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Co-optimization of the Power and Heat Market

Dissertation presented by
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for obtaining the Master's degree in
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List of Sets

Sets used in the modelling of the electricity and heat system	
$\mathrm{K}_{BoilerConventional}$	Set of biomass technologies
$\mathrm{K}_{BoilerConventional}$	Set of conventional heat boilers
K_{CHP}	Set of CHP technologies
K_{ComHW}	Set of technologies that can serve commercial hot water
K_{ComSH}	Set of technologies that can serve commercial space heating
$\mathrm{K}_{Conventional}$	Set of conventional power plants
$\mathrm{K}_{ElBoiler}$	Set of electric boilers
$\mathrm{K}_{ElHeatPump}$	Set of electric heat pumps
K_{elec}	Set of all power producing technologies
$\mathrm{K}_{elec/CHP}$	Set of power producing technologies excluding CHP
K_{heat}	Set of all heat producing technologies
$\mathrm{K}_{heat/CHP}$	Set of heat producing technologies excluding CHP
K_{HP}	Set of heat pump technologies
K_{IndHW}	Set of technologies that can serve industrial hot water
K_{IndSH}	Set of technologies that can serve industrial space heating
K_{IndPH_1}	Set of technologies that can serve industrial process heating $< 100°C$
K_{IndPH_2}	Set of technologies that can serve industrial process heating $100 - 500°C$
K_{ResHW}	Set of technologies that can serve residential hot water
K_{ResSH}	Set of technologies that can serve residential space heating
S_{ComSH}	Set of storage technologies that can serve commercial space heating
S_{elec}	Set of electric storage technologies
S_{IndPH_1}	Set of storage technologies that can serve industrial process heating $< 100°C$
S_{IndPH_2}	Set of storagetechnologies that can serve industrial process heating $100 - 500°C$
S_{IndSH}	Set of storage technologies that can serve industrial space heating
S_{ResHW}	Set of storage technologies that can serve residential hot water
S_{ResSH}	Set of storage technologies that can serve residential space heating

List of Parameters

Parameters used in the modelling of the electricity and heat system	
a_t	PV profile [-]
b_t	Onshore wind profile [-]
c_t	Offshore wind profile [-]
c^{dist}	Distribution cost [€/MWh]
$c^{fixOp}{}_k$	Fixed operational cost of the technology [€/MW]
$c^{fuel}{}_k$	Fuel cost of the technology [€/MWh]
$c_k^{specInv}$	Specific investment cost of the technology [€/MW]
c_k^{varOp}	Variable operational cost of the technology [€/MWh]
$\mathrm{c}^{VoLL,elec}$	Value of Lost Load for electricity [€/MWh]
$\mathrm{c}^{VoLL,heat}$	Value of Lost Load for heat [€/MWh]
$\mathrm{E}^{annualBiomass}$	Annual availability of biomass [MW]
E^{CO_2}	Maximum $\mathrm{CO}_2 emission[MWh]$
f^{CO_2}	$\mathrm{CO}_2 emissionfactor[-]$
l_s	Self-discharge of the electric storage [-]
P_t^{demand}	Power demand at timestep t [MWh]
$Q_t^{demand,ComHW}$	Commercial hot water demand in timestep t [MWh]
$Q_t^{demand,ComSH}$	Commercial space heating demand in timestep t [MWh]
$Q_t^{demand,IndHW}$	Industrial hot water demand in timestep t [MWh]
$Q_t^{demand,IndPH_1}$	Industrial process heating $< 100°C$ demand in timestep t [MWh]
$Q_t^{demand,IndPH_2}$	Industrial process heating $100 - 500°C$ demand in timestep t [MWh]
$Q_t^{demand,IndSH}$	Industrial space heating demand in timestep t [MWh]
$Q_t^{demand,ResHW}$	Residential hot water demand in timestep t [MWh]
$Q_t^{demand,ResSH}$	Residential space heating demand in timestep t [MWh]
r	Investment rate [-]
$s^{distLoss}$	Distribution loss parameter [-]
T_k	Life span of the technology [year]
η_k	Efficiency of the technology [-]
σ_k	Power-to-heat ratio [-]

List of Variables

Variables used in the modelling of the electricity and heat system	
$\mathbf{C}_k^{inv}$	Investment cost of the technology [€]
$\mathbf{C}_k^{fuel}$	Total fuel cost of the technology [€]
$\mathbf{C}_k^{op}$	Operational cost of the technology [€]
$\mathbf{C}^{tot}$	Total annual system cost [€]
$\mathbf{C}^{tot,CHP}$	Total annual CHP cost [€]
$\mathbf{C}^{tot,elec}$	Total annual electricity cost (excluding CHP costs) [€]
$\mathbf{C}^{tot,heat}$	Total annual heat cost (excluding CHP costs) [€]
$\mathbf{D}_{k,t}^{fuel}$	Fuel consumption [MWh]
$\mathbf{E}_s$	Capacity of the electric storage [MW]
$\mathbf{F}_{s,t}$	Fill level of the electric storage [MWh]
$\mathbf{G}^{total}$	Total $CO_2 emission [MWh]$
$\mathbf{P}_{k,t}$	Power generation in heat and power plants in timestep t [MWh]
$\mathbf{P}_k^{cap}$	Capacity of the electric component [MW]
$\mathbf{P}_{s,t}^{charge}$	Power charged into the storage in timestep t [MWh]
$\mathbf{P}_{s,t}^{discharge}$	Power discharged from the storage in temestep t [MWh]
$\mathbf{P}_{g,t}^{elHeatBoiler}$	Extra power load created by an electric boiler in timestep t [MWh]
$\mathbf{P}_{f,t}^{elHeatPump}$	Extra power load created an electric heat pump in timestep t [MWh]
$\mathbf{P}_{s,t}^{input}$	Power charged in the electric storage in timestep t [MWh]
$\mathbf{P}_{s,t}^{output}$	Power discharged in the electric storage in timestep t [MWh]
$\mathbf{P}_t^{supply}$	Power that needs to be served in timestep t [MWh]
$\mathbf{P}_t^{nosupply}$	Not supplied power in timestep t [MWh]
$\mathbf{Q}_{k,t}$	Heat generation in heat and power plants in timestep t [MWh]
$\mathbf{Q}_k^{cap}$	Capacity of the heat component [MW]
$\mathbf{Q}_{s,t}^{charge}$	Heat charged into the storage in timestep t [MWh]
$\mathbf{Q}_{s,t}^{discharge}$	Heat discharged from the storage in timestep t [MWh]

$\mathbf{Q}_t^{supply,ComHW}$	Commercial hot water that needs to be served in timestep t [MWh]
$\mathbf{Q}_t^{supply,ComSH}$	Commercial space heating that needs to be served in timestep t [MWh]
$\mathbf{Q}_t^{supply,IndHW}$	Industrial hot water that needs to be served in timestep t [MWh]
$\mathbf{Q}_t^{supply,IndPH_1}$	Industrial process heating $< 100°C$ that needs to be served in timestep t [MWh]
$\mathbf{Q}_t^{supply,IndPH_2}$	Industrial process heating $100 - 500°C$ that needs to be served in timestep t [MWh]
$\mathbf{Q}_t^{supply,IndSH}$	Industrial space heating that needs to be served in timestep t [MWh]
$\mathbf{Q}_t^{supply,ResHW}$	Residential hot water that needs to be served in timestep t [MWh]
$\mathbf{Q}_t^{supply,ResSH}$	Residential space heating that needs to be served in timestep t [MWh]
$\mathbf{Q}_t^{nosupply,ComHW}$	Not supplied commercial hot water in timestep t [MWh]
$\mathbf{Q}_t^{nosupply,ComSH}$	Not supplied commercial space heating in timestep t [MWh]
$\mathbf{Q}_t^{nosupply,IndHW}$	Not supplied industrial hot water in timestep t [MWh]
$\mathbf{Q}_t^{nosupply,IndPH_1}$	Not supplied industrial process heating $< 100°C$ in timestep t [MWh]
$\mathbf{Q}_t^{nosupply,IndPH_2}$	Not supplied industrial process heating $100 - 500°C$ in timestep t [MWh]
$\mathbf{Q}_t^{nosupply,IndSH}$	Not supplied industrial space heating in timestep t [MWh]
$\mathbf{Q}_t^{nosupply,ResHW}$	Not supplied residential hot water in timestep t [MWh]
$\mathbf{Q}_t^{nosupply,ResSH}$	Not supplied residential space heating in timestep t [MWh]
$\mathbf{U}_{s,t}$	Fill level of the heat storage [MWh]
$\mathbf{U}^{cap}$	Capacity of the heat storage [MW]

List of acronyms

- CHP: Combined heat and power
- FLH: Full load hours
- HDD: Heating degree days
- HP: Heat Pump
- PV: Photovoltaic
- TES: Thermal Energy Storage

Chapter 1

Introduction

1.1 Problem Outline

Our current era is characterized by a power and heat market relying mostly on fossil fuel energy. These resources might be cheap and easy to use, but the scarcity and climate impact on fossil fuels require a change in power and heat systems. The burning of fossil fuels by humans is the largest source of emissions of carbon dioxide. Greenhouse gasses like carbon dioxide contribute to global warning and harm the atmosphere in a way that cannot be overlooked anymore. Our society has been focusing for too long on the economic perks, disregarding the environmental consequences. A significant drop in greenhouse gas emissions is needed in order to entrust to the future generations a healthy earth. One of the purposes of this work is to evaluate the consequences of a mandatory drop of the greenhouse gas emissions on the power and heat market.

The global warming being an issue high on the agenda this last decade, a lot of research has been conducted in order to come up with alternative energy sources to fossil fuel. Innovative technologies such as photovoltaic systems, onshore and offshore wind turbines or hydroelectric run-of-the-river systems are a result of this research. The current literature however primarily concentrates on the electricity sector, leaving the heat sector on a secondary position. Yet, the heat sector is responsible for a major part of the carbon dioxide emission and should in consequence not be overlooked. The few studies that do focus on the heat sector usually consider it independently from the power sector. The same can be said for the power market; it is commonly analyzed omitting the heat market. The particularity of this thesis is that it combines the power and heat market and views them as one entity.

For a long time, the heat market was seen as a decentralized market. This means that each building or industry for example has its own individual technology to generate its heat. The main drawback of a decentralized market is that it prioritizes small technologies with a low investment cost, leaving no room for bigger, more expensive technologies that might be more efficient. By centralizing the heat market and merging it with the power market, the set of cost-effective technologies expands. Fuel efficient technologies such as combined heat and power (CHP) plants will be more likely to appear in the market as they can generate both electricity and useful heat at the same time. Cogeneration of heat and power is a more thermally efficient use of fuel than electricity generation alone, and releases as a consequence less carbon dioxide in the atmosphere.

The consolidation of the power and heat sector will allow us to conduct a more thorough study of changes occurring when decreasing the level of emitted greenhouse gasses. First, it enables us to inspect the distribution of the energy resources between the electricity and the heat sector. The energy resources are available to all sectors, and the technologies of different sectors are competing for the same resources, which are not always available in infinite quantity. Knowledge on the distribution of renewable energy sources is especially interesting if we are trying to switch to a fully decarbonized market. Second, as stated previously, it broadens the set of available technologies by including cogeneration or combined heat and power. Finally, it allows us to identify which sector is most affected by a mandatory greenhouse gas reduction.

1.2 Objective and Structure of this Work

The aim of this work is to develop a model describing a centralized heat and electricity market and to carry out tests on this model. These tests have as an objective tracking the changes arising when a limit is put on the maximum CO_2 emission. The evolution of many variables is studied: power and heat production, fossil and renewable fuel consumption, electricity and heat prices, system costs etc. The analysis of the changes occurring will help us answer to a set of questions:

- How much do CHP plants improve the system economically and environmentally?
- What effect does the consolidation of the power and heat market have on the total costs and the total emissions?
- In what extent does the reduction of the CO_2 emission limit influence the mix of optimal technologies and their production?
- Which market is the most affected economically?
- How importantly do the renewable technologies take over the power and heat generation?
- Is the scenario of a fully decarbonized system feasible?

The model described in this work is mainly based on the REMIX-OptiMO model (**R**enewable Energy **M**ix **O**ptimization **M**odel) established by Hans Christian Gils [8], which is an enhancement of the REMIX model developed by Yvonne Scholz [14]. As this work is done in collaboration with ENGIE (French multinational electric utility company), all the data used as input for the optimization model are real data of the actual market provided by ENGIE. The focus is put on the Belgian market in this thesis, but most of the conclusions drawn are applicable to many other European countries. The model is actually independent of the Belgian market and could be used to describe the market of most countries. The data file however, which contains the entire set of input such as the climate data or the technology parameters, is specific to each country.

This work is structured in three main parts, which correspond to the three principal chapters (chapters 2, 3 and 4). A first step is to compute the power and heat demand profiles in Belgium. These demand profiles are crucial to run the model as they give the values of required supply of heat and power for each hour of the year. A year ahead market is studied in this thesis, which means that the optimization model considers a look-ahead horizon of an entire year. In consequence, heat and electricity demands over an entire year need to be generated. As the knowledge of the power market is very broad, ENGIE possessed a year-ahead power demand profile and provided it for the purpose of this work. Heat demand on the other hand is quite unexplored in today's literature and needs to be analyzed in order to generate a heat demand profile. Chapter 2 provides a detailed analysis of the heat demand by splitting it into types of heating and sectors. Types of heating are space heating, hot water and process heating for instance, and the sectors considered are the residential, commercial and industrial one. Once all the demand profiles have been computed, they can be used as a set of parameters in the optimization model. Chapter 3 describes the mathematical model representing the power and heat market in detail. This model is an optimization model which minimizes the total annual cost. It is an optimal investment problem which finds the mix of technologies that should be built in order to minimize the total fixed and variable cost of serving demand.
Finally, chapter 4 analyzes the results of the tests conducted on the model. These tests aim to give us answers to the questions introduced previously. To find such answers, different scenarios are addressed and examined. The results of the different scenarios are then compared with one another. Figure 1.1 summarizes the structure of the entire work.

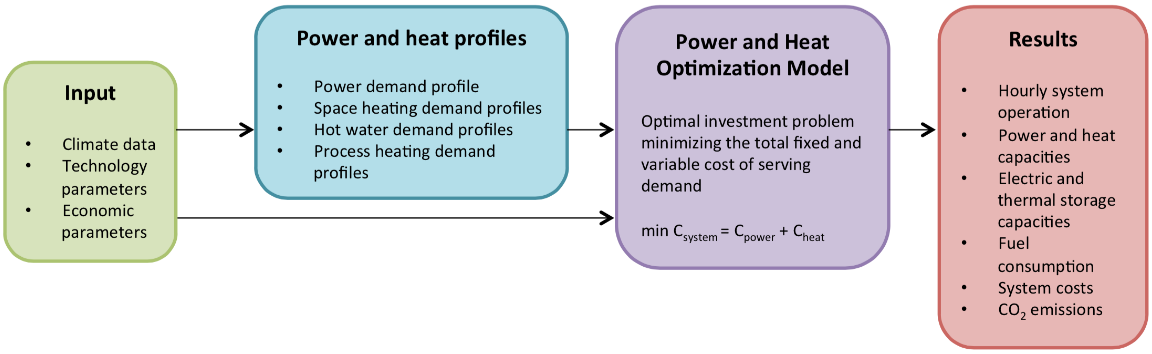
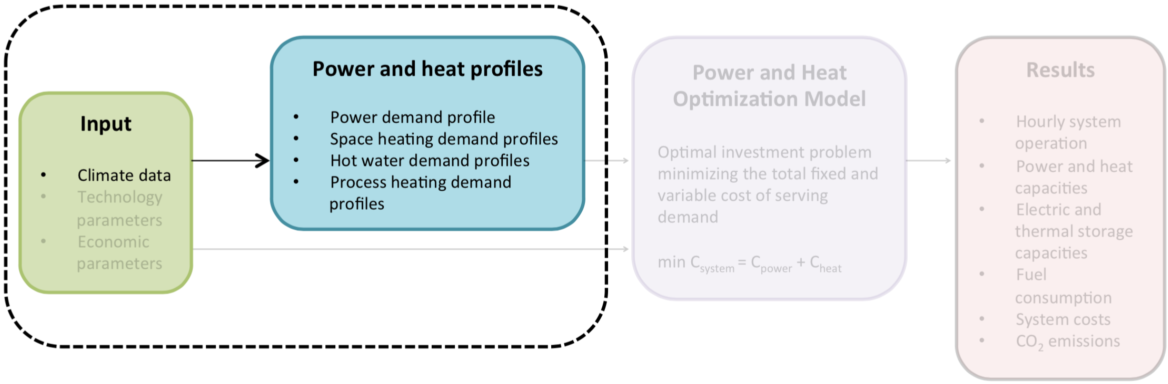


Figure 1.1: Structure of the work

Chapter 2

Heat Demand Profiles



The analysis of the electricity and heat market calls for a prerequisite: an understanding of the demand, and how demand profiles are generated. Indeed, demand profiles will bring up the amount of electricity and heat that needs to be generated by the system at each hour. As the electricity demand is already sufficiently analyzed in the current literature, this chapter will exclusively address the heat demand.
An electricity demand profile is provided by ENGIE and used to run the optimization model [1].

The heat demand can be split into different sectors and different classes. In this thesis, three sectors are considered; residential, commercial and industrial. As for the classes of heat, we make a distinction between space heating, hot water, and process heating. Since this work studies a year ahead market, the objective here is to generate heat demand profiles with an hourly resolution over a time span of an entire year; resulting in profiles of a length of 8760 entrees (=number of hours in a year). This profile length applies to the different types of heat demands, such as residential space heating, commercial hot water, industrial process heating etc.

In theory, a total of 9 profiles should be computed (since there are three sectors and three classes). However, process heating will only be considered in the industrial

[1] The electricity demand profile provided by ENGIE is illustrated in graphical form in Annex B

sector, since it is negligible both in the residential and commercial sector. Besides, we split process heating into two temperature classes: $\theta < 100°C$ and $100°C \leq \theta < 500°C$. This gives a total of 8 different hourly heat demand profiles.

The generation of the profiles depends heavily on the class of heating considered. Before explaining in detail how the several heat demand profiles are computed, some new terminology needs to be introduced. Once introduced, the computation of the eight heat demand profiles can be explained.

2.1 Terminology

Heating Degree Day

A heating degree day is a measure of how much (in degrees), and for how long (in days), the outside air temperature is below a certain level [2]. It is derived from outside air temperature measurements and defined relative to a base temperature.

To understand this definition, one needs to know what is meant by base temperature. The base temperature of a building is the temperature below which heating is needed. This temperature depends on two factors: what temperature is the building heated to, and how much free heating is generated by people and equipment inside the building. Let's illustrate this with an example: If we want the temperature of the building to be at $21°C$, and there is an average internal heat gain of $3°C$ caused by people, then the base temperature is $18°C$.

The heating degree day number is computed with the following formula:

$$n_{HDD} = max(0, \text{Base temperature - Outside air temperature}) \tag{2.1}$$

Since the model has an hourly time resolution and the heating degree day needs to be calculated over an entire day, its value is obtained by summing up the 24 instances of the HDD number n_{HDD}.

In order to compute the heating degree days over one year, the only data needed are the base temperature and the hourly outside air temperature measurements. The base temperature has a fixed value and its value depends on the type of heating considered. The choice of value will be mentioned and explained further in this chapter when discussing the generation of the profiles. The outside air temperature measurements are provided by ENGIE and are measurements taken at airports all over the world. The outside temperatures of a certain city thus correspond to the measurements of the closest airport. Once these outside temperature measurements obtained, it is possible to compute the heating degree days over an entire year.

Full Load Hour

Full load hours describe the (calculated) amount of time a generator would have to run at full capacity to produce the quantity it actually generates in a given time. In other

[2] Definition from the website http://www.degreedays.net/introduction

words, it is the time that a generator would have to operate at full load given it always operates at that level [3].

2.2 Generation of the Heat Demand Profiles

This section will discuss the generation of each type of heat demand profile based on the terminology just introduced. It is divided into two subsections: space heating and hot water demand profiles, and process heating demand profiles.

2.2.1 Space Heating and Hot Water Demand Profiles

Space heating and hot water demand profiles are generated following two main steps: (i) distribute the annual space heating and hot water demands, which are given as parameters, over each day of the year and (ii) once the daily heat demands computed, distribute them over each hour of the day.

Daily Space and Water Heating Demand Computation

The computation of the space heating and hot water demands rely on a method which uses the concept of heating degree days (HDD). The HDD values of each day of the year, which are calculated using the formula 2.1, are used to find the daily shares of the annual space heating and hot water demand. Heating degree days are adequate to represent these two types of demand profiles because they give a good representation of the amount of heating necessary to heat a building or the amount of heating necessary to heat water as they are based on the outside air temperatures.

The total annual space heating and hot water demands of each sector (commercial, residential and industrial) are given as parameters. No information is however available on the dispatch of this total demand throughout the days of the year. The daily shares U_d^{SH} and U_d^{HW} of respectively the annual space heating demand U_y^{SH} and the annual hot water demand U_y^{HW} are computed using a method called the extended degree day method (equations 2.2 and 2.3).

$$U_d^{SH} = \frac{\sum_a \frac{1}{2^a} \cdot n_{HDD,d-a}^{SH}}{\sum_a \frac{1}{2^a} \sum_{d=1}^{365} n_{HDD,d}^{SH}} \cdot U_y^{SH} \qquad a = 0...6 \tag{2.2}$$

$$U_d^{HW} = \frac{\sum_a \frac{1}{2^a} \cdot n_{HDD,d-a}^{HW}}{\sum_a \frac{1}{2^a} \sum_{d=1}^{365} n_{HDD,d}^{HW}} \cdot U_y^{HW} \qquad a = 0...6 \tag{2.3}$$

This method was developed in Hansen Christian Gils' thesis and computes the daily shares by calculating the weights of the heating degree days for each day of the year [4]. These weights are obtained by dividing the value of the HDD of the considered day by the sum of the HDD values of the entire year. In its formula, the method does

[3] The definition of full load hours comes from the website http://www.germanenergyblog.de/?p=16726

[4] The extended degree day method is briefly explained on pages 54-55 of Hansen Christian Gils' thesis [8]

not solely consider the HDD value of the considered day, but also the HDD values of the six preceding days (weighted each with members of a geometric series). Previous HDD values are considered because the daily shares of heating depend in some way on the heating that was used in the previous days, since the heating inside a building for instance does not just disappear overnight. The members of the geometric series express the decreasing influence of the previous HDD values as the day is prior to the actual day. A number of days equal to six is an arbitrary value assumed in the scope of this thesis.

