CHALMERS

Modeling and analysis of a district heating system containing thermal storage

Case study of the district heating system of Borås

Master's Thesis within the Sustainable Energy Systems programme

BERNA MELISSA AKKAYA

DMYTRO ROMANCHENKO

Report No. T2013-394

Department of Energy and Environment
Division of Energy Technology
CHALMERS UNIVERSITY OF TECHNOLOGY
Göteborg, Sweden 2013

MASTER’S THESIS

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Cover: Picture of ”Accumulator tank in Borås”, source: Borås Energi och Miljö AB

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ABSTRACT

The need for space heating and hot water in the residential and services sector makes up a major part of the total Swedish energy demand. This need is to a large extent satisfied by district heating (DH). In the future, it is expected that the energy system will include a larger share of intermittent renewable energy sources. This is likely to result in more fluctuating supply of electricity and hence, more volatile electricity prices. The presence of thermal storage (TS) can increase the flexibility of the DH system in terms of mitigating imbalances between demand and supply. It could also imply a substantial economic value if electricity price becomes more variable.

The aim of this master thesis project is to increase the understanding of rational operational strategy in DH systems and assess the value of the TS in present and future perspectives. For this reason a techno-economic computer-based model, along with four scenarios, has been developed. A nonlinear mixed integer optimization implemented in the GAMS software. The model analysis is applied to the DH system of Borås.

The reference scenario, representing the current DH system of Borås including TS, can be compared to real operational records. In addition, the reference scenario is also analyzed without TS in the system to estimate its value. The second scenario reflects a future with higher volatility in the electricity market price than today. Scenario three investigates the ability of the TS to serve as a redundancy unit while the fourth scenario estimates the most economically beneficial investment alternative in the case of a system expansion or unit replacement. Thus, the first and the third scenarios put emphasis on the TS from a current system perspective whereas the other two provide insights into future prospects.

The model results indicate a drop in total system heat production cost when including TS in the DH system. This would also enhance overall efficiencies of the base load units and reduce the number of starts and stops of the peak load boilers. A sensitivity analysis of the minimum allowed TS capacity level showed that there is no incentive for keeping it at low capacity levels. The results based on a possible future price pattern imply that the total heat production costs drops with higher volatility in electricity prices given the presence of combined heat and power (CHP) and TS units. The model results also suggest that the TS could be a sufficient back-up unit in the case of a sudden black out of some of the heat generation capacities. In the case of a DH system expansion it would be environmentally and economically advantageous to invest in a base load production unit.

Key words: district heating, optimization, modeling, thermal storage

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Preface

Within the scope of this master thesis project, an optimization computer model for running heat and power production units has been developed and an analysis of the district heating system of Borås has been performed. The project was carried out from February 2013 to October 2013 at the Division of Energy Technology at the Department of Energy and Environment at Chalmers University of Technology, and was performed in close collaboration with Borås Energi och Miljö AB.

The project has been supervised by assistant professor Mikael Odenberger at the Division of Energy Technology, who has also been the examiner. We would like to thank him for directing us along the way and for very helpful ideas regarding modeling and the results assessment steps. The collaboration with Borås Energi och Miljö AB should also be acknowledged and, especially, the assistance by energy analyst Doctor Stefan Hjärtstam who was co-supervising the work. In addition, his help with data gathering and arranging the meeting with other company employees is highly appreciated. We would also like to thank Anders Gunnarsson, employed at Dalkia (Borås Energi och Miljö AB's contractor in operating their production units), for clarifications around district heating system operation and storage utilization strategy.

In addition, we would like to thank Christopher Saunders, a research fellow at Brunel University, for helping us to establish the Master Thesis topic and for assistance in programming. We thank Lisa Göransson and Joel Goop for providing us with the data regarding electricity prices in a future perspective. We would also like to express our gratitude to Ulrika Claeson Colpier for the help with the report finalization.

Finally, we would like to thank all the Energy Technology Division staff for a friendly atmosphere and a nice working place.

Göteborg October 2013

Berna Melissa Akkaya

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Abbreviations

BOHOB	Bio oil fired heat only boiler
CHP	Combined heat and power
DH	District heating
EH	Electric heater
TS	Thermal storage
HP	Heat pump
MILP	Mixed integer linear programming
MINLP	Mixed integer non- linear programming
MIP	Mixed integer programming
OHOB1	Oil fired heat only boiler number 1
OHOB2	Oil fired heat only boiler number 2
PHOB	Propane fired heat only boiler
WCHP1	Waste fired CHP number 1
WCHP2	Waste fired CHP number 2
WCCHP1	Wood chips fired CHP number 1
WCCHP2	Wood chips fired CHP number 2
WCD	Wood chips dryer

Notations

H	total number of hours in the modeling period
h	set of hours in the modeling period
k	subset of hours *h* in the modeling period
n	indicator of heat production unit
E	energy produced by unit *n* [MWh]
C_{fuel}	fuel price [SEK/MWh]
η	efficiency of unit *n* (total efficiency for CHP plant)
$Start_{up}$	start-up cost of unit *n* [SEK]
$Shut_{down}$	shut-down cost of unit *n* [SEK]
Q	heat produced by unit *n* [MWh]
$Variable_{cost}$	operation and maintenance cost of unit *n* [SEK/MWh]
$Energy_{tax}$	energy tax [SEK/MWh]
CO_{2tax}	CO_2 tax [SEK/MWh]
Capacity	installed capacity of unit *n* [MW]
$Fixed_{cost}$	fixed hourly cost of running unit *n* [SEK/MW]
P	power produced by CHP plant [MWh]
Cel	electricity price [SEK/MWh]
RU	ramp up limit of unit *n* [MWh/h]
RD	ramp down limit of unit *n* [MWh/h]
u	1/0 variable, 1 if unit *n* is committed at hour *h*
y	1/0 variable, 1 if unit *n* is not committed at hour *h*

on_trans	1/0 variable, 1 if unit *n* is turned on at hour *h*
off_trans	1/0 variable, 1 if unit *n* is turned off at hour *h*
min_on_time	minimum up time of unit *n* [hours]
min_off_time	minimum down time of unit *n* [hours]
Tsupply	supply water temperature at hour *h* [˚C]
Treturn	return water temperature at hour *h* [˚C]
min_gen	minimum heat output of unit *n* [MW]
$q_{storage}$	charge and discharge rate of the thermal storage unit at hour *h* [MWh/h]
$e_{storage}$	energy level of the thermal storage unit at hour *h* [MWh]
$loss_{storage}$	loss coefficient of the thermal storage unit
heat_demand	heat demand at hour *h* [MW]

1 Introduction

Anthropogenic global warming as well as scarcity of fossil fuels can lead to an increased rate of renewable energy sources in the future energy system. In such a scenario a high penetration of fluctuating energy sources in the energy system may call for increased flexibility for keeping the system in balance. In addition, a greater volatility in electricity prices and possibly, an even greater difference between minimum and maximum daily prices than today is likely to be experienced. A district heating (DH) system containing a combined heat and power plant (CHP) and a thermal storage (TS) unit could play a critical role in handling the fluctuations and help to turn the volatility of electricity prices into an advantage.

Examples of driving forces enabling the development of energy systems in this direction are for instance the Swedish climate goals prescribing an increase of the proportion of renewable energy sources so that 50% of the total energy use at year 2020 should be satisfied by renewable energy sources, and moreover to increase efficiency of the energy use by 40 % considering the period 2008-2020 (Energimyndigheten, 2013). Additional targets and goals are set to mitigate the energy sector's contribution to global warming, such as the EU Directive 2004/8/EC (Official Journal of the European Union, 2004), which directly promotes the development of high-efficiency cogeneration plants, which are major units in DH systems, in Europe. The German Combined Heat and Power Act (KWK) of 2008 can be considered as a milestone for regional normative standards promoting electricity being produced from CHP facilities (Umweltbundesamt, 2013).

1.1 Aim and scope

The main hypothesis behind this thesis project is that electricity is converted into heat during off-peak hours. The resulting excess heat is stored in a thermal storage, and thereafter retrieved at the point in time when heat demand is high. If the described strategy is implemented, the district heating system will be able to profit by:

- generating electricity from CHP plants, if such are available in the system, by increasing the power-to-heat ratio during periods of high electricity prices;

- utilizing low-price excess power from the grid (e.g., during off-peak hours or when availability of power from intermittent renewables is high).

The aim of the research is first of all to provide insights in the operation strategy of a DH system. Additionally, the goal is to assess both technical and economic value of a thermal storage, if the one is available, in a local/regional district heating system. The main tasks are set to be:

- develop a computer based model, capable of generating an optimal operation schedule for all the units present in a DH system, with the objective to minimize the total system cost of heat production;

- investigate the operation strategy of the DH system under the conditions of changed input data e.g. seasonal electricity prices or heat demand;

- assess probable changes in the operation strategy of the DH system in a future perspective, assuming increased and more frequently varying electricity prices;

- evaluate the reliability of the DH system and the techno-economic value of having the TS unit given failures of one or several heat generating units in the system;

- investigate system development by simulating DH system expansion and unit substitution.

This thesis project is focused on the DH production and does not include a comparison with other decentralized heating options available on the market. Additionally, the thesis considers the DH system as a concealed structure and does not take into account details regarding electricity or fuel supply. Data regarding weather conditions, electricity prices and heat demand is exogenously given to the model as an input.

The obtained results can be considered as a basis for further research, assessment of different development scenarios and partly for preliminary decision making.

2 Background and theory

2.1 District heating systems

A district heating (DH) system is a system where heat, centrally produced, is delivered to end-users by using water as energy carrier. Heat is then used by consumers in form of hot tap water and space heating. DH systems may be beneficial both from economic and environmental point of views. Firstly, centrally produced heat assures higher fuel efficiencies and, thereby, lower fuel consumption compared to decentralized heat production (Werner & Frederiksen, 1993). Secondly, heat is produced centrally, which means that cleaning systems and environment-protecting systems may be implemented in a more secure and easier way. Finally, the consumers are not affected by harmful noises or odors, which are produced by the units present in the DH system.

On the other hand, a large investment in both district heating infrastructure and in production utilities is often required. In addition, the losses in the DH grid are high and therefore the heat should not be transported over too long distances (Werner & Frederiksen, 1993).

Different kinds of fuels can be used to produce district heat. Swedish statistics for the year 2011 show that 41 % of delivered heat was produced from biofuels, 18 % from solid waste and 7 % from waste heat. Only 14% of heat was produced by incineration of fossil fuels and the remaining 20% was obtained from other sources (Svenskfjärrvärme, 2011). A DH system can contain a number of heat production units such as combined heat and power (CHP) plants, heat only boilers (HOB), electric heaters (EH), heat exchange pumps (HP) and TS units (Dotzauer & Homlström, 1997). A brief introduction to the production units available in DH systems is given in Section 2.2.

2.2 Units in a district heating system

2.2.1 Combined heat and power plants

Combined heat and power plants (CHP) are specific combustion units, which are able to produce both heat and electricity simultaneously. Therefore, they have higher total efficiencies, ranging between 70 to 95 %, than conventional power plants, which have efficiency levels in the range of 25 to 45 % (Dotzauer, 1997). High total efficiencies also ensure a good fuel economy. Different types of fuels are used for combustion where the most commonly used fuels in Sweden are biomass and waste. The produced electricity is usually sold to the electricity grid, however, it can also be used to cover internal electricity demand.

The ratio of produced power to heat by a CHP plant, also called the “alpha value”, is used when describing the operational pattern of CHP plants. It is possible to operate a

CHP plant with different levels of electricity, *p*, and heat, *q*, outputs, by varying the alpha value within a technically limited feasibility region. The feasibility region of operation of a CHP plant, Ω, is demonstrated in Figure 2-1 (Dotzauer, 1997).

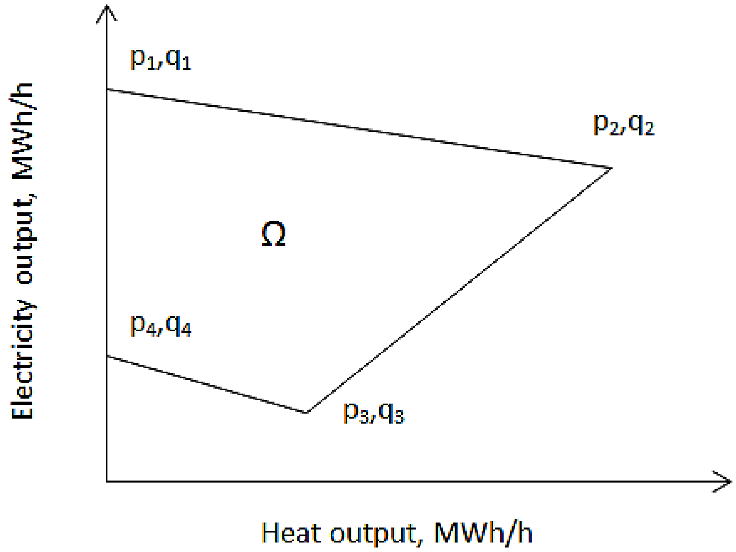


Figure 2-1: The feasibility region of a CHP plant operation, Ω, with different levels of electricity, p, and heat, q, outputs.

