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Comparing Biomass-Based and Conventional Heating Systems with Costly CO_2 Emissions: Heat Cost Estimations and CO_2 Breakeven Prices

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This study investigates the full cost of heat for combustion technologies in a context of reducing CO2 emissions and increasing renewable energy consumption share in the European Union. The use of biomass in only-boilers or CHPs in both the industrial sector and in District Heat Systems may contribute to reach these European targets.

This study aims to better understand the economics of heat production technologies. We attempt to determine the most profitable heat production technology given parameters such as the load factor and the carbon price level. This study proposes a method to find Carbon Switching Prices that correspond to carbon prices from which biomass technologies become more profitable than fossil fuelled technologies for the production of heat.

Heat cost structures and thus Carbon Switching Prices (CSPs) are highly dependent on the load factor. Biomass technologies turn out to be high capital-intensive compared to fossil fuelled technologies so that the lower the load factor, the higher the CSP. Generally, gas technologies enjoy low fixed costs that enable them to be the most profitable technologies for low load factors. Without any CO2 price, biomass only boilers and CHPs are never competitive compared to fossil fuelled technologies. For low load factors (at 2500h), biomass boilers CSPs range between 80€/ton and 90€/ton whereas CHP CSPs are 40€/ton higher. However, for higher load factors (at 5000h), lower carbon prices (between 40 and 60€/ton) are needed to make profitable biomass technologies. Finally, the study shows that CSPs are very sensitive to biomass prices.

Keywords: Heat Costs, Breakeven Price, LLCOH, CHPs, Boilers, Biomass.

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Outlines

Abstract

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Abstract

(FR) L'objectif de cette étude est de comparer le coût complet de production de la chaleur pour différentes technologies de combustion dans le contexte Européen de réduction des émissions de CO2 et d'augmentation de la part consommée en énergies renouvelables. La combustion de biomasse dans des chaudières seules ou fonctionnant en cogénération que ce soit dans le secteur industriel ou intégrée au sein d'un réseau de distribution de chaleur est en mesure de contribuer aux objectifs fixés par l'Union Européenne.

Cette étude vise à mieux comprendre les fondamentaux économiques de la production de chaleur selon les technologies utilisées. Un ordre de mérite peut être établi à prix du carbone et durée d'utilisation donnés. Cette étude propose une méthode de calcul des prix seuils de rentabilité du CO2. Ce prix du CO2 correspond au prix du carbone à partir duquel il devient plus intéressant d'investir dans une technologie valorisant la biomasse que dans une technologie utilisant un combustible fossile pour la production de chaleur.

La structure des couts ainsi que les prix seuils du CO2 sont très dépendants de la durée d'utilisation de la technologie. Les technologies biomasse sont très capitalistiques comparées aux technologies fossiles si bien que plus la durée d'utilisation est faible, plus le prix seuil du carbone est élevé. Généralement, les technologies gaz bénéficient de faibles coûts d'investissement et de coûts de combustible élevés ce qui les rend rentables pour de faibles durées d'utilisation. Sans un prix du carbone, les technologies biomasse ne sont jamais les moins couteuses pour la fourniture de chaleur. Pour de faibles durées d'utilisation (2500h/an), les chaudières biomasse deviennent compétitives avec un prix du carbone compris entre 80€/tonne et 90€/tonne tandis que la compétitivité est atteinte entre 120€/tonne et 130€/tonne pour les cogénérations biomasse. Cependant, pour des durées d'utilisation plus conséquentes (5000h/an), un prix du carbone moins élevé (compris entre 40€/tonne et 60€/tonne) suffit généralement pour rendre les technologies biomasse compétitives par rapport aux technologies fossiles. Enfin, les prix seuils du carbone calculés sont très dépendants des prix des matières premières considérés dont celui de la biomasse.

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1. Introduction

1.1. Types of heat demand in France and comparison with OECD countries

1.1.1. Heat demand features by sectors

In France, the total heat demand in 2010 was 640 TWh (final energy). More than a half of the heat demand comes from residential needs that include principally space heating and to a lesser extent warm water supply. A fifth comes from space heating in the service sector (health and educational buildings, sports activities, commercial establishments, offices etc.). Roughly a fifth comes from the industrial sector for industrial processes.

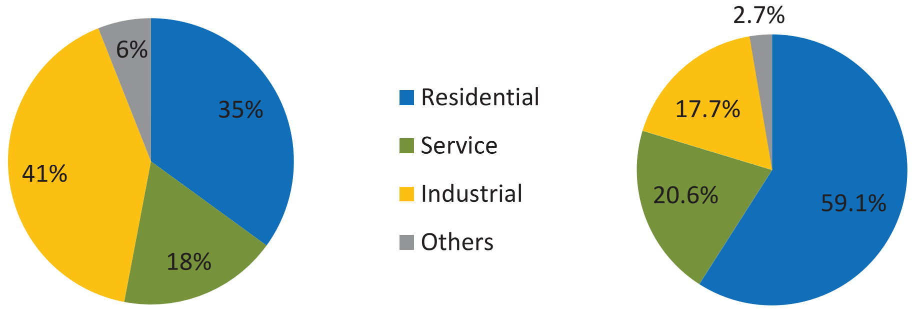

Figure 1 : (LEFT) OECD heat demand (IEA, 2012) and (RIGHT) French heat demand in 2010 by sector (MEDDEE-DGEC, 2010) (ADEME, 2013)

Demand features are different between sectors. Concerning the quality of heat determined by the temperature level, space heating requires coolant fluid temperature to be between 40°C and 90°C according to the heating technology used. 60°C are at least necessary for warm water supply. Finally for industrial use, temperatures needed are generally higher than 100°C (the drying process for example).

Regarding heat demand distribution during a year, industrial demand is likely to be constant but residential demand is seasonal. This is due to the need for space heating taking place during the colder months (generally between October and April). Moreover, space heating is dependent on the seasonal variation of the climate.

The figure below represents heat load curves for different types of demand. This graph shows the relationship between the percentage of maximum heat demand and the operating period (hours/year).

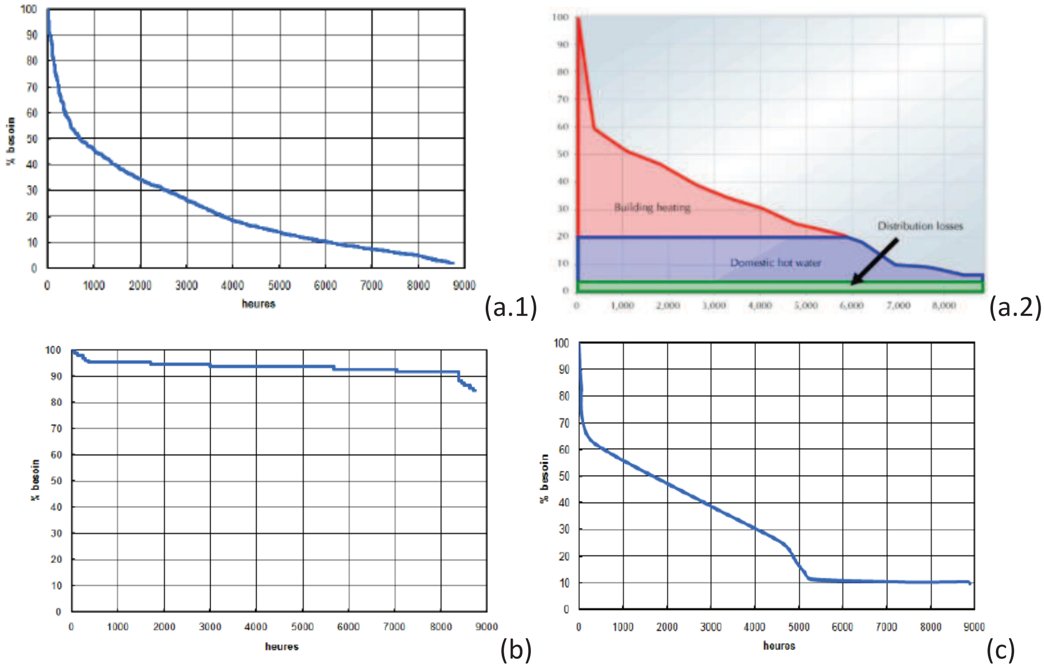

Figure 2 : Typical heat load curve shapes for different use: (a.1) residential in France (a.2) residential in Sweden (b) industrial in France (wood/paper industry) (c) District Heating System in France (MEDDEE-DGEC, 2010) (JRC European Commission, 2012)

1.1.2. Heat demand trends and determining factors

In France, as space heating (and warm water supply) in both the residential and the services sector represent the most important heat demand (70% of the total heat demand in France and 80% if we include warm water supply), we are going to focus on the determining factors of this demand. In addition, data on the specific industrial heat demand is difficult to find.

Between 1982 and 2011, there is not significant change regarding residential heat consumption. Since 2000, space heating has decreased by roughly 12% (from 370TWh in 2000 to 325TWh in 2011). This is related to an improvement of energy efficiency in the building sector Indeed, for space heating, 30% savings have been made between 1990 and 2011 (see figure 4). The share of old buildings is a driving factor for the residential heat demand and significant investments are often required to improve the energy efficiency.

Concerning the service sector, there is a rise of 7% of heat consumption between 1995 and 2011 (see figure 3 for further details) even if there has been a little improvement in energy efficiency[1] (see figure 4).

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[1] Energy Efficiency by sector represented in Figure 4 is an energy efficiency trend that include specific electricity consumptions, air cooling and other uses in addition to the heat demand. Therefore, it is impossible to find the exact cause of energy efficiency changes.