The HDD numbers n_{HDD} have however different values for space heating and hot water because of their different base temperature values. A base temperature of $18°C$ is assumed for space heating, and one of $60°C$ for water heating. The space heating base temperature is likely to decrease over time due to a enhancing insulation of buildings.

Hourly Space and Water Heating Demand Computation

Once the daily demand shares computed, their values need to be distributed over each hour of the day. Dividing the daily demand equally into 24 hours would be too strong of an assumption. Therefore, hourly profiles are computed to correctly distribute the demand. These profiles are obtained from Gils' thesis and are based on the pattern of use of space heating and hot water by the population[5]. Multiple profiles are computed as the hourly distribution depends on two factors: the day of the week and the outside temperature. Indeed, the pattern of space heating use is different during a working day than a weekend day, and also differs with the seasons. We assume however that hourly water heating profiles are not impacted by the outside temperature. Indeed, people usually use hot water even during hot days.

A total of ten different hourly space heating profiles are identified: two types of days (workday or weekend) and 5 ranges of temperature ($\theta < 0°C, 0°C \leq \theta < 5°C, 5°C \leq \theta < 10°C, 10°C \leq \theta < 15°C, \theta \geq 15°C$). These profiles are illustrated in figure 2.1. A general pattern to all of these profiles is a peak value attained around 9am, and for some of the profiles a second one around 8pm. Note that the y-axis of this figure defines the hourly demand relative to the space heating day peak.

As previously indicated, the profiles are obtained from Gils' thesis. They however should be validated by benchmarking them with profiles from other sources. To that end, benchmarking the space heating profiles with an electric heating profile found in an RTE («Réseau de transport d'électricité ») report is relevant[6]. The electric heating profile derived from the RTE report is a winter day profile, and is therefore compared with one of Gils' profiles of low temperature range (figure 2.2). As the two profiles are close to each other and the peaks are observed at the same hours, the hourly profiles provided by Gils can be validated.

As the hourly hot water demand profiles are independent of the outside air tem-

[5] The profiles are explained on pages 54-55 of Hansen Christian Gils' thesis [8]

[6] The hourly profiles are illustrated on page 45 of the RTE report [3]

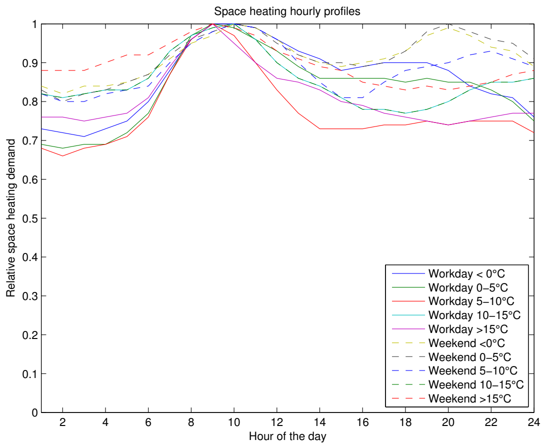


Figure 2.1: Hourly space heating profiles

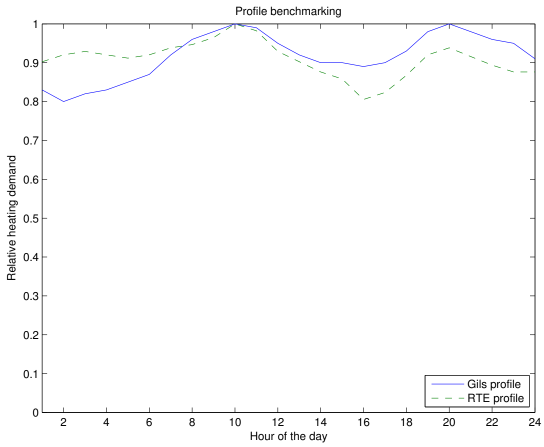


Figure 2.2: Comparison of profiles

peratures, only two different profiles are identified: one for a working day, and another for a weekend day (figure 2.3). Again, the hourly demands are represented relative to the water heating day peak at 9pm. The pattern of the profiles can be explained by the fact that most people take their shower (using hot water) around 9pm, and do not similar quantities of water in the evening.

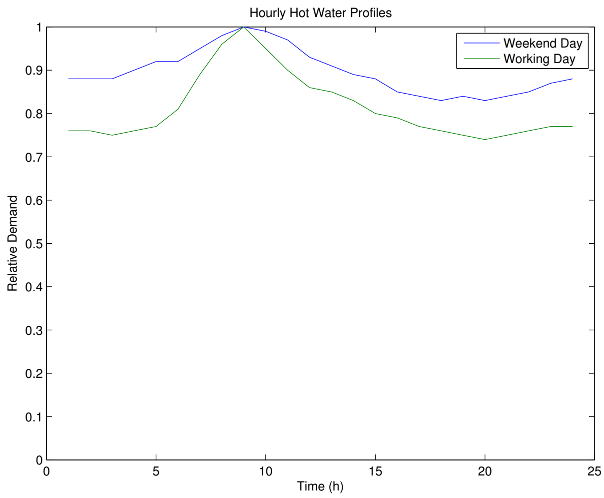


Figure 2.3: Hot water profiles

Generation of the Space Heating and Hot Water Demand Profiles

As the daily shares and the hourly profiles are computed, we can at last generate the different annual space heating and hot water demand profiles. The daily heating demand needs to be multiplied with the fitting hourly profile for each day of the year such as to obtain a distribution of the total annual space heating and hot water heat demand to all 8760 hours of the year.

The environment used to compute the demand profiles is R. The programming features of R make it the perfect programming language for data analysis. The general structure of the linear program is described on table 2.2.1.

Structure of the R program generating the space heating and hot water demand profiles
Input: Base temperature, Outside air temperatures
For day 1...8760:
Step 1: Compute daily heat demand
1.1: Calculate the heating degree day HDD
1.2: Compute the daily heat demand share using the extended degree day method
Step 2: Compute hourly profiles
Step 3: Generate the annual heat demand profiles
3.1: Identify which profile to use
3.1.1: What day of the week is it?
3.1.2: In what range is the outside air temperature located?
3.2: Multiply the daily heat demand with the fitting profiles

Table 2.1: Structure of the R program

Recall that the heat demand is separated into three different sectors: commercial, residential and industrial. Given the total annual space heating and hot water demands of each sector, the profiles illustrated on the next page are generated (figure 2.4 for space heating and figure 2.5 for hot water).

The space heating demand profiles show that the demand is the highest during the first hours of the year, drops heavily around the middle of the year and increases again close to the end of the year. This distribution makes sense as the very first hour on the graphs corresponds to January 1st at midnight, and the very last hour to December 31st at midnight. Since these days are winter days, the space heating demand is significantly higher during those hours than in the middle of the year, which corresponds to the spring and summer seasons.

The hot water demand profiles show a similar drop of the heat demand around the middle of the year. This drop is however less significant than in the case of space heating because of the higher base temperature value ($60°C$ for water heating compared to $18°C$ for space heating). Indeed, when analyzing and computing tests on the extended degree day formula, it can be noticed that a higher value of the base load causes smaller differences between the daily share values. This less significant drop in hot water demand is justified by the fact that unlike space heating, hot water is needed throughout the entire year as people usually do not like to take cold showers even during summer days. Note that the hot water demand profile of the industrial sector is not included in figure 2.5. Indeed, the industrial hot water demand is an exception to the rule and is not generated using the extended degree day method. Instead, the profile is computed using the same method as for process heating generation, which will be discussed in the next section.

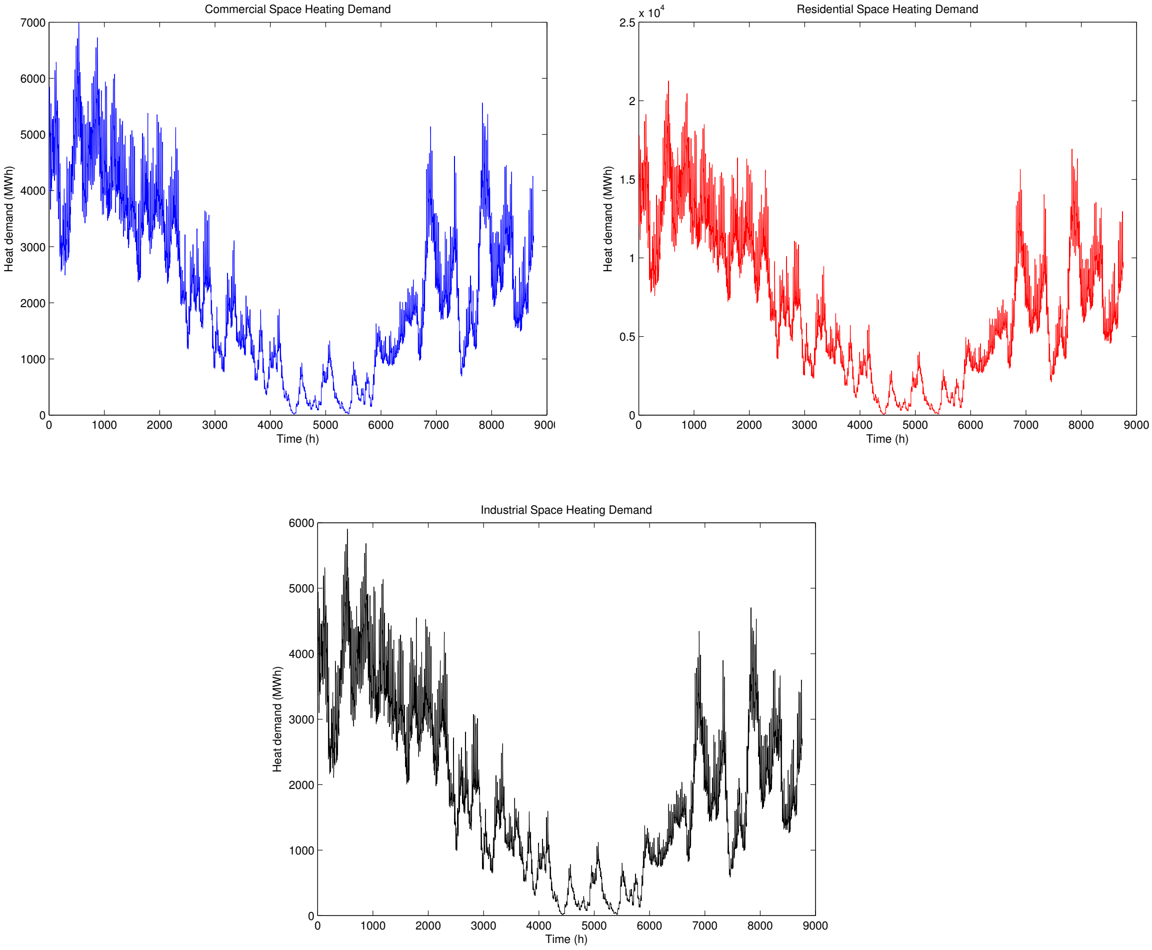


Figure 2.4: Space heating demand profiles over a year

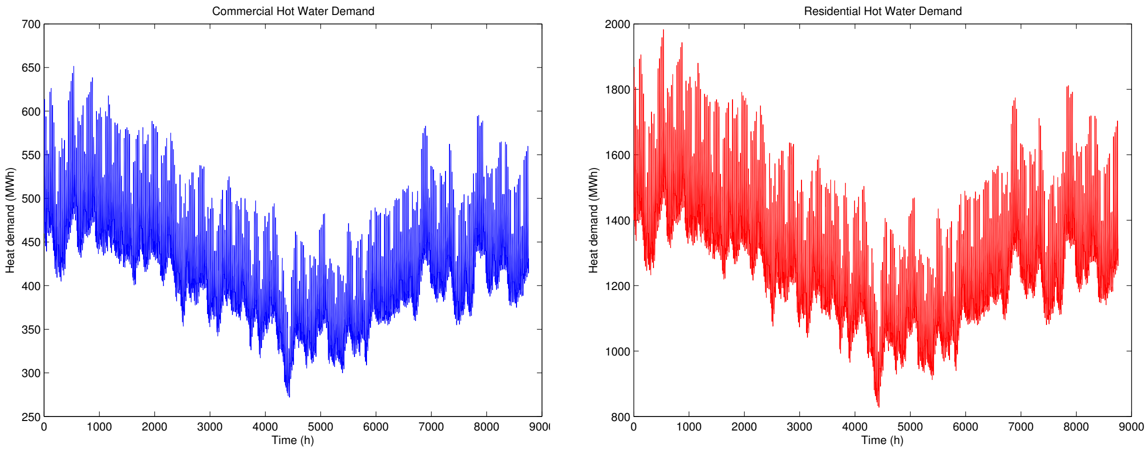


Figure 2.5: Hot water demand profiles over a year

2.2.2 Process Heating Demand Profiles

Process heating demand is only considered in the industrial sector, since it is negligible in both the residential and commercial sector. The industry heat demand is actually dominated by process heating, while space heating and hot water have a secondary role.

The method adopted to generate process heating demand profiles is more complex than the one used for the computation of space heating and hot water demand profiles, mainly because the industrial sector needs to be divided into different branches of industry in order to be studied correctly. Twelve branches of industry are considered in this work, namely:

- Steel
- Chemical
- Non-metallic
- Food
- Construction
- Mining
- Machinery
- Paper and pulp
- Transport equipment
- Textile
- Wood
- Miscellaneous

In each branch, the process heating demand is split up into two temperature ranges; (i) $\theta < 100°C$ and $100°C \leq \theta < 500°C$. The share of each heating use per class for every branch is represented in figure 2.6. It includes space heating and hot water as they cannot be neglected, even though they have a secondary role in the industry sector.

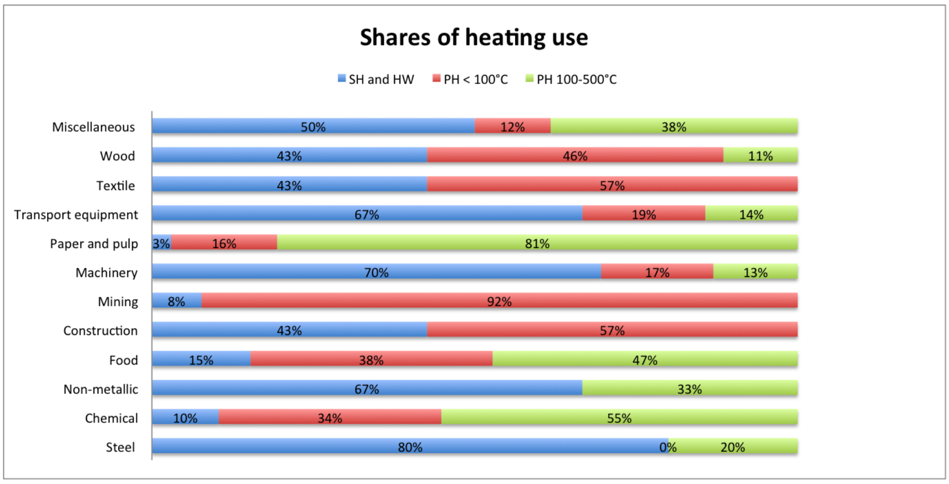


Figure 2.6: Shares of each heating use in the industrial heating demand

The generation of the annual process heating profiles follows a different methodology from the one used for the space heating and hot water profiles. The steps to follow remain however the same: (i) compute the daily heat demands and (ii) distribute them over each hour of the day. The first step is easily realized; in the case of process heating, the daily shares are assumed to be equal for each day of the year. In consequence, process heating profiles are not calculated based on heating degree day values. The assumption of an equal share is reasonable considering the daily shares of process heating do not really depend on the time of the year; contrarily to the space heating demand for example where the share for a winter day is much more important than the share for a summer day. It is however not a perfect assumption as it has been noticed that the process heating demand slightly decreases during the short period between Christmas and New Year. The slight decrease is most probably due to the lack of workers during this holiday period.

To realize the second step, hourly process heating profiles need to be computed. Unlike the hourly profiles of space heating, the main dependency parameter for these profiles is not the outside air temperature but the full load hours value (FLH), which has been introduced in the terminology section. Full load hours depend on the industry branch considered and are an interesting parameter to use since they are able to categorize the generators based on their production patterns. Beside the full load hours value, the hourly process heating profiles also depend on the day of the week, since the demand usually decreases on weekends. The different profiles are illustrated in figure 2.7. [7]

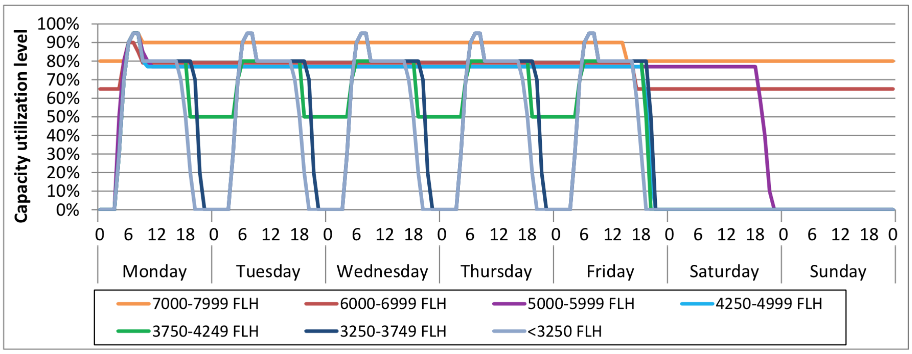


Figure 2.7: Hourly process heating profiles

The specific pattern of the profiles represented in figure 2.7 is justified by a series of assumptions taken from Gils' thesis. First, we assume that the demand is cut down or even cut off on weekends and at night time. Second, every scheduled production down time is succeeded by a process heating demand peak because of the re-heating requirements. Finally, all the industry branches operating at more than 8000 full load hours are considered to have a constant demand throughout the entire year.

From a thorough analysis of the heat market, Gils was able to find values for the shares each FLH class has on the annual process heating demand. These shares are used in this work and are available on table 2.2. The weekly overall process heating demand profile is then realized by superimposing the profiles of all the FLH classes, each weighted with its corresponding demand share.

At last, the annual process heating demand profiles are computed by multiplying each daily demand share (which has an equal value throughout the entire year) with the corresponding hourly profile which depends on the day of the week. The final yearly process heating demand profiles are represented in figure 2.8 and include a zoom of the first 1000 hours to have a better view of the general pattern. The pattern is the same

[7]This figure is taken from Gils [8] on page 57

FLH	Share
< 3250	0.15
3250-3749	0.17
3750-4249	0.16
4250-4999	0.12
5000-5999	0.08
6000-6999	0.08
7000-7999	0.24
≥ 8000	0

Table 2.2: Shares of FLH classes

for both types of process heating. The only difference lies in the annual demand level, given as parameters.

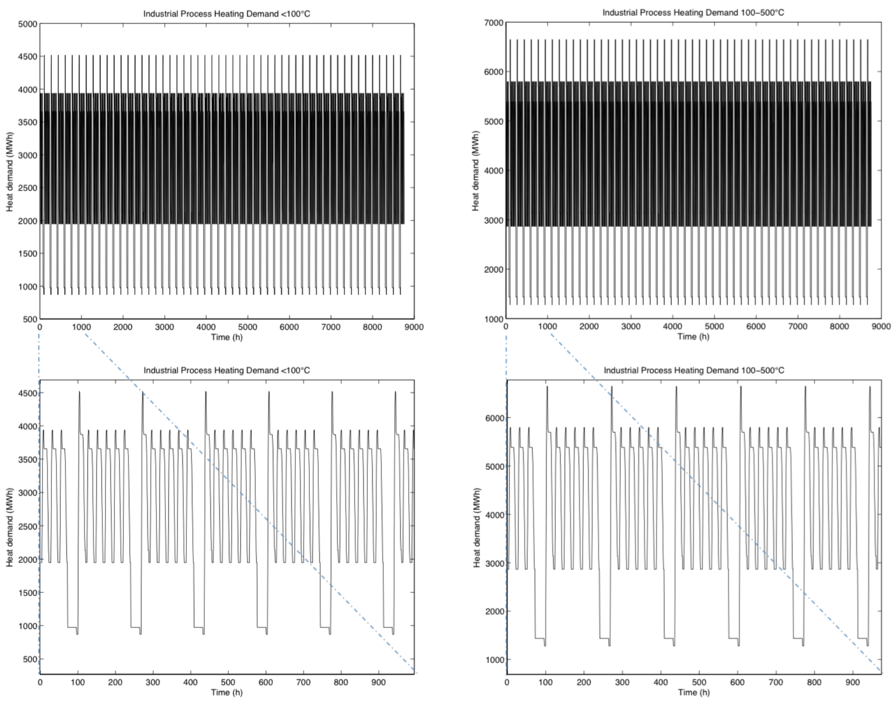
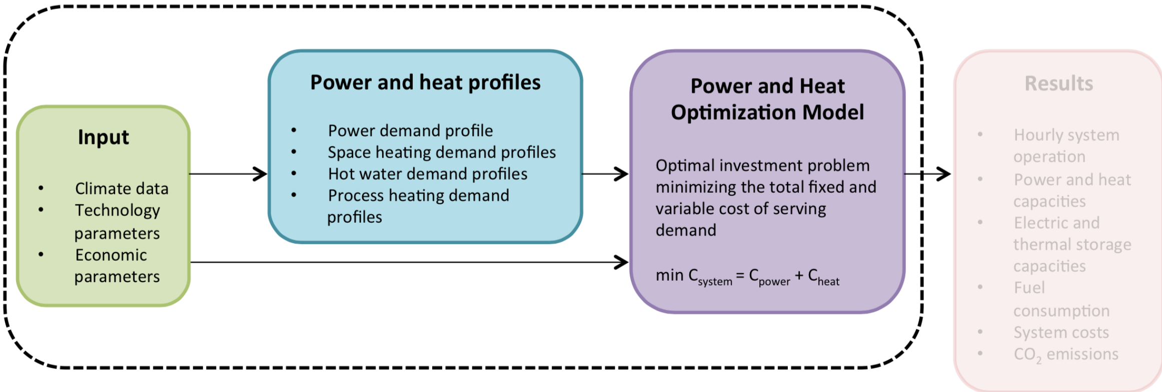


Figure 2.8: Process heating demand profiles over a year

The industrial hot water demand profile, as aforementioned, is generated differently from the commercial and residential hot water profiles. Instead of using the extended degree day method and the hourly profiles depicted in figure 2.3, the industrial hot water demand profile is computed by considering an equal daily demand share and multiplying the demand of each day with the hourly profiles used for process heating. This results in a graph comparable to the one in figure 2.8, but with a much smaller demand level.

