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Power-to-heat and thermal energy storage in district heating networks

A techno-economic assessment from a power grid perspective

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Abstract

The Netherlands has set ambitious climate mitigation targets that call for decarbonisation of the energy system. The resulting increase in decentralised solar power, together with the electrification of cars and heat supply, leads to high power loads on the distribution grid. The capacity of existing cables and transformers often falls short to cope with these power loads. A solution to capacity shortages, could be the combined application of power-to-heat (P2H) and thermal energy storage (TES). With this solution, surplus solar power could be converted and stored as heat for later use, thereby relieving the power grid. This research aims to assess the desirability of P2H combined with thermal energy storage in district heating networks, from a power grid perspective. To this end, an energy system model is built to perform a techno-economic assessment for the neighbourhood of Eva-Lanxmeer in Culemborg.

Energy flows in the model are calculated from measured data, combined with standardized profiles and assumptions. A selection of applicable P2H and TES technologies and their techno-economic parameters are obtained from a literature review. In total, 89 system configurations have been assessed that differ in terms of technology combinations, installed capacities and storage strategies. Electric boilers and heat pumps are considered as P2H technologies. Tank thermal energy storage (TTES), pit thermal energy storage (PTES) and borehole thermal energy storage (BTES) are considered as TES technologies. Three storage strategies are formulated, containing algorithms that determine how and when these technologies are operated. Storage strategy 1 aims to increase self-consumption, Storage strategy 2 aims to benefit from fluctuating electricity prices and storage strategy 3 aims at reducing the power grid peak load. The outcomes of all system configurations are compared to the reference system, in which no power-to-heat and thermal energy storage is present and where capacity shortages are solved by investing in more grid capacity.

It is found that the combination of an electric boiler and PTES system with storage strategy 3 is most desirable. It has the potential to reduce power grid peak loads, while increasing solar power self-consumption and having a lower LCOH than the reference system. System configurations using strategy 1 can achieve even higher self-consumption and lower power grid peak loads but yield high LCOH's. System configurations using strategy 2 are found to be undesirable due to high costs and no additional benefits compared to the reference system. Electric boilers outperform heat pumps in every system configuration by leading to higher self-consumption, lower power grid peak load and a higher LCOH.

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Sven Korpershoek,

Montfoort, 30 June 2021

List of abbreviations

ATES	Aquifer thermal energy storage
BTES	Borehole thermal energy storage
COP	Coefficient of performance
DH	District heating
e	Electric
EB	Electric boiler
HP	Heat pump
HT	High temperature
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized cost of energy
LCOH	Levelized cost of heat
LHS	Latent heat storage
LT	Low temperature
MSES	Molten salt thermal energy storage
MT	Medium temperature
MW	Megawatt
MWh	Megawatt-hour
O&M	Operation and maintenance
P2H	Power-to-heat
PCM	Phase-change material
PTES	Pit thermal energy storage
PV	Photovoltaic
SHS	Sensible heat storage
TES	Thermal energy storage
th	Thermal
THS	Thermochemical heat storage
TTES	Tank thermal energy storage
VLT	Very low temperature

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1. Introduction

1.1. Societal background

By signing the 2015 Paris agreement, The Netherlands has shown its commitment to limit global warming to 1.5 °C compared to pre-industrial levels (Hulme, 2016). To reach this goal, the member states of the European Union have agreed together to aim for a minimum of 40% CO_2 emission reduction in 2030 compared to 1990. The national goals of the Netherlands are to reach 49% and 95% CO_2 emission reduction, compared to 1990, by 2030 and 2050, respectively (Rijksoverheid, 2021) .

This calls for decarbonisation of the energy system, amongst other things by moving away from fossil fuels. Another driver for moving away from fossil fuels is the persistence of problems in the province of Groningen, where natural gas extraction has led to frequent earthquakes and land subsidence, damaging thousands of buildings (van Thienen-Visser & Breunese, 2015).

As such, the energy system in the Netherlands will change significantly over the next decades. This presents distribution grid operators (DSO's) with a major challenge, as they are responsible for maintaining a reliable and affordable electricity distribution grid. Especially the increase of decentralised solar power is challenging (van Westering & Hellendoorn, 2020). The capacity of existing cables is typically dimensioned according to electricity demand and is often unable to cope with the electricity feed-in during peaks of solar power. In other regions in the Netherlands there is the opposite problem, where the rapid increase of electricity demand causes congestion in the distribution grid. Major drivers for the increase in electricity demand include the electrification of cars and heat supply (Netbeheer Nederland, 2019).

While reinforcing cables is one way to mitigate congestion problems, there are also other solutions. Thermal energy storage (TES) could be one of these solutions when applied together with the power-to-heat (P2H) principle. This implies that surplus electricity is converted into heat after which the heat is stored and used in times of high demand. This solution could be interesting, because it mitigates congestion problems and at the same time contributes to the challenge of making heat supply more sustainable. After all, increased integration of solar power leads to a decrease in high-carbon grid-electricity.

It is expected that especially in residential areas with solar panels and a district heating network, the combination of TES and power-to-heat could work very well. This is because these types of areas often have large peaks in both supply and demand of electricity that do not occur simultaneously, but during different times of the day and year. Typically, solar electricity (supply) peaks in the afternoons of sunny days while household electricity demand peaks in the evenings of colder days. In both situations, power-to-heat combined with TES has the potential to reduce peaks on the grid and at the same time increase the share of usable renewable energy.

1.2. Scientific background and previous studies

The combined application of power-to-heat and thermal energy storage in district heating systems, is becoming more and more desirable (Bloess et al., 2018; Stinner et al., 2016). However, recent literature very rarely considers a combined application of the two. Most studies focus on the separate application of either power-to-heat or thermal energy storage in district heating networks.

Regarding power-to-heat technologies, their use in district heating networks has been reviewed in multiple studies (Bloess et al., 2018; Gjorgievski et al., 2021). At the same time, there are currently no studies that assess impacts of power-to-heat from the perspective of solving grid congestion problems. The majority of studies uses either renewable energy integration, cost optimisation or decarbonisation as main criteria to assess the desirability of power-to-heat in district heating networks (Bloess et al., 2018). For example, studies in Germany, Sweden and the Nordic countries have shown significant potential of power-to-heat in district heating based on increased renewable energy integration. They also stated that the technical potential is highest in areas with high shares of renewable electricity (Böttger et al., 2014; Kirkerud et al., 2017; Schweiger et al., 2017). A key aspect for the economic potential was found to be the price of electricity (including taxes and charges) versus the price of saved fuels. Thermal energy storage could further increase the technical potential, according to the Swedish study (Schweiger et al., 2017).

Regarding thermal energy storage technologies, these have been researched on different aspects (Alva et al., 2018; Ioan Sarbu & Calin Sebarchievici, 2018). The use of thermal energy storage specifically in district heating networks is however (similar to power-to-heat) mostly studied with a focus different from electricity grid congestion. Examples of common criteria to assess the desirability of thermal energy storage in district heating networks include renewable energy integration (Carpaneto et al., 2015; Zheng et al., 2018), primary energy savings (Verda & Colella, 2011), decarbonisation (Morvaj et al., 2016) or operational performance (Schuchardt, 2016; Verrilli et al., 2017). Only one recent study was found that looks into the ability of thermal energy storage to reduce grid transport capacities (Jebamalai et al., 2020). However, this study looked at the gas grid instead of the electricity grid, because a combination with power-to-heat was not considered. Results for this study showed that the total gas grid investment cost could be reduced by 4 to 7%, depending on the location of storage (centralised, substation or buildings).

All in all, the separate application of power-to-heat and thermal energy storage in district heating systems has been already researched, but a combined application of the two is studied only to a very limited extend or was assessed from a different perspective. Several studies call addition of thermal energy storage to power-to-heat in district heating networks promising, but in-depth quantitative analysis of such a system is lacking in existing research.

This study aims to fill this research gap by assessing the desirability of power-to heat combined with thermal energy storage in a district heating network based on three quantitative criteria: power grid peak load reduction, renewable energy integration and economic performance. An additional novelty is that this research is based on the Dutch situation.

1.3. Goal, research question and scope

The goal of this research is to assess the desirability of power-to-heat combined with thermal energy storage in district heating networks, from the perspectives of power grid peak load, renewable energy integration and economic performance.

Accordingly, the main research question is formulated as follows: "*How desirable is the application of power-to-heat combined with thermal energy storage in residential district heating networks, from the perspectives of power grid peak load, renewable energy integration and economic performance?"*

Sub-questions:

1. *What combinations of power-to-heat and thermal energy storage technologies are applicable to residential district heating networks and what are their techno-economic properties?*
2. *How to develop a model that calculates power grid peak load, renewable energy integration and economic performance, based on case-specific energy data, energy prices and different system configurations?*
3. *What are the impacts of different system configurations on power grid peak load, renewable energy integration and economic performance compared to a reference system?*
4. *How are the impacts influenced by uncertainties in technological and economic parameters?*

To achieve the goal of this research and to answer the research questions, a techno-economic assessment is done for the neighbourhood of Eva-Lanxmeer in Culemborg. This case-study is introduced in the methods section. A model is developed to simulate various system configurations for this neighbourhood, in which a combination of P2H and TES is applied. Based on a literature review, a selection of applicable technologies is made. The impacts of all modelled system configurations are compared to a refence system, to see whether or not the combined application of P2H and TES is desirable (in any particular system configuration).

The geographical scope of this research is the neighbourhood of Eva-Lanxmeer in Culemborg, including only the part of the neighbourhood that is connected to the district heating system. This temporal scope of this research is the present situation. The reference system is defined as a system where no power-to-heat and thermal energy storage is applied and where capacity shortages are solved by investing in more grid capacity.

2. Methods

This chapter gives a description of methodological steps taken to answer the research question. The methodological steps are divided into four phases. Each phase aims to answer one sub-question. Note that phase 1a and 1b are carried out simultaneously. An overview is given in Figure 1. First, a brief description of the case is given (section 2.1) after which the methodological steps for each research phase are described in more detail (sections 2.2 to 2.5).

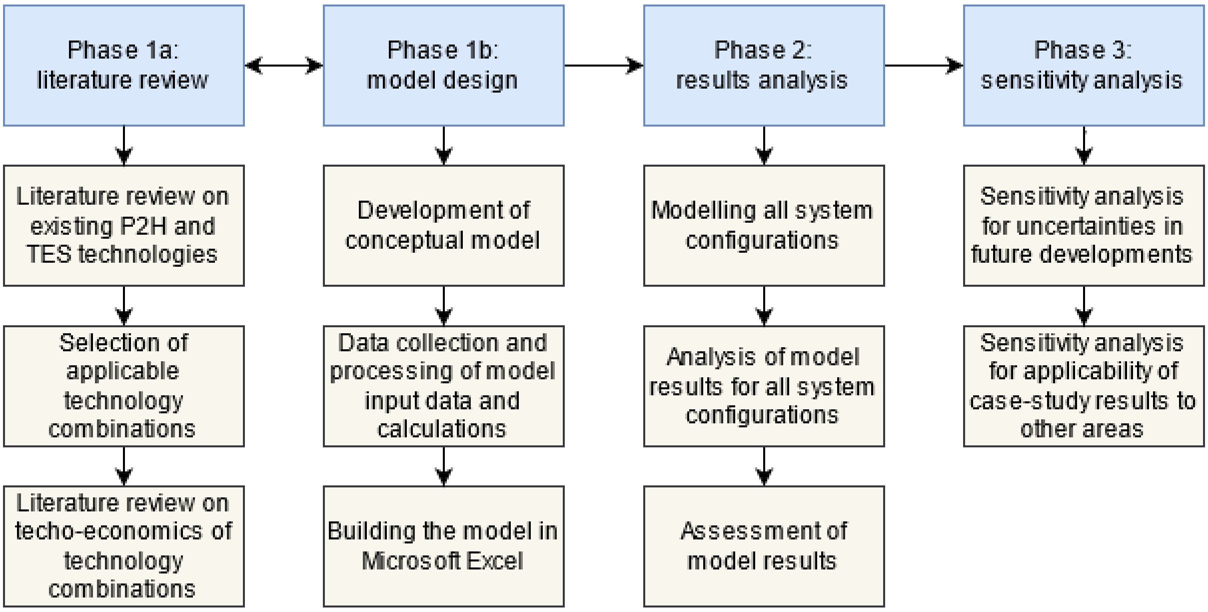

Figure 1: Overview of methodological steps

2.1. Case description

The neighbourhood of Eva-Lanxmeer is located in Culemborg and is largely built in the years after 2000. In this neighbourhood, a variety of buildings is present of which around two-thirds are connected to a local district heating network. Only the buildings that are connected to this district heating network are considered as part of this research. This includes 220 residential buildings and 7 commercial buildings (G. Verschuur & H. Bos, personal communication, 11 March 2021). An impression of the neighbourhood is given in Figure 2.

The district heating network is operated by local energy cooperative Thermo Bello and supplies heat at around 30-50 °C to the connected buildings. This heat is supplied by a heat pump with a thermal capacity of 0.65 MW_{th}, that uses drinking water of 12-13 °C as a heat source. There is also 1000 kW_{th} of peak-load capacity installed, in the form of two 500 kW_{th} gas-fired boilers (G. Verschuur & H. Bos, personal communication, 11 March 2021).

The total heat demand of the district heating network amounts to 2,697 MWh/year (2016 data), in which the parts of the households and commercial buildings are approximately the same size. Of this total heat demand, 2,347 MWh/year is supplied by the heat pump and 350 MWh/year is supplied by the gas-fired boiler, resulting in an annual electricity consumption of around 647 MWh_e/year for the heat pump and a gas consumption of around 299 MWh/year for the gas-fired boiler.

The buildings of Eva-Lanxmeer have an annual electricity demand of 2466.94 MWh/year, of which roughly one-third for the households (775.83 MWh_e/year) and two-thirds for the commercial buildings (1691,11 MWh_e/year). Furthermore, some buildings are equipped with solar panels, that for the whole neighbourhood together generate around 439 MWh_e/year (Afman et al., 2018).

However, it should be noted that the solar power production used in this research is tweaked from reality so that electricity production equals electricity demand of the buildings and heat pump together. That is because this study wants to determine the potential of P2H and TES specifically for neighbourhoods with large amounts of solar power, as this is expected to become a major reason for grid congestion in many Dutch neighbourhoods.

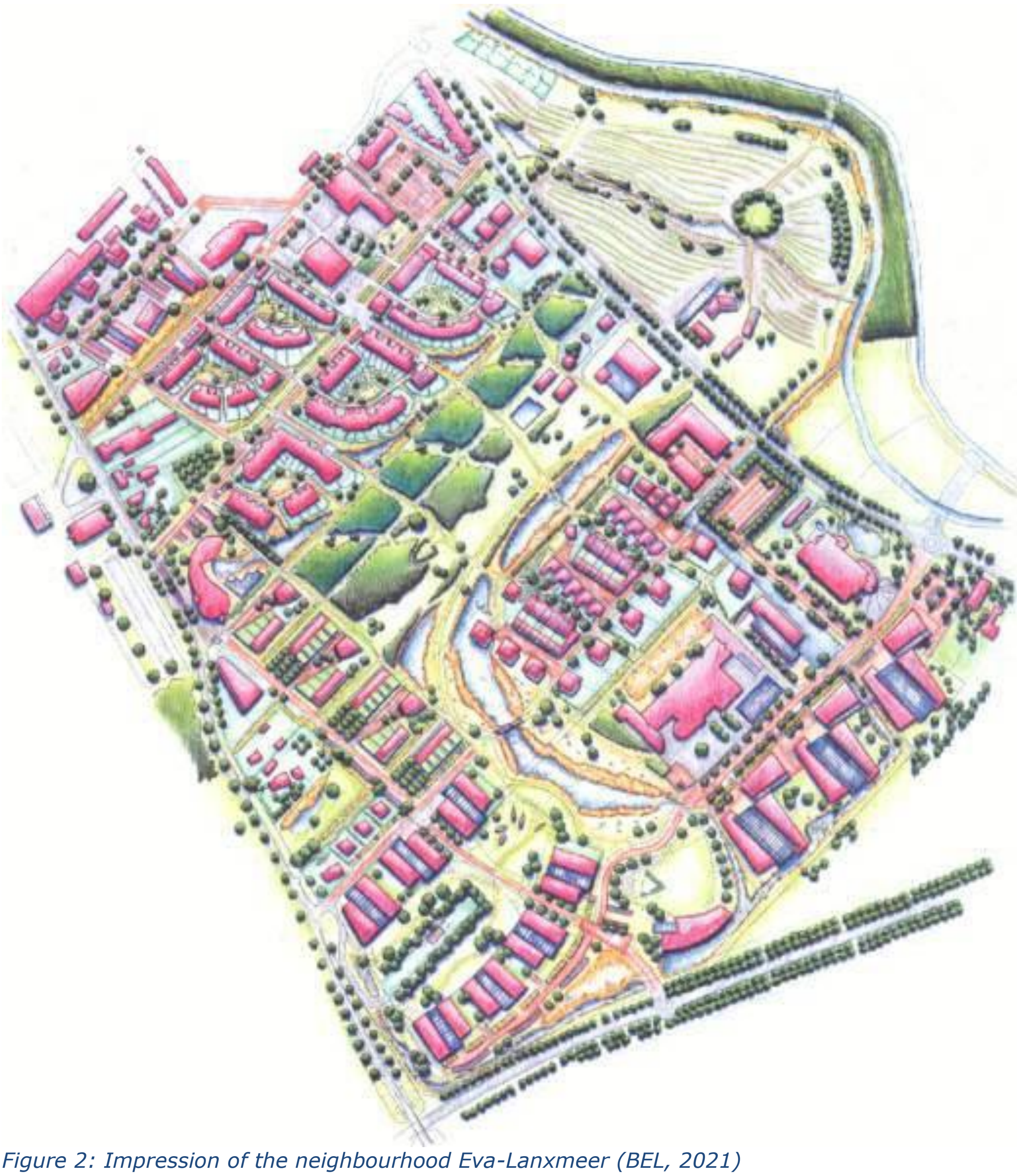

Figure 2: Impression of the neighbourhood Eva-Lanxmeer (BEL, 2021)

2.2. Phase 1a: literature review

The first sub-question "What combinations of power-to-heat and thermal energy storage technologies are applicable to residential district heating networks and what are their techno-economic properties?" is answered during the first phase of the research (see section 3). Note that phase 1a and 1b are carried out simultaneously.

During phase 1a, combinations of power-to-heat and thermal energy storage technologies are defined that are applicable to district heating systems (e.g. heat pumps with borehole thermal storage, electric boilers with tank thermal energy storage, etc.). First, an extensive literature review is done to explore the variety of power-to-heat and thermal energy storage technologies. Out of all available technologies, a selection of applicable technologies is made based on multiple criteria. Combinations of power-to-heat and thermal energy storage are then defined for those technologies that can be applied together.

After defining the technology combinations that are further used in this research, techno-economic parameters are be given for each of these technology combinations. These include for investment costs, O&M costs, efficiency and lifetime. Those parameters are obtained from literature.

2.3. Phase 1b: model design

The second sub-question: "How to develop a model that calculates power grid peak load, renewable energy integration and economic performance, based on case-specific energy data, energy prices and different system configurations?" is also answered during the first phase of the research. Again, note that phase 1a and 1b are carried out simultaneously.

To answer the second sub-question, the first step is to make a conceptual model or scheme of how the model will operate, including the necessary input parameters, calculations and output parameters. After that, the input data for the model is gathered and the model is built in Excel. This excludes the input data for the different P2H and TES technologies, as those are presented in the literature review of this study.

2.3.1. System design

In order to create a conceptual model, a better understanding of the neighbourhood's energy system is required. Figure 3 depicts the local energy system of Eva-Lanxmeer after adding thermal energy storage and power-to-heat. In this figure, rectangles represent system components, arrows represent energy flows and the dotted line represents the system boundaries for this research. Note that the system components and arrows with a dashed line refer to new elements that do not exist in the current energy system (i.e. the reference system).