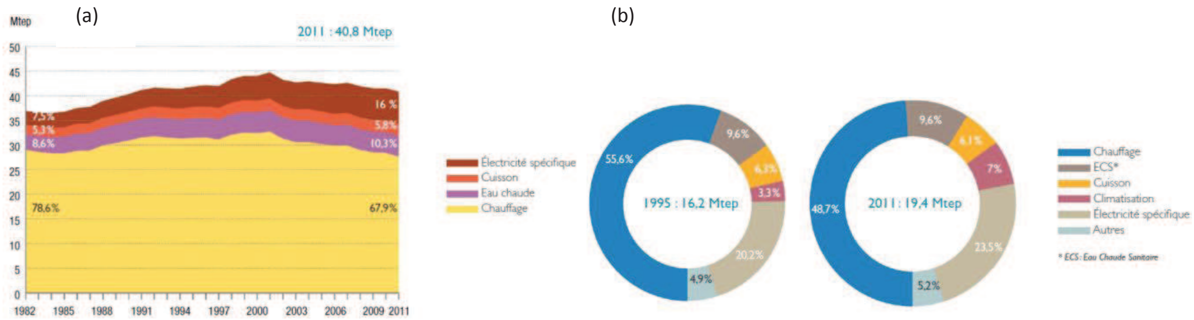


Figure 3: Residential (Left) and Services (Right) heat demand trends in France (ADEME, 2013)

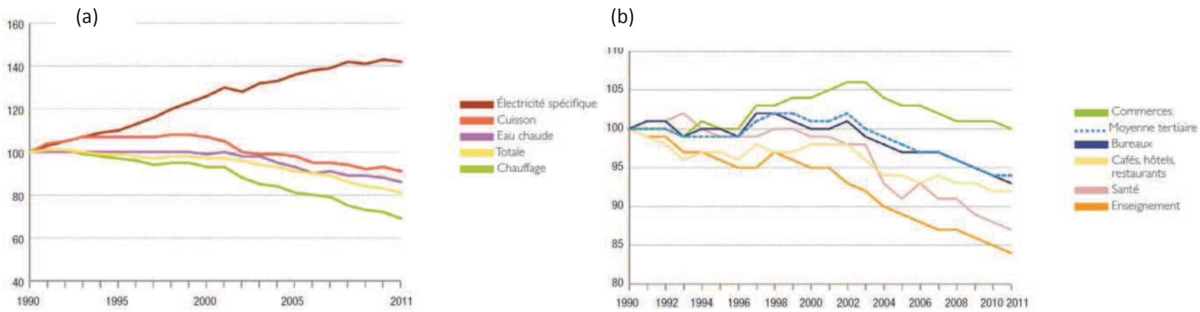


Figure 4: Residential (Left) and Services (Right) energy efficiency (kWh/dwelling/year and kWh/m2/year, index base 100 for 1990)

<u>KEY POINTS</u>: Heat demand in France (1.1)

Space heating (in both residential and services sectors) is the main component of heat demand in France. This specific demand is seasonally dependent. Recent energy efficiency improvements enabled to lower this demand. Industrial processed heat demand is particular because of the required temperature (often higher than 100°C). In addition, heat demand shape depends on industries.

1.2. Heat Supply in France and comparison with OECD countries

After giving some key information on the current distribution of fuel used to produce heat and its trends, this part will focus on two points. The first focuses on a specific production technology; Combined Heat and Power systems also called cogeneration systems. The second one focuses on a specific distribution system called District Heating System (DHS). So far, both of them are marginal but they are often subject to state subsidies because of their own potential advantages.

1.2.1. Types of fuel used to meet the heat demand

To meet specific residential and service heating demand (space heating essentially) which is the main heat demand component, countries use either fossil fuels (such as oil, gas or coal) or renewable energy sources (including biomass and waste). The use of a district heat system enables different energy sources to be used.

In 2011, in the French residential sector, natural gas is the main fuel used (39%), followed by electricity and oil fuel (19% for each). Renewable energy (wood) represents 18%. District Heating Systems only supply 5% (percentages of heat demand considering **cooking**, warm water supply and space heating. Specific electricity has been removed). Coal has rapidly disappeared. The share of oil has much decreased and has given way to gas and electricity. District Heat Systems share has remained small (see details on DHS in 1.2.3).

Regarding the services sector, natural gas covers about half of the space heating demand followed by electricity (26%) and oil fuel (18%). Here again, oil fuel has gradually given way to electricity and gas since 1990. The share of oil fuel has been divided by 2 between 1990 and 2011.

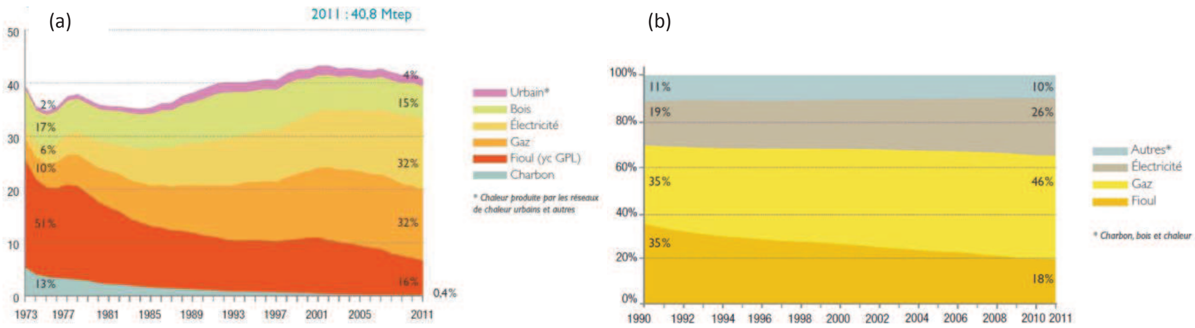


Figure 5: Residential final consumption trends by types of fuel used (Left) and types of fuel used for space heating in the service sector (Right) in France [2]

The distribution of fuel used changes from country to country. North European countries such as Denmark, Finland and Sweden have mainly developed District Heating Systems. This sort of heating represents roughly 40% of the total share in these countries but does not tell us anything about the types of fuel used. Another example is that of Italy and in the United Kingdom, 70% and 75% respectively of heat comes from gas combustion. Finally, in Sweden and Norway, the share of electricity is high (40-50%).

Generally, the share of coal has decreased drastically in the studied countries from 1990 to 2006.

[2] Graph (a) should be read carefully because the French residential final consumption includes not only the heat demand for space heating or warm water supply but also electrical specific consumption and cooking. Graph (b) only concerns the specific space heating demand in the French service sector.

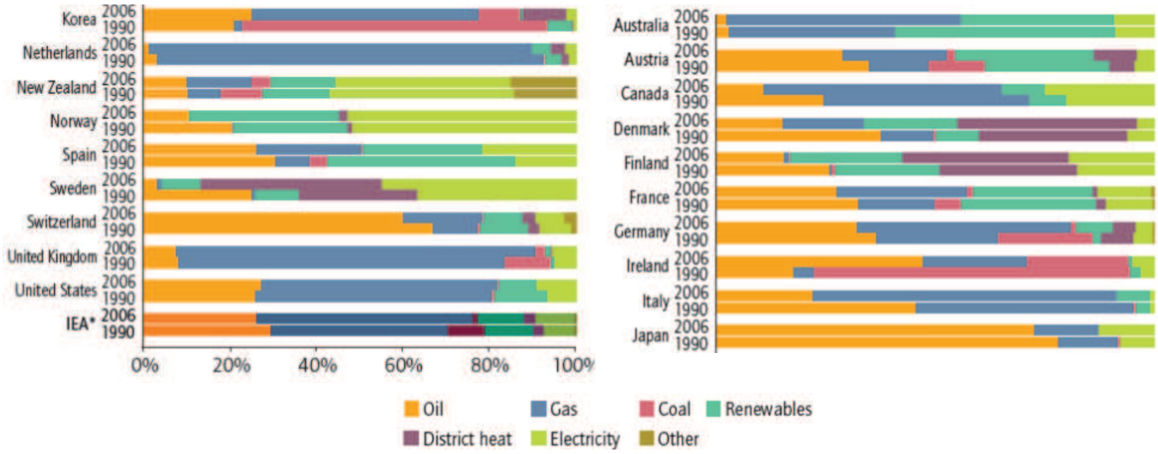


Figure 6 : Share of space heating (residential and services sectors) by fuel in some OECD countries – comparison 1990-2006 (IEA-OECD, 2009)

1.2.2. Combined Heat and Power Systems

Combined Heat and Power also known as cogeneration, is the simultaneous generation of usable heat and power (usually electricity) in a single process. CHP can be seen as a source of heat, with electricity as a by-product. The conversion efficiency of these systems (primary energy to useful energy) is generally around 80% while the latest CHP plants can reach efficiencies of 90% and higher (IEA-OECD, 2008). Thus, this system allows both energy and carbon emission savings compared to the separate generation of electricity and heat. In the following example (see Figure 7), gas CHP is 21% more efficient (carbon emission and primary energy) than the separate production of heat with a gas boiler and electricity with a gas power plant.

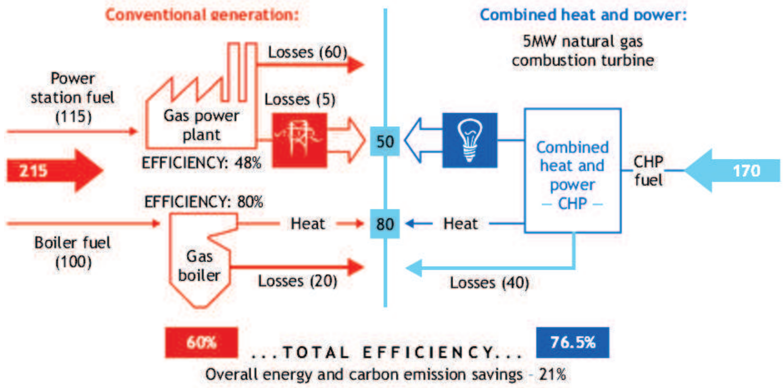


Figure 7 : Efficiency gains of CHP: one example (all values in MWh) (IEA-OECD, 2008)

In addition to these savings, other benefits cited by policy makers and industry professionals include : cost savings for the consumer, reduced reliance on imported fuel, reduced investment in energy system infrastructure, enhanced electricity network stability through reduction in congestion and 'peak saving' and finally the beneficial use of local energy resources (waste, biomass, residues) (IEA-OECD, 2008).

In 2011, 11.2% of European electricity is generated by a CHP plant even percentages differ from country to country (from 0% to 47.4%). About half of the fuel primary mix is natural gas followed by solid fossil fuels and peat (≈21%). Renewable energy sources stand for ≈15% of the total energy mix (see figure 11). The highest installed capacity is by far in Germany with roughly 26GWe plus 65GWth. In France, there are approximately 5GWe and 14GWth (see figure 12).

