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Optimal Localization of Biofuel Production on a European Scale

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Abstract

Second generation biofuels use non-food lignocellulosic feedstock, for example waste or forest residues, and have in general lower environmental impact than first generation biofuels. In order to reach the 2020 target of 10% renewable energy in transport it will likely be necessary to have a share of at least 3% second generation fuels in the EU fuel mix. However, second generation biofuel production plants will typically need to be very large which puts significant demand on the supply chain. This makes it necessary to carefully choose the geographic location of the production plants. A geographic explicit model for determining the optimal location of biofuel production has been developed at IIASA and has previously been used in studies on national scale. The model is based on mixed integer linear programming and minimizes the total cost of the supply chain, taking into account supply as well as demand side.

The aim of this study is to develop the localization model to cover the European Union, and to use it to analyze how for example policy instruments and energy prices affect second generation biofuel production. Two policy instruments are considered; targeted biofuel support and a CO_2 cost. Two feedstock types (forest residues and lignocellulosic waste) and three biofuel production technologies (methanol, Fischer-Tropsch diesel (FTD) and lignocellulosic ethanol) are included. For all three technologies heat for district heating is co-produced, and for FTD and ethanol electricity is also co-produced.

The results show that with current energy prices and a targeted biofuel support equivalent to existing tax exemptions, over 1.5% of the total transport fuel demand can be met by second generation biofuels to a cost of 18 €/GJ. A CO_2 cost of 100 €/t_{CO2}results in a biofuel production equivalent to 2% of the total fuel demand, but to a higher cost (23 €/GJ). Targeted biofuel support promotes FTD which has higher biofuel efficiency, while a CO_2 cost shifts the production towards ethanol due to larger co-production of electricity and high CO_2 emissions from displaced electricity. In order to reach a 3% second generation fuel share to a reasonable cost waste feedstock must be used. If only forest residues are considered the biofuel supply cost exceeds 30 €/GJ, compared to around 11 €/GJ if low cost waste can also be used. The CO_2 reduction potential is found to be strongly connected to the co-products, in particular electricity, with a high biofuel share not being a guarantee for a large decrease of CO_2 emissions.

It is concluded that in order to avoid suboptimal overall energy systems, heat and electricity applications should also be included when evaluating optimal bioenergy use. It is also concluded that while forceful policies promoting biofuels may lead to a high share of second generation biofuels to reasonable costs, this is not a certain path towards maximized reduction of CO_2 emissions. Policies aiming at promoting the use of bioenergy thus need to be carefully designed in order to avoid conflicts between different parts of the EU targets for renewable energy and CO_2 emission mitigation.

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About the Author

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Nomenclature

Abbreviations

CEPCI	Chemical Engineering plant cost index
CHP	combined heat and power
DME	dimethyl ether
FT	Fischer-Tropsch
FTD	Fischer-Tropsch diesel
G4M	Global Forest Model
HOB	heat-only-boiler
LHV	lower heating value
MILP	mixed integer linear programming
O&M	operation and maintenance

Variables

$XB_{y,m,s,f,p,n,q}$	amount of biomass of type *f* delivered from supply site *s* to production plant *p* of type *n* and capacity *q* in year *y*, season *m* ($GJ_{biomass}$)
$XB^{exp}_{y,m,r,s,f,h}$	amount of biomass of type *f* delivered from supply site *s* in region *r* to export trade point *h* in year *y*, season *m* ($GJ_{biomass}$)
$XB^{imp}_{y,m,f,p,n,q,h_d}$	amount of biomass of type *f* delivered from destination trade point h_d to production plant *p* of type *n* and capacity *q* in year *y*, season *m* ($GJ_{biomass}$)
XB^{traded}_{y,f,h,h_d}	amount of biomass of type *f* traded between regions from exporttrade point *h* to destination trade point h_d in year *y* ($GJ_{biomass}$)
$XH_{y,m,p,n,q}$	amount of heat produced in production plant *p* of type *n* and capacity *q* in year *y*, season *m* (GJ_{heat})
$XH^{excess}_{y,m,p,n,q}$	amount of excess (waste) heat produced in production plant *p* of type *n* and capacity *q* in year *y*, season *m* (GJ_{heat})
$XH^{usable}_{y,m,p,n,q,g}$	amount of heat delivered as district heating to demand area *g* from production plant *p* of type *n* and capacity *q* in year *y*, season *m* (GJ_{heat})
$X_{y,p,n,q,z,g}$	amount of biofuel of type *z* delivered from production plant *p* of type *n* and capacity *q* to demand area *g* in year *y* ($GJ_{biofuel}$)
$X^{exp}_{y,p,n,q,h}$	amount of biofuel delivered from production plant *p* of type *n* and capacity *q* to export trade point *h* in year *y* ($GJ_{biofuel}$)
$X^{fossil}_{y,g}$	amount of fossil fuel used in demand area *g* in year *y* (GJ_{fuel})
X^{imp}_{y,g,h_d}	amount of biofuel delivered from destination trade point h_d to demand area *g* in year *y* ($GJ_{biofuel}$)
$X^{power}_{y,p,n,q}$	amount of electricity delivered from production plant *p* of type *n* and capacity *q* in year *y* ($GJ_{electricity}$)
X^{traded}_{y,h,h_d}	amount of biofuel traded between regions from export trade point *h* to destination trade point h_d in year *y* ($GJ_{biofuel}$)
$UP_{y,p,n,q}$	binary variable indicating if production plant *p* of type *n* and capacity *q* is in operation in year *y* (–)

Parameters

$\bar{B}_{y,r,s,f}$	biomass supply capacity ($GJ_{biomass}$)
$\bar{B}^{plant}_{p,n,q}$	plant capacity($GJ_{biomass}$)
$\bar{B}^{traded}_{h,h_d}$	biomass trade capacity ($GJ_{biomass}$)
C	number of countries
$\tilde{C}$	set of countries
$c_{y,s,f}$	biomass production cost (€/$GJ_{biomass}$)
$c^{emissions}$	cost for emitting fossil CO_2 (€/t_{CO2})
$c^{gasstn}_{y,g}$	cost for handling and dispensing biofuels (€/$GJ_{biofuel}$)
$c^{prod}_{y,p,n,q}$	variable cost of biofuel production (€/$GJ_{biofuel}$)
$c^{setup}_{p,n,q}$	annualised plant investment cost (€/year)
d_{y,g,t,h_d}	transport distance from trade destination point to biofuel demand using transport means t (km)
$d_{y,s,p,t}$	transport distance from biomass supply site to production plant using transport means t (km)
$d_{y,s,t,h}$	transport distance from biomass supply site to export trade point using transport means t (km)
$d_{y,p,g,t}$	transport distance from production plant to biofuel demand using transport means t (km)
$d_{y,p,t,h}$	transport distance from production plant to export trade point using transport means t (km)
d_{y,p,t,h_d}	transport distance from trade destination point to production plant using transport means t (km)
d_{y,t,h,h_d}	transport distance from export trade point to trade destination point using transport means t (km)
$e_{y,f,t}$	CO_2 emission factor of biomass transportation using transport means t (t_{CO2}/$GJ_{biomass}$,km)
$e_{y,z,t}$	CO_2 emission factor of biofuel transportation using transport means t (t_{CO2}/$GJ_{biofuel}$,km)
e^{fossil}_c	CO_2 emission factor of fossil transport fuels (t_{CO2}/GJ_{fuel})
e^{heat}_c	CO_2 emission factor of displaced heat production (t_{CO2}/GJ_{heat})
e^{power}_c	CO_2 emission factor of displaced electricity production (t_{CO2}/$GJ_{electricity}$)
F	number of feedstocks
$\tilde{F}$	set of feedstocks
G	number of demand areas
$\tilde{G}$	set of demand areas
H	number of trade points
$\tilde{H}$	set of trade points

$\bar{H}^{demand}_{m,g}$	heat delivery potential (GJ_{heat})
M	number of seasons
$\tilde{M}$	set of seasons
N	number of plant types
$\tilde{N}$	set of plant types
P	number of plants
$\tilde{P}$	set of plants
Q	number of plant sizes
$\tilde{Q}$	set of plant sizes
$p^{fossil}_{y,c}$	fossil transport fuel price (€/GJ_{fuel})
$p^{heat}_{y,m,c}$	district heating price (€/GJ_{heat})
$p^{power}_{y,c}$	electricity price (€/$GJ_{electricity}$)
R	number of regions
$\tilde{R}$	set of regions
S	number of supply sites
$\tilde{S}$	set of supply sites
$s^{initial}_{p,n,q}$	initial plant status (–)
T	number of transportation means
$\tilde{T}$	set of transportation means
$t^{fix}_{y,f,t}$	fixed biomass transportation cost using transport means t (€/$GJ_{biomass}$)
$t^{var}_{y,f,t}$	variable biomass transportation cost using transport means t (€/$GJ_{biomass}$)
$t^{fix}_{y,z,t}$	fixed biofuel transportation cost using transport means t (€/$GJ_{biofuel}$)
$t^{var}_{y,z,t}$	variable biofuel transportation cost using transport means t (€/$GJ_{biofuel}$)
$\bar{X}^{demand}_{g}$	transport fuel demand (GJ_{fuel})
$\bar{X}^{traded}_{y,h,h_d}$	biofuel trade capacity ($GJ_{biofuel}$)
Y	number of years
$\tilde{Y}$	set of years
Z	number of biofuel types
$\tilde{Z}$	set of biofuel types
$\eta^{biofuel}_{p,n,z}$	biomass to biofuel conversion efficiency ($GJ_{biofuel}/GJ_{biomass}$)
$\eta^{heat}_{p,n}$	biomass to heat conversion efficiency ($GJ_{heat}/GJ_{biomass}$)
$\eta^{power}_{p,te}$	biomass to electricity conversion efficiency ($GJ_{electricity}/GJ_{biomass}$)

Subscripts

c	country
f	biomass feedstock type
g	demand area
h	export trade point
h_d	destination trade point
m	season
n	plant type
p	plant location
q	plant capacity
r	region
r_d	trade destination region
s	biomass supply site
t	transportation means
y	year
z	biofuel type

Optimal Localization of Biofuel Production on a European Scale

Elisabeth Wetterlund

1 Introduction

With the aim of mitigating CO_2 emissions, diversifying the energy supply and reducing the dependence on unreliable imported fossil fuels, the European Union (EU) has set ambitious targets for a transition to renewable energy. The integrated energy and climate change policy adopted in 2008 defines general targets of 20% greenhouse gas reduction, 20% reduced energy use through increased energy efficiency and a 20% share of renewable energy by 2020 (European Commission, 2008a). Increased production and use of bioenergy is promoted as a key to reaching the targets (European Commission, 2005), as biomass can replace fossil fuels in stationary applications, such as heat or electricity production, as well as in the transport sector. In order to explicitly stimulate a shift to renewables in transportation the European Commission has, in addition to the overall 20% renewable energy target, set a mandatory target of 10% renewable energy in transport by 2020 (Dir 2009/28/EC), with a transitional target of 5.75% for 2010 (Dir 2003/30/EC). Today the total annual energy use in road transport is approximately 12 EJ (European Commission, 2008b). Of this less than 4% consists of renewable energy (EurObserv'ER, 2010), which implies that the 2010 goal will be difficult to reach.

A number of policy instruments that directly or indirectly affect the production and use of biofuels are today in place. Targeted biofuel policies such as exemption from or reduction of transport fuel taxes, quotas and blend obligations of course have a direct effect on the competitiveness and market shares of biofuels. Policy instruments not directly targeting the transport sector, for example tradable CO_2 emission permits and policies targeting renewable electricity production, can also affect biofuel production by stimulating the demand for bioenergy with potentially increased prices as a result.

The last few years have seen increased criticism against biofuels, especially regarding first generation biofuels, i.e. biofuels that are commercially available today and that in general use agricultural feedstocks. The criticism is mainly related to issues regarding competition with food production and potential negative environmental impact from biofuel production, in particular associated with effects from land use change (Fargione et al., 2008; Searchinger et al., 2008). Second generation biofuels are advanced biofuels using lignocellulosic feedstock; for example gasification-derived fuels such as methanol, Fischer-Tropsch diesel (FTD) or dimethyl ether (DME), or lignocellulosic ethanol. In general second generation biofuels have lower specific land use requirements than first generation fuels, and since they are based on non-food feedstocks such as various types of waste and forest residues, the competition with food production is considerably lower. Although these biofuels are not yet commercially available much hope is currently placed on them. Studies show that it will likely be necessary to have a significant share of second generation fuels in the EU fuel mix, around 3% of the total transport energy demand, in order to reach the biofuel target for 2020 without substantial interference with other goals (see e.g. Al-Riffai et al., 2010; Fonseca et al., 2010).

Second generation biofuel production plants will likely need to be very large to reach necessary efficiencies and economies of scale, as discussed by for example Faaij (2006). Large plant sizes increase the necessary feedstock supply area and put significant demands on the supply chain, which makes it necessary to carefully choose the geographic location of the production plants with respect to fuel demand and feedstock locations. Since the potential for biomass is limited, efficient utilization is necessary. Co-production of several energy carriers as a means to reach increased system efficiency is promoted in the EU cogeneration directive for simultaneous production of electricity and heat (Dir 2004/8/EC). Cogeneration can also be an option for second generation biofuel production, where a considerable part of the feedstock energy not converted into biofuel can be recovered as other energy products, such as heat, electricity, lignin or biogas (see e.g. Börjesson and Ahlgren, 2010; Wetterlund and Söderström, 2010). Co-production thus gives an opportunity for higher total conversion efficiencies, but also puts additional requirements on the determination of the optimal biofuel production plant locations.

A model for determining the optimal location of biofuel production has been developed by Leduc (see Leduc, 2009; Leduc et al., 2010a; Leduc et al., 2009; Leduc et al., 2008; Leduc et al., 2010b; Schmidt et al., 2010). The model has been used in studies of smaller regions or countries, incorporating different biofuel production technologies as well as other bioenergy conversion technologies, such as combined heat and power (CHP). In this study the model is further developed to encompass biofuel production in the European Union.

1.1 Objective

The aim of this study is to further develop the EU biofuel localization model and use it to investigate how different parameters affect second generation biofuel production regarding costs, plant locations, production volumes and the possibility to reduce global fossil CO_2 emissions. Key parameters to be studied are:

- Policy instruments affecting biofuel production, such as targeted biofuel support and the cost for emitting CO_2
- Energy prices
- The possibility to sell excess heat
- Feedstock costs and availability

The abovementioned 3% share of second generation biofuels for fulfillment of the 2020 target is used as a starting point, with the analysis focusing on boundary conditions that affect the possibility to meet this goal.

2 Methodology and input data

The optimization model is used to determine the location and size of biofuel production plants, given the locations of feedstock and energy demand. The model minimizes the costs of the complete biofuel supply chain of the studied system, including biomass harvest, biomass transportation, conversion to biofuel, transportation and delivery of biofuel, and sales of excess heat and electricity. Fossil CO_2 emissions are also considered, by including a cost for emitting CO_2 cost, such as a tax or tradable emission permits.

