Unlocking Thermal Flexibility for the Electricity System by Combining Heat Pumps and Thermal Storage

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Abstract

The expansion of heat pumps drives the electrification of the heating sector which is important to achieve Germany's ambitious climate targets. This paper examines the impact of heat pumps in combination with thermal storage on the flexibility of the German electricity system in 2030, focusing on its market and grid impacts. A timely and spatially detailed electricity market and transmission grid model evaluates the impact of thermal storage. The results show that, overall, unlocking the flexibility of thermal storage consistently reduces total supply costs. However, while the flexibility provided by thermal storage supports the integration of RES and reduces supply costs in the dispatch, the use of flexibility increases grid violations and hence, redispatch measures. By further studying a model setup with locational marginal prices (LMPs), the analysis highlights regional differences in the value of flexibility, which is particularly high in northern Germany, where proximity to wind generation enhances the benefits of thermal storage.

Keywords: Market Design, Electricity Markets, Nodal Pricing, Energy System Modeling, Renewable Energies, Heat Pumps, Thermal Storage, Flexibility

JEL classification: D47, D61, C61, Q40

1. Introduction

Electrification of the residential heating sector is key to achieve the policy goal of decarbonization, particularly with the increased use of electricity from renewable energy sources (RES). For example, space heating accounted for 63.5% of final energy consumption in the residential sector in the EU in 2022, with 68.6% supplied by fossil fuels (c.f. Eurostat, 2024). Electrical heat pumps are widely

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recognized as a suitable technology to replace fossil fuels and integrate renewable energies, as they provide heat from a medium such as air or water with low electricity consumption (c.f. Bloess et al., 2018; Maruf et al., 2022).

The expansion of heat pumps in the coming years is a key strategy in the pursuit of Germany's ambitious climate goals, reflected in the government's target to install six million heat pumps by 2030 compared to 1.7 million heat pumps in 2023 (BDEW, 2024). In combination with the government's target to increase electricity generation from RES to generate 80% of gross electricity consumption in 2030 (EEG, 2023), these measures aim to support the transformation of the heating sector. This presents both opportunities and challenges for the electricity market and the electricity grid. On the one hand, heat pumps increase electricity demand, and therefore affect market dynamics and grid load. On the other hand, heat pumps can be combined with thermal storage, which could also bring benefits if the flexibility potential of thermal storage is used for the electricity system, e.g., in order to balance volatile RES generation.

By now, thermal storage is widely recognized for optimizing heat pump efficiency and reducing costs at the household level (see e.g. Frings and Helgeson, 2022), but it is discussed less from the perspective of the electricity system. By decoupling the electricity demand of heat pumps from the heat demand, thermal storage can increase the flexibility of the electricity system, but requires coordination between electricity markets and the grid. As the imbalance between Germany's RES generation concentrated in the north and demand centers predominantly located in the west and south already leads to congestion in the transmission grid, the perspective of the grid should be taken into account when evaluating the flexibility potential of thermal storage.

Against this backdrop, this paper analyzes the impact of the combined expansion of heat pumps and thermal storage on the electricity system, focusing on market and grid dynamics. The paper assesses the system value of the flexibility provided by thermal storage, taking into account the restrictions of the transmission grid.

To do so, the paper presents Germany as a case study and applies a timely and spatially highly resolved model of the Central European electricity markets and transmission grid for the year 2030.

The high spatial resolution captures regional variations in electricity demand profiles of heat pumps, which is a relevant aspect due to their dependence on weather conditions.

The analysis evaluates six scenarios, combining two model setups and three heat pump distributions. The first model setup reflects the current German market design with a uniform wholesale price and subsequent redispatch to relieve grid congestion. The second setup represents a theoretical first-best benchmark using locational marginal prices (LMPs). The three heat pump distributions are based on the current geographic locations of heat pumps, the allocation of wind capacity, and the allocation of PV capacity. Each scenario is compared for three storage sizes (2h, 4h, and 8h shifting potential) with a base case of inflexible heat pumps.

Across all scenarios and shifting potentials, flexibility provision through thermal storage reduces total supply costs compared to an inflexible use of heat pumps. The model setup with LMPs confirms its role as the first-best benchmark. Total supply costs are consistently lower than in the uniform model setup and fall continuously with increasing shifting potential for all three distributions. The latter contrasts with the uniform setup, where an increased shifting potential does not generally lead to lower total supply costs. This divergence arises because flexibility provision through thermal storage in the uniform setup affects the market result (dispatch effects) and the grid dynamics (redispatch effects) in opposing directions. While the market results benefit from the flexibility for all heat pump distributions, redispatch measures increase.[1] Specifically, when heat pumps are allocated based on their current locations or PV capacity, the 4h shifting potential results in lower total supply costs than the 8h shifting potential, as redispatch supply costs increase over-proportionally for these distributions.

The comparison of the heat pump distributions further reveals that flexibility provision through thermal storage provides the highest system value when thermal storage is located near wind capacities in northern Germany. The regionalized analysis within the LMP model setup confirms this observation, showing that the system value of flexibility is particularly high in northern Germany.

In summary, within the uniform model setup, thermal storage reduces total supply costs due to the predominantly beneficial market effects, yet at the same time leading to increasing redispatch

[1] By assumption, small scale storage units like thermal storage do not actively participate in redispatch.

costs. Policymakers should therefore promote the installation of thermal storage and its market participation, while simultaneously introducing locational signals to maximize system-wide benefits, taking into account market conditions and grid constraints.

Related literature and research gap

The paper at hand extends the literature by examining the impact of thermal storage on the electricity system in a numerical analysis for Germany, including grid dynamics and spatial differences in heat pump demand profiles.

The paper adds to the literature evaluating the impact of heat pumps and thermal storage on electricity markets. Bloess et al. (2018) and Maruf et al. (2022) present extensive literature reviews on various power-to-heat and thermal storage technologies. Bloess et al. (2018) highlight the role of power-to-heat technologies in integrating RES by reducing curtailment and substituting fossil fuels, with benefits enhanced by thermal storage. Maruf et al. (2022) focus on the European context, emphasizing the technological maturity of thermal storage and highlight its importance in the residential sector in lowering RES curtailment and total system costs.

More recently and similar to the analysis in this paper, Roth et al. (2024) show in a numerical model analysis for Germany in 2030, that coupling heat pumps with thermal storage effectively aligns the electricity demand of heat pumps with the residual demand, and thus reduces overall system costs. Schöniger et al. (2024) find similar results for Austria in 2030, demonstrating that flexible heat pumps cut costs and curtailment of RES in all scenarios examined. However, this literature solely focuses on the impact of heat pumps and thermal storage on the electricity market, without accounting for grid dynamics.

Another strand of literature takes the grid into account when analyzing the flexibility potential of thermal storage in electricity system models. However, these studies focus on sector coupling at a higher level of aggregation in technology modeling, evaluating the combined flexibility of decentralized resources such as heat pumps with thermal storage, electric vehicle charging, and demand-side management. Heitkoetter et al. (2022), for example, assess a large set of demand response options and their endogenous deployment using an energy system model with 100 nodes in Germany. Their findings reveal an equal distribution of demand response options across Germany, with a high expansion in western Germany, where large aggregated demand response potential exists. Büttner et al. (2024) analyze the impact of flexibility options on the German transmission grid in 2035, including the gas, heat and mobility sector. They consider large-scale thermal storage in combination with district heating grids, but do not equip decentralized heat pumps with a thermal storage. Their results show that these technologies, taken together, can reduce total system costs and CO2 emissions. Bauknecht et al. (2024) assess the role of decentralized flexibility options in reducing congestion in the transmission network and the impact on the need for network expansion. The authors show that with increasing shares of RES, decentralized flexibilities are particularly valuable to relieve transmission bottlenecks if they are located close to net feed-in nodes. Further studies analyze the impact of flexibility provision by other technologies than thermal storage, for example, vom Scheidt et al. (2022) for the integration of hydrogen and electrolyzers and Lindner et al. (2023) for batteries as grid boosters. Within a similar model setup, Czock et al. (2023) assess the optimal allocation of battery storage investments in Germany and show that simple allocation rules such as aligning the locations of batteries and PV capacities can approximate an optimal allocation if locational price signals are missing.

This paper combines the two strands of literature: a thorough analysis of decentralized heat pumps combined with thermal storage in a spatially and temporally high-resolution electricity model that incorporates grid constraints. This approach captures regional weather dependencies of heat pumps and assesses the flexibility of thermal storage on electricity markets and the transmission grid.

Adding the spatial component to the analysis improves research on heat pumps and thermal storage in two ways: First, accounting for regional temperature differences is crucial to adequately model electricity demand (c.f. Eggimann et al., 2019; Büttner et al., 2022) and to prevent system over- or undersizing when integrating heat pumps (c.f. Halloran et al., 2024). Second, by representing the grid dynamics, redispatch measures can be included in the analysis, providing a more complete picture of the current electricity system in Germany. For the European electricity system, Frysztacki et al. (2021) show that ignoring congestion can raise system costs by up to 23%. Furthermore, the representation of the grid allows to study alternative pricing mechanisms, such as LMPs. The results provide valuable insights for policymakers to promote the combination of heat pumps with thermal storage and to make the electricity market more accessible for decentralized flexibility options.

The paper is organized as follows. Section 2 introduces the model framework and describes the main assumptions, the input data, the scenarios, and the numerical model setup. Section 3 presents the results of the analysis for the uniform and the LMP model setup. Section 4 discusses the results in relation to model assumptions, data and policy implications. Section 5 concludes.

2. Methodology

This paper uses the SPIDER (Spatial Investment of Distributed Energy Resources) electricity system model developed by Schmidt and Zinke (2023), Czock et al. (2023) and Zinke (2023) to analyze the impact of heat pumps in combination with the flexibility provided by thermal storage. SPIDER is a model of the European power sector and considers a detailed depiction of the Central European transmission grid. Dispatch modeling is based on the mechanisms of flow based market coupling (FBMC) and enables dispatch analyses with a high regional and timely resolution (Zinke, 2023). In this paper, commissioning and decommissioning of transmission and generation, as well as total demand and the expansion of heat pump and thermal storage, are exogenous. The methodology is described below, along with the input data, and the numerical model setup. The notation is provided in Table A.1 in the Appendix.