In France, there are roughly 800 plants for an annual electricity production of 22TWhe and an annual heat production of 51TWh essentially fuelled by natural gas (90%). The capacity of the plants is normally higher than 2MWe. CHP plants are mainly built to meet industrial demand (62% of the total CHP electric capacity) or district heat systems (24%) and to a lesser extent, the service sector (7%) and the residential sector (5%). The main technologies used are gas turbines (56% of the total CHP electric capacity), internal combustion engines (23%) steam turbines (19%) and combined cycles (2%) (MEDDEE-DGEC, 2010).

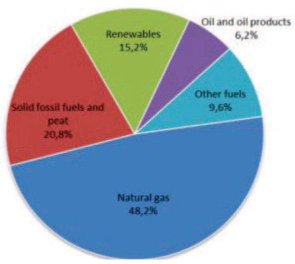


Figure 8 : CHP fuel mix for EU-27 in 2011 (COGEN Europe based on Eurostat data, 2013)

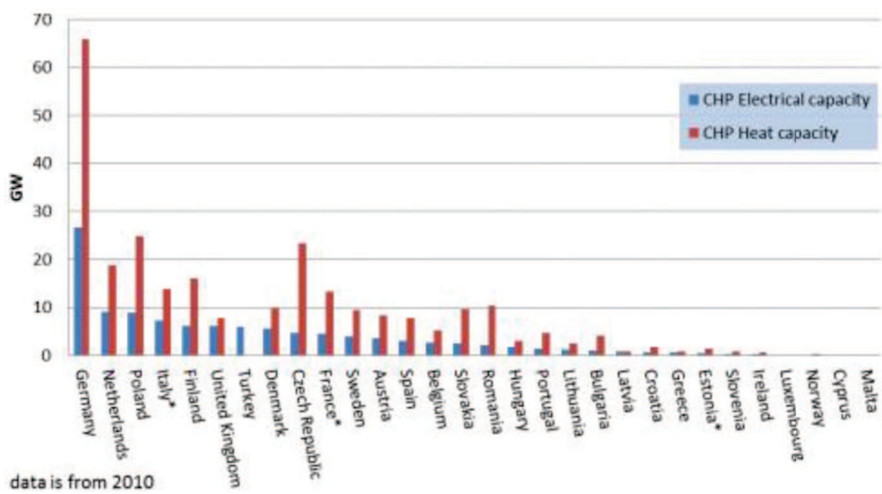


Figure 9 : CHP electrical and heat capacity in EU-27 in 2011 (COGEN Europe based on Eurostat data, 2013)

Finally, CHP technologies are supported by the European Union (directive 2004/8/CE) and Member States have set up measures to promote their use. For instance, green certificates, CHP cap, Feed-in-Tariff for cogenerated electricity or investment subsidies have been implemented across the EU.

1.2.3. District Heating Systems

A District Heating System also known as a heat network, supplies heat from one (or several) central source(s) directly to homes and business through a network of pipes carrying hot water or steam. A DHS is composed of heat production plants (such as CHPs, heat-only boilers, incineration plants...), distribution networks and customer installations. The system can meet both the warm water demand and the space heating demand.

Compared to individual boilers, DHS enables economies of scale on the production units. Indeed, the higher the capacity, the lower the investment cost (expressed in €/kW). However, other costs for DHS such as heat network costs, heating station costs or network pumping costs have to be considered.

Figure 10 : District Heating System principle (ADEME)

In Europe, DHS have mainly been developed in Northern and Eastern countries (and in Italy). They are principally used to meet a residential demand (see Figure 8). Between 40% and 60% of the citizens in the Czech Republic, Denmark, Estonia, Finland, Latvia, Lithuania, Poland, Slovenia and Sweden are served by district heating (Euroheat & Power). It is mainly 'recycled heat' (heat from CHP and from industrial processes independently from the fuel used and waste-to-energy) but the data does not give us a precise analysis. The use of renewable energy sources is very high in Iceland and Latvia (respectively 70% and 50%). Otherwise, biomass resources cover between 10% and 30% of the heat generated in Austria, Denmark, Estonia, France, Lithuania, Norway, and Sweden. The use of fossil fuelled heat-only boilers represents roughly between 20% and 40% of the heat production (see figure 9).

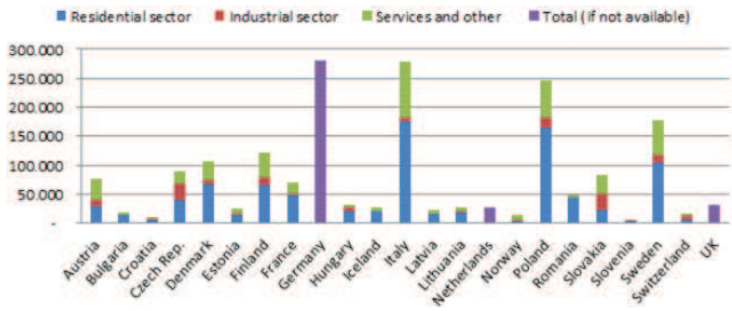
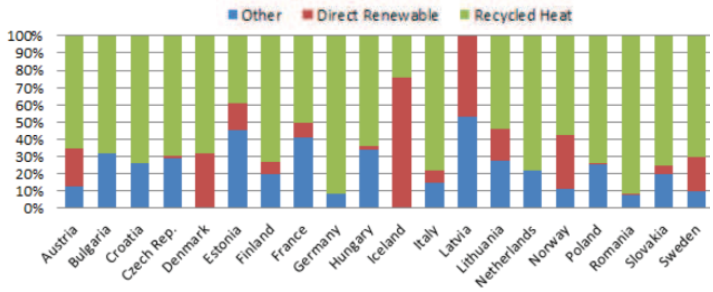


Figure 11: European District heating sales to customers in 2012 in TJ (Euroheat & Power)



'Recycled heat' includes surplus heat from electricity production (CHP), waste to energy plants and industrial processes independently from the fuel used for the primary process. Two third of the energy delivered by heat pumps are also considered as recycled heat. **'Direct Renewable'** covers the use of renewable in heat-only boilers and installations other than CHP. **'Others'** covers fossil fuelled heat-only boilers, electricity and one-third of the heat originating from heat pumps.

Figure 12: Fuel composition of European District Heat Generated in 2012 (Euroheat & Power)

In France, the share of district heating is low. It only represents 5% of the total heat demand (MEDDEE-DGEC, 2010). In 2011, 458 are in use with 16GWth installed and 22TWh supplied. Residential heat stand for 55% of the total share, 35% for services needs 10% for industrial needs. Fuels used are mainly fossil fuels (45% gas, 35% renewable sources, 20% coal, oil and others). Among the 10TWh of renewable heat produced in 2011, 67% comes from a waste incineration plant, 16% from biomass, 9% from geothermal energy and 8% from other sources. Coal and fuel have gradually given way to gas. The share of biomass has remained quite stable with a small increase since 2009 (SNCU, 2012). Between 1987 and 2011, French district heat production has remained almost stable (see figure 10).

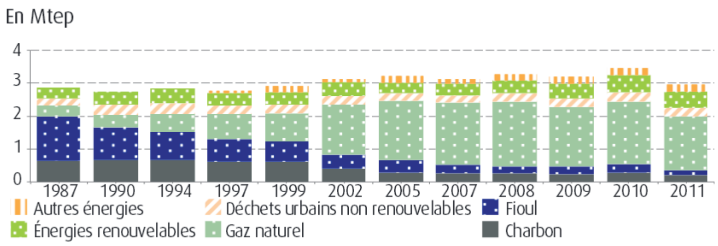


Figure 13 : District Heating System development in France by fuel source from 1987 to 2011 (MEDDEE, 2014)

In France, subsidies are provided to these systems to promote the use of renewable energy sources to produce heat. For instance, tax credits are granted when at least 50% of the produced heat comes from renewable sources.

<u>**KEY POINTS**</u>**: Heat supply in France (1.2)**

The main fuel used to produce heat is natural gas both in the residential and services sectors (industrial sector excluded). Electricity and oil fuel rank just behind. Renewable energy sources cover 20% of the residential heat demand (mainly log wood).

CHP systems allow fuel and CO2 savings thanks to a better energy efficiency whereas DHS enable economies of scale and allow the use of a range of energy sources (heat recovery, biomass, fossil fuels). They are both subsidized by the governments under specific conditions. CHPs are mainly used to meet an industrial demand whereas DHSs principally provide a residential and service heat.

Both French CHP and DHS heat productions are low compared to the total heat demand (50TWh/year and 22TWh/year respectively). The position of gas versus other forms of energy in the overall energy balance of these systems is high (90% for CHPs and 45% for DHSs) even if renewable energy sources represent 35% of the total DHS heat supply.

1.3. Objectives and questions of the study

By 2020, the Directive 2009/28/EC (Climate and Energy Package) aims to reduce GHG emissions by 20% compared to the 1990 level, reach 20% of renewable energy in the total energy consumption and increase energy efficiency by 20%. France adopted more stringent targets with 23% of renewable energy in the total energy consumption by 2020 and 32% by 2030. To meet these requirements, one conceivable solution could be the deployment of DHS and the use of CHP (Lund and al., 2009) to supply heat. The use of biomass in these systems could contribute to reach the Renewable Energy Sources targets.

This study aims to better understand the economics of heat production technologies. We try to determine the optimal heat production technology given parameters such as: the load factor (measure of the operating time at full capacity throughout a year) and the carbon price level (European-Union Emission Trading System). The study is organised into three main parts.

Firstly, we calculate full heat production costs and discuss cost structures. We use the Levelised Lifetime Cost Of Energy (LLCOE) which is the usual indicator to evaluate the economic performance of a power system (IEA, 2010). Calculation methods are based on Bertrand and Le Cadre (2014). And we adapted the method for heat production cost calculations as it has already been done in IPCC (2011). Calculations are done for heat-only boilers and Combined Heat and Power plants.

