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Comparing the effects of flexibility options on conventional and low-temperature district heating networks

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Comparing the effects of flexibility options on conventional and low-temperature district heating networks

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Abstract

District heating (DH) systems have been commonplace in Europe for over a century. These systems have undergone an evolution since their conceiving, and today we are at the precipice of the next major transition from the third-generation district heating system (3GDH) to the fourth generation (4GDH). Current 3GDH systems operate at a supply temperature in-between 80 °C - 100 °C and a return temperature of around 45 °C. Future 4GDH systems will operate at a supply temperature below 70 °C and return temperature as low as 25 °C, and therefore, will integrate waste heat available at low temperatures, and renewable heat sources.

The literature review performed here shows that low temperature DH (LTDH) systems have several benefits over their conventional temperature DH (CTDH) predecessor and achieve lower operating costs for some technologies when compared to the CTDH alternative. Therefore, in this thesis, a TIMES (The Integrated MARKAL-EFOM System) model is used to simulate the operation of a DH system. The learnings from the literature review were incorporated into the model so that certain operational differences between CTDH and LTDH systems could be compared.

In this context, the aim of this project is to analyse the effects of flexibility options on the operation of a DH system, and to compare these effects between CTDH and LTDH systems. Flexibility options in DH systems are technologies and concepts that work towards balancing heat generation and demand in thermal grids and can also help balance power generation and demand in electrical grids. Examples of flexibility options are thermal energy storage (TES) tanks, and seasonal energy storages (e.g., borehole TES (BTES), caverns (CTES), and pits (PTES)). These flexibility options have already been implemented in varying amounts in today's CTDH systems and will therefore have to provide the same service with LTDH systems in the future.

As part of the REWARDHeat project (grant agreement No. 857811), the Swedish city of Helsingborg was used as the case-study in this thesis. The city's heating sector was incorporated into a TIMES heat model and simulated for the period 2017 to 2052. The existing CTDH system model was then adapted to a LTDH system model and simulated for the same time horizon. Both the CTDH model and LTDH model were simulated for a case with TES available and then for a case where TES was not available, to better-identify the flexibility benefits. The effect of electricity prices on the operation of the system was also studied, where one case uses electricity prices that are on the conservative (i.e., higher) side and another on the ambitious (i.e., lower) side. This means that a total of eight scenarios were simulated and analysed.

The results show that more heat storage capacity is utilised in the LTDH system due to TES technologies having lower heat losses. Also, it was found that peak shaving was more pronounced in the LTDH system. This is due to more base heat supply in the system from more excess heat, and from STES discharging. This means that the required installed capacity of heat generating technologies are lower compared to the CTDH alternative. This all translates to TES technologies facilitating greater savings in total system cost, by almost 10%, in the LTDH system. The CTDH and LTDH systems studied in this thesis (i.e., with and without TES) are seen to transition from being a net electricity generator to being a major electricity consumer. This is due to reducing electricity prices going into the future, which incentivise investments into heat pumps (HPs), eventually making the systems (with combined heat and power (CHP) plants in the mix in the earlier years) HP-dominated. The inclusion of TES technologies is shown to accelerate this transition in both CTDH and LTDH systems studied in this thesis. More electricity is generated in the CTDH system than in a LTDH system as the cost savings from running HPs (due to higher coefficients of performance (COP) in low-temperature operation) offsets the revenue from electricity sales.

Finally, the effect of electricity prices is also seen in the results. Lower electricity prices favour more DH production from HPs, while higher electricity prices incentivise increased production from CHP plants. The results show that the CTDH system gives the network operator more freedom (than in the LTDH system) to respond to electricity prices.

Therefore, to conclude, LTDH systems can make more use of the flexibility provided by TES technologies due to lower heat losses, as shown through DH production volumes being lower, and through more peak shaving.

Similar studies in future could incorporate a sensitivity analysis on the COPs of HPs in LTDH systems, given that this parameter seems to greatly influence the cost optimised strategy for operating DH systems. Also, it may be beneficial to expand the study into incorporating the city’s power sector, which would mean incorporating the electricity demand into the model. It would be interesting to see if this would cause the model to invest in other technologies other than HPs, or if it might still make more financial sense to import the electricity at market prices. Finally, the cost of transitioning from a CTDH system to a LTDH system could also be considered in the model, as it was not the case in this project. This would probably show that the financial benefit of LTDH systems is less than what is predicted in this study.

Keywords: District heating (DH), low-temperature district heating (LTDH), 4GDH, Flexibility, Thermal energy storage (TES), Optimization, Modelling

Sammanfattning

Fjärrvärmesystem har varit vanliga i Europa i över hundra år. Dessa system har utvecklats sedan de utformades, och idag står vi inför nästa stora övergång från tredje generationens fjärrvärmesystem (3GDH) till fjärde generationen (4GDH). Dagens 3GDH-nät fungerar med en framledningstemperatur mellan 80 °C och 100 °C och en returtemperatur på cirka 45 °C. Framtida 4GDH-nät kommer att fungera vid en framledningstemperatur under 70 °C och en returtemperatur så låg som 25 °C, och kommer därför att integrera spillvärme som är framkomlig vid låga temperaturer och förnybara värmekällor.

Litteraturstudien som gjorts i den här studien visar att fjärrvärmenät med låg temperatur har flera fördelar jämfört med deras föregångare med konventionell temperatur och att driftskostnaderna för vissa tekniska system är lägre än för alternativet med konventionell temperatur. I denna avhandling används därför en TIMES-modell (The Integrated MARKAL-EFOM System) för att simulera driften av ett fjärrvärmesystem. Lärdomarna från litteraturstudien användes i modellen för att vissa driftskillnader mellan dessa två system så att de kunde jämföras. I detta sammanhang är syftet med detta projekt att analysera effekterna av flexibilitetsalternativ på driften av ett fjärrvärmesystem och att jämföra dessa effekter mellan konventionella temperaturer och lågtemperaturssystem. Flexibilitetsalternativ i fjärrvärmenät är teknologi och koncept som arbetar för att balansera värmeproduktionen och efterfrågan i termiska nät och som också kan bidra till att balansera elproduktionen och efterfrågan i elnätet. Exempel på flexibilitetsalternativ är lagringstankar av värmeenergi och säsongsbundna energilägen (till exempel lagring av värmeenergi i borrhål, grottor och gropar). Dessa flexibilitetsalternativ har redan införts i varierande omfattning i dagens fjärrvärmenät och kommer därför att användas med lågtemperaturnät i framtiden.

Som en del av REWARDHeat-projektet (bidragsavtal nr 857811) användes den svenska staden Helsingborg som fallstudie i denna studie. Stadens värmesektor införlivades i en TIMES-värmemodell och simulerades för perioden 2017–2052. Den befintliga fjärrvärmenät modellen med konventionell temperatur anpassades sedan till en fjärrvärmenätmodell med låg temperatur och simulerades för samma tidsperiod. Båda modellerna simulerades för ett fall där värmeenergilagring var tillgänglig och sedan för ett fall där värmeenergilagring inte var tillgänglig, för att bättre identifiera flexibilitetsfördelarna. Effekten av elpriserna på systemets funktion undersöktes också, där ett fall använder elpriser som är på den konservativa (dvs. högre) sidan och ett annat på den ambitiösa (dvs. lägre) sidan. Detta innebär att totalt åtta scenarier simulerades och analyserades.

Resultaten visar att mer värmelagringskapacitet utnyttjas i fjärrvärmesystemet med låg temperatur på grund av att tekniken för lagring av värmeenergi har mindre värmeförluster. Det konstaterades också att lastutjämning var mer i fjärrvärmesystemet med låg temperatur.

Detta beror på att det finns mer grundvärme i systemet på grund av mer överskottsvärme och på att värmeenergilagringar i borrhålen laddas ur. Detta innebär att den installerade kapacitet som krävs för värmeproducerande teknologi är lägre jämfört med alternativet med konventionell temperatur. Allt detta innebär att tekniken för lagring av värmeenergi möjliggör större besparingar i den totala systemkostnaden, med nästan 10 %, i fjärrvärmesystemet med låg temperatur. De konventionella och lågtemperatur fjärrvärmesystem som studeras i denna avhandling (dvs. med och utan lagring av värmeenergi) övergår från att vara nettogeneratorer av el till att bli stora elkonsumenter. Detta beror på att elpriserna kommer att sjunka i framtiden, vilket ger incitament till investeringar i värmepumpar, vilket i slutändan gör att systemen (som har haft kraftvärmeverk i mixen under tidigare år) kommer att domineras av värmepumpar. Införandet av tekniken för värmeenergilagring visar sig påskynda denna övergång i båda de system som studeras i denna avhandling. Det produceras mer el i fjärrvärmesystemet med konventionell temperatur än i ett fjärrvärmesystem med låg temperatur, eftersom kostnadsbesparingarna från drift av värmepumpar (på grund av högre prestandakoefficienter) med låg temperatur uppväger intäkterna från elförsäljning.

Slutligen syns också effekten av elpriserna i resultaten. Lägre elpriser gynnar mer värmeproduktion från värmepumpar, medan högre elpriser stimulerar ökad produktion från kraftvärmeverk. Resultaten visar att fjärrvärmesystemet med konventionell temperatur ger nätoperatören större frihet (än i fjärrvärmesystemet med låg temperatur) att reagera på elpriserna.

Sammanfattningsvis kan man därför konstatera att fjärrvärmesystem med låg temperatur i högre grad kan utnyttja den flexibilitet som tekniken för värmeenergilagring ger på grund av lägre värmeförluster, vilket visas genom att produktionsvolymerna för fjärrvärme är lägre och genom en högre grad av lastutjämning.

Liknande studier i framtiden skulle kunna omfatta en känslighetsanalys av värmepumparnas prestandakoefficient i fjärrvärmesystem med låg temperatur, eftersom denna parameter verkar ha stor betydelse för den kostnadsoptimerade strategin för driften av systemet. Det kan också vara fördelaktigt att utvidga studien till att omfatta stadens energisektor, vilket skulle innebära att elbehovet inkluderas i modellen. Det skulle vara intressant att se om detta skulle få modellen att investera i andra tekniker än värmepumpar, eller om det fortfarande skulle vara mer ekonomiskt fördelaktigt att importera el till marknadspris. Slutligen skulle kostnaden för att övergå från ett fjärrvärmenät med konventionell temperatur till ett fjärrvärmenät med låg temperatur också kunna beaktas i modellen, eftersom så inte var fallet i detta projekt. Detta skulle förmodligen visa att den ekonomiska fördelen med fjärrvärmenät med låg temperatur är mindre än vad som förutses i denna studie.

Nyckelord: Fjärrvärme, Låg-temperatur fjärrvärme, 4GDH, Flexibilitet, Termisk energilagring (TES), Optimering, Modellering

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Nomenclature

3GDH	Third-generation district heating
4GDH	Fourth-generation district heating
BTES	Borehole thermal energy storage
CHP	Combined heat and power
COM	Commercial
COM_FR	Commodity fraction
COP	Coefficient of performance
CRG	Cost reduction gradient
CT	Conventional temperature
CTDH	Conventional temperature district heating
CTES	Cavern thermal energy storage
DH	District heating
DHC	District heating and cooling
DHW	Domestic hot water
EB	Electric boiler
EU	European Union
FPC	Flat-plate collector
GAMS	General Algebraic Modelling System
HEX	Heat exchanger
HP	Heat pump
HT	High temperature
kEuro	Thousand Euro
LT	Low temperature
LTDH	Low-temperature district heating
LWT	Large water tank
PTES	Pit thermal energy storage
PVT	Photovoltaic-thermal
RES	Reference energy system

RSD	Residential
SC	Sector coupling
SH	Space heating
STES	Seasonal thermal energy storage
TES	Thermal energy storage
TIMES	The Integrated MARKAL-EFOM System
VRE	Variable renewable energy
YRFR	Year fraction

1. Introduction

District heating (DH) systems move hot water or steam through highly insulated pipes from sources of heat to buildings and processes that require heat. These systems have been commonplace in one form or the other across Europe for over a century. Today, the total length of distribution pipes stands at about 200,000 km in Europe. In 2010, the residential and service sector buildings across the EU consumed about 3300 TWh in heat of which 25% was supplied by DH networks (Fahl & Dobbins, 2017). Major sources of heat include residual heat from thermal power plants, renewable energy sources, and of course fossil fuels which still largely dominate as a primary energy source for heat supply. The Scandinavian countries of Iceland, Sweden, Finland, and Denmark are world leaders in renewable energy used for heating and cooling with over 50% of their heat consumption coming from clean sources, compared to the EU average of only 23.1% (eurostat, 2022). Solar thermal, geothermal energy, ambient heat captured by heat pumps, biofuels, and waste are all considered renewable energy sources (eurostat, 2021).

1.1. Project background

The 2012 European Energy Efficiency Directive requires that all member states of the EU assess the potential of expanding cogeneration and efficient district heating and cooling (DHC) systems, and this is the driving force for the next generation of these networks. Future DH systems will operate in different market conditions. On the demand side, peak heat demands from customers will fall due to more energy efficient buildings, and on the supply side, falling prices of renewable energy sources, and low-grade heat recovery will replace fossil fuels as the primary energy source for heating (Lygnerud & Werner, 2021). While this may sound like we already have the answer to a completely decarbonised European DH sector, it is unfortunately not the full picture. The integration of waste heat available at low temperatures and renewable heat sources into DH networks requires new technological features and concepts using low temperatures to be adopted. Therefore, to achieve full decarbonisation of the European DH sector, future networks will require enhanced district heating systems. This new state-of-the-art makes up the latest generation of DH systems and has the collective label ‘fourth-generation district heating’ (4GDH). Current third generation (3GDH) systems operate at a supply temperature in-between 80 °C - 100 °C and a return temperature of around 45 °C, while a 4GDH system will utilise supply temperatures below 70 °C and return temperatures as low as 25 °C (Thorsen, et al., 2018). From this point onwards in the thesis, the term ‘low-temperature district heating (LTDH)’ systems will be used to refer to 4GDH systems, and ‘conventional-temperature district heating (CTDH)’ systems for 3GDH systems.

The integration of more renewable energy in the energy system brings with it the challenge of balancing energy production and demand. Electricity grids and DH grids are becoming more interconnected through combined heat and power plants (CHP), and heat pumps (HPs). Volatility in heat generation and demand can therefore be absorbed by the flexibility of DH networks (Flexi-Sync, 2021). Broadly speaking, flexibility in DH networks refers to the available freedom for changes in operating parameters while still complying with the demands of the network. In the context of this project, flexibility is thought of as the *volatility absorbing potential* of the DH system. Therefore, ‘flexibility options’ in DH networks are technologies and concepts that work towards balancing heat generation and demand in thermal grids and can also help balance power generation and demand in electrical grids. Examples of flexibility options are thermal energy storages (TES), like centralised and distributed storage tanks, and borehole thermal energy storage (BTES). Through their built-in flexibility, DH networks can also provide flexibility service to the electrical grid through their operation of electricity consuming and electricity generating technologies (e.g., HPs and CHP plants, respectively). Achieving flexibility through all these options depends on the operational and control strategies of both the thermal and electrical grids.

Different flexibility options have already achieved varying levels of penetration in today’s CTDH systems. They already provide a valuable flexibility service to the electrical and thermal grids, and with reducing renewable energy prices, they will have to provide the same service with LTDH systems in the future. It is expected that the implementation of flexibility options and the resulting flexibility will vary depending on if it is a CTDH or a LTDH system. The effects of flexibility on the operation of the DH system are the focus of the work. Additionally, this thesis intends to compare these effects between LTDH and CTDH systems.

1.2. REWARDHeat

This degree project falls under the REWARDHeat (Renewable and Waste Heat Recovery for Competitive District Heating and Cooling Networks) project (REWARDHeat, 2020) which aims to demonstrate a new generation of low-temperature district heating and cooling (LTDHC) networks. The project is coordinated by Eurac Research in Italy, bringing together a total of 28 partners from 10 European countries and receives funding from the European Union's Horizon 2020 research and innovation programme (grant agreement No. 857811). Partners include industrial organisations, utilities, small and medium enterprises (SMEs), research organisations, universities, and international associations. The project works on the development and installation of 8 different innovative DH networks in different European cities. The demonstrator sites are shown as a collage in Figure 1.

These networks aim to drastically reduce the consumption of fossil fuels for heating and cooling purposes with the aim of up to 80% of the energy demand being satisfied with renewable and waste heat sources by 2030 in the ambitious scenario (REWARDHeat, 2020), thus reducing emissions of CO_2 and other harmful pollutants. The focus is on the exploitation of energy sources in urban environments, and therefore this should provide a cost-efficient and technically viable decarbonisation of the European DH sector as it expands and modernizes. The REWARDHeat project specific objectives are stated to be (REWARDHeat, 2020) to:

1. Effectively integrate multiple urban renewable and waste energy sources
2. Develop innovative technologies for flexible use of heat in DH networks
3. Demonstrate digitalisation, allowing to optimise the management of the DH network
4. Develop business models and financial schemes to enable large public and private investments to be mobilised

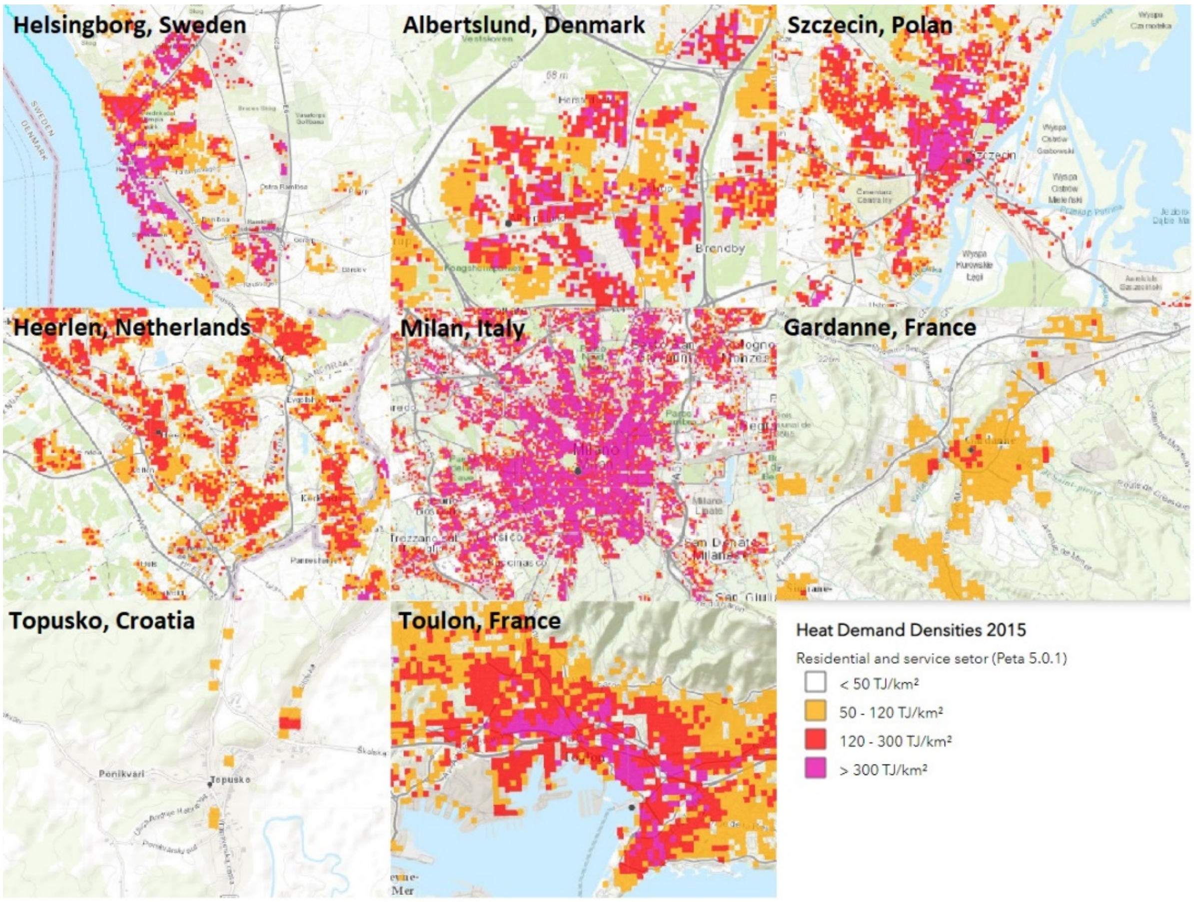

Figure 1 - REWARDHeat Demonstrator sites (redrawn from ("Pan-European Thermal Atlas version 5.2", Flensburg, Halmstad and Aalborg Universities (2022), 2022)*)*

1.3. Aims and objectives

This degree project is done in collaboration with IVL Svenska Miljöinstitutet (IVL Svenska Miljöinstitutet, 2022), which is one of the partners of the REWARDHeat project. The overarching aim of this thesis is to identify and analyse the effects that flexibility options (i.e., TES technologies) have on the operation of LTDH systems and to compare these effects with those on CTDH systems. Another aim is to investigate how the price of electricity will affect the operation of these technologies in DH systems, and to compare the effects between CTDH and LTDH systems.

Therefore, one of the objectives for reaching the overarching aim is to create a heating sector model of one of the REWARDHeat demonstrator cities, and another is to discuss the contribution of flexibility options to DH systems by analysing the results of the simulations. The capacities for TES technologies, HPs, and CHP plants will be analysed, and their activity levels (i.e., charging/discharging for TESs, and power consumption and heat generation by HPs, and CHP plants, respectively) will be discussed as well. The energy-system is chosen in this thesis to be modelled in the TIMES (The Integrated MARKAL-EFOM System) software (IEA-ETSAP, 2005) which is an economic model generator for energy systems. TIMES is also the standard tool for energy system modelling in the REWARDHeat project. TIMES aims to supply energy services at minimum global cost (Loulou, et al., 2021). The implementation of TIMES will be expanded on in section 3.2 of this report.

Therefore, to summarise, the objectives of this degree project are to:

1. Create a heating sector model of one of the REWARDHeat demonstrator cities in TIMES
2. Analyse and discuss the effects of flexibility options on the operation of DH systems
3. Analyse and discuss the deployment and use of TES technologies, HPs, and CHP plants

Ultimately these objectives will aid in achieving the overarching aim of the thesis, which is to compare, between CTDH and LTDH systems, the effects of flexibility options on the operation of either type of system. These objectives will also allow the investigation into the 'sub-aims' which are to investigate the deployment of certain technologies, and to investigate the effects of electricity price on their operations.

1.4. Research questions

- How do the effects of TES technologies (and the lack of it) on the operation of DH systems differ between CTDH and LTDH systems?
- How do the capacities and activity levels for TES technologies, HPs, and CHP plants differ between CTDH and LTDH systems?
- How are the operations of certain technologies in a DH system affected by electricity prices, and how do these effects differ between CTDH and LTDH system?

1.5. Project scope

The overall scope of the thesis is limited to DH. District cooling is not considered. Furthermore, the focus of this thesis is limited to the REWARDHeat demonstrator city – Helsingborg, and its

DH system which is operated by the utility provider Öresundskraft. The city's current district heating and electricity production and distribution infrastructure are known and are used for the modelling of the system. The system, in its current configuration employs a centralised TES tank. It also uses various heat generation technologies (i.e., HPs, CHP plants, excess heat, and an oil boiler). Over the modelled time horizon, the flexibility options that are considered in the study are short-term thermal energy storage (TES) (i.e., storage tanks), and seasonal TES (STES) using water such as boreholes, caverns, and pits. It is important to note that the model treats the operation of all available types of STES' in the same way. The model chooses which type of STES technology to invest in such that the objective function of the optimization (i.e., total system cost) is minimized. This choice is influenced by the fed techno-economic inputs for each of the STES technologies.

Electricity consuming and electricity generating technologies (i.e., HPs, and CHP plants) are also considered in the study.

Furthermore, all local production of electricity (i.e., by CHP plants) is immediately exported at market prices, and all electricity that is consumed by the DH sector is imported. As such, the electricity demand of the city is not included in the model. Finally, the thermal hydraulic aspects of the DH grid (i.e., pressure drops, electricity consumption of pumps, etc) are not considered. Instead, the grid is represented only in terms of its annual thermal capacity, and energy losses.

2. Literature review

This chapter presents the current available information on areas of knowledge that inform this study. It starts with introducing and expanding on the different flexibility options in DH systems that are in the scope of this thesis. It then moves on to the characterisation of LTDH systems, and then presents how the performance of different technologies are affected by lower temperatures in DH systems.

2.1. Flexibility options in DH systems

As mentioned earlier in section 1.1, ‘flexibility options’ in DH systems are technologies and concepts that work towards balancing heat generation and demand in thermal grids and can also help balance power generation and demand electrical grids. Examples of flexibility options are thermal energy storages (TES), like centralised and distributed storage tanks, and borehole thermal energy storage (BTES). These flexibility options that are considered in this study are expanded on in this section.

2.1.1. Thermal energy storage (TES) tanks

Thermal storage tanks, or large water tanks (LWTs) in DH systems add flexibility and offer additional business opportunities to these systems (Schuchardt, 2016). The capacities of these tanks are influenced by the peak loads in the DH system, and the operation of these tanks allow the increased supply of heat from intermediate and base load heat sources (see Figure 2). The peak heat requirements (i.e., heating power (MW_{th}) and heat delivered (MWh_{th})) of the DH system are substituted by the heat contents from the LWT (Schuchardt, 2016).

LWTs have the following advantages. They often already exist in DH systems (Dave, et al., 2016), are low cost (Lund, 2018), and have shown to decrease total system annual operating cost (Dmytro, et al., 2018). LWTs are commonly used as short to medium term (daily to weekly) heat storage to cover peak demand periods, enabling plant peak capacity installation to be reduced and to operate at full capacity for a longer time (Dave, et al., 2016) (Eriksson, 2016).

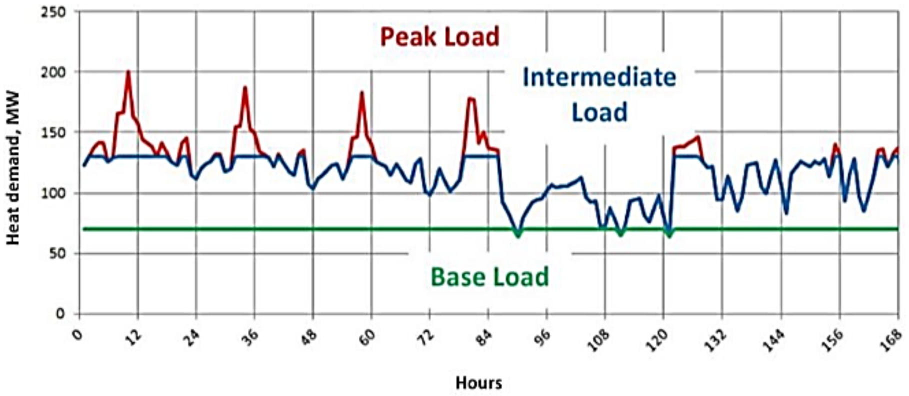

Figure 2 - Segmentation of heat loads occurring within a DH system. Split into peak, intermediate, and base load (taken from (Schuchardt, 2016) under the terms of the CC BY 4.0 license)

2.1.2. Seasonal TES

Borehole thermal energy storage (BTES), cavern thermal energy storage (CTES), and pit thermal energy storage (PTES) are examples of seasonal TES (STES) that are used in different extents in DH systems around the world. STES amplifies the effect of short-term storages by allowing DH production to take place during the summer (when production costs are generally lower) and then siphoning of the produced heat for use during the winter months. These types of energy stores can be built at a very large scale, therefore providing significant storage capacity at a relatively low cost (CELSIUS EU, 2020).

BTES systems use the ground as a heat storage medium. They are typically large because their storage capacity is proportional to the volume. Nevertheless, their construction is relatively cheap, which favours its use from an economical point of view (Reuss, 2021).

BTES systems are most used for heating and cooling of individual houses, which requires the system to be paired with a ground source HP. The HP extracts the low-grade heat that has been stored underground and transfers high-grade energy to the house to meet the heating demand. The HP works in reverse during the summer months, where it extracts heat from the living space and deposits it underground through the borehole (Cruickshank & Baldwin, 2016). This cycle repeats itself 1-2 times a year. BTES systems are increasingly being used as part of large DH systems as well. A large-scale BTES can even be used as a standalone system where e.g., heat is supplied by a large array of solar thermal collectors (Gao, et al., 2015).

CTES are like BTES, in that they store heat underground. Their use is dependent on the geological, hydrogeological, and other site conditions (Cabeza, et al., 2015). PTES, on the other hand are large artificial pools in which a large pool is sealed off from the soil, insulated, filled with water, and given a floating cover (Energiewendebauen, 2021).

Conversion technologies such as HPs and electric boilers can be used to convert power to heat when there is an oversupply of electricity from VRE sources. This heat can be deposited into the STES system to be used later when there is greater heat demand.

2.2. Characteristics of LTDH systems

This section begins with briefly describing the challenges that fourth-generation district heating (4GDH) systems will have to overcome, in the context of LTDH systems. It then moves on to presenting the literature that has attempted to study how the performance of different technologies are affected by lower temperatures in DH systems.

2.2.1. 4GDH

Future sustainable energy systems (comprising of electrical and thermal grids, and transportation fuels) that comprise of up to 100% renewable energy are based on a combination of variable renewable energy (VRE) sources (e.g., Wind, geothermal, solar) together with residual resources such as municipal waste and biomass (Lund, et al., 2014). It is important to keep in mind, that resources such as municipal waste and biomass are small compared to the European energy demand and therefore solutions to future 4GDH systems (which make up future sustainable energy systems) will have to incorporate more investments into renewable energy, energy conservation, and energy efficiency measures (Ericsson & Nilsson, 2006). In such a case, 4GDH systems will be designed to integrate with the electricity and transport sectors to identify synergies between these sectors to achieve an optimal solution for each individual sector as well as for the overall energy system (Lund, 2010). For LTDH to remain competitive, one important condition is to minimise distribution costs and heat losses, and therefore, heat demands must be concentrated spatially, as low heat densities in sparse areas lead to relatively higher distribution costs and losses (Möller & Lund, 2010). However, it has been shown by (Werner & Persson, 2011), that major European cities are densely populated enough to keep future DH systems competitive. Therefore, to fulfil its role in future sustainable energy systems, 4GDH systems will have to overcome the following remaining challenges (Lund, et al., 2014):

- Ability to supply LTDH for space heating (SH) and domestic hot water (DHW) to existing buildings, energy-renovated existing buildings, and new low-energy buildings
- Ability to distribute heat in networks with low grid losses
- Ability to recycle heat from low-temperature sources and integrate renewable heat sources such as solar and geothermal heat
- Ability to be an integrated part of smart energy systems (sector coupling)

There are different proposed measures that can be taken to overcome these challenges. The methods to be able to overcome these are discussed in sections 3.1, 3.2, 3.3, and 3.4, respectively, in (Lund, et al., 2014).

It is important to note that the modelling done in this thesis assumes that all challenges associated with 4GDH systems are overcome. The next section presents the literature that has attempted to study how the performance of different technologies (that are considered in this thesis) are affected by lower temperatures in DH systems.

2.2.2. Technology performance in LTDH systems

Lower heat distribution temperatures have the benefits of increased efficiency and capacity gains, both of which are major motivating factors for achieving a lower cost decarbonisation of the energy system (Geyer, et al., 2021). This section highlights where these performance enhancements may be experienced in the REWARDHeat demonstrator sites across Europe, and more specifically in the DH systems that is being analysed in this thesis.

Additionally, given that TIMES (the modelling tool used in this thesis) is an economic model generator for energy systems, the inputs fed to the model that characterise the operation of different technologies are techno-economic in nature. These inputs are presented in Table 1, in section 3.2. Therefore, the performance of technologies considered in this model are explained in this section, with some references to their techno-economic performance. Examples of techno-economic parameters are thermal capacity, efficiency, operating costs, etc.

This section also contains results from (Averfalk & Werner, 2020), whose study investigates cost motivational structures to improve the rate of district heating development into low-temperature operation, i.e., 4GDH. The main performance indicator in their analysis is the cost reduction gradient (CRG – [euro/(MWh·°C)]) for different heat supply sources, which is calculated according to Equation 1.

$$CRG = \frac{B}{E \times \Delta T_{avg}} \qquad \text{Equation 1}$$

Where B is the annual economic benefit (Euro), E is the annual heat deliveries (MWh) and ΔT_{avg} is the reduction of the average heat distribution temperatures in the DH network (K). They model a DH system that has an annual heat sale (SH and DHW demand) of 1800 TJ which is a medium-sized system. The geographical location of Strasbourg was chosen as an example of the average heat demand in Europe, with a design outdoor temperature[1] of -14.6 °C and an average outdoor temperature of 10.5 °C. The 3GDH alternative had an average supply temperature of 80 °C, while the average return temperature was 45 °C. The corresponding 4GDH temperatures were 55 °C and 25 °C, respectively. The 3GDH alternative had an annual heat-loss of 8.4%, while that for the 4GDH alternative amounted to 3.2%.

The following sub-sections also have references to the CRG obtained for different heat supply sources in (Averfalk & Werner, 2020). The values are ultimately translated into useable inputs in the developed heating sector model in TIMES. The decision to use these values is taken because the inputs used in (Averfalk & Werner, 2020) are for the average European DH system, and therefore should be representative of the DH system modelled in this thesis. Also, if these inputs remain constant across the investigated scenarios, the results obtained should provide representative results.

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[1] Design outdoor temperature is the temperature used in the design and sizing of a heating or cooling system. It corresponds to how low the temperature gets in winter and vice versa for summer.

2.2.2.1. Heat pumps

HPs are already widely used in European DH (and even DC) systems, most commonly using sewage water, ambient air, and industrial waste heat as heat sources (David, et al., 2017). The performance of HPs is strongly affected by the temperature levels of the source (cold side) and sink (hot side). Equation 2 represents the theoretical maximum COP that is achievable according to the Carnot efficiency law and is fundamental to the field of thermodynamics. Equation 3 is the calculation of the real achievable COP of a HP based on the supplied heat rate and power input required. Equation 4 (Averfalk & Werner, 2020) calculates the 2nd law efficiency of the HP and represents the effectiveness of the HP at achieving its theoretical maximum COP.

$$COP_{Carnot} = \frac{1}{\tau_{Carnot}} = \frac{T_{sink}}{T_{sink} - T_{source}}$$ Equation 2

$$COP = \frac{\dot{Q}_{th}}{P_{el}}$$ Equation 3

$$\tau_{2nd} = \frac{COP}{COP_{Carnot}} \rightarrow COP = \tau_{2nd} \times COP_{Carnot}$$ Equation 4

Where:

COP_{Carnot} – Maximum achievable COP according to Carnot efficiency law [-]

τ_{Carnot} – Carnot efficiency [-]

T_{sink} – Temperature of heat sink [K]

T_{source} – Temperature of heat source [K]

τ_{2nd} – 2nd law (of thermodynamics) efficiency of the HP [-]

COP – Practically achievable COP of the HP [-]

$\dot{Q}_{th}$ - Heating (supply) rate [kW_{th}]

P_{el} – Power input [kW_{el}]

In practice, it has been observed that HPs can achieve second law efficiencies up to 0.8 (Averfalk & Werner, 2020), while the more common range is in between 0.4 and 0.6

(Arpagaus, et al., 2018). If a DH supply temperature (heat sink) of 50 °C (LTDH) and a heat source temperature of 2 °C is assumed, the practical achievable COP for a HP would range in between 2.7 for τ_{2nd} = 0.4, and 4.3 for τ_{2nd} = 0.64. For COP calculation, a useful rule of thumb value for τ_{2nd} is 0.5, which is confirmed by a certifier's test bench of different HPs (Grosse, et al., 2017).

Figure 3 shows a HP's achievable Carnot efficiency at various temperature levels and Figure 4 shows the practically achievable COP for different τ_{2nd} at different source temperatures, assuming the sink temperature is at 50 °C (LTDH).

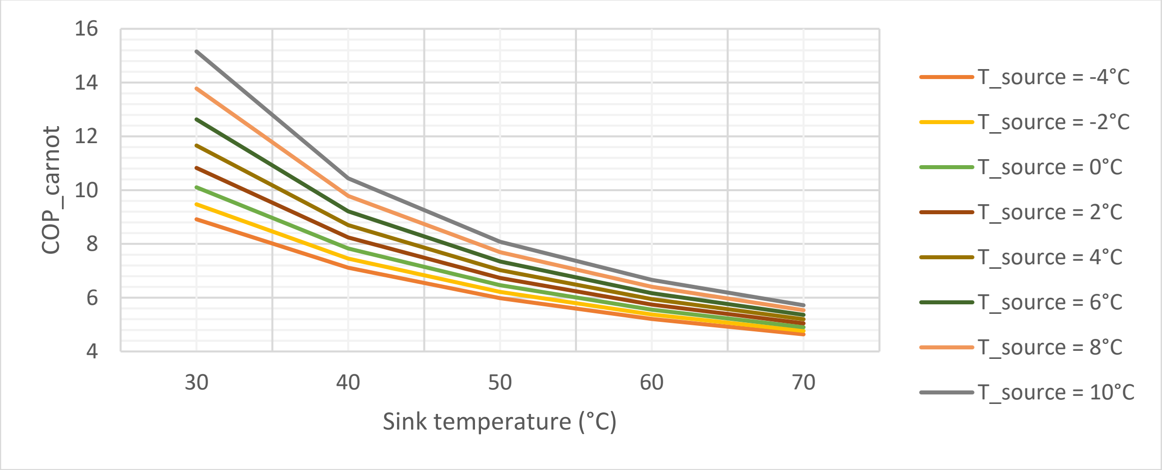

Figure 3 - Carnot efficiencies for different temperature levels (generated using Equation 2)

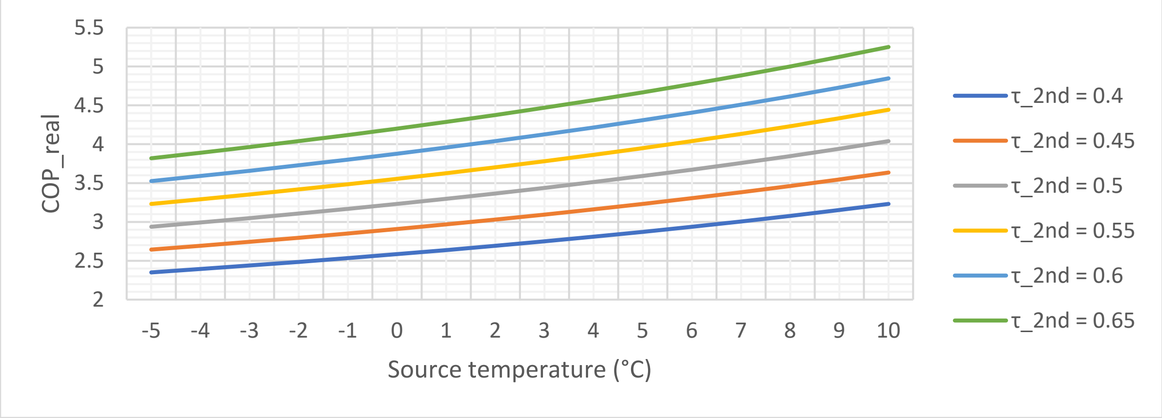

Figure 4 - Practically achievable COP of a HP (assumed T_sink = 50 °C) (generated using Equation 4)

From Figure 3 one can see that, the lower the supply (sink) temperature is, the higher the COP is for a given source temperature. Figure 4 shows that higher achievable COPs are possible with higher source temperatures. This means that for LTDH systems where the supply temperatures are below 70 °C, more commonly available source temperatures in urban areas can be used. For example, a HP supplying a temperature of 50 °C could use a source temperature of 5 °C (e.g., seawater temperature in winter) and achieve a COP_{real} of 3.6, assuming τ_{2nd} is 0.5. In such a case, for an unchanged heat output (i.e., where E from Equation 1 is the same between the CTDH and LTDH systems) , (Averfalk & Werner, 2020) calculated a CRG of 0.41 euro/(MWh·°C).

