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Assessing the change in national CO_2 emissions from an investment in the local energy system

A Case Study of Gothenburg

Master's thesis in Sustainable Energy Systems

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Department of Energy and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
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MASTER'S THESIS

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ABSTRACT

More and more cities reduce CO_2 emissions by making investments in the local energy system, such as solar power production and energy efficiency measures. One important step for decision makers considering such investments is to assess the impacts concerning CO_2 emissions. The common methods used are average electricity production method and marginal electricity production method, which both have the drawback that they are not affected by the investment and do not consider power transfer limitations in the power system. Thus, the aim of the thesis is to estimate how investments in the local energy system will affect national CO_2 emissions.

In the thesis a dispatch model of the Swedish power system is presented, as an alternative to the two aforementioned methods used for assessing the CO_2 emissions from an investment. The three methods are then employed in a case study where an investment is made in the heating sector of Gothenburg which results in a change in the production pattern from CHP district heating units.

The result demonstrates that, for the case study, the changes in CO_2 emissions using the three methods differ. More specifically, the dispatch model, average electricity production method and marginal electricity production method show approximately +16, -27 and +89 kton CO_2 change respectively, for the Swedish power system as a whole. In the dispatch model, the investment has negligible effects on the electricity generation in Sweden. Instead, it leads to a change in import and export. The increased import mainly comes from Norway and Denmark, while the increased export mostly goes to Finland. Denmark is responsible for most of the increased CO_2 imported to Sweden. In the average electricity production method, the investment is replaced by the Swedish average electricity generation, which has less CO_2 emissions. In the marginal electricity production method, the investment causes a response by coal condensing power plants, which has much higher CO_2 emissions. Hence, the dispatch model results in CO_2 emissions between these two extremes.

Furthermore, increasing the level of the investment, i.e. reducing the electricity contribution coming from CHP district heating units further, shows that both the average electricity production method and the marginal electricity production method have a linear trend in the changed CO_2 emissions. However, the dispatch model indicates some fluctuations in the changed CO_2. This is due to the fluctuations in the net import from Denmark and Finland. The change in electricity mainly comes from net imports from Norway, Denmark and Finland. Moreover, electricity generation from condensing power plants displays a continuous increase in electricity generation, and hence, the CO_2 emissions from this technology increase.

Key words: Dispatch model, Average electricity production, Marginal electricity production, CO_2 emissions.

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Abbreviations

CHP	Combined heat and power plant
CO_2	Carbon dioxide
DE	Germany
DH	District heating
DK	Denmark
FI	Finland
MCP	Market clearing price
NTC	Net transmission capacity
NO	Norway
PL	Poland
SE	Sweden
SvK	Svenska Kraftnät
TSO	Transmission system operator

Notations

Sets

Θ	Bidding areas: Θ = {SE1, SE2, SE3, SE4}
Φ	The surrounding areas: Φ = {NO4, NO2, NO1, DK1, DK2, DE, PL, FI}
Γ	Generation technologies: Γ = {Nuc, Win, Hyd, CHPind, CHPDH, Con, Gas}
Ω	Nuclear reactors: Ω = {O1, O3, R1, R2, R3, R4, F1, F2, F3}

Indices

t	Time
i,j	$\forall\, i, j \in \Theta$

k	$\forall\, k \in \Phi$
p	$\forall\, p \in \Gamma$
nn	$\forall\, nn \in \Omega$
Nuc	Nuclear power
Win	Wind power
Hyd	Hydropower
CHPind	CHP industry
CHPDH	CHP District heating
Con	Condensing power
Gas	Gas turbine
O1	Oskarshamn 1
O3	Oskarshamn 3
R1	Ringhals 1
R2	Ringhals 2
R3	Ringhals 3
R4	Ringhals 4
F1	Forsmark 1
F2	Forsmark 2
F3	Forsmark 3

Parameters

$\mathrm{Cap}_{i,p}$	Installed capacity of power plant type *p* in area *i* [MWh/h]
Rc_{p}	Running costs of generation technology *p* [EUR/MWh]
$\mathrm{Ntc}_{i,j}$	Net transmission capacity from area *i* to area *j* [MWh/h]
$\mathrm{Crossntcim}_{k,i}$	Cross-border transmission capacity from area *k* to area *i* [MWh/h]
$\mathrm{Crossntcex}_{i,k}$	Cross-border transmission capacity from area *i* to area *k* [MWh/h]
$\mathrm{Consp}_{i,t}$	Consumption in area *i* at time *t* [MWh/h]

$Elp_{k,t}$	Electricity price in area *k* at time *t* [EUR/MWh]
$Pmax_{i,p}$	Maximum power production [MWh/h]
$Pmin_{i,p}$	Minimum power production [MWh/h]
$Rup_{i,p}$	Ramp up rate of power plant type *p* in area *i* [MWh/h]
$Rdn_{i,p}$	Ramp down rate of generation technology *p* in area *i* [MWh/h]
$Inflow_{i,t}$	Hydro inflow in area *i* at time *t* [MWh/h]
$Capsto_{i}$	Reservoir storage capacity for hydro in area *i* [MWh]

Variables

$On_{i,p,t}$	Binary indicator, 1=starting generation technology *p* in area *i* at time *t*
$Storage_{i,t}$	Hydro reservoir level in area *i* at time *t* [MWh/h]
$Gen_{i,p,t}$	Generation of generation technology *p* in area *i* at time *t* [MWh/h]
$trans_{i,j,t}$	Transmission from area *i* to area *j* at time *t* [MWh/h]
$crosstransim_{k,i,t}$	Cross-border transmission import from area *k* to area *i* at time *t* [MWh/h]
$crosstransex_{i,k,t}$	Cross-border transmission export from area *i* to area *k* at time *t* [MWh/h]

1 Introduction

There is a growing concern about global warming which is mainly caused by greenhouse gas emissions, such as carbon dioxide (CO_2) [1]. Global warming mitigation requires CO_2 emission reduction in all sectors including the electricity sector. Given this concern, more and more cities are participating in reducing CO_2 emissions by making investment alternatives in the power system, e.g. development of solar power and energy efficiency measures. An example is that the city of Gothenburg sets out to improve the energy efficiency of the municipal property holdings [2].

When decision makers consider investments in the local energy system, one important step is to assess the impact of the investment concerning CO_2 emissions. The assessment often uses average electricity production or marginal electricity production on a national level to estimate emissions [3]. However, these two methods have two drawbacks when assessing the impacts of an investment:

- The average electricity production method and marginal electricity production method are static, as they look at historical data to assess the effects of an investment. Therefore, these two methods miss out detailed information regarding what actual factors in the system reacting to the investment.
- Since the average electricity production and marginal electricity production are on a national level, the power transfer limitations are not considered and the impact of the investment on congestion is not taken into account.

Estimating CO_2 emissions when subjected to an investment constitutes a challenge. The estimation method used should be accurate enough to help decision makers in identifying promising investments, otherwise, they could be misinformed. However, using too detailed methods might lead to an over confidence in the results, while they in reality are affected by many uncertainties.

1.1 Purpose

This master's thesis aims to assess change in CO_2 emissions when making an investment in the local energy system, in order to assist the decision makers. The assessment is performed using a dispatch model of the Swedish power system. Two other commonly used methods average electricity production and marginal electricity production are also investigated and used as references for the results.

The intended outcome will result in recommendations on what aspects, factors or parameters to consider when assessing an investment in the local energy system in terms of CO_2 emissions.

1.2 Limitations

The thesis evaluates how an investment in the local energy system influence the national CO_2 emissions. The investigated system is limited to the border of Sweden. However, as the Swedish power system interplays with other countries by import and export, the surrounding countries have to be represented with approximations. Only CO_2 emissions from fuels used for electricity generation are accounted for. Any indirect emissions such as the transport of fuels and power plant maintenance are not included.

The dispatch model constructed in this thesis has limitations. Firstly, the model is developed based on perfect foresight. The electricity consumption, the electricity prices outside Sweden and wind power generation are given as input data in time series. The heat from CHP industry and CHP district heating is not considered in the thesis. Only electricity production from CHP is considered and given exogenously. Secondly, the model is validated using values from 2014. Hence, any forthcoming, planned investments in installed capacity and infrastructure of the grid are not within the scope of thesis. Lastly, any losses of electricity in transmission and distribution are not considered in the study, since information regarding electricity losses in transmission, distribution and consumption data is not explicitly stated.

1.3 Problem statement

The thesis aims to answer the following questions:

1. How are national CO_2 emissions associated with electricity generation, import and export affected when making an investment in the local energy system?
2. What is the effect of using a dispatch model, average electricity production and marginal electricity production on the results in 1?
3. How does increasing the investment influence the results in 1 & 2?

1.4 Report structure

The remaining part of this report is organized according to the following:

Chapter 2 gives some background to the performed work.

Chapter 3 describes the theoretical framework upon which the analyses are based.

Chapter 4 describes the data used for the analyses.

Chapter 5 describes the validation process of the developed dispatch model as well as sensitivity analyses, combining the information given in Chapter 3 and 4.

Chapter 6 describes the case study of an investment in the city of Gothenburg and the results.

Chapter 7 presents the discussion around the three methods and the results.

Chapter 8 presents the conclusion and suggests future work.

2 Background

This section describes the Nordic power system and methods used for assessing the environmental impact from a change in electricity generation, or consumption.

2.1 Nord Pool

In 1996, the first steps towards a common Nordic wholesale market for electricity was formed as Norway and Sweden merged their markets into a jointly owned and operated power exchange known as Nord Pool [4]. The market is designed by a number of bidding areas, thought to represent the major bottlenecks in the transmission grid. The price of electricity is based on the buy and sell bids submitted to the power exchange from each bidding area. The market is then cleared by Nord Pool, meaning that a price is determined for each area by arranging the buy and sell bids, submitted by producers' and consumers', into a supply and demand curve where the price of electricity is given by the point of intersect in each area, also known as market clearing price (MCP). Initially the MCP is unison for all the bidding areas, but, due to transfer limitations between areas the flow of electricity is sometimes constrained, causing congestions and price differences [5].

Initially, the power exchange only encompassed day-ahead trading, i.e. trading 24 hours before delivery, but was during the successive years complemented to also encompass other markets such as the reserve market and ELbas, which adjust any mismatch between the scheduled dispatch from the spot market and updated forecast of demand [2]. As of now, ten countries are included and represented by 17 bidding areas, as seen from Figure 2.1, forming an integrated power market that reaches beyond the definition of being a Nordic power system.

Figure 2.1 Bidding areas of Nord Pool.

2.2 The Swedish power system

The Swedish power system is characterized by having large amounts of hydropower and nuclear power as well as small amounts of thermal and wind power in its generation mix. Most of the generation is located in the northern regions whereas the majority of the loads are situated in the southern parts. This creates a predicament since the power then has to travel long distances, which increase the losses in the system. It also increases the risks of congestion in the transmission grid during peak demand hours. In an attempt to mitigate congestion, Sweden was divided into four bidding areas in 2011. The notion of having bidding areas is that different prices in each area will occur when transmission lines are congested. This in term is thought to increase the incentives for consuming less power, or build new generation capacity, and thereby decrease the congestions. The transmissions system operator (TSO), responsible for maintaining, monitoring and operating the transmission grid within safe limits is Svenska Kraftnät (SvK). In effect, this means monitoring the frequency and balancing production and consumption of electricity as well as maintaining the scheduled interchange between other countries [6]. The TSO is also responsible for developing the infrastructure of the power system, thus, creating a framework for how the power system will look like in the future [7].

In recent years, on an annual basis Sweden is a net exporter of electricity, averaging well above 10 TWh in the last few years [8]. The factor influencing the export and import balance the most is the inflow to the hydro reservoirs. During a normal year, hydropower produces around 65 TWh of electricity whereas a dry or wet year differs 10 and 15 TWh respectively, from a normal year [9].

2.3 Environmental assessment

Assessing the environmental impacts of using electricity is often debated as there is no default method in place on how to calculate. This section describes three concepts used for this matter, which are dispatch model, average electricity production and marginal electricity production.

2.3.1 Dispatch model

An electric power system can be simplified to consist of generators, loads, a power market and a transmission grid. Each production technology consists of a range of different generators all of which have a unique cost characteristic. Hence, determining the total cost of supplying a load for a power system is highly related to what units that are scheduled (dispatched) to generate electricity. Determining the least cost for a power system commonly involves using an optimization model, most often a dispatch model. Due to the model being deterministic it is a good tool to use when assessing the impacts of a change in the power system, since the production pattern of each generator in the system is determined [10, 11].

2.3.2 Average electricity production

Assessing the environmental impact of electricity using the average electricity production implies accumulating the emission associated with the total produced electricity in the system and dividing it with the number of units of produced electricity. It is also possible to divide the total accumulated emission with electricity consumption, as well as include export and/or import [12]. The benefits of using this method is that the total emissions, within the boundaries of the defined system, equates to the total emissions in the system. It is therefore easy to assess, and allocate, the responsibility of a sector. On the other hand, it is difficult to employ this method on a national basis as most power systems of today are integrated with other power systems. In order to get reasonable values using this method one must include emissions deriving from imports and exports [13]. This notion is further discussed and advocated in [14, 15], based on the statement that there is extensive trading between the Nordic countries.

2.3.3 Marginal electricity production

The marginal electricity production method is based on the notion of cause and effect which in the context of power systems is seen as what, or which, units react and change its power output in case of a perturbation. In other words, a consequence analysis. Assessing the consequence of a perturbation requires knowledge about the dynamics and characteristics of the investigated system as well as the systems connected to it, i.e. surrounding power systems [16]. As a clarifying example, imagine a country that has zero emitting generators operating at full capacity meanwhile exporting to another country. In the case that the demand increases within the borders of that country, the extra demand is likely to come from a reduced export, at the expense of the importing country. Consequently, the demand for electricity is shifted to the exporting country instead, which might use generators with higher emissions to supply the extra unit of electricity.

Nevertheless, the marginal electricity production method is still advocated by [15, 17] compared to other methods as it gives a good representation of reality, although, approximating the surrounding systems could prove to be difficult.

3 Methodology

This chapter describes three different methods for assessing CO_2 emissions in the Swedish power system, i.e. a dispatch model, average electricity production and marginal electricity production. The first method involves making a dispatch model of the Swedish power system whereas the latter two representations involve data collection and simple calculation.

3.1 Dispatch model

Developing the dispatch model entails using a modeling software. Matlab is chosen for the task due to its good abilities in managing large quantities of data.

Before building the dispatch model it is necessary to define the investigated system. This means determining what to include and exclude in the model. The initial system boundary for the dispatch model is set to the borders of Sweden. However, as electricity is not bound to a certain geographical area, in the way that for instance the heating sector is, the power systems of the surrounding regions are also represented by approximations.

The data used as input to the model can be seen from Figure 3.1 below, which are described in detail in the following sections. Furthermore, the time resolution of the model is set to one hour. The studied year is chosen to 2014 as it does not distinguish itself as being an extreme year for any of the factors and parameters used in the model in addition to being the most recent year having all the required data for the model. The expected output form the model are hourly electricity generation and CO_2 emissions from each generation technology and import/export in Sweden.

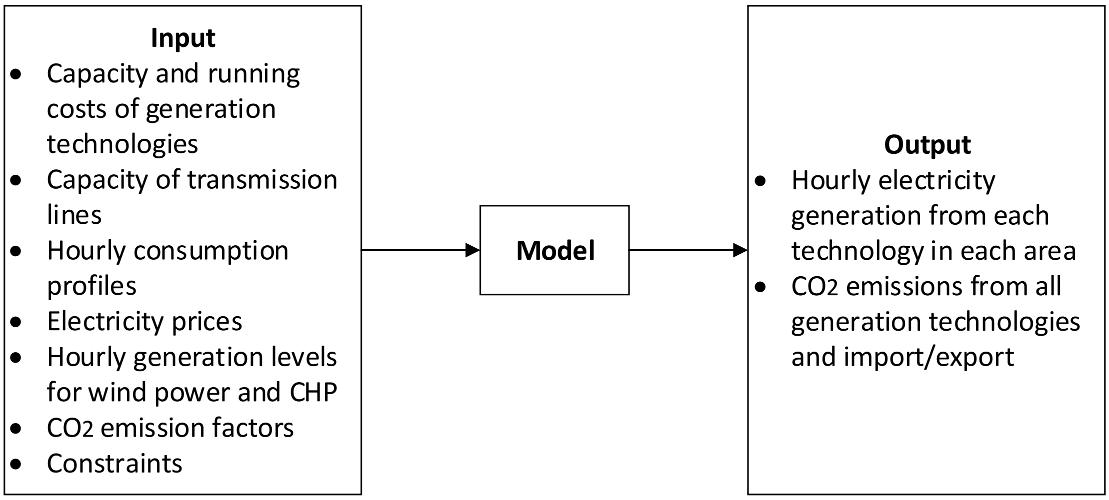

Figure 3.1 Input and output to and from the model.

3.1.1 Generation technologies

This section describes the model for each technology. The generation technologies included in the model are Nuclear power, Hydropower, Wind power, CHP industry, CHP district heating, Condensing power and Gas turbine. The technology specific characteristics modelled are described in the following section.

Nuclear power

Nuclear power is modelled as nine individual reactors, all of which are located in SE3. Each reactor has a planned yearly maintenance during which hours there is no electricity generation. This is set using

$$Gen_{nn,t} = 0, \textit{ where t is maintenance hour and } \forall\ nn \in \Omega. \tag{3.1}$$

Nuclear power plants are assumed to operate as base load in the Nordic power system for economic reasons. Ramp rates are therefore introduced to restrict rapid changes in power output. Since production data from each reactor is not available, aggregated ramp rates of nuclear power are used instead. The maximum ramp up rate (Rup_{Nuc}) corresponds to the maximum increase between two consecutive hours, and vice versa for the maximum ramp down rate (Rdn_{Nuc}) as shown in Equation 3.2 and 3.3 below [18].

$$Rup_{Nuc} = \max_{t \in [1,8759]} \left(Gen_{Nuc,t+1} - Gen_{Nuc,t}\right). \tag{3.2}$$

$$Rdn_{Nuc} = \max_{t \in [1,8759]} \left(Gen_{Nuc,t} - Gen_{Nuc,t+1}\right). \tag{3.3}$$

Equation 3.4 and 3.5 show the constraints for ramp rates of nuclear power generation.

$$Gen_{Nuc,t+1} \leq Gen_{Nuc,t} + Rup_{Nuc}, \forall\ t \in [1,8759]. \tag{3.4}$$

$$Gen_{Nuc,t+1} \geq Gen_{Nuc,t} - Rdn_{Nuc}, \forall\ t \in [1,8759]. \tag{3.5}$$

Also, each nuclear reactor is assumed to have a minimum load capacity of 80%, represented as

$$Gen_{nn,t} \geq 80\% \times Cap_{nn}, \forall\ t \in [1,8760], \forall\ nn \in \Omega. \tag{3.6}$$

Wind power

Wind power is seen as an intermittent generation source dependent on the prevailing wind conditions for a given location. It could therefore be seen as a non-dispatchable unit that does not interplay with the market. Wind power production could therefore be given exogenously to the model.

Hydropower

Hydropower plants can be divided into three types, namely run-of-river, reservoir and pumped storage. The installed capacity of pump storage is negligible compared to the other two types and are therefore neglected in the model [19]. The remaining two types are approximated, and modelled, into one unit consisting of a reservoir and generator illustrated in Figure 3.2. The reason for this is related to the increasing solving times caused by the cascading effects occurring when modelling hydropower plants in series, i.e. when the production is dependent on another unit upstream of a river.

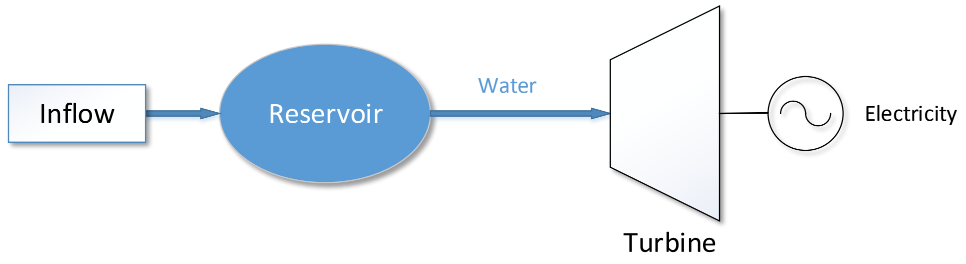

Figure 3.2 Schematic illustration of how hydropower is modelled as a single unit.