Secondly, we calculate the carbon price that enables biomass-based technologies to become profitable compared with conventional technologies. We rely on literature about fuel switching, which describes the ability of European power producers to reduce their CO2 emissions by switching fuels from coal to gas in electricity generation (e.g. Delarue et al., 2010; Bertrand, 2012; Solier, 2013). Thus, a switching price is derived, which reflects the CO2 price that is compatible with a profitable fuel switching. Similarly to Bertrand (2013), we adapt this method in order to investigate the profitability of biomass against competing technologies. However, we focus on long-term investment costs for heating generation systems. This allows us to derive ***Carbon Switching Prices (CSP)*** that correspond to the carbon prices that make investment in biomass or fossil-fuel technologies equally attractive. These values reflect the carbon price levels from which it becomes more profitable to invest in biomass-based technologies than in conventional units.

Finally, as types of resources used can be different according to the local context, biomass prices may show a discrepancy from 11€/MWh to more than 30€/MWh (European Climate Foundation, 2010). As a result, a sensitivity analysis is carried out.

2. Methodology

2.1. Calculation of Levelised Lifetime Cost Of Heat (LLCOH)

2.1.1. General assumptions

General economical assumptions are presented in table 1. Similarly to Le Truong and Gustavson (2014), we assume an equal lifetime of 25 years for all equipments. With an 8% discount rate this translates into a 9.37% capital recovery factor. As a simplification, we do not consider heat distribution costs (such as distribution network in case of a DHS) and heat network losses. On the one hand, these costs are pretty small compared with other expenses and they do not modify the merit order as they apply in the same way to each technology[3]. On the other hand, this allows deriving more general values that do not apply to resident heat with network only. Finally, for sake of generality, we do not include tax or subsidies other than carbon price that can highly differ from one country to another.

Change €/$	1,25
Discount rate	8%
Lifetime (years)	25
Capital Recovery Factor	9,37%

Table 1 : General economic assumptions

2.1.2. Base methodology for heat-only boilers

We use the calculation methods developed by Bertrand and Le Cadre (2014) but have adapted them to heat production instead of electricity generation. The LLCOH is the ratio of the total lifetime discounted cost divided by the total lifetime discounted heat. It takes into accounts different streams of costs such as investment cost, Operation and Maintenance (Variable and Fixed) costs, fuel and carbon costs for each technology and in the same unit (Euros/MWh heat). It is the heat production cost that breakeven the sum of discounted future expenditure flow. In other words, it is the minimum price heat has to be sold to pay off all the expenditures during the life of the plant. Thus, it allows us to compare heat prices between technologies.

The general formula of LLCOH for a given technology is developed in equation 1.

NB: So that the reader can understand, no technology index and type of fuel index has been included except for the Emission Factor (EF) which is defined for a given type of fuel f.

$$\mathbf{LLCOH} = \frac{\sum_{t=1}^{n} \frac{(\mathbf{Investment\ cost + O\&M\ cost + Fuel\ cost + Carbon\ cost})_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{(\mathbf{Heat\ produced})_t}{(1+r)^t}}$$

eq.(1)

*Where **n** is the life of the plant (years) and **r** is the discount rate (%).*

[3] The Swedish Energy Agency (2013) estimates distribution losses at roughly 7%. Another study carried out by Poredos et al. (2001) finds losses up to 10%.
Regarding distribution costs, they are estimated by Prévot H. (2006) between 5€/MWh and 10€/MWh of heat produced.

We can separate each term of eq. (1) as followed:

$$\mathbf{LLCOH = \underbrace{LLCINV + LLCOMF}_{Fixed\ costs} + \underbrace{LLCOMV + LLCF + LLCC}_{Variable\ costs}}$$

eq.(2)

Where,

LLCINV *Levelised Lifetime Cost of Investment*

LLCOMF *Levelised Lifetime Cost of Operation and Maintenance Fixed*

LLCOMV *Levelised Lifetime Cost of Operation and Maintenance Variable*

LLCF *Levelised Lifetime Cost of Fuel*

LLCC *Levelised Lifetime Cost of Carbon*

Equations 2a, 2b, 2c, 2d, 2e are the five calculations for each term of this sum.

$$\mathbf{LLCINV} = \frac{\sum_{t=1}^{n} \frac{\mathbf{CRF \times invcost}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{\mathbf{8760 \times lf}}{(1+r)^t}} = \frac{\mathbf{CRF \times invcost}}{\mathbf{8760\ x\ lf}}$$

eq.(2a)

*Where '**CRF**' is the Capital Recovery Factor, invcost is the investment cost (€/MW)*

*'**lf**' is the load factor of 0 to 1 which is the utilization rate. It takes the value 0 if the plant is not used at all and it takes the value 1 if the plant is used 8760h (number of hours in one year).*

$$\mathbf{LLCOMF} = \frac{\sum_{t=1}^{n} \frac{\mathbf{fcost}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{\mathbf{8760 \times lf}}{(1+r)^t}} = \frac{\mathbf{fcost}}{\mathbf{8760\ x\ lf}}$$

eq.(2b)

*Where '**fcost**' is the fixed Operating and Maintenance Cost (€/MW/year)*

$$\mathbf{LLCOMV} = \frac{\sum_{t=1}^{n} \frac{\mathbf{8760 \times lf}}{(1+r)^t} \times \mathbf{vcost}}{\sum_{t=1}^{n} \frac{\mathbf{8760 \times lf}}{(1+r)^t}} = \mathbf{vcost}$$

eq.(2c)

*Where '**vcost**' is the variable Operating and Maintenance Cost (€/MWh heat)*

$$\mathbf{LLCOF} = \frac{\sum_{t=1}^{n} \frac{8760 \times lf}{(1+r)^t} \times \frac{FP}{\eta_{heat}}}{\sum_{t=1}^{n} \frac{8760 \times lf}{(1+r)^t}} = \frac{FP}{\eta_{heat}}$$

eq.(2d)

*Where '**FP**' is the Fuel Price (€/MWh fuel) and* η_{heat} *is the efficiency rate of the plant (ratio MWh of heat output / MWh of primary energy input.*

$$\mathbf{LLCOC} = \frac{\sum_{t=1}^{n} \frac{8760 \times lf}{(1+r)^t} \times \frac{CP \times Ef}{\eta_{heat}}}{\sum_{t=1}^{n} \frac{8760 \times lf}{(1+r)^t}} = \frac{CP \times EF}{\eta_{heat}}$$

eq.(2e)

*Where '**CP**' is the Carbon Price (€/ton), '**EF**' the CO2 Emission Factor associated with a given fuel (tCO2/MWh fuel)* η_{heat} *is the efficiency rate of the plant (ratio MWh of heat output / MWh of primary energy input)*

2.1.3. Extension to CHP technologies

Calculations are not as straightforward as for heat only boilers because of the joint production of heat and electricity. This issue has already been discussed in some studies carried out by Sjödin & Henning (2004) or Gustavsson et al. (2011). Different methods of allocation are explained. The approach used in this study is the residual approach which considers the value of generated electricity set to the generation cost in a standard reference power plant. Total CHP costs (heat and electricity) are subtracted by this electricity value to get the heat costs. This method has been used by Le Truong & Gustavsson (2014).

Let **α** the electricity to heat ratio (**α**<1 means that each time 1MWh of heat is produced, **α** MWh of electricity is cogenerated).

$$\mathbf{LLCOH_{CHP}} = \mathbf{LLCINV_{CHP}} + \mathbf{LLCOMF_{CHP}} + \mathbf{LLCOMV_{CHP}} + \mathbf{LLCOF_{CHP}} + \mathbf{LLCOC_{CHP}} - \alpha_{CHP} \times V_{elec,ref}$$

Then, using the previous equations (2a to 2e), we get:

$$\mathbf{LLCOH_{CHP}} = \frac{CRF \times invcost + fcost}{8760 \text{ x } lf} + vcost + \frac{FP}{\eta_{heat}} + \frac{CP \times EF}{\eta_{heat}} - \alpha_{CHP} \times V_{elec,ref}$$

eq.(3)

Where $\mathbf{LLCOH_{CHP}}$ is the Levelised heat production cost for a CHP plant (€/MWh heat), **invcost** is the investment costs (€/MW heat), **fcost** is the fixed O&M costs (€/MW heat), **vcost** is the variable O&M costs (€/MWh heat), **FP** is the fuel cost of the plant (€/MWh fuel), η_{heat} is the efficiency of heat production of the CHP plant, **CP** is the Carbon Price (€/ton), **EF** is the CO2 Emission Factor associated with a given fuel (tCO2/MWh fuel) and $\boldsymbol{\alpha}_{\mathbf{CHP}}$ is the electricity to heat ratio.

As we chose to apply the residual approach to calculate the cogeneration heat costs, we subtract $\boldsymbol{\alpha} \times \mathbf{V_{elec}}$ where $\mathbf{V_{elec}}$ is the value of a reference power plant. It is calculated with the same method developed in 2.1 but applied for electricity so that a Levelised Cost of Electricity (instead of Heat) is calculated. Thus, for each carbon price and load factor combination the value of cogenerated electricity is assumed to be equivalent to the electricity from minimum-cost standalone condensing power plants. Further details of these technologies are provided in 2.2. The objective is to find which type of power plant would have been used to produce this cogenerated electricity (opportunity cost approach).

The following power plants are considered: Combined-Cycle-Gas-Turbine, Internal Gas Turbine and Supercritical Pulverized Coal Plant. In general, for small load factors, Gas Turbines are the most profitable. For off-peak periods, Combined-Cycle-Gas-Turbines turn out to be the best technologies. Coal power plants are only profitable for very high load factors and at a low CO2 price.

2.2. Calculation of Long Term Carbon Switching Prices

2.2.1. Base methodology for heat-only boilers

By making the long-term-marginal cost (LLCOH) between a fossil-fuel-based-technology and a biomass-based-technology equal, we derive the expression of Long Term Carbon Switching Price which is the price from which it becomes economically interesting to invest in a biomass plant to produce heat.

For two technologies f and b respectively associated with 2 types of fuel f (meaning fossil) and b (meaning biomass).