2.2.2.2. Waste heat extraction

Heat recovery and the use of waste heat (also called excess heat) increases the overall energy efficiency of the DH system and reduces emissions. It also reduces operating costs due to lower fuel costs. The EU has also identified waste heat extraction as one of the major pathways to decarbonise its heating and cooling sectors (European Commission, 2016). LTDH systems simply make available more conventional and non-conventional waste heat sources, which further aids the decarbonisation of DH systems. (Averfalk & Werner, 2020) estimated a CRG of 0.51 euro/(MWh·°C), which exemplifies the potential in cost reductions in waste heat recovery in this context.

2.2.2.3. Combined heat and power (CHP) plants

An optimally designed and operated CHP plant can save up to a third of the primary energy that would be required for the separate generation of useful electrical and thermal energy (Schaumann & Schmitz, 2010).

When supplying DH at lower temperatures, more electricity is generated per unit of heat in CHP plants because higher power-to-heat ratios are obtained by lower steam pressures in the turbine condensers. According to (Geyer, et al., 2021), the power-to-heat ratio of CHP plants increases by 0.71% for every °C the DH supply temperature reduces by. Lower steam pressures are achieved in the condensers due to the lower temperature of the DH network. The hot and cold sides of the condensers are connected to the supply and return sides respectively of the

DH network. Therefore, increased revenue from electricity, or reduced fuel costs (if electricity supply is not changed) is the benefit of LTDH systems on the operation of CHP plants. (Averfalk & Werner, 2020) estimate a CRG of 0.16 euro/(MWh·°C) for a system that uses biomass CHP with flue gas condensation. In this study the 3GDH alternative had a supply and return temperature of 80 °C and 45 °C, respectively, while the 4GDH alternative had temperatures of 55 °C and 25 °C, respectively.

2.2.2.4. Thermal energy storage (TES) technologies

Heat storages have become a vital element in today's DH systems, given their ability to allow the system to decouple heat generation from heat demands. For a given storage volume, the storage capacity of the TES depends on the temperature spread within the storage. Greater temperature spreads increase the amount of usable storage capacity. Reducing return temperatures of DH systems and maintaining the same supply temperatures enables increased storage capacity as the temperature spread is increased. Therefore, economic benefits are only realised if charging temperatures of the TES are kept high. In this case, the TES would have to be directly integrated with a high-temperature heat source and would therefore need to be located next to the source (Averfalk, et al., 2021).

For cases where the TES is not directly integrated to a high temperature source, i.e., it is charged by the supply stream of the DH network and discharged into the return stream, the only benefit would be lower thermal loss from the TES because of lower operating temperatures (Averfalk, et al., 2021).

(Gadd & Werner, 2020) estimate a CRG of 0.011 euro/(MWh·°C) for short-term TES, and a CRG of 0.073 euro/(MWh·°C) for seasonal TES (STES). However, these estimates are based only on a reduction in return temperature, and no reduction in supply temperature. Therefore, the estimates are not used in this study as the modelling assumes that TES are directly charged by and discharged into the DH network.

2.2.2.5. Heat distribution network

The lower temperatures used in LTDH systems mean that compared to current 3GDH systems, the temperature difference between the average water distribution temperature and the ground will be cut by a factor of 2 (Lund, et al., 2014). Distribution losses impact the overall efficiency and economic benefits of DH systems. Target values for annual heat loss in CTDH networks are under 10%, however in regions where heat demands are not that spatially concentrated (e.g., small, and rural DH networks) this is very hard to achieve (Nussbaumer & Thalmann, 2016). Also, by reducing peak flow rate in the network, the dimensions of DH pipes can be reduced which would allow the use of better insulated twin pipes. Twin pipes have half the heat loss coefficient of existing two single pipes and therefore, incorporating lower-temperatures and smaller pipes can reduce distribution losses by up to a factor 4 (Lund, et al., 2014). (Averfalk & Werner, 2020) estimate a CRG in-between 0 and 0.13 euro/(MWh·°C) depending on the heat generation mix of the DH network. In this thesis, no reduction in cost associated with operating the heat distribution network under low temperatures is applied, as the change in heat generation mix of the DH system is a result of the simulations, and not forced on the model.

3. Methodology

This chapter discusses the methodology used in this thesis. It begins by describing the TIMES modelling environment, and then moves on to describing the model that is used in this thesis and the adaptations that were made to it. The input data and assumptions that are fed to the model are then presented. It then moves on to describing the rationale behind the modelled scenarios, and finally, the explanation of the energy balance calculation used to verify the model is presented.

3.1. TIMES modelling environment

TIMES (The Integrated MARKAL-EFOM System) is an economic model generator which uses linear-programming to produce a least-cost energy system, optimized according to various user constraints over a user-defined time horizon, usually a few decades (Loulou, et al., 2021). The TIMES Model Generator contains the GAMS source code that processes each dataset (the model) and generates a matrix that represents the energy system model as a mathematical programming problem. The model generator also post-processes the optimization results into a format that can be read by model management systems.

The model consists of a set of data files (spreadsheets) that describe an energy system. The spreadsheets contain various inputs required to define the energy system (e.g., technologies, commodities, resources, and demands for energy services) in a format that is compatible with an associated model management system[2], which in this project is VEDA2.0. The General Algebraic Modelling System (GAMS) is the programming language in which the TIMES model generator is written. GAMS was designed to integrate with various solvers for optimization. It passes on the mathematical programming problem to solvers and then post-processes the results into the required format for VEDA2.0 to read. The TIMES modelling environment is presented in Figure 5.

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[2] A model management system or “shell” is a user interface that allows the user to work with a model and invokes the model generator and facilitates the examining of the results (Goldstein, et al., 2016)

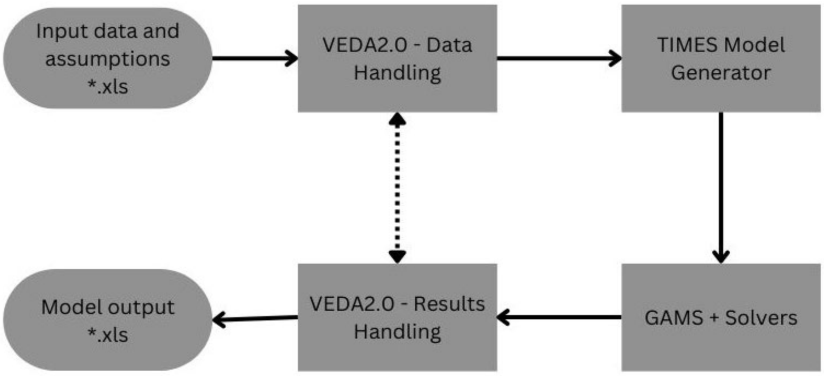

Figure 5 - Components of the TIMES Modelling environment (redrawn from (Goldstein, et al., 2016))

TIMES is usually used to model energy systems over a long period of time and is therefore well suited to explore different energy futures (scenarios). In TIMES, a complete scenario consists of the following inputs: energy service demand curves, primary resource supply curves, and techno-economic parameters of a set of available technologies.

The user provides the demands for the reference system only. Demand drivers like population, gross domestic product (GDP), GDP per capita, or number of households can be set by the user, but the demands can also be inserted by the user for the entire modelling period if the data exists – which is the case in this thesis.

Supply curves for primary energy and material resources describe the resource availability at a particular cost. It is possible to express this availability as a cumulative potential over the model horizon, or even annual potentials for certain commodities[3].

TIMES allows the analysis of the impact that policies may have on the energy system. Different policies can be grouped together to define a certain policy landscape (Goldstein, et al., 2021). Examples of policy landscapes are specific emission restrictions or taxes, subsidies to

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[3] In the context of TIMES modelling, commodities are energy carriers, energy services, materials, monetary flows, and emissions. A commodity is produced by one or more processes and/or consumed by other processes. E.g., bio pellets, high-temperature heat produced by DH plants, heat demands, CO_2 emissions from combustion, etc.

technologies, or a general carbon tax. In this thesis, a carbon tax, and an energy tax is applied, and the implementation of these are presented in Appendix A4.2.

The objective function of the optimization is the total system cost, which is the sum of all total costs for each year in the modelled period. Each year, the total cost includes the following elements:

- Capital costs (incurred for investing into new processes)
- Fixed and variable annual operation and maintenance costs
- Imports and extraction of resources
- Revenues from exports (appears with a negative sign in the cost expression)
- Taxes and subsidies associated with commodity flows
- Damage costs due to emissions of certain pollutants (if defined)
- Salvage value of processes and embedded commodities at the end of the modelled period (calculated by the model and appears with a negative sign in the cost expression)

The capital costs are divided into annual payments, which are calculated for each year in the modelled period. The salvage value of all investments still active at the end of the modelled period is calculated as a lump sum revenue and is assumed to be added in the next year following the modelled period. All costs (except the salvage value) are added to the annualized capital cost payments to form the $ANNCOST$ quantity in Equation 5 (Loulou, et al., 2021). Equation 5 constitutes the calculation of the objective function of the optimization where NPV is the net present value of the total cost (the TIMES objective function), $years$ is the set of years for which there are costs, d is the general discount rate, $REFYR$ is the reference year for discounting, and $ANNCOST(y)$ is the total annual cost in the year y.

$$NPV = \sum_{years} (1+d)^{REFYR-y} \cdot ANNCOST(y)$$

Equation 5

3.2. TIMESCity_heat model

Once adequate proficiency in working with the TIMES modelling environment is achieved, the next step is to develop the model that represents the Helsingborg DH system. For the purposes of the Flexi-Sync project (Mata, et al., 2022), a TIMES model which spans the heating sector of the Swedish city of Eskilstuna was already developed by IVL, which is referred to as the TIMESCity_heat model.

The city's DH infrastructure are represented as different processes that are connected by flows of commodities. Each commodity (e.g., a fuel) is described by its availability, costs (for importing, or extracting), and environmental impacts (if applicable). Various scenarios can also be applied to the model to explore different energy futures.

Once the model is fully defined, the TIMES model generator passes the model to solvers which optimize for the objective function, which is to minimize the total system cost. This is done while ensuring that the system meets the energy demands over the defined time horizon. Models developed in TIMES assume perfect foresight, which is to say that all investment decisions are made in each investment period with full knowledge of future events (Loulou, et al., 2021). A discount rate of 3.5% is assumed in the models used in this thesis, with the reference year for discounting being 2017.

In the context of the TIMES modelling environment, the TIMESCity_heat model incorporates all DH plants, individual units, and TES technologies for a given city's DH system, as processes. DH plants consist of CHP plants (that generate both heat and electricity), and heat only plants (e.g., HPs, boilers, etc). Individual units are technologies that are installed in individual buildings (e.g., HPs, electric boilers, electrical resistance heating, air conditioners, etc.) that are used to supply the remainder of the heat demand that is not supplied by the DH system.

The techno-economic inputs that characterise the operation of heat production technologies (i.e., DH plants and individual units) and heat storage technologies, in the TIMESCity_heat model, are listed in Table 1.

Table 1 – Techno-economic inputs characterising the operation of different technologies

DH plants	
Input parameter	**Unit**
Installed thermal capacity	MW
Installed power capacity (if applicable)	MW
Efficiency	-
Availability factor	-
Heat-to-power ratio (if applicable)	-
Investment cost (for new units)	Euro/kW
Fixed operation and maintenance costs	Euro/kW
Variable operation and maintenance costs	Euro/kW
Operational period	Years
Individual units	
Input parameter	**Unit**
Efficiency	-
Availability factor	-
Investment cost (for new units)	Euro/kW
Fixed operation and maintenance costs	Euro/kW
Variable operation and maintenance costs	Euro/kW
Operational period	Years
Heat storage technologies	
Input parameter	**Unit**
Storage losses	%/day
Maximum charge/discharge rate (for existing LWT)	MW
Maximum capacity (for existing LWT)	MWh
Minimum capacity (for existing LWT)	MWh
Investment cost (for new units)	kEuro/TJ
Fixed operation and maintenance costs	Euro/TJ
Operational period	Years

The TIMESCity_heat model has a time horizon of multiple decades. In this thesis, the base year is set as 2017 and the time horizon goes thirty-five years into the future (ending at 2052), using 5-year steps. The year 2017 is used as the base year as this is the year for which sufficient published data on Helsingborg's DH system was available. In the base year, DH plants, individual units, and TES represent the existing infrastructure of the modelled DH system. During the modelled time horizon, this existing capacity will be phased out and replaced with new capacity, while optimizing for minimal total system cost. The choice of simulating for thirty-five years into the future was made as a compromise between wanting to see how existing generation capacities are gradually phased out and replaced with new capacities (therefore seeing what the new generation mix would look like) and managing computational resources (as longer time horizons would call for more computational time). All relevant data (i.e., technology capacities, commodity flows, operating levels, etc.) are interpolated for the 'in-between' years by the TIMES model generator.

Each year is split into 72-time divisions, also called time-slices. It is up to the user to decide how the year is sliced up. This is also based on the available computational resources (i.e., higher time resolution calling for more computational time). For every year, the model operates at a seasonal level, weekly level, or day-night level. In the TIMESCity_heat model and in this thesis, the months constitute the seasonal level (12 months), while the weekly level is split into weekday and weekend, and the day-night level is split into day hours, night hours, and the peak hour (which is an aggregate of all the 'peak' demand hours in a corresponding weekday or weekend level). The slices are shown in Table 2. As you can see, each month is split into six slices, hence the 72 time-slices for each year.

Table 2 - Simulated time-slices for each year

Time-slice level	**Time-slices**					
Seasonal	Each month of the year (Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec)					
Weekly	Weekday			Weekend		
Day-night	Day	Night	Peak	Day	Night	Peak

The length of each time-slice is defined by an attribute called the 'year-fraction' (YRFR) and is the fraction of the year for which that time-slice applies. The YRFR applied to each time-slice can be found in Appendix A1.1.

The city's heating demand consists of the demands from the city's residential and commercial building stocks. The demand is either supplied through DH pipes (that are connected to DH plants and TES), or by individual units. The annual heat demands are split up into heat demands for each of the 72 time slices in each year. The demand in each time-slice is defined by an attribute called the 'Commodity fraction' (COM_FR) which is the fraction of the annual sector heat demand that needs to be supplied in a particular time-slice. When COM_FR is plotted against the time slices it represents the shape of the heat demand curve (presented in Appendix A1.2).

The DH pipes are represented only in terms of their annual energy flow capacity (in TJ) and their heat losses (as a percentage). Physical parameters such as volume flows, temperatures, and pressure drop in the pipes are disregarded.

3.3. Model adaptation to the Helsingborg case study

The TIMESCity_heat model is adapted to encompass the DH system of Helsingborg in the base year of 2017. Öresundskraft (Öresundskraft, 2022) is a Swedish energy company in the Öresund region and is fully owned by the municipality of Helsingborg. It owns the electricity and DHC grid in the city of Helsingborg. As of the base year (2017), the company operates a municipal waste CHP plant, bio pellet CHP plant, HPs, and utilizes excess heat from industrial processes. The largest supplier of this heat is Kemira which is a chemicals processing plant in Helsingborg. The company also operates oil-fired boilers as reserve capacity. In total, the heat generation capacity available from DH plants was 320 MW. The system also utilizes a LWT for short term TES (Öresundskraft AB, 2022).

It is helpful to visualize the relationships among various entities in the model using a network diagram, referred to as a Reference Energy System (RES) (Goldstein, et al., 2021). The simplified TIMES RES for the base year of Helsingborg's DH system is shown in Figure 6. In the figure, processes are represented as rectangles, commodities as vertical lines, and commodity flows as horizontal links between the rectangles and vertical lines.

The TIMESCity_heat model that is adapted to the Helsingborg DH system for the purposes of this thesis is referred to as the conventional temperature district heating (CTDH) model from here on out. Given that the main goal of this study is to identify and analyse the effects that flexibility options (i.e., TES technologies) have on the operation of low temperature district heating (LTDH) systems and to compare these effects with those on CTDH systems, a low temperature (LT) model is adapted from the CTDH model to enable the LT study. This model is referred to as the LTDH model from here on out.

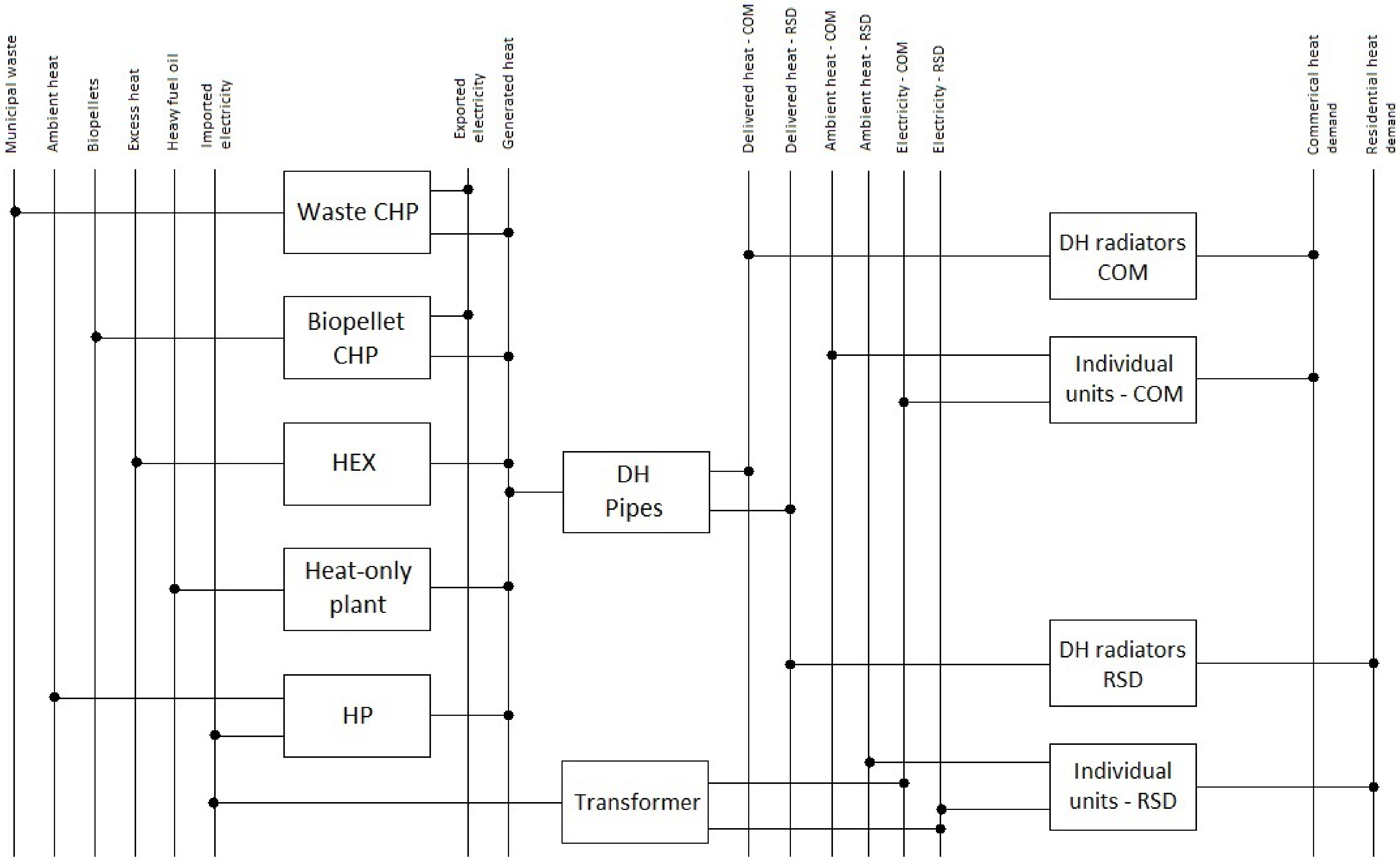


Figure 6 - TIMES Reference Energy System (RES) of the Helsingborg DH system

The differences between the CTDH and LTDH models are in the techno-economic inputs for heat generation and heat storage technologies, and the assumed heat losses in the pipes that deliver the DH.

In the CTDH model, the grid losses are assumed to be 10%. In section 2.2.2.5 it was discussed that LTDH networks can achieve grid loss reductions by up to a factor of 4, but in the LTDH model, a reduction by a factor of 2 is applied as the assumption is that the loss reductions are only a result of the lower distribution temperatures, and not also by the use of better insulated twin pipes as this would imply that the entire existing grid is upgraded to the new pipes. Therefore, 5% grid losses are assumed in the LTDH model. Furthermore, in the LTDH model, the relevant techno-economic inputs for heat generation and heat storage technologies are changed assuming a 30 °C reduction in average distribution temperatures compared to the CTDH model. The cost reduction gradients (CRGs) for the different technologies discussed in section 2.2.2, are multiplied by 30 °C to determine the reductions in the operation and maintenance costs in the LT configuration. For CHP plants, their power-to-heat ratios increase in the LT case (as stated in section 2.2.2.3). As stated in section 2.2.2.2, LTDH systems allow the use of LT excess heat available in the built environment to heat or preheat the supply stream, therefore in the LTDH model more excess heat is made available, in addition to the already existing 50 MW in the CTDH model. For TES technologies, new storage losses are calculated based on an assumed 30 °C reduction in storage temperature.

3.4. Input data and assumptions

This section presents the inputs to the CTDH and LTDH models, any relevant calculations that were done to determine certain inputs, and the assumptions that underly some inputs and calculations.

3.4.1. Helsingborg’s heat demand

The city’s heat demand is split into a commercial (COM) heat demand and a residential (RSD) heat demand, to show a difference in supplied heat in the sectors. Each sector is further split into sub-sectors according to different building types. The sectoral heat demands for 2017 (COM and RSD sectors) were taken from (Länsstyrelserna - LEKS, 2022). The total heat demand in the city of Helsingborg was assumed to be just under 1472 GWh (i.e., 5300 TJ) in the base year. The heat demand of Helsingborg for future years is calculated by assuming that the city's heat demand will drop by 3.69% every five years. This is the assumption made for Sweden's heat demand in the REWARDHeat project (REWARDHeat, 2022), and in this thesis it is assumed that Helsingborg's heat demand will also follow Sweden's overall heat demand. Figure 7 shows the city's heat demand for all modelled years split into the COM and RSD sectors.

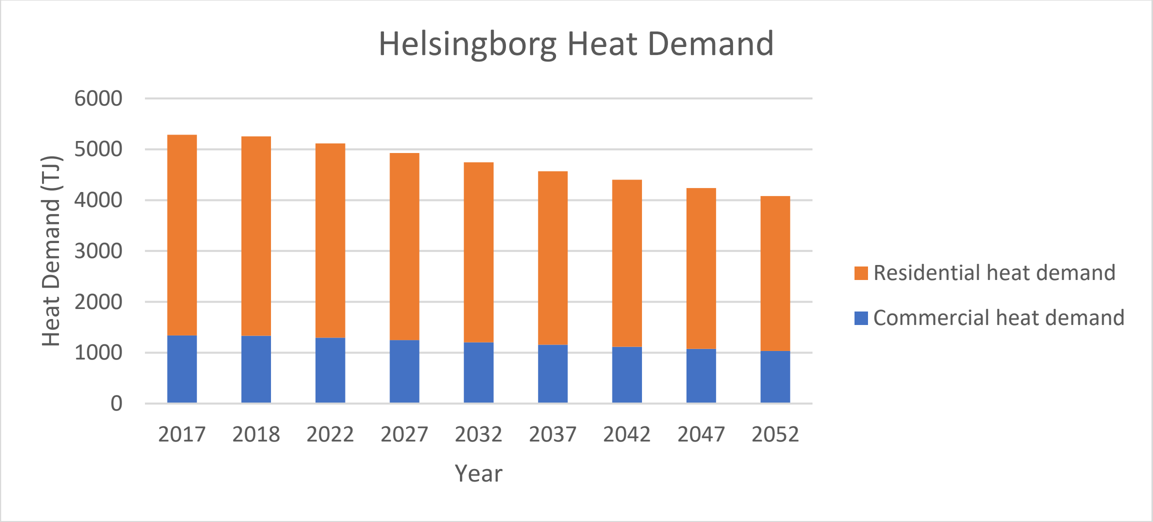


Figure 7 - Helsingborg heat demand breakdown

The heat demands for all sub-sectors and for all simulated years are presented in Appendix A2.

3.4.2. DH plants

The techno-economic inputs fed to the model that characterise the operation of the existing CHP plants in Helsingborg are listed in Table 16, in Appendix A3.1. Values for both the conventional-temperature (CT) and low-temperature (LT) cases are shown. In the LT case, the heat-to-power ratio and fixed operation and maintenance costs for the power plants are lower, as discussed in section 2.2.2.3. The bio pellet CHP plant has a thermal generation capacity of 138 MW and a heat-to-power ratio of 2.0 in the CT case. In the LT case an unchanged thermal generation capacity is assumed, and the heat-to-power ratio is 1.65. The bio pellet CHP plant was originally constructed for coal in 1982, but in 2006 was converted to use bio pellets. It recently underwent life-extending upgrades to keep it operational until 2040 (Öresundskraft AB, 2022). The municipal waste CHP plant has a thermal generation capacity of 72 MW and a heat-to-power ratio of 4.0 in the CT case. In the LT case an unchanged thermal generation capacity is assumed, and the heat-to-power ratio is 3.3. The municipal waste CHP plant was commissioned in 2013 and is assumed to be operational throughout the modelled period. Öresundskraft claims that that 100% of the energy contained in the waste is converted to electricity and hot water. This claim sounds plausible when considering that the CHP plant does use flue-gas condensation augmented by large HPs (Öresundskraft, 2022). (Energistyrelsen, 2022) also states that CHP operation with HP augmented flue-gas condensation can achieve total efficiencies of above 100% (given that HPs have COPs above 1). The availability of waste for the purposes of DH production going into the future is questionable given the Swedish governments position on the circular economy, which can be seen in its policy landscape that regulates waste management. The government has prioritised increased recycling rates for plastics, textiles, electronic waste, construction material, etc., (Johansen, 2022), and therefore it is foreseen that the availability of non-recycled municipal waste for the purposes of DH production will reduce going into the future. For this reason, the municipal waste (fuel) availability is reduced by 10% every 5 years from the base-year consumption level (i.e., around 260 GWh (Öresundskraft, 2017)).

The techno-economic inputs fed to the model that characterise the operation of the existing heat-only plants in Helsingborg are listed in Table 17, in Appendix A3.1. Values for both the CT and LT cases are shown. The industrial HP has a thermal generation capacity of 30 MW. The calculation and implementation of the HP efficiencies are discussed in section 3.4.4. Also, the operational period for the industrial HPs is not known, and therefore it is assumed that they were installed in 2017 and have the typical lifetime for HPs which is 25 years (Energistyrelsen, 2022). HT excess heat capacity in the DH network is 50 MW and is assumed to be available throughout the modelled period. The input fed to the model for installed thermal capacity for LT excess heat in the LTDH system are explained in section 3.4.6. The LT excess heat is treated as an additional heat generation technology in the LTDH model. Finally, the oil boiler is assumed to be in operation till the year 2024, following Öresundskraft target of having only renewable energy in DH by 2024 (Öresundskraft, 2017). It has a thermal generation capacity of 30 MW.

The techno-economic inputs fed to the model for new DH plants available for investment are listed in Table 19 for the CT case, and Table 20 for the LT case, in Appendix A3.1. All values for the CT case are taken from (Energistyrelsen, 2022) and the values for the LT case are different for the operation and maintenance costs, heat-to-power ratio and efficiency for CHP plants, which were calculated according to the 30 °C reduction in average distribution temperatures in the LT case compared to the CT case.

3.4.3. Individual units

In the base year, the heat demand of Helsingborg is not fully supplied by the DH network. Some buildings have individual units (e.g., air-source HPs, electric boilers, electrical resistance heating, air conditioners, and ground-source HPs) to supply the remaining demand. Due to the complexity of getting data on the level of deployment of each type of unit, assumptions are made on the percentage of remaining heat demand that is supplied by each of them. The assumptions are taken from (Mata, et al., 2022) and, assuming similar distribution of individual units' deployment in Helsingborg and Eskilstuna, are applied to the remaining heat demand in both COM and RSD sectors. Table 21, in Appendix A3.2 shows this breakdown. The inputs for existing, and new individual units available for investment are from (Riekkola, et al., 2019), and are presented in Table 22 and Table 23 (in Appendix A3.2), respectively, for the CTDH model. All parameters presented in Table 22 and Table 23 remain the same in the LTDH model, except for the HP efficiencies, which are discussed in section 3.4.4.

3.4.4. Heat pump (HP) COPs

Air-source HPs and ground-source HPs each have their own set of COPs assigned to them for each of the 72 time-slices in the model, as the COPs vary depending on the heat source and sink temperatures. In the CT case, the COPs used in this thesis are calculated using Equation 6 (Cozzini, et al., 2021). The COPs are calculated based on the air and ground temperatures that are presented in Appendix A1.3, and a DH supply temperature of 80 °C in the CT case, and 50 °C in the LT case. In Equation 6, T_{supply} is the supply temperature of the DH network, DT_{HEX}

is the logarithmic mean temperature difference of the HEX (which couples the ambient to the respective HP), T_{amb} is the ambient temperature, and η is the 2nd law efficiency of the HP.

$$COP = \eta\left(\frac{T_{supply} + DT_{HEX}}{T_{supply} - (T_{amb} - 5) + 2 \cdot DT_{HEX}}\right)1 - \eta \quad \text{Equation 6}$$

The average air and ground temperatures from the source data presented in Figure 33 are 8.5 °C and 8.6 °C, respectively. The 2nd law efficiency of the HPs (τ_{2nd}) are assumed to be 0.8, for both air-source and ground-source HPs. The calculated COPs are aggregated and assigned to each of the 72 time-slices. The COPs used in the CTDH and LTDH model are presented in Table 9 and Table 10, in Appendix A1.3, respectively.

3.4.5. Storage technologies

A simplifying assumption is made to calculate the storage losses for TES technologies in the LT case which is that the storage losses are proportional to the temperature difference between the storage temperature (80 °C in the CT case and 50 °C in the LT case) and the ambient temperature. The ambient temperature assumed for this calculation is based on the air and ground temperatures used for the HP COPs, which are discussed in section 3.4.4. Given the CT storage losses (x_{CT} [%/day]) for different heat storage technologies, the LT storage losses (x_{LT} [%/day]) are calculated using Equation 13. H [%/day. °C] is the heat loss coefficient of the storage technology. $T_{storage_{CT}}$ and $T_{storage_{LT}}$ are the storage temperatures in the CT and LT cases, respectively. ΔT_{CT} and ΔT_{LT} are the temperature difference between the storage temperature and the ambient (Equation 9 and Equation 10), in the CT and LT cases, respectively. The derivation of Equation 13 is as follows. Note that this derivation is for LWTs, which are exposed to the ambient, therefore $T_{amb_{avg}} = 8.5\ °C$ is used. For underground energy storage technologies $T_{amb_{avg}} = 8.6\ °C$ is used. Given that the difference in temperature is minimal, the resulting difference in Equation 13 is also minimal (i.e., within two decimal places).

Assuming: $$x_{CT} = H \times \Delta T_{CT} \quad \text{Equation 7}$$

$$x_{LT} = H \times \Delta T_{LT} \qquad \text{Equation 8}$$

Given the assumptions that $T_{storage_{CT}} = 80\ °\mathrm{C}$ and $T_{storage_{LT}} = 50\ °\mathrm{C}$:

$$\Delta T_{CT} = T_{storage_{CT}} - T_{amb_{avg}} = 80 - 8.5 \qquad \text{Equation 9}$$

$$= 71.5\ °\mathrm{C}$$

And

$$\Delta T_{LT} = T_{storage_{LT}} - T_{amb_{avg}} = 50 - 8.5 \qquad \text{Equation 10}$$

$$= 41.5\ °\mathrm{C}$$

Therefore:

$$x_{CT} = 71.5H \qquad \text{Equation 11}$$

$$x_{LT} = 41.5H \qquad \text{Equation 12}$$

Given that H from Equation 11 and Equation 12 is a property of a given storage technology (LWT, BTES, etc.,), it is the same across the CT and LT cases. Therefore, by dividing Equation 12 by Equation 11 we get Equation 13.

$$x_{LT} = 0.58x_{CT} \qquad \text{Equation 13}$$

Between the CT and LT cases, the only affected parameter for heat storage technologies is the storage losses. Therefore, Equation 13 is used to obtain the storage losses in the LT case, given a certain storage loss in the CT case, for a given TES technology. An increase in storage capacity is not assumed, given that the assumption in this thesis is that both supply and return temperatures are reduced in the LTDH model (refer to section 2.2.2.4).

Öresundskraft has one large water tank (LWT). The exact techno-economic parameters for the LWT are not available, therefore the inputs used to characterise the LWT in the Eskilstuna model (Mata, et al., 2022), were used in the CTDH model for this thesis. The LWT has a maximum storage capacity of 900 MWh and a maximum charge and discharge rate of 60 MW. The inputs fed to the model for the existing LWT, and for new TES technologies are presented in Appendix A3.3. Inputs for LWTs and Pit TES (PTES) are based on different projects completed or proposed by PlanEnergi ((PlanEnergi, et al., 2013)(https://planenergi.eu/en/)). Inputs for Cavern TES (CTES) and Borehole TES (BTES) are from a project based in Kiruna, looking into possibilities of maximizing the use of waste heat from mining operations in the local DH system (IVL Svenska Miljöinstitutet, 2022).

3.4.6. LT Excess heat potential

LTDH systems allow the use of low temperature excess heat available in the built environment to heat or preheat the supply stream. The LT excess heat availability is not known for Helsingborg specifically, however, the data for potential LT excess heat in Sweden is available and is based on research by (Papapetrou, et al., 2018) and (Persson, et al., 2020). As of 2015, the potential excess heat available in Sweden is 9027.8 GWh and is expected to increase to 16611.1 GWh by 2050. The sources of excess heat are from various industrial processes, data centres, metro stations, sewage, and from sources in the service sector (Persson, et al., 2020). A constant increase in LT excess heat potential is assumed between 2017 and 2055. These numbers are adjusted for the Helsingborg case by multiplying Sweden's potential with the fraction of Sweden's population that lives in Helsingborg for every year between 2017 and 2055. The population data used to project the LT excess heat potential is presented in Appendix A3.4. The population projections for Sweden are obtained from (World Population Review, 2022) and the population projections for Helsingborg are obtained from (Statistics Sweden, 2022). An annual availability factor (AF) of 0.9 (i.e., same AF for HT excess heat) was assumed for the LT excess heat potential to determine what the capacity (in MW) would be. This calculated capacity for LT excess heat is fed to the model. Table 3 presents the calculated excess heat potential, and capacity for Helsingborg.

Table 3 - Input to model for Helsingborg's LT excess heat capacity

Year	**2017**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**
LT excess heat potential [GWh]	138.8	149.8	168.7	190.0	213.7	240.5	269.6	300.4	331.9
LT excess heat capacity [MW]	17.6	19.0	21.4	24.1	27.1	30.5	34.2	38.1	42.1

3.5. Scenario descriptions

Four scenarios are investigated in the CTDH model, and an additional four similar scenarios are investigated in the LTDH model. These scenarios arise from the desire to study how electricity prices, and additionally, how a lack of TES technologies (flexibility options), affects the operation of the DH system. The eight scenarios are summarized in Table 4.

Table 4 - Scenario descriptions

DH temperature level	Case	TES or no TES	Scenario code
Conventional temperature (CT)	Conservative (-)	No TES	No_TES_CT-
		With TES	CT-
	Ambitious (+)	No TES	No_TES_CT+
		With TES	CT+
Low temperature (LT)	Conservative (-)	No TES	No_TES_LT-
		With TES	LT-
	Ambitious (+)	No TES	No_TES_LT+
		With TES	LT+

By having scenarios where no TES technologies are part of the network, we have a sort of ‘baseline’ to compare the effect of flexibility options to. As electricity production becomes ‘cleaner’ in coming years, and as it is also anticipated for the cost of renewable electricity to reduce, it is also interesting to see how the electricity prices will affect the operation of technologies in a DH system that has a significant share of electricity consuming technologies. So, while comparing the effects of flexibility options between the operation of CTDH and LTDH network is the main purpose of the thesis, a higher electricity price (conservative) scenario and a lower electricity price (ambitious) scenario are incorporated into the larger CT and LT scenarios. It is impossible to exactly predict what the future electricity prices will be, and therefore, a conservative and ambitious case respectively are studied. It is expected that the future DH system will operate somewhere within the bounds of these scenarios.

The conservative and ambitious cases are defined by their respective electricity prices and, corresponding electricity emission factors. For both conservative and ambitious cases, electricity prices for 2017, 2030, and 2050 are given as inputs, and the model interpolates the values for the in-between years and extrapolates for the year 2052. The same is done for the electricity emission factors. The electricity prices for the year 2017 were obtained from the NordPool wholesale electricity market (Nord Pool AS, 2022). The 2030 and 2050 prices are obtained through a study commissioned by Nordic Energy Research (NER), called the Nordic Clean Energy Scenarios project (NCES), where the Balmorel software tool was used (Wråke, et al., 2021). This project was a result of a signed joint commitment by the Nordic countries (i.e., Denmark, Finland, Iceland, Norway, and Sweden) to make the countries carbon neutral, in line with the COP21 Paris Climate Agreement. The study incorporates five solution tracks that capture most of the options needed to reach carbon neutrality: direct electrification; Power-to-X; bioenergy; carbon-capture and storage (CCS) technologies; and behavioural change. Direct electrification forms the core of both conservative and ambitious scenario, referred to as the Nordic Powerhouse (NPH) and Climate Neutral Behaviour (CNB) scenarios, respectively, in (Wråke, et al., 2021), while the other solutions tracks have varied importance in the two scenarios. The NPH scenario storyline is characterised by increased electricity and other energy intensive manufacturing demand. There are also higher levels of synthetic fuel production (i.e., Power-to-X fuel production). The CNB scenario is motivated by strong political and citizen engagement. The storyline is characterised by the adoption of high energy and material efficiency measures in all sectors which lead to lower energy demand, and more use of decentralised generation technologies. Figure 8 presents Sweden’s power production in 2050, split into different energy sources, as obtained through modelling in (Wråke, et al., 2021) that incorporates the two different storylines.

