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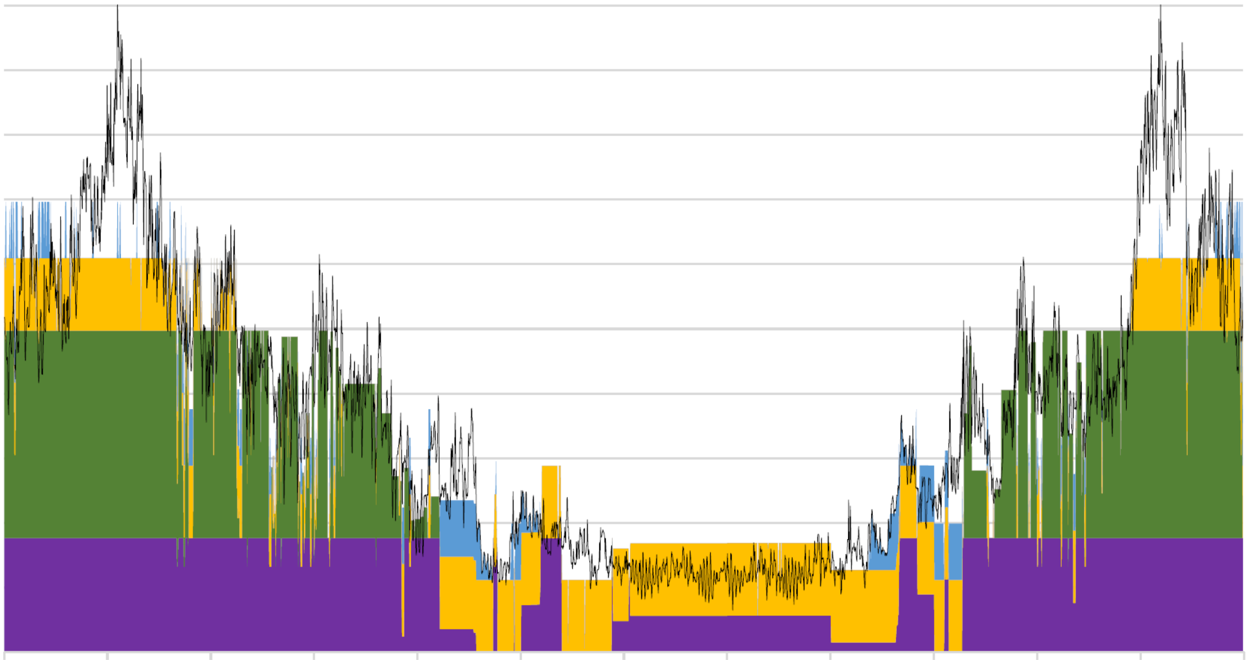

The potential of heat storage as variation management in the electricity and district heating sectors

Greenfield modelling of the electricity and district heating sectors in an isolated region at trihoral resolution

Master's thesis in Sustainable Energy Systems

Petra Holmér and Jonathan Ullmark

Department of Space, Earth and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2018

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Cover: Heat generation during one year in the base case, for a middle-sized DH network, with TES.

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Abstract

In the current transition to a carbon neutral society, variable renewable energy sources (VRESs) are becoming ever more important, and so are the strategies and technologies that manage the mismatch in time between the intermittent VRES and the energy demand. This thesis examines the effects of thermal energy storage (TES) as a variation management technology using a greenfield cost-optimising model integrating the district heating (DH) and electricity systems in one model. Wind, solar and hydropower availability is selected according to the Swedish Stockholm-Gothenburg electricity price area, but a low-flex scenario with less hydro, waste and biomass is also investigated. Using projected costs for year 2050 in combination with a zero-limit on CO_2 emissions, TES is found to greatly affect the cost-optimal DH system composition and operation while promoting wind power in the electricity system, especially so in the low-flex scenario. This impact is mainly through reducing curtailment but also through increasing the demand for electricity. The CHP and power-to-heat units become increasingly active in the electricity system, using the TES for flexibility and detachment from the heat demand curve. Furthermore, TES is found to be important also when combined with other variation management strategies (demand side management and hydrogen storage), and some synergies are found both in promoting wind power and reducing the total system cost.

Keywords: thermal energy storage (TES), district heating (DH), variable renewable energy sources (VRES), variation management strategies (VMS).

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Petra Holmér and Jonathan Ullmark, Gothenburg, May 2018

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Abbreviations

BTES Borehole thermal energy storage.

CCS Carbon capture and storage.
CHP Combined heat- and power.

DH District heating.
DSM Demand-side management.

EB Electric boiler.

FC Fuel cell.
FLH Full-load hour.

GWG Natural gas and biogas mix.

HOB Heat-only boiler.
HP Heat pump.
HW Coal and biomass mix.

NG Natural gas.

O&M Operation & maintenance.

PTES Pit thermal energy storage.

RES Renewable energy source.

TES Thermal energy storage.
TTES Tank thermal energy storage.

VMS Variation management strategy.
VRES Variable renewable energy source.

WG Biogas.

1
Introduction

1.1 Background

The increasing share of variable renewable energy sources (VRES) in the electricity system brings challenges as to how to make the most use of the renewable energy while still satisfying the demand for electricity during hours of low variable production. This has placed a new need for flexibility on the electricity system, and energy storage technologies could play an important role for this flexibility. Countries with reservoir hydropower can use the water level in the reservoirs as energy storage, but few countries have enough hydropower to manage the required RES levels to meet their climate targets. Furthermore, unless there is pumped hydro storage, the reservoirs can only store energy from water inflow, not VRES overproduction. There are many other ways to store energy (e.g. batteries, hydrogen, or as heat) and many other sectors of society already store and use significant amounts of energy. Thus there may exist a potential for interaction between storage and usage of energy in the electricity sector and in other sectors. One such example is electric and hydrogen vehicles storing cheap energy from high VRES production periods for use during hours of higher electricity prices. District heating (DH) networks can use thermal energy storage (TES) and heat pumps or electric boilers to minimise their heat generation costs but also for flexible consumption of electricity and optimisation of the total system cost.

The model [1] used in this thesis is a single-area green-field investment model which previously has been used in a number of studies and papers [2, 3, 4]. One of these [4] looks at the effects of variation management strategies (VMSs) in various system contexts and uses the categories of *Absorbing strategies*, *Complementing strategies* and *Shifting strategies*. These categories were previously introduced by Göransson and Johnsson [5], to generalise the effects and interactions between different VMSs. Descriptions of these categories are given in the beginning of Section 2. This thesis will build on the aforementioned model and attempt to analyse some VMSs through the same lens, but with a special focus on TES. Romanchenko et al. investigated in 2017 [6] the interaction between DH and electricity in the context of flexibility and operational strategies for DH systems with volatile electricity prices representing a future system with a high share of VRES. The study did not look at investment costs or costs in the electricity system, but instead imported hourly electricity prices from another model package ("ELIN-EPOD") [7]. This thesis instead has the electricity system as part of the model and thus any value of VMS as an endogenous part of the cost-minimising optimisation problem. By connecting the electricity and DH sectors in one model, a more accurate description of interactions, such as power-to-heat production, and possible effects of TES on the electricity system can be obtained.

1.2 Aim and Scope

The purpose of this thesis is to explore the extent to which DH networks and the electricity system can interact to provide, or benefit from, flexibility in a system with limited resources and requirements on net-zero CO_2 emissions. The main focus is on the role of thermal energy storage (TES) in the interaction between said sectors, although TES also will be examined in relation to other VMSs. More specifically, the aim is to answer the following questions:

- How are the cost-optimal investments in wind/solar affected from using TES?
- Which heat generation technologies can be of importance in a system with a large need for flexibility?
- How will heat storage as a variation management strategy affect the operation of heat production technologies?
- How does the different types of TES interact with each other and with other VMSs?

Only linear programming (LP) will be used to answer these questions, and any possible non-linear relations will be linearly approximated. The LP-model that is used includes various heat and electricity production technologies and VMSs, which are elaborately described from a large-scale perspective. This description includes for example start-up and part-load costs from thermal generation technologies, passive and charging losses from storages, and heat recovery from electrolysis. Since the model is a green-field investment model (does not include existing generation capacity but only new investments), real-world geographical areas have only been used to the extent of capturing correlations between electricity demand, heat demand and VRES production curves (such as wind patterns). Perfect foresight regarding demand and production curves is inherently part of the model, and insecurities concerning e.g. future demand and VRES availability are thus not taken into account.

The penetration and utilisation of VRES, electricity prices and usage of thermal plants are key aspects in the results, and the interaction and effects of VMSs will be primarily viewed through these elements.

2

Variation management strategies

This chapter will present the theory behind various VMSs as well as other notable effects on flexibility and the interaction between the heat and power sectors.

In the traditional electricity system there is a base, mid and peak power supply, each designed to be profitable with a different operating strategy. The base power typically runs at a high load for most of the year and is slow and expensive to change output level or shut down and start up. The mid power also runs for a large number of hours of the year, but with fewer full-load hours. It may be shut down during a period of low demand and may ramp up and down with each day and night cycle. Lastly, the peak power is designed to quickly change its output and might only run for a handful of days each year.

This paradigm of power production has been the standard for a long time, but is mostly based on fossil fuels and nuclear power. As the share of VRES in the power system increases, the operation of the traditional plants is affected which in turn affects their profitability. The intermittency of wind and solar power eventually leads to hours when the base load plus the VRES exceeds the demand, and unless this surplus can be stored - either the base load or the VRES has to reduce their output. This is generally an economically inefficient scenario which has come to be due to the mismatch between power plant life-spans and the rate of technological and political development. Instead, a cost-optimal system with low carbon emissions may be composed of a high share of VRES in combination with technologies that can complement and manage the intermittent production.

Thus, there may be an important role for VMSs to play in making the future energy system cost-efficient. In the following subsections, a range of VMS options will be presented and later investigated in the model. As mentioned in Section 1.1, the VMSs will be viewed and analysed through the lens of the categories *shifting, absorbing* and *complementing* technologies. The definitions given in [4, 5] roughly state that:

- *Shifting technologies* (such as batteries and DSM) store electricity for later use or shift the demand to fit the generation profile
- *Absorbing technologies* (e.g. power-to-heat) convert excess electricity to another energy carrier and may do so opportunistically when combined with a storage
- *Complementing technologies* (e.g. hydropower or flexible thermal power) are dispatchable and can complement variations from VRES to fill the gaps in the

generation profile

Since these definitions are made with the electricity system in mind, this thesis may loosely interpret them to fit also the DH system. One of the conclusions drawn in [4] was that VMSs from a specific category can have different effects on the investments in a certain VRES technology depending on if the considered technology is *system-limited* or *resource-limited*. For example, complementing technologies were found to be especially important in regions with resource-limited wind power. A technology is said to be system-limited if its penetration level in the system is high enough to decreases its own marginal value and hence inhibit further investments in the technology. This effect of decreasing its own marginal value happens when there is enough capacity that full, or high, generation changes which generation technology is on the margin (according to the dispatch order). This change in marginal technology necessarily reduces the marginal cost of producing electricity at these hours, and thus reduces the value of the VRES. Furthermore, this effect often leads to curtailment during some hours. A resource-limited technology is instead less competitive, relative to other available technologies, due to the prerequisite conditions. Resource-limited technologies thus do not get enough investments to significantly affect its own marginal value.

An additional form of variation, which is inherently part of the present electricity and heat demands, is the diurnal and seasonal variations. In Sweden, a warm summer night can require less than 11 GWh/h electricity and 2 GWh/h heat while a cold winter day can surpass 26 GWh/h electricity and 15 GWh/h heat. Since the varying demand does not necessarily match any existing variable production (solar or wind), there is an additional cost to the system in satisfying these variations. This cost arises mainly from having to invest in generation capacity which rarely get used. There is thus a value in levelling the demand throughout the year so that smaller capacities can cover the same energy demand through a higher load factor (more full-load hours (FLHs)). This seasonal shift of demand (or production) could for example be achieved through seasonal heat storages combined with power-to-heat technologies, and will be referred to as a '*seasonal* shifting'. An intentional distinction is made from the previously defined 'Shifting technologies' which includes batteries and DSM, typically more short-term strategies used to match the demand and supply at a closer level.

2.1 Thermal energy storage

An important advantage of including the district heating system in the electricity system investment model is the ability to model the use of power-to-heat technologies with and without thermal storage. When the access to intermittent electricity production is high, electric boilers (EBs) and heat pumps (HPs) can activate to *absorb* the excess electricity and convert it to heat. The conventional heat-only boilers (HOB) and combined heat and power (CHP) plants may also operate differently with the ability to store heat. Three types of TES will be included in the model: tank (TTES), pit (PTES) and borehole (BTES) storage. Aquifier TES will not be included due to its specific requirements on local geological formations. Although the included TESs' functions all fit the description of a *shifting technology* in the DH sector, the TTES and PTES (which can be charged and discharged relatively quickly compared to BTES) could also have the effects of *absorbing* and *complementing technologies*. This might be the case in the sense that the TES could absorb/store cheap heat from the summer (e.g. from solar heating or cheap wind peaks) and enable the EB, HP and CHP plants to depend more on the electricity price. The electricity price dependence of CHP and power-to-heat is a central part of how the heating sector can provide flexibility for the electricity system [8, 9]. To the DH sector, the electricity price dependent technologies then become semi-variable, using the TES to complement the variations. This possible effect will be further discussed in Section 4. A brief description of the different TESs follows below.

Tank thermal energy storage (TTES)

TTES is a well-established technology used in both households and some district heating networks [10]. Although commonly used for short-term storage (peak-shaving and domestic warm-water tanks), they can also be used for seasonal storage [11], especially when accompanied by a heat pump. If used with a heat pump, the operational temperature can be significantly lower which increases the capacity of the tank and reduces losses through heat dissipation. The tank can also be placed underground which further reduces losses by using the ground as additional insulation.

Pit thermal energy storage (PTES)

A pit storage is made of a 5-15 m deep artificial pool which can be closed by a lid and store approximately 60-80 kWh/m^3 [11]. The heat is stored in the pit by using either water or a water-gravel mixture as heating medium. PTES is mostly used for long-term heat storage, and in many cases combined with solar heating to provide solar heat for a larger portion of the year. The world's largest PTES (built in Denmark during 2014-2015) has a volume of 200 000 m^3 and can store temperatures up to 95°C [12], with a majority of the heat coming from solar heating.

Borehole thermal energy storage (BTES)

The idea behind BTES is that heat is fed into an array of boreholes and stored in the bedrock/soil. The holes are typically 50-200 m deep [10] and hence avoids seasonal temperature differences which generally has no impact beyond 12 m [13]. Assuming there is no water flow through the ground, the only losses are through conduction and these are reduced by increasing the size of the storage (increasing the volume-to-area ratio). BTES is well suited for seasonal storage, but can be limited by local geological conditions. Although the storage can reach temperatures of up to 80 °C [11], it is generally accompanied by a heat pump to make use of the heat at a sufficient temperature for district heating. One special limitation to BTES is in the charging and discharging rates which are dependent on heat conduction through the ground. This slow heat transfer [14] means that filling and emptying the storage can take months each way.

2.2 Other VMSs and impacts on flexibility

This section includes descriptions of several ways of managing variations in electricity generation and demand, as well as the possibilities and limitations with flexible hydropower and thermal generation. The taxes and fees that affect the electricity usage (e.g. for power-to-heat) are also described. An understanding of the other VMSs is important in order to understand the interactions and roles in the results in chapter 4.

Hydrogen from electrolysis

Hydrogen production via electrolysis is one of the ways that the electricity sector can interact with the transport and industry sectors. This provides flexibility to the electricity system by adding a demand that is not as time-sensitive as traditional electricity consumption. Hydrogen can be produced during hours of low prices and stored to meet future demand in hydrogen vehicles or industry, and thus fits well into the category of an *absorbing* technology. However, as pointed out in [4], hydrogen production in combination with storage could take the role of a complementing technology by increasing the electricity demand except for some hours of high net demand (load minus VRES production). This would in practice be equivalent to generating during the same hours and thus complementing the variable production. Another option is to produce the hydrogen with the purpose of returning the energy to the grid through fuel cells. Currently, the round trip efficiency[1] is however quite low for hydrogen with electrolysis and fuel cells (30%) compared to lithium batteries (90%) [15]. This means that the difference in electricity prices has to be large for hydrogen fuel cells to be profitable as flexibility in the electricity system, and the high investment cost of the electrolysers (and fuel cells) means that a high utilisation is required to pay for the investment. However, if there already is an infrastructure and demand for hydrogen (e.g. in transport or industry), its flexible production could have a significant impact on the profitability and use of VRES.

Demand-side management (DSM)

Although the current mindset is to use electricity whenever we want it with little regard for the electricity price or strains on the system, at least some portion of our electricity consumption can be moved a few hours without having a significant impact on our lives. If consumers had an incentive and the appropriate technology, some load shifting could be achieved in order to reduce peak demand and differences in demand throughout the day. This could also be used to, to some extent, match demand with high VRES production and thus help reduce net demand fluctuations. Many appliances such as the dishwasher, refrigerator/freezer and electric heating or

[1] round trip efficiency: the total efficiency of storing the electricity and then releasing it

heat pumps have some leeway and could be used for DSM. Especially electricity for heating has a large potential in this area, if the temperature in buildings is allowed to vary within some interval. The decision when to run the appliances could either be done by looking at the hourly market prices for the next few hours, or it could be centrally controlled by for example the electricity retailer or system operator.

Dam hydropower as a VMS

In the traditional power system presented in the beginning of this chapter, there is a need for semi-instantaneous responses to changes in load which can be difficult to provide from a nuclear or coal power plant with high mechanical and thermal inertia. Although the mid load power plants can be built to handle such quick changes, it is common that dam hydropower (if available) handles such changes in load due to its easily adjustable output and low variable cost. This potential for hydropower to act as a *complementing* variation management can be especially valuable in a system with a high share of VRES. However, the capacity of hydropower to manage flexibility in the system is limited by factors such as precipitation, dam size, turbine capacity as well as up and down stream environments. In Sweden and especially Norway, hydropower has such a large share of the electricity production that there is less need for other VMS. This flexibility is also partly provided to the rest of northern Europe by transmission of electricity between the countries.