As run-of-river hydropower plants produce electricity when water is available, and there is always some water flowing in the rivers, hydropower output should not be zero. Therefore, a minimum electricity generation is introduced as

$$Gen_{i,Hyd,t} \geq Pmin_{i,Hyd}, \forall\, i \in \Theta, \forall\, t \in [1{,}8760]. \qquad (3.7)$$

Furthermore, total installed capacities of hydropower are not available at any time, because the plants depend on each other if situated along the same river. The plant downstream can be greatly influenced by the plant upstream, through the amount of water released and the delay time of water inflow between two plants.

Moreover, the aggregated hydropower cannot change power output freely like individual hydropower plants. In order to avoid rapid changes in power output, ramp rates are included, which constraint hydropower generation as

$$Gen_{i,Hyd,t+1} \leq Gen_{i,Hyd,t} + Rup_{i,Hyd}, \forall\, i \in \Theta, \forall\, t \in [1{,}8759]. \qquad (3.8)$$

$$Gen_{i,Hyd,t+1} \geq Gen_{i,Hyd,t} - Rdn_{i,Hyd}, \forall\, i \in \Theta, \forall\, t \in [1{,}8759]. \qquad (3.9)$$

The annual hydropower generation is also restricted by the water availability, i.e. maximum yearly electricity generation cannot exceed the yearly hydro inflow plus reservoir level difference (ΔStorage), which is shown Equation 3.10 below.

$$\sum_{t\in[1,8760]} Gen_{Hyd,t} \leq \sum_{t\in[1,8760]} Inflow_t + \Delta Storage. \qquad (3.10)$$

Assuming that there is no spillage and no loss of water, the amount of water flowing into the reservoir as well as the difference in reservoir levels and water discharged for electricity generation should be balanced for each time step *t*. The hydropower generation Gen_$_{Hyd,t}$ can be obtained by

$$Gen_{Hyd,t} = Inflow_t + Storage_t - Storage_{t+1}, \forall\, t \in [1{,}8760]. \qquad (3.11)$$

Due to insufficient data of hourly inflow to the reservoir, in each area, values for hourly inflow rates are obtained by calculations. The calculating method is described in Appendix 2, however, start and stop values for the reservoir levels in the beginning and end of 2014 are required for the model and collected from Nord Pool, represented as

$$Storage_{i,t} = known\ value, \forall\ i \in \Theta, \mathrm{t} = 1. \tag{3.12}$$

$$Storage_{i,t} = known\ value, \forall\ i \in \Theta, \mathrm{t} = 8761. \tag{3.13}$$

Furthermore, the hydro reservoir level is limited by the storage capacity shown in Equation 3.14.

$$Storage_{i,t} \leq Capsto_i, \forall\ i \in \Theta, \forall\ t \in [1,8760]. \tag{3.14}$$

Thermal power

Thermal power plants are categorized into three subgroups: CHP industry, CHP district heating and condensing power plants.

CHP industry

The monthly electricity production levels from CHP industry are seen in Figure 3.3 below.

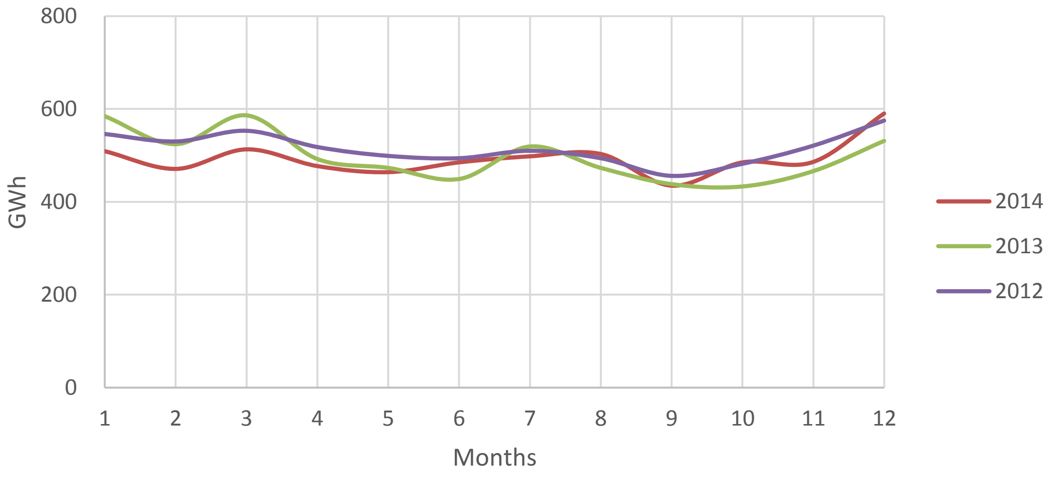

Figure 3.3 Monthly electricity production from CHP industry in Sweden during 2012-2014 [20].

It can be seen in Figure 3.3 that the electricity production fluctuates between months as well as between years. This is due to the industries being more prone to changes in the cost of producing as well as the price given for each sold goods. As the fluctuation are based on monthly values, it does not give any information on the hourly distribution.

For simplicity it is therefore assumed that electricity produced from CHP industry is constant during all the hours over the year.

CHP district heating

CHP for district heating is related to the heating sector and is assumed to have electricity generation correlated with the load pattern for heat. The heat load, is in term related to the weather conditions and ambient temperatures which illustrated in, Figure 3.4, where the sink represent the heat demand in the summer season in. Since the main objective is to supply the heat demand it is seen as a non-dispatchable unit, meaning that it does not respond to hourly changes in the power market. Generation levels are therefore assumed to be known and given exogenously to the model.

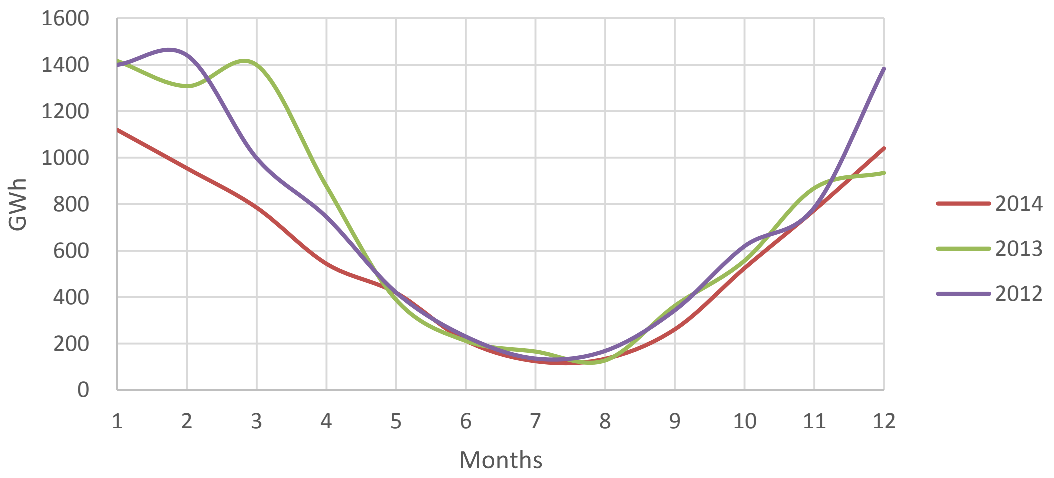

Figure 3.4 Monthly electricity production from CHP district heating in Sweden during 2012-2014 [20].

Condensing power

Condensing power plants are conventional thermal power plants. They are installed in SE3 and SE4 and are only used as reserve, or peak power, during hours of high demand. Condensing power plants are therefore modelled, as one unit in each area, with the ability to either produce or not. However, since these plants are constrained to a minimum generation level when committed [21], a minimum generation level is incorporated. Additionally, condensing power is also constrained by rapid changes in power output, even though they act as fast regulating generators.

The constraint equations for condensing power are listed below.

- Minimum and maximum generation:

$$Gen_t \geq on_t \times Pmin, \forall\, t \in [1{,}8760]. \tag{3.15}$$

$$Gen_t \leq on_t \times Pmax, \forall\, t \in [1{,}8760]. \tag{3.16}$$

- Maximum ramp up constraint:

$$Gen_t - Gen_{t-1} \leq Rup \times on_{t-1} + SU \times (on_t - on_{t-1}) + Pmax \times (1 - on_t), \forall\, t \in [2,8760]. \tag{3.17}$$

- Maximum ramp down constraint:

$$Gen_{t-1} - Gen_t \leq Rdn \times on_t + SD \times (on_{t-1} - on_t) + Pmax \times (1 - on_{t-1}), \forall\, t \in [2,8760], \tag{3.18}$$

  Where

$$SU = Pmax + Rup. \tag{3.19}$$

$$SD = Pmax + Rdn. \tag{3.20}$$

- Ramp rates cases
  Table 3.1 shows the four combination states of the power output at *t*-1 and *t*.

Table 3.1 Four combination states of the power output at *t-1* and *t*, $\forall\, \boldsymbol{t} \in [\mathbf{2}, \mathbf{8760}]$.

Case	*On_{t-1}*	*On_t*	Maximum ramp up constraint	Minimum ramp down constraint
1	0	0	$0 \leq Pmax$	$0 \leq Pmax$
2	0	1	$Gen_t \leq SU$	$-Gen_t \leq Rdn - SD + Pmax$
3	1	0	$-Gen_{t-1} \leq Rup - SU + Pmax$	$Gen_{t-1} \leq SD$
4	1	1	$Gen_t - Gen_{t-1} \leq Rup$	$Gen_{t-1} - Gen_t \leq Rdn$

Gas turbine

Gas turbines are characterized with very high variable costs and act as reserve power for periods of high demand. However, the annual produced electricity is negligible in comparison to the total produced electricity and could therefore be neglected, but in order for the model to always find a solution gas turbine is modelled as having infinite capacities in each area.

3.1.2 Consumption

The electricity consumption is given exogenously as a times series to the model for each bidding area.

3.1.3 Transmission

Figure 3.5 shows the transmission lines connecting different bidding areas. Each bidding area is connected with the neighboring areas, which allows power exchange between different areas. The power exchange is limited by the transmission capacity.

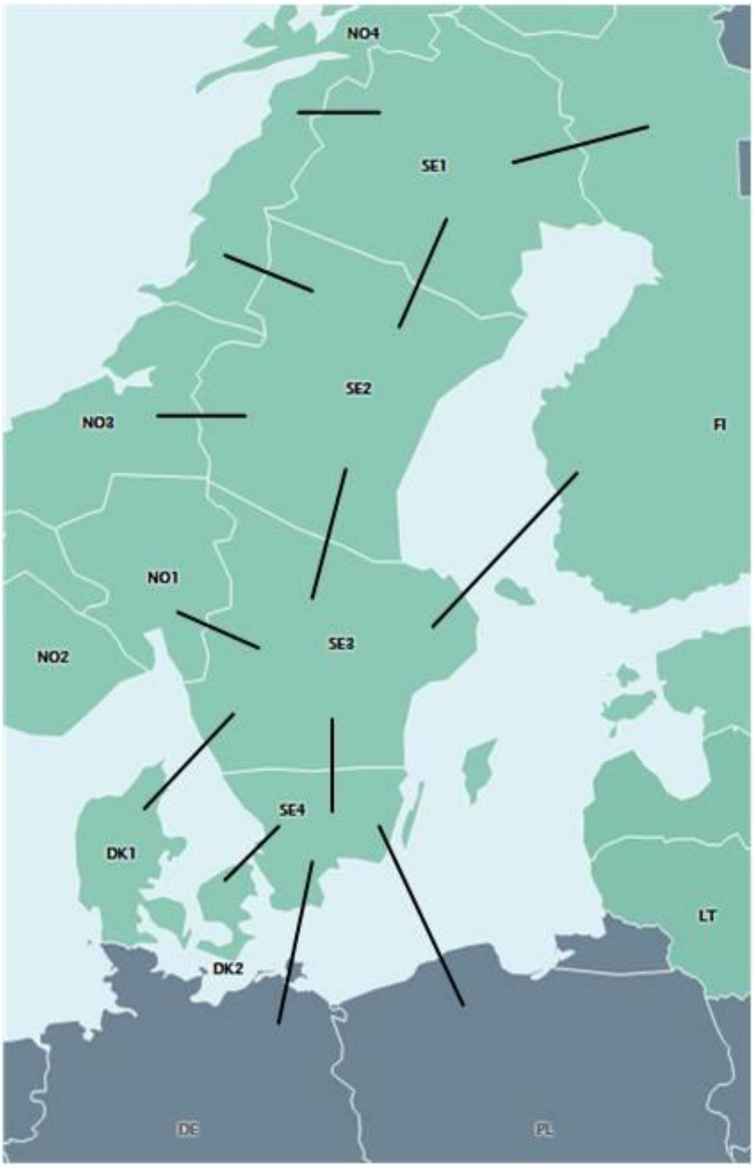

Figure 3.5 The black lines represent the transmission lines connecting different bidding areas in Sweden 2014 [4].

Domestic transmission

There are three domestic transmission connections in Sweden; SE1-SE2, SE2-SE3 and SE3-SE4, all of which are modelled with transmission capacities. The power exchange from area *i* to area *j* at any time *t* is limited by the net transmission capacity, seen as

$$trans_{i,j,t} \leq Ntc_{i,j}, \forall\, i,j \in \Theta, \forall\, t \in [1{,}8760]. \qquad (3.21)$$

Cross-border transmission

Sweden is connected with Norway (NO), Denmark (DK), Germany (DE), Poland (PL) and Finland (FI). The cross-border transmission connections are listed below.

Table 3.2 Cross-border transmission connections in Sweden.

Bidding area	Connected areas outside Sweden
SE1	NO4, FI
SE2	NO4, NO3
SE3	NO1, DK1, FI
SE4	DK2, DE, PL

In the model, there is a cost added for the import power, which is set to the electricity price in the respective area where the electricity imported from. Similarly, a revenue is generated for the export power, which is assumed to be the same price as the import of power. The export from area *i* to area *k* and the import from area *k* to area *i* are limited by the net transmission capacity, shown in Equation 3.22 and 3.23 respectively.

$$crosstransex_{i,k,t} \leq Crossntcex_{i,k}, \forall\, i \in \Theta, \forall\, k \in \Phi, \forall\, t \in [1{,}8760]. \qquad (3.22)$$

$$crosstransim_{k,i,t} \leq Crossntcim_{k,i}, \forall\, i \in \Theta, \forall\, k \in \Phi, \forall\, t \in [1{,}8760]. \qquad (3.23)$$

3.1.4 Equations

Apart from the specific constraint equations described in previous sections, there are some other equations used for the dispatch model, including objective function, capacity limit and energy balance.

3.1.4.1 Objective function

The objective of the model is to minimize the total system costs. Total system costs include electricity production costs, import costs and minus export revenue.

$$z = \sum_{i,p,t} Rc_{i,p,t} \times Gen_{i,p,t} + \sum_{k,i,t} Elp_{k,t} \times crosstransim_{k,i,t} - \sum_{k,i,t} Elp_{k,t} \times crosstransex_{i,k,t}, \forall\, i \in \Theta, \forall\, k \in \Phi, \forall\, p \in \Gamma, \forall\, t \in [1,8760]. \tag{3.24}$$

3.1.4.2 Capacity limit

The electricity generation of each unit is limited by the capacity, presented as

$$Gen_{i,p,t} \leq Cap_{p,i} \forall\, i \in \Theta, \forall\, p \in \Gamma, \forall\, t \in [1,8760]. \tag{3.25}$$

3.1.4.3 Energy balance

For area *i* at any time *t*, the electricity generation from all generators *p*, domestic import from area *j*, domestic export to area *j*, cross-border import from area *k*, cross-border export to area *k* and consumption should be balanced, formulated as

$$\sum_{p} Gen_{i,p,t} + \sum_{j} trans_{j,i,t} - \sum_{j} trans_{i,j,t} + \sum_{k} crosstransim_{k,i,t} - \sum_{k} crosstransex_{k,i,t} \geq Consp_{i,t}, \forall\, i,j \in \Theta, \forall\, k \in \Phi, \forall\, p \in \Gamma, \forall\, t \in [1,8760]. \tag{3.26}$$

3.1.5 CO_2 emissions

Net CO_2 emissions in Sweden, which include CO_2 emissions from electricity generation within Sweden and CO_2 emissions associated with imports and exports, are calculated based on the illustration seen in Figure 3.6 below. Imports and exports of electricity are assumed to increase and decrease, respectively, the CO_2 emissions in Sweden.

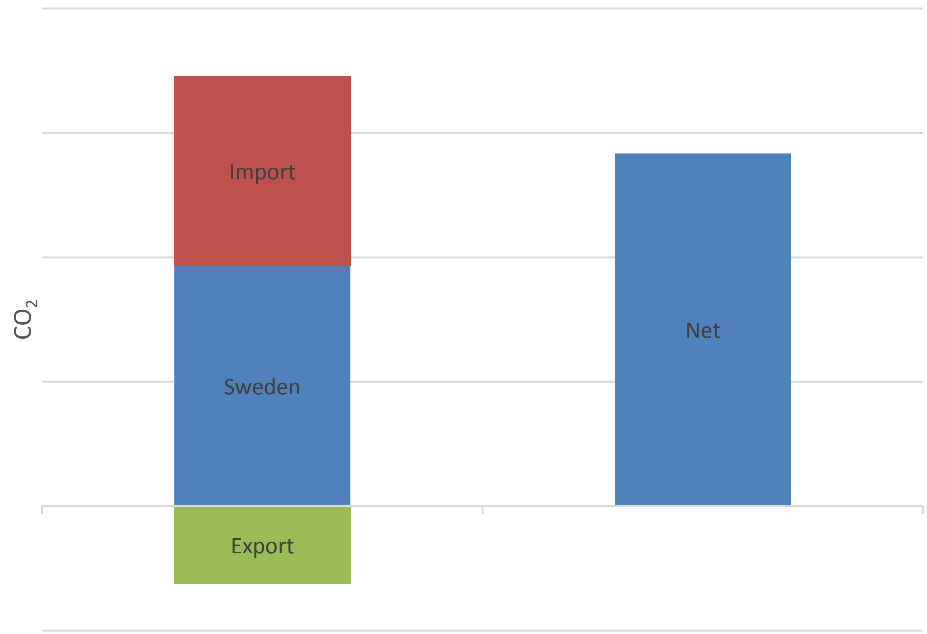

Figure 3.6 Illustration of the method for calculating gross and net CO_2 emissions in Sweden.

When Sweden imports electricity from one country, it increases the total CO_2 emissions in Sweden, by the amount of CO_2 emitted from the extra electricity generation in the respective country. This amount of CO_2 is calculated using an average CO_2 emission factor in each country, corresponding to emitted CO_2 per produced unit of electricity.

When Sweden exports electricity to other countries, the total CO_2 emissions decrease, by the extra amount of CO_2 produced. This amount of CO_2 is calculated using average CO_2 emissions in Sweden, i.e. the total CO_2 emissions from electricity generation (excluding imports) divided by the total electricity generation.

3.2 Average electricity production

This section describes how the method of average electricity production is calculated.

When subjected to a change, the changed electricity is assumed to be replaced with a combination of all the electricity generation sources with fixed shares. The shares of different sources are calculated based on historical annual generation, represented in Figure 3.7.