2.1 Geographical boundaries

The model incorporates the entire EU-27 with the exception of Malta and Cyprus, which are both island nations with relatively small populations. In order to reduce calculation times, the EU has been divided into eight regions, which are in turn divided into grid cells with a half-degree spatial resolution (approximately 50 x 50 km). The eight regions have been defined by the existence of natural boundaries, such as mountains or water. Within each region the distances between all grid points are computed, in order to be able to calculate transportation costs between any two points. Interchange of biomass feedstock or biofuel between the regions can only take place at defined trade points, situated at major harbour locations or strategically located border points. Figure 1 shows the eight regions with the included trade points. Countries not belonging to the EU-27 (hatched areas) are not considered with respect to energy demand or biomass supply, but trade is allowed through those countries. A list of the country-region relations can be found in Table 5 in Section 2.8.

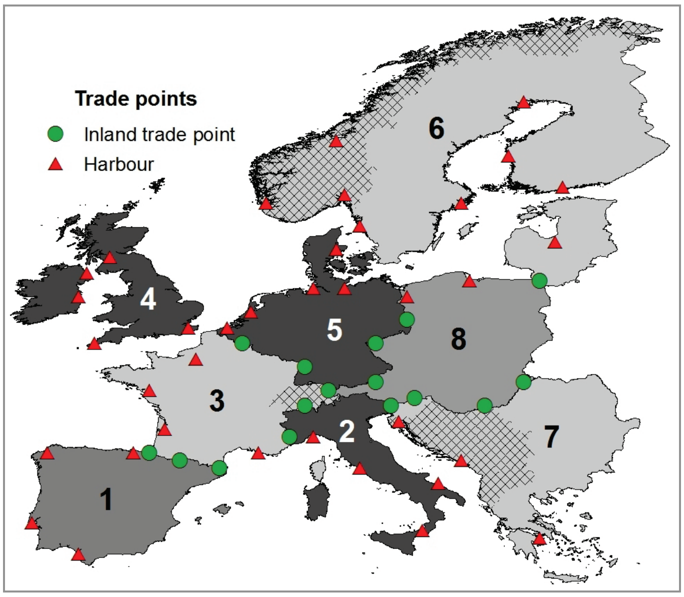

Figure 1. Region definition and location of the trade points. The red triangles represent the larger harbours and the green circles represent inland trade points. Feedstock and biofuel can be traded from one harbour to any other harbour, whereas inland trades can only occur at one specific inland trade point. Hatched areas are non-EU countries.

2.2 Biomass feedstock

A number of different cellulosic feedstocks could be used for production of second generation biofuels, for example various woody materials, grasses and agricultural residues. The main focus here is forest residues, but lignocellulosic waste has also been considered briefly.

2.2.1 *Forest residues*

The potential supply of forest biomass for use in biofuel production is assumed to be dependent on the annual increment of total forest biomass, which depends on the net primary production and the forest share of each grid cell. Data on annual increment of forest biomass above ground in m^3/ha/year has been achieved from IIASA's Global Forest Model (G4M) (Kindermann, 2010). The methodology has been described briefly in (Leduc et al., 2010b) and (Schmidt et al., 2010). It is here assumed that 20% of the total annual wood increment, representing forest residues such as branches and tops from final felling, is available for biofuel production. The share of the annual forest increment that is already utilized for energy purposes, for example in CHP plants, has not been regarded.

In this study no distinction is made between different tree species. The available forest biomass is assumed to have a density of 500 kg/m^3 (dry weight), with a heating value of 18.5 GJ/t (lower heating value (LHV) of dry feedstock) and a moisture content of 50%. Figure 2 shows the distribution of forest biomass resources assumed available for biofuel production. Only preliminary data was available for use in this study, with a probable underestimation of the biomass potential in some regions, in particular in region 6. In future work involving the model described in this report, updated forest data will be included.

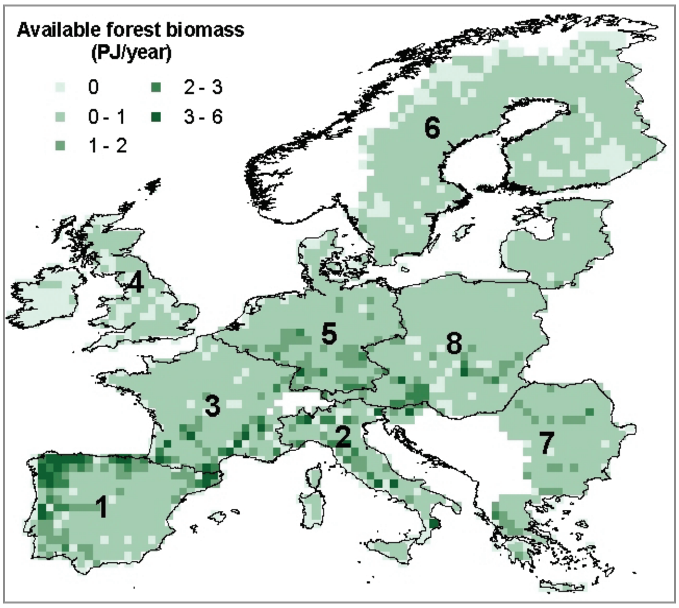

Figure 2. Amounts of forest biomass available for biofuel production (PJ/year).

The forest biomass production cost includes cost of felling and forwarding to the forest road, and depends on population density, forest share, land cost level and slope (see

Leduc et al., 2010b), with an average cost in EU of 5.4 €/GJ. When estimating the biomass production costs regional differences in for example development status of forest residue recovery, machine cost structures, labor costs and mechanization level were not considered. The distribution of forest biomass production costs is shown in Figure 3.

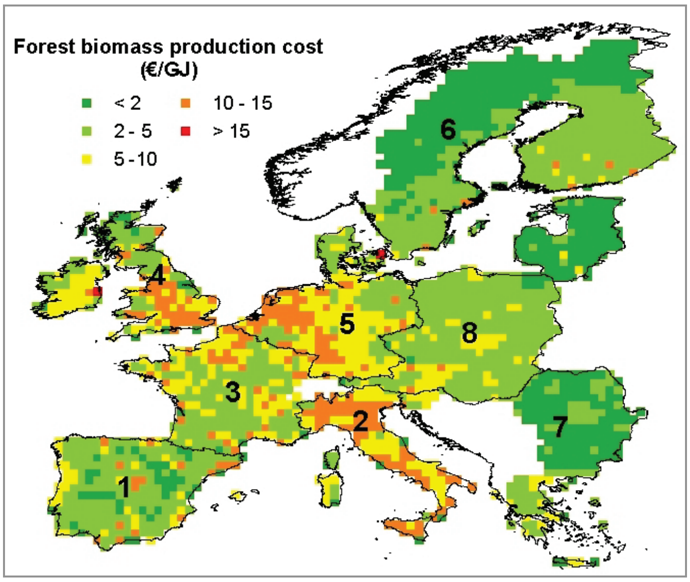

Figure 3. Forest biomass production costs (€/GJ).

2.2.2 Lignocellulosic waste

Two lignocellulosic waste fractions are included – wood waste and paper and cardboard waste. Wood waste mainly includes waste from the forest industry and from construction and demolition of buildings. Paper and cardboard waste includes collected waste as well as waste from pulp, paper and cardboard production. Data on the amount of waste for the individual EU member states in 2006 has been obtained from (Eurostat, 2010b). As a share of the total waste is already recovered, either for recycling or for energy recovery, only the share not currently reported as 'recovered' is assumed available for biofuel production.

The waste available is assumed to be dependent on the population of each grid point, with the per capita waste production assumed equal in all grid points for each country. In countries where a large amount of the total waste originates from the forest industry, in particular Sweden and Finland, this will result in an overestimation of the available waste in more populated areas and an underestimation of waste in more sparsely populated areas, where the forest industry is typically located. Figure 4 shows the distribution of available waste. For details on the waste data, see Appendix A.

The purchase price for all waste feedstock is assumed to be 0 €/GJ.

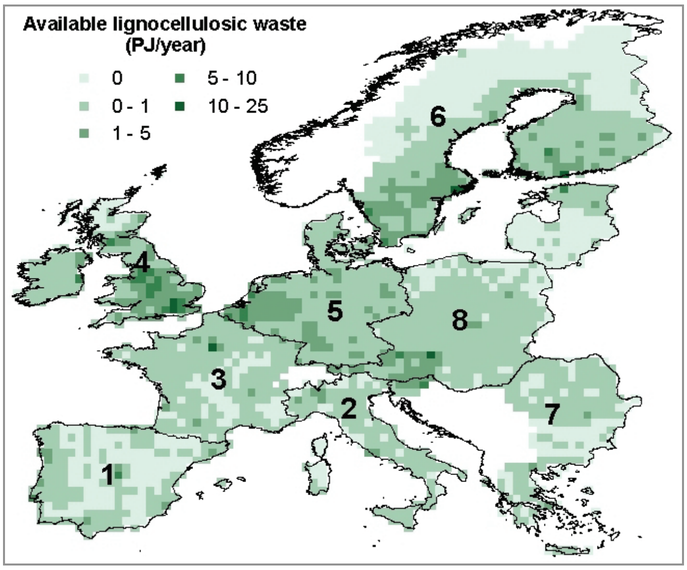

Figure 4. Amounts of wood waste and paper and cardboard waste available for biofuel production (PJ/year) (Eurostat, 2010b).

2.3 Biofuel production technologies

Three different technologies for producing second generation biofuels are considered; methanol via gasification, FTD via gasification, and cellulosic ethanol via hydrolysis and fermentation. For all three technologies heat suitable for use as district heating is co-produced, and for FTD and ethanol excess electricity is also co-produced. Produced heat can either be sold as district heating or, if no heat demand exists close to the plant location, be wasted. Produced electricity is sold to the grid.

An annual operating time of 8,000 hours is assumed for all three technologies. Scale effects have a strong impact on the costs of biomass conversion systems, as discussed by e.g. Dornburg and Faaij (2001) and Sørensen (2005). Investments costs are scaled using the general relationship

$$\frac{Cost}{Cost_{base}} = \left(\frac{Size}{Size_{base}}\right)^{R} \qquad (1)$$

where *Cost* and *Size* represent the investment cost and plant capacity respectively for the new plant, $Cost_{base}$ the known investment cost for a certain plant capacity $Size_{base}$, and R is the scaling factor. An overall scaling factor of 0.7, the average value for chemical process plants (Remer and Chai, 1990), is used. Process efficiencies are assumed constant over the entire scale range. The maximum size is set to 100 $t_{biomass}$/h, which corresponds to approximately 450 $MW_{biomass}$.

Investment costs for new plants are annualized using an assumed economical life time of 20 years and an interest rate of 10%, giving a capital recovery factor of 0.11. Table 1 summarizes key input data for the three technologies, with process descriptions given in the sections following.

Table 1. Key input data for the biofuel production technologies. Investment costs have been adjusted to €$_{2009}$ using the Chemical Engineering Plant Cost Index (CEPCI, 2010). All efficiencies concern dry feedstock (LHV).

Parameter	**Unit**	**Methanol**[a]	**FTD**[b]	**Ethanol**[c]
Base plant capacity	MW	357	300	372
Base investment cost	M€	505	304	490
Fixed O&M cost[d]	% of total inv. cost	3.5	3.5	3.5
Variable O&M cost[d]	€/$GJ_{biomass}$	0.97	0.97	0.97
Biofuel efficiency	$GJ_{biofuel}/GJ_{biomass}$	0.55	0.45	0.29
Electrical efficiency	$GJ_{electricity}/GJ_{biomass}$	0	0.064	0.20
District heating efficiency	$GJ_{heat}/GJ_{biomass}$	0.10	0.058	0.32

[a] (Hamelinck and Faaij, 2002; Wahlund et al., 2004).
[b] (van Vliet, 2010; van Vliet et al., 2009).
[c] Data on the ethanol process from (Hamelinck et al., 2003; Leduc et al., 2010b), data on biogas based electricity production from (Hansson et al., 2007).
[d] Since operation and maintenance (O&M) costs are reported very differently in the publications on biofuel production used for input data, generic O&M costs are used.

2.3.1 Methanol

Production of methanol from biomass is still on the development stage, with several different production concepts being investigated. The main development focus is on gasification and gas upgrading, while the synthesis step is similar to existing commercial processes for production of methanol from fossil feedstocks. In this study a process described by Hamelinck and Faaij(2002) is used. The process is based on atmospheric indirect gasification followed by steam reforming and liquid phase methanol synthesis. Electricity is co-produced in a steam cycle in enough quantities to cover the process demands. Hamelinck and Faaij do not report recovery of excess process heat. Instead data from Wahlund et al.(2004) is used to estimate the heat delivery potential.

2.3.2 Fischer-Tropsch diesel

Fischer-Tropsch (FT) fuels are synthetic hydrocarbons that are fully compatible with existing fossil fuel infrastructure and vehicles. Today FT fuels are produced from coal or natural gas. FT production from biomass feedstock is still not commercial, but research and development is being conducted (see e.g. CHOREN, 2010; Tijmensen et al., 2002). As for methanol, several potential production routes exist, incorporating different gasification technologies, cleaning and upgrading, and synthesis. Here a production route based on oxygen-blown gasification in a pressurized fluidized bed gasifier, followed by slurry phase FT synthesis and heavy paraffin conversion is selected. Electricity is co-produced in a combined cycle, using off-gas from the FT synthesis as fuel for the gas turbine and heat from the gas turbine and from the synthesis reactor in the steam cycle. Low-grade heat can also be recovered from the process and exported for use as district heating (van Vliet, 2010). For a detailed process description, see (van Vliet et al., 2009).

2.3.3 Ethanol

Today ethanol for use as transport fuel is mainly produced from corn or sugarcane, with much interest in development of production processes utilizing cellulosic feedstock. Focus is primarily on agricultural residues, but production from various wood feedstocks is also under development. Ethanol production from lignocellulosic material demands pre-treatment in order to separate the cellulose and hemicellulose from the lignin, typically using hydrolysis (enzymatic or acidic). Here a process using dilute acid hydrolysis is considered. The lignin and the biogas co-produced in the process are used to produce heat and electricity. Heat not used internally can be delivered for use as district heating. A detailed process description can be found in (Leduc et al., 2010a).

2.4 District heating

Data on district heating in the EU (as of 2003) has been obtained from (Werner, 2006) and (Egeskog et al., 2009a). No data on individual district heating systems has been collected. Instead the total national district heating demand has been downscaled under the assumption that the district heating demand is proportional to the population of each grid point. As discussed by Egeskog et al. the heat that could be replaced by the heat from biofuel production depends on a number of highly system specific factors, such as heat load, current production mix and age structure of the existing heat production plants. Here the district heating systems are described on a nationally aggregated level, with the heat delivered from the biofuel production plants assumed to displace heat corresponding to a heat mix specific to each country. Knutsson et al. (2006) have investigated the error introduced by using different aggregation methods when analyzing impacts on the district heating sector of investing in new base load production. They find that assuming that new production replaces a national heat mix will lead to underestimation of the amount of peak load replaced, and overestimation of the amount of base load replaced. Knutsson et al. comment, however, that analysis on an aggregated level can be acceptable when the main focus is not do describe detailed impact on the district heating sector, as this approach significantly lessens the data collection burden. Since the aim of this study is to give a broad view of the potential in EU for domestic biofuel production, an aggregated approach was considered sufficient.

