meet the RES-E targets for 2010. The RES-E production in 2005 is taken from Eurostat (2007b) and the RES-E targets are calculated in absolute terms by defining the gross national electricity consumption in 2010 as the sum of the electricity generation and net import of electricity for 2010 as given by EC (2006b).

The amount of biomass required for meeting the estimated technical biomass co-firing potential is obtained by using the conversion efficiencies defined for the plants. The estimated biomass demand is put in relation to the present national production of biomass for energy (as reported in Eurostat, 2007b) and estimates of national biomass supply potentials for 2010. The national biomass supply potential for 2010 is based on EEA (2006) (except for Bulgaria and Romania). The biomass supply potentials for Bulgaria and Romania are collected from Ericsson and Nilsson (2006). The technical potential demand for biomass from co-firing in the existing coal-fired power plants is also compared to an estimation of the amount of biomass needed to meet the EU biofuels targets for 2020.

The major addition for this part compared to the Refuel project concerns the location of this new potential biomass demand. In order to analyse the possibility for biomass transport by sea and inland waterways, information about the geographic location of the coal-fired power plants in the form of coordinates (based on the CPPD) is combined with GIS-based information about waterways in EU27 (Vladimirova, 2008), for an overview see Figure 2.2.1. In order to improve the quality the geographic location reported in the CPPD was for this reason updated for the majority of the plants using EPER (2008). The watercourses included are the navigable waterways of class I-VII as defined in (ECMC, 1992). These include inland waterways of international and regional importance (where the largest are capable of handling transport up to 27000 ton) and will hereafter be called main waterways.

The coal-fired power plants are in the analyses sorted based on their distance (0-1 km, 1-3 km, 3-5 km and 5-10 km) to the closest main waterway. By a complementary visual inspection of maps (generated for this analysis, an example is given in Figure 2.2.2) showing the coal-fired power plants as well as the main waterways on a national level the plants located in the vicinity of the coast are also identified. This information is used to estimate how large share of the possible biomass co-firing capacity that is located in the vicinity of watercourses.

Figure 2.2.1. A schematic overview of the waterways in the EU.

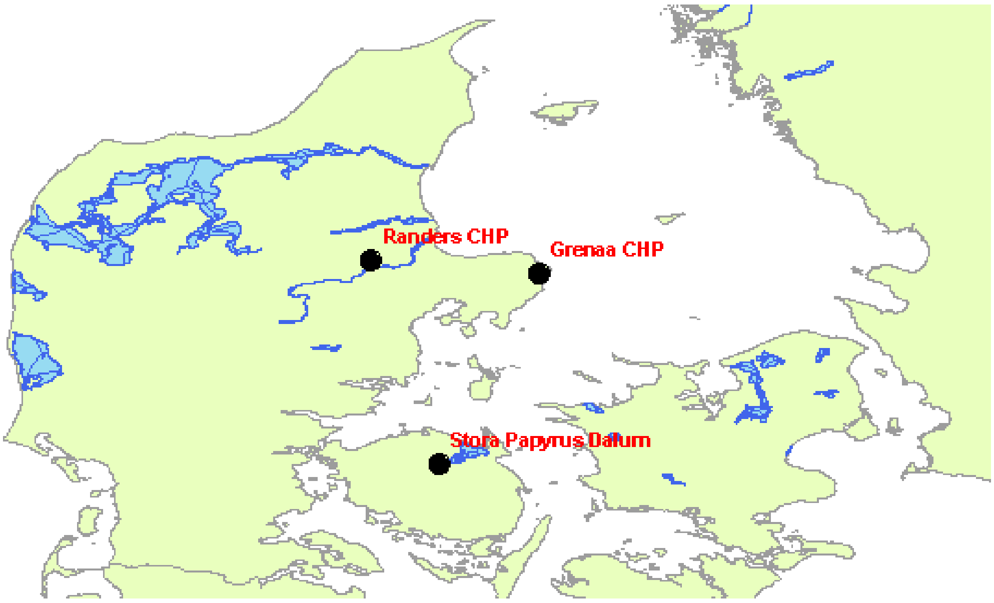


Figure 2.2.2 The location of coal-fired power plants in Denmark (divided after size).

2.2.1 The Chalmers Power Plant database: the European coal-fired power plant infrastructure

The CPPD includes slightly more than 1 000 coal-fired power plants in EU27 when each boiler is treated separately. The number of plants and installed net power capacity for coal-fired power plants per boiler type are given for each country in total and for the two analysed cases in Table 2.2.2. Cyprus, Latvia, Lithuania, Luxembourg, and Malta lack coal-fired electricity.

Germany followed by the UK and Poland has in total the largest installed coal-fired power capacity. For the boilers included in this study the total installed net power capacity in EU27 is 167 GW and 91 GW for Case 1 and 2, respectively (i.e., for boilers less than 40 and 30 years old). The majority of the plants have PC boilers with the other two types being GF boilers and FB boilers. About 70% of the total installed coal-fired net power capacity in EU27 uses hard coal as main fuel (71 and 66% for Case 1 and 2, respectively) while the remaining share uses lignite. The age structure of the coal-fired plants (all boilers included in the CPPD) and their net power capacity is described in Figure 2.2.3.

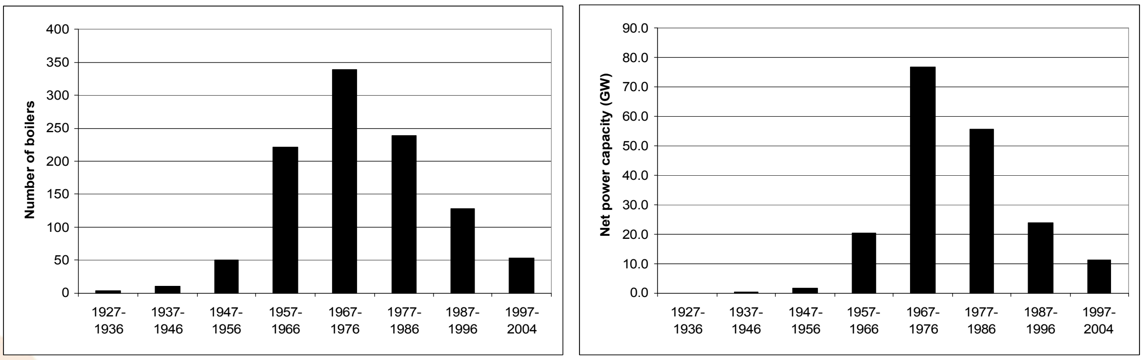
Table 2.2.2 The capacity per boiler type of coal-fired power plants in the EU27 MS in total and for the two assumptions on power plant age (Case 1 and 2). The number of plants (each boiler is treated separately) is given in brackets. Source: CPPD.

	Net power capacity (GW) and number of coal-fired power plants					
	Total		Case 1 (≤40 years old)		Case 2 (≤30 years old)	
Member State	**FB[1]**	**Other[2]**	**FB**	**Other**	**FB**	**Other**
A	0.08 (3)	1.79 (8)	0.08 (3)	1.72 (7)	0.08 (3)	1.67 (6)
B	-	2.68 (15)	-	2.20 (11)	-	0.27 (1)
BU	-	5.51 (38)	-	4.38 (26)	-	1.98 (12)
CZ	1.04 (13)	9.54 (79)	0.55 (4)	7.94 (55)	0.14 (2)	4.35 (27)
DK	0.02 (1)	5.25 (19)	0.02 (1)	4.96 (17)	0.02 (1)	4.00 (13)
EE	0.20 (1)	2.80 (8)	0.20 (1)	1.41 (7)	-	-
FIN	0.18 (2)	3.57 (18)	0.18 (2)	3.14 (16)	0.01 (1)	1.86 (10)
F	0.40 (4)	7.11 (24)	0.40 (4)	6.69 (20)	0.28 (3)	3.00 (6)
D	0.94 (12)	47.3 (163)	0.95 (11)	41.5 (126)	0.95 (11)	27.2 (85)

EL	-	4.87 (21)	-	4.54 (17)	-	3.20 (11)
HU	-	1.37 (20)	-	1.08 (14)	-	-
IRL	-	0.86 (3)	-	0.86 (3)	-	0.86 (3)
I	0.32 (1)	6.86 (24)	0.32 (1)	6.24 (19)	0.32 (1)	3.52 (8)
NL	-	4.17 (8)	-	4.17 (8)	-	2.73 (5)
PL	1.96 (14)	26.9 (341)	1.22 (9)	22.5 (210)	1.22 (9)	13.6 (120)
P	-	1.78 (6)	-	1.78 (6)	-	1.78 (6)
RO	-	6.42 (31)	-	6.17 (28)	-	4.44 (21)
SK	0.27 (4)	1.03 (10)	0.03 (1)	0.56 (5)	0.03 (1)	0.12 (2)
SI	-	0.90 (7)	-	0.78 (4)	-	0.35 (2)
E	0.05 (1)	12.0 (41)	0.05 (1)	11.4 (36)	0.05 (1)	8.45 (24)
S	0.23 (1)	0.37 (7)	0.23 (1)	0.27 (4)	-	0.16 (2)
UK	-	29.1 (64)	-	27.9 (61)	-	3.77 (11)
EU27	**6 (57)**	**182 (955)**	**4 (39)** [2]	**162 (700)**	**3 (33)**	**87 (375)**

[1] FB: fluidised bed boilers allowing for a higher biomass fuel share.
[2] Other: pulverised coal boilers and grate-fired boilers

Figure 2.2.3 Age structure of coal-fired power plants (left) and the corresponding net power capacity (right). Case 1 and 2 is represented by the four (Case 1) and three (Case 2) bars from the right, respectively. Source: CPPD.



2.3. Modelling the potential for co-generation of biofuels and heat for district heating

2.3.1 Approach

An inventory and characterization of the existing (2003) DH systems in the EU25 is made. Year 2003 was chosen to represent present time since more recent data sets are incomplete and the changes are estimated to be relatively small. The existing DH systems are characterized at the national aggregated level and include size of the heat sink and relevant characteristics such as the present fuel use and heat supply option used to provide the DH (Section 2.3.2). This characterization, along with the estimate of the sizes of the DH systems in 2020 (Section 2.3.4), form the basis for investigating the possibilities for *biofuel/heat co-generation* in the EU25 countries.

We present the current heat sink capacity in relation to the magnitude of surplus heat from *biofuel/heat co-generation* corresponding to significant—in the EU policy context—synthetic biofuels production. We estimate the volume of biofuels required, at the EU25 level and at the member state level, to achieve a share of 10% biofuels in the transportation sector by 2020, i.e., the entire target for renewable energy in the transportation sector (see Table 3.2.3). This volume, called the *2020 renewable transportation target*, is used as a basis for comparison. In reality the 2020 renewable transportation target will of course not only be met by synthetic biofuels but since the level remains to be determined we have used the full target as basis for this analysis. The plant configuration for *biofuel/heat co-generation* is also specified, including the biofuel conversion efficiency and amount of surplus heat generated per unit of synthetic biofuel produced.

The size of the national heat sink capacity (represented by specified segments of the aggregated DH systems, see Scenario definition in Section 2.3.3) is compared with the amount of surplus heat that would be generated if synthetic biofuels corresponding to the 2020 renewable transportation target were produced domestically. This amount of surplus heat is referred to as the *heat corresponding to the 2020 renewable transportation target*. Note that the 2020 target for renewable energy in the transportation sector is set in relation to the *use* of energy; the policy does not call for individual countries to produce these renewable fuels domestically. Nevertheless, the comparisons made will give insights into the possibility in different EU member states to meet the biofuels targets based on *biofuel/heat co-generation*. This study does not consider the possibility of importing or exporting biofuels. However, for countries that are estimated to have the potential to produce more than the amount of heat corresponding to the 2020 renewable transportation target by biofuel/heat co-generation this indicate that this countries might have the possibility to export synthetic biofuels.

Two different approaches are used to further assess the possibilities for *biofuel/heat co-generation* and to analyse how deployment of this option in the EU could influence existing DH systems, as well as an expansion of DH. Figure 2.3.1 gives a graphic illustration of the approaches (further described in Section 2.3.3 and Section 2.3.4).

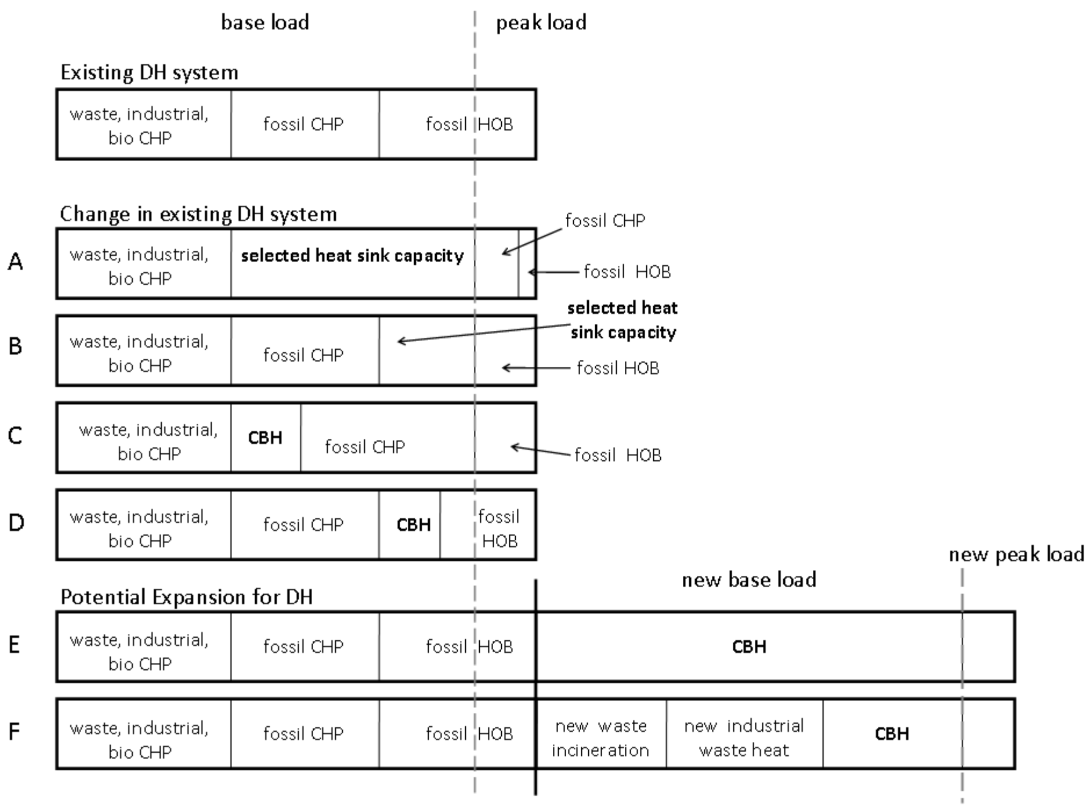


Figure 2.3.1 The boxes represent the aggregated DH systems. The uppermost box represents the existing DH systems. A and B illustrate the available heat sink when *biofuel/heat co-generation* (CBH) is modelled as cost-competitive compared to fossil-fuel-based CHP and/or HOB. C and D illustrate the case when *biofuel/heat co-generation* is competitive compared to fossil-fuel-based CHP and/or HOB

but only up to the biofuel production level corresponding to the 2020 renewable transportation target. E and F illustrate the case when the parts or all of the potential expansion of the DH systems by 2020 is met with *biofuel/heat co-generation*. In all cases, *biofuel/heat co-generation* is assumed to provide base load heat. For additional assumptions, see the text.

First, the possibility to use a country's existing heat sink (represented by specified segments of the aggregated DH systems in this country, including fossil-fuel-based CHP and/or HOB) for *biofuel/heat co-generation* is assessed by modelling the DH systems (illustrated by A and B in Figure 2.3.1). Applying the same modelling tool, the possibilities for (or possible impact of) *biofuel/heat co-generation* in the EU25 countries are (is) estimated, assuming that heat corresponding to the 2020 renewable transportation target is competitive compared to selected options (fossil-fuel-based CHP and/or HOB) and thus replaces a certain share of these heat supply options in the existing DH systems, the 2020 renewable transportation target case (illustrated by C and D in Figure 2.3.1). For each nation, we determine what share of the aggregated DH system *biofuel/heat co-generation* corresponding to the 2020 renewable transportation target represents.

Second, we assume that parts or all of the potential expansion of the DH systems by 2020 is met with *biofuel/heat co-generation* (illustrated with E and F in Figure 2.3.1). The estimate is based on combining a DH expansion scenario at the national level with an assessment of the future availability of industrial waste heat and heat from waste incineration. These two sources are assumed to potentially be more competitive than heat from *biofuel/heat co-generation*.

To assess the existing DH systems, we develop a new version of the Heatspot model (Knutsson et al., 2006), called the Euroheatspot model (see section 2.3.3). This model is used to assess what would happen if heat from *biofuel/heat co-generation* were to compete with other heat sources in the DH system. The model presents the heat mix in the European DH systems after *biofuel/heat co-generation* has been introduced at a certain position in the merit (production cost) order. The merit order indicates the different heat supply options relative competitiveness (see Section 2.3.3).

The DH systems would of course not change over-night just because *biofuel/heat co-generation* offered a heat supply option more competitive than some other options. Rather, the *biofuel/heat co-generation* option would expand at a rate defined by the demand for renewal of the already installed DH supply capacity, feedstock prices, and policies. In Sweden there has, for instance, been a transition from the use of fossil fuels, mainly oil, to the use of biomass in DH systems, in response to energy prices and the CO_2 tax (see, e.g., STEM, 2006). However, in the modeling with the Euroheatspot model we assume an instant change to *biofuel/heat co-generation* if it is assumed to be a more competitive heat supply option.

Biofuel/heat co-generation also has the possibility for establishment in expanding DH systems. An estimate of the potential DH expansion based on Werner (2006) is presented in Section 2.3.4. The share of the potential DH expansion by 2020 possibly available for *biofuel/heat co-generation* will depend on the development of other heat supply options, e.g., the relatively low cost base load heat supply options waste incineration and industrial waste heat. Therefore, we also estimate, roughly, the national expansion potential for these options (Section 2.3.4). The heat supply from waste incineration is expected to increase, since an increased waste incineration for heat and/or electricity production is promoted within the EU (EC, 2005b), and the amount of waste is assumed to increase. Industrial waste heat for DH generates an additional revenue stream for industry and represents heat that would otherwise be wasted.

The possibility for *biofuel/heat co-generation* also depends on e.g., the supply of biomass. We relate the biomass demand corresponding to the estimated possibility for *biofuel/heat co-generation* to estimates of national biomass supply potentials made by EEA (2006). In reality it is unlikely (and for some cases even not possible) that all EU countries would use only domestic biomass for production of biofuels for transportation but the comparison presents a first indication of the national possibility for biofuel/heat co-generation from a biomass supply perspective.

2.3.2 National DH systems

The DH systems in each EU25 member state are described at the national aggregated level. (i.e., is represented by the sum of contributions of the heat supply options from the individual systems). Information at the individual DH system level is not readily available for the majority of the EU25 countries. This includes also information about age structure of existing systems and plants under planning and construction. Information at the individual DH system level or at least company level (most DH companies operate only in one city, each city can have more than one system but often they are connected with bridging pipes and can therefore be seen as one system in this analysis) can be found for Sweden, Germany, Finland, Lithuania and Denmark but not for most other EU member states.

Data on the existing DH systems in EU25 are mainly collected from the comprehensive documentation for 2003 made within the EU project Ecoheatcool (Werner, 2006) and especially the WP4 report therein. The statistics in this report are based on data from IEA (2005), which contains information about the use of and input to the DH systems in EU25, aggregated at the national level[4]. Where higher level of detail is required, supplementary data is collected from (IEA, 2005) directly. This is done for the category "primary solid biomass" which is separated from the category "combustible renewables" as presented in Ecoheatcool. Heat (by heat supply option) delivered to the national aggregated DH systems in EU25 is presented in Table 2.3.1. Production can be calculated by assuming a 12% distribution loss.

There are large differences among DH systems in the EU25 countries regarding size and composition. Malta, Cyprus, and Spain lack DH systems. Ireland and Greece have relatively small DH systems, 0.1 PJ and 1.0 PJ, respectively (Werner, 2006). These five countries are excluded from the analysis. The term *EU20* will be used for the remaining EU25 member states. Figure 2.3.2 presents the aggregated DH production in 2003 in the EU20 nations. For numbers on share of heat from the different heat supply options of total aggregated national DH system (in percentage) see Table 2.3.2. More detailed information of the characteristics of these DH systems can be found in Table 2.3.3. As can be seen, the context for the introduction of *biofuel/heat co-generation* varies from nation to nation.

[4] The amounts of DH from all kinds of CHP in the UK, and from CHP based on combustible renewables as well as waste in France, have been altered from the values reported in IEA (2005) due to these being incorrect and are instead in accordance to the ones used in Werner (2006). The 2003 values are used since the more recent statistics also include heat from CHP that is not used in the DH systems (which is due to the demand for reporting of national electricity and heat production from co-generation in EP&C (2004)).