By making $\mathbf{LLCOH_f = LLCOH_b}$, we get:

$$\Downarrow$$

$$\mathbf{CP}_{\mathbf{f}=>b} = \frac{\boldsymbol{\eta}_{\mathbf{heat,f}}}{\mathbf{EF_f}} \times \Delta[\mathbf{LLCOMV} + \mathbf{LLCOF} + \mathbf{LLCOMF} + \mathbf{LLCINV}]_{\mathbf{b-f}}$$

eq.(4.a)

Developing each term, we get:

$$\mathbf{CP}_{\mathbf{f}=>b} = \frac{\boldsymbol{\eta}_{\mathbf{heat,f}}}{\mathbf{EF_f}} \times \left\{ (\mathbf{vcost_b} - \mathbf{vcost_f}) + \left(\frac{\mathbf{FP_b}}{\boldsymbol{\eta}_{\mathbf{heat,b}}} - \frac{\mathbf{FP_f}}{\boldsymbol{\eta}_{\mathbf{heat,f}}}\right) + \frac{\mathbf{CRF}}{\mathbf{8760 \times lf}} \times [\,(\mathbf{invcost_b} - \mathbf{invcost_f}) + (\mathbf{fcost_b} - \mathbf{fcost_f})\,] \right\}$$

eq.(4.b)

Where $\mathbf{CP}_{\mathbf{f}=>b}$ is the long-term carbon switching price (€/ton CO_2) that enables a biomass based technology **b** to be as profitable as a fossil fuel based technology **f**.

$\frac{\eta_{heat,f}}{EF_f}$ is the ratio of MWh heat produced per ton of CO_2 emitted for the fossil fuel based technology. The rest (in blue brackets) is the difference of cost (in €/MWh heat) excluding CO_2 between the biomass based technology and the fossil fuel based technology.

The higher the carbon efficiency ratio for the fossil fuel based technology $\frac{\eta_{heat,f}}{EF_f}$, the higher the carbon switching price. The higher the cost difference in blue brackets, the higher the carbon switching price.

2.2.2. Extension to CHPs (General Formula)

Calculations become more complicated as carbon price is introduced in $\mathbf{V_{elec,ref}}$. From eq.(5), we add the cost of electricity generated weighted by the electricity-to-heat ratio for both the biomass technology 'b' and the fossil fuel technology 'f'. 'elec' refers to a standalone power plant.

$$\mathbf{CP_{f=>b}} = \frac{\Delta[\mathbf{LLCOMV} + \mathbf{LLCOF} + \mathbf{LLCOMF} + \mathbf{LLCINV}]_{\mathbf{b-f}} - \Delta[\alpha]_{\mathbf{b-f}} \times (\mathbf{LLCINV} + \mathbf{LLCOMF} + \mathbf{LLCOMV} + \mathbf{LLCOF})_{\mathbf{elec}}}{\frac{\eta_{\mathbf{heat,f}}}{\mathbf{EF_f}} + \Delta[\alpha]_{\mathbf{b-f}} \left(\frac{\mathbf{EF_{elec}}}{\eta_{\mathbf{elec}}}\right)}$$

eq.(4.c)

With no CHPs, all the α become zeros and we get eq.(4.b).

2.3. Costs of technologies

The technologies considered correspond to our framework study so that we only deal with industrial combustion technologies with capacities roughly between 1 and 10 MW. There are strong economies of scale and it allows us to make a fair comparison between technologies with the same size. The technologies considered are: Gas boilers, Fuel boilers, Coal boilers, Biomass boilers, Biomass CHP with a back pressure steam turbine, Gas CHP with a back pressure steam turbine, Coal CHP with a back pressure steam turbine. The following configurations are not considered: thermal solar, geothermic heat, heat from waste.

For CHP plants, we don't consider any flexibility between the production of electricity and the production of heat. Therefore, we considered a specific constant ratio heat/electricity for each CHP.

Finally, an extra 10€/kW/year which is not included in the following tables is added for fossil fuel technologies (see 2.4 for details).

BOILERS	Size	Production efficiency		Investment costs	Fixed O&M costs	Variable O&M costs	Source
	MW heat	*η heat (%)*	*η elec (%)*	*€/kW heat*	*€/kWheat/year*	*€/MWh heat*	
Gas boiler	1 to 10	0,9	-	40	18	1	*DGEC, 2008*
Biomass boiler	1 to 10	0,9	-	500	50,4	1,4	*DGEC, 2008*
Fuel oil boiler	1 to 10	0,9	-	225	3,5	0,7	*Le Truong, 2014*
Coal boiler	1 to 10	0,9	-	500	12,5	2,9	*Le Truong, 2014*

Table 2 : Heat-only-boilers characteristics [4]

CHP	Size	Production efficiency		Investment costs	Fixed O&M costs	Variable O&M costs	Ratio elec/heat	Source
	MW elec	*η heat (%)*	*η elec (%)*	*€/kW heat*	*€/kWheat/year*	*€/MWh heat*	α	
Gas turbine	1 to 10	0,48	0,32	667	48	1,3	0,67	*DGEC, 2008*
Biomass steam turbine	1 to 10	0,64	0,26	1828	73	2,0	0,40	*DGEC, 2008*
Coal steam turbine	15 to 200	0,63	0,25	1071	30	0,4	0,40	*IEA, 2010*

η heat (elec) is the production efficiency expressed in MWh heat (elec)/MWh fuel

Table 3 : CHP plant characteristics [4]

POWER PLANTS	Size	Production efficiency		Investment costs	Fixed O&M costs	Variable O&M costs	Source
	MW elec	*η heat (%)*	*η elec (%)*	*€/kW elec*	*€/kWhelec/year*	*€/MWh elec*	
SCPC	600-1100	-	0,46	1800	79,2	1,1	*IEA, 2010*
NGCC	620	-	0,6	820	10,1	2,8	*IEA, 2013*
NGCT	210	-	0,36	580	5,4	8	*IEA, 2013*

SCPC: Super Critical Pulverized Coal plant - NGCC: Natural Gas Combined Cycle – NGCT: Natural Gas-fired Combustion Turbine

Table 4 : Condensing Power Plant characteristics

2.4. Fuel characteristics

Regarding fossil fuels (bituminous coal, fuel oil, natural gas) we chose to comply with the average 2013 European CIF (Cost Insurance and Fret) prices.

Biomass prices are highly dependent on the local context such as the proximity of a local resource or the existence of resources' tension. Besides, the supply is generally a mix of different biomass resources such as industrial wood pellets (and more recently torrefied pellets), wood chips, agricultural residues and so on. Each of them has its own local (or market) price. In this study, we consider an average value which is 23€/MWh LHV[5] (European Climate Foundation, Södra, Sveaskog and Vatenfall, 2010). A further developed sensitivity analysis will give us an idea of the biomass price effect.

Finally, prices are supposed to remain stable during all the lifetime of the plants (25 years for all).

[4] Data from DGEC, 2008 (see table 2 and table 3) have been rearranged because O&M costs were given in €/MWh for both fixed and variable costs. So, as the O&M costs are mainly fixed, we considered 90% of the previous cost as fixed and we applied a medium load factor (4 000h) to get a fixed O&M value.

[5] Calculated from the Lower Heating Value (MWh/ton) which is the amount of heat released by combusting a specified quantity and returning the temperature of the combustion products to 150°C, which assumes the latent heat of vaporization of water in the reaction products is not recovered.

	Emission Factor		Lower Heating Value		Prices	
	kgCO2/MWh primary energy		MWh/t PCI		Row Prices	Adapted Prices
Bituminous Coal	342	*ADEME, 2010*	7,22	*CEA, 2013*	100 €/t	13,9 €/MWh
Fuel Oil	281	*ADEME, 2010*	11,11	*CEA, 2013*	600 €/t	54,0 €/MWh
Natural Gas	205	*ADEME, 2010*			10 $/Mbtu	27,3 €/MWh
Biomass	0	*ADEME, 2010*	2 to 5	*Diverse*		23,0 €/MWh

Table 5 : Fuel characteristics

Biomass prices are given as received at the heat production plant so we consider that they already take into account transportation (and storage) costs between the production area and the plant. For fossil fuels, we add an extra 10€/kW/year for Operating Fixed Costs. This extra cost is added to the previous fixed O&M given in part 2.3. This is an assumption that certainly needs to be explored in greater detail.

2.5. Load Factor

The Load factor (LF) multiplied by the number of hours in a year (8 760h) gives the number of hours per year the plant is being used at full capacity. The levelised heat cost (LLCOH) is not the same according to the time of use. LF is a significant parameter to evaluate the LLCOH and in particular it plays a role for the fixed costs such as investment costs and O&M fixed costs (see equation 2a and 2b). Indeed, the longer the plant is being used, the smaller the fixed component per unit of produced heat (MWh heat). So, in order to analyze the influence of the operating g time, we use the following Load Factors:

- 500 h/year………LF=5.7%
- 2 500 h/year……LF=28.5%
- 5 000 h/year……LF=57%
- 7500 h/year…….LF=85.6%

However, to simplify the understanding of the study, all the results may not be introduced.

3. Results

3.1. Analysis of heat cost components

For each technology, the heat cost is made up of five components: investment costs (**LLCINV**), fixed O&M costs (**LLCOMF**), variable O&M costs (**LLCOMV**), fuel costs (**LLCF**), carbon costs (**LLCC**) (except for biomass where a zero CO_2 emission is considered).

For short load factors, fixed costs (fixed O&M and investment cost) represent an important component of the total cost but as soon as the utilization rate increases, the share of these components in the total cost decreases. On the contrary for long utilization rate, the main cost components turn out to be the variable costs such as fuel and carbon costs.[6]

In this study, to increase the understanding, analyses are only carried out for 2500h and 5000h even if full heat costs have also been calculated for 500h and 7500h.