2.2.2 Heat only boilers

Heat only boilers (HOB) provide useful heat for DH systems by using fossil fuels, biofuels or waste for the combustion process. If the unit is fired with relatively inexpensive fuels, depending on the availability this could be coal, waste or biofuel, they are often considered as base load heat generators. Oil-fired HOBs, on the other hand, are often peaking heat generators which are to be turned on when demand is high. However, with a presence of CHP plants in a DH system, even coal- and biofuel-fired boilers are usually used only in high-demand periods. The efficiencies of HOBs are quite high and are in the range of 85-89 % (Dotzauer, 1997).

2.2.3 Electric heaters

Electric heaters (EH), also called electric boilers, use electricity to heat water in order to supply it to the DH network. Industrial EH may be considered as a base-load technology when the electricity prices are low, for example at night or at a time when electricity supply is high i.e. windy days. Otherwise, they serve the system as reserve units or as peak-load units as they have a short start-up period (Dotzauer, 1997). Under the circumstances of more volatile electricity prices in future, EH units might act as key players in the DH system, since they are easy to run and regulate. (Dotzauer, 1997).

2.2.4 Heat exchange pumps

Heat pumps (HP) are driven by electricity and only require a comparatively low temperature heat source, such as waste water from industry, sea or rivers in order to produce heat of required temperature and supply it to a DH network. The ratio of produced heat to supplied electricity is called coefficient of performance, COP, and it is used to measure the performance of the HPs. Typically, COP values are in the range of three. Obviously the cost of running heat pumps is strongly dependent on electricity prices. In most cases, using HPs to produce heat is rather inexpensive and for this reason large HPs are used as base-load technologies. On the other hand, the disadvantage of heat pumps is rather low temperatures of generated heat. (Dotzauer, 1997).

2.3 Thermal storage

A thermal storage (TS) is often a simple accumulator tank (AT) which functions as a reservoir to store hot water for later consumption. There is a loss parameter associated with TS units and it defines how much of the heat content in the unit is lost from one time slot to the other one. Due to the losses of the heat content, the most optimal situation is to use the stored hot water within a few days (Dotzauer, 1997).

The presence of TS in DH systems has a number of benefits. Investments in thermal storage units may enable the smoothening of distortions between demand and supply, which will result in higher reliability of regional energy systems. Thermal storage in the DH system benefit in decreased number of occasions when costly, usually fossil fired, peaking boilers must be turned on to meet the demand. Additionally, utilization of thermal storage units will result in more flattened output from base load units, ipso facto, increase overall fuel efficiency. Furthermore, it is also likely that an increased number of thermal storages will be able to moderate volatile energy prices (Semadeni, 2004).

Moreover, a thermal storage unit makes it possible to avoid fast changes in heat production from generating units, and, by this, decrease an operational stress on them. Furthermore, if one of the units available in the system is forced to be turned off due to unexpected issues, thermal storage unit can supply required heat, and by that function as a back-up system for a DH system (Dotzauer, 1997).

It has also been claimed that one of the most important benefits of thermal storage capacities is enabling of higher penetration of renewable energy sources in the energy system (Sundararagavan & Baker, 2012). Thermal storage units will provide an option to store cheap renewable energy, in form of electricity or converted to heat, during off-peak hours, and retrieve it back to the system during hours with high demand. It will add value to supplied energy by making it predictable (Ibrahim, et al., 2008).

2.4 Literature review

Various studies focused on modeling approach of DH systems simulation, on best design of generating plants, or on an optimal capacity and utilization rate of a thermal storage has been conducted in both short-term and long-term perspectives.

An influence of the thermal storage on the profitability of an individual CHP plant and how the capacity of the TS affects the design of the production unit was investigated by Streckiene et al. (2009) and Pirouti et al. (n.d.). The former study uses an existing optimization tool, EnergyPro, whereas the latter one is based on the developed in Matlab optimization model. Both studies focus on the maximization of the income from selling electricity in the spot market and on the minimization of the heat production cost, respectively. Ristic et al. (2008) developed another optimization model to analyze optimal short-term operation schedules for CHP systems in combination with a secondary boiler and heat storage. They conclude that the most economically profitable strategy of running a CHP plant in a spot market is determined by defining the optimal operational set point of the CHP gas turbine.

In contrast to previously mentioned works, which were developed to follow exogenously given heat demand, Ren et al. (2007) presented a study in which electricity demand satisfaction is prioritized. The study mostly focused on the modeling technique, rather than obtained results, is presented by Zhao et al. (1998). Notably, the dynamics of the district heating network are considered, which is not the case in the previously mentioned studies. Mentioned models were created to analyze the behavior of CHP plants in combination with a heat storage unit in a short-term perspective, whereas Thorin at al. (2005) conducted the study which considered CHP plant operation in a long-term perspective. The tool for long-term optimization is based on the developed mixed integer linear model and implemented in GAMS using CPLEX 7.5 solver.

On the contrary to previous works, where the relation between a single CHP plant and heat storage are considered, studies are also conducted where the use of thermal storage in a DH system perspective have been investigated. The work by Rolfsman et al. (2004) covered two possibilities: using a TS unit either to maximize the amount of electricity produced from CHP during peak-price periods or to minimize the use of units with high operational costs. A simple model for forecasting the electricity price on the Nordic electricity market is also presented. Dotzauer developed a general mathematical model and an algorithm for short-term production planning of cogeneration plants in the DH systems (Dotzauer, 1997). All the mentioned studies are based on the common mathematical models, however include specific constraints or supplements depending on the aim of the research. Subjectively evaluating, the Dotzauer’s model is the most comprehensive model, hence it is used as a basis for the present thesis project, and will be further discussed in the Section 3.1.

3 Method

3.1 Description of the developed optimization model

The model developed within the present thesis project, hereinafter referred to as an "optimization model", used as a starting point the mathematical model developed by Erik Dotzauer which was analyzed in detail (Dotzauer, 1997). The optimization model was modified and implemented in the GAMS software, briefly described below, and applied to the DH system of Borås, which in this thesis is used as a case study to validate the optimization model. The optimization model is capable of generating an optimal operation schedule for the production units available in the DH and, at the same time, to define an optimal utilization strategy of the TS.

The optimization model is totally deterministic which means that the heat load and the spot electricity prices are assumed to be known and exogenously given to the model. Moreover, technical specifications and cost characteristics of all units are known and are described in Section 4.2. The heat production by each unit in hourly basis i.e. operational schedule of the DH system, utilization strategy of the thermal storage and the total system cost are considered of highest interest and chosen to be the main outputs from the optimization model.

GAMS (The General Algebraic Modeling System) is a modeling system which is constructed specially for modeling linear, non-linear and mixed-integer optimization problems. GAMS handles an optimization process from the stage of a defined mathematical model of a real life problem, to the stage of solution evaluation. A number of solvers are connected to GAMS such as CPLEX, MINOS, CONOPT and SCIP. In this thesis project the SCIP (Solving Constraint Integer Programs) solver is used. It uses the technique of branching which means that the problem is consecutively divided into a number of sub problems, which are solved recursively (SCIP, 2013).

3.1.1 The objective function

The objective of the model is to minimize the heat production cost which is calculated according to Equation 1. The cost function consists of a number of different terms i.e. fuel costs, start-up and shut-down costs, fixed and variable running costs and taxes. All the terms present in the following equations are explained in the notations list.

$$
\begin{aligned}
z = & \sum_{h=1}^{H} \sum_{n=1}^{N} \frac{\mathrm{E(h,n)} \cdot \mathrm{C_{fuel}(n)}}{\eta(\mathrm{n})} + \mathrm{Start_{up(h,n)}} + \mathrm{Shut_{down(h,n)}} \\
& + \sum_{h=1}^{H} \sum_{n=1}^{N} \mathrm{Q(h,n)} \cdot \left[\mathrm{Variable_{cost}(n)} + \mathrm{Energy_{tax(n)}} + \mathrm{CO_{2_{tax(n)}}}\right] \\
& + \sum_{n=1}^{N} \mathrm{Capacity(n)} \cdot \mathrm{Fixed_{cost}(n)} - \sum_{h=1}^{H} \sum_{n=1}^{N} \mathrm{P(h,n)} \cdot \mathrm{C_{el}} \qquad (1)
\end{aligned}
$$

Produced electricity by the CHP-unit is considered as an additional benefit besides the heat production, since produced electricity is later on sold in the spot market. Therefore, the income from electricity sale is noted as a negative term in the objective function.

The start-up cost is assigned as a transient value, i.e. the start-up cost is dependent on the number of hours the unit has been stayed turned off. An exponential function is therefore applied to calculate the transient start-up cost of a unit. On the other hand, the shut-down cost is included as a constant value. The implementation of a transient start-up cost and the shut-down cost constraints is one of the distinct contributions of this thesis project.

Energy production from each unit is calculated according to Equations 2 and 3. Electricity production, P is only valid for the CHP plants. The feasibility region of operation of a CHP plant is specified with heat-electricity constraints. It is assumed that CHP units are not allowed to operate at heat-only-production mode; however, they are enabled to operate at electricity-only-production mode.

$$\mathrm{E(h,n)} = \mathrm{Q(h,n)} + \mathrm{P(h,n)} = \mathrm{C_p} \cdot \mathrm{m(h,n)} \cdot \Delta\mathrm{T} + \mathrm{P(h,n)} \qquad (2)$$

$$\Delta\mathrm{T} = \mathrm{Tsupply} - \mathrm{Treturn} \qquad (3)$$

3.1.2 Demand-supply constraint

The objective function is a subject to a number of constraints. Overall heat balance is the major constraint and ensures that the sum of heat outputs by all units at hour *h* as well as the heat charged or discharged from the TS at hour *h* is equal to or larger than the heat demand at hour *h*, see Equation 4. This will ensure that the demand is covered by production units and the TS for all time steps in the modeling period. Charge and discharge rate of the TS, $\mathrm{q_{storage}}$, is assigned negative when charging the TS and positive when discharging.

$$\sum_{n=1}^{N} \mathrm{Q(h,n)} + \mathrm{q_{storage}(h)} \geq \mathrm{heat_{demand(h)}} \tag{4}$$

Additionally, there are a number of energy production unit-specific constraints. Minimum and maximum production levels constraints ensure that the heat produced by each unit can neither exceed its maximum heat output nor be less than its minimum heat output.

3.1.3 Ramp up and ramp down constraints

Ramp up and ramp down constraints limit the maximum heat and power output from unit *n* at hour *h*. The difference between the amount of heat produced at hour *h* and the hour *(h-1)* should be less than or equal to the ramp up rate if the production level is increased; and the difference between the heat produced at hour *(h-1)* and the hour *h* should be less than or equal to the ramp down rate if the production level is decreased. The Equations 5 and 6 show how ramp up and ramp down rates force the heat production at next hour to be within the limits.

$$\mathrm{Q(h,n)} \leq \mathrm{Q(h-1,n)} + \mathrm{RU(h,n)} \tag{5}$$

$$\mathrm{Q(h,n)} \geq \mathrm{Q(h-1,n)} - \mathrm{RD(h,n)} \tag{6}$$

In the case of an “on transition” of a unit, the model should ensure that the heat output is equal to a minimum allowed heat output of that unit. Similarly, in case of an “off transition” of one unit, the model should ensure that the heat output at that hour should be equal to minimum allowed heat output of that unit. Otherwise, the unit cannot be turned on or off. Equations 7 and 8 handle above mentioned issues.

$$\mathrm{RU(h,n)} = \mathrm{min\_gen(n)} \cdot \mathrm{on\_trans(h,n)} + \mathrm{u(h-1,n)} \cdot \mathrm{RU(n)} \tag{7}$$

$$\mathrm{RD(h,n)} = \mathrm{min\_gen(n)} \cdot \mathrm{off\_trans(h,n)} + \mathrm{u(h,n)} \cdot \mathrm{RU(n)} \tag{8}$$

Ramp up and ramp down limits are also valid for electricity production from CHP plants and are implemented similarly to Equations 5 to 8. The logic behind equations 7 and 8 is another novelty of this thesis project.

