Energy Economics of the Green Transition

What are the Equilibrium Effects of Increasing the Capacity for Thermal Energy Storage? A Case Study on the Danish District Heating System

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Contents

Disclaimer

A significant amount of our work for this paper lies in our code. The git repository can be accessed via the following link. The *README* file contains further documentation on the structure and the key files in the git repository.
https://github.com/marcherger/EnergyEconGroupWork.git

We used the generative AI tool *ChatGPT*[1] to work with both Python and LaTeX code.
For spell checking, we used the tool *DeepL*[2].

The following table tries to link the different chapters of our paper to us as the authors. The names are sorted according to contribution to the respective chapter.

Part	**Authors**
Introduction	Siikanen, Meißner, Herger
Literature Review	Siikanen
Model	Meißner, Herger
Data	Siikanen, Herger
Analysis	Meißner, Herger
Limitations	Herger, Meißner
Conclusion	Herger, Meißner
Data Download and Construction[1]	Herger
Figures	Herger

[1] This work is shown by all files in folder *EnergyEconGroupWork\DownloadDataForDK*.

[1]https://chat.openai.com
[2]https://www.deepl.com/translator

1 Introduction

Many nations have established explicit emission reduction targets in the mid term, aligning with the commitments under the Paris Agreement 2015 (United Nations, 2016). This emission reduction target led to an increase in the Danish electricity generation capacity of renewable energy sources (Statista, 2023). This new generation capacity is intermittent and cannot be predicted perfectly, as it varies with natural conditions. Additionally, seasonal temperature variations are prevalent, particularly in the Nordic region.

This current turning point in the energy sector sparked our interest in Vattenfall's investment in thermal water storage for the district heating system in Berlin, Germany. The intended aim of the commissioned heat storage facility is to store surplus production from wind and solar energy in the form of heat to increase flexibility of supply (Jekat, 2022). According to Tanja Wielgoß, CEO of *Vattenfall Wärme Berlin AG*, this will give "flexibility in Berlin's heat supply and at the same time making it more climate-friendly, independent and safer" (Jekat, 2022). Another interesting investment by Fortum, a Nordic energy company, is the thermal water storage for heat supply in Espoo, Finland (Fortum, 2022)[3]. It is used to cover peaks in demand for district heating. Fortum is also considering building more heat storage facilities in the Espoo area in the near future.

The literature review, Chapter 2, focuses on three publications, related to the field of heat storage. The first paper analyses the optimal size of a combined heat and power plant (CHP) with energy storage in Germany (Streckienė et al., 2009). The second paper aims to find the optimal size of heat storage facilities in Finland (Hast et al., 2017). The third publication highlights different concepts of thermal energy storage in a more technical analysis (Dahash et al., 2019). Chapter 3 guides through data downloading, cleaning and aggregation. In particular, it discusses the different data sources and explains assumptions. In Chapter 4 we develop a model based on Berg (2023) which combines sector coupling and heat storage. We explain the maximisation problem and its constraints and give an overview of the variables used. Chapter 5 builds the main part of our paper as it analyses the model results. We first provide descriptive insights into the baseline results and then analyse the effects of increasing thermal energy storage capacity in the Danish grid. As we make quite strong assumptions throughout our analysis we provide a critical discussion of those in Chapter 6. The final Chapter 7 concludes.

[3] Fortum's press release is unfortunately only available in Finnish but can easily be translated.

2 Literature Review

The paper by Streckienė et al. (2009) analyses the optimal size of a combined heat and power plant (CHP) with thermal energy storage capacity under German spot market conditions. The goal of zero emissions brings us to a new topic: price fluctuations between peak and off-peak hours due to intermittent renewable energy capacity. Streckienė et al. (2009) argue that these price fluctuations can be stabilised to some extent by thermal storage. Their paper is entitled *Feasibility of CHP-plants with thermal stores in the German spot market*, and analytically examines the optimal size of such thermal energy storage, taking into account fluctuations in prices for natural gas and electricity, as well as investment costs. For their modelling of the market, they use the software *EnergyPRO*.
The results show that these thermal storage facilities offer flexibility in the supply of electricity and heat, especially when prices fluctuate widely. Fluctuations in investment costs have the smallest impact on profitability. The thermal reservoirs of interest are relatively small compared to the ones examined in other papers, measuring only 650 m^3. Thus, storage plants offer flexibility and stable prices only in sparsely populated areas. Otherwise there would have to be several storage plants with sufficient capacity to keep prices stable. The results also show that the feasibility of the optimal thermal energy storage is affected by certain circumstances, such as electricity prices, investment costs and national differences in policies such as taxation.

In the paper *The role of heat storage plants in facilitating the adaptation of district heating systems to large amount of variable renewable electricity*, Hast et al. (2017) show that increasing the size of heat storage can result in economies of scale. The effects of more variable electricity prices were analysed in a district heating system (DH) that includes CHPs, fired mainly by biomass and heat-only boilers (Hast et al., 2017, p. 33). They analyse the optimal capacity to determine the optimal heat storage size in three different locations in Finland by analysing future electricity prices for district heating using CHPs.
The paper highlights renewables as the main source of energy, which increases the need for storage due to price and generation capacity fluctuations. In winter, in particular, heat demand is four times higher than in summer. The authors assume that the district heating system will be able to respond to changes, such as a rapid increase in demand. In their model, there are no start-up or shut-down periods, no minimum load requirements and no minimum operating times. The results show that the optimal capacity is around $110'000$ m^3 in an area with less than $80'000$ inhabitants and that further capacity increases will not lead to cost reductions.

Dahash et al. (2019) analyse the effects of Thermal Energy Storages (TES) in their publication *Advances in seasonal thermal energy storage for solar district heating applications: A critical* *review on large-scale hot-water tank and pit thermal energy storage systems*. The authors analyse four large-scale seasonal thermal energy storage concepts, including the storage efficiencies and costs associated with different designs and materials used. The results support certain TES techniques in terms of efficiency. But they also have drawbacks, such as high construction costs. In addition, these storage facilities can be used as in the short-term as well as the long-term. The document provides a broad description of the functionalities and uses of TES, but mainly as a long-term seasonal energy storage facility. An example of seasonal storage is a storage facility that uses solar-heated hot water, which is heated in the summer and consumed in the winter.

What is missing in light of the current research is the vision that these energy storage facilities can be part of the grid by smoothing the price levels continuously. These reservoirs can then be used in short term to store electricity and supply district heating. Intermittent electricity generation itself cannot be used continuously, and usually, a backup power plant is needed to provide electricity or heat during off-peak hours of intermittent supply. The TES allows for an analysis of the welfare and economic impacts when the use of back-up power plants can be reduced. Surplus energy can be supplied when supply is scarce. The TES plants already built in Denmark are relatively small: on average around $3'000$ m^3 (Energistyrelsen, 2020, p. 55).

3 Data

The data used in our model is mainly drawn from three different sources. These sources were also used during the course. We upload the data into different Excel files, as shown in the exercise lessons. Using Python[4], we then build one final dataset from the different download files stored in folder *EnergyEconGroupWork\DownloadDataForDK\ModelData*. The final dataset is the data for which the model is solved.