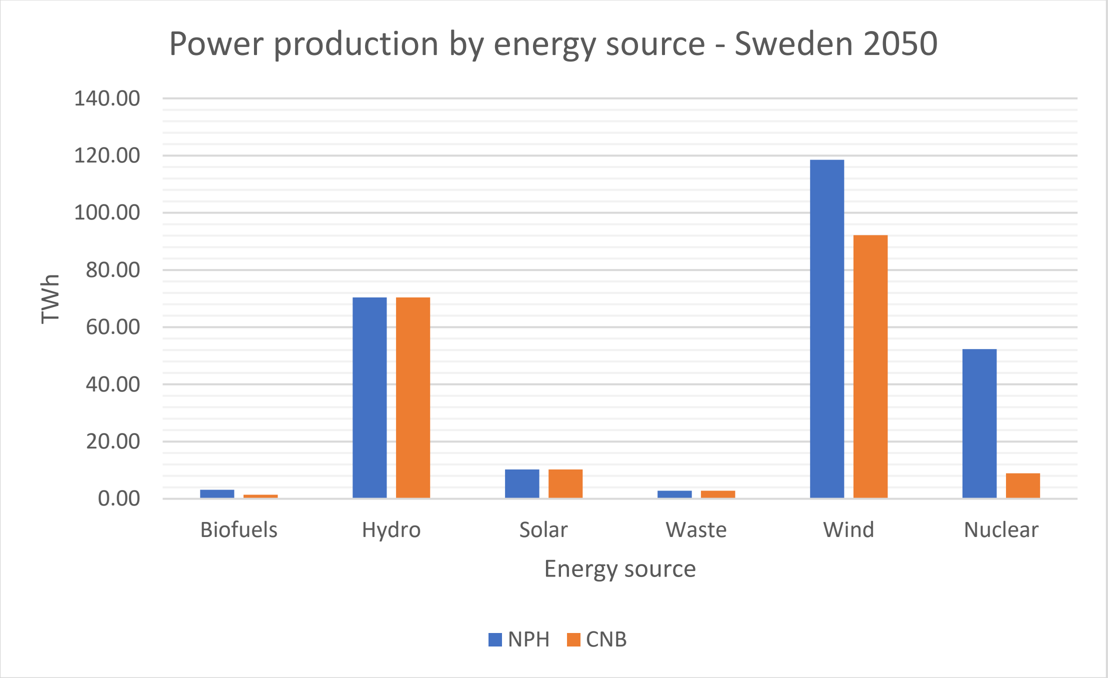


Figure 8 – Sweden's power production by energy source in 2050. Results from Balmorel modelling in (Wråke, et al., 2021)

The electricity prices and emission factors are aggregated from the source data and then assigned for each of the 72 time slices in the model. The source data and aggregated values are presented in Appendix A4.1.

Fuel costs and a carbon and energy tax are common to both scenarios. The prices and taxes for fuels used in the model are extracted from the TIMES model developed and applied in (Wråke, et al., 2021). The prices and taxes are assumed to be the same across all the scenarios. Their implementation is explained in Appendix A4.2.

3.6. Model verification with energy balance

The energy balance calculation accounts for heat generation, transmission, losses, and consumption within the DH system. Figure 9 presents the energy flows that need to be included in the calculation. The energy flows for every modelled year are checked.

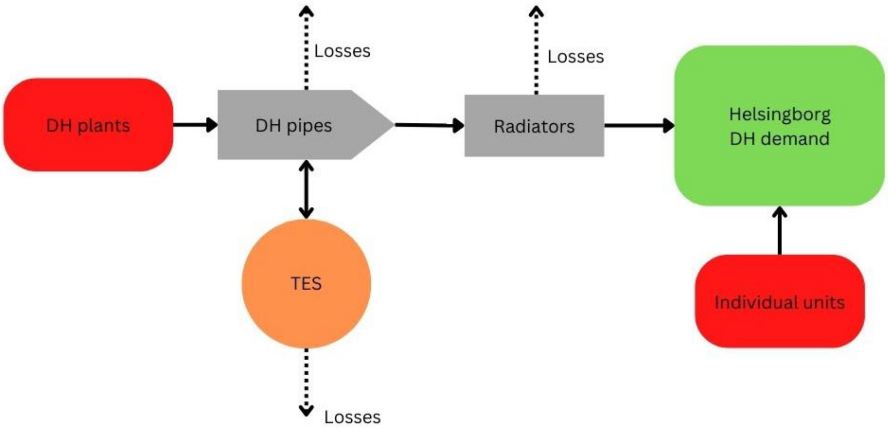


Figure 9 - Energy flows in the DH system

Heat flows into the system through DH plants and individual units. Heat supplied by individual units is directly consumed by the city. Heat supplied by DH plants is transmitted through DH pipes and the radiators in buildings, before being consumed by the city. Some heat from the DH grid flows into and out of TES technologies. During the transmission of heat towards the consumer, some heat is lost through the DH pipes and the radiators. There are additional heat losses from TES technologies as well.

Table 5 shows an example of an energy balance (just for the years 2017, 2032, and 2052) calculation that is done for the CT- scenario. The sum of heat generation subtracted by all the losses results in the total heat supplied. The consumed heat is equal to the city's heat demand. The negligible net heat values show that all supplied heat is consumed by the city, which verifies that the model has respected the first law of thermodynamics, i.e., energy conservation.

Table 5 - Compilation of all relevant energy flows for energy balance calculation

TJ	**2017**	**2032**	**2052**
Generation by DH plants	4627.63	4993.59	5001.67
Storage losses	-8.42	-326.52	-373.56
Grid losses	-461.92	-466.7	-462.8
Radiator losses	-174.6	-137.02	-83.3
Generation by individual units RSD	893.57	468.75	0
Generation by individual units COM	409.19	212.41	0
Total heat supplied	**5285.45**	**4744.51**	**4082.01**
Heat consumed	**5285.43**	**4744.47**	**4082.00**
Net Heat	**0.02**	**0.042**	**0.009**
%	**0.0004**	**0.0009**	**0.0002**

The energy balance breakdown for each of the modelled scenarios are presented in Appendix B1.

4. Results and Discussion

This section includes relevant results and their discussion from the CT-, CT+, LT-, and LT+ scenarios (i.e., scenarios with TES included). Then, results from No_TES_CT-, No_TES_CT+, No_TES_LT-, No_TES_LT+ scenarios (i.e., scenarios where no TES is included) are compared to the relevant scenarios with TES, to better-identify the flexibility benefits. Discussion on how electricity prices affect the operation of certain technologies (i.e., relating to RQ3) are provided along the entire section, at relevant stages. The energy balance breakdown for each of the modelled scenarios are presented in Appendix B1.

4.1. CTDH systems vs LTDH systems

This section reflects on the effects of flexibility options (i.e., TES technologies) in CTDH and LTDH systems. The DH production by DH plants, and the activity of TES technologies, at annual and sub-annual levels are presented, to discuss the operation of the DH system. The deployment and usage of TES is discussed. HPs, and CHP plant capacities and production volumes are also presented to discuss the flexibility service that these technologies provide to the power sector, across the modelled period. Additionally, it is important to note that the model treats the operation of all available types of STES’ in the same way. The reader will see that the model chooses to invest in BTES as the STES option, and therefore the results in this section refer to the operation of *BTES* specifically, when in fact, all STES options (i.e., including CTES, and PTES) would have been treated in the same way, if invested in.

4.1.1. DH plants and TES activity in the CTDH and LTDH systems

In 2017, Helsingborg’s DH systems consists of a bio pellet CHP plant, municipal waste CHP plant, industrial HP, HT excess heat, and an oil boiler. In both the CTDH and LTDH models, the only TES technology available in the base year is the LWT. In the LTDH model specifically, there is additional excess heat capacity in the form of LT heat that is made available to the DH system. Figure 10 and Figure 11 present the DH production for 2017, in the CT and LT scenarios, respectively. For the 2017 case, there is no difference between the conservative and ambitious scenarios as the electricity prices are already known and are therefore the same for that year in the CT-, CT+, LT-, and LT+ scenarios. Hence, Figure 10 and Figure 11 coincidentally present results for just a CT and LT scenario, respectively. Figure 12 through to Figure 15 present the DH production for 2032, in the CT and LT scenarios, for the conservative and ambitious cases. In 2017, we see that in the absence of seasonal TES options, the production from the DH plants and individual units matches the city's heat demand in both CT and LT scenarios. This is not the case moving into the future. By 2032, investments in seasonal thermal storage (i.e., BTES to be specific), in the CT and LT scenarios have been made. The lower investment costs of BTES as compared to CTES, and PTES (when referring to inputs fed to the model) make it the more attractive STES investment option. We see that industrial HPs and excess heat are used to charge the BTES in the summer and the BTES discharges into the DH network in the winter.

Excess heat consumption by the DH system remains stable throughout the year in both the CTDH and LTDH systems, while production volumes from industrial HPs and CHP plants varies monthly. The results are similar for the year 2052, whose figures are presented in Appendix B3. However, in 2052 there is no production from CHP plants, instead, industrial HPs are the only dispatchable DH generating units used, with excess heat being the only other source of heat in the system. In 2017 and 2032, we see that the production from CHP plants occurs only in the colder months and increases and decreases with the electricity price, regardless of temperature level and whether it is the conservative or ambitious case. The model chooses to have production from CHP plants in these months, as increased revenues can be made from electricity sales.

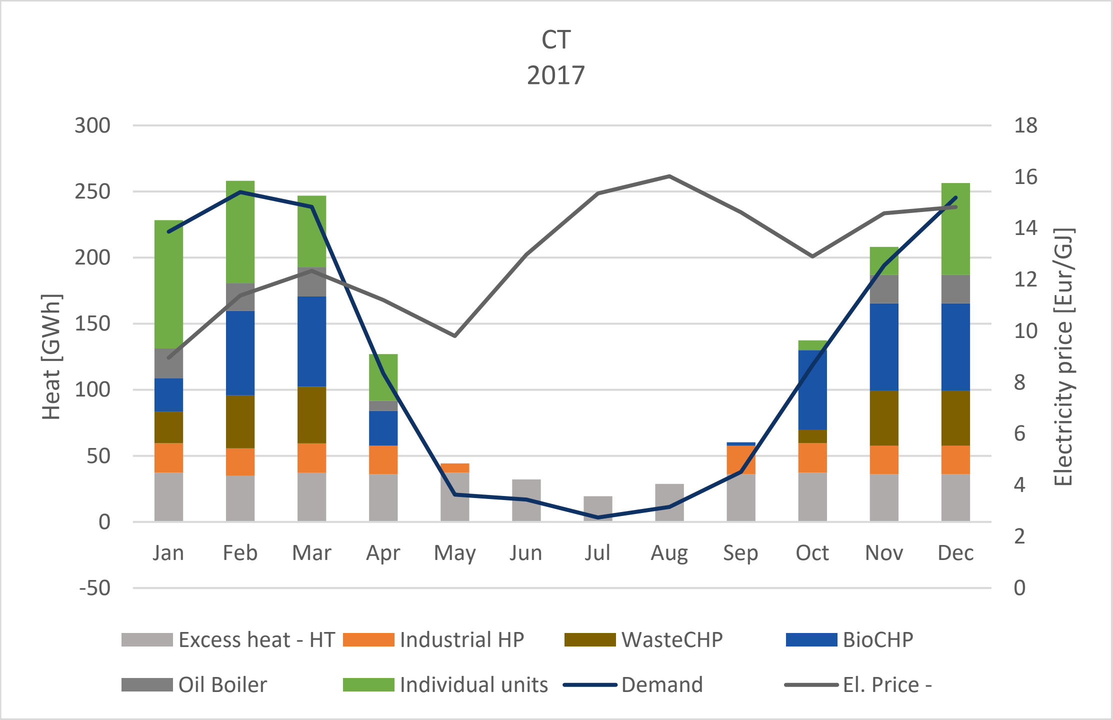


Figure 10 – DH production for 2017, CT

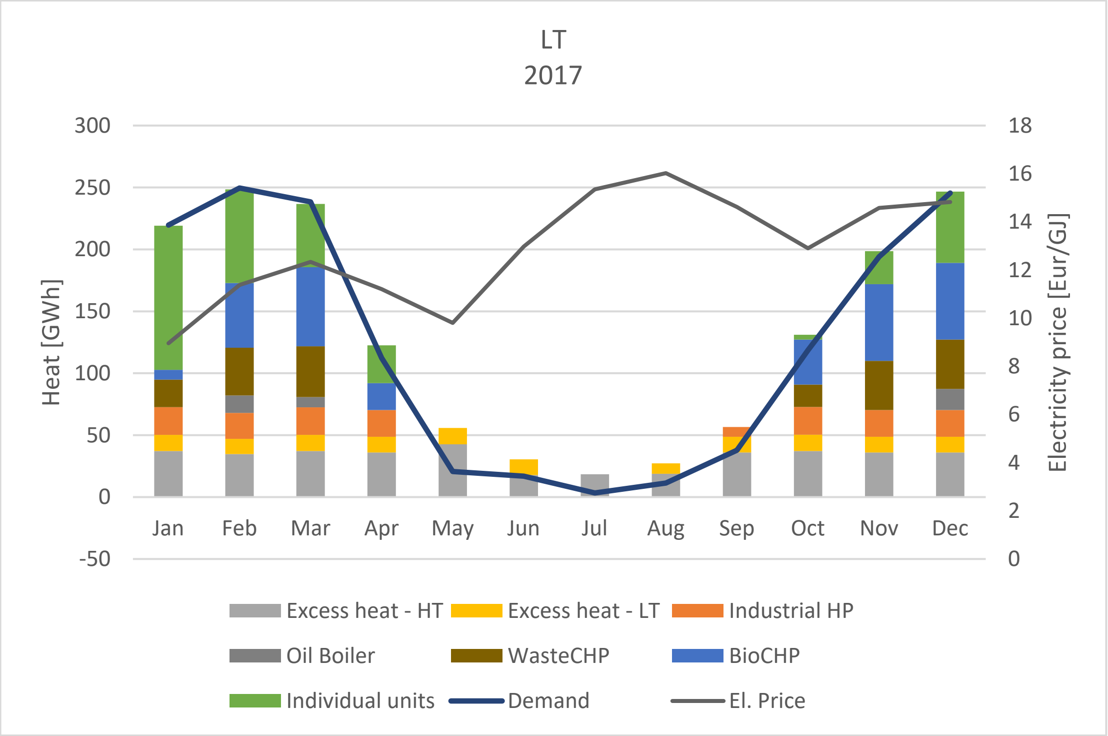


Figure 11 – DH production for 2017, LT

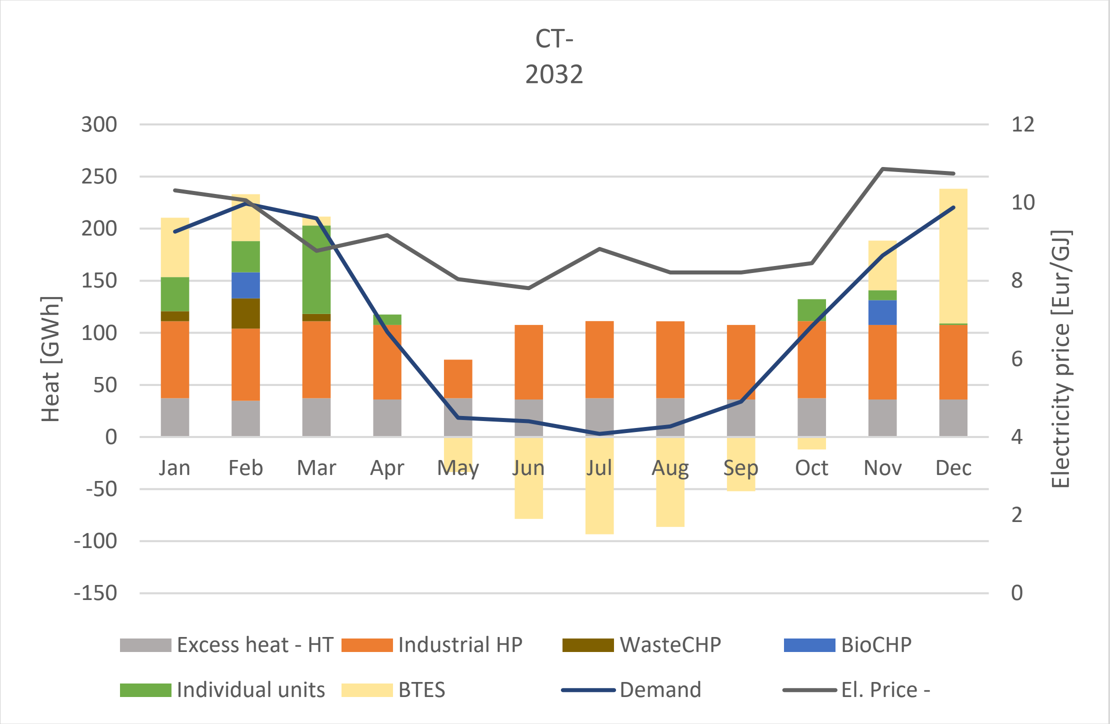


Figure 12 – DH production for 2032, CT-

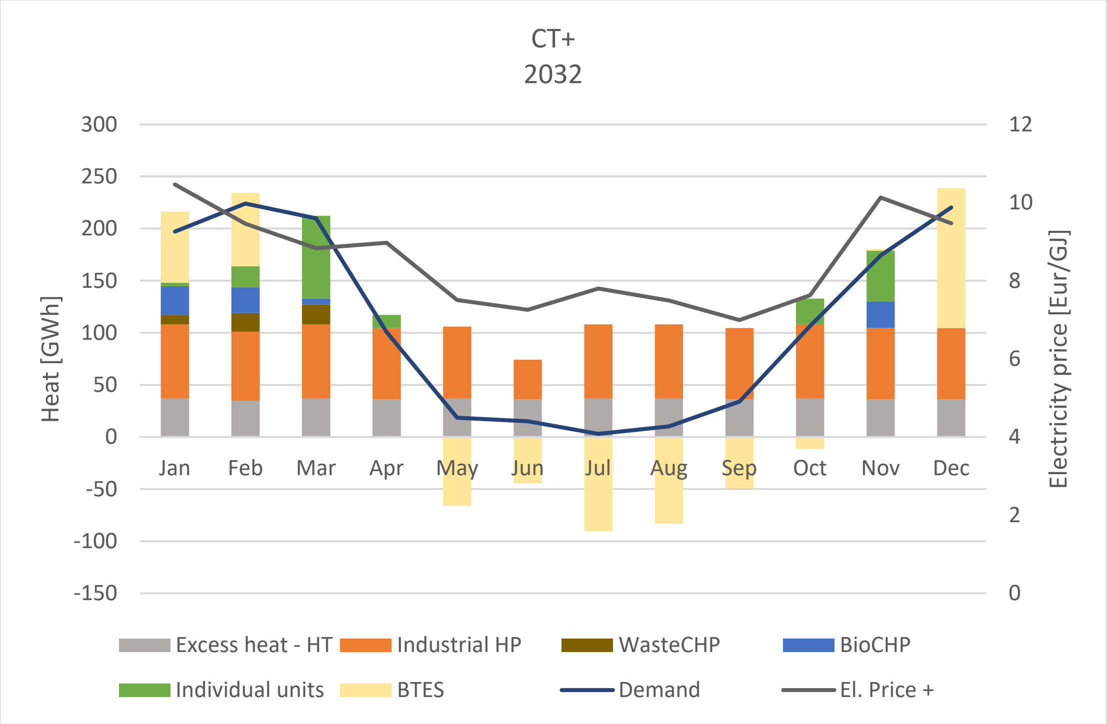


Figure 13 - DH production for 2032, CT+

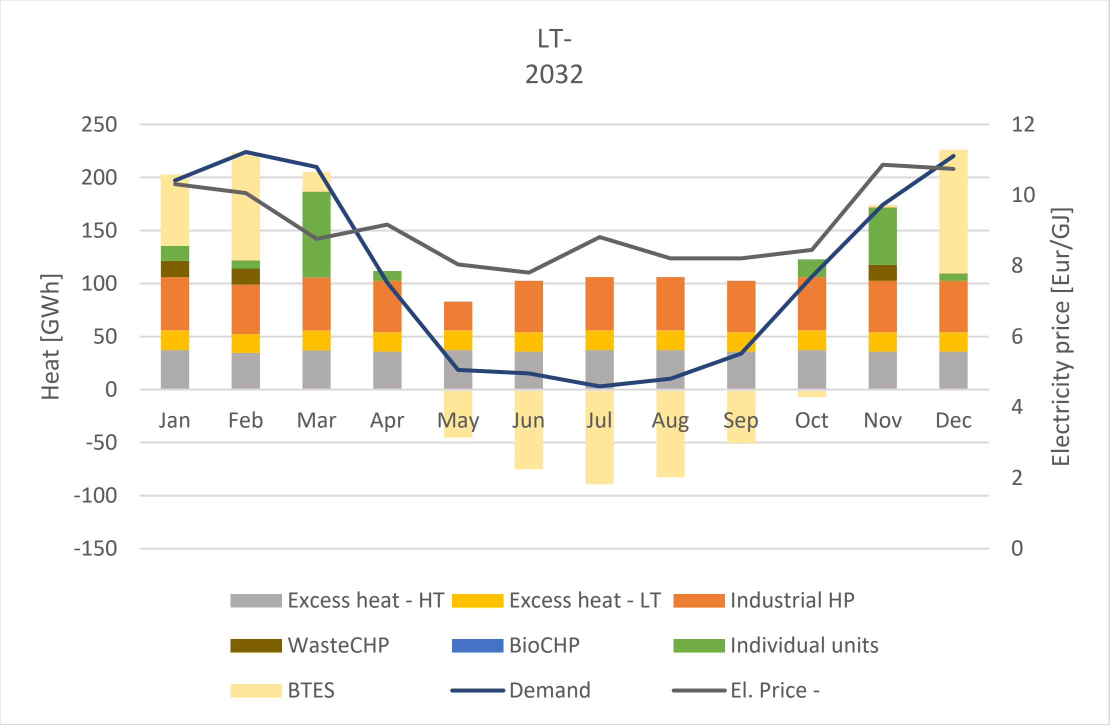


Figure 14 – DH production for 2032, LT-

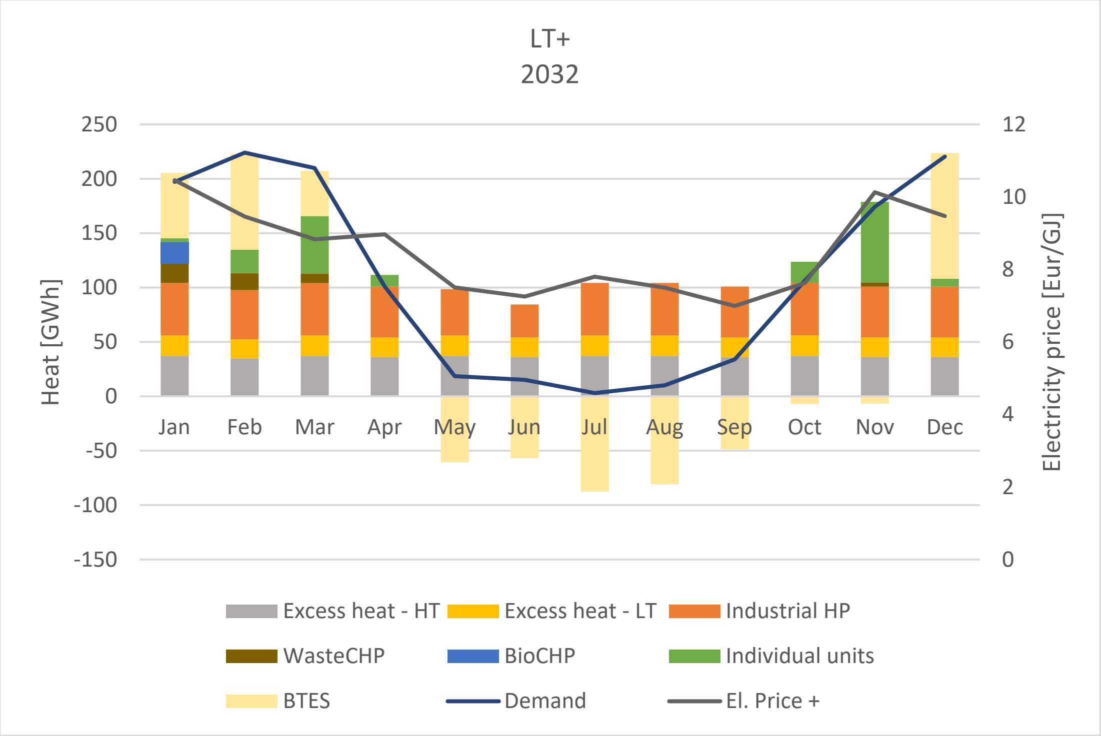
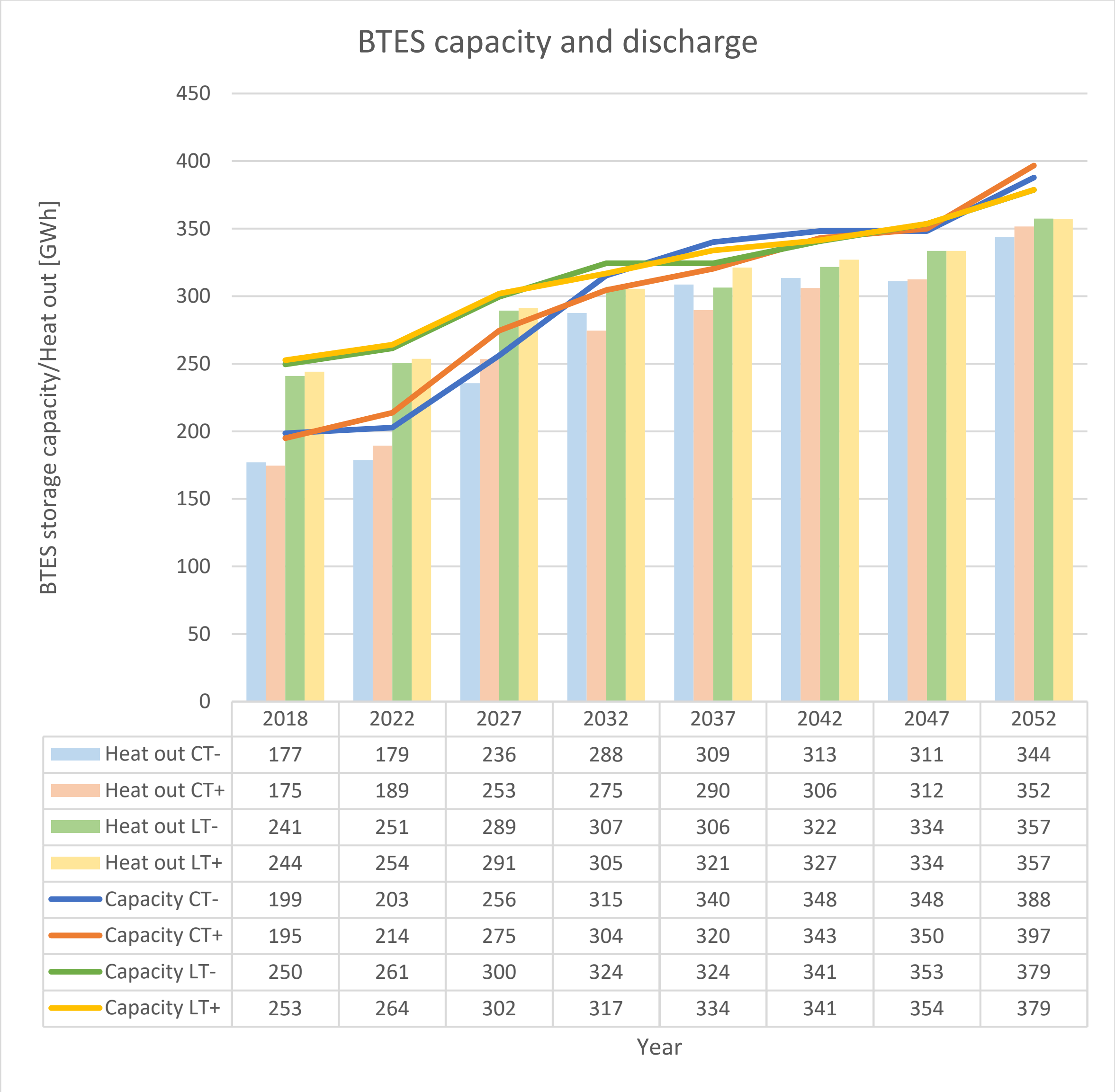


Figure 15 - DH production for 2032, LT+

The results show that on average, more of the BTES storage capacity in the LTDH system is utilised compared to the CTDH system. On average, 90% of BTES storage capacity is utilised each year in the CTDH system, while 95% is utilised in the LTDH system, as seen in Figure 16. This is because in the LTDH system, BTES has lower storage losses and therefore has more heat available to deposit back into the grid. Therefore, with regards to flexibility, this result shows that for LTDH systems more DH production can be avoided during high heat demand months. This is seen in Figure 17, where the total heat generation in the system in descending order in the scenarios with TES, are presented, for the year 2052. We see that in the time slices with high heat demand (i.e., time slices 1-25), heat generation from DH plants is lower in the LT scenarios. The same result is seen throughout the modelled period as well (as presented in Appendix B4). This is significant, given that the system, over the course of the modelled period, becomes more HP dominated, in both CT and LT cases (discussed in section 4.1.2). Therefore, their use in the summer to charge BTES has increased financial benefit, in that electricity prices are lower, and HP COPs are also higher in the summer.

The model chooses not to make new investments in LWT capacity in the CT (i.e., CT- and CT+) and LT (i.e., LT- and LT+) scenarios, so the existing tank is used throughout the modelled period. This is due to the existing LWT already being sufficiently capable of supplying the peak heat requirements the DH system, given that the city's heat demand is assumed, in the model, to be reducing every year (as discussed in section 3.4.1). The cost optimal method of using the LWT is to charge it when electricity prices are lower and to discharge it when electricity prices are higher, as shown in Figure 18 and Figure 19, for the CT and LT cases in February 2017. LWT activities for February are presented as it is the month with the highest heat demand. The same trends are seen for LWT throughout the modelled period (see Appendix B5 for LWT activity in the years 2032 and 2052). Therefore, the LWT provides a similar service as the BTES, with the contrast in just that it allows cost optimisation at a finer timescale. Additionally, we see in Figure 20, that the use of the LWT (represented as the heat discharged out of the LWT) in the LT scenarios reduces gradually over the modelled period, while its use in the CT scenarios oscillates around 66 GWh. In the earlier years, the LWT is used more in the LT cases due to the lower heat losses it encounters in LT operation. However, the gradual decrease is a result of increased LT excess heat capacity in the LTDH system over the years (as discussed in section 3.4.6). Excess heat does not influence the use of the LWT as it is a free source of energy, and therefore there is no cost benefit from charging the tank with it, as opposed to charging the tank with dispatchable capacity whose operation is influenced by electricity prices.



	2018	2022	2027	2032	2037	2042	2047	2052
Heat out CT-	177	179	236	288	309	313	311	344
Heat out CT+	175	189	253	275	290	306	312	352
Heat out LT-	241	251	289	307	306	322	334	357
Heat out LT+	244	254	291	305	321	327	334	357
Capacity CT-	199	203	256	315	340	348	348	388
Capacity CT+	195	214	275	304	320	343	350	397
Capacity LT-	250	261	300	324	324	341	353	379
Capacity LT+	253	264	302	317	334	341	354	379

Figure 16 - Capacity of BTES (lines) and heat discharged out (bars) of BTES for all modelled scenarios with TES

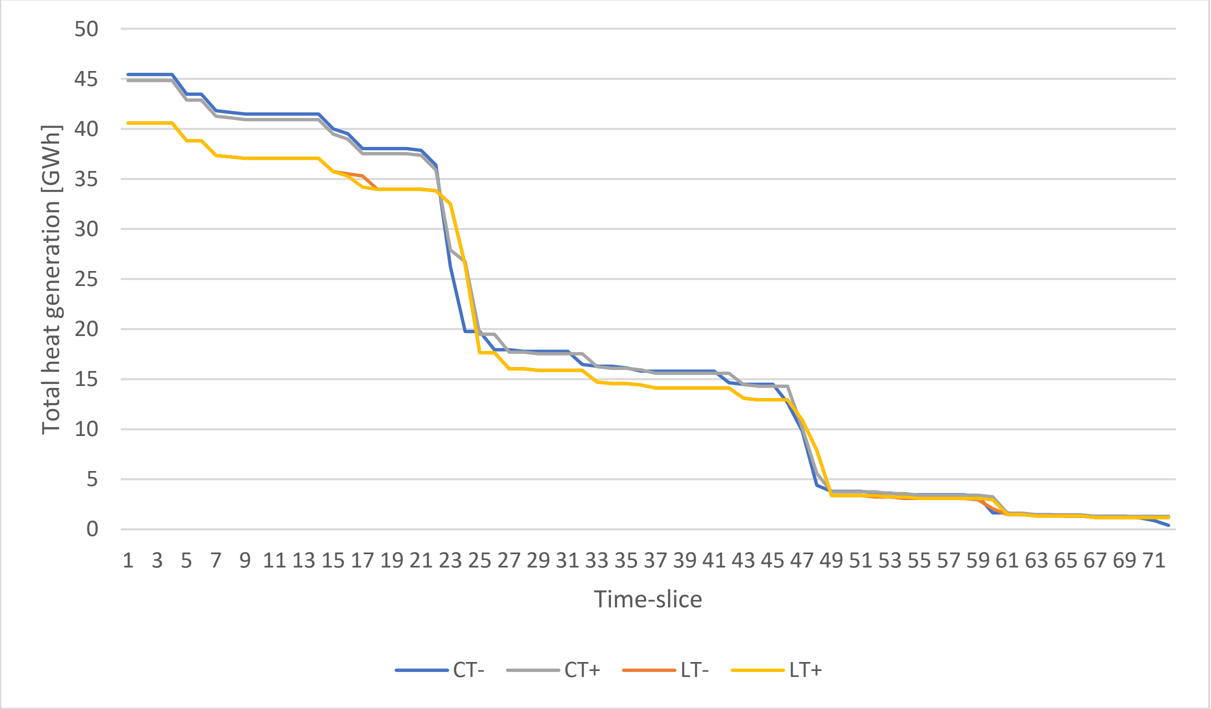


Figure 17 – Total heat generation in descending order comparison of all scenarios with TES, for the year 2052

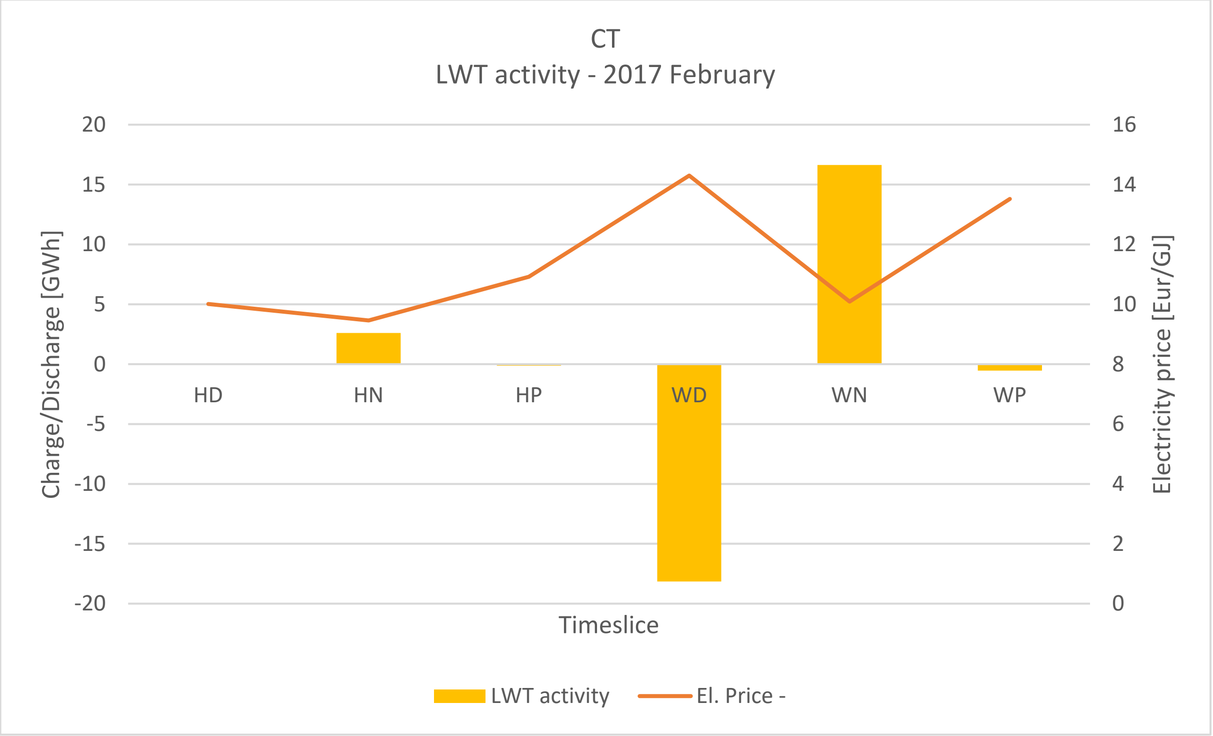


Figure 18 - LWT tank activity for February 2017, CT (tank charging is positive)

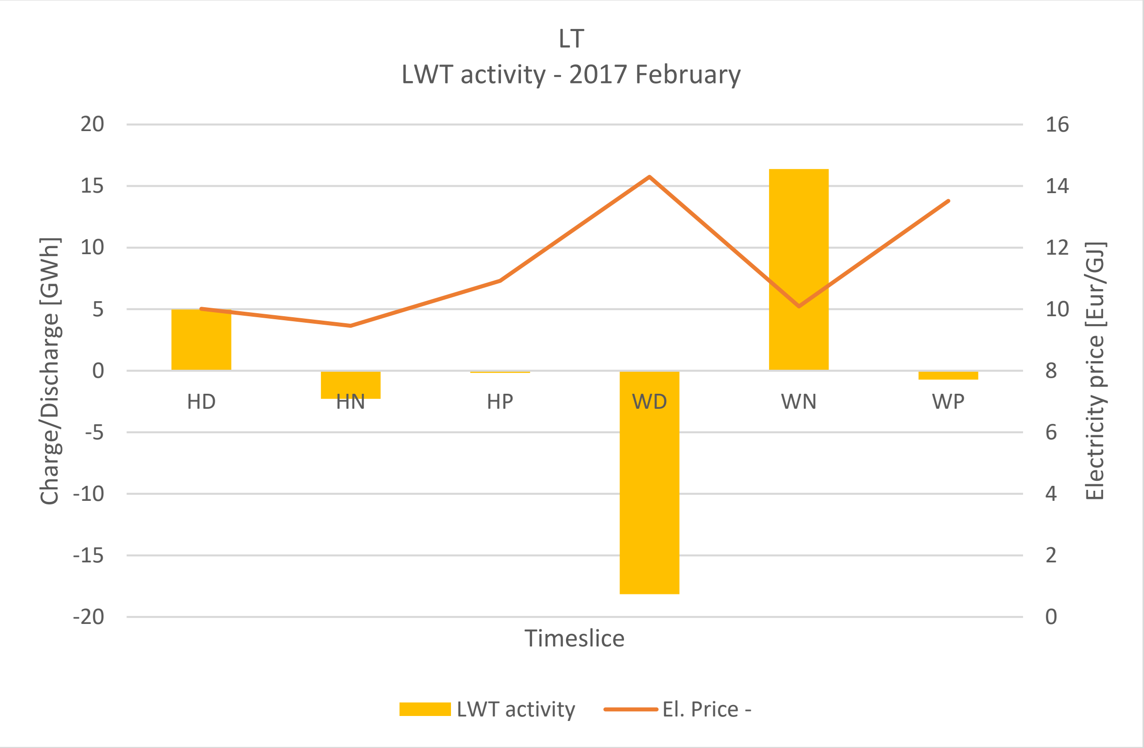


Figure 19 - LWT tank activity for February 2017, LT (tank charging is positive)

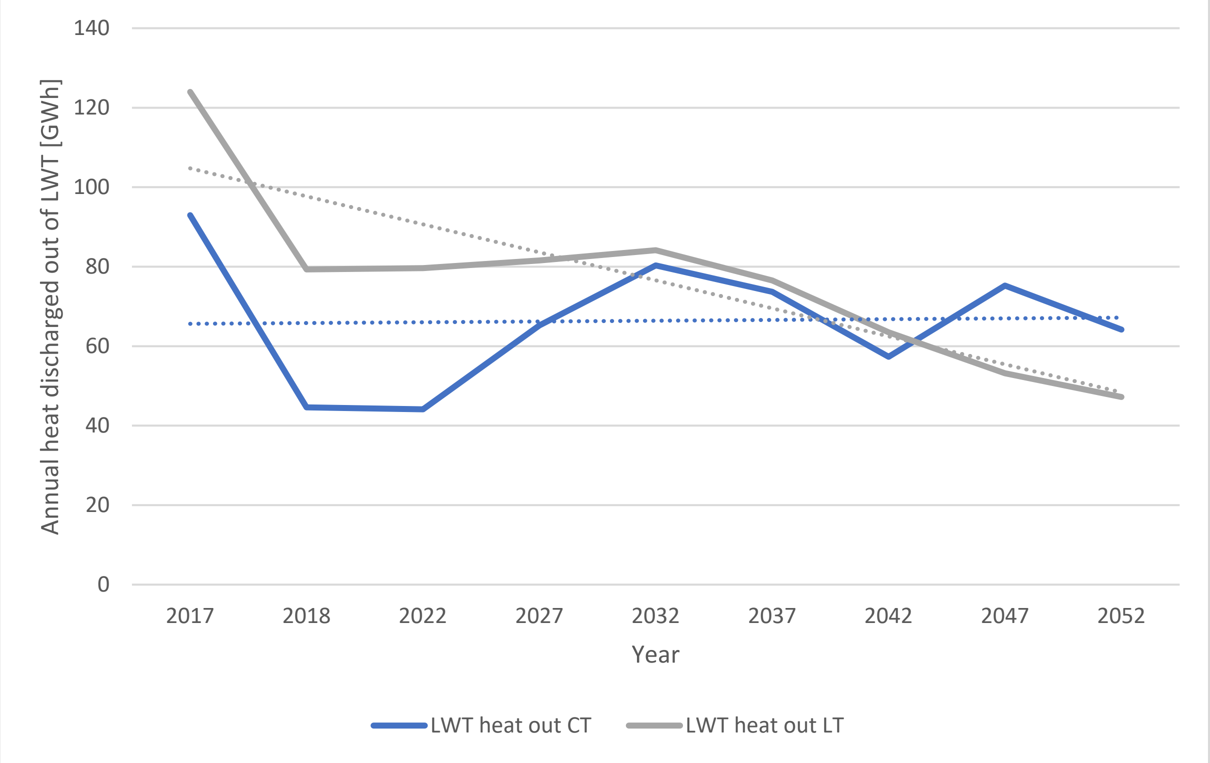


Figure 20 – Heat discharged out of the LWT (average between conservative and ambitious scenarios in the respective CT and LT cases) for every year

4.1.2. Annual DH production volume and capacity for DH plants

Table 40 through to Table 43, in Appendix B2 present the annual DH production by DH plants in the CT-, CT+, LT- and LT+ scenarios. In all the scenarios, the 30 MW oil boiler is only used in 2017, after which the model chooses to stop using it for the remainder of the modelled period. This is due to the high CO_2 and energy tax levied on their operation.