Chapter 3

Mathematical Model of the Heat and Electricity Market



Today's literature includes a great deal of models describing the electricity market. The heat market is however often overlooked or undervalued despite the fact that it emits an undeniable amount of greenhouse gasses and utilizes a significant portion of the available (renewable) energy resources. The particularity of the model described in this thesis is that it analyses the electricity and heat market as a whole. This is a substantial advantage for a multitude of reasons. First, it enables us to assess the utilization competition of the energy resources between the power and the heat sector. This is especially useful for resources which are available in limited amounts. If we want to shift to a more eco-friendly economy, the heat and electricity market must distance themselves from fossil fuel energy and aim towards renewable energy resources such as biomass, photovoltaic etc. It is therefore interesting to see what share of renewable energy is used for power generation and what share for heat generation. Second, by analyzing the power and the heat market together, we are able to assess which market is most affected by a mandatory drop of the CO_2 emission. We can do this by studying the cost evolution of both sectors to identify which sector suffers the most economically, or by studying the evolution of the fuel emission to determine which sector becomes the most eco-friendly. Finally, it also enables us to include technologies which are responsible for both power and heat production, such as combined heat and power (CHP) plants.

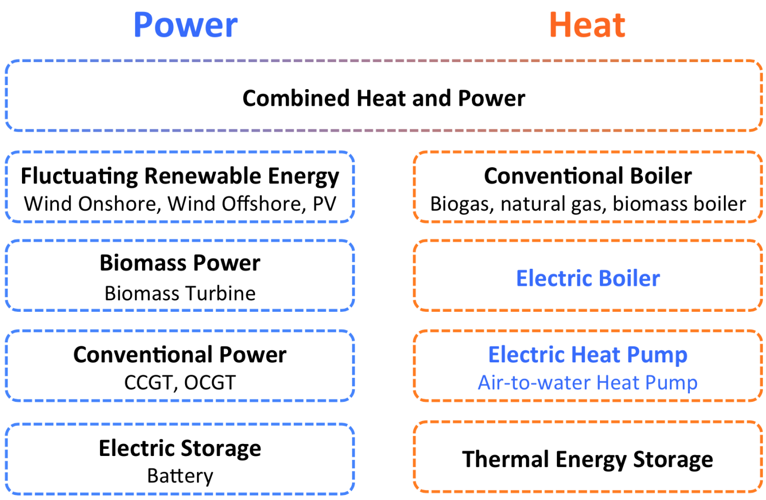


Figure 3.1: Power and heat technologies

Figure 3.1 shows the set of technologies available to satisfy the power and heat demands. Some technologies are used strictly for power production, others strictly for heat production, and the combined heat and power (CHP) plants can satisfy both the electricity and heat demand. Two of the heating technologies, i.e. the electric boiler and electric heat pump, are consuming electricity in order to produce heat. Therefore, the production of these technologies is paired with an increase of the total electricity demand.

There are obviously more technologies present on today's market, but all technologies are not necessarily applicable to satisfy the demands in Belgium. In this thesis, we concentrate solely on the power and heat market in Belgium. As a consequence, the set of available technologies has been adapted to the characteristics of the Belgian market. For instance, hydro power plants have been removed from the set of technologies as they cannot produce electricity in big quantities in Belgium. It is therefore not representative to include them in the set of power producing technologies since the optimized model will make them produce in big quantities, which cannot be achieved. Another example are geothermal heat and power plants which extract heat from the ground to the surface. Such plants are compelling to use because they produce power and heat at the same time. Nevertheless, the electricity generation needs high temperature resources, which are only available in deep underground. Therefore, geothermal heat and power technologies can only be used in areas where the geological conditions allow it. The conditions in Central Europe are however not suitable for such technologies.

3.1 Overview of the model

Before going into the different equations that constitute the model, it is necessary to have a general view on how the model works. This section will explain broadly the general functioning with the aid of figure 3.2. It concentrates on the elements that link the power and heat sector.

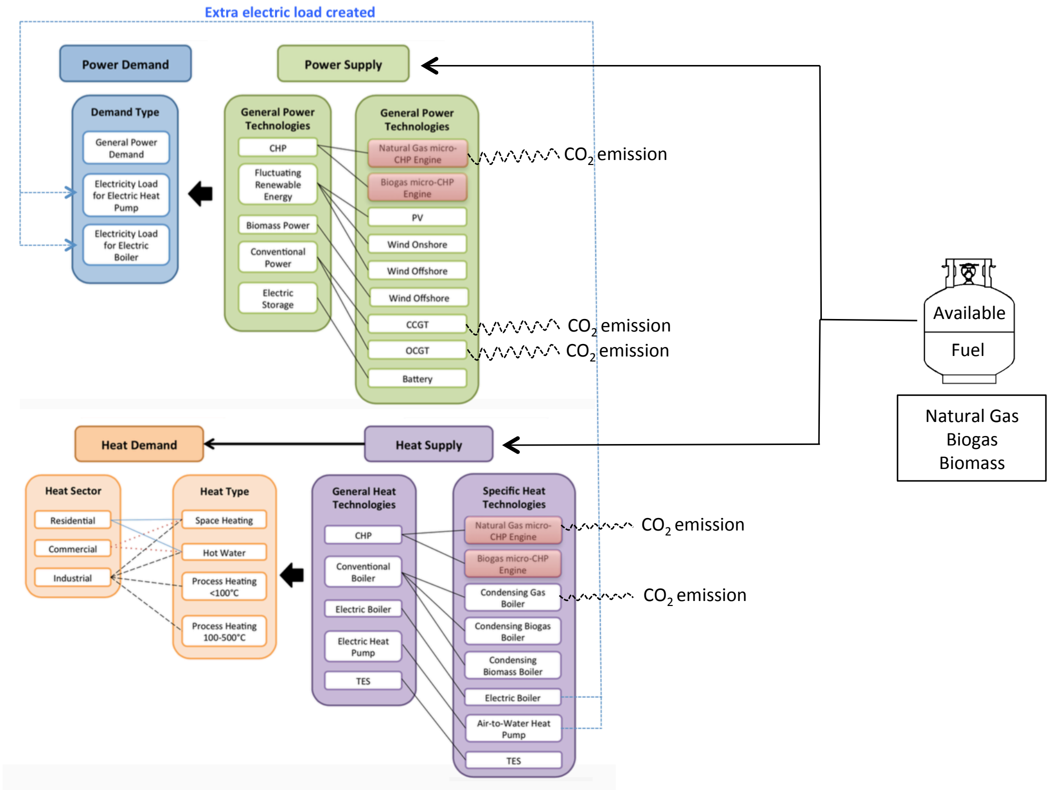


Figure 3.2: Overview of the functioning of the model

To build the model, we can consider the power and the heat market separately and write their respective equations. These include the demand equations, the cost equations as well as the technology constraint equations. But what does link the two markets together? First, we have the availability of the resources. As depicted in figure 3.2, we consider one fuel tank that provides fuel for both the power and heat supply. Some resources can however only be used in limited amounts, such as biomass. The model tries then to optimize the dispatch between the power and heat market. Secondly, for a certain amount of fuel, combined heat and power plants generate a fixed ratio of heat and power. These technologies are represented in red in figure 3.2 and show a clear link between the power and the heat market. A third link is established by the electric boilers and electric heat pump. Indeed, to generate heat, they need a certain amount of electricity. This creates an extra electricity load which is added to the power demand. Finally, the CO_2 emission of the fossil fueled technologies forms a fourth and final link. Indeed, to shift to a more eco-friendly economy, the model contains a CO_2 emission constraint that limits the emission of greenhouse gasses. This constraint includes the emission of both power and heat technologies.

3.2 Modelling Approach and Environment

The energy system model described in this chapter makes use of an optimization algorithm. It is an optimal investment problem which finds the mix of technologies that should be built in order to minimize the total fixed and variable cost of serving the electricity and heat demand. Since the requirements of the model are represented by linear relationships, the method used is linear programming. Its canonical form is given by equations 3.1 to 3.3.

$$min \quad c^T\mathbf{x} \tag{3.1}$$

$$A\mathbf{x} \geq b \tag{3.2}$$

$$\mathbf{x} \geq 0 \tag{3.3}$$

The objective function $c^T\mathbf{x}$ is minimized, where c is the known vector of cost parameters and $\mathbf{x}$ is the vector of variables to be determined. The inequalities $A\mathbf{x} \geq b$ and $\mathbf{x} \geq 0$ are the constraints which specify a convex polytope over which the objective function is to be optimized, where A is the known matrix of technology parameters and b is the known vector of constraint constants.

The environment used to build the linear optimization model is AMPL. This environment is convenient as in integrates a modeling language for describing optimization data, variables, objectives, and constraints. The general structure of the linear program is described on table 3.2. The objective function is the total system cost, which includes both power and heat costs. It is subject to a set of constraints, which can be split in six categories. The first two categories describe the demand balance equations. The third category defines the set of equations which are basic to all technologies, such as maximum capacity constraints or investment and operational costs. The technology constraints category comprises all the constraints specific to the functioning of the different power and heat technologies. The resource availability constraint limits the amount of energy sources available to serve power and heat. Finally, the CO_2 emission constraint forces the model to reduce its greenhouse gas emissions. The model is tested for several CO_2 emission limits and the results are compared with one another.

Structure of the linear optimization program
Minimize Total System Cost subject to Power Demand Balance Equation Heat Demand Balance Equations Basic Power and Heat Supply Constraints Technology Constraints Resource Availability Constraint CO_2 Emission Constraint

Table 3.1: Structure of the AMPL program

In the next few sections, the different equations constructing the mathematical model will be explained in detail. Note that all variables are represented in bold, while the parameters are not. The explanations of all the symbols used are available in the tables at the very beginning of the thesis.

3.3 Objective Function

The model aims to minimize the total annual costs of both the electricity and heat market. A clear distinction between the annual cost arising from electricity production and the annual cost arising from heat production is difficult to achieve because of the CHP technologies, whose costs should be assigned both to the electricity and heat sector as they produce both power and heat. Therefore, the annual cost of investing in CHP is considered separately from the annual electricity and heat costs. The objective function thus has the following form:

$$min \quad \mathbf{C}^{tot} = \mathbf{C}^{tot,heat} + \mathbf{C}^{tot,elec} + \mathbf{C}^{tot,CHP} \tag{3.4}$$

These costs include the investment and operational costs of the different production and storage technologies, the fuel costs as well as the costs of not supplying heat or electricity. The latter costs provide an extra flexibility to the system as they do not constraint the system to serve the entire demand.

$$\mathbf{C}^{tot,elec} = \sum_k (\mathbf{C}_k^{inv} + \mathbf{C}_k^{op} + \mathbf{C}_k^{fuel}) + \mathbf{C}^{nosupply,elec} \qquad k \in K_{elec/CHP} \tag{3.5}$$

$$\mathbf{C}^{tot,heat} = \sum_k (\mathbf{C}_k^{inv} + \mathbf{C}_k^{op} + \mathbf{C}_k^{fuel}) + \mathbf{C}^{nosupply,heat} \qquad k \in K_{heat/CHP} \tag{3.6}$$

$$\mathbf{C}^{tot,heat} = \sum_k (\mathbf{C}_k^{inv} + \mathbf{C}_k^{op} + \mathbf{C}_k^{fuel}) \qquad k \in K_{CHP} \tag{3.7}$$

3.4 Demand Balance Equations

The power and heat demand balance equations described in the next paragraph enforce the model to serve, at each time step, at least as much demand as the demand profiles computed in chapter 2. The technologies are however free to produce less than the demand level defined by profile, but are then penalized by a cost of not supplying this demand. This cost is called the Value of Lost Load (c^{VoLL}), which is a monetary indicator expressing the costs associated with an interruption of electricity supply[1].

3.4.1 Power Demand Balance Constraint

The power demand balance constraint is expressed by equation 3.8 and the equations expressing the lost load of electricity are depicted in 3.9 and 3.10. Note that, in the electricity balance constraint, the extra loads created by the heat pumps and electric boilers are added to the demand side as they consume electricity in order to produce heat.

[1]Definition taken from the following website: http://journal.frontiersin.org/article/10.3389/fenrg.2015.00055/full

$$\sum_k \mathbf{P}_{k,t} + \sum_s (\mathbf{P}_{s,t}^{discharge} - \mathbf{P}_{s,t}^{charge}) \geq \mathbf{P}_t^{supply} + \sum_f \mathbf{P}_{f,t}^{elHeatPump} + \sum_g \mathbf{P}_{g,t}^{elHeatBoiler} \tag{3.8}$$

$$k \in K_{elec}, s \in S_{elec}, f \in K_{HP}, g \in K_{boiler}, \forall t$$

$$\mathbf{P}_t^{nosupply} = P_t^{demand} - \mathbf{P}_t^{supply} \qquad \forall t \tag{3.9}$$

$$\mathbf{C}^{nosupply,elec} = \sum_t \mathbf{P}_t^{nosupply} \cdot c^{VoLL,elec} \tag{3.10}$$

3.4.2 Heat Demand Balance Constraints

Contrarily to the power market, we do not have a single heat demand balance constraint but 8 of them. Indeed, as seen in chapter 2, we consider the different types of heat demands and the different sectors independently. A simplification could have been to add all these demands up and have one heat demand balance equation which satisfied the total demand. This would however be too strong of an assumption as the different heat demands have specific characteristics. Indeed, not all technologies are adequate to satisfy all types of heat demands. Combined heat and power plants can be taken as an example as they are usually not used in the residential sector but mostly in the industrial sector. Another example are thermal energy storage technologies which can be used for process heating, but only for temperatures inferior to $100°C$. As a consequence, we consider the different heat demands separately and define a suitable set of technologies for each type of heat demand. We will have a total of 8 heat demand balance equations, each with the same structure but with a different demand and a different set of technologies. The residential hot water demand balance constraint for instance is given by equation 3.11 and the no supplied residential hot water by equation 3.12. These two equations are repeated for the seven other types of heat demands. Note that for some types of heat demands (commercial hot water for example), the term representing the thermal energy storage is removed as it is not included in the set of technologies.

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,ResHW} \tag{3.11}$$

$$k \in K_{ResHW}, s \in S_{TES,ResHW}, \forall t$$

$$\mathbf{Q}_t^{nosupply,ResHW} = Q_t^{demand,ResHW} - \mathbf{Q}_t^{supply,ResHW} \qquad \forall t \tag{3.12}$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,ComSH} \qquad \forall t \tag{3.13}$$

$$k \in K_{ComSH}, s \in S_{TES,ComSH} \tag{3.14}$$

$$\mathbf{Q}_t^{nosupply,ComSH} = Q_t^{demand,ComSH} - \mathbf{Q}_t^{supply,ComSH} \qquad \forall t \tag{3.15}$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,IndSH} \qquad \forall t \tag{3.16}$$

$$k \in K_{IndSH}, s \in S_{TES,IndSH} \tag{3.17}$$

$$\mathbf{Q}_t^{nosupply,IndSH} = Q_t^{demand,IndSH} - \mathbf{Q}_t^{supply,IndSH} \qquad \forall t \tag{3.18}$$

$$\tag{3.19}$$

$$\sum_k \mathbf{Q}_{k,t} \geq \mathbf{Q}_t^{supply,IndHW} \qquad \forall t, k \in K_{IndHW} \tag{3.20}$$

$$\mathbf{Q}_t^{nosupply,IndHW} = Q_t^{demand,IndHW} - \mathbf{Q}_t^{supply,IndHW} \qquad \forall t \tag{3.21}$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,IndPH_1} \qquad \forall t \tag{3.22}$$

$$k \in K_{IndPH_1}, s \in S_{TES,IndPH_1} \tag{3.23}$$

$$\mathbf{Q}_t^{nosupply,IndPH1} = Q_t^{demand,IndPH_1} - \mathbf{Q}_t^{supply,IndPH_1} \qquad \forall t \tag{3.24}$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,IndPH_2} \qquad \forall t \tag{3.25}$$

$$k \in K_{IndPH_2}, s \in S_{TES,IndPH_2} \tag{3.26}$$

$$\mathbf{Q}_t^{nosupply,IndPH_2} = Q_t^{demand,IndPH_2} - \mathbf{Q}_t^{supply,IndPH_2} \qquad \forall t \tag{3.27}$$

The cost of not supplied heat is given by equation 3.28.

$$\begin{aligned}\mathbf{C}^{nosupply,heat} = \sum_t (&\mathbf{Q}_t^{nosupply,ResHW} + \mathbf{Q}_t^{nosupply,ResSH} + \mathbf{Q}_t^{nosupply,ComHW} + \mathbf{Q}_t^{nosupply,ComSH} \\ &+ \mathbf{Q}_t^{nosupply,IndHW} + \mathbf{Q}_t^{nosupply,IndSH} + \mathbf{Q}_t^{nosupply,IndPH1} + \mathbf{Q}_t^{nosupply,IndPH2}) \cdot c^{VoLL,heat}\end{aligned} \tag{3.28}$$

3.5 Basic Power and Heat Supply Constraints

The functioning of each type of technology, should it be for heating or power, is described by a set of equations. The next sections in this chapter detail these equations per technology. Some equations are however general to all technologies, such as the investment and operational cost equations or the maximum production equations. These will be presented in this section.

At each time step, the technologies are restricted to produce less than its capacity, as is represented in equations 3.29 and 3.30. In the model, the capacity is not a fixed parameter, but an optimization variable. The technologies can therefore have a capacity as big as can be, but the bigger the capacity, the higher the investment cost.

$$\mathbf{P}_{k,t} \leq \mathbf{P}_k^{cap} \qquad \forall k \in K_{elec}, \forall t \tag{3.29}$$

$$\mathbf{Q}_{k,t} \leq \mathbf{Q}_k^{cap} \qquad \forall k \in K_{heat}, \forall t \tag{3.30}$$

Each technology is associated with two types of costs; investment cost and operational cost. The total investment cost of each technology is calculated using the equivalent annual cost (EAC) approach [2]. This approach calculates the constant annual cash flow generated by the use of a technology over its lifespan if it was an annuity; where an annuity is a fixed sum of money paid to someone each year, typically for the rest of their life. We opted to use this approach in order to represent the unequal life spans

[2]Approach described on the website http://www.investopedia.com/terms/e/equivalent-annual-annuity-approach.asp

of the different technologies, that would not have been considered if we only used the net present cost. The equivalent annual cost is calculated by dividing the net present value (NPV), which corresponds here to the specific investment cost of the considered technology, by the present value of an annuity factor:

$$EAC = \frac{NPV}{A_{T,r}}, \quad \text{where } A_{T,r} = \frac{1 - \dfrac{1}{(1+r)^T}}{r} \tag{3.31}$$

where r is the annual interest rate and T the life span of the technology. It has been assumed in this thesis that the annual interest rate r is equal to 5% for all the technologies.
The total investment cost of a technology is linked with the capacity built to satisfy the demand, and is represented by equation 3.32 for the power sector and equation 3.33 for the heat sector. Note that we exclude the CHP from the set of technologies as their investment cost is computed slightly differently (see section 3.6.3).

$$\mathbf{C}_k^{inv} = \frac{r \cdot c_k^{specInv}}{1 - \dfrac{1}{(1+r)^{T_k}}} \cdot \mathbf{P}_k^{cap} \qquad \forall k \in K_{elec/CHP} \tag{3.32}$$

$$\mathbf{C}_k^{inv} = \frac{r \cdot c_k^{specInv}}{1 - \dfrac{1}{(1+r)^{T_k}}} \cdot \mathbf{Q}_k^{cap} \qquad \forall k \in K_{heat/CHP} \tag{3.33}$$

The total operating cost is constituted of the fixed operating cost and the variable operating cost. The fixed operating costs do not change with an increase or decrease in production and are essentially capital costs. The variable operating costs are however dependent on the amount of heat or power produced at each time step. In theory, fuel costs are a part of the operating cost. However, in this thesis, we consider the fuel costs separately from the variable costs. Equations 3.34 and 3.35 describe the total operating costs. The operational cost includes the distribution cost of heat and power, where $s^{distLoss}$ represents the electricity and heat loss and c^{dist} the cost of distribution. Again, CHP technologies are excluded from the set of technologies as their operational cost is described in section 3.6.3.

$$\mathbf{C}_k^{op} = \sum_t (\mathbf{P}_{k,t}) \cdot (c_k^{varOp} + (1 - s^{distLoss}) \cdot c^{dist}) + \mathbf{P}_k^{cap} \cdot c_k^{fixOp} \qquad \forall k \in K_{elec/CHP} \tag{3.34}$$

$$\mathbf{C}_k^{op} = \sum_t (\mathbf{Q}_{k,t}) \cdot (c_k^{varOp} + (1 - s^{distLoss}) \cdot c^{dist}) + \mathbf{Q}_k^{cap} \cdot c_k^{fixOp} \qquad \forall k \in K_{heat/CHP} \tag{3.35}$$

3.6 Technology Constraints

This section will discuss the equations of the different kinds of technologies, and is divided into three parts: power technology constraints, heat technology constraints and combined heat and power technology constraints.