The electricity market data comes from the European Network of Transmission System Operators for Electricity (ENTSO-e, 2023). This ENTSO-e Transparency Platform is an extensive database from which we import the two variables forecast load, and forecast intermittent supply. Load reflects the variation in demand in the day-ahead market and varies hourly. Intermittent supply determines the exogenous hourly variation in intermittent electricity generation for the day-ahead market.
We take the heat market demand for Denmark in 2019 from the OPSD data platform (Open Power System Data, 2023). We take the latest version of the *when2heat* dataset and use the *heat_profile* columns as they correspond to the normalized heat demand from space and water

[4]see file *EnergyEconGroupWork\DownloadDataForDK\ModelData\0_Construct_Final_Dataset.ipynb*

heating.
The plant data comes from the Danish Climate Outlook 2023, published by the Danish Energy Agency (Energistyrelsen, 2023). The Danish Energy Agency uses the RAMSES linear programming model of the European electricity system to produce the climate outlook. The input data is an inventory of Danish electricity and district heat-generating plants in Denmark but also includes representative plants in the rest of Europe. Energy and heat prices are from 2019, while plant data is from 2023. We argue that modelling the increase in heat storage capacity using current technology at 2019 energy and heat prices is a good assumption. The energy and heat price markets are more volatile in 2023 due to uncertain external conditions such as COVID-19 and the war in Ukraine (Mier, 2023).
The technology data for the heat accumulator we use in this paper originates from the Technology Data for Energy Storage provided by the Energistyrelsen (2020). The data specifically concerns the technology associated with large water storage tanks, denoted as *141 Large hot water tank* in the Excel spreadsheet. The parameters in the sheet include energy storage capacity, output and input capacities, roundtrip efficiencies, and financial costs. It should be noted that the section on technology was updated in 2018, which is why we use the assumed data for 2015, as this data was certain at the time of the update. Costs are categorized as fixed and variable, and the reference years for these prices are either 2015 or 2020. Thus, we either adjust prices upwards (from 2015 to 2019) or downwards (from 2020 to 2019) to match the base year for heat and electricity prices. For simplicity, the technology data is assumed to remain accurate for larger TTES storage facilities, as the datasheet refers to a storage size of only $3'000\ m^3$.

The original datasets contain several market areas. For electricity there are the two bidding zones *DK1* and *DK2*. The heat markets are additionally subsetted into *Central*, *Large Decentral*, and *Small Decentral*. In total there are two electricity zones and six heat markets.
In our model we aggregate all those sub-markets into one single electricity (we call it DK) and one single heat market (we call it $DK\_Central$). This abstraction has the same implications as assuming transmission lines with unlimited capacity between all areas. It therefore counts into our limitations. See Chapter 6 for more detail. The aggregation simplifies our analysis as we can focus on only two markets. In a hypothetical scenario were we would not aggregate, we would have to analyze up to eight markets simultaneously. There would also be spillover effects between the different heat markets due to the sector coupling with electricity markets. Electricity demand from one heating area would influence the price for one electricity zone which in turn influences the two other heating areas within this electricity zone[5].

[5]If one would allow for transmission between the two electricity zones, one heat market could potentially generate spillover effects for all other heat markets.

4 Model

The model we develop is based on Berg (2023). Specifically, we combine the *mBasicPH* model with an extension of the *mBasicInt* model, presented in Exercise44 of this course. The aim is to allow for sector coupling of energy and heat as well as the storage of heat. The *mBasicPH* model provides three different types of technologies:

- **Standard energy plants** $[E]$ which produce electricity, dispatchable or intermittent
- **Combined heat and power plants** $[BP]$, specifically back-pressure plants which use fuels and other inputs to simultaneously produce electricity and heat
- **Heat pumps** $[HP]$ which use electricity to produce heat

We add two more systems to this set of technologies:

- **Standard heat plants** $[H]$ which use fuels to produce heat
- **Heat storage facilities** $[HS]$ that take heat from the grid in one hour and dispatch it again at a later time.

Welfare function

$$\max_{E_{i,h}, H_{i,h}, D_h^E, D_h^H, Y_{i,h}^c, Y_{i,h}^d}$$

(1)

$$\begin{aligned} W = &\sum_{h=1}^{H}\left(u_E \cdot D_h^E - \sum_{i\in\{\mathcal{I}^E,\mathcal{I}^{BP}\}} c_i \cdot E_{i,h}\right) - \sum_{i\in\{\mathcal{I}^E,\mathcal{I}^{BP}\}} FOM_i \cdot q_i^E \\ &+ \sum_{h=1}^{H}\left(u_H \cdot D_h^H - \sum_{i\in\{\mathcal{I}^H,\mathcal{I}^{HP}\}} c_i \cdot H_{i,h} - \sum_{i\in\{\mathcal{I}^{HS}\}} c_i \cdot (Y_{i,h}^c + Y_{i,h}^d)\right) - \sum_{i\in\{\mathcal{I}^H,\mathcal{I}^{HP},\mathcal{I}^{HS}\}} FOM_i \cdot q_i^H \end{aligned}$$

This equation compares the utility, measured in willingness to pay, and the costs associated with energy and heat production to estimate the total welfare of the market. The first line corresponds to the electricity market and the second line represents the heat market. Utility is derived from consumption of electricity and heat. The marginal costs of production are linear with the quantity of the respective energy medium produced. The fixed costs of a power plant depend on it's production capacity.

In addition to the marginal costs for energy and heat production, the equation also takes into account the marginal costs for using the storage technology. However, according to the technology data sheet for energy storage, these costs are equal to 0.

Marginal cost function

(2)
$$c_i = c_i^{oth} + \sum_j \mu_{i,j}\ p_j$$

This function characterizes the marginal cost of production for each plant. They contain non-fuel related costs and the cost of fuel consumption. These consist of the quantity of fuel j required to produce one unit of energy/heat and the price per unit of fuel j.

Co-generation constraint

(3)
$$E_{i,h} = \upsilon_i\ H_{i,h}, \quad \forall_i \in \left\{\mathcal{I}^{BP}, \mathcal{I}^{HP}\right\}$$

At this point, the two energy sectors are actually linked. The constraint specifies the ratio at which electricity and heat can be generated (in case of the back-pressure plants) or transformed (in case of heat pumps).

Equilibrium identities

(4)
$$\begin{aligned} D_h^E &= \sum_{i \in \{\mathcal{I}^E, \mathcal{I}^{BP}, \mathcal{I}^{HP}, \mathcal{I}^{HS}\}} E_{i,h} \\ D_h^H &= \sum_{i \in \{\mathcal{I}^H, \mathcal{I}^{BP}, \mathcal{I}^{HP}\}} H_{i,h} + \sum_{i \in \{\mathcal{I}^{HS}\}} (Y_{i,h}^d - Y_{i,h}^c) \end{aligned}$$

The equilibrium identities ensure that the energy and heat demand are exactly met by the respective supply in any given hour. It should be noted that the total heat supply consists of generation by normal heat plants as well as net-discharge $(Y_{i,h}^d - Y_{i,h}^c)$ of the storage plants.

Domain constraints on generation

(5)
$$\begin{aligned} E_{i,h} &\in \left[0, q_i^E\ \gamma_{i,h}\right], \quad \forall_i \in \left\{\mathcal{I}^E, \mathcal{I}^{BP}\right\} \\ H_{i,h} &\in \left[0, q_i^H\right], \quad \forall_i \in \left\{\mathcal{I}^H, \mathcal{I}^{HP}\right\} \end{aligned}$$

The domain constraints on generation ensure that the generated energy/heat in each hour h for each plant i does not exceed the installed generation capacity for the respective plant. For the intermittent energy plants the capacity in each hour depends on natural conditions (e.g., wind or cloud cover). The parameter $\gamma_{i,h}$ therefore takes a value between 0 and 1 for intermittent plants. For dispatchable plants it takes the value 1 over all hours.

Domain constraints on demand

$$D_h^E \in \left[0, L_h^E\right]$$
$$D_h^H \in \left[0, L_h^H\right] \tag{6}$$

These constraints ensures that demand is below or equal to load. In other words: load shedding can either be 0 or positive. Note that the model can choose D_h^E and D_h^H because it can choose load shedding.

Law of motion

$$S_{i,h} = S_{i,h-1}\left(1-\beta_i\right) + Y_{i,h}^c\ \sqrt{\eta_i} - \frac{Y_{i,h}^d}{\sqrt{\eta_i}}, \quad \forall_i \in \mathcal{I}^{HS} \tag{7}$$

The law of motion models the level of stored heat in each storage plant. The first part computes what storage level is left from the previous hour, after self discharge. The second and third part model the inflow and outflow of heat while accounting for the efficiency of that process.

Domain constraints on storage

$$Y_{i,h}^d \in \left[0, q_i^{HS}\right], \quad \forall_i \in \mathcal{I}^{HS}$$
$$Y_{i,h}^c \in \left[0, q_i^{HS}\right], \quad \forall_i \in \mathcal{I}^{HS} \tag{8}$$
$$S_{i,h} \in \left[0, \bar{S}_i\right], \quad \forall_i \in \mathcal{I}^{HS}$$

The first two constraints restrict the amount of charge/discharge that can take place within one hour. It corresponds to the speed at which the storage tank can be filled/emptied. The third constraint caps the maximum level of stored heat in the end of each hour. It corresponds to the size of the tank.