As can be seen from Figure 3, heat can be supplied to the district heating network by three devices: the main heat pump, the gas-fired peak boiler and the thermal energy storage. Households and commercial buildings are equipped with solar panels so that they are both producers and consumers of electricity. Based on this energy system design and the desired model outputs (renewable energy integration, power grid peak load and economic performance), a conceptual model is gradually set up.

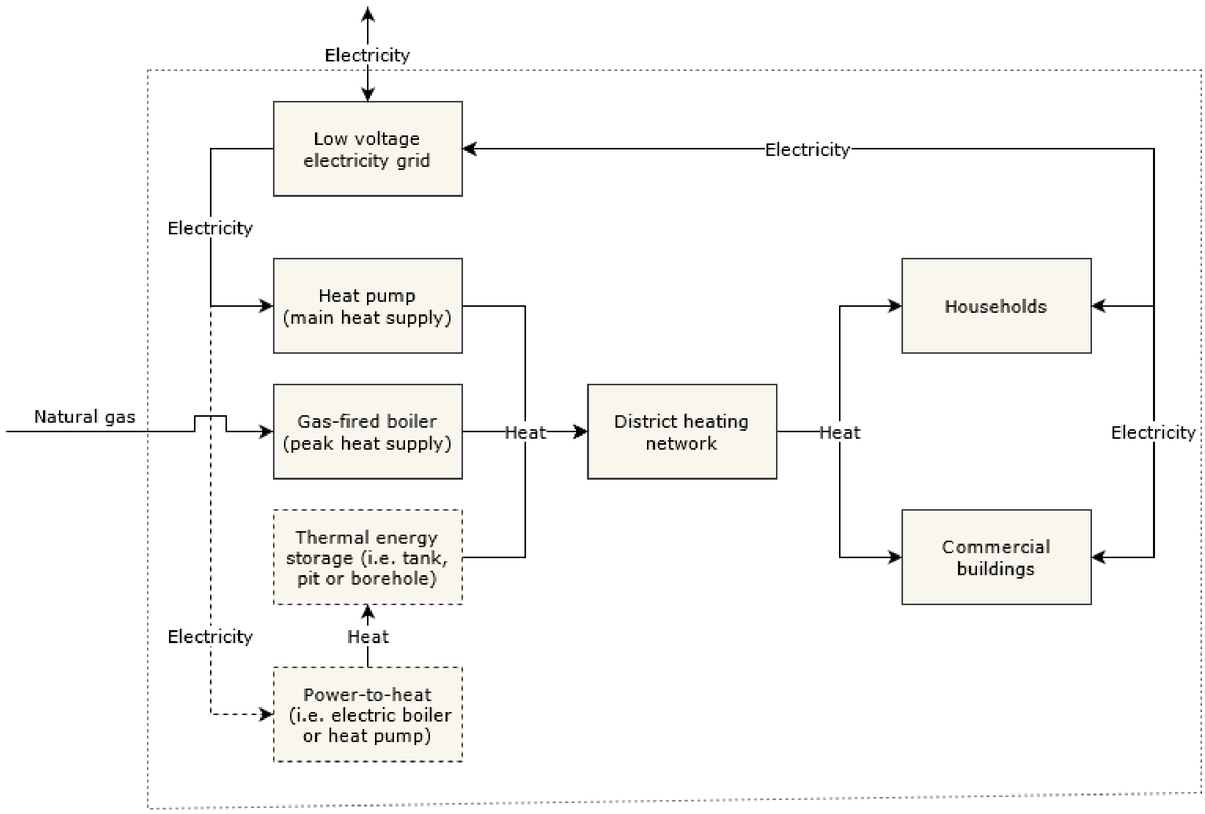

Figure 3: Local energy system of Eva-Lanxmeer

2.3.2. Conceptual model

The conceptual model is first shown in its entirety in Figure 4, after which the most important model sections are described in more detail (sections 2.3.3 to 2.3.7). Note that an arrow from one parameter to another indicates a direct influence. For example, the scheme shows that solar radiation on solar panels is directly influenced by solar radiation on the horizontal surface and by the positioning factor of solar panels.

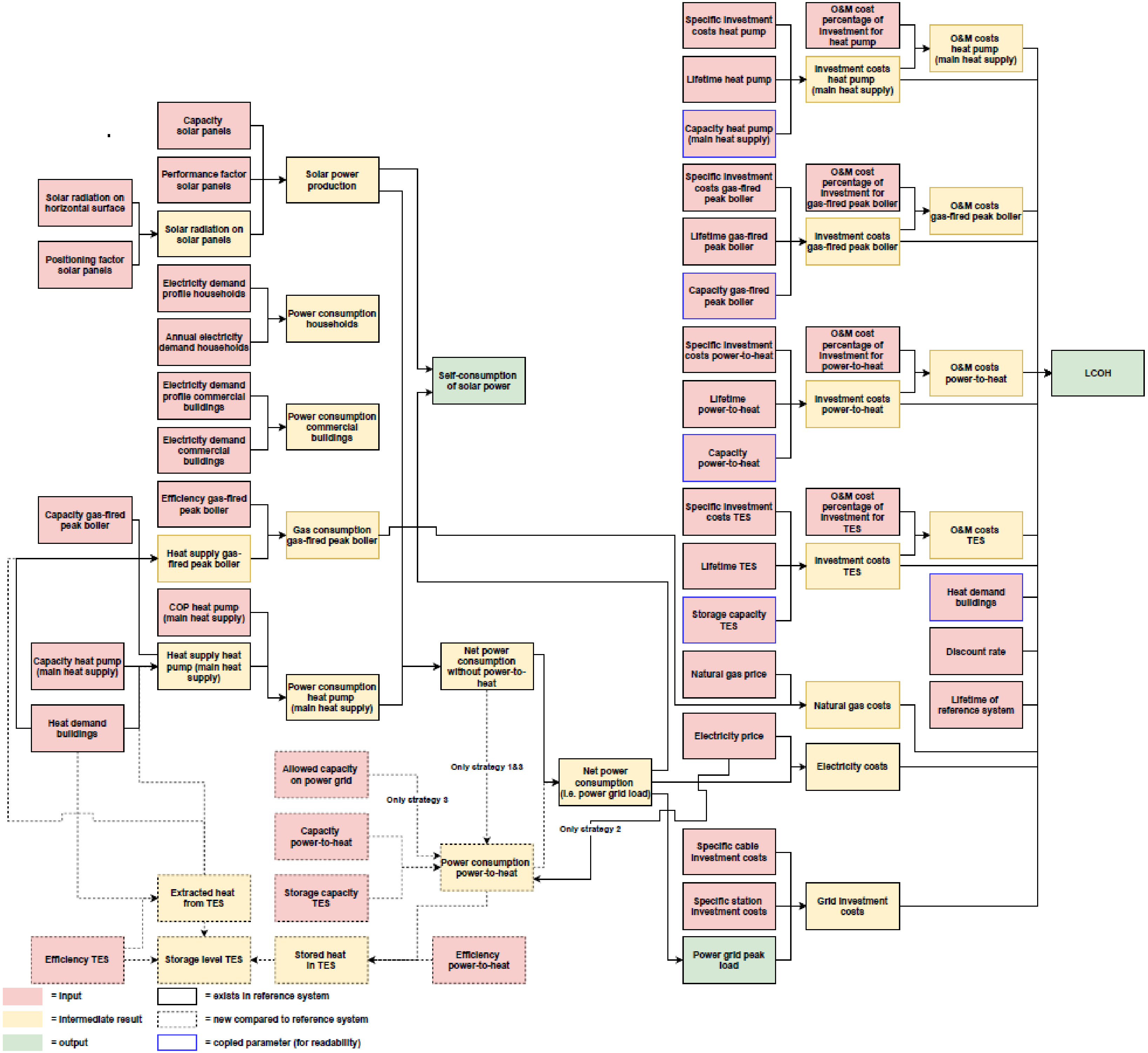

Figure 4: Conceptual model

2.3.3. Modelling buildings' energy consumption and production

Heat demand

Heat demand data from 2016 is supplied by the neighbourhood's local energy co-operative and heat supplier Thermo Bello. The annual heat demand equals 2,697 MWh/year. It concerns the heat demand for the district heating system and not the buildings themselves. There is thus no need to take the district heating network's efficiency into account.

However, the supplied heat demand data could not be used directly in the model for three reasons: (1) the data is only available on either a daily or 8-minute resolution, rather than an hourly resolution; (2) The 8-minute data is spread across 300+ Excel files; (3) There are quite a lot of times in the year where heat demand is not registered, resulting in time gaps ranging from a few hours to a couple of days. The gaps in time are caused as a result of ThermoBello having to extract data from their system manually, as their system stores the data only for 24 hours. Only when they would extract data every day of the year at the same time, a complete 8-minute data set could be obtained which is understandably not feasible for them. Processing of the provided data is thus needed in order to obtain a dataset with hourly heat demand for all of 2016. The data is processed to obtain hourly heat demand data according to the following steps:

1. Daily heat demand is categorised in 11 categories, based on the level of heat demand and distinguishing between working days and weekend days. Every day of the year fits in one of these 11 categories. The categories are named with letters based on the amount of heat demand (MWh/day): A (0-1), B (1-5), C (5-10), D (10-15), E (15-20) and F (20-30). Also, a numbers is added to the category name to indicate the type of day: 1 (working days), 2 (weekend days). For example, a Saturday with 8 MWh of heat demand would fit in category C2.
2. For each of those categories, one day of the year is selected. The selected days have an hourly heat distribution that is typical for that category.
3. For each of the selected days, its corresponding 8-minute heat demand data is converted into hourly heat demand data.
4. An hourly distribution profile (% of daily heat demand/hour) for that specific day is created, therewith representing its whole category. Every category thus has its own hourly distribution profile (see Appendix 1).
5. The daily heat demands are multiplied by the corresponding hourly distribution profiles to obtain hourly heat demand data for all of 2016.

The distribution of hourly heat demand over the year is shown in Figure 5. It should be noted that the modelled heat demand peaks at 1.8 MW_{th}. This is slightly more than the 1.65 MW_{th} (0.65 MW_{th} heat pump and 1 MW_{th} electric boiler) of actually installed capacity in the reference system, indicating that the heat demand cannot be met during certain times. This is a consequence of using hourly heat distribution profiles in the model that do not yield exact values for every hour of the year. However, this is expected to have a minor influence on results as demand exceeds the capacity only slightly during 9 hours of the year.

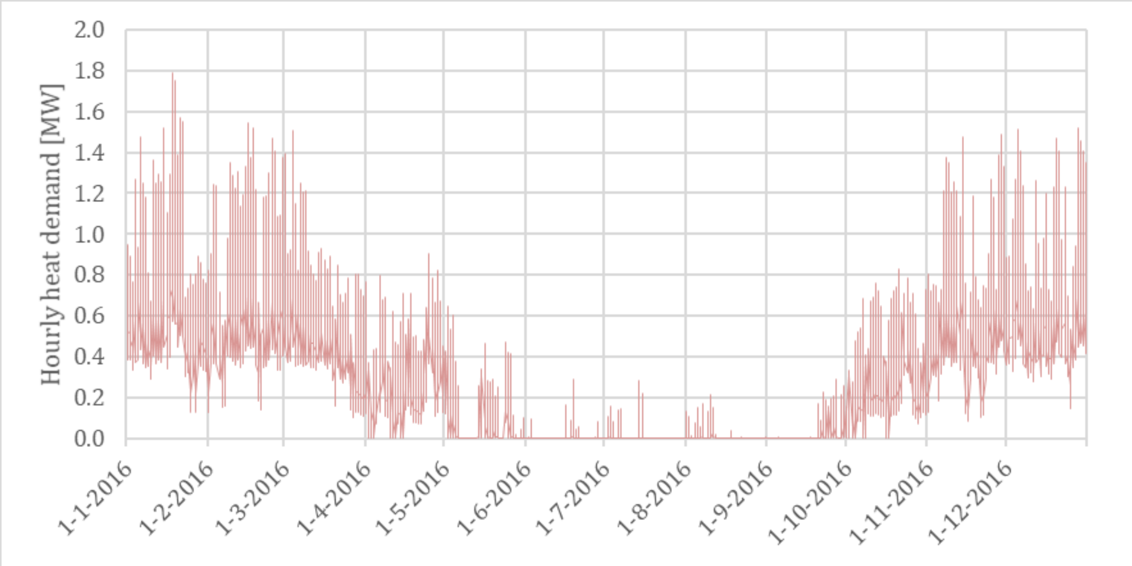

Figure 5: Heat demand distribution over 2016

Power consumption of buildings
The annual electricity consumption of households in Eva-Lanxmeer equals 775.83 MWh/year, whereas the commercial buildings in the area consume 1,691.11 MWh/year (Afman et al., 2018). To translate this to hourly values for power consumption, the well-recognised NEDU electricity demand profiles are used. For households, the 2016 NEDU E1A electricity profile is used. For the commercial buildings, the 2016 NEDU E3A electricity profile is used. 2016 electricity profiles are chosen as they originate from the same year as the used heat demand data.

Solar power production
It is very important to note that the neighbourhood of Eva-Lanxmeer is modelled to be energy-neutral in terms of electricity on an annual basis (which is very different from the actual current situation). This means that in the reference system, the annual solar power production is modelled so that it equals the annual electricity consumption of the buildings and the main heat pump together. In the real-world's current situation, this is by no means the case. The reason for still modelling it this way, is that this study wants to determine the potential of P2H and TES specifically for neighbourhoods with large amounts of solar power, as this is expected to become a major reason for grid congestion in many Dutch neighbourhoods.

Like all energy flows in the model, the solar power production is modelled on an hourly basis. As there is no case-specific hourly data available, the hourly solar power production is calculated using the methodology of ISSO (knowledge institute for the Dutch installation sector) for solar power.

According to the ISSO methodology, the annual solar power production can be calculated with the following formula, where P_{PV} is the energy output from the PV system (MWh/year), *PR* is the performance ratio, H_i is the in-plane irradiation (MWh/m^2/year) and P_{stc} (MW) is the power rating of the PV system under standard test conditions (ISSO, 2012).

$$P_{PV} = PR * H_i * P_{STC}$$

The performance ratio depends on system losses (e.g. due to reflection, temperature, cables and inverter) and is assumed to be 0.84, which in line with today's well performing PV systems (W.G.J.H.M. Van Sark et al., 2012). The H_i is calculated using a set of additional formulas as shown hereafter. However, as the model needs to calculate power output on an hourly rather than a yearly basis, a H_i unit of kWh/m²/h is used instead of kWh/m²/year. H_i is calculated as follows.

$$H_i = H_{max} * TCF * SF$$

In this formula H_{max} is the maximum in-plane irradiation (kWh/m²/h), *TCF* is the tilt correction factor and *SF* is the shadow factor. The tilt correction factor depends on the orientation and tilt of solar panels and will in reality vary across the neighbourhood. For this research, a *TCF* of 0.9 for the whole neighbourhood is assumed, which is somewhere in between a south and east-west oriented setup, also depending on the average tilt angle. There is assumed to be no shadow losses, resulting in a *SF* of 1. H_{max} is calculated from irradiation on the horizontal plane with the formula stated below.

$$H_{max} = G * 1.15$$

Here, *G* is the irradiation on the horizontal plane (kWh/m²/h) as measured by the KNMI weather station in De Bilt. The factor 1.15 is used as solar panels in an ideal plane (with a 36° tilt and south orientation) generally produce 1.15 times the power compared to solar panels on the horizontal plane (JansZon, 2021).

Using the aforementioned performance factor and the calculated hourly in-plane irradiation, the solar power capacity (P_{STC}) is set to 3.47 MW, which is required to make Eva-Lanxmeer energy-neutral in terms of electricity. As a result, the modelled solar power production amounts to around 3,166 MWh/year. These numbers are used in the remainder of this research. For reference, the real-world solar power production is only around 439 MWh/year (Afman et al., 2018).

2.3.4. Modelling heat supply, power-to-heat and thermal energy storage

Energy consumption main heat pump and gas-fired peak boiler

Three devices can provide the district heating system with heat: the main heat pump, the gas-fired peak boiler and the thermal energy storage. Sometimes only one device is needed, but at other times multiple devices are needed simultaneously. The amount of heat supplied by each device at a certain moment in time, is an important aspect to model and is defined by algorithms.

Heat supply from the TES has priority. The amount of heat supply from the TES depends on the storage strategy as described later in this section. After heat extraction from the TES, the remaining heat demand is covered by the main heat pump for as far as possible (i.e. up to the heat pump's maximum thermal capacity of 0.65 MW_{th}). This is expressed in the following algorithm, where Q_{HP} is the heat supply by the heat pump (MW_{th}), Q_{demand} is the heat demand (MW_{th}), $Q_{TES,extracted}$ is the heat extracted (and supplied) by the thermal energy storage (MWh_{th}) and $C_{HP,th}$ is the thermal capacity of the heat pump (MW_{th}).

$$Q_{HP,t} = MIN(Q_{demand,t} - Q_{TES\ extracted,t}; C_{HP,th})$$

The heat pump's power consumption is modelled according to the following formula, where $P_{HP,t,}$ is the power consumption of the heat pump (MW_e) and COP_{HP} is the heat pump's COP. Daily COP values are used in this calculation, as supplied by ThermoBello. The heat pump's average COP over 2016 year is 3.73.

$$P_{HP,t} = Q_{HP,t} * COP_{hp,t}$$

The still remaining heat demand is covered by the gas-fired peak boilers (limited by their maximum capacity of 1 MW_{th}) as shown in the algorithm below, where Q_{GB} is the heat supply by the gas-fired boiler (MW_{th}) and C_{GB} is the thermal capacity of the gas-fired boiler (MW_{th}).

$$Q_{GB,t} = MIN(Q_{demand,t} - Q_{HP,t} - Q_{TES\ extracted,t}; C_{GB,th})$$

The gas consumption is modelled by multiplying the heat supply by the gas-fired boiler by its efficiency η_{GB} (%). A standard efficiency of 99% is assumed (Berenschot et al., 2017).

$$E_{NG,t} = Q_{GB,t} * \eta_{GB}$$

Residual load

The residual load excluding the P2H device $P_{res\ ex}$ (MW) is the sum of power consumption from households $P_{households}$ (MW), commercial buildings $P_{commercial}$ (MW) and the main heat pump P_{HP} (MW) minus the total solar power production P_{PV} (MW). $P_{res\ ex}$ is an important model parameter, as it may determine how much electricity can be stored as heat (see storage strategies 1 and 3). The formula to calculate the residual load excluding P2H is shown below.

$$P_{res\ ex,t} = P_{households,t} + P_{commercial,t} + P_{HP,t} - P_{PV,t}$$

Logically, the residual load including power-to-heat P_{res} (MW_e) is then formulated as follows, where P_{P2H} is the power consumption of the P2H device (MW_e).

$$P_{res,t} = P_{households,t} + P_{commercial,t} + P_{HP,t} + P_{P2H} - P_{PV,t}$$

For the reference situation, the modelled hourly residual load over 2016 is shown in Figure 6. Note that negative numbers indicate a surplus of electricity.