In regards to the national heat mixes it is assumed that all existing fossil heat (2003), from CHP plants as well as from heat-only boilers (HOBs), can be replaced by heat from the biofuel production plants. As shown by Werner (2006) there is a substantial potential for expansion of the European district heating systems, by replacing fossil fuels used for heating. In total a doubling of the current district heating load could be achieved by 2020. In this study this entire expansion potential is also assumed available for heat from the biofuel production plants. Figure 5 shows the distribution of the available heat load. As can be seen, large potential for heat deliveries can be found in regions 4, 5 and 8. Region 5 and 8 both have relatively high existing heat loads, large shares of fossil heat and substantial potential for additional expansion. Considerable expansion potential can also be found in regions 1, 2 and 4, all of which are relatively under-developed regarding district heating today. Even with expansion, however, region 1 constitutes a small heat sink, due to the short heating season of southern EU. One alternative to expand the heat sink in warm countries and thus increase the co-production capacity would be to also include the potential for heat driven absorption cooling (see e.g. Difs et al., 2009; Trygg and Amiri, 2007). This has however not been considered here. The countries of region 6, in particular Sweden and Finland, have well-developed district heating, but with a large share of renewable and waste heat and with little additional expansion potential. In combination with lower populations, this leads to relatively few sizeable heat sinks in region 6. For details on the district heating data, see Appendix B.

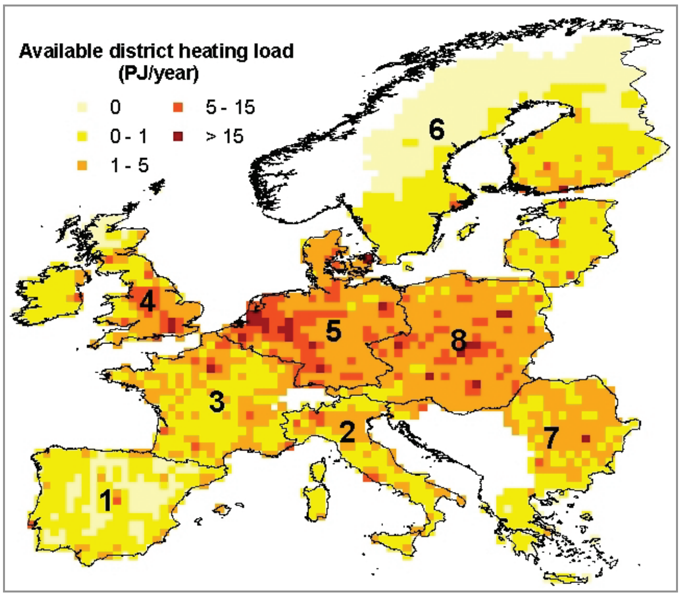

Figure 5. Available district heating load (PJ/year) (Egeskog et al., 2009a; Werner, 2006).

A simplified heat load duration curve is applied, with the year divided into three seasons of equal length. To accommodate for variance in annual load distribution at different latitudes, three different load profiles are used; one representing the northern EU countries, one representing the central and one representing the southern countries. The load distributions are summarized in Table 2, with more details given in Appendix B.

The heat distribution distance limit is set to 50 km. Costs for investments in district heating equipment, such as pipes, pumps or heat exchangers are not included.

Table 2. District heating load distributions used. Three seasons of equal length are applied. Load data from (Bennstam, 2008; Chinese and Meneghetti, 2005; Sigmond, 2010).

Part of EU	**Season 1**	**Season 2**	**Season 3**
North[a]	49%	35%	16%
Central[b]	60%	32%	8%
South[c]	82%	12%	6%

[a] Denmark, Estonia, Finland, Latvia, Lithuania, Sweden.
[b] Austria, Belgium, Bulgaria, Czech Republic, France, Germany, Hungary, Ireland, Luxembourg, Netherlands, Poland, Romania, Slovakia, United Kingdom.
[c] Greece, Italy, Spain, Portugal, Slovenia.

2.5 Transportation and distribution

2.5.1 Transport of feedstock and biofuels

Three transportation means for biomass feedstock and produced biofuels are included; truck, train and boat. Transport costs for logging residues and methanol reported by Börjesson and Gustavsson (1996) are used as base costs. Since Börjesson and Gustavsson report transport costs in $/TJ, heating values and moisture contents of feedstocks and biofuels are used to estimate the transport costs for other energy carriers.

The transport costs are also adjusted to account for currency development since 1996. The resulting transport costs are presented in Table 3.

Table 3. Transport costs in €/TJ for feedstock and biofuels. *d* is the transport distance in km. Adapted from (Börjesson and Gustavsson, 1996).

Energy carrier[a]	**Truck**	**Train**	**Boat**
Forest residues	307+6.92*d*	648+0.963*d*	744+0.394*d*
Waste (wood, paper and cardboard)	192+4.32*d*	406+0.602*d*	465+0.246*d*
Methanol	123+2.71*d*	377+0.587*d*	412+0.131*d*
FTD	55.5+1.23*d*	170+0.265*d*	186+0.0594*d*
Ethanol	91.0+2.02*d*	280+0.436*d*	306+0.0975*d*

[a] Forest residues are assumed to have a heating value of 18.5 GJ/t (lower heating value, dry feedstock) and a moisture content of 50%. Waste is assumed to have the same heating value but a moisture content of 20%. Heating value of methanol is 19.9 GJ/t, of FTD 44.0 GJ/t and of ethanol 26.8 GJ/t (Edwards et al., 2007).

A network map of roads, rails and shipping routes is used to calculate transportation routes and distances *d* between the supply points and the production plants, as well as between the production plants and the demand areas. This has been described in detail in (Leduc, 2009) and (Leduc et al., 2010b). The resulting transportation routes can consist of any combination of the three transportation means.

2.5.2 Distribution and dispensing of biofuels

All gas stations are assumed to be able to handle biofuel distribution, after certain alterations to the existing equipment. The dispensing costs for all biofuels are assumed equal, at 0.24 €/GJ (Leduc, 2009).

2.6 Transport fuel demand

As discussed in the introduction the annual energy demand in transport in EU is currently around 12 EJ. The demand is estimated to increase to 15 EJ in 2020 (European Commission, 2008b). If the entire available quantity of forest residues and lignocellulosic waste presented in Section 2.2 was to be used for production of second generation biofuels, 4-8% of the total transport fuel demand in 2020 could be covered, depending on biofuel conversion technology. This is well above the discussed 3% second generation biofuels that would be necessary in order to avoid negative economic and environmental effects from increased biofuel utilization.

The projected transport fuel demand and population for 2020 are used as a basis for this study. The national demand is downscaled based on grid point population, with the demand per capita assumed equal in all grid points of each country. When running the optimization model, any fuel demand not met by biofuels is covered by fossil transport fuels. No distinction is currently made between petrol and diesel. Figure 6 shows the distribution of the total transport fuel demand. For more details on fuel demand and population data, see Appendix C.

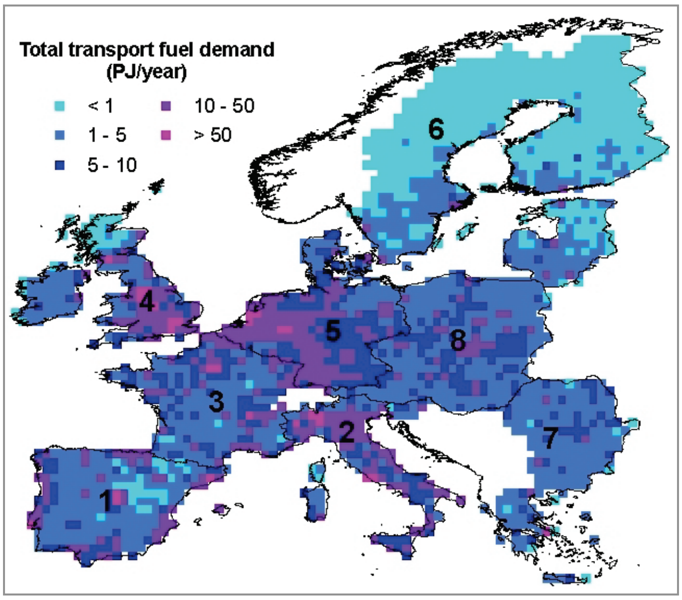

Figure 6. Transport fuel demand (PJ/year) (European Commission, 2008b).

2.7 CO_2 emissions

The cost of emitting fossil CO_2 is internalized in the model, by including the possibility of applying a CO_2 cost to the supply chain emissions. The cost could for example be a CO_2 tax or tradable emission permits. Emissions from transportation of feedstock and biofuels, as well as emissions from displaced fossil energy carriers are considered.

Produced biofuel is assumed to replace fossil transportation fuels (average of petrol and diesel) on a 1:1 ratio. Thus each GJ of biofuel produced displaces 78.1 kg of CO_2 (Uppenberg et al., 2001). Potential country specific differences in CO_2 emissions from transport fuels are not considered.

Concerning heat, all fossil district heating and a share of the fossil fuel based non-district heating is assumed replaceable, as described in Section 2.4. Thus, heat delivered from the biofuel production plants is assumed to displace heat corresponding to country specific fossil fuel heat mixes. Heat from CHP plants is credited with displaced country specific electricity. The CO_2 emission factors from heat are calculated using heat mix data from (Werner, 2006) and fuel emission data from (Uppenberg et al., 2001), and range from 29.6-104 kg CO_2/GJ.

Likewise, produced electricity is assumed to displace country mix electricity. Data on country specific end-user life cycle emissions has been obtained from (European Commission, 2010a), and range from 29.9–432 kg CO_2/GJ. Since 2007 the EU electricity market is deregulated, with the explicit ambition of the European Commission to overcome remaining obstacles to a fully integrated electricity market, such as transmission capacity bottlenecks (Dir 2003/54/EC; Dir 2009/72/EC). In light of this, it could be argued that it would be more appropriate to use a European electricity mix instead of country mix. Similarly, an alternative could be to assume that co-produced electricity displaces marginal electricity production, instead of average electricity. However, since this study uses country specific data for other parameters it was considered appropriate to use country mix. Future work involving the EU biofuel localization model will take into account effects of a fully integrated European electricity market.

CO_2 emissions from biomass are not considered as it is assumed that the CO_2 released when combusting the biomass is balanced by CO_2 uptake in growing trees. Also, since all the feedstocks considered are waste flows no land use change effects are taken into account. The use of for example forest residues can however affect soil carbon stocks (Holmgren et al., 2007), which could be of interest to include in future work. If considering marginal effects of energy use, as discussed for electricity above, marginal effects of drastically increased exploitation of biomass resources should also be included, as this can have significant impact (see e.g. Wetterlund et al., 2010). At this stage of the model development, however, only emissions from biomass transport are considered.

CO_2 emissions related to transportation of both biomass feedstock and biofuels are given in Table 4. Details of the CO_2 emission factors used for replaced fossil energy carriers can be found in Appendix D.

Table 4. CO_2 emissions from transportation in g_{CO2}/km/GJ of feedstock and biofuels (European Commission, 2010a).

Energy carrier[a]	**Truck**	**Train**	**Boat**
Forest residues	5.24	2.67	1.37
Waste (wood, paper and cardboard)	3.27	1.67	0.859
Methanol	2.43	1.24	0.639
FTD	1.10	0.562	0.289
Ethanol	1.81	0.922	0.474

[a] Emission factors calculated assuming a heating value of 18.5 GJ/t (LHV, dry feedstock) and a moisture content of 50% for forest residues. Waste is assumed to have the same heating value but a moisture content of 20%. Heating value of methanol is 19.9 GJ/t, of FTD 44.0 GJ/t and of ethanol 26.8 GJ/t (Edwards et al., 2007).

2.8 Energy prices

The energy prices assumed in this kind of study will naturally affect the results to a large extent. Today the energy prices in the different EU member states are highly diversified, with for example the electricity price in the country with the highest price (Slovakia) being almost three times the price in the country with the lowest price (Estonia). Since it is very difficult to predict future prices in all the EU states, country specific energy prices for 2009 are used in this study, with sensitivity analysis of various energy price parameters being performed.

For transport fuel average petrol and diesel pump prices (without taxes) in 2009 are used (European Commission, 2010b). District heating prices are estimated consumer price averages without VAT for 2003 (Werner, 2006), here currency is adjusted to $€_{2009}$. It is assumed possible to sell heat at 50% of the consumer price. Electricity prices are average end-user prices without taxes (industrial high-volume customers) in 2009 (Eurostat, 2010a).Table 5 shows the country specific energy prices used.

Table 5. Energy prices used in this study (€/GJ)European Commission, 2010b; Eurostat, 2010a; Werner, 2006.

Country	Region	Transport fuel	District heating[a]	Electricity
Austria	8	11.9	17.0	21.1
Belgium	5	12.6	13.1	20.8
Bulgaria	7	11.4	6.9	13.0
Czech Rep.	8	12.9	11.4	24.5
Denmark	5	13.5	19.9	19.2
Estonia	6	11.9	6.9	11.0
Finland	6	13.5	9.4	14.1
France	3	12.0	13.5	13.6
Germany	5	12.3	15.8	21.1
Greece	7	13.9	10.3	16.7
Hungary	8	12.9	10.7	25.2
Ireland	4	12.4	7.5	22.8
Italy	2	13.9	19.0	22.5
Latvia	6	12.5	9.9	20.0
Lithuania	6	12.6	10.5	18.9
Luxembourg	5	12.8	13.1	18.2
Netherlands	5	12.7	13.1	24.0
Poland	8	12.2	8.8	19.1
Portugal	1	13.5	7.5	16.0
Romania	7	12.7	6.7	16.2
Slovakia	8	12.6	9.9	27.1
Slovenia	7	12.0	10.3	20.0
Spain	1	13.3	6.7	19.0
Sweden	6	11.8	15.5	13.7
United Kingdom (UK)	4	11.3	7.5	24.9

[a] Consumer prices. Heat sales assumed to be possible at 50% of consumer prices.

2.9 Model description

The optimisation model, which is based on mixed integer linear programming (MILP), minimizes the system cost of the complete biofuel supply chain. Using different means of transportation (t), biomass of various types of feedstock (f) is transported from supply sites (s) to possible locations (p) for biofuel production plants of type (n) and capacity (q), producing biofuel of type (z). S is the number of supply sites, F the number of feedstocks, P the number of production plants, T the number of transportation means, N the number of plant types, Q the number of plant sizes and Z the number of biofuel types. The corresponding sets are $\tilde{S} = \{1, \ldots, S\}$, $\tilde{F} = \{1, \ldots, F\}$, $\tilde{P} = \{1, \ldots, P\}$, $\tilde{T} = \{1, \ldots, T\}$, $\tilde{N} = \{1, \ldots, N\}$, $\tilde{Q} = \{1, \ldots, Q\}$ and $\tilde{Z} = \{1, \ldots, Z\}$.