Terminal condition

$$S_{i,H} = S_{i,0}, \quad \forall_i \in \mathcal{I}^{HS} \tag{9}$$

The terminal condition ensures that the storage tank has the same storage level at the end of the year as it had at the beginning of the year. This eliminates the possibility of emptying the tank in one year at the expense of the following year.

An overview of all variables used in the model can be found in Table 1 in the Appendix.

5 Analysis

5.1 Intermittent Supply

Before analysing our model, we want to see whether there is significant intermittent energy production that is consumed by the heat market. This will determine whether we expect to see economic benefits from the storage technology. If there is intermittent production flowing into the heat market, prices will vary between hours with high and hours with low intermittent generation. These price fluctuations would make energy storage economically beneficial.

In our specific model, there are two ways in which intermittent generation can enter the heat market. Firstly, directly through intermittent heat generation. There is one plant that supplies intermittent heat: A solar thermal power plant with a maximum capacity of $1'107$ MW. Secondly, intermittent supply can enter the heat market indirectly, through intermittent energy production converted via heat pumps. There are four heat pumps[6] in our model with a total capacity of $1'019$ MW.

As Figures 1 and 2 show, there is variation in most of the natural conditions that determine intermittent production capacities. However, we observe more variation over the year than over an average day. Additionally, it should be noted that the values for $\gamma_{i,h}$ can in theory vary between 0 and 1 while the scale of the graphs 1 and 2 end at 0.35 and 0.25 respectively.
On-shore wind (WL_DK), off-shore wind (WS_DK), and run of river (ROR_DK) vary significantly over the year. For solar energy production (PV_DK) we see a comparably small but still visible variation. Over an average day, on-shore wind (WL_DK) and photovoltaics (PV_DK) vary considerably and we observe smaller variations for off-shore wind (WS_DK) and run of river (ROR_DK). It appears that solar heat ($SH\_DK\_Central$) fluctuates over the year and over an average day to a much lesser extent, if at all, than the other parameters.

We therefore take a closer look at the average hourly variation of solar heat ($SH\_DK\_Central$). Figure 3 shows that there are fluctuations, albeit very small ones. During the daylight hours, the parameter increases, but the average value reaches a peak value of only 0.0002. Compared to the other parameters, this peak value is very low.

Figures 1 and 2 show that there are intermittent capacity fluctuations that mainly originate from the electricity market as solar heat fluctuates only marginally. Moreover, the Figures show higher seasonal variations compared to hourly variations. We assume that some of these fluctuations are transferred to the heat market via sector coupling (i.e. via the heat pumps).

[6] $Central\_EP$, $Central\_HPstandard$, $Central\_HPsurplusheat$, $Central\_IndustryH$

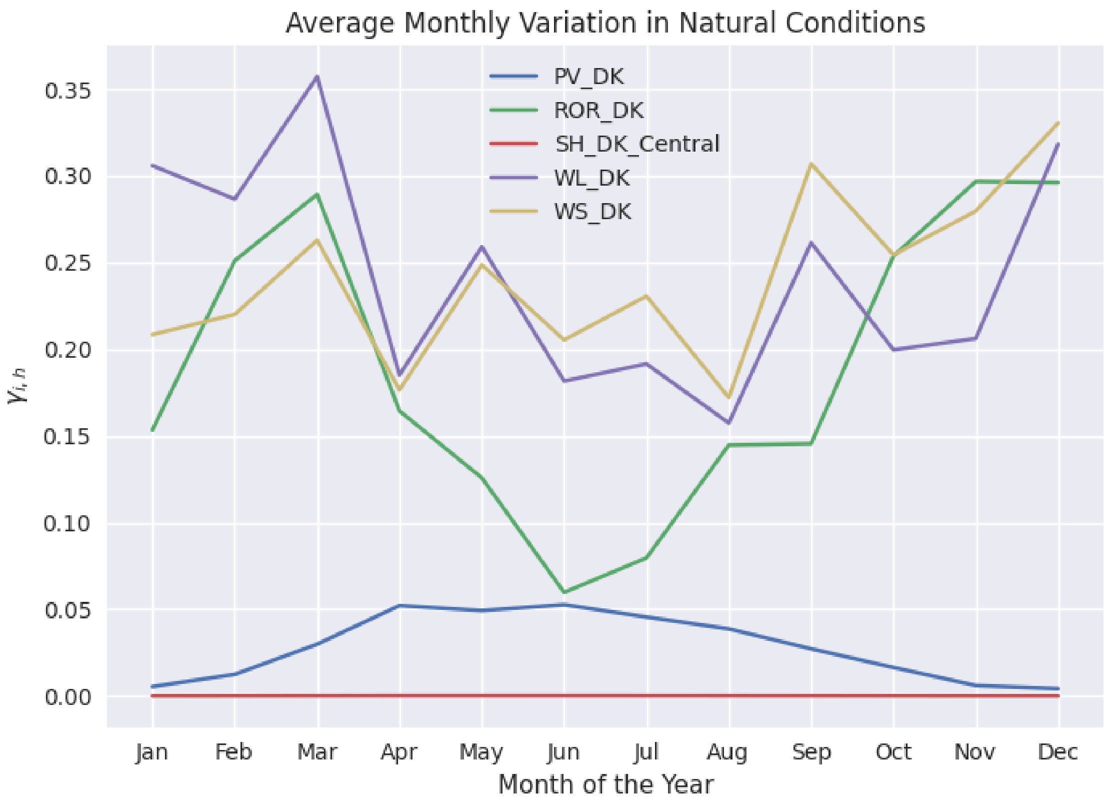

Figure 1: Average Monthly Variation in Natural Conditions

This observation leads to the intuition that an increase in heat storage capacities could be economically advantageous. The following two subsections examine this in more detail.

5.2 Baseline

The following model analysis is structured in two parts: Chapter 5.2 *Baseline* and Chapter 5.3 *Counterfactual Scenarios*. First, we provide descriptive insights into the baseline results. Then we analyse the effects of increasing thermal energy storage capacity with four counterfactual scenarios.

As described in Chapter 3, we aggregate all Danish district heating systems to one area. To set the baseline thermal energy storage capacity, we scale the technological data for the individual storage facilities from Energistyrelsen (2020, p. 59) with the estimated thermal energy storage capacity of the Danish grid. The estimated total volume of water tanks in the Danish grid is 875′000 m^3 for the year 2013 (Energistyrelsen, 2020, p. 54). We use this figure as it is the most recent one we can find. To convert the m^3 value to MWh we use the calculation from