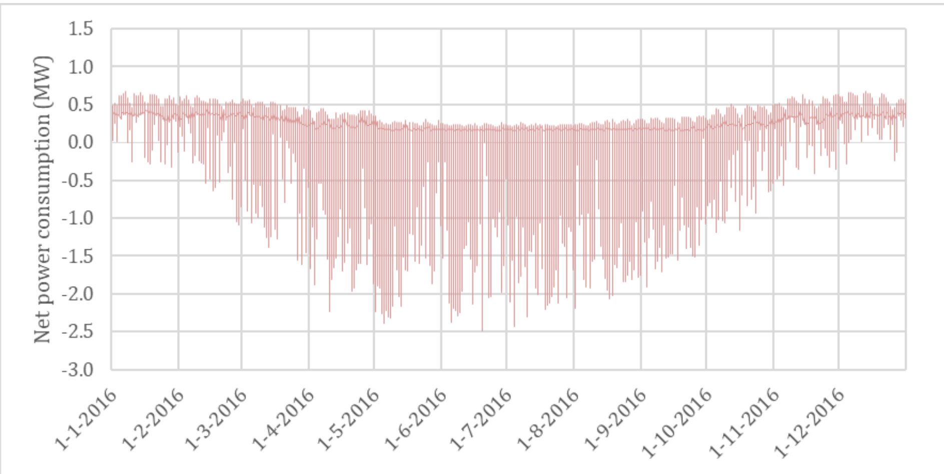

Figure 6: Residual load in reference system over 2016

Power-to-heat and thermal energy storage

A combination of power-to-heat and thermal energy storage can be operated in many different ways. In order to assess the desirability of such a combination from a techno-economic perspective, three different storage strategies are modelled and compared to the reference system (i.e. the system without power-to-heat and thermal energy storage). The storage strategies all have their own purpose and therefore differ in terms of when P2H and TES systems are used.

Storage strategy 1: increasing solar power self-consumption

The first storage strategy aims to increase self-consumption of solar power on the neighbourhood level. This implies that solar power is converted into heat whenever there is a surplus of electricity. The electricity consumption of power-to-heat is thus driven by the available surplus of electricity in the local system.

The following algorithms apply to storage strategy 1:

$$P_{P2H,t} = IF(P_{res\ ex,t} < 0; MIN\left(-P_{net,t}; C_{P2H,el}; \frac{C_{TES} - Q_{TES\ level,t-1}}{\eta_{P2H}}\right)); 0)$$

$$Q_{TES\ stored,t} = P_{P2H,t} * \eta_{P2H}$$

$$Q_{TES\ extracted,t} = MIN(Q_{demand,t}; \eta_{TES} * \ Q_{TES\ level,t-1})$$

$$Q_{TES\ level,t} = Q_{TES\ level,t-1} + Q_{TES\ stored,t} - \frac{Q_{TES\ extracted,t}}{\eta_{TES}}$$

In these algorithms, $C_{P2H,el}$ is the electrical capacity of the P2H device (MW_e), C_{TES} is the storage capacity of the TES (MWh_{th}), $Q_{TES\ level}$ is the storage level of the TES (MWh_{th}), $Q_{TES\ stored}$ is the amount of heat stored in the TES (MW_{th}), η_{TES} is the TES efficiency (%) and η_{P2H} is the P2H efficiency (%). Note that efficiencies differ per P2H and TES technology. The values for different technologies are given in the literature review chapter of this report.

Storage strategy 2: profiting from fluctuating electricity prices

The second storage strategy aims to profit from fluctuating electricity prices. In principle, electricity is converted into heat for storage when electricity prices are low and the stored heat is used at times where electricity prices are high. The electricity consumption of power-to-heat in this strategy is driven by national electricity prices.

The following algorithms apply to storage strategy 2:

$$P_{P2H,t} = IF(Price_{el,t} < Price_{el,low}; MIN\left(C_{P2H}; \frac{C_{TES} - Q_{TES\ level,t-1}}{\eta_{P2H}}\right)); 0)$$

$$Q_{TES\ stored,t} = P_{P2H,t} * \eta_{P2H}$$

$$Q_{TES\ extracted,t} = IF(Price_{el,t} > Price_{el,high}; MIN(Q_{demand,t}; \eta_{TES} * \ Q_{TES\ level,t-1})$$

$$Q_{TES\ level,t} = Q_{TES\ level,t-1} + Q_{TES\ stored,t} - \frac{Q_{TES\ extracted,t}}{\eta_{TES}}$$

In these algorithms, $Price_{el}$ is the day-ahead electricity price (€/MWh_e), $Price_{el,high}$ is the high day-ahead electricity price threshold (€/MWh_e) and $Price_{el,low}$ is the low day-ahead electricity price threshold (€/MWh_e).

The thresholds for the high and low day-ahead electricity prices are set for each month. The low day-ahead electricity price threshold is defined as the first quartile of all hourly electricity prices in the corresponding month (on average 24.14 €/MWh). The high day-ahead electricity price threshold is defined as the third quartile of all hourly electricity prices in the corresponding month (on average €37.44 €/MWh).

<u>Storage strategy 3: reducing the power grid peak load</u>

The third storage strategy aims at reducing the peak load on the power grid to a value of 1 MW_e. The is achieved through peak shaving of solar power using power-to-heat and storing the heat for later use. Practically, this implies that solar power is converted into heat whenever the power surplus in the local system is higher than 1 MW_e. The reason for allowing a peak load of 1 MW_e, is that this number is estimated to be the current grid capacity in the neighbourhood. In this way, it can be assessed whether P2H and TES is an option over traditional grid reinforcement for this neighbourhood (as a result of the large increase in solar power capacity compared to the current situation).

The following algorithms apply to storage strategy 3, where C_{grid} is the grid capacity (i.e. the value of $1MW_e$ that the peak load should be reduced to).

$$P_{P2H} = IF(P_{res\ ex,t} < -C_{grid}; MIN\left(-P_{net,t} - C_{grid}; C_{P2H}; \frac{C_{TES} - Q_{TES\ level,t-1}}{\eta_{P2H}}\right); 0)$$

$$Q_{TES\ stored,t} = P_{P2H,t} * \eta_{P2H}$$

$$Q_{TES\ extracted,t} = MIN(Q_{demand,t}; \eta_{TES} * Q_{TES\ level,t-1})$$

$$Q_{TES\ level,t} = Q_{TES\ level,t-1} + Q_{TES\ stored,t} - \frac{Q_{TES\ extracted,t}}{\eta_{TES}}$$

2.3.5. Modelling cost components

The electricity costs in the model are calculated by multiplying hourly power consumption with the hourly day-ahead electricity price. The Dutch 2016 hourly day-ahead electricity prices are used for this, which are obtained from the ENTSOE transparency platform. The gas costs are calculated by multiplying gas consumption by the 2016 average gas price of 7.51 €/GJ or 27.02 €/MWh (CBS, 2021).

The investment costs of the main heat pump, gas-fired peak boiler, power-to-heat device, thermal energy storage and the grid are calculated based on the specific investment costs (€/MW or €/MWh) of those components combined with their capacities and lifetimes (the latter is needed for any reinvestments). The specific investment costs of the main heat pump is assumed to be 600 €/kW_{th}, with a lifetime of 20 years (Dominković, 2015; RVO, 2016). The specific investment costs of the gas-fired peak boiler is assumed to be 135 €/kW_{th}, also with a lifeitime of 30 years (Schepers & Dehens, 2020). The annual operation and maintenance (O&M) costs of all system components is expressed as percentage of the investment.

This percentage is 6% for the gas-fired boiler and 4% for the heat pump (Dominković, 2015; Schepers & Dehens, 2020). The specific grid investment costs are set to a typical value of 908 €/kW (Maarten Afman & Frans Rooijers, 2017), consisting of 708 €/kW for the cables and 200 €/kW for the transformers. Note that techno-economic parameters of the P2H and TES are mentioned in the literature review chapter (section 3.3).

2.3.6. *Evaluation indicators of the model*

As defined in the research questions, the model should be able to calculate renewable energy integration, power grid peak load and economic performance. While the calculation for the power grid peak load is straightforward, renewable energy integration and economic performance can be calculated in multiple ways. In this research, renewable energy integration is calculated as self-consumption of solar power. Economic performance will be calculated as the levelized cost of heat. This leads to the following in the following three evaluation indicators (main output parameters) of the model:

- Self-consumtpion of solar power (%);
- Power grid peak load (MW);
- LCOH (€/MWh).

All three evaluation indicators can be calculated using the (intermediate) modelling results for the different system components as described earlier.

Self-consumption of solar power

The self-consumption of solar power is the share of solar power that is consumed directly within the neighbourhood, without being exported to the grid. Self-consumption comes with the advantage that the neighbourhood can use more of its own renewable electricity, rather than using grid power that partly originates from fossil fuel power plants. In addition, self-consumption of electricity helps the grid operator to prevent capacity shortages. The self-consumption is therefore ideally as high as possible.

Solar power self-consumption (%) is calculated on an annual basis using the following formula, where $P_{to\ grid}$ refers to the electricity that is exported to the grid (MWh/year).

$$Self\ consumption = \frac{P_{PV} - P_{to\ grid}}{P_{PV}}$$

Power grid peak load

The power grid peak load refers to the highest (negative) residual load in the year. This determines the capacity that the grid (cables and stations) should have in the neighbourhood of Eva-Lanxmeer. In the model, the power grid peak load (MW) is found using the following algorithm that searches for the hour with the highest (negative) residual load of 2016.

$$Power\ grid\ peak\ load = MAX(MAX(P_{res,t}; P_{res,t+1}; P_{res,t+2} \dots P_{res,t+8783}); -MIN(P_{res,t}; P_{res,t+1}; P_{res,t+2} \dots P_{res,t+8783}))$$

LCOH

The levelized cost of heat (LCOH) is a common metric to assess economic performance of heating systems from a system level perspective. Like the LCOE, the LCOH is a tool that combines both fixed and variable costs in a single indicator to simplify analysis (Namovicz, 2013). It is suitable to compare results of the different technology configurations (Huang et al., 2019). The scope of the LCOH is the supply side of the local energy system, which includes the heat pump, gas-fired peak boiler, power-to-heat, thermal energy storage. The LCOH (€/MWh) is calculated with the following formula, where α is the capital recovery factor, I is the investment costs (€), M is the costs for operation and maintenance (€/year), F is the fuel (i.e. electricity and gas) costs (€/MWh) and E is the annual heat supply (MWh/year) to the neighbourhood.

$$LCOH = \frac{\alpha * I + M + F}{E}$$

In this formula, the capital recovery factor is function of the discount rate and the depreciation period of the project. This is shown below, where r is the discount rate (%) and n is the lifetime of the project (years).

$$\alpha = \frac{r}{1-(1+r)^{-n}}$$

The discount rate is set to 4% for this study, which represents a societal perspective (van der Molen et al., 2021). The lifetime of the project is set to 40 years, which equals the lifetime of an electricity grid.

2.3.7. Overview of model input parameters

Table 1 gives an overview of the most important model input parameters that were mentioned earlier in this section.

Table 1: Model input parameters

Parameter	Value	Unit
Heat pump capacity (main heat supply)	0.65	MW_{th}
Gas-fired boiler capacity (peak supply)	1.50	MW_{th}
Heat demand neighbourhood	2,697	MWh_{th}/year
Power consumption households	775.83	MWh_e/year
Power consumption commercial buildings	1,691.11	MWh_e/year
Installed solar power capacity	3.47	MW_e
Solar power production	3,166	MWh_e/year
Heat pump COP	3.73	-
Gas-fired boiler efficiency	99%	
Hourly day-ahead electricity prices	NL 2016 dataset ENTSOE	€/MWh_e
Gas price	27.02	€/MWh
Grid cable specific investment costs	708	€/kW_e
Grid transformer specific investment costs	200	€/kW_e
Investment costs heat pump	€600	€/kW_{th}
Investment costs gas-fired peak boiler	€135	€/kW_{th}
Annual O&M costs HP (% of investment)	4%	%
Annual O&M costs gas-fired peak boiler (% of investment)	6%	%
Lifetime heat pump	20	years
Lifetime gas-fired peak boiler	30	years

2.4. Phase 2: results analysis

The third sub-question "What are the impacts of different system configurations on power grid peak load, renewable energy integration and economic performance compared to a reference system?" is answered using the model results of the three evaluation indicators. These results are given in section 4.1.

The solar power self-consumption, power grid peak load and the LCOH are calculated for wide range of system configurations. These system configurations differ on three aspects:

- The storage strategy (1, 2 or 3) used to operate the P2H and TES;
- The technology combination (i.e. the types of P2H and TES used);
- Capacities of P2H (MW_e) and TES systems (MWh).

Five technology combinations are defined (see literature review). All five of these can be operated using storage strategy 1 and 3. For storage strategy 2, only two technology combinations can be used. In terms of capacities of P2H and TES systems, the possibilities are endless. For the purpose of this research, 3 P2H capacities and 4 TES capacities are selected for assessment after experimenting with the model. These differ per storage strategy as listed in Table 2.

Table 2: P2H and TES capacities per storage strategy

Storage strategy	P2H electrical capacities (MW_e)	TES capacities (MWh)
Storage strategy 1	0.5/1.5/2.5	500/1000/1500/2000
Storage strategy 2	0.1/0.2/0.3 for heat pumps 0/3/0.6/0.9 for electric boilers	0/10/20/30/40 0/5/10/15/20
Storage strategy 3	1.5	Technology dependent

There are 89 system configurations assessed in this research, consisting of the following system configurations per storage strategy:

- Strategy 1: 3 P2H capacities x 4 TES capacities x 5 technology combinations = 60 system configurations.
- Strategy 2: 3 P2H capacities x 4 TES capacities x 2 technology combinations = 24 system configurations.
- Strategy 3: 1 P2H capacity x 1 TES capacity x 5 technology combinations = 5 system configurations.

Because of the many possible configurations, the results are presented in a very structured way. The rough structure is shown in Figure 7. From this figure, it becomes clear that the results are first ordered by storage strategy, then by evaluation indicator, then by capacity and then by technology configuration.

Including the reference system, a total of 90 system configurations is assessed. Furthermore, the most notable differences between the reference and different system configurations are described.

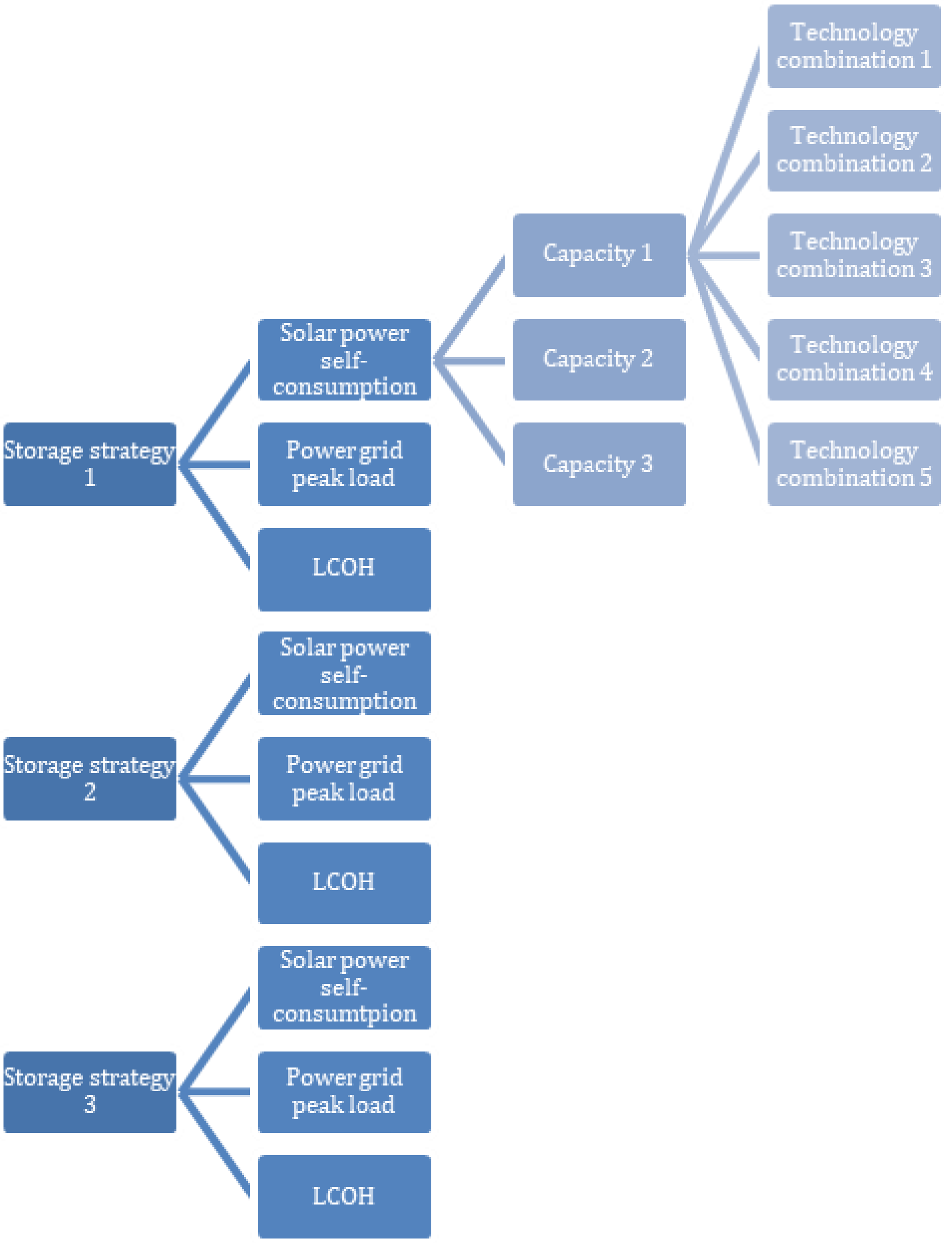

Figure 7: Rough structure of results section

2.5. Phase 3: sensitivity analysis

The fourth sub-question "How are the impacts influenced by uncertainties in technological and economic parameters?" is answered by doing a sensitivity analysis. The results of the sensitivity analysis are given in section 4.2.

In this sensitivity analysis, input parameters are changed within a certain range to see how the results are impacted. Because of the many system configurations that are assessed in this study (leading to lots of results), performing a sensitivity analysis is very time consuming. Therefore, a sensitivity analysis is only done for a limited selection of parameters, of which is expected that they have a big influence on model results. The selected parameters are COP, day-ahead electricity price and grid cable investment costs.

The COP is chosen as parameter because in the model, electric capacities of heat pumps are set to a fixed value as described in Table 2.

Changing the COP given a certain electric capacity of the heat pump would thereby affect the thermal capacity of the heat pump.
In turn, a higher thermal capacity leads to increased investment costs and O&M costs. The COP is thereby affecting many of the model's calculations. For the COP, a sensitivity analysis is performed for values of 2.73 (-1 from the base COP) and 4.73 (+1 from the base COP).

The day-ahead electricity price (€/MWh) is selected as parameter for the sensitivity analysis, to see how future electricity prices could affect results. However, to test sensitivity here, a whole new dataset of hourly day-ahead electricity prices is needed. Future day-ahead electricity prices are not available anywhere on the internet, so an attempt is made to create a dataset for this research. This is done by taking the 2020 electricity price distribution from Denmark, a country where almost 70% of electricity is generated by renewables, and combining them with the projected average Dutch day-ahead electricity price in 2030, which is € 51/MWh (PBL, 2020). This leads to a dataset called 'NL 2030 day-ahead electricity prices', containing more volatile and (on average) higher hourly prices. Note that the Danish electricity prices are retrieved from the ENTSOE transparency platform.

The grid cable investment costs (€/kW) are chosen as parameter for the sensitivity analysis, because they are a large cost component of the energy system. On top of that, the range of used cable investment costs differs quite a lot among various literature sources. For this research, sensitivity is tested for -30% and +30% compared to the 708 €/kW base costs. The upper and lower bounds represent values used by NvdT and Stedin, respectively (Maarten Afman & Frans Rooijers, 2017).

3. Literature review

This chapter provides insight in important characteristics of power-to-heat and thermal energy storage in district heating networks. An overview of available technologies is given as well as their techno-economic properties. For thermal energy storage technologies specifically, a selection of technologies is made that fall within the scope of this research.

3.1. Power-to-heat

Power-to-heat refers to the conversion of electricity into heat. When using renewable electricity for this conversion, power-to-heat may help to decarbonise the heat sector and contribute to the power system integration of variable renewables by providing additional flexibility. Furthermore, power-to-heat can help to prevent congestion problems on the local electricity grid, by producing heat on times where there would otherwise be a surplus of electricity.