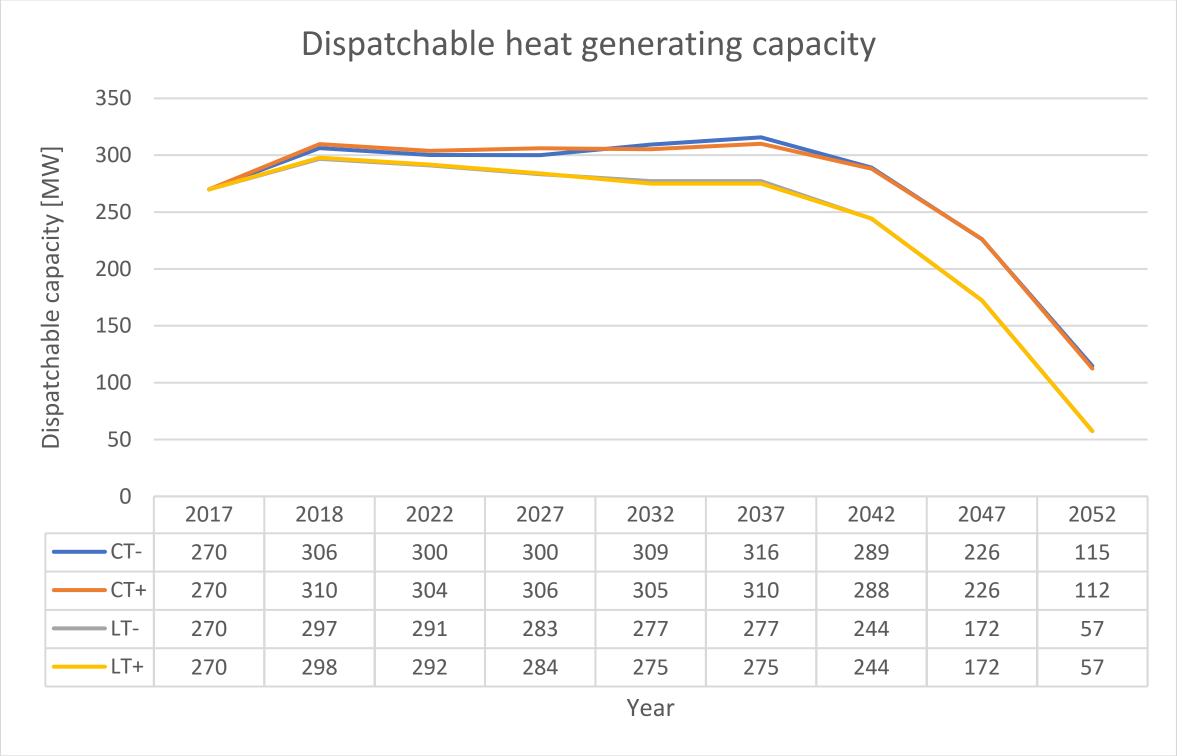
In the CT and LT scenarios, production from the bio pellet CHP plant reduces after 2017. Production from the municipal waste CHP plant is identical in the CT and LT scenarios. This is because production in the municipal waste CHP plant is limited by the availability of municipal waste, which will greatly reduce in the future as Sweden is expected to produce even less waste. It is important to note, that the availability of waste is kept the same in the conservative and ambitious cases.

Production from the bio pellet CHP plant is higher in the conservative scenarios than in the ambitious scenarios in the CTDH and LTDH systems, and is lower than the production from the municipal waste CHP plant despite having greater capacity. This is because, there is a fuel cost associated with bio pellets, but in the case of municipal waste, the operator is paid by municipalities for importing the waste (see Appendix A4.2). Therefore, the municipal waste CHP plant is run at maximum capacity for a longer time. It follows that if there is no limitation on municipal waste availability, the municipal waste CHP plant would have a greater production volume in the conservative scenario than in the ambitious scenario (as seen with the bio pellet CHP plant). In the LT scenarios (i.e., LT- and LT+), production by the bio pellet drops even more significantly than in the CT scenarios, due to the availability of LT excess heat in the LTDH system, on top of the HT excess heat that is also available in the CT scenarios. Excess heat has no fuel costs; therefore, it is always prioritised, and as a result, production from other DH plants can be reduced.

By 2032, the DH production is dominated by industrial HPs, followed by excess heat. There is very little production from the CHP plants, and by 2052 there is no production from the CHP plants at all. This is due to the retirement of the bio pellet CHP plant, and the unavailability of municipal waste for the municipal waste CHP plant. In the CT scenarios, production from the industrial HPs keep increasing throughout the modelled period as production from the CHP plants reduces, but in the LT scenarios, production from the HPs increases only till 2032, after which it gradually reduces. DH production by industrial HPs is higher in the ambitious scenarios than in the conservative scenarios, as can be seen when comparing production volumes between Table 40 and Table 41 for the CT scenarios, and Table 42 and Table 43 for the LT scenarios.

The model chooses to only invest in industrial HP capacity in the CT-, CT+, LT- and LT+ scenarios. Therefore, the heat generating capacities of the other DH plants (i.e., municipal waste CHP, bio pellet CHP, oil boiler, and excess heat) remain at base year levels, except for LT excess heat capacity in the LTDH system, which increases over the modelled period as more LT heat sources (e.g., data centres, sewage, various industrial processes, etc) are connected to the grid (explained in section 3.4.6). Capacities of all DH plants in the system are presented in Appendix B6. When considering that the industrial HPs, CHP plants, and oil boiler are the only dispatchable heat generating technologies in the system, we see that total dispatchable DH capacity in the LT scenarios (LT- and LT+) is less than the total dispatchable DH capacity in the CT scenarios (CT- and CT+), which is shown in Figure 21.

The fact that dispatchable DH capacity can be kept lower in the LTDH system is due to more excess heat, but also because of TES in the LTDH system, i.e., capacities of dispatchable heat generating units can be lower in a LTDH system than a CTDH system, as greater base load supply is achieved through BTES discharging. It is important to note that much of this reduced need in peak heating capacity in the LTDH system is a result of additional LT excess heat availability in the system. The differences in dispatchable DH capacities between the CT and LT scenarios, and the capacities of LT excess heat in the LTDH system are presented in Table 6. We see that after 2027, the differences in dispatchable DH capacity are greater than the LT excess heat capacity in the LTDH system and the differences increase at a faster rate than the increase in LT excess heat.



	2017	2018	2022	2027	2032	2037	2042	2047	2052
CT-	270	306	300	300	309	316	289	226	115
CT+	270	310	304	306	305	310	288	226	112
LT-	270	297	291	283	277	277	244	172	57
LT+	270	298	292	284	275	275	244	172	57

Figure 21 – Total dispatchable heat generating capacity (i.e., excluding excess heat) in the DH system across all modelled scenarios.

Table 6 – Differences in dispatchable heat generating capacity, and capacity of LT excess heat in LTDH system

	2017	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Difference in dispatchable capacity between CT- and LT- [MW]	0	9.4	9.2	16.8	32.1	38.5	44.9	53.8	57.3
Difference in dispatchable capacity between CT+ and LT+ [MW]	0	12.0	12.0	22.1	30.2	35.	43.7	54.1	55.1
LT excess heat [MW]	17.6	18.0	19.9	22.4	25.2	28.4	31.8	35.7	39.7

Industrial HP capacity in the CT- and CT+ scenarios keep increasing until 2052 (as seen in Figure 22). By 2052, industrial HP capacity stands at 114.6 MW and 112.4 MW in the CT- and CT+ scenarios, respectively. In the LT- and LT+ scenarios, industrial HP capacity is at its highest in 2037, with 67.3 MW and 65.0 MW in the LT- and LT+ scenarios, respectively, and then starts to drop as older units are retired and no more investments in new units are made. This is due to a multiple of reasons which are, the continued expansion of LT excess heat in the LTDH system, the fact that heat demand in the city is reducing, and because less dispatchable DH capacity is required. By 2052, industrial HP capacity stands at 57.4 MW and 57.3 MW in the LT- and LT+ scenarios, respectively. In both CT and LT cases, the systems become industrial HP dominated due to the reducing electricity prices that are forecasted for the future, as is the case in both conservative and ambitious scenarios (refer to Appendix A4.1).

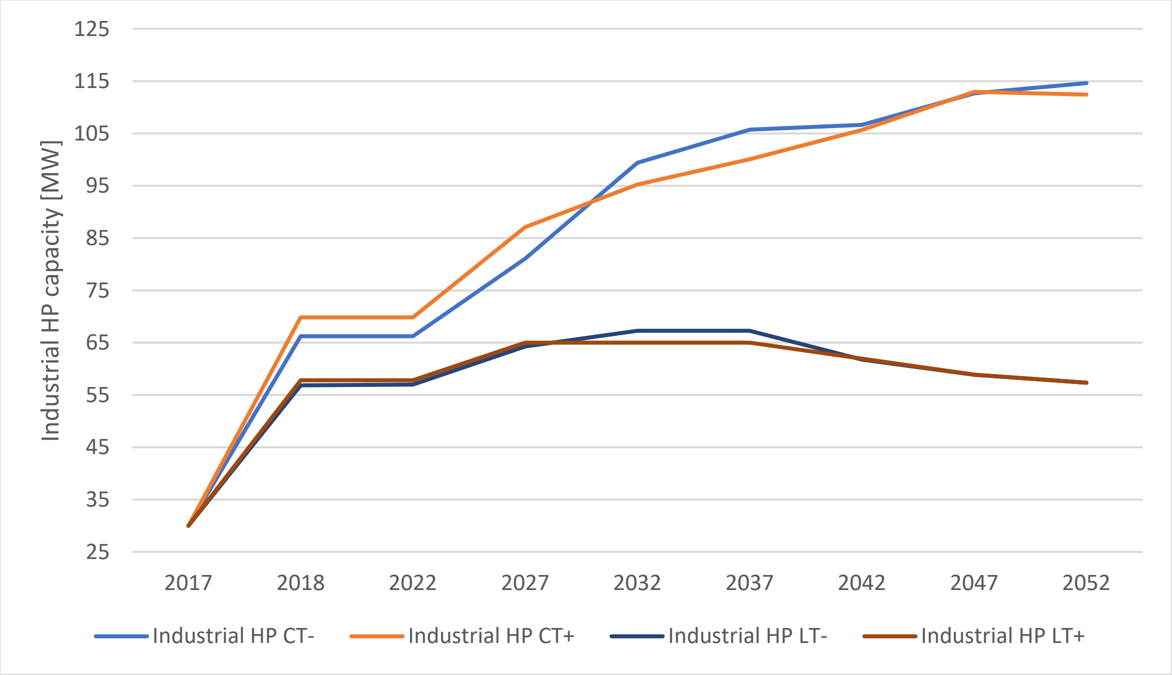


Figure 22 – Industrial HP capacity over the modelled period across all scenarios with TES

As seen from the energy balance tables presented in Appendix B1, production from individual units keeps reducing over the years in the CT and LT scenarios. There are no new investments made in individual units, but rather, the only investments made in DH plants are in industrial HPs. This shows that it is financially beneficial from a global perspective (particularly by indicating a reduced use of individual units for cost optimization) to be connected to the DH grid. In the real world, however, it is impossible to control the deployment of individual units as it is up to the individual user on whether they prefer to be connected to the DH grid or not.

Therefore, the results presented in this thesis, assume that the individual consumer follows the consumption levels presented in Appendix B1.

4.1.3. Heating sector's electricity consumption vs production

The results show that for both the CTDH and LTDH systems, the combined power and heating sector changes from being a net electricity generator in 2017, to being a major electricity consumer (thus shifting to just heating) by 2052 (seen in Figure 23).

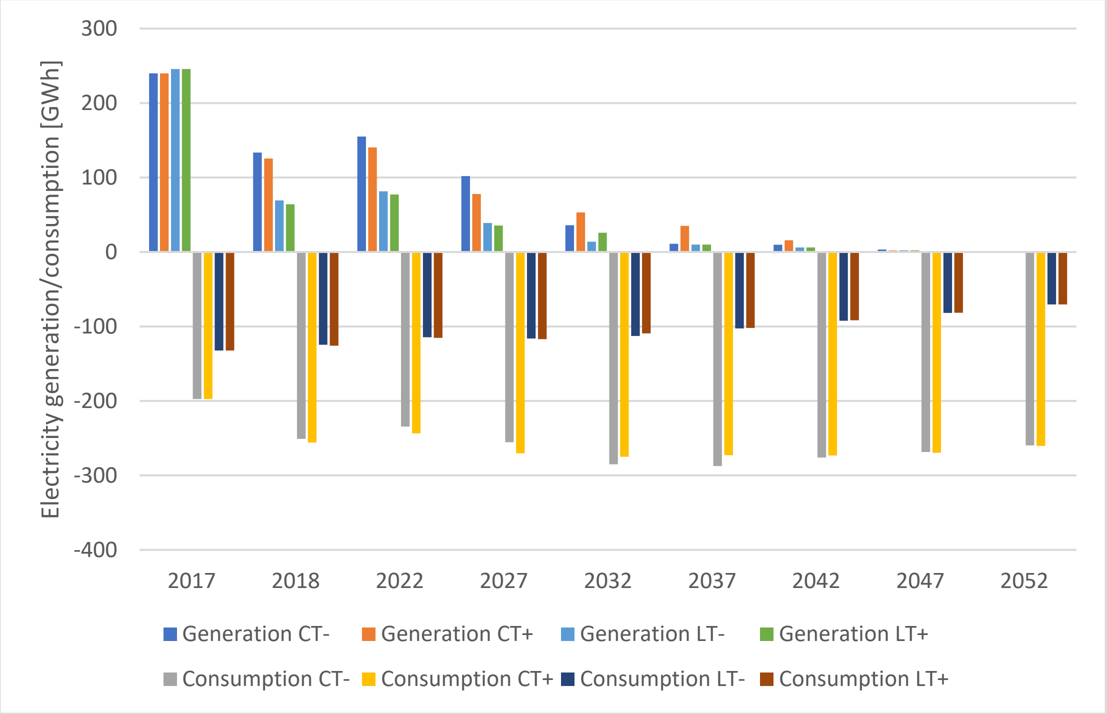


Figure 23 – Electricity generation/consumption balance for all modelled scenarios with TES

The significant drop in electricity generation in all the scenarios after 2017, is a result of the drop in DH and electricity production by the CHP plants and the replacement with industrial HPs (as discussed in section 4.1.2). In the CT- and CT+ scenarios, electricity consumption in the heating sector remains in between 200 GWh and 300 GWh. In contrast, in the LT- and LT+ scenarios, electricity consumption reduces from 2017 itself. In the LT scenarios, electricity consumption by industrial HPs does increase until 2032; however, this is covered by the reduction in electricity consumption from individual units in the commercial and residential sectors. Total electricity consumption is significantly lower in the LT scenarios as compared to the CT scenarios since the DH production by industrial HPs is lower and because HPs have higher COPs in LTDH systems.

These results show that the heating sector chooses to use cheap, excess electricity in the power sector, that is then increasingly imported from the national grid, as electricity prices drop in the future. The operational strategy of the CHP plants (i.e., reduced production after 2017, and production only in months with higher electricity prices) leads to the limited ability of the heating sector to provide flexibility service to the power sector.

4.1.4. Discussion on the effect of electricity prices on the operation of the DH system

The differences between the conservative and ambitious scenarios are seen in the results of the CT-, CT+, LT-, and LT+ scenarios. Both cases (i.e., conservative, and ambitious) predict that electricity prices will keep reducing into the future, which is one of the driving forces for both the CTDH and LTDH systems to become HP-dominated eventually. In the LTDH system, investment into HPs is even more incentivised given their higher COPs. Therefore, the combination of cheaper electricity in the future and better techno-economic performance of HPs in low temperature operation, causes the LTDH system to become 'locked-in' to using HPs. That is, in the case of Helsingborg, HPs will eventually be the only dispatchable heat generating technology, and as a result, the network operator would be forced to operate them to meet the city's heat demand regardless of electricity price. One can see in Figure 24, that DH production by CHP plants and HPs is quite similar between LT- and LT+, but more varied between CT- and CT+. This is evidence of the network operator having more freedom to react to electricity prices in the CTDH system than in the LTDH system. In the CTDH system, CHP plants maintain generation further into the future as they provide the opportunity to generate revenue from electricity sales.

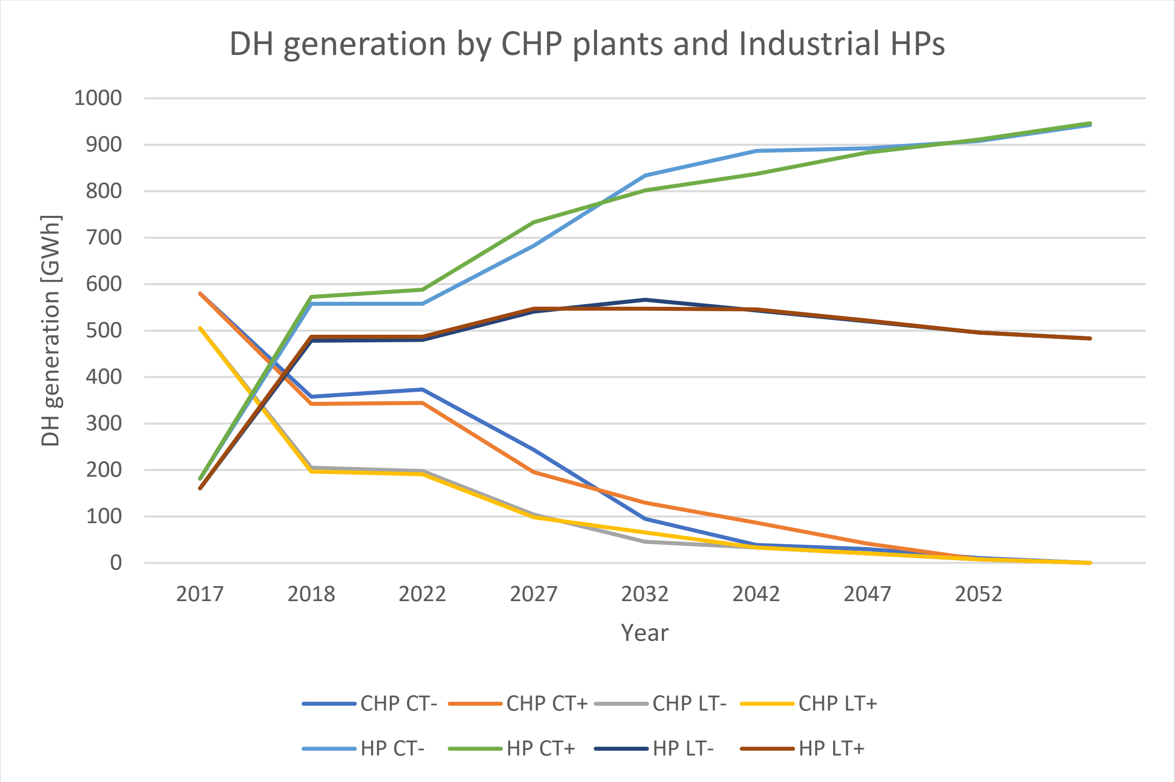
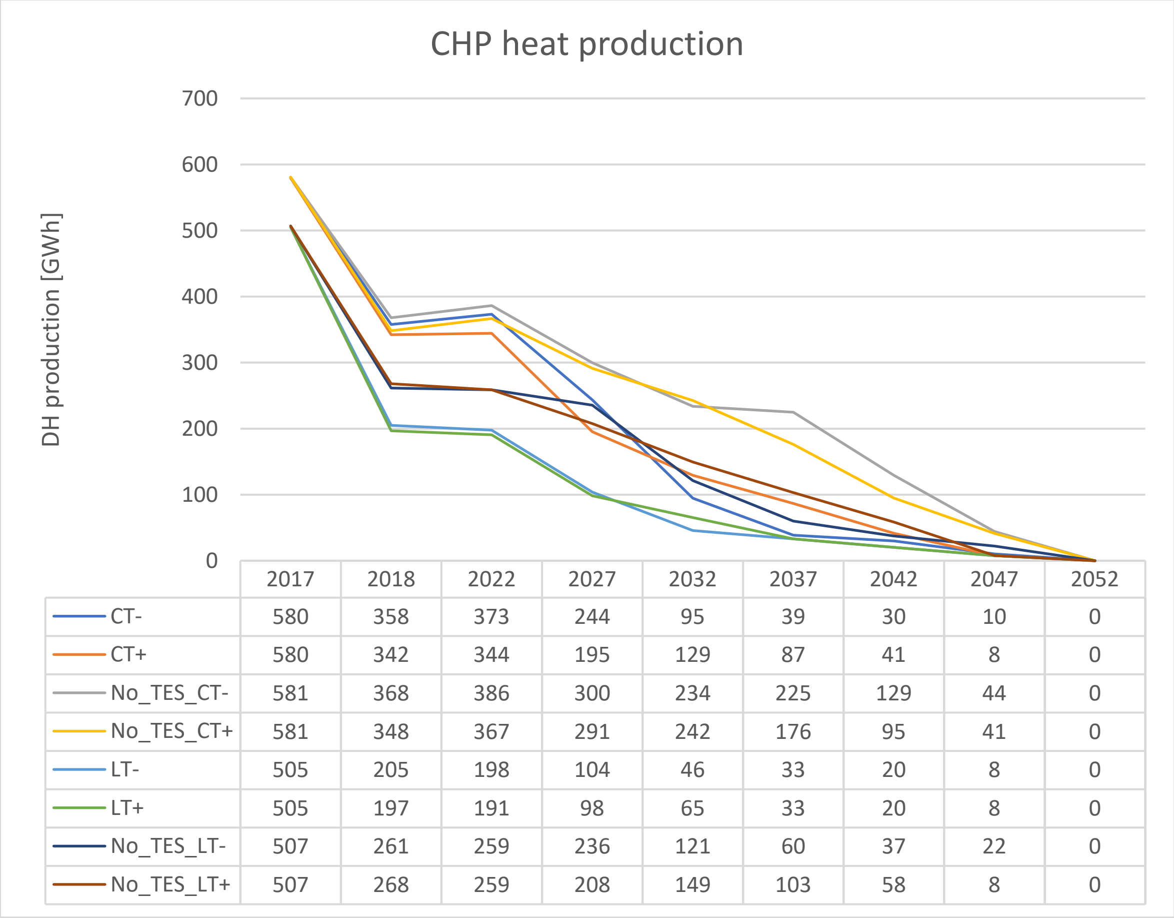


Figure 24 – Heat generated by CHP plants and HPs across the modelled period, for all scenarios with TES

4.2. TES vs No_TES in DH systems

In both CTDH and LTDH systems, it is apparent that, in the absence of TES, it is more cost optimal to use CHP plants to generate more revenue from electricity sales. This can be seen in Figure 25, where production from CHP plants in the No_TES scenarios is higher than the corresponding scenario with TES. The difference is more pronounced in the CT scenarios compared to the LT scenarios. This is due to the reasons discussed in section 4.1.4 (i.e., there is more incentive to keep CHP plants operating in CTDH systems).

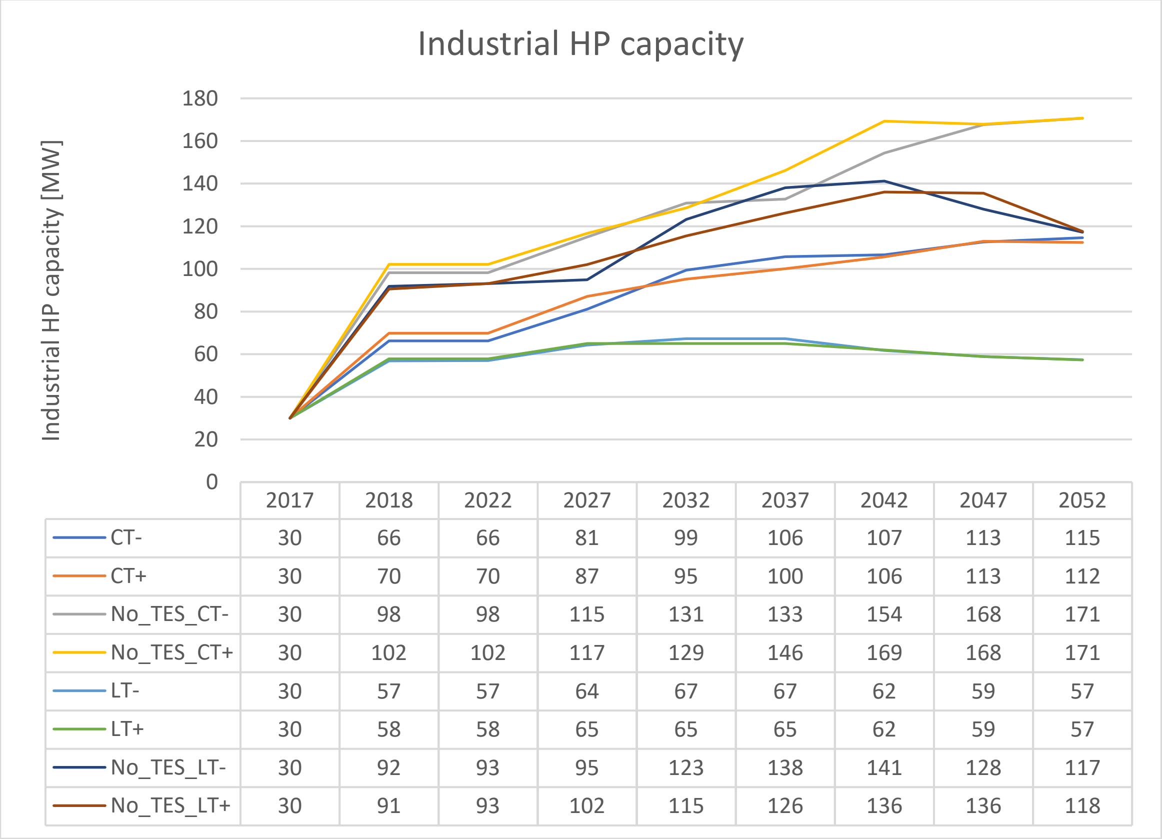


	2017	2018	2022	2027	2032	2037	2042	2047	2052
CT-	580	358	373	244	95	39	30	10	0
CT+	580	342	344	195	129	87	41	8	0
No_TES_CT-	581	368	386	300	234	225	129	44	0
No_TES_CT+	581	348	367	291	242	176	95	41	0
LT-	505	205	198	104	46	33	20	8	0
LT+	505	197	191	98	65	33	20	8	0
No_TES_LT-	507	261	259	236	121	60	37	22	0
No_TES_LT+	507	268	259	208	149	103	58	8	0

Figure 25 – DH production from CHP plants for all modelled scenarios

Therefore, with the inclusion of TES, heat generation from CHP plants is reduced, and replaced with generation from HPs, that are also operated in the summer (using cheap, imported electricity) to charge the BTES. This is a benefit of STES with regards to flexibility, in that it offers an alternative for DH systems that do not own a lot of electricity production.

Across all scenarios, industrials HPs still dominate the systems, and their use keeps increasing as production from CHP plants go down. Figure 26 shows the industrial HP capacity over the modelled period for all scenarios. In the No_TES_CT- and No_TES_CT+ scenarios, HP capacity keeps increasing throughout the modelled period, and is clearly higher than the capacities in the corresponding scenarios with TES. The same trend is seen in the LT scenarios (i.e., higher HP capacities in the No_TES scenarios), except that HP capacity in the No_TES scenarios peaks in 2042 and then begins to drop as old HPs are retired and increasing LT excess heat use takes over the deficit.



	2017	2018	2022	2027	2032	2037	2042	2047	2052
CT-	30	66	66	81	99	106	107	113	115
CT+	30	70	70	87	95	100	106	113	112
No_TES_CT-	30	98	98	115	131	133	154	168	171
No_TES_CT+	30	102	102	117	129	146	169	168	171
LT-	30	57	57	64	67	67	62	59	57
LT+	30	58	58	65	65	65	62	59	57
No_TES_LT-	30	92	93	95	123	138	141	128	117
No_TES_LT+	30	91	93	102	115	126	136	136	118

Figure 26 – Industrial HP capacity for all modelled scenarios

We see that investments into individual units are made in all No_TES scenarios. The model chooses to invest in individual air-source HP and gas furnace units, instead of investments into industrial HPs. The capacities of the individual units are presented in Table 53 through to Table 56, in Appendix B6**.** Investments into individual units are preferred over industrial HPs (in the No_TES scenarios) due to their lower investment costs. Industrial HPs have high investment costs, but their operational and maintenance costs are lower, therefore in the long run, with greater heat production, cost saving are realised. Therefore, there is heavy investment in industrial HPs just after the base year (from 2018 onwards), but not towards the end of the modelled period, as heat demand in the city is dropping anyways and therefore any required new heating capacity is small and so it is more profitable to use individual units over industrial scale units.

Figure 27 shows the same trend in electricity generation vs consumption in the heat and power sector in the absence of TES, as is seen in the scenarios with TES. That is, the heat and power sector changes from being a net electricity generator in 2017, to being a major electricity consumer by 2052.

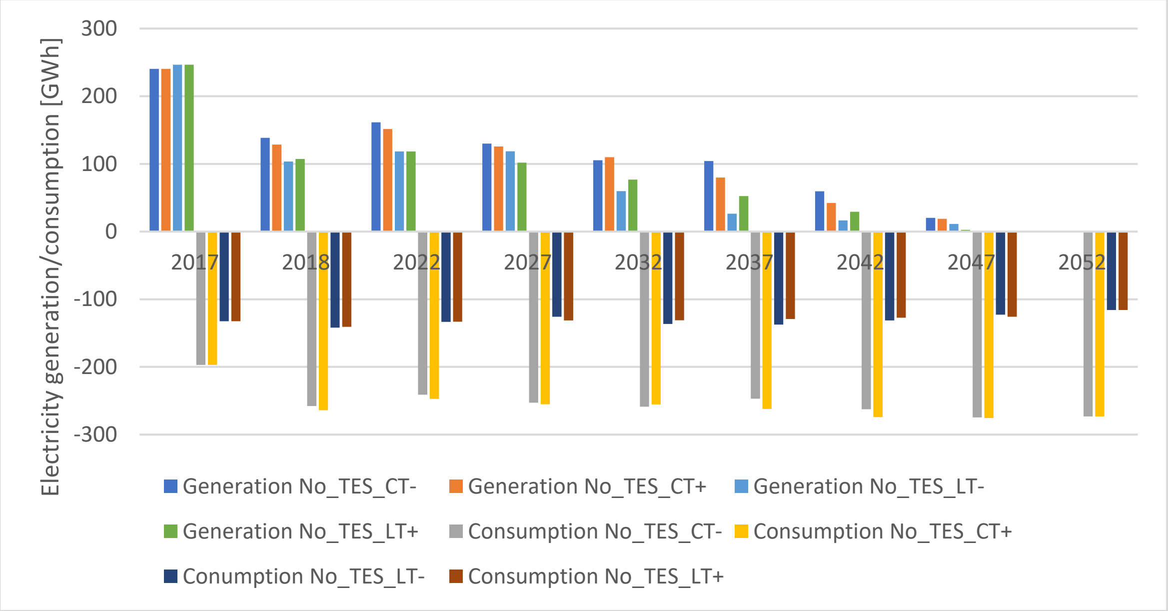


Figure 27 – Electricity generation/consumption balance for No_TES scenarios

However, higher generation is maintained, during the years that there is generation, in the No_TES scenarios compared to the scenarios with TES. This shows that as electricity prices reduce in the future, TES will accelerate the transition of DH system from being net generators of electricity, to major consumers, regardless of the operating temperatures of the system.

Figure 28 and Figure 29 show the total heat generation (i.e., by DH plants and individual units) in descending order for all the CT and LT scenarios for the year 2052, respectively, for all 72 time slices. We see that in periods of high heat demand (i.e., time slices 1-11), heat production in the No_TES scenarios is significantly higher than in the scenarios with TES. In this period, DH production in the scenarios with TES is lower as BTES is being discharged to meet the city's heat demand. Then there is a period (i.e., time slices 11-49) where heat production in the scenarios with TES is higher as this is when BTES is being charged. The heat generation in descending order for the year 2032 is presented in Appendix B7, where the same observation as for the year 2052 is made.

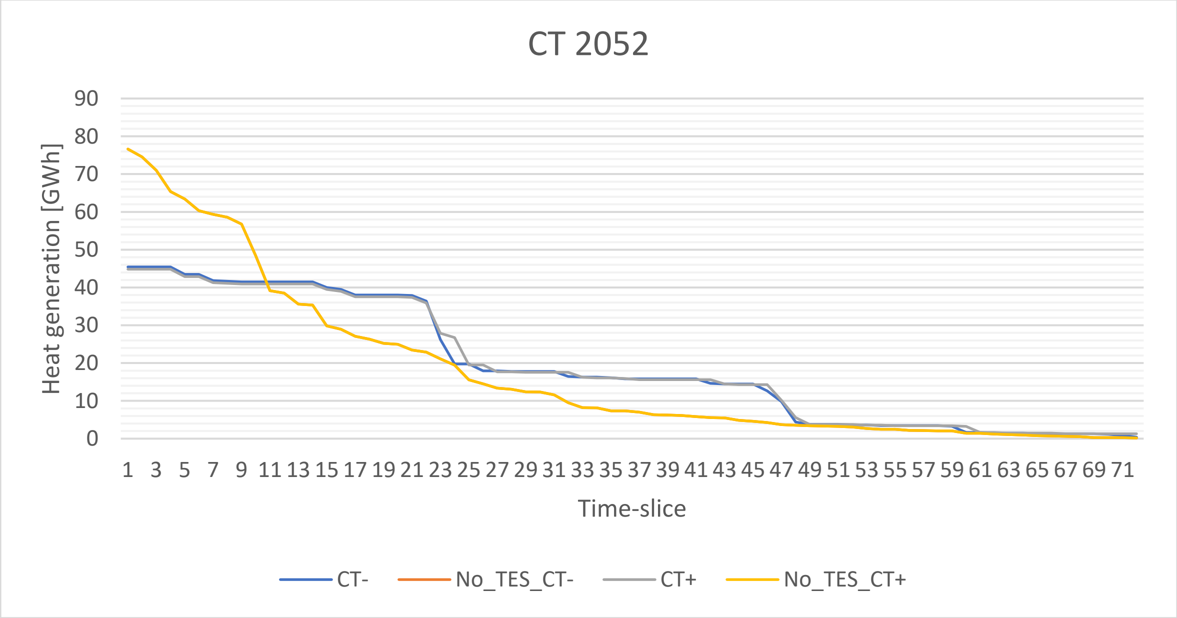


Figure 28 – Scenario comparison of total heat generation in descending order for 2052, CTDH

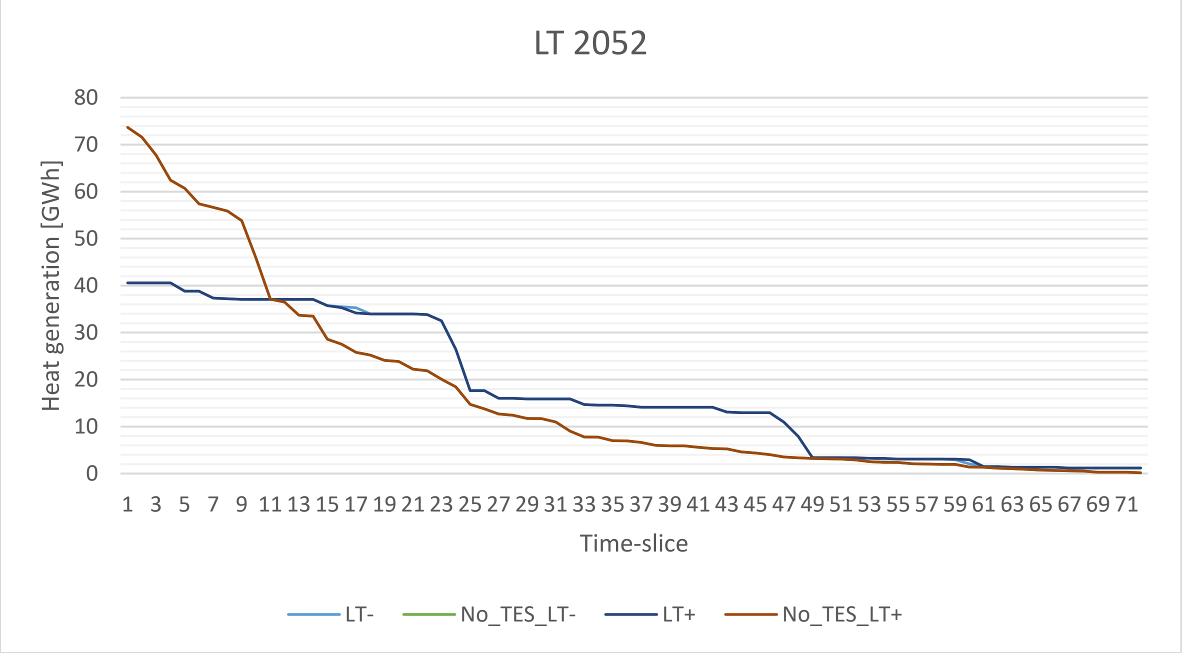


Figure 29 - Scenario comparison of total heat generation in descending order for 2052, LTDH

The results show that in the presence of TES, peak shaving (i.e., by how much heat generation is reduced in the time slice with highest demand) of DH production occurs due to a greater base supply from BTES discharging. In the LTDH system, the peak shaving is more pronounced due to more excess heat making up the base supply in the system, together with more utilisation of BTES storage capacity in LTDH system (as discussed in section 4.1.1). In the year 2052, peak shaving in the CTDH system is 40.7% in the conservative scenario, and 41.5% in the ambitious scenario. In the LTDH system, peak shaving is 44.90% in the conservative scenario, and 44.92% in the ambitious scenario (i.e., very similar), in the year 2052. Across the entire modelled period, we see that on average, peak shaving is 1.6% more in the LTDH system compared to the CTDH system.