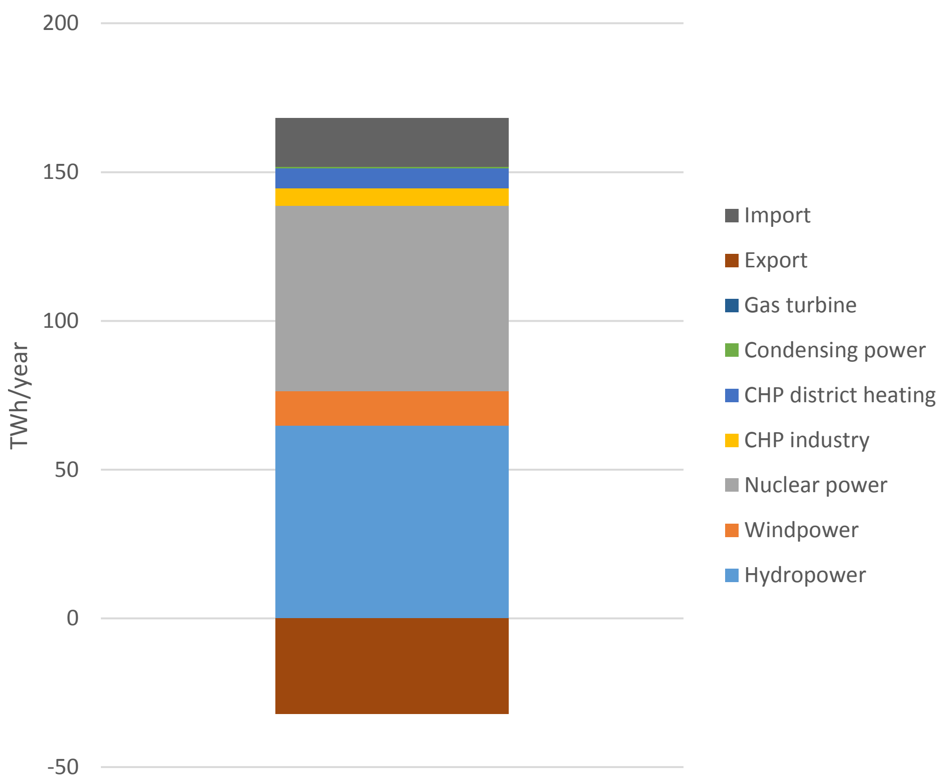

Figure 3.7 Electricity generation sources by source in Sweden 2014 [7, 22]. Negative values represent export.

The altered CO_2 emissions are derived from a combination of the different generation sources. The method used to calculate CO_2 emissions from different electricity generation sources is the same as in Section 3.1.5.

The CO_2 emission factor of average electricity production is derived by

$$CO_2\,factor = \sum_i \frac{Gen_i}{Gen_{tot}} \times CO_{2_i}, \forall\, i \in \Theta \tag{3.27}$$

Where i is different electricity generation sources, Gen_i is the electricity generation from source i, CO_{2_i} is CO_2 emission factor for source i and Gen_{tot} is the total electricity generation.

3.3 Marginal electricity production

This section describes how the marginal electricity production method is designed.

A change in electricity production or consumption would result in the response of the marginal unit to balance the electricity production and the consumption. According to [23] the marginal effects of a change in the Swedish power system is not believed to have any effect within the border of Sweden, due to the Nordic power system being well integrated to other countries. Instead the marginal effects form a change is thought to consist of coal condensing power plants from Denmark, Finland, Germany and

Poland [17, 24]. Therefore, coal condensing power plants are assumed to be the marginal unit to respond to a change in a local energy system of Sweden. CO_2 emission factors for coal condensing power plants vary and change continuously between years, due to developments in installed capacity, plant efficiency, transmission capacity and consumption to mention a few. The assessment, from reviewing reports, seems to have settled for a value in the range of 500-900 $kgCO_2/MWh_{el}$ [17, 24, 25]. In the search for a precise number to serve as a reference in the model and discussions, the report [26] estimated the value to 780 $kgCO_2/MWh_{el}$ and is henceforth used as the default value.

The CO_2 emission factor of marginal electricity production is thus the CO_2 emission factor of coal condensing power plants

$$CO_2\,factor = CO_{2_{coal}}, \tag{3.28}$$

Where $CO_{2_{coal}}$ is CO_2 emission factor of coal condensing power plants.

4 Input data

The dispatch model requires extensive and detailed input data. As this is not always available, or in case there is a discrepancy between two or more sources, it is necessary to approximate or make assumptions in order to move forward. This section describes the data used as input to the model and describe any assumptions made in the process.

This section is dedicated to describing the data used as input for the base case. The main sources used are [4, 7, 8, 22] and refers to Nord Pool, SvK, Energimyndigheten and Svensk Energi respectively.

4.1 Energy

The dispatch model requires production levels differentiated by generation technology and bidding area, most of which are obtained from SvK, which later on is used to validate the constructed base model. However, the data from SvK displayed different values for thermal generation compared to the other sources used; Energimyndigheten and Svensk Energi, as seen from Table 4.1.

Table 4.1 Comparison of thermal generation from different sources.

	Thermal Generation			
Generation technology	CHP industry	CHP district heating	Condensing power	Gas turbine
Energimyndigheten, TWh	5.6	7.6	0	0
SvK, TWh		6.7		0.04
Svensk Energi, TWh	5.9	6.9	0.5	0.01

The reason for the discrepancy rests in the method used by SvK for accounting the generated electricity. SvK does not differentiate between which thermal source that generates the electricity, meaning that all thermal generation sources are reported as an aggregated unit, excluding nuclear power. Furthermore, production coming from non-concessionary grids are measured as net production, which means that if production from a non-concessionary grid is equal to the consumption in that concession area it is seen as zero. Furthermore, non-concessionary grids usually constitute grids at low to medium voltage levels used by industries which, for economic reason, attempts to generate as much electricity as they consume themselves. It is therefore assumed that the data set denoted thermal generation from SvK consists of electricity generated by CHP plants related to the district heating sector. This is further strengthened by reviewing the thermal data set, from SvK, as the production pattern is typical for the district heating sector, seen in Figure 4.1 below.

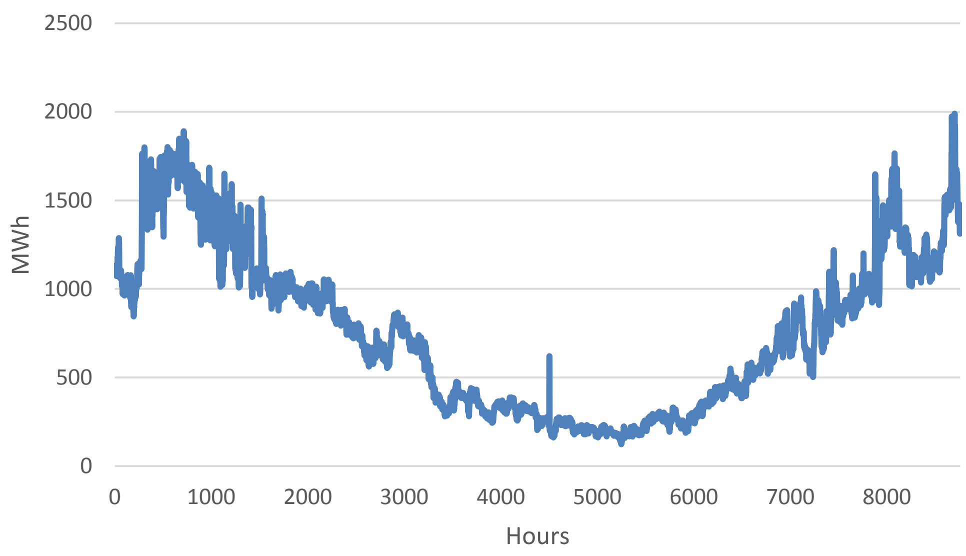

Figure 4.1 Hourly production level of thermal generation from historical data.

Data input coming from CHP industry plants is assumed to derive from Svensk Energi rather than Energimyndigheten. This is partly due to reduce the number of sources used as well as Energimyndigheten not having reasonable values concerning condensing power plants and gas turbine. Hence, the resulting values for each technology and the source of origin can be seen by the underlined numbers in Table 4.2 below.

Table 4.2 Total produced electricity for different generation technologies from different sources.

Sources	Svensk Energi, TWh	SvK, TWh
Hydropower	64.2	64.82
Wind power	11.5	11.59
Nuclear power	62.2	62.28
CHP industry	5.9	-
CHP district heating	6.9	6.71
Condensing power	0.5	-
Gas turbine	0.01	0.04

The resulting production from the underlined values above equates to 151.82 TWh. Furthermore, since the new value are constituents of two sources the production balance does not concur with any initial values form either of the used sources. As such, the export/import balance should also change to some extent. However, from Table 4.3, it is seen that the both used sources have identical values for net export as well as Energimyndigheten even though the production consumption balance are slightly different.

Table 4.3 Comparison of energy balance for different sources.

Energy balance	Total Production	Net Export balance	Total Consumption
Energimyndigheten, TWh	150.0	15.6	134.3
SvK, TWh	145.4	15.6	129.8
Svensk Energi, TWh	151.2	15.6	135.6
Nord Pool, TWh	150.2	16.4	133.8

As such, it is assumed that 15.6 TWh is the correct value representing exported electricity from Sweden. The annual consumption level of is thereafter obtained by calculations,

$$Total\ production - Net\ export = Total\ consumption. \qquad (4.1)$$

$$151.82 - 15.6 = 136.22\ [TWh]. \qquad (4.2)$$

However, this leads to another problem as hourly consumption levels differentiated by bidding area is only available and obtained from Nord Pool, and is inconsistent with the value, 136.21 TWh, derived above. This is solved by scaling the hourly consumption values from Nord Pool to SvK values, i.e. the consumption levels are increased by a factor of

$$136.22\ TWh/133.8\ TWh = 1.018. \qquad (4.3)$$

The reason for opting to scale consumption levels instead of production levels is based on the assumption that scaling production levels distorts the production pattern more than a scaling of consumption would, since consumption is only comprised of one factor as opposed to seven for the production option. The final values, used in the model, representing the base model are found in Table 4.4 below.

Table 4.4 Final values for each generation technology used for the base case.

Generation technology	TWh
Hydropower	64.82
Wind power	11.59
Nuclear power	62.28
CHP industry	5.9
CHP district heating	6.71
Condensing power	0.5
Gas turbine	0.01

4.2 Capacity

Installed capacities for each generation technology in different bidding areas used in the model are collected from the report [22] and can be found in Appendix 1. Moreover, from comparing installed capacities between 2014 and 2015 it is seen that the change is small. It is therefore assumed that installed capacities are static for the entire year.

The net transmission capacities (NTC) are obtained from Nord Pool, as shown in Figure 4.2. The detailed NTC values can be found in Appendix 3.

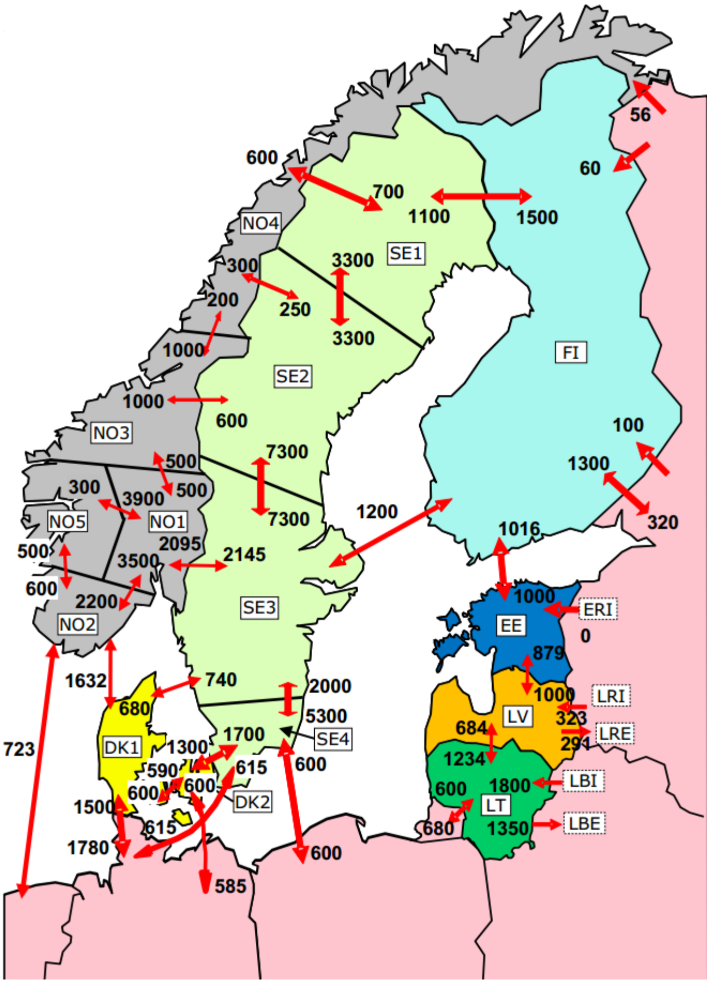

Figure 4.2 Maximum net transfer capacities map 2014 [4].

4.3 Input data for each generation technology

This section presents the specific input data for each generation technology.

4.3.1 Nuclear power

The available capacities and planned maintenance hours of each reactor are listed in Table 4.5 below.

Table 4.5 Available capacities and planned maintenance hours of nuclear reactors [4].

Nuclear reactors	Available capacity, MW	Maintenance hours, h
O1	473	2137-3217
O3	1400	2953-4345
R1	878	1945-3865
R2	807	5425-8760
R3	1063	3193-4225
R4	940	5209-6865
F1	984	2705-3209
F2	1120	3473-4025
F3	1170	4985-6209
Total	8835	-

Maximum ramp up and ramp down values of nuclear power are obtained through analysis of historical data from SvK [7], using Equation 3.2 and 3.3. The analysis results in ramp up and ramp down values of 397 and 829 MW respectively.

4.3.2 Wind power

Wind power production in each bidding area is given exogenously to the model as a time series of 8760 values from SvK.

4.3.3 Hydropower

The specific input data for hydropower includes minimum generation level, actual maximum available capacity, maximum ramp rates, initial and final reservoir levels as well as reservoir storage capacity.

The minimum hydropower generation level is obtained by analyzing historical hourly hydropower generation during the hours of 2014 from SvK. The lowest generation level is chosen as the minimum level and shown in Table 4.6.

Table 4.6 Minimum hydropower generation in each bidding area [7].

Bidding areas	SE1	SE2	SE3	SE4	Total
Minimum generation, MWh/h	226	770	476	20	1683

The actual maximum available capacity of hydropower is listed in Table 4.7, which is obtained from the report [27].

Table 4.7 Actual maximum available capacities in each bidding area [27].

Bidding areas	SE1	SE2	SE3	SE4	Total
Maximum available capacities, MW	4429	6756	2218	297	13700

The ramp rates of hydropower are obtained using the same method as for nuclear power ramp rates, shown in Table 4.8.

Table 4.8 Maximum ramp rates of hydropower [7].

Bidding areas	SE1	SE2	SE3	SE4
Maximum ramp up rate, MW	1637	1997	405	63
Maximum ramp down rate, MW	1349	1211	385	55

The initial and final values for hydro reservoir levels are obtained from Nord Pool, listed in Table 4.9.

Table 4.9 Reservoir content for each bidding area in the beginning and the end of year 2014 [4].

	SE1	SE2	SE3	SE4	Total
Initial reservoir content (t=1), GWh	8700	11134	2001	146	21981
Final reservoir content (t=8761), GWh	7566	9956	2162	170	19854

The capacity of hydro reservoir storage in each area is obtained from Nord Pool, shown in Table 4.10.

Table 4.10 Reservoir storage capacity in each bidding [4].

	SE1	SE2	SE3	SE4	Total
Reservoir storage capacity, GWh	14810	15730	2911	224	33675

4.3.4 CHP industry

The hourly electricity produced from CHP industry is constant over the year, given exogenously as time series to the model. The time series are obtained by distributing the annual electricity production from CHP industry in Table 4.4 over 8760 hours, according to the installed capacity of CHP industry units, found in Appendix 1.

4.3.5 CHP district heating

Generation levels of CHP district heating are given exogenously to the model as a times series for each bidding area. The data is collected from SvK as discussed in Section 4.1.

4.3.6 Condensing power

The minimum level of condensing power is set to 35% of its installed capacity.

The maximum ramp rates of condensing power, i.e. up and down, are both assumed to 50% of the installed capacity at a given hour.

4.4 Running costs

Running costs include fuel costs, operation and maintenance costs (O&M costs) and tax and fees. It should also be mentioned that even though cost characteristics in reality are highly specific for each plant, the model treats each generation technology as an aggregated unit for each bidding area. Consequently, only one value is used for each generation technology, as seen in Table 4.11 below.

Table 4.11 Running costs of different generation technologies [28].

Generation technology	Running costs, EUR/MWh$_{el}$
Nuclear power	23.08
Wind power	0
Hydropower	7.25
CHP industry	-
CHP district heating	-
Condensing power	43.41
Gas turbine	136.70

4.5 Import cost/export revenue

As described in Section 3.1.3, the cost of import and the revenue from export are set to the electricity prices in the surrounding bidding areas. The electricity price in each bidding area given exogenously to the model as a time series, which is obtained from Nord Pool.

4.6 CO_2 emission factors

As described in Section 3.1.5, CO_2 emissions include CO_2 from electricity generation in Sweden and CO_2 associated with imports and exports. The CO_2 emission factors of different generation technologies in Sweden and average CO_2 emission factors in countries outside Sweden are presented in this section.

4.6.1 Sweden

Since only emissions associated with the operation of the plant are accounted for, Hydropower, Nuclear power and Wind power are seen as zero emitting generation sources. Emissions attributed to the district heating and industry sector are obtained by calculations, where each fuel source is multiplied with an emission factor given by [29, 30]. The total emitted CO_2, for generating electricity, is then divided by the number of produced units. Emissions distributed to condensing power and gas turbine plants are obtained by dividing the CO_2 emission factor of the fuel source used with the plant efficiency. It is assumed that condensing power plants only use oil as their fuel source and gas turbines natural gas [22].

The technology specific CO_2 intensities can be seen in Table 4.12 whereas exact values for, fuel input, emission factors and plant efficiencies used in the calculation can be seen in Appendix 6, 7 and 8.

Table 4.12 CO_2 emission factor for different technologies in Sweden.

Generation technology	CO_2 emission factor, kg CO_2/MWh_{el}
Nuclear power	0.0
Wind power	0.0
Hydropower	0.0
CHP industry	30.8
CHP district heating	203.2
Condensing power	891.0
Gas turbine	512.0

4.6.2 Surrounding countries

CO_2 intensity levels for Norway, Denmark and Finland was obtained through reports whereas the factors for Germany and Poland involve calculations. The method used for the calculations is the same as mentioned in introduction of section 4.1.4. The CO_2 intensity levels for electricity generation in adjacent countries are presented in Table 4.13 below. Detailed description for the values used for calculating the German and Polish CO_2 intensity can be found in Appendix 4 and 5.

Table 4.13 CO_2 emission factor in different countries.

Country	**CO_2 emission factor, kg CO_2/MWh_{el}**	**Reference**
Norway	10	[31]
Denmark	401	[32]
Poland	905.7	Appendix 4
Germany	501.4	Appendix 5
Finland	133	[33]

5 Model validation and Sensitivity analysis

The validation process applies the data for 2014 as described in Chapter 4. The aim of this chapter is to show the feasibility of the developed model in Chapter 3 and the sensitivity of the model to assess changes in CO_2 emissions due to changes in the system.

5.1 Validation

Validation is an ongoing process when developing a model. The process of model development and validation is illustrated in Figure 5.1, as an iterative process.