Power-to-heat technologies can be categorised in centralised and decentralised options. Centralised options are located at a location distant to the point of actual heating demand, so that district heating networks are required to distribute the heat to where it is needed. In contrast, decentralised options are located right at, or very close to, the location of heat demand (Bloess et al., 2018). As the focus of this research is specifically on residential district heating networks, only centralised power-to-heat technologies are considered. It is however worth noting that many of the large-scale centralised power-to-heat technologies do have a small-scale counterpart for use in decentralised applications.

Two main power-to-heat technologies are available for use in district heating networks: electric boilers and heat pumps.

3.1.1. Electric boilers

Within the electric boiler category, two main types of electric boilers exist that can be used for residential heating. These are electric resistance boilers and electrode boilers (Bloess et al., 2018). Electric resistance boilers use an electrically resistive element, where the consequent heat is transferred to the water in order to heat it to the desired temperature (Alabama Power, 2021). Electrode boilers pass an electric current directly through water and use the conductive and resistive properties of water itself to generate heat (Marsidi, 2018).

Both types of electric boilers can have high efficiencies of between 99 and 100% (Berenschot et al., 2017). Electric resistance boilers generally have lower capacities than electrode boilers. Typical capacities of electric resistance boilers are up to 5 MW_e, whereas electrode boilers typically have capacities ranging from 3 MW_e to 70 MW_e (Marsidi, 2018). In the Dutch city of Diemen, energy company Vattenfall is planning an electrode boiler that is even larger than 70 MW_e (up to 200 MW_e depending on what market parties can offer) as addition to an existing district heating network (Vattenfall, 2021). The large capacity of electrode boilers is most likely the reason that this type of boiler is most commonly used in district heating networks in Europe (Bloess et al., 2018). However, in the Netherlands there are currently no existing cases where electric boilers are used in district heating networks.

The reason for this is most likely the low economic feasibility of electric boilers in the Dutch situation, caused by grid connection costs, capacity tariffs and relatively high electricity prices for most of the year. The economic viability may however change due to an increasing volatility of electricity prices, especially when applied in a parallel fashion to another heat source (Berenschot et al., 2017).

3.1.2. Heat pumps

Heat pumps are devices that absorb heat from a low temperature heat source (e.g. ambient air), upgrade its temperature using electricity and then release it to a high temperature heat sink (e.g. a district heating network or building). The most common design of a heat pump is based on a vapour-compression cycle that involves four main components: a condenser, an expansion valve, an evaporator and a compressor. A refrigerant fluid is used to transport the heat within the cycle, exploiting the physical properties of evaporation and condensation. Most heat pumps can also operate in reverse, thereby providing cooling.

A large advantage of heat pumps is that they use relatively little electricity to produce heat, as they are able to use available heat from a variety of ambient heat sources. The extent to which electricity is used to produce a certain amount of heat is represented by the COP (coefficient of performance) and strongly depends on temperatures of the heat source versus the heat sink (e.g. desired temperature in the district heating network). Heat sources that are used in large-scale heat pumps (>1 MW) in European district heating networks include sewage water, ambient water (i.e. sea, lake and river water), waste heat, geothermal heat and to a much lesser extent also flue gas, district cooling and solar heat (David et al., 2017). Heat pumps are available in a wide range of capacities, starting at a few kilowatts for household use. The largest mechanical heat pumps in the world have a capacity of 50 MW_e (Averfalk et al., 2017).

3.2. Thermal energy storage

3.2.1. Introduction to thermal energy storage

An energy storage system forms the coupling between the energy source and the energy user. The application of an energy storage system can provide a time independent link between supply and demand of energy. This means that energy supply and demand do not have to occur simultaneously and be of the same size (Schepers & Dehens, 2020). Thermal energy storage is one way of storing energy and refers to the storage of heat or cold in a storage medium. The storage medium can be a natural part of the environment (e.g. ground) or it can be an artificially made object (e.g. water tanks) (Koohi-Fayegh & Rosen, 2020).

A major advantage of thermal energy storage is that it allows for more efficient heat generation. Heat generation can be moved from peak load plants to base load plants that have better fuel economy and lower environmental impact. This allows the base load heat source to produce more often with a favourable efficiency while also making more full load hours per year. This decreases the variation in heat generation and reduces the number of daily starts and stops (Kensby et al., 2015).

When thermal energy storage is combined with power-to-heat technologies such as electric boilers or heat pumps, electricity can be stored in the form of thermal energy that be extracted whenever needed. Combining thermal energy storage with power-to-heat has several additional advantages:

- *Lower electricity costs*: Adding thermal storage to a power-to-heat source enables the use of low-cost electricity. The power-to-heat source can generate heat when the electricity price is low, after which the heat is stored and used when the electricity price is high (Kensby et al., 2015).
- *Increased RES integration:* Power-to-heat may help with the integration of renewable electricity. However, without thermal energy storage, power-to-heat generation should match heat demand in terms of time and size. This is no longer the case when power-to-heat is combined with thermal energy storage, as the storage provides a time independent link between heat supply and demand. Combining power-to-heat with thermal energy storage can therefore lead to significant RES integration (Schweiger et al., 2017).
- *Less grid congestion:* Power-to-heat combined with thermal energy storage can help prevent grid congestion caused by capacity exceedance in two ways. Firstly, in the case that congestion is caused by high electricity production (e.g. due to solar power), electricity can be extracted from the grid and stored as heat for later use. Secondly, in the case that congestion is caused by high electricity demand, stored heat can be used to lower the power requirements for heat production thereby lowering electricity demand peaks on the grid.

Thermal energy storage technologies exist in many forms but can be categorised into three types based on their physical principle: sensible heat storage, latent heat storage and thermochemical heat storage.

Sensible heat storage (SHS) makes use of the temperature increase of a storage material to store heat and is the most widely used type of storage in district heating systems. Several materials can be used as storage material, but water is used most often. Reasons for this include its low costs, technology simplicity, favourable thermal properties and high scalability (Gadd & Werner, 2021). Within the category of sensible heat storage, four main technologies exist: tank thermal energy storage (TTES), pit thermal energy storage (PTES), borehole thermal energy storage (BTES) and aquifer thermal energy storage (ATES). Out of these technologies, only TTES is suitable for short-term energy storage. All four technologies for sensible heat storage, including TTES, are suitable for long-term energy storage (Guelpa & Verda, 2019).

Latent heat storage (LHS) relies on phase change materials as storage medium, that absorb or release latent heat during a change of phase at a particular temperature (Ann Cruickshank & Baldwin, 2016). The main advantages of LHS compared to SHS is its higher energy density, but materials used are often corrosive, poisonous and lack thermal stability. Furthermore, LHS systems are more expensive than SHS systems. While data is limited, it is shown that the costs of LHS systems are currently over four times the costs of SHS systems (Guelpa & Verda, 2019; Yang et al., 2021). This gap is lower in networks with a small temperature difference between supply and return lines. LHS is therefore most suitable in district cooling networks.

For seasonal storage purposes, it is shown that the realisation of an LHS is very complicated and that no significant improvements can be obtained by using PCMs instead of water (Guelpa & Verda, 2019).

Thermochemical heat storage (THS) makes use of either reversible chemical reactions or the principles of absorption and adsorption. THS has the advantages of having a very high energy density and negligible heat losses. However, implementing THS requires a complex system and there are problems with the instability of available storage materials used. Furthermore, THS is currently still far from market commercialisation and requires further research on materials and system configurations (Yang et al., 2021).

3.2.2. Selection of technologies

Within the three categories of thermal energy storage (i.e. SHS, LHS and THS), many different technologies and configurations exist. Not all of these technologies are applicable or relevant for use in combination with power-to-heat in residential district heating systems. Therefore, the thermal energy storage technologies are narrowed down to a selection. The resulting selection of technologies is the focus when it comes to modelling and assessment further on in this research. The following factors are considered for selecting thermal energy storage technologies that lie within the scope of this study: storage temperature level, centralised vs. decentralised storage and physical principle.

Storage temperature level

Three different temperature levels are important when it comes to district heating systems: heat source temperature, heat storage temperature and heat supply temperature.

The heat source temperature is dependent on the heat source that is used and whether or not it is upgraded by using technology, for example a heat pump. The heat supply temperature is based on the desired temperature at building level and is influenced by the level of building insolation. District heating networks are often categorised based on their supply temperature as described in Table 3 (TKI Urban Energy, 2021). The heat storage temperature should fit heat source and supply temperatures and at the same time the thermal energy storage technology should be suitable to store at the desired temperature.

As the focus of this study in on thermal energy storage for residential district heating networks, the first criterium for selecting thermal energy storage technologies is defined as follows: *the thermal energy storage technology is suitable for storing temperatures of 100 °C and lower.*

Table 3: Categorisation of district heating networks based on heat supply temperature level

Type of district heating network	Heat supply temperature
High temperature district heating (HT-DH)	>75 °C
Medium temperature district heating (MT-DH)	55-75 °C
Low temperature district heating (LT-DH)	30-55 °C
Very low temperature district heating (VLT-DH)	10-30 °C

Centralised vs. decentralised storage
Thermal energy storage technologies can be applied in a centralised or decentralised way. As this study focusses on district heating networks using collective heat sources, it is most logical to use centralised thermal energy storage. While technically possible, storing heat at household level would imply losing economy of scale benefits, a larger capacity requirement on system level and significantly higher costs (Schepers & Dehens, 2020). The second criterium for selecting thermal energy storage technologies is therefore defined as follows: *the thermal energy storage technology can be applied as centralised solution in a residential district heating network.*

Physical principle
As described earlier in more detail, there are three main categories of thermal energy storage based on their physical principle: sensible heat storage (SHS), latent heat storage (LHS) and thermochemical heat storage (THS). For the purpose of this study, only SES technologies are considered. LHS is excluded because of its high costs and limited benefits compared to sensible heat storage in district heating networks. THS is excluded mainly because it requires much more additional research before it can be commercialised. The third criterium for selecting thermal energy storage technologies is therefore defined as follows: *the thermal energy storage technology falls into the category of sensible heat storage.*

Peak loads
To shave peak loads on the electricity grid, it is important that heat can be stored and extracted quickly from the storage system. Thermal energy storage technologies that cannot do that, are therefore excluded from this study.

The fourth criterium for selecting thermal energy storage technologies is therefore defined as follows: *the thermal energy storage technology is capable of storing and extracting heat quicky.*

Summary of selection criteria
As explained in the section before, the selection criteria for selecting thermal energy storage technologies that lie within the scope of this study are:

1. The thermal energy storage technology is suitable for storing temperatures of 100 °C and lower.
2. The thermal energy storage technology can be applied as centralised solution in a residential district heating network.
3. The thermal energy storage technology falls into the category of sensible heat storage.
4. The thermal energy storage technology is capable of storing and extracting heat quicky.

Technology selection
Table 4 gives an overview of the most common thermal energy storage technologies that are currently available in the Netherlands, or that will be available in the Netherlands before 2035. The overview is based on a recent study on thermal energy storage in the Netherlands by Schepers en Dehens from CE Delft (2020) and is further expanded based on other literature sources.

Technology characteristics relevant to the aforementioned selection criteria is given in the last four columns. The first column relates to the first criterion, the second column relates to the second criterion, the third column relates to the third selection criterion and the fourth column relates to the fourth criterion. Green-coloured cells indicate that the technology characteristic meets the related criterion, whereas red-coloured cells indicate that the technology characteristic does not meet the criterion. Only technologies where all criteria are met are (only green cells) will be considered in further stages of this research.

Table 4: Selection of thermal energy storage technologies

Technology	Description	Temperature	Application	Heat type	Quick response to peak loads
ATES - LT	Low temperature storage in an aquifer.	<25 °C	Centralised	Sensible	No
ATES - MT	Medium temperature storage in an aquifer.	25-50 °C	Centralised	Sensible	No
ATES - HT	High temperature storage in an aquifer	50-90 °C	Centralised	Sensible	No
ATES – mine water	Thermal storage in mines filled with water.	10-30 °C	Centralised	Sensible	No
ATES – geothermal	Thermal storage in shallow wells (250-1250 m depth).	30-60 °C	Centralised	Sensible	No
TTES – atmospheric	Thermal storage in a water tank under atmospheric conditions.	<100 °C	Centralised, decentralised	Sensible	Yes
TTES – pressurised	Thermal storage in a water tank under pressurised conditions.	>100 °C	Centralised, decentralised	Sensible	Yes
PTES	Thermal storage in an insulated water pit.	<100 °C	Centralised	Sensible	Yes
BTES	Thermal storage using an array of boreholes filled with pipes in the subsurface.	<25 °C	Centralised, decentralised	Sensible	Yes
PCM	Thermal storage in the form of latent heat exploiting the phase-changes of a material at a specific temperature.	-50-1600 °C (Liu et al., 2018)	Centralised, decentralised	Latent	No (Airò Farulla et al., 2020)
THS	Thermal storage using either reversible chemical reactions or the principles of absorption and adsorption.	< 1000°C (Chen et al., 2018)	Centralised, decentralised, industrial	Thermo-chemical	Yes (Airò Farulla et al., 2020)
Steam accumulator	Thermal tank storage using steam under high pressure.	100-200 °C	Industrial	Sensible	Yes
Solid material storage	Thermal storage in solid materials like concrete, stones and basalt.	400-600 °C	Industrial	Sensible	Yes
MSES	Thermal energy storage in molten salts.	300-750 °C	Power plants	Sensible	Yes

From Table 4, it can be concluded that the following three main categories of thermal energy storage are relevant for this research:

- TTES: Tank thermal energy storage.
- PTES: Pit thermal energy storage.
- BTES: Borehole thermal energy storage.

3.2.3. TTES

Thermal tank energy storage (TTES) is a mature technology that is widely applied in residential and commercial buildings as well as in district heating systems (Delta Energy & Environment Ltd., 2016). Typically, it consists of an insulated steel or concrete tank filled with water that can be located either above the ground or underground (Guelpa & Verda, 2019). The technology can be used for both short-term and long-term storage.

Several installations for short-term TTES in district heating systems can be found worldwide. Examples are located in Turin (Guelpa & Verda, 2019) and Saint Paul, Minnesota (BWBR, 2021), both having a storage volume of around 15,000 m^3. There are also several installations in the Netherlands, including a heat buffer in Diemen with a storage volume of 22,000 m^3 (Vattenfall, 2015). The largest long-term TTES installations for district heating systems can be found in Friedrichshafen and Kungalv, having water storage volumes of 12,000 m^3 and 10000^3, respectively. Both systems are fed by a solar collector plant connected to the district heating system. Similar systems are located be found in Hamburg (4500 m^3) and Hannover (2750 m^3) (Schmidt et al., 2004). There is currently no large long-term TTES installed in the Netherlands.

3.2.4. PTES

Pit thermal energy storage (PTES) is another mature technology and is used for long-term (e.g. seasonal) energy storage, often at a very large scale (Bott et al., 2019). The technology consists of a pit buried in the ground filled with water or a mixture of water and gravel that serves as storage medium (Guelpa & Verda, 2019). PTES installations are already used in many countries in Europe, but not in the Netherlands. Large scale PTES installations in Europe range from 800 m^3 to 200,000 m^3 and are most often used to store heat from a solar heating plant (Bott et al., 2019). The largest PTES in the world (200,000 m^3) is located in Vojens (Ramboll, 2021).

3.2.5. BTES

Borehole thermal energy storage (BTES) is a technology that uses the soil to store heat. It consists of an array of boreholes filled with U-pipes that can either be vertically or horizontally installed in the ground. A depth between 30-200 m is generally used (Pavlov & Olesen, 2011). As BTES systems store energy in the soil, they need specific soil characteristics including high heat capacity and thermal conductivity but low hydraulic conductivity and groundwater flow. Furthermore, it is important that the ground is suitable for drillings (Schmidt et al., 2004). BTES systems typically need a start-up process (3-4 years) to become efficient, because it takes time to heat up the ground surrounding the boreholes (Yang et al., 2021).

Recently, the number of BTES installations has rapidly increased in Europe (Sanner et al., 2003) and North America (Gao et al., 2009). The technology is also widely applied in the Netherlands, accounting for over 40,000 installations. However, today's BTES installations are mostly applied on the building level, but (Schepers & Dehens, 2020). BTES installations coupled to district heating networks are rare. Examples are located in Alberta (Wong et al., 2006) and Anneberg (Lundh & Dalenbäck, 2008), heating 52 and 50 households, respectively. Both systems are fed by a solar source.

3.3. Techno-economic characteristics

3.3.1. Power-to-heat

An overview of the most important techno-economic parameters for the power-to-heat technologies is given in Table 5. These parameters are integrated in the model.

Table 5: Techno-economic parameters power-to-heat technologies

	Electric boiler	Source	Heat pump	Source
Efficiency / COP	0.99	(Berenschot et al., 2017)	3.73	Case-study
Specific investment costs (€/kW)	90	(Dominković, 2015)	600	(RVO, 2016)
O&M costs as percentage of investment (%)	6%	(Dominković, 2015)	4%	(RVO, 2016)
Lifetime (years)	20	(Schepers & Dehens, 2020)	20	(Dominković, 2015; Lacal Arantegui, R. et al., 2014)

3.3.2. Thermal energy storage technologies

An overview of the most important techno-economic parameters for the selected TES technologies is given in Table 6. These parameters are integrated in the model.

Table 6: Techno-economic parameters TES technologies (adapted from (Schepers & Dehens, 2020))

	PTES	TTES (long-term)	TTES (short-term)	BTES
Specific investment costs (€/kWh)	1.00	2.827	6.71	1.10
Annual O&M [% of investment]	3%	0.5%		3%
Efficiency [%]	81%	89%		80%
Lifetime [years]	30	50		30

4. Results

This chapter gives an overview of the results arising from this research. The first part of this chapter describes the modelling results, in which the desirability of power-to-heat and thermal energy storage is described from a techno-economic perspective (section 4.1). The second part of this chapter consists of a sensitivity analysis to test the robustness and wider applicability of the modelling results (section 4.2).

4.1. Modelling results

The relevant modelling results consist of power grid peak load, renewable energy integration and LCOH resulting from every of the model simulations. The modelling results in this section are organised by storage strategy.

4.1.1. Reference system

The three main output parameters of the model (i.e. power grid peak load, self-consumption and LCOH) are shown in Table 7.

Table 7: Results for the reference system

Indicator	Value
Power grid peak load [MW]	2.49
Self-consumption [%]	39.7%
LCOH [€/MWh]	82.74

4.1.2. Storage strategy 1: increasing solar power self-consumption

Self-consumption

A large increase in self-consumption of solar electricity can be obtained with this storage strategy compared to the reference system. The magnitude of this increase depends on the technologies used, as well as their capacities. Figure 8 gives the self-consumption of solar power for storage strategy 1, using P2H capacities ranging from 0.5 to 2.5 MW_e and TES capacities ranging from 0 to 2000 MWh.

From this figure, it can be seen that electric boilers lead to higher self-consumption (up to 100%) of solar electricity than the heat pumps do. This can be explained by the difference in efficiency between electric boilers and heat pumps. Heat pumps have higher efficiencies and therefore generate more heat, which causes a storage system to reach its maximum capacity relatively quickly. When this happens, no more solar power can be converted into heat, eventually leading to lower self-consumption. Heat pumps would only be able to reach higher self-consumption when a larger TES capacity is used. This is however not feasible, as the large amount of stored heat would mismatch the heat demand of the neighbourhood (2,697 MWh/year.)