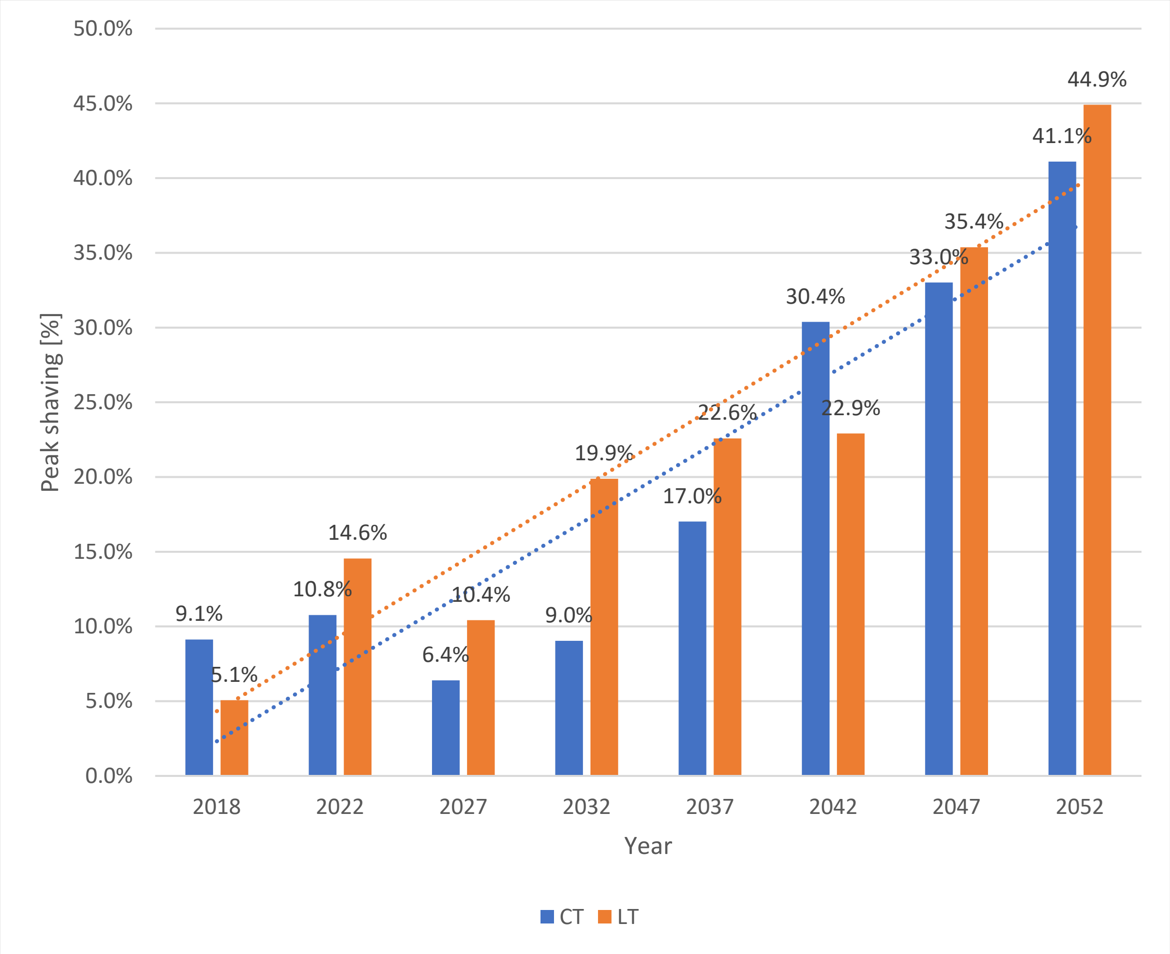
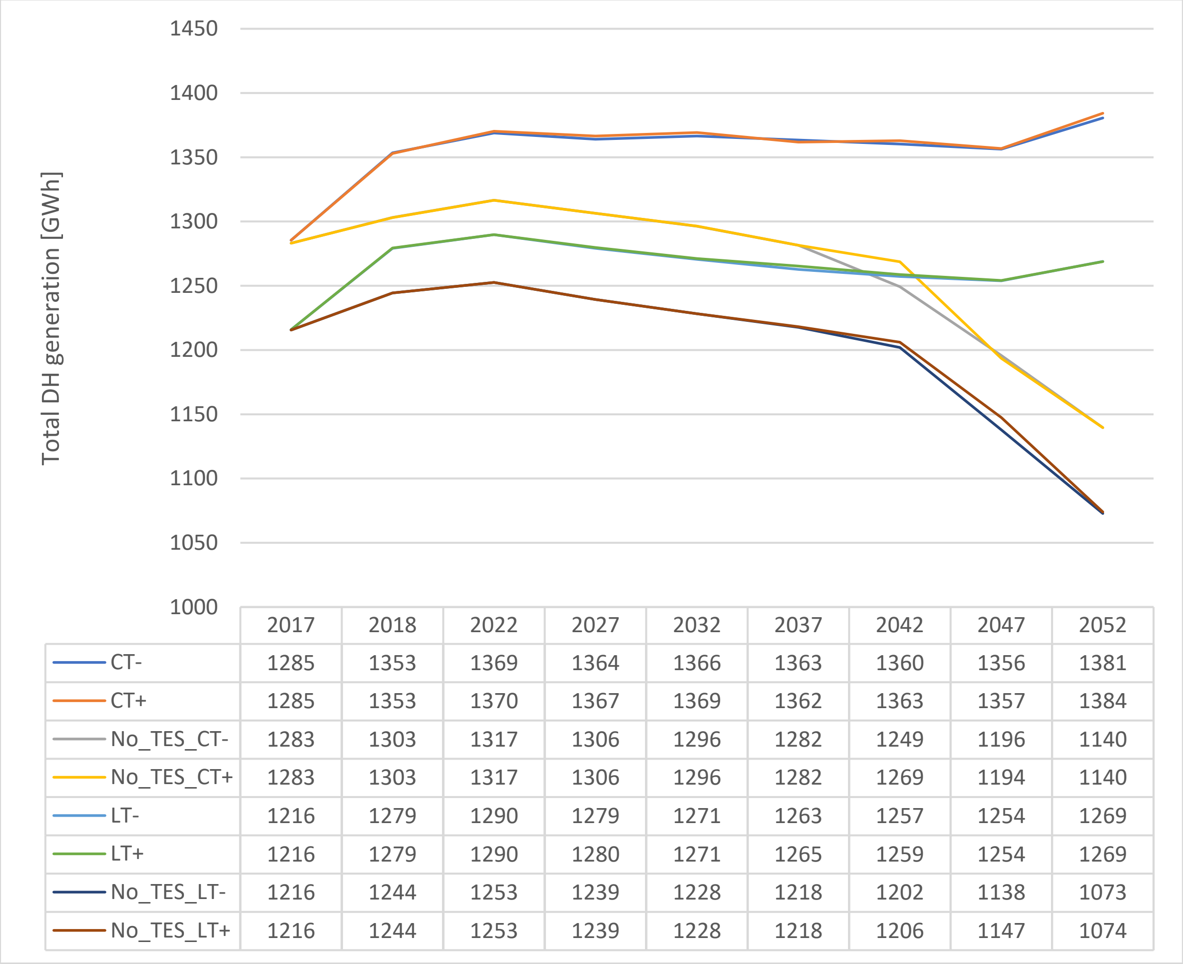


Figure 30 – Comparison of peak shaving between CTDH and LTDH systems. The average peak shaving amounts between the conservative and ambitious cases are plotted in this graph.

Figure 31 shows the total DH production volume by DH plants for all modelled years and for all scenarios. We see that when comparing scenarios with TES with their corresponding No_TES scenarios, total production volumes in the No_TES scenarios are lower. This is because, in the scenarios with TES, DH plants need to generate slightly more heat to account for losses in TES, while no such heat losses exist in the No_TES scenarios. In addition to this, individual units have more production in the No_TES scenarios compared to their corresponding scenarios with TES. Despite this, overall system costs are lower in the scenarios with TES, as BTES allows DH production to be shifted to the summer when production is cheaper, and the LWT provides the same service a finer timescale. The cost-optimal method to operate the system is to charge the BTES in the summer months and discharge them in the winter. This strategy means running the HPs in summer as well, despite the low DH demand, mainly to charge the BTES. This means the HPs do not need to increase their production in the winter when electricity prices are higher than in summer. Also, the HPs have higher COPs in warmer conditions due to smaller temperature 'lift' they must provide, therefore their electricity consumption is also reduced. This is where the financial benefit comes from. Additionally, this is a flexibility benefit as electricity demand is being shifted to lower demand months, as reflected by the electricity price.



	2017	2018	2022	2027	2032	2037	2042	2047	2052
CT-	1285	1353	1369	1364	1366	1363	1360	1356	1381
CT+	1285	1353	1370	1367	1369	1362	1363	1357	1384
No_TES_CT-	1283	1303	1317	1306	1296	1282	1249	1196	1140
No_TES_CT+	1283	1303	1317	1306	1296	1282	1269	1194	1140
LT-	1216	1279	1290	1279	1271	1263	1257	1254	1269
LT+	1216	1279	1290	1280	1271	1265	1259	1254	1269
No_TES_LT-	1216	1244	1253	1239	1228	1218	1202	1138	1073
No_TES_LT+	1216	1244	1253	1239	1228	1218	1206	1147	1074

Figure 31 – Total DH production volumes for all modelled scenarios

Table 7 shows the total system cost of heat supply over the modelled period for all modelled scenarios. The models handling of the total system cost (i.e., the objective function of the optimization) is discussed in section 3.1. In the CTDH system, when TES is available, the total cost of heat supply is reduced by 5.2% in the conservative scenario and by 5.5% in the ambitious scenario. In the LTDH system, when TES is available, the total cost of heat supply is reduced by 15.0% in the conservative scenario and by 15.3% in the ambitious scenario.

Table 7 – Total system cost (over the modelled period) for all modelled scenarios

Scenario	Total storage capacity of BTES in 2052 [GWh]	Total power capacity of BTES in 2052 [MW]	Total system cost [MEur]
No_TES_CT-	-	-	904
No_TES_CT+	-	-	899
CT-	387.8	144	857
CT+	396.7	142	850
No_TES_LT-	-	-	581
No_TES_LT+	-	-	580
LT-	378.7	130	494
LT+	378.8	130	491

Therefore, the results show that greater savings (i.e., by almost 10%) are possible when TES is included in LTDH systems as compared to in CTDH systems. We also see that electricity prices do affect the total system cost (i.e., 0.3% lower in the ambitious scenarios), however this benefit is independent of the system's temperature level (i.e., CTDH or LTDH).

4.3. Overall discussion

We see that in the LTDH system, more STES (i.e., assumed to be mainly BTES) storage capacity is utilised (i.e., 5% more in the LTDH system compared to the CTDH system), due to lower heat losses in LT operation. As a result, in the LTDH system, more DH production can be avoided during high heat demand periods. This leads to more cost savings as production costs are generally higher in the winter (i.e., during high heat demand periods) due to electricity prices being higher in the winter as well. Using HPs to charge BTES in the summer is beneficial, given that HPs have better techno-economic performance when ambient temperatures are higher. The benefits of this are amplified in LT operation as HPs have higher COPs given the lower temperature 'lift' they must provide. This provides a flexibility service to the power sector in that, electricity consumption occurs during low electricity demand months, as reflected by the electricity prices. We also see that dispatchable heat generating capacity in the LTDH system can be lower than in the CTDH system, as greater base load supply can be achieved from BTES discharging, and from increased capacity from LT excess heat.

When comparing the operation of the CTDH and LTDH system with and without TES technologies availability, we observe that around 1.6% more peak shaving occurs in the LTDH system (i.e., when TES is included as opposed to when it is not) compared to the CTDH system. Significantly more cost savings are experienced with the inclusion of TES in the LTDH system (almost 10% more), which makes a strong case for the adoption of these type of systems.

Therefore, to summarise, LTDH systems can make more use of the flexibility provided by TES technologies due to lower heat losses. The benefits provided by the flexibility from TES technologies in the LTDH system are:

1. Less DH production needed due to lower storage losses (seen in Figure 17)
2. Heat generating capacity can be lower (seen in Figure 21)
3. More peak shaving occurs when comparing system operation without TES being included (seen in Figure 29)

The results also show that the cost optimised strategy for operating CHP plants (i.e., reduced production after 2017, and production only in months with higher electricity prices) leads to the limited ability of the heating sector to provide flexibility service to the power sector in both CTDH and LTDH systems. The combination of cheaper electricity prices in the future and better techno-economic performance of HPs in LT operation causes the LTDH system to become 'locked-in' to using HPs. Therefore, the network operator is forced to run HPs to meet DH demand regardless of variations in electricity prices. In contrast, the CTDH system is seen to incentivise more production from CHP plants, therefore the network operator has more freedom to react to electricity prices. In the absence of TES, it is cost-optimal to use CHP plants more to generate revenue from electricity sales. Production from CHP plants is more in the CTDH system as there is more incentive to keep CHP plants operating. With TES included, the use of HPs is incentivised, as they can be used to charge e.g., BTES in the summer using cheap, imported electricity. The benefits of this are even greater in the LTDH system given the superior techno-economic performance of HPs. Therefore, in the case of Helsingborg, given that the general outlook is that CHP plants will be phased out, the city will not own a lot of electricity production. Therefore, TES provides a flexibility service to the power sector, in that it offers an alternative for DH systems that do not own a lot of electricity production.

4.4. Sustainability assessment of DH systems

Sustainable development is assessed along the lines of three pillars, which are: economic viability, social equity, and environmental protection (University of Nottingham, 2022). Thus, within the scope of this thesis (i.e., a study into DH systems, operating at either conventional or low temperatures), a case for sustainability considering its three pillars is made.

- **Economic viability**

In many European cities, consumers can decide on whether they are connected to the DH system, or if they use individual heating solutions to cater for their heating needs. In areas that are densely populated enough (i.e., many European cities), DH systems have shown to be more cost-efficient than individual heating solutions (Werner & Persson, 2011). The cost of DH is affected by several factors, such as: the system operators pricing philosophy, choice of fuel, municipal decisions, the size of the distribution network, fuel prices and taxes (Energimarknadsinspektionen, 2021). However, the inherent nature of district heating systems, in that their scale allows for higher fuel efficiency, means that they are most often the more cost-efficient choice (Hansen & Gudnundsson, 2018).

Within the DH industry, LTDH systems offer much lower operating costs compared to CTDH systems, as they allow better techno-economic performance for various heat generation technologies (as outlined in section 2.2). The cost of transitioning from a CTDH system to a LTDH system may be significant, however in the long run, the benefits of LTDH systems will offset these upfront costs.

- **Social equity**

DH systems provide a vital service to society; in that they provide the necessary heating required during harsh winters. As heat is generated in thermal plants and then distributed through a network of pipes, when operated properly, DH systems allow all members of society that are connected to the system to have access to the basic levels of energy required to keep warm, regardless of their ability, race, or socioeconomic status. A building connected to a DH system needs a DH substation. In Sweden, the Swedish District Heating Association certifies these substations, which ensures that the substation has undergone a thorough examination of performance, operation, and execution (Energimyndigheten, 2015). Therefore, every consumer can be confident that their connection to the system is appropriate.

In addition, heat generation in DH systems is more environmentally friendly (e.g., in-terms of emissions or hazardous substances' use) than individual consumers firing their own boilers. Therefore, consumers can avoid exposure to respiratory hazards like soot and smoke which can cause severe illnesses.

- **Environmental protection**

As DH systems are a vital service in many cities, and with additional heating capacities being deployed due to the many advantages in comparison to individual heating solutions, DH systems are having an increased impact on energy consumption, and by extension, on the environment. New DH systems have demonstrated several environmental benefits: they can reduce GHG emissions, air pollution, ozone depletion, and acid precipitation among others (Klaipeda University, 2020). In the EU, the share of renewable energy sources in the energy mix of DH systems has increased gradually over the years, from 12% in 2004, to 23% in 2020 (Eurostat, 2022). This means that fossil energy use is being phased out, and consequently, environmental impacts are decreasing. Compared to CTDH systems, LTDH systems have lower energy losses, and utilize more waste heat, therefore further reducing the environmental impacts of the systems.

Another sustainability aspect, that is interconnected to all three pillars, is the fact that the results of this study show that future electricity prices lead to the heating sector becoming a major electricity consumer. This may pose a problem to the city as relying solely on electricity imports, and not having any local production could prove unsustainable in the future. However, further research into this aspect is required to understand the consequences more precisely.

5. Conclusions

This thesis has evaluated the effect that flexibility options (mainly LWTs, and STES) have on the operation of a LTDH system and compared these effects to those experienced by a CTDH system. As part of the REWARDHeat project, the Swedish city of Helsingborg was used as the case study. The TIMESCity_heat model (developed at IVL) was adapted in this study, to encompass Helsingborg's heating (and part of the power, i.e., via CHP) sector and simulated for the period 2017 to 2052. The adapted model (referred to as the CTDH model in this thesis) was then further modified to represent the DH system as a LTDH system (referred to as the LTDH model) and simulated for the same time horizon. The modifications made to reach the LTDH model were in changing the heat losses in DH pipes and TES technologies, estimating, and including LT excess heat potential, and changing the techno-economic inputs that characterise the operation of affected technologies in the system. Both the CTDH model and LTDH model were simulated for a case with TES available and then for a case where TES was not available. The effect of electricity prices on the operation of the network was also studied, where one uses electricity prices that are on the conservative (i.e., higher) side and one on the ambitious (i.e., lower) side. This means that a total of eight scenarios were simulated and analysed.

The first research question (RQ) explored in this thesis was: **How do the effects of TES technologies (and the lack of it) on the operation of DH systems differ between CTDH and LTDH systems?**

To address RQ1; the results show that more DH production can be avoided during high heat demand months in LTDH systems due to lower heat losses. We also see that when comparing the operation of the systems with and without TES, during times of peak heat demand, peak shaving of total heat generation (i.e., by DH plants and individual units) is higher in LTDH systems compared to CTDH systems. In the systems studied in this thesis, peak shaving is on average, higher by 1.6% in the LTDH system when TES is included in the system.

Additionally, we see that in the LTDH system there is less interaction with the power sector compared to the CTDH system, as seen with the lower production levels from CHP plants in the LTDH system, and lower electricity consumption by the HPs due to their better techno-economic performance and higher availability of waste heat. Therefore, for the LTDH system studied in this thesis, there is less flexibility achievable through sector coupling.

The second RQ explored was: **How do capacities and activity levels for TES technologies, HPs and CHP plants differ between CTDH and LTDH systems?**

To address RQ2; the results show that on average, more of the BTES storage capacity in the LTDH system is utilised compared to the CTDH system (i.e., 90% vs 95% in the systems studied in this thesis), due to lower heat losses from TES in the LTDH system.

In addition, we see that the capacities of dispatchable heat generating units can be lower in a LTDH system than a CTDH system, as greater base load supply can be achieved through BTES discharging and higher availability of waste heat. Also, if DH systems were to become HP dominated in the future (as is the case in the systems studied in this thesis), the adoption of a LTDH system and more excess heat into the heat generation mix would mean that the burden on the power sector to supply electricity to the heat sector can be reduced. With regards to CHP plants, higher production levels are seen in the CTDH system compared to the LTDH system due to revenues from electricity sales being a higher priority in the CTDH system. This benefit is offset in the LTDH system by lower electricity consumption by HPs.

The third RQ explored was: **How are the operations of certain technologies in a DH system affected by electricity prices, and how do these effects differ between CTDH and LTDH systems?**

The differences between the conservative and ambitious scenarios are also seen in the results of the study. Both scenario classes predict that electricity prices will keep reducing into the future, which is the major driving force for both the CTDH and LTDH systems to become HP-dominated eventually. In the LTDH system, the combination of cheaper electricity in the future and better techno-economic performance of HPs in low temperature operation, causes LTDH systems to become ‘locked-in’ to using HPs. In the case of Helsingborg, HPs will eventually be the only dispatchable heat generating technology, and as a result, the network operator would be forced to operate them to meet the city’s heat demand regardless of electricity price. In the CTDH system, CHP plants maintain generation further into the future as they provide the opportunity to generate revenue from electricity sales. Therefore, the CTDH system would give the network operator more freedom to respond to electricity prices, while the LTDH system would not.

One major limitation of this study is that the thermal hydraulic aspects of the grid (i.e., the distribution network) are not considered. The operation of the grid is greatly simplified, into terms of the grid's annual capacity to transfer heat, and its heat losses. These considerations would have to be made outside the TIMES model, as TIMES is purely an economic model generator, and therefore these thermal hydraulic aspects would have to be 'translated' into techno-economic parameters that can be fed to the model, which would be an extremely complex task. Additionally, several techno-economic assumptions were made in the model (e.g., temperatures used to calculate HP COPs, municipal waste availability, method to calculate storage losses), but as these assumptions were treated consistently between the CTDH and LTDH models, useful results are still obtained from the study.

Another criticism is that the results suggesting that there would be heavy investment in industrial HPs and that there would be scaling back of CHP production, is quite exaggerated in this study. This would not normally be the case in the real world, as usually, the combined heat and power sector of a given municipality would have at least the same amount of electricity generation capacity as the municipality consumes. This exaggeration is a result of the model not incorporating the city's electricity demand, and not requiring that some of this demand be supplied by local generation.

Therefore, to conclude, we see that LTDH systems can make more use of the flexibility provided by TES technologies due to their lower heat losses. This means that DH production can be lower, which means less operational and maintenance costs can be encountered. This, paired with more peak shaving in LTDH systems, means that the capacities of DH generating units can be kept lower than in CTDH systems, which would mean lower investment costs for these units. These benefits, paired with lower electricity consumption by the LTDH system, translates to significant costs savings when compared to CTDH systems. However, as discussed briefly in the sustainability assessment (section 4.4), caution is advised in simply allowing LTDH systems to become HP-dominated, despite this being the cost-optimal strategy. Heavy reliance on one technology puts energy security and the resilience of the DH system into question.

6. Future work

In similar studies in the future, it may be beneficial to incorporate the city's electricity demand into the model, and then require that a part of this demand be supplied by local generation. This would require certain adjustments to the structure of the model. It would be interesting to see if this would cause the model to invest in other technologies other than HPs, or if it might still make more financial sense to import the electricity at market prices.

Including district cooling (DC) in a similar study could be done, given that Öresundskraft does operate a district cooling network as well. It may be the case, that when considering the costs associated with both systems (i.e., DH together with DC), investments into different technologies may be made by the model.

Also, given that the predicted electricity prices seem to make a better financial case for the deployment of HPs in the future, a sensitivity analysis on the COPs of HPs in LTDH systems would be interesting to investigate.

Finally, something else that could be done is to incorporate the cost of transitioning from a CTDH system to a LTDH system to the analysis. In this study, the LT scenarios are modelled with the base-year network already being a LTDH system. In real life, this is not the case, as most DH system are still operated at conventional temperatures. Therefore, to convert them to LTDH systems, there would be an investment cost associated with that. Additional costs may be incurred by the individual user when having to install larger radiators to facilitate the required heat transfer with lower temperatures. Incorporating these costs into the model would probably show that the financial benefit of LTDH systems is less than what is predicted in this study.

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Appendix A

Appendix A1

Appendix A1 presents the different time-series' that are fed to the model.

Appendix A1.1

Table 8 presents the YRFR for each of the 72 time slices. The YRFR defines the length of each time-slice and is the fraction of the year for which that time-slice applies.

Table 8 - Time-slice level year fractions

Time-slice	YRFR	Time-slice	YRFR	Time-slice	YRFR
JANWD	0.0315	MAYWD	0.0315	SEPWD	0.0288
JANWN	0.0289	MAYWN	0.0289	SEPWN	0.0263
JANWP	0.0026	MAYWP	0.0026	SEPWP	0.0024
JANHD	0.0110	MAYHD	0.0110	SEPHD	0.0123
JANHN	0.0100	MAYHN	0.0100	SEPHN	0.0114
JANHP	0.0009	MAYHP	0.0009	SEPHP	0.0010
FEBWD	0.0288	JUNWD	0.0274	OCTWD	0.0315
FEBWN	0.0264	JUNWN	0.0252	OCTWN	0.0290
FEBWP	0.0024	JUNWP	0.0023	OCTWP	0.0026
FEBHD	0.0110	JUNHD	0.0137	OCTHD	0.0110
FEBHN	0.0100	JUNHN	0.0124	OCTHN	0.0100
FEBHP	0.0009	JUNHP	0.0011	OCTHP	0.0009
MARWD	0.0288	JULWD	0.0315	NOVWD	0.0288
MARWN	0.0264	JULWN	0.0288	NOVWN	0.0264
MARWP	0.0024	JULWP	0.0026	NOVWP	0.0024
MARHD	0.0137	JULHD	0.0110	NOVHD	0.0123
MARHN	0.0124	JULHN	0.0102	NOVHN	0.0113
MARHP	0.0011	JULHP	0.0009	NOVHP	0.0010
APRWD	0.0301	AUGWD	0.0301	DECWD	0.0288
APRWN	0.0275	AUGWN	0.0277	DECWN	0.0264
APRWP	0.0025	AUGWP	0.0025	DECWP	0.0024
APRHD	0.0110	AUGHD	0.0123	DECHD	0.0123
APRHN	0.0102	AUGHN	0.0112	DECHN	0.0113
APRHP	0.0009	AUGHP	0.0010	DECHP	0.0010

Appendix A1.2

Figure 32 presents the commodity fraction time series for the 72-time-slice set up. The COM_FR values used in this model come from (Mata, et al., 2022). The assumption made here is that the heat demand curve for Helsingborg is of the same shape of Eskilstuna's heat demand curve, in this specific 72-time-slice set-up. This assumption is valid because for Swedish cities, the heating demand trends roughly tally for weekday, weekend, day, night, and typical highest peak demand hours respectively.

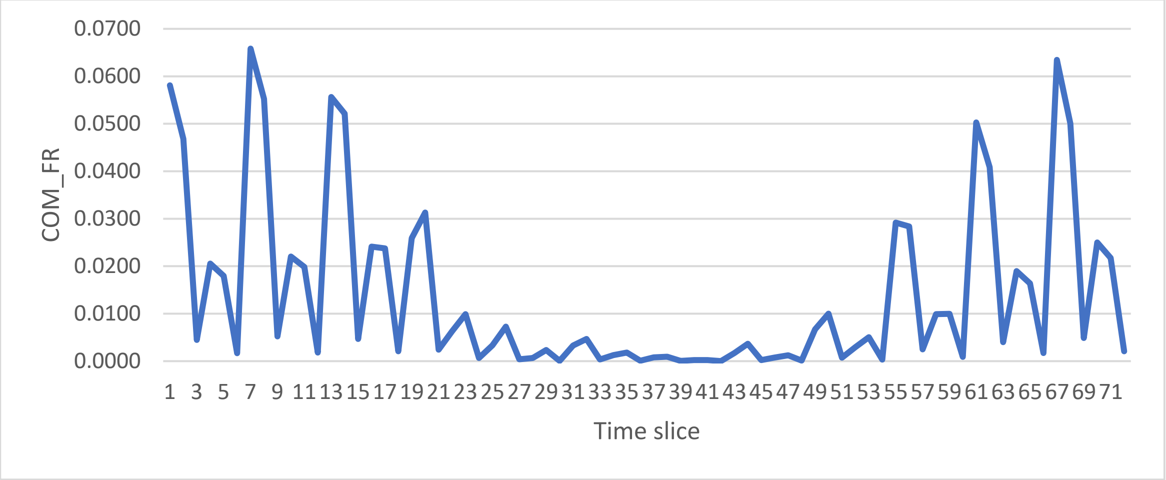


Figure 32 – Commodity fraction time series

Appendix A1.3

Figure 33 (next page) presents the air and ground temperatures that are fed to the model. Due to complexities related to obtaining temperature time-series for Helsingborg, the time-series used in the work of (Mata, et al., 2022) (i.e., for Eskilstuna) was adjusted to represent the temperatures for Helsingborg. The average air temperature of Helsingborg is 8.5 °C (Weather Spark, 2022), which is 0.6 °C higher than the ambient temperature calculated from the source data for Eskilstuna. Therefore 0.6 °C was added to each of the values in the Eskilstuna time-series, resulting in a new time-series that has Helsingborg's average air temperature, while still having the same 'shape' as the time-series for Eskilstuna. Therefore, the assumption is that the temperatures in Helsingborg follow the same trend as in Eskilstuna but are just 0.6 °C higher.

Figure 33 - Air and ground temperatures source data fed to the models

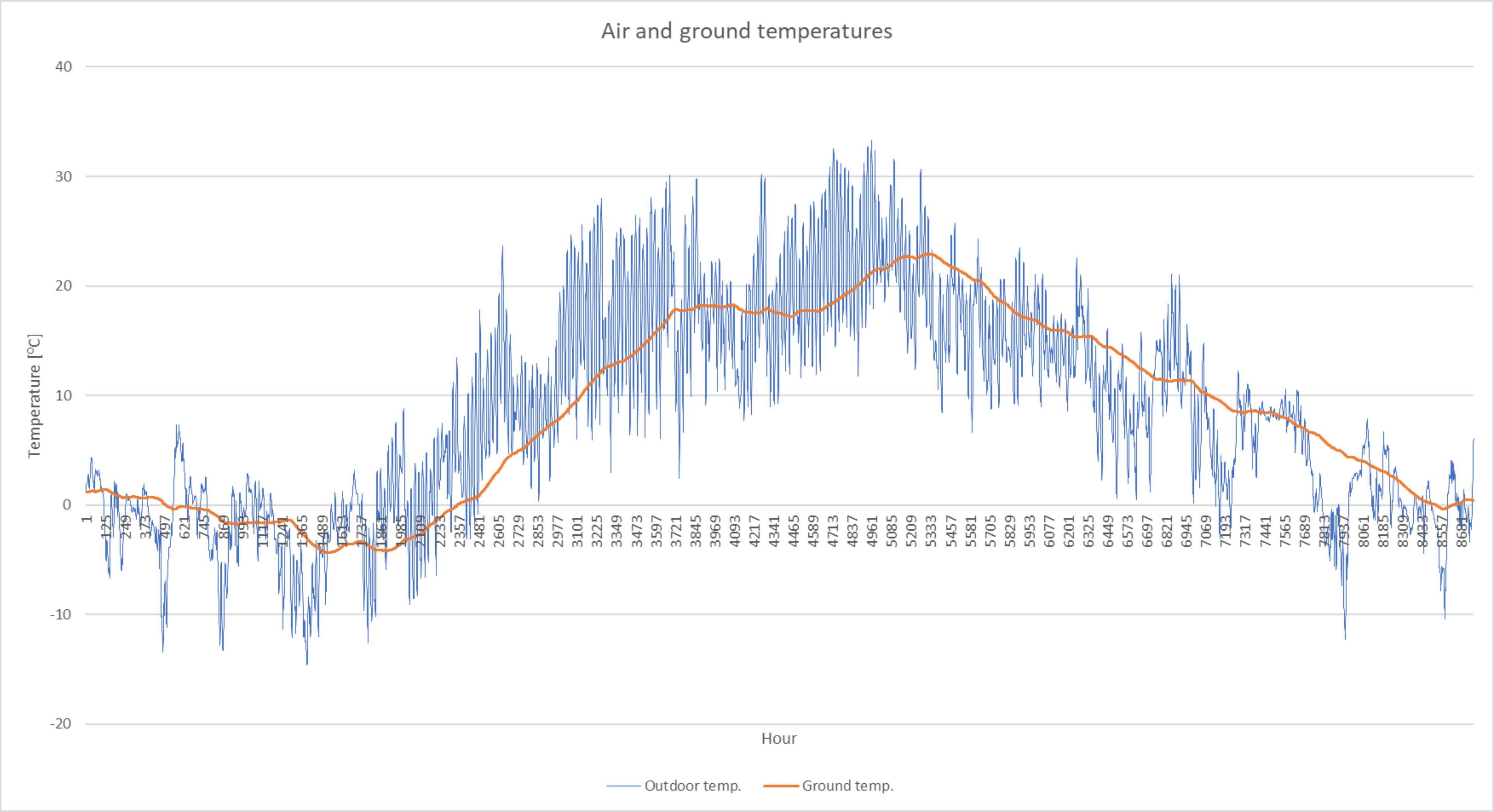


Table 9 - Heat pump COPs, CTDH

Air-source HPs				Ground-source HPs			
Time-slice	**COP**	**Time-slice**	**COP**	**Time-slice**	**COP**	**Time-slice**	**COP**
JANWD	3.30	**JULWP**	4.23	**JANWD**	3.38	**JULWP**	4.22
JANWN	3.28	**JULHD**	4.41	**JANWN**	3.28	**JULHD**	4.22
JANWP	3.30	**JULHN**	4.02	**JANWP**	3.38	**JULHN**	4.02
JANHD	3.21	**JULHP**	4.15	**JANHD**	3.38	**JULHP**	4.22
JANHN	3.19	**AUGWD**	4.17	**JANHN**	3.19	**AUGWD**	4.33
JANHP	3.19	**AUGWN**	3.91	**JANHP**	3.38	**AUGWN**	3.91
FEBWD	3.18	**AUGWP**	3.97	**FEBWD**	3.30	**AUGWP**	4.33
FEBWN	3.13	**AUGHD**	4.06	**FEBWN**	3.13	**AUGHD**	4.33
FEBWP	3.14	**AUGHN**	3.84	**FEBWP**	3.30	**AUGHN**	3.84
FEBHD	3.19	**AUGHP**	3.86	**FEBHD**	3.31	**AUGHP**	4.33
FEBHN	3.15	**SEPWD**	3.90	**FEBHN**	3.15	**SEPWD**	4.03
FEBHP	3.18	**SEPWN**	3.74	**FEBHP**	3.31	**SEPWN**	3.74
MARWD	3.28	**SEPWP**	3.77	**MARWD**	3.24	**SEPWP**	4.02
MARWN	3.17	**SEPHD**	3.89	**MARWN**	3.17	**SEPHD**	4.02
MARWP	3.21	**SEPHN**	3.67	**MARWP**	3.24	**SEPHN**	3.67
MARHD	3.29	**SEPHP**	3.70	**MARHD**	3.25	**SEPHP**	4.02
MARHN	3.17	**OCTWD**	3.65	**MARHN**	3.17	**OCTWD**	3.80
MARHP	3.23	**OCTWN**	3.55	**MARHP**	3.25	**OCTWN**	3.55
APRWD	3.64	**OCTWP**	3.58	**APRWD**	3.44	**OCTWP**	3.79
APRWN	3.43	**OCTHD**	3.65	**APRWN**	3.43	**OCTHD**	3.79
APRWP	3.49	**OCTHN**	3.53	**APRWP**	3.45	**OCTHN**	3.53
APRHD	3.73	**OCTHP**	3.55	**APRHD**	3.47	**OCTHP**	3.79
APRHN	3.44	**NOVWD**	3.43	**APRHN**	3.44	**NOVWD**	3.62
APRHP	3.52	**NOVWN**	3.40	**APRHP**	3.47	**NOVWN**	3.40
MAYWD	4.20	**NOVWP**	3.40	**MAYWD**	3.85	**NOVWP**	3.62
MAYWN	3.74	**NOVHD**	3.43	**MAYWN**	3.74	**NOVHD**	3.63
MAYWP	3.88	**NOVHN**	3.42	**MAYWP**	3.86	**NOVHN**	3.42
MAYHD	4.18	**NOVHP**	3.39	**MAYHD**	3.83	**NOVHP**	3.63
MAYHN	3.73	**DECWD**	3.30	**MAYHN**	3.73	**DECWD**	3.41
MAYHP	3.89	**DECWN**	3.30	**MAYHP**	3.84	**DECWN**	3.30
JUNWD	4.12	**DECWP**	3.30	**JUNWD**	4.15	**DECWP**	3.41
JUNWN	3.83	**DECHD**	3.29	**JUNWN**	3.83	**DECHD**	3.41
JUNWP	3.93	**DECHN**	3.27	**JUNWP**	4.14	**DECHN**	3.27
JUNHD	4.25	**DECHP**	3.26	**JUNHD**	4.13	**DECHP**	3.41
JUNHN	3.88			**JUNHN**	3.88		
JUNHP	4.03			**JUNHP**	4.13		
JULWD	4.52			**JULWD**	4.21		
JULWN	4.05			**JULWN**	4.05		

Table 10 - Heat pump COPs, LTDH

Air-source HPs				Ground-source HPs			
Time-slice	**COP**	**Time-slice**	**COP**	**Time-slice**	**COP**	**Time-slice**	**COP**
JANWD	4.43	**JULWP**	6.23	**JANWD**	4.61	**JULWP**	6.60
JANWN	4.43	**JULHD**	6.25	**JANWN**	4.43	**JULHD**	6.62
JANWP	4.43	**JULHN**	6.24	**JANWP**	4.60	**JULHN**	6.24
JANHD	4.43	**JULHP**	6.25	**JANHD**	4.61	**JULHP**	6.62
JANHN	4.43	**AUGWD**	6.52	**JANHN**	4.43	**AUGWD**	6.91
JANHP	4.43	**AUGWN**	6.52	**JANHP**	4.60	**AUGWN**	6.52
FEBWD	4.28	**AUGWP**	6.51	**FEBWD**	4.45	**AUGWP**	6.91
FEBWN	4.28	**AUGHD**	6.53	**FEBWN**	4.28	**AUGHD**	6.93
FEBWP	4.28	**AUGHN**	6.54	**FEBWP**	4.45	**AUGHN**	6.54
FEBHD	4.29	**AUGHP**	6.52	**FEBHD**	4.46	**AUGHP**	6.92
FEBHN	4.29	**SEPWD**	5.78	**FEBHN**	4.29	**SEPWD**	6.08
FEBHP	4.29	**SEPWN**	5.78	**FEBHP**	4.46	**SEPWN**	5.78
MARWD	4.16	**SEPWP**	5.78	**MARWD**	4.32	**SEPWP**	6.08
MARWN	4.16	**SEPHD**	5.78	**MARWN**	4.16	**SEPHD**	6.08
MARWP	4.17	**SEPHN**	5.78	**MARWP**	4.32	**SEPHN**	5.78
MARHD	4.18	**SEPHP**	5.77	**MARHD**	4.33	**SEPHP**	6.07
MARHN	4.18	**OCTWD**	5.26	**MARHN**	4.18	**OCTWD**	5.51
MARHP	4.18	**OCTWN**	5.27	**MARHP**	4.33	**OCTWN**	5.27
APRWD	4.56	**OCTWP**	5.26	**APRWD**	4.75	**OCTWP**	5.51
APRWN	4.56	**OCTHD**	5.26	**APRWN**	4.56	**OCTHD**	5.51
APRWP	4.57	**OCTHN**	5.26	**APRWP**	4.75	**OCTHN**	5.26
APRHD	4.60	**OCTHP**	5.25	**APRHD**	4.79	**OCTHP**	5.50
APRHN	4.60	**NOVWD**	4.90	**APRHN**	4.60	**NOVWD**	5.12
APRHP	4.61	**NOVWN**	4.90	**APRHP**	4.80	**NOVWN**	4.90
MAYWD	5.39	**NOVWP**	4.89	**MAYWD**	5.66	**NOVWP**	5.12
MAYWN	5.39	**NOVHD**	4.90	**MAYWN**	5.39	**NOVHD**	5.13
MAYWP	5.40	**NOVHN**	4.90	**MAYWP**	5.67	**NOVHN**	4.90
MAYHD	5.35	**NOVHP**	4.90	**MAYHD**	5.61	**NOVHP**	5.13
MAYHN	5.35	**DECWD**	4.50	**MAYHN**	5.35	**DECWD**	4.67
MAYHP	5.36	**DECWN**	4.49	**MAYHP**	5.62	**DECWN**	4.49
JUNWD	6.06	**DECWP**	4.49	**JUNWD**	6.40	**DECWP**	4.67
JUNWN	6.06	**DECHD**	4.49	**JUNWN**	6.06	**DECHD**	4.67
JUNWP	6.06	**DECHN**	4.49	**JUNWP**	6.39	**DECHN**	4.49
JUNHD	6.02	**DECHP**	4.49	**JUNHD**	6.36	**DECHP**	4.67
JUNHN	6.03			**JUNHN**	6.03		
JUNHP	6.03			**JUNHP**	6.36		
JULWD	6.23			**JULWD**	6.60		
JULWN	6.22			**JULWN**	6.22		

Appendix A2

Appendix A2 presents the heat demands and building stock breakdowns for Helsingborg

Table 11 presents the fraction of total built area per type of commercial building.