2.1. Model framework

SPIDER optimizes the dispatch decisions of the European power plant fleet and the usage of storage by minimizing the variable costs of electricity generation. It minimizes the net present value of the variable costs under several constraints concerning the market equilibrium, technical requirements and the grid. Variable costs are the product of electricity generation, $GEN_{t,m,i}$, in each timestep t, market zone m, and technology i and the technology-specific variable operating costs, $\gamma_{t,i}$:

$$\min! \quad VC = \sum_{t \in T, m \in M, i \in I} \gamma_{t,i} \cdot GEN_{t,m,i} \tag{1}$$

The setup of the model in terms of the markets is flexible, i.e. the scope and geographical granularity, down to the representation of individual transmission nodes, can be adjusted according to the research question. The model therefore allows both nodal and zonal modeling, with the latter also enabling a subsequent redispatch analysis (see Zinke (2023) for more details on the methodology). To ensure computational feasibility, simplifying assumptions are applied, including exogenous investments in transmission, generation, and demand capacities, the exclusion of combined heat and power plants, and approximations for ramping and minimum load constraints.

In this paper, the model is applied to analyze the dispatch of electricity generation and demand, as well as storage technologies. In particular, the impact of the regional expansion of heat pumps and their flexible use through thermal storage is evaluated, taking grid restrictions into account. For this purpose, the model of Zinke (2023) is extended by a detailed representation of the electricity demand of heat pumps and the flexibility of thermal storage.

Heat pumps

The modeling of demand in SPIDER is extended in this paper to include the electricity demand profiles of heat pumps. To account for the relationship between temperatures and the conversion efficiency (COP) of a heat pump, separate weather-dependent heat pump demand profiles, $demand_{t,m}^{heatpump}$, i.e., hourly time series of electricity demand used to operate heat pumps, are constructed for each market zone. The performance of heat pumps, measured by the COP, varies over time and depends on the temperature difference between the source and sink (cop_t). A larger delta between the source temperature and the desired flow temperature results in lower COPs, i.e., colder days result in lower efficiencies, especially for air source heat pumps.

A common approach to incorporate temperature-dependent COP values is to calculate the COP exogenously, assuming a sink temperature and given values for the source temperature, following Verhelst et al. (2012). This approach is used throughout the paper. The heat pump demand profiles are calculated based on information provided by the German DSOs (see Section 2.2 for a detailed description) and result in an hourly electricity demand profile for each market zone.

Thermal storage

Thermal storage shifts energy temporally, similar to battery storage, but operates within the constraints of the heat pump's electricity demand profile. Thus, unlike a battery, which charges and discharges freely, thermal storage shifts electricity demand over time without physically supplying electricity. Instead, it reduces the baseline electricity demand that would have occurred during a given hour without the shifting of the thermal storage.

It is important to note, that heat pumps convert electrical energy into thermal energy, which is stored as heat in the thermal storage. For modeling purposes, thermal storage is expressed in electrical terms, requiring consideration of the conversion between thermal energy and electricity. This results in the following storage equations.

The storage volume, $STOR\_VOL_m$, is defined by the hourly shifting capability, vol_factor, and the installed capacity, cap_m (eq. 2). The charging level of storage, $STOR\_LEVEL_{t,m}$, cannot exceed the storage volume, $STOR\_VOL_m$ (eq. 3).

$$STOR\_VOL_m = vol\_factor \cdot cap_m \tag{2}$$

$$STOR\_LEVEL_{t,m} \leq STOR\_VOL_m \tag{3}$$

In eq. 4, the storage level is determined by the storage level in the previous time step and the net balance of the current shift with the thermal storage, i.e., the difference of charged (consumed), $CON_{t,m}$, and discharged (supplied), $GEN_{t,m}$, electricity. Static efficiency, ϵ^{static}, determines the losses per hour and dynamic efficiency accounts for the losses during storage charging, $\epsilon^{dynamic}$. The storage level is parameterized in electrical terms, but corresponds to a storage of thermal energy. Thus, one has to account for the time-varying COP of the heat pump by including the ratio of the COP of the previous and current time step, $\frac{cop_{t\text{-}1,m}}{cop_{t,m}}$.[2]

$$\begin{aligned} STOR\_LEVEL_{t,m} = \frac{cop_{t\text{-}1,m}}{cop_{t,m}} \cdot (1 - \epsilon^{static}) \cdot STOR\_LEVEL_{t\text{-}1,m} \\ -GEN_{t,m} + (1 - \epsilon^{dynamic}) \cdot CON_{t,m} \end{aligned} \tag{4}$$

$$GEN_{t,m} \leq demand_{t,m}^{heatpump} \tag{5}$$

[2]The formulation is derived from substituting $STOR\_LEVEL_{t,m}^{thermal} = cop_{t,m} \cdot STOR\_LEVEL_{t,m}^{electric}$ for both time steps t and $t-1$ and by taking into account the $cop_{t,m}$ for $GEN_{t,m}$ and $CON_{t,m}$ in the thermal formulation of a typical storage level constraint (see e.g. Ruhnau et al., 2020).

The electricity supply of thermal storage, $GEN_{t,m}$, is constrained by the demand of heat pumps, $demand_{t,m}^{heatpump}$, in the respective hour (eq. 5). This limitation reflects that the thermal storage buffers the electricity demand of the heat pump and shifts it between different times.

2.2. Input Data

The configuration of the model corresponds to that in Zinke (2023). At regional level, the model represents Central Europe with a high spatial resolution at transmission grid node level, i.e., 220kV to 380kV voltage levels, covering the 13 European countries participating in the "Core Flow-Based Market Coupling project". The model is based on the published grid information provided by Joint Allocation Office (2022). In order to reduce complexity, the initial grid of 1063 nodes is reduced to 533 nodes and 859 lines in 2021 using a grid reduction algorithm proposed by Biener and Garcia Rosas (2020). Italy, Switzerland, Denmark, Norway, and Sweden, that are outside the FBMC area, are depicted as singular nodes without intra-country grid restrictions and interconnectors to these markets are approximated via net transfer capacities (NTC). Grid extensions are included in accordance to the German grid development plan (c.f. 50Hertz Transmission GmbH et al., 2023), and ENTSO-E's Ten-Year Network Development Plan (c.f. ENTSO-E and ENTSO-G, 2022). The regional scope and the reduced transmission grid are visualized in Figure 1.

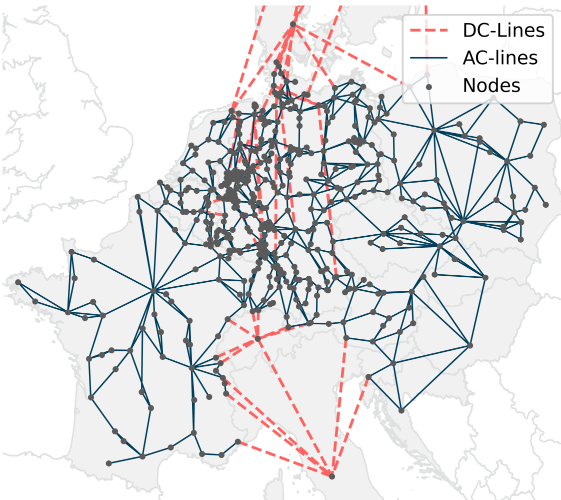


Figure 1: Transmission grid

The development of installed capacities and expansion of renewable energies are exogenous to the model. For all countries except Germany, the installed capacities are based on the scenario *Global Ambition* in ENTSO-E and ENTSO-G (2022). For Germany, the development of installed capacities follows the current legal and political targets and is shown in Appendix B. The time series for hourly onshore wind and solar generation are computed based on high-resolution reanalysis of meteorological data from the COSMO-REA6 model based on Henckes et al. (2017) and Pfenninger and Staffell (2016), respectively. The generation potential of offshore wind regions (hourly) and hydropower (weekly) is provided by Copernicus Climate Change Service (2020).

The analysis covers the year 2030 with an hourly resolution. Time series of country-specific hourly electricity demand are taken from ENTSO-E and ENTSO-G (2022). German demand is taken from Fraunhofer ISI et al. (2022) (see Table 1) and is then distributed by sectoral demand shares on the federal state level (c.f. Länderarbeitskreis Energiebilanzen, 2020). For residential demand, the distribution is assumed to follow population shares, while industrial and commercial electricity demand is distributed in proportion to the regional gross value added (c.f. Eurostat, 2020). This approach is similar to the one used by the transmission grid operators in Germany (50Hertz et al., 2022). For the other countries, the assumed demand distribution follows the population per local administrative unit (Eurostat, 2023).

Heat pumps

For Germany, in addition to the data on total electricity demand, the electricity demand of heat pumps is required. The annual electricity demand of heat pumps as well as the number of installed heat pumps and the installed capacity of heat pumps are from Fraunhofer ISI et al. (2022) (see Table 1). The installed capacity of thermal storage listed in table 1 is parametrized corresponding to the annual peak demand of heat pumps, following Ruhnau et al. (2019) and Marijanovic et al. (2022). The annual peak demand of heat pumps can be derived from the electricity demand profiles of heat pumps. The procedure for deriving these profiles is described in detail below.