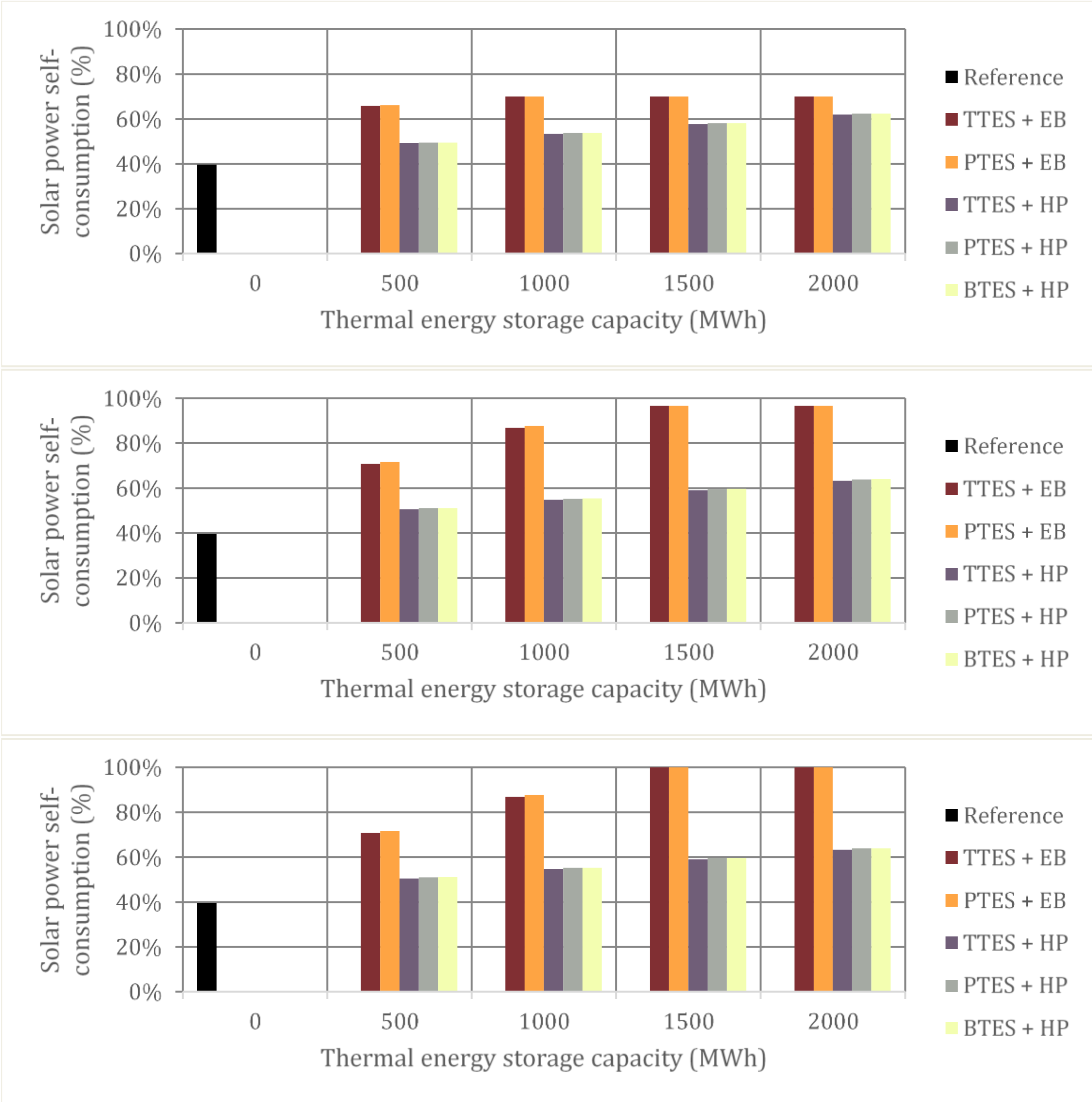

Figure 8: Solar power self-consumption in storage strategy 1, using power-to-heat capacities of 0.5 MW_e (top), 1.5 MW_e (middle) and 2.5 MW_e (bottom).

Furthermore, Figure 8 shows that only a TES coupled with a 2.5 MW_e electric boiler would be able to reach 100% self-consumption. The 1.5 MW_e electric boiler comes very close (96.7%), because solar power peaks higher than 1.5 MW are quite rare in the system. The 0.5 MW_e electric boiler can only reach a maximum self-sufficiency of 69.9%, as it shaves a relatively small amount of solar power.

Power grid peak load

Whenever there is a surplus of electricity in the neighbourhood, self-consumption of solar power can lead to reduced power loads on the grid. Figure 9Figure 9 shows the power grid peak loads using the aforementioned range of P2H and TES capacities operating according to storage strategy 1. As can be seen from this figure, the lowest power grid peak load can be achieved with an electric boiler due to its relatively low efficiency (i.e. high electricity consumption) as explained earlier in this section.

For the systems with an electric boiler, the general trend is that systems with larger P2H capacities and larger storage capacities cause lower peak loads on the grid. However, there is no significant improvement anymore above 500 MWh storage capacity for the 0.5 MW_e boiler and 1500 MWh storage capacity for the 1.5 and 2.5 MW_e boilers. An exception to the trend that larger P2H capacities result in lower power grid peak loads, can be observed for the 0.5 MW_e boiler combined with TES capacities up to 1000 MWh. In that case, the smaller 0.5 MW_e boiler leads to the lowest peak loads on the grid. This is because the 0.5 MW_e boiler fills the TES at a relatively slow rate (TES maximum capacity is reached at the end of August), leaving room to shave some of the high solar peaks in the summer. The 1.5 and 2.5 MW_e boilers reach the maximum TES capacities in June when coupled with capacities up to 1000 MWh.

Regarding the systems with a heat pump and TES, only the configuration with the 0.5 MW_e heat pump leads to a (limited) reduction in power grid peak load. Larger heat pumps have no effect on power peak loads as they reach maximum TES capacities already at the end of May, before the largest solar peak occurs (16 June).

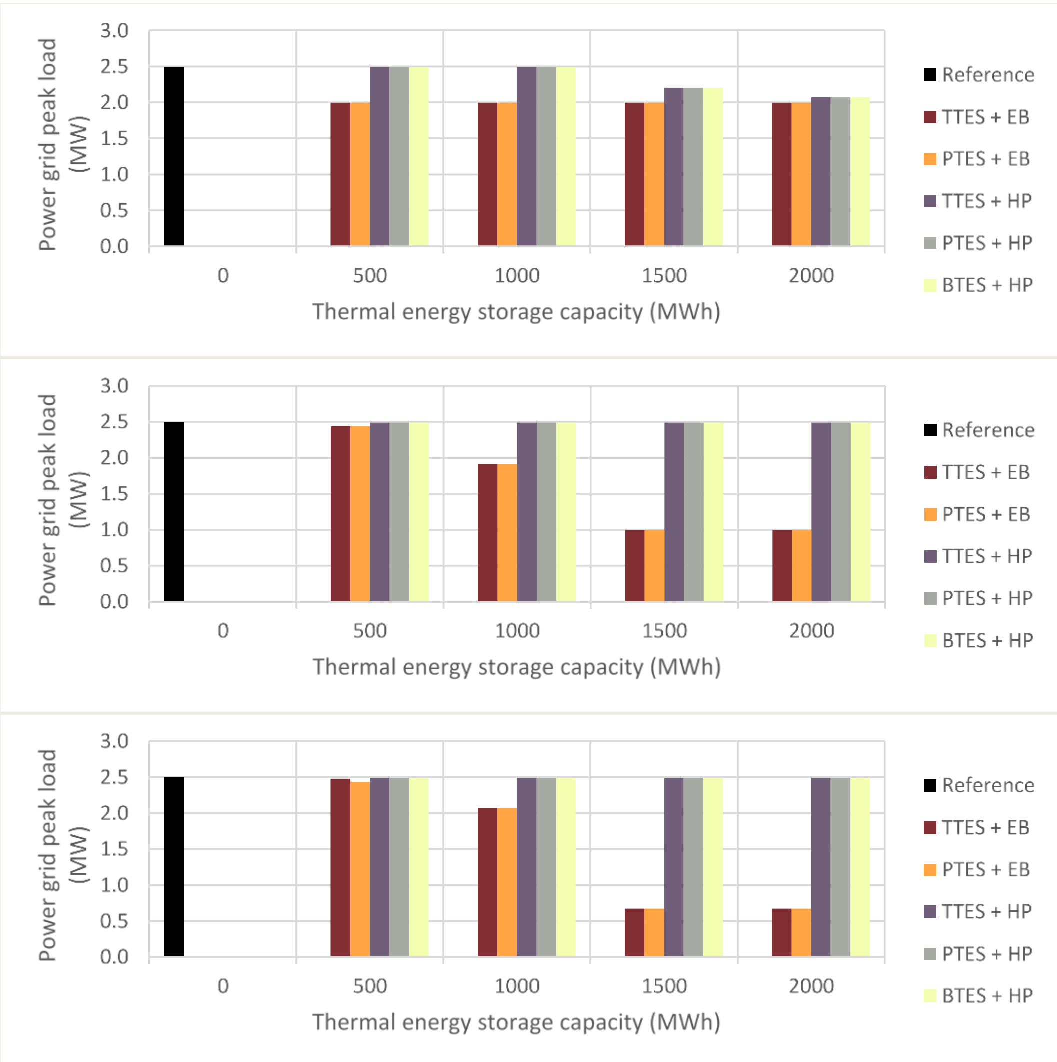

Figure 9: Power grid peak load in storage strategy 1, using power-to-heat capacities of 0.5 MWe (top), 1.5 MWe (middle) and 2.5 MWe (bottom).

LCOH

Although systems with storage strategy 1 can increase solar power self-consumption and decrease power grid peak loads, this strategy is not desirable from an economic perspective. Figure 10 presents the LCOH of all technology combinations operating according to storage strategy 1. It shows that the LCOH of any technology configuration is higher than the LCOH of the reference system.

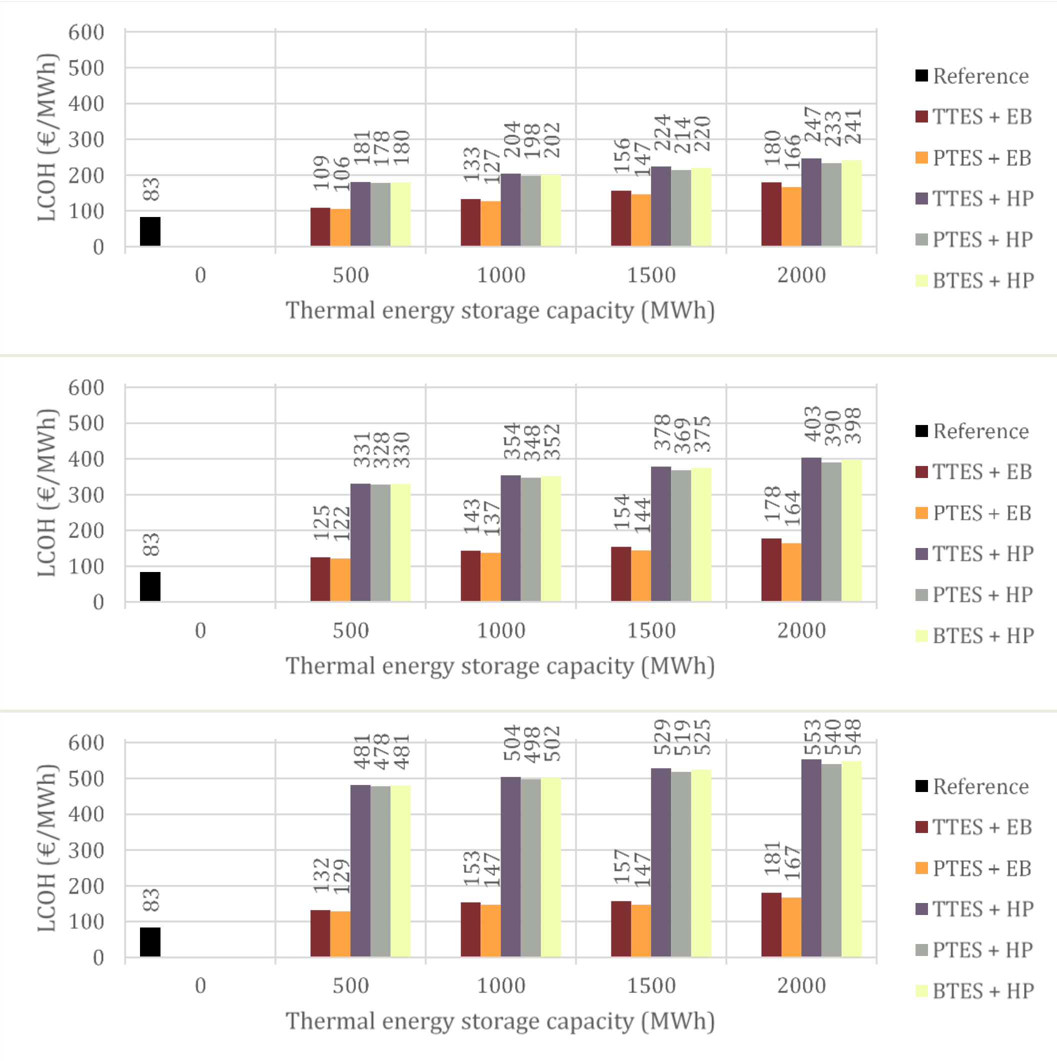

Figure 10: LCOH in storage strategy 1, using power-to-heat capacities of 0.5 MWe (top), 1.5 MWe (middle) and 2.5 MWe (bottom).

To better understand this outcome, it should be realised that the LCOH of a technology configuration can only be lower than the LCOH of the reference system under certain conditions. That is, when a decrease in grid reinforcement costs and/or fuel costs (i.e. electricity and gas costs) outweigh the extra costs of adding P2H and TES. That is not the case in any of the modelled technology configurations.

In the systems with an electric boiler, savings can be obtained from reduced grid reinforcement costs that result from lower power grid peak loads. On the other hand, the electricity costs suffer from a huge increase.

That has two main causes: (1) surplus electricity is largely self-consumed instead of sold to the grid using this strategy; (2) the main heat supply (i.e. heat pump) is partly replaced by a relatively low-efficiency electric boiler, together with storage losses resulting in higher annual electricity consumption. In other words, the savings in grid reinforcement costs do not outweigh the increase in electricity costs together with the additional costs of adding P2H and TES.

In the systems with a heat pump, there are generally no savings from grid reinforcement costs possible. Electricity consumption and thereby electricity costs are higher than in the reference system mainly due to storage losses. Although there is a slight decrease in gas costs, the increased electricity costs and additional costs of the P2H and TES lead to a huge overall increase of the LCOH.

The drastically lower LCOH of systems with electric boilers compared to systems with heat pumps, is mainly caused by the large difference in investment and O&M costs. To illustrate, the estimated investment costs of a 2.5 MW_e electric boiler and a 2.5 MW_e heat pump (i.e. 9.3 MW_{th}) are €445,500.- and €5,595,000., respectively. The O&M costs account for a fixed percentage of this investment each year. There are two main reasons for the heat pumps to be so much more expensive than electric boilers: (1) heat pumps have higher specific investment costs (€/kWh_{th}); (2) heat pumps are usually dimensioned on the basis of thermal capacity requirements, but its electric capacity is a factor 3.73 lower (i.e. its COP). As this case requires dimensioning based on electric capacity, this results in a very large heat pump.

4.1.3. Storage strategy 2: electricity price trading

Self-consumption

Storage strategy 2 is aimed at electricity price trading. An incentive to increase self-consumption of solar power is not built into the algorithm. Furthermore, modelling experiments has shown that this strategy functions best with short-term storage using small storage capacities. For these reasons, the change in self-consumption compared to the reference system is negligible for all technology combinations operating with storage strategy 2. There are also no notable differences between the TES and P2H technology combinations.

Nevertheless, Figure 11 shows the self-consumption of solar power for strategy 2 to further support this. Note that only TTES is included out of all TES technologies, as that it is the only technology suitable for short-term storage.

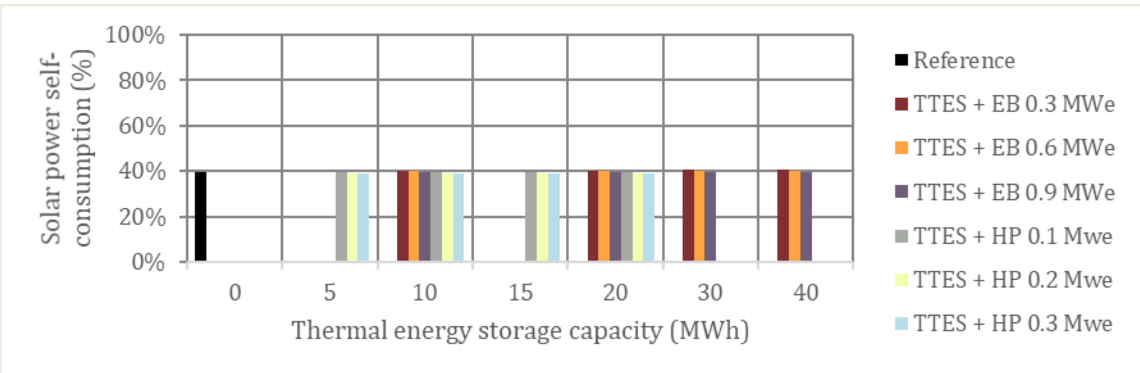

Figure 11: Solar power self-consumption in storage strategy 2

Power grid peak load reduction
For similar reasons as stated under the header 'self-consumption', there is no change in power grid peak load reduction compared to the reference for all technology combinations operating with storage strategy 2. Figure 12 shows the self-consumption of solar power for strategy 2 to further support this.

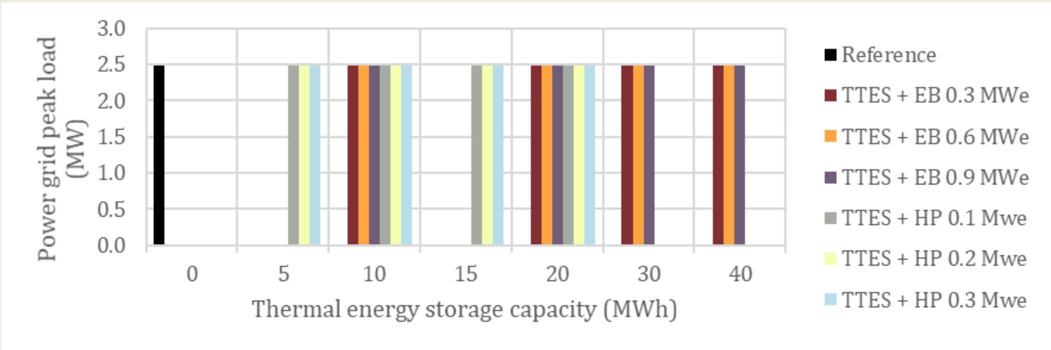

Figure 12: Power grid peak load in storage strategy 2

LCOH
Although storage strategy 2 is intended to gain economic advantage through electricity trading, this strategy has turned out to be economically undesirable. Figure 13 presents the LCOH of all technology combinations operating according to storage strategy 2. From this figure, it can be observed that the LCOH of any technology configuration is higher than the LCOH of the reference system, with values varying between 87.51 €/MWh and 128.56 €/MWh.

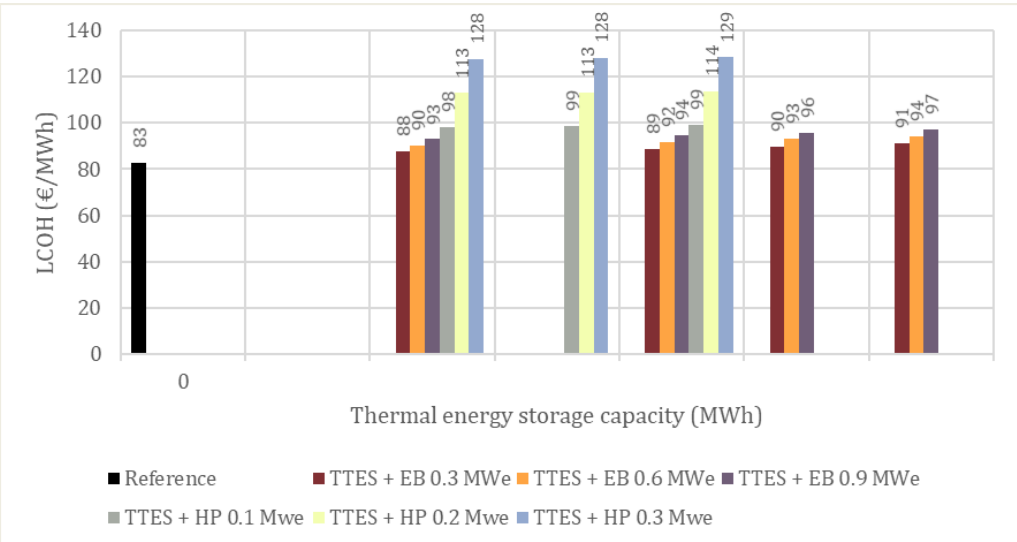

Figure 13: LCOH in storage strategy 2

For the heat pump variants, it has turned out that the electricity cost savings do not outweigh the additional costs for the heat pump and the TES. In fact, the costs associated with either a heat pump or TES alone are enough to make the business-case undesirable. For the electric boiler variants, the electricity costs savings are not obtained at all. On the contrary, the electricity costs increase because the main heat supply (i.e. heat pump) is partly replaced by a relatively low-efficiency electric boiler, together with storage losses resulting in higher annual electricity consumption. Yet the electric boiler configurations result in a lower LCOH than the heat pump configurations, mainly because of the large cost difference between boilers and electric heat pumps as stated earlier.