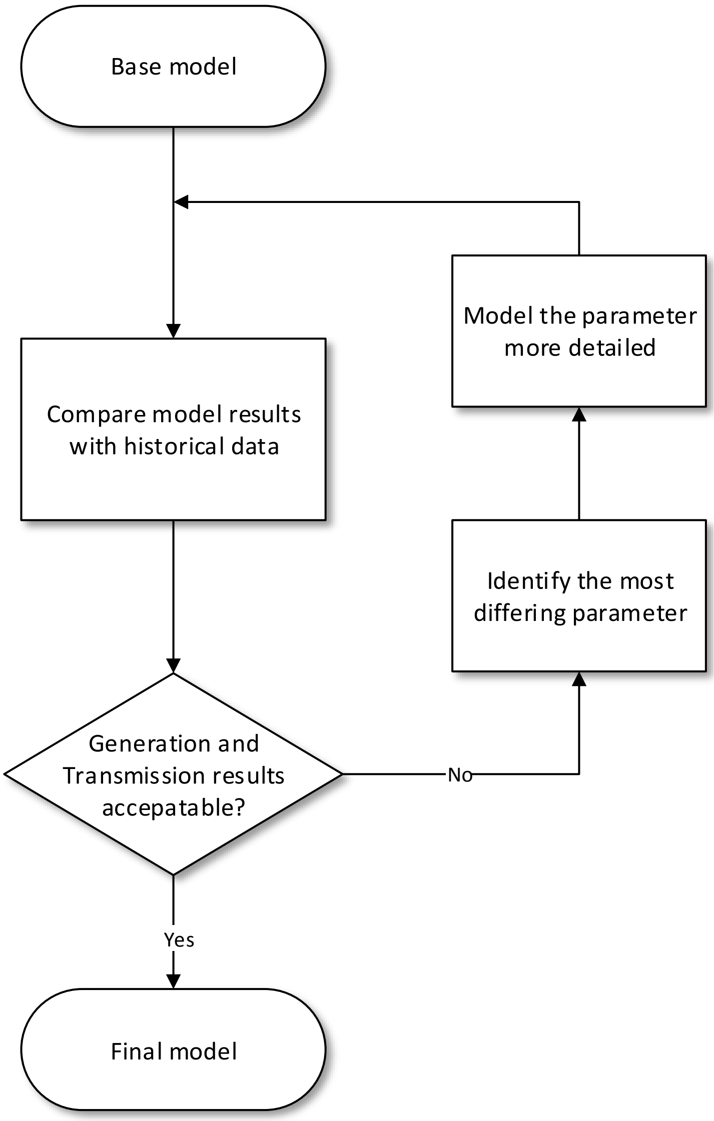

Figure 5.1 Schematic illustrating the process of improving and validating the model.

First, an initial model is constructed, which includes four bidding areas. For each bidding area except SE3, the electricity generation technologies include four generators: Hydropower, Wind power, Thermal power and Gas turbine. In SE3, the generation also includes nuclear power plants. The consumption of each bidding area is given exogenously as input data. The domestic and cross-border transmissions in each bidding area are limited by maximum transmission capacities. After that, the results from the model are compared with historical data, based on electricity generation of each technology and transmissions. After some iterations, if there is not much improvement in the model results, the model can be considered as good enough. Otherwise, the parameter which differs most from historical data needs to be identified. This parameter is modelled more detailed and thus improved.

In the following sections, only the results from the final dispatch model is presented. The historical data refers to the year 2014, collected from SvK and Nord Pool. Since the electricity generation from CHP industry, CHP district heating and Wind power are given as exogenous input data, they are excluded in the validation of the model. Below follows how each generation technology and transmission are validated.

5.1.1 Hydro power

Figure 5.2 and Figure 5.3 show the hourly hydropower generation patterns from historical data and the dispatch model, respectively. As can been seen, the dispatch model shows more fluctuations in hourly electricity generation levels than historical values. It is also observed that the generation reach the maximum and the minimum levels more often in the dispatch model, which is further illustrated in the duration diagrams in Figure 5.4.

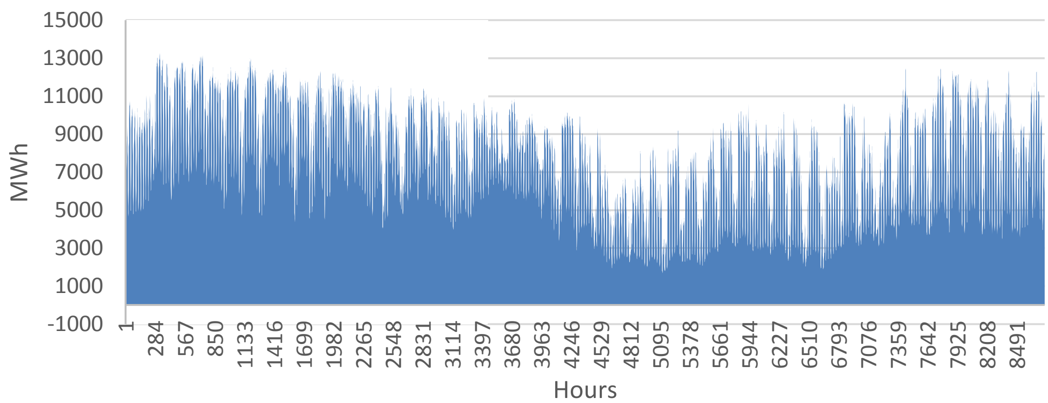

Figure 5.2 Hourly hydropower generation from historical data.

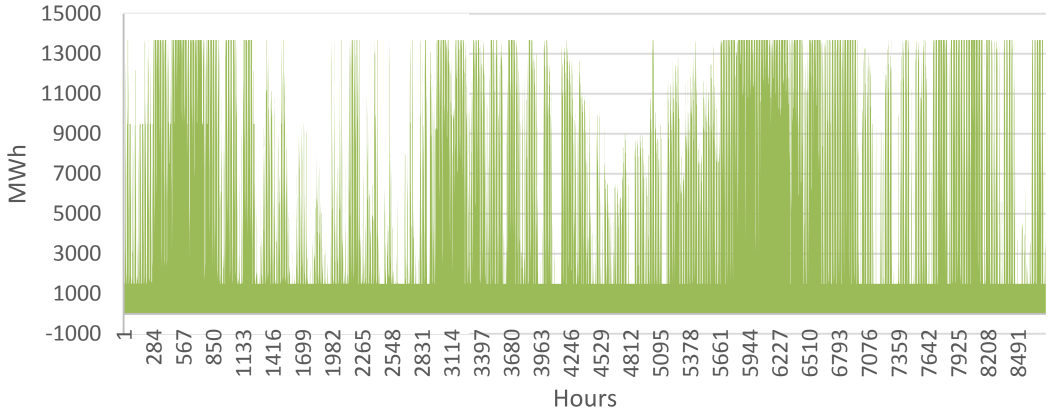

Figure 5.3 Hourly hydropower generation from the dispatch model.

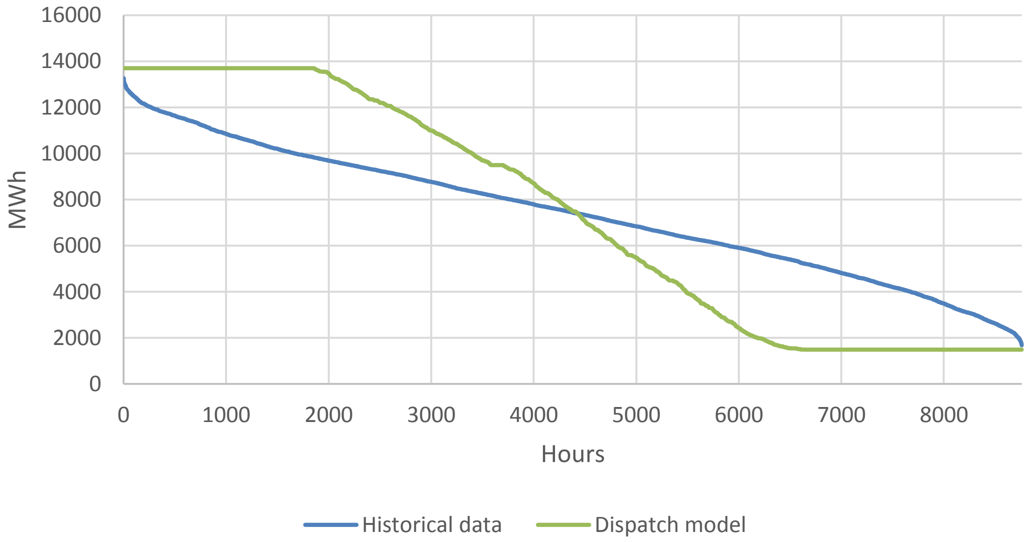

Figure 5.4 Comparison of duration diagrams of hydropower generation from historical data and the dispatch model.

The main reason for why the dispatch model shows more fluctuations and has more maximum or minimum power outputs is probably that the model uses ramp rates to represent the correlations between different hydropower plants. In this case, the change of hydropower output is only restricted by a maximum ramp rate. This means that when the electricity price goes up or down, the hydropower output is always able to shift at the maximum ramp rate. However, as stated in Section 3.1.1, the correlations between hydropower plants are much more complicated in reality. The change of hydropower output cannot always be at the maximum ramp rate used in the dispatch model.

Table 5.1 shows the annual hydropower production in each bidding area from historical data and the dispatch model. There are negligible differences in produced electricity. The minor differences are probably due to the numerical errors in the solver.

Table 5.1 Comparison of annual hydropower production from historical data and the dispatch model.

Hydropower	SE1	SE2	SE3	SE4	Total
Historical data, TWh	17.56	33.24	12.51	1.51	64.82
Dispatch model, TWh	17.54	33.28	12.51	1.51	64.83
Difference	0%	0%	0%	0%	0%

The total reservoir levels in Sweden is also compared, as shown in Figure 5.5.

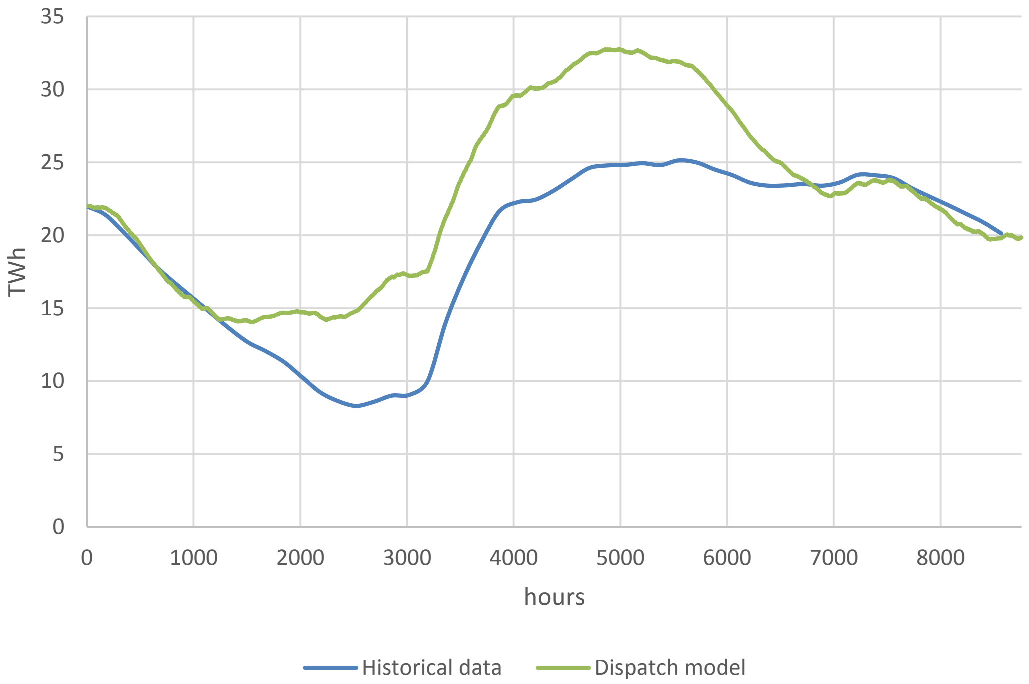

Figure 5.5 Comparison of reservoir levels in Sweden from historical data and the dispatch model.

As can be seen there is a difference in reservoir levels during the year between the dispatch model and historical values. The main difference is that the dispatch model saves more water during the hour 1200-3200, thereafter producing almost the same amount of electricity between hour 3200-5100. After hour 5100, the dispatch model produces more than historical values. The probable reason for why the dispatch model saves more water in the beginning of the year compared to historical values is that it has perfect information, i.e. consumption, hydro inflow, available wind and prices for import and export are all known parameters. In reality, these are variables that have to be estimated or forecasted, which makes the outcome more uncertain. Furthermore, the model also tries to minimize the total system costs. As such, the objective for the plant owner and the model is slightly different, meaning that the owner tries to maximize profits whereas the model seeks to minimize costs of producing electricity. Moreover, since the profit for the plant owner is a function of the cost of producing electricity and the revenue; and the fact that the production cost for hydro is a nonlinear relationship between the head and the discharge rate, this could also be a factor influencing for the difference in reservoir levels.

5.1.2 Nuclear power

Figure 5.6 shows the nuclear power generation levels from historical data and the dispatch model. The patterns of these two generation are quite similar, except that the dispatch model has more rapid ramping. It can also be seen that the dispatch model produces much more or much less electricity during some hours, such as hour 2200-2400, 4300-5200, 6600-6900, etc.

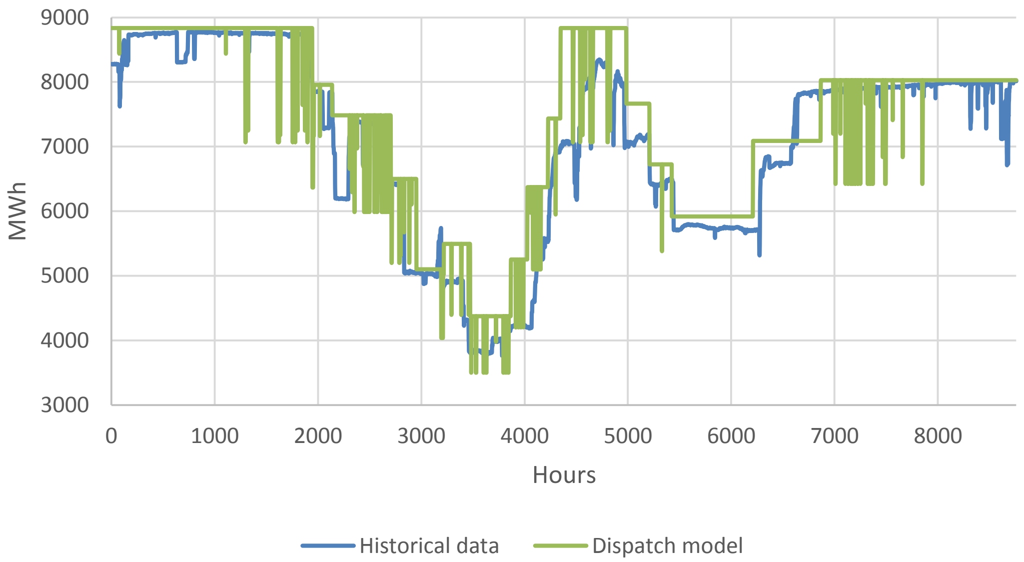

Figure 5.6 Comparison of nuclear power production from historical data and the dispatch model.

The reason for the frequent ramping behavior seen in the dispatch model compared to the historical data is mainly related to the cost of producing electricity, as well as the ramp up and down constraints used. Since the objective of the model is to minimize the total cost of the system subjected to fulfilling the demand of electricity, it will dispatch the units in the most cost efficient way and the dispatch model has a perfect foresight of the electricity prices. This means that when the cost of producing electricity from nuclear power is higher than the electricity price, the model will decrease its generation by ramping down production as fast as possible. Similarly, when the cost of producing electricity is lower, the model will increase its power output as fast as possible. However, in reality nuclear reactors tend to produce at a steady level rather than shifting the power output. This is due to economic reasons. More specifically, during most of hours the running cost of nuclear power is lower than the electricity price in the Swedish power system, shifting power output during the few hours when the electricity price is lower would not be more profitable because of the probable increased the maintenance costs [34].

The deviations of the annual electricity generation from historical data and the dispatch model can be explained with two reasons. Firstly, the planned yearly maintenance periods of nuclear reactors used in the dispatch model differ from the real maintenance periods. Secondly, the failures of nuclear reactors are not taken into consideration in the dispatch model.

Table 5.2 shows the annual nuclear power generation from historical data and the dispatch model. The electricity loss in historical data is mainly due to failures of nuclear reactors during some hours, which are not considered in the model.

Table 5.2 Comparison of annual nuclear power production from historical data and the dispatch model.

	Nuclear power
Historical data, TWh	64.70
Dispatch model, TWh	62.28
Difference	4%

5.1.3 Condensing power

Table 5.3 shows that the dispatch model underestimates the condensing power generation by 57.9%. The large deviation is related to the running cost of condensing power being set to a value that is perhaps is too high, which would cause condensing power to be replaced by cheaper generation coming from import. However, even though the deviation is large, it is still able to display qualitatively the same production pattern as expected for peak power plants, as seen in Table 5.3. For that reason, as well as the deviation being relatively small compared to the total produced electricity in the system, the deviation is considered to be acceptable.

Table 5.3 Comparison of annual condensing power production from historical data and the dispatch model.

	Condensing power
Historical data, TWh	0.50
Dispatch model, TWh	0.21
Difference	57.9%

5.1.4 Gas turbine

The generation from gas turbine in the dispatch model is 0, and the number is also negligible in historical data, shown in Table 5.4.

Table 5.4 Comparison of annual gas turbine electricity production from historical data and the dispatch model.

	Gas turbine
Historical data, TWh	≈ 0
Dispatch model, TWh	0
Difference	0%

5.1.5 Transmission

The power exchanges between Sweden and bidding areas outside of Sweden are illustrated in Figure 5.7 below.

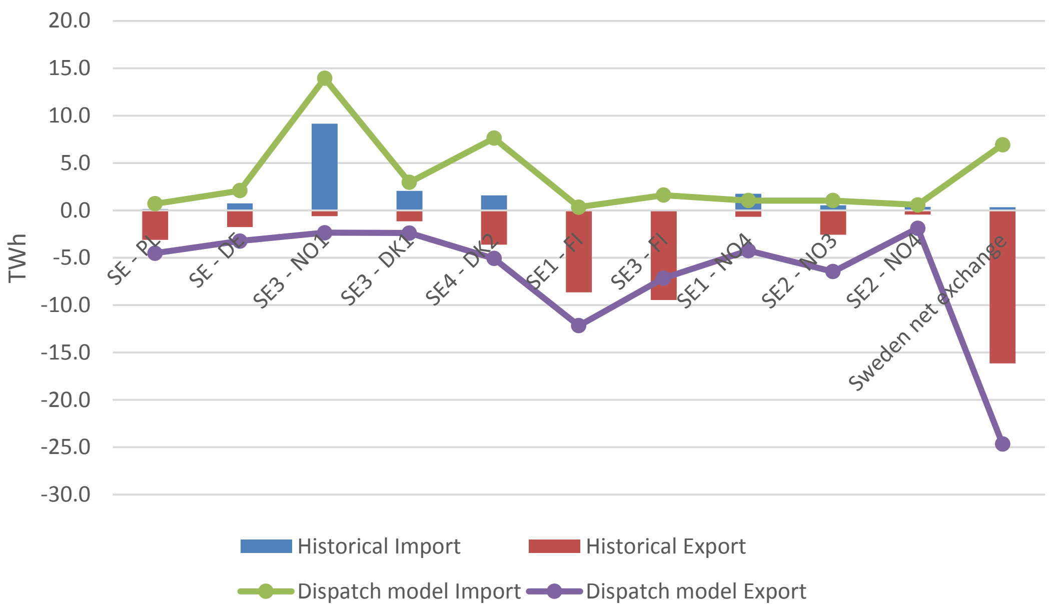

Figure 5.7 Comparison of Import and export with bidding areas outside Sweden from historical data and the dispatch model. Import is represented by positive values and export by negative values.

It is observed that even though there are quantitative differences between the dispatch model and the historical data, the model still behaves qualitatively correct, reflecting the reality. Though some differences can be observed, e.g. the import from SE1 to NO4 and the export from SE3 to FI. One reason for the differences is due to transmission capacity reductions. Transmission capacity reductions are limitations, such as planned outage and network failure, resulting in reduction of the transmission capacity [4]. Thus in reality, the transmission capacities might be smaller, allowing less power exchanges. Another possible reason is that the bidding areas outside Sweden are assumed to have unlimited electricity generation capacities as well as unlimited consumption capabilities. This means the imports and exports are only limited by the transmission capacities and the electricity prices in the surrounding areas are not affected by the Swedish power system. However, in reality, when Sweden imports more from an area, the import cost would increase. On the contrary, when Sweden exports more to an area, the export revenue would decrease. However, due to the scope of the thesis that the surrounding regions outside Sweden are simplified and modelled less detailed, the transmission results are regarded as acceptable.