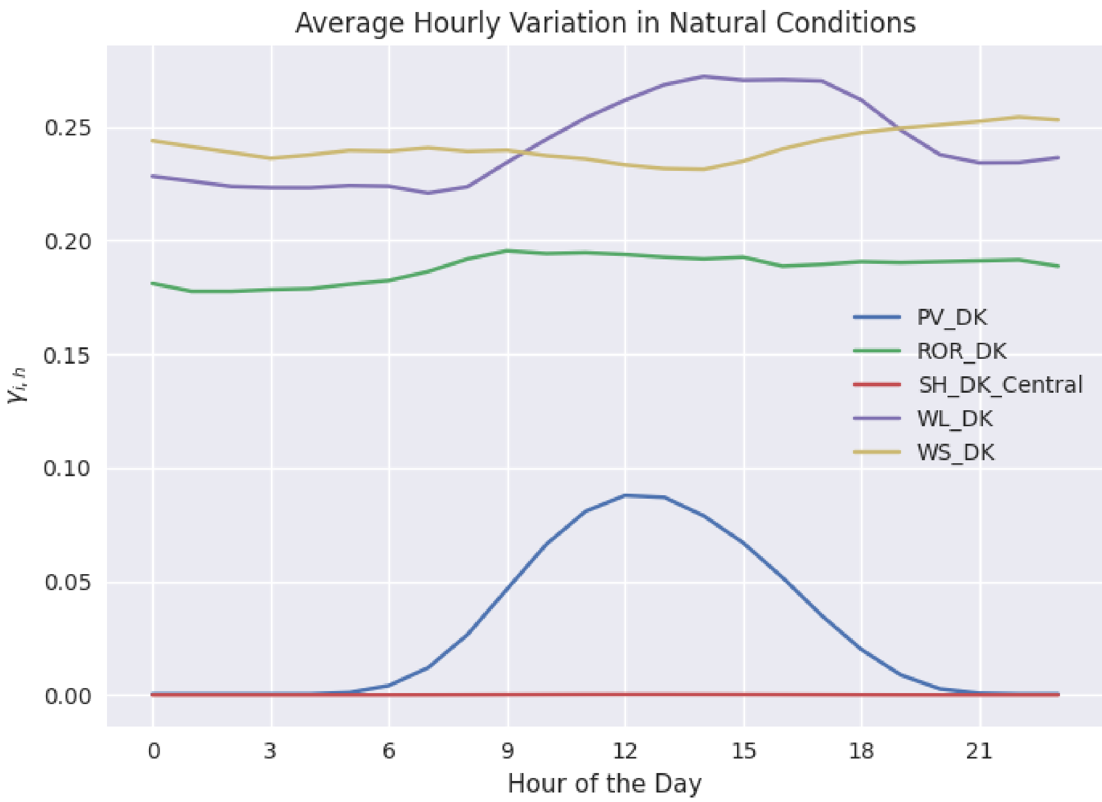

Figure 2: Average Hourly Variation in Natural Conditions

Energistyrelsen (2020)[7]. This gives us $50'365$ MWh as the baseline heat storage capacity.

5.2.1 Marginal System Costs

Figure 4 shows that the marginal system costs on the heat market broadly follow a seasonal pattern. In the summer weeks, the heat price is comparatively low, while the heat price peaks in the winter weeks. This is in line with the intuition that the demand for heat is high in winter and low in summer. Some price volatility can be observed during the transitions between summer and winter (e.g. around the weeks 20 and 40). According to our intuition, the origin of this volatility can be found on the demand side. Temperatures can fluctuate considerably during these periods of the year. Accordingly, the demand for heat also fluctuates, which would cause price volatility.

Figure 5 shows the average daily variation in marginal system costs on the heating market. The heating price is lowest at night. It rises between three and five in the morning and peaks

[7]See cell C8 of sheet *141 Large hot water tank* in *EnergyEconGroupWork\DownloadDataForDK \ModelData \technology_datasheet_for_energy_storage.xlsx*

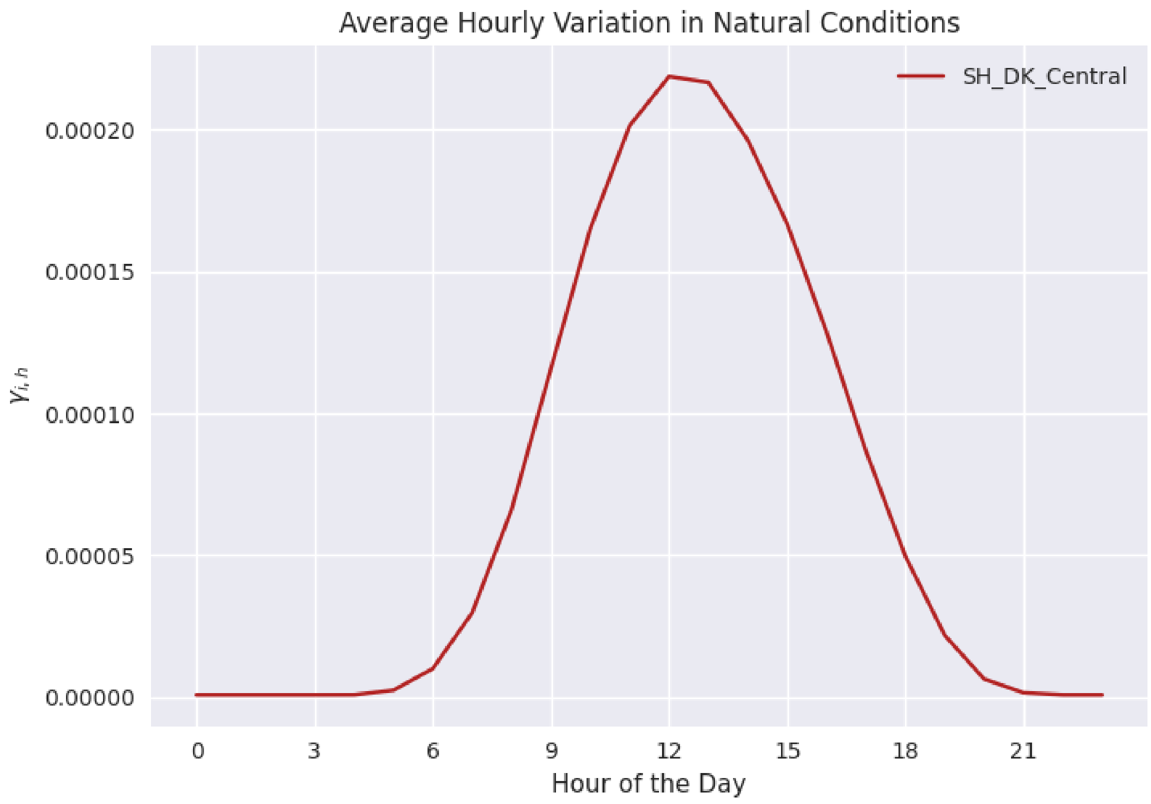

Figure 3: Average Hourly Variation in Natural Conditions for Solar Heat

at six in the morning. Prices decrease during midday, and after a small peak at eight o'clock in the evening, begin to drop again to restart the cycle. According to our intuition, this pattern reflects the daily routine of an average consumer. Low demand at night while the consumer sleeps. High demand in the morning for a warm start in the day. Lower demand during the day when the consumer is at work. Here, heating per person is more efficient because, for example, there is less space per person which needs to be heated in an open-plan office than in a private home. Higher demand in the evening, when she returns home from work and spends her time until she goes back to sleep.

5.2.2 Usage of Storage

Figure 6 shows the average hourly net-charge of the thermal storage tank. Positive values mean that the storage tank is on average charged in the respective hour of the day. Conversely, negative values mean that it is on average discharged. If we compare this graph with the marginal system costs (Figure 5) we see a strong negative correlation. This is in line with our intiution that the tank is stored in hours were the price is low and emptied in hours were