Table 2.3.1 Present (2003) heat (by heat supply options) delivered to the EU member states district heating systems. The category other includes heat from industrial waste heat, waste incineration, as well as waste heat from nuclear power, biomass, and geothermal and solar thermal energy. (Calculated based on Werner, 2006 and IEA, 2005).

country	waste CHP (PJ)	waste HOB (PJ)	waste heat (PJ)	other (PJ)	combustible renewable CHP (PJ)	coal CHP (PJ)	combustible renewables HOB (PJ)	electricity (PJ)	natural gas CHP (PJ)	petroleum CHP (PJ)	coal HOB (PJ)	natural gas HOB (PJ)	petroleum HOB (PJ)	total 2003 (PJ)
Austria	3	1	0	0	1	3	11	0	22	7	0	6	1	55
Belgium	2	0	0	0	0	0	0	0	21	0	0	0	0	23
Cyprus	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Czech Republic	2	1	0	0	2	88	0	0	17	4	9	22	3	147
Denmark	17	6	0	0	7	37	13	0	39	6	0	3	2	130
Estonia	0	0	0	0	0	5	3	0	5	0	3	7	3	26
Finland	3	6	0	0	25	64	6	0	36	2	6	12	11	170
France	18	0	2	4	0	0	1	2	0	0	14	53	14	109
Germany	27	0	4	0	0	132	0	0	211	16	0	0	0	391
Greece	0	0	0	0	0	1	0	0	0	0	0	0	0	1
Hungary	0	0	0	1	0	10	0	0	30	3	2	17	1	64
Ireland	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Italy	0	2	0	0	0	0	1	0	12	0	2	0	1	20
Latvia	0	0	0	0	0	0	5	0	14	1	0	12	2	34
Lithuania	0	0	0	2	0	0	3	0	18	2	0	14	3	44
Luxembourg	0	0	0	0	0	0	0	0	2	0	0	0	0	2
Malta	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Netherlands	8	0	0	0	0	5	0	0	100	2	0	0	0	115
Poland	1	0	0	0	2	209	1	0	10	4	127	10	5	368
Portugal	0	0	0	0	0	0	0	0	6	3	0	0	0	9
Slovak Republic	0	0	0	2	0	11	0	0	16	1	1	24	0	56
Slovenia	0	0	0	0	0	6	0	0	1	0	0	3	0	10
Spain	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sweden	16	5	36	0	56	14	22	9	6	7	4	2	8	185
United Kingdom	0	0	0	0	2	14	0	0	54	0	0	0	5	75
EU25	96	21	42	11	96	600	67	12	618	58	169	185	59	2034

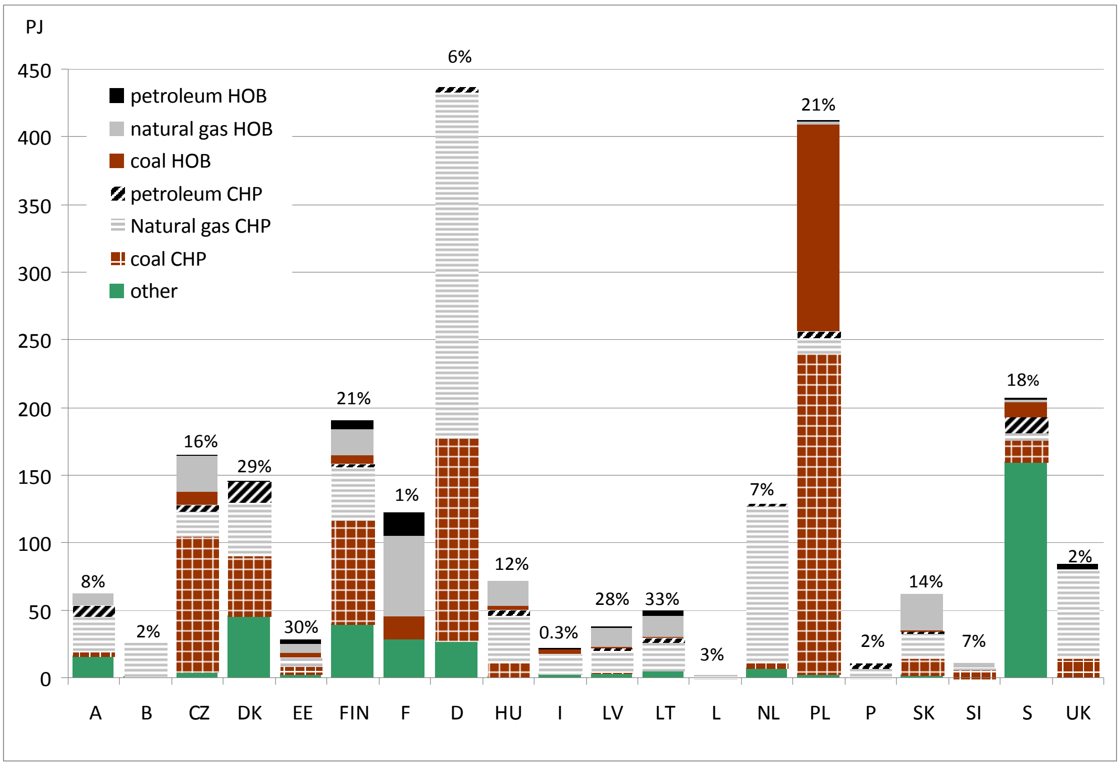


Figure 2.3.2 DH production from the heat supply options in the aggregated DH system in the EU20 countries in 2003 (calculated based on Werner, 2006 and IEA, 2005). The country abbreviations are explained in Table 2.3.3. The numbers above the bars show the share of DH of the total national end-use of heat from fossil fuels and from electricity in the industrial, residential, and service sectors (IEA, 2005). The category "other" includes industrial waste heat, waste incineration, as well as waste heat from nuclear power, biomass, and geothermal and solar thermal energy.

Table 2.3.2 Present (2003) share (in percentage) of heat from the different heat supply options in the EU member states (calculated based on Werner, 2006 and IEA, 2005).

Member state	waste CHP	waste HOB	waste heat	other	combustible renewable CHP	coal CHP	Combustible renewables HOB	electricity	natural gas CHP	petroleum CHP	coal HOB	natural gas HOB	petroleum HOB
Austria	5%	2%	-	1%	2%	6%	19%	-	39%	12%	-	11%	2%
Belgium	7%	1%	-	-	-	-	-	-	92%	-	-	-	-
Czech Republic	1%	1%	-	-	1%	60%	-	-	11%	3%	6%	15%	2%
Denmark	13%	4%	0,05%	-	5%	28%	10%	-	30%	5%	-	3%	1%
Estonia	-	-	-	-	-	21%	12%	-	19%	-	10%	28%	10%
Finland	2%	3%	0,01%	-	14%	38%	4%	-	21%	1%	4%	7%	6%
France	17%	-	2%	4%	-	-	1%	2%	-	-	13%	48%	13%
Germany	7%	-	1%	-	-	34%	-	-	54%	4%	-	-	-
Hungary	1%	-	-	1%	-	16%	-	-	46%	5%	3%	26%	1%
Italy	-	10%	1%	2%	-	-	4%	1%	63%	-	12%	-	7%
Latvia	-	-	-	-	1%	1%	13%	-	41%	3%	1%	36%	5%
Lithuania	-	-	-	5%	1%	-	8%	-	41%	4%	1%	33%	8%
Luxembourg	-	-	-	-	4%	-	-	-	96%	-	-	-	-
Netherlands	7%	-	-	-	-	4%	-	-	87%	2%	-	-	-
Poland	-	-	-	-	1%	57%	-	-	3%	1%	34%	3%	1%
Portugal	-	-	-	-	-	-	-	-	67%	33%	-	-	-
Slovak Republic	-	-	0,01%	4%	1%	20%	-	-	28%	1%	1%	43%	-
Slovenia	-	-	-	-	1%	61%	3%	-	6%	-	-	26%	2%
Sweden	9%	3%	19%	-	30%	8%	12%	5%	3%	4%	2%	1%	4%
United Kingdom	-	-	-	-	3%	18%	-	-	72%	-	-	-	7%
EU20	5%	1%	2%	1%	5%	30%	3%	1%	30%	3%	8%	9%	3%

Table 2.3.3 Overview of the present size, composition, and expansion potential for the aggregated DH systems in the EU20 countries in 2003 (based on Werner, 2006 and IEA, 2005).

Member state	**Existing DH systems**					**Potential DH expansion (2020)**[1]
	Total DH (PJ)	Share of heat from coal and petroleum	Share of heat from natural gas	Share of heat from biomass	Share of HOB (only fossil-fuel-based HOB)	Additional DH (PJ)
Austria (A)	55	21%	51%	21%	35% (13%)	42[2]
Belgium (B)	23	0%	92%	0%	1% (0%)	66[3]
Czech Republic (CZ)	147	70%	26%	2%	24% (23%)	66[4]
Denmark (DK)	130	35%	32%	16%	18% (4%)	9[5]
Estonia (EE)	26	42%	46%	12%	60% (48%)	3[4]
Finland (FIN)	170	49%	28%	18%	24% (17%)	9[5]
France (F)	109	26%	48%	1%	75% (74%)	302[2]
Germany (D)	391	38%	54%	0%	0% (0%)	538[2]
Hungary (HU)	64	25%	72%	0%	31% (31%)	72[4]
Italy (I)	20	19%	63%	4%	33% (19%)	78[6]
Latvia (LV)	34	10%	76%	14%	55% (41%)	4[4]
Lithuania (LT)	44	13%	73%	9%	49% (41%)	4[4]
Luxembourg (L)	2	0%	96%	4%	0% (0%)	5[2]
Netherlands (NL)	115	6%	87%	0%	0% (0%)	112[2]
Poland (PL)	368	94%	5%	1%	39% (39%)	133[4]
Portugal (P)	9	33%	67%	0%	0% (0%)	5[6]
Slovakia (SK)	56	23%	71%	1%	45% (44%)	30[4]
Slovenia (SI)	10	64%	33%	4%	31% (28%)	11[4]
Sweden (S)	185	18%	4%	42%	23% (8%)	11[5]
United Kingdom (UK)	75	25%	72%	3%	7% (7%)	251[3]
EU total	2033	44%	39%	8%	24% (20%)	1751

[1] The potential DH expansion is based on Werner (2006). For a more detailed description of the underlying assumptions see Section 2.3.4.
[2] 70% of the substitutable fossil fuels today used for heating are replaced by DH
[3] 50% of the substitutable fossil fuels today used for heating are replaced by DH
[4] 100% of the substitutable fossil fuels today used for heating are replaced by DH
[5] 40% of the substitutable fossil fuels today used for heating are replaced by DH
[6] 20% of the substitutable fossil fuels today used for heating are replaced by DH

2.3.3 Description of the Euroheatspot model

The Euroheatspot model is a simulation tool for national DH analyses in the EU20. The original Heatspot model includes the description of all the existing DH systems in a country and uses this system level in analyses to provide results for the individual DH systems and at the national level. It has been used for analyses of DH systems in Sweden, Norway, Denmark, and Finland (see e.g., ÖPwC, 2005 and Rydén et al., 2003). The Heatspot model analyses the national DH systems by looking at the different DH systems system by system. Results and insights are therefore produced on a system level. The Euroheatspot model uses aggregated country level information (see Section 2.3.2) instead of information at the individual DH system level and generates results and insights at the national and EU20 level. Results may of course vary depending on if they are calculated based on system level or on an aggregated national level. However, Knutsson et al. (2006) find that if the impact of measures on the DH sector does not have to be assessed with great precision, (this study, for instance, does not require great precision in this regard) an aggregated systems level may be sufficient. A comprehensive description of a large number of DH systems requires extensive work dedicated to data collection.

The description of the existing DH systems in the Euroheatspot model represents a situation where all the DH systems in a country are connected and thus have the characteristics of this aggregated system. The merit order for the heat supply options included in the model (i.e., the assumed cost relation between the options) is presented in Table 2.3.4. This merit order will be fixed throughout the modelling (unless otherwise stated). This means that the relative costs of the different heat supply options are taken into consideration. The reason for not including specific cost estimates is (i) that cost estimates for *biofuel/heat co-generation* are uncertain due to that this technology is not yet commercial on large-scale and (ii) that future costs for all heat supply options to a large extent will depend on the development of policies and might also differ between countries.

Table 2.3.4 The merit order (increasing cost, bottom to top) and energy conversion characteristics for the heat supply options in EU20, based on the Heatspot model used in ÖPwC (2005) representing the Swedish situation. The assessed positions for *biofuel/heat co-generation* are indicated.

Heat supply option	**Total conversion efficiency**	**Power to heat ratio**
Petroleum HOB	90%	-
Natural gas HOB	90%	-
Coal HOB	85%	-
biofuel/heat co-generation in the After CHP scenario		
Petroleum CHP	85%	0.4
Natural gas CHP	90%	0.4
biofuel/heat co-generation in the Before natural gas CHP scenario		
Electricity by heat pumps[1]	300%	-0.33
Combustible renewables[2] HOB	85%	-
Coal CHP	85%	0.4
biofuel/heat co-generation in the Before fossil CHP scenario		
Combustible renewables[1] CHP	85%	0.4
Waste heat from nuclear power, geothermal and solar thermal energy	100%	-
Waste heat (from industry etc.)	100%	-
Waste HOB	85%	-
Waste CHP	85%	0.2

[1] The use of electricity is assumed to be represented by the use of heat pumps only.
[2] Includes primary solid biomass.

In the Euroheatspot model, the national DH systems are described by a heat load duration diagram, in which the heat supply options in the system are placed in the specified merit order and are ranked by size (illustrated in Figure 2.3.3a). The same annual load curve (describing the duration, i.e., hours of use over the year) is used for all EU20 countries. The shape of the annual load curve is based on the representation of the Swedish situation used in ÖPwC (2005). It is judged to be a fair representation of the average situation in the EU. Although it may overestimate the base load heat generation in Southern EU countries with longer summers and overestimate peak load heat generation in countries with more even annual temperatures. The annual load curve used represents a situation in which the total installed heat generation capacity (i.e., maximal heat load) on average needs to be used 3,000 hours per year to meet the total heat demand. The maximal annual operation time is assumed to be 8,000 hours[5].

The installed capacity (in MW) for each included heat supply option, corresponding to the compiled production levels in each country, is estimated by using an analytical expression representing the annual load curve[6]. Based on the estimated installed capacity the annual DH production from the different heat supply options is recalculated after the *biofuel/heat co-generation* has been introduced in the DH systems. An illustration of how *biofuel/heat co-generation* is introduced in the existing DH systems is presented in Figure 2.3.3.

The *biofuel/heat co-generation* option is introduced at three different positions in the merit order, (see Table 2.3.4). The same scenarios are used for the initial comparison of magnitudes (see Section 3.2.1).

- *Before fossil CHP scenario: biofuel/heat co-generation* is assumed to be more competitive than coal-based CHP, i.e., it mainly replaces fossil-fuel-based heat options. In this scenario, the introduction of *biofuel/heat co-generation* affects the electricity production from fossil fuels. This because all fossil CHP heat supply options are pushed upwards in the merit order and thus they can no longer deliver the same amount of heat as they used to.
- *After CHP scenario: biofuel/heat co-generation* is only more competitive than fossil-fuel-based HOB.
- *Before natural gas CHP scenario: biofuel/heat co-generation* is placed before natural gas CHP in the merit order, i.e., it is assumed to be more competitive than gas- and oil-based CHP and all fossil-fuel-based HOB but more expensive than coal based CHP.

The rationale for the scenario construction is the potential competition between CHP and *biofuel/heat co-generation* pointed out by, e.g., Hansson (2003) and Börjesson and Ahlgren (2008). *Biofuel/heat co-generation* plants are still at the research/demonstration stage, and it is not possible to set cost estimates for such plants with a high level of confidence. Therefore, only relative costs are discussed in this study.

Figure 2.3.3b-c illustrates how the model works. When a certain capacity of *biofuel/heat co-generation* is introduced in the existing DH systems, the heat supply options with higher production costs will be pushed upward in the duration diagram to make space for the specified capacity of *biofuel/heat co-generation* introduced. The heat supply options pushed upward may have the same installed heat capacity as before, but a higher position in the diagram represents a shorter production time.

In the modelling it is assumed that about 90% of the total amount of heat delivered to the DH systems comes from base load heat applications i.e., from heat supply applications that deliver

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[5] The remaining amount (about 10% of the year) is supposed to cover maintenance and other downtime.

[6] Accumulated effect share in MW (y1) for each heat supply option is calculated from accumulated energy share in GWh (x) using the following formula: $y1 = 0{,}2889x^2+0{,}2241x$ (if $x<0{,}92$) and $y1 = 6{,}5x-5{,}5$ (else). When calculating accumulated energy share in GWh (y2) from accumulated effect shares in MW (z) this formula is used: $y2 = 1{,}6908z^3-3{,}6613z^2+3{,}3144z$ (if $z<0{,}44$) and $y2 = 1{,}2807z^3-3{,}3419z^2+2{,}9104z+0{,}151$ (else).

heat during a large share of the year; the rest is peak load applications. In the Euroheatspot model this implies that base load heat constitute about 50% of the total present installed heat generation capacity. *Biofuel/heat co-generation* is assumed to be suitable only as base load capacity. Therefore, in the modelling the *biofuel/heat co-generation* together with the more competitive base load heat supply options will represent at most 50% of the initial total installed heat capacity in a country's DH system.

In order for *biofuel/heat co-generation* to be installed in the modelled DH systems the plants are required to, on average, deliver heat to the system at least 4,000 hours per year (which approximately represents the situation for base load capacities). However, once installed, it is assumed that the *biofuel/heat co-generation* plants run and produce synthetic biofuels 8,000 hours per year, with the same conversion efficiency, while the additional heat is assumed to be wasted or used for other purposes[7]. However, the case in which synthetic biofuels are only produced during the hours when the surplus heat can be delivered to the DH system will also be indicated.

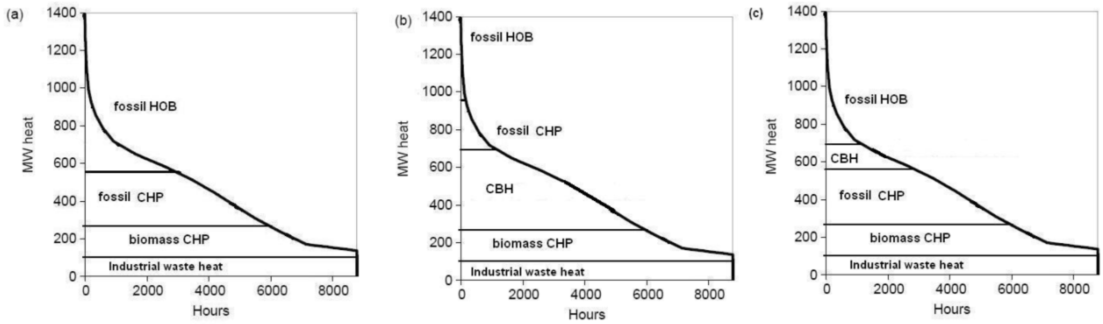

Figure 2.3.3 Heat load duration diagram of the aggregated DH systems and of the changes in heat source mix when biofuel/heat co-generation is introduced at two different positions in the merit order, representing (b) the *Before fossil CHP scenario* and (c) the *After CHP scenario*. Note that in the modelling for the *After CHP scenario*, the introduction of *biofuel/heat co-generation* will be determined in part by the minimum annual operation time of 4,000 h (see Section 2.3.3), and since the indicated location in (c) is below the minimum level it will not be introduced. The area under the graph represents the total amount of heat produced during the year.

For the 2020 renewable transportation target case, the corresponding *biofuel/heat co-generation* capacity level is found for each EU20 member state based on an iteration procedure in the Euroheatspot model that identifies the combination of installed capacity (MW) and annual operation time, i.e., load factor (hours) that corresponds to the needed amount of heat production. For the cases in which this installed capacity is lower than when *biofuel/heat co-generation* is only restricted in accordance with the scenarios, the span for the annual load factor (in the duration diagram) is shorter. It is possible that the average annual load factor for *biofuel/heat co-generation* is higher than 4,000 hours in the 2020 renewable transportation target case but lower in the case in which *biofuel/heat co-generation* is introduced with fewer restrictions. In this case *biofuel/heat co-generation* will be introduced in the 2020 renewable transportation target case but not in the other case.

The amount of fossil fuels replaced by the use of *biofuel/heat co-generation* is estimated using the characteristics of the heat supply options presented in Table 2.3.4. The DH values reported represent production of DH and not the demand for DH, which is obtained by taking the distribution losses in the DH systems into consideration.

[7] Instead of being wasted the surplus heat could be used for drying the biomass used in the plant or be used for pellet production or ethanol production if pellets/ethanol plants are located nearby.

Biofuel/heat co-generation

The plant configuration for *biofuel/heat co-generation* is defined so as to represent a case where the production of biofuels for transportation is maximized. The conversion efficiencies from biomass to synthetic biofuels and heat for the *biofuel/heat co-generation* process are in this study set to 50% and 10%, respectively (on an energy basis, based on Göransson, 2008; Thunman et al., 2008; Ecotraffic/Nykomb Synergetics, 1997) and represent the relation of 5:1 for biofuels versus heat production per unit. This means that one energy unit of biomass is converted to 0.5 energy units of biofuel for transport and 0.1 energy units of surplus heat suitable for district heating. Thus, 0.4 energy units are lost in the *biofuel/heat co-generation* plant. In reality, the amount of surplus heat varies depending on feedstock characteristics and process configuration. If the biomass fuel has relatively high moisture content, there is a heat demand for drying it which reduces the amount of surplus heat possible to use in a DH system[8]. We assume that drying of the feedstock is taken into consideration or is not necessary (see e.g., Larson et al., 2005). The impact of having higher conversion efficiency is assessed in the sensitivity analysis (Section 3.2.4). The possibility of using part of the heat for electricity production is not taken into consideration. This since the focus here is to maximize production of biofuels for transportation and electricity production would decrease the conversion efficiency for biomass to synthetic biofuels.

2.3.4 Potential DH Expansion to 2020 – in total and for industrial waste heat and waste incineration

The possible national expansion of DH depends on many factors such as size, type, and location of the heat demand and the current market share for DH. Werner (2006) developed an expansion scenario for DH systems in Europe (EU27 plus Croatia, Turkey, Iceland, Norway, and Switzerland) up to 2020 that corresponds to a doubling of the present total DH deliveries in the specified region in total. The expansion of DH is assumed to likely target substitution of fossil fuels used for heat in urban industrial, residential, and service sectors. Werner (2006) defines the national DH expansion potential as proportional to the national non-DH use of fossil fuels for heat, (given in IEA, 2005) which DH can substitute.

Werner (2006) assumes that only 30% of the industrial heat demand from fossil fuels can be replaced by DH due to discriminating industrial temperature demands. The share of the remaining fossil fuel use for heating (in all sectors) for which DH can substitute is estimated at the country level and used to represent the total expansion possibility (see footnotes in Table 2.3.3 and Werner (2006) for further information). Finally, in order to obtain a doubling of the total DH deliveries in the assessed region, Werner (2006) assumes that about 30% of the estimated total national DH expansion potential can be realized by 2020. The obtained DH expansion scenario for year 2020 in the EU20 member states is presented in Tables 2.3.3 and 2.3.6. In this scenario, Germany, the UK, France, Poland, and the Netherlands have the largest estimated DH expansion in absolute terms.