Table 11 - % of total build area of each building type in COM sector (CUL – Cultural spaces, EDU – education, HLT – Health, OFF – Offices, OTH – Other, RET – retail business, SPO – swimming pools and gyms, TUR – tourism hotels and restaurants)

	CCUL	CEDU	CHLT	COFF	COTH	CRET	CSPO	CTUR	SUM
% of built area	3.6%	27.2%	14.0%	21.0%	13.9%	9.8%	5.8%	4.7%	100%

Table 12 shows the residential building stock.

Table 12 - Number of apartments by region, type of house, construction period and year

SCB **Number of apartments by region, type of house, construction period and year**		
1283 Helsingborg - 2017	**Construction year**	**Number of houses**
Houses	**-1930**	**4033**
	1931-1940	**895**
	1941-1950	**577**
	1951-1960	**1333**
	1961-1970	**2867**
	1971-1980	**4382**
	1981-1990	**3553**
	1991-2000	**1691**
	2001-2010	**1844**
	2011-	**844**
	data not available	**0**
Apartment buildings	**-1930**	**4260**
	1931-1940	**3605**
	1941-1950	**4304**
	1951-1960	**5938**
	1961-1970	**8314**
	1971-1980	**7232**

	1981-1990	**3697**
	1991-2000	**1265**
	2001-2010	**1488**
	2011-	**3205**
	data not available	**0**

Table 13 shows the split between houses and apartment buildings as percentages. The data presented in Table 12 is used to calculate these percentages.

Table 13 - % of total number of buildings in RSD sector (APB – Apartments high efficiency, HSC – Houses medium efficiency)

	RAPB	**RHSC**
% of total RSD buildings	66.3%	33.7%

Building stock data for Helsingborg is taken from (Statistikmyndigheten SCB, 2022).

The heat demand assigned to each building type in Helsingborg is the total sector heat demand (taken from (Länsstyrelserna - LEKS, 2022)) multiplied by the fractions shown in Table 11 and Table 13.

Table 14 and Table 15 list the heat demands for all sub-sectors for all the modelled years.

Table 14 – COM heat demand breakdown

[TJ]	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
CCUL	58.1	57.75	56.23	54.15	52.15	50.23	48.38	46.59	44.87
CEDU	361.58	359.43	349.93	337.01	324.58	312.6	301.07	289.96	279.26
CHLT	186.63	185.52	180.61	173.94	167.53	161.34	155.39	149.65	144.13
COFF	279.08	277.42	270.08	260.11	250.51	241.27	232.36	223.79	215.53
COTH	185.43	184.32	179.45	172.82	166.45	160.3	154.39	148.69	143.21
CRET	130.19	129.41	125.99	121.35	116.87	112.55	108.4	104.4	100.55
CSPO	77.15	76.69	74.66	71.9	69.25	66.71	64.23	61.87	59.59
CTUR	62.11	61.75	60.11	57.89	55.76	53.69	51.71	49.81	47.97

Table 15 - RSD heat demand breakdown (APB – Apartments high efficiency, HSC – Houses medium efficiency)

[TJ]	2017	2018	2022	2027	2032	2037	2042	2047	2052
RAPB	2628.53	2612.91	2543.77	2449.9	2359.76	2272.68	2188.83	2107.84	2030.04
RHSC	1316.63	1308.81	1274.17	1227.16	1181.87	1138.26	1096.26	1055.81	1016.85

Appendix A3

This appendix presents the techno-economic inputs for DH plants, individual units, and TES technologies for the CTDH and LTDH models. Please note that any instances in tables that have a section number included, refer to techno-economic inputs that are not kept constant throughout the modelled time horizon. These inputs are explained in the respective sections that are shown in the tables.

Data from the Danish Energy Agency – Technology Data Catalogue for Electricity and district heating production is used in this study as "the catalogue is meant for use by international audiences and relies primarily on well-documented and public information sourced from experts and power plant operations across Europe". Also, "it is not the target of the catalogue to provide an exhaustive collection of specifications on all available incarnations of energy technologies. Only selected, representative, technologies are included, to enable generic comparisons to technologies with similar function in the energy system" (Energistyrelsen, 2022).

Appendix A3.1

Table 16 and Table 17 present the techno-economic inputs for base-year CHP plants and heat-only plants, respectively. Table 18 explains the sources for this data.

Table 16 - CT and LT input parameters for base-year CHP plants

	Bio pellet CHP		**Municipal waste CHP**	
Input parameter	**CT**	**LT**	**CT**	**LT**
Installed thermal capacity [MW]	138 [1]		72 [1]	
Installed power capacity [MW]	69 [1]	83.7	18 [1]	21.83
Efficiency [-]	0.87 [2]	0.93	1.0 [1]	1.04
Availability Factor [-]	0.47 [3]		0.72 [3]	
Heat-to-power ratio	2.0 [4]	1.65	4.0 [4]	3.30
Fixed Operation and maintenance costs [Euro/kW]	45.8 [5]	44.7	69.3 [5]	68.9
Variable operation and maintenance costs [Euro/GJ]	0.389 [5]		1.64 [5]	
Operational until [year]	2040		Entire modelled period	

Table 17 - CT and LT input parameters for base-year heat-only plants

	Industrial HP (ambient heat)		Excess Heat - HT		Excess Heat - LT	Oil Boiler	
Input parameter	**CT**	**LT**	**CT**	**LT**	**LT**	**CT**	**LT**
Installed thermal capacity [MW]	30 [1]		50 [1]		Section 3.4.6	30 [1]	
Efficiency [-]	Section 3.4.4	Section 3.4.4	0.9 [6]		0.9[6]	0.87 [5]	
Availability factor	0.96 [3]		1.0		0.9	0.9 [3]	
Fixed Operation and maintenance costs [Euro/kW]	2 [5]	1.9 [5]	0.5 [5]		0.29 [5]	2 [5]	
Variable operation and maintenance costs [Euro/GJ]	0.47 [5]		0.05 [5]		0.03 [5]	0.31 [5]	
Operational until [year]	2042		Entire modelled period		Entire modelled period	2024	

Table 18 - Sources for data in Table 17 and

Table 18

Number	**Source**
1	Öresundskraft website. (Öresundskraft AB, 2022)
2	Electrical efficiency calculated using data from (Länsstyrelserna - LEKS, 2022). Overall efficiency obtained by multiplying electrical efficiency with CHPR.
3	Value varied iteratively until the model showed heat generation close to that stated in (Öresundskraft, 2017)
4	Thermal capacity divided by electrical capacity
5	Taken from the Danish Energy Agency – Technology Data Catalogue for Electricity and district heating production. (Energistyrelsen, 2022)
6	Assumed HEX effectiveness

Table 19 and Table 20 present the techno-economic inputs for DH plants that are available for investment, in the CT and LT cases, respectively. All values for the CT case are taken from (Energistyrelsen, 2022).

Table 19 - Input parameters for new DH plants available for investment (CTDH)

	Efficiency [-]	Heat-to-power ratio [-]	Investment cost [kEuro/MW]				Fixed operation and maintenance cost [Euro/kW]				Variable operation and maintenance costs [Euro/GJ]	Availability factor [-]	Lifetime [years]
			2018	**2020**	**2030**	**2050**	**2018**	**2020**	**2030**	**2050**			
Ambient air DH - HP	Section 3.4.4	-	860	860	760	760	2	2	2	2	0.47	0.96	25
Geothermal DH – HP	Section 3.4.4	-	2710	2650	2500	2380	22.6	21.9	21.3	19.9	1.58	0.96	25
Electric boiler	0.99	-	150	150	140	130	1.1	1.07	1.02	0.92	0.22	0.99	20
Municipal waste CHP	1	3.45	2110	2061	2012	1825	69.3	59.9	57.1	50.4	1.64	0.94	25
Bio pellet CHP	1	2.94	974	947	902	848	45.8	40	37.7	34.1	0.389	0.95	25

Table 20 - Input parameters for new DH plants available for investment (LTDH)

	Efficiency [-]	Heat-to-power ratio [-]	Investment cost [kEuro/MW]				Fixed operation and maintenance cost [Euro/kW]				Variable operation and maintenance costs [Euro/GJ]	Availability factor [-]	Lifetime [years]
			2018	**2020**	**2030**	**2050**	**2018**	**2020**	**2030**	**2050**			
Ambient air DH - HP	Section 3.4.4	-	860	860	760	760	1.9	1.9	1.9	1.9	0.47	0.96	25
Geothermal DH – HP	Section 3.4.4	-	2710	2650	2500	2380	22.5	21.8	21.2	19.8	1.58	0.96	25
Electric boiler	0.99	-	150	150	140	130	1.1	1.07	1.02	0.92	0.22	0.99	20
Municipal waste CHP	1.04	2.84	2110	2061	2012	1825	68.8	59.5	56.5	49.5	1.64	0.94	25
Bio pellet CHP	1.07	2.42	974	947	902	848	44.7	38.9	36.6	33.0	0.389	0.95	25

Appendix A3.2

Table 21 presents the percentage of remaining heat demand that is supplied by different types of individual units that are used in the model.

Table 21 - Individual unit deployment in both COM and RSD sectors

	Air-source HP	Electric boilers	Electrical resistance heating	Air conditioners	Ground-source HP
% Of remaining heat demand supplied	70%	5%	1%	4%	20%

Table 22 and Table 23 present the inputs to the CTDH model for base-year and new individual units available for investment, respectively. The values in Table 22 and Table 23 are from (Riekkola, et al., 2019).

Table 22 - Input parameters for base-year individual units (CTDH)

	Air-source HP	Electric boilers	Electrical resistance heating	Air conditioners	Ground-source HP
Efficiency [-]	Section 3.4.4	0.95	0.7	1.30	Section 3.4.4
Availability factor [-]	0.15	0.25	0.25	0.20	0.20
Lifetime (years)	20	20	20	14	25

Table 23 - Input parameters for new individual units available for investment (CTDH)

	Efficiency [-]	Investment costs [kEuro/MW]	Fixed operation and maintenance cost [Euro/kW]	Variable operation and maintenance cost [Euro/GJ]	Availability factor [-]	Lifetime [years]
Pellet boiler	0.85	225	4.4	-	0.15	20
Gas furnace	0.95	63	1.7	-	0.15	25
Diesel furnace	0.92	88	2.1	-	0.15	20
Ground-source HP	Section 3.4.4	663	4.1	0.1	0.2	25
Air-source HP	Section 3.4.4	375	4.1	0.1	0.2	20

Appendix A3.3

Table 24 shows the inputs fed to the model for the existing LWT.

Table 24 - CT and LT input parameters for the LWT

	Case	
Input parameter	**CT**	**LT**
Storage losses [%/day]	0.19	0.11
Maximum charge/discharge rate [MW]	60	
Maximum capacity [MWh]	900	
Minimum capacity [MWh]	200	
Fixed operation and maintenance costs [Euro/kW]	2.39	

The inputs fed to the model for new TES technologies are presented in Table 25. The inputs are from projects conducted in industry and were also used in the TIMESCity_heat model for Eskilstuna (Mata, et al., 2022). Inputs for LWTs and Pit TES (PTES) are based on different projects completed or proposed by PlanEnergi ((PlanEnergi, et al., 2013) (https://planenergi.eu/en/)). Inputs for Cavern TES (CTES) and Borehole TES (BTES) are from a project based in Kiruna, looking into possibilities of maximizing the use of waste heat from mining operations in the local DH network (IVL Svenska Miljöinstitutet, 2022). The project is a collaboration between IVL, Tekniska verken i Kiruna, LKAB, LKAB Wassara, and NeoEnergy.

Table 25 - CT and LT input parameters for new TES technologies available for investment

	Large Water Tanks (LWT)		**Borehole Thermal Energy Storage (BTES)**		**Cavern Thermal Energy Storage (CTES)**		**Pit Thermal Energy Storage (PTES)**	
Input parameter	**CT**	**LT**	**CT**	**LT**	**CT**	**LT**	**CT**	**LT**
Storage losses [%/day]	0.19	0.11	0.45	0.26	0.26	0.15	0.15	0.08
Investment cost [kEUR/TJ]	823.6		52.9		500.8		161.0	
Fixed operation and maintenance cost [kEUR/TJ]	2.4		-		-		0.8	
Lifetime [years]	40		40		40		20	

Appendix A3.4

Table 26 presents the population data used to calculate the LT excess heat potential in Helsingborg. Helsingborg's population fraction represents the fraction of Sweden's population that lives in Helsingborg. This value is multiplied with the LT excess heat potentials for Sweden, which are presented in Table 3.

Table 26 - Population projections

	2017	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**
Population - Sweden [millions]	10.242	10.38	10.61	10.84	11.07	11.3	11.53	11.76	11.99
Population - Helsingborg [millions]	0.1482	0.15	0.1553	0.1608	0.1657	0.1703	0.1746	0.1785	0.181
Helsingborg's population fraction [%]	1.45%	1.45%	1.46%	1.48%	1.50%	1.51%	1.51%	1.52%	1.51%

Appendix A4

This appendix presents scenario specific inputs to the model.

Appendix A4.1

Table 27 and Table 28 present the aggregated electricity prices and electricity emission factors that are fed to the model, respectively. Figure 34 through to Figure 37 present the electricity price and electricity emission source data for the different scenarios.

Table 27 - Aggregated electricity prices for conservative and ambitious cases

	Conservative case electricity prices [Euro/GJ]			**Ambitious case electricity prices [Euro/GJ]**		
	2017	**2030**	**2050**	**2017**	**2030**	**2050**
JANWD	10.04	12.15	7.5	10.04	13.04	8.89
JANWN	7.98	10.34	10.34	7.98	10.02	10.02
JANWP	9.48	12	7.41	9.48	12.94	8.66
JANHD	8.99	9.21	7.03	8.99	9.02	6.38
JANHN	8.08	8.93	8.93	8.08	8.37	8.37
JANHP	9.19	9.24	7.03	9.19	9.38	6.31
FEBWD	14.3	12.07	8.65	14.3	11.38	8.83
FEBWN	10.09	10.64	10.64	10.09	9.34	9.34
FEBWP	13.52	12.69	9.04	13.52	11.55	8.49
FEBHD	10.01	8.1	6.08	10.01	8.07	4.81
FEBHN	9.46	7.73	7.73	9.46	7.39	7.39
FEBHP	10.92	9.12	7.44	10.92	9.01	4.67
MARWD	13.98	9.42	5.28	13.98	9.61	6.54
MARWN	11.43	8.91	8.91	11.43	8.86	8.86
MARWP	14.39	9.57	7.08	14.39	9.81	7
MARHD	11.29	7.75	3.63	11.29	7.87	3.89
MARHN	11.03	8.2	8.2	11.03	8.14	8.14
MARHP	11.91	8.74	6.34	11.91	8.7	5
APRWD	11.91	9.31	5.47	11.91	9.24	6.53
APRWN	10.71	9.37	9.37	10.71	9.17	9.17
APRWP	11.93	9.56	9.01	11.93	9.37	6.97
APRHD	10.82	8.57	4.05	10.82	8.21	5.19
APRHN	10.61	9.12	9.12	10.61	8.94	8.94
APRHP	11.26	9.06	8.89	11.26	8.89	6.29
MAYWD	11.56	7.96	6	11.56	7.36	5.8
MAYWN	8.69	8.16	8.16	8.69	7.36	7.36
MAYWP	11.3	8.33	8.84	11.3	7.69	6.79
MAYHD	8.83	7.14	6.73	8.83	7.31	5.7

MAYHN	8.42	8.27	8.27	8.42	7.58	7.58
MAYHP	10.03	8.37	8.98	10.03	7.73	7.15
JUNWD	13.54	8.12	5.11	13.54	8.27	5.49
JUNWN	12.23	8.27	8.27	12.23	7.6	7.6
JUNWP	13.51	9.05	8.74	13.51	8.39	7.51
JUNHD	12.94	5.43	4.69	12.94	5.78	3.87
JUNHN	12.21	7.92	7.92	12.21	6.68	6.68
JUNHP	13.41	8.06	8.85	13.41	6.8	6.93
JULWD	16.12	8.67	6.09	16.12	7.84	7.23
JULWN	14.81	9.07	9.07	14.81	7.45	7.45
JULWP	16.41	9.87	9.56	16.41	9.06	8.92
JULHD	14.89	7.53	6.55	14.89	6.66	6.99
JULHN	14.51	8.59	8.59	14.51	7.28	7.28
JULHP	15.37	9.15	9.53	15.37	8.5	8.03
AUGWD	17.8	8.44	7.61	17.8	8.18	6.11
AUGWN	15.35	8.37	8.37	15.35	7.19	7.19
AUGWP	17.72	8.74	10.94	17.72	8.48	7.59
AUGHD	14.77	7.58	8.76	14.77	6.88	5.89
AUGHN	14.65	7.97	7.97	14.65	6.79	6.79
AUGHP	15.85	8.16	10.72	15.85	7.44	6.9
SEPWD	16.48	8.54	9.58	16.48	7.19	7.83
SEPWN	13.67	8.05	8.05	13.67	6.72	6.72
SEPWP	16.61	9.17	10.71	16.61	7.55	8.03
SEPHD	13.48	7.45	8.12	13.48	6.69	6.61
SEPHN	12.44	7.94	7.94	12.44	6.74	6.74
SEPHP	15.05	8.11	9.99	15.05	7.06	7.24
OCTWD	14.12	8.9	9.69	14.12	8.49	7.4
OCTWN	12.16	8.11	8.11	12.16	7.21	7.21
OCTWP	14.38	8.91	9.88	14.38	8.48	7.58
OCTHD	12.27	8.29	8.89	12.27	7.2	5.7
OCTHN	11.05	8.15	8.15	11.05	7.17	7.17
OCTHP	13.43	8.34	9.06	13.43	7.21	5.83
NOVWD	16.39	13.1	13.35	16.39	12.3	11.4
NOVWN	13.31	10.33	10.33	13.31	9.43	9.43
NOVWP	17.77	13.05	13.65	17.77	12.29	11.51
NOVHD	13.31	9.92	11.83	13.31	9	9.77
NOVHN	12.81	9.1	9.1	12.81	8.46	8.46
NOVHP	13.89	9.66	11.75	13.89	9.29	9.37
DECWD	16.2	11.08	7.16	16.2	9.83	8.14
DECWN	13.82	10.17	10.17	13.82	9.08	9.08
DECWP	15.84	11.21	7.05	15.84	9.73	8.14
DECHD	14.34	10.76	6.95	14.34	9.56	7.39

DECHN	13.59	9.79	9.79	13.59	8.65	8.65
DECHP	15.14	11.44	6.82	15.14	9.97	7.63

Table 28 - Aggregated electricity emission factors for conservative and ambitious cases

	Conservative case emission factors [kgCO$_2$/GJ]			**Ambitious case electricity prices [kgCO$_2$/GJ]**		
	2017	**2030**	**2050**	**2017**	**2030**	**2050**
JANWD	**273.25**	**-5.04**	**4.31**	**273.25**	**-34.13**	**7.45**
JANWN	**237.77**	**-33.45**	**-33.45**	**237.77**	**-30.27**	**-30.27**
JANWP	**291.02**	**1.23**	**4.16**	**291.02**	**-33.91**	**3.95**
JANHD	**276.73**	**-57.45**	**-45.21**	**276.73**	**-60.00**	**10.86**
JANHN	**295.14**	**-37.82**	**-37.82**	**295.14**	**-70.88**	**-70.88**
JANHP	**229.64**	**-42.55**	**-30.29**	**229.64**	**-52.50**	**8.36**
FEBWD	**206.28**	**12.22**	**23.59**	**206.28**	**7.80**	**20.01**
FEBWN	**251.50**	**11.14**	**11.14**	**251.50**	**-4.67**	**-4.67**
FEBWP	**172.05**	**25.23**	**28.62**	**172.05**	**-0.93**	**31.86**
FEBHD	**233.42**	**-33.12**	**-39.26**	**233.42**	**11.74**	**0.33**
FEBHN	**167.17**	**-21.28**	**-21.28**	**167.17**	**-30.64**	**-30.64**
FEBHP	**262.29**	**-30.84**	**-58.34**	**262.29**	**-11.26**	**5.95**
MARWD	**153.35**	**4.93**	**21.71**	**153.35**	**-3.46**	**10.22**
MARWN	**218.39**	**10.13**	**10.13**	**218.39**	**-8.65**	**-8.65**
MARWP	**127.09**	**3.76**	**23.41**	**127.09**	**-4.91**	**14.38**
MARHD	**231.68**	**36.77**	**1.70**	**231.68**	**-22.77**	**6.07**
MARHN	**208.52**	**10.01**	**10.01**	**208.52**	**-16.24**	**-16.24**
MARHP	**128.37**	**7.98**	**-29.59**	**128.37**	**-8.40**	**1.23**
APRWD	**149.62**	**31.50**	**76.32**	**149.62**	**-20.47**	**0.75**
APRWN	**171.08**	**26.23**	**26.23**	**171.08**	**-20.84**	**-20.84**
APRWP	**133.66**	**33.53**	**67.54**	**133.66**	**-21.92**	**3.85**
APRHD	**296.66**	**74.24**	**92.12**	**296.66**	**-16.34**	**-5.74**
APRHN	**236.19**	**20.32**	**20.32**	**236.19**	**-27.42**	**-27.42**
APRHP	**273.01**	**18.11**	**55.63**	**273.01**	**-27.17**	**5.26**
MAYWD	**98.15**	**-0.67**	**7.98**	**98.15**	**30.33**	**0.45**
MAYWN	**145.22**	**-2.61**	**-2.61**	**145.22**	**22.29**	**22.29**
MAYWP	**62.10**	**-7.49**	**3.59**	**62.10**	**15.47**	**29.47**
MAYHD	**49.19**	**-3.09**	**56.23**	**49.19**	**9.02**	**16.54**
MAYHN	**253.46**	**-4.64**	**-4.64**	**253.46**	**15.81**	**15.81**
MAYHP	**107.47**	**-9.36**	**27.49**	**107.47**	**28.19**	**4.87**
JUNWD	**196.00**	**13.48**	**7.65**	**196.00**	**-6.65**	**-43.24**
JUNWN	**206.57**	**3.70**	**3.70**	**206.57**	**-17.61**	**-17.61**
JUNWP	**205.77**	**10.82**	**6.40**	**205.77**	**-57.64**	**-26.62**

JUNHD	95.50	9.91	12.32	95.50	-10.36	-53.18
JUNHN	136.49	1.80	1.80	136.49	-13.77	-13.77
JUNHP	133.32	17.54	12.02	133.32	33.99	-70.78
JULWD	133.21	16.45	28.32	133.21	3.80	0.76
JULWN	141.40	17.09	17.09	141.40	3.66	3.66
JULWP	96.87	9.74	29.42	96.87	-1.78	2.10
JULHD	266.64	15.45	13.36	266.64	-9.62	8.71
JULHN	93.81	20.98	20.98	93.81	0.24	0.24
JULHP	151.45	13.56	32.51	151.45	-8.24	-2.49
AUGWD	136.87	16.28	14.98	136.87	-2.45	6.76
AUGWN	157.40	12.72	12.72	157.40	1.58	1.58
AUGWP	122.66	19.08	12.71	122.66	7.42	13.58
AUGHD	296.28	26.50	0.01	296.28	31.84	2.93
AUGHN	160.87	18.59	18.59	160.87	-3.12	-3.12
AUGHP	169.34	32.33	12.15	169.34	43.21	-2.26
SEPWD	164.44	15.91	3.51	164.44	-15.54	7.78
SEPWN	123.69	13.23	13.23	123.69	-9.89	-9.89
SEPWP	112.02	6.12	1.59	112.02	-20.53	6.27
SEPHD	288.27	11.39	-5.94	288.27	-2.56	-5.01
SEPHN	-78.17	10.19	10.19	-78.17	-2.17	-2.17
SEPHP	267.23	13.44	3.69	267.23	-5.30	-1.75
OCTWD	112.04	12.50	20.84	112.04	-0.99	7.69
OCTWN	220.43	8.99	8.99	220.43	4.58	4.58
OCTWP	106.14	19.72	21.08	106.14	11.80	-2.31
OCTHD	237.52	-1.44	-5.22	237.52	-9.63	-3.40
OCTHN	338.44	-3.98	-3.98	338.44	-18.65	-18.65
OCTHP	150.07	-10.35	4.84	150.07	-6.50	-4.83
NOVWD	174.79	83.24	123.33	174.79	47.35	46.85
NOVWN	214.48	77.02	77.02	214.48	30.43	30.43
NOVWP	164.51	86.72	125.84	164.51	54.30	72.70
NOVHD	333.93	10.27	101.90	333.93	11.00	48.27
NOVHN	262.82	6.79	6.79	262.82	-3.55	-3.55
NOVHP	230.78	-1.85	82.15	230.78	10.24	45.51
DECWD	312.41	54.26	92.73	312.41	-15.91	12.56
DECWN	221.94	73.18	73.18	221.94	-23.84	-23.84
DECWP	288.03	62.61	94.98	288.03	-12.65	5.03
DECHD	323.89	94.28	61.72	323.89	-40.23	42.98
DECHN	237.25	94.36	94.36	237.25	-43.67	-43.67
DECHP	297.24	91.89	89.69	297.24	-38.11	32.19

Figure 34 - Electricity price source data for the conservative case

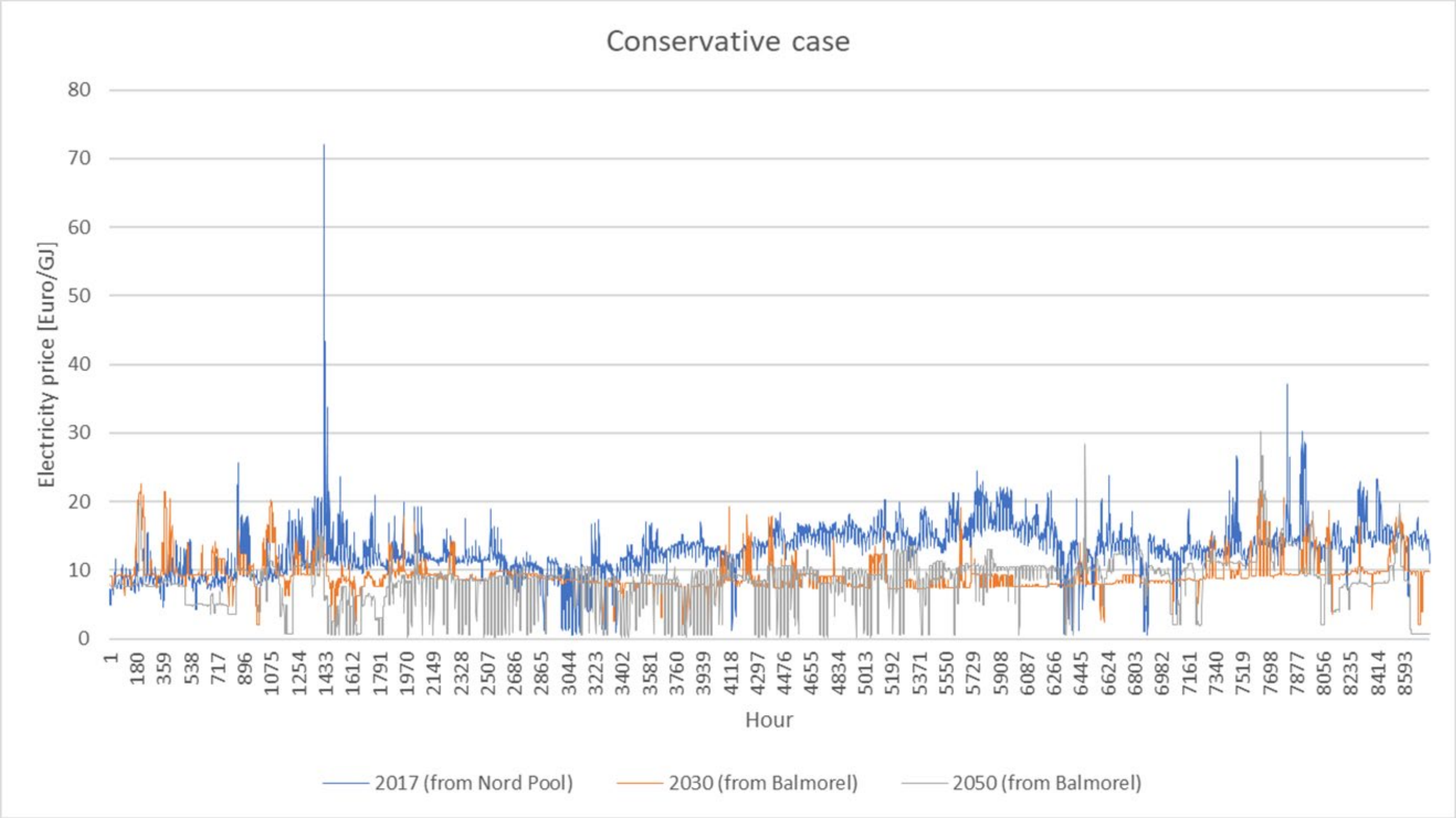


Figure 35 - Electricity price source data for the ambitious case

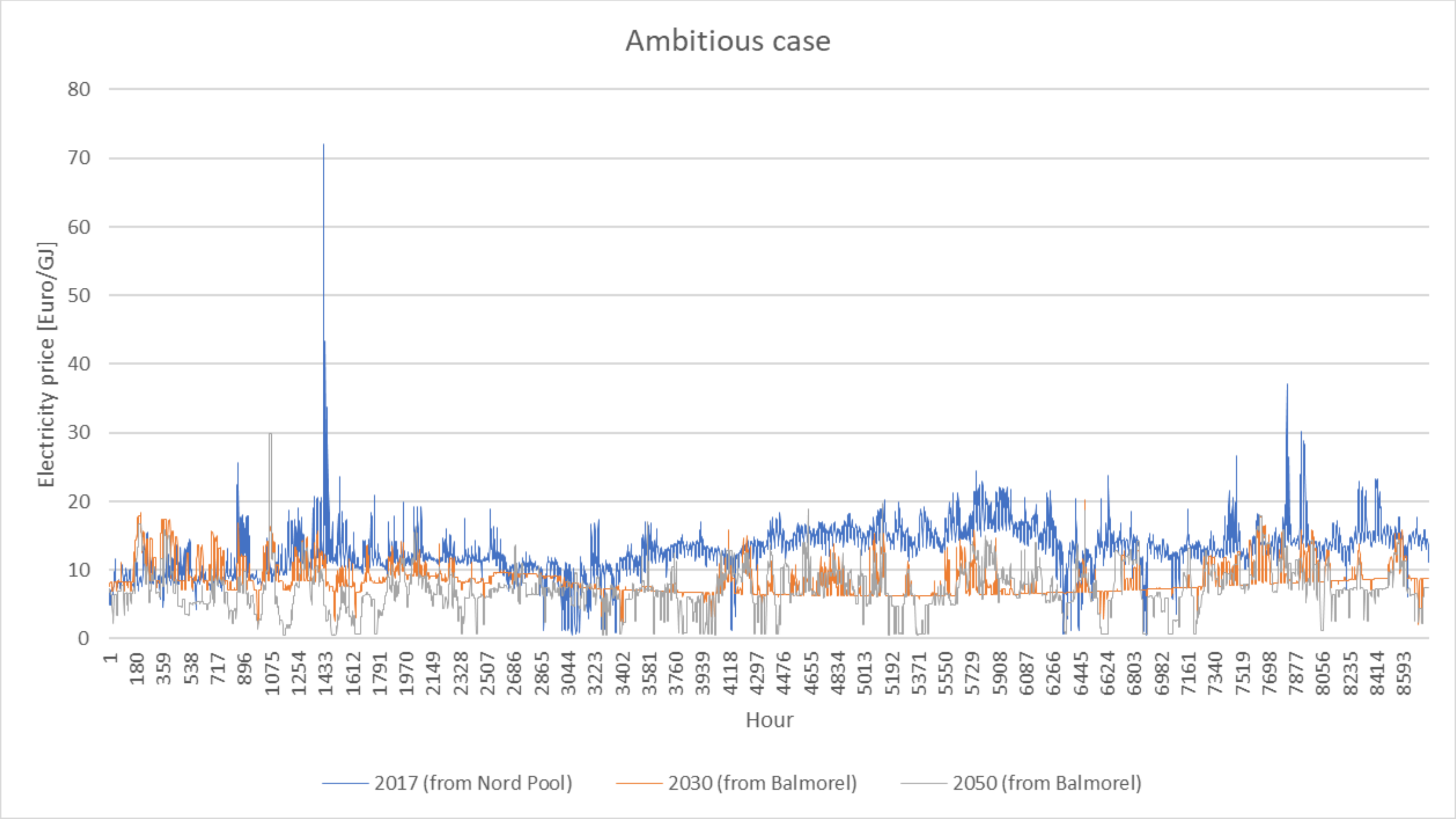


Figure 36 - Electricity emission factor source data for the conservative case

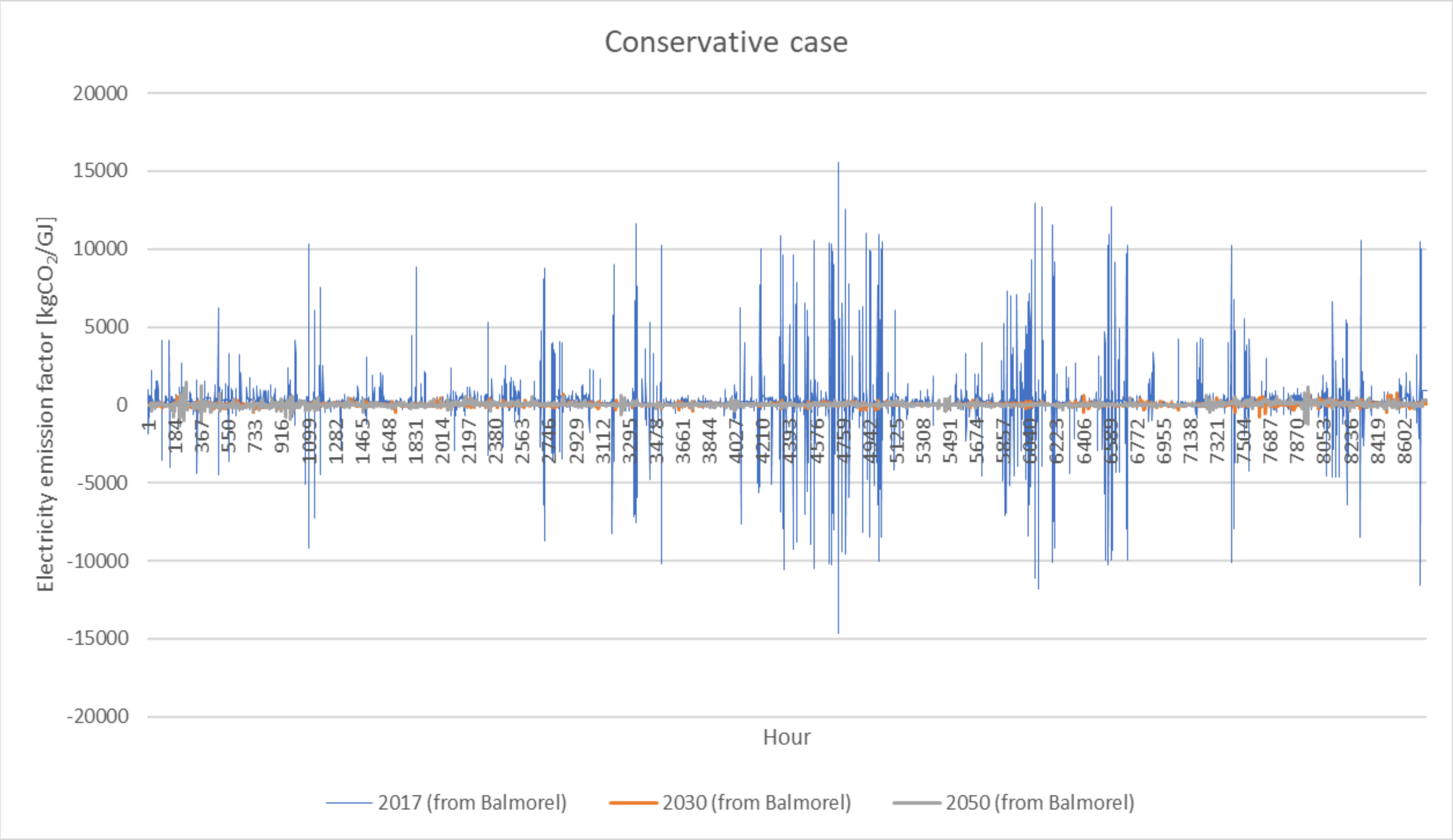
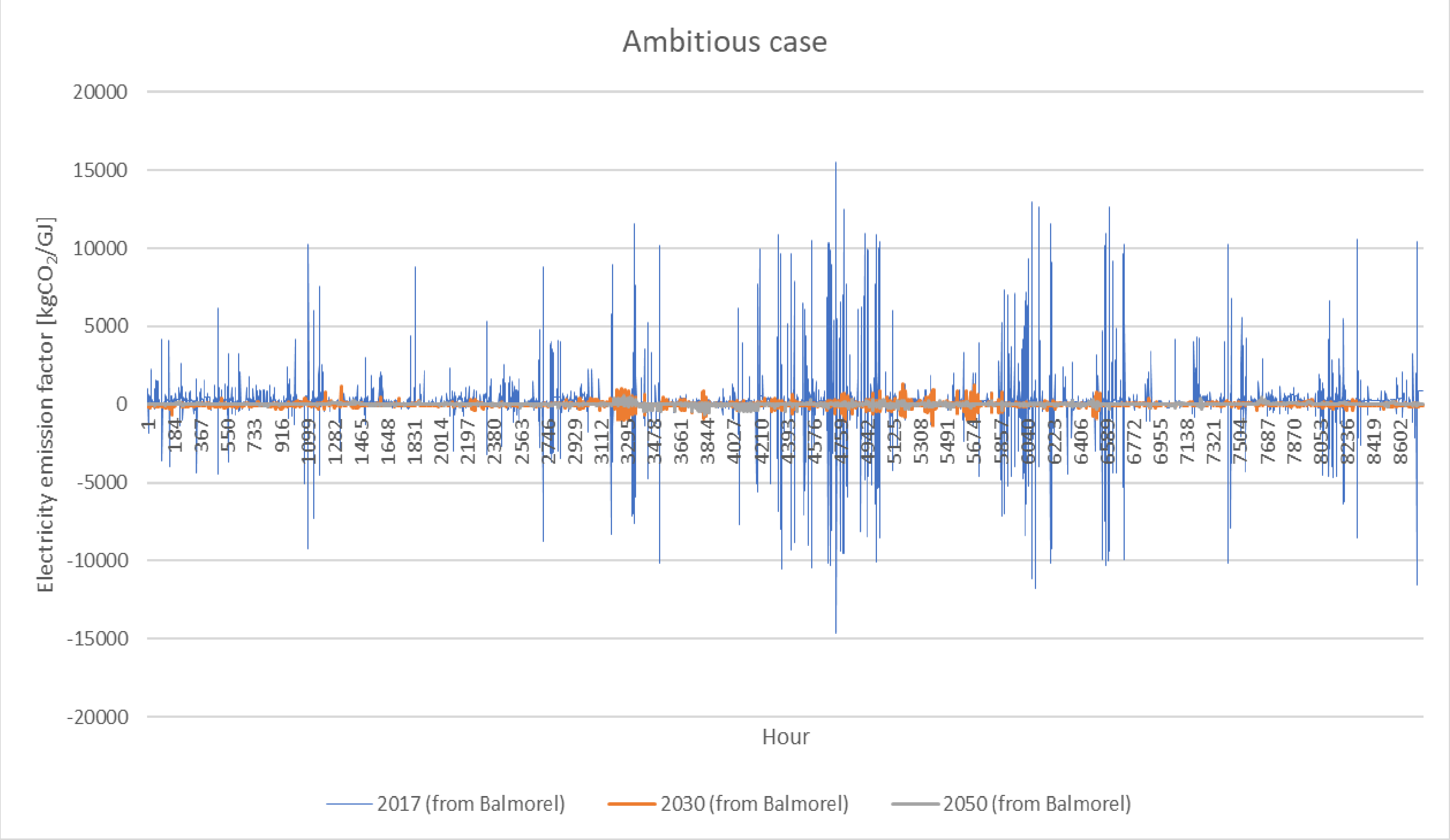


Figure 37 - Electricity emission factor source data for the ambitious case



Appendix A4.2

The prices for fuels used in the model are shown in Table 29. Fuel cost for municipal waste is negative because the operator is paid by municipalities to import the waste.