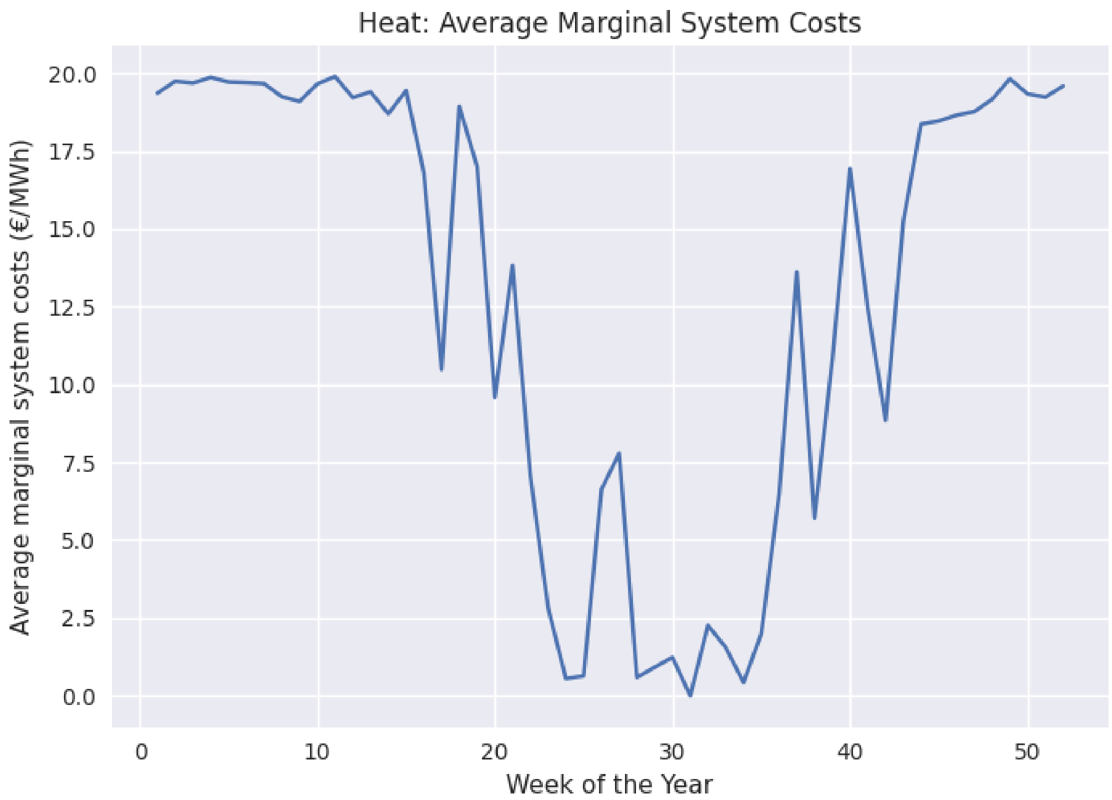

Figure 4: Weekly Average Marginal System Costs on the Heat Market

the price is high. In our baseline configuration, the maximum charge/discharge capacity is 839.4 MW (specified by the parameter q_i^{HS}). At six o'clock in the morning, an average of 66.8 % of this capacity is used for discharging[8]. This is quite significant considering that we take the average over the whole year and that the net charge values can theoretically also be positive (which would have a strong upward effect on the mean).

5.3 Counterfactual Scenarios

For the counterfactual scenarios we increase the thermal energy capacity while holding the storage duration constant. In other words: we scale up the storage and charge/discharge capacity at the same rate. This way the time it takes to fully empty/fill the tank stays constant. We scale up the storage according to the same rationale as described in chapter 5.2. From $875'000\ m^3$ in our baseline, we increase the storage capacity in four steps up to $1'750'000\ m^3$.

[8]
$$\frac{561.0\ [MW] \cdot 100\ [\%]}{839.4\ [MW]} = 66.8\ [\%]$$

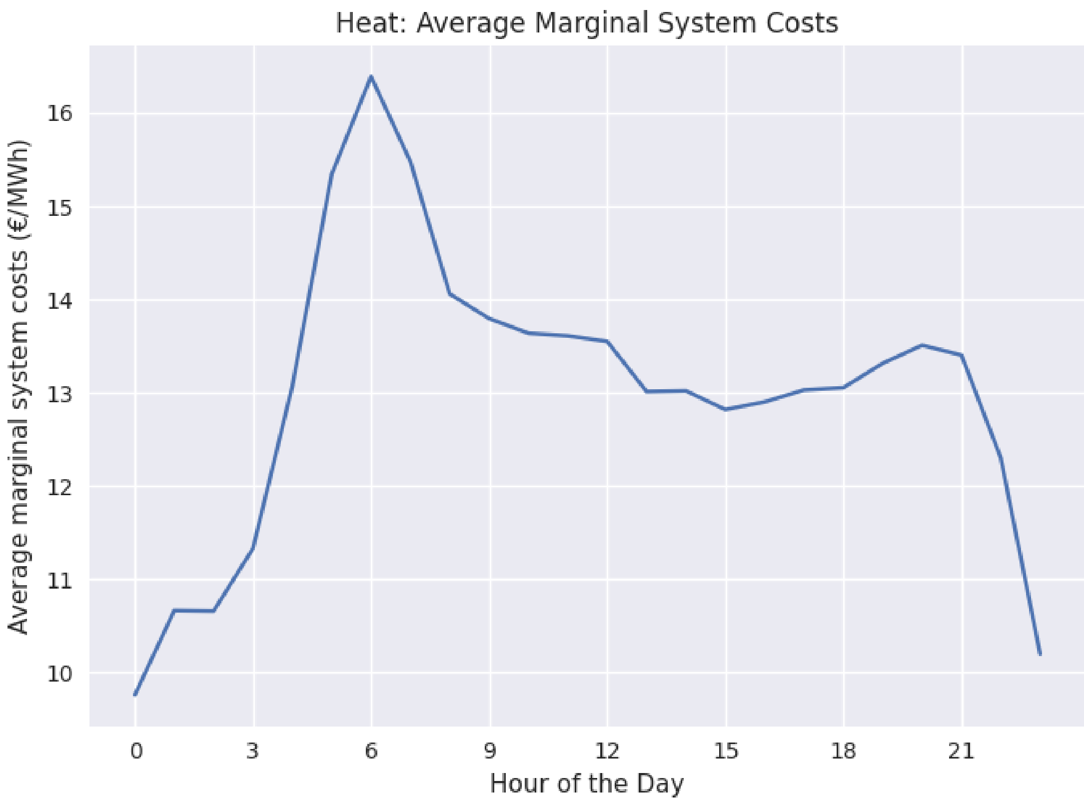

Figure 5: Hourly Average Marginal System Costs on the Heat Market

This upper bound value represents a doubling of the total heat storage capacity from 2013. To convert the m^3 value to MWh we use the calculation from Energistyrelsen (2020)[9].

5.3.1 Prices and Costs

When considering Figure 7, we observe that the marginal system costs for the average hour of the day only vary marginally when increasing the thermal storage capacity. Contrary to our expectations, we only observe a minor smoothing of marginal system costs (specifically between hour 8 and 12 in the morning). As we discussed in *Exercise44*, our expectation would be that the increase in the electricity capacity of the storage system significantly smoothes out the marginal system costs for the average hour. As we do not see this in our model, we hypothesise that the arbitrage opportunities of charging the heat storage during low price periods and discharging it during high price periods are limited. Additionally, we observe only limited longer-term smoothing of system costs (i.e. over weeks) in the heat market (see Figure

[9]See cell C8 of sheet *141 Large hot water tank (loop)* in *EnergyEconGroupWork\DownloadDataForDK \ModelData \technology_datasheet_for_energy_storage.xlsx*