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[8] The biomass gasification process also needs electricity which could be produced internally. In order to become self-sufficient with respect to electricity, the biomass input would need to increase which means that the total amount of biomass used per unit biofuel output would increase (Ecotraffic/Nycomb, 1999, Thunman et al., 2008).

Industrial waste heat

Since Sweden at present is the largest user of industrial waste heat for DH in the EU, the Swedish industry has been chosen as reference for the rough estimate of the future potential amount of DH from industrial waste heat in the EU countries. According to Werner (2006), about 20% of the DH deliveries in Sweden consist of industrial waste heat. Table 2.3.5 presents an estimate of theoretical heat recovery factors for the Swedish case, expressed as share of the fuel input for energy purposes (in primary energy terms) to the industry that in the end can be (or is) used for DH. To obtain an estimate of the potential national supply of DH from industrial waste heat, the Swedish heat recovery factors were combined with data on fuel input to the industries in 2005 reported by IEA (2008).

The result is presented in Table 2.3.6, including both the estimated total potential national supply of DH from industrial waste heat and the potential with the present supply subtracted. It should be noted that a substantial share of this potential is already used in Sweden (about 70-80% in the case of pulp and paper, petroleum refineries, and chemical industries, 50% in the food and tobacco industry, and about 25% for the included mineral and metal industries, based on Svensk fjärrvärme, 2002).

Table 2.3.5 Theoretical Swedish industrial heat recovery factors.

Industries	Theoretical heat recovery factor[1]
Food and tobacco	6.7%
Pulp and paper	3.1%
Petroleum refineries	2.8%[2]
Chemical	13.5%
Non-metallic minerals	3.9%
Basic metals	20.0%

[1] (Svensk fjärrvärme, 2002): The potential industrial waste heat is divided by the fuel input to the industries (as presented in Svensk fjärrvärme, 2002).
[2] Information missing in Svensk fjärrvärme (2002). Calculated as difference between the total industrial waste heat to DH reported in Werner (2006) and the sum of DH from waste heat from the industries reported in Svensk fjärrvärme (2002).

Waste incineration

Up to about 30-50% of total waste volumes generated are presently incinerated in some EU member states (CEWEP, 2008). The potential amount of heat that can be delivered to the DH systems from waste incineration in 2020 is estimated based on the following assumptions:

- 40% of all the waste generated in the EU countries in 2020 (as estimated in ETC/RWM, 2008) is incinerated
- the waste incineration takes place in CHP plants with an average heat conversion efficiency at 70% and all the derived heat is used for DH
- the average energy content of the incinerated waste is 10 GJ/ton (Werner, 2006)

The results are presented in Table 2.3.6, including the total potential amount of heat that can be delivered to the DH systems from waste incineration in 2020 and the potential when the present use of heat from waste incineration is subtracted.

The estimates made for the potential DH supplies from waste incineration and industries are optimistic considering that 2020 is not so far away. In addition, the possibility to realize these potentials depends on many factors, including the locations of production and demand and location of the sources in relation to each other. It is beyond the scope of this project to include an analysis of how such factors influence the development of DH supply from waste incineration and industrial waste heat. Instead, the estimated potentials are used as basis for the subsequent analysis of the possibilities for *biofuel/heat co-generation*, in order to illustrate the impact of competing options (even if they may overestimate the near term size of these specific DH supply options).

When we estimate the possibilities for *biofuel/heat co-generation* based on the DH expansion scenario for 2020, we assume that waste incineration, industrial waste heat, and *biofuel/heat co-generation* together can provide as a maximum about 90% of the total expansion of DH demand, (peak load heat cannot be covered by heat from *biofuel/heat co-generation)*.

Table 2.3.6 Potential expansion of the DH systems (base load share, i.e., representing about 90% of the total potential expansion); the potential supply of industrial waste heat and heat from waste incineration in the EU20 member states, in total (in parenthesis) and when the present use of heat from waste incineration is subtracted. Included for comparison is the amount of surplus heat that would be generated from *biofuel/heat co-generation* producing synthetic biofuels corresponding to the national 2020 renewable transportation target level if produced in each member state domestically (with the characteristics specified in the text). See the text for references.

Member state	Potential *base load* DH expansion[1] (PJ, 2020)	Potential heat from waste incineration (PJ, 2020)	Potential industrial waste heat supply (PJ, 2020)	Heat from *biofuel/heat co-generation* corresponding to the 2020 renewable transportation target[7] (PJ)
A	39[2]	13 (17)	29	7.8
B	61[3]	14 (15)	109	9.7
CZ	61[4]	11 (14)	40	7.6
DK	8[5]	0 (23)	15(15.2)	5.0
EE	3[4]	3	1	0.9
FIN	9[5]	0 (8)	40	4.5
F	280[2]	103 (122)	209 (210)	48.0
D	501[2]	136 (162)	313 (317)	57.0
HU	67[4]	23	21	4.7
I	73[6]	113 (115)	228 (228.3)	44.1
LV	4[4]	4	2	1.5
LT	4[4]	3	10	1.7
L	4[2]	1	3	2.8
NL	104[2]	22 (29)	155	14.8
PL	124[4]	46	78	16.4
P	5[6]	17	27	7.2
SK	28[4]	6	23	2.1
SI	10[4]	2	5	2.1
S	10[5]	0 (21)	17 (53)	8.3
UK	234[3]	131	177	52.7
EU TOTAL	1628	646 (762)	1502 (1543)	299

[1] The potential DH expansion is based on Werner (2006). For a more detailed description of the underlying assumptions see Section 2.3.4. For a description of base load heat see Section 2.3.3.
[2] 70% of the substitutable fossil fuels today used for heating are replaced by DH
[3] 50% of the substitutable fossil fuels today used for heating are replaced by DH
[4] 100% of the substitutable fossil fuels today used for heating are replaced by DH
[5] 40% of the substitutable fossil fuels today used for heating are replaced by DH
[6] 20% of the substitutable fossil fuels today used for heating are replaced by DH

[7] Transport demand collected from EC (2008c).

2.4. Modelling the European Electricity system

2.4.1 Approach

The ELIN model (ELectrcity-INvestment model) is a techno-economic model developed for the European electricity supply system focusing on investments to meet future electricity demand. The ELIN model describes and visualises how the present electricity supply system can be transformed into the future, in terms of timing of investments for different pathways. Thus, one prime objective with the ELIN model is to describe the electricity supply system at a high level of detail in a transparent modelling framework focused on the electricity sector. This is important when assessing timing of replacements of present power plants, described in the model down to single power plant/block level.

2.4.2 Description of the ELIN model

The Elin model:

- has a time scope from the present until mid-century, i.e. up to the year 2050, with an annual time resolution.
- assesses net electricity generation.
- includes a detailed description of the present electricity supply system, as derived from the Chalmers Energy Infrastructure databases.
- calculates cost-efficient investments necessary to meet the demand for electricity under stringent CO_2 emission reductions while the present power plants are phased out.
- is regionalised down to each EU member state, allowing a regional scope of the analysis which is flexible within the European electricity supply system. Thereby, model calculations are possible for single member states as well as multiple regions up to the entire EU.

The model has been developed under the following conditions and assumptions:

- Estimates of the availability of the existing capital stock (on a plant-by-plant basis) over time are based on the current age structure of power plants and assumptions of technical lifetimes.
- Electricity generation technologies are aggregated to technology classes differentiated by fuel type and generation type (e.g. natural gas condensing/CHP/BP, wind power on-/offshore) and whether or not it is residual capacities from the existing system (from Chalmers Power Plant database) or new investments that are obtained from the model.
- New investment options are limited to presently known technologies: conventional thermal technologies, CCS (carbon capture and storage, solar PV (photo voltaics), tidal barges, wave power and geothermal power.
- Technology change is given exogenously in the form of increased efficiencies for thermal technologies and increased annual load factors for intermittent electricity generation.
- Costs included are limited to technology costs and costs arising from the applied CO_2 targets. Taxes or support schemes linked to electricity supply are not included in the modelling.

The objective of the ELIN model is to minimise the total system cost for the electricity generation system. This is done over the entire period investigated, i.e. the sum of all annual costs of generating electricity until 2050 as obtained by applying optimisation including perfect foresight. As given above, inclusion of the existing energy system – in this case the electricity generation system – is an essential feature of the model as well as part of the reason for developing the model. The existing system is taken from the Chalmers power plant database (for details on the database see Kjärstad and Johnsson, 2007). The development of the electricity supply system over time is based on phasing out existing electricity-generation capacities with respect to assumed technical lifetimes, combined with investments in new generation capacity to meet the demand projections given a number of constraints, such as emission caps. Therefore, each model run is preceded by defining a scenario, which in brief has three main parameters shaping the development of the electricity supply system.

Firstly, an annual growth rate in total electricity demand is assumed, which may vary over time. This growth rate is applied to the net electricity generation from the present system to determine the demand for each year in the period investigated. In this work the growth rates on electricity demand are taken from other work, which projects electricity demand from a macro-economic perspective. Second, an assumed CO_2 emission cap is introduced to limit emissions. Third, assumptions on technical lifetimes determine the availability of existing generation capacities over time, i.e. the phase-out pattern. In addition, a number of technology-specific parameters (e.g. thermal efficiencies) and boundary conditions are applied (e.g. national RES (renewable energy sources) potentials or national strategies on nuclear energy). Figure 2.4.1 gives a schematic description of the modelling procedure. Thus, when the development of the present system is estimated, in terms of residual capacities, the electricity generation is determined via a cost-minimising procedure yielding the net present value of the total system cost over the entire period. Consequently, the development of the present system is taken into account (1 in Figure 2.4.1) as well as policy targets (2 in Figure 2.4.1) and any shortfall in generation is covered with additional investments according to least-cost criteria (3 in Figure 2.4.1).

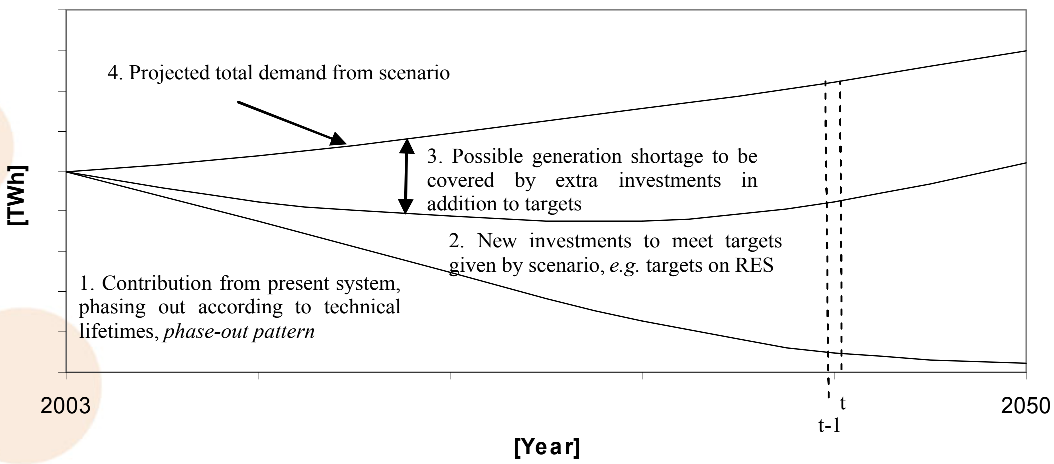


Figure 2.4.1 Schematic description of the modelling procedure applied in this work to determine a development pathway for a given set of assumptions in a scenario

While the existing capacity is described on a single block basis, investments in new capacity are made through annual capacity investments aggregated into specified technology classes, e.g. nuclear power, lignite condensing power and onshore wind power. Yet, to preserve the level of detail, as given by the detailed database (current system description) used as input to the model, the aggregated output of new investments obtained is compared with current capacities in terms of required number of sites for current and future electricity supply systems. This should give a first estimate of whether there is a need for new sites. Obviously, wind power requires new sites, whereas this is less obvious for replacements and expansion of centralised electricity generation. On the other hand, development of new sites for large power plants should be difficult in most parts of Europe.

Model Inputs and outputs

Main inputs to the model include the description of the existing electricity supply system as well as projections in electricity demand and overall economic parameters (e.g. technology costs and fuel costs). Data from the Chalmers Power Plant database is used. The Chalmers Power Plant database provides almost full coverage of European grid connected power plants with rated net capacity above 10MW. Smaller installations, e.g. individual wind turbines, are included as regionalised aggregates. Thus, power plants are represented down to block level or as regional assets where the Chalmers Power Plant database provides information on:

- Block/regional capacity, net electric power.
- Block location, member-state origin within EU or Norway, Iceland and Switzerland.
- Type of fuel (lignite, hard coal, gas oil, peat, biomass and waste, wind (onshore and offshore), hydro, hydro pump storage, nuclear, others.
- Type of technology, i.e. intermittent, condensing, CHP or industrial back pressure (BP).
- Year of commission, the year the facility went into commercial operation.
- Year of decommission, based on assumptions about technical lifetimes. The remaining technical lifetime is a key parameter which the model is especially well designed for to evaluate.

This information is included as input data to the model along with additional assumptions described in the scenario setup in each study. For this work a CO_2 emission cap common for several countries or for the entire EU27 (plus Norway) is a main input, which gives a cost to meet the cap as main output. The scenario parameters and the outputs from the model – the Pathway – are summarised in Table 2.4.1.

The main outputs from the model are:

- Generation mix for the region studied until the year 2050 (capacity and generation). In the case of multi-regional scope, the development can be obtained for each member state included as well as aggregate results for the entire region.
- Cost data, e.g. marginal electricity generation cost, system cost and marginal CO2 abatement costs for meeting the cap.
- CO_2 emissions.
- Fuel consumption.

Table 2.4.1 Inputs and outputs in the model

INPUTS ("Scenario")	OUTPUTS ("Pathway")	
Description of present system	For each scenario and each region	Technical parameters
Generation technologies & age distribution	Total net electricity generation	
Block Capacities	Electricity supply from present system	
Number of sites / generation technology	Electricity supply from new facilities	
Emission factors	New investments	
Carbon intensity / fuel type	Required new sites	
	Fuel Consumption	

Exogenous scenario parameters Regional demand projections[a] (electricity and heat from co-generation from CHP) Common CO_2 emission cap Additional targets (e.g. targets on RES) Technical lifetimes / generation technology Efficiency / generation technology (in case of CHP/BP both thermal and total efficiency) Intermittent load hour statistics or assumptions	CO_2 emissions Heat from CHP	
Discount rate Investment cost / generation technology O & M costs / generation technology Fuel costs[1] (Capital costs for present system considered as sunk costs)	Capital costs (Annuities) Fixed & Variable O&M costs Fuel costs System cost Electricity generation cost Shadow prices on electricity, CO_2 emissions and heat Costs calculated both as real and discounted values Calculations at an annual resolution for the period of interest (to the year 2050)	Economic parameters

[1] In the present research taken from other work assessing the development of the energy system from a macroeconomic perspective.

Model formulation

As presented in Figure 3.6 the model finds the optimal technology mix that satisfies the given electricity demand for any year over the modelled period, while taking into account contributions from present technologies (assumed to have sunk capital costs) and new investment options (represented by technology descriptions) under influence of competition due to technology costs and an increased cost to emit CO_2 from the cap defined by the input. All costs are modelled on an annual basis. The objective function of the model is the sum of discounted annual costs for the electricity generated during the investigated time period. The model formulation given below is inspired by the MARKAL model description given in the MARKAL handbook (Loulou et al, 2004). The objective function can therefore be written:

$$NPV(r) = \sum_{t=start}^{t=end} (1+d)^{start-t} \bullet ANNCOST(r,t) \qquad (1)$$

where:

***NPV*(*r*)** is the net present value of all costs associated with meeting electricity generation demand in the region.

ANNCOST*(*r,t*)** is the annual cost of electricity generation (including costs for CHP) in region ***r for year ***t***. Further discussed below.

d is the general discount rate.

start is the initial year for which the CEI db provides a system description (2003).

end is the final year within the analysis (usually year 2050).

The annual cost *ANNCOST*(r,t) is the sum of all costs associated with electricity generation over all fuels $\boldsymbol{f}$ and technologies $\boldsymbol{k}$, including costs for co-generated heat in CHP. This includes costs for annualised investments, fixed and variable operation, and maintenance costs. In the case of multi-regional scope, the costs are summarised and minimised for the entire system studied. The term for the annual cost is expressed as:

$$\begin{aligned} ANNCOST(r,t) = \textstyle\sum_k \{ & AnInvCost(\mathrm{r,t,k}) \bullet INV(\mathrm{r,t,k}) \\ & + FixOM(r,t,k) \bullet CAP_{el}(\mathrm{r,t,k}) \\ & + VarOM(r,t,k) \bullet GEN(\mathrm{r,t,k}) \} \\ + \textstyle\sum_f \{ & FuelCost(r,t,f) \bullet FUEL(\mathrm{r,t,f}) \} \end{aligned} \qquad (2)$$

where:

***AnInvCost*(*r,t,k*)** is the investment cost annualised to a stream of equal payments throughout the physical lifetime of the investment, which discounted to the investment year is equivalent to the actual lump sum of the investment. To include an "End of World" criterion, the summation of annualised payments is stopped at the final model year even if the physical lifetime of the investment exceeds this year, and hence, the neglected annualised payment becomes the salvage value of all assets present in the final model year.

***INV*(*r,t,k*)** is the investment in region $\boldsymbol{r}$ by technology $\boldsymbol{k}$ at year $\boldsymbol{t}$, which consists of new investments to meet policy (2 in Figure 2.4.1) and new investments to cover any shortfall in generation (3 in Figure 2.4.1), and is a variable optimised by the model.

***FixOM*(*r,t,k*)** is the fixed annual operation and maintenance costs (€/kW_{el} per year) in region $\boldsymbol{r}$ by technology $\boldsymbol{k}$ at year $\boldsymbol{t}$.
$\boldsymbol{CAP_{el}}$(*r,t,k*) is the sum of active generation capacity in region $\boldsymbol{r}$ by technology $\boldsymbol{k}$ at year $\boldsymbol{t}$. Hence, this variable consists of residual capacities at year $\boldsymbol{t}$ from the present system and new investments made within one technical lifetime prior to year $\boldsymbol{t}$ (see Equation system 3). New investments are obtained from *INV*(*r,t,k*), and consequently, *CAP*(*r,t,k*) is a variable optimised by the model.

***VarOM*(*r,t,k*)** is a variable of operation and maintenance costs (€/MWh_{el}) in region $\boldsymbol{r}$ in technology $\boldsymbol{k}$ at year $\boldsymbol{t}$.

***GEN*(*r,t,k*)** is the sum of electricity generation in region $\boldsymbol{r}$ in technology $\boldsymbol{k}$ at year $\boldsymbol{t}$ and is a variable optimised by the model by relation to *CAP*(*r,t,k*). Intermittent technologies included in *CAP*(*r,t,k*) are assumed to generate according to fixed annual average full load hours, whereas thermal power plants are subjected to variable annual load hours included as a model variable and making the model non-linear (see Equation system 3).

***FuelCost*(*r,t,k*)** is the fuel cost in region $\boldsymbol{r}$ in technology $\boldsymbol{k}$ at year $\boldsymbol{t}$.

***FUEL*(*r,t,k*)** is the total fuel consumption in region $\boldsymbol{r}$ in technology $\boldsymbol{k}$ at year $\boldsymbol{t}$ and a variable optimised by the model by relation to *GEN*(*r,t,k*), *CAP*(*r,t,k*) and assumptions on thermal efficiencies (see Equation system 3).

The electricity generation in thermal power plants and corresponding fuel consumption are interconnected by the relation given by the thermal efficiencies in the power plants. In the model this is described as:

$$\begin{cases} GEN(r,t,k) = CAP_{el}(r,t,k) \bullet LF(r,t,k) \\ FUEL(r,t,k) = CAP_{boiler}(r,t,k) \bullet LF(r,t,k) \\ CAP_{el}(r,t,k) = \sum_{t=t-TL}^{t} INV(r,t,k) \qquad \text{for } k \in \text{thermal tech.} \\ CAP_{boiler}(r,t,k) = \sum_{t=t-TL}^{t} \frac{INV(r,t,k)}{\eta(r,t,k)} \end{cases} \tag{3}$$

where:

LF(r,t,k) is the annual load hours included as a model variable for thermal technologies. Furthermore, this variable is differentiated between existing capacities and new investments, which allow for reduced utilisation of existing low-efficiency power plants to the benefit of utilisation of new high-efficiency investments within each technology class.

η(r,t,k) is the thermal efficiency as obtained from Equation (4), i.e. time-dependent thermal efficiencies for any investment $INV(r,t,k)$.
CAP_{boiler}(r,t,k) is the thermal boiler capacity as obtained from applying thermal efficiencies $\eta(r,t,k)$ on the investments $INV(r,t,k)$.

$CAP_{el}(r,t,k)$ and $INV(r,t,k)$ are described above.

All of the above are model variables included in the optimisation, except for $\eta(r,t,k)$ given by Equation (4). Hence, the model is non-linear. By calculating electric capacities $CAP_{el}(r,t,k)$ and boiler capacities $CAP_{boiler}(r,t,k)$ from summing up investments $INV(r,t,k)$ with thermal efficiencies depending on year of installation, one captures the competition between existing (low-efficiency) power plants and new (high-efficiency) investments in a more realistic sense than assuming an average efficiency improvement applied across all capacity. Thus, including vintage in efficiency gives a competitive advantage to new technologies, i.e. the latest investments have the lowest fuel consumption and, hence, the lowest fuel costs.

Although Equations (1) and (2) and the equation system (3) give an overview of the modelling framework applied, the assumptions and boundary conditions explained below are required for a complete system description.

Since power demand is unevenly distributed throughout a year following seasonal variations, and due to the fact that calculations are on an annual basis, a simplified load curve is included to eliminate underinvestment. Thus, to capture the need of investing in capacity enough to meet peak demand, a boundary condition is included based on annual mean capacity utilisation. Statistics on historical relations between total capacity and electricity generation give a capacity utilisation factor, i.e. the capacity utilisation factor is the generation at any year divided by the installed capacity for that year. The default is to keep this factor constant over time, yielding a system with the ratio of base to peak load capacity at similar levels as in the present system.