3.6.1 Power Technology Constraints

As represented in figure 3.1, we differentiate four types of power technologies: fluctuating renewable energy technologies, biomass powered technologies, conventional power generators and electric storage.

Fluctuating Renewable Energy Model Equations

The fluctuating renewable energies identified are photovoltaic power, onshore wind power and offshore wind power. Note that renewable energy sources such as biomass or run-of-the-river hydroelectricity are not fluctuating sources as they are either controllable or relatively constant.

Technologies powered by fluctuating renewable energies are very attractive to use as they do not emit any greenhouse gasses. An ideal power and heat market would be one where all technologies would be working on renewable sources. Fluctuating renewable energies have nonetheless a major drawback; they only produce energy when the wind is blowing or the sun is shining, which is non predictable. As a consequence, it would be incorrect to allow the model to produce any amount of power using fluctuating renewable sources. Indeed, the next chapter discussing the results of the model shows that, if no constraint is put on the production of the photovoltaic technology, the entire power demand will be satisfied solely by photovoltaic power. To avoid this problem, fixed profiles provided by ENGIE are used for the photovoltaic, onshore wind, and offshore wind plants. For the photovoltaic profile, we can expect the value to be zero at night time, to increase between sunrise and sun peak, and then decrease between sun peak and sunset. Furthermore, the value will also be higher on summer days than on winter days. This is illustrated in figure 3.3, which includes a zoom of the yearly profile to illustrate clearly the pattern of production. As for the wind profiles, it is difficult to predict their behavior. Their graphs have not been included in this section as they do not provide us with useful information, but they can be found in the annexes (figure C.1).

The production profiles are expressed by equations 3.36, 3.37 and 3.38, where a, b and c are their respective hourly profiles. The profiles represent the share of capacity produced at each time step.

$$\mathbf{P}_{PV,t} = a_t \cdot \mathbf{P}^{cap}_{PV} \qquad \forall t \tag{3.36}$$
$$\mathbf{P}_{windOn,t} = b_t \cdot \mathbf{P}^{cap}_{windOn} \qquad \forall t \tag{3.37}$$
$$\mathbf{P}_{windOff,t} = c_t \cdot \mathbf{P}^{cap}_{windOff} \qquad \forall t \tag{3.38}$$

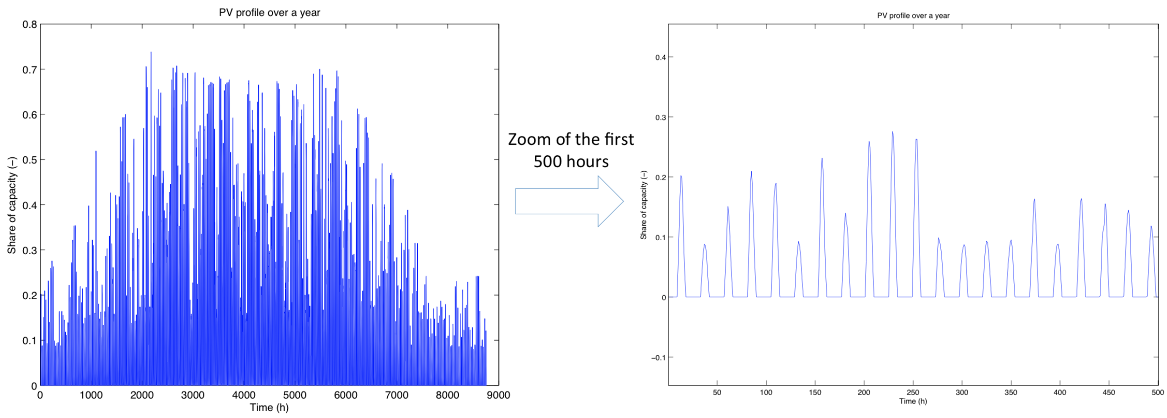


Figure 3.3: Yearly PV profile

Conventional Power and Biomass Model Equations

The conventional power plants considered in this thesis are open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT). These turbines can work either on natural gas or biogas. Natural gas is cheaper than biogas, but pollutes the air while biogas is eco-friendly. These turbines are modelled using the equations introduced in section 3.5, but we need to add an extra constraint representing the total fuel used to make the turbines run. The fuel consumed to produce a specific amount of power depends on the efficiency η of the turbine. The fuel consumption is given by equation 3.39, and the associated cost by equation 3.40.

$$\mathbf{D}_{k,t}^{fuel} = \frac{\mathbf{P}_{k,t}}{\eta_k} \qquad \forall t, \forall k \in K_{conventional} \tag{3.39}$$

$$\mathbf{C}_{k}^{fuel} = \sum_t (\mathbf{D}_{k,t}^{fuel}) \cdot c_k^{fuel} \qquad \forall k \in K_{conventional} \tag{3.40}$$

Biomass turbines have exactly the same fuel equations, except for the fact that the considered fuel is biomass instead of natural gas or biogas.

Electric Storage Model Equations

Electric storage enables the model to capture electricity produced at one time for use at a later time. These technologies are a big asset because they allow the model to store electricity during times when the production exceeds the consumption. The storage can use electricity from renewable sources to shave off power demand peaks.This will enable us to reduce, or even shut down, fossil fuel power plants. The only power storage technology considered in this thesis are batteries.

The central equation for electric storage is the storage balance 3.41, which reflects all variations in the filling level. At each time step, the storage level $\mathbf{F}$ equals the sum of the self discharge l_s, the storage input $\mathbf{P}^{input}$ and the storage output $\mathbf{P}^{output}$. The efficiency η in the balance equation represents the losses occurring while charging and discharging the battery. Equations 3.42 and 3.43 respectively equate the storage level and the power output to zero at the very first time step. The maximum storage capacity is expressed by equation 3.44, and equations 3.45 and 3.46 puts a limit on the amount of electricity that can be charged or discharged at each time step. We assume that the fastest time frame to fully charge a battery would be six hours if the fill level was equal to zero. Equivalently, it would take six hours for the battery to fully discharge if the fill level had reached the maximum capacity.

$$\mathbf{F}_{s,t} = \mathbf{F}_{s,t-1} \cdot (1 - l_s) + \mathbf{P}^{input}_{s,t} \cdot \eta_s - \frac{\mathbf{P}^{output}_{s,t}}{\eta_s} \qquad \forall t, \forall s \in S_{elec} \tag{3.41}$$

$$\mathbf{F}_{s,1} = 0 \qquad \forall s \in S_{elec} \tag{3.42}$$

$$\mathbf{P}^{output}_{s,1} = 0 \qquad \forall s \in S_{elec} \tag{3.43}$$

$$\mathbf{F}_{s,t} \leq \mathbf{E}^{cap}_{s} \qquad \forall t, \forall s \in S_{elec} \tag{3.44}$$

$$\mathbf{P}^{input}_{s,t} \leq \frac{\mathbf{E}^{cap}_{s}}{6} \qquad \forall t, \forall s \in S_{elec} \tag{3.45}$$

$$\mathbf{P}^{output}_{s,t} \leq \frac{\mathbf{E}^{cap}_{s}}{6} \qquad \forall t, \forall s \in S_{elec} \tag{3.46}$$

3.6.2 Heat Technology Model Equations

Identically to the previous section, this section will discuss the equations modeling the functioning of the heat technologies. The technologies considered are electric and conventional boilers, electric heat pumps and thermal energy storage.

Conventional Boiler Model Equations

Three types of conventional boilers are considered: condensing gas boilers, condensing biogas boilers, and condensing biomass boilers. Equivalently to the conventional power technologies, the only equations that need to be added on top of the basic heat supply model equations are the ones describing the fuel consumption and cost. These depend on the efficiency of the conventional boiler considered, and are expressed by 3.47 and 3.48.

$$\mathbf{D}^{fuel}_{k,t} = \frac{\mathbf{Q}_{k,t}}{\eta_k} \qquad \forall t, \forall k \in K_{BoilerConventional} \tag{3.47}$$

$$\mathbf{C}^{fuel}_{k} = \sum_{t} (\mathbf{D}^{fuel}_{k,t}) \cdot c^{fuel}_{k} \qquad \forall k \in K_{BoilerConventional} \tag{3.48}$$

Electric boiler and electric heat pump model equations

Electric boilers and electric heat pumps are one of the few technologies that create a direct link between the power and the heat market. Indeed, they need electricity to produce heat, hence the electricity load is added to the electricity demand equation in the power market. The amount of electricity needed to produce a specific amount of heat is given by equations 3.49 and 3.50.

$$\mathbf{P}^{elHeatBoiler}_{k,t} = \frac{\mathbf{Q}_{k,t}}{\eta_k} \qquad \forall t, \forall k \in K_{ElBoiler} \tag{3.49}$$

$$\mathbf{P}^{elHeatPump}_{k,t} = \frac{\mathbf{Q}_{k,t}}{\eta_k} \qquad \forall t, \forall k \in K_{ElHeatPump} \tag{3.50}$$

Thermal energy storage model equations

Thermal energy storage (TES) is the equivalent of a battery, but for heat instead of power. The principle is exactly the same; TES allows excess thermal energy to be collected for later use, and by doing so, enables the model to use renewable sources to shave off heat demand peaks. It also reduces excessive waste of useful heat.

Equations 3.51 to 3.56 describe the functioning of TES, and are similar to the ones of electric storage. The only difference is that, for TES, we do not assume for the storage to take 6 hours to fully charge or discharge.

$$\mathbf{U}_{s,t} = \mathbf{U}_{s,t-1} \cdot (1 - l_s) + \mathbf{Q}^{input}_{s,t} \cdot \eta_s - \frac{\mathbf{Q}^{output}_{s,t}}{\eta_s} \qquad \forall t, \forall s \in S_{heat} \tag{3.51}$$

$$\mathbf{U}_{s,1} = 0 \qquad \forall s \in S_{heat} \tag{3.52}$$

$$\mathbf{Q}^{output}_{s,1} = 0 \qquad \forall s \in S_{heat} \tag{3.53}$$

$$\mathbf{U}_{s,t} \leq \mathbf{U}^{cap}_{s} \qquad \forall t, \forall s \in S_{heat} \tag{3.54}$$

$$\mathbf{Q}^{input}_{s,t} \leq \mathbf{U}^{cap}_{s} \qquad \forall t, \forall s \in S_{heat} \tag{3.55}$$

$$\mathbf{Q}^{output}_{s,t} \leq \mathbf{U}^{cap}_{s} \qquad \forall t, \forall s \in S_{heat} \tag{3.56}$$

3.6.3 Combined heat and power model equations

Combined heat and power (CHP) plants are more productive than conventional power plants. The reason behind this lies in a more thermodynamically efficient use of fuel, as CHP plants can generate both electricity and heat at the same time using the same fuel. Typically, in conventional power plants, some energy must be rejected as waste heat in the atmosphere. CHP plants however can capture the heat that would otherwise be wasted in order to provide useful thermal energy. A typical CHP system reclaims a minimum of 80% of the heat that would otherwise be wasted. A consequence of this efficient fuel use is a reduced environmental harm. Indeed, as less fuel is used to serve a same amount of heat and power, the quantity of CO_2 emission drops.

The CHP plants are represented by the model equations 3.57 to 3.61. The central equation is the one describing the link between power and heat production (3.59). For a certain amount of fuel, CHP technologies generate a fixed ratio of heat and power. The parameter σ is the ratio of the maximum power generation in CHP operation and the maximum heat production. The capacity constraints for CHP (3.57 and 3.58) are slightly different from the basic capacity constraints discussed in section 3.5. Indeed, the power-to-heat ratio σ is now used to switch from a heat limit to a power limit. Equation 3.60 expresses the hourly fuel consumption. This equation is also somewhat different from the fuel consumption equations seen so far because of the multiplying

factor $\dfrac{1+\sigma_k}{\sigma_k}$. This factor enables us to compute the total production (heat and power). On the actual market, CHP plants usually run on fossil fuel. We can however also use renewable energy sources such as biogas as fuel input.
Finally, the system costs resulting from CHP production are described by equations 3.61, 3.62 and 3.63.

$$\mathbf{P}_{k,t} \leq \mathbf{Q}_k^{cap} \cdot \sigma_k \qquad \forall t, \forall k \in K_{CHP} \tag{3.57}$$

$$\mathbf{Q}_{k,t} \leq \mathbf{Q}_k^{cap} \qquad \forall t, \forall k \in K_{CHP} \tag{3.58}$$

$$\mathbf{P}_{k,t} = \mathbf{Q}_{k,t} \cdot \sigma_k \qquad \forall t, \forall k \in K_{CHP} \tag{3.59}$$

$$\mathbf{D}_{k,t}^{fuel} = \frac{\mathbf{P}_{k,t}}{\eta_k} \cdot \frac{1+\sigma_k}{\sigma_k} \qquad \forall t, \forall k \in K_{CHP} \tag{3.60}$$

$$\mathbf{C}_k^{fuel} = \sum_t \mathbf{D}_{k,t}^{fuel} \cdot c_k^{fuel} \qquad \forall k \in K_{CHP} \tag{3.61}$$

$$\mathbf{C}_k^{inv} = \frac{r \cdot c_k^{specInv}}{1 - \dfrac{1}{(1+r)^{T_k}}} \cdot \mathbf{Q}_k^{cap} \cdot \sigma_k \qquad \forall k \in K_{CHP} \tag{3.62}$$

$$\mathbf{C}_k^{op} = \sum_t (\mathbf{P}_{k,t} \cdot c_k^{varOp} + \mathbf{Q}_{k,t} \cdot (1 - s^{distLoss}) \cdot c^{dist}) + \mathbf{Q}_k^{cap} \cdot \sigma_k \cdot c_k^{fixOp} \tag{3.63}$$

$$\forall k \in K_{CHP}$$

The CHP technologies used in this work have a fixed ratio of electricity to heat output. However, there exist CHP plants on the market which adapt the proportions of power and heat production through adjustable steam. Such CHP plants are more advantageous as they provide an additional degree of freedom. Their equations are however more complex since they introduce a new variable $\mathbf{Q}cond$. This variable describes the condensed heat that can be used for an additional power generation. The extra power generation is obtained by multiplying the condensed heat $\mathbf{Q}^{cond}$ with the power loss coefficient β which defines the additional power generation that can be realized. For such adjustable steam CHP plants, the equations 3.57 to 3.61 need to be replaced by the corresponding equations 3.64 to 3.68. The logic behind the equations is the same. They are just adapted to include the extra power generation through condensed heat.

$$\mathbf{P}_{k,t} \leq \mathbf{Q}_k^{cap} \cdot (\sigma_k + \beta_k) \qquad \forall t, \forall k \in K_{CHP} \tag{3.64}$$

$$\mathbf{Q}_{k,t} + \mathbf{Q}_{k,t}^{cond} \leq \mathbf{Q}_k^{cap} \qquad \forall t, \forall k \in K_{CHP} \tag{3.65}$$

$$\mathbf{P}_{k,t} = \mathbf{Q}_{k,t} \cdot \sigma_k + \mathbf{Q}_{k,t}^{cond} \cdot (\sigma_k + \beta_k) \qquad \forall t, \forall k \in K_{CHP} \tag{3.66}$$

$$\mathbf{D}_{k,t}^{fuel} = \frac{(\mathbf{P}_{k,t} + \mathbf{Q}_{k,t} \cdot \beta_k)}{\eta_k} \cdot \frac{1+\sigma_k}{\sigma_k + \beta_k} \qquad \forall t, \forall k \in K_{CHP} \tag{3.67}$$

$$\mathbf{C}_k^{fuel} = \sum_t \mathbf{D}_{k,t}^{fuel} \cdot c_k^{fuel} \qquad \forall k \in K_{CHP} \tag{3.68}$$

$$\mathbf{C}_k^{inv} = \frac{r \cdot c_k^{specInv}}{1 - \dfrac{1}{(1+r)^{T_k}}} \cdot \mathbf{Q}_k^{cap} \cdot (\sigma_k + \beta_k) \qquad \forall k \in K_{CHP} \tag{3.69}$$

$$\mathbf{C}_k^{op} = \sum_t (\mathbf{P}_{k,t} \cdot c_k^{varOp} + \mathbf{Q}_{k,t} \cdot (1 - s^{distLoss}) \cdot c^{dist}) + \mathbf{Q}_k^{cap} \cdot (\sigma_k + \beta_k) \cdot c_k^{fixOp} \tag{3.70}$$

$$\forall k \in K_{CHP}$$

The tests discussed in the next chapter are realized using CHP technologies with a fixed ratio by cause of a lack of study of the adjustable CHP. The equations of the adjustable CHP are given for the lecturer interest.

3.7 Resource Availability Constraint

The available energy resources are used to serve both power and heat. This means that the power and heat technologies compete for the same fuel, which is not always available in unlimited amounts. The resource availability constraint puts a limit on the amount of fuel that can be used over one year. In the scope of this work however, a limit is not fixed for each type of fuel but only for biomass fuel. We assume that natural gas and biogas can be consumed in infinite quantities. This assumption is not irrational as the availability of natural gas or biogas is far greater than the amount needed to satisfy the entire demand over a year. Putting a restriction on biomass consumption on the other hand makes quite some sense. Biomass is collected by burning wood and other organic matter. Although it is a renewable energy source, as organic matter can re-grow, burning biomass releases carbon emissions. As a consequence, we want biomass consumption to be limited to a certain level (equation 3.71). The maximum annual biomass consumption is given by the parameter $E^{annualBiomass}$.

$$\sum_k \sum_t \mathbf{D}_{k,t}^{fuel} \leq E^{annualBiomass} \qquad k \in K_{BiomassTechnologies} \tag{3.71}$$

3.8 CO_2 Emission Constraint

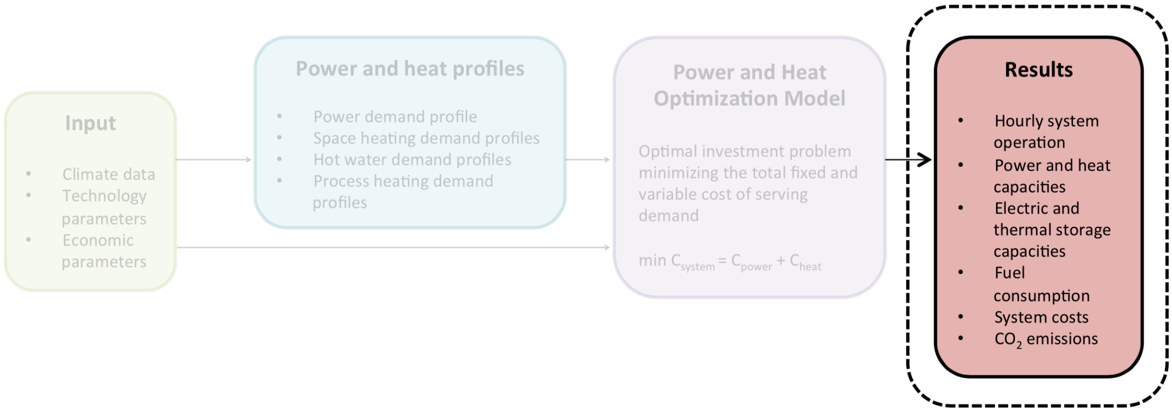
One of the most important model equations is the CO_2 emission constraint which limits the amount of CO_2 released in the atmosphere over a year (equation 3.72). This constraint ensures an environmental improvement of the system as it reduces the consumption of fossil energy sources, which otherwise would be used in abundance due to their economic interest. The total greenhouse gas emission level $\mathbf{G}^{total}$ is computed by multiplying the fuel consumption of the different technologies with their corresponding CO_2 emission factor f_{CO_2}. This emission factor represents the amount of CO_2 released in the atmosphere per unit of fuel consumed, and is equal to zero for renewable energy sources. The total CO_2 emission is then limited by the maximum level E^{CO_2}

$$\mathbf{G}^{total} = \sum_k \sum_t \mathbf{D}^{fuel}_{k,t} \cdot f^{CO_2}_k \qquad k \in K_{fuel} \tag{3.72}$$

$$\mathbf{G}^{total} \leq E^{CO_2} \tag{3.73}$$

Chapter 4

Tests on the Model and Discussion of Results



This chapter will analyze and discuss the results of the optimization model presented in chapter 3. The main objective is to study the evolution of the model when changing the maximum CO_2 emission constraint. A multitude of model variables will be monitored closely throughout the evolution of this constraint. The primary variables to consider are undoubtedly the power and heat production variables $\mathbf{P}_k$ and $\mathbf{Q}_k$. Indeed, the central goal of this thesis is to analyze the changes that will happen in the production of heat and power if we switch to a more eco-friendly economy. Therefore, we are most interested in observing the evolution of the technologies producing when a reduction of the greenhouse gasses occurs. Instinctively, we expect the fossil fuel consuming technologies to produce the major share of heat and power, if no limit is put on the level of emitted CO_2 . The reason behind this is that fossil fuel technologies are usually cheaper to construct, and as the model tries to minimize the total cost, the priority will be put on these technologies. Once we introduce the CO_2 emission constraint, the "stronger" this constraint becomes, the lower the production of fossil fuel technologies and the higher the production of renewable technologies. Other variables to pay attention to are the total power and heat costs $\mathbf{C}^{tot,elec}$ and $\mathbf{C}^{tot,heat}$. Although the safety of our planet becomes a growing issue nowadays, cutting off all fossil fueled plants is economically not achievable since it would induce a colossal cost increase. By tracking the evolution of the power and heat costs, we can observe which market is most affected by the decrease of the greenhouse gas emission. A last set of variables that can be interesting to study are the hourly prices of heat and electricity. These variables are not explicitly described in the optimization model, but can be obtained by computing the dual of the demand balance equations; which will be explained in more detail in the following sections of this chapter.