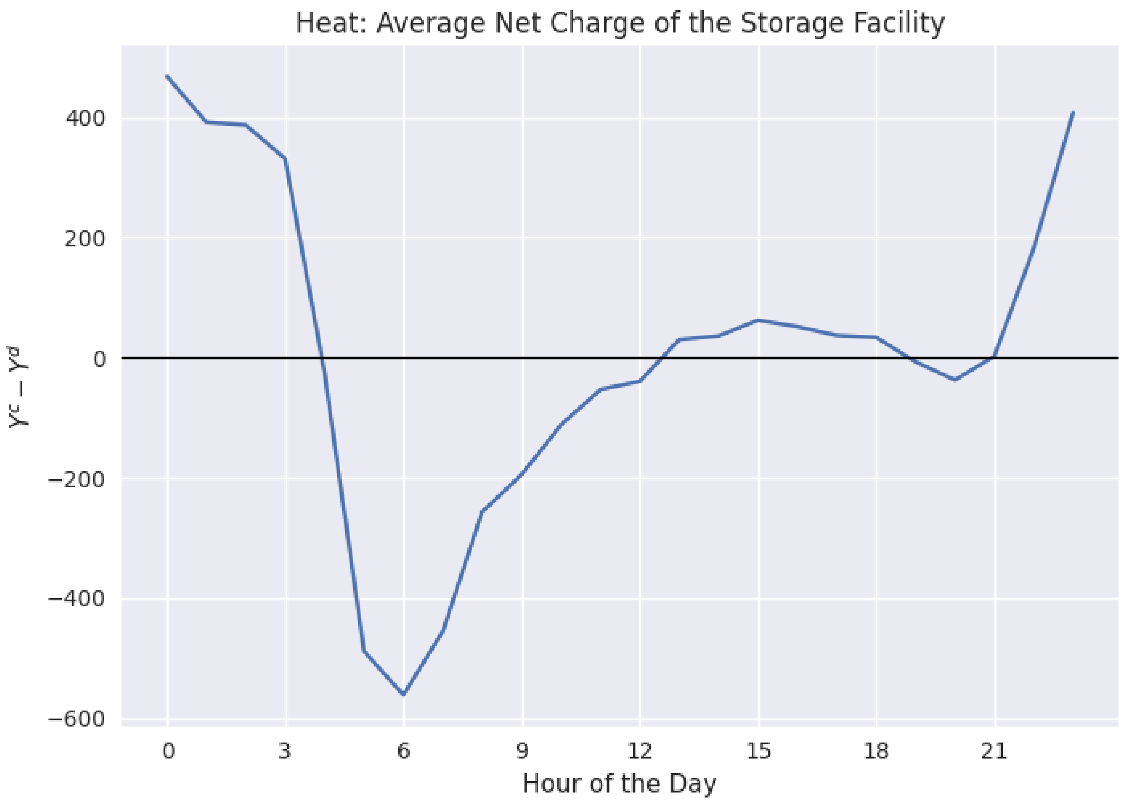

Figure 6: Hourly Net-Charge of the Heat Storage Facility

11). This could be due to the fact that we assume a storage duration of 60 hours[10].
Considering Figure 8, we first note that the absolute changes in mean consumer prices are negligible. While controlling for significance is out of scope for this paper, we still comment on the relative changes in mean consumer prices.
The direction of the effect of increasing heat storage capacity is in line with our intuition. The increase of thermal storage capacity has two effects on the average heat price. The first effect comes from additional demand in low price hours for charging the tank. This pushes average prices downwards. The second effect comes from additional demand being satisfied in high price hours, as the tank is emptied. This pushes average prices upwards. According to our intuition the second effect should outweigh the first effect. Demand for charging can also be satisfied by heat pump production which demands energy from the electricity market rather than the heat market. It therefore does not influence heat prices through demand effects. Discharging can only take place in the form of heat while the charging effect can take place on the heat as well as the electricity market. This is why in our intuition average prices on the heat market

[10]We discuss further research possibilities for seasonal storage in Chapter 7.

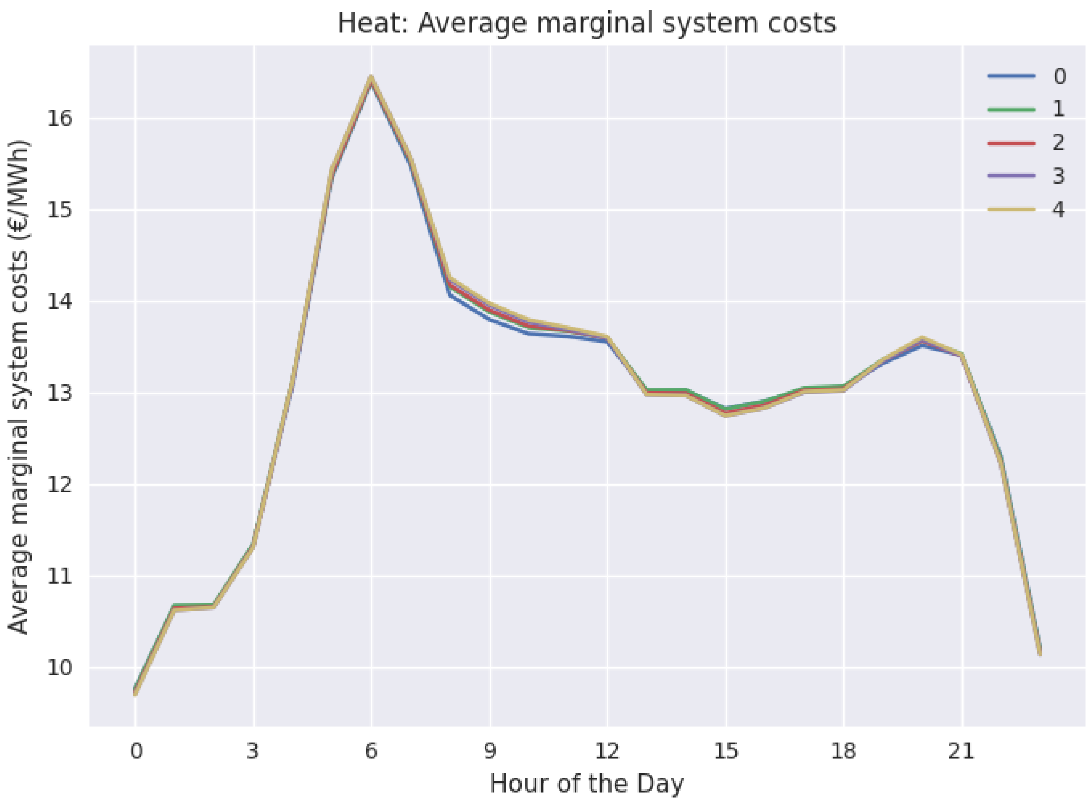

Figure 7: Hourly Average Marginal System Costs on the Heat Market

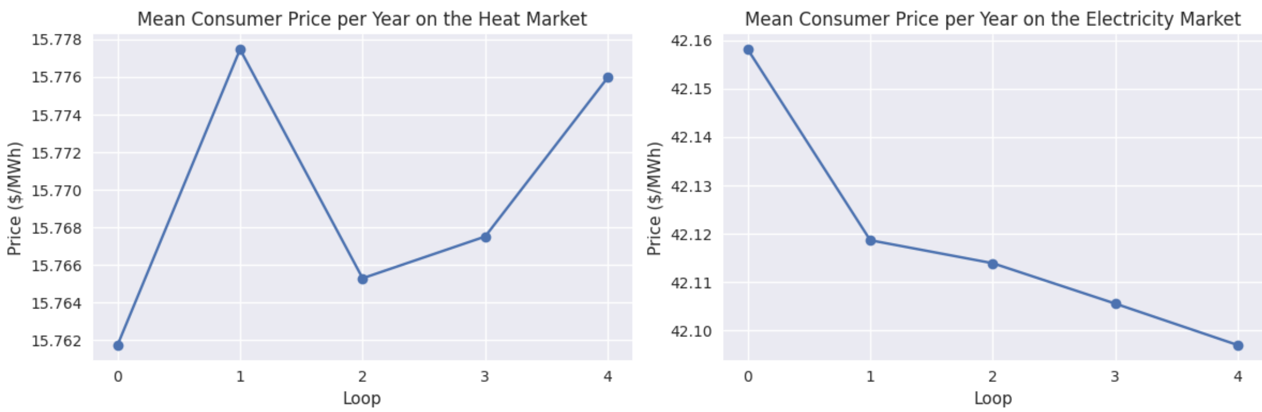

Figure 8: Average Mean Consumer Prices per Year on the Heat and Electricity Markets

should increase, when storage capacity increases. What we cannot explain is the spike of the mean consumer price on the heat market in the first loop.

On the electricity market we see a different picture. Here there is only one effect from increasing heat storage. Demand in low price hours increases as heat pumps produce heat which can be stored in the tank. As there is an increasing demand satisfied in low price hours, our intuition expects the average electricity price to fall.