3.1.4 Minimum on and off time constraints

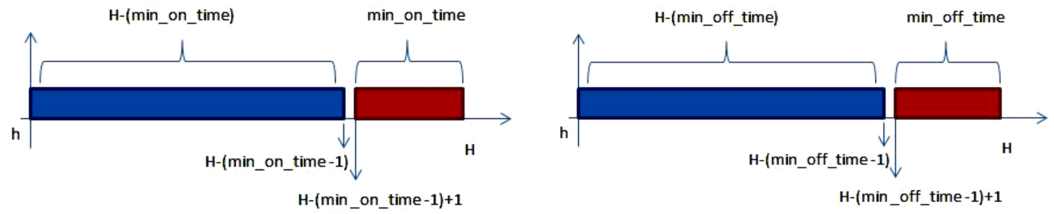
Minimum on time constraints are assigned in order to prevent a unit to be switched off before it has been run at least as long as its “minimum on time”. Similarly, minimum off time constraints are defined to prevent a unit to be switched on before it has been off at least as long as the “minimum off time”. Minimum on time constraints are defined by Equations 9 and 10 (Saunders, 2013).

$$\sum_{k=h}^{h+\min\_on\_time(n)-1} \mathrm{u(k,n)} \geq \mathrm{on\_trans(h,n)} \cdot \mathrm{min\_on\_time(n)} \tag{9}$$

$$\sum_{k=h}^{H} (\mathrm{u(k,n)} - \mathrm{on\_trans(h,n)}) \geq 0 \tag{10}$$

Minimum on time is implemented and distinguished for two different time periods within the whole modeling time span, as illustrated in Figure 3-1. The reason why the whole time period is divided into two is that the constraint has different logical implementations. Equation 9 is only valid for the blue-colored period, as shown in Figure 3-1, and makes sure that if the unit is switched on at hour *h*, the sum of the binary variable *u* (equals to 1 if unit is committed) under a time period of *k*, should be more or equal to minimum on time of that unit.

On the other hand, Equation 10 is only valid for the red-colored period which has time steps equal to minimum on time, as shown in Figure 3-1,a. If a unit is already switched on within the red period, Equation 10 ensures that it is not switched off until the modeling period is finished. The division of the whole time period into two is another input of this thesis project to the general mathematical model, which is taken as a reference.



a) b)

Figure 3-1: a) Schematic representation of different time periods for minimum on time constraints; b) Schematic representation of different time periods for minimum off time constraints.

In a similar fashion, minimum off time constraints are modeled. Equations 11 and 12 show the mathematical expression of the constraints where Equation 11 is only valid for the blue-colored period and Equation 12 is only valid for the red-colored period which is shown in Figure 3-1,b.

$$\sum_{k=h}^{h+\min\_off\_time(n)-1} \mathrm{y(k,n)} \geq \mathrm{off\_trans(h,n)} \cdot \min\mathrm{\_off\_time(n)} \tag{11}$$

$$\sum_{k=h}^{H} (\mathrm{y(k,n)} - \mathrm{off\_trans(h,n)}) \geq 0 \tag{12}$$

3.1.5 Thermal storage related constraints

The heat balance equation used for the TS is defined by Equation 13. The heat content in the TS at hour h, $\mathrm{e_{storage}}$, should be equal to the sum of heat content at the hour *(h-1)* and the charge/discharge rate, $\mathrm{q_{storage}}$ at that hour h. $\mathrm{q_{storage}}$ is assigned negative when charging the TS and positive when discharging.

$$\mathrm{e_{storage}(h) = e_{storage}(h-1) \cdot (1 - loss_{storage}) - q_{storage}(h)} \tag{13}$$

Constraints for minimum and maximum charge/discharge limits are created to ensure that charge/discharge rates are within the allowable limits, respectively. Additionally, minimum and maximum capacities of the TS are specified.

3.1.6 Logical constraints

In addition to the constraints explained above, a number of logical constraints are defined in the model. For instance, if a unit is at “on” state at one specific hour, it cannot be at “off” state at the same hour. Additionally, when there is an on-transition of a unit, there cannot be an off-transition of that unit at that specific hour.

4 Assumptions, input data and scenarios

In order to run and evaluate the developed optimization model, a large amount of data must be gathered and some assumptions are to be made. This chapter contains three sections, where the first one explains assumptions and simplifications which are taken into account and included in the optimization model. The second section provides a description of the data which is used, origin of this data and how it was processed and transformed in order to reflect the actual system as much as possible. This section also includes a brief introduction to the operational strategy of running available capacities currently in use in the DH system of Borås. The third section contains a description of the scenarios which are developed and analyzed under the scope of this study.

4.1 Assumptions and simplifications

In cases where there is a lack of data or some information is not specific, appropriate assumptions and simplifications can be accurate enough to reflect the reality. Thus, the developed model includes some assumptions related to the computer model itself, as well as to the district heating system’s operation and to the production units.

The first assumption is related to the heat losses along the pipes in the distribution network. Since data concerning heat production from each unit, as well as heat load data, was available, these were compared and heat losses are in the model taken into account as a part of heat demand. Thereby, one can say that heat load includes heat consumed by industries, households, plant’s internal heat demand and heat losses in the network.

It is also assumed that efficiencies of the units remain constant regardless of heat output. Loss of accuracy of results obtained by the program runs with constant and variable efficiencies can be assumed to be insignificant. Moreover, since the goal of the research is to compare different modeling results with other parameters being variable, efficiency can be assumed as a constant value without diminishing the results accuracy.

4.1.1 Thermal storage related assumptions

In addition to the varying temperature level in the thermal storage unit over time, there is also a so called temperature gradient present. This implies that there is a difference in water temperature between the top and the bottom of the unit. In the optimization model it is assumed that both the temperature change and the temperature gradient may be combined into one heat loss coefficient. In this thesis it is assumed that a heat loss from the TS is 1 % of available capacity in ten days (Skogfält, 2009). It is also assumed that charge and discharge rates to and from the thermal storage have a maximum level of 50 MWh/h and 100 MWh/h, respectively.

4.1.2 Ramp limits and minimum on/off times related constraints

In order to clarify some of the assumptions made, specific terminology is here explained. Utilization of a heat or power generation unit can be logically divided into three main periods: start-up period, operation period and shut-down period.

- The start-up period indicates how much time it takes to increase heat output from zero to minimum production level of the unit.
- The operation period is when the unit's heat output lies between its minimum and maximum levels.
- The shut-down period indicates the time it takes to decrease the heat output from minimum production level to zero.

The term "minimum on time" includes only the hours when a unit generates useful heat to the network. Whereas, the term "minimum off time" includes all hours when a unit is shut off, as well as time of start-up and shut-down periods.

For the start-up/shut-down periods, ramp rates are specified by dividing minimum allowable production level by the number of time steps (in this thesis project it corresponds to number of hours) in start-up or shut-down period, respectively. Additionally, it is assumed that all production units change their output step-wise within each time step. For the operation period, ramp rates are specified by dividing the useful heat output range (difference between minimum to maximum production level) by the number of hours needed to increase the heat output from minimum to maximum production level.

4.1.3 Price related assumptions

The total system heat production cost is the value, which is used to govern an optimal operation strategy. To calculate the total system heat production cost, some prices must be provided as input data to the optimization model. Within the scope of this thesis project and the case study of Borås DH system, only fuel prices, electricity prices, start-up and shut-down costs for all generation capacities are considered. However, the model is developed so that supplementary costs can be easily added to the objective function.

The fuel prices that are applied are assumed to be constant for the whole year. As it can be observed in the Table 4-1, the waste fired CHP plants have virtually zero fuel prices. Behind the term "virtually zero prices" the assumption is made that the revenues for waste reception, are compensated by expenses for pre- and after treatment of waste. Fossil fuel prices include the actual purchasing price, fuel tax, energy tax and carbon dioxide tax. NOx and SOx taxes are excluded in this thesis. There is no extra cost assigned for wood chips regarding CO_2 emissions, however, the price includes a small share of fuel treatment expenses.

Start-up costs are in the model provided as constant values, i.e. not as transient values, as this would require heavy computational time. In order to calculate start-up costs, for example for the wood chips fired CHP plants, the amount of fuel consumed during the start-up period is determined and multiplied with fuel costs. However, a particularity for the waste incineration CHP plants is that oil is used to heat up the units during a 16 hour long start-up period. As a result, start-up costs of waste fired CHP plants are considerably higher than start-up costs of wood fired CHP plants. Start-up costs for all other units available in the system, as well as shut-down costs, are assumed to be equal to zero.

4.2 Input data

In this section technical and economic data regarding production units is presented. The district heating system analyzed here (Borås DH) consists of four CHP plants, four heat only boilers, a heat pump, an electric heater and a wood chips industrial dryer. The main technical parameters are presented in the Table 4-1 and Table 4-2, respectively.

Table 4-1: Technical and economic characteristics of the production units available in the Borås district heating system.

	Unit type	Type of fuel	Fuel price, SEK/MWh	Efficiency / COP
WCHP1	CHP	Waste	0	0.89
WCHP2	CHP	Waste	0	0.89
WCCHP1	CHP	wood chips	200	0.87
WCCHP2	CHP	wood chips	200	0.87
WCD	fuel dryer	wood chips	var*	0.87
HP	heat pump	Electricity	el.spot+394**	3
BOHOB	heat only boiler	bio oil	600	0.85
PHOB	heat only boiler	Propane	800	0.90
OHOB1	heat only boiler	Oil	850	0.90
OHOB2	heat only boiler	oil	850	0.90
EH	electrical heater	electricity	el.spot+394**	0.99

** A price of running the dryer depends on its capacity level at each hour.*

****** *394 SEK/MWh is an estimated overall extra cost of delivering electricity to a consumer.*

The electricity prices used in this study are extracted from the NordPool website (NordPool, 2013). Data is taken for the year 2012 in order to cover an entire year. There is also a price difference between the electricity bought from the grid and the electricity sold to the grid. The price of produced electricity by CHP plants sold to the grid equals to NordPool prices, whereas the electricity purchasing price is higher by assuming that the constant value of 394 SEK/MWh is added to the NordPool prices. This constant value is calculated specifically for Borås City case and accounts for cost of delivering electricity and a fee for being connected to the grid.

Table 4-2: Technical characteristics of the production units available in the district heating system of Borås.

	Max heat output, MW	Min heat output, MW	Minimum on time, h	Minimum off time, h	Ramp up time*, h	Ramp down time*, h
WCHP1	16.5	11.5	48	56	21	2
WCHP2	16.5	11.5	48	56	21	2
WCCHP1	42	21	48	48	8	3
WCCHP2	42	21	48	48	8	3
WCD	22	11	48	48	8	3
HP	7.5	4.5	1	0	1	0
BOHOB	25	6.25	1	0	2	1
PHOB	40	10	1	0	2	1
OHOB1	25	2.5	1	0	1	1
OHOB2	25	2.5	1	0	1	1
EH	20	2	1	0	0	0

** ramp up and ramp down times indicate for how long does it take to increase and, respectively, decrease output from a production unit from zero to maximum level and back to zero.*

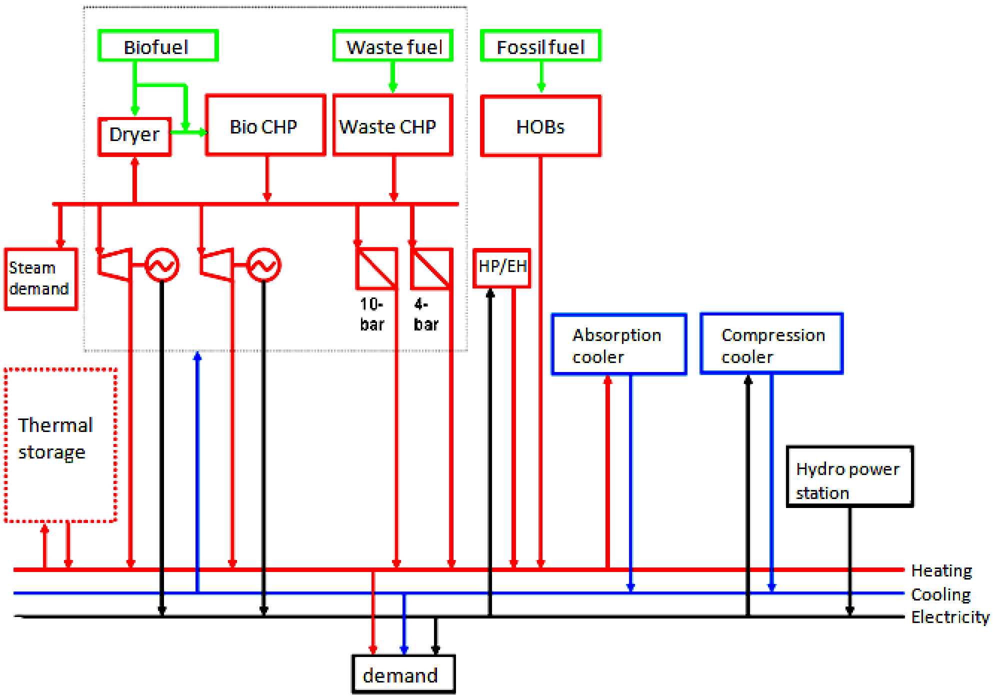


Figure 4-1: Unit configuration of the district heating system of Borås. The system and units marked by red is included within the scope of this thesis project while the district cooling units (colored blue) and the hydro power units (colored black) are not included.