Table 29 - Fuel prices used in the models

Fuel	2017 Cost [Euro/GJ]	2020 Cost [Euro/GJ]	2030 Cost [Euro/GJ]	2050 Cost [Euro/GJ]
Bio pellets	9.5	8.0	8.1	8.1
Municipal waste	-4.5	-4.5	-4.5	-4.5
Oil	6.4	8.0	7.1	6.3
Diesel	10.3	12.5	11.6	10.8
Natural gas	17.6	13.3	13.3	13.7

A carbon and energy tax are applied across all scenarios for all relevant processes. Fossil fuels are taxed in Sweden with the aim of minimizing their use. Fuels used in electricity generation are tax free, but fuels used for heat generation are generally subjected to taxation. The fuel tax is split into an energy tax, CO_2 tax, and sulphur tax (Patronen, et al., 2017), but in this thesis only the energy and CO_2 tax are considered. There is a variation in the energy tax depending on if the fuel is used in the energy sector or otherwise. The CO_2 tax is payable on every kilogram of carbon dioxide emitted for all fuels other than biofuels and peat. Heat production at CHP plants that are part of the European Union emissions trading scheme (EU ETS) is exempted from the CO_2 tax, and for heat-only plants that are part of the EU ETS, the CO_2 tax rate is 80% of the general CO_2 tax rate. Furthermore, the energy tax for CHP plants is 30% of the general energy tax rate (Patronen, et al., 2017).

The inputs to the model for the CO_2 tax for taxable fuels in Sweden are listed in Table 30 and the energy tax is shown in Table 31. These inputs already consider the 20% reduction in the general CO_2 tax rate for heat-only plants. For CHP plants, the inputs consider the 70% reduction in the general energy tax rate and an additional assumption that 74% of energy production is heat, with the rest being electricity. This is due to the fact (as stated earlier) that only fuels used for heat generation are subjected to taxation.

Table 30 – CO_2 tax rate for taxable fuels in Sweden

Fuel	CO_2 tax [Euro/GJ]
Coal	9.23
Diesel	7.22
Natural gas	4.96
Oil	7.22

Table 31 - Energy tax rate for different sectors

Fuel	Energy sector tax – Heat only plants [Euro/GJ]	Energy sector tax – CHP plants [Euro/GJ]	COM and RSD tax [Euro/GJ]
Coal	2.37	0.52	-
Diesel	2.36	0.52	11.5
Electricity (used for DH production)	7.86	-	11.86
Natural gas	2.43	0.52	8.46
Oil	2.36	0.52	-

Appendix B

Appendix B1

Appendix B1 presents the energy balance breakdowns for all modelled scenarios

Table 32 – Energy balance breakdown, CT-

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
DH plants	1285.45	1353.43	1368.94	1364.07	1366.49	1363.47	1360.25	1356.36	1380.60
Storage losses	-2.34	-43.86	-46.79	-55.88	-70.08	-76.74	-81.14	-82.93	-95.01
Grid losses	-128.31	-130.96	-132.22	-130.82	-129.64	-128.67	-127.91	-127.34	-128.56
Individual units RSD	248.21	224.51	190.08	160.14	130.21	100.28	70.34	40.41	0.00
Individual units COM	113.66	101.73	86.12	72.56	59.00	45.45	31.90	18.34	0.00
Radiator losses	-48.50	-45.40	-45.31	-41.67	-38.06	-34.52	-30.99	-27.49	-23.14
Total Heating	**1468.18**	**1459.45**	**1420.83**	**1368.40**	**1317.92**	**1269.26**	**1222.45**	**1177.35**	**1133.89**
Net Heat	**0.00556**	**-0.00833**	**0.00000**	**0.00083**	**0.00889**	**-0.01583**	**0.00639**	**0.01444**	**0.00250**

Table 33 - Energy balance breakdown, CT+

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
DH plants	1285.45	1352.96	1370.28	1366.51	1369.30	1361.78	1362.89	1356.87	1384.27
Storage losses	-2.34	-43.16	-48.13	-58.32	-72.88	-75.03	-83.79	-83.44	-98.69
Grid losses	-128.31	-130.98	-132.22	-130.82	-129.64	-128.68	-127.91	-127.34	-128.56
Individual units RSD	248.21	224.51	190.08	160.14	130.21	100.28	70.34	40.41	0.00
Individual units COM	113.66	101.73	86.12	72.56	59.00	45.44	31.91	18.34	0.00
Radiator losses	-48.50	-45.61	-45.31	-41.67	-38.06	-34.52	-30.99	-27.49	-23.14
Total Heating	1468.18	1459.44	1420.83	1368.40	1317.92	1269.26	1222.45	1177.35	1133.89
Net Heat	0.00556	-0.01389	0.00000	-0.00194	0.00889	-0.01583	0.00361	0.01167	-0.00028

Table 34 – Energy balance breakdown, LT-

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
DH plants	1215.85	1279.17	1289.77	1279.15	1270.59	1262.78	1257.23	1253.94	1268.94
Storage losses	-0.27	-34.69	-37.17	-39.79	-42.39	-43.73	-45.41	-47.49	-50.99
Grid losses	-60.78	-62.23	-62.63	-61.97	-61.41	-60.95	-60.59	-60.32	-60.89
Individual units RSD	248.21	224.51	190.08	160.14	130.21	100.28	70.34	40.41	0.00
Individual units COM	113.66	101.73	86.12	72.56	59.00	45.44	31.89	18.33	0.00
Radiator losses	-48.50	-48.99	-45.31	-41.68	-38.06	-34.51	-30.98	-27.49	-23.14
Total Heating	1468.18	1459.50	1420.86	1368.42	1317.95	1269.30	1222.48	1177.36	1133.91
Net Heat	**0.00556**	**0.04444**	**0.02778**	**0.02028**	**0.03944**	**0.02028**	**0.03972**	**0.02833**	**0.02194**

Table 35 – Energy balance breakdown, LT+

GWh	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
DH plants	1215.85	1279.38	1289.78	1279.73	1271.21	1265.30	1258.74	1254.11	1268.80
Storage losses	-0.27	-34.90	-37.18	-40.37	-43.00	-46.24	-46.91	-47.66	-50.85
Grid losses	-60.78	-62.22	-62.63	-61.97	-61.41	-60.95	-60.59	-60.32	-60.90
Individual units RSD	248.21	224.51	190.08	160.14	130.21	100.28	70.34	40.41	0.00
Individual units COM	113.66	101.73	86.12	72.56	59.00	45.44	31.89	18.32	0.00
Radiator losses	-48.50	-48.99	-45.31	-41.68	-38.06	-34.51	-30.98	-27.49	-23.14
Total Heating	1468.18	1459.50	1420.86	1368.42	1317.95	1269.30	1222.48	1177.36	1133.91
Net Heat	0.00556	0.04444	0.02778	0.02028	0.03667	0.02028	0.03694	0.02833	0.02194

Table 36 - Energy balance breakdown, No_TES_CT-

GWh	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
DH plants	1283.11	1303.13	1316.59	1306.35	1296.38	1281.53	1249.23	1195.71	1139.60
Storage losses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grid losses	-128.31	-130.31	-131.66	-130.63	-129.64	-128.15	-124.92	-119.57	-113.96
Individual units RSD	248.21	224.51	190.08	160.14	130.21	100.28	70.34	40.41	4.94
Individual units COM	113.66	101.73	86.12	72.56	59.03	50.04	58.26	86.89	123.82
Radiator losses	-48.50	-39.60	-40.29	-40.02	-38.06	-34.42	-30.45	-26.09	-20.51
Total Heating	**1468.18**	**1459.45**	**1420.83**	**1368.40**	**1317.92**	**1269.28**	**1222.45**	**1177.35**	**1133.89**
Net Heat	**0.00556**	**-0.00833**	**0.00000**	**-0.00194**	**0.00889**	**-0.00194**	**0.00639**	**0.01167**	**0.00250**

Table 37 - Energy balance breakdown, No_TES_CT+

GWh	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
DH plants	1283.11	1303.08	1316.54	1306.35	1296.40	1281.53	1268.66	1193.58	1139.60
Storage losses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grid losses	-128.31	-130.31	-131.66	-130.63	-129.64	-128.16	-126.87	-119.36	-113.96
Individual units RSD	248.21	224.51	190.08	160.14	130.21	100.28	70.34	40.41	4.94
Individual units COM	113.66	101.73	86.12	72.56	59.01	50.03	41.11	88.77	123.83
Radiator losses	-48.50	-39.56	-40.25	-40.02	-38.06	-34.42	-30.80	-26.05	-20.51
Total Heating	**1468.18**	**1459.45**	**1420.83**	**1368.40**	**1317.91**	**1269.26**	**1222.45**	**1177.35**	**1133.89**
Net Heat	**0.00556**	**-0.01111**	**0.00000**	**-0.00194**	**0.00611**	**-0.01306**	**0.00639**	**0.01444**	**-0.00028**

Table 38 - Energy balance breakdown, No_TES_LT-

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
DH plants	1215.59	1244.48	1252.60	1239.36	1228.20	1217.65	1201.98	1137.89	1072.81
Storage losses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grid losses	-60.78	-62.23	-62.63	-61.97	-61.41	-60.89	-60.10	-56.89	-53.64
Individual units RSD	248.21	224.51	190.08	160.14	130.21	100.28	70.34	40.41	14.24
Individual units COM	113.66	101.73	86.12	72.56	59.00	46.74	41.06	82.15	120.88
Radiator losses	-48.50	-48.99	-45.31	-41.68	-38.06	-34.49	-30.80	-26.18	-20.39
Total Heating	**1468.18**	**1459.50**	**1420.86**	**1368.42**	**1317.95**	**1269.30**	**1222.48**	**1177.37**	**1133.90**
Net Heat	**0.00556**	**0.04444**	**0.02778**	**0.02028**	**0.03667**	**0.01750**	**0.03417**	**0.03944**	**0.01361**

Table 39 – Energy balance breakdown, No_TES_LT+

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
DH plants	1215.59	1244.48	1252.60	1239.36	1228.20	1218.15	1206.08	1147.47	1074.01
Storage losses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grid losses	-60.78	-62.22	-62.63	-61.97	-61.41	-60.91	-60.31	-57.37	-53.70
Individual units RSD	248.21	224.51	190.08	160.14	130.21	100.28	70.34	40.41	13.56
Individual units COM	113.66	101.73	86.12	72.56	59.00	46.28	37.23	73.23	120.45
Radiator losses	-48.50	-48.99	-45.31	-41.68	-38.06	-34.50	-30.87	-26.37	-20.40
Total Heating	**1468.18**	**1459.50**	**1420.86**	**1368.42**	**1317.95**	**1269.30**	**1222.47**	**1177.36**	**1133.91**
Net Heat	**0.00556**	**0.04444**	**0.02778**	**0.02028**	**0.03667**	**0.01750**	**0.02861**	**0.03111**	**0.02472**

Appendix B2

Appendix B2 presents the DH production by DH plants for all modelled scenarios.

Table 40 – DH production by DH plants, CT-

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
Bio pellet CHP	379.72	175.89	246.52	164.17	48.93	5.52	9.48	2.67	0.00
Municipal waste CHP	200.00	181.93	126.81	79.33	45.76	33.05	20.34	7.63	0.00
Industrial HP	181.34	557.61	557.61	682.56	833.80	886.90	892.43	908.06	942.60
Excess Heat - HT	408.09	438.00	438.00	438.00	438.00	438.00	438.00	438.00	438.00
Oil Boiler	116.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 41 – DH production by DH plants, CT+

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
Bio pellet CHP	379.72	160.36	217.54	115.97	83.62	53.53	21.14	0.00	0.00
Municipal waste CHP	200.00	181.93	126.81	79.33	45.76	33.05	20.34	7.63	0.00
Industrial HP	181.34	572.66	587.94	733.21	801.91	837.20	883.41	911.24	946.27
Excess Heat - HT	408.09	438.00	438.00	438.00	438.00	438.00	438.00	438.00	438.00
Oil Boiler	116.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 42 - DH production by DH plants, LT-

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
Bio pellet CHP	305.66	23.39	71.14	24.78	0.00	0.00	0.00	0.00	0.00
Municipal waste CHP	199.54	181.51	126.51	79.15	45.65	32.97	20.29	7.61	0.00
Industrial HP	160.52	478.30	479.79	541.00	566.36	543.20	520.02	495.69	483.16
Excess Heat - HT	374.22	438.00	438.00	438.00	438.00	438.00	438.00	438.00	438.00
Excess Heat - LT	136.44	157.97	174.33	196.23	220.58	248.61	278.92	312.64	347.77
Oil Boiler	39.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 43 - DH production by DH plants, LT+

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
Bio pellet CHP	305.66	15.18	64.23	19.16	19.78	0.00	0.00	0.00	0.00
Municipal waste CHP	199.54	181.51	126.51	79.15	45.65	32.97	20.29	7.61	0.00
Industrial HP	160.52	486.71	486.71	547.19	547.19	545.71	521.53	495.86	483.03
Excess Heat - HT	374.45	438.00	438.00	438.00	438.00	438.00	438.00	438.00	438.00
Excess Heat - LT	136.20	157.97	174.33	196.23	220.58	248.61	278.92	312.64	347.77
Oil Boiler	39.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 44 - DH production by DH plants, No_TES_CT-

GWh	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Bio pellet CHP	380.78	185.96	259.40	220.33	188.02	191.86	109.02	36.71	0.00
Municipal waste CHP	200.00	181.93	126.81	79.33	45.76	33.05	20.34	7.63	0.00
Industrial HP	180.00	529.11	526.21	605.47	664.50	661.82	728.25	762.81	755.04
Excess Heat - HT	406.42	406.12	404.16	401.22	398.10	394.80	391.62	388.56	384.56
Oil Boiler	115.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 45 - DH production by DH plants, No_TES_CT+

GWh	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Bio pellet CHP	380.78	166.41	239.86	211.84	196.74	143.02	74.60	33.73	0.00
Municipal waste CHP	200.00	181.93	126.81	79.33	45.76	33.05	20.34	7.63	0.00
Industrial HP	180.00	548.61	545.71	613.96	655.80	710.66	782.10	763.67	755.04
Excess Heat - HT	406.42	406.12	404.16	401.22	398.10	394.80	391.62	388.56	384.56
Oil Boiler	115.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 46 - DH production by DH plants, No_TES_LT-

GWh	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Bio pellet CHP	307.32	79.97	132.26	156.39	75.65	27.01	17.12	14.66	0.00
Municipal waste CHP	199.54	181.51	126.51	79.15	45.65	32.97	20.29	7.61	0.00
Industrial HP	161.01	471.52	474.50	475.74	568.52	607.93	602.64	539.48	483.39
Excess Heat - HT	372.99	375.39	369.36	370.34	361.29	359.68	356.62	355.87	344.39
Excess Heat - LT	136.44	136.08	149.97	157.74	177.09	190.06	205.31	220.28	245.03
Oil Boiler	38.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 47 - DH production by DH plants, No_TES_LT+

GWh	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Bio pellet CHP	307.32	86.39	132.24	128.52	103.76	70.20	38.15	0.26	0.00
Municipal waste CHP	199.54	181.51	126.51	79.15	45.65	32.97	20.29	7.61	0.00
Industrial HP	161.01	465.11	474.52	503.61	540.41	565.24	585.71	563.46	484.59
Excess Heat - HT	372.99	371.68	369.16	367.41	361.29	356.95	356.62	355.87	344.39
Excess Heat - LT	136.44	139.79	150.17	160.68	177.09	192.79	205.31	220.28	245.03
Oil Boiler	38.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Appendix B3

Appendix B3 presents the DH production for the CT-, CT+, LT-, and LT+ scenarios, for the year 2052.

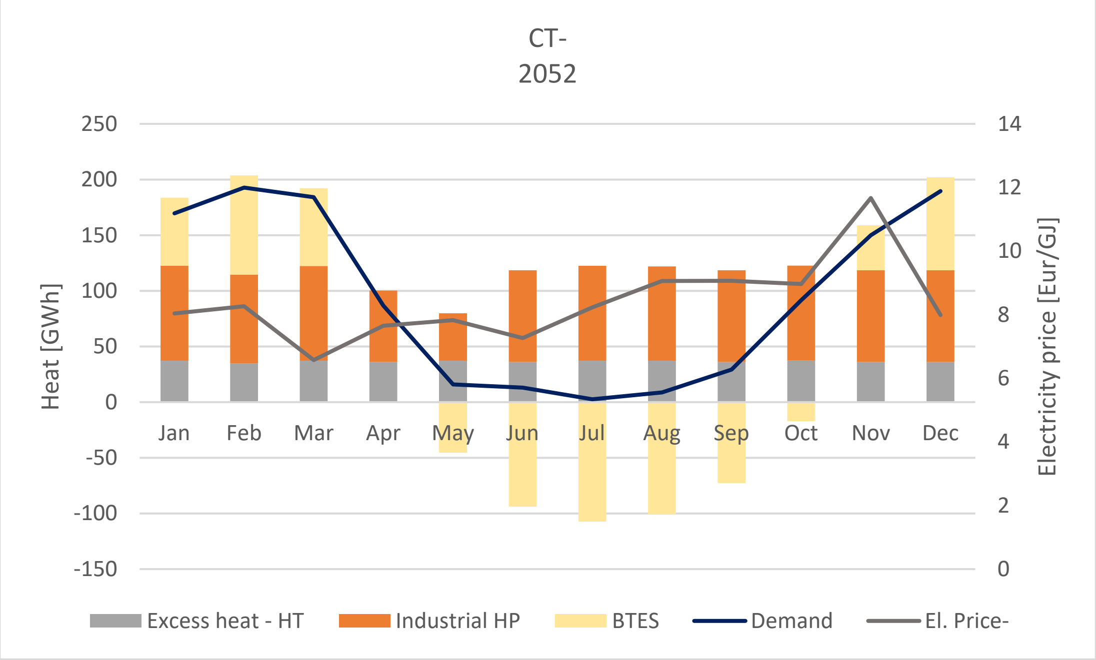


Figure 38 – DH production for 2052, CT-

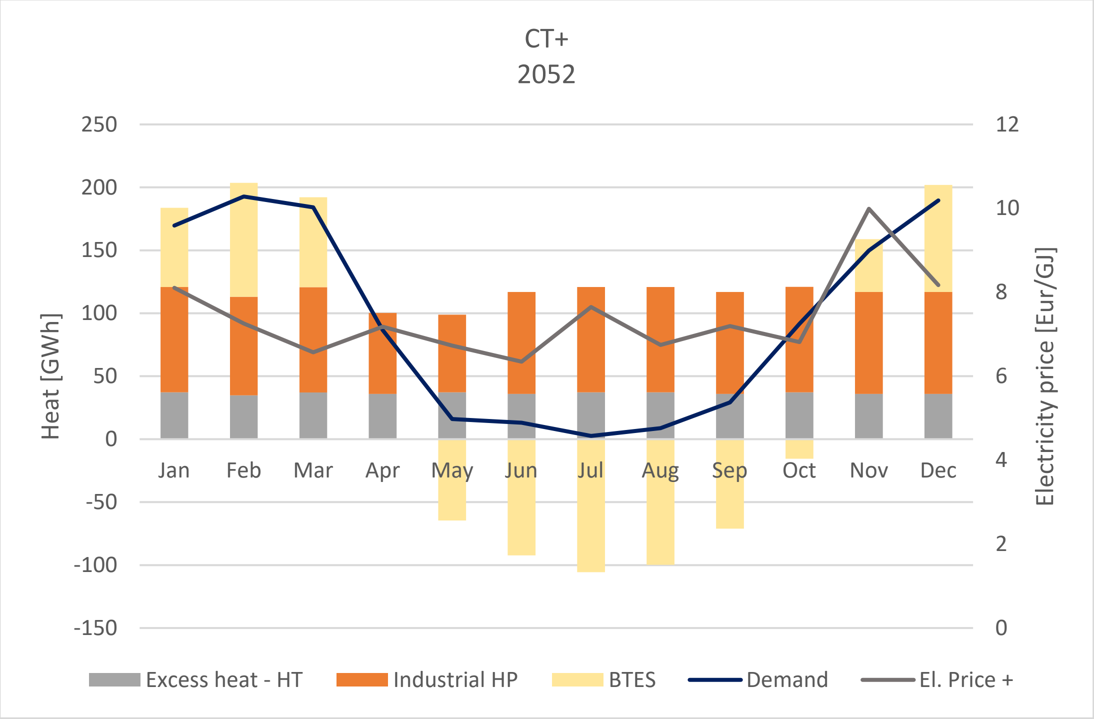


Figure 39 - DH production for 2052, CT+

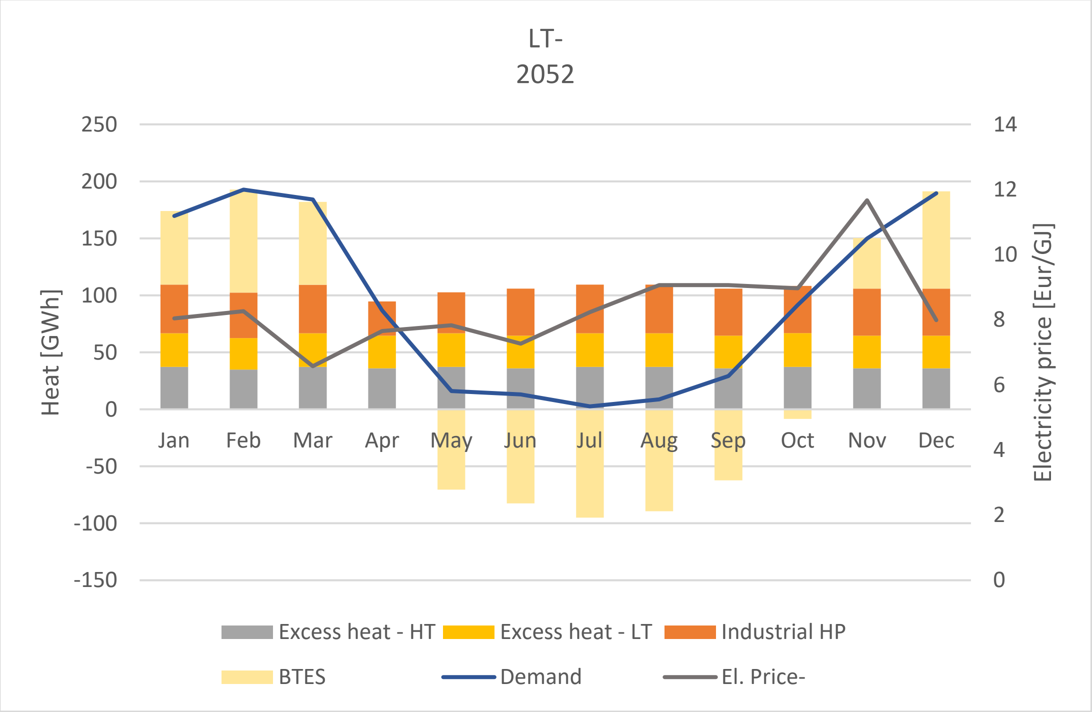


Figure 40 - DH production for 2052, LT-

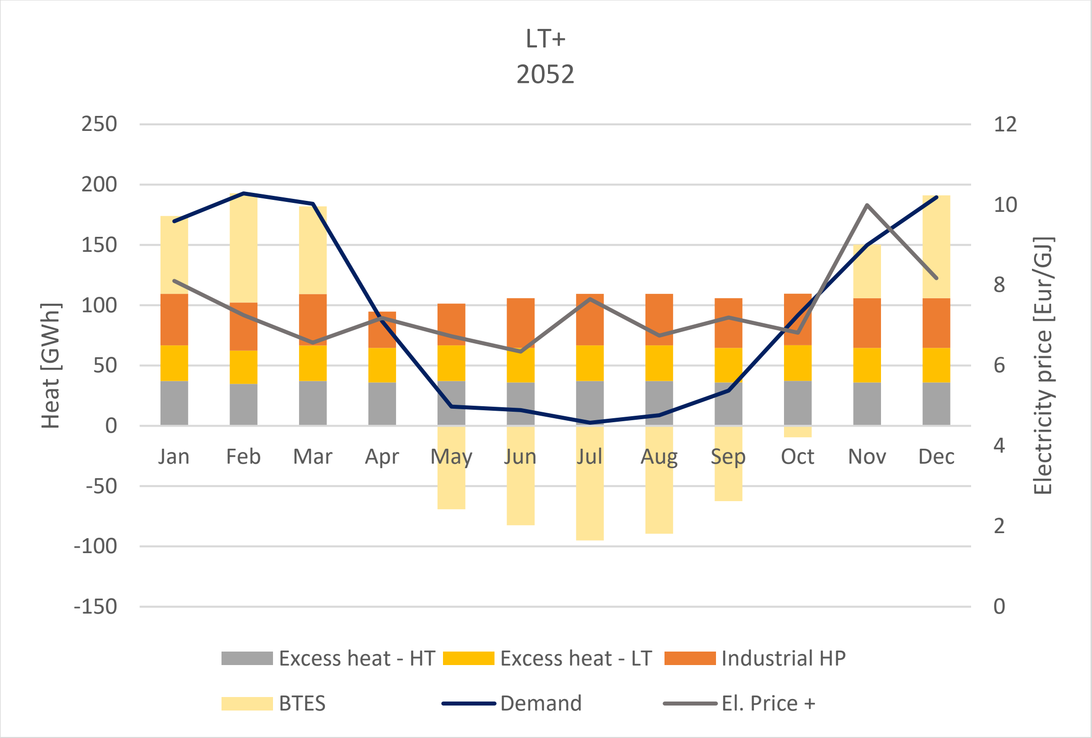


Figure 41 - DH production for 2052, LT+

Appendix B4

Appendix B4 presents the total system heat generation in descending order in the scenarios with TES for all modelled years.

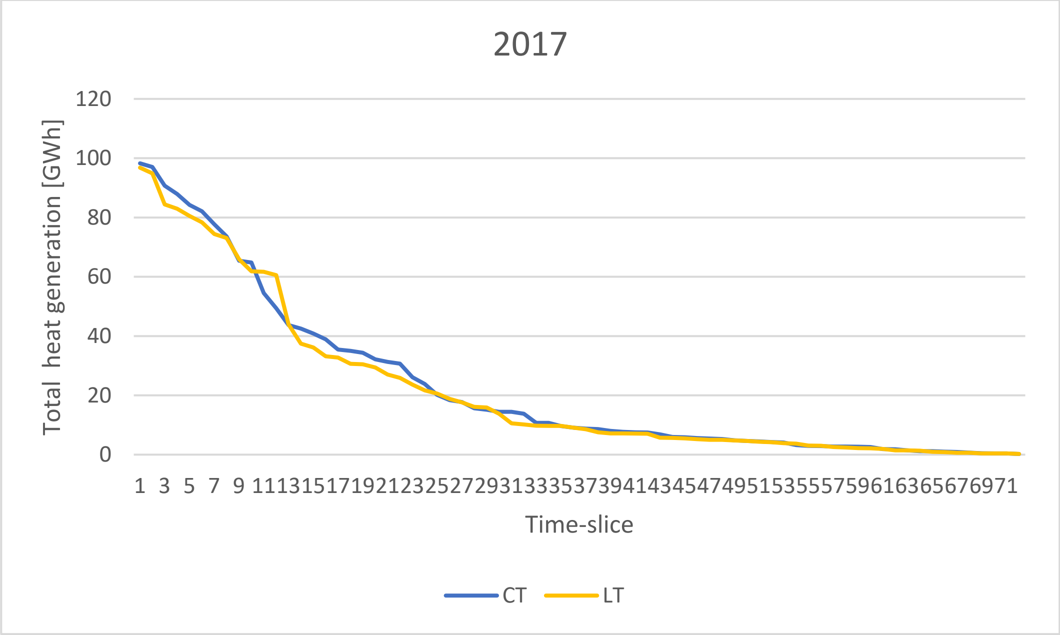


Figure 42 - Total heat generation in descending order comparison of all scenarios with TES, for the year 2017

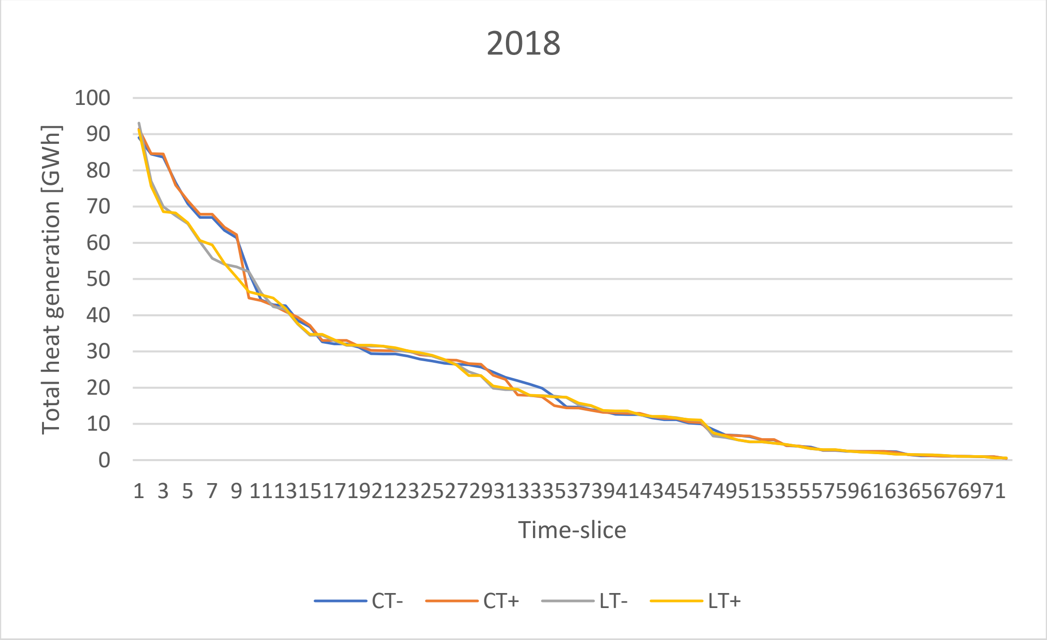


Figure 43 - Total heat generation in descending order comparison of all scenarios with TES, for the year 2018

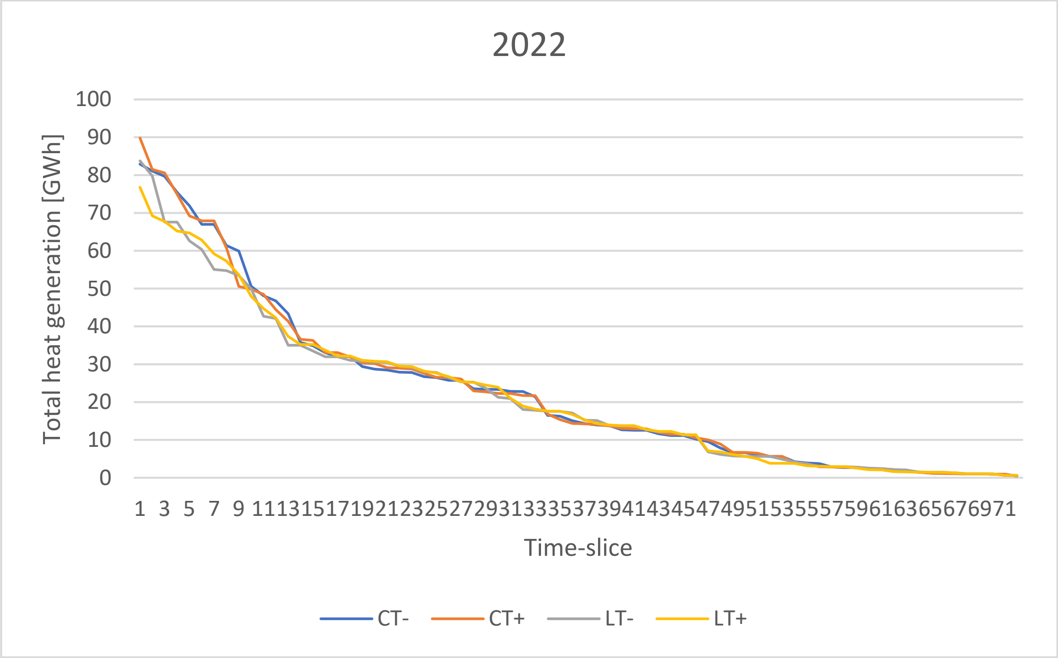


Figure 44 - Total heat generation in descending order comparison of all scenarios with TES, for the year 2022

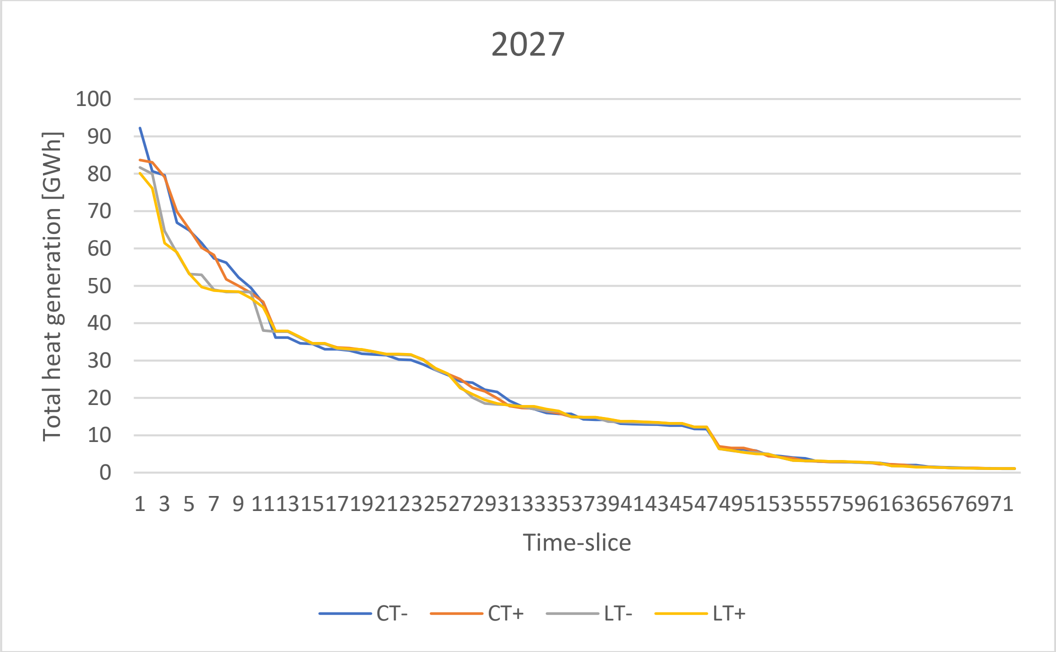


Figure 45 - Total heat generation in descending order comparison of all scenarios with TES, for the year 2027