3.1.1. Heat cost components analysis for heat-only-boilers

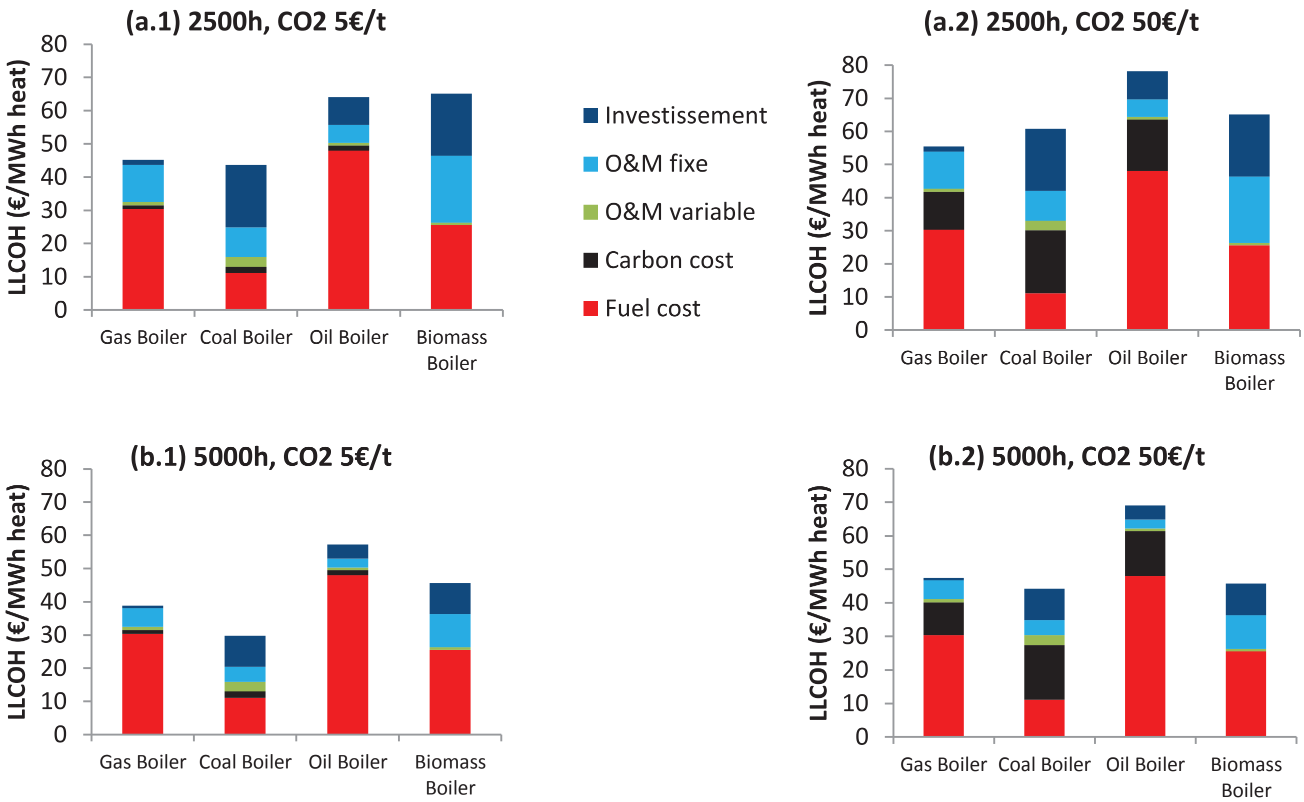


Figure 14 : LLCOH for heat-only-boilers different load factors (a)500h, (b)2500h, and different carbon prices (1) 5€, (2) 50€.

[6] To increase the readability, analysis is only carried out for 2500h and 5000h even if full heat costs have also been calculated for 500h and 7500h. However, all the results are available upon request.

For 2500h and 5000h, at a 5€/ton EU-ETS carbon price

Generally, heat costs range between 30€/MWh and 65€/MWh and decrease when the load factor increases. The decrease is more important for capital-intensive technologies such as coal and biomass.

For low load factors, gas boilers are the most profitable technologies because they have low fixed costs (mainly low investment costs). Even with low load factors, fuel costs are the main cost components for gas boilers. On the contrary, coal and biomass technologies are capital-intensive so that the main cost components for low load factors are the fixed costs. Consequently they are not profitable.

Due to high fuel oil prices, the cost oil fuel boiler heat is very high and therefore this technology is never profitable whatever the load factor. The price of coal relatively low compared to other fuels such as biomass or gas allows this technology to be as profitable as gas boilers at 2500h.

Raising the carbon price from 5€/ton to 50€/ton

A rise of carbon price (**CP**) leads to a rise of carbon costs proportional to the specific fuel emission factor (**EF**). Therefore, a rise of CO2 price has a higher impact on technologies using fuels with high emission factors. The coal EF is two thirds higher than the gas EF. Consequently, carbon costs for coal boilers are two third higher than gas boilers because we considered the same efficiency rate for all fuels. As the carbon price increases, competitiveness of high emission rate fuel based technologies decreases compared to lower emission rate fuel based technologies.

Biomass is unaffected directly by the carbon price as the combustion of biomass if considered emission-neutral in the European-Union. Therefore, competitiveness of biomass boilers increases when the carbon price increases.

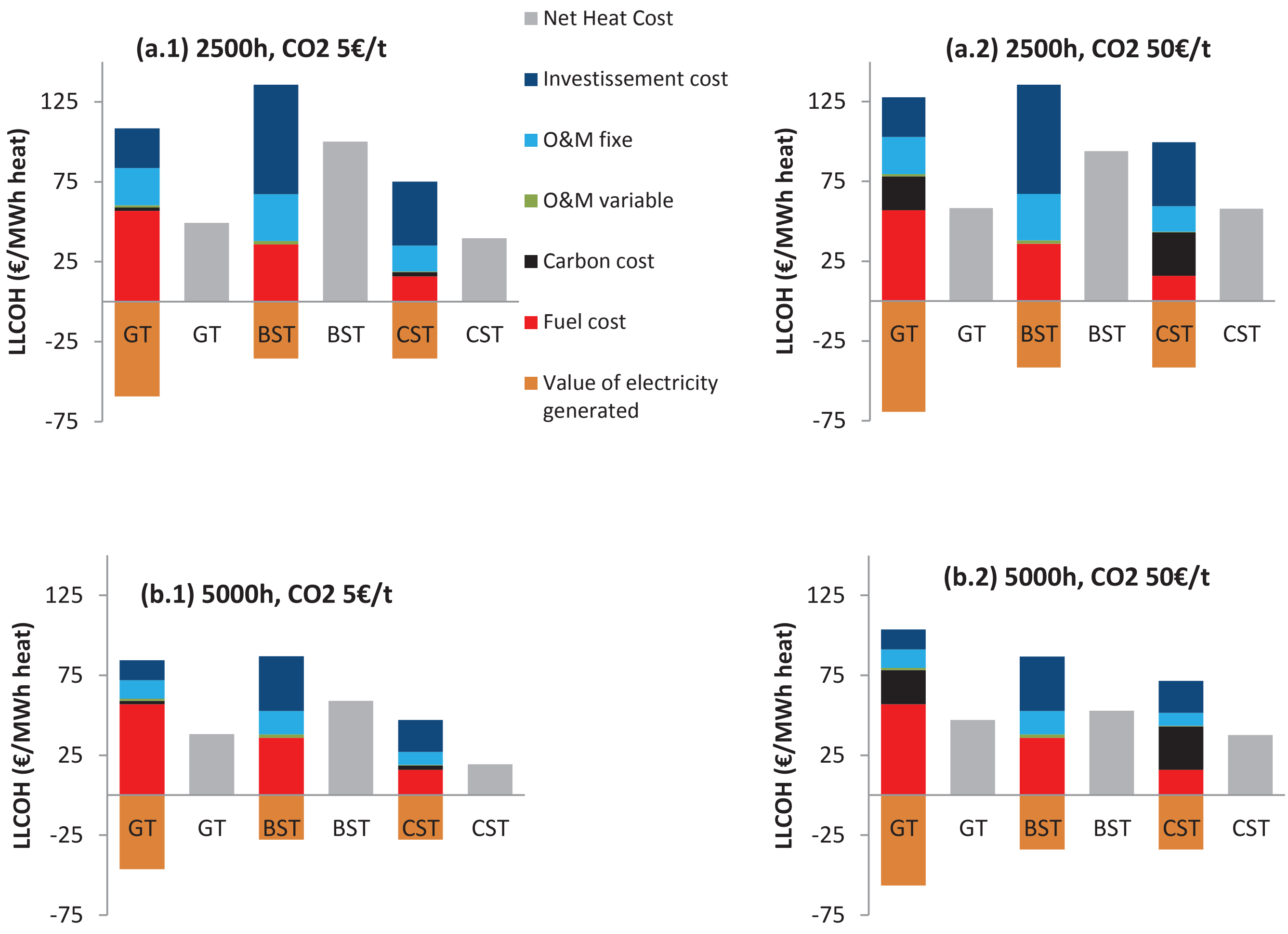
Gas boilers are still the most competitive technologies for low load factors because carbon costs are not high enough to compensate the fixed costs of other technologies. Biomass boilers become the most profitable technologies for high load factors.

<u>KEY POINTS</u>: heat-only boilers economics (3.1.1)

Up to a 50€/ton carbon price, gas boilers are the most profitable technologies for low load factors because they are low capital-intensive. On the contrary, biomass boilers are high capital-intensive so that their competitiveness increases with high load factors and become competitive with a 50€/ton CO2 price. Without a CO2 price, coal boilers are the most profitable technologies from a medium load factor.

3.1.2. Heat cost components analysis for CHP plants

Compared to heat cost components from heat only boilers, the main differences are that CHPs have higher investment costs and that an electricity reference cost has been subtracted (see 2.Methods for more details). It has two main consequences. Firstly, for low load factors, the heat generated is very expensive. So, CHPs are potentially efficient for higher utilization rates. Secondly, the value of jointly produced electricity tends to reduce heat costs significantly. The **Net Heat Cost** is the cost of heat-only after removing the cogenerated electricity value.



CST: Coal Steam Turbine - **BST**: Biomass Steam Turbine - **GT**: Gas Turbine

Figure 15 : LLCOH for CHP plants at different load factors (a)500h, (b)2500h, and different carbon prices (1) 5€, (2) 50€.

Value of electricity generated

This value depends on several parameters. Firstly, it is highly dependent on the electricity-to-heat ratio. Indeed, we considered the same ratio (0.4) for both Biomass and Coal CHPs and a higher ratio for gas CHPs (0.67) due to technological assumptions. This is the reason why the value of electricity is higher for gas than for biomass and coal CHPs. It is just linked to the fact that more electricity is generated (so less heat) with a gas turbine. Secondly, this value decreases when the load factor rise because of the decrease of the fixed costs share in the total cost of electricity (see figure 15 between (a) and (b)). Thirdly, a carbon cost is also considered for power plants so that a rise of CO2 price increases the value of electricity (see figure 15 between (1) and (2)).