4.3 Scenarios

4.3.1 Scenario 1 - The Reference scenario

The Reference scenario represents the current DH system of Borås i.e., the TS is present in the system. The model is run in order to find an optimal dispatch of heat production technologies and an optimal utilization strategy of the TS under different circumstances.

In order to analyze how variations in heat demand and electricity prices affect the results, the model will be run for three cases:

- A winter month (January)
- An autumn month (October)
- A summer month (July)

The typical winter month represents a case with high and volatile electricity prices supplemented by high heat demand. A typical autumn month characterizes a case with high electricity prices but substantially lower heat demand in comparison to a winter month. July case symbolizes a period with low heat demand and low electricity prices. All input data as presented in Section 4.2 are valid for this scenario. The initial and final thermal storage states as well as the minimum allowable capacity level are assumed to be 500 MWh in all three monthly optimizations.

Additionally, the impact on the total system cost of different allowable TS levels is investigated within this scenario. The aim of this analysis is to define the most suitable thermal storage level that provides a comparatively low total system cost while also assuring a high degree of security in case of unexpected break-downs of any of the production units. For that purpose, a sensitivity analysis on minimum allowable TS level is conducted. Three sub-cases are tried and minimum allowable TS levels, the initial states and the end states of the TS unit for each case are shown in Table 4-3.

Table 4-3: Input data for the sub-cases tried for the sensitivity analysis on minimum allowed thermal storage level.

	Minimum allowed ES level , Initial state, End state [MWh]
Case 1	1000,1000,1000
Case 2	700,700,700
Case 3	500,500,500
Case 4	200,200,200

Another aim of the reference scenario is to assess whether there is a techno-economic value of having a TS in the DH system. For that purpose, the thermal storage unit is excluded from the current DH system. The model is run to calculate the total system cost for this case which is thereafter compared with the optimization results that are obtained from the case including the TS.

4.3.2 Scenario 2 - Borås 2022

This scenario represents a future with a higher ratio of intermittent renewable power sources both in the regional and national energy systems which is assumed to change the electricity price pattern, as discussed in Section 1. Assessment of the TS utilization strategy under the assumption of changed electricity price dynamics and sensitivity analysis of different price increments is conducted under the scope of this scenario.

In this scenario, simulated marginal electricity prices for the year 2022, as given by Göransson et al (2013), is used as input data. These prices are generated by the computer modeling package, which considers commissioning and decommissioning of power production units in Europe within the next decade. The prices are obtained in the three hours resolution and interpolated to the one hour resolution.

Within this Scenario 2 the main focus is to evaluate two different cases:

- The first case is focused on the reflection of different dynamics of price variations on the TS exploitation. For this reason average electricity prices from the year 2022 are equalized to the respective average electricity prices for winter, autumn and summer weeks from the year 2012. Differences in total system heat production costs will reflect an economic value of the TS, considering changed price dynamics;

- The second case is focused on the sensitivity analysis of probable changes in prices in the year 2022 years. Obtained data from the year 2022 is not being equalized to the reference 2012 year. Simulations are instead conducted, first with prices taken from (Göransson, et al., 2013) and afterwards, are increased by 10%, 20% and 30% in order to evaluate a probable future with higher prices.

In Scenario 2, all input data is taken for one winter week starting from the hour 337, one summer week from the hour 4705 and one autumn week from the hour 6889[1]. Electricity price curves, including the additional 394 SEK/MWh as explained in Section 4.2, for the year 2012 as well as assumed future prices can be observed from Figure 4-2, Figure 4-3 and Figure 4-4.

[1] This fact must be kept in mind in order not to be confused by different model results when comparing to the Reference scenario.

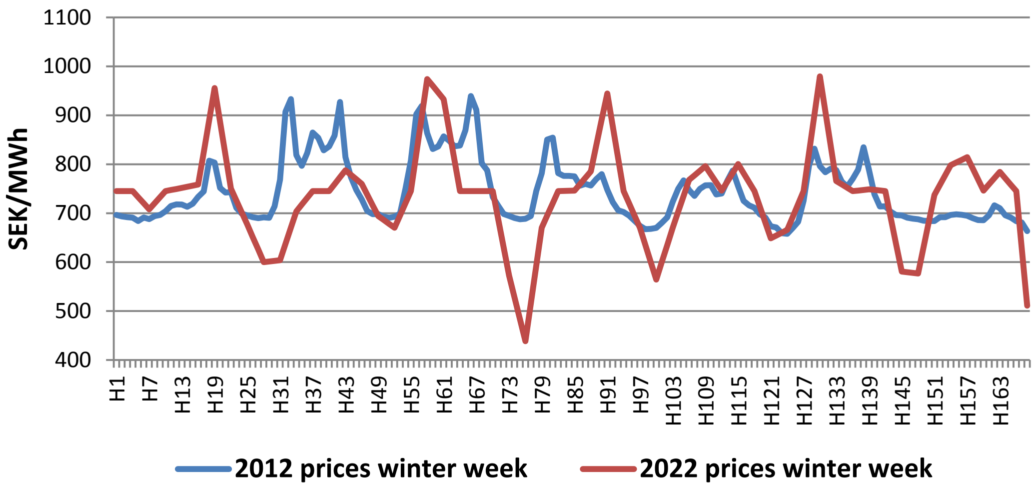


Figure 4-2: Electricity price curve of one winter week in the year 2012 and 2022. Source NoordPool **(2013)** and Göransson et al. **(2013)**.

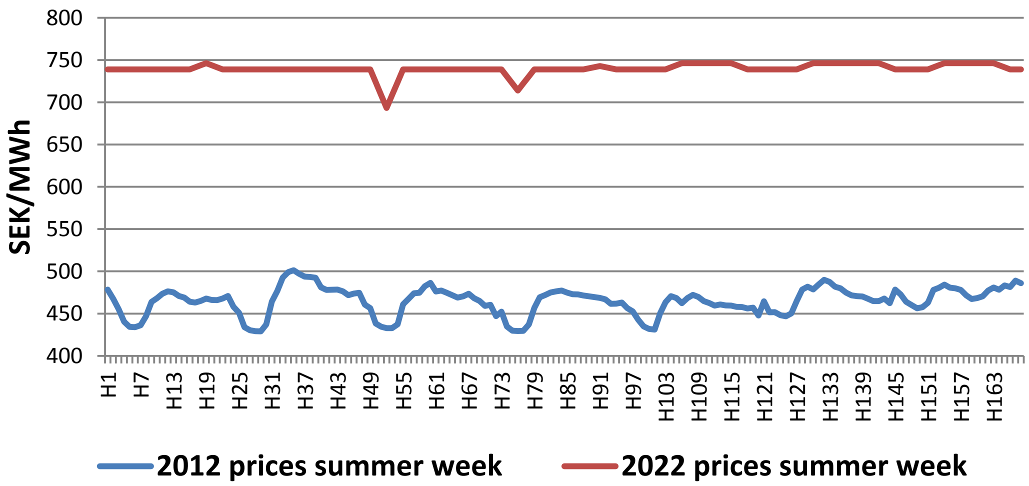


Figure 4-3: Price curve of one summer week in the year 2012 and 2022. Source NoordPool **(2013)** and Göransson et al. **(2013)**.

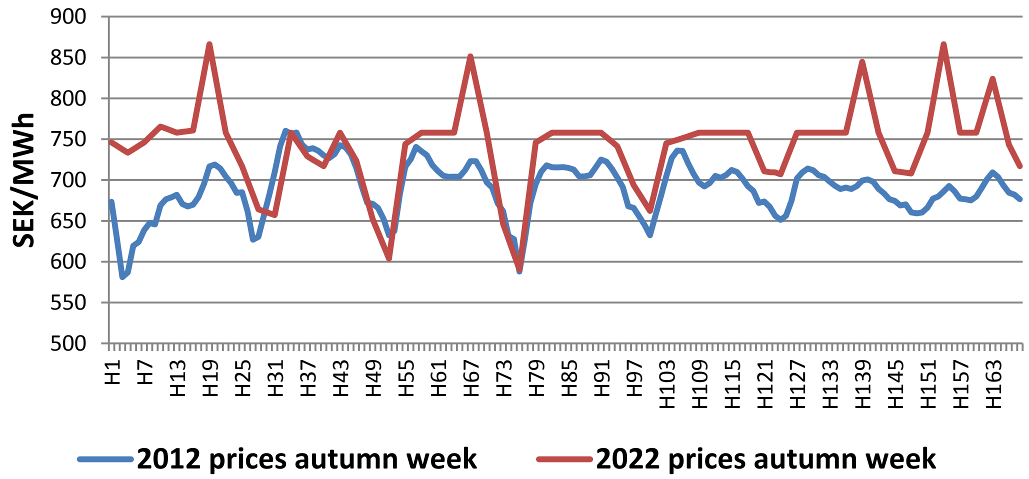


Figure 4-4: Price curve of one autumn week in the year 2012 and 2022. Source NoordPool **(2013)** and Göransson et al. **(2013)**.

4.3.3 Scenario 3 - An unexpected breakdown

The balance of the minimum allowable TS capacity level against the security-of-supply issues is under the scope of this scenario. The ability to handle a breakdown of one or more production units under the assumption of different initial TS states and duration of breakdowns is therefore estimated within this scenario.

Since the thermal storage unit performs the role of redundancy unit in the DH system of Borås, security aspects should be fulfilled while the utilization of the TS is optimal. In a case of an unexpected breakdown of one or more heat generation units, the DH system should still be able to satisfy the customers' heat demand. Therefore, a stress testing analysis is conducted for a winter week with extremely high heat demand, while setting several possible initial states of the TS unit. The system is tested by forcing one or more units to be uncommitted from first hour until the fault is cleared. The fault duration is also changed and investigated.

In order to simulate the worst case scenarios, the system is first tested under the condition of a breakdown of one and afterwards of few main generation units. In the first case it is assumed that there is a fault in the operation of one of wood fired CHP plants, which results in useful output drop from the dryer by 50 %. The second case will represent the situation when both the wood fired CHP plants are out of operation and, as a consequence, the output from the dryer is zero.

Minimum allowable TS capacity level is set to 100 MWh, which is assumed to be the internal storage capacity of the DH network itself. That means that the thermal storage is allowed to be discharged until it is empty in a case of an unexpected fault. The Initial TS unit's capacity levels are chosen randomly and are set to 500 MWh, 1000 MWh, 1500 MWh, 1900 MWh. The TS capacity level at the end of the simulated period is not specified, since the aim of the scenario is only evaluate the capability of the system to handle a unit's breakdown and do not focus on heat production costs. Fault durations are assumed to be 10 hours, 20 hours and 30 hours, respectively. Heat demand curve and electricity price curve, including the extra fee of 394 SEK/MWh, for the reference year 2012 are presented in Appendix A.

4.3.4 Scenario 4 - Changed production mix

Just as Scenario 2, this scenario represents a future case of Borås DH system. The current production mix is changed in order to analyze new investment alternatives and to evaluate the techno-economic value of the TS as a part of the system with the new production mix. Since the wood chips dryer has a low availability, it is excluded from the production mix in this scenario. Instead of the dryer, probable substituting technologies of 22 MW of heat capacity will be introduced for each optimization one at the time. Table 4-4 shows the different investment alternatives and input data for these cases.

Table 4-4: Input data for new investment alternatives investigated in Scenario 4.

	Investment alternative	**Fuel**	**Capacity [MW]**	**Efficiency/COP**
Case 1	Electrical heater	Electricity	22	1
Case 2	Heat pump	Electricity	22	3
Case 3	Heat-only-boiler	Wood chips	22	0.85
Case 4	Wood chips CHP	Wood chips	22	0.87

The cases are analyzed for a winter week by using 2012 electricity prices (NordPool, 2013) and also assumed electricity prices for 2022 (Göransson, et al., 2013) as input. To find the most economically and technically attractive investment or retrofitting alternative, the total system costs of each case are compared.

5 Results

5.1 Reference scenario

The first scenario was the present set-up including thermal storage. Results from the three seasonal cases and respective TS' capacity level sub-cases are presented in this section.