Flexible thermal power

Approximately 80% of the global energy demand is currently satisfied by fossil fuels [16]. To decrease the CO_2 emissions caused by these fuels, different policy instruments may be implemented. Such instruments can be market based (making emissions more expensive) or in the form of regulations (e.g. energy efficiency or technology standards). As a result it can be necessary, or economically preferable, to use more renewable energy sources (RES). During the last decades the use of biomass has increased in Sweden, where a tax on CO_2 emissions was implemented in the early 1990s and an electricity certificate scheme was introduced in 2003 [17]. Being a RES that can be utilised in already well established thermal generation technologies, biomass is a popular alternative to fossil fuels. Since thermal energy is used both for base, mid and peak power production, it does not only constitute an important share of the total energy supply, but also of the flexibility in the system. An increased demand of biomass might increase its cost, and a large-scale use of biomass also implicates environmental issues such as land use change. The resulting limitations on fossil fuels and biomass could increase the importance of VRES to satisfy the energy demand. It also implicates a restricted access to flexible generation in general, and may thus increase the demand for other VMSs.

Electricity tax

For a VMS to be economically viable without other subsidies or programmes, there needs to be enough of a difference in price between high-price and low-price hours.

There also needs to be enough hours of sufficient price difference where the VMS can be active for the profit to offset investments and fixed costs. However, if there is a fee (e.g. tax or transmission fee) to pay for the purchase which is not somehow regained or offset, then the required price difference increases by that same amount. For options such as DSM this has no effect since the same fee is payed regardless (only at a later time), but for storage options where the electricity is purchased and then sold again this could have a significant impairing effect. Figure 2.1 illustrates industry electricity prices in various EU countries and shows the difference between the energy price, which the producer receives, and the total amount which the consumer pays (note that this is for industries so VAT is excluded). In Sweden, use of electricity for the production of energy products (e.g. hydrogen, biogas etc.) is only subject to a network fee and not the electricity tax. However, production of heat for district heating is not exempt of electricity taxes, so heat pumps and electric boilers would suffer an additional 34 €/MWh tax to the network fee of 10 €/MWh [18].

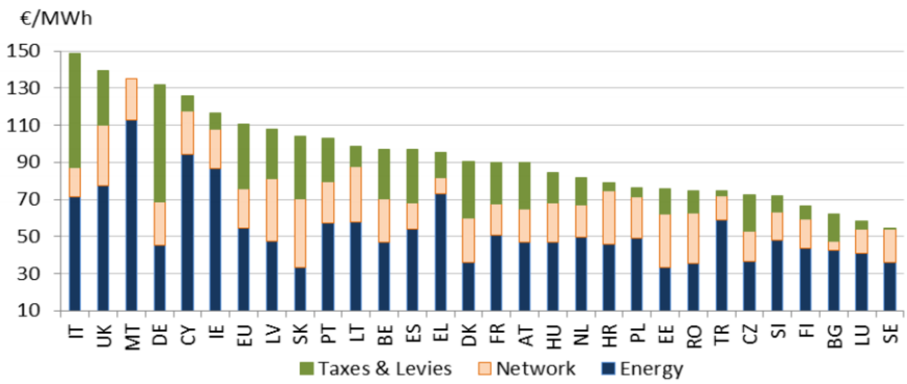

Figure 2.1: Average industry electricity prices in by EU country in 2015. Figure originally by European Commission [19]

3
Methodology and input data

This chapter describes the model used in this thesis and presents input data that has been added to the pre-existing data. Thus, the main focus is on how the district heating system and particularly TES is implemented. Finally, the model scenarios used to answer the questions posed in Section 1.2 are presented along with their specific conditions and settings.

3.1 Energy systems modelling

The model [2] used in this report describes the electricity system in a single region without any inter-regional transmission of electricity. It is a greenfield investment model, meaning that the model builds its own optimal mix[1] of technologies rather than using or expanding from an existing mix. Currently the model is continuously updated in order to fit new studies and contain more refined technologies with realistic properties available for investment. Besides many different electricity production technologies, it contains carbon capture and storage (CCS) technologies, battery and hydrogen storage and the possibility for DSM. It also describes different ways of producing biogas. Each technology have properties such as investment-, operation & maintenance (O&M)-, start-up-, and part load costs, and expected efficiencies for 2050 based on learning curves for the technologies that are not considered well-established. The model package includes wind and solar profiles and area limitations for investment in such technologies in different regions. Restrictions on e.g. hydropower inflow and fuels for thermal production technologies in different countries are also available. Technical and economical data of all technologies can be found in Appendix A.2.

Since the model can be run with hourly temporal resolution (further discussed in Section 3.4), it is suitable for describing the intermittency of renewable energy sources such as wind and solar power. However, the model only contains an oversimplified representation of how the DH system is connected to the electricity system – a value of produced heat is assumed and represented by a negative operational cost for heat pumps HPs and EBs. It can thus be considered insufficient for describing a scenario where excess electricity is used to produce heat for storage or direct use. To analyse the effects of the DH system and investments in heat storage capacity on the electricity system, a more detailed representation of the DH system is added to the model. The DH system is represented by type systems according to Section 3.2,

[1]Hydropower is the exception, due to its unique properties and environmental limitations

each of which is assigned a set of available technologies. Technologies such as HOBs and different types of TES are added, while a better representation of EBs, HPs and CHPs plants are implemented in the technological properties and load constraints.

Below follows a simplified mathematical description of the model, starting with a list of notations.

Table 3.1: Sets, parameters and variables used in the model

Sets	
I	Electricity production technologies
J	Heat production technologies
K	Type systems
L	Heat storage technologies
T	Timesteps

Parameters	
C_{inv}	Annualized investment cost and fix O&M costs [€/kW]
C_{run}	Running cost (variable O&M and fuel cost) [€/MWh]
D^{el}	Electricity demand [MWh/h]
D^{h}	Heat demand [MWh/h]
α	Power to heat ratio for CHP
η	Efficiency
γ	Loss factor (share of stored energy)
γ_c	Constant-loss factor (share of storage capacity)
COP	Coefficient of performance (for heat pumps)
C_f	C-factor (maximum charging rate, share of storage capacity)

Variables	
p	Generated electricity[MWh/h]
q	Generated heat [MWh/h]
s	Investment [kW]
r	Total amount of stored heat [MWh]
z^{ch}	Heat charged into storage [MWh/h]
z^{dis}	Heat discharged from storage [MWh/h]
c_{cycl}	Cycling cost [€][1]
c_{tot}	Total system cost (objective value) [€/year]

[1] The determination of this variable is described in [1].

The objective function to be minimised is the total system cost for one year, including running costs and investment costs. For the electricity system, this looks as follows.

$$c_{tot} = \sum_{i \in I} \left(C_{inv}(i)s(i) + \sum_{t \in T} (C_{run}(i,t)p(i,t) + c_{cycl}(i,t)) \right) \tag{3.1}$$

The first constraint ensures that the electricity demand is satisfied for every timestep:

$$\sum_{i \in I} p(i,t) \geq D^{el}(t), \quad t \in T \tag{3.2}$$

where $D^{el}(t)$ is the electricity demand for hour t. The model also contains several other constraints concerning for example carbon dioxide emissions and intermittency of renewables. Mathematical descriptions of the electricity system model including e.g. part-load and emissions constraints [1] and the implementation of demand side management (DSM) and batteries [4] have previously been made by Göransson et al.

When adding investment and running costs for heat production and storage, the objective function can be modified according to

$$c_{tot} = \sum_{i\in I}\left(C_{inv}(i)s(i) + \sum_{t\in T}(C_{run}(i,t)p(i,t) + c_{cycl}(i,t))\right) +$$
$$\sum_{k\in K}\left(\sum_{j\in J\setminus J_{CHP}}\left(C_{inv}(j)s(k,j)+\sum_{t\in T}(C_{run}(j,t)q(j,t)+c_{cycl}(j,t))\right)+\sum_{l\in L}C_{inv}(l)s(k,l)\right) \tag{3.1'}$$

The demand constraint (3.2) also needs to be modified to take electricity for heat production into account. The new constraint can be formulated as

$$\sum_{i\in I}p(i,t) \geq D^{el}(t) + \sum_{k\in K}\left(\frac{q(k,EB,t)}{\eta_{EB}} + \sum_{j\in J_{HP}}\frac{q(k,j,t)}{COP(j)}\right), \quad t\in T \tag{3.2'}$$

where J_{HP} is a subset of J consisting of all heat pumps, including those used for discharging the thermal energy storages. Regarding the CHP plants, the sets I and J is overlapping, hence for the subsets of CHP plants we have that $I_{CHP} = J_{CHP}$, and J_{CHP} is excluded from the objective function (3.1'). For the production it holds that

$$\frac{p(i,t)}{q(j,t)} = \alpha(i), \quad \text{for } i\in I_{CHP},\ j\in J_{CHP}, \quad i=j, \quad t\in T \tag{3.3}$$

Similar to the electricity system, the district heating system also needs constraints for heat demand and capacity of generation and storage. With the amount of heat to and from storage $z^{ch}(l,t)$ and $z^{dis}(l,t)$, respectively, and the stored amount $r(l,t)$ for storage alternative l at time t, we have that

$$D^h(k,t) + \sum_{l\in L}z^{ch}(k,l,t) \leq \sum_{j\in J}q(k,j,t) + z^{dis}(k,TES_{nonHP},t), \tag{3.4}$$
$$k\in K,\ t\in T$$
$$0 \leq q(k,j,t) \leq s(k,j), \quad k\in K,\ j\in J,\ t\in T \tag{3.5}$$
$$r(k,l,t) = r(k,l,t-1)(1-\gamma(l)) + \eta_{ch}z^{ch}(k,l,t) - z^{dis}(k,l,t) - \gamma_c(l)s(k,l), \tag{3.6}$$
$$k\in K,\ l\in L,\ t\in T$$
$$0 \leq r(k,l,t) \leq s(k,l), \quad k\in K,\ l\in L,\ t\in T \tag{3.7}$$
$$z(k,l,t) \leq C_f(l)s(k,l), \quad k\in K,\ l\in L,\ t\in T \tag{3.8}$$
$$q(k,HP_{TES},t) \leq z^{dis}(k,l,t)\left(1+\frac{1}{COP(HP_{TES})-1}\right), \tag{3.9}$$
$$k\in K,\ l\in L\setminus TES_{nonHP},\ t\in T$$

The first equation describes the heat demand balance i.e., that the sum of the demand and stored heat must be lower than the sum of produced heat and heat discharged from storages. The discharged heat from the TESs with HPs is accounted for in the summation over J in Equation (3.4), since J includes all HPs. The last term in equation (3.6) describes the hourly constant losses for a TES without heat pump. For other TESs, $\gamma_c(l)$ is zero. Equation (3.8) describes how much heat that can be charged or discharged during one hour depending on the storage capacity. Equation (3.9) ensures that the heat discharged from the storage corresponds to the heat pump output[2], and HP_{TES} represents the heat pump that is connected to TES l.

3.2 District heating type systems

In a district heating (DH) system, heat is generated centrally and distributed to consumers, usually with hot water as the energy carrier. This central production enables higher efficiencies and lower fuel cost for heat generation but also utilisation of excess heat from industries. Compared to electricity however, the distribution range of district heating is more limited and require higher investments and larger space [20]. Thus, the possible economic benefits of DH are heavily dependent on the distance to consumers and the consumer density in nearby areas. This leads to a large amount of isolated networks of different sizes. The description of the DH system in a large region then needs to separate densely populated cities from rural areas, since they have different potentials of using heating technologies. This is done by implementing *type systems* in the model.

In a Master's thesis by Goop [21], several different type systems are defined to represent different DH systems in Sweden, Finland and Denmark. The type systems were constructed from statistics concerning the countries' various DH systems, and the presented production level of each system is an average of the real systems of that type. Goop has defined four type systems for Denmark and six for Finland and Sweden, where some represent the DH-network in specific (large) cities while others represent generic or average networks of some size. In this thesis, the main interest is to separate small towns, where large plants are unrealistic, from larger cities and more densely populated areas. Therefore the type systems defined by Goop are aggregated to define type systems according to size: A (small), B (medium) and C (large), and are used to determine the production technologies available. The technologies available are also separated into sizes to represent the differences in specific costs and efficiencies between large and small plants. The total heat demand is then split into the different type systems which each has to fulfil the heat balance independently.

While Goop's type systems are designed for the entire country, the model used here

[2]This equation is correct, but an error in the code made the right side of the equation a factor COP too large in the model. The TES investments have thus in this thesis, through the required HP sizes, been too cheap.

divides Sweden into four electricity price regions, where only one of them (SE2[3]) is used in this thesis. It is assumed that all price regions have the same relative allocation of type systems (20% A, 49 % B and 31 % C). Since SE2 covers the area in the middle of Sweden including Stockholm and Gothenburg, this assumption may result in a larger share of energy demand in type system A (small towns) than in reality. Due to lack of heat demand data it is also assumed that the heat demand allocation between price regions is the same as the electricity demand allocation, which may result in a slightly warped combination of heat and electricity demand. Furthermore, to get a realistic heat demand curve for the model, the hourly heat production by Göteborg Energi in 2012 is used, and scaled to sum up to the total annual demand in the price region.

3.3 District heating technologies

Each (aggregated) type system described above has access to several DH production technologies, also determined by Goop [21]. Since the same technologies of several sizes are used in this thesis, most of their properties are also taken from Goop. However, the model used in this thesis only contains three type systems and thereby no more than three different plant sizes. In the cases where Goop has four different sizes, an average of the properties for the sizes in the same (aggregated) type systems are calculated. Since the costs are given in SEK, they are recalculated to EUR according to the exchange rate on February 22, 2018, when 1 EUR = 10 SEK.

The production technologies are also separated in the model based on which fuel they use, as shown in Tables 3.2 and 3.3. Biogas HOB is however assumed to have the same properties as the natural gas (NG) HOB. The HOBs and CHPs driven by biomass and coal have three different sizes (can be used in all type systems), as have the heat pumps. The oil-driven HOB has the same size in all type systems, while technologies fuelled by natural gas and the oil CHP can only be used in the densely populated type system. Waste HOB and CHP, and biogas HOB can not be used in the type system representing rural areas (A). From Tables 3.2 and 3.3, one can see that it is also assumed that a DH type system only invest in the largest applicable size of a technology. In reality, smaller boilers and CHP plants can be used also in larger cities. In this model however, only the costs separates the different technology sizes. Since all investments are described on a system level and the model does not consider separate plants or cities, it will always invest in the technology with the cheapest average costs (larger size).

One DH production technology not included in Goop's thesis is also added, namely solar heating. This is assumed to be applicable in all type systems at the same cost due to the modularity of solar collectors. For commercial applications of this technology, the investment cost is estimated to 154 €/m^2 [22]. Assuming an effect

[3] approximately the same region which Nordpool calls "SE3"

Table 3.2: Costs, efficiencies [21] and minimum load [22, 23] for heat production technologies, and in which type systems they are intended to be used. Since minimum load data for coal and oil plants are missing, they are assumed to be the same as for biomass plants. Listed η for HPs is the COP.

Technology	Inv. cost [€/kW_h]	Fix O&M [€/kW_h]	Var. O&M [€/MWh_h]	η [%]	Min. load [%]	Type system
HOB, bio (small)	860	10.7	2	95	25	A
HOB, bio (medium)	800	10	2	95	25	B
HOB, bio (large)	730	9.1	2	95	25	C
HOB, coal (small)	860	10.7	2	90	25	A
HOB, coal (medium)	800	10	2	90	25	B
HOB, coal (large)	730	9.1	2	90	25	C
HOB, waste (medium)	1320	40	4	90	75	B
HOB, waste (large)	1200	36	4	90	75	C
HOB, biogas	400	2.5	1.5	92	15	B, C
HOB, NG	400	2.5	1.5	92	15	C
HOB, oil	400	2.5	1.5	90	25	A, B, C
EB	100	1.5	1	95	5	A, B, C
Solar collector	220	0	0.57	100[1]	0	A, B, C
Heat pump (small)	800	8	1	300	0	A
Heat pump (medium)	700	7	1	300	0	B
Heat pump (large)	600	6	1	300	0	C

[1] the real efficiency is part of the assumption of heat output per area

of 700 W/m^2 [24], this results in an investment cost of 220 €/kW[4]. Due to lack of data, the fix O&M cost is assumed to be non-existing while the variable O&M cost is assumed to be the same as in [22], 0.57 €/MWh. The variation in heat generation is represented by the solar insolation profile that is already included in the model and used for solar PVs.

While the model already had the ability to produce hydrogen from electrolysis and

[4]The investment cost of solar collectors without heat storage. When implementing the model scenarios in this thesis, the cost of solar heating including diurnal heat storage (171 €/m^2 or 244 €/kW) was erroneously used.

also convert it back to electricity by using fuel cells (FCs), it has not been possible to utilise the excess heat from these processes. This is now included in the model, and the excess heat is assumed to be free, but available only in the largest type system, C. The usable heat is assumed to be 18% of the electric energy for PEM electrolysis and 35% of the hydrogen energy input to FCs [22].

Table 3.3: Costs, efficiencies, power-to-heat ratios [21] and minimum load [22, 23] for CHP plants, as well as which type systems they are intended to be used in. Since minimum load data for coal and oil plants are missing, they are assumed to be the same as for biomass plants.

Technology	Inv. cost [€/kW$_e$]	Fix O&M [€/kW$_e$]	Var. O&M [€/MWh$_e$]	η [%]	α [-]	Min. load [%]	Type system
CHP, bio (small)	5650	125	9.2	25	0.32	40	A
CHP, bio (medium)	3975	75	9.2	29.5	0.39	40	B
CHP, bio (large)	2550	38	8.7	33	0.43	40	C
CHP, coal (small)	4270	95	8.8	25	0.38	40	A
CHP, coal (medium)	2980	56.5	8.85	29	0.45	40	B
CHP, coal (large)	1830	27	8.6	32	0.56	40	C
CHP, waste (medium)	7700	220	28	20	0.26	75	B
CHP, waste (large)	6000	150	28	20	0.26	75	C
CHP, NG	950	20	1.6	52.5	1.3	32	C
CHP, oil	1100	16.5	4	30	0.5	40	C

All fuels used for energy production and their properties such as price and CO_2 emissions were already included in the model before the work of this thesis, and can be found in Appendix A.2. Some of these fuels (such as waste, biomass and lignite) are limited by regional availability. Naturally, waste as a fuel is limited by household habits in Sweden and other countries from which waste is currently imported. Biomass is instead restricted by available land area. The fuel limitations for Sweden are assumed to be 138 TWh/year of biomass according to an estimate by WWF [25] and 12.41 TWh/year of waste according to the preexisting input data.[5]. Although biomass may also be used in e.g. the transportation sector, it is assumed here that the whole amount is available for heat and electricity generation. The different price areas in a country are then assigned resources according to their share of the electricity demand. Since it is not viable to store large amounts of waste for

[5]Approximately 4.6 million tonnes of waste was utilised in 2015 [26] which, assuming a LHV of 3 MWh/tonne [27], results in 13.8 TWh i.e., a bit more than the assumed amount

a long time, a constraint in the model also states that an equal amount of waste has to be consumed every month (for each region).