Different scenarios will be considered in this chapter. These scenarios will help us understand the functioning of the model. It is not enough to only consider one scenario and draw conclusions from its results. What interests us is the evolution of the results, from a simple power-only-producing market to a more complex power and heat market with a CO_2 emission constraint. The scenarios examined are the following:

- **Scenario 1: Power only market**
  Before combining the power and heat markets, it is interesting to study the power market on its own. Today's literature focuses a lot on the power market without any regards of the heating demands. As a consequence, the conclusions drawn from the power only model do not provide us with additional information compared to the current literature. However, the assessment of this scenario is crucial to see how the production technologies are affected by adding the heat market, how the costs of the power market increase or decrease etc. Similarly, we could have considered a scenario which only studied the heat market. However, three out of the five technologies available for heating, i.e. CHP plants, electric boilers and electric heat pumps, are directly linked with the power market. It would therefore be difficult and quite unreasonable to analyze the heat market without any regard of the power market.

- **Scenario 2: Power and heat market without CO_2 emission constraint**
  This scenario more or less corresponds to the situation we are in at the present time. It can be seen as a "business as usual" scenario. Business as usual describes the unchanging state of affairs despite difficulties or disturbances. Today's market has indeed identified the hazards of greenhouse gasses and has come up with renewable technologies that can counter these dangers. Nevertheless, the priority is often put on the economy rather than on the environment, which is why changes have not been happening fast. This scenario is probably the most important one as it helps us understand where the problem lies with our current market and what needs to be changed.

- **Scenario 3: Power and heat market with a decreasing CO_2 emission**
  This scenario comprises a multitude of scenarios. In scenario 2, we were able to compute the total emission generated by the model. Scenario 3 studies the power and heat market enforcing a decrease of the CO_2 emission level calculated in scenario 2. Several scenarios are considered in scenario 3 because we consider incremental decreases of 10% for the allowed CO_2 emission level. In other words, we consider first a scenario where 90% of the CO_2 emission level of scenario 2 is allowed, then 80% etc. We descend untill an allowed emission of 0% of the original level. This corresponds to the ideal environmental case where no pollution is allowed. The entire power and heat demand is strictly satisfied by renewable technologies.

4.1 Result predictions: Screening Curves

Before digging in to the different scenarios and testing their results with the developed optimization model, it would be interesting to predict the results following the theory. The optimal investment problem consists of finding the mix of technologies that should be built in order to minimize the total fixed and variable cost of serving demand. This mix is given by the optimization model, but can be derived graphically from the screening curves of the technologies. A screening curve describes the total hourly cost of each technology as a function of the fraction of time that is producing [1]. These curves provide a simple method for eliminating from further consideration those technologies which are significantly less economic.

The screening curves are computed as follows. First, we calculate the total fixed cost following formula 4.1. This fixed cost includes the equivalent annual investment cost, explained in section 3.5, and the fixed operational cost. Then we calculate the total variable cost, which is composed of the variable operational cost as well as the fuel cost (4.2). Note that the fuel cost needs to be divided by the efficiency of the technology in order to represent correctly the total variable cost. The screening curves are then represented using equation 4.3 where x is the vector of time.

$$C_k^{fix} = \frac{r \cdot c_k^{specInv}}{1 - \dfrac{1}{(1+r)^{T_k}}} + c_k^{fixOp} \tag{4.1}$$

$$C_k^{var} = c_k^{varOp} + \frac{c_k^{fuel}}{\eta_k} \tag{4.2}$$

$$y_k = C_k^{fix} + C_k^{var} \cdot x \tag{4.3}$$

4.1.1 Power technology screening curves

The screening curves representing the power producing technologies are given in figure 4.1. CHP technologies are not considered in these screening curves although they can produce power. The reason behind this is simple; as CHP technologies can produce both power and heat, adding their screening curves would not be representative. Indeed, imagine we add the screening curves of the CHP technologies and these curves are strictly dominated by other technologies. A conclusion would be to eliminate the CHP technologies from further consideration. However, as CHP plants can also produce heat with the same amount of fuel, eliminating them would be an error.

The graph on the left of figure 4.1 shows us that PV is economically more interesting than all other power producing technologies. It has a zero variable cost, and its investment cost is relatively low compared to the other technologies. Following the logic of the screening curve approach, this would mean that the only technology producing power throughout the entire year would be PV. This would be beneficial for the environment as PV does not emit any greenhouse gasses. Unfortunately, in practice, it is incorrect to draw this conclusion. Indeed, as mentioned in section 3.6.1, PV has

[1]Information taken from the course "Quantitative Energy Economics: Optimization Models in Electricity Markets" from Professor Anthony Papavasiliou

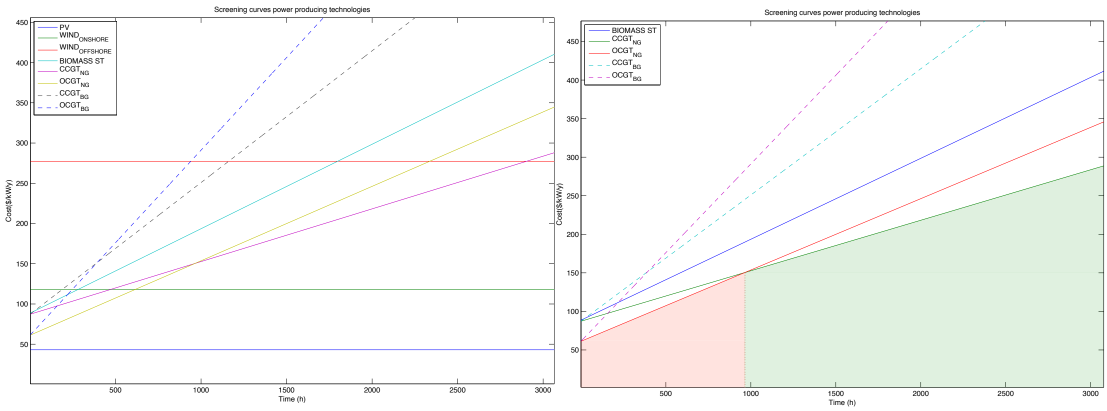


Figure 4.1: Power screening curves with (left graph) and without (right graph) considering technologies with a fixed profile

a fixed profile in our model. Photovoltaic power is a fluctuating source of energy and it would be incorrect to assume that it can produce as much power as we want it to. The same goes for onshore and offshore wind technologies. As a consequence, it is not representative to show their curves on the screening curve graph, as all their profiles are already fixed.

The graph on the right of figure 4.1 shows the screening curves of the remaining technologies, and these curves can give us information about the optimal mix of power production, excluding PV, onshore wind, offshore wind and CHP technologies. This graph shows that for about 1000 hours of the year, it is economically interesting to produce power through an OCGT plant functioning with natural gas. For the remaining hours of the year, a CCGT plant working on natural gas would be used. It would be illogical for a biomass steam turbine, biogas OCGT or biogas CCGT to produce any power as all three technologies are strictly dominated. The biogas OCGT technology is dominated by the natural gas OCGT technology because the price of biogas is higher than that of natural gas. Equivalently, biogas CCGT is dominated by natural gas OCGT. Finally, the biomass steam turbine is dominated by both the natural gas OCGT and the natural gas CCGT.
It is however not possible to remove indefinitely these three technologies from the set of power producing technologies. For scenarios 1 and 2, it would make sense for these technologies not to be producing. This will be confirmed, or not, in the sections analyzing the results of these scenarios. Scenarios 3 and 4 however cannot correctly make use of the screening curves as a limit is put on the total CO_2 emission. Therefore, the polluting CCGT and OCGT plants fueled with natural gas are not allowed to produce as much power as wanted, triggering the appearance of more environmental friendly technologies such as biogas OCGT and CCGT, or even biomass turbines.

4.1.2 Heat technology screening curves

Computing the screening curves of the heat producing technologies is a more complex matter than for the power producing technologies. This is because many heat producing technologies have a direct link with the power sector. Electric heat pumps and electric boilers for instance do not need fossil fuel to function, but electricity. The fuel cost c_k^{fuel} in equation 4.2 is equal to zero, but needs to be replaced by the electricity cost. The formula describing the variable cost then becomes 4.4. The trouble arising when trying to compute the variable cost is that we do not have a fixed electricity price c_k^{elec}. Indeed, the electricity price is determined by the optimization model and depends on the hour of the year. As a consequence, we cannot plot a single screening curve for each technology.

$$C_k^{var} = c_k^{varOp} + \frac{c_k^{elec}}{\eta_k} \tag{4.4}$$

Although the electricity price is variable, we will assume that it is constant in this section, just to have a general idea of the shape of the screening curves. Two prices will be considered in order to see the effect both prices have on the screening curves. Remember however that in the sections describing the results of the different scenarios, no fixed price is put on electricity. For an electricity price of 60€/MWh, we get the screening curves on the left graph of figure 4.2. For a price of 30€/MWh, we get the screening curves on the right graph of figure 4.2. For the same reason as the power technology screening curves, the combined heat and power technologies are not considered. Note also that only the space heating technologies are considered in this figure. The hot water and process heating technologies are similar, but can sometimes have a slightly different investment cost or efficiency, which modifies the curves by a little. It is however useless to plot the screening curves for all three types of heating technologies as they look very alike.

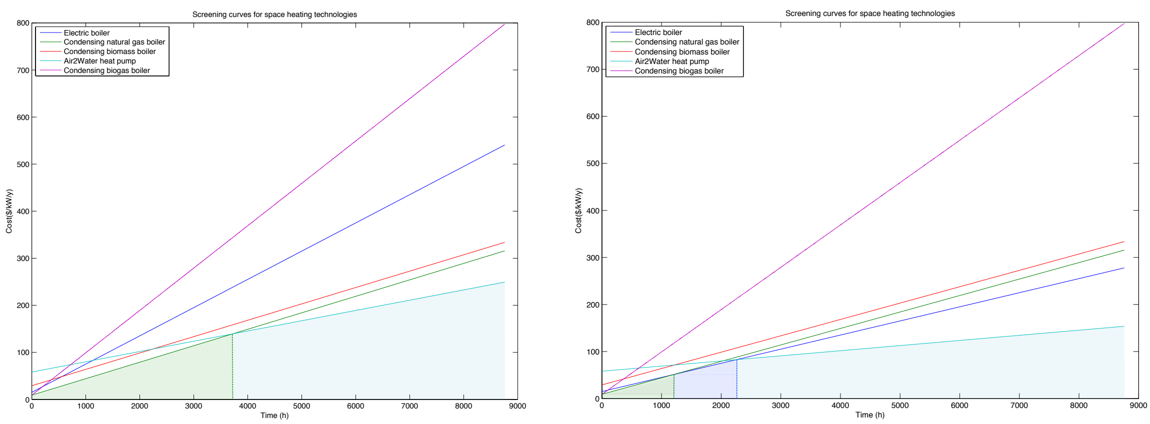


Figure 4.2: Space heating screening curves for an electricity price of 60€/MWh (left) and 30€/MWh (right)

The left-sided graph of figure 4.2, which corresponds to an electricity price of 60€/MWh, shows us that the electric boiler, the condensing biomass boiler and the condensing biogas boiler are all dominated by either the air-to-water heat pump or the condensing natural gas boiler. As a consequence, these dominated technologies will not produce heat in the case no limit is put on the maximum CO_2 emission. The condensing natural gas boiler however, which pollutes the atmosphere, will produce heat for about 2/5 of the year, and the air-to-water heat pump for about 3/5 of the year. In the case the electricity price decreases to 30€/MWh, the slope of the electricity consuming technologies changes. This is represented on the right-sided graph of figure 4.2. We can see that now, the electric boiler becomes economically interesting and starts to produce heat. The condensing biomass and biogas boilers will however always remain dominated by the condensing natural gas boiler and will not start producing unless a maximum level is put on the CO_2 emission. We can also observe that for an electricity price of 30€/MWh, the heat production of the heat pump increases, while the production of the condensing natural gas boiler decreases. The heat pump is now responsible for the production during approximately 6000 hours out of the 8760 hours of the year. The heat demand during the remaining hours is satisfied by either the electric boiler of the condensing natural gas boiler.

Although the electricity price is not fixed in the real model, we can guess from these two screening curve graphs by which mix of technologies the heat demand will be satisfied. The air-to-water heat pump will probably play a major role in the generation of heat. The electric boiler will likely produce some heat, but not in a big amount as it is unlikely for the electricity price to be as low as 30€/MWh for many hours of the year. The condensing natural gas boiler will most certainly produce, but the amount will depend on the CO_2 emission constraint. Finally, the remaining technologies will only start producing once the CO_2 emission level is low enough for these technologies to be economically interesting.

4.2 Scenario 1: Power only market

This first scenario consists of a capacity expansion model of the power sector, without any consideration of the heat demands. As a consequence, CHP plants are not considered in this scenario. If they are running, they will generate some heat which will be lost as it cannot satisfy any heat demand, so it has been decided to exclude these technologies for the moment being.

4.2.1 Power production profiles

Four technologies are satisfying the power demand in this first scenario; natural gas powered CCGT, natural gas powered OCGT, PV and onshore wind. Their production over the entire year is depicted in figure 4.3. All graphs have identical axis limits in order to clearly see the difference between the production levels of the four technologies. As mentioned in section 3.6.1, PV and wind technologies have fixed production profiles. Their only optimized variable is the size of the capacity constructed. The CCGT plant has a relatively constant production over the year, and produces a lot more power than the OCGT plan. The latter has a decrease in production during the summer months, which is probably due to the fact that the demand during these months is mostly satisfied by the PV technology.

4.2.2 Residual power load duration curve

The power production levels for CCGT and OCGT in figure 4.3 coincide with the theory of the screening curve approach. As a reminder, this approach finds a graphical solution to the optimal investment problem and is derived from the screening curves and the load duration curve. The load duration curve represents the variation of the

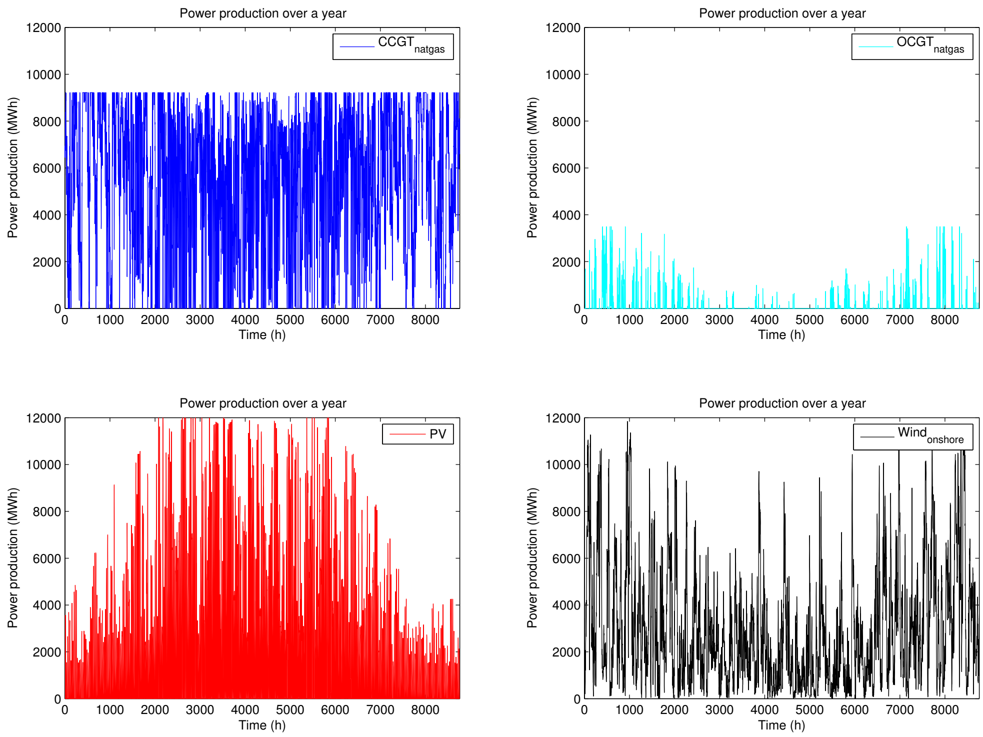


Figure 4.3: Power production of the technologies over a year

power load in a downward form such that the greatest load is plotted in the left and the smallest one in the right. The electric load is plotted on the vertical axis and the time on the horizontal axis. The area under this curve represents the energy demanded by the system. By combining the screening curves and the load duration curve, we are able to represent the technologies producing and their capacity levels. This is illustrated in figure 4.4. An important note is that the load duration curve represented in the figure is actually the "residual" load duration curve. This means that we subtract from the electricity demand the PV production as well as the onshore wind production. The subtraction is crucial for the graphical approach to be correct as both PV and onshore wind have fixed profiles, which would tamper with the solution.

As depicted in figure 4.4, the height of the slice in the residual load duration curve is a measure of capacity. The capacity of OCGT is considerably smaller than the capacity of CCGT, which is confirmed by the production levels in figure 4.3. The exact capacities of the power producing technologies are given in table 4.1. We can clearly notice that the capacity values of CCGT and OCGT coincide with the heights of the slices on the load duration curve.

4.2.3 Price duration curve

Similarly to the load duration curve, the price duration curve can be computed and shows the proportion of time for which the price exceeds a certain value. The price of electricity at each hour of the year can be collected by taking the dual of the electricity

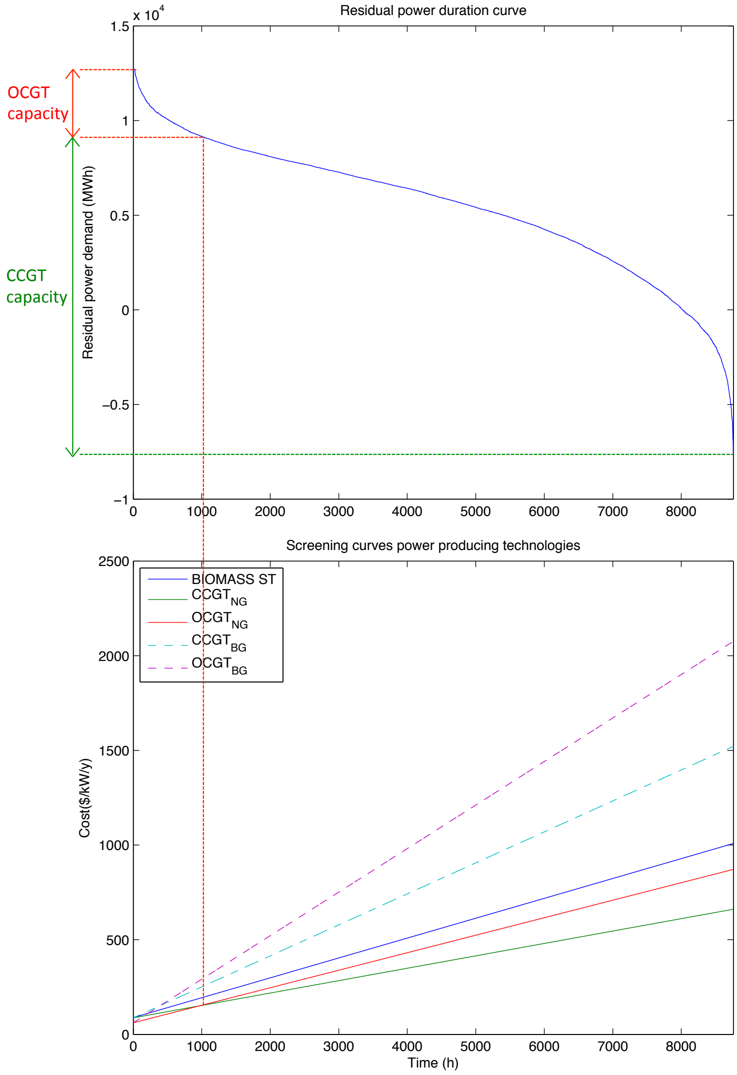


Figure 4.4: Residual load duration curve for power production

demand balance equation. This dual price gives the improvement in the objective function if the constraint is relaxed by one unit. More precisely, it gives the cost of meeting the last unit of the minimum production target.

By ordering these hourly prices in decreasing order, we get the graph in figure 4.5. We can see on this graph that three price levels are identified; 92.5€/MWh, 65.5€/MWh and 0€/MWh. The price of 92.5€/MWh corresponds to the variable cost C^{var} of the OCGT technology (see formula 4.2), the price of 65.5€/MWh to the variable cost of the CCGT technology, and the null price to the variable cost of PV and onshore wind. By taking a close look at figure 4.5, we can see that for the very first hours (the first 21 hours to be exact), the price plummets. The price then has a value of 3000€/MWh, which corresponds to the value of lost load. As a reminder, the value of lost load corresponds to the cost of not satisfying the heat demand. This means that for 21 hours throughout the entire year, it is economically more interesting to pay the cost of not supplying electricity rather than make the power generators produce an extra power unit.