4.1.4. Storage strategy 3: reducing power grid peak loads

Storage strategy 3 aims to reduce the peak load on the grid to a certain value. In this research, this value is set to 1 MW_e as described in the methods (section 2.3.4). In order to reduce the peak load from 2.5 (i.e. the peak load in the reference situation caused by solar panels) to 1 MW_e, a 1.5 MW_e power-to-heat device is needed. A higher P2H capacity would lead to higher investment costs without adding anything to the system, while a lower P2H capacity leads to a power grid peak load higher than the desired 1 MW_e. Because of this, the P2H capacity is fixed at 1.5 MW_e for this storage strategy.

To be able to store all electricity generated by the P2H device, a certain TES capacity is needed. Similar to the P2H capacity, the TES capacity has only one optimal value in this strategy. The optimal TES capacity is reached at the point where all power grid loads in the year higher than 1 MW can be stored in the storage system. Extending the TES capacity beyond this optimal value is pointless, as strategy 3 is designed in such a way that no P2H conversion will occur for purposes other than peak-shaving. Hence, the results for storage strategy 3 are presented in another, shorter way compared to the other storage strategies.

Table 8 shows the optimal storage capacity, together with the related self-consumption, power grid peak load and LCOH.

Table 8: Solar power self-consumption, power grid peak load and LCOH in storage strategy 3

Indicator	Reference	TTES + EB	TTES + HP	PTES + EB	PTES + HP	BTES + HP
Storage capacity (MWh)	0	250	1126	246	1119	1118
Self-consumption (%)	39.7%	50.7%	50.0%	50.8%	50.0%	50.1%
Power grid peak load (MW)	2.49	1.00	1.00	1.00	1.00	1.00
LCOH (€/MWh)	82.74	83.31	334.74	81.56	327.31	331.79

As becomes clear from Table 8, the LCOH of the PTES combined with an electric boiler is the lowest out of all technology combinations. Although by a small margin, it also requires the lowest storage capacity and leads to the highest self-consumption of solar electricity. The LCOH of the system with the PTES and electric boiler is even lower than the LCOH of the reference system. This implies that it is economically more favourable to solve grid capacity problems with this technology combination, rather than using the traditional approach of reinforcing grid cables and stations.

The TTES and electric boiler combination also comes close to the reference situation in terms of economic performance. However, despite the higher efficiency and lifetime of the TTES system, it does not provide the reduction in LCOH that the combination of PTES and an electric boiler offers. The difference between these two can be explained by the lower specific investment costs of the PTES system compared to the TTES system. The systems using heat pumps are much more expensive. This is mainly due to the high costs associated with the heat pumps as explained earlier, but also because relatively large TES capacities are required to reach 1.5 MW_e peak load reduction.

4.2. Sensitivity analysis

A sensitivity analysis was performed for the following parameters: COP of the P2H heat pump, hourly electricity price and grid reinforcement costs. This section provides the most important results of this sensitivity analysis. A complete overview of sensitivity analysis results is given in Appendix 2.

4.2.1. COP of the heat pump

As becomes clear from the modelling results section, technology configurations with heat pumps are undesirable from all perspectives (self-consumption, power grid peak load and LCOH) using any storage strategy. This is in many cases related to the COP of heat pumps. To clarify, for a given electric capacity of a heat pump, the COP determines its thermal capacity, on which its investment costs and O&M costs but also the required storage capacity of the TES is based. The COP is thereby affecting many of the model's calculations.

Reference system

The reference system has no power-to-heat device (i.e. additional heat pump) and its output parameters are therefore not affected by a change in COP.

Storage strategy 1: increasing solar power self-consumption

Figure 14 shows the sensitivity analysis results for strategy 1, obtained after altering the COP by 1. To improve readability, only results are shown for a combination of PTES (overall best performing) and 1.5 MW_e heat pump (medium capacity). General trends are very similar for the other technology combinations.

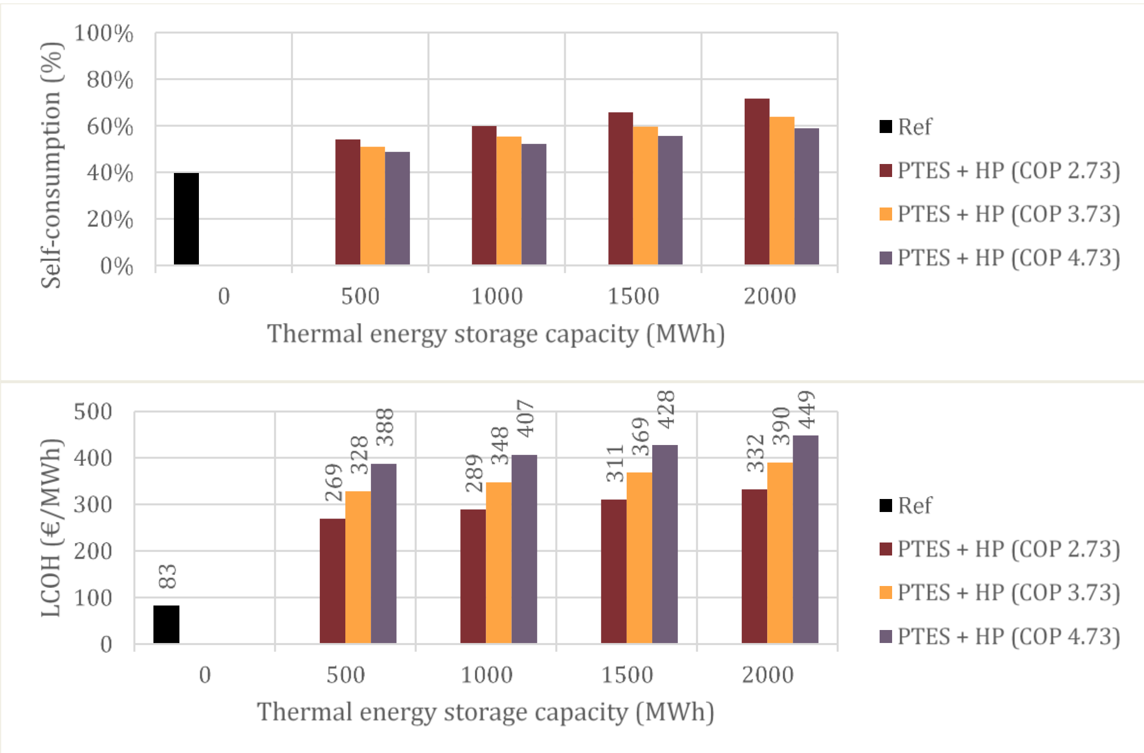

Figure 14: Sensitivity of self-consumption and LCOH to COP in storage strategy 1, using PTES and a 1.5 MWe heat pump

This figure shows that a higher COP of 4.73 causes a decrease of up to 5% in solar power self-consumption, whereas a lower COP of 2.73 causes an increase of up to 8%. As explained in 4.1.2, this happens because a higher COP means more heat generation, causing a storage system to reach its maximum capacity quicker thereby leaving less room to store solar power.

Besides increasing self-consumption, a lower COP also positively effects the LCOH. Lowering the COP to 2.73 leads to around 20% decreased LCOH, while increasing the COP to 4.73 leads to around 15% increased LCOH. The changes in LCOH are mainly driven by the investment costs of heat pumps. However, the results show that the LCOH of any configuration using any COP is still higher than the LCOH in the reference system.

Altering the COP does not result in any notable changes in power grid peak load. Sensitivity of COP on power grid peak load is therefore not included in the results here.

Storage strategy 2: electricity price trading
The LCOH is the only output parameter that significantly changes after altering the COP in storage strategy 2. Figure 15 shows how different COP values affect the LCOH using strategy 2. Only the TTES system with a 0.2 MW_e heat pump is shown, as the other technology configurations show similar trends.

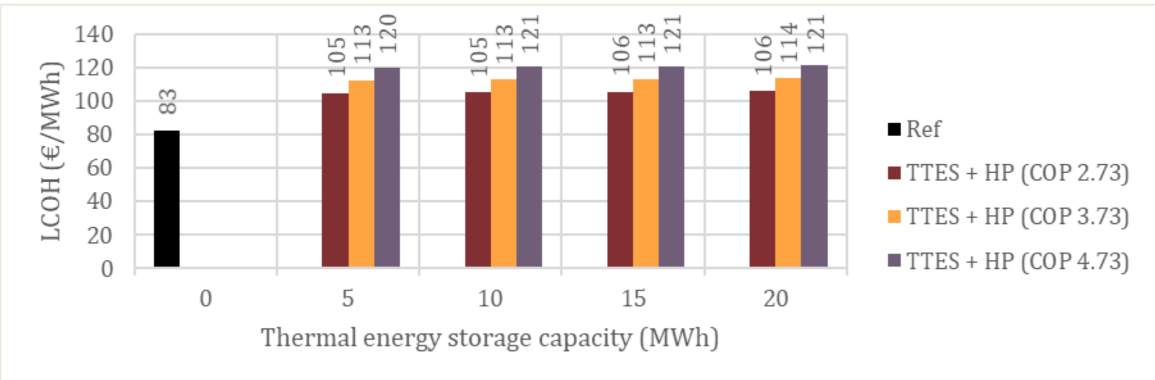

Figure 15: Sensitivity of LCOH to COP in storage strategy 2, using TTES and a 0.2 MW_e heat pump

The results show a change of around -7 to +6% as a result of different COP values. This is mainly driven by changes in heat pump investments, as higher investments are needed for heat pumps with higher COP and therefore higher thermal capacity. Electricity costs slightly decrease as a result of a higher COP, but they cannot outweigh the additional costs of the more expensive heat pump.

The LCOH of any configuration is higher than the LCOH of the reference system.

Storage strategy 3: reducing power grid peak loads
In strategy 3, there are only two parameters that change significantly when altering the COP. These are the required storage capacity and the LCOH.

Table 9 shows the required TES capacity for the different COP values and technology combinations. These results show that increasing or decreasing the COP of the heat pump by 1, leads to around 29% change in the required TES capacity. Table 10 shows the LCOH for different COP values.

It indicates that increasing or decreasing the COP of the heat pump by 1, leads to around 22% change in LCOH. This change is caused by the difference in heat pump investment costs, heat pump O&M costs and the required TES capacity.

Table 9: Sensitivity of required storage capacity (MWh) to COP in storage strategy 3

	TTES + HP	PTES + HP	BTES + HP
COP 2.73	805	798	797
COP 3.73 (base)	1126	1119	1118
COP 4.73	1453	1440	1439

Table 10: Sensitivity of LCOH (€/MWh) to COP in storage strategy 3

	Reference	TTES + HP	PTES + HP	BTES + HP
COP 2.73	82.74	260.78	255.42	258.59
COP 3.73 (base)	82.74	334.74	327.31	331.79
COP 4.73	82.74	409.84	399.56	405.26

For every COP value, the best economically best performing technology combination consists of the PTES and a heat pump. However, the LCOH is still far higher than the LCOH of the electric boiler variants and the LCOH of the reference system.

4.2.2. Hourly electricity prices

Using the 'NL 2030 day-ahead electricity prices' dataset as developed according to the method section, sensitivity of the hourly day-ahead electricity prices is tested. It has turned out that only the LCOH changes significantly. Power grid peak load and self-consumption do not show any significant change and are therefore not discussed in this section.

Reference system

The LCOH of the reference system changes from 82.74 to 82.62 €/MWh as a result of using different hourly electricity prices. There is thus very little change here despite the 58% difference in average electricity price between the datasets. However, this is to be expected as the neighbourhood production and consumption of electricity are roughly equal in the case-study area.

Storage strategy 1: increasing solar power self-consumption

In the first storage strategy, the 2030 electricity prices lead to an increased LCOH compared to 2016 electricity prices for the systems with an electric boiler. This is shown in Figure 16, with the PTES as storage technology. General trends for other storage technologies are found to be very similar.

The increase in LCOH amounts to 2% to 10%, depending on the boiler's capacity and the type of TES technology that it is combined with. This increase is caused by the relatively high electricity use of electric boilers, that result in higher costs with higher electricity prices. For the systems configurations with a heat pump, the relative change in LCOH is negligible (<0.3%).

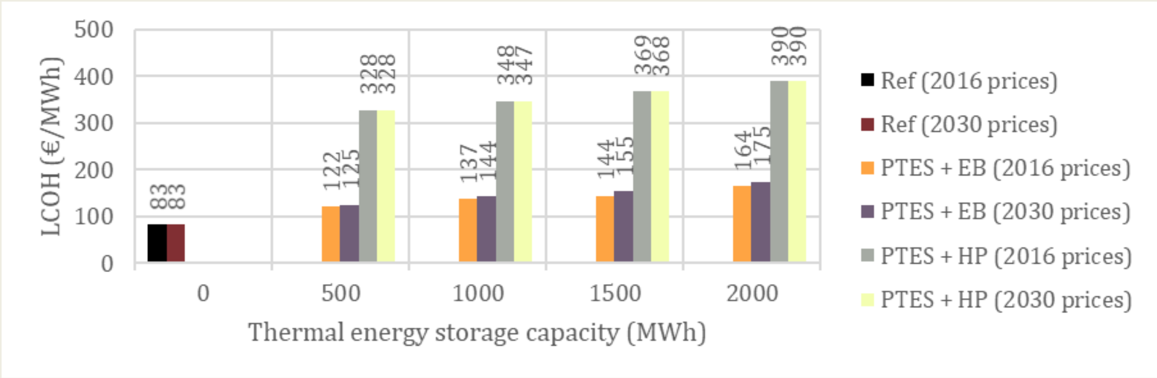

Figure 16: Sensitivity of LCOH to hourly electricity prices in storage strategy 1, using PTES and a 1.5 MWe electric boiler

Storage strategy 2: electricity price trading
In the second storage strategy, the 2030 electricity prices result in a lower LCOH for every technology combination. This is expected as strategy 2 is built-around trading in electricity prices and the more volatile 2030 electricity prices give this strategy more economic potential to trade.

However, the change in LCOH is limited with only 2.5-5% decrease for the electric boiler variants and 0.3-1.5% decrease for the heat pump variants. The LCOH of the reference scenario is still lower in every case. This emphasises that storage strategy 2 is economically undesirable, also with higher and more volatile electricity prices.

Figure 17 provides insight in the LCOH based on the different hourly electricity prices, using middle capacity P2H devices.

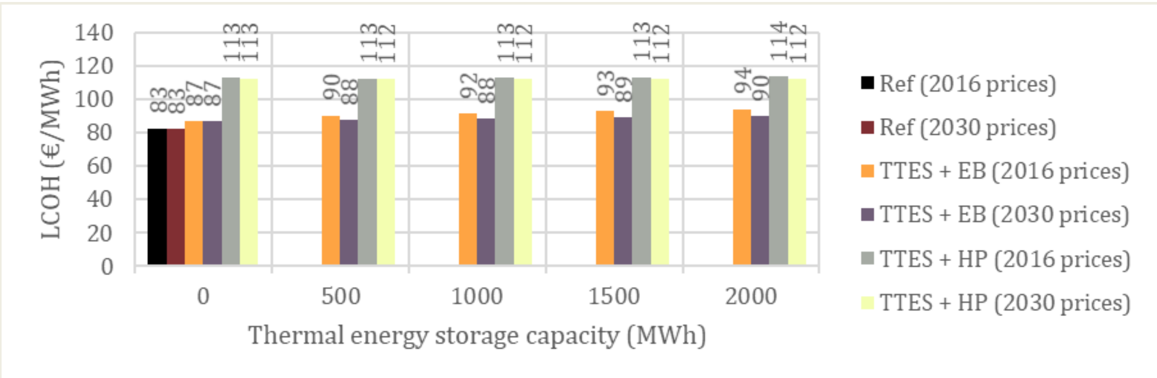

Figure 17: Sensitivity of LCOH to hourly electricity prices in storage strategy 2, using TTES and a 0.6 MW_e boiler or a 0.2 MW_e heat pump

Storage strategy 3: reducing power grid peak loads
Table 11 shows the LCOH outcomes of the 2016 and 2030 electricity price datasets. As becomes clear from this table, the 2030 electricity prices result in a 2% increase of LCOH in the electric boiler system configurations (due to their relatively low conversion efficiency). As a result of this, the combination of PTES and an electric boiler is now less economically more attractive than the reference system. The LCOH of the heat pump variants stays roughly the same.

Table 11: Sensitivity of LCOH to hourly electricity prices in storage strategy 3

	Reference	TTES + EB	TTES + HP	PTES + EB	PTES + HP	BTES + HP
2016 prices	82.74	83.31	334.74	81.56	327.31	331.79
2030 prices	82.62	85.06	335.03	83.34	327.65	332.11

4.2.3. Cable reinforcement costs

The cable reinforcement costs make for a large part of the LCOH and are therefore tested on sensitivity. The other results (power grid peak load and self-consumption) do not show any significant change and are therefore not discussed in this section.

Reference system

If cable reinforcement costs were to increase by 30%, the LCOH of the reference system would go from 82.74 to 92.66 €/MWh (12% increase). Likewise, a decrease of 30% in cable reinforcement costs would mean that the LCOH would decrease from 82.74 to 72.81 €/MWh (12% decrease).

Storage strategy 1: increasing solar power self-consumption

For storage strategy 1, the LCOH is slightly less sensitive to a change in cable reinforcement costs compared to the reference scenario. This is expected, as less cable reinforcement is needed in this strategy compared to the reference system. The change in LCOH for storage strategy 1 amounts to plus or minus 2-6% for the heat pump variants and to plus or minus 2-9% for the electric boiler variants. This is because the relative share of cable reinforcement costs is larger in the LCOH of electric boiler variants than in heat pump variants (due to higher total costs of heat pump variants).

To illustrate, Figure 18 gives the results on LCOH using a PTES system with a 1.5 MW_e P2H device. Trends for the other technology configurations have turned out to be very similar.