5.1.1 A winter month - January

The relation between the electricity prices and the operation strategy of the production technologies during a month with a high heat demand can be seen in Figure 5-1. Since the heat demand is high during this period, the waste fired CHP plants (WCHP), which are the base load technologies, operate at maximum heat output level independently of electricity prices. However, the heat output from the wood chips fired CHP (WCCHP) units varies substantially with the electricity prices. When electricity price is high, the heat output from the WCCHP plants decreases, whereas the electricity output rises. However, when the electricity price is relatively low, the heat output from the WCCHP plants is kept at its maximum level, with respective power output. In other words, WCCHP plants operate with a high alpha value at times when electricity price is high.

The reason behind these output variations is the trade-off between the costs of running next production units in the merit order and the benefits from selling electricity. Contrarily, during times with low electricity price, operating the CHP capacities at full heat capacity is preferable compared to committing the more expensive bio-oil unit (BOHOB).

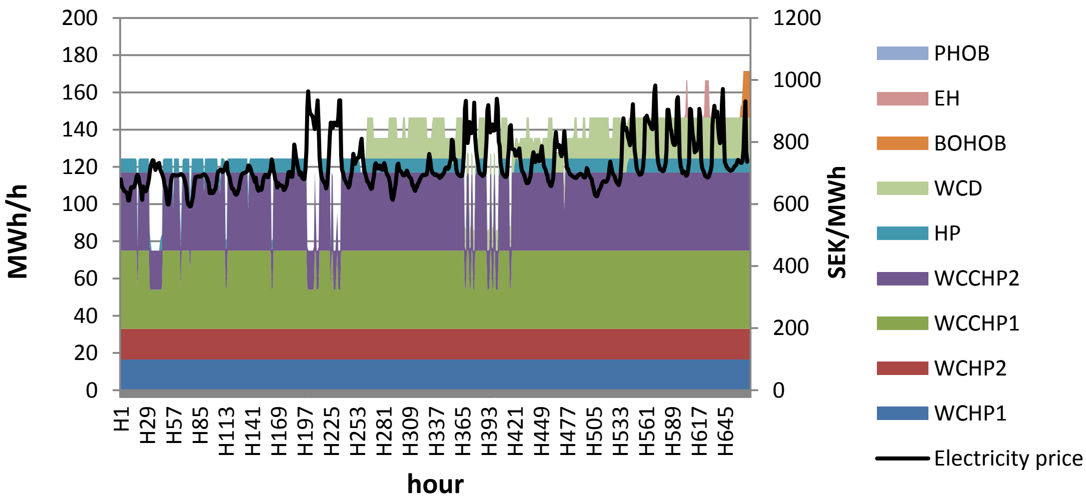


Figure 5-1 Modeling results of cumulative heat production from the reference scenario and the electricity price curve for January, 2012

The use of electricity driven units are directly affected by the electricity prices. In this period, the electric heater (EH) competes with the BOHOB. The EH has higher efficiency than the BOHOB, hence it turns on prior to the BOHOB when the electricity price is low, which can be observed in the Figure 5-1 in the period between hour 589 and 617. Vice versa with high price for electricity. This may be observed in Figure 5-1 considering the last few hours (after the hour 645 until the end of the modeled period) when the BOHOB is operated instead of the EH. However, the heat pump can be considered as an exception among the electricity driven units, since it is close to three times cheaper to run than the EH, which diminish the dependency on the electricity price. Even if the cost of electricity is higher than the other fuels, such as bio oil, it is still more profitable to run the HP than fossil fuel fired boilers.

Figure 5-2 shows the relation between the TS behavior and the operation strategy of production technologies during a month with a high heat demand. The gap between heat demand and total heat output from commited units represents the contribution of the TS. As it can be seen from Figure 5-2, when the total amount of produced heat is higher than heat demand, the TS is charged with the excess heat. Charging occurs when heat demand and electricity prices are low and the CHP plants and the HP operate with maximum heat output. When electricity price is high but demand is low, the model chooses to produce more electricity from the WCCHPs, resulting in less heat output. The gap between demand and production is then satisfied with discharged heat from the thermal storage unit. It can be also noticed that the TS level rarely approaches 500 MWh, which corresponds to the minimum allowable thermal storage capacity level for this scenario.

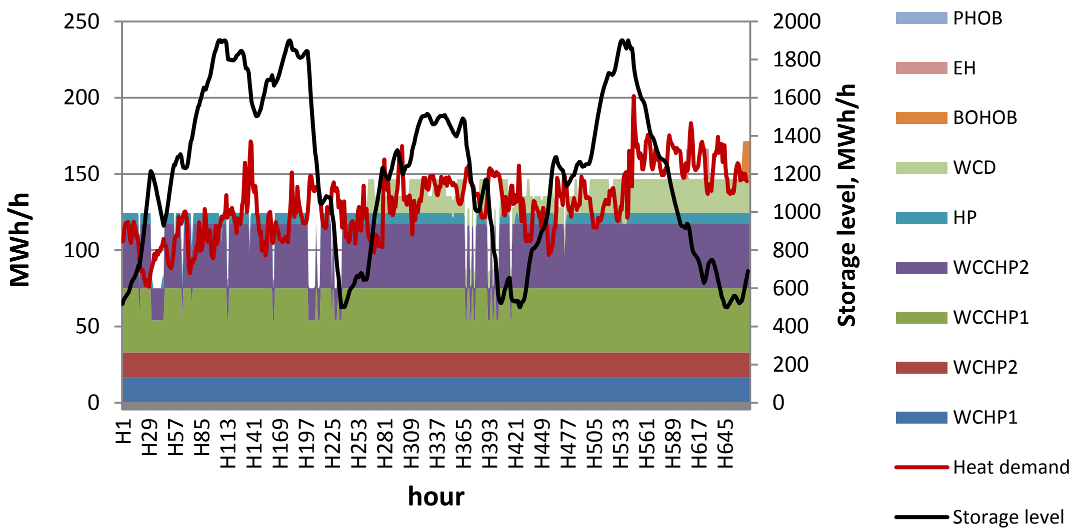


Figure 5-2 Modeling results of cumulative heat production and TS utilization from the reference scenario and the heat demand curve for January, 2012

5.1.2 An autumn month - October

Figure 5-3 shows the cumulative heat production during one autumn month depending on electricity price. Considering the first 197 hours of this period, it can be noted that the heat demand is relatively low and, therefore, there is a clear correlation, in terms of changeable heat and power production, between CHP operation strategy and the electricity price curve. In the period between hour 197 and 290, the heat demand is considerably higher and, as a result, the heat output from CHP plants is kept constant almost all the period, independently of electricity prices. At the same time, the TS, which was intentionally previously charged, drastically discharges because of the extreme spikes in the heat demand (to be observed from the Figure 5-4). The spike at the hour 292 is a distinct example when the electricity price is low whereas there is a peak in heat demand. Under this condition the optimization model suggests to curtail electricity production from CHP plants to the level when the maximum heat output is reached.

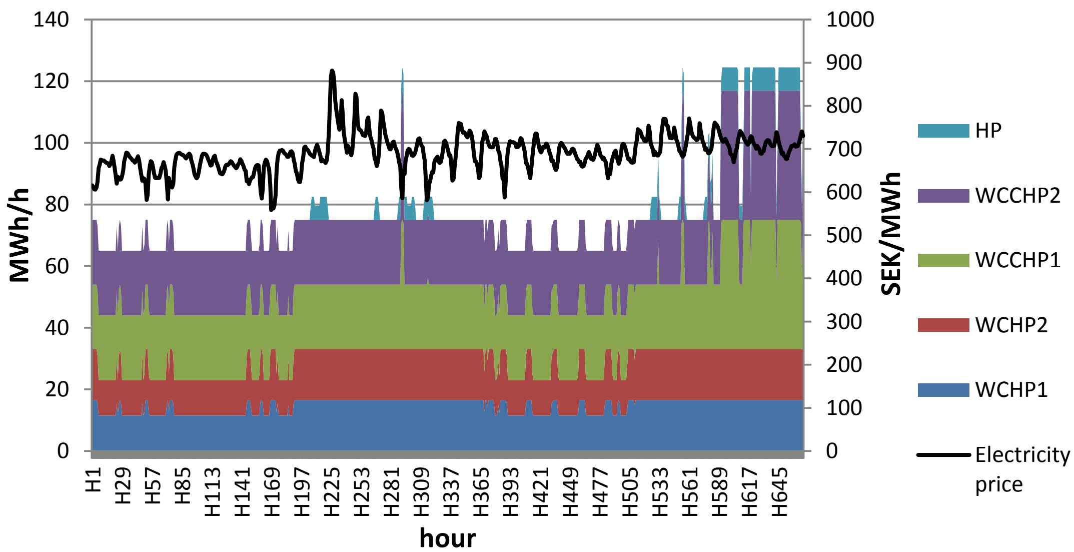


Figure 5-3 Modeling results of cumulative heat production for the reference scenario and the corresponding electricity price curve for October, 2012

The HP is operated during periods with high heat demand and relatively high electricity price. In these periods, the total heat output from the CHP plants is insufficient to cover the heat demand. On the other hand, around the hour 205, it is possible to increase the heat output from the CHP plants, yet the optimization model chooses to operate the HP instead. That is because it is more profitable to run the CHP plants with high alpha values when the electricity prices are high and instead satisfy the remaining part of the heat demand with heat from the HP and the TS. Nevertheless, once electricity price exceeds the break point level, the cost of running the HP becomes so high that the model chooses to turn off the HP and instead discharge higher amounts of heat from the TS unit.

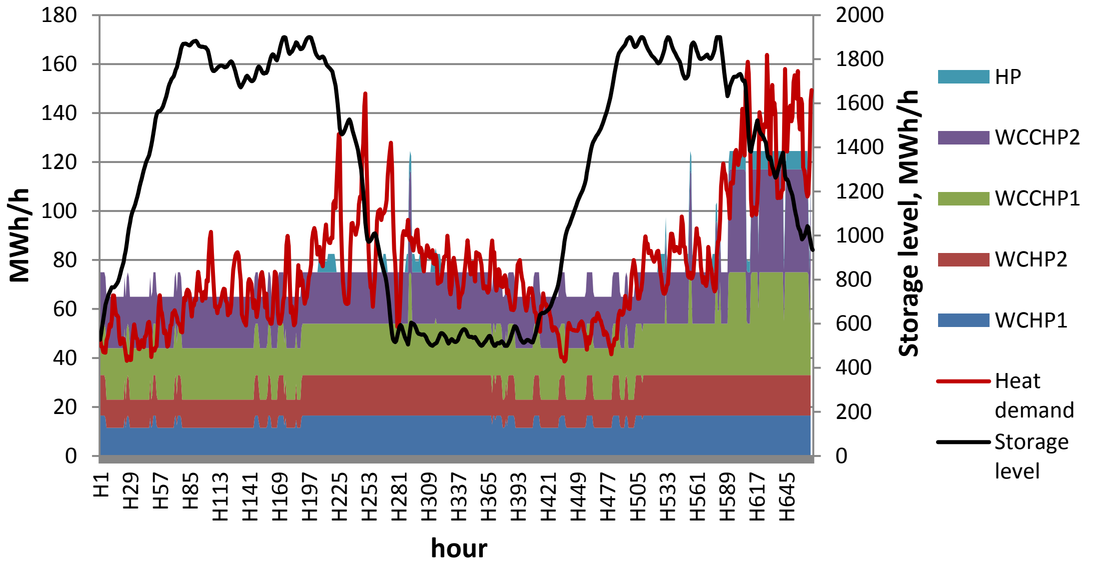


Figure 5-4: Modeling results of cumulative heat production and TS utilization for the reference scenario and the heat demand curve for October, 2012

5.1.3 A summer month - July

The summer period is characterized by low heat demand and low electricity prices; and where the district heat demand is satisfied only by using the waste fired CHP plants. One can also notice that the impact of electricity prices on the operational strategy of the CHP plants is still the similar as to the winter and autumn cases see Figure 5-5. When the heat production decreases, the heat demand is covered with a heat from the TS unit.