Investment costs for the investigated TES are primarily taken from a collection of specific costs for seasonal storage projects by Solites [28]. The collection includes storages from 300 m^3 to 75000 m^3 and specifies the cost per cubic meter of water equivalent including planning and instalment but excluding heat pumps and VAT. The data is presented in a graph (Figure 2.10 in [28]) to illustrate the size-dependency of the specific cost. Because of this size-dependency, some data points of appropriate size and technology were chosen to represent the TES in the model, which are shown in Table 3.4 with the resulting costs.

There are also technical limitations to how quickly a storage can be filled and emptied. In addition to discharging being limited by the accompanying heat pump, a C-factor (charging factor) is multiplied with the storage size to set an upper limit on charging and discharging rate. TTES is assumed to have a minimum (dis)charging time of six hours (if the whole storage is emptied), corresponding to a C-factor of 1/6. Six hours was chosen since this allows the storage to manage daily variations in heat load. PTES, which generally are much larger in size, is instead assumed to have a C-factor of 1/24. However, the borehole storage is limited by the conductive heat transfer in the ground which would depend on soil/rock type and borehole configuration. Here, an upper limit on the extraction and injection rate of 70 W/m borehole depth [14] is assumed. This is then combined with borehole data [29] from the site in Crailsheim to get a C-factor in the range of 1/3000 to 1/3500, which also is what the Crailsheim heat pump capacity to storage size results in (1/3300). The BTES C-factor is thus implemented as 1/3000, and further analysed in the sensitivity analysis along with the other C-factors.

All operational and maintenance costs for the TES are neglected, but the heat pumps used for each TES has an investment and O&M cost according to 'Heat pump (*TES size*)' in Table 3.2. However, the COP is increased from 3 to 6 for TTES and PTES and 5.5 for BTES which is limited to lower temperatures. Furthermore, the heat capacity of the TTES and PTES is assumed to be 80 kWh/m^3 [30], while data specific to Crailsheim [29] is used for the BTES. Coincidentally, this results in 30 kWh/m^3 which is the upper limit for BTES in [30]. There is little data to be used for the losses from each TES type, but a thesis in 2009 [31] calculated a 1% loss per 10 days for a 40000 m^3 tank with 400 mm insulation. A review of seasonal TES from 2017 [32] found BTES to have a lower energy recovery than hot water TES, meaning that a higher portion of the injected energy is lost in the case of BTES. However, due to differences in the number of annual cycles, this does not necessarily mean that the hourly loss per stored energy is higher for BTES. As such, a loss of 1% per 10 days will be used for all TES and then further studied in the sensitivity analysis.

In addition to the other storages, a tank without heat pump is also included. This tank can charge and discharge without being limited by the heat pump capacity, with the drawback of a higher investment cost. The higher investment cost comes from the higher storage temperature required to operate without a heat pump, which narrows the total temperature range of the stored water. Instead of an interval of roughly 69 °C which 80 kWh/m^3 represents, this tank is limited to 15 °C to stay between the DH temperature and the boiling point. The investment cost of the tank without HP has thus been increased by a factor of 4.6. However, this increased minimum temperature also affects the losses in the sense that a simple $Q_{losses} = k * Q_{stored}$ no longer describes the losses well at low storage levels (see Appendix A.1 for more details). Instead, the losses for the tank without heat pump is described as $Q_{losses} = K + k * Q_{stored}$ for a K such that the losses are the same for both tanks when at the same temperature.

Table 3.4: TES types and investment costs. The TTES without HP is based on Tank (small) but more expensive due to the narrower temperature range.

TES type	Inv. cost [€/MWh]	Inv. cost 2050 [€/MWh]	Data point in source [28]	Size [m³]	Specific cost [€/m³]	Type system
Tank (no HP)	26165	26165	-	-	455	A,B,C
Tank (small)	5688	5688	Rottweil	600	455	A
Borehole (medium)	533	457	Crailsheim	10000	60	B,C
Pit (medium)	1000	857	Marstal	10000	80	B
Pit (large)	313	268	Marstal-2	75000	25	C

3.4 Model scenarios

In order to answer the questions posed in Section 1.2, several scenarios are implemented and analysed in three parts. The *system scenarios* compares the effects of TES under different conditions concerning fuels and energy production technologies. In the *TES scenarios*, different types of TES are made available in order to examine their different roles relative to each other. The *VMS scenarios* includes different combinations of VMS to enable analysis of their interaction with TES. All scenarios include VMS possibilities such as battery and hydrogen storage, while the DSM level generally is set to zero. In the subsection below are description of each scenario in the three groups.

The categorisation into *system* and *VMS* scenarios can be questioned since energy production technologies also can be VMSs. However, to separate the different questions and analyses, and to present the results in a clear way, this categorisation is considered the most appropriate. While the main purpose of energy production technologies is to fulfil the electricity and heat demand, storage technologies exist only for variation management purposes.

All scenarios are implemented with a resolution of every third hour in order to improve the run-time of the model. The time it takes to run the model with an hourly resolution is considerably higher than with a resolution of every third hour. Moreover, the differences in the results are expected to be negligible for all purposes of this thesis. The sensitivity analysis will compare some results with different temporal resolutions.

3.4.1 System scenarios

In the system scenarios, each scenario has different limitations that concerns available technologies and fuels. The interaction between the sectors is also examined by including a scenario with the electricity system only. All system scenarios are summarised in Table 3.5 and each of them are implemented with and without access to TES.

When the CO_2 emissions restriction is implemented, the limit is set to zero. This constraint can be fulfilled either by using renewable technologies only, or by combining fossil fuels with bio energy[6] CCS (BECCS) or biogas CCS (WGCCS). In this thesis, BECCS and WGCCS are not allowed in most scenarios in order to promote the use of RES. Since waste incineration may be preferred over landfilling for environmental purposes, zero emissions from waste is assumed in this model in order to allow utilisation of waste energy even if no CO_2 emissions are allowed. In the scenarios with higher biomass cost, a cost of 80 €/MWh is used instead of 30 €/MWh.

Table 3.5: Summary of the included parameters for each system scenario

Scenario	1	2	3	4	5	6	7	8
DH		x	x	x	x	x	x	x
CO_2 limit	x	x		x	x	x	x	x
Taxes+Fees				x				
BECCS					x			
10% hydro						x		x
High bio cost							x	x
No waste							x	x

Electricity only (1)

The first scenario describes the electricity system only. This means that there is no heat demand, and also no economic compensation for producing heat. The purpose of this scenario is mainly to gauge the effects of adding power-to-heat so that the effects of other scenarios and VMSs can be compared to this. It should be noted that although power-to-heat and DSM isn't available, even this electricity-only scenario

[6]although 'bio energy' could be either biomass or biogas, BECCS uses biomass in this thesis

has the option of investing in batteries, hydrogen and net zero[7] emissions CCS if optimal.

Base case (2)

This scenario includes the district heating system and will be regarded as the base case throughout the rest of the thesis. By including the DH system, this scenario should have a decent amount of flexibility through power-to-heat, CHP and heat storage. From this base level, various parameters and VMS will be included or restricted to test the effects from DH and TES in different circumstances.

CO_2 emissions allowed (3)

In this scenario, the zero CO_2 emissions constraint is excluded. The system can then use technologies driven by fossil fuels, if it is economically preferable. The technology mix in this scenario is likely to contain less VRES and more emitting base load technologies, which makes it an interesting case for comparing the effects of TES.

Electricity taxes and fees (4)

In Sweden, producers of heat using electricity currently need to pay an electricity tax of 34 €/MWh. Also, when using electricity from the grid, there is a network fee of 10 €/MWh (see Section 2.2). These additional costs are now implemented in the model with the expectation that the interaction between the sectors and hence the effects of TES will decrease.

BECCS (5)

Instead of only using carbon-neutral technologies, this scenario allows for fossil fuelled technologies if the emissions are compensated for with biomass or biogas CCS. Cheaper fuel would generally have the greatest impact on technologies with the most FLH but since the amount of fuel is limited by the BECCS use, this may not be the case.

Less hydro (6)

All simulations for this thesis are made with conditions that represent a part of Sweden, which has a significantly larger amount of hydropower than most countries. Hydropower is both cheap, renewable and flexible, which makes it easier to achieve a renewable energy system. This scenario, with only 10% of the usually available water resources and capacity, examines how TES affects a system that does not have the same unique conditions as the Nordic countries regarding hydropower.

[7]GWG (biogas and natural gas mix) and HW (coal and biomass mix) are mixed in such a way that their total CO_2 emissions are zero in CCS

High biomass cost and no waste (7)

Currently, the Swedish energy system has access to a relatively large amount of waste due to low landfill usage and waste importation from surrounding countries. Because of the large forest-covered areas in the country, the availability of fuel wood is also high. These fuels are quite cheap and can be used in CHP plants, condensing plants (biomass) or heat only boilers. However, approximately 50% of the waste used in Sweden today is imported [26]. If other countries would start utilising their own waste or if the recycling would increase (which is also an important factor in creating a better environment), a significant part of this fuel would have to be replaced in Sweden. Regarding biomass, several sectors (but especially transportation) are interested in utilising this fuel to become more environmentally friendly. How this will affect the fuel cost in the future is highly uncertain. Therefore, the model has no access to waste in this scenario, and the cost of biomass is increased from 30 to 80 €/MWh to represent possible conditions. This will also test the role of CHP plants since this scenario should have less of them.

Less hydro, high biomass cost and no waste (8)

This scenarios difference from the base case is a combination of the two previous scenarios, with 10% of the usual hydropower, a biomass cost of 80 €/MWh and no access to waste. This represents a system without the special conditions in Sweden (cheap and available waste, bio and hydropower). It also makes VRES considerably more important to satisfy the energy demand. This is in turn expected to make TES more important as a VMS for the electricity sector.

3.4.2 TES scenarios

In the TES scenarios, different types of thermal energy storages are made available in order to examine their roles and interactions with each other. The scenarios are summarised in Table 3.6. The first scenario (1) is the base case i.e., system scenario 2, with all TES included. The rest of the scenarios include different combinations of the storage types allowed in the larger type systems B and C (TTES without HP, PTES and BTES). The scenario with all TES types except BTES is excluded since the model does not invest in BTES in the base case.

In type system A, the only TES types allowed are TTES with and without heat pumps. As can be seen in Table 3.6, TTES with HP is only excluded from the model in one scenario. Also, when a TES type is included, it exists in all type systems where it is allowed to be used according to Table 3.4. In the DH sector as a whole, there are more possible TES combinations that could have different impacts on the electricity system. However, since the purpose of these scenarios is to examine the roles of different TES types, and how they interact with each other within a DH type system, those combinations are not investigated.

Table 3.6: Summary of the included TES types for each TES scenario

Scenario	1	2	3	4	5	6
TTES	x		x	x	x	x
TTES no HP	x	x			x	
PTES	x		x			x
BTES	x			x	x	x

3.4.3 VMS scenarios

This group of scenarios examines how TES interacts with other VMS, namely DSM and hydrogen storage. The VMS scenarios are based on system scenarios 2 and 8, which are the base case and the scenario with the least flexibility, respectively. Since flexible electricity production technologies also work as complementing VMSs, it is interesting to examine the effects of DSM and hydrogen storage when these technologies are limited. The scenarios are furthermore implemented with the VMSs included both separately and combined. Similar to the system scenarios, the VMS scenarios are implemented with and without TES. Battery storage is always available for investment and not included specifically in the VMS scenarios since it rarely is cost-optimal in the investigated system.

When DSM is allowed, it means that up to 20% of the hourly electricity demand can be delayed for a maximum of 12 hours. As mentioned in Section 3.1, the model have so far always had the possibility of investing in hydrogen production and storage capacity, but most often does not. To examine the interaction between hydrogen storage and TES, an industrial demand of hydrogen is included in all VMS scenarios, and the storage possibilities are excluded in all scenarios except those that specifically examine H_2 storage. The hydrogen demand corresponds to 20% of the electricity demand and an equal amount of hydrogen needs to be supplied during each time step. Also, the electricity demand for other purposes than electrolysis is reduced by the same amount which it takes to produce the hydrogen.

4 Results and discussion

The results will be presented in three parts. The first part will use the *system scenarios* presented in Table 3.5 to look at changes in optimal investments and operation when the DH sector, consisting of three different type systems, is connected to the electricity system. The different type systems A, B and C represent sparsely populated areas, medium-sized towns and densely populated large cities, respectively. The first section will also include the effects of adding TES to systems with different conditions for waste, bio and hydropower use. The second part will use the *TES scenarios* to explore how the different TESs each affect the electricity and DH systems and if they can be likened to the roles that other VMS can be categorised into (as explained in the beginning of Section 2). Lastly, the third part will look at the interactions between TES and other VMSs through the *VMS scenarios*.

Note that due to an error in the model (see footnote in section 3.1), the accompanying heat pumps for TES have only needed to invest in a capacity corresponding to the electricity input. This leads to an investment cost that is too low by a factor COP. Hence the obtained effect of the TESs with HPs in this thesis are greatly amplified - discharge from these TESs should not be able to outcompete the regular HP (or other technologies) to the same extent since the costs should be the same and only the COP would differ. The principal behaviour of each TES is however quite accurate in this report, compared to additional model runs with the correct equations.

4.1 District heating and TES

The cost-optimal installed capacities for each of the *system scenarios* with and without TES can be seen in Figure 4.1. As can be seen by comparing scenario 1 to scenario 2 without TES, the addition of the district heating system has a significant effect on the curtailment of wind (12 to 6%), but no large changes to the system composition as a whole. Some wind power capacity is offset by the added CHP capacity, but the total energy from wind power is increased due to the lower curtailment. The addition of CHP plants mainly replaces the biogas power ('WG' in the figures) from scenario 1.

Including TES in the model has some significant effects on the system. In general, the effects that can be seen across all system scenarios is that (i) the installed wind capacity increases while (ii) curtailment is reduced and (iii) the number of FLHs is increased, especially for bio CHP. Already when DH is added to the model, a significant level of *absorbing* VMS is made available in the electricity system through power-to-heat and the operational flexibility between CHP versus power-to-heat. Although TES affects the system in several ways, it clearly amplifies the absorbing effect of power-to-heat by acting as a *shifting* VMS in the DH sector, allowing the heat production to exceed the heat demand at times. To the electricity system, this means that TES has the role of an *absorbing* technology which contributes to both (i) increased wind capacity and (ii) reduced curtailment. It also has a clear effect on the operation of the marginal heat producing technology in the sense that there often is little reason to run a technology at part load. For power-to-heat technologies, the electricity price either is low enough that the storage should be filled, or the price is high enough that the storage should be used as a supply. For CHP plants, the same principle applies regarding whether the electricity output is needed or not. This disconnection from the hourly heat demand is directly responsible for (iii) the increase in FLHs, and can be regarded as TES *complementing* the production units in the DH system. These effects will be exemplified by an examination of the system scenarios, starting with a thorough explanation of the investments and generation in the base case (2).

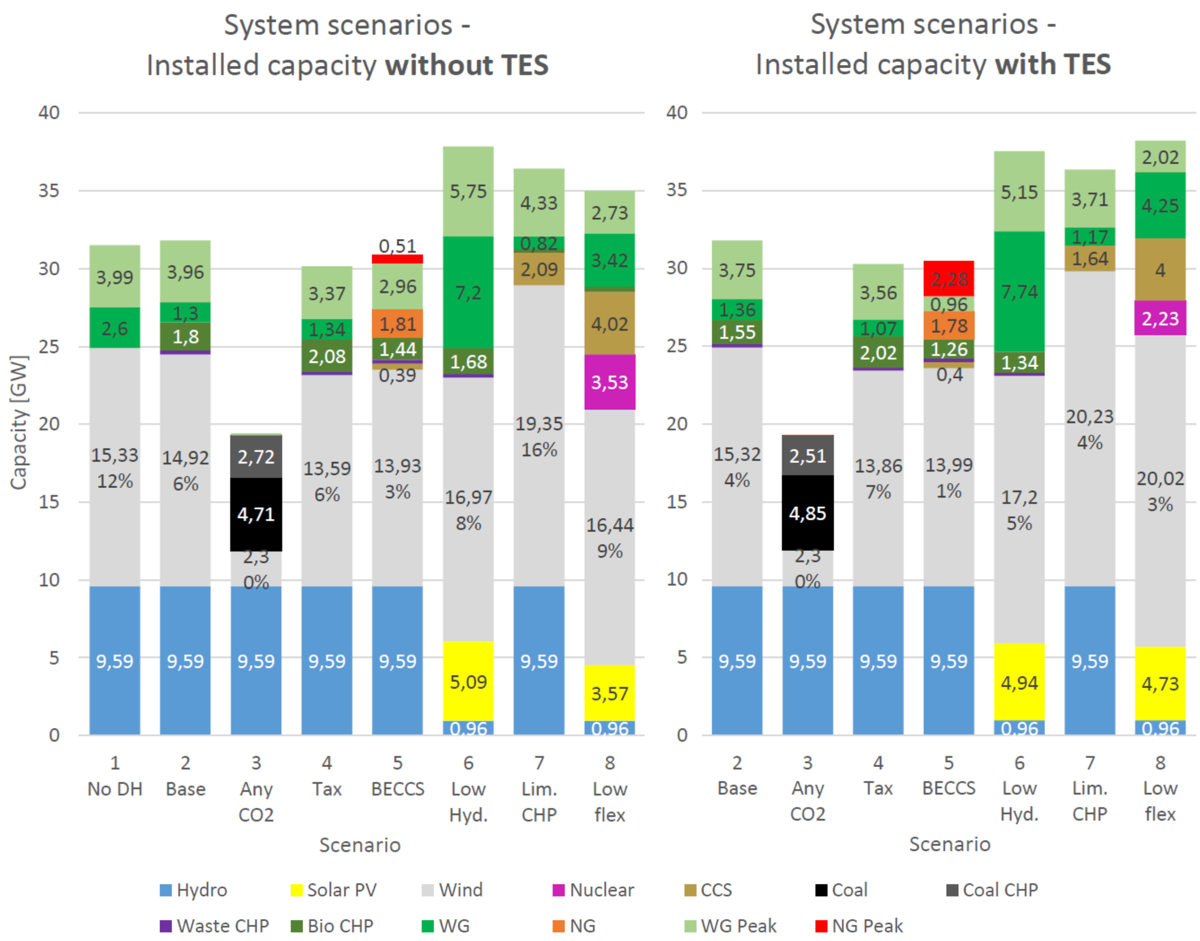

Figure 4.1: Cost-optimal capacities in the *system scenarios*. Data labels have been omitted for capacities smaller than 1% of the total capacity in that scenario, and the numbers underneath the wind capacities is the curtailed wind energy per year.