The produced biofuel is also transported using different means of transportation (t) to demand areas (g) where it is delivered to the consumers. Co-produced electricity is delivered directly to the grid, while co-produced heat is delivered to end-users in the demand areas (g). In order to limit calculation times, the EU has been divided into eight regions (r, r_d). Import/export of feedstock or biofuel between the regions can only take place at defined trade points (h, h_d), situated at major harbour locations or strategically located border points. G is the number of demand areas, R the number of regions and H the number of trade points, with $\tilde{G} = \{1, \ldots, G\}$, $\tilde{R} = \{1, \ldots, R\}$ and $\tilde{H} = \{1, \ldots, H\}$ being the corresponding sets. Prices and energy demands are country (c) specific, with C being the number of countries with the set $\tilde{C} = \{1, \ldots, C\}$. The model can be run for any number of years (y) where Y is the number of years, but is here run for one year. In order to accommodate for annual variations in heat demand the year has been divided into three seasons (m), with M being the number of seasons. $\tilde{Y} = \{1, \ldots, Y\}$and $\tilde{M} = \{1, \ldots, M\}$ are the corresponding sets.

The impact of fossil CO_2 emissions is internalized by adding the possibility to include a CO_2 cost in the objective function. The total system cost to be minimized is defined by the function *h(XB,X,XH,UP),*

$$h(XB, X, XH, UP) = f(XB, X, XH, UP) + c^{emissions} g(XB, X, XH, UP) \tag{2}$$

where

$$\begin{aligned}
&f(XB, X, XH, UP) \\
&\quad = \sum_{y,m,s,f,p,n,q} c_{y,s,f} XB_{y,m,s,f,p,n,q} + \sum_{y,m,r,s,f,h} c_{y,s,f} XB^{exp}_{y,m,r,s,f,h} \\
&\quad + \sum_{y,m,s,f,p,n,q,t} \left(t^{fix}_{y,f,t} + t^{var}_{y,f,t} d_{y,s,p,t}\right) XB_{y,m,s,f,p,n,q} \\
&\quad + \sum_{y,m,r,s,f,t,h} \left(t^{fix}_{y,f,t} + t^{var}_{y,f,t} d_{y,s,t,h}\right) XB^{exp}_{y,m,r,s,f,h} \\
&\quad + \sum_{y,m,f,p,n,q,t,h_d} \left(t^{fix}_{y,f,t} + t^{var}_{y,f,t} d_{y,p,t,h_d}\right) XB^{imp}_{y,m,f,p,n,q,h_d} \\
&\quad + \sum_{y,f,t,h,h_d} \left(t^{fix}_{y,f,t} + t^{var}_{y,f,t} d_{y,t,h,h_d}\right) XB^{traded}_{y,f,h,h_d} \\
&\quad + \sum_{y,p,n,q} c^{setup}_{p,n,q} \left(UP_{y,p,n,q} - UP_{y-1,p,n,q}\right) + \sum_{y,p,n,q,z,g} c^{prod}_{y,p,n,q} X_{y,p,n,q,z,g} \\
&\quad + \sum_{y,p,n,q,h} c^{prod}_{y,p,n,q} X^{exp}_{y,p,n,q,h} + \sum_{y,p,n,q,z,g,t} \left(t^{fix}_{y,z,t} + t^{var}_{y,z,t} d_{y,p,g,t}\right) X_{y,p,n,q,z,g} \\
&\quad + \sum_{y,p,n,q,z,t,h} \left(t^{fix}_{y,z,t} + t^{var}_{y,z,t} d_{y,p,t,h}\right) X^{exp}_{y,p,n,q,h} \\
&\quad + \sum_{y,z,g,t,h_d} \left(t^{fix}_{y,z,t} + t^{var}_{y,z,t} d_{y,g,t,h_d}\right) X^{imp}_{y,g,h_d} \\
&\quad + \sum_{y,z,t,h,h_d} \left(t^{fix}_{y,z,t} + t^{var}_{y,z,t} d_{y,t,h,h_d}\right) X^{traded}_{y,h,h_d} + \sum_{y,p,n,q,z,g} c^{gasstn}_{y,g} X_{y,p,n,q,z,g} \\
&\quad + \sum_{y,g,h_d} c^{gasstn}_{y,g} X^{imp}_{y,g,h_d} - \sum_{y,m,c,p,n,q,g} p^{heat}_{y,m,c} XH^{usable}_{y,m,p,n,q,g} - \sum_{y,c,p,n,q} p^{power}_{y,c} X^{power}_{y,p,n,q} \\
&\quad + \sum_{y,c,g} p^{fossil}_{y,c} X^{fossil}_{y,g}
\end{aligned} \tag{3}$$

and

$$
\begin{aligned}
g(XB,X,XH,UP) \\
&= \sum_{y,m,s,f,p,n,q,t} e_{y,f,t} d_{y,s,p,t} XB_{y,m,s,f,p,n,q} + \sum_{y,m,r,s,f,t,h} e_{y,f,t} d_{y,s,t,h} XB^{exp}_{y,m,r,s,f,h} \\
&+ \sum_{y,m,f,p,n,q,t,h_d} e_{y,f,t} d_{y,p,t,h_d} XB^{imp}_{y,m,f,p,n,q,h_d} + \sum_{y,f,t,h,h_d} e_{y,f,t} d_{y,t,h,h_d} XB^{traded}_{y,f,h,h_d} \\
&+ \sum_{y,p,n,q,z,g,t} e_{y,z,t} d_{y,p,g,t} X_{y,p,n,q,z,g} + \sum_{y,p,n,q,z,t,h} e_{y,z,t} d_{y,p,t,h} X^{exp}_{y,p,n,q,h} \\
&+ \sum_{y,z,g,t,h_d} e_{y,z,t} d_{y,g,t,h_d} X^{imp}_{y,g,h_d} + \sum_{y,z,t,h,h_d} e_{y,z,t} d_{y,t,h,h_d} X^{traded}_{y,h,h_d} \\
&- \sum_{y,c,p,n,q,z,g} e^{fossil}_{c} X_{y,p,n,q,z,g} - \sum_{y,c,g,h_d} e^{fossil}_{c} X^{imp}_{y,g,h_d} \\
&- \sum_{y,m,c,p,n,q,g} e^{heat}_{c} XH^{usable}_{y,m,p,n,q,g} - \sum_{y,c,p,n,q} e^{power}_{c} X^{power}_{y,p,n,q} + \sum_{y,c,g} e^{fossil}_{c} X^{fossil}_{y,g}
\end{aligned}
\tag{4}
$$

The different summands of *f(XB,X,XH,UP)* represent:

1) – 2) biomass production cost (parameter $c_{y,s,f}$) times the total amount of biomass used (variables $XB_{y,m,s,f,p,n,q}$, $XB^{exp}_{y,m,r,s,f,h}$),

3) – 6) biomass transportation cost (parameters $t^{fix}_{y,f,t}$, $t^{var}_{y,f,t}$) times the total amount of biomass transported (variables $XB_{y,m,s,f,p,n,q}$, $XB^{exp}_{y,m,r,s,f,h}$, $XB^{imp}_{y,m,f,p,n,q,h_d}$, XB^{traded}_{y,f,h,h_d}), with parameters $d_{y,s,p,t}$, $d_{y,s,t,h}$, d_{y,p,t,h_d}, d_{y,t,h,h_d} representing the transportation distance,

7) annualized cost of plant investment (parameter $c^{setup}_{p,n,q}$) times the binary variable indicating plant operation ($UP_{y,p,n,q}$),

8) – 9) variable biofuel production cost (parameter $c^{prod}_{y,p,n,q}$) times the total amount of biofuel produced (variables $X_{y,p,n,q,z,g}$, $X^{exp}_{y,p,n,q,h}$),

10) – 13) biofuel transportation cost (parameters $t^{fix}_{y,z,t}$, $t^{var}_{y,z,t}$) times the total amount of biofuel transported (variables $X_{y,p,n,q,z,g}$, $X^{exp}_{y,p,n,q,h}$, X^{imp}_{y,g,h_d}, X^{traded}_{y,h,h_d}), with parameters $d_{y,p,g,t}$, $d_{y,p,t,h}$, d_{y,g,t,h_d}, d_{y,t,h,h_d} representing the transportation distance,

14) – 15) cost for handling and dispensing biofuels (parameter $c^{gasstn}_{y,g}$) times the total amount of biofuel delivered to customer (variables $X_{y,p,n,q,z,g}$, X^{imp}_{y,g,h_d}),

16) price of district heating (parameter $p^{heat}_{y,m,c}$) times the amount of heat delivered to district heating customers (variable $XH^{usable}_{y,m,p,n,q,g}$),

17) price of electricity (parameter $p^{power}_{y,c}$) times the amount of electricity delivered to grid (variable $X^{power}_{y,p,n,q}$),

18) price of fossil transport fuel (parameter $p_{y,c}^{fossil}$) times the amount of fossil fuel used (variable $X_{y,g}^{fossil}$).

The different summands of *g(XB,X,XH,UP)* represent:

1) – 4) CO_2 emission factor of biomass transportation (parameter $e_{y,f,t}$) times the total amount of biomass transported (variables $XB_{y,m,s,f,p,n,q}$, $XB_{y,m,r,s,f,h}^{exp}$, $XB_{y,m,f,p,n,q,h_d}^{imp}$, XB_{y,f,h,h_d}^{traded}), times the transportation distance,

5) – 8) CO_2 emission factor of biofuel transportation (parameter $e_{y,z,t}$) times the total amount of biofuel transported (variables $X_{y,p,n,q,z,g}$, $X_{y,p,n,q,h}^{exp}$, X_{y,g,h_d}^{imp}, X_{y,h,h_d}^{traded}), times the transportation distance,

9) – 10) CO_2 emission factor of fossil transport fuels (parameter e_c^{fossil}) times the amount of fossil fuel displaced by biofuel (variables $X_{y,p,n,q,z,g}$, X_{y,g,h_d}^{imp}),

11) CO_2 emission factor of district heating (parameter e_c^{heat}) times the amount of displaced district heating (variable e_c^{heat}),

12) CO_2 emission factor of electricity (parameter e_c^{power}) times the amount of displaced grid electricity (variable $X_{y,p,n,q}^{power}$),

13) CO_2 emission factor of fossil transport fuels (parameter e_c^{fossil}) times the amount of fossil fuel used (variable $X_{y,g}^{fossil}$).

The system cost in Eq. (1) is minimized subject to a number of constraints.

The amount of biomass possible to utilize for biofuel production is restricted by

$$\sum_{p,n,q} XB_{y,m,s,f,p,n,q} + \sum_{h} XB_{y,m,r,s,f,h}^{exp} \leq \bar{B}_{y,r,s,f}, \quad y \in \tilde{Y}, m \in \tilde{M}, r \in \tilde{R}, s \in \tilde{S}, f \in \tilde{F} \tag{5}$$

where parameter $\bar{B}_{y,r,s,f}$ is the total amount of biomass feedstock of type *f* available at supply site *s* in region *r*. Variables $XB_{y,m,s,f,p,n,q}$ and $XB_{y,m,r,s,f,h}^{exp}$ denote biomass used in the region *r*, and biomass exported to other regions, respectively.

The amount of biomass delivered from one supply site *s* to one export trade point *h* in region *r* must be equal to the amount of biomass traded from that export point to any other destination trade point h_d,

$$\sum_{m,s} XB_{y,m,r,s,f,h}^{exp} = \sum_{h_d} XB_{y,f,h,h_d}^{traded}, \quad y \in \tilde{Y}, r \in \tilde{R}, f \in \tilde{F}, h \in \tilde{H} \tag{6}$$

Similarly, the amount of biomass delivered from destination trade point h_d in region r_d to the production plant *p* must be equal the amount of biomass traded from any export trade point *h* to that destination trade point,

$$\sum_{m,p,n,q} XB_{y,m,f,p,n,q,h_d}^{imp} = \sum_{h} XB_{y,f,h,h_d}^{traded}, \quad y \in \tilde{Y}, r_d \in \tilde{R}, f \in \tilde{F}, h_d \in \tilde{H} \tag{7}$$

The total amount of biomass possible to trade between any two trade points h and h_d is restricted by

$$\sum_{f} XB_{y,f,h,h_d}^{traded} \leq \bar{B}_{h,h_d}^{traded}, \quad y \in \tilde{Y}, h \in \tilde{H}, h_d \in \tilde{H} \tag{8}$$

where parameter $\bar{B}_{h,h_d}^{traded}$ denotes the limit of the amount of biomass that can be traded.

Biofuel produced in plant p can be delivered to customers in the same region ($X_{y,p,n,q,z,g}$) or exported to other regions ($X_{y,p,n,q,h}^{exp}$). The total amount of biofuel produced in plant p is defined as

$$\eta_{p,n,z}^{biofuel}\left(\sum_{m,s,f} XB_{y,m,s,f,p,n,q} + \sum_{m,f,h_d} XB_{y,m,f,p,n,q,h_d}^{imp}\right) = \sum_{g} X_{y,p,n,q,z,g} + \sum_{h} X_{y,p,n,q,h}^{exp}, \quad y \in \tilde{Y}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q}, z \in \tilde{Z} \tag{9}$$

where parameter $\eta_{p,n,z}^{biofuel}$ is the biomass to biofuel conversion efficiency. Variables $XB_{y,m,s,f,p,n,q}$ and $XB_{y,m,f,p,n,q,h_d}^{imp}$ denote biomass supplied from the same region, and biomass imported from other regions, respectively.

The amount of biofuel delivered from one plant p to one export trade point h in region r must be equal to the amount of biofuel traded from that export point to any other destination trade point h_d,

$$\sum_{p,n,q} X_{y,p,n,q,h}^{exp} = \sum_{h_d} X_{y,h,h_d}^{traded}, \quad y \in \tilde{Y}, r \in \tilde{R}, h \in \tilde{H} \tag{10}$$

Similarly, the amount of biofuel delivered from destination trade point h_d in region r_d to demand area g must be equal to the amount of biofuel traded from any export trade point h that belongs to any other region r than the destination trade point,

$$\sum_{g} X_{y,g,h_d}^{imp} = \sum_{h} X_{y,h,h_d}^{traded}, \quad y \in \tilde{Y}, r_d \in \tilde{R}, h_d \in \tilde{H} \tag{11}$$

The total amount of biofuel possible to trade between any two trade points h and h_d is restricted by

$$X_{y,h,h_d}^{traded} \leq \bar{X}_{y,h,h_d}^{traded}, \quad y \in \tilde{Y}, h \in \tilde{H}, h_d \in \tilde{H} \tag{12}$$

where parameter $\bar{X}_{y,h,h_d}^{traded}$ denotes the limit of the amount of biofuel that can be traded.