5.1.6 The full year dispatch

A full year simulation of the developed dispatch model and an equivalent model, based on historical data can be seen in Figure 5.9 and Figure 5.8 respectively. The figures display the dispatch order and generation pattern of all the generation technologies, included in the investigated system, for all hours of the year. It is also observed that the historical equivalent has a smoother oscillating behavior than the developed dispatch model as well as lower and less frequent occasions of peak power. This is probably related to not having a limit on export other than the transmission capacity limit, which results in the model increasing the generation of some units when the electricity price is higher in the surrounding areas compared to the running costs of the generators in Sweden. Since hydropower is characterized as having low running costs, high ramp rates and an abundance of energy, is is most likely the cause for this behavior.

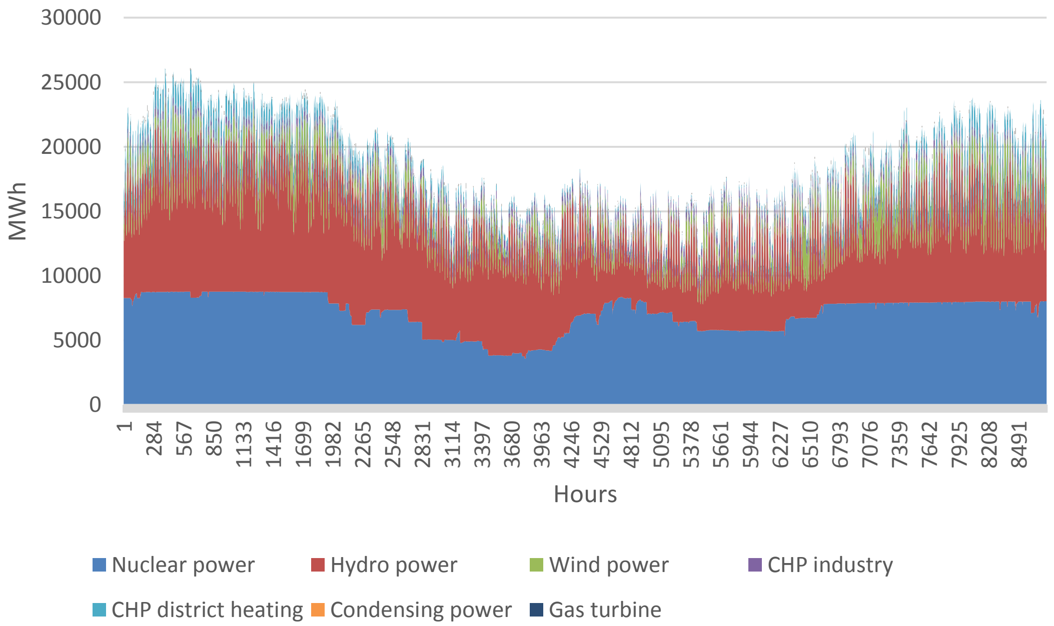

Figure 5.8 The full year dispatch from historical data.

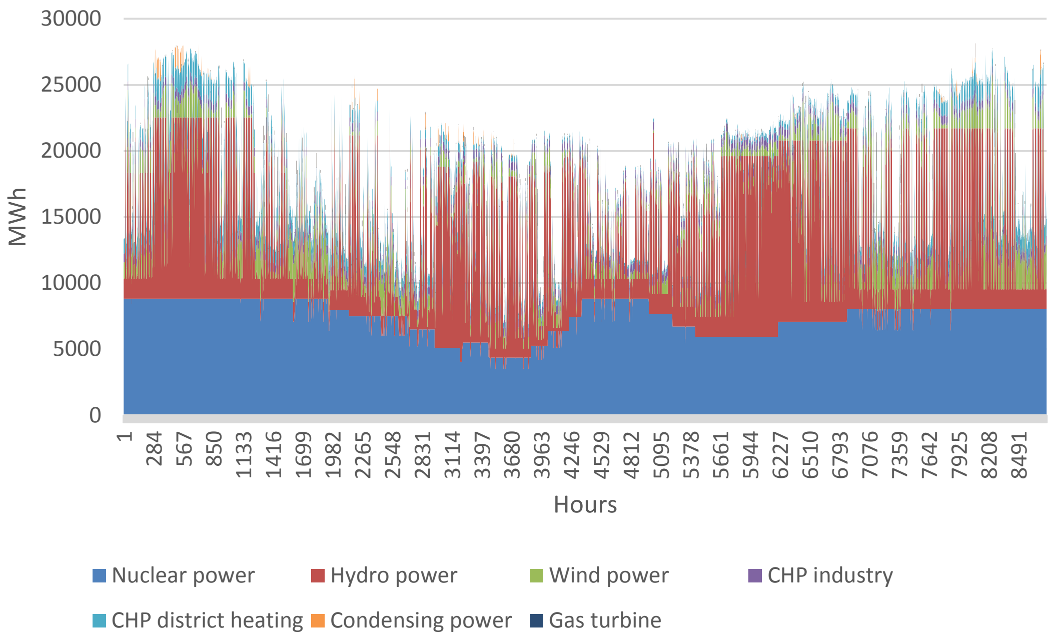

Figure 5.9 The full year dispatch from the dispatch model.

5.1.7 Summary

To conclude, hydropower has same annual production as historical data, with deviations on ramping rates. Though nuclear power produces more electricity in the model, it shows the same generation pattern. Condensing power differs significantly compared to historical data, but still acceptable due to the negligible annual generation. Gas turbine produces negligible amounts of electricity both in the model and historical data. Some differences occur in transmissions, however, they are acceptable because of the scope of the thesis.

Due to the insufficiency and uncertainty of input data as well as assumptions, the model is expected to have deviations from historical data. A sensitivity analysis of the dispatch model is further conducted in Section 5.2.

5.2 Sensitivity analysis of dispatch model

A sensitivity analysis is performed in order to evaluate the reliability in the output data of the finished dispatch model as well as learn how the model functions. Since the objective function of the model involves minimizing the total cost for the system, changing the operating costs of each component in the model is assumed to be an important aspect to consider. Other parameters investigated also include ramp rates, final storage level of hydro reservoirs and net transmission capacity (NTC) reduction.

5.2.1 Running costs

A change in running cost of +/- 5% is investigated and compared against the annual produced electricity. The generation technologies investigated include: Nuclear power, Hydropower, Condensing power and Gas turbine. The other technologies; Wind power, CHP industry and CHP district heating are excluded since generation levels are given in the model.

5.2.1.1 Nuclear power

The results from the sensitivity analysis of running cost of Nuclear power are shown in Figure 5.10 below. The effect on annual generation from the analysis is seems to have a negligible effect.

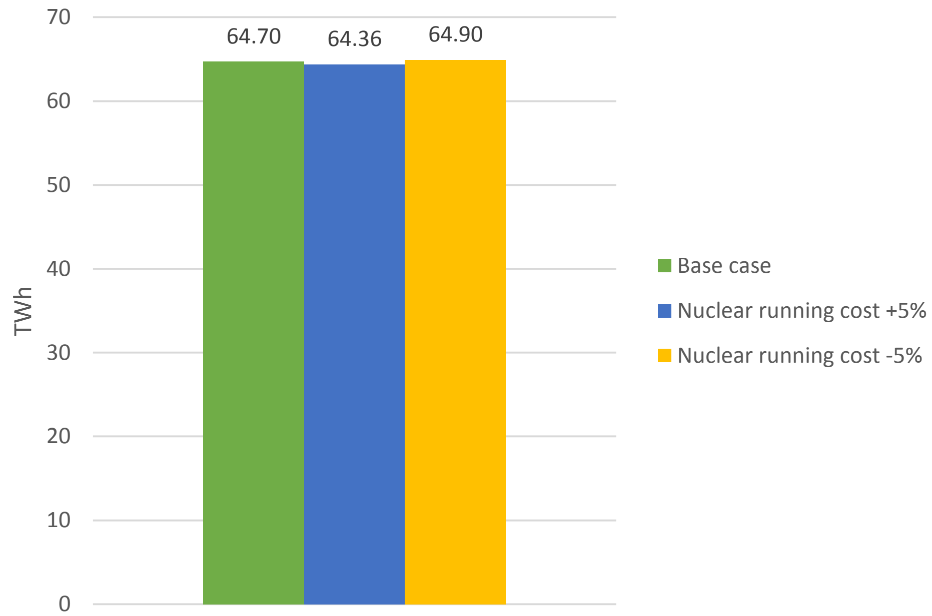

Figure 5.10 Sensitivity analysis of running cost for Nuclear power.

5.2.1.2 Hydropower

The annual electricity generation from hydropower from the sensitivity analysis is the same for each case. This is expected due to the annual amount of water that can be used for electricity generation is fixed in the model. Therefore, hourly reservoir levels are also compared, as shown in Figure 5.11.

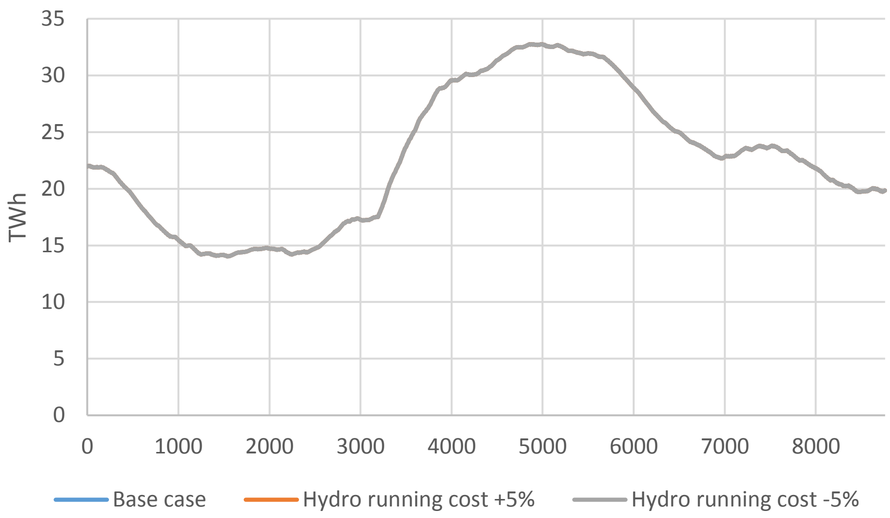

Figure 5.11 Sensitivity analysis of running cost for Hydropower on reservoir levels.

As can be seen in Figure 5.11, the reservoir levels in three cases are exactly the same. Hence, increasing/reducing running cost of hydropower by 5%, does not impact the hydropower production output. The most probable reason for this is that no other generation source is able to compete with this its cost of producing electricity, at least within the investigated range.

5.2.1.3 Condensing power

Acting as peak power, condensing power plants usually operate when there is a high demand for electricity, and as a result a high price for electricity. The results in Figure 5.12 show that the generation from condensing power plants are quite sensitive to changes in running cost. The reason for this is that condensing power competes with imports and exports to a high extent.

However, increasing the running cost of condensing power plants from -5% to 5% only results in 0,09 TWh increase in annual generation, and is therefore considered to have a negligible impact on the system as a whole.

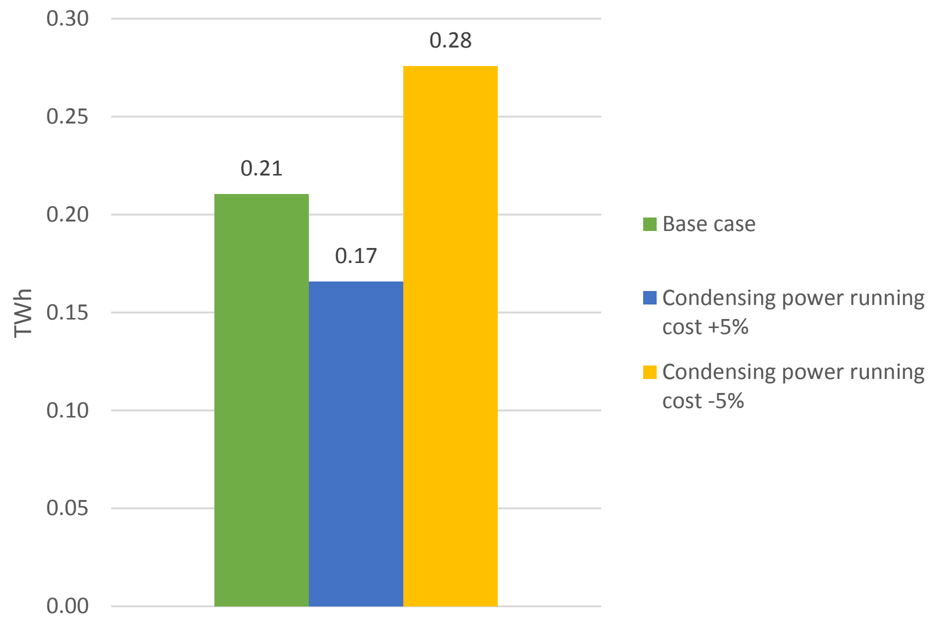

Figure 5.12 Sensitivity analysis of running cost for condensing power plants.

5.2.1.4 Gas turbine

In the case of gas turbines, the results show that there is no electricity production in all three cases.

5.2.2 Maximum ramp rates

A sensitivity analysis of maximum ramp rates is conducted for Hydropower and Nuclear power. Hydropower and Nuclear power are chosen because the method for obtaining maximum ramp rates of hydropower and nuclear power has great uncertainty. The ramp rates obtained might not represent the reality, for example, the maximum ramp down rate in historical data can be an emergency shut down. Moreover, hydropower and nuclear power are very important components since they comprise most of the electricity generation in Sweden.

5.2.2.1 Hydropower

A case that reduces the maximum ramp rates of hydropower by 50% is studied. Figure 5.13 illustrates that with a lower maximum ramp rates, hydropower produces electricity at both maximum capacity and minimum generation level with less hours compared to the base case. The reason for this behavior is that the hydropower has smaller ability to shift power out in this case and therefore has a less steep slope compared to the base case.

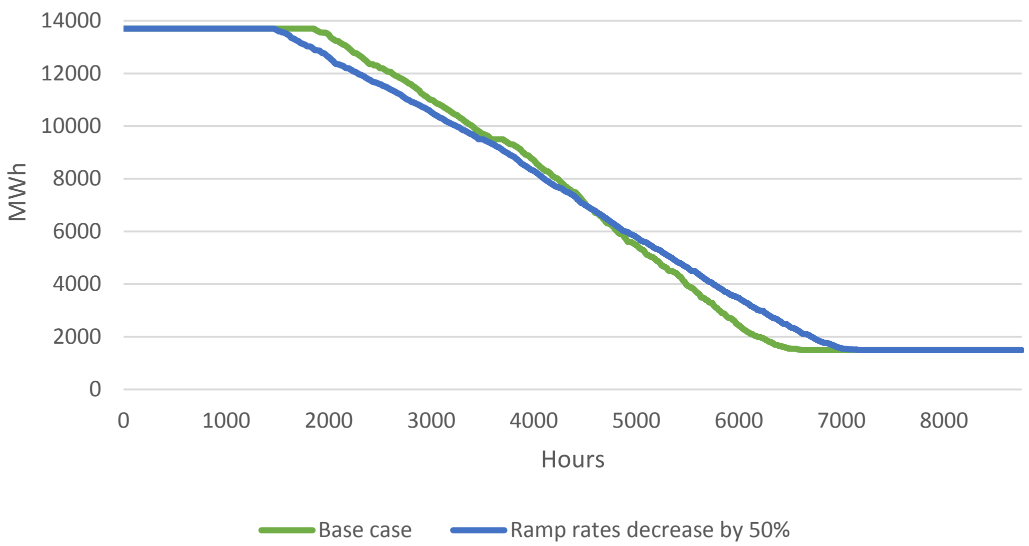

Figure 5.13 Comparison between duration curves of Base case and the case of decreasing hydropower maximum ramp rates by 50%.

As can be seen in Figure 5.14 below, the difference in the hourly hydropower generation between two models fluctuates a lot, up to +/- 5000 MWh/h. During some hours the base model produces more electricity from hydropower, but less during other hours. Therefore, the dispatch model is very sensitive to the ramp rates of hydropower. Since the hydropower is usually used to balance the electricity fluctuations, the ability of shifting power output is essential. The maximum ramp rates of hydropower need to be carefully chosen.

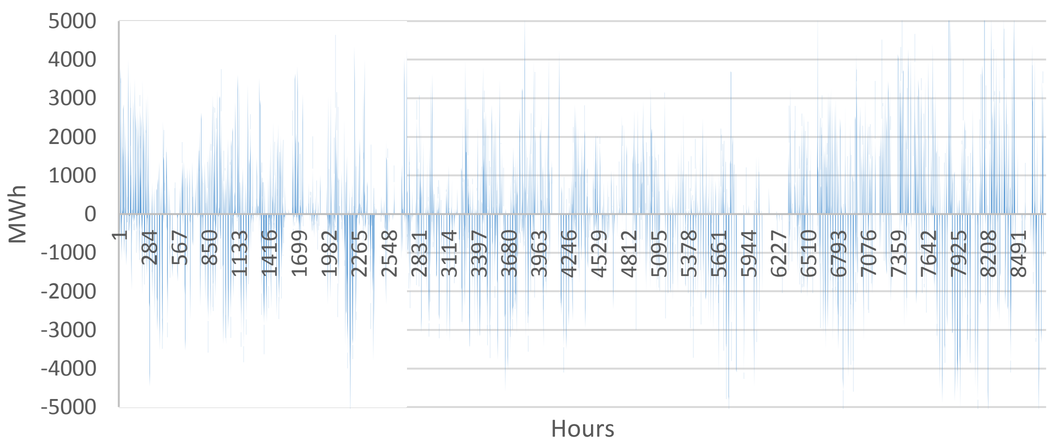

Figure 5.14 Difference in hourly hydropower generation between Base case and the case of decreasing hydropower maximum ramp rates by 50%.

5.2.2.2 Nuclear power

A case with maximum ramp rates at 300 MW of nuclear power is investigated, compared with the base case where the maximum ramp up rate and the maximum ramp down rate are 397 and 829 MW respectively. The comparison of hourly nuclear power generation in Figure 5.15 shows that there is no significant difference in two cases. The only difference can be found is the nuclear power generation during some hours is lower in the dispatch model. Thereby, it is reasonable to say that the maximum ramp rates of nuclear power would not have obvious effects on the model.

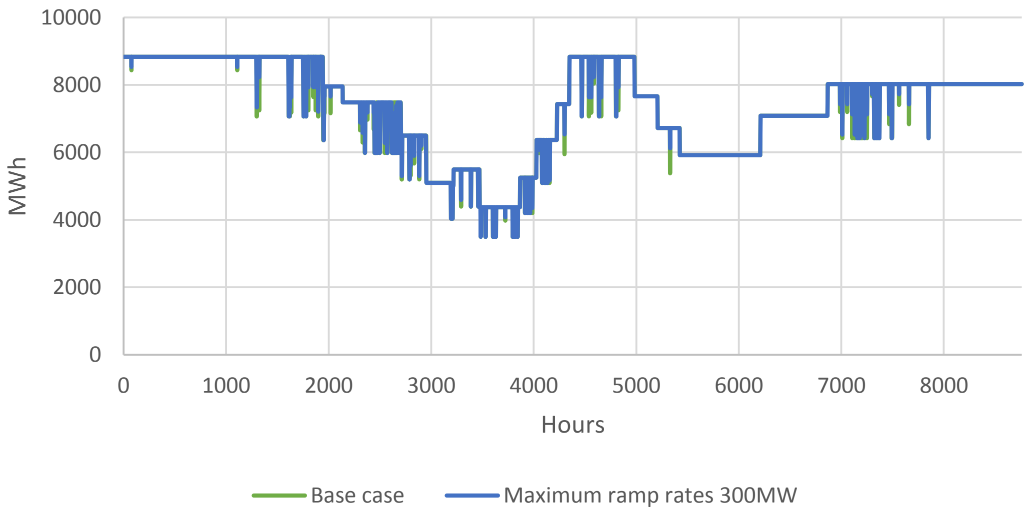

Figure 5.15 Comparison of hourly nuclear power generation between Base case and the case of changing ramp rates to 300 MW.