Comparing scenario 2 with and without TES in Figure 4.1, one can see that the investment in wind capacity increases with TES while the curtailed wind share is considerably smaller. The investments in bio CHP and biogas peak power have also decreased. This can be explained by examination of the heat generation curves in Figures 4.2 (the accompanying electricity production curves is found in Figure A.1, Appendix A.3). In DH type system A, which is mainly supplied by heat pumps, it is possible to see that the over-production of these technologies during hours with relatively low demand coincides with wind peaks in the electricity sector. The resulting excess heat is stored in the non-HP TTES and used during less windy hours in the near future.

Looking instead at type system C in scenario 2, Figure 4.2, the base load during summer is supplied by the waste HOB. This is mainly due to the regional restriction that an equal amount of waste needs to be used every month, and the lower electricity demand in the summer results in less production from the waste CHP in type system B. In addition to the waste HOB, type system C with TES also has a more uniform production of heat from electricity during the summer. As can be

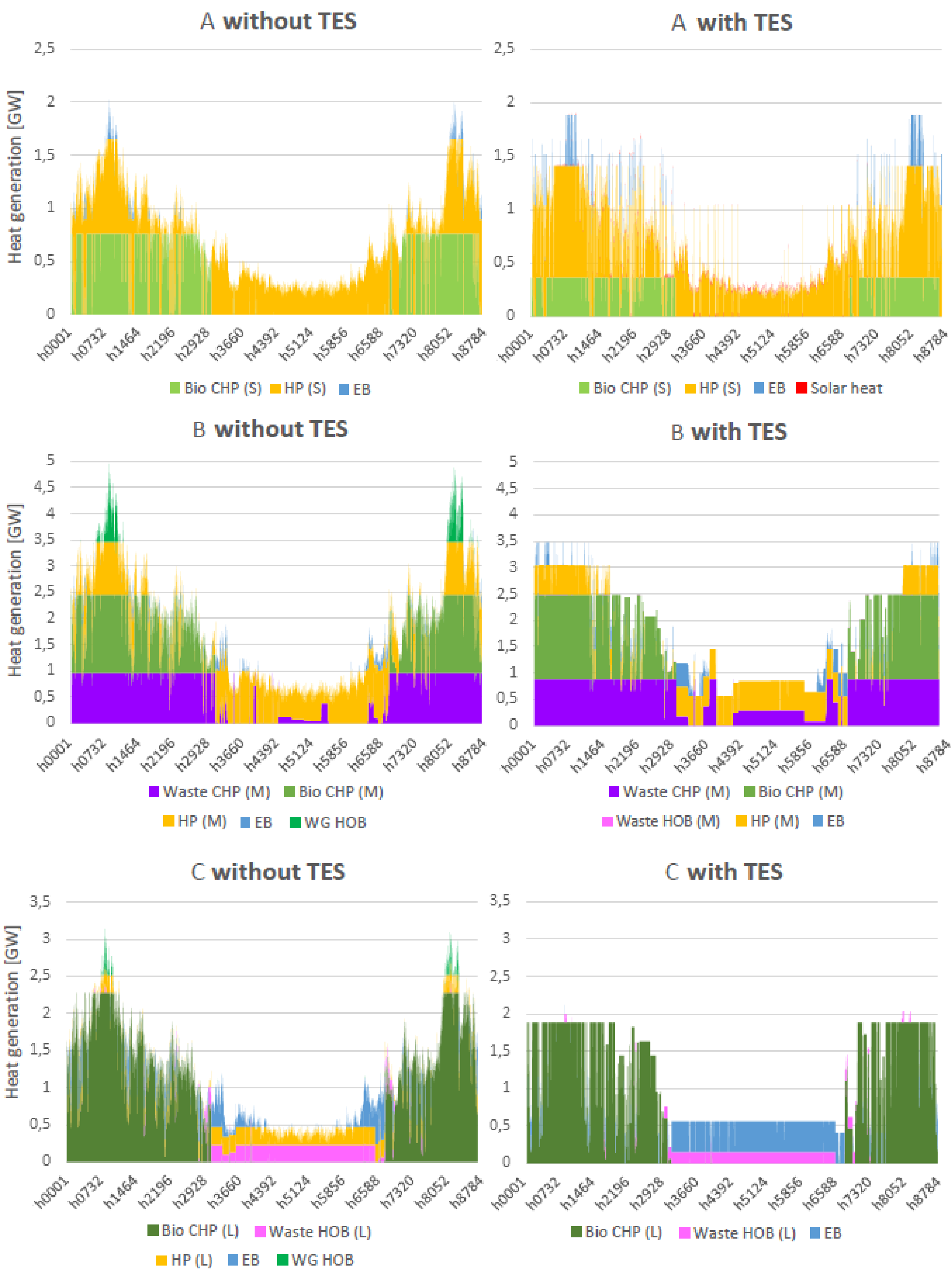

Figure 4.2: Heat generation for system scenario 2 in all DH type systems with and without TES. (S), (M) and (L) refers to plant sizes, as described in section 3.3. Figure A.3, Appendix A.3, shows the same graph but including TES net discharge.

seen by comparison to the case without TES, this results in an over-production of heat which is stored in the PTES. This stored heat is then released in the autumn before the CHP plants start.

Another interesting observation that is made most clear in type system C concerns the generation of the (biomass) CHP plants. In the case with no heat storage available, the generation of the CHP plants is during most hours adjusted to the heat demand, even though a small over-production occurs in some hours (see Figure 4.3). When TES is included however, the generation patterns of the CHPs depend almost exclusively on the electricity sector. They then have an even production at full capacity as long as there is a demand for electricity, and in winter time they lower their production only during wind peaks. In the DH sector, this uniform CHP production is redistributed by the pit storages in type systems B and C where stored heat is discharged during peak demand in the winter. Also, the investments in CHP capacity decreases, which is compensated for in the electricity system by increasing the capacity of biogas power. By examining the difference between the aggregated capacities of bio fuelled technologies versus wind power in the base case with and without TES, one can also see that the reduction of CHP capacity is compensated for by more investment in wind power.

In Figure 4.2 one can clearly see that the peak production units in the DH sector are affected the most by adding TES to the system. The biogas HOB is completely excluded, and the HP also vanishes from system C. Since the CHPs are less beneficial in smaller sizes, their share of capacity is lower in type systems A and B than in C. The higher investment cost but low running cost is why the CHP has a relatively even production already without TES in these type systems, which in turn is why the HP is more affected than the CHP in system B when TES is included. With TES, type system B also gets a higher electric boiler capacity, which makes it possible to utilise some wind peaks like in type system A, although this mainly happens during winter. To summarise, type system B, which consumes the highest amount of energy, is affected similarly to both system A and system C by making TES available.

The only case for which TES does not increase the wind capacity investments is scenario 3, where CO_2-emissions are allowed. In this case, the wind capacity is considerably smaller than for the other scenarios due to the access to cheap coal-fuelled base technologies, and there is no wind curtailment. In contrast to other system scenarios, wind power thus appears to be *resource-limited*. When adding TES to the model, the wind capacity remains *exactly* the same. This agrees with the conclusion drawn by Göransson and Johansson [4], namely that only *complementing* strategies increases cost-optimal investments in resource-limited wind power. This conclusion is supported by running scenario 3 with only 10% hydropower, which decreases the wind capacity. As explained in the previous paragraph, TES only has *absorbing* effects on the electricity system which explains the otherwise unique wind capacity results in scenario 3. In the DH type system C, scenario 3 was also unique in how the CHP already ran according to the electricity demand even without TES. This can be seen in the difference between the CHP operation between scenarios 2 and

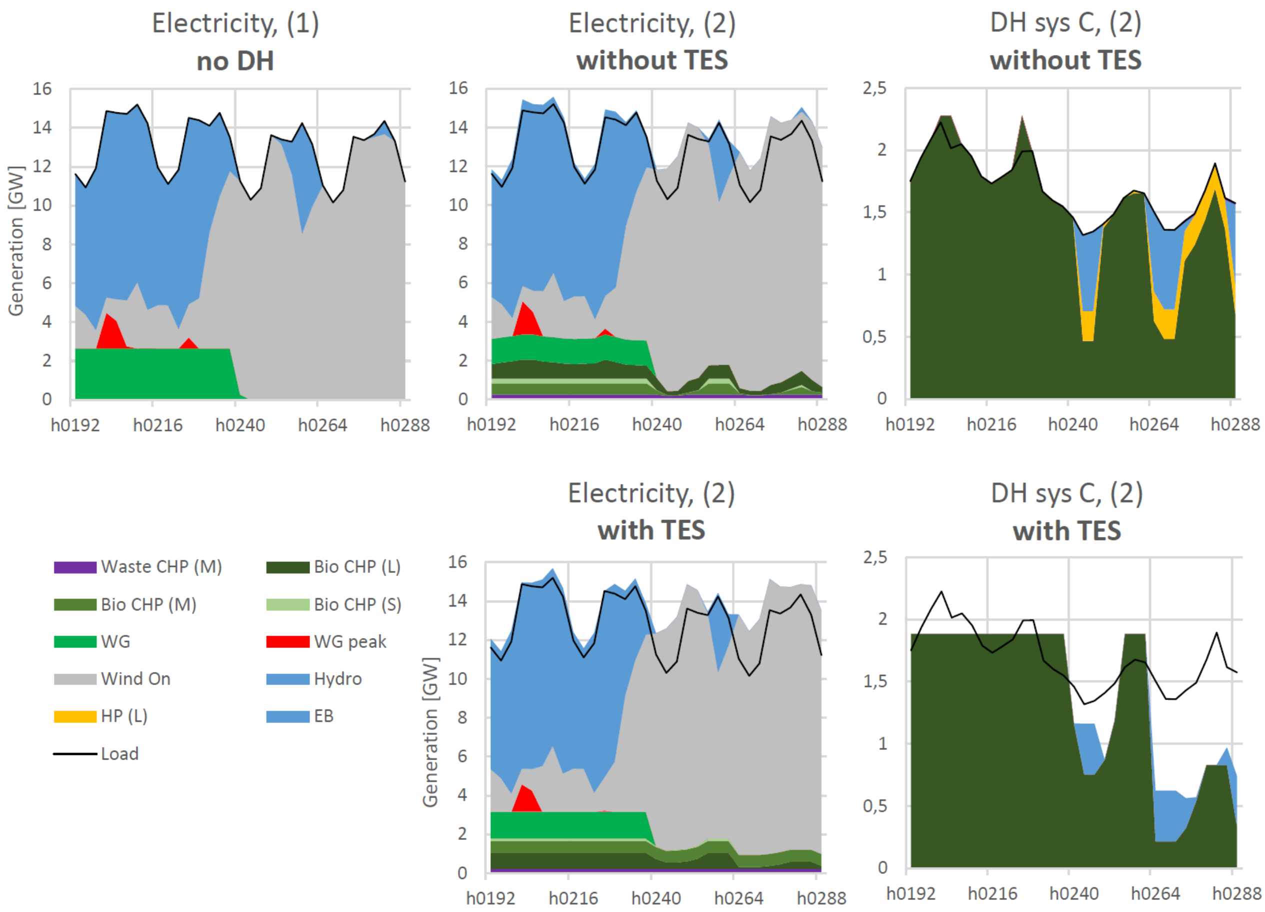

Figure 4.3: Electricity and heat generation in system scenarios 1 and 2 with and without TES for the same winter days (Mon-Thu). Any heat generation above the 'Load' line *without TES* is wasted and only a by-product of electricity output from the CHP. The 'Load' line in the electricity system shows demand from the electricity sector only, thus excluding electricity used through power-to-heat.

3 without TES in Figures 4.3 and 4.4, respectively. Thus, the only effect of TES in scenario 3 occurs in the DH sector as it stores this overproduction of heat from CHP plants. Similar to other scenarios, this completely eliminates the peak HOBs from the system.

In scenario 3, the peak HOBs in DH system A and C without TES are driven by fossil fuels (oil and gas), as is the case in scenario 5 (with BECCS). Since the peak HOBs generally have more capacity and FLHs than the peak gas turbines (which increases their capacity with TES), this suggests that TES decreases the use of fossil fuels in these scenarios. This is confirmed for scenario 5 by looking at the decrease in capacity of BECCS in Figure 4.1, for which the FLHs also decreases slightly with TES. The overall effects of TES on the electricity system in scenario 5 is however relatively small. Similar to scenario 3 (but to a lower extent) there already are both mid and peak technologies that are quite cheap. This makes the variation management provided by TES less influential on cost-optimal wind investments and energy share.

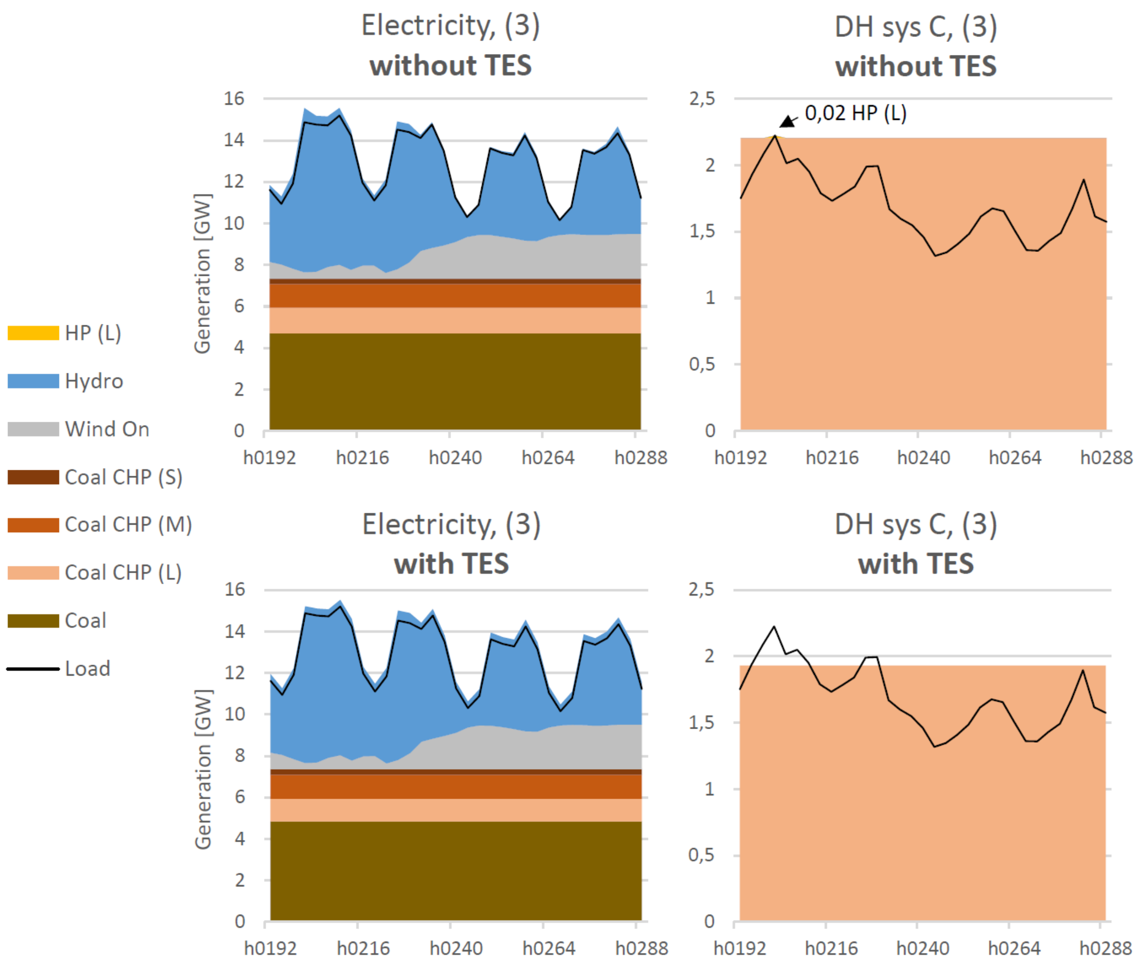

Figure 4.4: Heat and electricity generation in system scenario 3 with and without TES for 4 winter days (Mon-Thu). Any heat generation above the 'Load' line *without TES* is wasted and only a by-product of electricity output from the CHP. The 'Load' line in the electricity system shows the demand from the electricity sector only

Scenario 4 (with electricity tax and network fee), too, has lower effects on the investment level and curtailment of wind power when adding TES than the base case has. This is also the only scenario without additional resource limitations where the DH sector invests in a significant amount of solar heating. In previous scenarios it is found (from the negligible curtailment and low/no investment) that solar heating is *resource-limited* compared to wind power when the DH and electricity sectors are connected. However, the tax and fee in scenario 4 makes power-to-heat, and by extension wind, less valuable. Then, with a 4% curtailment and large portion of solar heat during summer, solar heat may be considered *system-limited*. When TES is included, its effects on the system is that the DH sector to a larger extent can be supplied by solar heat and CHP, rather than utilising wind peaks from the electricity sector. The *absorbing* effect on the electricity sector thus decreases compared to the base case. In type system A, the tanks handle the daytime overproduction from solar collectors and discharge at night. Even though it has no effect on the electricity system, this is a good example of when storage tanks act as a short-term *shifting*

VMS. In the other type systems (which have access to waste CHPs that generate heat all summer), the pit storages instead slowly absorb the solar heat during the summer, acting as a complementing technology when the demand is higher. This is also the scenario where the investment in CHP decreases by far the least when TES is included, while the number of FLHs still increases. The capacities and approximate FLHs can be seen in Figure 4.5, which shows the aggregated load duration curves of the CHP plants in scenarios 2 and 4. Thus, the *complementing* effects of TES on CHP are amplified compared to the base case. However, some of the electricity absorbing effects from TES that occur in the base case are present in scenario 4 as well, although they are small and caused only by type system A since TES completely displaces the power-to-heat from the larger type systems.