The maximum biofuel production of plant p is restricted by

$$\left(\sum_{m,s,f} XB_{y,m,s,f,p,n,q} + \sum_{m,f,h_d} XB_{y,m,f,p,n,q,h_d}^{imp}\right) \leq \bar{B}_{p,n,q}^{plant}\, UP_{y,p,n,q}, \quad y \in \tilde{Y}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q}, z \in \tilde{Z} \tag{13}$$

where parameter $\bar{B}_{p,n,q}^{plant}$ denotes the plant capacity and $UP_{y,p,n,q}$ is the binary variable that indicates plant operation.

The minimum part load is assumed to be 50% of the maximum load, according to

$$\left(\sum_{m,s,f} XB_{y,m,s,f,p,n,q} + \sum_{m,f,h_d} XB^{imp}_{y,m,f,p,n,q,h_d}\right) \geq 0.5\bar{B}^{plant}_{p,n,q} UP_{y,p,n,q}, \quad y \in \tilde{Y}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q}, z \in \tilde{Z} \tag{14}$$

Once a plant is built, it remains available in the following years, according to

$$UP_{y,p,n,q} \geq UP_{y-1,p,n,q} + s^{initial}_{p,n,q}, \quad y \in \tilde{Y}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q} \tag{15}$$

where parameter $s^{initial}_{p,n,q}$ is the initial plant status.

The total demand for transportation fuel in a demand area *g* can be satisfied by fossil fuel (variable $X^{fossil}_{y,g}$) or biofuel, where the biofuel can be produced in the same region (variable $X_{y,p,n,q,z,g}$) or imported from other regions (variable X^{imp}_{y,g,h_d}),

$$\sum_{p,n,q,z} X_{y,p,n,q,z,g} + \sum_{h_d} X^{imp}_{y,g,h_d} + X^{fossil}_{y,g} = \bar{X}^{demand}_{g}, \quad y \in \tilde{Y}, g \in \tilde{G} \tag{16}$$

where parameter $\bar{X}^{demand}_{g}$ denotes the total transport fuel demand in *g*.

Electricity $X^{power}_{y,p,n,q}$ and heat $XH_{y,m,p,te,si}$ is co-produced in plants *p*, according to

$$\eta^{power}_{p,te}\left(\sum_{m,s,f} XB_{y,m,s,f,p,n,q} + \sum_{m,f,h_d} XB^{imp}_{y,m,f,p,n,q,h_d}\right) = X^{power}_{y,p,n,q}, \quad y \in \tilde{Y}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q} \tag{17}$$

and

$$\eta^{heat}_{p,n}\left(\sum_{s,f} XB_{y,m,s,f,p,n,q} + \sum_{f,h_d} XB^{imp}_{y,m,f,p,n,q,h_d}\right) = \sum_{g} XH_{y,m,p,te,si}, \quad y \in \tilde{Y}, m \in \tilde{M}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q} \tag{18}$$

where parameters $\eta^{power}_{p,te}$ and $\eta^{heat}_{p,n}$ denote the conversion efficiency for biomass to electricity and heat, respectively.

Electricity is assumed to be delivered to the grid, with no capacity restrictions. Heat is divided into heat used for district heating (variable $XH^{usable}_{y,m,p,n,q,g}$) and excess (waste) heat (variable $XH^{excess}_{y,m,p,n,q}$),

$$XH_{y,m,p,n,q} = \sum_{g} XH^{usable}_{y,m,p,n,q,g} + XH^{excess}_{y,m,p,n,q}, \quad y \in \tilde{Y}, m \in \tilde{M}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q} \tag{19}$$

Heat can only be used for district heating under the condition that the distance from plant *p* to heat demand *g* is shorter than the maximum allowed distance for heat delivery. The amount of heat that can be delivered to demand area *g* is restricted by

$$\sum_{p,n,q} XH^{usable}_{y,m,p,n,q,g} \leq \bar{H}^{demand}_{m,g}, \quad y \in \tilde{Y}, m \in \tilde{M}, g \in \tilde{G} \tag{20}$$

where parameter $\bar{H}^{demand}_{m,g}$ denotes the demand for district heating in *g*.

Finally, the mixed integer linear problem is defined as

min[$h(XB,X,XH,UP)$]

s.t.

(2) – (20)

$$XB_{y,m,s,f,p,n,q}, XB^{exp}_{y,m,r,s,f,h}, XB^{imp}_{y,m,f,p,n,q,h_d}, XB^{traded}_{y,f,h,h_d}, XH_{y,m,p,n,q}, XH^{excess}_{y,m,p,n,q}, \\ XH^{usable}_{y,m,p,n,q,g}, X_{y,p,n,q,z,g}, X^{exp}_{y,p,n,q,h}, X^{fossil}_{y,g}, X^{imp}_{y,g,h_d}, X^{power}_{y,p,n,q}, X^{traded}_{y,h,h_d} \geq 0, \\ y \in \tilde{Y}, m \in \tilde{M}, r \in \tilde{R}, c \in \tilde{C}, s \in \tilde{S}, f \in \tilde{F}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q}, z \in \tilde{Z}, \\ g \in \tilde{G}, t \in \tilde{T}, h \in \tilde{H} \tag{21}$$

$$UP_{y,p,n,q} \in \{0,1\}, \qquad y \in \tilde{Y}, p \in \tilde{P}, n \in \tilde{N}, q \in \tilde{Q}$$

The model has been developed in the commercial software GAMS and is solved using CPLEX (McCarl et al., 2008).

3 Scenarios

The input data described in Sections 2.2–2.8 is used as a base scenario (scenario 0). In the base scenario country specific energy prices are applied, with no policy support for biofuels and no cost for CO_2 emissions. The available heat load is assumed to be all existing fossil district heating as well as the expansion potential for 2020, as described in Section 2.4. The only feedstock included is forest residues. To investigate how different parameters affect the biofuel production regarding costs and plant locations a number of scenarios where key parameters are varied are created. The scenarios are summarized in Table 6.

Targeted biofuel support, such as tax reduction, feed-in tariffs or green certificates, is simulated by applying a multiplier of varying size to the fossil fuel price (scenarios 1-3). The other policy instrument in focus, a cost for emitting fossil CO_2, is also applied in varying levels (scenarios 4-5). To analyze the impact of market energy prices a number of scenarios with varying energy prices are included. Five scenarios (6-10) are based on the assumption that energy prices are harmonized in all the individual EU member states, with three different price levels (average prices, prices corresponding to the current lowest prices, and prices corresponding to the current highest prices). Scenarios 11-16 focus on heat related parameters, with varying heat load and heat prices, while in scenario 17-18 the impact of increased electricity prices is examined. The forest biomass production cost is increased in scenario 19-20. In scenario 21 and 23 lignocellulosic waste is assumed available as feedstock for biofuel production in addition to forest residues. In the two last scenarios (22-23) the EU demand for second generation biofuels is fixed to 3% and must be fulfilled.

In scenarios where the optimal solution contains no biofuel plants complementing scenarios are included, with support in the form of either targeted biofuel support or CO_2 cost, in order to make it possible to analyze the impact of varying other parameters. For biofuel support a fossil fuel price multiplier of 1.7 is used as standard level, which corresponds to biofuel support of approximately 9 €/$GJ_{biofuel}$. This is comparable to the EU minimum rate of excise tax on fossil transport fuels (ACEA, 2010), from which biofuels in many EU countries is exempted. When instead a CO_2 cost is applied a level of 100 €/t_{CO2} is used, which is higher than the current level of tradable emission permits in the EU, but in line with the CO_2 tax in for example Sweden.

Table 6. Summary of scenarios modeled. Bold text represents parameters changed compared to scenario 0. Scenarios marked with * include policy support.

Scenario	CO_2 cost (€/t_{CO2})	Biofuel support	Feedstock	Foss. fuel price	El. price	Heat price	Heat load	Description
0	0	0	base	base	base	base	base	Base scenario
1*	0	**1.5**	base	base	base	base	base	Variation of support for bio-fuels (given as a multiplier of the fossil transport fuel price)
2*	0	**1.7**	base	base	base	base	base	
3*	0	**3**	base	base	base	base	base	
4*	**50**	0	base	base	base	base	base	Variation of the cost for emitting fossil CO_2
5*	**100**	0	base	base	base	base	base	
6	0	0	base	**av.**	**av.**	**av.**	base	Energy prices harmonized in the individual EU member states[a]
7*	0	**1.7**	base	**av.**	**av.**	**av.**	base	
8	0	0	base	**min**	**min**	**min**	base	
9*	0	**1.7**	base	**min**	**min**	**min**	base	
10	0	0	base	**max**	**max**	**max**	base	
11	0	0	base	base	base	base	**no exp.**	No expansion of current district heating load
12*	0	**1.7**	base	base	base	base	**no exp.**	
13*	**100**	0	base	base	base	base	**no exp.**	
14*	0	**1.7**	base	base	base	**0**	base	Heat price variation
15	0	0	base	base	base	**+100%**	base	
16*	0	**1.7**	base	base	base	**+100%**	base	
17	0	0	base	base	**+50%**	base	base	Electricity price variation
18	0	0	base	base	**+100%**	base	base	
19*	0	**1.7**	**cost +50%**	base	base	base	base	Biomass cost increased
20*	**100**	0	**cost +50%**	base	base	base	base	
21	0	0	**+waste**	base	base	base	base	Waste included as feedstock
22	0	0	base	base	base	base	base	**Fixed 3% biofuel demand[b]**
23	0	0	**+waste**	base	base	base	base	

[a] Scenario 6-7: weighted average prices (transport fuel, 12.5 €/GJ, electricity 19.9 €/GJ, heat 6.1 €/GJ).
Scenario 8-9: lowest current prices (transport fuel, 11.3 €/GJ, electricity 11.0 €/GJ, heat 3.3 €/GJ).
Scenario 10: highest current prices (transport fuel, 13.9 €/GJ, electricity 27.1 €/GJ, heat 9.9 €/GJ).
[b] No limit on how large share of the total annual forest increment that is available for biofuel production.

4 Results

4.1 Biofuel production plant locations

Large scale biomass production plants with a capacity of 25 $t_{biomass}$/h or larger have been considered. In the base scenario (0) the optimal solution does not contain any biofuel production plants. Instead the entire transport fuel demand is met by fossil fuels. In the 23 studied parameter variation scenarios the optimal number of plants range from 0 to 74. For all the scenarios all resulting production plants reach the maximum plant capacity of 100 $t_{biomass}$/h. Table 7 summarizes the number of production plants of each biofuel production technology type included in the optimal solution for each scenario.

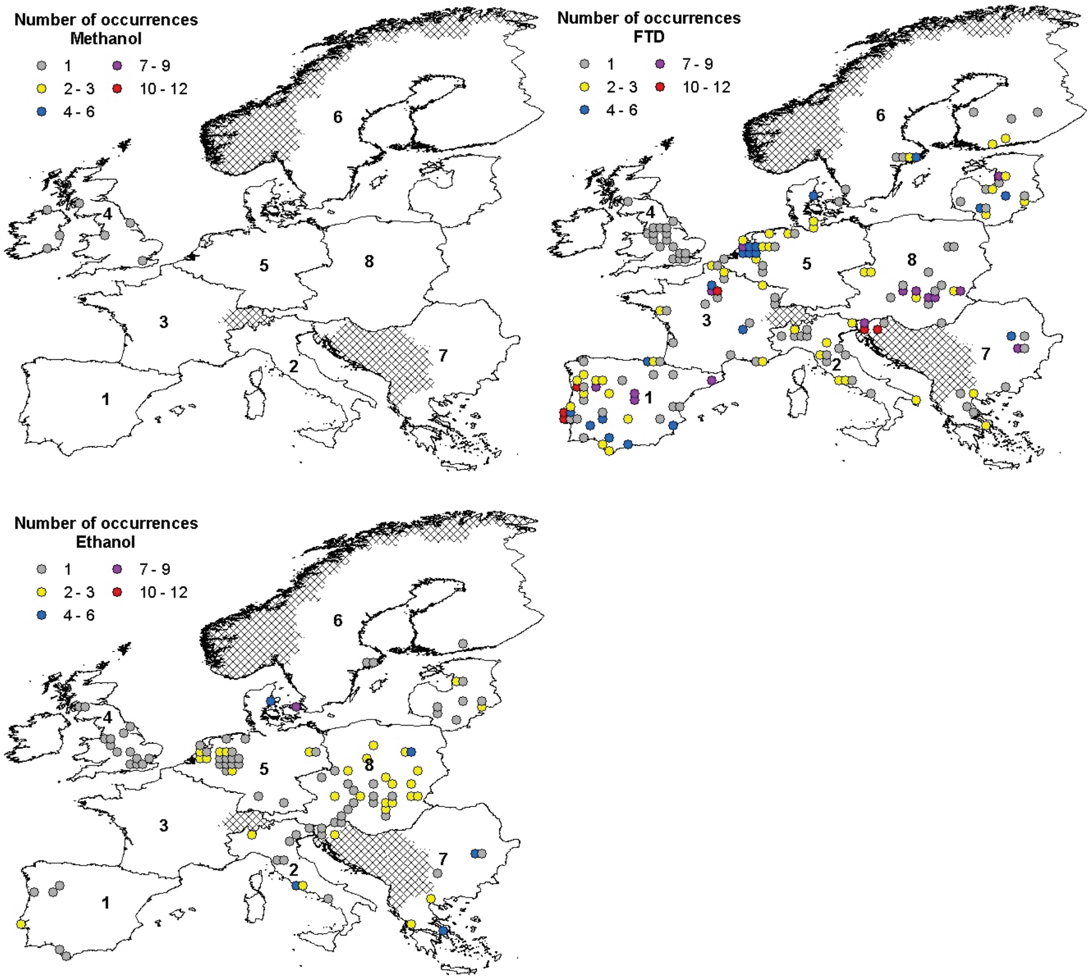

Figure *7* shows the geographic distribution of the optimal plant locations, grouped by number of occurrences over all the analyzed scenarios for each of the three studied technologies.

Table 7. Number of production plants per technology in each studied scenario. Scenarios marked with * include policy support.

Scenario	Methanol	FTD	Ethanol
0	–	–	–
1*	–	16	–
2*	–	36	–
3*	–	49	–
4*	–	20	14
5*	–	23	28
6	–	–	–
7*	–	31	–
8	–	–	–
9*	–	5	–
10	–	–	12
11	–	–	–
12*	–	30	–
13*	–	23	22
14*	–	20	–
15	–	–	–
16*	–	20	12
17	–	1	7
18	–	–	27
19*	–	12	–
20*	–	14	21
21	–	57	7
22	7	60	–
23	–	54	20

As can be seen, FTD is the dominating technology, with the optimal plant locations distributed over large areas of the EU. Typically, plants are located close to sites with large population, as these locations allows for both direct delivery of biofuel and sale of excess heat. When removing the revenue for heat (scenario 14) most of the large city locations consequently become unprofitable since they are in general located far from the biomass supply.