Power technology	Capacity (GW)
CCGT	9.2
OCGT	3.4
PV	17.6
$\text{Wind}_{onshore}$	13.1

Table 4.1: Capacity values of the power producing technologies

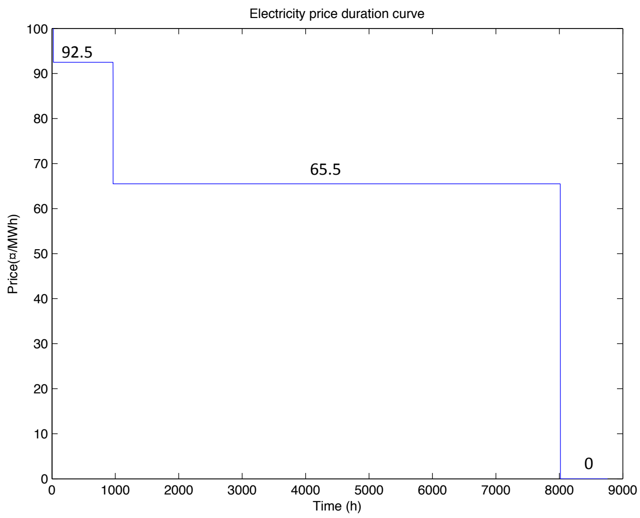


Figure 4.5: Price duration curve for electricity

4.3 Scenario 2: Power and heat market without CO_2 emission constraint

This section will discuss a scenario where no limit is put on greenhouse gas emissions and where the power and heat markets are combined. It is without doubt one of the most important scenarios to analyze as it is the one closest to the actual market. From the results, we will see which technologies pollute the most, and in the following scenarios, we will try to adapt its production in order to decrease the CO_2 emission level. This scenario will actually be composed of two sub-scenarios; one without considering the CHP plants and a second including CHP production. A separation of these two sub-scenarios has been done to clearly see the impact CHP technologies have on the power and heat market. The CHP plants can play a major role in decreasing pollution, which will be showed in this thesis.

4.3.1 Scenario 2.1: without CHP

Power production

When no CHP is available, three technologies are responsible for the power production; natural gas fueled CCGT, PV and onshore wind. The difference with the results of a power only scenario is the absence of OCGT production. The hourly productions of CCGT, PV and onshore wind are similar to the ones of scenario 1 (figure 4.3) and are available in figure E.1 in annex D. Although the patterns of the production profiles are almost identical, all three technologies produce considerably more in this scenario where the heat market is considered. This increase of power production can be justified by the following two reasons. First, as the OCGT technology does not satisfy any of the electricity demand in this second scenario, the load it was responsible for in scenario 1 is now handed over to the three remaining technologies. Second, the electricity demand is much higher in this scenario than it was in a power only market as extra electricity loads appear due to the production of electric heat pumps and electric boilers in the heat market. Their production will be confirmed later in this section when discussing the heat production.

These results show us the impact the heat market has on the power market. Combining the two markets causes a change in the mix of power producing technologies. The loss of OCGT production seems however illogical when looking at the screening curves in figure 4.1. We would have expected a small OCGT production. The results make however sense when analyzing the screening curves with the residual load duration curve (figure 4.6). The residual load duration curve is obtained by adding to the electricity demand the extra electricity load generated by the heat pumps and the electric boilers, and by subtracting once again the PV and wind production. The residual load duration curve has a different shape from the one of the power only market. Indeed, it shows now a plateau of more than 1000 time steps. As previously indicated, the height of each slice in the residual load duration curve is a measure of capacity. Since we have a plateau, the height of the OCGT slice is zero and we do not have any OCGT power production.

The capacity values of the power producing technologies are available on table 4.2. Compared to scenario 1, we have an increase of capacity of approximately 40% for the CCGT, 50% for the PV and 55% for the onshore wind technology. These capacity values are not necessarily representative of the share of total production each technology has, meaning that CCGT is for example not automatically the technology which produces the least power because it has the smallest capacity. On the contrary, as we can see on table 4.2, CCGT is actually the technology which satisfies the most demand with approximately 51%, followed by onshore wind and then PV. This is due to the fact that PV and onshore wind have fixed production profiles and can therefore not produce constantly at full capacity, which is not the case for CCGT. We can actually see in figure E.1 in annex D that the CCGT technology functions at at full capacity during most hours of the year.

Power technology	Capacity (GW)	Share of total production (%)
CCGT	12.8	50.7
PV	26.5	18.8
$\text{Wind}_{onshore}$	20.2	30.5

Table 4.2: Capacity values of the power producing technologies

Consolidating the heat and power market also has an impact on the hourly electricity prices. In scenario 1, the electricity prices were strictly defined by the power generating technologies. In the current scenario however, the heat market plays a major role on

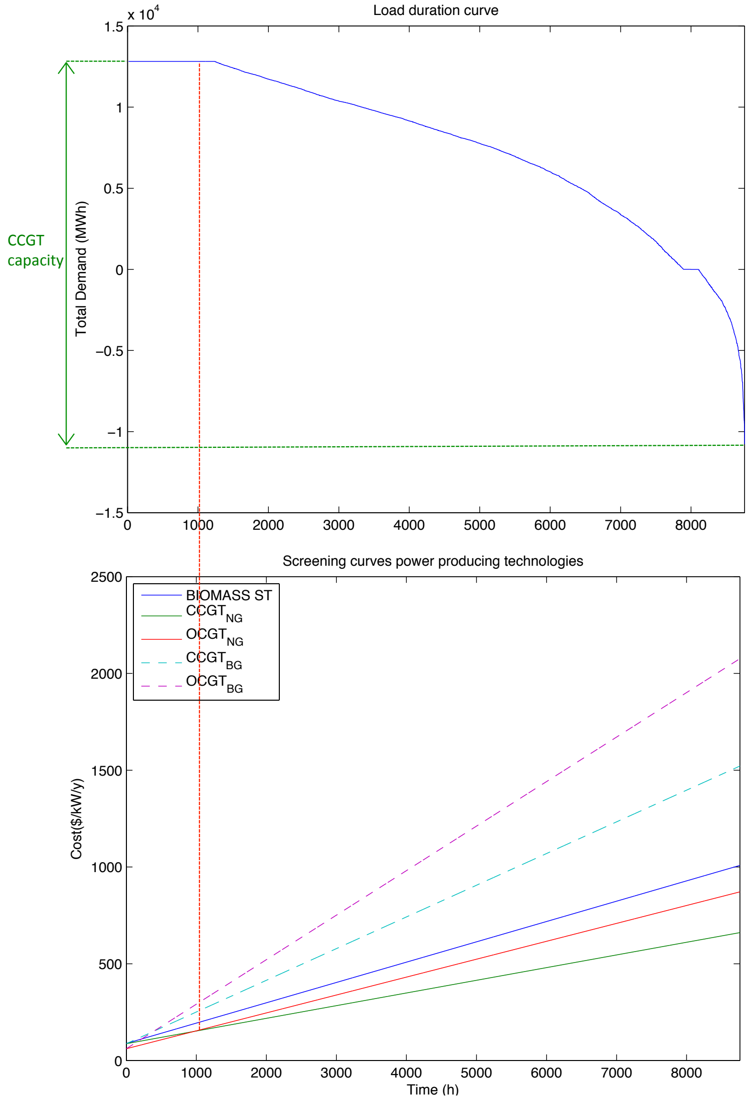


Figure 4.6: Residual load duration curve for power production

the values of these hourly prices. Recall that the electricity prices are obtained from the dual of the electricity demand balance equation. As mentioned in section 3.3, the electricity demand balance equation is given by equation 4.5. Two elements of this equation emanate from the heat market; the extra electricity load created by the electric heat pumps and the extra electricity load created by the electric boilers. As a consequence, the heat market will have a direct impact on the electricity prices.

$$\sum_k \mathbf{P}_{k,t} + \sum_s (\mathbf{P}_{s,t}^{discharge} - \mathbf{P}_{s,t}^{charge}) \geq \mathbf{P}_t^{supply} + \sum_f \mathbf{P}_{f,t}^{elHeatPump} + \sum_g \mathbf{P}_{g,t}^{elHeatBoiler} \tag{4.5}$$

$k \in K_{elec}, s \in S_{elec}, f \in K_{HP}, g \in K_{boiler}, \forall t$

The electricity price duration curve is given by figure 4.7. This price duration curve contains more price levels than in the scenario of a power only market. Three price levels are identical in both scenarios; 3000€/MWh corresponding to the value of lost load, 65€/MWh corresponding to the variable cost of CCGT and 0€/MWh corresponding to the variable cost of PV and onshore wind. The price level of 92.5€/MWh, which corresponds to the variable cost of OCGT, is not present in this electricity price duration curve as there is no OCGT production. The remaining prices are related to the heat sector, and their justification is a little more complex. Recall that the dual electricity price represents the cost of meeting an extra unit of the electricity supply $\mathbf{P}_t^{supply}$. Sometimes, it is too expensive to satisfy this extra power supply unit, and in order to cancel it, we can decrease the variables $\mathbf{P}_t^{elHeatPump}$ or $\mathbf{P}_t^{elHeatBoiler}$ by a single unit. A decrease of one of these variables by one unit means that we also have a decrease of one unit of heat production. This lost unit of heat production however needs to be satisfied by an alternative heat producing technology, which induces a cost. This cost represents the value of the electricity price. The price of 35€/MWh corresponds to the variable cost C^{var} of a condensing natural gas boiler satisfying either space heating or process heating. Equivalently, the price of 35.71€/MWh corresponds to the variable cost of a condensing natural gas boiler satisfying hot water demand. Finally, the prices of 96.25€/MWh and 98.21€/MWh are obtained quite differently. They correspond to the hours where there is no difference in producing an extra unit of heat through an electric heat pump or a condensing natural gas boiler. The electricity price is then computed using equation 4.6. The price of 96.25€/MWh is in the case a space or process heating condensing boiler is used, and the price of 98.21€/MWh in the case of a hot water condensing boiler.

$$\frac{C^{elec}}{\eta_{HeatPump}} = \frac{C^{naturalGas}}{\eta_{CondensingBoiler}} \tag{4.6}$$

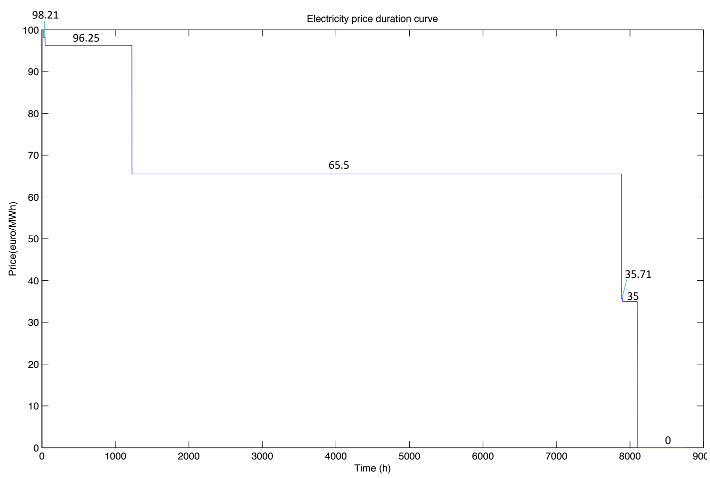


Figure 4.7: Price duration curve for electricity

Heat production

The total heat demand is satisfied by three types of technologies; electric heat pumps, electric boilers and condensing gas boilers functioning on natural gas. The heat pumps and condensing gas boilers provide heat for all three types of heating, i.e. space heating, hot water and process heating. The electric boilers on the other hand do not contribute to the space heating provision, but only to the hot water and process heating provision. Their hourly provision over the entire year is illustrated in figure 4.8. Once again, the limits on the axes of the three graphs are identical in order to clearly see the differences in production. Note that the productions of all types of heat demands (space heating, hot water and process heating) and all sectors (commercial, residential and industrial) have been summed up in order to represent the total hourly production of each technology.

The results are what we expected from the heat technology screening curves in figure 4.2. We have a very small electric boiler production, and quite important heat pump and condensing natural gas productions. The screening curves of the heating technologies showed us that the electric boiler was economically interesting for an electricity price of 30€/MWh, but not for a price of 60€/MWh. Besides, the electricity price duration curve in figure 4.7 shows us that for about 8000 hours out of the entire year, the electricity price exceeds 60€/MWh. This means that for most of the year, electric boilers are not used to satisfy the heat demand. They will only be used for the remaining 1000 hours, which explains their very small share in heat production. The heat pump production is quite constant over the entire year, except for a little drop during the summer months. This drop is perfectly coherent with the heat demand profiles described in chapter 2. Indeed, remember that during the spring and summer months, the space heating demand is much smaller than during the autumn and winter months. A stronger drop would actually have been expected. This strong heat provision difference is provided by the condensing natural gas boiler. The condensing natural gas boiler is therefore responsible for the majority of the seasonal fluctuation, with high peaks in the winter and low values in the summer. The reason why the heat pumps are not responsible for the seasonal variations is because they have a high fixed cost and a zero variable cost, contrarily to condensing gas boilers which have a low fixed cost but a high variable cost. Therefore, if money is invested in creating heat pumps, they better produce as much as possible at full capacity since they have a zero variable cost.

Although figure 4.8 represents a single production profile for each technology, we do not have a single capacity value for each technology. Indeed, each sector and each heating type has a different capacity. Their values can be found on table 4.3. We can see that in each sector and for each type of heating, the condensing gas boiler has a greater capacity than the heat pump, which makes sense as the investment cost of the condensing gas boiler is way lower. Table 4.3 also shows the shares of total heat production for each type of heating. The air-to-water heat pump produces the most heat for all four types of heating, followed by the condensing gas boiler and the electric boiler. In the case of space heating, the difference in total production between the heat pump and the condensing gas boiler is small, with respective percentages of 51% and 48%. In the other sectors however, heat pumps produce a lot more, with shares between 75% and 89%.

Equivalently to the electricity prices, the heat prices can be obtained by taking the dual of the heat demand balance equations. Since we have eight different heat demand balance equations, we can compute eight heat price duration curves. Figure 4.9 shows one of the price duration curves. All eight price duration curves are by logic

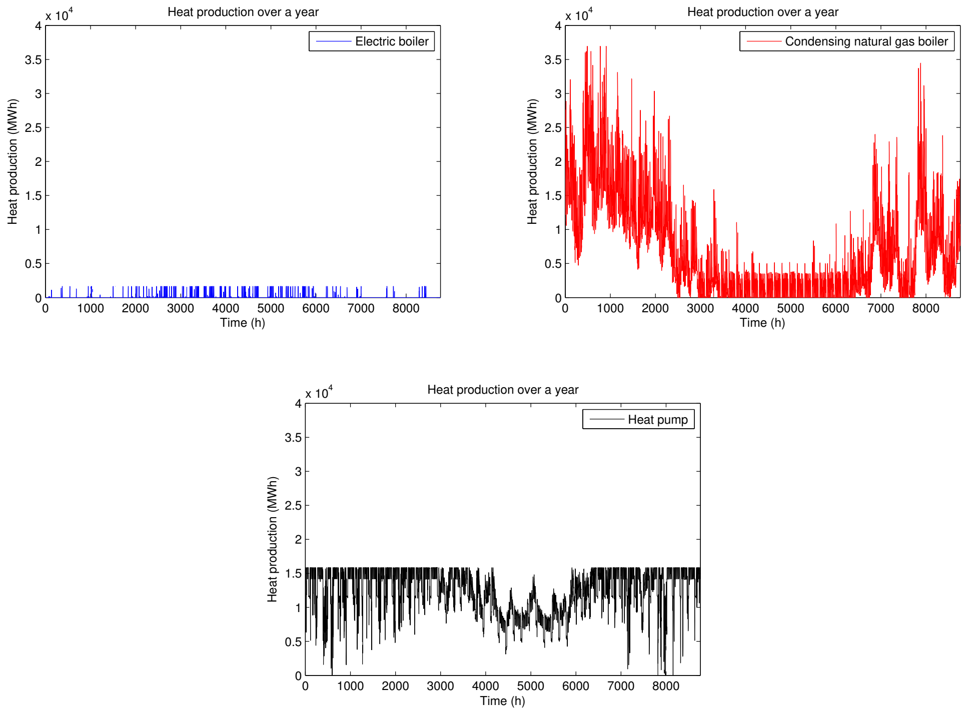


Figure 4.8: Heat production of the technologies over a year

very similar, which is why only one is showed in this thesis. The values of the different price levels correspond to the variables costs of the heat producing technologies. These variable costs include the fuel or electricity cost and the distribution cost. In case of a heat pump or an electric boiler, the variable cost is given by equation 4.7. The variable cost of a condensing gas boiler is given by equation 4.8.

$$C^{var} = \frac{c^{elec}}{\eta} + (1 - s^{distLoss}) \cdot c^{dist} \tag{4.7}$$

$$C^{var} = \frac{c^{fuel}}{\eta} + (1 - s^{distLoss}) \cdot c^{dist} \tag{4.8}$$

The price levels in figure 4.9 correspond to the following variable costs:

- **36.71€/MWh**: corresponds to the variable cost of a heat pump with an electricity price of 98.21€/MWh.
- **35.99€/MWh**: corresponds to the variable cost of a heat pump with an electricity price of 96.25€/MWh.
- **24.81€/MWh**: corresponds to the variable cost of a heat pump with an electricity price of 65.5€/MWh.
- **13.72€/MWh**: corresponds to the variable cost of a heat pump with an electricity price of 35€/MWh.

Space heating			
Technology	Sector	Capacity (GW)	Share of total production (%)
Air-to-water heat pump	Com	1.5	10
	Res	4.7	33
	Ind	1.3	8
Condensing gas boiler	Com	5.5	10
	Res	16.6	29
	Ind	4.6	9
Hot water			
Technology	Sector	Capacity (MW)	Share of total production (%)
Air-to-water heat pump	Com	0.4	19
	Res	1.2	58
	Ind	0.3	12
Condensing gas boiler	Com	0.5	2
	Res	1.4	5
	Ind	0.3	3
Electric boiler	Com	0.002	0.01
	Res	0.008	0.04
	Ind	0.1	0.6
Process heating $< 100°C$			
Technology	Sector	Capacity (MW)	Share of total production (%)
Air-to-water heat pump	Ind	2.6	75
Condensing gas boiler	Ind	3.3	23
Electric boiler	Ind	0.7	2
Process heating 100-500$°C$			
Technology	Sector	Capacity (MW)	Share of total production (%)
Air-to-water heat pump	Ind	3.8	76
Condensing gas boiler	Ind	4.8	23
Electric boiler	Ind	0.8	1

Table 4.3: Capacity values of the heat producing technologies

- **0.99€/MWh**: corresponds to the variable cost of a heat pump or an electric boiler with an electricity price of 0€/MWh.

4.3.2 Scenario 2.2: with CHP

In this second sub-scenario, CHP technologies are included in the mix of power and heat producing technologies. This section enables us to investigate the impact cogeneration has on the actual market. Conventional fossil-fueled power plants are substantially less efficient than CHP plants, as the latter make a better use of the fuel integrated into them. A major part of the energy used to run conventional plants is wasted in the form of heat discharged in the atmosphere. CHP systems are able to recover this wasted heat, achieving therefore a higher efficiency. Because of its higher efficiency, we could expect CHP plants to take over the production of conventional plants. This would be beneficial both environmentally and economically. Indeed, CHP requires less fuel to produce a given energy output, decreasing consequently the level of greenhouse gas

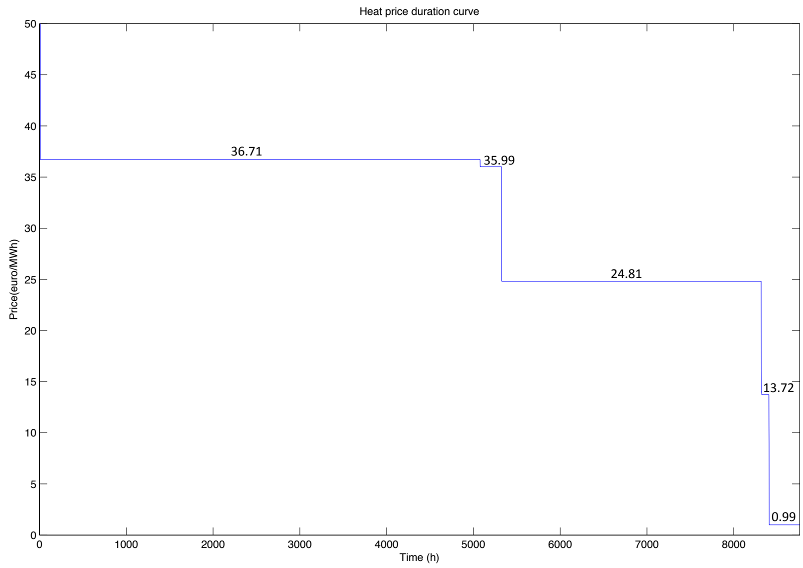


Figure 4.9: Price duration curve for heat

emissions. At the same time, it saves money due to its high efficiency.

This section is organized as follows. It will first describe the changes occurring with the power producing technologies. The same analysis will be then done to the heat producing technologies. Finally, the impacts on the fuel consumption, the CO_2 emission level and the total cost will be adressed.

Power production

Entering the CHP plants in the mix of technologies causes, as expected, a change in the optimal investment of power production. The CHP plants take over some of the power generation, leaving the remaining electricity demand to the technologies used in scenario 2.1, i.e. natural gas fueled CCGT, PV and onshore wind. Their production over the year is represented in figure 4.10. Although the CHP plant produces the least out of the four technologies, it plays an important role by taking over a major part of the power production of the CCGT plant. Both fluctuating renewable technologies produce approximately the same amount of power as in the previous scenario which prohibited CHP plants. The power generation provided by CCGT however decreases by approximately one third (compare figure E.1 in annex D with figure 4.10 below). This one third is entirely taken over by the CHP plant.