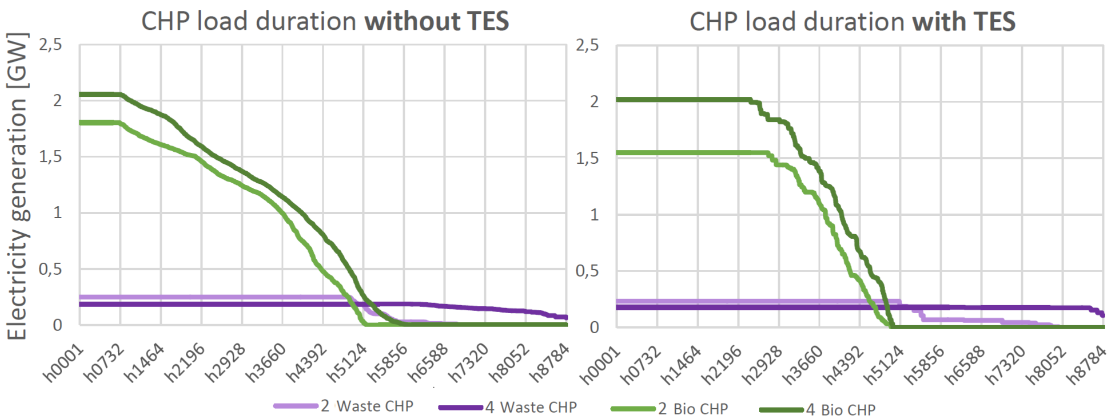

Figure 4.5: Aggregated load duration curves for all sizes of CHP plants, in system scenario 2 and 4, with and without TES

When 90 % of the hydropower capacity and energy is removed in scenario 6, the same general trends and effects from adding TES are found. However, the demand for flexibility increases significantly which results in a DH sector with more power-to-heat and, when available, more tank storage without heat pump (non-HP TTES) to shift the production from the opportunistic power-to-heat. In the case without TES, the additional need for flexibility results in some electrolyser (0.1 GW) and fuel cell (0.6 GW) capacity, of which the electrolyser runs very opportunistically with only 3900 FLH. Another consequence of the lower flexibility is the type of wind capacity that is installed, where installation sites with more FLHs (mainly off-shore) were more highly valued than the cheaper but more variable alternatives. These results from increasing the need for flexibility are in line with those seen when adding the CO_2 restriction between scenarios 3 and 2. Opportunistic usage of power-to-heat and CHP plants becomes more important, and so does TES (especially non-HP TTES).

When all waste is removed from the system and the cost of biomass increases (scenario 7), we obtain the case with the highest wind power capacity, with and without TES. The high amount of wind is mainly used to compensate for the missing biomass and waste CHPs (see Figure 4.1) in the electricity and DH systems. However, when

TES is not available to absorb the peaks, wind power combined with hydropower can not fully supply the heat demand in the summer without becoming severely system-limited. Solar heating, which otherwise is resource-limited in the considered area, is then used to supply the remaining demand. When TES is included, solar heating is out-rivalled by power-to-heat in type systems A and B, which is the opposite effect from scenario 4 (with taxes) where the shifting TESs take an important role in promoting solar heating. In type system C however, the solar heating capacity almost is doubled when TES is added. Type system C then differs from other scenarios by producing the main part of its heat in the summer season and using PTES as a large seasonal storage and the main heat source during winter. The fact that large PTES (only available in type system C) is the cheapest TES makes it most suitable for long term storage. This is the reason that the solar heating, which unlike wind power generates most energy during the summer, only is used in type system C. Seasonal storage is however also found in type system B (which has a more constant power-to-heat production throughout the year) since it invests in BTES. This scenario exemplifies how TES can promote VRES in the heating sector (solar heating) and the absorbing effects of power-to-heat technologies by acting as a *seasonal shifting* VMS.

Scenario 8, which is the combination of scenarios 6 and 7, is the only scenario that invests in nuclear power due to its high resource limitations. When TES is included, this scenario also has the highest increase in wind power investments. This large increase is partly due to a significant amount of the nuclear capacity being replaced by wind power when TES is available to absorb excess electricity. Similar to scenario 7, the bio CHP is replaced by power-to-heat which produces more in the summer season. The solar heat production also increases in the larger type systems as can be seen in Figure 4.6. With the lack of hydropower, however, more shifting effects from TES are used during summer and the power-to-heat production is more opportunistic. Hence, the effects of TES on the heat generation curve is a combination of the effects from scenarios 6 and 7. From Figures A.1 and A.2 in Appendix A.3, one can also see that the overall effects from TES on the electricity sector is significantly larger in this low-flex scenario than in the base case.

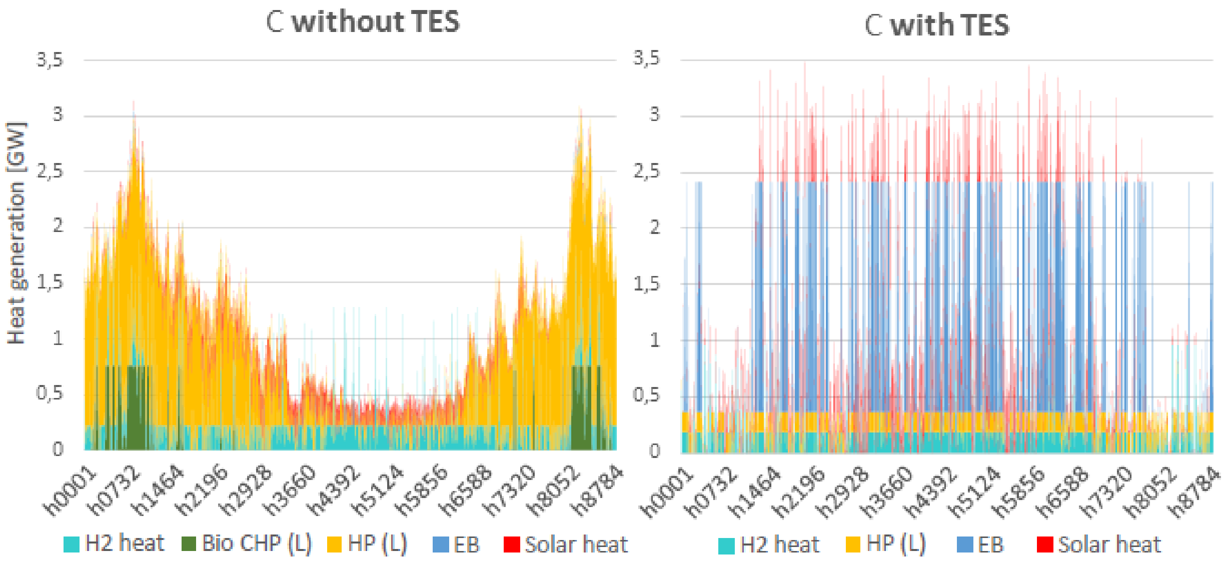

Figure 4.6: Heat generation curve for system scenario 8, type system C, with and without TES. Note that the peaks of heat from electrolysis/fuel cells in in the left graph (without TES) exceed the demand and thus are not utilised.

4.2 Characteristics of different TES

In analysing the different TES (TTES with and without HP, PTES and BTES), their key effects and their roles, some easily identifiable indicators will be attributed to each role in order to help analyse the *TES scenarios* from Table 3.6. The previous results suggests that there is a *shifting* and *complementing* effect in the DH-sector from the thermal storage, confirming what was expected in Section 2.1. However, only an *absorbing* effect could be seen in the electricity system which raises the question of 'which TES is most important for the absorbing effect in the electricity system?'

As such, the results in this section will focus on:

- Short-term (hourly to daily) detachment from the heat demand - which would signify a *shifting* TES.
- Long-term (weekly) detachment from heat demand, and indirectly an increase in FLH (especially for bio CHP) and reduction in peak production - which is expected from a *complementing* and *absorbing* TES.
- Increased VRES capacity and reduced curtailment - which would result from a TES with an *absorbing* effect on the electricity system.

While there are more effects one could assign to the different categories, this categorisation should be easy to identify and has little overlap.

The first scenario, which includes all TES, is the same as the base case in the system scenarios and will here too be referred to as the base case. Its full heat generation curves can be seen in Figure 4.2 which also shows a comparison to the 'no TES' case.

Table 4.1: General results from the TES scenarios. "Savings" are total system costs relative to the 'no TES' case (5557 M€/year). "Wind share" indicates the annual electricity share coming from wind power, while the CHP and power-to-heat (PtH) shares cover the total DH sector. Red numbers mark the lowest savings, wind capacity, and wind share, and the highest curtailment.

Scenario	Savings [M€/year]	Wind cap. [GW]	Curtail. [%]	Wind share [%]	CHP share [%]	PtH share [%]
no TES	0	14.92	6.1	50.1	64	32
1	100	15.32	4.1	51.2	63	36
2	58	15.22	6.6	50.4	61	36
3	85	15.02	3.7	50.8	68	30
4	17	15.00	5.8	50.3	63	33
5	58	15.25	6.1	50.8	61	37
6	85	15.02	3.7	50.8	68	30

When only allowing for the tank storage without HP in scenario 2, we see in Figure 4.7 that although the production does not always match the hourly demand, it follows closely on a daily basis. The system shown in figure 4.7 uses 3.6 GWh of non-HP TTES which allows for 0.6 GW of discharge. This scenario uses both HP, EB and HOB during peak hours and shuts down some bio CHP capacity when the demand drops. Scenario 2 thus clearly has a short-term but *not* long-term detachment from the demand curve.

This result is in line with the expectations of a storage with high energy cost and low capacity cost, meaning that the storage has a high relative costs per storage size, but low cost per charging and discharging capacity. Furthermore, looking at Table 4.1 one can see that although adding non-HP TTES increased the cost-optimal wind capacity, wind share and power-to-heat, it also *increased* the wind curtailment. The increased curtailment is likely due to the combination of two factors: (i) HP having the same variable O&M cost as EB (1 €/MWh), and (ii) the lack of heat replacement during summer. The first (i) matters since it leads to the model choosing to run HPs before EBs even when the electricity is very cheap. This leads to a lower effect on the wind curtailment since the HP consumes less electricity per heat output. However, even if some of the curtailed energy was used through an EB instead of HP (due to cheaper O&M), it would have very little value and thus very little impact on the system. The second factor (ii) makes it so that no short-term shifting can make use of the curtailed energy. If there is no replaceable thermal heat generation during summer, then there is no fuel consumption to offset by absorbing excess electricity. The distinction "*replaceable* heat generation" is made due to the restriction on waste storage (as mentioned in Section 3.3). Here, a long-term shifting VMS could offset thermal production after the summer, but the non-HP TTES is too expensive for storing large amounts of energy.

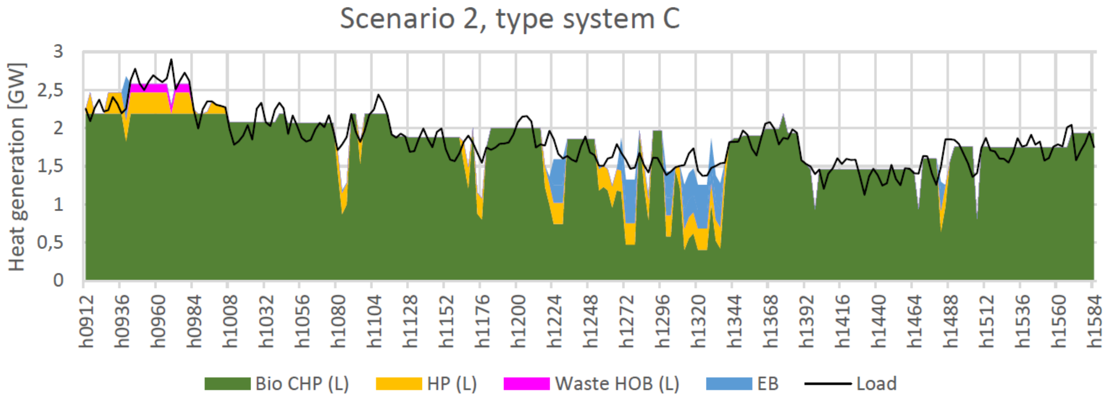

Figure 4.7: Heat production in TES scenario 2, using only non-HP tank storage, during 28 days in February-Mars

If instead only TTES and PTES are made available without the option of a non-HP tank storage, we can see a significant difference in the operation of all heat technologies. Since non-HP TTES is not allowed, only type system A has any tank storage (5.9 GWh) while type system C, which is shown in figure 4.8, uses 528 GWh of PTES only. When comparing this scenario (3) in Figure 4.8 to scenario 2 in Figure 4.7 there are three main points which differentiate the heat production. Firstly, scenario 3 has almost no additional production during peak demand and instead relies on previously stored heat. Secondly, the CHP in scenario 3 appears to run independently of the hourly heat demand and only responds to wind peaks (during the shown month). Lastly, scenario 3 has far less compensating power-to-heat production at hours of low CHP output, instead relying on high PTES output. It is clear that PTES provides long-term detachment from the load-curve and further adaptability to the electricity system through CHP and power-to-heat operation. While Table 4.1 confirms that PTES has the greatest impact on total system cost, wind share and curtailment, scenario 2 (non-HP TTES) has a greater effect on wind capacity. However, this can be explained by scenario 2's inability to store excess wind energy from the summer, thus requiring additional capacity to produce the same amount of useful energy.

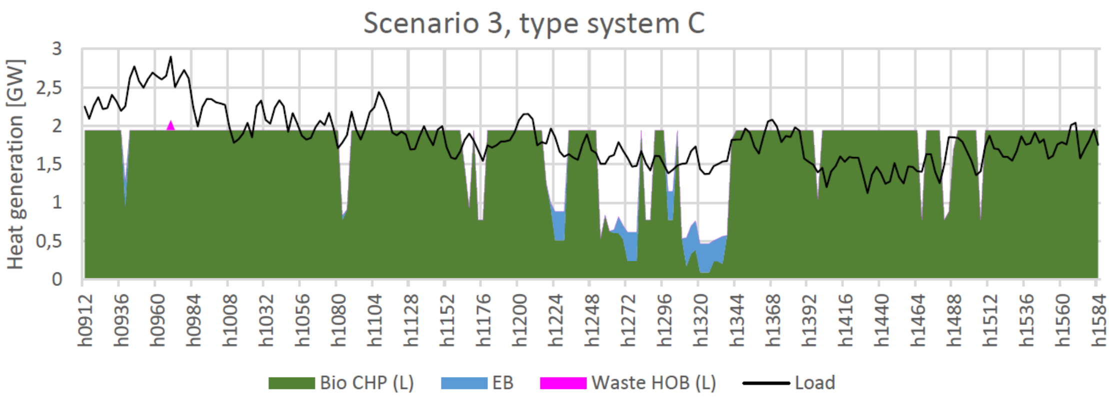

Figure 4.8: Heat production in TES scenario 3, using only PTES, during 28 days in February-Mars

BTES, which only appeared in the system scenarios with limited resources (7 and 8), is tested in TES scenario 4 and found to allow neither daily nor hourly disconnection from the heat demand variations. As shown in Figure 4.9, the heat production still follows the demand, but dislocated 0.13 GW as the BTES discharges at its full capacity for almost the whole investigated period. Although this has some effect on the cost of the DH system, it has a relatively weak effect on the operation. Figure 4.9 also displays type system B instead of C since only B had any BTES investments. In general, there was very little change in system composition and operation compared to the 'no TES' case, and this is also highlighted in the table (4.1) where scenario 4 has the lowest impact on cost and wind capacity. The curtailment is slightly lower due to the increased power-to-heat usage during summer. It should however be noted that the BTES alternated its charging and discharging during spring and autumn to allow for a steadier CHP production. This is part of what the non-HP tank normally does and causes some part of the cost savings through lower start-up and part load costs.

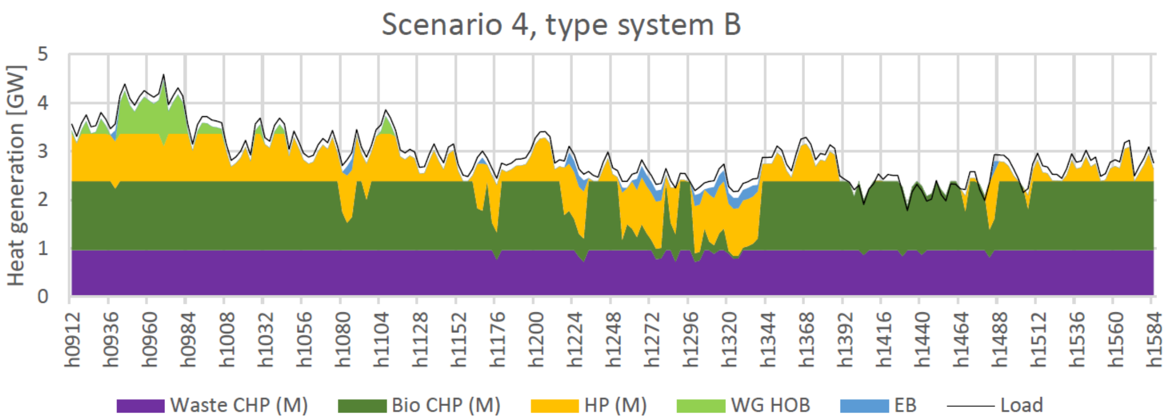

Figure 4.9: Heat production in TES scenario 4, using only BTES, during 28 days in February-Mars

The low impact and usage of BTES is further investigated in the sensitivity analysis in Section 4.5, where it is found that the investment cost is very important for the usage of BTES. As such, this TES scenario is also tested with a 15% reduction in the BTES investment cost which increases the storage capacity from 325 GWh to 1135 GWh[1] in type system B (still no BTES in type system C). This also increased the heat output from the BTES from 0.13 GW to 0.46 GW which can be seen in Figure 4.10. At this point the total savings only increased slightly to 20 M€ from 17 M€, and the system in general looks the same but with further shift to waste CHP and power-to-heat production in summer. The peak power is also slightly decreased.

When both BTES and TTES (with and without HP) is allowed in scenario 5, *no BTES enters the system*. The slight differences between scenario 2 and 5 in Table 4.1 instead shows the impact of adding TTES with HP to type system A. This change causes a slight shift from biomass CHP to power-to-heat, but with no significant change in the time-span of load curve detachment.

[1]for reference, the annual heat demand in type system B is 5351 GWh

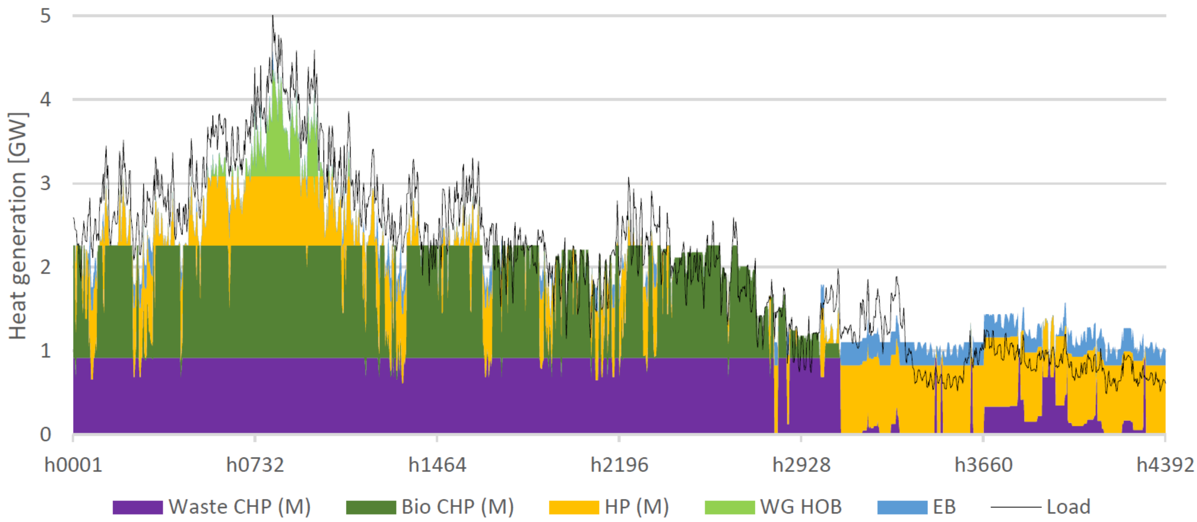

Figure 4.10: Heat production for half a year in TES scenario 4, type system B, with a 15% cost reduction to BTES

Lastly, scenario 6 which allows for both TTES with HP, PTES and BTES results in the exact same system as scenario 3 which did not allow for BTES. This is to be expected since there was no BTES in the base case and the effects of the missing non-HP tank storage is more cheaply managed by more PTES than BTES.