5.2.3 NTC reduction

The results from the validation part shows that the model overestimates the import and export. This is assumed to be related to the NTC reduction, seen Appendix 3, chosen as input data for the model as it does not consider any failure or maintenance work during the simulated period. Including the failure rates into the model is therefore assumed to alleviate the difference between the historical values and simulated values, however, at the expense of restricting the model further.

The actual transmission capacity of the lines connecting Sweden with the surrounding countries Norway, Denmark, Poland and Finland are illustrated in Figure 5.16, Figure 5.17, Figure 5.18 and Figure 5.19, respectively, obtained from Nord Pool. Germany is excluded since the hourly NTC is not available.

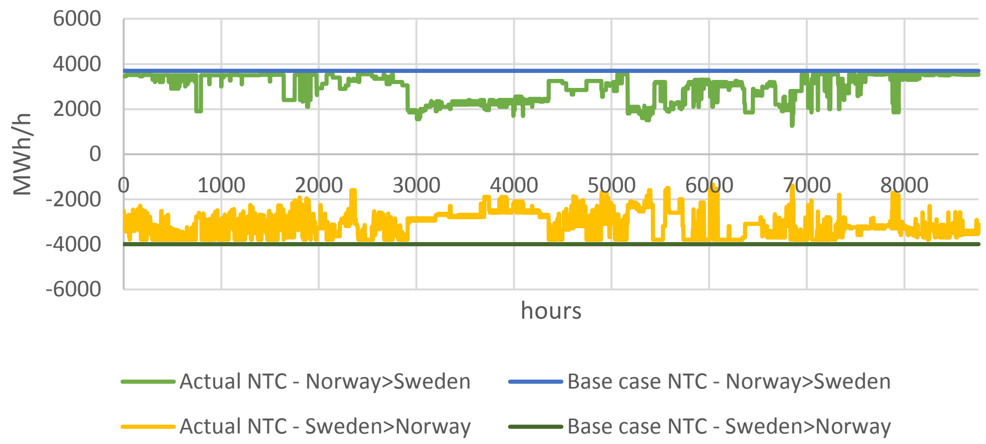

Figure 5.16 Actual and Base case NTC between Norway and Sweden. Negative values represent export.

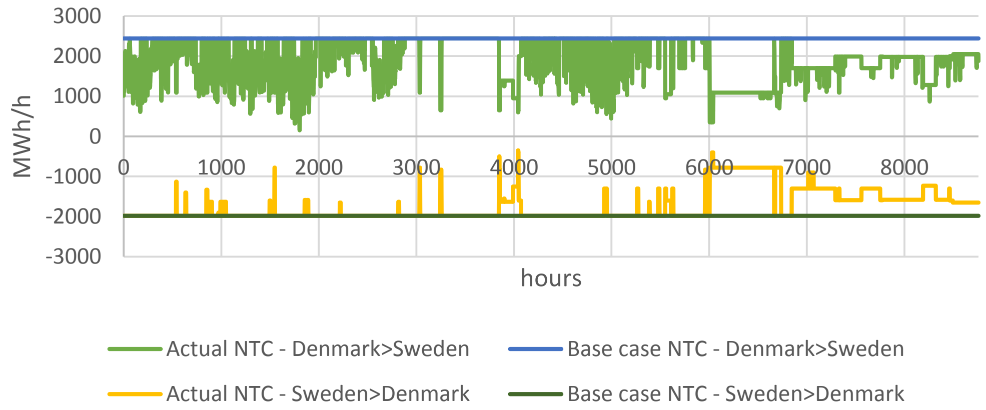

Figure 5.17 Actual and Base case NTC between Denmark and Sweden. Negative values represent export.

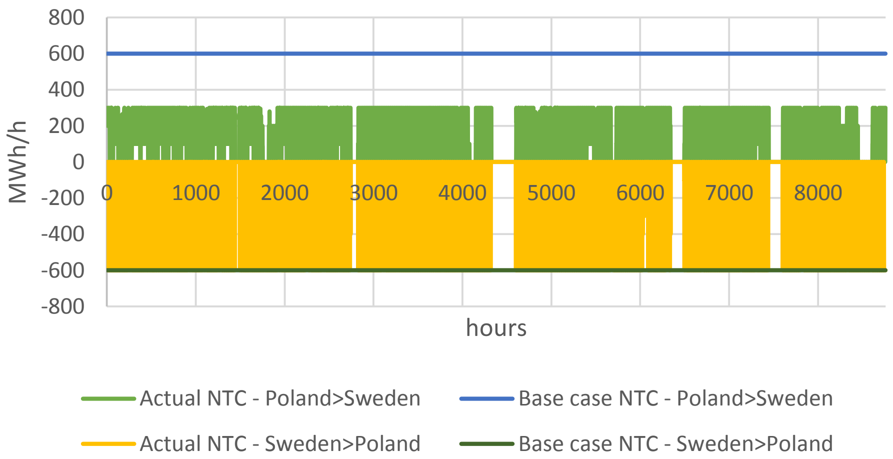

Figure 5.18 Actual and Base case NTC between Poland and Sweden. Negative values represent export.

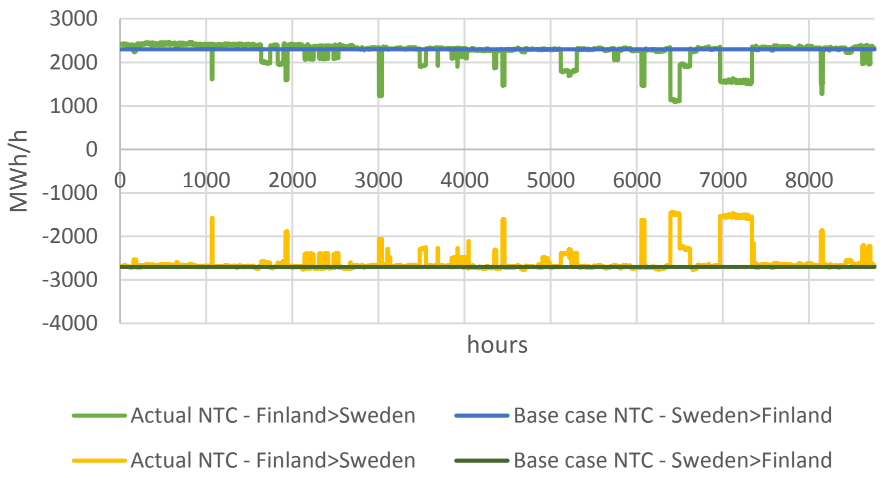

Figure 5.19 Actual and Base case NTC between Finland and Sweden. Negative values represent export.

Figure 5.20 and Figure 5.21 show the differences between the results from using the actual NTC levels and the Base case.

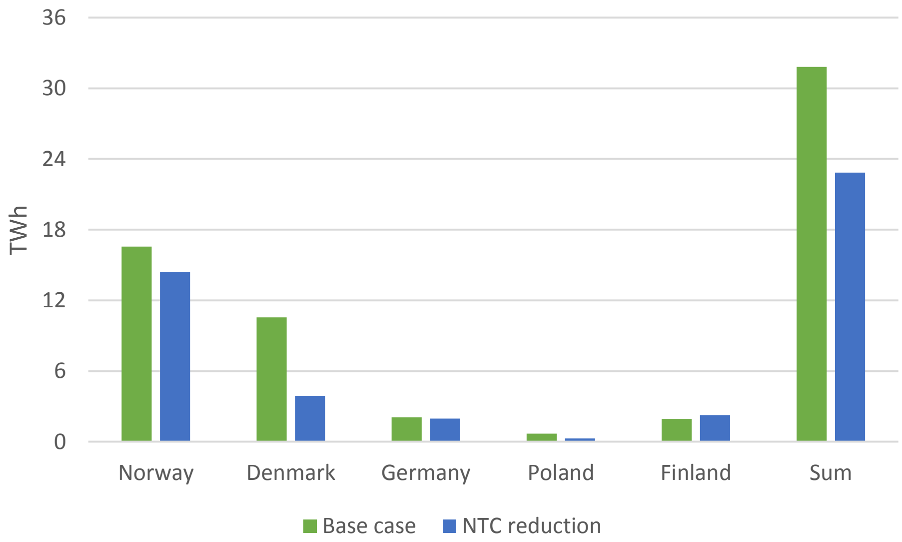

Figure 5.20 Sensitivity analysis of NTC reduction on gross import from the surrounding countries.

Figure 5.20 above shows a significant decrease in electricity import from Denmark, as well as a notable difference in Norway. The reason for this behavior is that there is much reduction in NTC values during lots of hours. Imports from Germany and Poland also see minor reductions. However, Sweden imports slightly more from Finland. This is because some increase in the actual NTC in the beginning of the year, probably resulted from some investment in the transmission line. In total, the aggregate import to Sweden decreases by around 9 TWh.

In the case of export Figure 5.21 shows a change in all nations except Germany. All countries decrease their import which is expected as the transmission capacity is reduced more often. The total decrease of export from Sweden is about 9 TWh, similar to the drop in import.

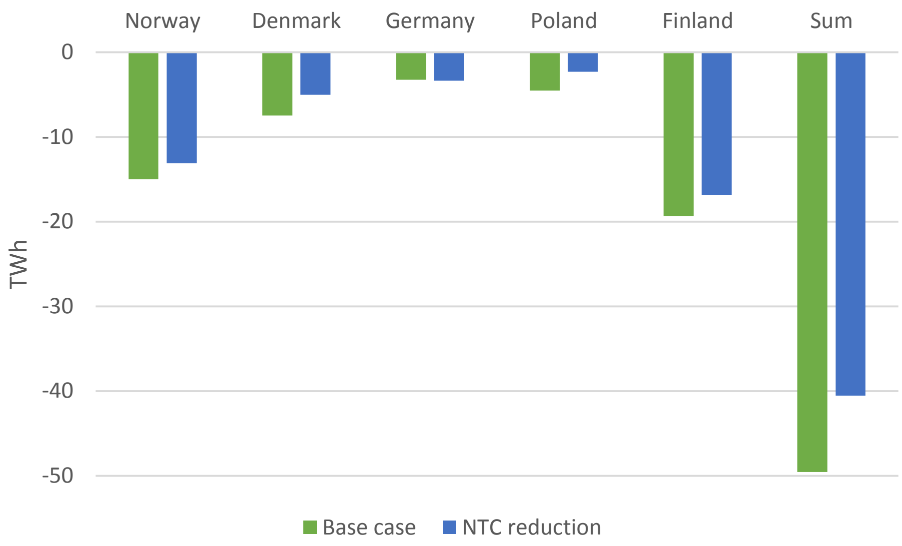

Figure 5.21 Sensitivity analysis of NTC reduction on gross export to the surrounding countries. Negative values represent export.

Therefore, the reduction in NTC values have an abundant impact on the import and export.

5.2.4 Final reservoir level

The annual amount of generated electricity coming from hydropower is dependent on the existing reservoir level, the water flowing into the reservoir and how much of that water that is saved for future use. Since the inflow to the reservoirs is given exogenously to the model and a final reservoir level is predetermined, the annual production coming from hydropower is already decided, though it can be dispatched freely during the year.

Furthermore, it is assumed that not setting a final storage level for the reservoirs would result in a significantly higher annual hydropower production compared to historical values. This is because the operating cost of hydropower is low compared to the other generators available for the model to dispatch. Consequently, this assumption is investigated to determine if the model behaves as predicted.

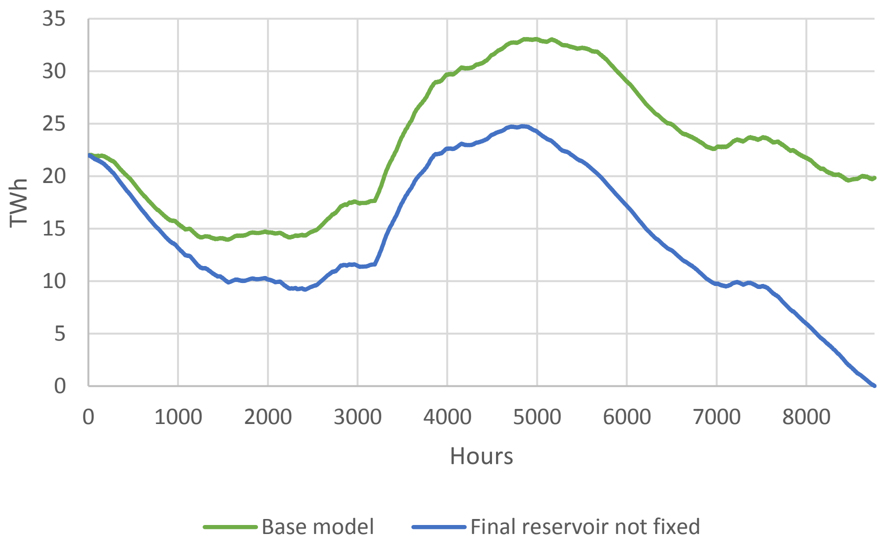

Figure 5.22 Comparison of two sets showing the available water in the reservoir during all hours of the year, measured in energy.

As seen in Figure 5.22 above the model behaves as expected, that is, emptying the reservoir completely by the end of the year. The consequence of this is that the future value of stored water is not accounted for when setting the reservoir level free, neither does the case of a fixed reservoir level. This is due to the model has perfect information regarding future electricity prices and demand, which enables the model to dispatch hydropower in the most optimal manner, subjected to the implemented constraints.

6 Case study and Results

In this chapter, a case study of an investment in Gothenburg is proposed. Three methods are then investigated to assess this investment concerning CO_2 emissions. After that increasing of the investment is studied. The main findings from the investigation are presented.

6.1 Case study: Investment in Gothenburg

An investment in the heating sector of Gothenburg is proposed. The investment is thought to reduce the heat demand by 20% which in term affects the production pattern coming for CHP district heating plants. The change in produced electricity from CHP district heating is given exogenously by SP as a time series of 8760 time steps, shown in Figure 6.1. It is observed that electricity production fluctuates during the winter season whereas remains constant during summer season. The total electricity reduction from the investment corresponds to 0.155 TWh.

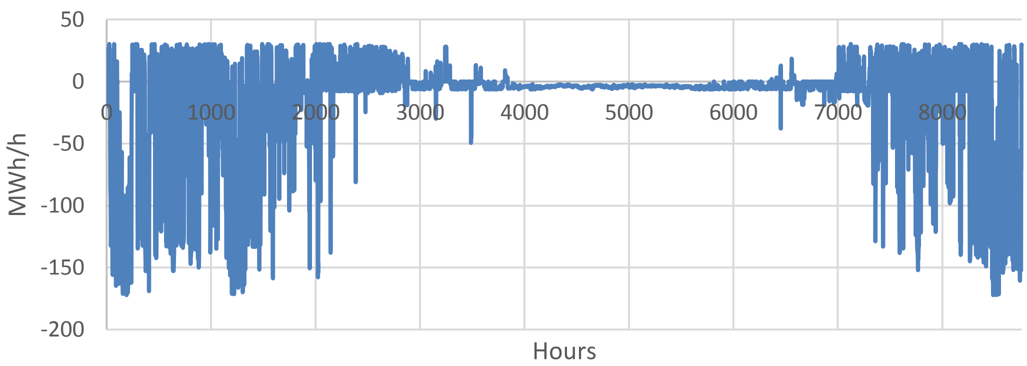

Figure 6.1 Change in produced electricity from CHP district heating due to the investment.

6.2 Different methods

This section presents the effects of the investment in Gothenburg using three methods, which are the dispatch model, average electricity production method and marginal electricity production method.

6.2.1 Dispatch model

The Dispatch model assesses the investment in terms of CO_2 emissions with two aspects, namely electricity generation from each technology and net imports.

The change in electricity generation and CO_2 emissions from each technology due to the investment are seen in Table 6.1 below.

Table 6.1 Change in production levels and CO_2 emissions for each generation technology.

Generation technology	Generation change, GWh	CO_2 change, kton CO_2
Hydro power	0	0.0
Wind power	0	0.0
Nuclear power	0	0.0
CHP industry	0	0.0
CHP district heating	-155	-31.5
Condensing power	1	1.0
Gas turbine	0	0.0
Sum	-154	-30.5

It can be observed that there are no changes in the electricity generation and CO_2 emissions except for the decrease in CHP district heating and negligible increase in Condensing power. This means that except for the direct decrease in CHP district heating, the investment would have negligible effect on the generation within Sweden.

Figure 6.2 below illustrates the changes in net imports from the surrounding countries. It shows that Sweden imports more from Norway and Denmark whereas more is exported to Finland. The increase in imports from Norway and Denmark is due to the cheaper electricity available when the investment reduces electricity production from CHP district heating. While, the most probable reason for increase in export to Finland is that though the investment reduces the total produced electricity from CHP district heating, it also increases the electricity production during some hours, which can be seen in Figure 6.1. The increased electricity can be exported to the more expensive

Finland. Besides, the net imports from Germany and Poland are relatively small. In total, net imports of Sweden increase.

Instead of shifting the generation mix within Sweden, the reduced electricity due to the investment is balanced with net imports from the surrounding countries.

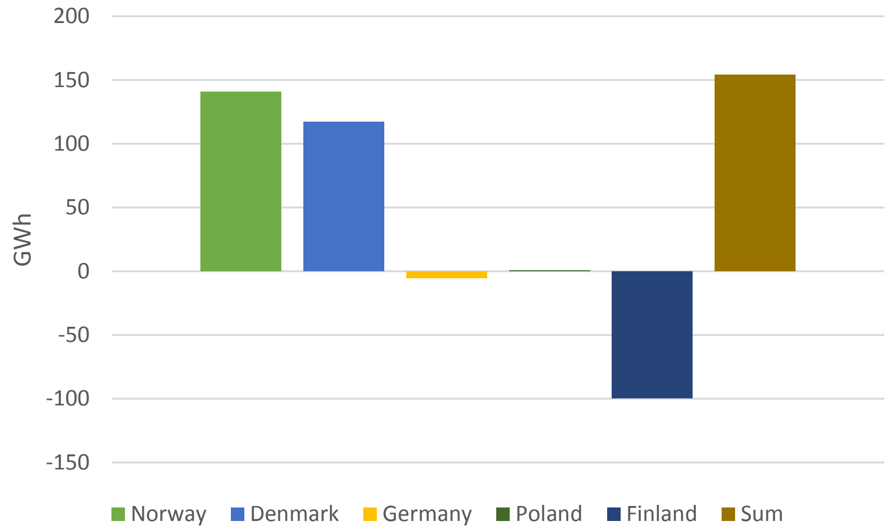

Figure 6.2 Change in net import of electricity from the surrounding countries, positive values represent import and negative values represent export.

The CO_2 emissions associated with net imports can be seen in Figure 6.3.

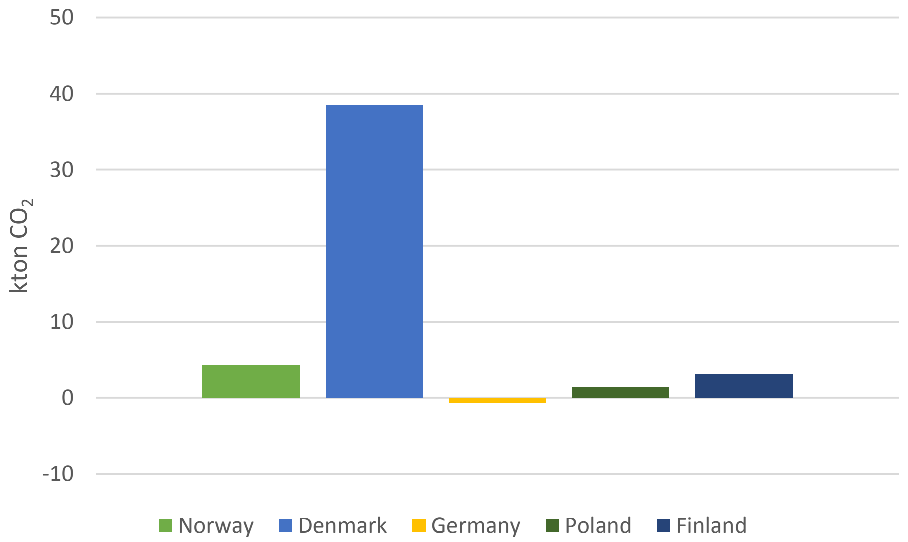

Figure 6.3 Change in net import of CO_2 from the surrounding countries, positive values represent import and negative values represent export.