Thermal power plants are given a thermal efficiency, which remains over the technical lifetime for each specific power plant (or new investment), based on the year of commission. Thus, as mentioned previously, the average thermal efficiency for a class of thermal power plants (e.g. coal condensing plants) will depend on the amount of power remaining from the present system, as well as on how much and when new investments take place, since new power plants generally have higher efficiency than older plants. Development of thermal efficiencies for specific thermal power plants is provided from an S-shaped exponential function derived from a least-square curve-fitting process applied to historical statistics and future projections of total thermal efficiencies for each power plant technology (Thorén, 1999; Strömberg, 2005; OECD/IEA, 2006; Thunman, 2006). The thermal efficiency for a specific plant commissioned in year *t* is given by the function:

$$X(t) = a\left(1 - e^{-b(t-c)^d}\right) \qquad (4)$$

where *a*-*d* depend on the plant technology (e.g. coal condensing power and biomass CHP). Figure 2.4.2 gives an example of such an efficiency curve. The reason for using an S-shaped exponential curve is to obtain a realistic asymptotic development approaching assumed Carnot efficiencies for thermal power plants.

As shown in Table 2.4.1, heat is accounted for when co-generated in CHP. Thus, the scenarios include assumptions on to what extent national heat demands will be covered by CHP, i.e. heat-only boilers and industrial back-pressure (BP) heat is not included in the model. The CHP heat demand is based on the current fraction of CHP in total heat supplies in the region studied, i.e. statistics and projections of future total heat supplies and assumptions about future development of fractions of CHP. Furthermore, assumptions about total efficiencies are included for CHP technologies, which provide a relation between electricity and heat generation in such facilities. The resulting demand for CHP heat, given in the scenarios, should be fulfilled for all years which yield a shadow price on heat acting as a driver for CHP. For industrial BP applications, electrical efficiencies only reflect the part of the fuel that is used for electricity generation, and hence, the electrical efficiency is equal to total efficiencies of around 75-85% (also described by an S-shaped time-dependent function adapted to Equation (4)). This is done in order to compensate for the exclusion of co-produced steam in the model, and thus, exclusion of the fuel used for BP heat.

In all, the above-described modelling framework and scenario inputs are implemented in the General Algebraic Modelling System (GAMS), which is a high-level programming syntax suitable for mathematical programming including optimisation and solved with the aid of a non-linear programming (NLP) solver.

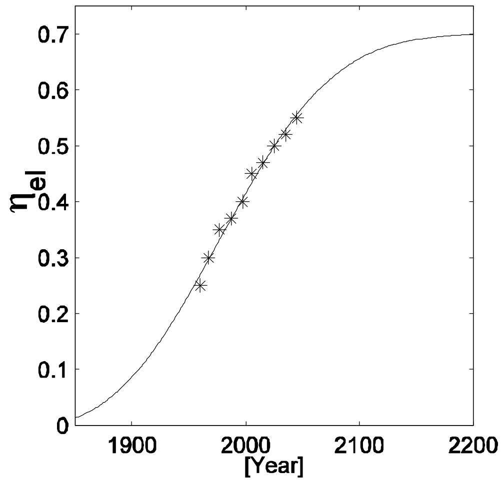


Figure 2.4.2 Example of total thermal efficiency for coal-burning power plants as applied in the model. Historical statistical and projected values are marked as asterisks, and the line represents the function according to Equation (4).

2.5. Additional modelling to investigate food secor impacts of high biomass paying capacity in the stationary energy sector

The modelling to investigate food sector impacts of high biomass paying capacity in the stationary sector is done based on combining calculations of biomass paying capacity in the stationary energy sector with calculations of production cost relations for lignocellulosic crops and cereals.

The estimates of biomass paying capacity in the stationary sector is here based on (Axelsson and Harvey 2009) that developed and used a tool (see Figure 2.5.1) for constructing eight energy scenarios covering a time period from 2010 to 2050, based on combining two levels of fossil fuel prices and four level of CO2 emissions charge. Two levels of fossil fuel prices represent different developments on the fossil fuel world market. Four levels of CO2 emission charge were chosen so as to reflect a wide spectrum of political ambitions to decrease CO2 emissions, ranging weak to strong ambition levels. The tool and the scenarios were developed for European conditions without taxes.

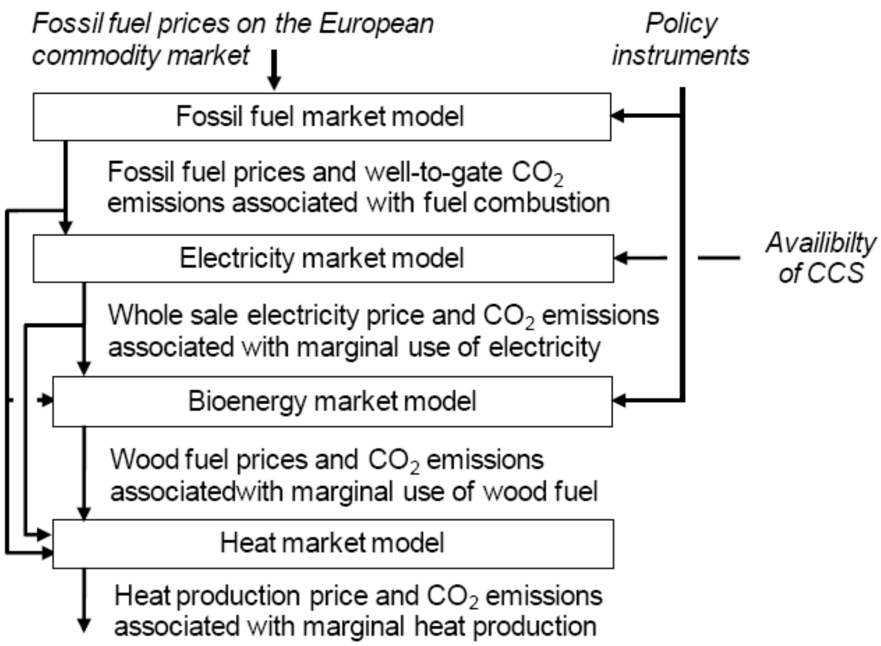


Figure 2.5.1. The calculation procedure adopted in the tool. Required inputs are given in italics and calculations are represented by boxes. It is assumed that fossil fuel prices are set on the world commodity market. These prices must then be adjusted to obtain prices for end-users. Assumptions regarding policy instruments such as the charge for emitting CO2 are set by the user. The adjusted fuel prices are then assumed to determine the market electricity price, which in turn influence price levels in the bio energy market and the heat market. CO2 emissions associated with different energy streams are also calculated and are based on well-to-gate emissions data.

Based on the inputs shown in Figure 2.5.1, the marginal technology for electricity generation can be determined by setting the technology with lowest cost of electricity production as build margin. The resulting build margin determines the electricity wholesale price together with CO2 emissions associated with marginal use of electricity and the wood fuel market price can be calculated based on the willingness to pay for a marginal wood fuel user.

The model crops used for the calculations of production cost relations for lignocellulosic crops and cereals are wheat and willow, which is used since there is experience of commercial cultivation of willow. The calculations are made without considering subsidies for farmers, land cost development, or cultivation risk perceptions among farmers, which are discussed separately.

The estimation of the willow production cost is complicated by that production takes place over a period of several years with payments and disbursements unevenly distributed over the cultivation period, and also that willow cultivation does not require the same set of resources as traditional crop cultivation. The methodology adopted for the calculations is a modified total step calculation method that was developed to make it possible to analyse the economy of willow cultivation and compare willow with other crops.

The time aspect is taken into account by combining two calculation methods: the present value method and the annuity method. One factor for each single element is multiplied by the cash flow for different payments and disbursements. This factor is based on the sum of present value factors for payments and disbursements for the total lifespan of the cultivation multiplied by the annuity factor for the interest rate and the number of years assumed for the cultivation (See the equation below). If the revenues are included, the equation describes the annual gross margin of growing the crop.). The method is based on a traditional calculation of variable costs extended step by step into a calculation of total costs.

$$\text{Annual cultivation cost } = \frac{r}{1-(1+r)^{-n}} \sum_{T_{t-0}} (1+r)^{-t} \cdot A_t$$

n=length of the calculation period (lifespan) in years
r=discount rate (6%)
t= time (year) at which a disbursement (or revenue) is made (or received)
T=time period during which the disbursements (or revenues) are made (or received)
At=size of payment

Based on the modified total step calculation method, the present and prospective future willow production costs are estimated based on a comprehensive assessment of possible developments for all main cost components: establishment (mechanical treatment of the soil and costs for planting, including costs for cuttings), fertilization, harvest, field transports, road transports, brokerage, weed control, administration, overhead costs, and the costs for winding up the field when terminating the cultivation. Several types of costs, such as machinery and labour costs, are included in the different cost components.

The assessment of how the cost components changes due to learning and increasing scales in production is based on the knowledge and technology existing today. Comparisons of willow production with the present production of well-established conventional food crops, such as sugar beet and cereals, provide a basis for defining the future performance of willow production. The evaluation of the specific cost parameters also uses insights from interviews and discussions with relevant companies, entrepreneurs, farmers and willow users. Both specific changes in the willow production system (such as modification of machines leading to improved economic performance) and system level effects of expanded production and learning (such as that machines are used more efficiently in a situation where there are shorter distances between willow fields) are considered.

The estimated cost reductions due to expanded cultivation reflect what would be obtained from using present technologies and cultivation practice on a substantially larger scale. With a large cultivation area, costs for special machinery such as a harvester dedicated to willow is estimated to decrease to a cost level which is similar to that of other machines in traditional agriculture. Therefore, the machinery cost reductions can be estimated based on comparing costs for special machinery that are used for new energy crops and machinery used today in production of conventional crops.

Large scale production will make room for several machine manufacturers, which will compete with each other. This will stimulate incremental improvements of machinery as well as innovation. However, such effects are allocated to learning in this assessment.

It is the cost reduction obtained in addition to the general trend that is estimated: the development in agriculture in general, leading to efficiency improvements and cost reductions, is not considered. For the calculations, the following assumptions are made regarding the willow production and supply:

- 30 km road transport to an energy plant is included,
- willow is chipped at harvest,
- no storage of wood chips is included,
- the discount rate is set to 6 percent.
- price level 2006, which is the most recent year where the recorded price-cost relations are judged to reflect a resonably stable situation

The economic calculations are given in € assuming that 1 € = 9 SEK.

The connection between wheat and willow goes via the land cost. The land cost will in this calculation be calculated based on the paying capacity for biomass on the one hand and the production cost of willow on the other hand. As paying capacity goes up – or production cost goes down – land prices go up and this leads to increasing wheat prices.

Results

3.1. Co-firing biomass with coal for electricity generation – an assessment of the national possibilities in the EU countries

3.1.1 Technical biomass co-firing potential

The technical potential demand for biomass from co-firing with coal is estimated to about 940 and 520 PJ per year in Case 1 and 2, respectively. The demand for biomass from co-firing for the different EU27 MS is presented in Figure 3.1.1. For Case 1, a comparison is also made with the national biomass production for energy in 2005 (Eurostat, 2007b). There is a substantial variation among the countries both regarding the absolute size of the technical potential biomass demand from co-firing and what regards the size in relation to the national biomass production for energy. For several countries the technical potential demand for biomass from co-firing is substantial in relation to the present biomass production for energy.

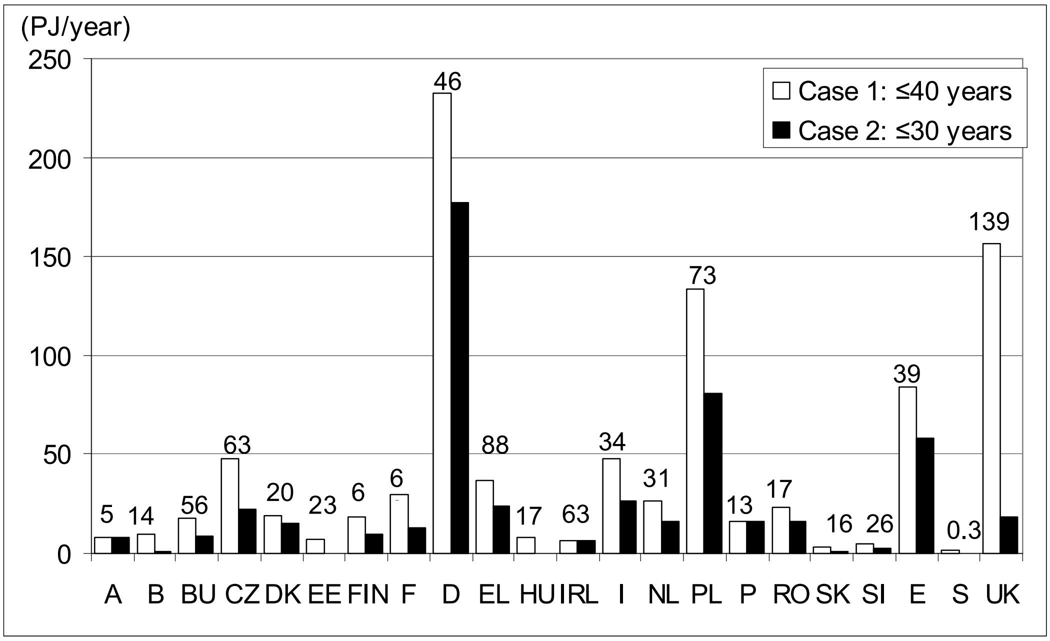


Figure 3.1.1. The technical potential demand for biomass from co-firing in the existing coal-fired power plants (in PJ of biomass). The potential for Case 1 is given as share (as percentage) of the national biomass production for energy in 2005 above the bars (Eurostat, 2007b).

3.1.2 Comparison with the national biomass demand corresponding to the biofuels for transportation targets

The estimated possible biomass demand for co-firing with coal is compared to the national biomass demand corresponding to future biofuels for transport targets, in order to investigate the possibility of biomass co-firing with coal to represent an important stepping-stone for the production of lignocellulosic crops based transportation fuels.

The targets for biofuels for transport used are 5.75% of the total transport energy demand in 2010 and 10% in 2020. The future final energy demand in the transport sector is obtained from EC (2006). To obtain the approximate amount of biomass that the biofuels for transportation targets correspond to, the conversion efficiency from biomass to biofuels at 50% is used. The share of the biomass required to reach the biofuels for transport targets, that the estimated amount of biomass from co-firing with coal represents is shown in Table 3.1.1 and illustrated for 2020 in Figure 3.1.2.

Table 3.1.1 Estimated biomass co-firing potential in PJ of biomass/year (for Case 1 and Case 2 respectively) as share of the amount of biomass required to reach the biofuels for transport targets in 2010 and 2020.

	Biomass co-firing potential as share of biomass for trp demand (%)			
	including plants <40 years		**including plants <30 years**	
Member state	**2010 target**	**2020 target**	**2010 target**	**2020 target**
Austria	21	12	21	11
Belgium	18	10	2	1
Bulgaria	106	43	53	22
Czech Republic	172	83	82	39
Denmark	77	44	60	34
Estonia	181	79	-	-
Finland	77	44	39	22
France	10	6	4	2
Germany	66	37	51	28

Greece	85	44	57	29
Hungary	38	19	-	-
Ireland	25	12	25	12
Italy	23	13	12	7
Netherlands	35	18	22	11
Poland	199	95	120	58
Portugal	45	24	45	24
Romania	71	27	49	19
Slovakia	35	19	8	4
Slovenia	72	37	34	17
Spain	42	21	29	15
Sweden	3	1	1	0.3
UK	58	32	7	4
EU27	49	26	27	15

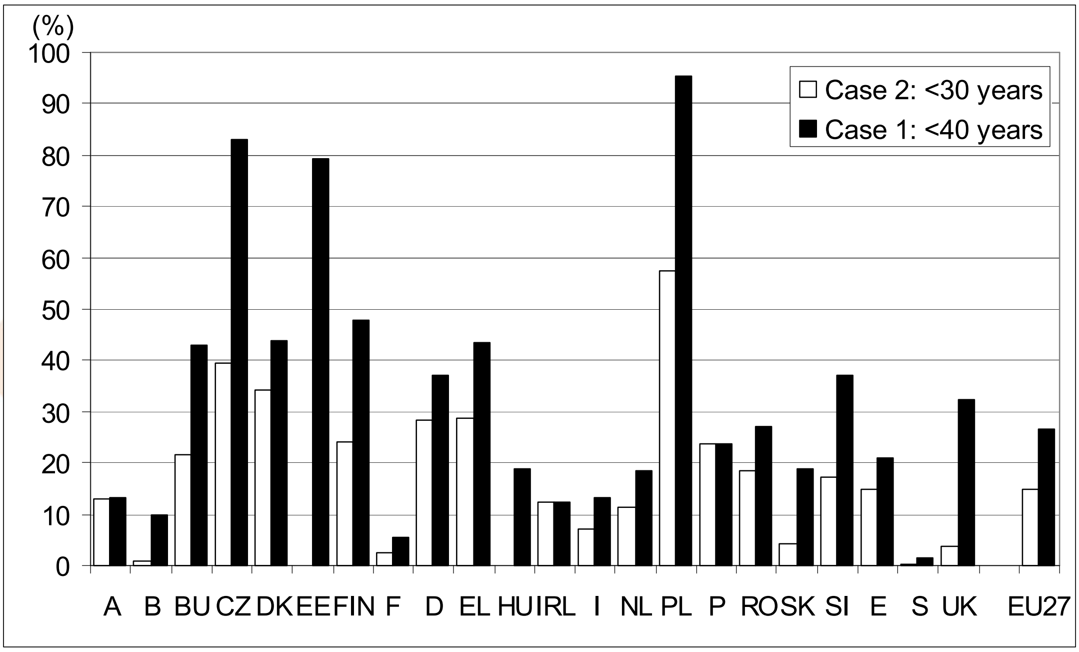


Figure 3.1.2 Estimated biomass co-firing potential in PJ of biomass/year (assuming the use of all plants in Case 1 and 2 respectively) as share of the amount of biomass required to reach a 10% biofuels for transport targets in 2020.

3.1.3 Comparison with the EU RES-E targets

In total, the technical potential for RES-E production from biomass co-firing with coal amounts to 87 and 52 TWh per year in EU27 for Case 1 and 2, respectively. The technical potential for RES-E from co-firing in Case 1 is roughly as large as the total biomass-based electricity production in EU27 in 2005 (Eurostat, 2007b).

The 2010 RES-E target for EU27 is 21% (of the gross electricity consumption) and the estimated technical potential for RES-E from co-firing corresponds to 2.4% and 1.4% of the projected gross electricity consumption in EU27 in 2010 for Case 1 and 2, respectively. The technical potential for RES-E from co-firing corresponds to roughly 10% of the RES-E required to reach the EU27 RES-E target for 2010. However, significant amounts of RES-E are already produced in several EU27 member states. In Figure 3.1.3 the technical potential for RES-E from co-firing is compared with the RES-E production in 2005 and to the gap between this RES-E production and the estimated amount of RES-E corresponding to the 2010 RES-E targets. Note that when the technical potential for RES-E from co-firing exceeds the gap it is no longer possible to identify the RES-E target level in the figure. This is the case in Germany, Denmark, and Poland for Case 2 and also the Czech Republic, Estonia, and Hungary for Case 1. For the EU27 as a whole, the technical potential for RES-E from co-firing corresponds to about 33% (Case 1) and 20% (Case 2) of the gap between the RES-E production in 2005 and the estimated amount of RES-E required to reach the 2010 target.

Since 2010 is so close in time it is unlikely that countries presently far from the target can reach it by 2010 simply by virtue of a large technical biomass co-firing potential. However, the results indicate the relative importance of this potential compared to the present use of RES-E in the EU27 member states. Countries that have an estimated technical potential for RES-E from co-firing that exceeds the gap between the 2005 RES-E production and the 2010 RES-E target might have the possibility to export part of their RES-E potential from co-firing (if realised) to other countries with limited RES-E capacity in relation to RES-E targets.

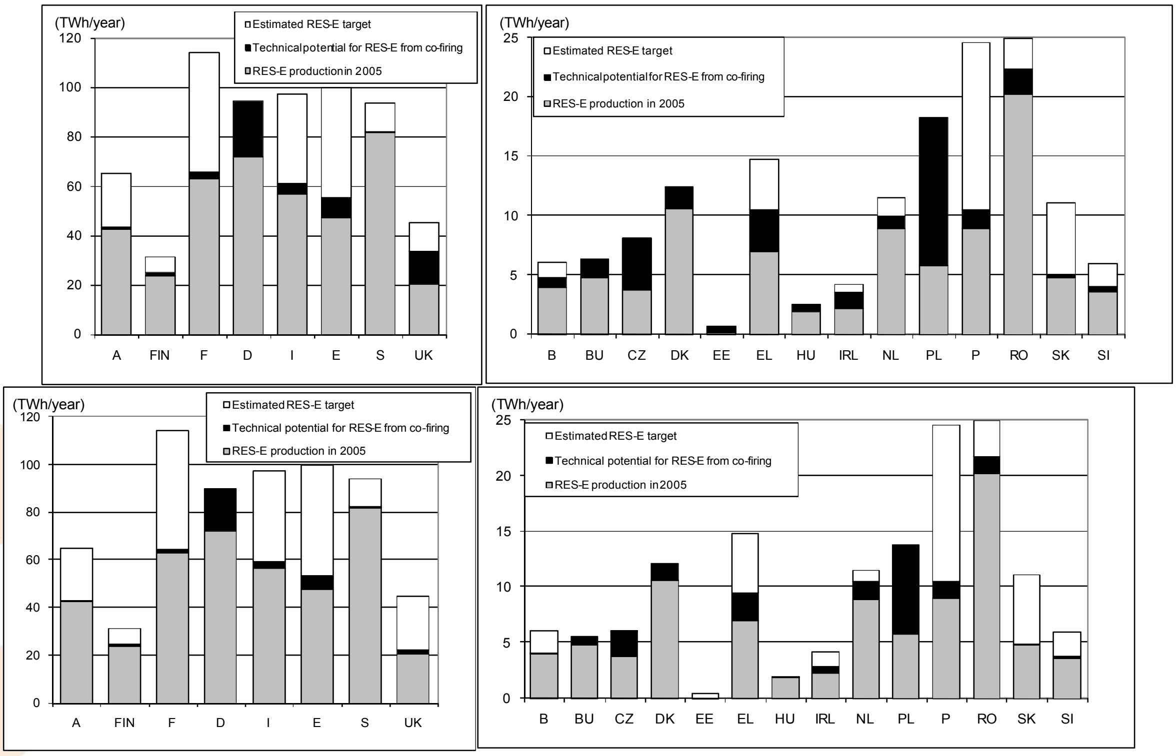


Figure 3.1.3 Comparison of the estimated technical potential for RES-E production from biomass co-firing with coal with the RES-E production in 2005 (calculated from Eurostat, 2007b) and the estimated additional amount of electricity required to reach the RES-E targets for 2010 in EU27 (EP&C, 2001; EC, 2003b; CEU, 2006; EC, 2006b). The white field represents the difference between the estimated RES-E target and the sum of the RES-E production in 2005 and the estimated potential RES-E production from co-firing. The upper figure shows Case 1 and the lower figure Case 2. For the countries where the technical potential for RES-E from co-firing exceeds the gap between the 2005 production and the 2010 targets the total technical potential is indicated (i.e., the upper level does not correspond to the RES-E target level in these cases) .