To summarise, the impact of BTES is not in disconnecting the production from the load variations, but simply as a seasonal heat storage which allows for more production from power-to-heat and waste CHP plants during summer and less mid-load production during the rest of the year. PTES allows for long-term detachment from the load curve while non-HP tank storage allows for short-term detachment. The two can thus be regarded as complementing/absorbing and shifting, respectively. Furthermore, they have no apparent synergistic effects, and while PTES can handle short-term variations in the absence of a non-HP TTES, non-HP TTES can not provide long-term storage in a cost-optimal way. As shown in Table 4.1, scenario 2 has the highest wind capacity out of scenarios 2, 3 and 4 (non-HP tank, PTES and BTES) but scenario 3 has the lowest curtailment, highest wind share and highest cost savings. Comparing both scenarios reveals that scenario 3 has a higher utilisation of wind peaks during summer when the total wind production exceeds the total electricity demand, while scenario 2's slightly higher wind capacity only gets used during winter at hours of high electricity demand. As such, PTES appears to have a higher *absorbing* effect of the two.

Table 4.2: Summary of the different roles of TES in the DH sector

	VMS category	Effect on generation
TTES	Shifting	Less CHP and more power-to-heat
PTES	Absorbing/Complementing	Peak shaving, even CHP-production
BTES	Seasonal shifting	More power-to-heat during summer

4.3 Interactions between TES and other VMSs

This section will look at how TES interacts with absorbing (H_2 demand with storage), complementing (hydro and CHP) and shifting (DSM) VMSs in the electricity sector. Some main focuses that will be discussed are:

- If different VMSs have specific impacts on the system such as higher investments in vRES, reduced peak capacity or reduced curtailment
- If there are any competing or synergistic effects between TES and other VMSs, by examining the sum of the effects of separate VMSs compared to the combined effect on different indicators
- If connections can be drawn between the different VMS categories and resource- versus system-limited VRESs

In order to answer these questions, the *VMS scenarios* are used, i.e. system scenarios 2 and 8 are implemented with different VMSs and with 20% of the annual electricity demand represented by a constant industrial demand for hydrogen. The scenarios based on system scenario 2 will be referred to as the *standard* scenarios. The *low-flex* scenarios based on system scenario 8 are included to examine the effects of different VMSs in the absence of flexible electricity generation. The results considered most relevant for this analysis are provided in Tables 4.3 and 4.4.

Table 4.3: Wind and system cost results for the standard VMS scenarios (based on system scenario 2). The total system cost with no VMSs included is 5711 M€/year.

	available VMS	Wind cap. [GW]	Wind share [%]	Curtail. [%]	PtH share [%]	Savings [M€/year]
no TES	no VMS	14.66	51.3	3.2	27.5	0
	DSM	15.86	53.8	5.2	28.9	190
	H_2 store	14.83	51.7	3.3	28.2	64
	DSM, H_2 store	16.26	54.4	6.1	28.8	208
TES	no VMS	14.76	51.2	3.2	29.3	96
	DSM	16.19	54.3	5.5	27.0	266
	H_2 store	15.35	52.6	3.9	29.1	163
	DSM, H_2 store	16.46	54.8	5.7	29.2	282

Looking at the effects of DSM in the standard case we see that, both with and without TES, it increases the wind capacity and the share of electricity generated by wind. This is to be expected since DSM makes it possible to shift some demand to hours of higher wind production which reduces peak power usage (see Figure 4.11), increases the useful FLHs of existing wind power and makes new wind power more profitable. Hence it is cost-optimal to invest in 1.2 GW more wind capacity even though the curtailment increases during the summer. It can also be seen in Table 4.3 that DSM increases the power-to-heat share in the DH system without TES. This is due to the increased wind capacity and curtailment which results in more low price electricity. When TES is available, however, DSM decreases the power-to-heat share. Similarly, TES only increases the power-to-heat share when DSM is not available. Hence we obtain the lowest power-to-heat share when combining

TES and DSM. This is due to the fact that when these two VMSs are combined, shifting can occur in both the electricity and DH system, which decreases the value of opportunistic absorption while making the CHP plants even less affected by wind peaks (see Figure 4.11). Combining DSM and TES also gives an additional increase in wind power investments, and the combined effect (wind capacity increase of 1.53 GW) is larger than the sum of the separate effects (1.3 GW). This indicates that there is synergy between DSM and TES in promoting VRES. One explanation to this synergy is that while TES only can help to opportunistically absorb wind peaks, the shifting of electricity demand can allow for a smoother production of power-to-heat. The system can then use a lower power-to-heat capacity to absorb the same amount of energy. Examination of Table 4.3 reveals that, regarding cost reduction, there is a bit of competition between TES and DSM since they can not quite achieve their full separate effects.

Comparing the investments in TES to the scenario without DSM, it is found that the *total* pit storage capacity has increased while the capacity of the non-HP TTES has decreased. This is expected since DSM has the ability to utilise fast variations in electricity output, which evens the electricity price and some of the variations in CHP and power-to-heat output. In type system A, which does not have access to a large TES, the non-HP TTES is to a large extent replaced by TTES, even though they have similar roles. This replacement is due to two factors: a reduced need for TES during summer (which favors TTES due to the constant losses of non-HP TTES), and a shift in demand from charging and discharging capacity to energy storage capacity.

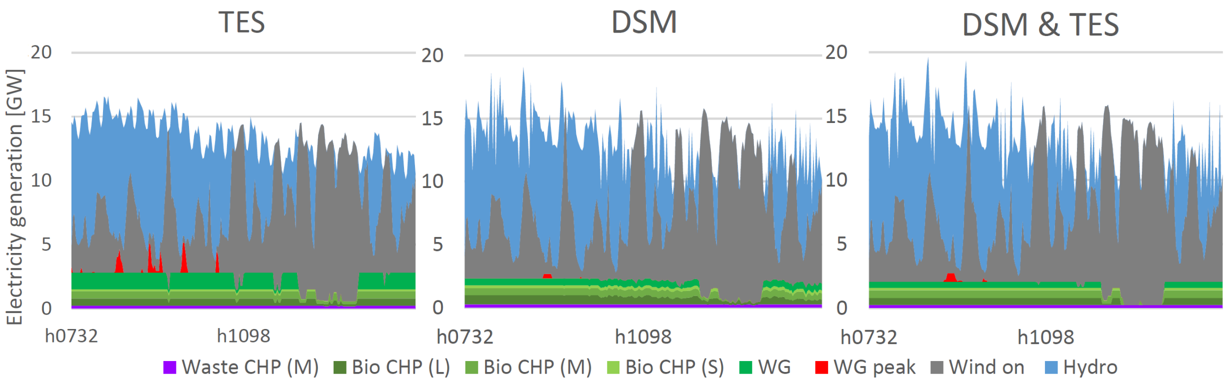

Figure 4.11: Electricity generation during February in three cases: with TES only, DSM only, and DSM and TES combined

The effects of adding a hydrogen storage include increased wind capacity, wind share and curtailment, but it also reduces peak power capacity. This is due to how the H_2 storage works as an *absorbing/complementing* strategy by using stored hydrogen to supply the industrial demand during the hours when the electricity net demand is especially high. Thereby the H_2 storage levels the non-peak and peak demand and thus reduces the peak power capacity, which is also found in [4]. Another noteworthy observation is that, in the presence of TES, the H_2 storage size is almost doubled (not included in the table) and its effect on wind capacity and share more than doubled. When TES is available, the total capacity of dispatchable technologies (CHP and biogas) typically decreases, and a larger amount of hydrogen discharge is used as complement during peak demand, hence the increased storage capacity. The increased hydrogen production for charging of the storage and decreased dispatchable capacity both increases the wind capacity, and some of the peaks from the larger wind capacity can be absorbed by the DH sector. We can see from Table 4.3 that this results in a synergistic effect between H_2 storage and TES on the wind capacity, and in contrast to DSM and TES, they are also synergistic in reducing the system cost.

Regarding investments in TES, the difference when adding H_2 storage compared to adding DSM is that the non-HP TTES capacity increases instead of decreases in type system C. This type system has almost no power-to-heat capacity other than the PTES HP, and the discharge capacity limited by that HP is not large enough to supply the heat demand when the CHP production responds to wind peaks. In addition to investing in more PTES HP capacity, the model thus also invests in more non-HP TTES due to its cheaper discharging capacity.

To summarise the standard case, we can see from Table 4.3 that any pair of the VMSs TES, DSM and H_2 storage have synergistic effects on the wind capacity and energy share. Furthermore, the existing synergistic effect is *increased* when adding a third VMS, except when adding a DSM to a system with H_2 storage and TES. Regarding system cost reduction, the only synergy that is found is between H_2 storage and TES. However, the effect of any combination of VMSs is significantly larger than the separate effects. In terms of reducing peak power capacity, H_2 storage is most effective although DSM also has a significant impact.

Table 4.4: Wind and cost results for the low-flex VMS scenarios (based on system scenario 8). The total system cost with no VMSs included is 8346 M€/year.

	available VMS	Wind cap [GW]	Wind share [%]	Curtail. [%]	PtH share [%]	Savings [M€/year]
no TES	no VMS	11.23	39.9	6.7	73.6	0
	Batteries	11.30	40.2	6.8	73.6	0.2
	DSM	14.72	51.4	6.7	73.6	384
	H_2 store	19.39	71.8	7.1	72.4	402
	DSM, H_2 store	21.20	77.2	7.2	74.3	743
TES	no VMS	14.59	50.2	1.8	86.2	289
	DSM	18.04	62.5	2.5	75.9	617
	H_2 store	22.97	78.8	2.7	82.2	711
	DSM, H_2 store	24.83	83.7	3.8	73.8	1019

When waste is not available, hydropower is limited, and the biomass is expensive, we can see from Table 4.4 that the effects of the VMSs are somewhat different from the standard case. Due to the scarcity of resources, the model invests in 0,2 GWh of battery capacity when no other VMSs is available, but it is not enough to have considerable effects on the system. In contrast to the standard case, the system now has a lack of *complementing* technologies. In line with the findings in [4] the *absorbing/complementing* hydrogen storage now has a significantly larger effect on the wind capacity and energy share than DSM, which is strictly *short-term shifting*. When H_2 storage is available, even the relatively inefficient hydrogen fuel cells are used to complement the electricity supply with the absorbed hydrogen. The effects of the hydrogen storage on the electricity generation pattern with and without TES can be seen in Figure 4.12.

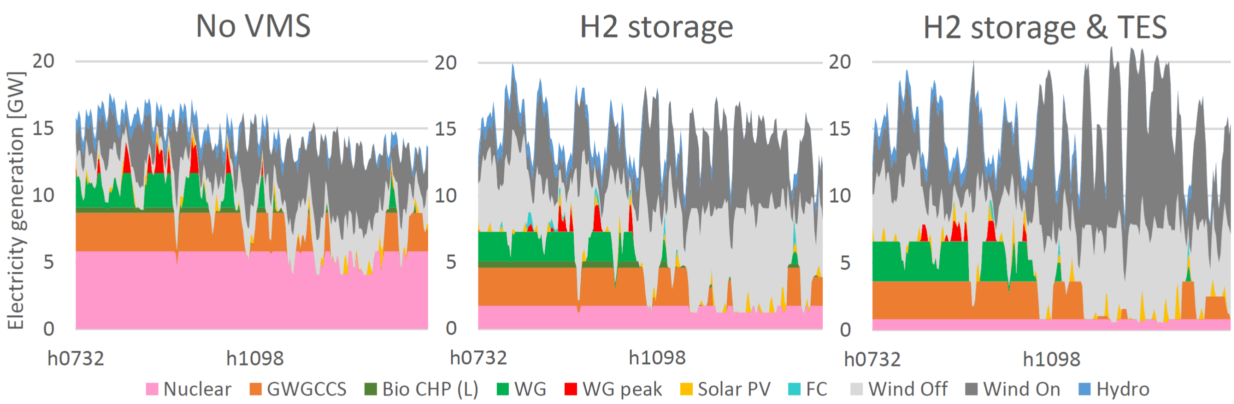

Figure 4.12: Electricity generation during February in three low-flex cases: without VMSs, H_2 storage only, and TES combined with H_2 storage. 'Wind Off' is offshore wind power.

The power-to-heat share is significantly larger in these scenarios, even when the wind capacity is relatively low, since the biomass fuelled heat production technologies are more expensive than in the standard case. Unlike the standard case, the power-to-heat share now always become higher when TES is added, although DSM lowers this effect. Adding TES causes power-to-heat to replace bio CHP during winter in type system C, and solar heating during summer in type system A. Similarly to the system scenarios, only the type systems with access to large TESs invest in solar heat. However, when DSM or H_2 storage is available there still is solar heating in type system A, which only have short-term shifting TESs. Furthermore, the highest total solar heat capacity, with and without TES, is obtained when DSM and H_2 storage is combined. This indicates that when the system has access to VMSs that can increase the utilisation of wind peaks in the electricity sector, this has a larger value than using the same energy in the DH sector. This is confirmed by examination of the marginal costs of heat and electricity production.

When no VMS is included, the curtailment of wind is large compared to the standard case since the highly flexible hydropower to a large extent is replaced by inflexible nuclear power. The curtailment remains on approximately the same share after the addition of DSM and hydrogen storage, despite the considerable increase of investments in wind power. Only TES significantly decreases the wind curtailment, in contrast to the standard scenario where the effects on curtailment are small. This decrease in curtailment compared to other VMSs hints at a shift in the equilibrium of how much of the wind energy which can be curtailed while the wind capacity still is cost-optimal. This shift can be explained by the value the offset energy, where heat as previously mentioned has a lower marginal value. In the low-flex scenarios, the curtailment with TES is *lower* than in the base case even though it is significantly higher without TES. This is due to the lack of complementing strategies and cheap production in the electricity sector, which makes the electricity price higher and more fluctuating (especially during winter). Without TES, the heat is supplied with HP and solar heat for almost the whole year, regardless of the electricity price. However, with TES the heat pumps run much more opportunistically and uses seasonal storage to make use of the excess electricity from summer, which normally is where the curtailment takes place.

Another difference from the standard case is that solar PV now is included. Solar PV is, in contrast to wind, resource-limited in the investigated area and the curtailment is negligible. As mentioned in Section 4.1, the effects from VMSs can be different on resource- versus system-limited VRES. In the low-flex VMS scenarios, the solar PV capacity is always larger with than without TES, decreases with DSM and *increases* with H_2 storage. The combined effect of DSM and H_2 storage is however that solar PV *decreases* by a considerable amount more than with DSM only. Since solar PV produces during the day when the electricity demand (and generally price) is higher, DSM can be expected to decrease the solar PV capacity by removing a significant part of the diurnal variations. When there is a hydrogen demand, the storage works as a complementing VMS by allowing for gaps in the H_2 production. In these low-flex scenarios, TES partly takes a similar role in the electricity sector by allowing for gaps in the otherwise high usage of power-to-heat. Johansson and Göransson [4] concludes that complementing VMSs promote resource-limited *wind power*, and the results in this thesis suggest that they also can promote resource-limited solar PV.

Out of the synergies present in the standard case, only the one between H_2 storage and TES is present in the low-flex case, and it still affects both the wind capacity and system cost reduction. However, the combined effect of DSM and TES is just slightly smaller than the sum of the separate effect, so they are close to being non-competitive/synergistic. Overall, the VMSs show similar effects in the low-flex case and standard case. All VMSs increase the cost optimal investment in wind and decrease base load capacity, and combined VMSs have significantly larger effects on both wind capacity and cost reduction than one VMS only.

From these results, it can be concluded that a *shifting* VMS such as DSM has the largest effect on *system-limited* VRES in the presence of flexible generation, while the *absorbing/complementing* H_2 storage increases the cost-optimal wind power investments the most in the low-flex case. Flexible generation as a VMS can thus be considered *competing* with H_2 storage in promoting VRES investments. H_2 storage does however show *synergistic* effects with TES on both cost reduction and wind investments. TES is also the only VMS that can considerably reduce the wind curtailment, although this only occurs in the low-flex case because of the increased value of seasonal storage. Since the only strictly resource-limited technology examined in this section is solar PV, which only appears in some scenarios with a lack of cheap energy, it is difficult to draw any general conclusions regarding this type of technology.

4.4 Limitations

It should be kept in mind that since batteries almost never are used, DSM is the only shifting VMS in the electricity sector in this thesis. This weakens any conclusions regarding shifting VMSs as a category as opposed to conclusions regarding specifically DSM. However, the focus of this thesis is mainly to examine thermal energy storage, and all conclusions regarding different types of VMS are in general compared to those in the article by Johansson and Göransson [4]. Furthermore, DSM has zero costs (while TES, power-to-heat and the hydrogen storage requires investments) and the allowed level of delayed electricity demand is somewhat arbitrarily decided. Although the cost of demand shifting may be assumed to be negligible, it can be implemented in different ways and magnitudes (see Section 2.2), which could lead to different costs. Hence, results that indicate that DSM is more or less effective than other VMSs may be considered unfair.

While using a linear model significantly improves the time it takes to solve, it also carries some drawbacks compared to a non-linear model. The limitations related to TES concerns mainly the COP and the heat losses. The COP of the TES HP should ideally depend on the temperature of the stored water, being more efficient as the required temperature lift decreases. The linearised heat losses are described in Appendix A.1, and mainly misrepresents the non-HP TTES which is required to stay at a high temperature (and thus have constant heat losses) regardless of usage. In reality, such a tank might be emptied or allowed to cool down rather than kept at an operable temperature. However, this possibility could not be implemented linearly in the model.