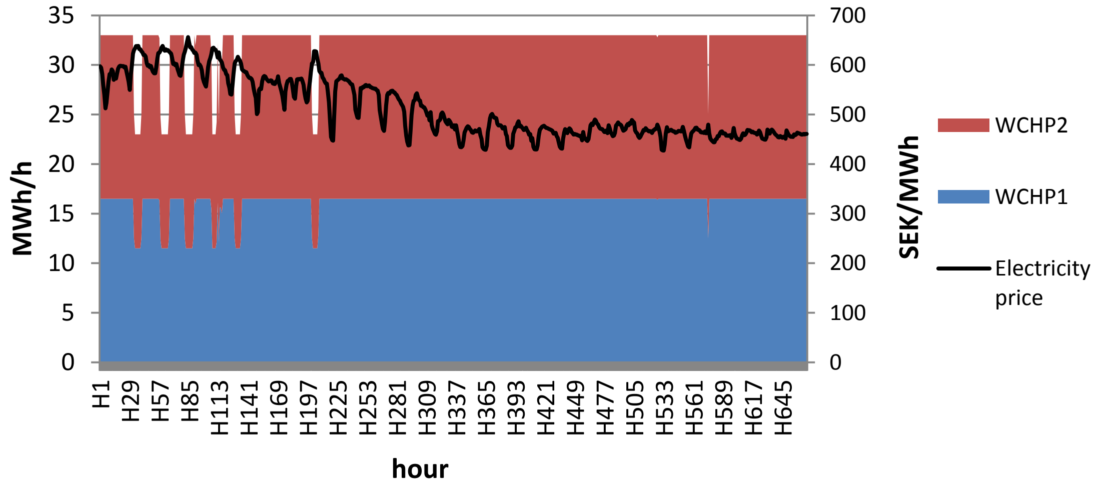


Figure 5-5: Modeling results of cumulative heat production for the reference scenario and the electricity price curve for July, 2012

5.1.4 The techno-economic value of the TS

Figure 5-6, Figure 5-7 and Figure 5-8 show the cumulative heat production during one week in autumn, winter and summer, respectively, both when the TS is included in the DH system and when it is excluded.

The results indicate that the overall strategy of DH system operation is still the same: to precisely fulfill the heat demand with the available heat generation capacities. In a typical autumn week, in case of no TS present in the system, the peak demand periods are handled by rapidly changed heat output from the CHP plants and, at some time slots, also with the HP and the EH, see Figure 5-6 a. However, when there exist a TS unit in the system, a more constant CHP operation may be observed and there is no need to operate the EH at all, see Figure 5-6 b.

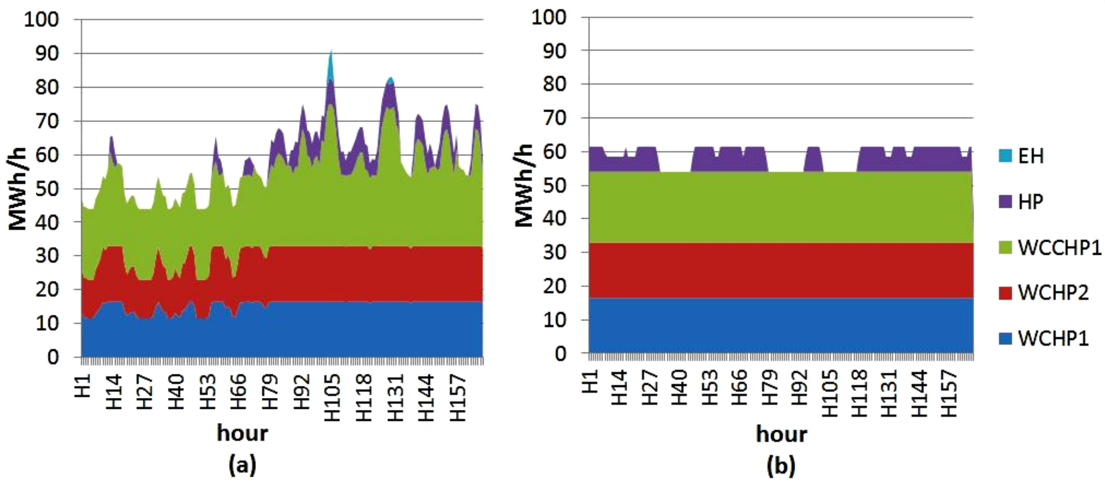


Figure 5-6 Modeling results of cumulative heat production for the reference scenario in an autumn week in October a) with no TS in the DH system b) with TS in the DH system

The optimal dispatches of heat production technologies for a winter week are shown in Figure 5-7. Without the thermal storage possibility, the heat pump and all CHP plants run continually, whereas periods with high heat demand are handled by engaging the WCD, EH, BOHOB and, at a few time slots, by oil fired heat only boiler (OHOB), see Figure 5-7 a. Contrarily, having the TS in the DH system enables a more flexible operation of the heat pump Furthermore, there is no need to engage the EH, WCD and BOHOB during periods with high heat demand, see Figure 5-7 b.

Obviously, it is more challenging to attain the goal of precise demand coverage from hour to hour when no TS is available in the DH system. The heat output from the CHP plants is more fluctuating when no TS available. It is to be noted that engagement of peaking units is needed, comparing to the case with the TS available. To conclude, the availability of the TS unit facilitates the operation of the DH system, since regulating the charging and discharging of the TS is easier than regulating the heat output from several generation units.

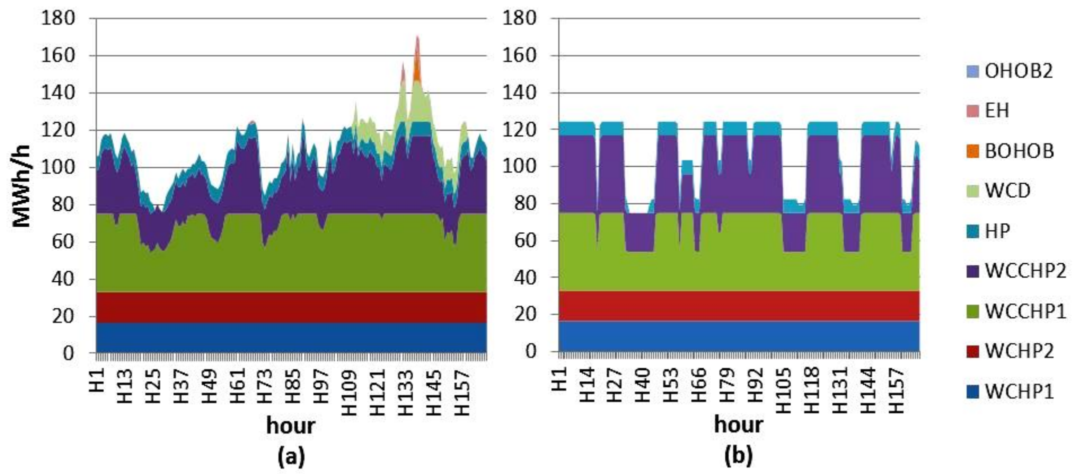


Figure 5-7 Modeling results of cumulative heat production for the reference scenario in a week in January a) with no TS in the DH system b) with TS in the DH system

In the summer case, with included TS, the WCHP plants are sufficient to cover the heat demand, even during periods of high demand. The CHP plants are operated in a flexible way, with variable alpha values when appropriate. The peak demand periods are completely handled by the TS. Without the TS in the system, the peaking periods are instead satisfied by using the HP and the EH, see Figure 5-8.

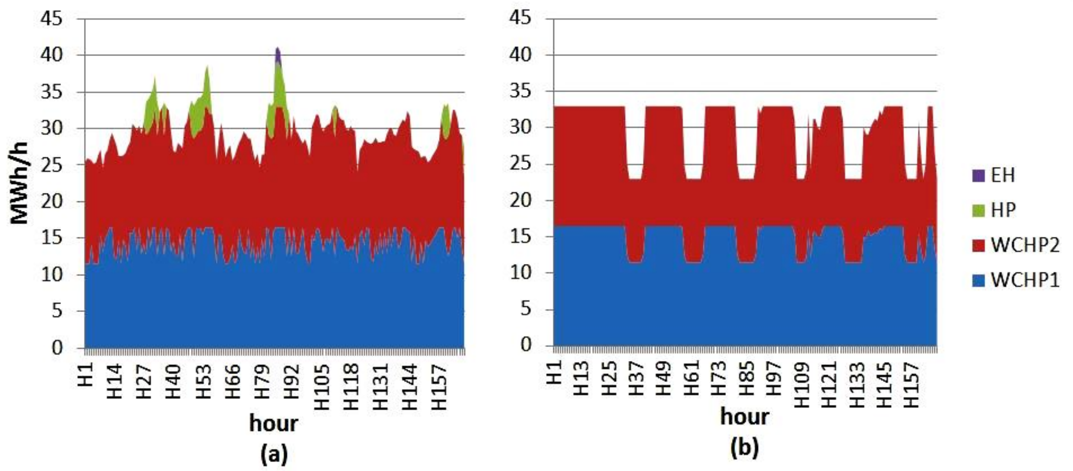


Figure 5-8 Modeling results of cumulative heat production for the reference scenario in a week in July a) with no TS in the DH system b) with TS in the DH system

The economic value of having a thermal storage unit present in the system can be evaluated based on the results that are presented in the Table 5-1. It can be observed, that the presence of a TS in the DH system decreases the total system heat production cost significantly for the analyzed summer and autumn weeks, whereas it is not as notable for a winter week. The discrepancy in the costs is influenced by which unit is next in the merit order and what is the price difference between that unit and the base load capacities.

Table 5-1 Modeling results of total system cost [SEK/week] of producing heat in the investigated DH system. The costs are calculated with and without TS unit for different seasons for the reference scenario

	October week	**January week**	**July week**
No TS	852 664	2 669 367	-63 547*
With TS	746 002	2 593 214	-95 362*
Savings in percentage	12.5	2.85	33

** The minus sign means that only the revenues from electricity production are accounted. Revenues from sold heat are disregarded.*

5.1.5 The impact of minimum allowable thermal storage capacity level on the total system heat production cost

The modeling results obtained from the sensitivity analysis of a minimum allowable thermal storage capacity level are shown in the Table 5-2. The model results indicate that the total system cost of producing heat is rather insensitive to the minimum allowable TS level.

Table 5-2: Modeling results of total system cost [SEK/week] for different TS capacity levels from the reference scenario

	Minimum allowable TS level , Initial state , End state [MWh]	**October week**	**January week**	**July week**
Case 1	1000,1000,1000	746 465	2 594 142	-95 293
Case 2	700,700,700	746 002	2 593 545	-95 334
Case 3	500,500,500	746 002	2 593 214	-95 362
Case 4	200,200,200	744 578	2 592 717	-95 403

It should be kept in mind that initial and final TS capacity levels are also set for the modeling time span. One should, therefore, make a tradeoff between the minor decrease in total system cost and the system security aspect. In other words, the opportunity cost of discharging the TS to a relatively low capacity level is to increase the risk of not being able to satisfy the heat demand in case of an unexpected break-down of one or more units in the system. Consequently, there is no incentive to operate the TS unit at low levels. Thus, keeping the TS relatively charged, so that the TS is also ensuring the system security, might be the most beneficial strategy.

5.2 Scenario 2 - Borås 2022

The possible influences that a future electricity price, which is expected to be higher and more fluctuating, may have on the DH system are shown in this section. The generation units which are used to cover the demand during the modeled period are the CHP plants, the HP and the WCD. The WCHP plants act as the base load units and generate heat equaled to maximum rated capacity. Depending on the electricity prices, either the WCD or the HP is a peaking unit. The heat production costs are used to compare the considered cases and, are summarized in the Table 5-3.

The solution strategy of the model is still the same as for the reference scenario:

- if the heat demand is not extreme, whereas electricity price is high, the decision is made to reduce heat output from WCCHP plants, while discharging the TS;
- if electricity price and heat demand are low, the TS is constantly charged;
- if both heat demand and electricity price are very high, than the tradeoff between the revenues from sold electricity and costs of running more expensive generation units is in place.

Comparing electricity prices from 2012 and assumed prices from 2022 for winter case, total system heat production costs in 10 years is modeled to be slightly lower than today's costs. Whereas calculated costs of heat production for one summer and autumn week in future are higher than respective costs in 2012. Since all input data remained unchanged and only the pattern of electricity price curves was modified, the conclusion can be made that the dynamics of electricity prices actually influences the system.

Earlier in the report, Figure 4-2 showed that the discrepancies between highest and lowest price levels during one winter week are larger in the year 2022 compared to current prices. Moreover, the duration of low price periods is longer in the future case. As a result of this more dynamic pattern of electricity price variations, utilization of CHP generation units and the TS is influenced in a way that actually causes a drop in the total heat production cost. On the other hand, a more plane shape of the electricity price curve during the 2022 summer week results in an increase in heat production cost compared to corresponding week in 2012. An actual correlation between electricity price and production units/thermal storage operation can be observed in Figure 5-9 and Figure 5-10.

Table 5-3: Modeling results of total system costs [SEK] for Scenario 2

	El.prices 2012	Equalized el.prices 2022	Reference el.prices 2022	El.prices 2022 + 10% increment	El.prices 2022 + 20% increment	El.prices 2022 + 30% increment
October week	761 365	778 233	530 737	362 561	193 542	22 702
July week	129 082	130 221	-214 930	-258 372	-301 814	-362 616
January week	3 181 56	3 164 730	3 209 266	3 036 799	2 860 504	2 682 486

Comparing the total system costs from a winter week by using current prices for 2012 and assumed prices from 2022, respectively, it can be observed that these costs are almost equal; whereas the respective total system costs for the summer period differ with several orders of magnitude. The reason for this result is the notable difference in electricity prices during the summer period in the two compared years. The amount of electricity sold is the same for both years, but the revenue from the sold electricity is much higher for the analyzed summer week in 2022, so high that it even results in a negative total system cost.