The EU aims at a 20% reduction of greenhouse gases by 2020 compared to 1990 levels (EC, 2007). The contribution from the estimated RES-E from biomass co-firing with coal (when assuming that biomass is CO_2 neutral and replaces coal with a carbon content of about 25 g C/MJ) corresponds to approximately 5 % of the required emission reduction in EU27 estimated using EC (2006c).

3.1.4 Development of co-firing over time

The technical potential for RES-E from co-firing (and the corresponding biomass demand) for the plants under construction and planning (for the period 2007-2015) are estimated using the same assumptions as for the existing power plant infrastructure. The additional RES-E from the plants under construction is about 8 TWh/year, with an additional biomass demand at almost 70 PJ/year. If also planned plants are included the corresponding values are about 30 TWh/year and 230 PJ/year. Compared to the estimated technical potential demand for biomass from co-firing in the existing infrastructure the additional potential for plants under construction is considerable in the Netherlands and Italy, as well as in Belgium for Case 2. These estimates are of course highly uncertain; only reported plans for some countries are included, new projects arise and some of the planned plants will not be built. Yet, the numbers give an indication of the current trend for coal-fired power generation, with possible implications for the future for biomass co-firing.

3.1.5 Relation to biomass supply

The estimated technical potential demand for biomass from co-firing with coal in EU27 corresponds to about 10% of the estimated biomass supply potential in EU27 for 2010 (see Figure 3.1.4, where also the different EU27 member states explicitly are included). There is a large variation between the different countries but all have an estimated biomass supply potential that is larger than the estimated technical potential biomass demand from co-firing. However, meeting the prospective biomass demand from co-firing will require a substantial increase compared to the present biomass production in many EU27 member states.

Organic waste and residue flows in agriculture and forestry represents one possible source of biomass for co-firing. In all the EU27 MS (except Romania and Bulgaria where information is missing), the national supply potential for waste in 2010 (as reported in EEA, 2006) including e.g., agricultural residues such as straw and manure as well as wood processing residues but not residues from fellings, is larger than the estimated technical potential demand for biomass from co-firing. For EU27, the technical potential demand for biomass from co-firing corresponds to about 20% and 10% of the supply potential for waste for Case 1 and 2, respectively and an even smaller percentage if also all forest sector residues are included. However, competition for these biomass resources may arise in some countries if also other uses expand e.g., conversion to biofuels for transport.

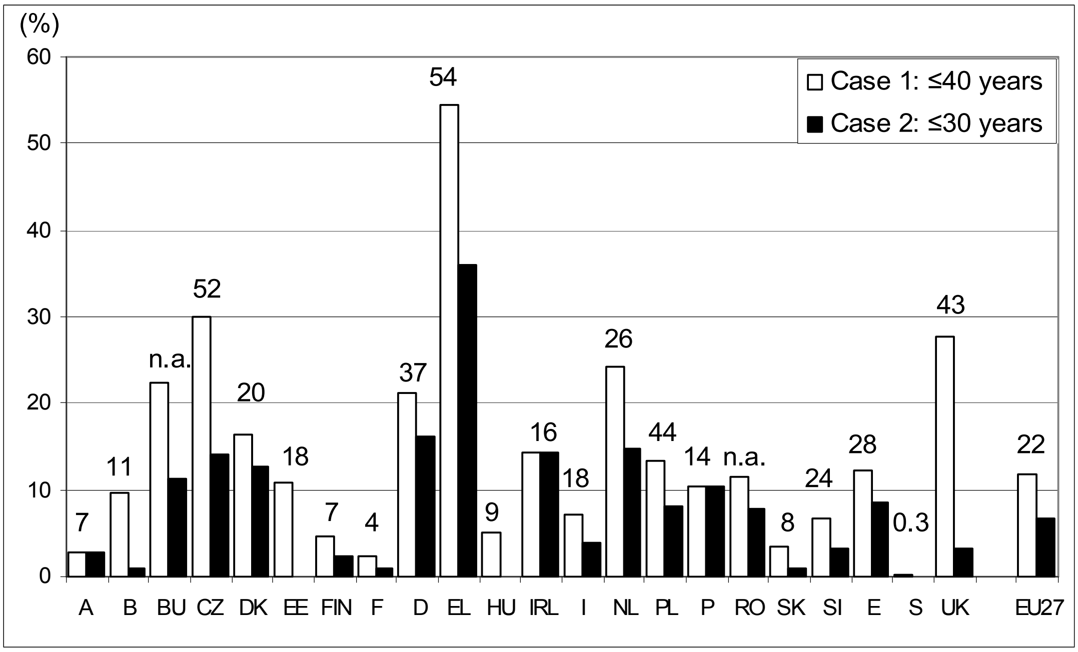


Figure 3.1.4 The estimated technical potential demand for biomass from co-firing expressed as share (as percentage) of the estimated national biomass supply potential, set based on EEA (2006) and Ericsson and Nilsson (2006). The numbers above the bars, show for Case 1, the technical potential biomass demand from co-firing expressed as share (as percentage) of the national biomass supply for waste (EEA, 2006).

3.1.5 Possibilities for biomass import by sea

The location of a power plant will influence the access to biomass and will thus influence the introduction of co-firing and is stepping stone function. Power plants close to the sea or near rivers supporting boat transport of relevant size may import biomass from long distances, increasing the access of biomass and possibly at lower costs than for domestic biomass. The locations of the coal-fired power plants included in the CPPD are indicated in Figure 3.1.5.

Figure 3.1.6 shows the share of the estimated potential biomass demand from co-firing that comes from power plants located close to the sea or near main navigable rivers, and this indicates the amount that would be possible to import by sea transport. It is found that about 20% of the total potential biomass demand from co-firing in EU27 comes from power plants which are located by the sea. About 25 % are located within a distance of 3 km from main waterways (about 15% within 1 km) and about 30 % within a distance of 10 km (for both analysed cases). Note that in Germany and Poland, with high potential biomass demand from co-firing, a relatively small share of the power plants assessed to have a co-firing capacity are located by the sea. If also the main waterways are included about 40 % for Germany and 30-35% for Poland of the estimated biomass demand for co-firing comes from plants located close to water. Countries where the major share of the coal-fired power capacity is located close to coastal areas and navigable rivers are Belgium, Denmark, Finland, Italy, the Netherlands, and Portugal (when including plants ≤40 years old), and, when assuming the use of plants ≤30 years old, also the UK, and Sweden.

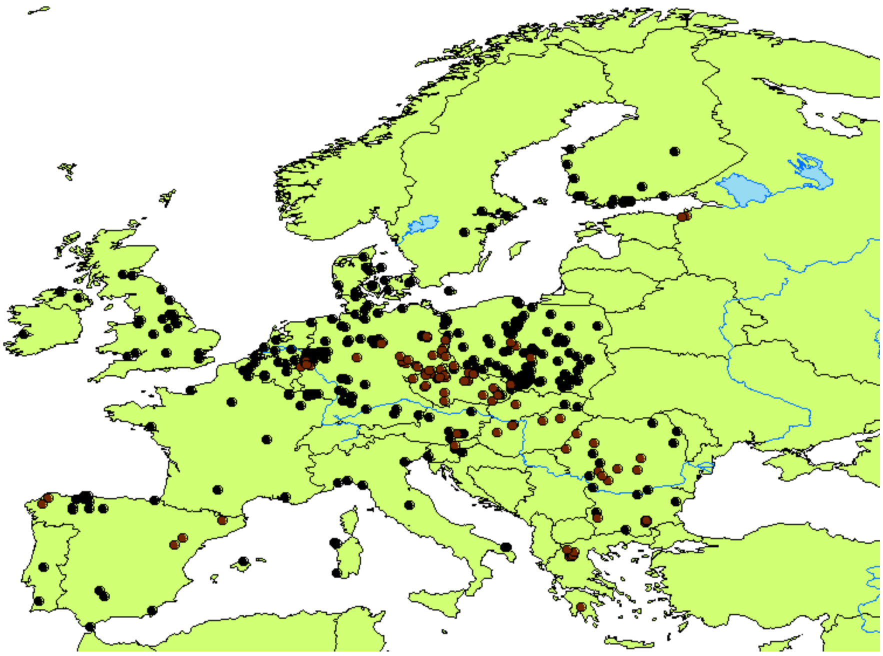
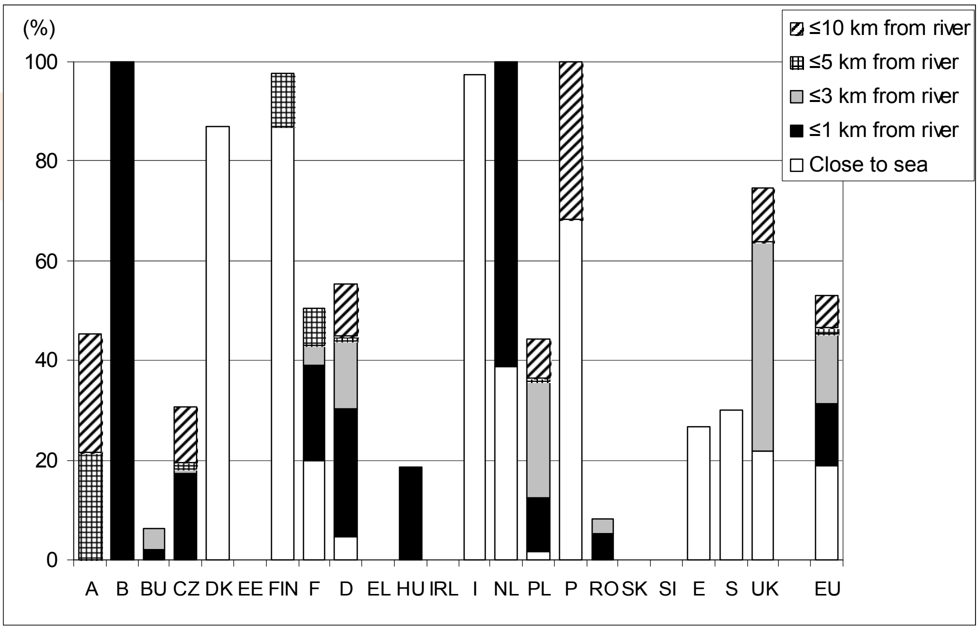


Figure 3.1.5 Location of the European (EU27) coal-fired-power plants included in the CPPD.



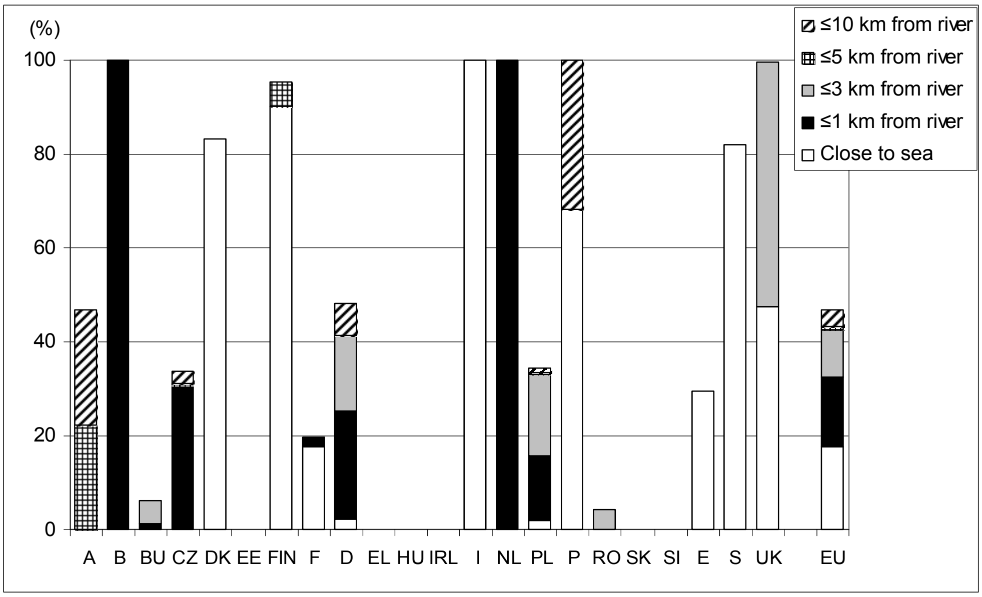


Figure 3.1.6 The share in percentage of the estimated technical potential demand for biomass from co-firing that is located by the sea and also close to navigable waterways. The upper figure shows Case 1 and the lower figure Case 2.

3.1.6 Policy option assessment

Policies specifically addressing co-firing, such as those present in the Netherlands and the UK, as well as general CO_2 emission reduction policies obviously influence the prospects for co-firing. But also other policies can be important, such as supply directed policies or policies promoting other uses of biomass leading to increased competition for the available biomass resources. The development of carbon capture and storage (CCS) will influence the longer term demand for biomass co-firing with coal. If CCS is implemented at large-scale, biomass co-firing in combination with CCS could generate negative CO_2 emissions for the biomass part of the fuel. This possibility would increase the attractiveness of co-firing.

Policies will also be crucial for the development of biomass co-firing with coal. One aspect for consideration concerns the balance between different biomass sources. As has been shown, several countries have a considerable co-firing capacity in power plants located close to the sea or near navigable rivers. Such power plants may import the biomass from countries outside the EU27 if it turns out as the cheapest option. On the other hand, policymakers may see a strategic value in promoting the use of domestic biomass resources and have the opportunity to link this to the use of biomass for co-firing. The same reasoning applies to the use of different domestic resources. Waste and residue flows have the potential to meet the total biomass demand for biomass co-firing with coal, but policymakers may want to link co-firing to the use of lignocellulosic short rotation crops (SRC) in order to stimulate the production of these crops (which are commonly proposed as important future resources but still are used to a marginal extent in the EU27).

3.2. Co-generation of biofuels for transportation and heat for district heating systems – an assessment of the national possibilities in the EU countries

3.2.1 The possibility for biofuel/heat co-generation in the existing DH systems

Table 3.2.2When comparing the existing total aggregated DH sink in the EU20 member states with the amount of surplus heat that would be generated from a synthetic biofuels production of a substantial scale one finds that the DH sink is large. For the sake of comparison only, the total heat sink is as large as the generation of surplus heat from synthetic biofuel production (production characteristics as specified in Section 2.3.3) at a scale corresponding to about 80% of the total transport energy demand in the EU20 in 2005 (EC, 2003). Thus, at the EU20 level, *biofuel/heat co-generation* cannot be disregarded as an option for production of synthetic biofuels that cover (at least part of) the 2020 renewable transportation target. This based on the notion that a substantial expansion would generate much more surplus heat than what could possibly be useful in the EU20 DH systems.

Table 3.2.1 provides a first indication of the possibilities for *biofuel/heat co-generation* in the different EU20 member states, by showing the size of the assessed heat sink segments for DH in the different scenarios. For comparison, Table 3.2.1 also includes data on the amount of surplus heat that would be generated if *biofuel/heat co-generation* (characteristics as specified in Section 2.3.3) provided biofuels corresponding to the 2020 renewable transportation target in each EU20 member state.

As can be seen in Table 3.2.1, the size of the DH heat sink is large compared to the amount of heat corresponding to the 2020 renewable transportation target in most EU20 member states for the *Before fossil CHP scenario* and the *Before natural gas CHP scenario*. Exceptions are Italy and Luxembourg whose DH heat sinks are smaller and France, Portugal, and the UK, where the DH heat sinks are larger than, but less than twice as large as, the amount of heat corresponding to the 2020 renewable transportation target. In the *After CHP scenario*, the DH heat sinks are substantially smaller than in the other scenarios for most member states. Only Finland and some of the new member states (the Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland and Slovakia) have a DH sink that is several times larger than the amount of heat corresponding to the 2020 renewable transportation target.

Table 3.2.1 The size of the heat sinks in the EU20 member states for the different scenarios. Included for comparison is the amount of surplus heat that would be generated if biofuel/heat co-generation provided domestic synthetic biofuels corresponding to the national 2020 renewable transportation target level in each member state (with the characteristics specified in the text).

Member state	Heat sink in: Before fossil CHP scenario (PJ)	Heat sink in: Before natural gas CHP scenario (PJ)	Heat sink in: After CHP scenario (PJ)	Heat from *biofuel/heat co-generation* corresponding to the 2020 renewable transportation target[1] (PJ)
A	50	36	7	7.8
B	21	21	0	9.7
CZ	142	54	34	7.6
DK	100	50	5	5.0
EE	26	17	12	0.9

FIN	137	67	29	4.5
F	84	81	81	48.0
D	360	228	0	57.0
HU	63	52	16	4.7
I	17	16	4	44.1
LV	33	28	14	1.5
LT	42	38	18	1.7
L	2	2	0	2.8
NL	107	102	0	14.8
PL	365	156	142	16.4
P	9	9	0	7.2
SK	53	41	25	2.1
SI	10	3	3	2.1
S	73	28	14	8.3
UK	73	59	5	52.7
EU TOTAL	1767	1089	412	299

[1] Calculated based on EC (2008c) and using conversion efficiencies from biomass to synthetic biofuels and heat at 50% and 10% respectively.

However, assuming, e.g., that *biofuel/heat co-generation* needs to deliver heat to the DH system a certain amount of hours of the year to be introduced, it will not be possible to use the entire heat sink presented in Table 3.2.1. If *biofuel/heat co-generation* is allowed to fill up the base load heat in the Euroheatspot model in the *Before fossil CHP scenario* with a restriction of minimum 4,000 delivering hours it could satisfy about 70-90% of the heat demand in the EU20 countries. This with the exception of Sweden, in this case there will be no *biofuel/heat co-generation* due to the already large amount of heat from e.g., biomass based CHP, waste incineration, and waste heat from industries[9]. The corresponding potential amount of synthetic biofuels would be substantial, in most countries far exceeding the 2020 renewable transportation target. In the *Before natural gas CHP scenario*, the possibility for *biofuel/heat co-generation* is also substantial. However, from a biomass supply perspective, the production at the EU level would require significant amounts of biomass. In the *Before fossil CHP scenario*, this would correspond to approximately twice the estimated total biomass supply potential in the EU20 in 2020 (see Table 3.2.3 for the biomass supply potential). Thus, in these scenarios, the heat sink capacity of the DH systems is not limiting the possibility for *biofuel/heat co-generation*. Rather, the biomass supply is the limiting factor.

When *biofuel/heat co-generation* is instead assumed to only be more cost-competitive than heat from fossil-fuel-based HOB (i.e., the *After CHP scenario*), the possibilities for *biofuel/heat co-generation* are reduced. The DH heat sink that is considered available in this scenario is located higher up in the heat load duration diagram than in the *Before fossil CHP* and *Before natural gas CHP* scenarios. Estonia and France are the only EU countries that can use the entire heat sink available in the modelling for *biofuel/heat co-generation* in this case (in both cases corresponding to a production that exceeds the 2020 renewable transportation target). The reason is that Estonia and France are the only EU countries that to a large extent

[9] There seems to be a limited possibility for countries (e.g., Sweden) with a large share of biomass-based CHP to retrofit these for full-scale CBH due to differences in demand for materials due to process differences etc. However, the biomass-based CHP plants could be complemented with systems for gasification-based biofuels for transportation production as described in Thunman et al. (2007).

use heat from fossil-fuel-based HOB as base load heat (about 50% and 75%, respectively, of the heat is covered by heat from fossil HOB, see Table 2.3.3). For most other countries, the average annual load factor for the location where *biofuel/heat co-generation* could be introduced will be below 4,000 hours in this scenario. This means that they will not be able to use the entire available heat sink for *biofuel/heat co-generation*. A certain share of the heat sink is below the level of hours for DH sale that is considered needed for *biofuel/heat co-generation* to be attractive. The amount of biofuels that could be produced in the *After CHP scenario* is indicated in the following Section.

3.2.2 Possible impact of biofuel/heat co-generation on the existing DH systems

In order to reach the 2020 renewable transportation target with synthetic biofuels from *biofuel/heat co-generation* only, (assuming the energy conversion characteristics described in Section 2.3.3) about 15% of the total heat demand in the existing aggregated DH systems in the EU20 would be needed. However, the national shares differ considerably.

Figure 3.2.1 shows the national DH systems when *biofuel/heat co-generation* required for meeting the 2020 renewable transportation target has been introduced in the *Before fossil CHP scenario*. In this case, all EU20 countries except Italy can accommodate the scale of *biofuel/heat co-generation*. For Italy, the total possible share of *biofuel/heat co-generation* production is shown instead of the amount corresponding to the biofuels target. (Italy can reach about 90% of the renewable transportation target.) Table 3.2.2 shows heat from *biofuel/heat co-generation* corresponding to the biofuels target for 2020 as national share of the existing aggregated DH systems, in all scenarios.