For 2500h and 5000h, at a 5€/ton EU-ETS carbon price

Generally, considering 2500h and 5000h, heat costs range between 20€/MWh and 100€/MWh. Coal CHPs are by far the most profitable technologies followed by gas and biomass. This is mainly because coal CHPs have the lowest fuel costs even if this technology is high capital-intensive (more than gas CHPs but less than biomass CHPs).

Biomass CHPs are high capital-intensive so that they are not profitable even at 5000h.

Raising the carbon price from 5€/ton to 50€/ton

A rise in carbon price has two main consequences. Firstly it provokes an increase of carbon costs for fossil fuelled CHPs. But it also leads to an increase of the cogenerated electricity value. These two effects have an opposite impact on the net heat cost. The main effect is different according to the technology considered. It leads to a rise of net heat cost for fossil fuelled CHPs and to a decrease of net heat cost for biomass CHPs. This is due to the fact that we considered a zero emission factor for biomass combustion.

Gas CHPs become as competitive as coal CHPs at 2500h. For high load factors, biomass CHPs become almost competitive with gas CHPs because the extra carbon cost enable to compensate high biomass CHP investment costs. However, coal CHPs are still the most competitive at 5000h.

KEY POINTS: CHPs economics (3.1.2)

Biomass CHPs are high capital-intensive so that they become competitive with gas CHPs for high load factors and for a high CO2 price. Coal CHPs turn out to be the most profitable technologies whatever the load factor and at both 5€/ton and 50€/ton mainly because of the low coal price. Finally, the value of electricity generated which is dependent on the electricity-to-heat ratio enable a significant decrease of the heat cost.

3.1.3. Comparison of heat costs between heat-only boilers and CHPs

The main differences are that CHPs are high capital-intensive technologies compared to only-boilers and that the value of electricity cogenerated enables a significant decrease of heat costs for CHPs. For low load factors (2500h), CHPs turn out to be more expensive than boilers mainly because of the high fixed costs. Nevertheless, there is no significant difference between coal CHPs and coal boilers at 2500h. This may come from coal CHPs assumptions because the data refers to a high capacity (15MW to 200MW) whereas capacities are lower for other technologies.

For high load factors, except for biomass CHPs, CHPs heat costs are lower than boiler heat costs for a given fuel. This is the combined effect result of the subtraction of the electricity cogenerated value and the decrease of CHPs fixed costs.

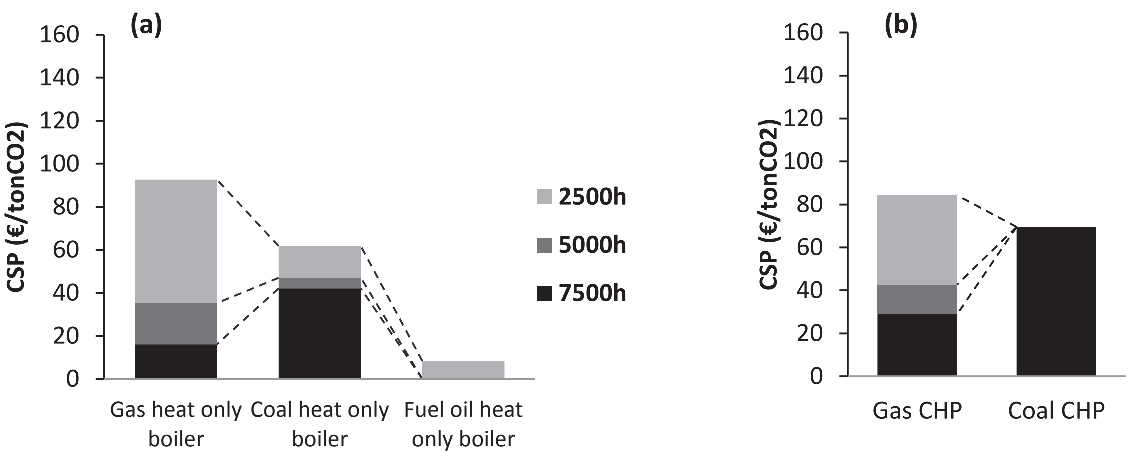
KEY POINTS: CHPs versus Boilers economics (3.1.3)

CHPs are high capital intensive compared to heat-only boilers so that they are not considered profitable for low load factors. However, for high load factors and thanks to the subtracted value of electricity cogenerated, CHPs tend to be more profitable than boilers.

3.2. Long-term Carbon Switching Price

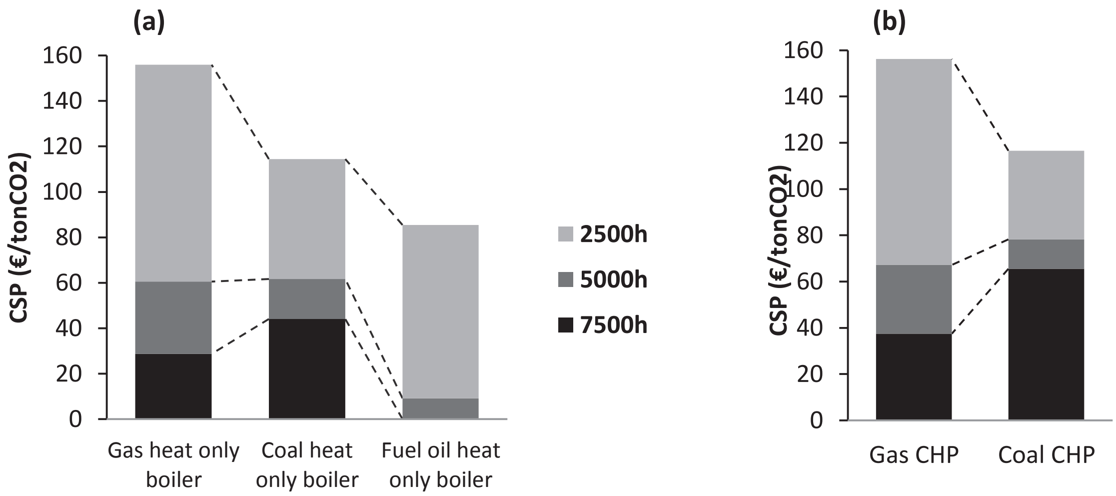
The previous part aimed to introduce cost structures for both CHPs and heat-only boilers to better understand competitiveness between biomass technologies and fossil technologies according to different load factors and CO2 prices. In the following part, we focus on the specific carbon cost component and we try to find the minimum carbon price from which a biomass technology is more profitable as a fossil technology. We call this carbon price the Carbon Switching Price (CSP) (see 2.2 Methods for further details).

At a 500h utilization rate, the Carbon Switching Price turned out to be very high (several hundred Euros per ton of CO2) so that the data has been removed from this study. This is due to the combined effect of high fixed costs (mainly investments costs) for biomass technologies and a low load factor. Furthermore, we decide to compute the CSP at 7500h because it is easily representable and also interesting to analyse. Finally, when we get a zero CSP, it means that a carbon price is not needed to make a biomass technology more profitable than a fossil technology. This happens only with oil boilers.



At 5000h and 2500h, only the additional carbon price has been represented because lower the load factor, higher the CSP.

Figure 16: Long Term Carbon Switching Price between biomass heat only boilers and fossil fuelled boilers (left) or CHPs (right) at three different load factors



At 5000h and 2500h, only the additional carbon price has been represented because lower the load factor, higher the CSP.

Figure 17: Long Term Carbon Switching Price between biomass CHP and fossil fuelled boilers (left) or CHPs (right) at three different load factors

Load factor influence

The load factor has a very important effect because our calculations are based on the long term (25 years) so that they include investment costs and this cost component is high for biomass technologies. As a result, CSP are always higher for short load factors. This is the reason why it becomes possible to pile up the additional carbon price for 5000h and 2500h on the 7500h carbon price basis (see figures 16 and 17). The load factor effect on the CSP level is only related to the specific fixed cost of considered technologies. Indeed, variable costs such as fuel costs, CO2 emission costs and variable O&M costs are the same whatever the load factors for a given technology. This effect is much more visible when there is an important difference of fixed costs between the two technologies at stake. For example, the carbon price needed to switch from a biomass boiler to a gas boiler is roughly six times higher at 2500h than 7500h. In like manner, the carbon price needed to switch from a biomass CHP to a gas CHP is approximately 4 times higher at 2500h than 7500h.

CSP analysis between heat-only-boilers *(see figure 16 (a))*

The carbon switching price becomes smaller for higher utilization rates as previously explained. For high utilization rate (sup. to 5000h), the carbon price turns out to be negative for the fuel oil boiler principally because of the high fuel oil price. It means that the decision to invest in a biomass boiler is profitable comparing to a fuel oil boiler option even for a zero CO2 price.

CSPs for gas boilers and coal boilers do not look similar. Indeed, the lower the load factor, the higher the additional CSP for gas boilers. On the contrary, the additional CSP for coal boilers (that is to say for 5000h and 2500h) is much smaller. This is due to the cost structure. Indeed, gas boilers are not capital-intensive whereas coal boilers are rather capital-intensive. Therefore, when the load factor decreases, the gap between gas boiler fixed costs and biomass boiler fixed costs widen so that higher CO2 prices are needed to balance the costs. Moreover, coal is at a low price and this mainly explains the high CSP at 7500h (42€/ton).

CSP analysis between CHP plants *(see figure 17 (b))*

CSPs are higher than before. It means that switching from a biomass CHP to a fossil technology (both CHPs and boilers) is more costly than switching from a biomass boiler to a fossil technology (both CHPs and boilers). For this reason, carbon switching prices are higher when it comes to make profitable biomass CHPs. Even at 7500h the CSP turn out to be ranged between 37 and 65€/ton. This is the combined effect results of biomass CHPs high capital-intensiveness, a low coal price and gas CHPs low fixed costs. Using logic as previously developed we explain the evolution of the additional CSPs (5000h and 2500h) for both gas and coal CHPs.

Crossed CSP analysis between CHPs and only-boilers *(see figure 16 (b) and figure 17 (a))*

The high CSP values between a biomass CHP and fossil boilers are the best example to illustrate the role of fixed costs (figure 17 (a)). Indeed, this is clear that additional CSPs (especially between 5000h and 2500h) are very high. It emphasises both that biomass technologies have higher fixed costs compared to fossil technologies and that CHPs technologies are more capital-intensive than heat-only boilers.