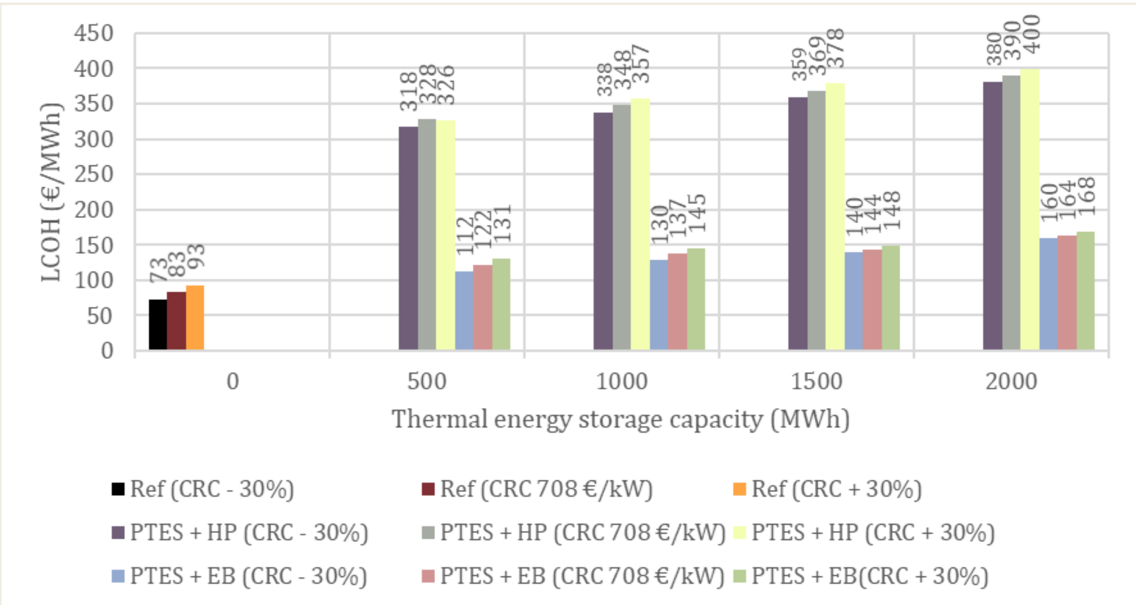

Figure 18: Sensitivity of LCOH to cable reinforcement costs in storage strategy 1, using PTES and a 1.5 MW_e P2H device

In this strategy, the LCOH of the reference system is lower than the systems using P2H and TES, no matter the grid reinforcement costs.

Storage strategy 2: electricity price trading
Figure 19 shows the LCOH of all systems using different grid reinforcement costs.

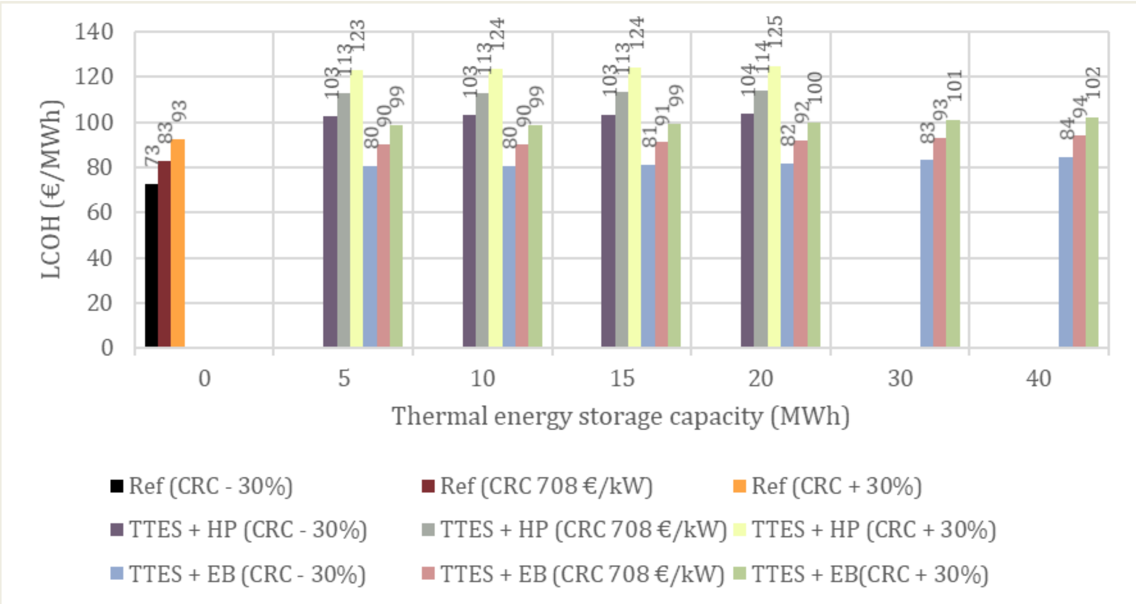

Figure 19: Sensitivity of LCOH to cable reinforcement costs in storage strategy 2, using a 0.2 MW_e heat pump or 0.6MW_e electric boiler

The change in LCOH for storage strategy 2 amounts to plus or minus 8-10% for the heat pump variants and to plus or minus 10-11% for the electric boiler variants. Again, this is because the share of cable reinforcement costs is larger in the LCOH of electric boiler variants than in heat pump variants. The LCOH of the reference system is lowest for every scenario of cable reinforcement costs.

Storage strategy 3: reducing power grid peak loads
Also in storage strategy 3, the electric boiler variants are most affected by a change in grid reinforcement costs (plus or minus 5%), while there is only 1% change in the LCOH of heat pumps. Table 12 gives the LCOH values for strategy 3, using different values for cable reinforcement costs.

Table 12: Sensitivity of LCOH to cable reinforcement costs in storage strategy 3

	Reference	TTES + EB	TTES + HP	PTES + EB	PTES + HP	BTES + HP
CRC - 30%	72.81	79.33	330.76	71.70	296.60	327.86
CRC 708 €/kW	82.74	83.31	334.74	81.56	327.31	331.79
CRC + 30%	92.66	87.28	338.72	79.66	304.56	335.77

Interestingly, a 30% increase in grid reinforcement costs gives the TTES and electric boiler variant a lower LCOH than the reference system. Without that increase in cable reinforcement costs, only the PTES and electric boiler would be cheaper than the reference system.

5. Discussion

5.1. Results and implications

The results of this study indicate that electric boilers outperform heat pumps on every front, by leading to higher self-consumption, a lower power grid peak load and a lower LCOH. The lower LCOH of electric boilers compared to heat pumps contradicts the findings of many other studies that compare these two technologies for use in district heating systems (Meesenburg, 2020; Popovski et al., 2019). However, it should be noted that these studies aim at selecting the most cost-effective way of heat supply, favouring efficient technologies that require a low power input. This study argues the other way around, by looking at the most cost-effective way of shaving power loads, where a high efficiency only limits the maximum amount of power shaving. This study is quite unique in doing so and thereby contributes to filling the research gap that is present in this field. It adds insights to existing research, about the techno-economic impacts of different system configurations from a power grid perspective.

One of the few studies that looks at power-to-heat from a power perspective, shows results that are more aligned with this study. They acknowledge that electric boilers have 2-4 times more power-to-heat potential than heat pumps due to the difference in efficiency (Schweiger et al., 2017). This is also the reason electric boilers to perform better on the fronts of self-consumption and power grid peak load, as it takes longer for the thermal energy storage to reach its maximum capacity. However, heat pumps would most likely perform better on some other evaluation indicators, such as primary energy consumption, that were not including in this study.

Out of all 89 system configurations, only storage strategy 3 with a PTES and electric boiler combination has turned out to be economically attractive. However, even for this system configuration, the reduction in LCOH compared to the reference system is quite small (1.18 €/MWh or 1.4%). The sensitivity analysis has indicated that strategy 3 using PTES and an electric boiler can become either more economically favourable (e.g. due to higher cable reinforcement costs) or less economically favourable (as a result of future electricity prices). This questions the robustness of such a system's economic desirability. However, it is likely that the LCOH of various system configurations could be further lowered by improving or combining storage strategies. For example, storage strategy 3 utilises the P2H and TES only from March to October and rarely needs the full P2H capacity. This leaves room for storage strategy 2 to come in and profit from fluctuations in day-ahead electricity prices. The potential future decrease in the price of thermal energy storage can also contribute to achieving a better business case (Delta Energy & Environment Ltd., 2016).

Whether or not the combination of P2H and TES is preferred to mitigate grid congestion, also depends on whether self-consumption is considered to be a relevant indicator. The results have shown that a large amount of self-consumption (up to 100%) can be achieved, depending on the system configuration. This offers the advantage of having more renewable electricity integration, rather than using power that partly originates from fossil fuel. While this is a good thing, it is not expected that increased self-consumption will be the only driver for an investment.

Especially, since the system configurations that enhance self-consumption are expensive. However, if there is a system configuration that is only slightly more expensive than the reference situation (e.g. the PTES + electric boiler with future electricity prices), it is likely that self-consumption could be the decisive parameter.

Overall, the combination of PTES and electric boiler using strategy 3 is the recommended system configuration and can compete with investing in more grid capacity.

5.2. Limitations of the research

Building the model of this research in Microsoft Excel provides advantages as well as limitations. The main advantages are its ease-of-use and high customisability. It has allowed for building an energy system model that is tailored towards this project specifically, where all the available input data and calculations could be used in the desired way. However, no optimisation model could be built, which would have been really useful in performing the techno-economic assessment. Microsoft Excel can only handle optimisation models with limited numbers of variables and constraints, much less than are required to optimise an energy system over a whole year with 1 hour-resolution. Because of this, the model in this study is designed to perform what-if-analyses and the outcomes of many system configurations had to be calculated manually.

The model in this study is designed so that it can perform heat supply and storage calculations without modelling temperatures and flow rates. This is done by using average efficiencies, rather than calculating them as function of temperatures and flow rates. By modelling this way, it is easier to compare between different technologies and storage strategies, without having to model each system configuration on a very detailed level. There are two limitations resulting from this approach: (1) heat flow calculations on an hourly level can be less precise (2) upgrading of heat after storage is ignored. However, this modelling approach allows for a decent comparison between system configurations (which is needed as prior research is lacking) while being feasible in terms of time.

Another limitation of this research lies in the simplification of the distributions grid's infrastructure. It is assumed that the neighbourhood's distribution grid covers the exact same buildings (no more and no less) as the district heating network does. It is essentially modelled as if all buildings are connected to the same transformer. This simplification is implemented specifically for storage strategy 3, so that there is one number for grid capacity that determines the required amount of peak-shaving. In reality, there is no such thing as 'one grid capacity of the neighbourhood'. All cables and transformers have their own capacity and buildings are connected to different transformers. As a result of this simplification, the grid investment costs and required peak shaving (strategy 3) might differ slightly from reality. However, a detailed analysis and modelling of grid infrastructure goes beyond the scope of this study.

Furthermore, this research focusses specifically on the neighbourhood of Eva-Lanxmeer. The results will therefore be only reasonably applicable to cases with similar characteristics. That is, in energy-neutral neighbourhoods with high solar power generation and medium-temperature district heating system where heat is supplied by a heat pump.

Applying a similar P2H and TES system to an area with a difference in key characteristics, such as in heat demand (profile), solar power production, heat supply technologies and temperature levels, could lead to very different results. In the first place, that is because the sizing and efficiency of installations can differ depending on the case. It could also be that a storage strategy is better suited to one case than in another. For example, operating an electric boiler with strategy 2 (profiting from electricity price fluctuations) could yield a lower LCOH in carbon intensive systems with higher fuel costs, especially with the projected future increase in gas prices (PBL, 2020). In fact, this is the idea behind the plans for an electric boiler in the district heating network of Diemen (Vattenfall, 2021). From existing research, it has become clear that there is a clear link between TES size and specific investment costs (Yang et al., 2021). This could potentially increase the economic desirability of P2H and TES in larger district heating systems.

5.3. Recommendations for further research

It is recommended that further research is done on the applicability of similar P2H and TES concept to other district heating systems. It would be interesting to do a techno-economic assessment for a range of case-studies with different characteristics, for example in terms of heat supply temperature and heat demand and electricity profiles. In this way, more generalisable results could be obtained that could indicate which technology combinations and storage strategies suit certain types of areas.

Furthermore, it is suggested to build model detailed version of the system configurations that performed best in this study, thus prioritising electric boiler system configurations. More detail could be added by more precise temperature and flow calculations to the calculation or by including a more comprehensive grid infrastructure component to the model (as explained in 5.2). It is also possible to use the existing model for this and expand it with these more detailed calculations.

This research has performed a techno-economic assessment of P2H and TES in district heating networks, but it is also very important that research is done on the social and practical desirability of such a system. For example, implementation of such a system also relies on aspects like space requirement, geological conditions and stakeholder engagement and legal conditions that were not assessed in this study.

6. **Conclusion**

This research provides insights in the desirability of power-to-heat combined with thermal energy storage in district heating networks, from a power grid perspective. To this end, the following main research question is answered:

"How desirable is the application of power-to-heat combined with thermal energy storage in residential district heating networks, from the perspectives of power grid peak load, renewable energy integration and economic performance?"

To answer this question, the neighbourhood of Eva-Lanxmeer in Culemborg is used as a case-study. A techno-economic assessment is performed for 89 system configurations in which power-to-heat and thermal energy storage are applied. The results for these system configurations are evaluated based on three indicators: solar power self-consumption, power grid peak load and LCOH. The results are compared to a reference system, in which no power-to-heat and thermal energy storage are present.

A modelling approach is taken to perform the techno-economic assessment. Using case-specific data for heat demand, power consumption and power production, a model of the local energy system is developed. Raw heat demand data and conversion efficiencies are obtained from local heat supplier ThermoBello and are further processed so that hourly heat demand and energy consumption of the district heating system could be modelled. The power consumption of buildings in the area is modelled by combining NEDU electricity profiles with the annual electricity demand of buildings in the neighbourhood. The solar power production is modelled using the ISSO methodology for solar power and is tailored to cover the annual electricity demand of the neighbourhood.

The 89 assessed system configurations differ in terms of technology combinations, installed capacities and storage strategies. Based on a literature review, a selection of applicable technologies and their techno-economic properties is obtained. The considered technology combinations consist of either tank thermal energy storage (TTES), pit thermal energy storage (PTES) or borehole thermal energy storage (BTES) with a heat pump or an electric boiler. The formulated storage strategies contain the algorithms that determine how and when these technologies are operated. Storage strategy 1 aims to increase self-consumption, Storage strategy 2 aims to benefit from fluctuating electricity prices and storage strategy 3 aims at reducing the power grid peak load.

Results for system configurations using storage strategy 1 show increased solar consumption compared to the reference scenario. There is a clear difference between systems using electric boilers and heat pumps, that reach up to 100% and 64% self-consumption, respectively. This is both higher than the 40% self-consumption in the reference situation. System configurations also come with lower peak loads than in the reference situation. However, system configurations using storage strategy 1 yield high LCOH's ranging from 105.55 to 553.48 €/MWh, compared to 82.74 €/MWh in the reference system.

System configurations using storage strategy 2 have no impact on self-consumption and power grid peak loads. LCOH's are higher compared to the reference situation, ranging from 87.51 to 128.56 €/MWh.

System configurations using storage strategy 3 lead to increased self-consumption of around 50%. The power grid peak load is 1 MW in all cases, opposed to 2.5 MW in the reference situation. The LCOH of most system configurations using strategy 3 is higher than the LCOH of the reference system, with 327.31-334.74 for the heat pump system configurations and 83.31 €/MWh for the electric boiler and tank thermal energy storage configuration. There is only one system configuration with a lower LCOH than the reference system, which is the electric boiler combined with pit thermal energy storage combined and storage strategy 3.

Overall, the results indicate that electric boilers are more desirable than heat pumps, by leading to significantly higher self-consumption, a lower power grid peak load and a lower LCOH in all system configurations. Only pit thermal energy storage and tank thermal energy storage can be applied together with electric boilers. Out of these two, pit thermal energy storage is found to be more desirable in most situations, mainly due to its lower costs.

7. References

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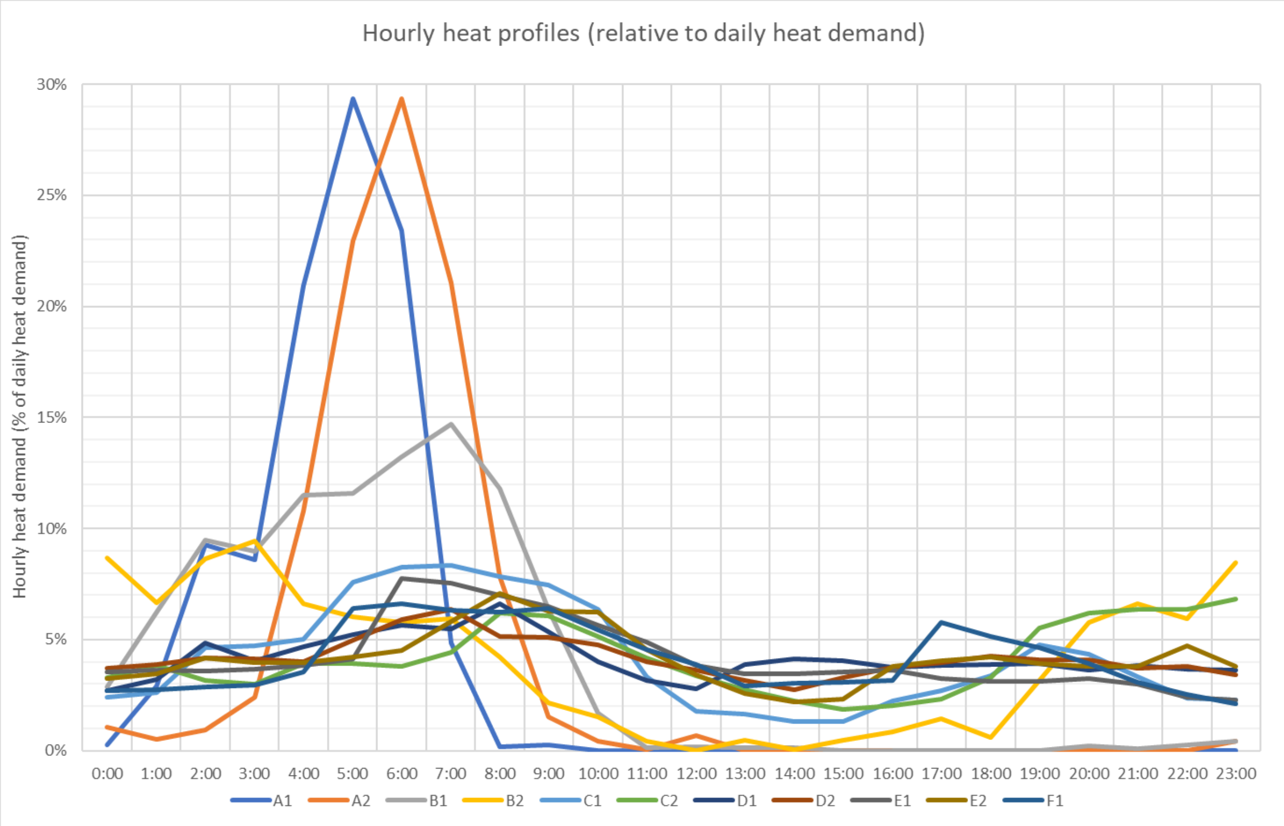
Appendix 1: Heat demand distribution profiles

This appendix shows the 11 heat demand distribution profiles that are developed for the model.



Appendix 2: Sensitivity analysis results tables

In this appendix, a complete overview of sensitivity analysis results is given. The tables are ordered by parameter that is subject to change (COP, day-ahead electricity price and specific grid cable investment costs) and by storage strategy.