As explained in section 4.1, the screening curve approach, which gives a graphical solution of the optimal investment problem, cannot be used if the curves of the CHP engines are added. The explanation is simple; CHP provides both heat and power, so it is not representative to show its screening curve together with power-only technologies or heat-only technologies. Adding the CHP screening curves blocks us from finding an exact graphical solution. In consequence, the production profiles in figure 4.10 cannot be graphically validated, but they make complete sense when considering the features

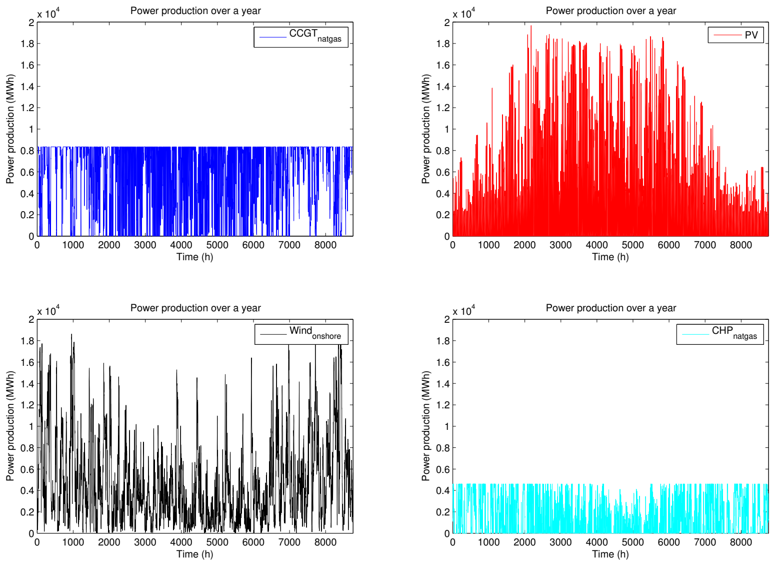


Figure 4.10: Power production of the technologies over a year

of CHP.

The CHP engines also induce changes in the electricity prices because of the adjustment of the electricity demand balance equation which now includes the CHP power production. The new electricity price duration curve is illustrated in figure. We can see that many new price levels have appeared.

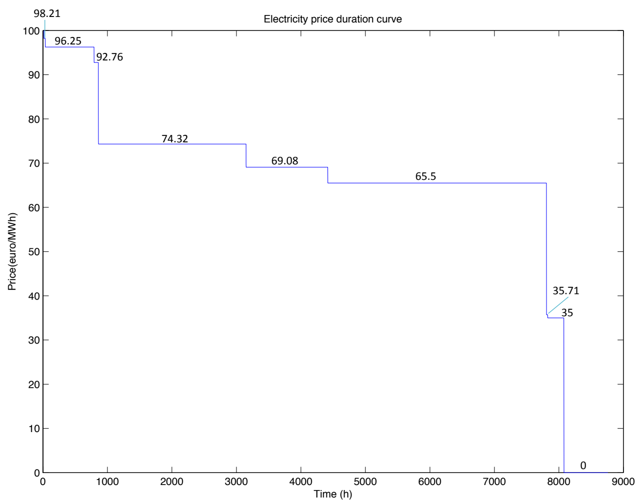


Figure 4.11: Price duration curve for electricity

Heat production

The types of combined heat and power plants used in this model generate a fixed ratio of heat and power. Seeing that we already know the amount of power produced by the natural gas CHP engine, we can easily compute the heat production profile by multiplying the hourly power production with the heat to power ratio. The heat originating from the CHP engines is only used to satisfy the process heating demands in the industrial sector. Indeed, we mentioned previously that we only considered industrial CHP. Electric boilers, condensing natural gas boilers and air-to-water heat pumps satisfy the remaining heat demands. The share of total heat production each technology has can be found on table 4.4

Heat technology	Share of total production (%)
Electric boiler	1
Condensing gas boiler	34
Heat pump	61
CHP	4

Table 4.4: Shares of total heat production

Both electric boilers and heat pumps produce roughly as much heat as in scenario 2.1. The production level of the condensing gas boilers however shrinks considerably. This shrinkage is associated with a commensurate increment of the CHP heat production. In other words, the CHP engines take over a fraction of the heat production of the condensing natural gas boilers, keeping the production levels of the electric boilers and heat pumps practically untouched.

Fuel and cost evolution

Introducing CHP engines affects the optimization model exclusively in a positive way. First, the CHP engines only take over power and heat production from polluting technologies. Indeed, they take over power from gas turbines and heat from gas boilers, leaving the renewable technologies or electric functioning technologies alone. As CHP engines are more fuel-efficient than conventional plants, they induce a reduction of the total fuel emission.

A more efficient use of the fuel is correlated with a lower fuel cost. In consequence, the total costs of both the heat and power sectors decrease.

4.4 Scenario 3: Power and heat market with a decreasing CO_2 emission

The core of the thesis is being addressed in this scenario; what effect does a decreasing CO_2 emission level have on the power and heat production dispatch, the total system cost, the fuel consumption etc. ? The results are collected by monitoring the several variables which characterize the environmental and economic aspects of the model. The environmental study consists of an analysis of the fuel consumption evolution and the renewable production evolution. We wish to determine which technologies cut down their fuel consumption the most when a transition of the CO_2 emission constraint arises, and which renewable sources are most used to salvage this loss of fossil fueled production. The economic study on the other hand evaluates the evolution of the costs. The evolution of the total system cost is analyzed.

The decrease of the authorized CO_2 emission level in the system occurs linearly in this scenario. Consecutive decreases of 10% of the original emission are considered, from 0% to 100%. By original emission, we mean the total greenhouse gas emission computed when no constraint is put on the CO_2 emission. In other words, at the first step, any quantity of emission is allowed. At the second step, 90% of the emission computed in step 1 is allowed. At the third step, 80% of the emission of step 1 is allowed, etc. The emission evolution is illustrated in figure 4.12. The quantity of emitted greenhouse gasses is consistently equal to (or extremely close to) the limit applied to the CO_2 emission constraint. The system will always consume as much fossil fuel as it is allowed to, since it is economically the best option.

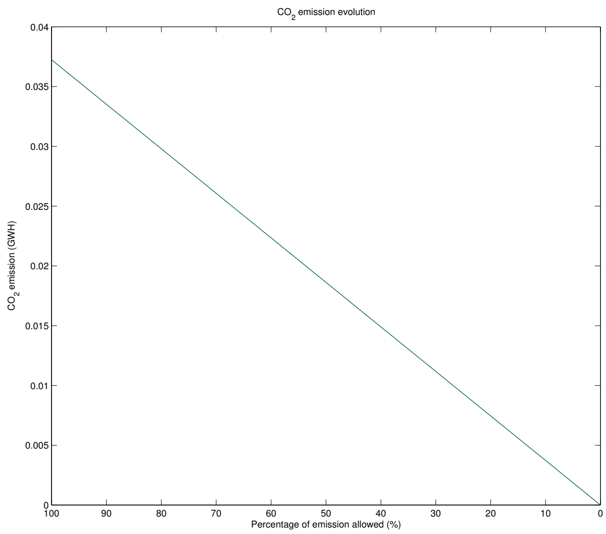


Figure 4.12: CO_2 emission evolution

This section will first discuss the evolution of the mix of technologies satisfying the power an heat demands. It will then examine the variables characterizing the environmental and economic factors.

4.4.1 Technology dispatch evolution

The optimal investment problem manages to identify the set of technologies to invest in and their production such as to satisfy all the constraints and minimize the total cost. When changing the CO_2 emission constraint, the mix of producing technologies is ought to adjust. The total production of each technology has therefore been monitored in order to see which technologies appear when decreasing the CO_2 emission limit and which technologies vanish.

Evolution of power producing technologies

Figure 4.13 depicts the evolution of the power production for a decreasing CO_2 emission level. Down to an emission level of 40%, four technologies provide the entire production. Out of these four technologies, two are polluting (natural gas fueled CCGT and CHP) and two are renewable (PV and onshore wind). As expected, the production of the natural gas fueled technologies decreases almost linearly with the decreasing CO_2 emission limit, until it reaches a zero production when no greenhouse gas emissions are allowed. The reverse effect can be noticed for the fluctuating renewable technologies. They are required to take over the production from the fossil fueled technologies, and are therefore bound to increase continually their power generation. At an emission limit of 30% however, their total production stabilizes. The stabilization is due to the fact that starting from a 30% CO_2 emission limit, new technologies step in to assist with the generation of power: biogas fueled CCGT and CHP. The mix of technologies has now changed and includes two new technologies running on biogas, making the system more eco-friendly. The production of the biogas fueled technologies increases for each drop of the CO_2 emission limit.

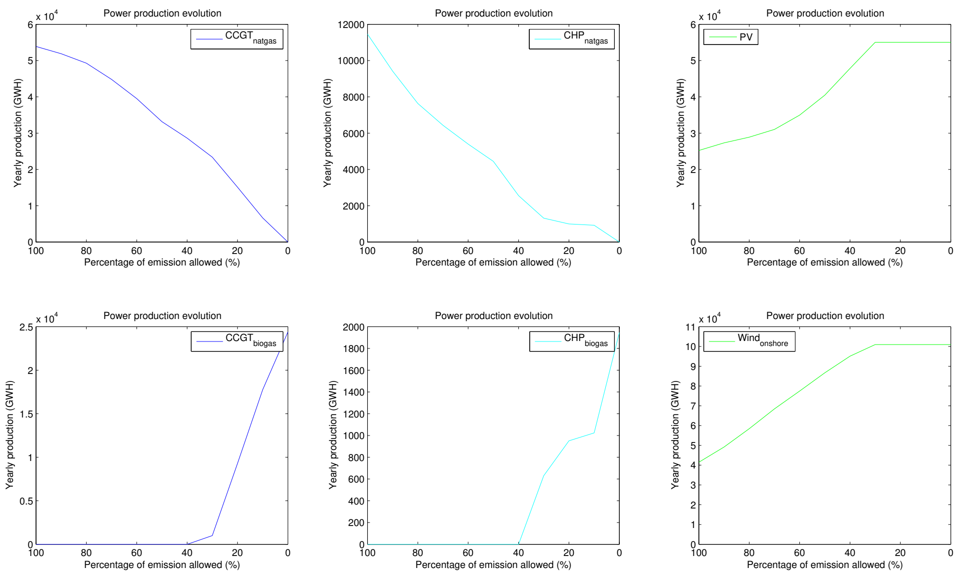


Figure 4.13: Power production evolution for a decreasing CO_2 emission limit

One surprising outcome of the optimized mix of power technologies is the absence of a biomass turbine. The screening curves discussed in section 4.1 (figure 4.1) show us that technologies running on biogas are mostly dominated by the biomass turbine because of their high fuel cost. In consequence, a rational result would have been for the biomass turbine to generate power. Its absence is due to the biomass limitation constraint defined in the model, which puts a limit on the maximum amount of biomass that can be used throughout the entire year. The available biomass can be used to generate either power or heat. The only explanation for a zero investment in biomass turbines is that the entire biomass is used to fuel heat producing technologies.

Evolution of heat producing technologies

The heat producing technologies undergo the same effects as the power generating technologies. Indeed, the fossil fueled technologies reduce their production while technologies running on renewable fuel or electricity take a bigger share of the total production (figure 4.14). We can see that starting from a emission limit of 90%, the condensing biomass boilers start providing heat to the system at a constant level. The heat production through biomass does not rise, as we would have normally expected, because of the biomass limitation constraint. This confirms that the entire biomass is used in the heat sector, leaving no fuel for the power generating biomass turbines.

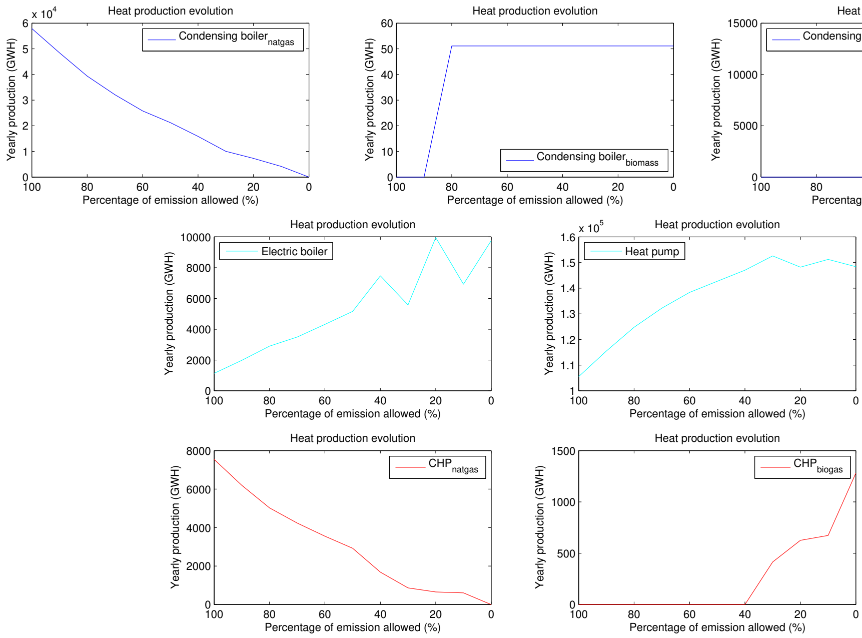


Figure 4.14: Heat production evolution for a decreasing CO_2 emission limit

Evolution of the storage capacities

Storage is an important asset to the model as it enables the system to store excess power or heat for later use. Since the thermal energy storage technologies used in this work are quite expensive, the system will never invest in them. Electric storage technologies (batteries) however appear in the mix of technologies when decreasing the CO_2 emission limit as can be seen on figure 4.15. Equivalently to the fluctuating renewable technologies, the electric storage capacity stabilizes at a limit of 30%.

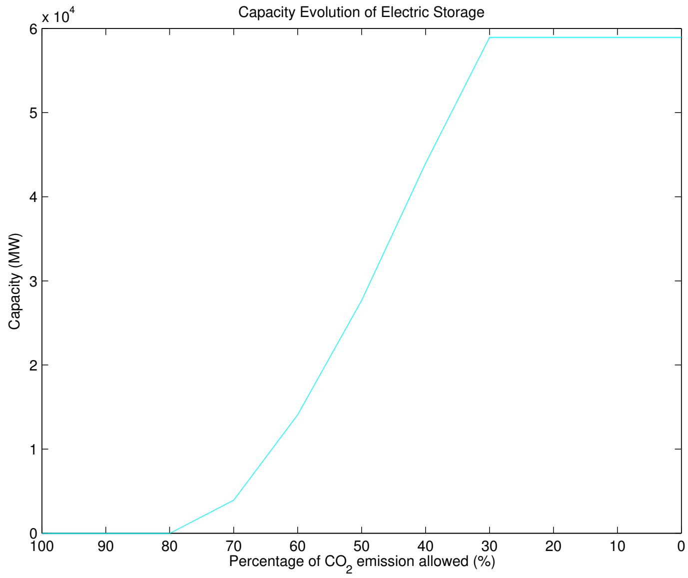


Figure 4.15: Evolution of the electric storage capacity

4.4.2 Environmental analysis

The main purpose of decreasing the CO_2 emission level is to shift to a power and heat system which does not damage the environment as strongly as the current one. The burning of fossil fuels to produce energy releases significant amounts of carbon dioxide and other greenhouse gases into the environment. By monitoring the consumption of all fuel types, i.e. natural gas, biogas and biomass, we are able to identify when the renewable fuel sources outweigh the fossil sources. For each type of fuel, the total consumption over a year is computed (figure 4.16).

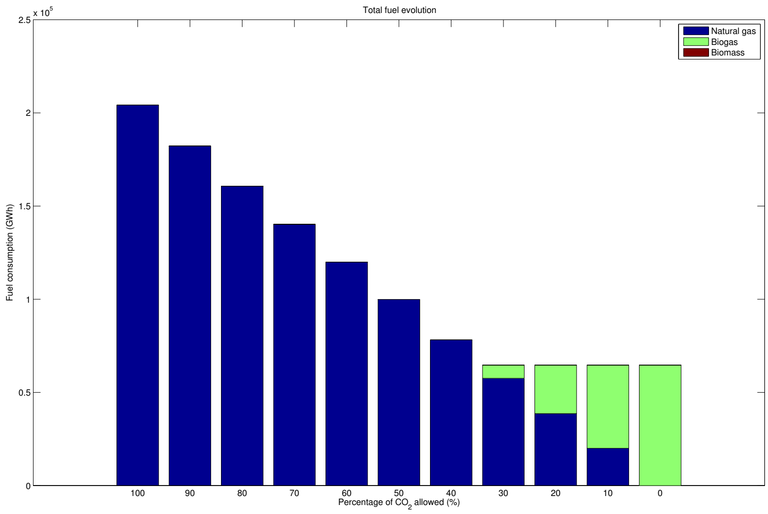


Figure 4.16: Fuel consumption evolution for a decreasing CO_2 emission limit

This figure shows us that the total fuel decreases in a linear pattern down to a limit of 30%, then remains constant. The share of total consumption each fuel source covers is however modifying as biogas fuel serves more and more demand. The reason why the total fuel consumption decreases down to a limit of 30% and not further is because of the appearance of the biogas fuel consumption. The CO_2 emission constraint does not force a decrease of the fuel consumption but only of the polluting fuel consumption such as natural gas. The stabilization of the total fuel consumption induces a stabilization of the PV and onshore wind capacity. Indeed, up to a limit 30%, the fluctuating renewable technologies are constrained to increase their capacity in order to serve the power demand "lost" by the natural gas turbines. Once biogas fueled technologies emerge on the market however, this increase of capacity is not required anymore as the biogas technologies can take over a part of the power production.
Note that the biomass consumption is not visible in figure 4.16 because of its insignificant share compared to natural gas or biogas. This is because of the very strong resource availability constraint put on biomass fuel (see section 3.7) which limits the amount of biomass that can be used over a year.

4.4.3 Economic analysis

Aiming on an electricity and heat market relying mostly on renewable energy is surely environmentally beneficial, but not necessarily profitable for the economy. Indeed, the current market uses fossil fuels because of their economic perks, and decreasing their consumption might be too damaging for the economy. Studying the evolution of the costs is therefore crucial to validate the feasibility of a scenario with a strong CO_2 emission constraint.

Figure 4.17 describes the total system cost evolution, which sums up the costs of power and heat generation. Note that the y-axis representing the costs is not defined in euro but in percentage, such as to depict the evolution of the total cost relative to its value at a 100% (which corresponds to the scenario without CO_2 emission).

As expected, the system cost increases as we reduce the quantity of CO_2 released in the atmosphere. This increase is however not linear. At first, the system cost curve rises slightly, but the slope of the curve becomes steeper towards a 50% CO_2 emission limit. The shape of this curve shows us that a small, but definitely not insignificant drop of the greenhouse gas emissions is economically feasible. Cutting out 20% of the CO_2 emission for instance causes a system cost increase of only 1%. If we want to cut the CO_2 emission by half, the system cost would increase approximately by 8%, which is still a reasonable value considering the great environmental benefits. Switching to a fully decarbonised model however increases the cost by almost 45%.

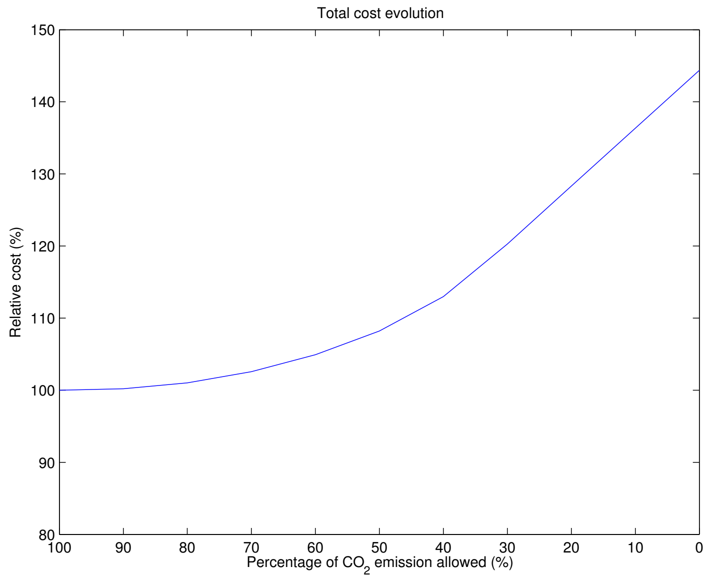


Figure 4.17: Total cost evolution relative to its value at 100% for a decreasing CO_2 emission limit

Chapter 5

Conclusion and Future Work

5.1 Key Concluding Remarks

In this work, a system co-optimizing the electricity and heat market is studied. Many models describing an optimal investment problem of the electricity sector exist, but a few models analyze the electricity and heat sector unitedly. The results discussed in this thesis confirm the benefits of a co-optimization of electricity and heat.

The benefits of co-optimization mainly arise from the efficiency of combined heat and power. The particularity of cogeneration or combined heat and power is that it generates electricity and heat at the same time, and by doing so, uses fuel more efficiently than conventional power plants such as open or closed cycle gas turbines (OCGT and CCGT). This work displayed the interest of using CHP by comparing two scenarios: one preventing CHP production and one allowing investment in CHP. The results showed us that when allowing CHP production, the system cost decreases considerably, as well as the CO_2 emission level.

The objectives of this thesis were attained by following three main steps: (i) studying the heat demands and generate their profiles, (ii) describe the co-optimization of the heat and electricity sector as a linear program minimizing the total cost of serving demand and (iii) conduct tests on the model and study their results. The third step was realized by analyzing several scenarios and comparing them with one another. The aim was to try to find answers to the questions presented in the introduction; how importantly do renewable technologies take over the power and heat generation when decreasing the CO_2 emission limit? Is the scenario of a fully decarbonized system feasible?