In order to incorporate the temporal dimension of heat pump demand, hourly electricity demand profiles for heat pumps are derived for each transmission node. As the demand profiles of heat pumps are dependent on the weather, regional temperature differences are taken into account when

Table 1: Demand development and heat pump expansion in Germany

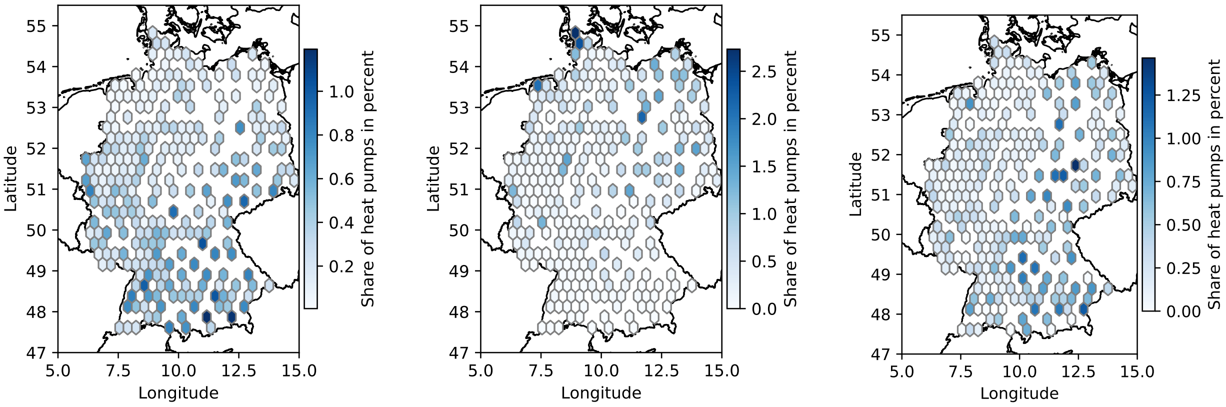
		2021	2030
Total electricity demand	[TWh]	532	624
Electricity demand of heat pumps	[TWh]	8.5	34.7
Number of heat pumps	[Mio]	1.4	5.9
Installed capacity of heat pumps	[GW]	6.5	26.7
Installed capacity of thermal storage	[GW]	3	12.3

creating the profiles. Meteorological data on temperature is used for this purpose, provided by Copernicus Climate Change Service (2020). The temperature time series are combined with temperature dependent load profiles for heat pumps published by the DSO SWM Infrastruktur (2024).[3] The DSO's load profiles and thus the resulting heat pump demand profiles ($demand_{m,t}^{heatpump}$) capture the current operation of a heat pump and thus implicitly reflect the technical optimization of the heat pump. This includes, for example, taking into account passive storage from the thermal inertia of the building and the consumption relevant properties of the heat pump. The latter includes in particular that the COP of the heat pump is already taken into account in the load profiles. The resulting demand profiles per node of the transmission grid depend on the temperature and therefore differ regarding their level.

Three alternative distributions are considered for the regional allocation of the installed capacity of heat pumps in Germany. The first distribution, referred to as the *hp-distribution*, is based on the current geographic locations of heat pumps. This distribution is derived from Heitkoetter et al. (2021), who provide regional data for the installed capacity of heat pumps in 2030, using historical data on building types and heating technologies at the district level. The second distribution, the *wind-distribution*, aligns heat pump capacity with the locations of onshore wind capacity. The third distribution, the *pv-distribution*, allocates heat pump capacity based on the locations of PV capacity.

Figure 2 illustrates the three distributions of installed heat pump capacity at transmission nodes and shows the percentage of heat pump capacity at each transmission node relative to the total heat pump capacity in Germany in 2030.

[3] The methodology for creating the profiles was initially developed by the formerly German Association of DSOs VDN and the University of Cottbus. For more information see Verband der Netzbetreiber (VDN) (2002).



(a) (b) (c)

Figure 2: Heat pump capacity at transmission nodes as a percentage of total heat pump capacity in Germany in 2030 distributed by (a) currently installed heat pump capacity, (b) installed onshore wind capacity and (c) installed PV capacity

With the *hp-distribution*, heat pump capacity increases from north to south, with most capacity concentrated in southern regions below the 50th parallel, while eastern and western regions show a relatively even allocation. In contrast, the *wind-distribution* concentrates heat pump capacity in northern Germany, predominantly above the 53rd parallel, with fewer installations in southern regions. The *pv-distribution* results in a broad allocation across Germany, resembling the *hp-distribution* in its southern concentration below the 50th parallel. However, due to the greater expansion of PV in eastern Germany, heat pump capacity is more pronounced in that region. The differing heat pump distributions impact electricity demand within the grid. Variations in demand at individual nodes arise from both the reallocation of heat pumps and their associated electricity demand and from location-specific differences in demand profiles due to varying weather conditions (see Figure B.1 in the Appendix).

Thermal storage

This paper incorporates thermal storage capacities to analyze the system-friendly shifting of heat pump demand. It is assumed that each installed heat pump is equipped with a thermal storage and that this is used exclusively for system-friendly use. By assumption, the technical optimization of heat pump operation, i.e., optimizing the operation according to the COP, is done by separate 'technical storage capacity' excluded from the analysis. This is because already today heat pumps are commonly installed together with some thermal storage capacities in order to optimize the technical operation of the heat pump. As the heat pumps' electricity demand profiles are based on DSO data, this technical optimization is likely to be included in the current data. The thermal storage capacities considered in this paper are assumed to be installed in addition, such that system-use friendly heat pump operation can be performed in addition to the technical optimization.

The thermal storage is parameterized in terms of an hourly load shifting potential. The shifting potential, i.e., the storage size, is varied throughout the analysis. It is assumed that thermal storage is able to store twice the installed capacity (2h shifting potential). This corresponds to the already allowed interruption interval for DSOs during network peak times (§14a EnWG, 2024). Further, a shifting of four hours (4h shifting potential) and eight hours (8h shifting potential) is considered. At the household level, this corresponds to storage units of 400 l, 800 l, and 1500 l, typical for single- and multi-family homes (Agora Energiewende, 2023).

The efficiency of the thermal storage is set as follows: as an average estimate, the dynamic losses, $\epsilon^{dynamic}$, are set to 5% and static losses, ϵ^{static}, are set equal to 1% (Ruhnau et al., 2020; Frings and Helgeson, 2022). COP values for heat pumps and data on the mix of currently installed systems, used to calculate an average value for Germany, are retrieved from Ruhnau et al. (2019).

The formulation of the thermal storage can be interpreted as a classical hot water-based heat storage, which is the most used thermal storage i.a. due to its low cost, compactness, scalability, and usability (Maruf et al., 2022).[4]

The investment costs for thermal storage are used to evaluate the profitability of thermal storage from the perspective of the heat pump owner. Based on data from Frings and Helgeson (2022) and own research of industry data, the annualized costs are on average 88 EUR/a for a 400 l storage, 105 EUR/a for an 800 l storage, and 134 EUR/a for a 1500 l storage. The discount rate is set to 5% and a technical lifetime of 30 years is assumed (c.f. Frings and Helgeson, 2022).

[4]Passive storage, i.e., the buildings' thermal mass, is not considered in the optimization model. It is indirectly captured by the DSO's demand profiles. For further analysis, it could be integrated into the model by allowing a certain temperature band for the heat demand to fluctuate, see for example (Papaefthymiou et al., 2012; Marijanovic et al., 2022).

2.3. Scenarios and numerical model setup

The analysis examines the combination of heat pumps with thermal storage in Germany in six scenarios: The three heat pump distributions described above are analyzed within two different model setups described in the following.

The first model setup represents the current market design in Germany with a uniform wholesale electricity price, i.e. one market zone. This means that physical restrictions on electricity flows within the market area are not taken into account in the market clearing. This is addressed in the model setup by defining the market zone m as one zone for the whole of Germany. The dispatch run calculates the market clearing and is complemented by a subsequent redispatch run. Grid restrictions are taken into account as part of the redispatch and it is checked whether physical grid restrictions are violated after market clearing. If this is the case, the dispatch results require curative redispatch measures, which in practice are carried out by the grid operators. Within the redispatch run, the zonal net trade positions are fixed and generation adjustments are only possible within one market zone. It is assumed that wind and solar generation can be curtailed, but not ramped up, within the redispatch run. Furthermore, small-scale storage units, like thermal storage, are not yet part of the redispatch.

Within this model setup, the effects of providing flexibility through thermal storage can be split into their effects on the market result (dispatch) and on the grid (redispatch). However, as thermal storage does not participate in redispatch, only indirect effects of its use on the grid can be analyzed. The analysis of regional effects in this model setup is therefore limited, as the use of thermal storage in dispatch does not differ regionally due to the lack of grid information.

The second model setup considers the first-best benchmark with LMPs in order to show direct, regional effects through an integrated view of the market and the grid. Each transmission grid node represents a market and grid constraints are considered within the price formation. When grid constraints are binding, LMPs differ between nodes. Without any frictions, such a price formation represents the first-best benchmark for efficient coordination of electricity generation, demand and the grid and sets an upper limit for the benefit of providing flexibility through thermal storage.

Hence, the two model setups differ in terms of the amount of information available or, more specifically, in terms of the consideration of transmission constraints, RES curtailment and the participation of thermal storage.

3. Numerical model results

This section presents the numerical model results for six scenarios that are a combination of the two model setups for the German electricity system, the uniform and the LMP model setup, and the three heat pump distributions, based on the current geographic locations of heat pumps, the allocation of wind capacity, and the allocation of PV capacity (c.f. Sections 2.2 and 2.3). For each scenario, three storage sizes (2h, 4h, and 8h shifting potential) are compared with the base case of inflexible heat pumps that operate strictly according to their demand profiles. The total supply costs of each scenario are compared in Table 2.

Table 2: Percentage change in total supply costs for different heat pump distributions and shifting potentials for the uniform and the LMP setup

Model setup	Heat pump distribution	Inflexible heat pumps [%]	2h [%]	4h [%]	8h [%]
uniform	*hp-distribution*		-1.22	-1.51	-1.09
uniform	*wind-distribution*	-1.97	-3.55	-3.86	-4.20
uniform	*pv-distribution*	-0.37	-1.62	-1.73	-1.68
LMP	*hp-distribution*	-10.75	-12.20	-12.82	-13.28
LMP	*wind-distribution*	-11.42	-12.92	-13.63	-14.21
LMP	*pv-distribution*	-10.91	-12.43	-13.05	-13.54

Note: The base (100 %) for the percentage change is given by the uniform model setup and the *hp-distribution* with inflexible heat pumps.