It is also notable that with a supposed graduate increase of electricity prices in the future (as exemplified by 2022), the total system costs are decreased compared to 2012. There are occurrences when the electricity prices are considered high enough to advocate heat output curtailment from the WCCHP plants. Higher power output result in lower total heat production cost and higher number of the TS charging/discharging cycles. Because of the increased electricity prices, the total HP output was reduced, replaced by a more intense utilization of the WCD.

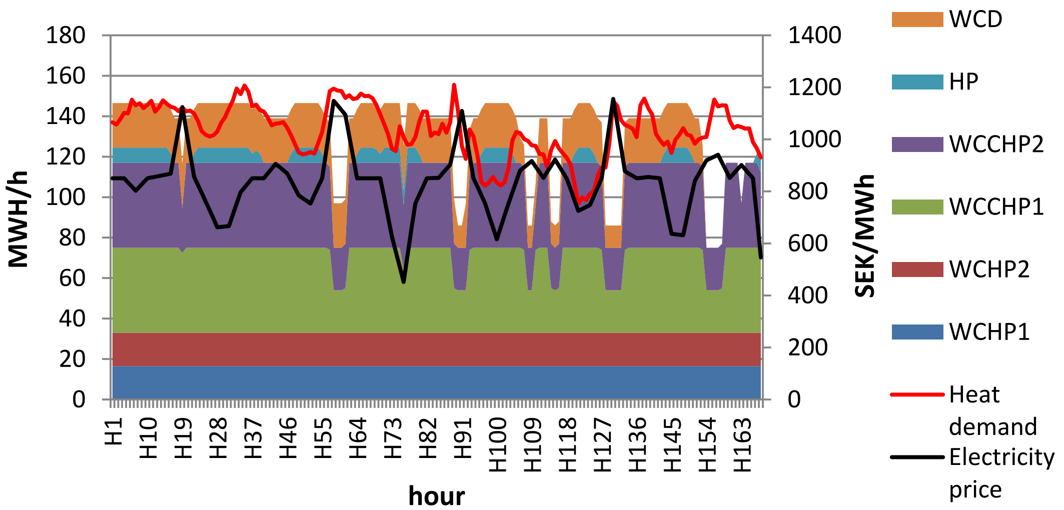


Figure 5-9: Modeling results of cumulative heat production for Scenario 2 and the heat demand and electricity price curves for a week in January, 2022

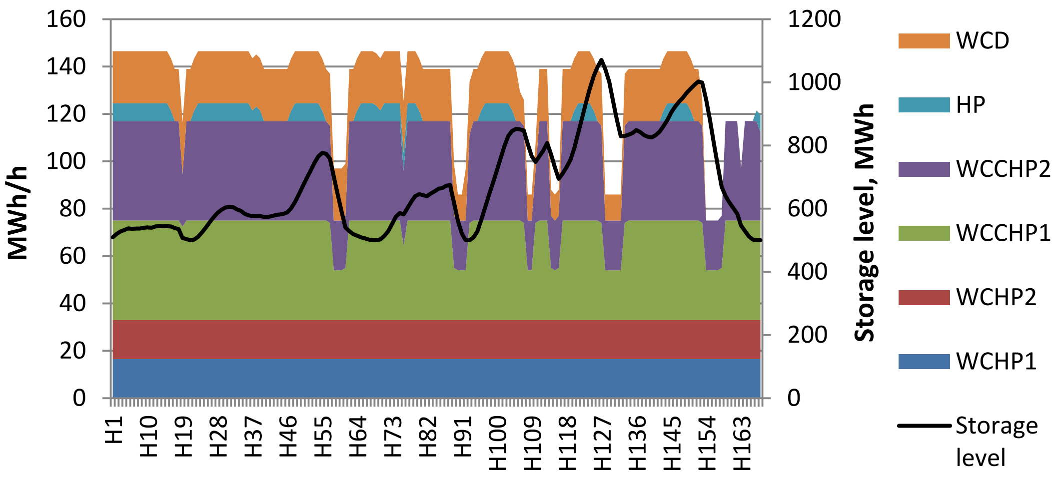


Figure 5-10: Modeling results of cumulative heat production for Scenario 2 and the thermal storage utilization for a week in January, 2022

5.3 Scenario 3 - An unexpected breakdown

The results obtained by a stress testing of the DH system for a winter week are represented in this section. Total system production costs are congregated in the Table 5-4.

A simulated breakdown of one of the WCCHP plants does not result in any risk of heat supply deficiency in the DH system. Even with the lowest tested initial TS capacity level – 500 MWh, and failure duration of 30 hours, the district heating system would still be capable of satisfying the heat demand. Heat production costs, as one could expected, are increased with respect to the failure duration. This is due to a longer "stay on" state of the expensive OHOB, which is the assigned peaking boiler for the case of 30 hours breakdown duration.

It is also predictable that the additional cost due to a breakdown of a unit is lower for the cases when initial TS capacity level is set to a higher value. This is a result of having a substantial amount of free heat capacity at the beginning of the simulated period. Heat production costs increase, as one may expect, with the length of the failure duration for all cases regardless of initial TS level.

Table 5-4: Modeling results of total system heat production costs [SEK] for Scenario 3 for different initial TS capacity levels and for different durations of the breakdown of units investigated

Initial TS capacity level, MWh	Breakdown of WCCHP2, dryer works with 0.5 of max capacity*			Breakdown of WCCHP1 and WCCHP2, dryer is shut off**		
	10 hours	20 hours	30 hours	10 hours	20 hours	30 hours
1900	5 353 518	5 884 575	6 377 991	5 792 430	6 737 860	7 643 430
1500	5 708 463	6 239 764	6 733 381	6 147 489	7 113 632	8 021 081
1000	6 152 405	6 684 133	7 190 655	6 591 724	7 586 024	Infeasible
500	6 596 729	7 154 383	7 662 655	7 061 211	Infeasible	Infeasible

** with an assumption of a breakdown of one of wood fired CHP plants, maximum pretreated fuel from wood chips dryer is reduced by a factor of two. Assumption is valid only for the hours of a breakdown.*

*** in the situation when both wood fired CHP plants are out of order, wood chips dryer is forced to turned off too.*

The results from the worst case scenario, with a breakdown of both WCCHP plants and the WCD, are also shown in Table 5-4 and have more debatable nature.

It can be observed that, in the case of initial TS level of 500 MWh, the system can operate safely if the WCCHP plants are out of order for less than 10 hours. For the cases when the units are modeled to be unavailable for a longer time period, the model does not find a feasible solution. This means that the available production capacities together with an initial TS capacity level of 500 MWh cannot provide enough heat to cover the demand of the system.

In the case of an initial TS level of 1000 MWh, the system can cope with a breakdown of the WCCHPs and the WCD for at least 20 hours. An interesting result is that the obtained heat generation schedule for the case of 20 hours breakdown and 1000 MWh initial state shows that the output from the EH was not equal to its maximum capacity. Neither were the maximum limits of the TS discharge rates ever reached. However, the TS capacity level at the hour 20 was equal to the minimum allowed level, notably 100 MWh. This means that the system could resist a longer breakdown, however not exceeding 30 hours, since the model renders an infeasible result for this case. Thus, the thermal storage unit’s capacity and initial level of 1000 MWh is not sufficient to handle a breakdown of 30 hours.

The results differ for the cases when the initial TS capacity levels are set to 1500 and 1900 MWh. At both levels, regardless of failure duration, the system is able to supply enough heat to cover the heat demand. Even in the case of 30 hours of blackout and

TS level of 1500 MWh, the EH was working with a partial or zero heat output for a few hours, indicating a possibility to support even longer breakdown times.

The results suggest that the decision of what capacity level of the TS unit should be maintained in specific period of a year is to be mainly based on the availability of each specific unit. However, there is no need to always keep the TS fully charged, since it is still possible to follow redundancy precautions with a lower TS unit capacity.

5.4 Scenario 4 - Changed production mix

The optimization results of the different cases in Scenario 4, when the WCD is excluded from the DH system, are presented in the Table 5-5. For all cases, the heat production cost increases notably when the dryer is excluded from the production mix. That is because the dryer's contribution is replaced by the EH or the BOHOB which are usually peak load technologies.

In Case 1, an additional EH is included to the system. The total system cost is decreased inconsiderably in this case. There is no need to run BOHOB, whereas the EH runs at maximum load. Since the EH is an electricity driven peak load unit, the cost for producing heat remains high.

On the other hand, inclusion of an additional HP in the DH system results in a noticeable drop of the cost of producing heat. In this case, there is no need for the EH and the HP is sufficient to replace the WCD's heat production. Since the HP has an assumed COP of 3, it has a good fuel economy. In a similar way, inclusion of a new heat only boiler (Case 3) results in the total system cost decrease. The boiler would run as a base load unit with wood chips as fuel input which is relatively cheap and also favorable from the environmental aspects.

In Case 4, an additional WCCHP plant is added to the system to act as a base load unit. This addition results in a considerable decrease in the total system cost, see Table 5-5, which may be explained by the low fuel price and the additional revenues from selling electricity. It should be noted that the additional investment costs for the different cases are not included in the analysis.

Table 5-5: Modeling results of total system costs [SEK] for Scenario 4

January week	**The change in the current production mix**	**2012 prices**	**2022 prices ref.**	**2022 prices 10% increm.**	**2022 prices 20% increm.**	**2022 prices 30% increm.**
	None	3 181 256	3 209 266	3 036 799	2 860 504	2 682 486
	No dryer	3 829 187	3 821 264	3 664 969	3 504 621	3 342 840
Case 1	No dryer + EH	3 826 243	3 793 033	3 642 012	3 485 114	3 325 988
Case 2	No dryer +HP	3 142 905	3 145 196	2 995 280	2 842 877	2 689 036
Case 3	No dryer+	3 108 984	3 131 043	2 949 578	2 766 111	2 581 706

	WCHOB					
Case 4	No dryer + WCCHP	2 959 808	2 989 106	2 772 054	2 552 745	2 332 224

6 Discussion

This chapter contains some discussions around the relevance of the obtained results and on the assumptions made. In what way outcomes from the model runs can be different, if e.g. the forecasts regarding electricity prices and heat demand were more certain, is to be argued in the following sections. Suggestions for future research are also stated in this chapter.

6.1 Strengths and weaknesses of the modeling approach

While the optimization model was developed, a better understanding of GAMS software particularities, main challenges met by optimization model developers, and, for sure, singularities of district heating systems operations was achieved. This would not have been the case if an existing optimization model for the DH system evaluation had been chosen. Moreover, since GAMS is a coding type software, in contrast to existent visualized programs, the developed optimization model has a high level of flexibility regarding any desired changes.

The objective function included in the code of the model is to minimize overall system heat production cost. Undoubtedly, this is the main concern for most heat production companies. However, taking into account recent more environmentally oriented thinking, the objective function of the model may be modified. It can be done in a way of assigning additional costs for specific emissions or environmental impacts, or in the way of direct inclusion of amount of harmful emissions e.g. in ton/MWh of produced heat or power, with respective changes to objective function. As a result a more substantiated decision, regarding the utilization of every production unit will be possible to make.

It was decided to create a mixed integer nonlinear model in order to get the most accurate replication of the operation strategy of the existing DH system. This goal is achieved, as supported by the obtained results, especially from the scenario when the TS was not present in the system. It can here be clearly observed that the heat output from the operated heat generators is varying from hour to hour in order to cover the demand precisely, which is exactly what would happen in the reality.

Nevertheless, there are drawbacks of using a nonlinear model. Firstly, because of nonlinearity, some important simplifications are necessary, which could influence the obtained results. For example, the efficiencies of the units are assumed to be constant regardless of the load of the units. Secondly, nonlinear models require high computational times, what makes it impossible to run the model for a time period of one year, in order to make a long-term assessment of the system’s dynamics and thermal storage utilization strategy. The nonlinear nature of the model also resulted in a more complicated program code. After all, the choice between using a precise but computationally heavy model or a simpler but less accurate model should mainly be based on the time perspective, the number of needed runs and the computational resources.

Within this thesis project, running the optimization model for the one year time duration was rejected due to the very long computational time that would be required. Therefore, the year is divided into monthly and weekly time spans. Modeled periods for the scenario when future electricity prices are used, are chosen regarding the availability of data for the year 2022. The other scenarios time spans are chosen to represent average heat demands and electricity prices for different seasons. Within this thesis, the spring season is not specifically analyzed since it has similar patterns regarding heat demand and electricity prices as the autumn season. The point here is that time spans can be chosen differently dependent on particular situations that are under the scope of the analysis.