The implementation of only three type systems is also a limitation that has been made to keep the run time of the model low. When examining an entire electricity price region including many different cities (DH networks), a more detailed system representation could be made by separating those cities from each other and using their respective load curves. This thesis uses the heat production in Gothenburg year 2012 for the entire region, see section 3.2, which is likely not realistic since the hourly heat demand can vary within the region. However, if load curves from different sub-areas were to be aggregated and used for the three type system in this thesis, the resulting demand would be somewhat evened out, hence the model would not capture detailed variations within the DH system. This could have a significant effect on the usage of TES in the model, since TES has levelling effects in the DH system. Hence, even though aggregating heat load curves would give a better representation of the effects on the *electricity* system, using the same load curve may be the appropriate choice for the purposes of this thesis, since TES operates in the DH system.

When large-scale TES is implemented in reality, it is often specifically for the purpose of storing solar heat, and the storage is thus in direct connection to a solar heating plant, e.g. the seasonal PTES in Denmark [12]. In this thesis it is instead assumed that all technologies connected to the DH network have access to all connected TES, and besides the allocation into type systems, no practical or economic considerations have been made for DH transmission capacity. The cost-optimal operation of TES in this thesis may thus not be practically feasible at all times. However, the TES sizes listed in Table 3.4 are significantly smaller than those generally invested in in this model, even when taking into account the number of networks which every type system represents. This means that the TES investment costs could have been even lower (due to economies of scale), or the storages could have been split and connected to different heat producing units.

4.5 Sensitivity analysis

The purpose of this thesis is not to predict or even make suggestions about the future energy system in Sweden - but rather to investigate TES as a VMS and interactions between DH and electricity systems. As such, the main parameters in the sensitivity analysis should be related to the available capacity (profitability) and performance of the TESs. The installed TES capacities in themselves may even be unimportant to the discussion and conclusions of the thesis, but will be analysed in case different effects come into play at different investment levels. The indicators in this sensitivity analysis are: wind share in the electricity system, wind curtailment, and total cost, all of which will be tested in system scenario 2 (the base case). The DSM level and time-resolution will however also be included.

The C-factor, which determines the maximum charging and discharging rate of the TESs (as a fraction of the storage capacity per hour), is set to 1/6, 1/24 and 1/3000 for tank, pit and borehole storages in this thesis, respectively. A recent master's thesis [33] which looked at possibilities for the Gothenburg DH system used a C-factor of 1/20 for both tank and pit storage, but made no deeper analysis of the operation or roles of the different storages. Moreover, that thesis assumed both the tank and pit storages to run without heat pumps which this thesis does not. This is a significant difference since the heat pump requirement puts an additional cost on the discharging capacity. Instead, this thesis assumes that, by virtue of the generally smaller storage sizes, tank storages may be built to charge and discharge faster than a pit storage (per total storage volume). The non-HP tank storage was also implemented in this thesis as a technology specifically designed as an alternative for quick variations. However, system scenario 2 was also tested with a C-factor of 1/20 for TTES and PTES which completely removes the non-HP tank investments and its benefits to wind capacity and share. The system becomes very similar to TES scenario 3 in Section 4.2 with only minor differences due to the faster charging of PTES. The BTES limit was also analysed and found to give investments (at the current investment cost) at a C-factor around 1/2750. However, this is significantly lower than values in some other thesis' featuring BTES [34, 35], which both has values around 1/3500. Furthermore, changing the C-factor for PTES from 1/24 to 1/6 or 1/168 (one week) has no significant impact on the results.

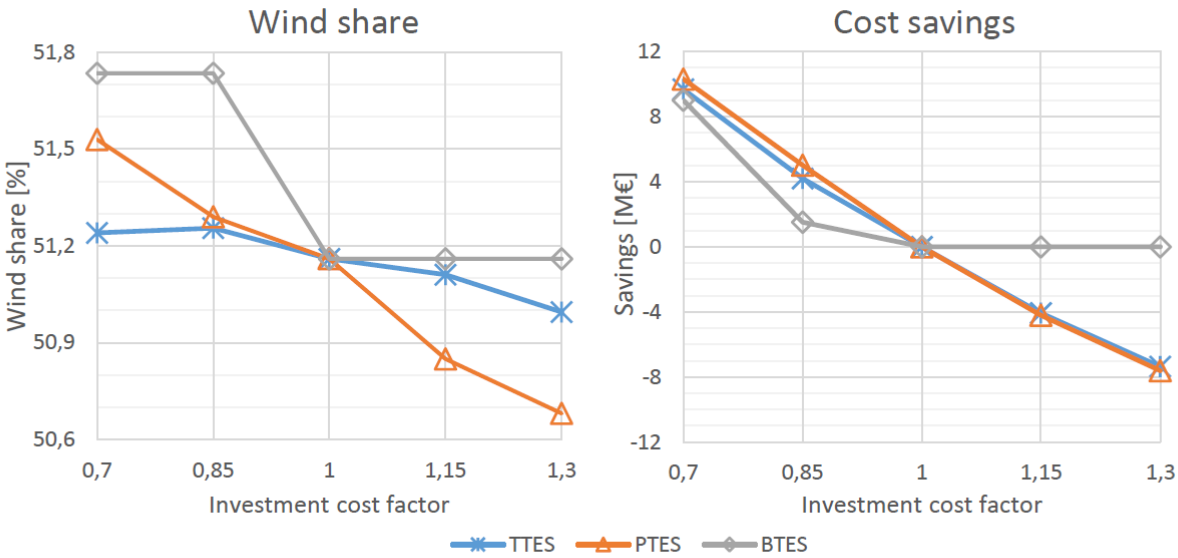

Figure 4.13: Change in system cost savings and electricity share from wind power by changing the investment cost of TTES (with and without HP), PTES and BTES

As can be seen in Figure 4.13, the TES investment cost has a noticeable and mostly linear impact on the total system cost. For reference, the total cost savings of allowing for TES are 100 M€ per year. The strange behaviour of the BTES curve in 'Wind share' (Figure 4.13) is partly due to it not being invested in at the normal investment cost, and partly due to the order of which the summer heat production increases as more BTES capacity is installed in a type system. At first, the power-to-heat increases its output until it runs at full capacity for most of the summer (which it does at 15 % BTES cost reduction), and then the waste CHP increases its output (running at 8240 FLHs at 30 % BTES cost reduction). Thus, the impact on curtailment and wind energy share diminishes as the impacts shift to promoting base load heat plants.

Doubling the TES losses to 1% per 5 days decreases the cost-optimal TES capacities and their impacts on the system, *but not much*. The total annual savings of adding TES to system scenario 2 (the base case) are reduced from 100 M€ to 99 M€ while the wind energy share increased from 50.13% without TES to 51.04% instead of 51.16%. If the losses instead are halved (1% per 20 days), the effects of adding TES only slightly increases. The cost savings go from 100 M€ to 101 M€ and the wind share from 51.16% to 51.20%. However, these effects only apply to TTES and PTES since only these get investments in the base case. The BTES losses are therefore tested by varying the losses in a case where the BTES investment cost is reduced by 30% (the 0.7 point in Figure 4.13). Increasing the BTES losses to 1% per 5 days does not change the behaviour or characteristics of BTES, although it reduces the cost-optimal capacity from 1846 GWh to 1431 GWh and thus reduces its effect on waste CHP. Similarly, reducing the BTES losses slightly increases the

BTES capacity but has very little impact on the rest of the system.

In Section 4.4 it is mentioned that the DSM level (the share of the electricity demand that can be delayed) is somewhat arbitrarily decided at 20%. A sensitivity analysis has therefore been made, where the standard VMS scenarios with DSM (with and without TES) have been implemented with DSM-levels ranging from 5% to 30%. The results show that the synergistic effects with TES on wind investments at a DSM level of 20% holds from low DSM levels up to 25%, but at 30% they instead compete. The reduction of synergistic effects at larger DSM levels is not due to diminishing effects from DSM, but diminishing effects from adding TES at already high DSM levels. The effect on wind capacity from the zero-cost DSM is still linearly increasing at a DSM level around 25-30%. It is also found that regarding cost reduction there is almost no competition (and in some cases a small synergy) with TES when the DSM level is 15% or lower i.e., the competition starts at the DSM level mostly used in this thesis.

The standard and low-flex scenarios have also been tested with a time resolution of every, instead of every third, hour and the results are very similar. The energy mix shifts slightly from base/mid power to VRES, mostly affecting solar PV (about 10% or 0.47 GW) but also leading to a larger seasonal shift through BTES. The BTES capacity increased from 716 to 946 GWh, corresponding to a shift in discharge capacity from 0.29 GW to 0.39 GW.

5
Conclusions

This thesis has investigated the impacts of TES by integrating the DH and electricity sectors and studying the effects of adding various VMSs to the model. TES is found to have *shifting* and *complementing* effects on the DH system, while having mainly *absorbing* effects on the electricity system. Furthermore, the effect on the electricity system is weakest in the presence of an electricity tax and strongest when there is a low availability of hydropower and flexible thermal power.

The primary findings are that TES:

- Provides a large degree of flexibility to the DH system by disconnecting the heat production units from the heat demand profile, allowing for further adaptability to the electricity system. This disconnection from the heat demand curve also displaces the peak HOBs and generally allows for more FLHs and reduced capacities.
- Provides flexibility for the electricity system by allowing CHP and power-to-heat units to complement and absorb VRES production, respectively.
- Promotes wind power investments at already high wind penetration levels due to its absorbing effect on the electricity system.
- Has strong additive effects with both DSM and hydrogen storage in reducing total system cost and promoting wind power investments.

PTES and the non-HP TTES have the greatest impacts on wind power and total system cost in both the standard and low-flex cases. This is due to the value of being able to quickly absorb and release heat in response to VRES and demand variations. PTES is the only TES which has a significant complementing effect on the DH system, and the only TES which significantly affects peak heat production and the heat technology mix. The non-HP TTES mainly acts as a short-term shifting VMS and enables the other heat producing technologies to further act according to the electricity system. The seasonal storage which BTES can provide is found to mainly increase waste CHP and power-to-heat during summer while decreasing bio CHP during winter, with only weak effects on managing variations or peak demand. While this seasonal shifting has a value in the low-flex cases, BTES has the lowest impacts on total system cost and wind power investments.

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A

A.1 TES losses

Newton's law of cooling, which expresses the rate at which an object loses heat to its surroundings, can be written as

$$\frac{dT}{dt} = k(T_s - T)$$

where T is the temperature of the object, T_s the temperature of the surroundings and k some constant. Furthermore, the heat loss depend on the surface area of the object and thermodynamic properties related to the specific object (such as insulation) and its surroundings. The equation can thus be rewritten as

$$\frac{dT}{dt} = UA(T_s - T) = Q_{loss}$$

where U is the total heat transfer coefficient per area and A is the surface area.

For a TES without a heat pump, an "empty" storage means that the temperature is at the minimum usable temperature for the DH system, which is significantly higher than the atmospheric temperature. A per cent loss as used in the thesis by Lundahl and Kärkkäinen [33] may suit a TES where the minimum temperature is close to the temperature of the surroundings, but not one without a heat pump. The temperature difference between the "empty" storage and the surroundings would mean that there are significant losses even when the storage is "empty". A more accurate approximation would be a loss which depends on the storage level ($T_{overheated}$) as follows

$$Q_{loss} = UA * (T_s - (T_{emptystore} + T_{overheated})), \quad T_{emptystore} + T_{overheated} = T$$

which can be rewritten as

$$Q_{loss} = K + k * T_{overheated}$$

where $K = UA(T_s - T_{emptystorage})$ and $k = UA$. Finally, converting the storage level from a temperature to an amount of energy can be done through the heat capacity of water and the volume of the storage. However, it should be noted that this still is a rough approximation due to the handful of assumptions such as constant T_s, constant (and size-independent) UA, and constant $T_{emptystorage}$.

A.2 Technologies and input data

Properties of the fuels used in the heat- and power production technologies below can be seen in table A.1. Note that the mixes of fuels used in CCS plants (HW, GWG) are not shown in the table. HW consist of 10.6% biomass with hard coal, while GWG consists of 11.5% biogas mixed with natural gas, and their properties are linear combinations of the components. For the data not added in this thesis (which can be found in section 3.3), most economic data is taken from the World Energy Outlook by IEA in 2014. However, for the CCS technologies, the data origins from the Zero Emission Platform (ZEP) in 2011. Furthermore, cycling costs are based on a NREL report ”Analysis of cycling costs in western wind and solar integration study” by Jordan and Venkataraman in 2011.

Table A.1: Properties of all fuels used in the model

Fuel	Carbon intensity [kg/MWh]	Price [€/MWh]	Limitation SE2 [MWh]
Lignite (B)	30.35	5.45	0
Hard coal (H)	25.93	9.77	-
Natural gas (G)	15.68	34.27	-
Oil (O)	20	66.18	-
Biomass (W)	30.68[A]	30	86 388
Waste (Wa)	0[B]	1	7 767
Uranium (U)	0	8.07	-
Biogas (WG)	15.68[A]	-[C]	-[C]

[A] Biomass is considered carbon neutral but the carbon intensity is needed to calculate the "negative emissions" from CCS with biomass.
[B] Carbon intensity of waste is around 10 kg/MWh, but assumed to be 0 here, see section 3.4.1
[C] Price and limit of biogas depend on biomass properties, and the technology used for producing biogas.

Table A.2: Economic and technical data for the heat-only technology. Not shown in this table is that the waste HOB has startup and part load costs equal to those for the waste CHP, save for the start fuel amount which is 0.3 MWh instead of 2.93 MWh.

	Lifespan [yr]	Inv. cost [k€/MW]	OM_var [€/MWh]	OM_fix [€/MW/yr]	η [%]	Min. load [-]
Electric boiler	20	100	1.0	1.5	95	0.05
Heat pump (S)	25	800	1.0	8.0	300	-
Heat pump (M)	25	700	1.0	7.0	300	-
Heat pump (L)	25	600	1.0	6.0	300	-
Bio HOB (S)	20	860	2.0	10.7	95	0.25
Bio HOB (M)	20	800	2.0	10.0	95	0.25
Bio HOB (L)	20	730	2.0	9.1	95	0.25
Coal HOB (S)	20	860	2.0	10.7	90	0.25
Coal HOB (M)	20	800	2.0	10.0	90	0.25
Coal HOB (L)	20	730	2.0	9.1	90	0.25
Oil HOB	20	400	1.5	2.5	90	0.25
Gas HOB	25	400	1.5	2.5	92	0.15
Biogas HOB	25	400	1.5	2.5	92	0.15
Waste HOB (M)	20	1320	4.0	40.0	90	0.75
Waste HOB (L)	20	1200	4.0	36.0	90	0.75

Table A.3: Economic and technical data for thermal electricity generation plants

	Lifespan [yr]	Inv. cost [k€/MW]	OM_var [€/MWh]	OM_fix [€/kW]	η [%]	Start time [h]	Min. load [-]	Start cost [k€]	Start fuel [MWh]	Start fuel type [-]	Part load cost [€/MW]
Coal power (H)	40	1560	2.1	27.4	56	12	0.35	56.9	2.93	Oil	1.9
NGCC (G)	30	780	0.8	13.0	71	6	0.20	42.9	0.05	NG	0.5
GT (G_peak)	30	390	0.4	7.9	42	0	0.50	20.2	0.45	NG	0.5
WGCC (WG)	30	755	0.8	13.0	71	6	0.20	42.9	0.05	WG	0.5
Bio GT (WG_peak)	30	378	0.7	7.9	42	0	0.50	20.2	0.45	WG	0.5
Biomass power (W)	40	1856	2.1	50.0	50	12	0.35	56.9	2.93	WG	1.9
Nuclear power (U)	60	5148	0	154.4	43	24	0.70	0	81.4	U	1

Table A.4: Economic and technical data for the CCS plants. Additional costs for transporting and storing the CO_2 are applied, 5.83 and 5.4 €/tonne respectively.

	Lifespan [yr]	Inv. cost [k€/MW]	OM_var [€/MWh]	OM_fix [€/kW]	η [%]	Start time [h]	Min. load [-]	Start cost [k€]	Start fuel [MWh]	Start fuel type [-]	Part load cost [€/MW]	CC share[1] [%]
HCCS	40	3003	2.1	90.5	43	12	0.35	56.9	2.93	Oil	1.9	88
GCCS	30	1800	2.1	35.1	53	12	0.35	56.9	2.93	Oil	1.9	89
BECCS	40	3759	2.1	130.2	34	12	0.35	56.9	2.93	WG	1.9	85
HWCCS	40	3463	2.1	107.6	41	12	0.35	56.9	2.93	WG	1.9	88
HCCS_flex	30	3153	2.1	95.0	43	6	0.15	42.7	0.879	NG	1.9	88
HWCCS_flex	30	3636	2.1	113.0	41	6	0.15	42.7	0.879	WG	1.9	88
WGCCS	30	1800	2.1	35.1	53	12	0.35	56.9	2.93	WG	1.9	89
GWGCCS	30	1800	2.1	35.1	53	12	0.35	56.9	2.93	WG	1.9	89

[1] CC share: CO_2 capture share, portion of the CO_2 emissions that are captured for storage

Table A.5: Economic and technical data for the variable renewable technologies. The 200 W/m^2 wind power is the only onshore wind technology which got used in this thesis. Onshore wind has limited capacities at different wind sites. FLHs marked with * are at the optimal wind sites.

	Lifespan [yr]	Inv. cost [k€/MW]	OM_var [€/MWh]	OM_fix [€/kW/yr]	FLH [hr/yr]
Onshore wind, 200 W/m^2 (WON)	25	1225	1.1	30.0	5263*
Onshore wind, 300 W/m^2 (WON_300)	25	1106	1.1	30.0	4236*
Offshore wind (WOFF)	25	1838	1.1	100.0	5263
Solar PV (cSi)	25	724	1.1	10.0	1048
Tracking solar PV	25	1014	1.1	30.0	1472
Solar heating	30	220	0.6	0.0	1048

Table A.6: Economic and technical data for the CHP technologies

	Lifespan [yr]	α[1] [%]	Inv. cost [k€/MW]	OM_var [€/MWh]	OM_fix [€/kW/yr]	η [%]	Start time [h]	Min. load [-]	Startup cost [€/MW]	Start fuel [MWh]	Start fuel type [-]	Part load cost [€/MW/h]
Coal CHP (S)	40	0.38	4270	8.8	95.0	25	12	0.40	56.9	2.93	Coal	1.9
Coal CHP (M)	40	0.45	2980	8.9	56.5	29	12	0.40	56.9	2.93	Coal	1.9
Coal CHP (L)	40	0.56	1830	8.6	27.0	32	12	0.40	56.9	2.93	Coal	1.9
Oil CHP	30	0.5	1100	4.0	16.5	30	12	0.40	56.9	2.93	Oil	1.9
Gas CHP	30	1.3	950	1.6	20.0	53	12	0.32	50.6	2.05	NG	1.5
Bio CHP (S)	40	0.32	5650	9.2	125.0	25	12	0.40	56.9	2.93	Biomass	1.9
Bio CHP (M)	40	0.39	3975	9.2	75.0	30	12	0.40	56.9	2.93	Biomass	1.9
Bio CHP (L)	40	0.43	2550	8.7	38.0	33	12	0.40	56.9	2.93	Biomass	1.9
Waste CHP (M)	40	0.26	7700	28.0	220.0	20	12	0.75	56.9	2.93	Biomass	1.9
Waste CHP (L)	40	0.26	6000	28.0	150.0	20	12	0.75	56.9	2.93	Biomass	1.9

[1] Power-to-heat ratio

Table A.7: Economic and technical data for the VMSs and gasifiers. Not shown in this table is the 12 hr start time and 0.35 minimum load for gasifiers. The flow battery technology is only the storage capacity and requires 'Flow bat. cap.' for (dis)charge capacity. Investment costs for storage capacities are per MWh.