5.3.2 Usage of Storage

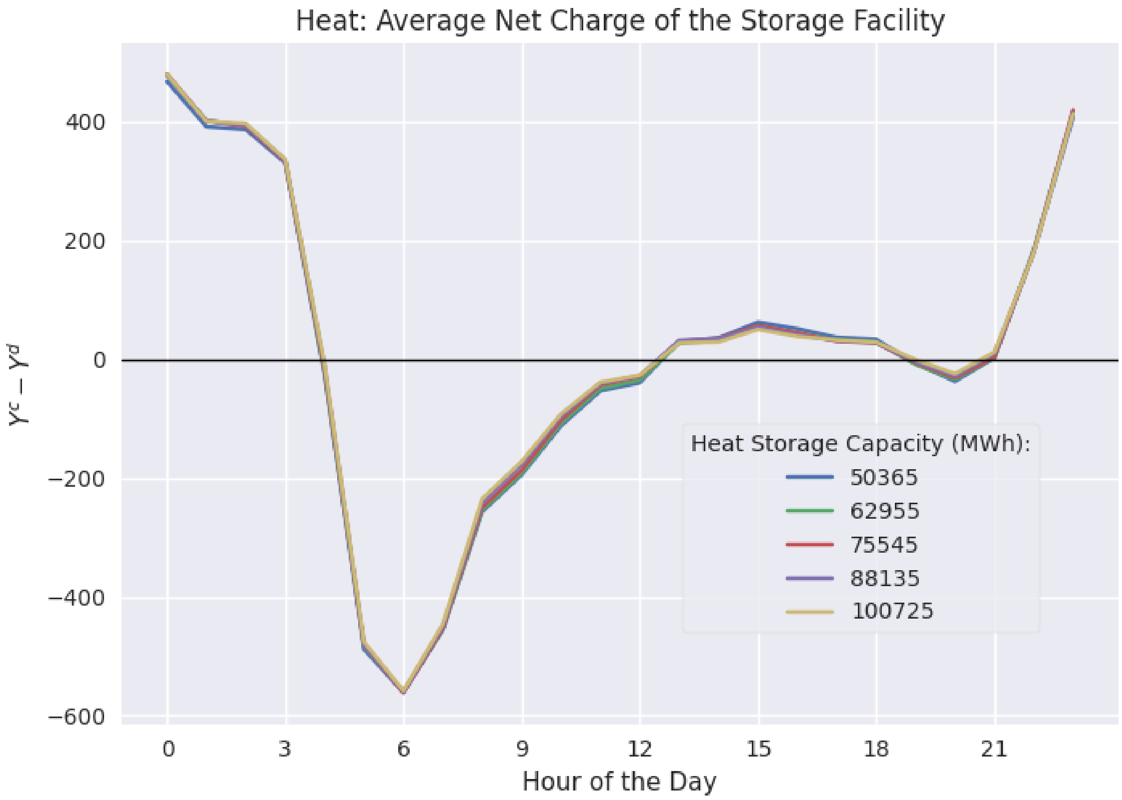

Figure 9: Hourly Net-Charge of the Heat Storage Facility

Figure 9 shows that the overall change compared to the baseline (blue line) is only slight and the differences between the scenarios are minor. The small effect we see around 2 a.m. is in line with our intuition, as it is economically profitable to charge more during low price hours. However, the fact that the same amount of heat is discharged around 6 a.m. in all scenarios contradicts our intuition. We expected more discharging under scenarios with higher storage capacities as expensive, i.e. fossil based, heat is substituted for cheaper heat coming from the storage tank. This could be an indication that the optimal storage capacity for the high demand hours is already reached in the baseline scenario.
Further, the pattern in the later hours of the day contradicts our intuition. We observe that the higher the storage capacity, the less heat is loaded in the afternoon when prices are low, and the less heat is unloaded around 8 p.m. when heat demand is high.

5.3.3 Economic Value of Generators

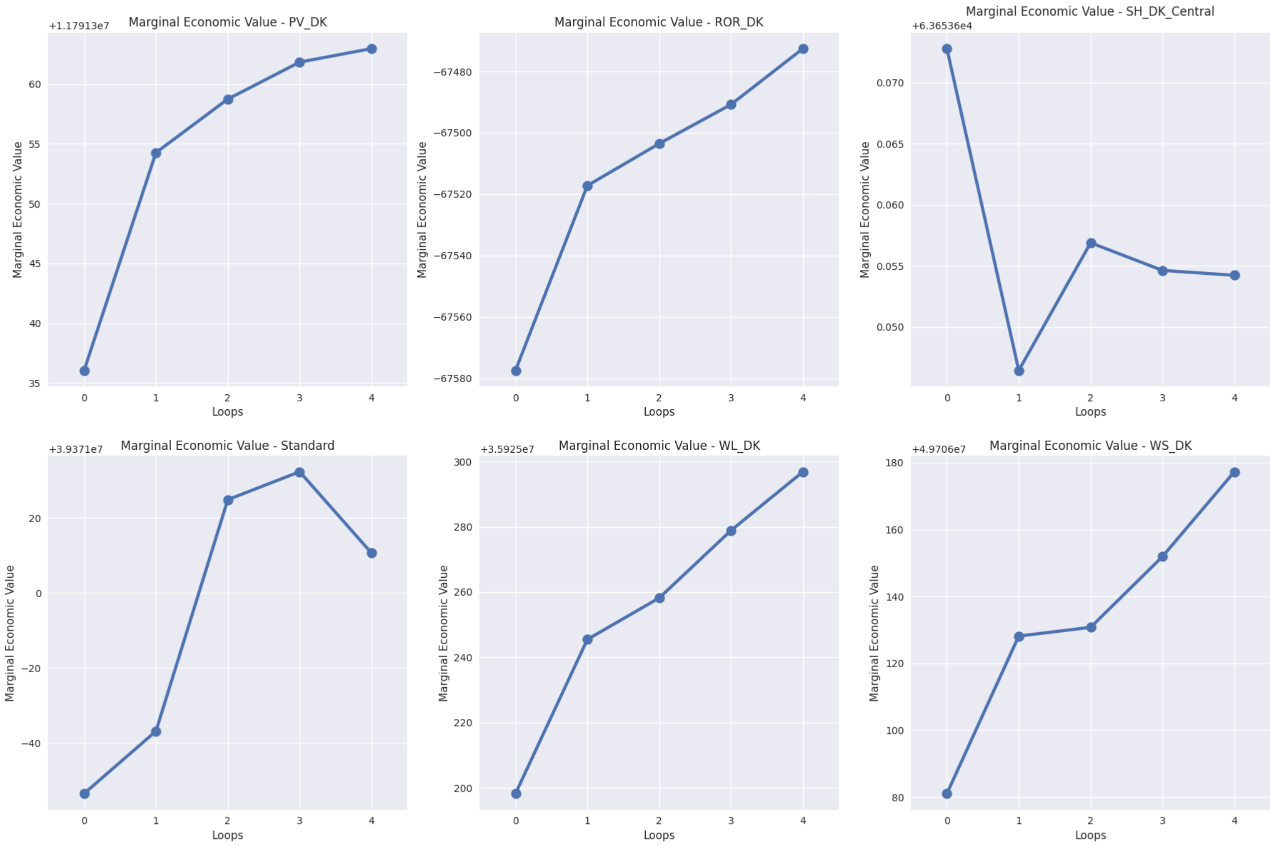

Figure 10: Marginal Economic Value of Intermittent and Dispatchable Generators

Figure 10 shows how the marginal economic value changes when the heat storage capacity is increased. The values are plotted for different categories of generators on the heat and electricity market. It should be noted that the scale of the y-axis is different in the various diagrams. If we plotted all graphs on the same scale, many trends would not be visible due to their small size. Overall the marginal economic value increases for solar, run of river, as well as on- and offshore wind. This is in line with our intuition that intermittent generators are used to fill up the storage tank, as high levels of intermittent generation are the characteristic feature of low price hours. Interestingly, the marginal economic value decreases for solar heat and is negative for the run-of-river plant. We are not able to find an explanation for these two phenomena.

The lower left graph in Figure 10 shows that the marginal economic value of standard plants increases as the heat storage capacity increases[11]. It should be noted that this variable summarises all standard plants, regardless of whether they produce electricity or heat. The increase

[11]Disregarding the small dip after loop 3, which we cannot explain.

is probably due to the fact that the dispatchable generators are at least partially used to fill the storage tank. This is not in line with our initial intuition. We would have thought that intermittent energy would be used to fill the storage, as argued above. This energy would then be dispatched in hours with high prices and thus lower the marginal economic value of the dispatchable generators. Since we see the opposite trend in Figure 10, this intuition cannot be applied to our model.
In our specific case, the marginal economic value of dispatchable plants increases with increasing heat storage capacity. It could be the case that intermittent generation is not sufficient to charge the storage tank. In this case, the dispatchable generators would contribute to charging the storage tank, which would lead to the increase in marginal economic value shown in the graph. This extends our intuition to the fact that the storage plants do not exclusively use intermittent generation to charge the tank. The conclusion is consistent with the result of *Exercise44* of this course, where increased storage capacity led to a crowding in of dispatchable generators.

