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Heating with wind: Economics of heat pumps and variable renewables

Oliver Ruhnau [a,b,*], Lion Hirth [a,c,d], Aaron Praktiknjo [b]

[a] Hertie School, Berlin, Germany
[b] Institute for Future Energy Consumer Needs and Behavior (FCN), RWTH Aachen University, Germany
[c] Neon Neue Energieökonomik GmbH (Neon), Germany
[d] Mercator Research Institute on Global Commons and Climate Change (MCC), Germany

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ABSTRACT

With the growth of wind and solar energy in electricity supply, the electrification of space and water heating is becoming a promising decarbonization option. In turn, such electrification may help the power system integration of variable renewables, for two reasons: thermal storage could provide low-cost flexibility, and heat demand is seasonally correlated with wind power. However, temporal fluctuations in heat demand may also imply new challenges for the power system. This study assesses the economic characteristics of electric heat pumps and wind energy and studies their interaction on wholesale electricity markets. Using a numerical electricity market model, we estimate the economic value of wind energy and the economic cost of powering heat pumps. We find that, just as expanding wind energy depresses its €/MWh$_{el}$ value, adopting heat pumps increases their €/MWh$_{el}$ cost. This rise can be mitigated by synergistic effects with wind power, "system-friendly" heat pump technology, and thermal storage. Furthermore, heat pumps raise the wind market value, but this effect vanishes if accounting for the additional wind energy needed to serve the heat pump load. Thermal storage facilitates the system integration of wind power but competes with other flexibility options. For an efficient adoption of heat pumps and thermal storage, we argue that retail tariffs for heat pump customers should reflect their underlying economic cost.

1. Introduction

Previous studies describe the decline in value of wind and solar energy as these technologies expand. The more these variable renewable energy sources are deployed, the stronger prices decrease in times of high availability of these sources, and the lower the average value of that electricity tends to become (e.g., Grubb, 1991; Joskow, 2011; Mills and Wiser, 2012; Hirth, 2013; Gowrisankaran et al., 2016; López Prol et al., 2020). This drop in value can be significant. For example, Hirth (2013) estimates that the wind energy "capture rate", or value factor, declines to 50–80% of the average electricity price at a 30% market share.[1] The decreasing value jeopardizes the competitiveness of renewables: without subsidies, a rational investor will install new wind turbines and solar panels only if the market value exceeds the levelized cost. Put differently, the decreasing value of variable renewables limits their economically efficient market share (Hirth, 2015). If the market penetration is to be increased beyond that share, society needs to pay out deployment subsidies. The falling economic value can also be related to rising "integration costs" of renewable energy (Ueckerdt et al., 2013; Hirth et al., 2015).

The expansion of renewable energy is not the only aspect in transforming energy systems. Another key ingredient is the electrification of space and water heating through heat pumps (Barton et al., 2013; Connolly, 2017; Jacobson et al., 2017; Ruhnau et al., 2019a). This trend is expected to be amplified by decarbonization targets: electric heating using renewable electricity is a low-carbon substitute for fossil-fueled alternatives. For example, Ruhnau et al. (2019a) review decarbonization scenarios for Germany 2050 and find that 40–80% of the heat demand in the building sector may be served by electric heat pumps, thereby increasing the overall electricity demand by 10–30%. In addition to decentralized heat pumps in the building sector, larger power-to-heat systems may support the decarbonization of centralized district heating systems and industrial applications (Bloess et al., 2018).

Like power generation from variable renewables, electricity consumption of decentralized heat pumps is intrinsically volatile; it depends on the heat demand and the heat pump efficiency, both of which fluctuate over time as a function of the ambient temperature and human activity. Similar to renewable generation, these fluctuations show both deterministic (diurnal, seasonal) as well as random (weather-related) patterns, and they may impose additional challenges on the electricity system. For example, previous studies find that heat

* Corresponding author at: Hertie School, Berlin, Germany.
E-mail address: ruhnau@hertie-school.org (O. Ruhnau).

[1] Note that the decline in value of renewables is stronger and more persistent than the "merit-order effect", which describes the short-term depression of the average electricity price (base price) due to growing supply with zero marginal costs (e.g., Praktiknjo and Erdmann, 2016).