In scenarios that include a CO_2 cost (scenarios 4, 5, 13 and 20) the technology choice shifts towards ethanol plants. The reason is the high electrical efficiency of the ethanol plants in combination with the generally significantly higher CO_2 emission factor of displaced electricity compared to displaced fossil transport fuel. The inclusion of a CO_2 cost thus favors the technology with the highest co-production of electricity. With high electricity prices (scenarios 10, 17 and 18) the shift to ethanol plants is even more pronounced. Increased heat prices (scenario 16) also favor ethanol production, if to a somewhat lesser extent. Again the reason is the high co-product efficiency.

The co-products also influence which plant type dominates a particular region. While a larger share of the FTD plants is located in the western regions, the eastern regions dominate the optimal plant locations for ethanol plants. This can be explained by the high CO_2 emission factors of electricity in large parts of eastern EU, where low-efficiency coal condensing power dominates the electricity supply, as well as by high electricity prices, in particular in Slovakia and Hungary (region 8).

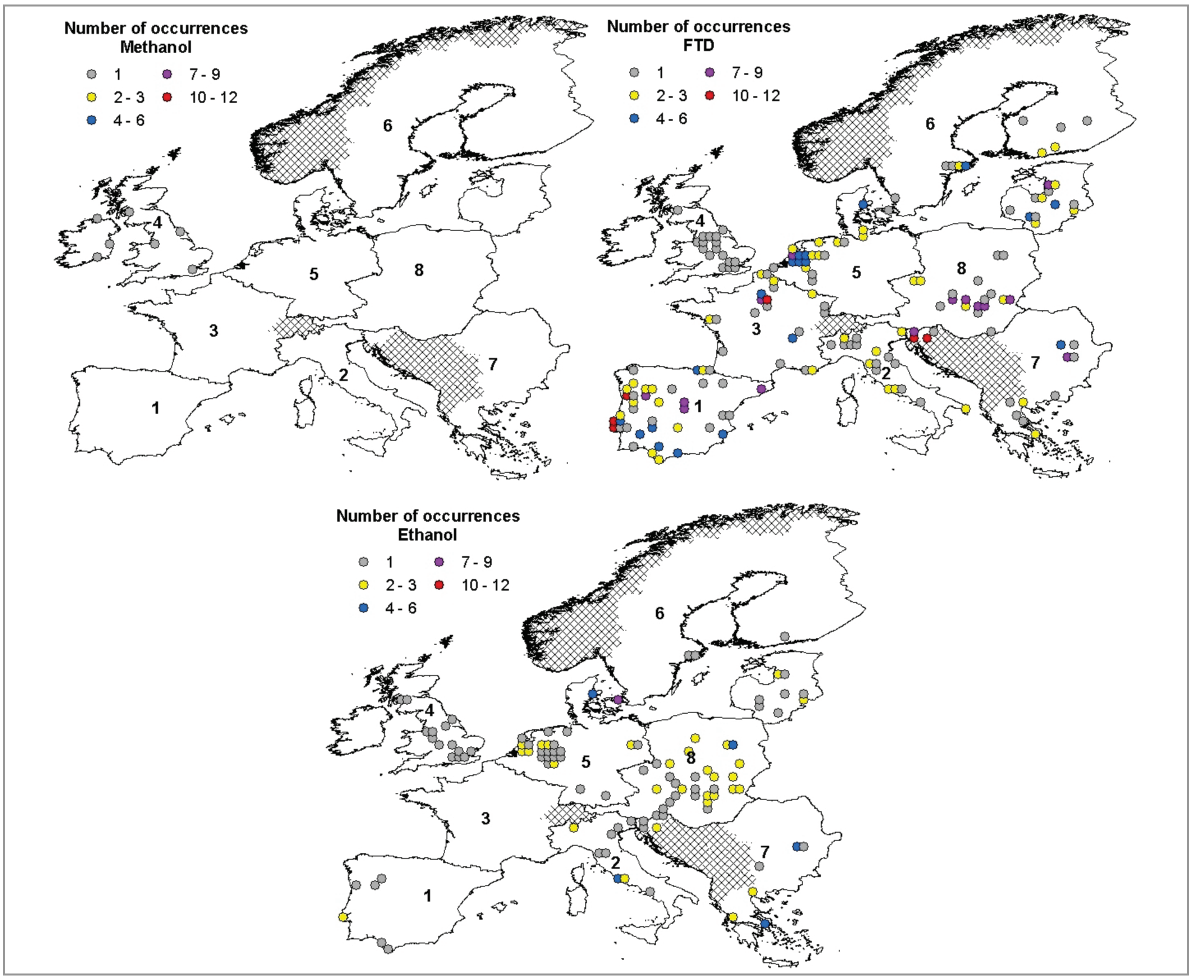

Figure 7. Number of plant occurrences for each of the three studied biofuels.

Methanol notably is only included in one scenario (scenario 21, with fixed biofuel demand), and then only in region 4 (UK and Ireland), where the fuel demand is high and the availability of forest biomass very low, which favors high biofuel efficiency. The low co-production of heat and electricity of methanol plays a certain role in this. However, of larger influence are likely differences in input data. Investment cost data has been attained from different sources and adjusted to the same economic base year (2009), using the CEPCI (2010), as described in Section 2.3. However, the data for methanol as well as ethanol is significantly older than the FTD data, which makes the uncertainty introduced by the currency adjustment larger. Ideally data from all the technologies included would come from the same source and using the same economic base year. It is reasonable to assume that the production costs of two similar technologies, the gasification based methanol and FTD, should be comparable which they are not here, as can be seen in Table 1.

It should be noted that nine of the modeled scenarios include targeted biofuel support while only four include a CO_2 cost, which is why the magnitude of the FTD plant occurrence shown in

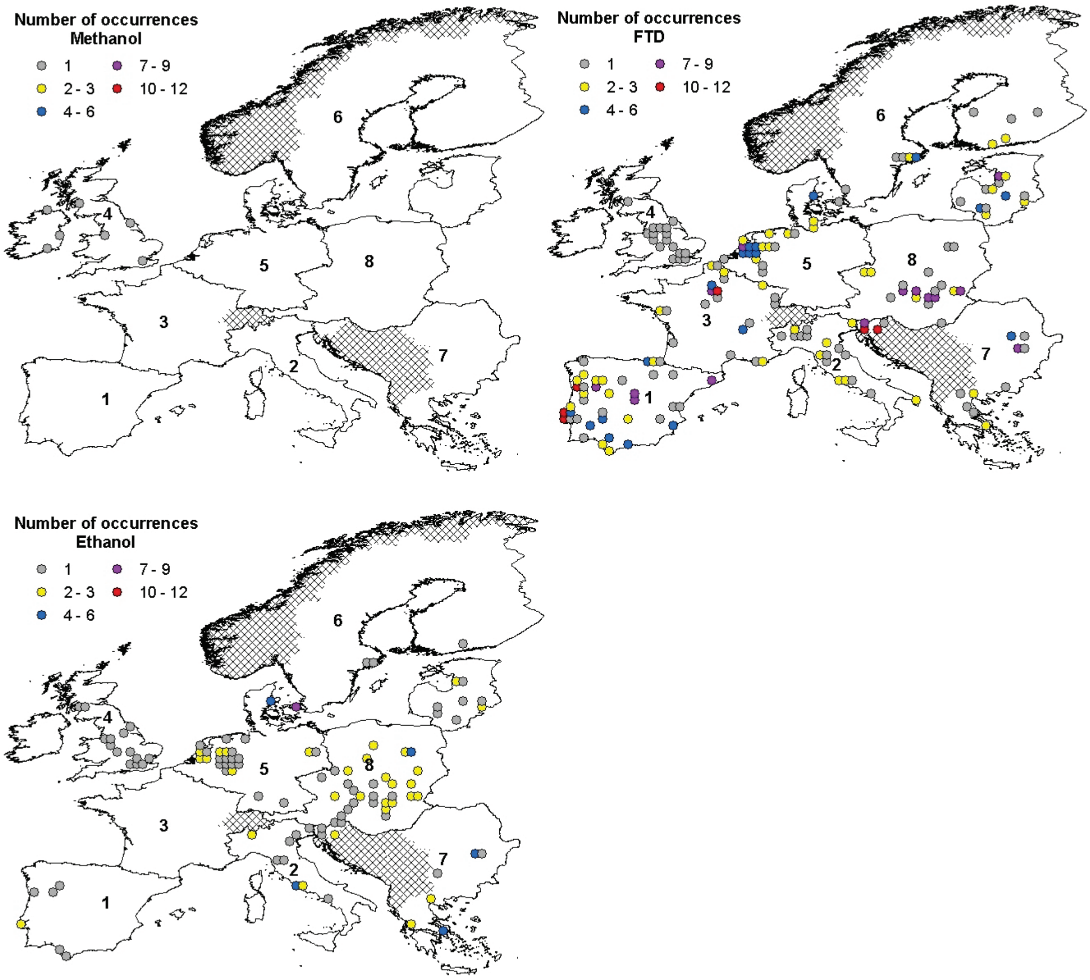

Figure *7* is naturally somewhat larger than the occurrence of ethanol plants. The number of scenarios incorporating CO_2 cost was considered adequate for the aim of this study, as the total number of scenarios is still rather large.

4.2 Biofuel production costs

The production costs have been calculated for each possible plant location, for one technology and plant size at a time. The results are shown in Figure 8-10 for 100 $t_{biomass}$/h plants, using either forest residues only as feedstock, or forest residues and waste. Energy prices and energy demand as in the base scenario (0) have been used, with no policy support included.

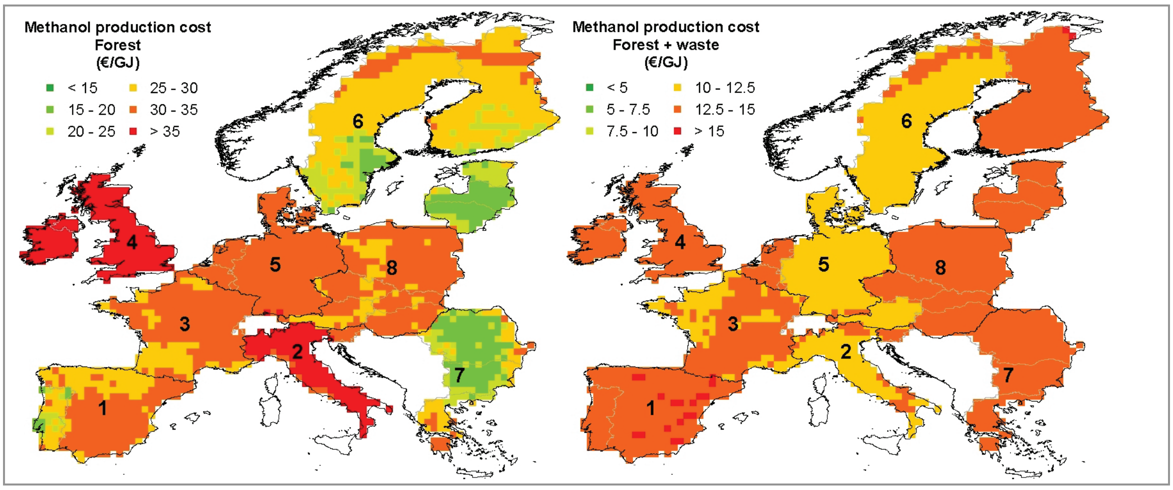

Figure 8. Production costs (€/GJ$_{biofuel}$) for a 100 t$_{biomass}$/h methanol plant, using forest residues (left) and forest residues + waste (right) as feedstock.

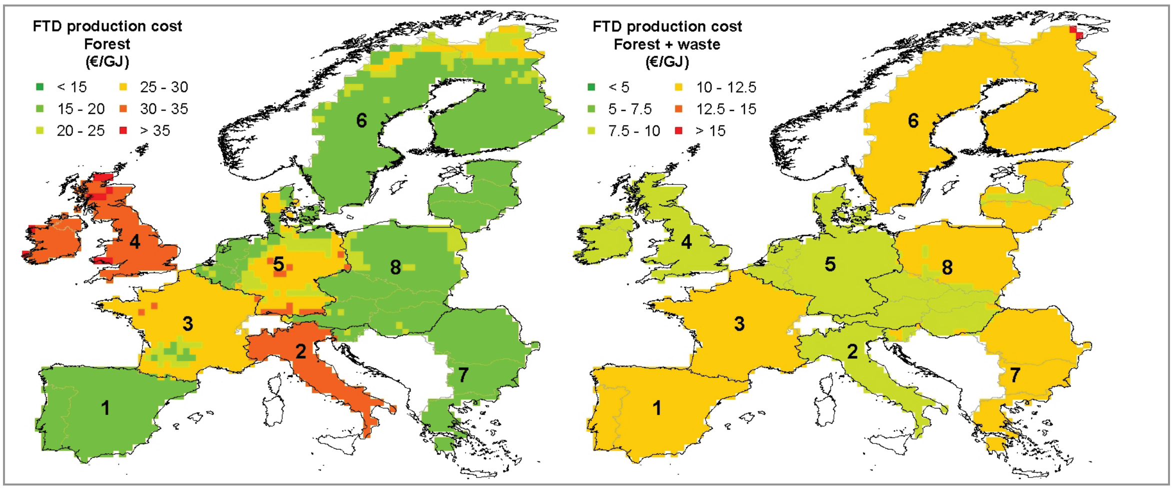

Figure 9. Production costs (€/GJ$_{biofuel}$) for a 100 t$_{biomass}$/h FTD plant, using forest residues (left) and forest residues + waste (right) as feedstock.

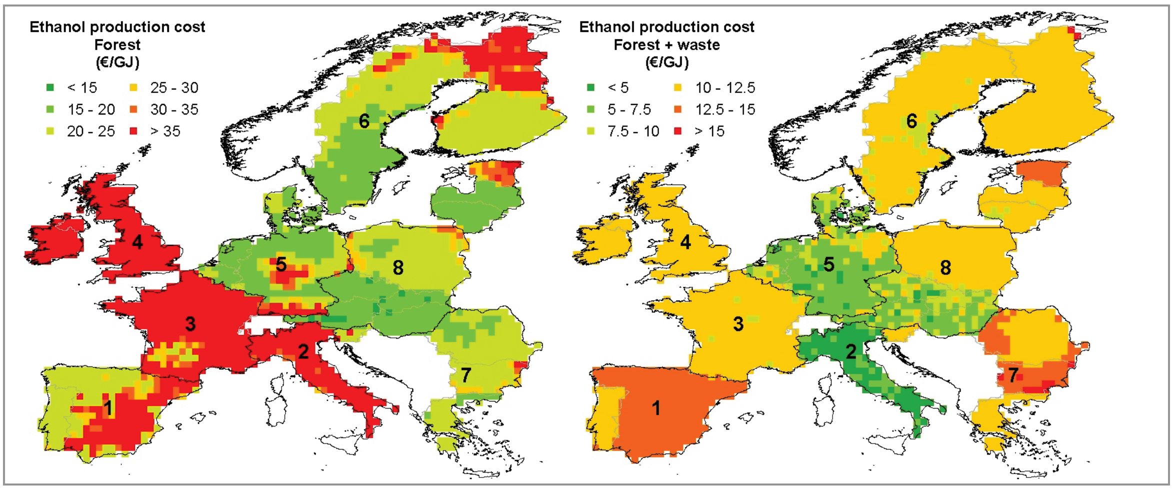

Figure 10. Production costs (€/GJ$_{biofuel}$) for a 100 t$_{biomass}$/h ethanol plant, using forest residues (left) and forest residues + waste (right) as feedstock.