All countries (except Italy) could potentially meet a larger production of synthetic biofuels than necessary to cover the 2020 renewable transportation target. In Denmark, Estonia, Finland, Latvia, Lithuania, Poland, and Slovakia the heat corresponding to the biofuels targets represents less than 5% of total demand of DH and the *biofuel/heat co-generation* is located in the lower part of the bar, see Table 3.2.2 and Figure 3.2.1, implying an export possibility for biofuels for transportation if this case were realised. In Sweden the heat corresponding to the 2020 renewable transportation target represent also less than 5% of total demand but since heat from *biofuel/heat co-generation* is located in the upper part of the bar the export possibility of producing biofuels for transportation is small. In this case (the *Before fossil CHP scenario*), *biofuel/heat co-generation* produces heat slightly less than 8,000 hours per year in France, Luxembourg, Portugal, Sweden and the UK, while producing biofuels 8,000 hours per year. If biofuels are only produced simultaneously with heat for DH, Luxembourg would not be able to accommodate *biofuel/heat co-generation* corresponding to the biofuels target.

The share of the estimated biomass supply potential in 2020 that would be needed to meet the 2020 renewable transportation target at the national level is indicated in Table 3.2.3. The national biomass supply potential is here included to indicate the possibility for *biofuel/heat co-generation* from a domestic biomass supply perspective. In reality there is of course also the possibility to import biomass and biofuels and there are other competing demands for biomass.

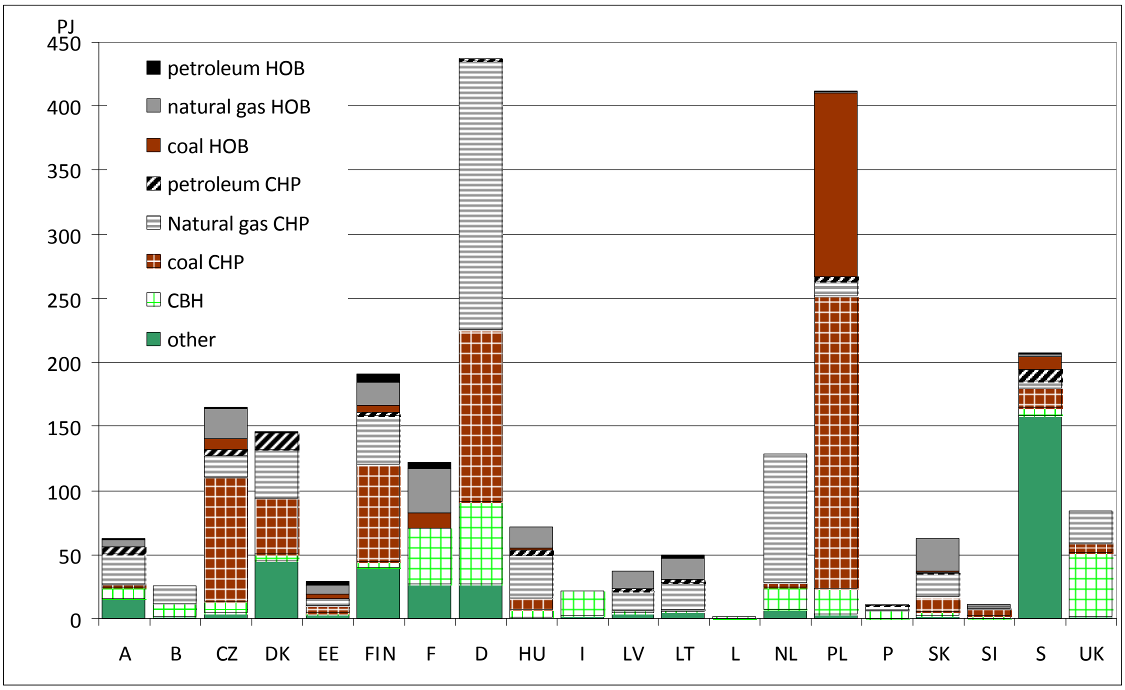


Figure 3.2.1 The national aggregated DH systems when biofuel/heat co-generation at a scale corresponding to the 2020 renewable transportation target (assuming the characteristics specified in the text) is placed ahead of electricity, renewable HOB, and all fossil options in the merit order (Before fossil CHP scenario). See assumptions described in the text. The category "other" includes industrial waste heat, waste incineration, as well as waste heat from nuclear power, biomass and geothermal and solar thermal energy.

When *biofuel/heat co-generation* required for meeting the 2020 renewable transportation target is introduced in the *Before natural gas CHP scenario,* the DH systems in Italy and Sweden cannot accommodate this scale of *biofuel/heat co-generation*. Italy can reach about 80% of the renewable transportation target, while Sweden has no possibility to produce biofuels in this case. This depends on that the annual operation time is below the required minimum level.

When the *biofuel/heat co-generation* corresponding to the biofuels targets is only assumed more competitive than fossil fuel HOB, i.e., the *After CHP scenario*, the following nine countries have the potential to produce biofuels corresponding to the target: the Czech Republic, Estonia, France, Hungary, Latvia, Lithuania, Poland, Slovakia, and Slovenia. These are the countries with the highest share of fossil-fuel-based HOB in EU. More countries produce biofuels more hours than heat in the *Before natural gas CHP scenario* and *After CHP scenario* than in the *Before fossil CHP scenario.* All countries (except Italy) produce the main part of the biofuels in co-generation with heat in all three scenarios.

Table 3.2.2 Heat from biofuel/heat co-generation corresponding to the 2020 renewable transportation target as share of national aggregated DH system (in PJ heat) in the assessed scenarios.

	Share of total DH system (%)		
Member state	**Before fossil CHP scenario**	**Before natural gas CHP scenario**	**After CHP scenario**
A	14%	11%[1]	-
B	38%	37%	-
CZ	6%	3%[1]	2%[1]
DK	4%	2%[1]	-

EE	4%	3%	2%[1]
FIN	3%	2%[1]	-
F	36%[1]	34%[1]	34%[1]
D	15%	11%[1]	-
HU	8%	7%	4%[1]
I	88%[2]	83%[2]	-
LV	5%	4%	3%[1]
LT	4%	3%	2%[1]
L	89%[1]	89%[1, 3]	-
NL	13%	11%	-
PL	5%	3%[1]	3%[1]
P	65%[1]	64%[1]	-
SK	4%	3%	2%[1]
SI	22%	11%[1]	10%[1]
S	3%[1]	-	-
UK	59%[1]	52%[1]	-
EU TOTAL	12%	9%[1]	3%[1]

[1] In these countries, *biofuel/heat co-generation* produces heat slightly less than 8,000 hours per year, while producing biofuels 8,000 hours per year. When biofuels and heat are only produced simultaneously, a larger share of the DH systems will be needed to meet the biofuels target.
[2] Italy can only produce about 80% of the biofuels target (about 40% if assuming only simultaneous production; about the same share of the DH system is needed in both cases).
[3] Assuming only simultaneous production of heat and biofuels, Luxembourg can only reach 92% of the biofuels target (90% of the DH system is needed).

Table 3.2.3 Estimates of national biomass supply potentials and the biomass demand corresponding to the 2020 renewable transportation targets in the EU20 countries.

	Biofuels for transportation and biomass supply		
	2020 renewable transportation target (PJ)[1]	**Biomass supply potential in 2020 (PJ)[2]**	**Share of biomass potential used for EU biofuels target**
A	39	327	24%
B	48	96	100%
CZ	38	188	40%
DK	25	105	48%
EE	5	92	10%
FIN	22	410	11%
F	240	1557	31%
D	285	1415	40%
HU	23	188	25%
I	220	783	56%
LV	7	80	19%
LT	8	318	5%
L	14	-	no biomass
NL	74	92	161%
PL	82	1382	12%
P	36	163	44%
SK	10	100	21%

SI	10	71	29%
S	42	544	15%
UK	264	795	66%

[1] Calculated based on EC (2008c).
[2] (EEA, 2006)

Impact on electricity production, CO_2 emissions, and oil and natural gas dependency

In the *Before fossil CHP scenario* heat from *biofuel/heat co-generation* corresponding to the 2020 renewable transportation target is assumed competitive compared to fossil-fuel-based CHP and HOB. This means that a certain share of these heat supply options in the existing DH systems will be replaced. In a systems perspective the system will gain production of synthetic biofuels but might lose electricity production from the replaced CHP plants. Assuming that the CHP plants that no longer deliver heat to the DH systems will continue to produce electricity with the same conversion efficiency as in CHP mode, only the CO_2 emissions from the replaced fossil-fuel-based HOB will be displaced. The total CO_2 emissions possible to reduce with *biofuel/heat co-generation* in this case correspond to 0.1% of the total GHG emissions in the EU20 in 1990 (EC, 2006a). If the relevant fossil-fuel-based CHP plant instead is shut down, the total CO_2 emissions possible to reduce with *biofuel/heat co-generation* corresponding to the 2020 renewable transportation target correspond to 0.6% of the total GHG emissions in the EU20 in 1990 (EC, 2006a). However, the electricity displaced will have to be replaced by either efficiency measures or other electricity production. If the electricity is replaced by other electricity production this may lead to decreased, same or even increased emissions depending on what the new technology is. But there will also in both cases be reductions in the transportation sector from the replacement of gasoline and diesel by the biofuels produced by *biofuel/heat co-generation*.

From an energy systems perspective, one unit of biomass used in biomass-based CHP can displace more CO_2 emissions than when used for *biofuel/heat co-generation*, assuming that the electricity and biofuels (both produced with a conversion efficiency of 50%) replace fossil-fuel-based electricity and gasoline, respectively. Thus, more biomass would be needed for *biofuel/heat co-generation* in order to displace the same amount of CO_2 emissions as with biomass-based CHP. The reason is that the conversion efficiency for fossil fuels to electricity is lower than the conversion efficiency for oil to petrol and that CHP is assumed to have higher total conversion efficiency than *biofuel/heat co-generation*.

In 2003 almost 10% of the total primary energy supply of natural gas in the EU20 (about 16,000 PJ) was used in DH systems (IEA, 2008 combined with the data in the Euroheatspot model). When *biofuel/heat co-generation* is introduced in the *Before fossil CHP scenario*, about 300 PJ of natural gas is replaced in the DH systems in the EU20, assuming that both CHP and HOB are shut down if replaced. This amount of natural gas corresponds to 2% of total natural gas used for primary energy supply. If only HOB are shut down, the amount of natural gas displaced corresponds to 0.3% of total primary energy supply of natural gas in EU20. The amount of natural gas replaced in the different countries varies between 0% and 3% (7% for Luxembourg and Portugal).

3.2.3 Possibility for biofuel/heat co-generation based on the potential expansion of the DH systems

The present heat demand in the EU20 is to a large extent not covered by heat connected to the DH systems and the potential for DH to grow is large in most member states. According to the expansion potential for DH by 2020 estimated by Werner, (2006) the potential for DH is large enough to accommodate surplus heat corresponding to a substantial production of synthetic biofuels (corresponding at the EU level to the total transportation demand for 2020, EC (2008c)). In all countries, except Portugal (where the expansion potential corresponds to about 5% of the total transport demand in 2020), the expansion potential for DH to 2020 is large enough to accommodate *biofuel/heat co-generation* corresponding to the 2020 renewable transportation target (see Table 2.3.6).

If the expansion potential for DH by 2020 is first covered by the estimated potentials for waste incineration and industrial waste heat, only the Czech Republic, Hungary, and Slovenia have a remaining DH expansion potential that is large enough to accommodate the heat corresponding to the 2020 renewable transportation target. In Germany the remaining DH expansion potential corresponds to 90% of its 2020 renewable transportation target. In the remaining countries waste incineration and industrial waste heat could be able to provide more heat than what would be demanded in the expanded DH systems.

3.2.4 Sensitivity analysis

Even though Knutsson et al. (2006) find that if the impact of measures on the DH sector does not have to be assessed with great precision and an aggregated systems level may be sufficient, the fact that this study is carried out on a national level instead of on an individual DH systems level of course have impacts on the results. The diversified and local character of DH systems is not captured when assessing national data instead of systems level data. Hence, the actual impact of introducing *biofuel/heat co-generation* is somewhat different than presented in this paper. First, we overestimate the possibility for *biofuel/heat co-generation* since we assume that it is possible to implement it in all individual DH systems independent of their size (an aspect analyzed in Section 3.2.5). Second, performing the analysis with information at the individual DH systems level (concerning e.g., load curve and heat supply options) would also influence the outcome to some extent. The impact of introducing a new technology, when using an aggregated description of the national DH systems, will be sensitive to the slope of the national load curve for the affected heat supply options. The impact will thus vary between countries and scenarios. For a discussion of the impact of introducing a new technology on the use of a certain heat supply option, when using an aggregated description of the national DH systems, see Knutsson et al. (2006).

Assuming a different annual load curve influences the outcome, depending on how large a difference is assumed. In countries with less constant heat demand during the year than given by the annual heat load curve used, the possibilities for *biofuel/heat co-generation* to be introduced in the existing DH system might be smaller than found in this study. In countries with a more constant heat demand during the year the opposite is true.

If it is possible to double the amount of DH from *biofuel/heat co-generation* (i.e., assuming an energy conversion efficiency from biomass to synthetic biofuels at 50% but to heat at 20% rather than 10%) the countries presented in Section 3.2.2 can produce biofuels for transportation in all scenarios (i.e., all except Sweden in the *Before natural gas CHP scenario* and the nine countries indicated in Table 3.2.2 in the *After CHP scenario*). However, larger shares of the national DH systems are in many cases covered by heat from *biofuel/heat co-generation* as can be seen in Table 3.2.4. A higher efficiency in generating heat for DH in *biofuel/heat co-generation* might be possible if, e.g., heat with lower temperatures may be used for DH in the future.

If the amount of hours required for heat delivery of DH for *biofuel/heat co-generation* plants is increased to 5,000 hours, the effect (difference from Table 3.2.2) for the *Before fossil CHP* scenario is that Italy can now reach about 70% of its renewable transportation target. The effect for the *Before natural gas CHP* scenario is that Italy and Slovenia can reach about 70% and 30% of their renewable transportation targets respectively. In the *After CHP* scenario Estonia, France, Latvia, Lithuania Poland and Slovakia can reach their renewable transportation targets. If the heat delivery time is instead decreased to 3,000 hours, the only effect is that Finland and Sweden also are able to produce enough biofuels to cover the EU biofuels target in the *After CHP* and *Before natural gas CHP* scenarios, respectively.

If *biofuel/heat co-generation* is allowed to represent at most 30% (instead of 50%) of the initial total installed heat capacity in a country (representing about 70% of total heat deliveries) there is no effect on the result. An increase of the maximum allowed installed capacity share is not tested since 50% of installed capacity already represents 90% of the total heat deliveries (with the assumed annual load curve), and in most countries it is not likely that a larger share consists of base load heat.

The merit order could also be different than assumed. For example, if the price on CO_2 emissions increases, heat from coal-based CHP might become more expensive than heat from natural-gas-based CHP causing these to change place in the merit order. If *biofuel/heat co-generation* could compete with coal-based CHP (but not natural-gas-based CHP), Belgium, Germany, Italy, Luxembourg, Netherlands, Sweden, and the UK would not be able to produce biofuels corresponding to the 2020 renewable transportation target by *biofuel/heat co-generation* and Portugal could reach about 60% of its renewable transportation target.

If the potential expansion of DH is half the amount assumed here, the DH expansion is still considerable, in most countries, compared to the national heat supply corresponding to the EU biofuels target.

Table 3.2.4 Heat from biofuel/heat co-generation corresponding to the 2020 renewable transportation target as share of existing national aggregated DH system (in PJ of heat), assuming 50% conversion efficiency for biofuels and 20% for heat.

	Share of total DH system (%)		
Member state	**Before CHP scenario**	**Before natural gas CHP scenario**	**After CHP scenario**
A	25%	25%	-
B	75%	75%	-
CZ	9%	9%	4%
DK	7%	7%	-
EE	6%	6%	6%
FIN	5%	5%	-
F	78%[1]	74%[1]	74%[1]
D	26%	26%	-

HU	13%	13%	13%
I	88%[2]	83%[2]	-
LV	8%	8%	8%
LT	7%	7%	7%
L	93%[2]	93%[2]	-
NL	23%	23%	-
PL	8%	8%	8%
P	93%[2]	93%[2]	-
SK	7%	7%	7%
SI	38%	24%[3]	14%[3]
S	8%	-	-
UK	93%[2]	80%[2]	-
EU TOTAL	22%	20%	7%

[1] France does not completely reach its 2020 renewable transportation target but could deliver almost 100% of the target.
[2] Italy, Luxembourg, Portugal and the UK do not reach their 2020 renewable transportation target but could deliver about 20%, 40%, 70% and 70% respectively of the target.
[3] Slovenia does not reach its 2020 renewable transportation target but could deliver about 60% of the target in the *Before natural gas* scenario and about 40% in the *After CHP* scenario.

3.2.5 Size of individual DH systems

Since this study is carried out on a national aggregated system level instead of an individual DH systems level the size of the actual DH systems has not been included in the analysis so far. The importance of the size of the individual DH systems depends on the size of *biofuel/heat co-generation* plants. In the literature, there are numbers for *biofuel/heat co-generation* plants from about 250 to 2,000 MW of biomass input, depending on, e.g., biofuel, time perspective, biomass availability, and assumptions on the importance of economy of scale (Hamelinck and Faaij, 2002; Tijmensen et al., 2002; Larsson et al., 2005; Ahlgren et al., 2007; Renew, 2008; Thunman et al., 2008; Vliet et al., 2009). The size distribution of the individual DH systems in Finland, France, Germany, Lithuania, and Sweden (which is where this information is available in aggregated format) is presented in Table 3.2.5. In reality, an individual DH system is not always completely connected, i.e., there may be limitations in the transfer capacity within the system. Thus, it might not be possible to replace several heat supply capacities at different locations with one *biofuel/heat co-generation* plant. However, a comparison of the size of DH production from *biofuel/heat co-generation* and the size of individual DH systems will indicate the importance of the size issue.

Table 3.2.5 The size distribution of individual DH systems in Finland, France, Germany, Lithuania, and Sweden (2001-2006) presented as the number of DH systems per size interval and share of the total DH production at each level (the latter in parenthesis). The size of the main individual DH systems in the majority of the remaining EU20 countries is also indicated.

Member state	**>0.4-0.7 PJ**	**>0.7-1.4 PJ**	**>1.4-2.2 PJ**	**>2.2-2.9 PJ**	**>2.9-3.6 PJ**	**>3.6-5.4 PJ**	**>5.4-7.2 PJ**	**>7.2-11 PJ**	**>11-14 PJ**	**>14 PJ**
FIN[1]	31 (7%)	21 (9%)	9 (7%)	3 (3%)	4 (6%)	4 (9%)	4 (11%)	5 (19%)	0 (-)	2 (22%)
F[2]	18 (24%)	7 (20%)	0 (-)	1 (7%)	0 (-)	0 (-)	0 (-)	0 (-)	0 (-)	1 (49%)
D[3]	41 (4%)	41 (8%)	22 (7%)	17 (7%)	5 (3%)	13 (9%)	6 (7%)	10 (14%)	3 (6%)	7 (31%)
LT[4]	4	1	1	2	1	0	0	1	0	0

	(9%)	(3%)	(7%)	(20%)	(13%)	(-)	(-)	(39%)	(-)	(-)
S[5]	30 (8%)	26 (14%)	7 (7%)	7 (10%)	5 (9%)	5 (12%)	2 (7%)	1 (5%)	0 (-)	2 (23%)
Largest individual DH system in other member states (PJ)[6]										
A										18 Wien
CZ										15 Prague
DK										15 Copen-hagen
EE							7 Talinn			
I						4 Torino				
HU										15 Buda-pest
LV									12 Riga	
NL								8 Rotter-dam		
PL										38 Warsaw
SI						4 Ljublijana				
SK						5 Bratislava				

[1] (Tiitinen, 2005)
[2] Based on data available via: http://www.viaseva.com/ (2001)
[3] (AGFW, 2006)
[4] Based on data available via: www.lsta.lt and http://lsta.lt/files/statistika/2005-1-apzvalga.pdf (2005)
[5] Based on data available via: www.svenskfjarrvarme.se
[6] Compilation made by Sven Werner, based mainly on annual DH reports (national or for individual DH systems). There is no information for Belgium, Luxembourg, Portugal, and the UK.

Assuming that biofuel/heat co-generation plants are cost-competitive only at 1000 MW of biomass input (corresponding to about 2.9 PJ heat) or above, about 20-30% of the DH systems in the five first countries listed in Table 3.2.5 (except France with 5%) have the corresponding heat demand (assuming a conversion efficiency of 10% from biomass to heat). Assuming that biofuel/heat co-generation plants are cost-competitive already at 500 MW of biomass input (corresponding to about 1.4 PJ heat), about 35-50% of the DH systems in the assessed countries (except France with 10%) have the corresponding heat demand. For sizes of 250 MW (corresponding to about 0.7 PJ heat), the corresponding values are 60-75% for the assessed countries (except France where the corresponding value is 35%).

The size of the main individual DH systems in each EU20 member state is also presented in Table 3.2.5. The compilation shows that the largest DH system has the potential to accommodate biofuel/heat co-generation plants of 1000 MW biomass. However, the cost-competitiveness of smaller biofuel/heat co-generation plants is of importance for large-scale implementation of biofuel/heat co-generation in the DH systems in the EU20.

3.2.6 Policy option assessment

At present, DH is not directly regulated in the EU policy framework. One explanation for this is that the district heating in Europe mainly consists of local markets and therefore falls outside the scope of the EU (Aronsson and Hellmer, 2009). However, DH is addressed in current legislation as well as in draft legislation. DH is mentioned in all energy efficiency plans and is eligible for proposed support programs. The following EU directives are relevant for district heating (based on Aronsson and Hellmer, 2009):

- The Emission Trading Scheme (ETS) based on Directive 2003/87/EC. According to the European Parliament electricity generators shall receive free allowances for district heating from 2012.
- The Buildings Directive 2002/91/EC. This directive sets minimum energy performance standards to new buildings and existing buildings being refurbished.
- The CHP Directive 2004/8/EC, which is a framework for promotion of co-generation in general.
- The Energy Services Directive 2006/32/EC, is a directive for energy end-use efficiency and energy services.