The results show that, across all scenarios and shifting potentials, flexibility provision from thermal storage always reduces total supply costs compared to an inflexible use of heat pumps. The model setup with LMPs consistently achieves lower total supply costs than the uniform model setup, confirming its role as the first-best benchmark. Furthermore, the results show that within the LMP setup, total supply costs fall continuously with increasing shifting potential for all three distributions. This contrasts with the uniform setup, where an increased shifting potential does not generally lead to lower total supply costs. When allocating heat pumps according to the *hp-distribution* and the *pv-distribution*, the 4h shifting potential achieves lower total supply costs than the 8h shifting potential. For these distributions, the redispatch supply costs increase over-proportionally. Consequently, the divergence between the results under the uniform setup and the LMP setup grows with greater shifting potential. This is illustrated in Figure 3.[5]

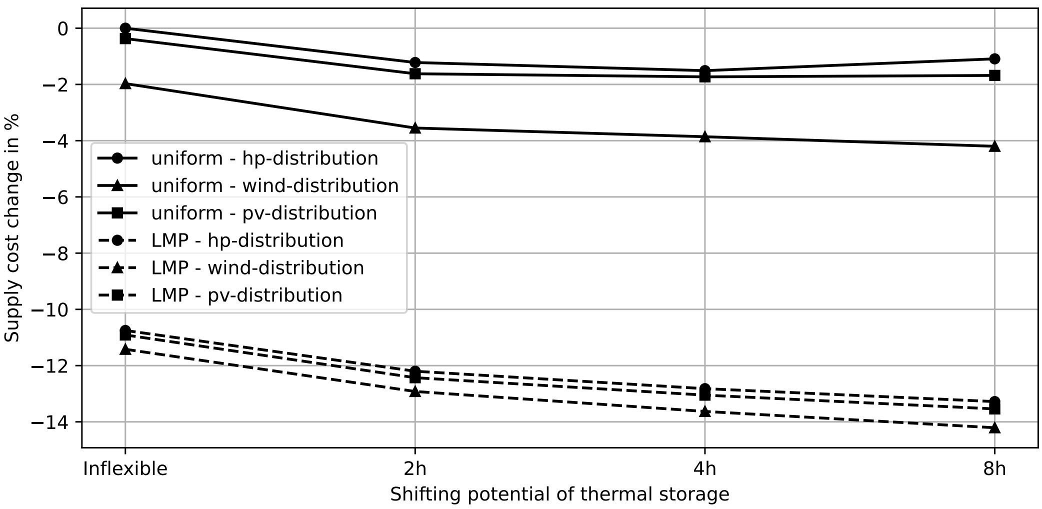


Figure 3: Impact of heat pump distributions and shifting potentials on total supply costs for the uniform and the LMP setup in percentage changes

The following Sections analyze the results in more detail. Section 3.1 further elaborates the results under the uniform setup, differentiating between the impact of flexibility provision on the market result (dispatch effects) and the grid result (redispatch effects). Section 3.2 examines the regional value of thermal storage by making use of the LMP setup. Section 3.3 assesses the profitability of installing thermal storage for system use from the perspective of the individual household.

3.1. Impact of flexibility from thermal storage in the uniform setup

Within the uniform setup, total supply costs consist of the market result (dispatch effects) and the grid result (redispatch effects). Although the flexibility provision by thermal storage consistently reduces total supply costs across all heat pump distributions and shifting potentials, the isolated effects on the market and the grid are opposing, presented in Table 3 for each heat pump distribution.

[5]The base (100 %) for the percentage change is given by the uniform model setup and the *hp-distribution* with inflexible heat pumps.

Table 3: Percentage change in supply costs with flexibility provided by thermal storage compared to supply costs with inflexible heat pumps for each heat pump distribution

Heat pump distribution	Type of supply costs	2h [%]	4h [%]	8h [%]
hp-distribution	Dispatch supply costs	-2.34	-3.34	-3.74
hp-distribution	Redispatch supply costs	2.97	5.35	8.80
hp-distribution	Total supply costs	-1.22	-1.51	-1.09
wind-distribution	Dispatch supply costs	-2.66	-3.42	-4.33
wind-distribution	Redispatch supply costs	2.73	4.29	6.28
wind-distribution	Total supply costs	-1.62	-1.93	-2.27
pv-distribution	Dispatch supply costs	-2.31	-2.97	-3.65
pv-distribution	Redispatch supply costs	2.75	4.74	7.55
pv-distribution	Total supply costs	-1.26	-1.36	-1.32

Note: The base (100 %) for the percentage change is given for each row by the respective base case with inflexible heat pumps.

Across all distributions, the shifting through thermal storage positively affects dispatch results and therefore lowers dispatch supply costs compared to the inflexible use of heat pumps. The higher the shifting potential of the thermal storage, the lower dispatch supply costs are. For example, given the *hp-distribution*, dispatch supply costs decrease by -2.34%, -3.34%, and -3.74% with a 2h, 4h, and 8h shifting potential, respectively.

However, as the uniform model setup neglects grid constraints within the dispatch, the market result with flexibility provision can either reinforce or mitigate grid constraints.[6] Table 3 shows that redispatch supply costs increase with an increasing flexibility potential for all distributions, i.e. the market results increase the need for grid management. With the *hp-distribution*, the redispatch supply costs increase by 2.97%, 5.35%, and 8.80% with a 2h, 4h, and 8h shifting potential, respectively.

The resulting effect on total supply costs depends on how these two effects balance each other. With the *hp-distribution* and the *pv-distribution*, total supply costs benefit most from a 4h shifting potential. With a 2h shifting potential, the flexibility potential is lower, resulting in a smaller reduction in dispatch supply costs. With an 8h shifting potential, the negative effect on the grid increases over-proportionally such that the total supply costs are above the case with 4h shifting

[6]Since thermal storage is not part of the redispatch, the electricity shifting of thermal storage only indirectly affects redispatch results if the dispatch result is physically better or worse for the grid than it would be without the shifting of the thermal storage.

potential. With the *wind-distribution*, the larger thermal storage with 8h shifting potential achieves the lowest total supply costs, as the locations of heat pumps and thermal storage better align with wind locations and generation patterns. Thus, with an increasing shifting potential, the location of the storage becomes increasingly important, as the spatial alignment between RES generation and flexibility provision within the grid becomes a more critical factor relative to the market result.

The spatial alignment between RES generation and thermal storage locations also explains why the allocation of heat pumps following the *wind-distribution* results in the lowest total supply costs among the three distributions. Compared to the *hp-distribution*, the allocation of heat pumps based on the *wind-distribution* reduces total supply costs by -1.97% in the base case with inflexible heat pumps, and by -3.55%, -3.86%, and -4.20% with 2h, 4h, and 8h shifting potential, respectively (see Table 2). A large part of the reduction is already observable in the base case with inflexible heat pumps and is thus the result from the reallocation of heat pump demand from southern to northern Germany. Installing heat pumps close to wind capacity increases demand in northern Germany, which helps mitigating grid bottlenecks between north and south and facilitates onshore wind integration without violating grid restrictions. The cost reductions are therefore largely driven by lower redispatch costs, which, in comparison to the *hp-distribution*, decrease by -10.0% in the base case, and by -10.2%, -10.9%, and -12.1% with 2h, 4h, and 8h shifting potential, respectively.

All in all, the installation of a thermal storage is recommendable from the system perspective independent of the underlying distribution of heat pumps. A recommendation regarding storage size depends on the location of the thermal storage.

The following Sections 3.1.1 and 3.1.2 explain the driving factors behind the positive impact of thermal storage on the market and the adverse impact on the grid.

3.1.1. Dispatch effects

The flexibility provision through thermal storage positively impacts the market result by enabling the temporal shifting of electricity demand. The dispatch effects are shown below exemplarily for the *hp-distribution*.[7] The annual electricity shifted amounts to 6.7 TWh, 10.1 TWh, and 12.3 TWh

[7] In the dispatch, grid restrictions are not considered. Consequently, changes in the distribution of heat pumps and thermal storage do not affect the market result apart from variations in weather profiles across different nodes, which alter electricity demand. These effects are small on an aggregated level and therefore the direction and magnitude of the effects are comparable for *wind-distribution* and *pv-distribution*.

with a 2h, 4h, and 8h shifting potential, which corresponds to approximately 19.3%, 29.2%, and 35.5% of electricity demand from heat pumps or about 1.1%, 1.6%, and 1.9% of total electricity demand.

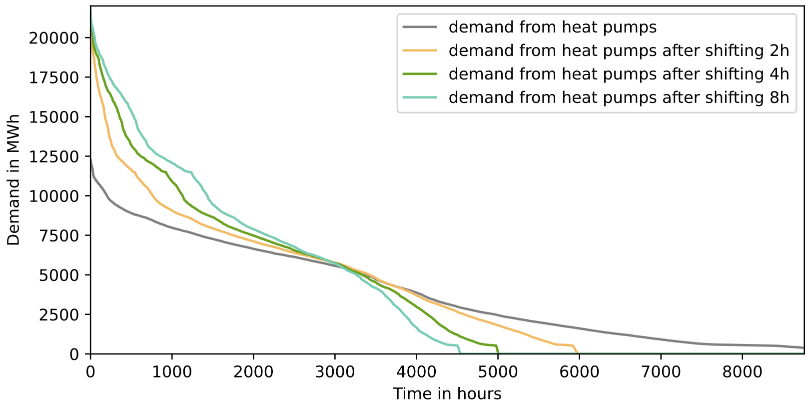


Figure 4: Duration curve of electricity demand from heat pumps in 2030 in MWh

The electricity shifting of thermal storage therefore alters the structure of the electricity demand of heat pumps. The corresponding duration curves of electricity demand from heat pumps are depicted in Figure 4. While the electricity demand of heat pumps without thermal storage is positive in all 8760 hours, the shifting of thermal storage reduces it to zero in 2778, 3751, and 4224 hours, depending on storage size. Charging increases electricity demand from heat pumps, raising peak load from 12.3 GW with inflexible heat pumps to 21.1 GW, 21.5 GW, and 21.9 GW, for 2h, 4h, and 8h shifting potential.[8].