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pumps increase the electricity systems' peak load and the corresponding need for dispatchable back-up generation capacity (Hedegaard and Münster, 2013; Wilson et al., 2013; Fehrenbach et al., 2014; Patteeuw et al., 2015; Cooper et al., 2016; Quiggin and Buswell, 2016; Baeten et al., 2017; Waite and Modi, 2020).

Renewables and heat pumps interact with each other through electricity systems and markets in three ways: additional heat pumps increase the need for electricity, part of which may stem from renewable sources to support successful decarbonization; the temporal profile of heat demand and renewable supply may be temporally correlated, be it positively or negatively; and heat pumps may provide flexibility to the electricity system.

In this context, previous studies show that the additional electricity consumption of heat pumps helps the integration of wind power by reducing curtailment (Hedegaard et al., 2012; Schaber et al., 2013; Waite and Modi, 2014; Patteeuw et al., 2015; Heinen et al., 2016) and increasing its market value (Kirkerud et al., 2014). At closer look, however, the finding of reduced wind power curtailment is little surprising since most of these studies increase the *absolute* electricity consumption by adding heat pumps while fixing the *absolute* electricity generation from wind power. As a result, the *relative* share of renewable generation in the total electricity consumption declines, which naturally facilitates their integration. In contrast, renewable energy policy targets are often defined in relative terms, e.g., 65% in gross electricity demand for Germany 2030 (German Federal Government, 2019). This implies that the adoption of heat pumps (or any other electrification) must go hand in hand with a further expansion of renewable electricity generation.

Beyond this volume effect, interaction of heat pumps and renewables is determined by the related temporal profiles. In Europe, heat demand and wind speeds feature a positive seasonal correlation, both being more abundant in winter (Erdmann and Dittmar, 2010). Hence, heat pumps may over-proportionately use wind power, profiting from relatively low electricity prices when there is large supply and helping increase the *relative* wind share. For solar power, however, adverse seasonal patterns give less reason to expect synergies with heat pumps (Felten et al., 2018).

Furthermore, heat pumps can provide flexibility to the electricity system, effectively being a specific type of demand response. By using thermal storage in hot water tanks or in the building structure, they can decouple their electricity consumption from the heat demand and shift it towards times with low prices and high availability of renewables.[2] As compared to an inflexible operation, which ignores electricity prices and renewable supply, such a flexible operation of heat pumps can further reduce wind power curtailment (Nabe et al., 2011; Hedegaard et al., 2012; Papaefthymiou et al., 2012; Patteeuw et al., 2015; Arteconi et al., 2016; Heinen et al., 2016; Teng et al., 2016) and decrease the need for dispatchable back-up capacity (Nabe et al., 2011; Papaefthymiou et al., 2012; Hedegaard and Münster, 2013; Patteeuw et al., 2015; Arteconi et al., 2016; Cooper et al., 2016; Heinen et al., 2016; Quiggin and Buswell, 2016; Teng et al., 2016; Baeten et al., 2017). Nevertheless, even under flexible operation, heat pumps increase the power system's peak capacity as compared to not adopting heat pumps at all (Hedegaard and Münster, 2013; Arteconi et al., 2016; Cooper et al., 2016; Heinen et al., 2016; Quiggin and Buswell, 2016; Baeten et al., 2017).

Against this background, this study aims to investigate the economics of wind power and heat pumps.[3] Following previous studies, the economics of wind energy are characterized in terms of its market value (capture price). This is defined as the marginal value that an additional MWh of wind energy provides to the electricity system. The additional electricity consumption of heat pumps can be expected to drive up the market value of wind power. Furthermore, the flexible operation of heat pumps may help mitigating its drop in value, similar to other flexibility options. However, if more wind farms are installed to supply the additional heat pumps, this increase in supply will cause a further decline in its market value. Hence, the net effect of additional heat pumps on the wind market value is ambiguous *ex ante*.

To assess the economics of heat pumps, we introduce the new metric of "load cost". By analogy with the market value of wind power, the load cost of heat pumps is defined as the marginal cost to the electricity system for serving one additional MWh of heat pumps' electricity consumption.[4] The additional electricity supply from wind power can be expected to reduce the load cost of heat pumps because the marginal cost of supplying heat pumps will be low when there is abundant supply of wind energy. A flexible operation of heat pumps will amplify these benefits. On the other hand, the need for costly back-up capacity indicate high marginal cost of supplying the heat pump peak load. Hence, the overall trend in the load cost of heat pumps remains ambiguous *ex ante*.