The cost distribution charts accentuate the differences between the technologies regarding dependency on co-product sales. When looking at the case with forest residues only as feedstock, ethanol (Figure 10, left chart) with its high co-production of heat and electricity shows a large variance in production costs (13-52 €/GJ), depending mainly on electricity prices and heat load availability. Methanol (Figure 8, left chart) and FTD (Figure 9, left chart) both show somewhat less disparity (methanol 18-38 €/GJ, FTD 15-35 €/GJ). For all three technologies region 4 (UK and Ireland) has the highest production costs, due to the long transportation distances of biomass from other regions. Ethanol with its low biomass to biofuel conversion efficiency shows the most sensitivity to the high transportation costs.

Conversely, when also considering waste as a feedstock ethanol benefits more than the two gasification technologies from the possibility to use low cost feedstock. Also with waste ethanol shows the widest cost range – 2-31 €/GJ compared to 12-23 €/GJ for methanol and 9-19 €/GJ for FTD, respectively. The possibility to use waste also influences the cost dispersal between regions. This is most notable for regions 2 (Italy) and 4, which are both high cost regions for all three technologies when only forest residues are considered as feedstock, but not when waste can be used. Regions 2 and 4 both have good waste availability, but a small supply of low cost forest biomass.

4.3 Biofuel supply costs and biofuel share

The optimal plant locations are not only affected by the production costs, but also by the distance to the biofuel end-users. Figure 11 shows the average EU biofuel supply costs in each studied scenario, where the supply cost includes the production cost as well as the cost for transporting and distributing the produced biofuel. In the figure the supply costs are shown in relation to the resulting share of second generation biofuels in the EU transport fuel mix.

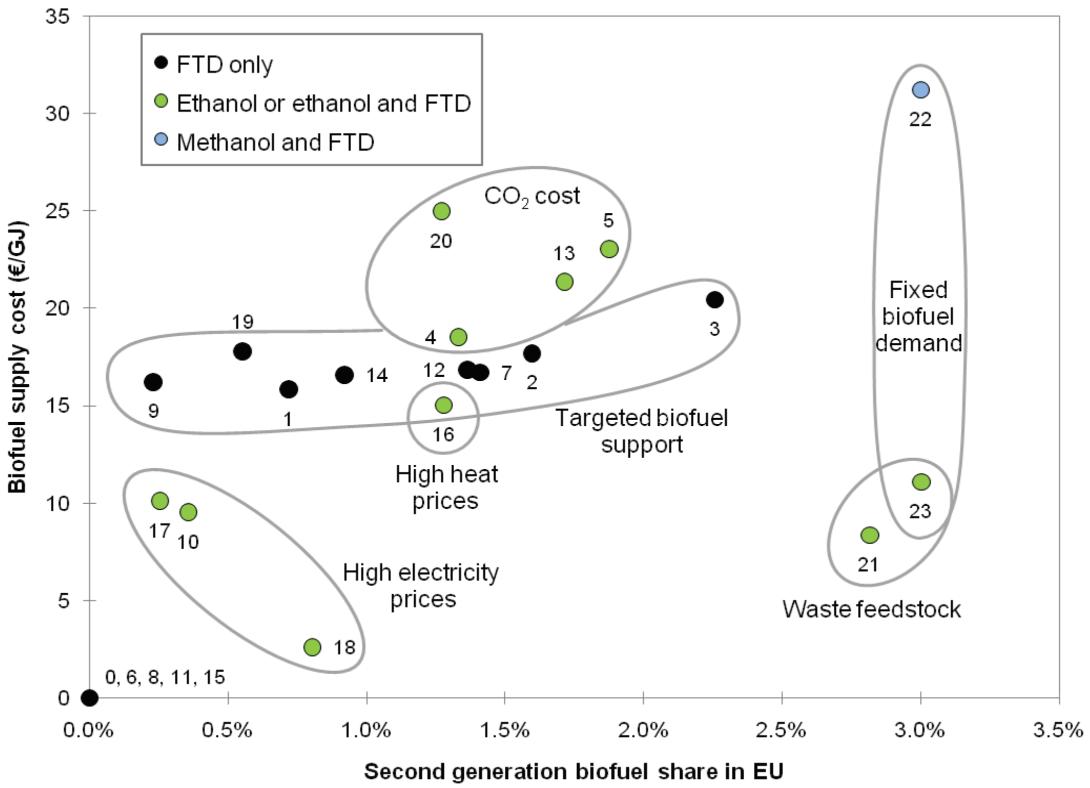

Figure 11. Average biofuel supply costs (€/GJ) related to second generation biofuel share for all modeled scenarios. The color of the markers indicates plant types in the optimal solution for each scenario. For scenarios 0, 6, 8, 11 and 15 the optimal solutions contain no biofuel plants.

The inclusion of targeted biofuel support has a large impact on the biofuel share but a relatively small impact on the cost of supplying biofuel. If comparing scenario 3 in which a very high support level (approximately 25 €/GJ) is applied, with scenario 1 which incorporates a low support (about 6 €/GJ), the biofuel production is more than three times as high in scenario 3, while the supply cost is less than 30% higher. It should be noted that the cost of the support is not included in the calculated supply costs, but will of course still affect the final consumer price. With a CO_2 cost applied the supply costs are in general higher and the biofuel share lower, because of a shift towards ethanol which has lower biofuel efficiency and on average higher production costs.

Increased electricity and heat prices (scenarios 10, 17 and 18, and 16) also further ethanol production. This leads to lower biofuel shares, but also to lower supply costs due to the increased revenues from co-products. Correspondingly, lowered heat and electricity prices (scenarios 6-9 and 14) also reduce the biofuel shares and, in the scenarios where plants are set up, lead to slightly lower biofuel supply costs (compared to scenario 2 which incorporates the same policy level).This is due to that with lower prices fewer plants are set up in the optimal solution and thus only the lowest cost locations are chosen. The same effects can be seen when the heat delivery potential is lowered (scenarios 12 and 13). Ethanol production is more affected than FTD production by changes in the heat load. When the available heat load is reduced in scenario 13 (compared to scenario 5 with the same policy level applied) the number of FTD plants remains unchanged, while the number of ethanol plants decreases.

Higher feedstock costs drastically affect the biofuel production volume when a targeted biofuel support is applied (compare scenario 19 to scenario 2). This effect is less pronounced when a CO_2 cost is applied (compare scenario 20 to scenario 5). Including waste as a feedstock (scenarios 21 and 23) also triggers the inclusion of ethanol plants. Even though scenario 21 does not contain any specific biofuel incentives a biofuel share of almost 3% is reached. At this production rate about 80% of all available lignocellulosic waste is utilized for biofuel production, with all regions except the sparsely populated region 6 using all or almost all their waste.

When fixing the second generation biofuel demand to 3% a larger share of the total annual forest biomass increment than the 20% assumed available for biofuel production will be needed. The higher feedstock costs and longer transportation distances significantly increase the biofuel supply cost (scenario 22), unless waste can be used as feedstock (scenario 23).

4.4 Biofuel share and CO_2 emission reduction potential

As mentioned in the introduction reduced fossil CO_2 emissions is one of the motivators for a transition towards biofuels. This study considers CO_2 emissions from transportation of biomass and biofuel, as well as offset emissions from displaced fossil energy carriers. Figure 12 shows the potential CO_2 emission reduction in the studied scenarios. In the same figure the biofuel share is included.

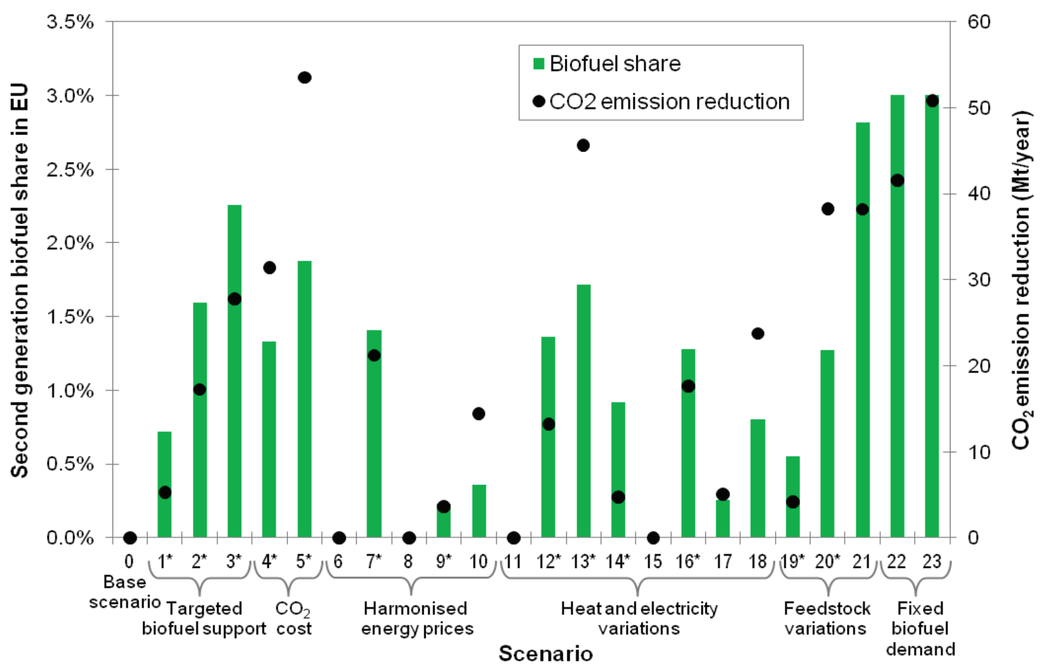

Figure 12. Second generation biofuel share and CO_2 emission reduction potential (Mt_{CO2}/year) for all modeled scenarios. Scenarios marked with * include policy support.

Scenarios with a high CO_2 cost (scenarios 5, 13 and 20) naturally have large emission reduction potentials, as the cost of emitting CO_2 is included in the objective function. An increasing biofuel share in general entails an increasing reduction potential (compare scenarios 1, 2 and 3), but a high biofuel share does not however guarantee a large decrease of CO_2 emissions. For example, the emission reduction potential in scenario 21 (waste included as feedstock) is comparable to the reduction potential in scenario 20 (CO_2 cost and high forest prices), even though the biofuel production in scenario 20 is less than half that in scenario 21.

The scenarios with large CO_2 emission reductions in relation to the biofuel production have in common a significant share of ethanol plants. As discussed in Section 4.1 a significant part of the reduced CO_2 emissions can be attributed to the co-products, in particular electricity, since electricity in general has a higher CO_2 emission factor than fossil transport fuel, especially in large parts of eastern EU. This indicates that if stationary biomass applications, for example CHP plants or co-firing with coal in condensing power plants, were included in the model biofuel production might not benefit from a high CO_2 cost, in particular in the case of ethanol.

5 Discussion

This study has presented the development of an already existing optimization model to a larger scale – from the national to the EU level. The analyzed scenarios have been chosen both to be able to make a broad screening of which parameters that have large impact on the results, and to be able to identify areas where the model and input data can be improved.

On the feedstock side only preliminary G4M forest data was available for this study. In particular data for northern EU (region 6) needs updating. However, since region 6 has a relatively low population density and consequent low fuel demand, a higher volume of available forest biomass is not likely to significantly affect for example the number of biofuel plants in this region. Further, the forest data now included regards annual increment of all above ground forest biomass and does not take into account the actual utilization rate of biomass in different countries, the inclusion of which would improve the quality of the model results. Also the waste data could be improved, as the downscaling from national waste supply data underestimates the waste supply in sparsely populated areas, which is typically where a large share of the waste from the forest industry would be located. Additional improvement potential on the feedstock side can be found by including agricultural residues as well as dedicated cellulosic energy crops, such as short rotation forest, since these resources constitute the main lignocellulosic feedstock potential in many regions within the EU. Different pre-treatment options could also be considered, something which has been shown in previous studies to have significant impact on supply chain costs.

Current energy prices here have been used as a basis, with sensitivity analysis of one price parameter at a time. Since various energy market parameters are strongly linked it would be interesting to include price scenarios with interdependent parameters in the analysis. It would also be of interest to include country specific policies on biofuels and other renewable energy, to study the effects of national policies in relation to EU policies.

The results show that the two policy instruments studied, targeted biofuel support and a CO_2 cost, respectively, to a certain extent counteract each other and the corresponding EU targets. The introduction of a CO_2 cost has been shown to favor production of ethanol, due to the high displacement of fossil electricity and heat. This suggests that if other biomass use alternatives, such as biomass based CHP or co-firing with coal in condensing power plants, were included in the study the results may be very different. Similarly other high-volume biomass users, in particular the forest industry which is currently highly interesting as basis for future biorefineries, should be included, to be able to analyze effects of feedstock competition.

Since all the considered biofuel production technologies have reasonably high co-production of heat, that in this study has been assumed to be possible to use in district heating, the optimal plant locations are typically close to cities with large heat demands. In reality large cities are unlikely to be considered for biofuel production, due to high land prices and issues related to the logistics of largescale biomass handling. This has not been taken into account in the model work performed in this study, but could be included in future work. Also, as discussed in Section 2.4 no data on actual district heating systems has been included. Since district heating systems are typically of a highly local character, with large individual differences between different systems, data on at least the location and size of actual district heating systems would be a significant improvement. This would however require an extensive data collection effort.

This study has been limited to the study of a few second generation biofuels. It would also be possible to include first generation fuels as well as import options, both regarding biofuels such as sugar-cane ethanol, and regarding biomass feedstock, both of which are already today traded over the EU borders. This would give the possibility to further analyze the dynamic effects of various policy instruments related to the EU renewable energy targets.

6 Conclusions

The aim of this study has been to use the EU biofuel localization model to investigate how second generation biofuel production is affected by different parameters, in particular policy instruments and energy prices. Two policy instruments have been considered – a targeted biofuel support in the form of for example tax reduction, feed-in tariffs or green certificates, and a cost of emitting fossil CO_2, in the form of for example a tax or tradable emission permits. A 3% goal for second generation biofuels in the EU transport fuel mix has been used as a basis for the analysis.