As can be seen, Denmark is responsible for most of the CO_2 emissions imported to Sweden due to the investment, while the other countries are significantly smaller. By comparing Figure 6.2 and Figure 6.3, the CO_2 emission seems no need to be greater with a larger net import. It is also related to the CO_2 emission factors in the respective country.

The decreased CO_2 emissions from the investment, the increased CO_2 from the net import and net change of CO_2 emissions in Sweden are shown in Figure 6.4. It sees an increase of 16.1 kton CO_2.

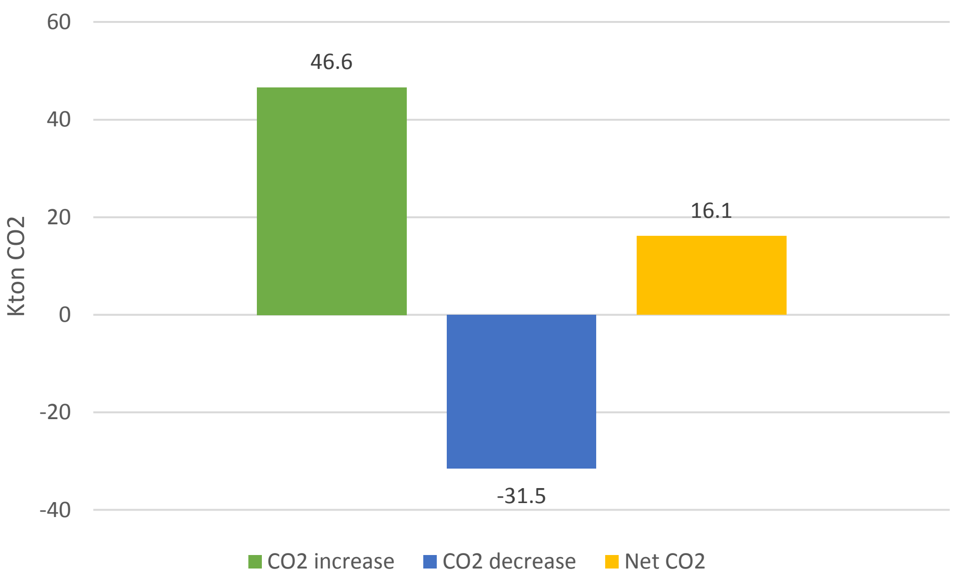

Figure 6.4 CO_2 increase, decrease and net change resulted from the investment using dispatch model.

6.2.2 Average electricity production method

With average electricity production method, the reduced electricity production from CHP district heating is replaced by the Swedish average electricity generation, i.e. a combination of different generation sources as well as import and export, shown in Figure 6.5.

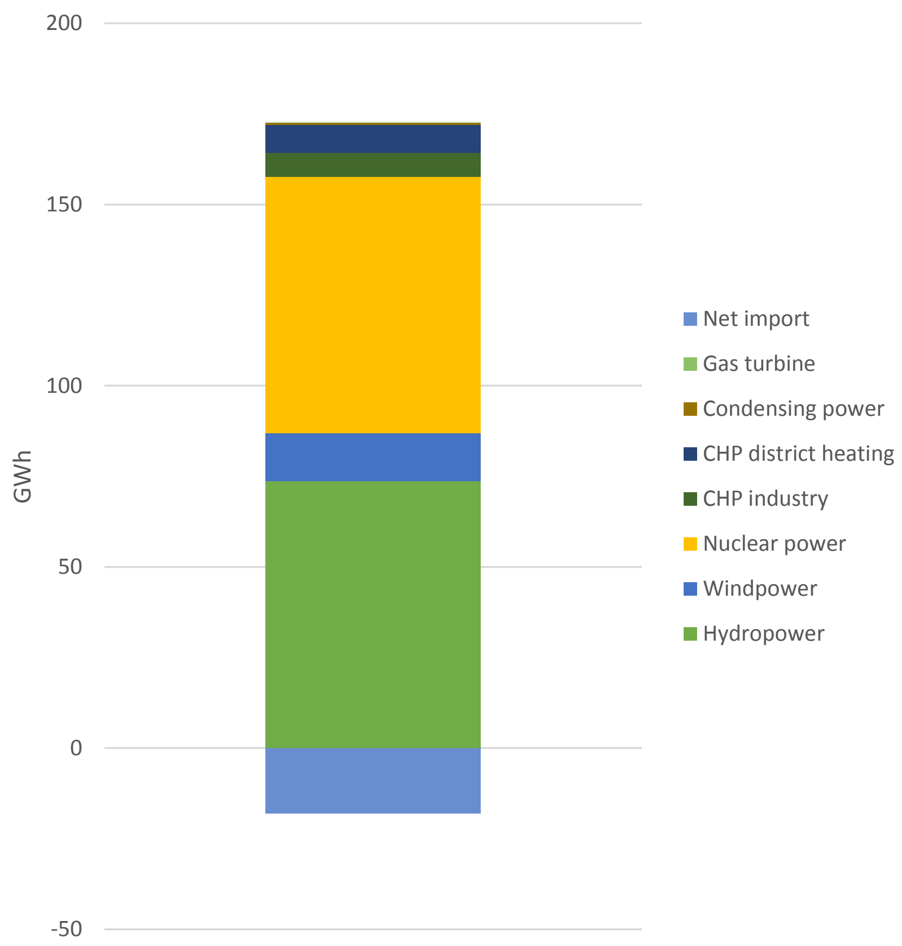

Figure 6.5 Change from different electricity generation sources, negative values represent export.

Figure 6.5 shows that the reduced electricity is mostly replaced by Hydropower, Nuclear power and Wind power, accounting for 39%, 37% and 7% respectively. This also results in 9% of the amount of reduced electricity exported to other countries.

The CO_2 emission shares from different sources are illustrated in Figure 6.6.

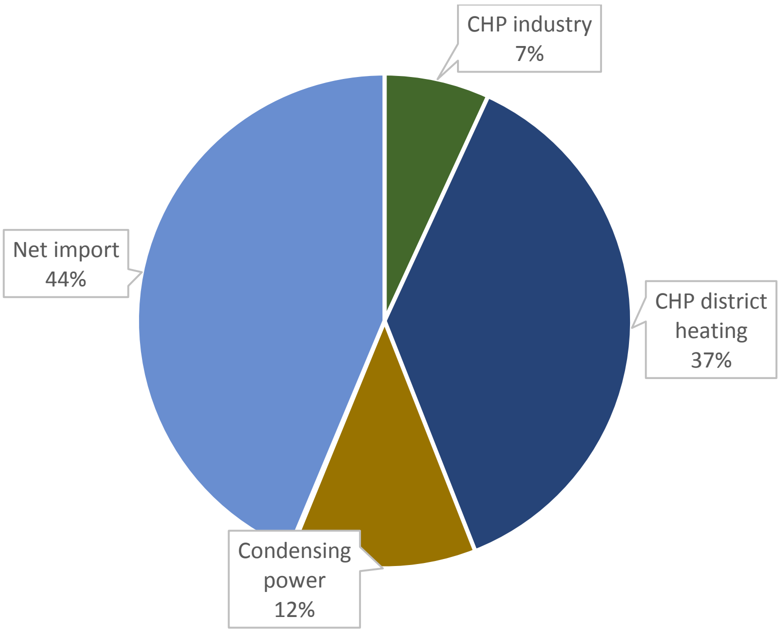

Figure 6.6 CO_2 emission share form different electricity generation sources.

Figure 6.7 shows that most of the CO_2 emissions come from net import, CHP district heating and Condensing power. The changes in CO_2 emissions due to the investment are presented in Figure 6.7 below. The increased CO_2 from the generation mix is 4.1 kton and the reduced CO_2 from CHP district heating is 31.5 kton, resulting in the net reduction of 27.3 kton CO_2.

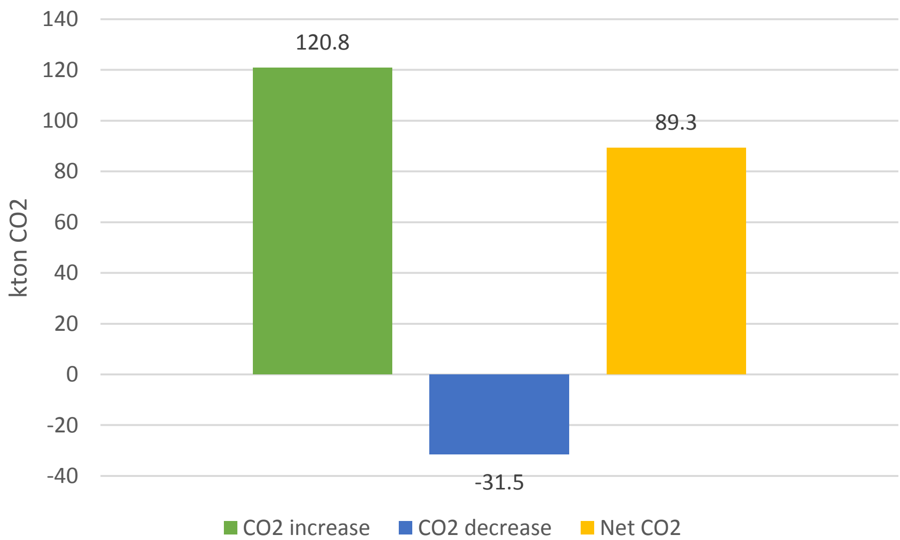

Figure 6.7 CO_2 increase, decrease and net change resulted from the investment using average electricity production method

6.2.3 Marginal electricity production method

Reduced electricity generation coming from CHP district heating is replaced by the marginal electricity production unit, thought to consist of coal condensing power plants.

The reduced CO_2 from CHP district heating, the increased CO_2 from coal condensing power plants and the net CO_2 change are derived in Figure 6.8 below.

Since the emission factor of coal condensing power plants is much larger than the one of CHP district heating, which is stated in Table 4.12, the reduced electricity due to the investment is replaced by dirtier electricity. Thus, it sees a large net increase of CO_2 emissions.

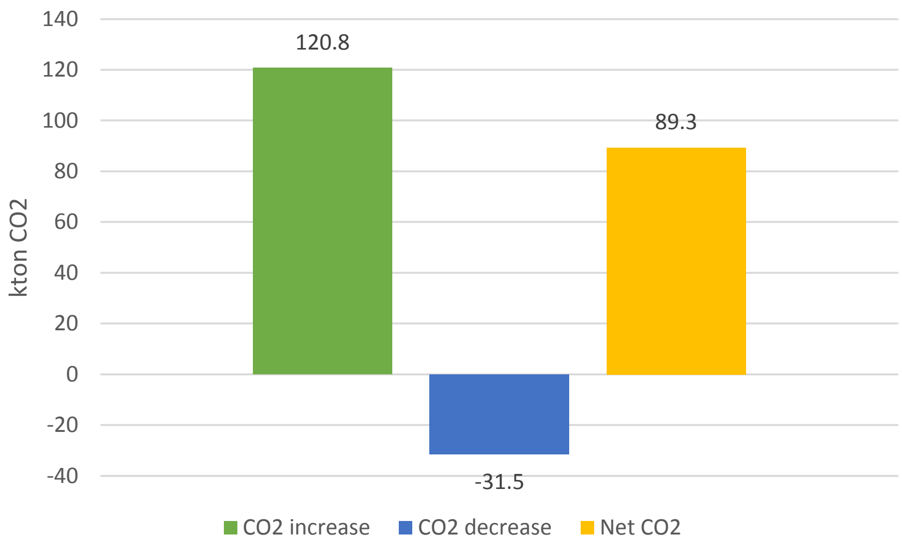

Figure 6.8 CO_2 increase, decrease and net change resulted from the investment using marginal electricity production method.

6.2.4 Comparison of the three methods

The results from the different methods used in assessing the investment described in the previous sections are compared, as illustrated in Figure 6.9 below.

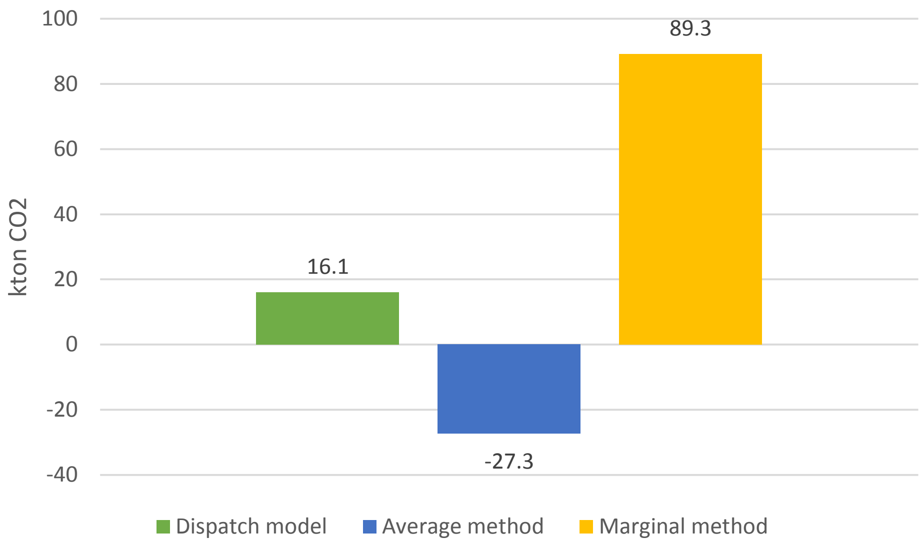

Figure 6.9 Comparison of CO_2 changes using three methods.

As can be seen that both dispatch model and marginal electricity production method show an increase in CO_2 emissions, whereas average electricity production method show a decrease. As discussed previously, the reduced electricity production due to the investment is balance by net import in dispatch model, average electricity production in average electricity production method and coal condensing power in marginal electricity production method. The reason for the difference in net CO_2 change is that the emission factors of net import, average electricity production and coal condensing power differ. The emission factors of average electricity production in Sweden, net import and coal condensing power are thought to increase in order.

6.3 Increasing of the investment

In this section, increasing of the investment by decreasing production level of CHP district heating is studied. The decreased production levels are obtained using a scale factor based on the annual production level.

Figure 6.10 and Figure 6.11 illustrate the change in electricity production from different technologies and net imports from different countries, using the dispatch model.

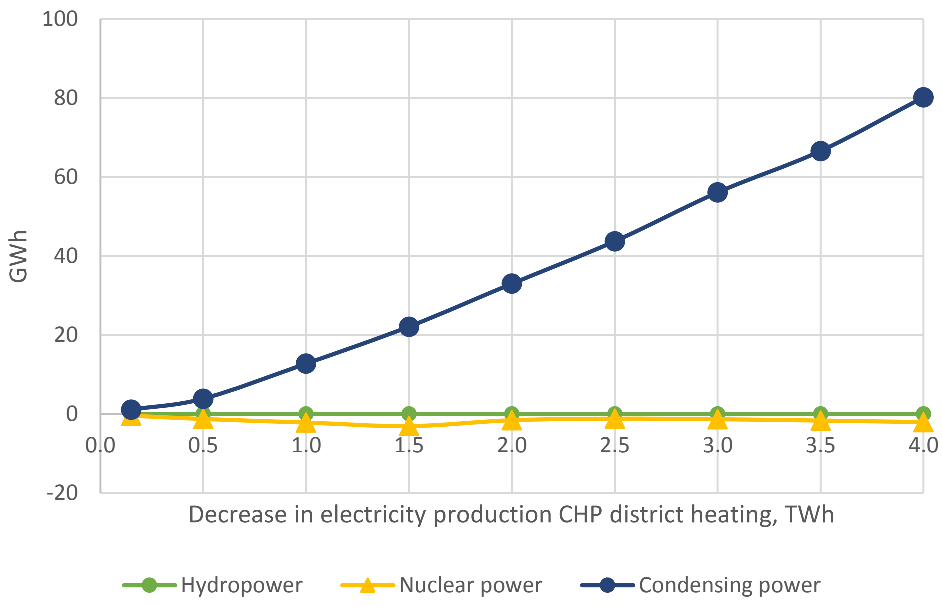

Figure 6.10 Change in electricity production from different technologies using dispatch model when subjected to an increase in the investment. Wind power, CHP industry, CHP district heating and Gas turbine are excluded. X-axis starts from 0.155 TWh.

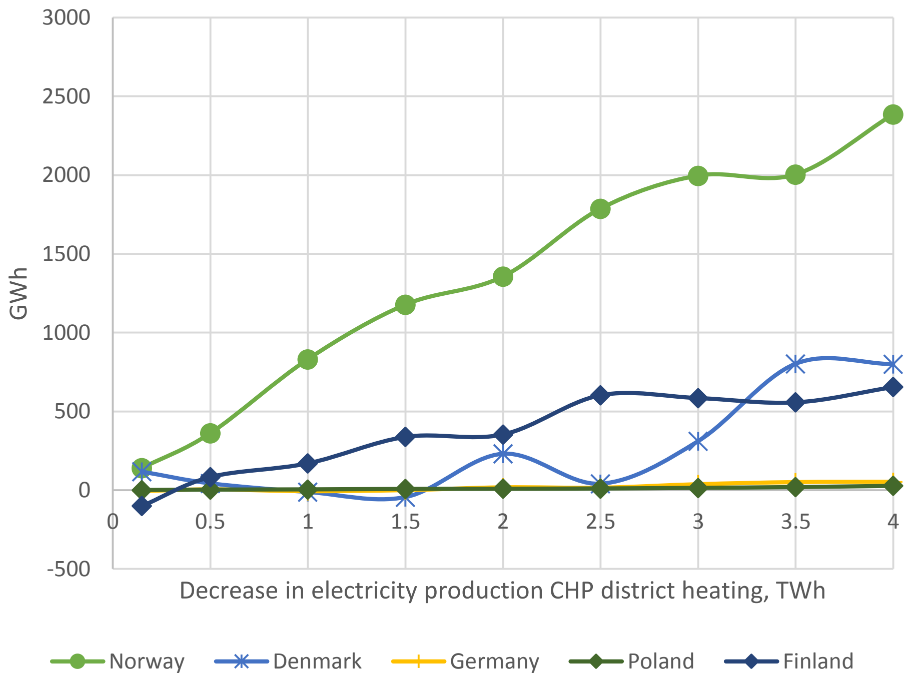

Figure 6.11 Change in net import of electricity from different countries using dispatch model when subjected to an increase in the investment. Norway and Denmark represent increased import. Germany, Poland and Finland represent decreased export. X-axis starts from 0.155 TWh.

It can be observed from Figure 6.10 that for electricity generation, only condensing power sees a constant increase when the level of the investment increases. However, the change in condensing power is relatively small compared to the change in net imports.

As seen in Figure 6.11, the change in net imports comes from Norway, Denmark and Finland. The import from Norway increases continuously since there is cheap electricity in Norway, while the net imports from Denmark and Finland fluctuates. The fluctuations might be related to the investment, as it increases the produced electricity from CHP district heating during some hours but also decreases during other hours.

The results of comparing the three methods when subjected to an increase of the investment are illustrated in Figure 6.12.