6 Limitations

We do not model energy storage on the electricity market. Therefore, the mere fact of eliminating intermittency problems is decisive for our results and less so the specific characteristics of thermal energy storage. In the real world, where there is energy storage on the electricity market, the economic potential for thermal storage would probably be lower, as some of the arbitrage opportunities on the electricity market would already be exploited by electricity storage. Because the economic potential for heat storage is intuitively higher than in reality, we probably overestimate the economic effects of increasing thermal heat storage capacity.

A further limitation arises from using Denmark's heat storage capacity as the baseline[12]. Denmark already has significant heat storage capacity, as heat storage has been used widely to control the operation and reduce emissions from CHP plants and biomass heating plants (Energistyrelsen, 2020, p. 54). Increasing it therefore has less potential than in a system where there is very little thermal storage capacity to begin with.

Additionally, we do not model transmission in our paper. Neither transmission between *DK1* and *DK2*, nor transmission between Denmark and neighbouring countries influence our results. As explained in Chapter 3 we aggregate the whole of Denmark to one single electricity and one single heat market. This way we assume that there is zero capacity for international trade

[12] The practical reason for choosing Denmark as a baseline is the quality of data available for Denmark and the poor quality of data in other countries with greater heat storage potential (e.g. Germany).

and unlimited capacity for domestic trade. This abstraction is likely to affect the potential for intermittent electricity storage in our model in two ways. On the one hand, we expect an inflow of international intermittent electricity which could be used to produce and store heat. On the other hand, we expect export of Danish intermittent energy which would decrease the potential of using intermittent electricity to charge the heat storage. We note that the net effect is unclear ex ante and would need to be analysed in a more complex model.

We disregard additional cost effects by keeping the fixed and variable costs constant when increasing the storage capacity. Firstly, we abstract from modelling the cost increase with increasing tank size. Secondly, we ignore the effects of economies of scale or scope, as costs are likely to increase at a decreasing rate as the size of the heat storage tank increases.

7 Conclusion

As Section 5 highlighted on multiple occasions, we only observe marginal differences between our counterfactual scenarios. Therefore, we cannot conclude with certainty that there are significant equilibrium effects of increasing the capacity for thermal energy storage. Likely, this results from choosing Denmark as the country of interest. As Denmark has considerably invested in heat storage since the 1980s, the heat storage capacity for our baseline scenario exceeds capacities of other countries (PlanEnergi, 2013). For example, we have assumed a storage capacity of $50'365$ MWh for Denmark in our model. Contrarily, Germany's installed capacity in 2021 was $30'900$ MWh (AGFW, 2023, p. 27). Given that the German district heating system supplies around 6 million and the Danish system supplies around 1.8 million private households, the potential for increasing the heat storage capacities within the German heat networks would likely provide more research opportunities (AGFW, 2021, Statistics Denmark, 2023). However, the database for constructing a similar energy system model for Germany is much thinner. As the report from AGFW (2023, p. 35) shows, data for some states cannot be published due to confidentiality.

Another driver for our marginal results could be the assumed storage duration of 60 hours for our technology. Such a technology is not specified for seasonal storage. As we have more seasonal variation compared to hourly variation in intermittent supply (see Chapter 5.1), we expect seasonal storage to be more economically viable than the short-term storage we have analysed. Thus, further research could be focused towards investigating the effects on increasing the storage capacity of a technology such as *140 PTES seasonal* described in Energistyrelsen (2020). The main idea is to reduce the problem of seasonal intermittency, which in our model mainly originates from seasonality in solar heat, photovoltaics and run of river.

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Appendix

Variable	Unit	Description
$E_{i,h}$	MWh	Energy production of plant i at hour h
$H_{i,h}$	MWh	Heat production of plant i at hour h
L_h^E	MWh	Energy demand in hour h before load shedding
L_h^H	MWh	Heat demand in hour h before load shedding
D_h^E	MWh	Energy demand in hour h after load shedding
D_h^H	MWh	Heat demand in hour h after load shedding
$Y_{i,h}^c$	MWh	Thermal energy charged by plant i at hour h
$Y_{i,h}^d$	MWh	Thermal energy discharged by plant i at hour h
u_E	€	Marginal utility from energy consumption
u_H	€	Marginal utility from heat consumption
c_i^{oth}	€	Marginal cost of non-fuel inputs for energy/heat production
$\mu_{i,j}$	MWh	MWh of fuel j used to produce one MWh electricity/heat
p_j	€	Price of fuel j
FOM_i	€	Marginal operating and maintenance cost of production capacity
q_i^E	MW	Theoretical maximum energy production capacity
$\gamma_{i,h}$	-	Natural conditions in hour h that affect intermittent capacity
q_i^H	MW	Theoretical maximum heat production capacity
v_i	-	Ratio of electricity-to-heat generation
β_i	%	Self discharge during one hour
$\sqrt{\eta_i}$	%	Round trip efficiency of storage
q_i^{HS}	MW	Maximum discharge per hour
$S_{i,h}$	MWh	Amount of stored energy in hour h
$\bar{S}_i$	MWh	Maximum storage capacity

Table 1: Explanations of Variables

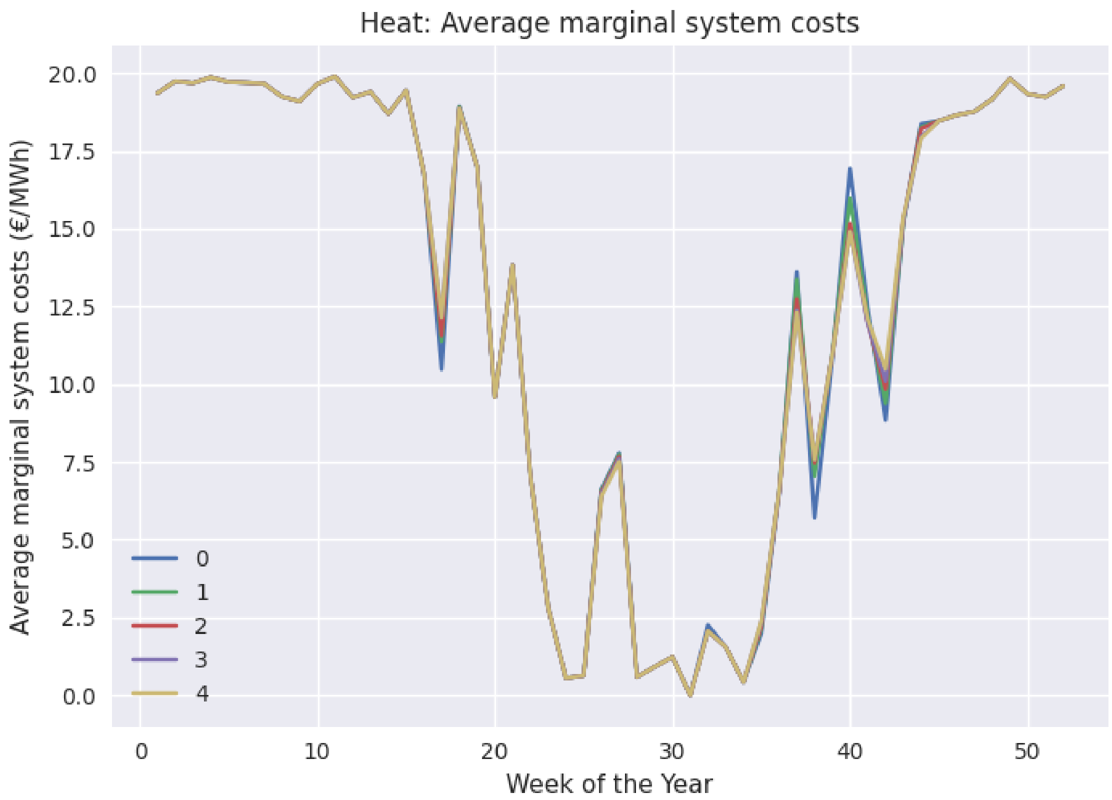

Figure 11: Weekly Average Marginal System Costs on the Heat Market