Consequently, the electricity shifting enabled by thermal storage impacts the price formation, reducing price volatility as flexibility increases. Specifically, it shifts electricity demand away from high-price periods and decreases the number of zero-price hours. The average annual electricity price decreases by 0.6%, 1.0%, and 1.2% for 2h, 4h, and 8h shifting potentials, respectively, compared to the average price of 70.5 EUR/MWh for the base case with inflexible heat pumps.

A detailed analysis of the hourly profiles shows the factors that influence the dispatch behavior of thermal storage. Typically, storage charges when electricity prices are low, which often coincides

[8]Note that, the cumulative peak demand from heat pumps that results after the shifting of the thermal storage does not exceed the installed capacity of heat pumps in the model. If this condition does not hold, an extension of the heat pump capacity (and possibly also the grid connection) would be necessary. This would consequently increase the household's annualized investment cost for providing flexibility.

with high RES generation, and discharges when prices are high, reflecting lower RES generation and higher fossil fuel contributions to setting marginal prices.

The results show that thermal storage charging correlates more strongly with PV generation than wind, as PV has a greater impact on electricity prices. The charging of the thermal storage shows a positive correlation with PV generation, reflected in Pearson correlation coefficients of 0.42, 0.51, and 0.54 for 2h, 4h, and 8h shifting potentials, respectively. In contrast, the correlation with wind generation is significantly weaker (0.01, 0.02, and 0.05). This is due to the different feed-in profiles of PV and wind: While wind generation is positively correlated with heat pump demand (0.27 for wind vs. -0.37 for PV), PV generation shows a stronger negative correlation with electricity prices (-0.65 for PV vs. 0.22 for wind). The resulting price reductions from high PV generation incentivize storage charging, whereas wind's weaker price correlation makes its influence on storage charging more ambiguous.

As a result, the flexibility provision by thermal storage leads to an increase in generation from PV, onshore and offshore wind power, and hence a decrease in market based curtailment, while at the same time electricity generation from coal and gas turbines is declining, as listed in the Appendix in Table C.1.

3.1.2. Redispatch effects

The impact of flexibility provision through thermal storage on the transmission grid can be evaluated by analyzing the results of the redispatch. Since thermal storage does not actively participate in redispatch, its electricity shifting indirectly affects redispatch results by making the dispatch either more or less compatible with grid constraints compared to the inflexible use of heat pumps.

The results show that, regardless of the distribution of heat pumps and thermal storage, the redispatch volume consistently increases with an increasing shifting potential relative to the inflexible use of heat pumps, as listed in Table 4.

Hence, for all distributions, the market results with flexibility provision through thermal storage require more redispatch measures compared to an inflexible use of heat pumps. The underlying reason is the spatial mismatch between generation technologies and heat pumps combined with thermal storage. This includes increasing curtailment of RES in the redispatch compared to the

Table 4: Redispatch volumes with inflexible heat pumps and percentage changes with thermal storage and different shifting potentials

Heat pump distribution	Inflexible heat pumps [TWh]	2h [%]	4h [%]	8h [%]
hp-distribution	55.0	2.9	4.7	6.0
wind-distribution	52.3	1.9	2.9	3.3
pv-distribution	54.8	2.0	3.6	4.5

base case with inflexible heat pumps. RES generation that can be additionally integrated in the market through thermal storage is partially curtailed in redispatch and replaced by fossil fuel-based generation, thus, partly offsetting the environmental and economic benefits of flexibility provision. Among the analyzed distributions, the *wind-distribution* results in the lowest increase in redispatch volume. This outcome stems from a better spatial alignment between wind generation and heat pumps compared to *hp-distribution* and *pv-distribution*, which also explains why total supply costs are lowest for the *wind-distribution*.

The results suggest that the system value of thermal storage differs between locations, but within the uniform setup these differences cannot be signaled to the market.

3.2. Regional value of flexibility from thermal storage

The LMP model setup offers the possibility to analyze the regional differences across Germany in more detail and allows to assess the regional system value of flexibility provision through thermal storage. The regional system value of thermal storage is reflected in the expected revenue depending on its location. Figures 5 (a)-(c) illustrate the expected revenue with the *hp-distribution* for each shifting potential by latitude, distinguishing in color shades between nodes west and east the 10th meridian.[9]

For all three shifting potentials, it can be observed that the regional system value of thermal storage in terms of the expected revenue increases from south to north. In southern Germany, the expected revenues tend to be higher east of the 10th meridian. Further north, with a few exceptions, the

[9] The 10th meridian is marked in the maps of Germany in Figure 2. To the west of the 10th meridian, most nodes are located in Baden-Wuerttemberg and the federal states of former Western Germany, whereas to the east, they are predominately located in Bavaria and the federal states of former Eastern Germany.

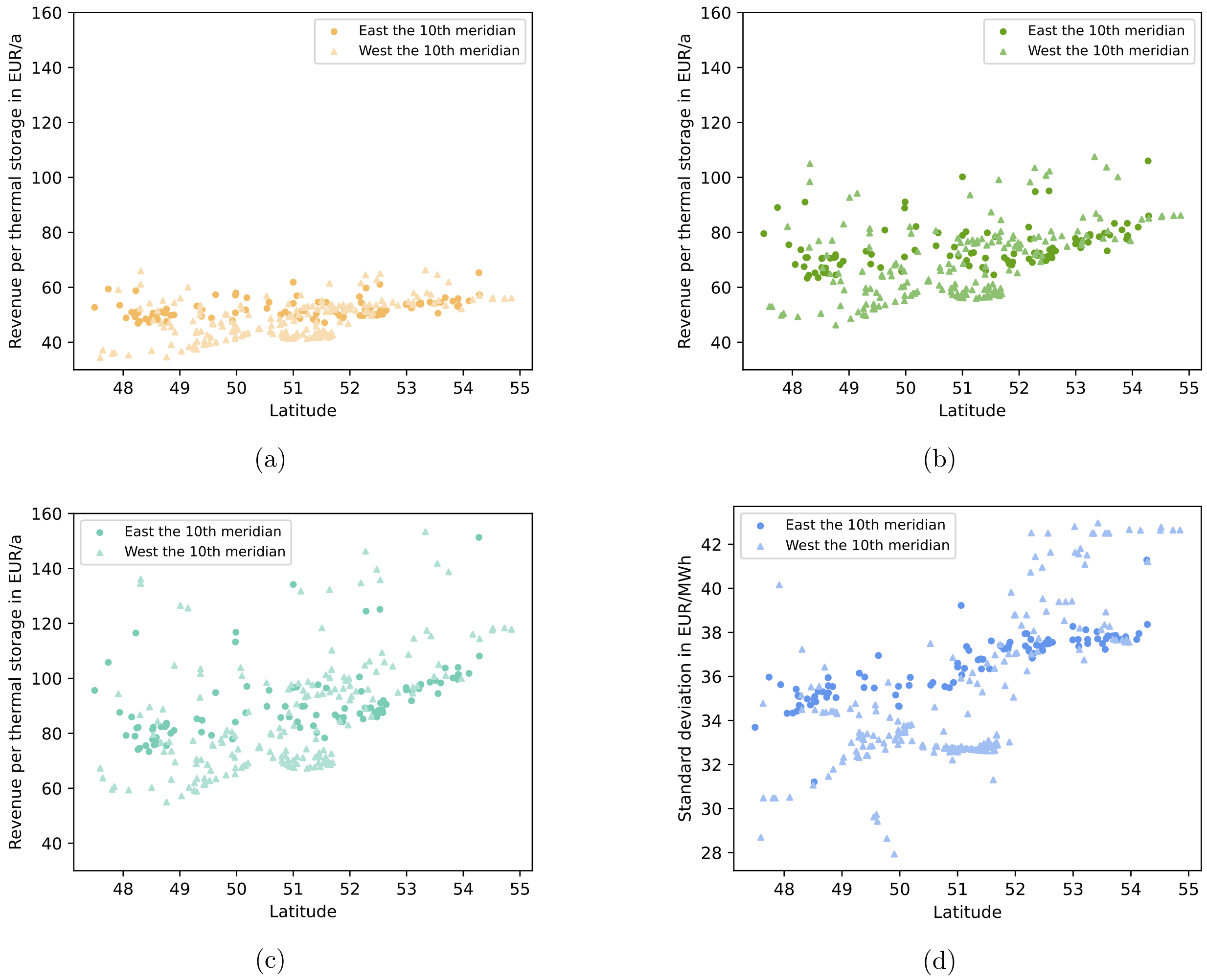


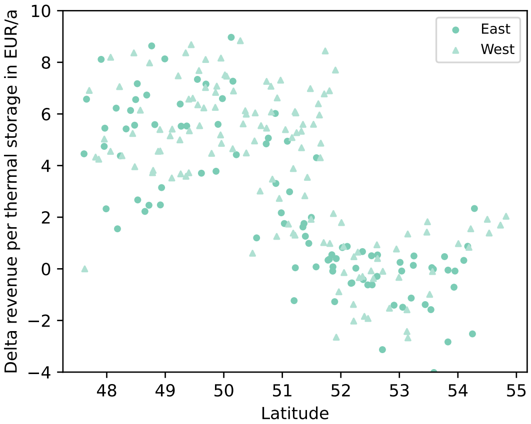
Figure 5: Expected revenues for thermal storage by latitude for (a) 2h shifting potential, (b) 4h shifting potential, (c) 8h shifting potential, and (d) the standard deviation of LMPs in the base case with inflexible heat pumps

regions in eastern Germany follow the upward trend but set the lower limit of expected revenues, while the outliers with relatively high expected revenues are mainly found in western Germany. The differences in the expected revenues between nodes can be explained by looking at the LMPs in each node. As thermal storage shifts electricity over time, their expected revenue is less dependent on the average level of prices and more dependent on the variation of hourly prices.[10] To illustrate this, the standard deviation of the LMPs per node by latitude is presented in Figure 5 (d), showing

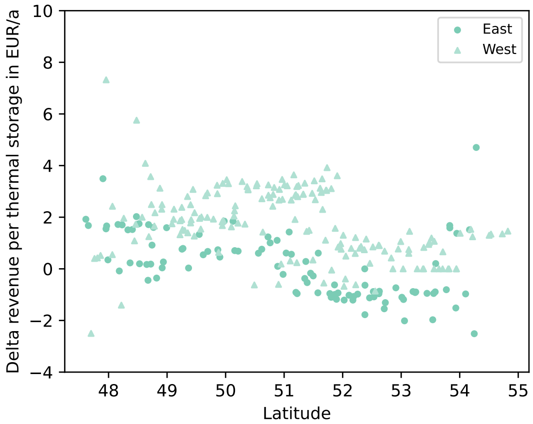
[10]Figure C.2 in the Appendix shows the average annual LMPs per node by latitude.

that higher expected revenues correspond with a greater standard deviation of LMPs.[11] A more detailed examination of the data further reveals that wind and PV generation is relatively high at these nodes, which explains the higher price fluctuations. Consequently, the flexibility of thermal storage is more valuable to the electricity system at these nodes with high RES generation and is utilized more frequently and extensively than at other nodes with lower expected revenues.