Sensitivity to COP in storage strategy 1

TTES & heat pump (0.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	137.72
500	52.0%	2.49	162.09
1000	57.9%	2.21	180.95
1500	63.7%	1.99	202.71
2000	69.6%	1.99	228.27

TTES & heat pump (0.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	178.01
500	47.5%	2.49	200.06
1000	50.9%	2.49	222.69
1500	54.2%	2.49	247.31
2000	57.6%	2.21	267.10

TTES & heat pump (1.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	247.70
500	53.6%	2.49	272.07
1000	59.5%	2.49	295.20
1500	65.3%	2.49	320.60
2000	71.2%	2.44	345.50

TTES & heat pump (1.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	368.55
500	48.4%	2.49	390.45
1000	51.7%	2.49	413.14
1500	55.1%	2.49	437.46
2000	58.5%	2.49	461.80

TTES & heat pump (2.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	357.68
500	53.6%	2.49	382.06
1000	59.5%	2.49	405.16
1500	65.3%	2.49	430.38
2000	71.2%	2.44	455.40

TTES & heat pump (2.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	559.10
500	48.4%	2.49	580.98
1000	51.7%	2.49	603.69
1500	55.1%	2.49	628.00
2000	58.5%	2.49	652.30

PTES & heat pump (0.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	137.72
500	52.4%	2.49	159.11
1000	58.3%	2.21	174.83
1500	64.1%	1.99	192.77
2000	69.7%	1.99	214.88

PTES & heat pump (0.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	178.01
500	47.8%	2.49	197.11
1000	51.2%	2.49	216.32
1500	54.5%	2.44	236.50
2000	57.9%	2.21	253.83

PTES & heat pump (1.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	247.70
500	54.1%	2.49	269.18
1000	60.0%	2.49	289.10
1500	65.8%	2.49	310.73
2000	71.6%	2.44	332.24

PTES & heat pump (1.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	368.55
500	48.8%	2.49	387.60
1000	52.2%	2.49	406.71
1500	55.6%	2.49	427.54
2000	59.0%	2.49	448.53

PTES & heat pump (2.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	357.68
500	54.1%	2.49	379.12
1000	60.0%	2.49	399.02
1500	65.8%	2.49	420.52
2000	71.6%	2.44	442.19

PTES & heat pump (2.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	559.10
500	48.8%	2.49	578.13
1000	52.2%	2.49	597.23
1500	55.6%	2.49	618.11
2000	59.0%	2.49	639.07

BTES & heat pump (0.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	137.72
500	52.5%	2.49	161.15
1000	58.3%	2.21	178.88
1500	64.2%	1.99	198.77
2000	69.7%	1.99	222.85

BTES & heat pump (0.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak load	
0	39.7%	2.49	178.01
500	47.8%	2.49	199.15
1000	51.2%	2.49	220.38
1500	54.6%	2.44	242.50
2000	57.9%	2.21	261.82

BTES & heat pump (1.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	247.70
500	54.2%	2.49	271.23
1000	60.0%	2.49	293.17
1500	65.9%	2.49	316.75
2000	71.7%	2.44	340.24

BTES & heat pump (1.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak load	
0	39.7%	2.49	368.55
500	48.9%	2.49	389.65
1000	52.3%	2.49	410.78
1500	55.7%	2.49	433.53
2000	59.0%	2.49	456.53

BTES & heat pump (2.5 MW_e) (COP -1)

Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	357.68
500	54.2%	2.49	381.15
1000	60.0%	2.49	403.08
1500	65.9%	2.49	426.53
2000	71.7%	2.44	450.18

BTES & heat pump (2.5 MW_e) (COP +1)

Storage capacity	Self-consumption	Power grid peak load	
0	39.7%	2.49	559.10
500	48.9%	2.49	580.17
1000	52.3%	2.49	601.29
1500	55.7%	2.49	624.11
2000	59.0%	2.49	647.06

Sensitivity to COP in storage strategy 2

TTES & heat pump (0.1 MW$_e$) (COP -1)				**TTES & heat pump (0.1 MW$_e$) (COP +1)**			
Storage capacity	Self-consumption	Power grid peak loac	LCOH	Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	93.73	**0**	39.7%	2.49	101.79
5	39.5%	2.49	93.98	**5**	39.3%	2.49	101.47
10	39.5%	2.49	94.45	**10**	39.2%	2.49	101.81
15	39.5%	2.49	94.96	**15**	39.2%	2.49	102.22
20	39.5%	2.49	95.49	**20**	39.2%	2.49	102.68
TTES & heat pump (0.2 MW$_e$) (COP -1)				**TTES & heat pump (0.2 MW$_e$) (COP +1)**			
Storage capacity	Self-consumption	Power grid peak loac	LCOH	Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	104.73	**0**	39.7%	2.49	120.85
5	39.3%	2.49	104.88	**5**	39.0%	2.49	120.32
10	39.4%	2.49	105.30	**10**	39.0%	2.49	120.56
15	39.4%	2.49	105.75	**15**	39.0%	2.49	120.90
20	39.4%	2.49	106.25	**20**	38.9%	2.49	121.31
TTES & heat pump (0.3 MW$_e$) (COP -1)				**TTES & heat pump (0.3 MW$_e$) (COP +1)**			
Storage capacity	Self-consumption	Power grid peak loac	LCOH	Storage capacity	Self-consumption	Power grid peak loac	LCOH
0	39.7%	2.49	115.73	**0**	39.7%	2.49	139.90
5	39.1%	2.49	115.83	**5**	39.0%	2.49	139.30
10	39.2%	2.49	116.22	**10**	38.9%	2.49	139.46
15	39.2%	2.49	116.65	**15**	38.9%	2.49	139.79
20	39.1%	2.49	117.13	**20**	38.9%	2.49	140.23

Sensitivity to COP in storage strategy 3

TTES & heat pump (COP - 1)				**TTES & heat pump (COP + 1)**			
Storage capacity	Self-consumption	Power grid peak loac	LCOH	Storage capacity	Self-consumption	Power grid peak loac	LCOH
805	50.2%	1.00	260.78	1453	49.8%	1.00	409.84
PTES & heat pump (COP - 1)				**PTES & heat pump (COP + 1)**			
Storage capacity	Self-consumption	Power grid peak loac	LCOH	Storage capacity	Self-consumption	Power grid peak loac	LCOH
798	50.2%	1.00	255.42	1440	49.9%	1.00	399.56
BTES & heat pump (COP - 1)				**BTES & heat pump (COP + 1)**			
Storage capacity	Self-consumption	Power grid peak loac	LCOH	Storage capacity	Self-consumption	Power grid peak loac	LCOH
797	50.2%	1.00	258.59	1439	49.9%	1.00	405.26

Sensitivity to NL 2030 day-ahead electricity prices in reference

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	82.62

Sensitivity to NL 2030 day-ahead electricity prices in storage strategy 1

TTES & electric boiler (0.5 MW$_e$)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	86.27
500	65.8%	1.99	112.89
1000	69.9%	1.99	139.12
1500	69.9%	1.99	162.40
2000	69.9%	1.99	185.69

TTES & electric boiler (1.5 MW$_e$)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	93.58
500	70.7%	2.44	128.13
1000	86.8%	1.91	149.57
1500	96.7%	0.99	164.81
2000	96.7%	0.99	188.09

TTES & electric boiler (2.5 MW$_e$)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	100.88
500	70.8%	2.48	135.38
1000	86.9%	2.07	158.53
1500	100.0%	0.67	168.46
2000	100.0%	0.67	191.75

TTES & heat pump (0.5 MW$_e$)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	157.75
500	49.2%	2.49	180.54
1000	53.4%	2.49	202.93
1500	57.7%	2.21	223.97
2000	62.0%	2.07	247.68

TTES & heat pump (1.5 MW$_e$)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	308.01
500	50.5%	2.49	330.89
1000	54.8%	2.49	352.95
1500	59.1%	2.49	378.12
2000	63.3%	2.49	403.16

TTES & heat pump (2.5 MW$_e$)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	458.27
500	50.5%	2.49	481.19
1000	54.8%	2.49	503.08
1500	59.1%	2.49	528.24
2000	63.3%	2.49	553.22

Storage capacity	Self-consumption	Power grid peak load	LCOH
PTES & electric boiler (0.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	86.27
500	66.1%	1.99	109.89
1000	70.0%	1.99	132.90
1500	70.0%	1.99	152.80
2000	70.0%	1.99	172.71
PTES & electric boiler (1.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	93.58
500	71.6%	2.44	125.31
1000	87.7%	1.91	143.50
1500	96.7%	0.99	154.74
2000	96.7%	0.99	174.65
PTES & electric boiler (2.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	100.88
500	71.6%	2.44	132.13
1000	87.7%	2.07	153.01
1500	100.0%	0.67	158.39
2000	100.0%	0.67	178.30
PTES & heat pump (0.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	157.75
500	49.5%	2.49	178.00
1000	53.8%	2.49	197.03
1500	58.1%	2.21	214.12
2000	62.3%	2.07	234.52
PTES & heat pump (1.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	308.01
500	51.0%	2.49	328.27
1000	55.3%	2.49	346.97
1500	59.6%	2.49	368.19
2000	63.9%	2.49	389.88
PTES & heat pump (2.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	458.27
500	51.0%	2.49	478.57
1000	55.3%	2.49	497.17
1500	59.6%	2.49	518.55
2000	63.9%	2.49	539.94

BTES & heat pump (0.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	157.75
500	49.6%	2.49	180.08
1000	53.8%	2.49	201.03
1500	58.1%	2.21	220.14
2000	62.4%	2.07	242.53
BTES & heat pump (1.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	308.01
500	51.1%	2.49	330.36
1000	55.4%	2.49	351.12
1500	59.7%	2.49	374.20
2000	63.9%	2.49	397.85
BTES & heat pump (2.5 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	458.27
500	51.1%	2.49	480.64
1000	55.4%	2.49	501.31
1500	59.7%	2.49	524.57
2000	63.9%	2.49	547.96

Sensitivity to NL 2030 day-ahead electricity prices in storage strategy 2

TTES & electric boiler (0.30 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	84.81
10	40.0%	2.49	85.38
20	40.2%	2.49	86.26
30	40.3%	2.49	86.97
40	40.4%	2.49	87.87
TTES & electric boiler (0.60 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	87.00
10	40.0%	2.49	87.70
20	40.3%	2.49	88.36
30	40.3%	2.49	89.28
40	40.2%	2.49	90.28
TTES & electric boiler (0.9 MW_e)			
Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	89.19
10	39.8%	2.49	89.89
20	40.1%	2.49	90.59
30	40.2%	2.49	91.42
40	40.2%	2.49	92.49

TTES & heat pump (0.1 MW_e)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	97.65
5	39.4%	2.49	97.09
10	39.4%	2.49	97.10
15	39.4%	2.49	97.30
20	39.3%	2.49	97.58

TTES & heat pump (0.2 MW_e)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	112.67
5	39.4%	2.49	112.03
10	39.3%	2.49	111.98
15	39.4%	2.49	112.08
20	39.3%	2.49	112.21

TTES & heat pump (0.3 MW_e)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	127.70
5	39.3%	2.49	127.04
10	39.3%	2.49	126.94
15	39.3%	2.49	127.03
20	39.4%	2.49	127.16

Sensitivity to NL 2030 day-ahead electricity prices in storage strategy 3

TTES & electric boiler

Storage capacity	Self-consumption	Power grid peak load	LCOH
250	50.7%	1.00	85.06

TTES & heat pump

Storage capacity	Self-consumption	Power grid peak load	LCOH
1126	50.0%	1.00	335.03

PTES & electric boiler

Storage capacity	Self-consumption	Power grid peak load	LCOH
246	50.8%	1.00	83.34

PTES & heat pump

Storage capacity	Self-consumption	Power grid peak load	LCOH
1119	50.0%	1.00	327.65

BTES & heat pump

Storage capacity	Self-consumption	Power grid peak load	LCOH
1118	50.1%	1.00	332.11

Sensitivity to specific grid cable investment costs in reference

Reference (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	72.81

Reference (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	92.66

Sensitivity to specific grid cable investment costs in storage strategy 1

TTES & electric boiler (0.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	76.47
500	65.8%	1.99	100.70
1000	69.9%	1.99	125.17
1500	69.9%	1.99	148.45
2000	69.9%	1.99	171.74

TTES & electric boiler (0.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	96.31
500	65.8%	1.99	116.57
1000	69.9%	1.99	141.04
1500	69.9%	1.99	164.33
2000	69.9%	1.99	187.61

TTES & electric boiler (1.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	83.77
500	70.7%	2.44	114.83
1000	86.8%	1.91	135.66
1500	96.7%	0.99	150.38
2000	96.7%	0.99	173.66

TTES & electric boiler (1.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	103.61
500	70.7%	2.44	134.24
1000	86.8%	1.91	150.87
1500	96.7%	0.99	158.29
2000	96.7%	0.99	181.57

TTES & electric boiler (2.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	91.07
500	70.8%	2.48	122.49
1000	86.9%	2.07	145.23
1500	100.0%	0.67	154.74
2000	100.0%	0.67	178.02

TTES & electric boiler (2.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	110.92
500	70.8%	2.48	142.21
1000	86.9%	2.07	161.71
1500	100.0%	0.67	160.10
2000	100.0%	0.67	183.38

TTES & heat pump (0.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	147.94
500	49.2%	2.49	170.91
1000	53.4%	2.49	193.78
1500	57.7%	2.21	215.15
2000	62.0%	2.07	238.40

TTES & heat pump (0.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	112.60
500	65.8%	1.99	132.86
1000	69.9%	1.99	157.33
1500	69.9%	1.99	180.61
2000	69.9%	1.99	203.90

TTES & heat pump (1.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	298.20
500	50.5%	2.49	321.18
1000	54.8%	2.49	343.94
1500	59.1%	2.49	368.55
2000	63.3%	2.49	393.38

TTES & heat pump (1.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	152.48
500	70.7%	2.44	183.11
1000	86.8%	1.91	199.73
1500	96.7%	0.99	207.16
2000	96.7%	0.99	230.44

TTES & heat pump (2.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	448.46
500	50.5%	2.49	471.43
1000	54.8%	2.49	494.24
1500	59.1%	2.49	518.79
2000	63.3%	2.49	543.58

TTES & heat pump (2.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	192.36
500	70.8%	2.48	223.65
1000	86.9%	2.07	243.15
1500	100.0%	0.67	241.54
2000	100.0%	0.67	264.82

PTES & electric boiler (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	76.47
500	66.1%	1.99	97.61
1000	70.0%	1.99	118.72
1500	70.0%	1.99	138.63
2000	70.0%	1.99	158.53

PTES & electric boiler (0.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	96.31
500	66.1%	1.99	113.48
1000	70.0%	1.99	134.59
1500	70.0%	1.99	154.50
2000	70.0%	1.99	174.40

PTES & electric boiler (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	83.77
500	71.6%	2.44	112.02
1000	87.7%	1.91	129.61
1500	96.7%	0.99	140.28
2000	96.7%	0.99	160.19

PTES & electric boiler (1.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	103.61
500	71.6%	2.44	131.43
1000	87.7%	1.91	144.81
1500	96.7%	0.99	148.19
2000	96.7%	0.99	168.10

PTES & electric boiler (2.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	91.07
500	71.6%	2.44	119.11
1000	87.7%	2.07	139.14
1500	100.0%	0.67	144.64
2000	100.0%	0.67	164.55

PTES & electric boiler (2.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	110.92
500	71.6%	2.44	138.52
1000	87.7%	2.07	155.62
1500	100.0%	0.67	150.00
2000	100.0%	0.67	169.91

PTES & heat pump (0.5MWe) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	147.94
500	49.5%	2.49	167.97
1000	53.8%	2.49	187.65
1500	58.1%	2.21	205.26
2000	62.3%	2.07	225.10

PTES & heat pump (0.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	167.79
500	49.5%	2.49	187.78
1000	53.8%	2.49	207.47
1500	58.1%	2.21	222.82
2000	62.3%	2.07	241.58

PTES & heat pump (1.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	298.20
500	51.0%	2.49	318.28
1000	55.3%	2.49	337.68
1500	59.6%	2.49	358.67
2000	63.9%	2.49	380.12

PTES & heat pump (1.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	338.09
500	51.0%	2.49	326.15
1000	55.3%	2.49	357.49
1500	59.6%	2.49	378.48
2000	63.9%	2.49	399.93

PTES & heat pump (2.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	448.46
500	51.0%	2.49	468.54
1000	55.3%	2.49	487.94
1500	59.6%	2.49	508.88
2000	63.9%	2.49	530.36

PTES & heat pump (2.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	468.31
500	39.7%	2.49	488.36
1000	39.7%	2.49	507.75
1500	39.7%	2.49	528.70
2000	39.7%	2.49	550.18

BTES & heat pump (0.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	147.94
500	49.6%	2.49	170.01
1000	53.8%	2.49	191.71
1500	58.1%	2.21	211.26
2000	62.4%	2.07	233.09

BTES & heat pump (0.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	167.79
500	49.6%	2.49	189.82
1000	53.8%	2.49	211.52
1500	58.1%	2.21	228.82
2000	62.4%	2.07	249.57

BTES & heat pump (1.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	298.20
500	51.1%	2.49	320.34
1000	55.4%	2.49	341.75
1500	59.7%	2.49	364.68
2000	63.9%	2.49	388.12

BTES & heat pump (1.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	318.05
500	51.1%	2.49	340.15
1000	55.4%	2.49	361.56
1500	59.7%	2.49	384.49
2000	63.9%	2.49	407.93

BTES & heat pump (2.5 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	448.46
500	51.1%	2.49	470.60
1000	55.4%	2.49	492.01
1500	59.7%	2.49	514.89
2000	63.9%	2.49	538.36

BTES & heat pump (2.5 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	468.31
500	51.1%	2.49	490.41
1000	55.4%	2.49	511.82
1500	59.7%	2.49	534.70
2000	63.9%	2.49	558.17

Sensitivity to specific grid cable investment costs in storage strategy 2

TTES & electric boiler (0.30 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	75.01
10	40.1%	2.49	77.59
20	40.4%	2.49	78.78
30	40.5%	2.49	79.91
40	40.6%	2.49	81.04

TTES & electric boiler (0.30 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	94.85
10	42.0%	2.44	95.47
20	42.5%	2.44	96.76
30	42.8%	2.44	97.99
40	43.1%	2.21	94.31

TTES & electric boiler (0.60 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	77.20
10	39.9%	2.49	80.42
20	40.0%	2.49	81.86
30	40.0%	2.49	83.13
40	40.1%	2.49	84.32

TTES & electric boiler (0.60 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	97.04
10	42.6%	2.48	98.67
20	43.1%	2.48	99.88
30	43.4%	2.48	101.08
40	43.7%	2.48	102.29

TTES & electric boiler (0.9 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	79.39
10	39.4%	2.49	82.99
20	39.7%	2.49	84.55
30	39.6%	2.49	85.91
40	39.7%	2.49	87.20

TTES & electric boiler (0.9 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH (€/MWh)
0	39.7%	2.49	99.23
10	42.8%	2.48	100.93
20	43.3%	2.48	102.12
30	43.6%	2.48	103.28
40	43.9%	2.48	104.49

TTES & heat pump (0.1 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	87.84
5	39.4%	2.49	87.77
10	39.4%	2.49	88.17
15	39.3%	2.49	88.62
20	39.3%	2.49	89.12

TTES & heat pump (0.1 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	107.68
5	40.1%	2.49	108.21
10	40.1%	2.49	108.76
15	40.2%	2.49	109.31
20	40.2%	2.49	109.87

TTES & heat pump (0.2 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	102.87
5	39.1%	2.49	102.61
10	39.1%	2.49	102.93
15	39.1%	2.49	103.31
20	39.0%	2.49	103.75

TTES & heat pump (0.2 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	122.71
5	40.3%	2.49	123.23
10	40.4%	2.49	123.79
15	40.4%	2.49	124.34
20	40.4%	2.49	124.89

TTES & heat pump (0.3 MW_e) (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	117.89
5	39.0%	2.49	117.57
10	39.0%	2.49	117.83
15	39.0%	2.49	118.20
20	39.0%	2.49	118.64

TTES & heat pump (0.3 MW_e) (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
0	39.7%	2.49	137.74
5	40.5%	2.49	138.26
10	40.6%	2.49	138.81
15	40.6%	2.49	139.37
20	40.6%	2.49	139.91

Sensitivity to specific grid cable investment costs in storage strategy 3

TTES & electric boiler (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
250	50.7%	1.00	79.33

TTES & electric boiler (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
250	50.7%	1.00	87.28

TTES & heat pump (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
1126	50.0%	1.00	330.76

TTES & heat pump (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
1126	50.0%	1.00	338.72

PTES & electric boiler (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
246	50.8%	1.00	71.70

PTES & electric boiler (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
246	50.8%	1.00	79.66

PTES & heat pump (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
1119	50.0%	1.00	296.60

PTES & heat pump (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
1119	50.0%	1.00	304.56

BTES & heat pump (-30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
1118	50.1%	1.00	327.86

BTES & heat pump (+30% cable costs)

Storage capacity	Self-consumption	Power grid peak load	LCOH
1118	50.1%	1.00	335.77