It should also be noted, that the optimization model operates under the condition of perfect foresight. All the decisions made are based on the input data, which is known in advance regardless of time span. As a result, the obtained result from each model run should be considered as a mathematically generated optimal solution for a specific situation with predefined conditions. The actual decision of e.g. how to run a particular production unit or how to utilize a thermal storage unit is to be made by taking into account availability of units and fuels, uncertainties in weather forecasts, inertia in the system and so on. The operation strategy is also influenced by the goals and strategic planning of the operating company. For example, if the intention is to promote “green” fuels, this will probably result in a usage of bio-oil fired units at the maximum capacity for the whole time span, disregarding the fact that the price for electricity is low, ipso facto to run electrical heater is more economically beneficial. Hence, there will be a risk that not the cheapest option will be chosen, however the obligation of delivering a necessary amount of heat to consumers will be fulfilled.

6.2 Input data and assumptions

Fuel prices, assigned for each heat production technology, have the biggest impact on the results generated by the optimization model. The fuel prices used in the present study are rounded and assumed to be constant for the whole year. With the precise data available, the obtained results could be slightly changed. Moreover, e.g. extra subsidies for bio fuels or additional fees for emissions released by burning fossil fuels might also make model results more realistic.

Technical parameters regarding production units and the TS are mostly based on the experience of operational personnel and data from measurement devices. For example, ramp rates for heat generation technologies and charge/discharge rates from/to the thermal storage unit, embedded to the model, most likely differ from situation to situation. Because of these discrepancies with reality, really sharp spikes and dips in the CHP plant’s outputs can be observed. If the system’s inertia and difficulties of adjusting an amount of produced heat or power were included, heat production curves would be smoother with no drastic changes from hour to hour.

The assumption made regarding the constant efficiencies of the units, losses in the DH network which are included in the overall heat demand, losses from the TS unit and WCD related simplifications could hypothetically change the model results as well. For example, it is assumed that the cost of running the WCD consists of wood chips price and electricity price for auxiliary electricity consumption. However, in reality the cost of using the dryer includes only the electricity price, since fuel is only pretreated in the dryer and the price paid for wood chips is already assigned to WCCHP plants.

One significant simplification is also made for the heat produced from the units during the start-up and shut-down periods. It is assumed that this heat is dumped and is not supplied to the network. This is actually the case in reality too. Nevertheless, if the decision is made to somehow utilize this heat, the logic of "power trajectories" can be applied to the model. This logic simply means that the heat output is being increased with a predefined increment in every time span during the start-up period and decreased in the same way during the shut-down. The difference is that this heat is not to be dumped anymore but successfully supplied to the network.

6.3 Discussion around the scenario results

In the reference scenario a comparison of two cases, when a DH system contains a thermal storage unit and not, is conducted. Although the obtained results are theoretically viable, they do not completely represent a real case. In reality, there is always an internal DH network capacity which can be used for moderation of small, but frequent, demand variations. To conclude, in order to make a deliberate decision regarding investment in a TS, real DH network volume should be first evaluated.

For the case when different allowed TS capacity levels are estimated, trial levels are chosen randomly and assumed to be constant for the whole modeled period. However, if the foresight regarding electricity prices and weather conditions was absolutely certain at least for one week ahead, whereas all the units were 100% reliable, the following strategy regarding TS utilization could be applied: in order to be on the safe side initial and final TS capacity levels would be set to a high level e.g. 1000 MWh, however minimum allowed level during the modeled period would be set to e.g. 200 MWh. With these constraints TS utilization could be more flexible and would probably lead to further savings, while still assuring that at the end of the period the TS will be charged and ready for the next week operations.

The results from Scenario 2 (a future scenario) show that with an increase in electricity prices the total heat production cost decreases. However, to conclude that these changes have happened only because of the presence of the TS is not legitimate. The actual reason is a combined effect of changed heat output from CHP plants, HP and TS utilization dynamics. In order to evaluate an actual contribution of the TS unit, the power production from the CHP units can be limited in accordance to the reference case results. Another way to asses this is to compare heat production costs but with excluded revenues from selling electricity. Eventually, in order to evaluate a real contribution to the system, under the condition of increased electricity prices, more model runs are needed with more parameters being first variable and afterwards constant.

Comparison of the achieved results, using actual electricity prices and assumed prices from the year 2022, cannot be considered as a robust and 100% accurate result. The dynamics of electricity prices are apparently different and the conclusion that dynamic price variations facilitate a decrease in heat production cost is valid. However, because of the fact that price peaks and dips occur at different time slots in the years 2012 and 2022, whereas heat demand is assumed to be the same, system production cost would be different anyway. One solution to account for this could be to take a price curve from the year 2012 and try to modify it in the way that when the price increases, values are multiplied with a multiplier higher than “1”, whereas when price decreases, values are multiplied with a multiplier lower than “1”. As a result a new price curve with larger price differences from hour to hour will be obtained, and can be used for achieving a new heat production cost, and consequently modified thermal storage behavior.

An attempt to estimate how the system will react to the failure of one or more production units is conducted within this thesis. For this reason the winter week with extreme cold weather conditions and high electricity prices is chosen. The results are reasonable and can be taken as basis for future research. Nevertheless, there are particularities that should be concerned. Firstly, the model operates with perfect ramp limits, what is probably unrealistic to achieve in reality. This means that system’s inertia and more casual smaller faults in the system should also be considered. Secondly, in contrast to the modeled situation when the heat demand is high at the first modeled hour and constantly decreases with every next time step, there can be a case when heat demand is extremely high for more hours in a row or even increases. In this case, there is a risk that the system will not cover the demand even with a fully charged TS unit. Obviously, the obtained results can serve only as a starting point for future discussions and cannot be taken as a suggested strategy for TS utilization.

For the scenario of changed production mix, Scenario 4, the most realistic investment alternatives are tested. Based on the obtained results a new HP is probably the cheapest alternative, comparing investment cost with a CHP plant or a heat only boiler. However, even though the cost of construction of a new CHP plant might be the highest in comparison to the other investment alternatives, it contributes with the biggest drop in the total heat production cost. Considering a probable increase in future electricity prices and Borås’ goal to become a fossil fuel neutral city (Anon., 2012), an additional CHP plant provides the most suitable investment alternative for the considered DH system in a longer term perspective.

7 Conclusions

In this thesis, a computer based model with the aim of generating an optimal operational schedule for all the units present in a district heating system was successfully developed and applied to the existing DH system of Borås. The model is a techno-economic model with an objective to minimize total system heat production cost. The developed model includes overall and unit specific heat production balances; transient start-up and shut-down costs; ramp up and ramp down production limits; minimum on- and off-times and thermal storage describing constraints.

The model-generated results show that the availability of the TS in the DH system is of technical and economic value. Within the reference scenario the total heat production cost decreased in all analyzed cases with the TS available in the system, in contrast to no TS cases. The result obtained for e.g. one autumn week indicated a decrease of the total system operational cost by around 12.5 %. In the examined system this should be well in range of being economically beneficial result.

Additionally, the existence of the TS resulted in a decreased number of situations when peak-production units, usually fossil fuel fired, must be turned on to meet the demand. With the TS present and utilized, the share of heat produced by base load units increased, ipso facto, enhanced overall production efficiencies of these units as well as the system as a whole. Thus, the economy is improved.

High electricity prices obviously increase the economic value of power produced by CHP plants. Thus, with part of the production costs covered by sold electricity the total heat production economy is improved by increased use of CHP. With an increase in 2022 autumn electricity prices by 30 %, the total system operational cost dropped from around 530 kSEK to around 20 kSEK.

Considering extremely cold winter conditions, the TS capacity level of 1000 MWh, around a half of maximum unit's capacity, is not sufficient to stand the breakdown situation of both WCCHP plants and the WCD for 30 hours in a row. Whereas, the capacity level of 1500 MWh is adequate to supplement heat output from working units and stand a fault of this scale. The system's reaction on more extreme weather conditions, and subsequently higher demand requirements, should be further evaluated in order to make a well-considered decision about the minimum allowed storage level.

To simulate probable DH system development, the WCD was excluded from the system and, consequently, substituted by available production technologies one in a time. With no WCD in the system the cost of producing heat during one winter week increased by around 650 kSEK, compared to the base case when WCD was available. The base load production capacities would result in the most economically beneficial result if the WCD is to be substituted. If the WCD was replaced by a new WCCHP plant of the same capacity, the total operational cost would drop by around 7 % for one winter week.

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Appendix A - Heat demand and electricity price curves for Scenario 3

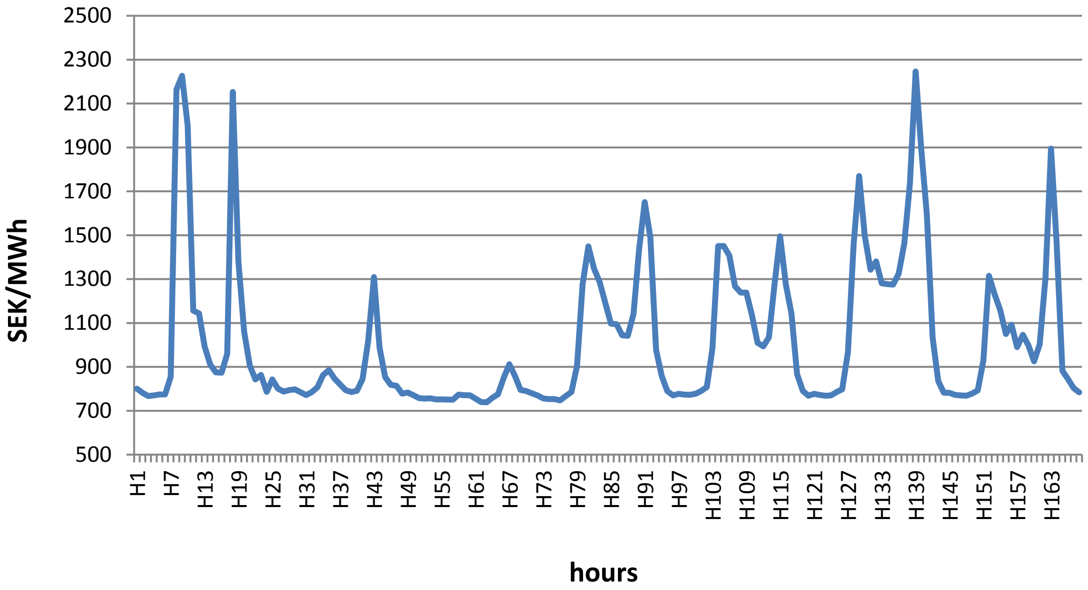

Figure A-1 Electricity price curve for one extremely cold winter week, year 2012

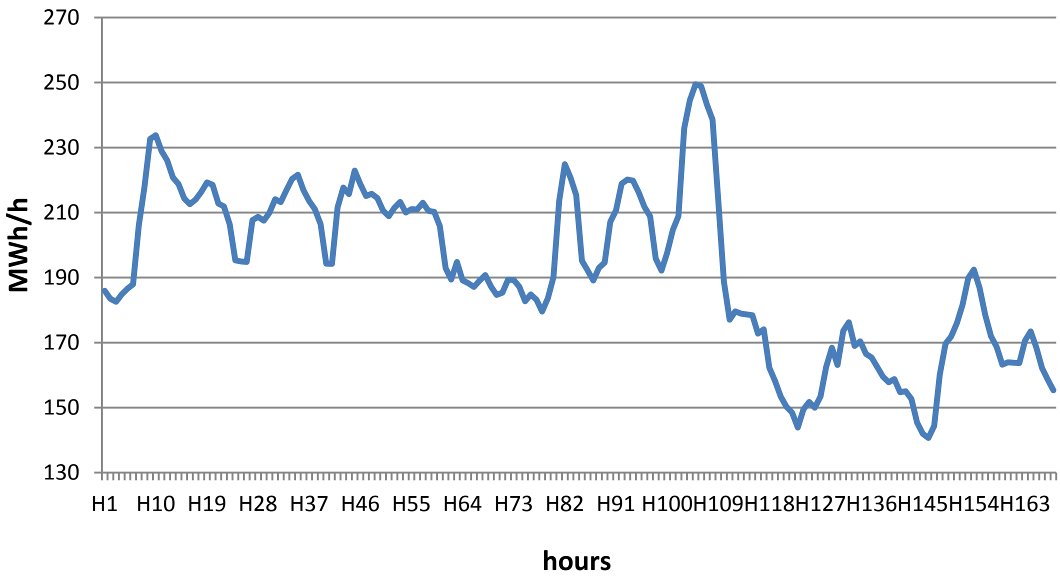

Figure A-2 Heat demand curve for one extremely cold winter week, year 2012