	Lifespan [yr]	Inv. cost [k€/MW]	OM_var [€/MWh]	OM_fix [€/MW/yr]	η [%]
TTES	25	5.688	0	0	98 [A]
non-HP TTES	25	26.165	0	0	98 [A]
BTES	25	0.457	0	0	98 [A]
PTES (M)	25	0.857	0	0	98 [A]
PTES (L)	25	0.268	0	0	98 [A]
TTES HP	25	700	1.0	7.0	600
PTES HP	25	700	1.0	7.0	600
BTES HP	25	700	1.0	7.0	600
TTES EB	20	95	1.0	1.5	95
PTES EB	20	98	1.0	1.5	95
H_2 fuel cell	20	500	3.0	0	60
H_2 electrolyser	10	1000	0	20.0	70
H_2 tank	40	40	0	0	99.9 [A]
H_2 LRC[1]	50	11	0	0	99.9 [A]
Li-ion battery	15	150	0	25.0	95 [A,B]
Flow battery	30	180	0	13.0	84 [A,B]
Flow bat. cap.	30	1100	0	54.0	-
Gasifier	25	2000	0	0	-
Gasifier (H_2)	25	2000	0	0	-
Gasifier (El.)	25	2000	0	0	-
Gasifier (H_2+El.)	25	2000	0	0	-

[1] Lined rock cavern
[A] charging efficiency
[B] discharging efficiency

The model describes several ways of producing biogas: from biomass only and with energy input in the form of electricity, hydrogen or a combination. The shares of the resulting biogas energy that needs to be supplied from biomass, electricity and hydrogen in the different gasifiers are shown in table A.8. Since the biogas production is a relatively new addition to the model, the values in the table are approximate, particularly the hydrogen demand which is likely to be larger in reality.

Table A.8: Demand for biomass, electricity and hydrogen in different gasifiers

	Biomass [MWh/MWh gas]	Electricity [MWh/MWh gas]	Hydrogen [MWh/MWh gas]
Gasifier	1.4	0	0
Gasifier (El.)	1.1	0.2	0
Gasifier (H_2)	0.9	0	0.3
Gasifier (H_2+El.)	0.75	0.15	0.25

A.3 Results

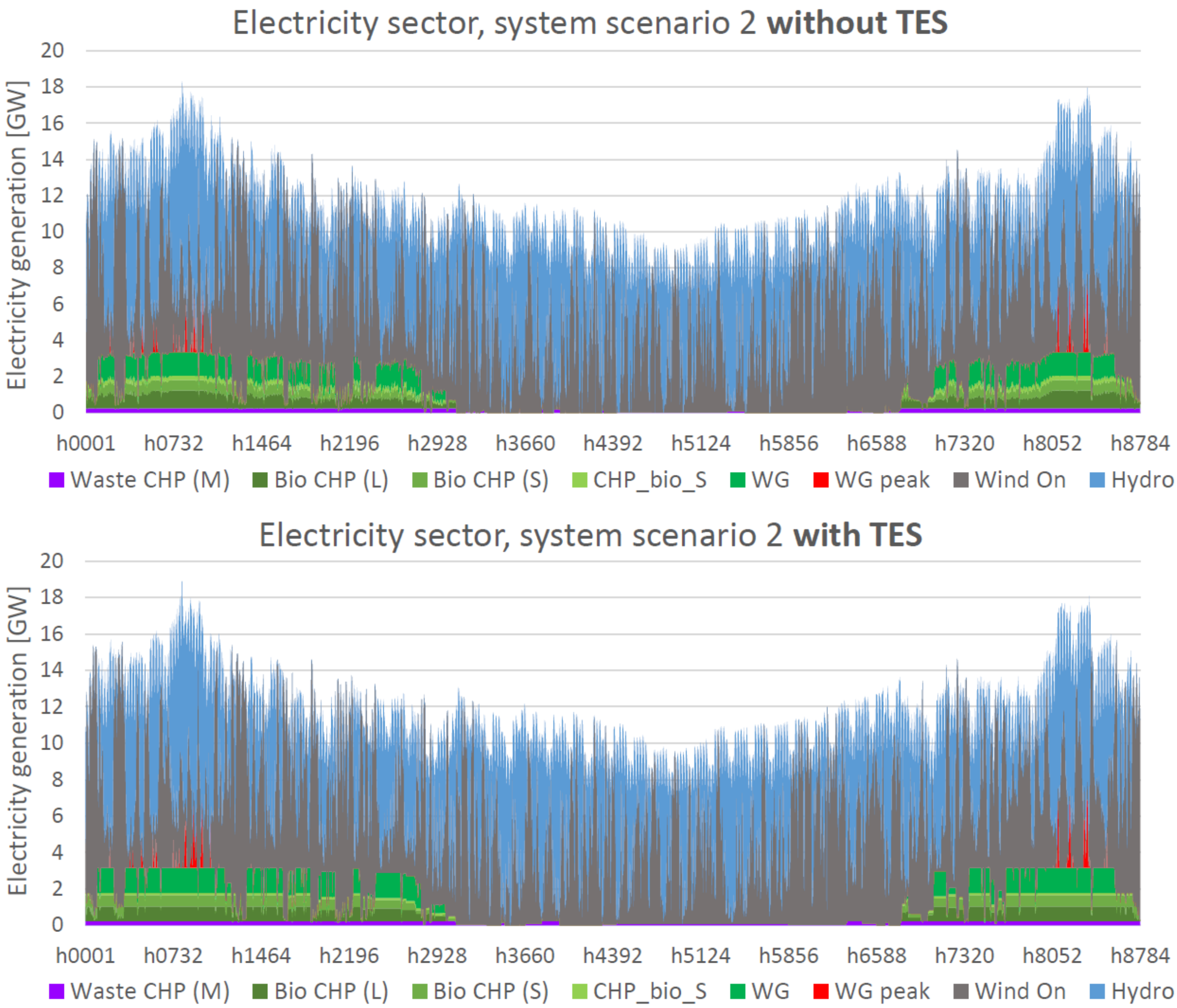

Figure A.1: Electricity generation during one year in system scenario 2 (the base case) with and without TES

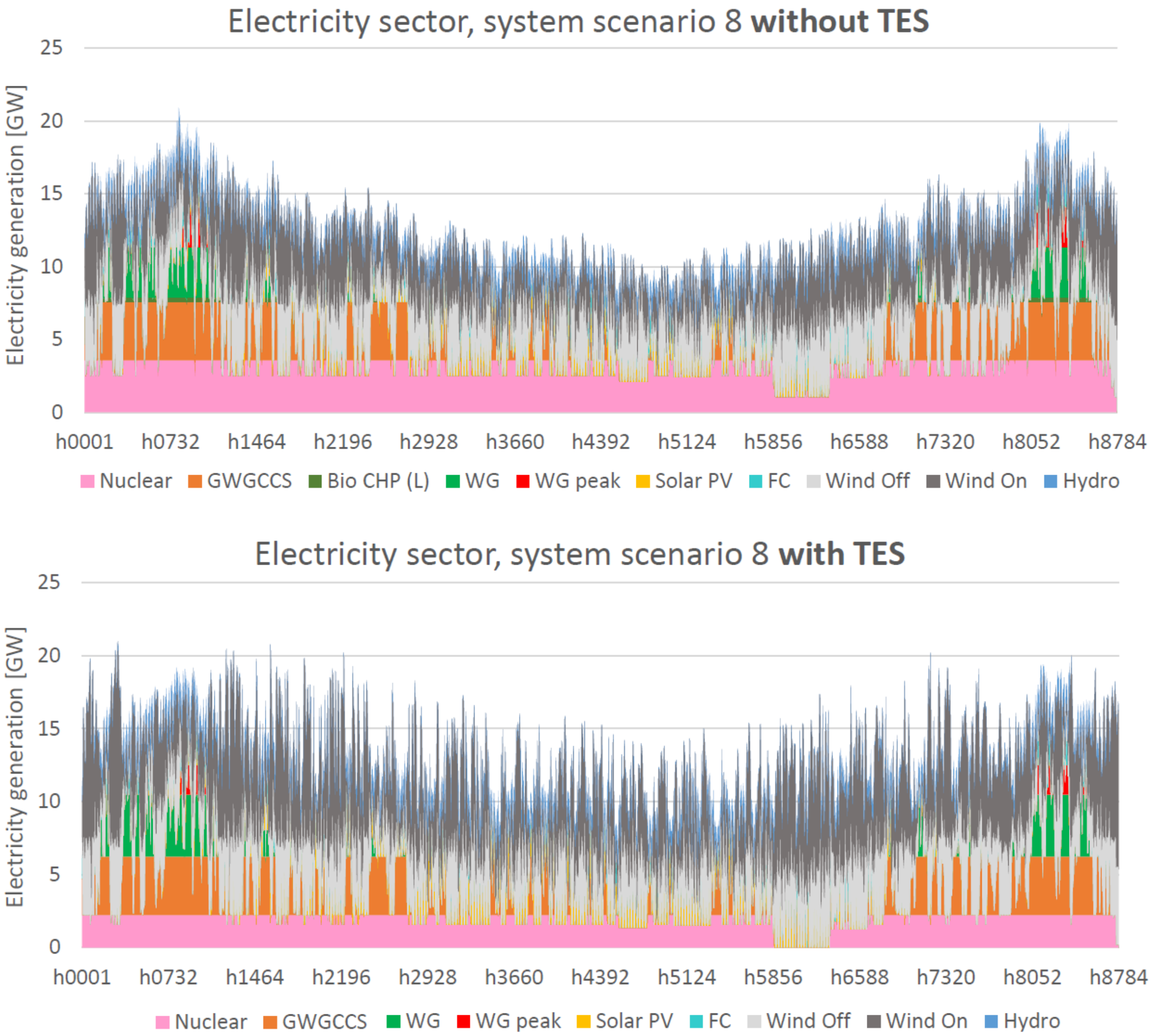

Figure A.2: Electricity generation during one year in system scenario 8 (the low-flex case) with and without TES

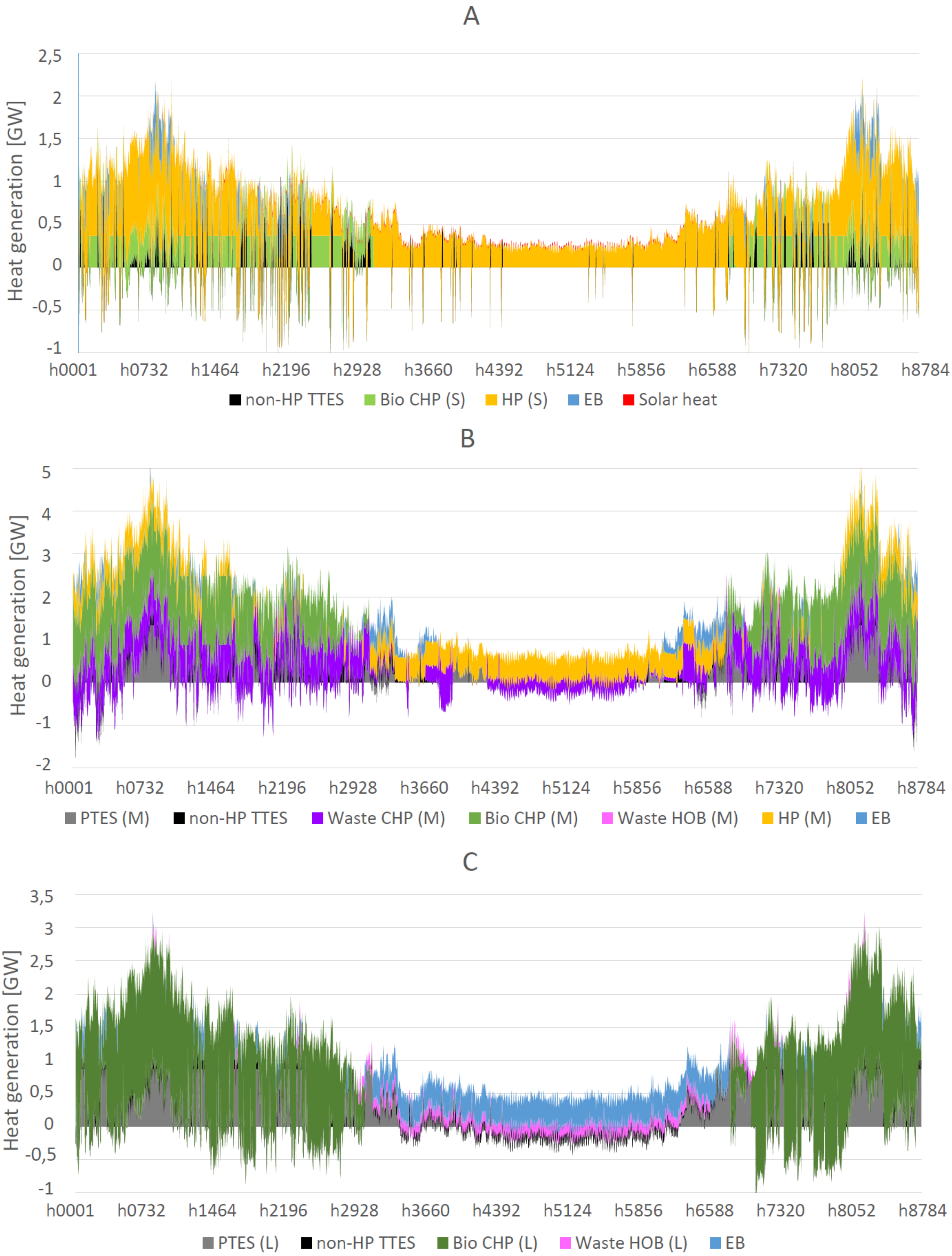

Figure A.3: Heat generation during one year in system scenario 2 with TES, including net discharge

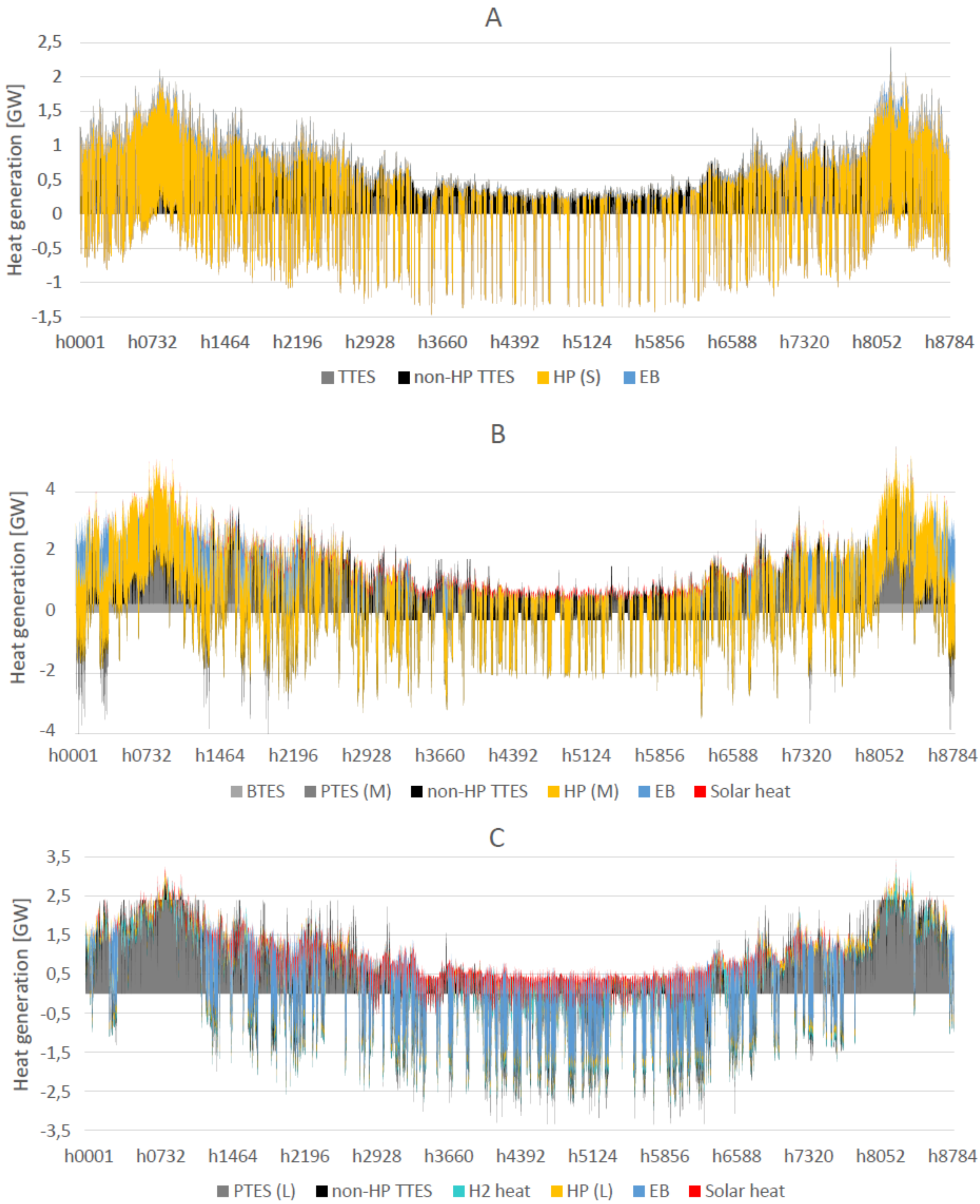

Figure A.4: Heat generation during one year in system scenario 8 with TES, including net discharge