The results show that with current energy prices and a targeted biofuel support corresponding to the tax exemption in place in many EU countries today, over 1.5% of the total transport fuel demand can be met by second generation biofuels to a cost of approximately 18 €/GJ, which can be compared to the fossil fuel price of on average 13 €/GJ used in this study. With higher support the biofuel share could reach almost 2.5%. The biofuel production volume is however sensitive to a number of parameters. For example, if the feedstock cost is increased by 50% or if the potential to sell excess heat is removed, the biofuel share drops to under 1%. Applying a CO_2 cost of 100 €/t_{CO2}results in a biofuel production equivalent to about 2% of the total fuel demand, but to a higher cost than with a specific biofuel support (23 €/GJ).

When targeted biofuel support is applied FTD is the dominating technology, while the inclusion of a CO_2 cost induces a shift towards more ethanol production. The reason is the large co-production of electricity and the high CO_2 emissions from displaced electricity in large parts of the EU, in particular in the eastern regions. Ethanol, with high co-production of both electricity and heat, is consequently more sensitive to energy market related parameters such as heat and electricity prices and available heat load, than is FTD. Only one studied scenario features methanol, the third biofuel included, due to low co-product efficiency and high capital costs.

In order to meet 3% of the EU transport fuel demand with second generation biofuels to a reasonable cost, waste must be used as a feedstock. If only forest residues are considered the biofuel supply cost exceeds 30 €/GJ, compared to around 11 €/GJ if low cost waste can be used.

The results further show that high shares of second generation biofuels can lead to considerable reductions of fossil CO_2 emissions. However, the reduction potential depends largely on the co-products, in particular electricity, which is why a high biofuel share is not a guarantee for a large decrease of CO_2 emissions. In the scenario with the resulting largest emission reduction, 54 Mt_{CO2}/year, the biofuel share is less than 2%, while the scenario with the highest biofuel share (3%) has a reduction potential of just over 50 Mt_{CO2}/year. Since the reduction potential of second generation biofuels can to a large extent be attributed to the co-products, it is recommended that, in order to avoid suboptimal overall energy systems, heat and electricity applications should also be included in future studies aiming at evaluating how biomass can be used to decrease CO_2 emissions.

It can be concluded that while forceful policies promoting biofuels may indeed lead to a high share of second generation biofuels to reasonable costs, this is not a certain path towards maximized CO_2 emission mitigation. The two policy instruments included in this study are to some extent both in place in the EU today. The results from this study show a potential conflict of interests between different parts of the overall EU targets of increased use of renewable energy in transport and decreased CO_2 emissions. Since biomass is a limited resource, policies aiming at promoting the use of it need to be carefully designed in order not to counteract each other. A final conclusion is that in order to reach the EU targets, interdisciplinary cross-sectoral energy system studies will be needed.

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Appendix A. Waste data

Data on the amount of waste for the individual EU member states has been obtained from (Eurostat, 2010b) and is shown in Table A.1. All waste is non-hazardous waste from all branches plus households in 2006. Recovered waste is all treatment recovered waste, from all branches plus households. All waste not currently recovered is assumed available for biofuel production. Wood waste and paper and cardboard waste are both assumed to have an energy content of 18.5 GJ/t and a moisture content of 20%.

Table A.1. Reported generated and recovered waste amounts in the EU member states in 2006.

Country	**Waste generation (1000 t)**		**Recovered waste (1000 t)**	
	Wood	**Paper/cardboard**	**Wood**	**Paper/cardboard**
Austria	2,020	6,277	1,425	2,282
Belgium	4,524	1,721	630	440
Bulgaria	317	159	125	0
Czech Rep.	637	634	201	120
Denmark	788	862	788	862
Estonia	439	1,791	6	398
Finland	1,231	13,223	734	4,122
France	7,611	7,411	6,050	3,727
Germany	9,334	8,261	5,922	2,502
Greece	474	745	425	63
Hungary	574	482	344	174
Ireland	1,101	401	26	180
Italy	5,612	2,450	4,143	2,450
Latvia	28	239	18	0
Lithuania	95	220	95	34
Luxembourg	97	63	0	0
Netherlands	2,751	1,728	2,731	705
Poland	769	2,803	212	419
Portugal	2,380	1,168	781	681
Romania	1,099	1,458	335	109
Slovakia	199	768	108	421
Slovenia	175	1,154	175	0
Spain	4,648	1,904	3,346	573
Sweden	2,405	22,277	1,846	10,916
UK	14,242	7,596	4,174	2,747

Appendix B. District heating data

Data on district heating in the EU has been obtained from (Egeskog et al., 2009a; Werner, 2006). Table B.1 gives details on the existing total district heating demand (2003) as well as the potential additional demand for 2020. The existing district heating production mix is also shown. For details on assumptions for the potential district heating expansion, see (Werner, 2006).

Table B.1. District heating demand in 2003, expansion potential for 2020 and composition of the aggregated national DH systems (Egeskog et al., 2009a; Werner, 2006).

Country	**Heat demand (PJ)**		**Heat production mix 2003[a]**				
	Total 2003	**Additional 2020[a]**	**Fossil CHP**	**Fossil HOB**	**Bio/waste CHP**	**Bio/waste HOB**	**Other**
Austria	55	49	58%	13%	6.5%	21%	0.8%
Belgium	23	81	92%	0%	7.3%	0.9%	0%
Bulgaria	54	12	77%	22%	0%	0%	1.3%
Czech Rep.	147	67	73%	23%	2.7%	0.9%	0%
Denmark	130	15	63%	4.0%	19%	14%	0.2%
Estonia	26	3.3	40%	48%	0%	12%	0%
Finland	170	17	60%	17%	16%	7.0%	0.1%
France	109	342	0.0%	74%	17%	1.2%	7.8%
Germany	391	584	92%	0%	6.8%	0%	1.0%
Greece	1.0	18	100%	0%	0%	0%	0%
Hungary	64	77	67%	31%	0.7%	0.2%	1.4%
Ireland	0.1	20	0.0%	0%	0%	0%	100%
Italy	20	152	63%	19%	0%	14%	4.5%
Latvia	34	4.9	44%	41%	0.8%	13%	0%
Lithuania	44	5.0	45%	41%	0.9%	7.7%	5.1%
Luxembourg	1.9	5.4	96%	0%	4.5%	0%	0%
Netherlands	115	143	93%	0%	7.0%	0%	0%
Poland	368	167	61%	39%	0.7%	0.3%	0%
Portugal	9.4	13	100%	0%	0%	0%	0%
Romania	151	48	74%	26%	0.3%	0.1%	0%
Slovakia	56	32	50%	44%	1.1%	0.9%	3.9%
Slovenia	10	11	68%	28%	0.6%	3.2%	0%
Spain	0.0	85	0.0%	0%	0%	0%	0%
Sweden	185	18	15%	7.7%	39%	15%	24%
UK	75	289	90%	7.1%	2.7%	0%	0%

[a]'Fossil CHP' and 'Fossil HOB' include coal, oil and natural gas fired CHP and HOB, respectively. 'Bio/waste CHP' and 'Bio/waste HOB' include CHP and HOB heat from combustible renewables and waste. 'Other' includes waste heat, electricity (direct or in heat pumps), nuclear, geothermal, solar etc.

The year has been divided into three seasons of equal length to accommodate for seasonal heat load variations. Three different load curves are used; one representing the northern EU countries (Denmark, Estonia, Finland, Latvia, Lithuania, Sweden), one representing the central (Austria, Belgium, Bulgaria, Czech Republic, France, Germany, Hungary, Ireland, Luxembourg, Netherlands, Poland, Romania, Slovakia, United Kingdom) and one representing the southern countries (Greece, Italy, Spain, Portugal, Slovenia). For the northern countries the heat load profile of Linköping, Sweden (Bennstam, 2008; Difs et al., 2010) was assumed to be representative, for the central countries the load profile of Budapest, Hungary (Sigmond, 2010) was used, and for the southern countries the load profile of Manzano, Italy (Chinese and Meneghetti, 2005).

For Italy the load in (Chinese and Meneghetti, 2005) was supplemented with a hot tap water load. The adapted, seasonalized heat loads are shown in Figure B.1.

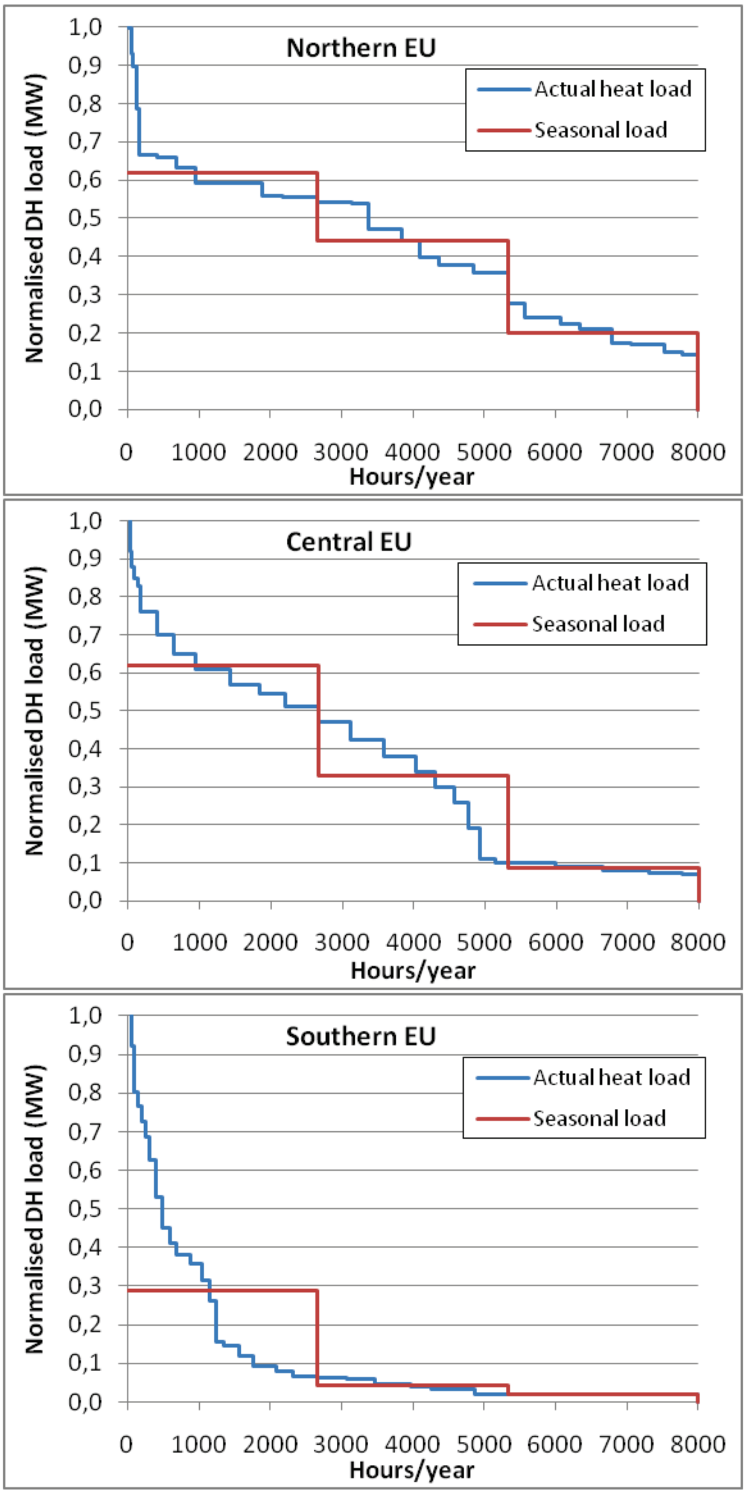

Figure B.1. Heat load profiles for different latitudes. Actual loads (normalized) and seasonal load adaptations.

Appendix C. Transport fuel demand

Data on projected transport fuel demand and population sizes in 2020 has been obtained from (European Commission, 2008b), taking into account the energy use for public road transport, trucks and private cars and motorcycles is considered. Country specific data is presented in Table C.1.

Table C.1. Projected population, total transport fuel demand and second generation biofuel at a 3% share in 2020 (European Commission, 2008b).

Country	**Population (million inhabitants)**	**Total transport fuel demand (PJ/year)**	**2nd gen. biofuel demand at a 3% share (PJ/year)**
Austria	8.44	333	9.98
Belgium	10.8	383	11.5
Bulgaria	6.80	154	4.62
Czech Rep.	9.90	341	10.2
Denmark	5.53	187	5.60
Estonia	1.25	39.7	1.19
Finland	5.41	179	5.38
France	63.6	1980	59.3
Germany	82.7	2220	66.6
Greece	11.4	334	10.0
Hungary	9.69	213	6.39
Ireland	4.76	210	6.29
Italy	58.3	1900	57.0
Latvia	2.12	63.8	1.91
Lithuania	3.18	75.6	2.27
Luxembourg	0.52	114	3.41
Netherlands	17.2	523	15.7
Poland	37.1	767	23.0
Portugal	10.8	302	9.06
Romania	20.3	293	8.79
Slovakia	5.27	98.8	2.96
Slovenia	2.02	99.2	2.98
Spain	45.6	1680	50.3
Sweden	9.58	342	10.2
UK	62.9	1760	52.9

Appendix D. CO_2 emission factors

Excess heat from biofuel production is assumed to replace both existing fossil fuel based district heating, and a share of the non-district heating fossil fuel based heat of each country. From the country specific mixes of replaceable heat CO_2 emission factors are calculated using generic heat production efficiencies and fuel emission factors (Egeskog et al., 2009b; Uppenberg et al., 2001; Werner, 2006). Electricity produced in CHP plants is given an emission credit based on the country specific electricity emission factor. Electricity emissions are end-user life cycle emissions for national grid mixes (European Commission, 2010a). Transport fuel emissions are average emissions for petrol and diesel, with no country specific differences considered (Uppenberg et al., 2001). Applied emission factors are given in Table D.1.

Table D.1 CO_2 emission factors for displaced fossil energy carriers (kg_{CO2}/GJ).

Country	Transport fuel	District heating	Electricity
Austria	78.1	73.5	87.3
Belgium	78.1	67.3	109
Bulgaria	78.1	48.8	242
Czech Rep.	78.1	66.4	214
Denmark	78.1	48.0	208
Estonia	78.1	29.6	432
Finland	78.1	80.7	135
France	78.1	72.1	39.3
Germany	78.1	59.7	187
Greece	78.1	79.1	311
Hungary	78.1	58.0	175
Ireland	78.1	76.9	234
Italy	78.1	65.1	186
Latvia	78.1	55.8	152
Lithuania	78.1	74.5	51.4
Luxembourg	78.1	60.3	159
Netherlands	78.1	44.0	195
Poland	78.1	64.3	316
Portugal	78.1	54.1	210
Romania	78.1	36.0	275
Slovakia	78.1	72.9	89.2
Slovenia	78.1	78.4	158
Spain	78.1	70.9	176
Sweden	78.1	104	29.9
UK	78.1	59.7	173