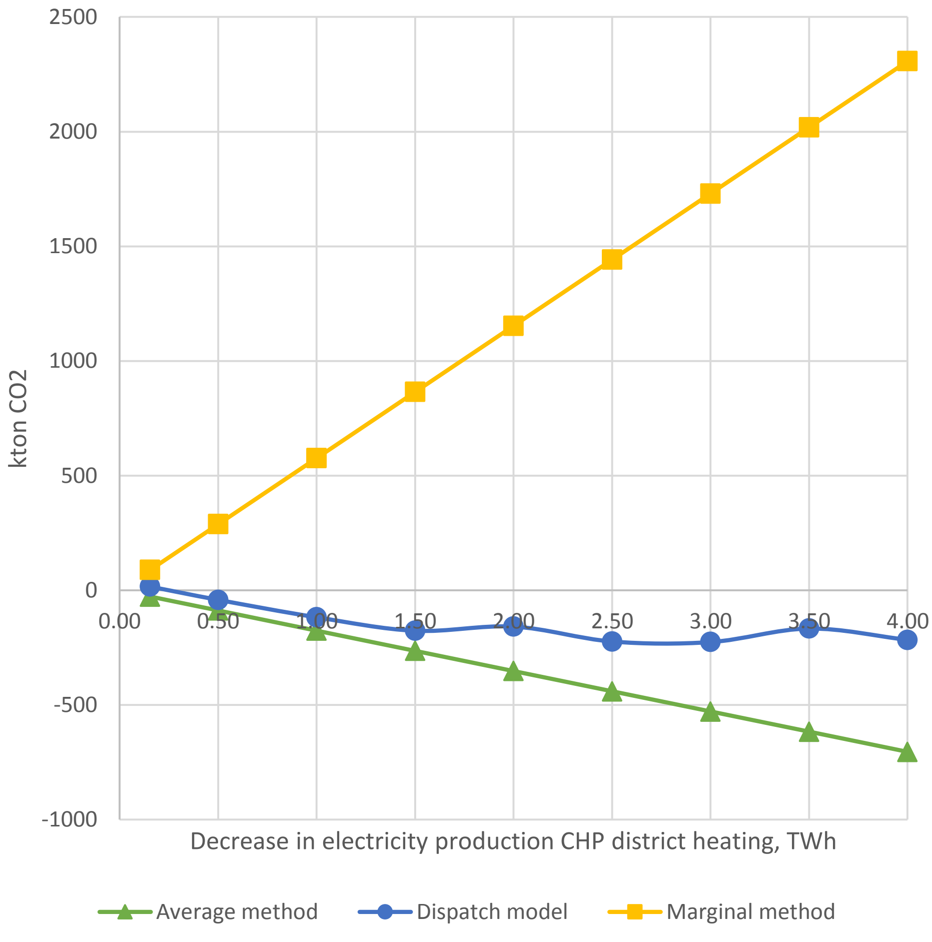

Figure 6.12 Comparison of different methods with increase in the investment. X-axis starts from 0,155 TWh.

It can be seen in Figure 6.12. that both the CO_2 change using average electricity production method and marginal electricity production method are linear. With the increase of the level of the investment, marginal electricity production method sees a proportional increase in the CO_2 change, while it is the opposite for average electricity production method. This can be explained by the fixed CO_2 emission factors of the alternative electricity used to replace the reduced electricity from CHP district heating, which also means that average electricity production method and marginal electricity production method are static, where the marginal effects are not dependent on the level of the investment. The results from dispatch model, however, show a different trend in from 1.50 to 4.00 TWh, the CO_2 change shows certain fluctuations, due to the fluctuations in net imports from Denmark and Finland.

7 Discussion

This chapter discusses the validity of the designed model, including the results from the sensitivity analysis as well as input data. The benefits and drawbacks of the three methods are also discussed.

7.1 Validity of the dispatch model

The validity of a model is related to how well the model captures the properties of the investigated system as well as the data used as input. Consequently, before making a model it is necessary to have good knowledge about the investigated system and understand how parameters and factors relate and interplay with one another, in addition to acquiring data. Hence, applying the aforementioned things to the model created for this thesis, it is reasonable to say that one must be cautious when applying the result from the model, as it lacks some dynamic behavior which is discussed further on in this section.

The model encompasses seven generation technologies, whereas only four are set as free to move, meaning that these technologies are free to change their generation output. Though, it is not believed to affect the validity of the model since all three technologies, wind power, CHP district heating. and CHP industry, have very little correlation to any changes occurring in the power market. On the contrary, the effects of how the other technologies are designed matter more.

For instance, in reality hydropower plant owners rely on estimations of the future electricity price in order to value the water in the reservoirs, to decide whether to produce now or later. In the model, the price of electricity is known which results in hydropower being dispatched in the most optimal manner, subjected to the constraints. This can be seen in Figure 5.5 by the difference in reservoir levels. The feature of incorporating the future value of stored water, is further explained in Section 5.2.4, though how that effects the model is uncertain.

Another important feature to consider is how to approximate power exchange between the surrounding power systems in the context of modelling the local energy system. The constructed dispatch model encompasses this by considering the import and export prices as known, and given exogenously as a time series to the model. Having predetermined prices for import and export are believed to impact the result to some extent, however, the implications of it is unclear. But, altering the import and export balance, as seen in Section 5.2.3 shows that it is likely that it would have a significant influence on the result.

In reflection, capturing the behavior of the reality in models often result in balancing between making it too free to move or too restricted, which is the case for hydropower and the import/export price. This issue is recognized, however, this is also an inherent problem within modeling, as it often resolves making assumptions based of an ideal market and perfect foresight. Thus, there will always be a discrepancy of how the model behaves in reality.

As such, all models are wrong. But, they can still be useful if the user has the knowledge of how the approximation of reality affects the end result.

7.2 Input data

Collecting the necessary data used as input to the model involved making several assumptions. The most significant are the ones made for the consumption and production levels, since they are used as the backbone in the validation process of the designed model. As neither of the two sources used, Nord Pool and SvK, contain both consumption and production levels in the same format, one data set has to be converted to the other. In retrospect, it would be better to only use one source. The solution of scaling the consumption and thereby obtaining the correct import balance is believed to be a better solution than other option would result in. The reason for being a good solution resides in the reason discussed in validity section, or in Section 5.2.3.

Concerning the emission factors in general, the major predicament is obtaining the reliable data for thermal generation plants in Sweden. This is due to the dilemma of how to allocate the fuel used for electricity production and heat, whereas the values used for the other countries are more related to finding reliable data sources, as seen in Section 4.6. Regardless of the methods used, the values obtained are highly related to the final results since the change in CO_2 emissions, deriving from the investment, is mostly associated with emissions originating outside of Sweden as seen in Figure 6.2 and Figure 6.3. The difficulty in obtaining reliable data and values is recognized as the main source weakening the results.

7.3 Benefits and drawbacks of the three methods

To start with there is no consensus in which method to use when assessing the effects of an investment, irrespective of the quantifying dimension. The reason for this, resides in how the different methods capture different aspects of an investment.

Literature suggests that the average electricity production method should be used for allocating the responsibilities, and works well if all emissions within the investigated system are accounted for as explained in Section 2.3.2. However, as the power systems are becoming more and more integrated, the emissions within the system will become distorted by the interchange in CO_2 coming from the surrounding regions, which is thought to be the reason for the significantly different results found in Figure 6.9, compared to the other methods. It could therefore be debated whether this method is well suited to capture the real effects of an investment. Furthermore, as the dynamic effects are badly captured in this method, imposing a greater change would only result in a linear increase, as seen in Figure 6.12.

Moreover, using the marginal method in assessing the marginal effects an investment made today might have in the future, involves estimating the infrastructure of the future power system. In order to do so, market aspects such as; incentives for building new plants, changes in subsidies, cap and trade systems, future electricity demand, transmission capabilities, etc. has to be considered. Thus, determining the marginal unit is affected by several factors which effectively makes marginal electricity production method could give a hint to the possible emissions that could be offset in the future, however, it might then also act as a very coarse estimate for a not too distant future. This could be one reason for the difference in between the marginal unit and the created dispatch model, as seen in Figure 6.9. It could therefore be argued that the developed dispatch model could give more detailed information of what the actual marginal unit was for a given year.

8 Conclusion and Future work

This chapter presents the conclusion and recommendations for future work.

8.1 Conclusion

The thesis sets out to assess the change in CO_2 emissions when making an investment in the local energy system. The literature on this subject shows no unison methods for this kind of assessment. A dispatch model of the Swedish power system is thus constructed as a part of the method for the assessment and compared with two other commonly used methods average electricity production and marginal electricity production.

The three methods are applied in a case study of Gothenburg, where an investment is made resulting in a reduction in produced electricity from CHP district heating. The main findings from the results are summarized to answer the proposed questions.

1. How are national CO_2 emissions associated with electricity generation, import and export affected when making an investment in the local energy system?

   The results from the dispatch model show that the investment does not necessarily influence annual electricity generation in Sweden, instead the electricity change from the investment is compensated with import and export. The increase in import for Sweden mainly comes from Norway as well as Denmark, whereas the increase in export mostly goes to Finland. Despite the lower import from Denmark, it accounts for the most CO_2 emissions imported to Sweden due to its high CO_2 emission factor. The aggregate CO_2 in the whole system decreases by around 16 kton with the proposed investment.

2. What is the effect of using the methods a dispatch model, average electricity production and marginal electricity production on the results in 1?

   The three methods give different results of CO_2 emission changes. More specifically, the dispatch model, average electricity production and marginal electricity production show approximately +16, -27 and +89 kton CO_2 change, respectively, in the Swedish power system as a whole. In the average electricity production method, the reduced electricity from CHP district heating is replaced by the Swedish average generation, which is cleaner. In contrast, coal condensing power plants used in the marginal electricity production method are much dirtier, hence, the increase in CO_2 emissions.

3. How does increasing the investment influence the results in 1 & 2?

   With an increase in the investment, both the average electricity production method and the marginal electricity production method show a linear change in CO_2 emissions, more specifically the average electricity production method shows a linear decrease while the marginal electricity production method shows a linear increase. However, the results based on the dispatch model have a different behavior. The change in CO_2 emissions first decreases linearly when the investment increases from 0.155 to 1.5 TWh, then it starts to fluctuate. This is mainly due to the fact that the investment causes a change in import and export with Norway, Denmark and Finland. Furthermore, electricity coming from condensing power increases continuously. Overall, the dispatch model reflects the interplay between the investment and the other component in the power system.

The method for estimating CO_2 emissions of an investment should be carefully chosen in order to better understand the impacts of the investment having on the whole system. Bear in mind that the investment would not affect the power system using average electricity production or marginal electricity production, whilst the dispatch model incorporates it in the system and gives a more comprehensive overview of how the power system reacts to the investment. However, as debated in the discussion, using a dispatch model requires lots of assumptions which could have an adverse effect on the results.

8.2 Future work

The following are some suggestions for future work:

- Modelling hydropower more detailed, such as cascading of hydropower plants and adding future value for water, is suggested for future work, since hydropower has the ability to influence the system to a great extent by acting as base load as well as balancing fluctuations.
- Step functions for import cost and export revenue can be introduced, in order to have better approximations for import and export. In the developed model, the import cost and export revenue are set the same time series, both being static. However, increasing import from another bidding area would cause an increase of the electricity price in that area, and thereby increase the import cost. As for export, when increasing export, the value for export would decrease, since the consumption in the surrounding areas is limited. Therefore, step functions could capture more dynamic features of import and export in reality.

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Appendix 1 – Installed capacity

Table A.1 Installed capacity in each bidding area on Jan 1st, 2014, MW [22].

Generation technology	SE1	SE2	SE3	SE4	Total
Hydropower	5177	8033	2593	347	16150
Nuclear power	0	0	9531	0	9531
Wind power	387	1047	1620	1416	4470
CHP district heating	160	270	2227	974	3631
CHP industry	122	316	602	335	1375
Gas turbine	0	0	992	577	1569
Condensing power	0	0	493	1005	1498
Solar power	n.i.	n.i.	n.i.	n.i.	43
Other	1	1	1	2	6
Total	5847	9667	18060	4656	38273

n.i. = no information

Appendix 2 – Hydro inflow calculation

Data of hourly hydro inflow in each bidding area is not available. However, weekly hydro reservoir levels in each bidding area and weekly hydro inflow in Sweden can be found in Nord Pool. Moreover, actual weekly electricity generation from hydropower in each bidding area can be obtained from SvK.

Weekly hydro inflow in each bidding area can be calculated according to the hydro balance of reservoir level, inflow and actual electricity generation from hydropower, as Equation A.1 shows.

$$Inflow_t + Storage_t - Storage_{t+1} = Gen_{Hyd,t}, \qquad t \in [1,52] \qquad \text{(A.1)}$$

where water spillage and water losses are neglected.

Calculated weekly hydro inflow of Sweden is then compared with actual values, shown in Figure A.1.

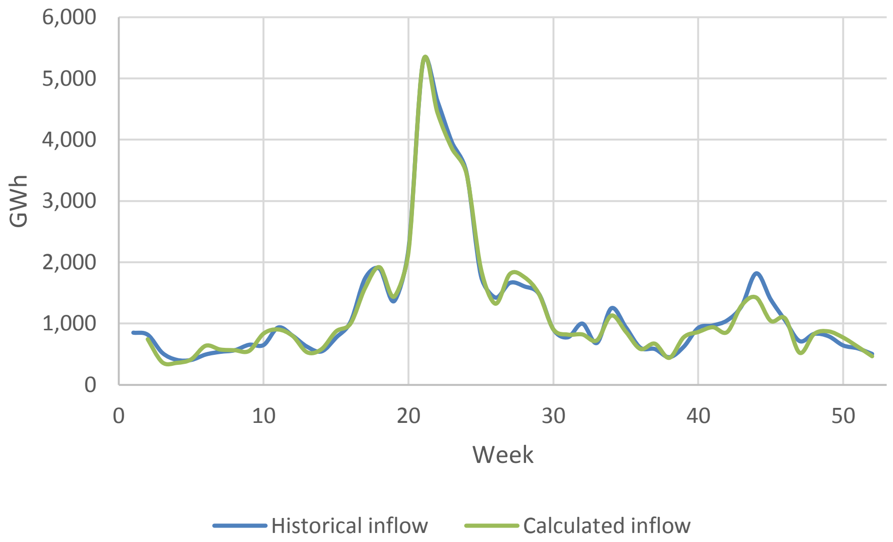

Figure A.1 Comparison between calculated and actual hydro inflow in Sweden.

The weekly hydro inflow is assumed to be distributed equally among all hours in a week, i.e. hourly hydro inflows during a week are the same for each hour.

Appendix 3 – NTC values of connections between bidding areas

Table A.2 NTC values of connections between bidding areas [4].

Connections	Import capacity	Export capacity
SE4-PL	600	600
SE4-DE	615	615
SE3-NO1	2145	2095
SE3-DK1	740	680
SE4-DK2	1700	1300
SE1-FI	1100	1500
SE3-FI	1200	1200
SE1-NO4	700	600
SE2-NO3	600	1000
SE2-NO4	250	300
SE1-SE2	3300	3300
SE2-SE3	7300	7300
SE3-SE4	2000	5300

Appendix 4 – CO_2 emission factor in Poland

Table A.3 Calculation of CO_2 emission factor in Poland.

Electricity generation by technology	
Technology	**Produced electricity, TWh**
Run-of-river	2.2
Pump hydro	0.6
Public thermal plants	128.3
Autoproducing plants	7.6
Biomass and waste plants	0.9
Wind	7.6
Solar PV	0.0
Total produced electricity	**147.1**
Energy input for electricity generation by source	
Fuel source	**Energy, TWh**
Steam coal	181.6
Cocking coal	0.3
Lignite	140.9
Methane NG	5.1
Nitrified NG	3.9
Biogas	0.3
Solid waste	13.7
Coke oven gas	4.1
Blast furnace gas	1.9
Fuel wood	10.3
Light oil	0.1
Heavy oil	2.4
Others	Neglected
Total fuel input	**364.6**
Energy input for electricity generation by source	
Aggregated fuel source	**Sum, TWh**
Coal	181.9
Lignite	140.9
Natural gas	8.9
Biogas	0.3
Waste	13.7
Coke oven gas	4.1
Blast furnace gas	1.9
Fuel wood	10.3
Oil (Light&Heavy)	2.5
Total fuel input	**364.6**

Table A.4 Calculation of CO_2 emission factor in Poland, cont'd.

CO_2 emissions from electricity generation		
Fuel source	**CO4 Emission factor, kg CO_2/MWh fuel**	**CO_2 emissions, kg**
Coal Lignite	370.8	119677
Biogas	0	0
Natural Gas	204.5	1828
Blast furnace gas	1104.2	2111
Waste	339.5	4646
Coke oven gas	165.1	676
Fuel wood	345.6	3576
Oil (Light&Heavy)	279.4	709
Total CO_2 emissions	**-**	**133223**
CO_2 emission factor in Poland	**905.7**	**kg CO2 / MWh_{el}**

The electricity generation and energy input are taken from [35], and the CO_2 emission factors of different fuel sources are obtained from [30].

Appendix 5 – CO_2 emission factor in Germany

Table A.5 Calculation of CO_2 emission factor in Germany. CO_2 emissions deriving from Germany are all taken from the excel sheet coming from [36].

Total emissions from electricity generation	Gross produced electricity
314.8 Mton	**627.8 TWh**
CO_2 emission factor in Germany	**501.4 kg CO_2 / MWh_{el}**

Appendix 6 – CO_2 emission factor of CHP district heating

Table A.6 Calculation of CO_2 emission factor of CHP district heating.

Total fuel input in CHP D.H. plants allocated to electricity production 2014, [37]		
Fuel source	**GWh fuel**	
Avfall	3702.3	
Avfallsgas	16.9	
RT-flis	1670.1	
Trädbränsle, oförädlat3 bark grot	6887.0	
Trädbränsle, förädlat4 pellets briketter	476.9	
Tallbeckolja	7.4	
Bioolja	0.8	
Hjälpel7	548.4	
Torv o Torvbriketter	424.9	
Naturgas	363.6	
Eldningsolja1	123.2	
Stenkol	1003.4	
Övrigt fossilt bränsle	42.6	
Summa: Bränslen till elproduktion	15267.6	
Total electricity production, GWh	**6073.7**	
Emissions		
Fuel source	**Emission factor, kg CO_2 / MWh fuel**	**Referenc e**
Peat	386.3	[30]
Natural gas	204.5	[30]
Domestic heating oil	267.3	[30]
Coking coal	334.8	[30]
Other petroleum fuels	216	[30]
Waste	133.2	[29]
Own electricity use	227	[38]

Table A.7 Calculation of CO_2 emission factor of CHP district heating, cont'd.

CO_2 emissions	
Fuel source	**Emissions by fuel source, kg CO_2**
Waste	493151
Own electricity use	124493
Peat	164134
Natural gas	74347
Domestic heating oil	32936
Coking coal	335951
Other petroleum fuels	9208
Total emissions, kg CO_2	**1234219**
CO_2 emission factor of CHP D.H.	**203.2 kgCO_2 / MWh_{el}**

Appendix 7 – CO_2 emission factor of CHP industry

Table A.8 Calculation of CO_2 emission factor of CHP industry.

Generated electricity			
Steel and chemstry industries	396	GWh	
Pulp and paper	5524	GWh	
Total produced electricity	5920	GWh	
Steel and chemstry industries			
Oil based CHP power plant	**Parameters**		**Source**
Alpha value	0.55	kWh el/ kWe heat	[39]
Total efficiency	88	%	[39]
CO_2 allcated to electricity	52	%	Calculation based on [29]
CO_2 emission factor	274.3	kg CO_2 / MWh fuel	[30]
Fuel input	1268	GWh	Calculation
Total CO_2 emissions	347862	tCO_2	Calculation
CO_2 allcated to electricity	182214	tCO_2	Calculation
CO_2 emissions			
Sector			**Quantity, tCO_2**
Pulp n paper			0
Other industries			182214
Total			182214
CO_2 emission factor for CHP industry			**30.8 $kgCO_2$ / MWh_{el}**

Appendix 8 – CO_2 emission factors of Condensing power plants and Gas turbine

Table A.9 Calculation of CO_2 emission factors of Condensing power plants and Gas turbine.

Parameter	Condensing power plants	Gas turbine
CO_2 emission factor Plant efficiency	267.3 kg CO_2 /MWh_{el} 30 %	204.8 kg CO_2 /MWh_{el} 40 %
CO_2 emission factor	**891.0 kg CO_2 / MWh_{el}**	**512.0 kg CO_2 / MWh_{el}**

The CO_2 emission factors of different fuel sources are obtained from **[30]**. The plant efficiency of condensing power plants and gas turbine are taken from [40] and [28], respectively.