These findings generally also apply for the *wind-distribution* and the *pv-distribution* (see Figure C.3 in the Appendix). Figure 6 shows the differences in expected revenues per thermal storage with an 8h shifting potential between the *hp-distribution* and the (a) *wind-distribution* and (b) *pv-distribution*.[12]



(a)



(b)

Figure 6: Differences in expected revenues per thermal storage with 8h shifting potential for (a) *wind-distribution* - *hp-distribution* and (b) *pv-distribution* - *hp-distribution*

With the *wind-distribution*, expected revenues shift from north to south, especially from above the 51st parallel, with changes ranging from -4 to 10 EUR/a. A reallocation of thermal storage according to the *pv-distribution* yields smaller differences in expected revenues compared to the *hp-distribution*, as the two distributions are more similar. Most nodes show revenue changes between -2 and 4 EUR/a, with mixed impacts in northern and southern nodes. There is a notable shift in

[11]Thermal storage has a negligible effect on both the average annual LMPs and their standard deviation. As a result, the base case with inflexible heat pumps is presented.

[12]The effects are most pronounced for the 8h shifting potential. See Figure C.4 in the Appendix for the 2h and 4h shifting potential.

expected revenues between eastern and western nodes, with increases predominantly in the west and decreases in the east.

Relating these results to the observed shifts in heat pump demand, expected revenues rise in regions with less thermal storage capacities compared to the *hp-distribution* and fall in regions where more thermal storage is allocated. This suggests that the value of a single thermal storage depends not only on its own location but also on the distribution of other thermal storage capacities. Regions with decreasing thermal storage capacities face higher expected revenues per thermal storage, whereas regions with increasing thermal storage capacities experience lower expected revenues per thermal storage.

3.3. Individual household's investment decision

From a system perspective, combining a heat pump with thermal storage reduces total supply costs across all scenarios and shifting potentials. The profitability for individual households is evaluated by comparing expected market revenues with the investment costs of thermal storage, considering stand-alone solutions and storage extensions when installing a new heat pump system.

In the uniform setup with the *hp-distribution*, a household earns 53 EUR/a with a thermal storage with 400 l (2h shifting potential), 77 EUR/a with 800 l (4h shifting potential), and 96 EUR/a with 1500 l (8h shifting potential).[13] For stand-alone installations, average annualized investment costs of 88 EUR/a (2h shifting potential), 105 EUR/a (4h shifting potential), and 134 EUR/a (8h shifting potential) exceed the expected revenues. For storage extensions, upgrading a 400 l storage to 800 l, i.e. providing a 2h shifting potential for market use, costs an additional 17 EUR/a, and 29 EUR/a for upgrading an 800 l storage to 1500 l, providing a 4h shifting potential. These extensions yield profits of 36 EUR/a and 48 EUR/a, respectively, making them cost-efficient decisions for individual households.[14]

[13] Revenues are the same for the *pv-distribution* and slightly higher for the *wind-distribution* (54 EUR/a, 79 EUR/a, and 99 EUR/a, respectively).

[14] Additional revenues from providing flexibility in other markets, e.g. the intraday market or ancillary services, could improve profitability, especially if price fluctuations are greater than in the wholesale market. However, a detailed analysis of multi-market participation is beyond the scope of this paper, as it alters thermal storage operational patterns.

In the LMP setup, the value of flexibility is highest in northern Germany, particularly above the 53rd latitude, where expected revenues consistently exceed those in the uniform setup, reaching up to 66 EUR/a, 108 EUR/a, and 153 EUR/a, for 2h, 4h, and 8h shifting potentials, respectively. While stand-alone installations still remain unprofitable, storage extensions to either 800 l (2h shifting potential) or 1500 l (4h shifting potential) are profitable across all nodes. The storage extensions yield profits that range between 18 EUR/a and 49 EUR/a for a 2h shifting potential, and between 17 EUR/a and 79 EUR/a for a 4h shifting potential.

Given the heat pump expansion target for 2030, the majority of heat pumps will have to be built in the coming years. It is therefore reasonable to assume that most investment decisions will be made when installing new heat pump systems. At this stage, installing a thermal storage with increased capacity for market-oriented flexibility is a profitable decision, assuming that wholesale price signals are visible on the individual household level as discussed in Section 4.3.

4. Discussion

In order to understand the results, it is important to be aware of the underlying methodology and to critically assess it. This Section discusses the model assumptions (Section 4.1), the data (Section 4.2), and the results in the light of existing literature and its policy implications (Section 4.3).

4.1. Model assumptions

The numerical model uses idealizing assumptions which may lead to results deviating from reality. The model assumes perfect foresight, fully rational economic behavior, and perfect coordination among storage installations. In reality, achieving such a frictionless market participation is challenging and highlights the importance of aggregators and technical necessities like smart meters.

Additionally, the model assumes that flexibility from thermal storage on household level can be fully utilized in the transmission grid, even though they are installed at the distribution grid. Including the distribution grid into the analysis could provide further insights: First, it could accentuate regional differences due to the heterogeneous distribution networks in Germany. Second, interactions between distribution and transmission grid levels could either intensify or mitigate transmission congestion. While bottlenecks in the distribution grid may limit storage availability

for the transmission grid, offering flexibility at the distribution level could also create an additional revenue stream for heat pump owners, potentially increasing the profitability of thermal storage.
Furthermore, this paper assumes that only the additional thermal storage capacities are operated in a system-friendly manner. This provides a lower bound for the flexibility potential. The analysis does not determine if 'technical storage capacities' can be utilized for system-use when not required for technical optimization, or if reducing technical operational levels could increase revenues from system-use. In particular, thermal storage meeting §14a EnWG criteria may allow system-friendly optimization without incurring extra costs as this storage is designed for two-hour shifting and likely exceeds technical needs.
Despite possible deviations due to the idealized assumptions, the results indicate that thermal storage offers considerable shifting potential that can be effective even if only partially activated, particularly if it is located in grid-beneficial locations. As shown in Section 3 this is particularity the case if heat pumps are allocated close to onshore wind capacity.

4.2. Data

The current extrapolation of heat pump demand profiles to 2030 disregards potential changes in heat pump types, technological advancements, and variations in building characteristics like insulation. These factors could reshape future electricity demand profiles and current assumptions on the efficiency (COP) of heat pumps. While advancements in technology and insulation are expected to increase efficiency, the installation of heat pumps in less insulated buildings may lower efficiency. Presently, heat pumps are mainly installed in single-family homes, but broader adoption in multi-family buildings could either level out or intensify demand peaks as usage increases simultaneously. Additionally, a deeper understanding of heat pump operation in practice and thus improved technical optimization could smooth out demand profiles over the course of the day.
Furthermore, this paper investigates the impact of the regional allocation of heat pumps and thermal storage on the electricity market and the grid by analyzing three exemplary distributions. The results are robust with respect to the different distributions, as the core results and the direction of the effects remain essentially unchanged if the distribution assumption is changed. Future studies

could aim to improve the predictive quality for heat pump distribution in 2030, similar to the detailed analysis by Arnold et al. (2023) on the expansion of electric vehicles in Germany.

4.3. Results and policy implications

This section briefly summarizes the results, embeds them in the literature, and discusses key policy implications concerning the spatial distribution of new heat pump and thermal storage installations as well as the impact of flexibility provision by thermal storage on market effects and grid dynamics. With regard to the installation of new heat pumps combined with thermal storage, allocating them near wind capacities proves most beneficial for the overall system, achieving the lowest total supply costs. This outcome is primarily driven by the reallocation of heat pump demand, as most of the cost reduction is already observable in the base case with inflexible heat pumps. Shifting demand to northern Germany relieves the grid and reduces redispatch costs compared to installing heat pumps in southern Germany. These results suggest that policymakers should prioritize to incentivize heat pump installations in northern regions to align new demand with local renewable generation and reduce grid constraints — a target applicable to other sources of demand as well.

When considering the impact of flexibility provision by thermal storage, the results show its consistent potential to lower total supply costs independent of the chosen distribution of heat pumps. Unlocking flexibility from thermal storage mitigates RES curtailment and substitutes fossil fuel generation. These results align with the findings in previous studies (e.g., Bloess et al., 2018; Roth et al., 2024; Schöniger et al., 2024; Büttner et al., 2024; Bauknecht et al., 2024).

To fully utilize the flexibility potential of thermal storage, it is recommendable to incentivize equipping heat pumps with thermal storage and ensuring their flexibility is accessible to the market. A practical first step could involve integrating existing thermal storage, built in accordance to §14a EnWG, into the electricity market during periods when it is unused for this purpose or for other technical optimization of the heat pump. To facilitate market participation, existing market barriers should be addressed, in particular the distortions between wholesale price signals and retail prices. Heat pump owners often lack access to real-time electricity prices, limiting their ability to optimize electricity demand based on market conditions. Moreover, the addition of taxes, levies, and network fees distorts wholesale price signals, complicating effective household responses to price fluctuations. Regional variations in retail electricity prices, driven by network tariffs unrelated to grid congestion, add further complexity. The structure of retail electricity prices should therefore continue to be part of the political debate. Agora Energiewende (2023) and Eicke et al. (2024) recently explore various policy instruments such as dynamic retail pricing and time-varying network tariffs, to enable the use of decentralized flexibilities in Germany.