These ambiguities in the economics of wind power and heat pumps are addressed by this study. In short, we address the following research questions:

(1) How does heat pump load cost evolve as a function of heat pump expansion?
(2) What is the impact of heat pumps on the market value of wind energy, and vice versa?
(3) What is the impact of heat pump technology and thermal storage on the economics of both heat pumps and wind energy?

To answer these questions, we use and extend the open-source Electricity Market Model EMMA. This model has previously been used for estimating renewable market values, but the demand has so far been assumed to be perfectly inflexible apart from load shedding at very high prices (Hirth, 2016a). We introduce a stylized representation of individual heat pumps that provide space and water heating. For realistic variability and flexibility of the heat pumps, we use high-resolution demand and efficiency time series from the When2Heat dataset (Ruhnau et al., 2019b) and consider back-up heaters as well as a generic type of thermal storage. Except for wind power and heat pumps, all investment in power generation and storage is endogenous (greenfield model). Hence, the analysis accounts for long-term changes in the optimal mix of residual power generation as a response to the deployment of wind power and heat pumps. To capture varying degrees of heat pump variability and flexibility, the adoption of different types of inflexible heat pumps and the flexible operation of heat pumps with thermal storage are considered in turn. We focus on the value and cost of bulk electricity, neglecting grid constraints and costs within countries (copperplate assumption).

This paper connects and contributes to the fields of wind power integration, heat electrification, and the interaction of the two. Firstly, we complement the literature on the market value of wind power by estimating the impact of heat electrification and thermal storage. While many sensitivity analyses on the market value have been carried out (e.g., International Energy Agency, 2014; Mills and Wiser, 2014, 2015; Hirth, 2016b; Bistline, 2017; Eising et al., 2020), decentralized electric heating and related flexibility has not been in the focus so far. On the other hand, existing studies on the combination of wind power and heat electrification did not focus on the wind value.[5] In contrast to

[2] In addition to thermal storage, few studies consider the flexible operation of hybrid heat pumps with complementary fossil-fueled boilers (Heinen et al., 2016; Waite and Modi, 2020).

[3] We focus on decentralized heat pumps in the building sector, as opposed to larger power-to-heat systems. The latter feature distinct economic characteristics and merit separate analyses.

[4] Note that this is different from the recently proposed concept of "Levelized Cost of Consumed Load", which assesses the profitability of electricity generation technologies (Durmaz and Pommeret, 2020).

[5] With the exception of Kirkerud et al. (2014), but their results are specific to a Norwegian 2020 scenario, mainly driven by hydro power and the existing thermal electricity generation fleet in 2012. In contrast, our greenfield sensitivity analysis provides more general and long-term results.

most of these studies, we keep the wind share in total electricity consumption constant when analyzing the effect of additional heat pumps. This is in line with the decarbonization rationale behind heat electrification and policy targets for renewable energy shares, and it allows for isolating the mutual heat-wind interaction from the mere effect of increasing electric load on wind power with a constant capacity.

Secondly, we are – to the best of our knowledge – the first to introduce the concept of the heat pump load cost. This concept facilitates quantifying the net effect of costly volatility and beneficial flexibility of the heat pump load, bridging between contrasting results on the positive and negative power system implications of heat pumps in the existing literature. As opposed to other metrics that have been used in previous studies, namely renewable curtailment, back-up capacity requirements, and electricity system cost, the load cost directly allows for drawing conclusions about the economic viability of heat pumps – just as the market value does for wind power. Looking beyond electric heat pumps, this framework may also be useful for evaluating other increasing electric loads, such as with electric vehicles.

Finally, our numerous sensitivity analyses with respect to wind power and heat pump adoption, as well as heat pump volatility and flexibility, contribute to a more comprehensive economic understanding of heat-wind interactions. It is shown that the load cost of heat pumps increases with the heat pump load, just as the market value of variable renewable decreases with the renewable electricity generation. This raises questions on the competitiveness of heat pumps but highly depends on the heat pump technology and the availability of thermal storage. Regarding the heat pump technology, the load cost of ground source heat pumps with floor heating are found to be lower than of air source alternatives with radiators – not only due to a higher efficiency but also because their load is less volatile. Analogously to low wind speed turbines with less volatile power generation (Hirth and Müller, 2016), the term "system-friendly" is applied to this beneficial heat pump technology. Finally, this study discusses more generally substitution among flexibility options and the efficiency of heat pump retail pricing.