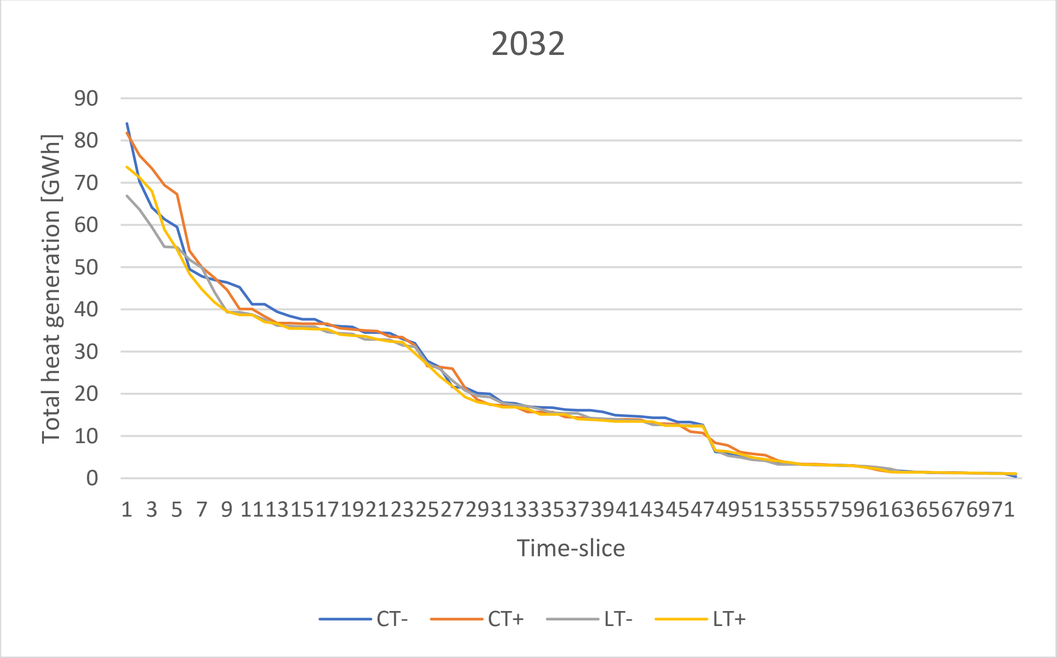


Figure 46 - Total heat generation in descending order comparison of all scenarios with TES, for the year 2032

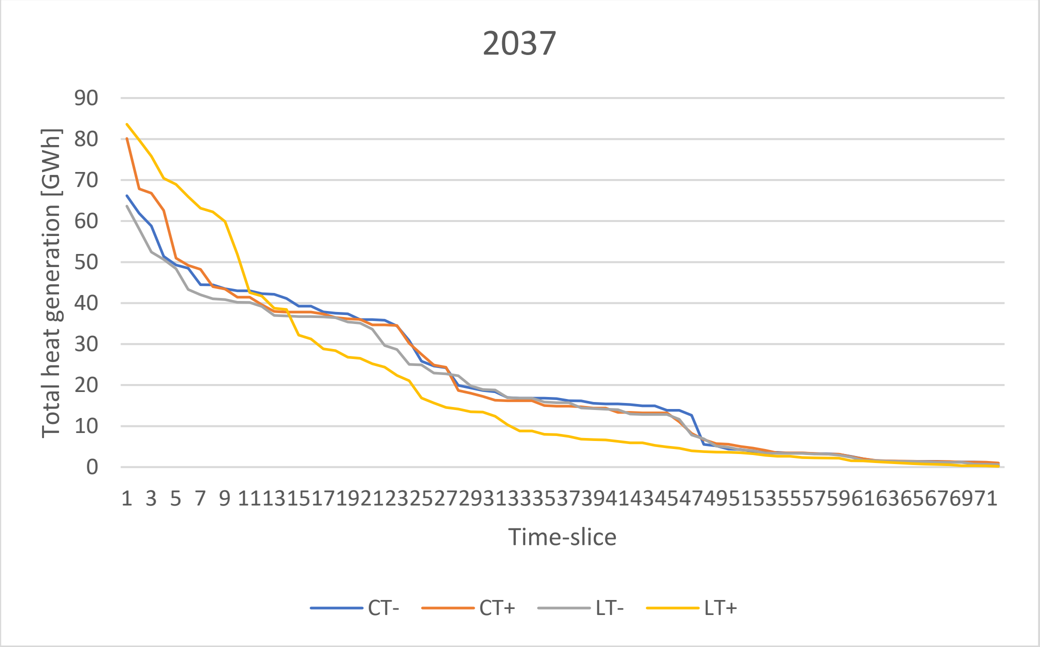


Figure 47 - Total heat generation in descending order comparison of all scenarios with TES, for the year 2037

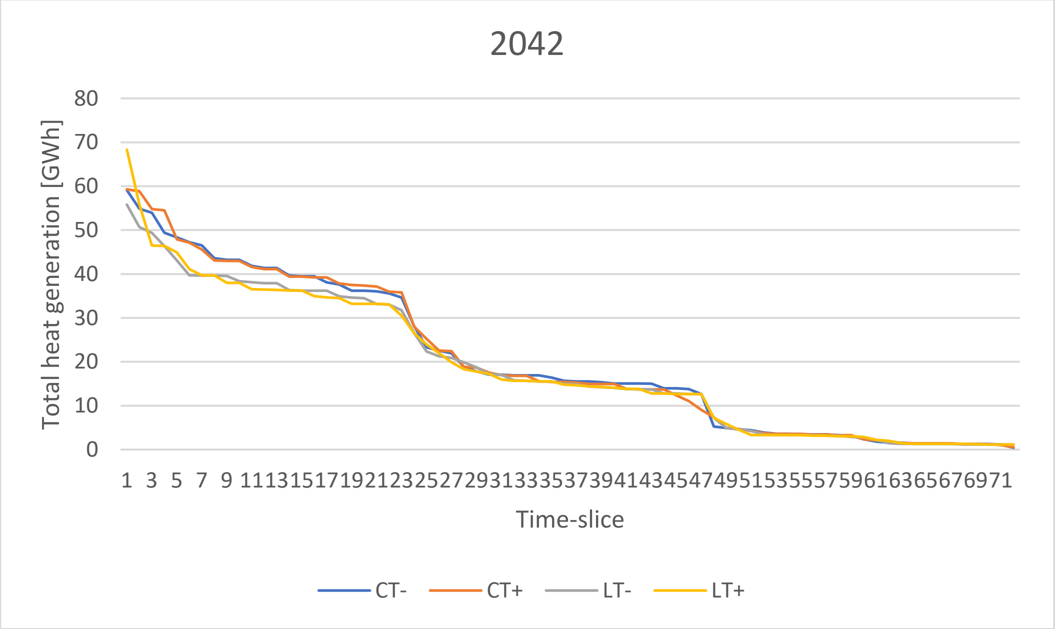


Figure 48 - Total heat generation in descending order comparison of all scenarios with TES, for the year 2042

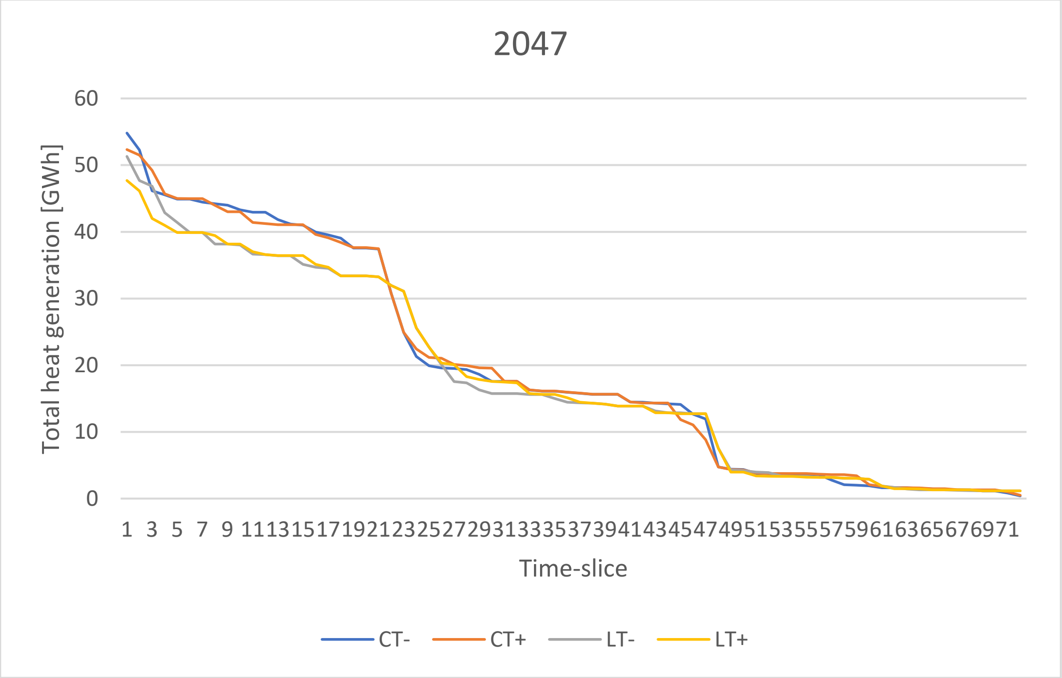


Figure 49 - Total heat generation in descending order comparison of all scenarios with TES, for the year 2047

Appendix B5

Appendix B5 presents results showing LWT activity in the month of February, for the years 2032 and 2052.

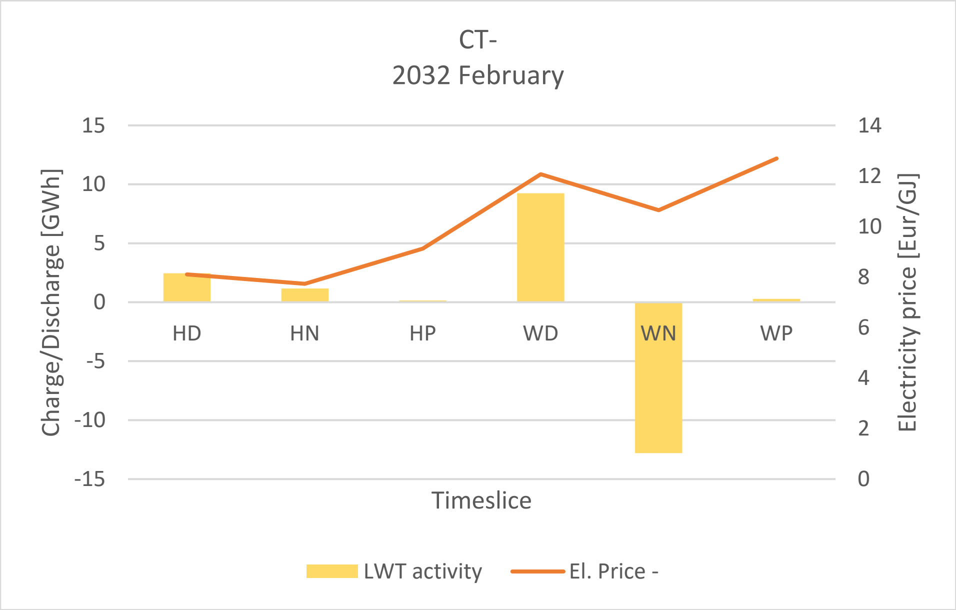


Figure 50 – LWT activity for February 2032, CT-

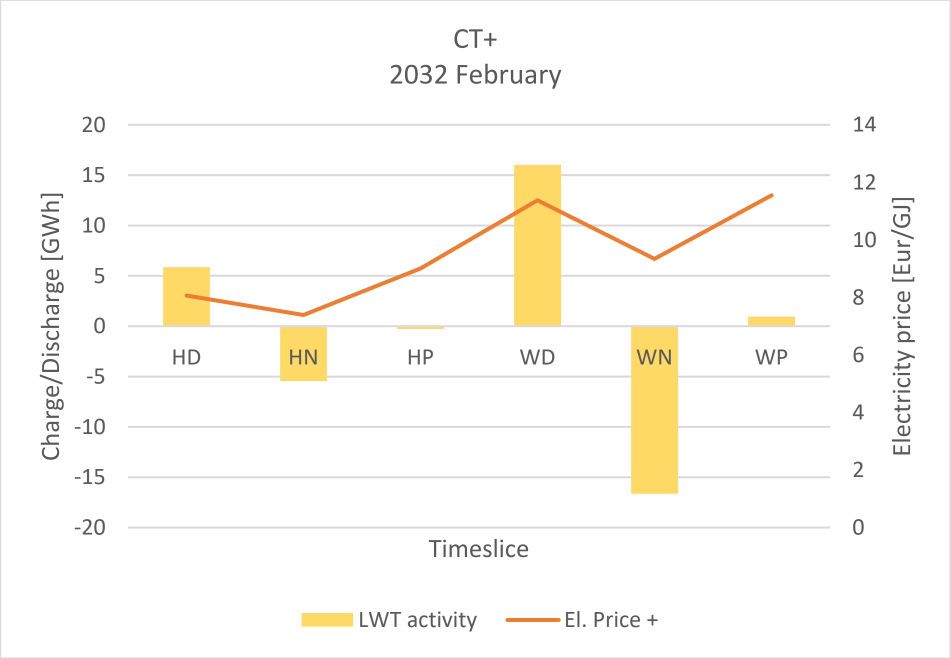


Figure 51 - LWT activity for February 2032, CT+

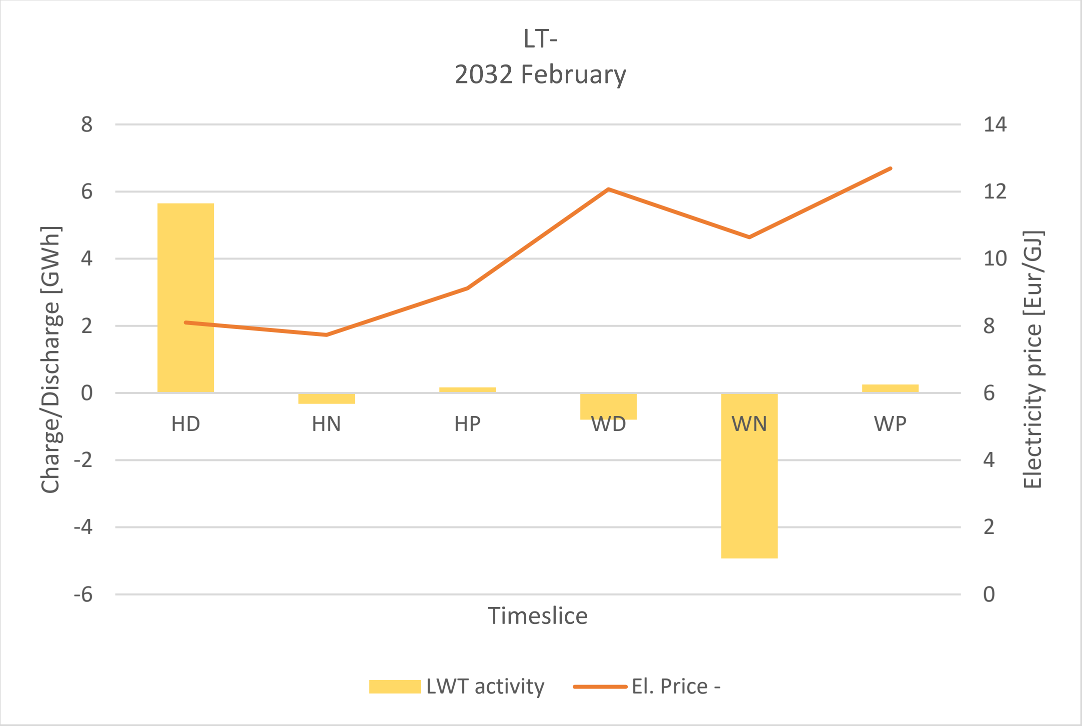


Figure 52 - LWT activity for February 2032, LT-

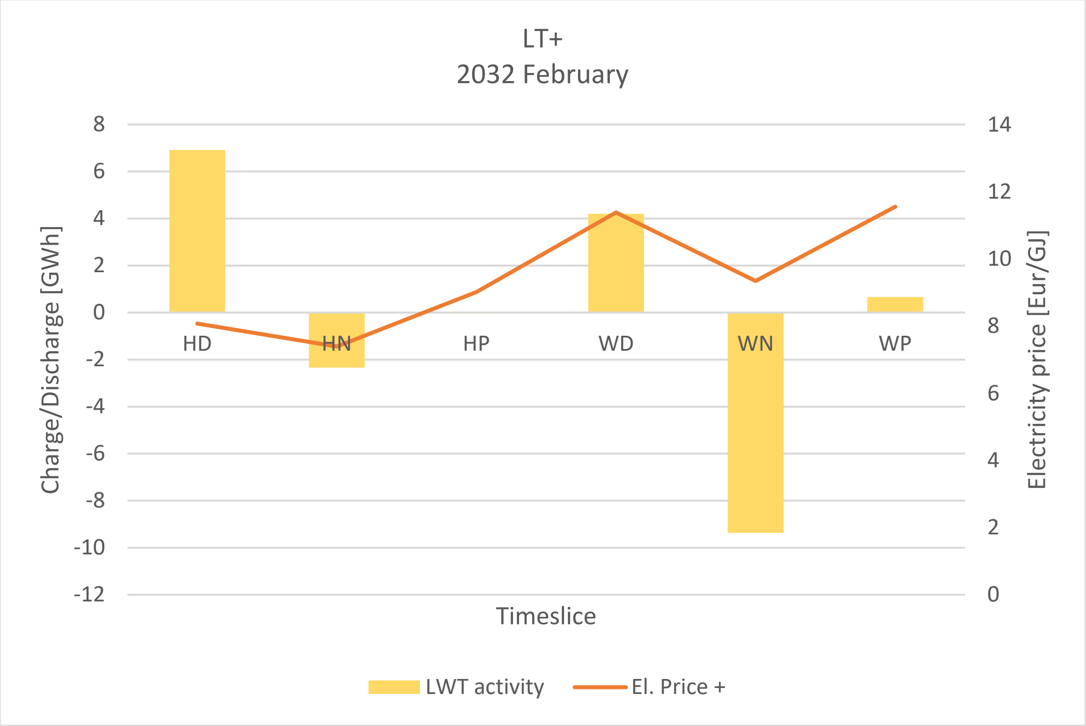


Figure 53 - LWT activity for February 2032, LT+

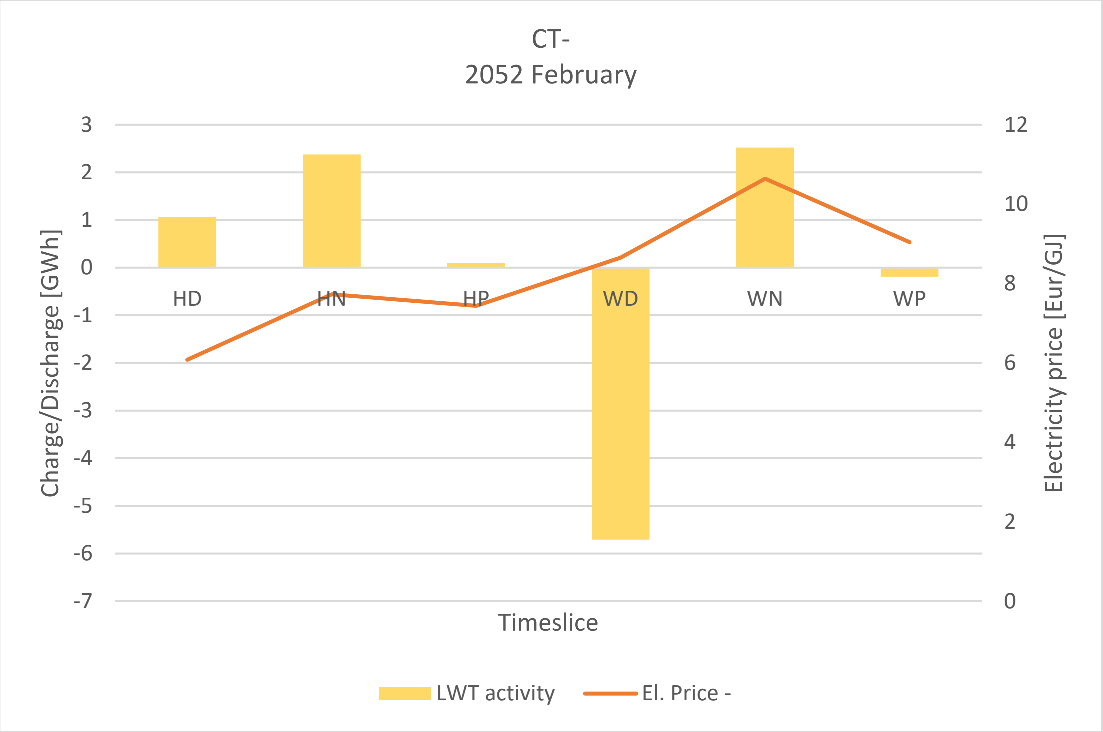


Figure 54 - LWT activity for February 2052, CT-

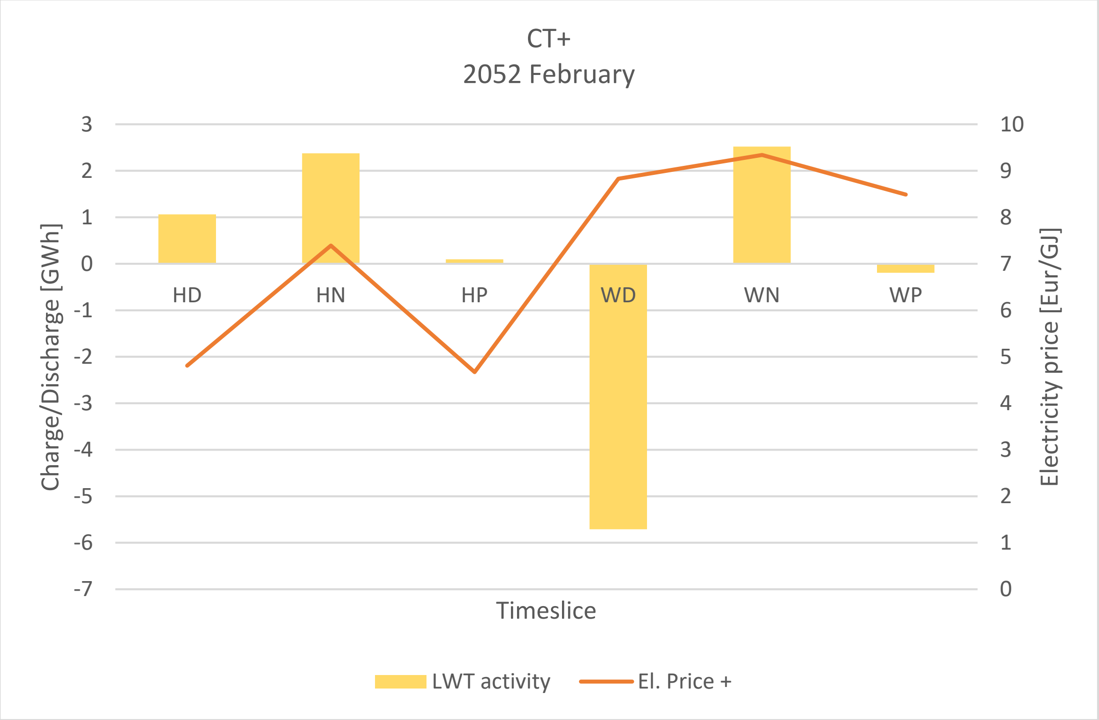


Figure 55 - LWT activity for February 2052, CT+

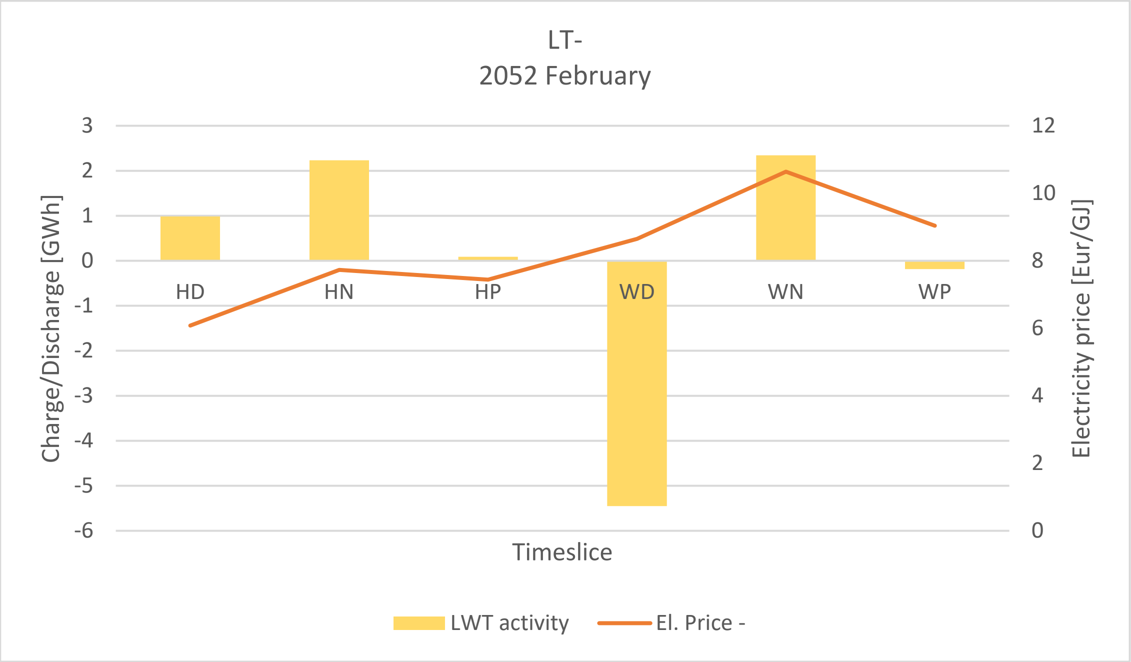


Figure 56 - LWT activity for February 2052, LT-

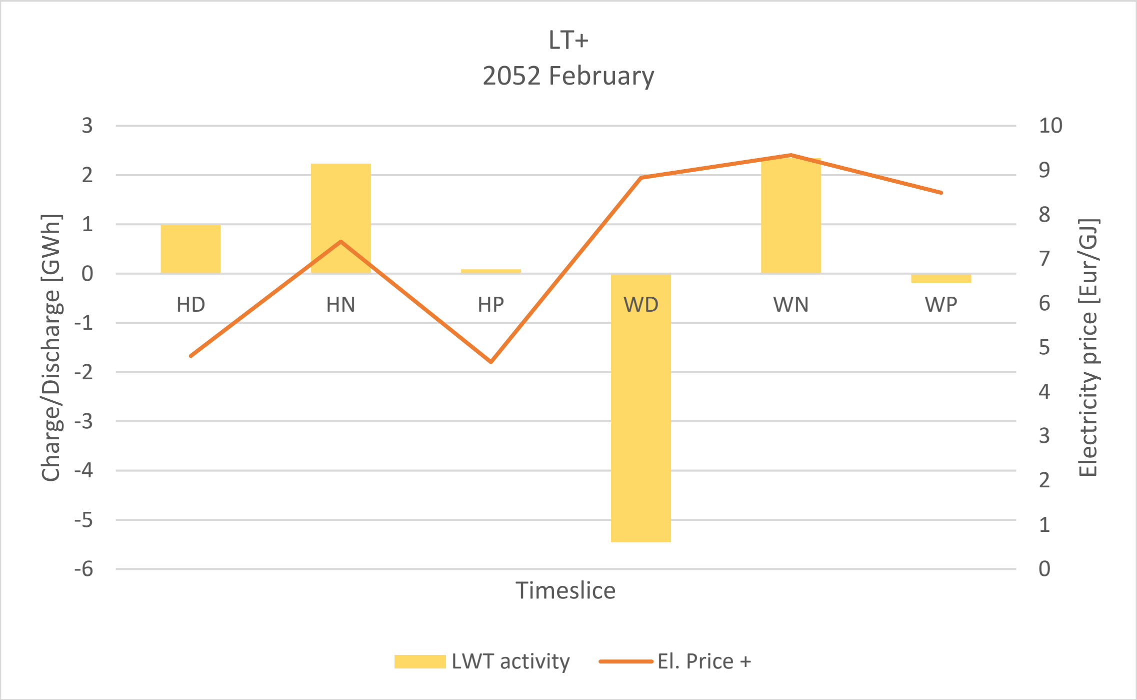


Figure 57 - LWT activity for February 2052, LT+

Appendix B6

Appendix B6 presents the heat generation capacities of DH plants and individual units throughout the modelled period, for all scenarios modelled.

Table 48 – Heat generation capacity (in MW) for DH plants, CT-

MW	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Bio pellet CHP	138	138	138	138	138	138	110.4	41.4	0
Municipal waste CHP	72	72	72	72	72	72	72	72	0
Oil boiler	30	30	24	9	0	0	0	0	0
Excess heat - HT	50	50	50	50	50	50	50	50	50
Excess heat - LT	-	-	-	-	-	-	-	-	-
Industrial HP	30	66.24	66.24	81.08	99.4	105.73	106.66	112.67	114.63

Table 49 – Heat generation capacity (in MW) for DH plants, CT+

MW	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Bio pellet CHP	138	138	138	138	138	138	110.4	41.4	0
Municipal waste CHP	72	72	72	72	72	72	72	72	0
Oil boiler	30	30	24	9	0	0	0	0	0
Excess heat - HT	50	50	50	50	50	50	50	50	50
Excess heat - LT	-	-	-	-	-	-	-	-	-
Industrial HP	30	69.84	69.84	87.09	95.24	100.07	105.67	112.96	112.43

Table 50 – Heat generation capacity (in MW) for DH plants, LT-

MW	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Bio pellet CHP	138	138	138	138	138	138	110.4	41.4	0
Municipal waste CHP	72	72	72	72	72	72	72	72	0
Oil boiler	30	30	24	9	0	0	0	0	0
Excess heat - HT	50	50	50	50	50	50	50	50	50
Excess heat - LT	17.6	18.03	19.9	22.4	25.18	28.38	31.84	35.69	39.7
Industrial HP	30	56.83	57.01	64.27	67.28	67.28	61.77	58.86	57.36

Table 51 – Heat generation capacity (in MW) for DH plants, LT+

MW	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Bio pellet CHP	138	138	138	138	138	138	110.4	41.4	0
Municipal waste CHP	72	72	72	72	72	72	72	72	0
Oil boiler	30	30	24	9	0	0	0	0	0

Excess heat - HT	50	50	50	50	50	50	50	50	50
Excess heat - LT	17.6	18.03	19.9	22.4	25.18	28.38	31.84	35.69	39.7
Industrial HP	30	57.83	57.83	65.01	65.01	65.01	61.95	58.88	57.34

Table 52 – Total capacity of individual units for all modelled scenarios with TES

MW	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
CT-	266.23	266.23	225.45	189.92	154.36	118.97	83.47	47.91	0
CT+	266.23	266.23	225.45	189.92	154.36	118.97	83.47	47.91	0
LT-	266.23	266.23	225.45	189.92	154.36	118.97	83.47	47.91	0
LT+	266.23	266.23	225.45	189.92	154.36	118.97	83.47	47.91	0

Table 53 – Capacities for individual units (in MW), No_TES_CT-

No_TES_CT-	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Air-source HP	180.8	180.8	153.08	128.98	104.86	83.36	71.7	71.69	70.67
Electric boiler	13.82	13.82	11.71	9.85	7.98	6.19	4.33	2.46	0
Electrical resistance	4.13	4.13	3.52	2.97	2.4	1.86	1.32	0.74	0
Air conditioner	1.36	1.36	1.15	0.96	0.76	0.61	0.43	0.22	0
Ground-source HP	66.12	66.12	55.99	47.16	38.36	29.54	20.73	11.93	0
Gas furnace	0	0	0	0	0	0	0	0	12.73
Total	**266.23**	**266.23**	**225.45**	**189.92**	**154.36**	**121.56**	**98.51**	**87.04**	**83.4**

Table 54 – Capacities for individual units (in MW), No_TES_CT+

No_TES_CT+	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Air-source HP	180.8	180.8	153.08	128.98	104.86	83.36	61.91	72.77	70.67
Electric boiler	13.82	13.82	11.71	9.85	7.98	6.19	4.33	2.46	0
Electrical resistance	4.13	4.13	3.52	2.97	2.4	1.86	1.32	0.74	0
Air conditioner	1.36	1.36	1.15	0.96	0.76	0.61	0.43	0.22	0
Ground-source HP	66.12	66.12	55.99	47.16	38.36	29.54	20.73	11.93	0
Gas furnace	0	0	0	0	0	0	0	0	12.73
Total	**266.23**	**266.23**	**225.45**	**189.92**	**154.36**	**121.56**	**88.72**	**88.12**	**83.4**

Table 55 – Capacities for individual units (in MW), No_TES_LT-

No_TES_LT-	**2017**	**2018**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2052**
Air-source HP	180.8	180.8	153.08	128.98	104.86	81.52	61.89	69	75.42
Electric boiler	13.82	13.82	11.71	9.85	7.98	6.19	4.33	2.46	0
Electrical resistance	4.13	4.13	3.52	2.97	2.4	1.86	1.32	0.74	0
Air conditioner	1.36	1.36	1.15	0.96	0.76	0.61	0.43	0.22	0

Ground-source HP	66.12	66.12	55.99	47.16	38.36	29.54	20.73	11.93	0
Gas furnace	0	0	0	0	0	0	0	0	10.02
Total	266.23	266.23	225.45	189.92	154.36	119.72	88.7	84.35	85.44

Table 56 – Capacities for individual units (in MW), No_TES_LT+

No_TES_LT+	2017	2018	2022	2027	2032	2037	2042	2047	2052
Air-source HP	180.8	180.8	153.08	128.98	104.86	81.26	59.71	63.89	74.72
Electric boiler	13.82	13.82	11.71	9.85	7.98	6.19	4.33	2.46	0
Electrical resistance	4.13	4.13	3.52	2.97	2.4	1.86	1.32	0.74	0
Air conditioner	1.36	1.36	1.15	0.96	0.76	0.61	0.43	0.22	0
Ground-source HP	66.12	66.12	55.99	47.16	38.36	29.54	20.73	11.93	0
Gas furnace	0	0	0	0	0	0	0	0	10.35
Total	266.23	266.23	225.45	189.92	154.36	119.46	86.52	79.24	85.07

Appendix B7

Appendix B7 presents miscellaneous results that are referred to from the results and discussion chapter.

Table 57 – Heat into BTES for all modelled scenarios with TES

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
CT-	-	219.74	224.34	289.55	355.93	383.84	393.01	392.13	437.20
CT+	-	216.42	236.34	310.29	345.03	362.46	388.26	394.19	449.03
LT-	-	275.38	287.57	328.88	349.16	349.88	366.77	380.78	408.23
LT+	-	278.78	290.61	331.39	348.17	367.15	373.65	380.95	408.16

Table 58 – Heat out of BTES for all modelled scenarios with TES

GWh	2017	2018	2022	2027	2032	2037	2042	2047	2052
CT-	-	177.06	178.76	235.56	287.56	308.67	313.40	311.07	343.89
CT+	-	174.60	189.45	253.46	274.50	289.67	306.07	312.47	351.57
LT-	-	240.97	250.69	289.35	307.00	306.39	321.61	333.51	357.42
LT+	-	244.16	253.73	291.30	305.48	321.21	326.97	333.52	357.21

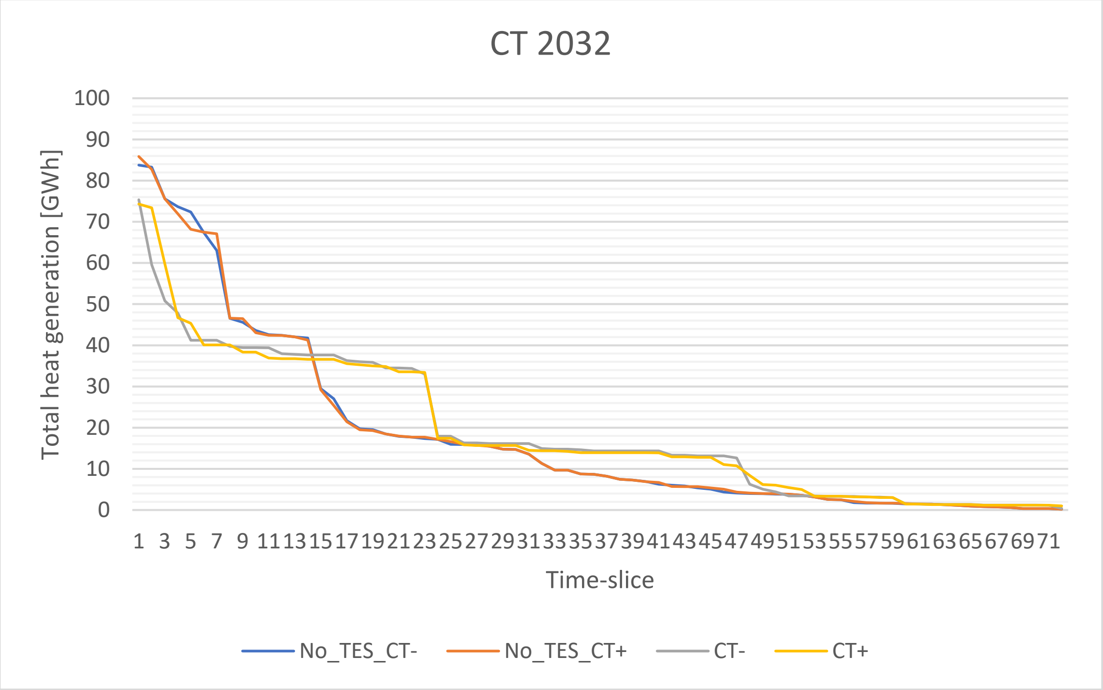


Figure 58 – Scenario comparison of total heat generation in descending order for 2032, CTDH

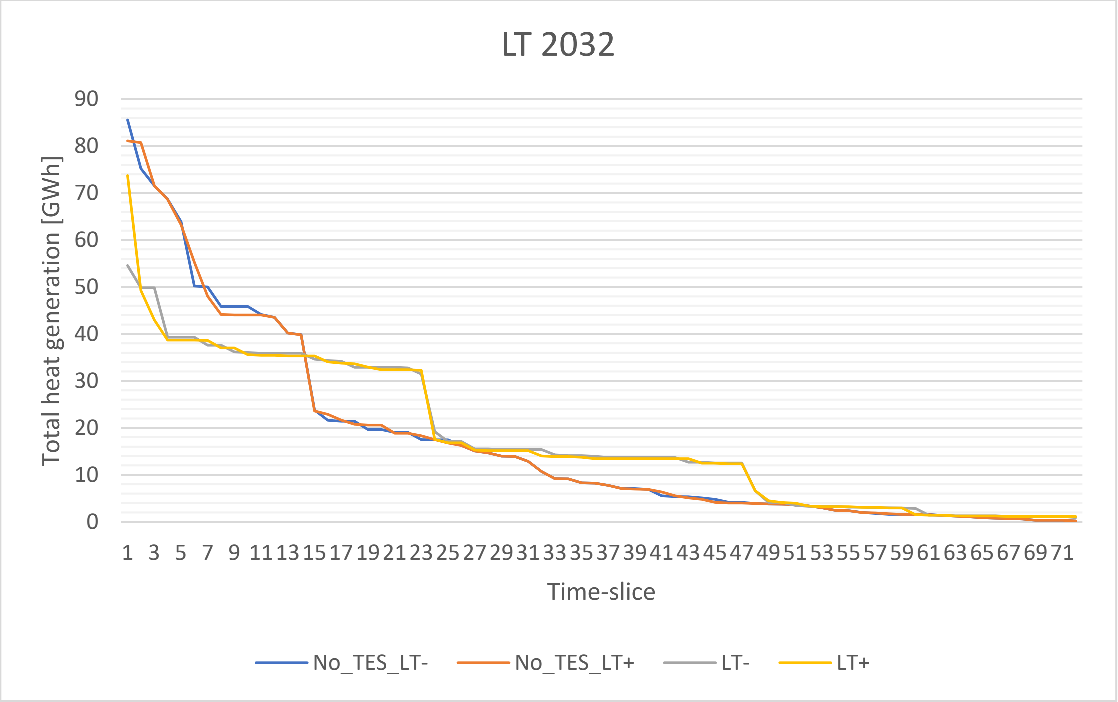


Figure 59 - Scenario comparison of total heat generation in descending order for 2032, LTDH