Regarding the size of the thermal storage, the results show that smaller systems with 2h or 4h shifting potential consistently lower total supply costs, independent of the underlying heat pump distribution. However, with an 8h shifting potential, thermal storage provides additional cost reductions only when allocated close to wind capacities. The larger storage size better aligns with wind generation patterns and grid constraints in northern Germany. This finding extends the existing literature, as previous studies (e.g., Schöniger et al., 2024; Roth et al., 2024) focus on market effects of thermal storage but neglect grid impacts.

Concerning the impact of flexibility provision on the grid, the results emphasize the need for locational signals. In the uniform setup, which represents the German electricity system, thermal storage reduces total supply costs through its positive market effects, but at the same time it increases redispatch costs. Unlike aggregated studies of decentralized flexibilities (e.g., Heitkoetter et al., 2022; Bauknecht et al., 2024; Büttner et al., 2024), this analysis highlights the grid impacts of heat pumps with thermal storage. The results suggest that with the introduction of flexibility from thermal storage, taking grid constraints into account becomes increasingly important in order to utilize the flexibility for the market without violating grid constraints. This applies in particular to larger shifting potentials. Although idealized LMPs are not directly applicable, they show the benefits of integrated price signals. Policy makers should ensure that heat pumps are operated with consideration for their impact on the grid. Current proposals for an electricity market reform in Germany, e.g. by the Federal Ministry for Economic Affairs and Climate Action, acknowledge the need for locational signals but have, so far, left out storage technologies (BMWK, 2024).

Overall, creating a cohesive regulatory framework that integrates both market and grid dynamics will be essential to fully realize the economic potential of heat pumps combined with thermal storage. Policymakers should incentivize the installation of thermal storage and ensure its participation in the electricity market. This particularly includes addressing distortions between wholesale price signals and retail prices. Additionally, locational signals should be implemented that account for both market conditions and grid constraints, ensuring that flexibility provision maximizes its system-wide benefits.

5. Conclusion

This paper analyzes the impact of heat pumps combined with thermal storage on the electricity system, accounting for market and grid dynamics. It evaluates the system value of the flexibility provided through thermal storage when taking grid restrictions into account. Six scenarios combine two model setups, a uniform and a LMP model setup, with three heat pump distributions, based on the current geographic locations of heat pumps, the allocation of wind capacity, and the allocation of PV capacity. Each scenario is compared for three storage sizes (2h, 4h, and 8h shifting potential) with the inflexible use of heat pumps.

The results show that across all scenarios and shifting potentials, flexibility provision through thermal storage reduces total supply costs compared to an inflexible use of heat pumps. In the uniform model setup, the provision of flexibility improves the market results but at the same time increases the necessity for grid management. The extent to which these two opposing effects outweigh each other depends on the shifting potential. When heat pumps are allocated based on their current locations or PV capacity, the 4h shifting potential results in lower total supply costs than the 8h shifting potential, as redispatch supply costs increase over-proportionally for these distributions. Allocating heat pumps and thermal storage near wind capacity in northern Germany leads to the largest reduction in total supply costs, which, in contrast to the other two distributions, benefit most from the 8h shifting potential. Thus, spatial proximity to wind generation enhances the benefits of the flexibility provision through thermal storage. The regional analysis within the LMP model setup supports these findings and shows that the regional system value of flexibility provided by thermal storage is highest in northern Germany. The results therefore suggest that the consideration of grid restrictions becomes more important with the introduction of flexibility from thermal storage in order to utilize the flexibility for the market without violating grid constraints. This applies in particular to larger shifting potentials.

The magnitude of effects depends on the model parametrization and data assumptions regarding the market and grid. Particularly, the effects of thermal storage depend on the assumptions about other flexibility options as they interact with the flexibility provided by technologies such as electrolyzers and batteries. Further studies for other countries or other scenarios, e.g. on the impact of heat pump demand profiles, the expansion of RES and other storage technologies, can therefore contribute to further understand the driving factors. In addition, future research could analyze the impact of the location of heat pumps and thermal storage with endogenous investment decisions to further extend the analysis of the different heat pump distributions used in this paper.

In conclusion, unlocking the flexibility potential of heat pumps in combination with thermal storage offers economic benefits for the electricity system across all scenarios. Policymakers are advised to incentivize the market deployment of thermal storage. This should be coupled with locational price signals to align market incentives with grid requirements, thereby ensuring that the benefits of the flexibility are fully realized across the electricity market and the grid. The question of how locational price signals can best be implemented within a uniform setup remains an ongoing topic of public and scientific debate.

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Appendix A. Notation

Throughout the paper at hand, the notation presented in table A.1 is used. To distinguish (exogenous) parameters and optimization variables, the latter are written in capital letters.

Table A.1: Sets, parameters and variables

Sets		
$i \in I$		Electricity generation and storage technologies
$m \in M$		Markets
$t \in T$		Timesteps
Parameters		
$demand_{t,m}$	[MWh]	Electricity demand
$demand_{t,m}^{heatpump}$	[MWh]	Electricity demand from heat pumps
ϵ^{static}	[-]	Static efficiency
$\epsilon^{dynamic}$	[-]	Dynamic efficiency
$\gamma_{t,i}$	[EUR/MWh]	Variable generation cost
cap_m	[MW]	Installed capacities of thermal storage
vol_factor	[-]	Volume factor
$cop_{t,m}$	[-]	Coefficient of performance
Variables		
VC	[EUR]	Yearly variable costs
$GEN_{t,m,i}$	[MWh]	Electricity generation
$CON_{t,m,i}$	[MWh]	Electricity consumption
$STOR\_VOL_m$	[MWh]	Storage volume
$STOR\_LEVEL_{t,m}$	[MWh]	Storage level

Appendix B. Additional model data

Appendix B.1. Assumptions on installed capacities, fuel and carbon prices

The data on the existing power plant capacities and on capacity developments as well as the allocation of power plant capacities on transmission nodes are taken from Zinke (2023). The capacity developments in Germany are based on current legal and political targets. EEG (2023) and WindSeeG (2023) set the legal targets for the expansion of wind onshore, offshore and solar energy. The phase-out of German nuclear, lignite, and hard coal power plants follows the path defined in KAG (2020) and BMWK (2022). While the capacity development of H2 electrolyzers is based on political targets set in BMWK (2023), the development of batteries follows the *Global Ambition* scenario in ENTSO-E and ENTSO-G (2022). The assumed capacity developments are shown in Table B.1. Furthermore, Table B.2 shows the assumptions made on the development of fuel and carbon prices.

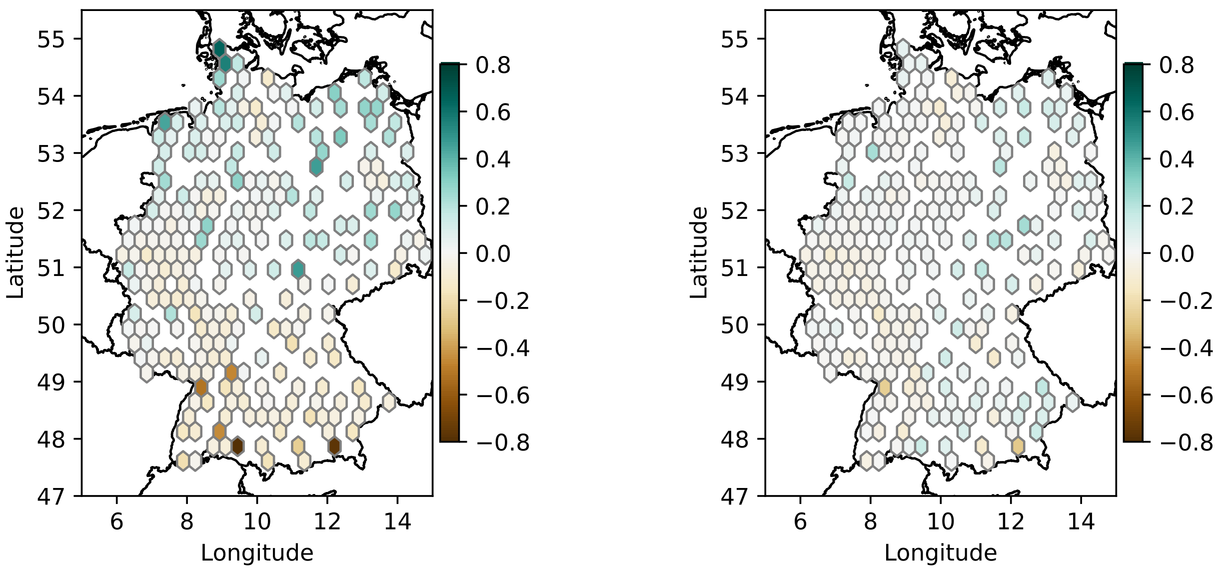
Table B.1: Assumptions on installed capacities [GW] in Germany

Technology [GW]	2021	2030
Wind Onshore	54.5	115.0
Wind Offshore	7.8	29.6
Solar	53.3	215.0
Hard Coal	23.5	8.4
Lignite	20.5	8.9
Gas	31.9	47.0
Nuclear	8.1	-
Batteries	0.0	14.6
H2 Electrolyzers	-	10.0
Others	27.5	27.5

Table B.2: Development of fuel and carbon prices, based on scenario *Stated Policies* in World Energy Outlook 2022 (IEA, 2022)

Fuel [EUR/MWh_{th}]	2021	2030
Uranium	5.5	5.5
Lignite	4.5	5.0
Coal	15.3	7.7
Natural Gas	28.8	25.8
Oil	37.7	44.8
Biomass	20.0	22.0
Carbon [EUR/tCO2]	54.0	100.0