One of the principal goals of this work was to assess the impact a decrease of the greenhouse gas emissions would have on the electricity and heat system. The current market is ruled by technologies emitting high levels of CO_2 emission. To ensure the sustainability of energy and to avoid aggravating the condition of an already damaged atmosphere, less dependency on natural gas is inevitable. But is this achievable without increasing the system cost too much? The evolution of the total system cost when decreasing the value of the maximum allowed CO_2 emission showed us that the system cost slightly increased up to a decrease of 50% of the CO_2 emission ($\approx$ 8% system cost increment), but started to increase more importantly if decreasing the CO_2 emission level further. Achieving a fully decarbonized Belgian electricity and heat market would create an important system cost increase ($\approx 45\%$).

Although strong conclusions can be drawn from the co-optimization of electricity and heat, it is difficult to guarantee the success of a transition to a fully decarbonised system. The environmental benefits and economic harms should be balanced when studying the transition. A sure thing is that such a transition will not happen in the coming years as it would generate a system cost difference which is too substantial. The literature however often aims for the market to be fully decarbonized in 2050. Could it happen? This work leans towards a positive answer.

5.2 Future Work

Everywhere around the world, the decarbonization of the energy system is a key issue in the current agenda. The different energy sectors need to be studied thoroughly in the hope to find effective solutions. As the area of study discussed in this thesis is extremely wide and not entirely explored, the work realized can definitely be pursued.

First, the set of technologies and energy resources used in the optimization model can be widened. For instance, synthetic fuel has not been included as one of the fuel sources. Concentrating solar power (CSP) plants have also been overlooked, as the only technology functioning on solar energy in the actual model is PV. Second, this work only analyzed the Belgian market, but could be extended to other countries. It could be interesting to compare the optimal investment solutions of the different (European) countries. A next step of this work could also be the analysis of district heating. District heating is a system for distributing heat generated in a centralized location for residential and commercial heating requirements. Such centralized locations providing heat for several sectors could play a major role in the decrease of fossil fuel consumption. Finally, we could extend the optimization problem to a co-optimization of the electricity, heat and transport sector. Indeed, the transport sector consumes a substantial fraction of the available resources, and is linked with the electricity sector through electric vehicles for instance. Studying the three sectors together would provide a better understanding of the distribution of the resources.

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Appendices

Appendix A

Full Model

$$min \quad \mathbf{C}^{tot} = \mathbf{C}^{tot,heat} + \mathbf{C}^{tot,elec} + \mathbf{C}^{tot,CHP}$$

$s.t.$

$$\mathbf{C}^{tot,elec} = \sum_k (\mathbf{C}_k^{inv} + \mathbf{C}_k^{op} + \mathbf{C}_k^{fuel}) + \mathbf{C}^{nosupply,elec} \qquad k \in K_{elec/CHP}$$

$$\mathbf{C}^{tot,heat} = \sum_k (\mathbf{C}_k^{inv} + \mathbf{C}_k^{op} + \mathbf{C}_k^{fuel}) + \mathbf{C}^{nosupply,heat} \qquad k \in K_{heat/CHP}$$

$$\mathbf{C}^{tot,heat} = \sum_k (\mathbf{C}_k^{inv} + \mathbf{C}_k^{op} + \mathbf{C}_k^{fuel}) \qquad k \in K_{CHP}$$

$$\sum_k \mathbf{P}_{k,t} + \sum_s (\mathbf{P}_{s,t}^{discharge} - \mathbf{P}_{s,t}^{charge}) \geq \mathbf{P}_t^{supply} + \sum_f \mathbf{P}_{f,t}^{elHeatPump} + \sum_g \mathbf{P}_{g,t}^{elHeatBoiler}$$

$k \in K_{elec}, s \in S_{elec}, f \in K_{HP}, g \in K_{boiler}, \forall t$

$$\mathbf{P}_t^{nosupply} = P_t^{demand} - \mathbf{P}_t^{supply} \qquad \forall t$$

$$\mathbf{C}^{nosupply,elec} = \sum_t \mathbf{P}_t^{nosupply} \cdot c^{VoLL,elec}$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,ResHW} \qquad \forall t$$

$k \in K_{ResHW}, s \in S_{TES,ResHW}$

$$\mathbf{Q}_t^{nosupply,ResHW} = Q_t^{demand,ResHW} - \mathbf{Q}_t^{supply,ResHW} \qquad \forall t$$

$$\sum_k \mathbf{Q}_{k,t} \geq \mathbf{Q}_t^{supply,ComHW} \qquad \forall t, k \in K_{ComHW}$$

$$\mathbf{Q}_t^{nosupply,ComHW} = Q_t^{demand,ComHW} - \mathbf{Q}_t^{supply,ComHW} \qquad \forall t$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,ResSH} \qquad \forall t$$

$k \in K_{ResSH}, s \in S_{TES,ResSH}$

$$\mathbf{Q}_t^{nosupply,ResSH} = Q_t^{demand,ResSH} - \mathbf{Q}_t^{supply,ResSH} \qquad \forall t$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,ComSH} \qquad \forall t$$

$k \in K_{ComSH}, s \in S_{TES,ComSH}$

$$\mathbf{Q}_t^{nosupply,ComSH} = Q_t^{demand,ComSH} - \mathbf{Q}_t^{supply,ComSH} \qquad \forall t$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,IndSH} \qquad \forall t$$

$k \in K_{IndSH}, s \in S_{TES,IndSH}$

$$\mathbf{Q}_t^{nosupply,IndSH} = Q_t^{demand,IndSH} - \mathbf{Q}_t^{supply,IndSH} \qquad \forall t$$

$$\sum_k \mathbf{Q}_{k,t} \geq \mathbf{Q}_t^{supply,IndHW} \qquad \forall t, k \in K_{IndHW}$$

$$\mathbf{Q}_t^{nosupply,IndHW} = Q_t^{demand,IndHW} - \mathbf{Q}_t^{supply,IndHW} \qquad \forall t$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,IndPH_1} \qquad \forall t$$

$k \in K_{IndPH_1}, s \in S_{TES,IndPH_1}$

$$\mathbf{Q}_t^{nosupply,IndPH1} = Q_t^{demand,IndPH_1} - \mathbf{Q}_t^{supply,IndPH_1} \qquad \forall t$$

$$\sum_k \mathbf{Q}_{k,t} + \sum_s (\mathbf{Q}_{s,t}^{discharge} - \mathbf{Q}_{s,t}^{charge}) \geq \mathbf{Q}_t^{supply,IndPH_2} \qquad \forall t$$

$k \in K_{IndPH_2}, s \in S_{TES,IndPH_2}$

$$\mathbf{Q}_t^{nosupply,IndPH_2} = Q_t^{demand,IndPH_2} - \mathbf{Q}_t^{supply,IndPH_2} \qquad \forall t$$

$$\mathbf{P}_{k,t} \leq \mathbf{P}_k^{cap} \qquad \forall k \in K_{elec}, \forall t$$

$$\mathbf{Q}_{k,t} \leq \mathbf{Q}_k^{cap} \qquad \forall k \in K_{heat}, \forall t$$

$$\mathbf{C}_k^{inv} = \frac{r \cdot c_k^{specInv}}{1 - \dfrac{1}{(1+r)^{T_k}}} \cdot \mathbf{P}_k^{cap} \qquad \forall k \in K_{elec/CHP}$$

$$\mathbf{C}_k^{inv} = \frac{r \cdot c_k^{specInv}}{1 - \dfrac{1}{(1+r)^{T_k}}} \cdot \mathbf{Q}_k^{cap} \qquad \forall k \in K_{heat/CHP}$$

$$\mathbf{C}_k^{op} = \sum_t (\mathbf{P}_{k,t}) \cdot (c_k^{varOp} + (1 - s^{distLoss}) \cdot c^{dist}) + \mathbf{P}_k^{cap} \cdot c_k^{fixOp} \qquad \forall k \in K_{elec/CHP}$$

$$\mathbf{C}_k^{op} = \sum_t (\mathbf{Q}_{k,t}) \cdot (c_k^{varOp} + (1 - s^{distLoss}) \cdot c^{dist}) + \mathbf{Q}_k^{cap} \cdot c_k^{fixOp} \qquad \forall k \in K_{heat/CHP}$$

$$\mathbf{P}_{PV,t} = a_t \cdot \mathbf{P}_{PV}^{cap} \qquad \forall t$$

$$\mathbf{P}_{windOn,t} = b_t \cdot \mathbf{P}_{windOn}^{cap} \qquad \forall t$$

$$\mathbf{P}_{windOff,t} = c_t \cdot \mathbf{P}_{windOff}^{cap} \qquad \forall t$$

$$\mathbf{D}_{k,t}^{fuel} = \frac{\mathbf{P}_{k,t}}{\eta_k} \qquad \forall t, \forall k \in K_{conventional}$$

$$\mathbf{C}_k^{fuel} = \sum_t (\mathbf{D}_{k,t}^{fuel}) \cdot c_k^{fuel} \qquad \forall k \in K_{conventional}$$

$$\mathbf{F}_{s,t} = \mathbf{F}_{s,t-1} \cdot (1 - l_s) + \mathbf{P}^{input}_{s,t} \cdot \eta_s - \frac{\mathbf{P}^{output}_{s,t}}{\eta_s} \qquad \forall t, \forall s \in S_{elec}$$

$$\mathbf{F}_{s,1} = 0 \qquad \forall s \in S_{elec}$$

$$\mathbf{P}^{output}_{s,1} = 0 \qquad \forall s \in S_{elec}$$

$$\mathbf{F}_{s,t} \leq \mathbf{E}^{cap}_s \qquad \forall t, \forall s \in S_{elec}$$

$$\mathbf{P}^{input}_{s,t} \leq \frac{\mathbf{E}^{cap}_s}{6} \qquad \forall t, \forall s \in S_{elec}$$

$$\mathbf{P}^{output}_{s,t} \leq \frac{\mathbf{E}^{cap}_s}{6} \qquad \forall t, \forall s \in S_{elec}$$

$$\mathbf{D}^{fuel}_{k,t} = \frac{\mathbf{Q}_{k,t}}{\eta_k} \qquad \forall t, \forall k \in K_{BoilerConventional}$$

$$\mathbf{C}^{fuel}_k = \sum_t (\mathbf{D}^{fuel}_{k,t}) \cdot c^{fuel}_k \qquad \forall k \in K_{BoilerConventional}$$

$$\mathbf{P}^{elHeatBoiler}_{k,t} = \frac{\mathbf{Q}_{k,t}}{\eta_k} \qquad \forall t, \forall k \in K_{ElBoiler}$$

$$\mathbf{P}^{elHeatPump}_{k,t} = \frac{\mathbf{Q}_{k,t}}{\eta_k} \qquad \forall t, \forall k \in K_{ElHeatPump}$$

$$\mathbf{U}_{s,t} = \mathbf{U}_{s,t-1} \cdot (1 - l_s) + \mathbf{Q}^{input}_{s,t} \cdot \eta_s - \frac{\mathbf{Q}^{output}_{s,t}}{\eta_s} \qquad \forall t, \forall s \in S_{heat}$$

$$\mathbf{U}_{s,1} = 0 \qquad \forall s \in S_{heat}$$

$$\mathbf{Q}^{output}_{s,1} = 0 \qquad \forall s \in S_{heat}$$

$$\mathbf{U}_{s,t} \leq \mathbf{U}^{cap}_s \qquad \forall t, \forall s \in S_{heat}$$

$$\mathbf{Q}^{input}_{s,t} \leq \mathbf{U}^{cap}_s \qquad \forall t, \forall s \in S_{heat}$$

$$\mathbf{Q}^{output}_{s,t} \leq \mathbf{U}^{cap}_s \qquad \forall t, \forall s \in S_{heat}$$

$$\mathbf{P}_{k,t} \leq \mathbf{Q}^{cap}_k \cdot \sigma_k \qquad \forall t, \forall k \in K_{CHP}$$

$$\mathbf{Q}_{k,t} \leq \mathbf{Q}^{cap}_k \qquad \forall t, \forall k \in K_{CHP}$$

$$\mathbf{P}_{k,t} = \mathbf{Q}_{k,t} \cdot \sigma_k \qquad \forall t, \forall k \in K_{CHP}$$

$$\mathbf{D}^{fuel}_{k,t} = \frac{\mathbf{P}_{k,t}}{\eta_k} \cdot \frac{1 + \sigma_k}{\sigma_k} \qquad \forall t, \forall k \in K_{CHP}$$

$$\mathbf{C}^{fuel}_k = \sum_t \mathbf{D}^{fuel}_{k,t} \cdot c^{fuel}_k \qquad \forall k \in K_{CHP}$$

$$\mathbf{C}^{inv}_k = \frac{r \cdot c^{specInv}_k}{1 - \frac{1}{(1+r)^{T_k}}} \cdot \mathbf{Q}^{cap}_k \cdot \sigma_k \qquad \forall k \in K_{CHP}$$

$$\mathbf{C}^{op}_k = \sum_t (\mathbf{P}_{k,t} \cdot c^{varOp}_k + \mathbf{Q}_{k,t} \cdot (1 - s^{distLoss}) \cdot c^{dist}) + \mathbf{Q}^{cap}_k \cdot \sigma_k \cdot c^{fixOp}_k \qquad \forall k \in K_{CHP}$$

$$\sum_k \sum_t \mathbf{D}^{fuel}_{k,t} \leq E^{annualBiomass} \qquad k \in K_{BiomassTechnologies}$$

$$\mathbf{G}^{total} = \sum_k \sum_t \mathbf{D}^{fuel}_{k,t} \cdot f^{CO_2}_k \qquad k \in K_{fuel}$$

$$\mathbf{G}^{total} \leq E^{CO2}$$

Appendix B

Power Demand Profile

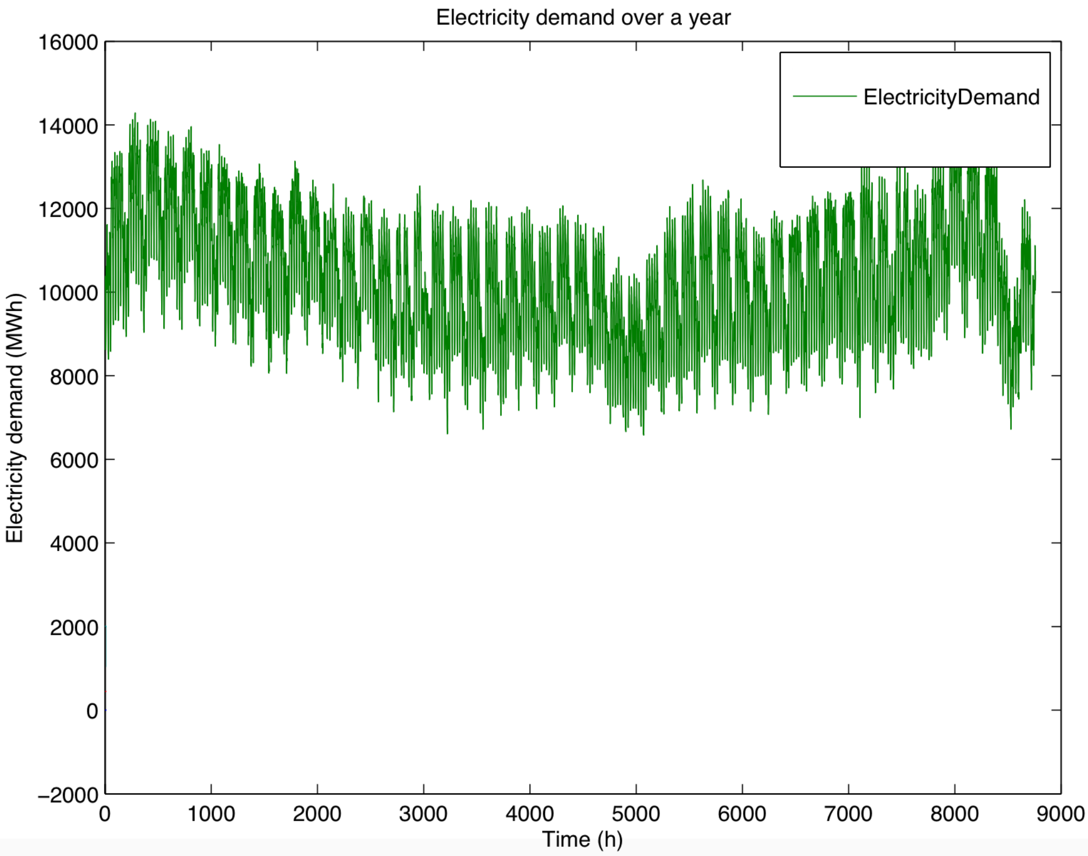

Figure B.1: Electricity demand profile over a year

Appendix C

Wind Demand Profiles

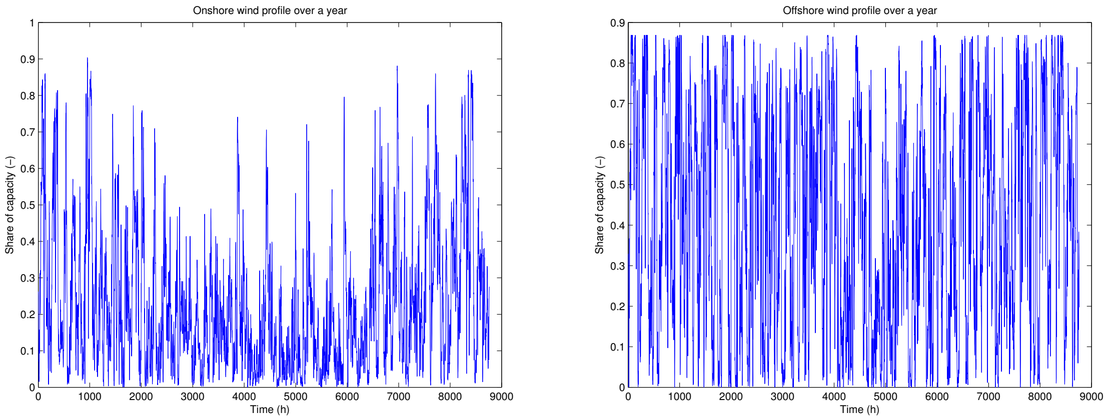

Figure C.1: Yearly onshore and offshore wind profiles

Appendix D

Scenario Results

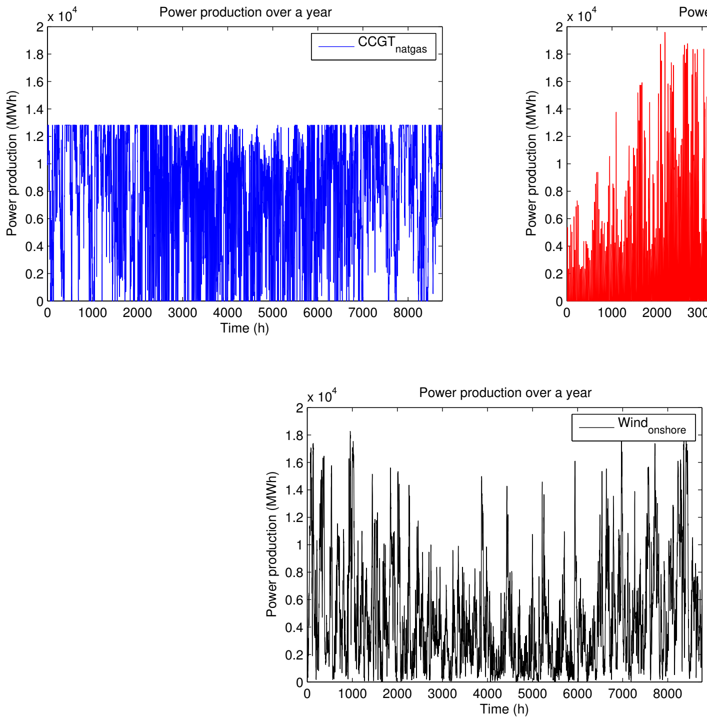

Figure D.1: Power production of the technologies over a year

Appendix E

Technology Parameters

Power production technologies	Specific Investment Cost (k€/MW)	Variable O&M (€/MWh)	Fixed Operational Cost (k€/MW)	Life span (year)	Efficiency (%)	
PV	350	0	15	20		
WIND_ONSHORE	1100	0	40	25		
WIND_OFFSHORE	2500	0	100	25		
BIOMASS_ST	1300	8	4	30	33%	
CCGT	800	3	23	20	56%	
OCGT	700	5	5	20	40%	
Heat production technologies	Specific Investment Cost (k€/MW)	Variable Operational Cost (€/MWh)	Fixed Operational Cost (k€/MW)	Life span (year)	Efficiency (%)	Coefficient of performance (-) (HP)
Boiler-Electric-DHW	100	0	3	20	100%	
Boiler-Electric-XS-HP-SH	150	0	3	20	100%	
Condensing-gas-boiler-SH	88	0	2	20	100%	
Condensing-biomass-boiler-SH	300	0	5	20	92%	
Condensing-biomass-boiler-DHW	300	0	5	20	82%	
Condensing-gas-boiler-DHW	88	0	2	20	98%	
HP-Air2Water-XS-SH	600	0	10	20		2.75
HP-Air2Water-XS-DHW	600	0	10	20		2.75
Electricity and heat production technologies (CHP)	Specific Investment Cost (k€/MW)	Variable Operational Cost (€/MWh)	Fixed Operational Cost (k€/MW)	Life span (year)	Efficiency (%)	Heat to power ratio
microCHP-SH	690	0	6	20	63%	1/1.52
microCHP-DHW	690	0	6	20	65%	1/1.52
Thermal energy storage technologies	Specific Investment Cost (k€/MWh)	Variable Operational Cost (€/MWh)	Fixed Operational Cost (k€/MW)	Life span (year)	Efficiency (%)	Self discharge (%/h)
TES-DHW-SH	30	0	5	20	90%	1%
Batterie	Specific Investment Cost (k€/MWh)	Variable Operational Cost (€/kW)	Fixed Operational Cost (k€/MW)	Life span (year)	Efficiency (%)	Self discharge (%/h)
Battery	170	0	8.5	20	90%	0.04%
Biomass limit (TJ/an)						
200						

Figure E.1: Technology Parameters

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