National public policy related to DH can be described in the following way (based on Aronsson and Hellmer, 2009):

- Countries with no specific district heating legislation but with some fiscal levers e.g. Sweden.
- Countries with no district heating legislation nor fiscal instruments e.g. Finland, Romania, and Germany.
- Countries with specific district heating law e.g. Denmark, Lithuania, Hungary, Estonia.

The design of policies introduced to stimulate energy system transformation will influence the prospects for *biofuel/heat co-generation*. Policies promoting DH are obviously of importance. Some of the EU countries (Austria, Denmark, Germany, Hungary, Latvia, and Sweden) have policies supporting DH (Euroheat and Power, 2007). Policies intended to promote biofuels for transport may also improve the interest for *biofuel/heat co-generation*. Other policies will directly and/or indirectly influence the prospects for *biofuel/heat co-generation*, with uncertain net effects. Policies intended to promote heat from renewable energy sources might stimulate *biofuel/heat co-generation* but will also stimulate biomass-based CHP and HOB. Similarly, policies promoting renewable electricity might stimulate *biofuel/heat co-generation* plants that also generate electricity, but they will also stimulate biomass-based CHP plants and biomass co-firing in coal-fired CHP plants.

3.3. Development of the European electricity supply – technology pathways and implications for biomass demand for heat and power

3.3.1 Results from selected modelling runs

This summary on the modelling of the development of the European electricity supply system reflects the methodological approach, i.e. starting with the development of the presently existing electricity supply system which is followed by a description of the trends in investments as obtained from the modelling. Three scenarios are presented, the BASE, EFF and the EFF-RES scenario. All three scenarios apply a cap on CO_2 emissions, i.e. CO_2

emissions are linearly reduced from current emissions (model initial year 2003) to 30% below 1990 emissions by 2020 and 85% below by 2050. The EFF scenario includes targets on energy efficiency measures, which gives 13% lower electricity demand by 2020 compared to the BASE scenario and 23% lower electricity demand by 2050. The EFF-RES scenario takes into account targets on efficiency measures as well as targets on electricity from RES, which should reach 20% of total electricity generation in 2020 and 60% in 2050. Thus, the EFF-RES scenario includes all three cornerstones of current EU energy policy for 2020 and beyond[10].

Development of the existing system

The present electricity supply system, i.e. the currently existing power plants, obviously limits the possibilities to transform the energy system. The system in place consists of a variety of technologies with respect to both power plant technology and age structure of these plants. Failing in replacement strategy or lacking a clear long-term policy during times of investment may call for costly early retirements, if a new strict policy is implemented with a shorter time-frame than the technical lifetimes of power plants.

Figure 3.3.1 provides an example of how existing capacities from the PP db are phased out between 2005 and 2050, as derived for EU-27 plus Norway given the assumptions on technical lifetimes (for detailes see Odenberger and Johnsson, 2009). Furthermore, it should be noted that the figure plots capacity and, thus, intermittent technologies (e.g. wind power) will have a less prominent representation in generation compared to base-load power plants (e.g. nuclear). Future economic lifetimes, however, may of course be different (e.g. shorter) as a result of various policies such as increased costs of emitting CO_2 or other environmental directives. Yet it is likely that in the short- to mid-term (up to 2020) there is only limited room for changing the electricity supply system.

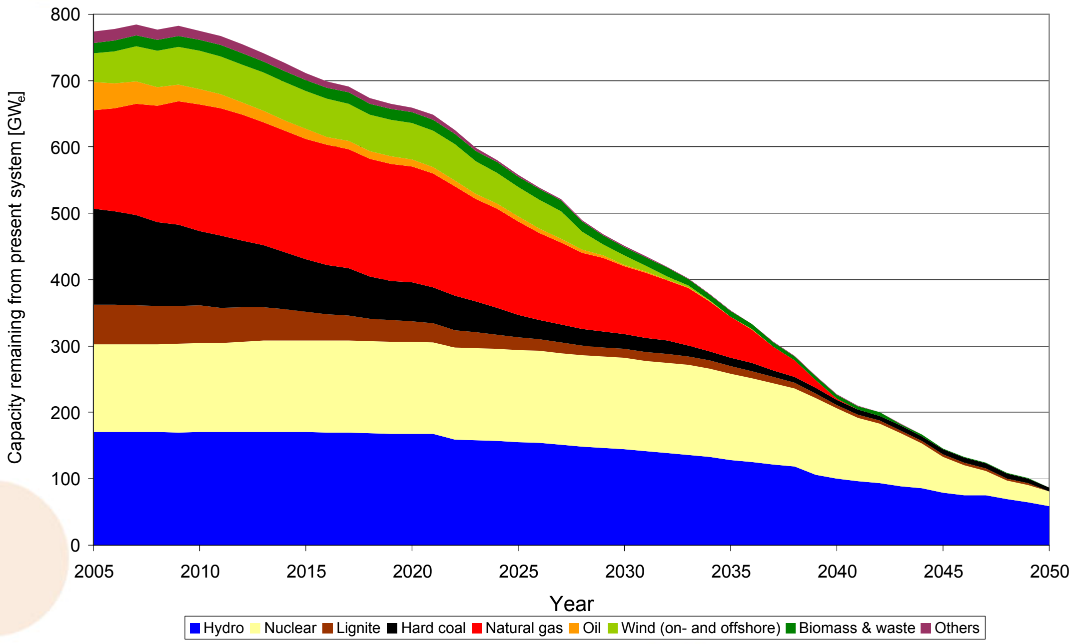


Figure 3.3.1 ***Residual capacities from the present electricity supply system for EU-27 plus Norway, as obtained from the CEI databases, with assumptions of technical lifetimes as given in Odenberger and Johnsson (2009).***

[10] EU targets on CO_2 emission reductions, efficiency measures and RES levels are not specifically given for the electricity sector. Yet, assumptions and discussions how these targets are interpreted and implemented for the electricity supply system can be found in Odenberger and Jonsson (2009).

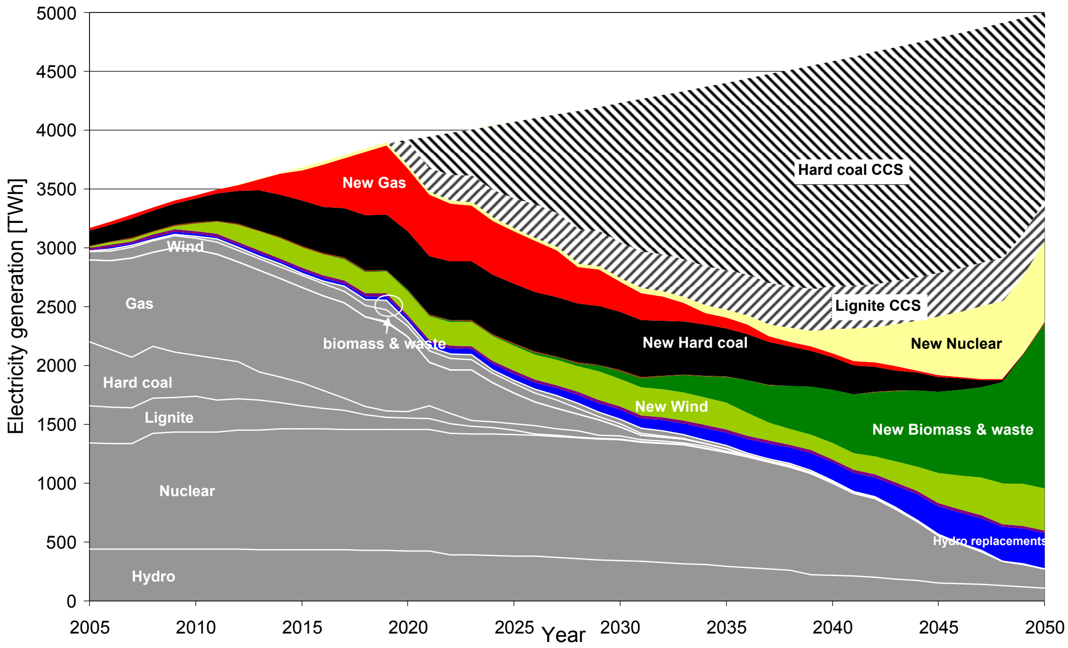


Figure 3.3.2 ***Electricity generation in EU-27 plus Norway aggregated from member state results as derived from the model in the BASE scenario (Paper IV). The grey field in the lower part of the graph represents the contribution to electricity generation from the present system, where fuel mix is indicated by white lines.***

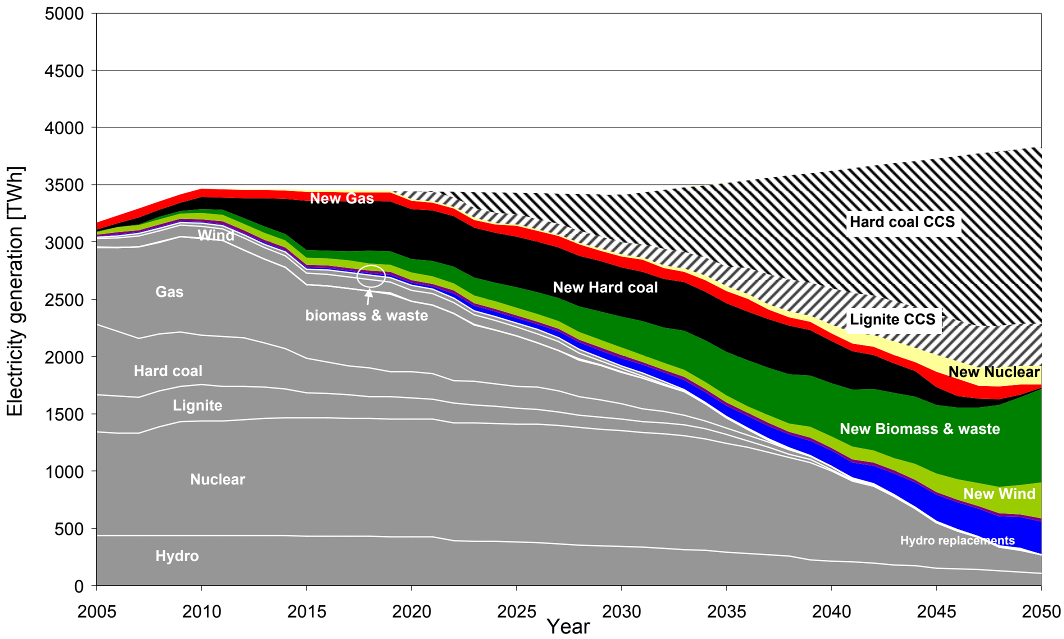
European electricity generation under stringent CO_2 emission reduction targets

Figures 3.3.2 and 3.3.3 present the development of the electricity supply system within EU-27 plus Norway corresponding to the three scenarios BASE, EFF and EFF-RES (for detailes and assumptions[11] see Odenberger and Johnsson, 2009).

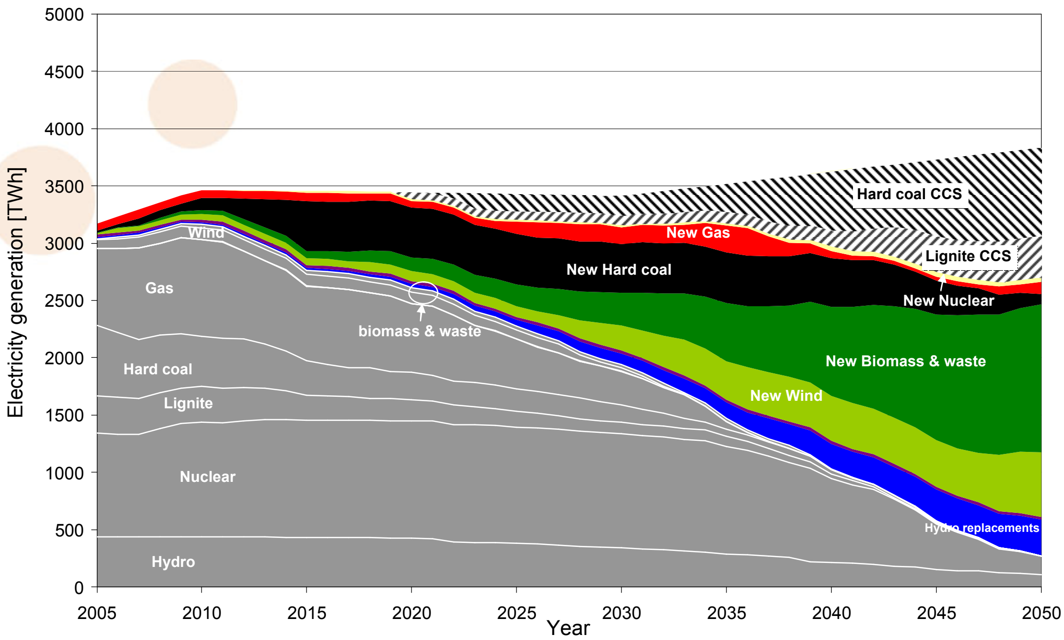
In Figures 3.3.2 and 3.3.3 the present electricity generation capacities are indicated by white lines in the lower grey field in the figure (cf. Figure 3.3.1). It can be seen that, under the assumptions made, by 2020 the present system (including investments planned for the nearest few years) accounts for about 60% of total electricity generation. This can be compared to the global estimates presented by IEA (OECD/IEA, 2008) indicating that about two thirds of the total electricity generation will originate from existing power plants in 2020. The EFF and EFF-RES scenarios are similar in this respect.

The CCS technologies in the model are in all three scenarios assumed to become commercially available from 2020, and hence, prior to 2020 a fuel shift from coal to gas is observed in the BASE scenario to meet the CO_2 emission cap. This is less prominent in the scenarios with a lower electricity demand (the CO_2 cap is the same). Part of the gas power expansions seen in the BASE scenario up to 2020 is configured as CHP, which saturates the given heat demand. However, the EFF and EFF-RES scenarios have less natural gas power (CHP), and thus employ biomass CHP at an earlier point than in the BASE scenario to meet the heat demand.

[11] The EFF and EFF-RES scenario is in the paper limited in geographical scope to the current six largest contributors of CO_2 emissions from power generation, i.e. Germany, Italy, Netherlands, Poland, Spain and the UK, whereas the model simulations presented here have a full EU geographical scope.



a.



b.

Figure 3.3.3 ***Electricity generation in EU-27 plus Norway aggregated from member state results as derived from the model from the most recent results (not included in the papers). The grey field in the lower part of the graph represents the contribution to electricity generation from the present system where fuel mix is indicated by white lines.*** *a.* ***the EFF scenario and*** *b.* ***the EFF-RES scenario.***

Employment of renewables

The RES levels obtained in the BASE and EFF scenarios are driven by climate policy alone (the implemented cap on CO_2 emissions and the subsequent cost of emitting CO_2), i.e. these scenarios do not include targets on RES levels. Still, the contribution of RES to electricity generation exceeds 20% in 2020 in both scenarios. The proportion of RES-based electricity generation relative to total generation continues to be similar over the period in the BASE and

EFF scenarios, reaching about 40% by 2050. However, in absolute numbers RES-based electricity is largest in the BASE scenario, corresponding to roughly 2200 TWh (about 450 TWh from hydro, 400 TWh from wind power and 1350 TWh from biomass) in year 2050, with the corresponding figure for the EFF scenario at 1550 TWh (about 425 TWh from hydro, 300 TWh from wind power and 825 TWh from biomass). The EFF-RES scenario includes targets on RES-based electricity generation, which require 20% of total electricity generation by 2020 and 60% by 2050 to be met by RES-E. Since cost-effective implementation lies above 20% in 2020, as seen in the BASE and EFF scenarios, the target does not become a binding condition until soon after this year. The RES-based electricity generation amounts to 2300 TWh in 2050 in the EFF-RES scenario, distributed as around 450 TWh from hydro, 550 TWh from wind power and 1300 TWh from biomass. Furthermore, under the given assumptions, the results indicate cost-efficient employment of onshore wind power, starting in member states that are expected to have the highest average annual full load hours for wind power – whereas cost-efficient employment of offshore wind power is limited to the EFF-RES scenario, which enforces RES levels resulting in a corresponding tradable green certificate price of about 20€/MWh of RES-E.

Fuel demand

Figure 3.3.4 presents the fuel consumption as obtained from the modelling of the three scenarios. It can be seen that all scenarios are heavily dependent on single sources of fuels varying over time. In the BASE scenario, natural gas serves as a bridge between the present system and the CCS system after year 2020, implying a doubling in gas consumption for power generation by 2020, which is then essentially phased out by 2040. At the same time, consumption of hard coal is almost cut by half until 2020 and then more than quadruples by 2040. Such an increase of coal consumption is roughly equivalent to the entire global trade of steam coal in 2006 (OECD/IEA 2007). Obviously, such drastic fluctuations in fuel demands will be difficult for the fuel supply chains to adapt to.

A smoother development is indicated for biomass fuels, but the levels seen in all three scenarios call for vast long-term expansions and establishment of biomass fuel supplies. European domestic resources are estimated to be about 1300 TWh of biomass fuels by 2020 (EC, 2004), which means that large-scale imports to the EU may be required if the potential for 2020 cannot be expanded further. Possibilities for less strained fuel supplies under the given assumptions would be economic incentives to expand other RES (full employment of wind power potential, solar PV, wave and tidal power) or allowing nuclear power to expand more than what is allowed in the model runs. For the latter, the long lead times and expected difficulty in establishing new sites mean that this is not an obvious solution.

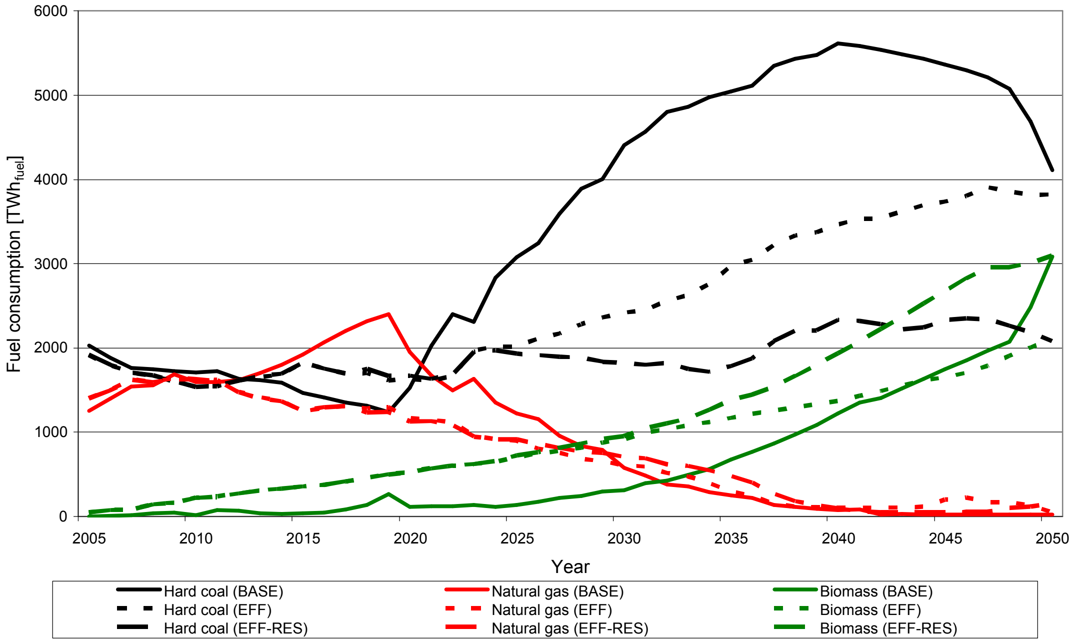


Figure 3.3.4 ***Fuel consumption of hard coal, natural gas and biomass as obtained from the modelling for the BASE, EFF and EFF-RES scenarios (for the results given in Figures 3.3.2 and 3.3.3).***

Costs for meeting targets

The costs associated with all these three scenarios are similar in terms of marginal costs of electricity. Marginal costs of electricity generation remain below 60 €/MWh over the period studied. This indicates that the price-setting technology[12] is more or less the same in the three scenarios. Thus, prior to 2020 natural gas power plants are price-setting, whereas after 2020 hard coal CCS is price-setting. The results indicate that marginal CO_2 abatement costs start at about 20€/t CO_2 in year 2005 and increase up to 40€/t CO_2 by 2020, then stabilise around 50€/t CO_2 over the last 20 years studied (2030-2050). Forecasts for the EU ETS indicate CO_2 prices of about 35€/t CO_2 by 2020 (Lewis, 2008). In addition, the EFF-RES scenario would require a support scheme to enable fulfillment of the renewable targets corresponding to a tradable green certificate price of about 20€/MWh of RES-E.

3.4. Implications for food prices of biomass demand for heat and power

Figure 3.4.1 gives an illustration of the possible impact of high paying capacity for biomass in the stationary energy sector on food prices in EU. The dashed and solid lines in the diagram show how the sellers price for biomass develops over time given certain fossil fuel prices and C taxes. The two shaded horizontal bars show – for two different cereal prices – how much a farmer needs to be paid for biomass in order to be better off economically compared to staying with cereal production.

As can be seen, for most combinations of fossil fuel price and C price development biomass becomes a very attractive option in the stationary energy sector and the paying capacity becomes rapidly very high compared to the prices farmers need in order to see better

[12] The price-setting technology is the last power plant applied and highest in cost on the order-of-merit curve.

economics for willow production than for cereal production. Note that farmers do not shift to willow just because it offers marginally higher returns than cereals. Besides that farmers in general require a risk premium for switching to less well-known crops, they can also see barriers in the form of required investments in machinery. Although, for willow that was considered in this calculations, the average producer does not invest in own machinery but rather pays an external actor for managing the field operations.