Appendix B.2. Heat pump distributions



(a) (b)

Figure B.1: Differences in annual electricity demand from heat pumps between the *hp-distribution* and (a) *wind-distribution* and (b) *pv-distribution*, in TWh

Appendix C. Additional results

Table C.1: Electricity generation with inflexible heat pumps and percentage changes with thermal storage and different shifting potentials based on the *hp-distribution*

	Inflexible heat pumps [TWh]	2h [%]	4h [%]	8h [%]
PV	217.5	0.4	0.6	0.9
Onshore wind	179.0	1.1	1.4	1.9
Offshore wind	115.8	0.4	0.7	1.0
Gas	86.0	-1.2	-2.1	-3.1
Coal	5.5	-5.6	-8.1	-9.8
Others	52.4	0.4	0.7	1.0
Total	656.2	0.2	0.3	0.5

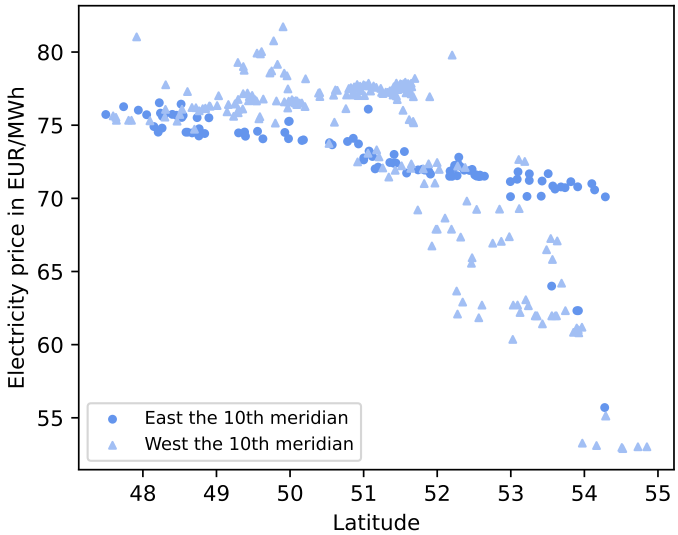


Figure C.2: Average LMPs by latitude in the base case with inflexible heat pumps based on the *hp-distribution*

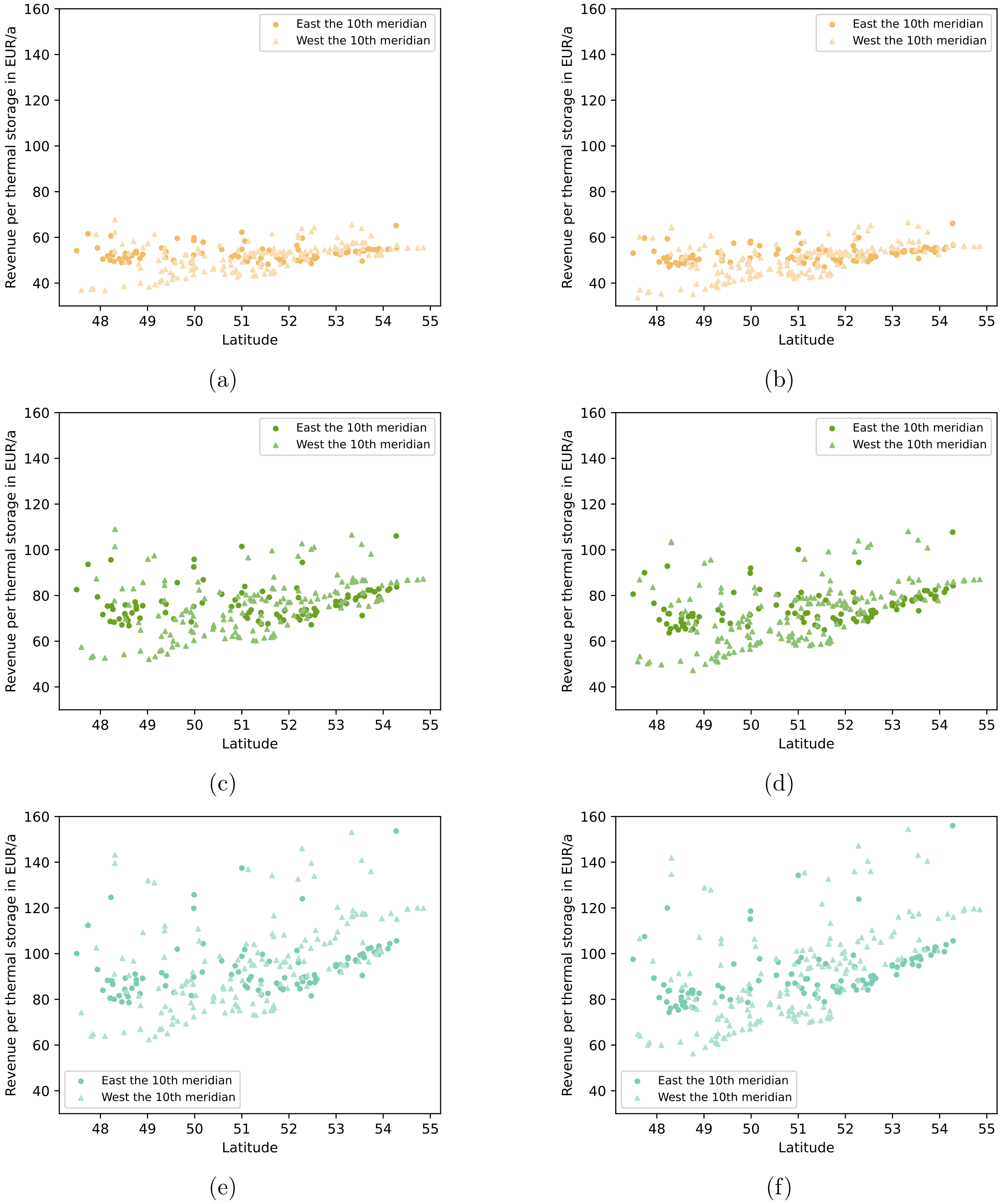
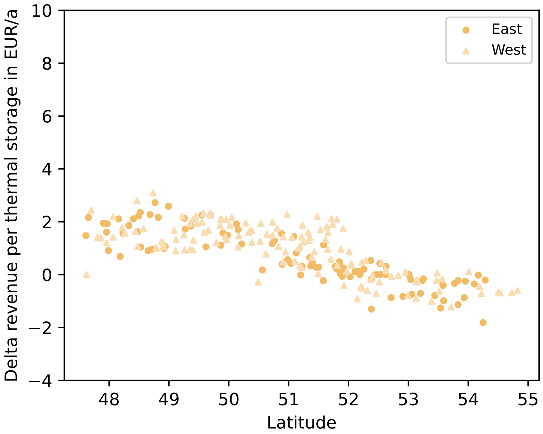
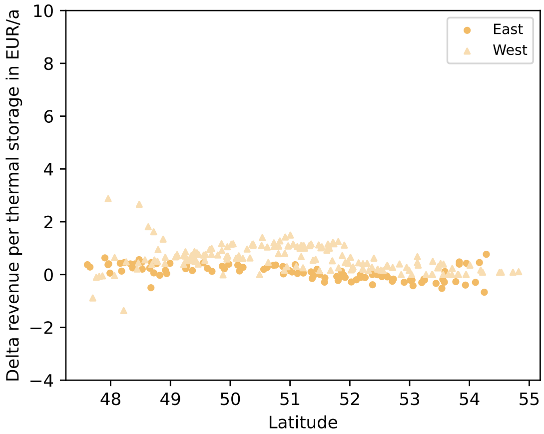


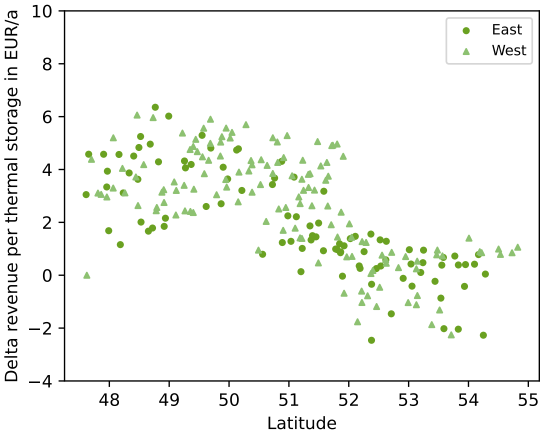
Figure C.3: Expected revenue per thermal storage with (a) *wind-distribution* and 2h shifting potential, (b) *pv-distribution* and 2h shifting potential, (c) *wind-distribution* and 4h shifting potential, (d) *pv-distribution* and 4h shifting potential, (e) *wind-distribution* and 8h shifting potential, and (f) *pv-distribution* and 8h shifting potential



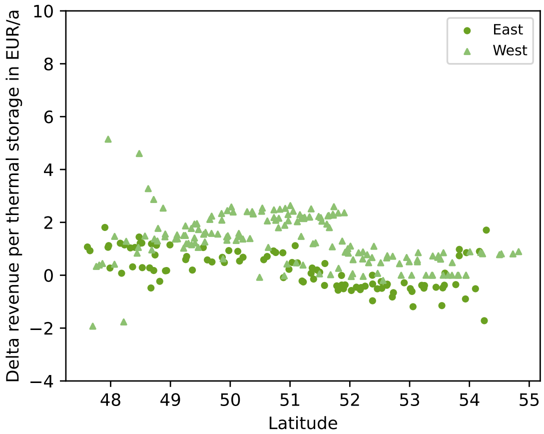
(a)



(b)



(c)



(d)

Figure C.4: Delta between the expected revenues per thermal storage for (a) *wind-distribution* - *hp-distribution* and 2h shifting potential, (b) *pv-distribution* - *hp-distribution* and 2h shifting potential, (c) *wind-distribution* - *hp-distribution* and 4h shifting potential, and (d) *pv-distribution* - *hp-distribution* and 4h shifting potential