The remainder of this paper proceeds as follows. Section 2 describes the assessment and modeling methodology. Section 3 presents the results in terms of market values and load costs. Section 4 discusses the results, and Section 5 draws conclusions.

2. Methodology

The system effects and the interplay of wind turbines and heat pumps are analyzed with an extended version of the Electricity Market Model EMMA. More precisely, *exogenous* changes are applied to the market shares of wind power and heat pumps as well as the size of thermal storage. As a response to these shocks, all other investment and dispatch decisions are *endogenously* optimized, and hourly electricity prices are derived from the shadow variables of the energy balance. These electricity prices are used to calculate the market value of wind power and the load cost of heat pumps. The following subsections discuss the metrics (2.1), the model and its extensions (2.2), and the input parameters (2.3) for this analysis.

2.1. Metrics for market penetration and economic valuation

For every hour of the year, t, and for every country, r, the total electricity load, $load_{t,r}$, is distinguished into the conventional load as observed in recent years, $load_{t,r,conv}$, plus the load of additional heat pumps, $load_{t,r,h}$, where the different heating technologies, h, include the actual heat pump and the back-up heater:

$$load_{t,r} = load_{t,r,conv} + \sum_h load_{t,r,h} \tag{1}$$

On this basis, the "wind share" and the "heat pump share" are calculated as the percentage of the yearly sum of the wind electricity generation, *wind generation*$_{t,r}$, and the yearly sum of the heat pump electricity load in the yearly sum of the *total* load, respectively:

$$Wind\ share_r = \frac{\sum_t wind\ generation_{t,r}}{\sum_t load_{t,r}} \tag{2}$$

$$Heat\ pump\ share_r = \frac{\sum_{t,h} load_{t,r,h}}{\sum_t load_{t,r}} \tag{3}$$

With these definitions, an increasing heat pump share implies an increase in the total electricity consumption and eventually more absolute wind generation for the same wind share. Thus, the definitions reflect the rationale that deep decarbonization requires heat electrification to go hand in hand with additional renewable electricity generation.

Following Hirth et al. (2015), the market value of wind power is defined here as the bulk power value minus balancing costs and network costs. In the following numerical analysis, the focus is on the bulk power value, which earlier studies find to be more significant than balancing and network costs in terms of both its level and its responsiveness to an increase in the wind power market share (Hirth et al., 2015). The bulk power value is calculated in accordance with Joskow (2011) as the weighted average of the hourly, regional wholesale electricity prices, $price_{t,r}$, where the weights are the hourly generation from wind energy:

$$Wind\ market\ value = \frac{\sum_{t,r} wind\ generation_{t,r} \cdot price_{t,r}}{\sum_{t,r} wind\ generation_{t,r}} \tag{4}$$

In economic terms, the wind market value can be interpreted as the marginal economic value of adding one MWh of variable wind generation to the electricity system. In practice, wind farms are likely to be exposed to wholesale prices. In this case, the market value corresponds to their market revenue, also referred to as capture price. Balancing and network costs will reduce the revenues if they are internalized. Note that the wind market value can be related to other metrics of wind power integration: high integration cost, curtailment, and the need for conventional back-up capacity with low utilization will reduce the market value (Hirth et al., 2015).

To assess the economics of heat pumps, we introduce here an analogous metric, the "cost of heat pump load". Equivalent to the wind value, it is defined as the weighted average of the hourly, regional wholesale electricity prices with the weights being equal to the heat pumps' electricity consumption:

$$Heat\ \ pump\ load\ cost = \frac{\sum_{t,r,h} load_{t,r,h} \cdot price_{t,r}}{\sum_{t,r,h} load_{t,r,h}} \tag{5}$$

From an economic perspective, the heat pump load cost quantifies the marginal electricity system cost of serving one additional MWh of variable heat pump consumption. For instance, if additional heat pumps increase the need for costly back-up capacity, this will be reflected in the load cost. In contrast to wind farms, individual heat pumps normally do not participate directly in the wholesale market, but pay a rate offered by a retail supplier. The suppliers' procurement at the wholesale market may be based on standard load profiles, and retail prices are subject to country-specific regulations, taxes, levies, and grid fees. The heat pump load cost and the following numerical analysis focuses on the public economic perspective of the total cost of the electricity system, but these issues relating to retail pricing should be borne in mind and will be discussed in Section 4. Balancing and network costs will generally increase the load cost of heat pumps.