KEY POINTS: ***Carbon prices and competitiveness between technologies - fuel oil boilers excluded (3.2)***

At the current CO2 price (between 0 and 10€/ton), only oil fuel heat only boilers are non competitive comparing to both biomass heat only boilers and biomass CHP plants (excluding at 2500h between fuel oil boilers and biomass CHP plants).

Generally, CSPs are higher when a biomass CHP is involved instead of a biomass boiler and especially for low load factors.

For low load factors, biomass technologies require a high CO2 price to become competitive with fossil technologies (80-160€/ton). At 5000h, a CO2 price between 40€/ton and 60€/ton allow biomass technologies to be more profitable than fossil fuel technologies in most cases. Finally, at 7500h, biomass technologies become the most profitable with a CO2 price between 30€/ton and 40€/ton.

3.3. Sensitivity Analysis of Carbon Switching Prices to a range of biomass prices

Biomass prices may differ significantly due to several factors such as biomass types, local context and local biomass availability. Previously we took an average of 23€/MWh. We define a lower limit at 16€/MWh and an upper limit at 30€/MWh which corresponds to a 30% variation from the average price and is representative to real biomass price range (European Climate Foundation, Södra, Sveaskog and Vatenfall, 2010).

Let us focus on a biomass price rise. Each extra euro caused by the biomass price increase has to be compensated by a rise of carbon cost (LLCOC) for the fossil fuelled technology. Only variable costs are at stake in this sensibility analysis (fuel and carbon costs). Fixed costs do not matter so that the extra CSP is the same whatever the load factor. For fossil technologies, carbon costs depend on the carbon price (€/tonCO2), the production efficiency (MWh heat/MWh fuel) and the Emission Factor (ton of CO2 emitted by MWh of fuel). The carbon price has to grow to compensate the biomass price rise (see the following equations).

For a fossil fuel heat production technology 'f' (associated with fuel 'f1'), a biomass heat production technology 'b' (associated with biomass 'b') and a fossil power plant 'elec' (associated with fuel 'f2') the extra CSP is given by:

$$\Delta \boldsymbol{LLCOF_b} - \boldsymbol{\alpha_b} \Delta \boldsymbol{LLCOC_{elec}} = \Delta \boldsymbol{LLCOC_f} - \boldsymbol{\alpha_f} \Delta \boldsymbol{LLCOC_{elec}}$$

We easily get:

$$\Delta \boldsymbol{CP} = \frac{\Delta \boldsymbol{FP_b}}{\boldsymbol{\eta_{heat,b}} \times \left[\frac{\boldsymbol{EF_{f1}}}{\boldsymbol{\eta_{heat,f1}}} + \frac{(\boldsymbol{\alpha_b} - \boldsymbol{\alpha_f}) \times \boldsymbol{EF_{f2}}}{\boldsymbol{\eta_{elec,f2}}} \right]}$$

eq.(5.a)

Where $\Delta \boldsymbol{CP}$ *(or* $\boldsymbol{\Delta CSP}$*) is the carbon price variation needed to balance the heat costs for technologies 'b' and 'f', caused by a biomass price variation (*$\Delta \boldsymbol{FP_b}$*),* $\boldsymbol{\alpha_b}$ and $\boldsymbol{\alpha_f}$ are electricity-to-heat ratios for the biomass and the fossil fuel technologies.

For a comparison between heat-only boilers, $\boldsymbol{\alpha_b}$ and $\boldsymbol{\alpha_f}$ are zeros. In addition, the term $(\boldsymbol{\alpha_b} - \boldsymbol{\alpha_f})$ turns out to be zero when we compare two CHP plants with the same electricity-to-heat ratio. For these cases, eq.(5.a) gives:

$$\Delta \boldsymbol{CP} = \frac{\Delta \boldsymbol{FP_b}}{\boldsymbol{EF_{f1}}} \times \frac{\boldsymbol{\eta_{heat,f1}}}{\boldsymbol{\eta_{heat,b}}}$$

eq.(5.b)

Equation (5.a) can be used for the calculations of the upper-left quadrants and between coal and biomass CHPs.

Finally, it is possible to simplify eq.(5.b) for a comparison between only-boilers because we considered the same heat production efficiency for all the technologies/fuels. We get:

$$\Delta \boldsymbol{CP} = \frac{\Delta \boldsymbol{FP_b}}{\boldsymbol{EF_{f1}}}$$

eq.(5.c)

Results are summarized in the following table:

ΔCSP (€/tCO2)	Gas heat only boiler	Coal heat only boiler	Oil fuel heat only boiler	Gas CHP	Coal CHP
Biomass heat only boiler	Δ34	Δ21	Δ25	Δ38	Δ20
Biomass CHP	Δ29	Δ21	Δ24	Δ32	Δ20

Table 6: CSP sensitivity due to a 30% variation of biomass prices

Between only-boilers, the extra CSP is directly related to the fossil fuel Emission Factor. Therefore, the variation of the carbon price is directly proportional to the variation of the biomass price. Between a coal and a biomass CHP, it is almost the same because η_{heat} are quite similar. However, calculations are a little trickier for all other cases because of carbon costs included in the value of electricity cogenerated. Generally, the method we use tends to advantage CHP technologies. This happens because the value of electricity (which includes carbon costs) is subtracted to the full cost to get the net heat cost.

Increasing biomass prices of 30% has significant effects on heat costs and thus on CSPs. Generally, it increases the CSPs of 20€/ton to 38€/ton. For example, at 5000h, the CSP between gas boilers and biomass boilers was 35€/ton but with a 30% rise of biomass prices, the CSP turns out to be twofold higher (69€/ton). On the contrary, a 30% decrease of biomass prices makes the CSP close to zero meaning that biomass boilers become as competitive as gas boilers.

In order to balance the CSP changes when moving biomass prices, ΔCSPs has to be compared with CSPs original values (see 3.2) computed with the average biomass price (23€/MWh fuel). For instance the ΔCSP for biomass boilers against oil boilers (Δ25€/ton) is higher than the one for biomass boilers against coal boilers (Δ21€/ton). However, after moving biomass prices, the CSP turns out to be lower in the first case than in the second one.

Comparing ΔCSPs with the original CSPs values allows assessing the significance of change. For instance, for a 5000h load factor, when the biomass price increases by 30%, biomass boilers need a 97% (43%, respectively) increase of the carbon price to remain profitable against gas boilers (coal boilers, respectively)". [7]

[7] Full details are given in appendix 1.

4. Discussion and Conclusions

This study explored heat cost structures for different technologies that can be used at a District Heat System scale or for industrial use. It highlighted biomass profitability in a context of reducing CO2 emissions. The load factor turned out to be a key parameter when studying technologies' competitiveness. Indeed, high capital-intensive technologies such as biomass boilers or CHPs are never the most profitable technologies for low load factors. On the contrary, gas technologies enjoy low fixed costs so this enables them to produce the cheapest heat for low load factors even if gas prices are higher than biomass prices. Coal heat production plants enjoy medium fixed costs but low fuel costs which allow them to be the most profitable technologies from a medium load factor. By putting a price on CO2, fossil fuelled technologies tend to become less competitive than biomass technologies. In most cases a CO2 price ranged between 40€/ton and 60€/ton makes biomass technologies more profitable than the corresponding fossil fuelled technologies. Biomass technologies are likely to be profitable for high load factors. Finally, Carbon Switching Prices turned out to be highly dependent on biomass price levels.

Moreover, the cost of heat generated with CHPs is highly dependent on the method used to give a value to the co-generated electricity. In this study, we considered that the electricity generated replaces electricity from standalone power plants. We mainly used a Natural Gas Combined Cycle as the power production reference. Other methods may give different heat costs.

This study aimed to better understand the economic fundamentals of heat production and therefore, no regulation has been taken into account except from a carbon price. However, feed-in-tariff for electricity and subsidizes profoundly shift the economics landscape. In particular, incentives for CHPs may have important impacts on CHP plant operating periods. Indeed, it is more profitable to produce only electricity when the price of electricity is high (peak-demand period). This flexibility, if any, has not been considered and may be of interest for further investigations.

To further this study, it could be interesting to take into account the quality of biomass introduced in boilers because biomass price variations often imply biomass quality discrepancies. For instance, the use of local wood chips (roughly 20€/MWh) may be not as efficient as the use of wood pellets (more than 30€/MWh) in terms of heat production rate. Furthermore, as wood pellets have a higher energetic density (energy per ton of raw product) than wood chips (or log wood), operating costs may be higher with wood chips.

This study focused on heat production costs at a DHS level. A comparison between full heat costs from DHS (including distribution costs and distribution losses) and full heat costs from individual heat production systems could offer interesting findings.

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6. Appendix

Appendix 1: CSP raw results

CSP* (€/tCO2)		Gas heat only boiler	Coal heat only boiler	Oil fuel heat only boiler	Gas CHP	Coal CHP
Biomass heat only boiler	2500	93	62	8	84	68
	5000	35	47	-	43	70
	7500	16	42	-	29	71
Biomass CHP	2500	156	114	85	156	116
	5000	61	62	9	67	78
	7500	29	44	-	37	65

Table 7: Carbon Switching Prices for all technologies at a 23€/MWh biomass price

CSP* (€/tCO2)		Gas heat only boiler	Coal heat only boiler	Oil fuel heat only boiler	Gas CHP	Coal CHP
Biomass heat only boiler	2500	59	41	0	46	49
	5000	2	27	0	4	51
	7500	0	22	0	0	52
Biomass CHP	2500	126	94	61	124	97
	5000	31	41	0	35	58
	7500	0	23	0	5	46

Table 8: Carbon Switching Prices for all technologies at a 16€/MWh biomass price

CSP* (€/tCO2)		Gas heat only boiler	Coal heat only boiler	Oil fuel heat only boiler	Gas CHP	Coal CHP
Biomass heat only boiler	2500	126	82	33	123	87
	5000	69	67	0	81	89
	7500	50	62	0	67	90
Biomass CHP	2500	185	135	109	188	136
	5000	90	83	33	99	98
	7500	58	65	0	70	85

Table 9: Carbon Switching Prices for all technologies at a 30€/MWh biomass price

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