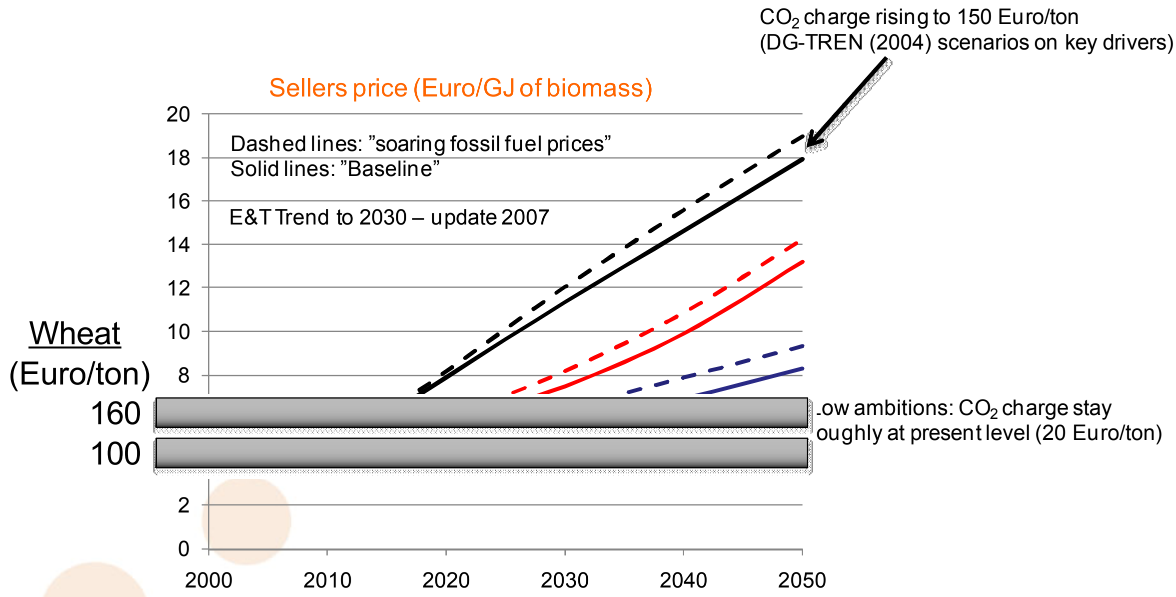


Figure 3.4.1. Illustration of the possible impact of high paying capacity for biomass in the stationary energy sector on food prices in EU. The dashed and solid lines show how the sellers price for biomass develops over time given certain fossil fuel prices and C costs. The shaded horizontal bars show how much a farmer needs to be paid for biomass in order to be better off economically compared to staying with cereal production.

Conclusions and discussion

4.1. Biomass co-firing with coal

The estimated technical biomass co-firing potential in existing coal-fired power plants in EU27 corresponds to approximately 500-900 PJ of biomass/year, with a possible RES-E generation at about 50-90 TWh/year (where the higher values assume the use of all plants ≤40 years old and the lower represent the use of plants ≤30 years old). This roughly corresponds to 10% of the estimated amount of RES-E required to meet the 2010 RES-E target in EU27 (at 21% of total gross electricity consumption). Compared to the estimated RES-E gap in EU27, i.e., the difference between the estimated RES-E target in 2010 and the RES-E production in 2005, the technical potential for RES-E from co-firing is substantial. Biomass co-firing corresponds to 20-33% of the RES-E gap in EU27 (where the higher values assume the use of plants ≤40 years old and the lower represent the use of plants ≤30 years old).

The technical potential for biomass co-firing with coal is largest in Germany, UK, and Poland when plants ≤40 years old are considered and in Germany, Poland, and Spain when plants

≤30 years old are considered. Interesting is that is several countries, the technical potential for RES-E from co-firing is larger than the estimated RES-E gap (Germany, Denmark, and Poland when including plants ≤30 years and also Czech Republic, Estonia, and Hungary when including plants ≤40 years old).

Regarding biomass demand, the technical potential demand for biomass from co-firing with coal in EU27 corresponds to roughly 10% of the estimated biomass supply potential in EU27 for 2010. On a country basis the potential biomass demand from co-firing is considerably smaller than the total biomass supply potential in 2010 in all the EU27 MS and it is also smaller than the supply potential for waste only. Note however, that for several countries the technical biomass co-firing potential is substantial compared to the present production of biomass for energy.

About 20% of the estimated biomass demand for co-firing is located by the sea and an additional 25% within a distance of 3 km to main waterways. The underlying plants might be better positioned to implement biomass co-firing since they can import biomass via sea transport. Less than 50% of the estimated biomass demand for co-firing in Poland and Germany, which have a large potential for biomass co-firing with coal, is located close to waterways. It can be noted that from a supply perspective it might be easier for primarily Italy, Finland, and, Denmark to realize a larger share of their biomass co-firing with coal potential due to the possibility to import biomass by sea.

By providing an early market for lignocellulosic short rotation crops (SRC), co-firing has the opportunity to bridge to not yet commercially available technologies using lignocellulosic biomass, such as advanced gasification based electricity production and the production of lignocellulose-based biofuels for transportation. In particular in a situation where the biomass demand for co-firing gradually decreases (due to e.g., phase-out of coal-fired power plants) these technology options can benefit from the already developed supply infrastructure and become an important subsequent use of lignocellulosic SRC and other lignocellulosic resources. Thus, when implementing the co-firing potential policy makers have the opportunity to promote a certain use of biomass.

4.2. Co-generation of biofuels and heat for district heating

The main result is that the heat sinks represented by the existing national aggregated DH systems in the EU20 in general are large compared to the amount of surplus heat that would be generated from *biofuel/heat co-generation* providing an amount of biofuels corresponding to the 2020 renewable transportation target. However, the possibilities for DH-integrated *biofuel/heat co-generation* differ considerably in the different EU member states. Besides the overall size of the DH heat sink, the possibility depends also on the cost-competitiveness of *biofuel/heat co-generation* compared to other heat supply options. Especially influential on the possibilities in many member states is the competitiveness relative to fossil-fuel-based CHP in the existing DH systems. In about half the EU20 member states (Austria, Belgium, Denmark, Finland, Germany, Italy, Luxembourg, the Netherlands, Portugal, Sweden, and, the UK), DH-integrated *biofuel/heat co-generation* would not be able to expand to provide biofuels sufficient to meet the 2020 renewable transportation target unless it replaces some fossil-fuel-based CHP or provides heat to new DH systems. The remaining countries (that have relatively large possibilities in a prospective situation with replacement of fossil-fuel-based HOB) include in particular Estonia and France but also the Czech Republic, Hungary, Latvia, Lithuania, Poland, Slovakia, and Slovenia.

When considering only the magnitude of the assessed possible expansion of the DH systems by 2020, it is clear that if *biofuel/heat co-generation* becomes a major heat source in these new DH systems, substantial biofuels for transportation quantities could be produced in the EU20. In almost all member states, the amount of surplus heat generated by using *biofuel/heat co-generation* to produce the amount of biofuels corresponding to the 2020 renewable transportation target is smaller than that corresponding to the assessed possible DH expansion. However, as with the existing DH systems, the possibility for *biofuel/heat co-generation* is determined by the competitiveness compared to other heat supply options. But will also depend on whether the DH systems will expand significantly.

The assessment of the potential increase in the use of the potentially low-cost heat options, industrial waste heat and waste incineration, in the DH systems shows that in the majority of the member states the assessed possible DH expansion is smaller than the estimated expansion potential for DH from these options. However, the expansion of DH from waste incineration and industrial waste heat may be considerably smaller than what is indicated by the estimated expansion potential. It remains to be determined what share of this waste heat that actually can be used. One advantage for *biofuel/heat co-generation* in comparison to industrial waste heat is also that *biofuel/heat co-generation* plants can be located in regions where there is a demand for DH but where there are no other waste heat options. Access to biomass may in turn limit the deployment of *biofuel/heat co-generation*.

In the most recent EU documents it is indicated that the contribution to the 10% target for renewable energy for transportation made by biofuels produced from wastes, residues, non-food cellulosic material, and lignocellulosic material shall be considered to be twice that made by other biofuels (EP, 2009). This implies that only half the amount of *biofuel/heat co-generation* used as reference in the analysis in this paper would be needed to meet the 2020 targets. This increases the possibility for the DH systems to accommodate surplus heat from *biofuel/heat co-generation*.

Large-scale implementation of *biofuel/heat co-generation* in the DH systems in the EU20 requires *biofuel/heat co-generation* plants smaller than 1000 MW (of biomass input) to be cost-competitive.

To summarise, the assessment of the co-generation potential has showed that the DH heat sink in the EU20 could accommodate *biofuel/heat co-generation* at a scale that makes this option highly relevant to EU biofuel development. Thus, the size of the national aggregated DH heat sink capacity does not limit the possibility for *biofuel/heat co-generation*. However, since there are e.g., several other options competing for the DH heat sink and that there are other production possibilities for biofuels for transportation, further analyses are needed in order to draw any conclusions about the attractiveness and development of *biofuel/heat co-generation* in the future European energy systems.

4.3. European electricity sector development

In summary, all results from the ELIN model runs imply a tremendous challenge in terms of changing the composition of the system to meet strict CO_2 emission targets.

The challenge is not due to a lack of technologies. These are available at costs which should not be prohibitive for society and which, indeed are expected from the EU-ETS. The challenge is rather due to the large investment ramp-up required and to fuel-market implications, as well as the institutional challenge (permitting procedures, establishing CCS networks and biomass markets/supplies etc.).

However, the actual penetration levels of technologies will depend on infrastructural limitations on the present capital stock, development of fuel markets and the ability of the power plant industry to supply new facilities. It is of greatest importance to put strong policy in place in order to meet targets.

Furthermore, corresponding domestic potential for biomass in the entire EU-27 plus Norway is about 1300 TWh (EC, 2004) whereas the presented scenarios (BASE, EFF and EFF-RES) has a demand for biomass higher than this potential. This implies imports of biomass fuels of about 1700 TWh, if domestic resources cannot be expanded further, corresponding to about 6% of estimated global trading potential for biomass by 2050 (Hansson et al., 2006). Hence, it is of great importance to establish policy promoting a diverse mix of technologies to meet the demand for electricity, including efficiency measures and possibly nuclear expansions.

4.4. Land use competition and food sector impacts

The stationary energy sector can become a strong competitor for the available biomass – in other words for land, water and input sources. Thus, it is not only the producers of first generation biofuels – that compete for the food commodity crops – that can cause food price increases.

The competition may even be more serious when technologies using lignocellulosic feedstocks are high in demand. In many instances these technologies are used in very large energy plants that have high capital costs and such plants can accept a higher biomass price before reducing their production since the capital cost makes up such a large part of the total production cost. Consequently, different to 1st generation technologies that can slow production or temporarily close down during periods of high crop prices; large scale plants using lignocelluosic biomass do not function as buffers against high crop prices. Also, farmers that have shifted to lignocellulosic plantations that are subject to multi-year rotations and having an ideal renewal interval at typically 20 years may be reluctant to shifting back to cultivating food crops again unless very high food crop prices become reality.

The biomass demand in the energy sector is highly dependent on the development of other energy technologies – modelling done in this WP, that focused on the implications of different development pathways for CCS, showed that whether this technology becomes successful or not can implicitly influence the food price.

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Appendix

Table A.1 (indata) Present (2003) heat (by heat supply options) delivered to the EU member states district heating systems (assuming 12% distribution losses). The category other includes heat from industrial waste heat, waste incineration, as well as waste heat from nuclear power, biomass, and geothermal and solar thermal energy. (Calculated based on Werner, 2006 and IEA, 2005).

Member state	Waste CHP (PJ)	Waste HOB (PJ)	Waste heat (PJ)	Other (PJ)	Combustible renewable CHP (PJ)	Coal CHP (PJ)	Combustible renewables HOB (PJ)	Electricity (PJ)	Natural gas CHP (PJ)	Petroleum CHP (PJ)	Coal HOB (PJ)	Natural gas HOB (PJ)	Petroleum HOB (PJ)	Total 2003 (PJ)
Austria	2,.58	1.0	-	0.43	1.03	3.42	10.81	-	21.90	6.90	0.07	6.14	1.20	55
Belgium	1.69	0.15	-	-	-	-	0.06	-	21.11	-	-	-	-	23
Cyprus	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Czech Republic	1.76	0.90	-	-	2.18	87.67	0.47	-	16.55	3.82	8.89	22.03	2.87	147
Denmark	17.31	5.57	0.06	0.13	7.02	36.88	13.13	-	38.60	6.07	0.03	3.31	1.87	130
Estonia	-	-	-	-	0.02	5.47	2.99	-	4.77	0.06	2.68	7.11	2.50	26
Finland	2.79	5.73	0.02	-	24.59	64.16	6.21	0.08	35.84	2.17	6.0	11.76	11.04	170
France	18.25	-	1.72	4.40	-	-	1.30	2.39	-	-	13.98	52.75	14.03	109
Germany	26.57	-	3.67	0.41	-	132.32	-	-	211.28	16.34	-	-	-	391
Greece	-	-	-	-	-	1.01	-	-	-	-	-	-	-	1
Hungary	0.42	-	-	0.91	0.05	10.24	0.11	-	29.58	3.09	2.20	16.80	0.58	64
Ireland	-	-	0.13	-	-	-	-	-	-	-	-	-	-	0.13
Italy	-	1.93	0.25	0.46	-	-	0.74	0.18	12.33	-	2.44	-	1.37	20
Latvia	-	-	-	-	0.26	0.35	4.51	-	13.61	0.91	0.26	11.94	1.69	34
Lithuania	-	-	-	2.23	0.40	-	3.42	0.04	18.09	1.99	0.29	14.47	3.38	44
Luxembourg	-	-	-	-	0.09	-	-	-	1.86	-	-	-	-	2
Malta	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Netherlands	7.85	-	-	-	0.22	4.83	-	-	99.73	2.34	-	-	-	115
Poland	0.79	0.10	-	-	1.85	208.86	0.92	-	10.05	3.86	126.66	10.16	4.97	368
Portugal	-	-	-	-	-	-	-	-	6.32	3.13	-	-	-	9
Slovak Republic	0.11	0.24	0.01	2.15	0.49	11.26	0.24	-	15.70	0.67	0.76	23.70	0.25	56
Slovenia	-	-	-	-	0.05	5.86	0.30	-	0.62	0.03	-	2.51	0.20	10
Spain	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Sweden	15.76	5.43	35.78	-	55.58	14.08	22.11	9.03	6.12	7.11	4.47	1.86	7.96	185
United Kingdom	-	-	-	-	2.06	13.66	-	-	54.19	-	-	-	5.31	75
EU25	96	21	42	11	96	600	67	12	618	58	169	185	59	2034

Table A.2 (share) Present (2003) share (in percentage) of heat from the different heat supply options in the EU member states (calculated based on Werner, 2006 and IEA, 2005).

Member state	Waste CHP	Waste HOB	Waste heat	Other	Combustible renewable CHP	Coal CHP	Combustible renewables HOB	Electricity	Natural gas CHP	Petroleum CHP	Coal HOB	Natural gas HOB	Petroleum HOB
Austria	5%	2%	-	1%	2%	6%	19%	-	39%	12%	-	11%	2%
Belgium	7%	1%	-	-	-	-	-	-	92%	-	-	-	-
Czech Republic	1%	1%	-	-	1%	60%	-	-	11%	3%	6%	15%	2%
Denmark	13%	4%	0.05%	-	5%	28%	10%	-	30%	5%	-	3%	1%
Estonia	-	-	-	-	-	21%	12%	-	19%	-	10%	28%	10%
Finland	2%	3%	0.01%	-	14%	38%	4%	-	21%	1%	4%	7%	6%
France	17%	-	2%	4%	-	-	1%	2%	-	-	13%	48%	13%
Germany	7%	-	1%	-	-	34%	-	-	54%	4%	-	-	-
Hungary	1%	-	-	1%	-	16%	-	-	46%	5%	3%	26%	1%
Italy	-	10%	1%	2%	-	-	4%	1%	63%	-	12%	-	7%
Latvia	-	-	-	-	1%	1%	13%	-	41%	3%	1%	36%	5%
Lithuania	-	-	-	5%	1%	-	8%	-	41%	4%	1%	33%	8%
Luxembourg	-	-	-	-	4%	-	-	-	96%	-	-	-	-
Netherlands	7%	-	-	-	-	4%	-	-	87%	2%	-	-	-
Poland	-	-	-	-	1%	57%	-	-	3%	1%	34%	3%	1%
Portugal	-	-	-	-	-	-	-	-	67%	33%	-	-	-
Slovak Republic	-	-	0.01%	4%	1%	20%	-	-	28%	1%	1%	43%	-
Slovenia	-	-	-	-	1%	61%	3%	-	6%	-	-	26%	2%
Sweden	9%	3%	19%	-	30%	8%	12%	5%	3%	4%	2%	1%	4%
United Kingdom	-	-	-	-	3%	18%	-	-	72%	-	-	-	7%
EU20	5%	1%	2%	1%	5%	30%	3%	1%	30%	3%	8%	9%	3%

Table A.3 (BF) Heat (by heat supply options) produced for the EU member states district heating systems in the *Before fossil CHP scenario*. The heat delivery from the categories Waste CHP, Waste HOB, Waste heat, Other and Combustible renewables CHP are not affected and are therefore not reported here (for their values see Table A.1).

Before CHP scenario	Biofuel/heat co-generation (PJ)	Coal CHP (PJ)	Combustible renewables HOB (PJ)	Electricity (PJ)	Natural gas CHP (PJ)	Petroleum CHP (PJ)	Coal HOB (PJ)	Natural gas HOB (PJ)	Petroleum HOB (PJ)
Austria	53.25	0.57	1.74	-	1.76	0.04	-	0.19	-
Belgium	22.34	-	0.01	-	1.77	-	-	-	-
Czech Republic	149.23	10.44	0.02	-	0.38	0.03	0.03	0.50	-
Denmark	105.26	6.76	1.50	-	1.36	0.45	-	-	-
Estonia	26.68	0.79	0.41	-	0.48	-	0.14	0.09	0.07
Finland	145.11	10.47	0.57	0.01	1.51	0.02	0.03	0.60	-
France	89.07	-	0.27	0.50	-	-	2.74	4.54	0.39
Germany	379.64	20.29	-	-	9.98	-	-	-	-
Hungary	65.52	1.52	0.02	-	3.05	0.08	0.03	0.25	-
Italy	18.05	-	0.13	0.03	1.29	-	0.07	-	-
Latvia	34.72	0.05	0.65	-	1.58	0.05	0.01	0.26	-
Lithuania	43.87	-	0.54	0.01	2.36	0.13	0.02	0.36	0.02
Luxembourg	1.95	-	-	-	0.15	-	-	-	-
Netherlands	112.65	0.77	-	-	8.14	-	-	-	-
Poland	381.57	25.37	0.05	-	0.49	0.16	2.46	-	-
Portugal	9.85	-	-	-	0.69	0.05	-	-	-
Slovak Republic	55.32	1.76	0.04	-	1.85	0.05	0.05	0.56	-
Slovenia	9.93	0.68	0.01	-	0.01	-	-	0.04	-
Sweden	-	16.29	23.71	8.90	5.76	11.07	10.99	1.75	1.60
United Kingdom	76.65	2.05	-	-	3.78	-	-	-	-
EU20 today	1781	98	30	9	46	12	17	9	2

Table A.4 (BNG) Heat (by heat supply options) produced for the EU member states district heating systems in the *Before natural gas CHP scenario*. The heat delivery from the categories Waste CHP, Waste HOB, Waste heat, Other, Combustible renewables CHP, Coal CHP, Combustible renewables HOB and Electricity are not affected and are therefore not reported here (for their values see Table A.1).

Before natural gas CHP scenario	Biofuel/heat co-generation (PJ)	Natural gas CHP (PJ)	Petroleum CHP (PJ)	Coal HOB (PJ)	Natural gas HOB (PJ)	Petroleum HOB (PJ)
Austria	37.32	3.77	0.30	-	0.23	-
Belgium	22.28	1.78	-	-	-	-
Czech Republic	-	18.58	4.05	9.02	27.21	0.51
Denmark	-	40.03	13.87	0.02	0.48	0.42
Estonia	17.72	1.04	0.01	0.41	0.42	0.09
Finland	-	39.34	2.14	5.77	19.58	6.70
France	84.83	-	-	2.95	5.09	0.40
Germany	229.22	30.27	-	-	-	-
Hungary	55.27	4.36	0.17	0.08	0.35	-
Italy	17.08	1.45	-	0.08	-	-
Latvia	30.06	2.10	0.08	0.02	0.40	-
Lithuania	40.45	2.76	0.17	0.02	0.41	0.07
Luxembourg	1.95	0.15	-	-	-	-
Netherlands	107.93	8.91	-	-	-	-
Poland	-	11.99	4.56	153.10	1.61	1.16
Portugal	9.85	0.69	0.05	-	-	-
Slovak Republic	43.14	2.95	0.09	0.10	1.17	-
Slovenia	-	0.70	0.04	-	2.90	0.03
Sweden	-	5.76	11.07	10.99	1.75	1.60
United Kingdom	62.84	5.76	-	-	-	0.07
EU20 today	760	182	37	183	62	11

Table A.5 (A) Heat (by heat supply options) produced for the EU member states district heating systems in the *After CHP scenario*. The heat delivery from the categories Waste CHP, Waste HOB, Waste heat, Other, Combustible renewables CHP, Coal CHP, Combustible renewables HOB, Electricity, Natural gas CHP and Petroleum CHP are not affected and are therefore not reported here (for their values see Table A.1).

After CHP scenario	Biofuel/heat co-generation (PJ)	Coal HOB (PJ)	Natural gas HOB (PJ)	Petroleum HOB (PJ)
Austria	-	0.07	8.29	0.19
Belgium	-	-	-	-
Czech Republic	-	9.02	27.21	0.51
Denmark	-	0.02	0.48	0.42
Estonia	11.78	0.75	1.06	0.18
Finland	-	5.77	19.58	6.70
France	84.83	2.95	5.09	0.40
Germany	-	-	-	-
Hungary	-	2.43	18.67	0.17
Italy	-	3.15	-	1.03
Latvia	-	0.31	14.54	0.50
Lithuania	-	0.34	16.39	3.30
Luxembourg	-	-	-	-
Netherlands	-	-	-	-
Poland	-	153.10	1.61	1.16
Portugal	-	-	-	-
Slovak Republic	-	0.92	26.48	0.08
Slovenia	-	-	2.90	0.03
Sweden	-	10.99	1.75	1.60
United Kingdom	-	-	-	4.14
EU20 today	97	190	144	20

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