2.2. The electricity market model EMMA with heat pumps

This study builds upon and extends the open-source Electricity Market Model EMMA, which is a techno-economic model of the integrated north-western European power system. In economic terms, EMMA is a partial equilibrium model, clearing demand and supply on the electricity market. The model linearly minimizes the total electricity system cost by deciding upon both investment and dispatch under a large set of technical constraints. Temporally, the optimization is based on a one-year period with an hourly resolution, and geographically, international interconnector restrictions are considered while the copperplate assumption applies within each country. Furthermore, the model assumes perfect foresight. Besides demand and capacity adequacy constraints, the model includes major power system inflexibilities, namely must-run restrictions for combined heat and power production and for the provision of ancillary services, and flexibilities, namely inter-regional electricity transfers and pumped hydro storage. The model has been applied in previous studies on the market value of renewables (e.g. Hirth, 2013), and it is able to replicate historical prices (Hirth, 2018). For a detailed description of the original model, the reader may refer to Hirth (2016a).

Here, EMMA is applied to analyze *long-term* partial equilibria of the interconnected wholesale electricity markets of five European Countries, Germany, France, Belgium, the Netherlands, and Poland. Long-term means that we do not consider existing electricity generators, but all generation capacity (except for the exogenously fixed wind power) is optimized on a "green field". While investment and dispatch on the supply-side used to be endogenous in EMMA, the electricity demand has so far been set exogenously according to the historical profile, and it has been assumed to be perfectly inelastic apart from load shedding at very high prices. In this study, potentially flexible electricity demand of additional heat pumps is introduced into the model.

2.2.1. Heat pumps

The aim of the model is to assess the impact of different quantities of individual heat pumps and thermal storage. Hence, the heat pump and storage capacities are fixed, and only their dispatch is optimized. In the case of inflexible heat pumps, the storage capacity is set to zero and the heat pumps must follow the thermal load. In other words, the adoption of inflexible heat pumps implies an exogenous change in the electricity demand.

By introducing a heat balance (Eq. (6)), the heat generation, $generation_{t,r,h}^{heat}$, is constrained to fulfil a given heat demand for space and water heating, $demand_{t,r}^{heat}$, at each time, t, and in every country, r. In addition, heat input to and heat output from the thermal storage is considered ($storage_{t,r}^{heat,in}$ and $storage_{t,r}^{heat,out}$). To ensure efficient computability, the model does not individually consider single decentralized heat pumps and thermal storage but virtually aggregates them into one equation. This does not imply that the single heat pumps feature homogeneous characteristics. In fact, while only one generic heat pump type is explicitly considered, this is parametrized specifically to represent a national mix of various types of decentralized heat pumps as described in Subsection 3.3. The dispatch of the aggregated heat pump in the model can be interpreted as the sum of this heterogenous heat pump portfolio. In the case of flexible heat pumps, the portfolio's price-responsiveness may be coordinated with centralized or decentralized optimization approaches (Dengiz and Jochem, 2019). The single heat pumps are assumed to be operated mono-energetically, i.e., no fuels besides electricity are used. We consider that the heat pumps may be complemented with electric back-up heaters. As compared to heat pumps, back-up heaters have lower investment costs per capacity but higher operational cost due to their lower conversion efficiency. Hence, back-up heaters are designed to cover the peak heat demand, being dispatched only few hours per year when the heat pump is fully utilized (bivalent operation). To endogenously model the dispatch of both the actual heat pump and the back-up heater, we introduce two distinct heating technologies, h. As a result, flexible back-up heaters may not necessarily supply the peak heat demand because the output of thermal storage could substitute for this, but they may run when electricity prices are low to charge the thermal storage.

The heat generation of the heat pumps and back-up heaters is linked to their electricity consumption by their conversion efficiency, $\varepsilon_{t,r,h}$ (Eq. (7)). For the heat pumps, this efficiency refers to the temporally and spatially varying coefficient of performance (COP), depending on the mix of different heat pump technologies (Subsection 3.3). For the back-up heaters, a constant efficiency is assumed. The resulting additional electricity consumption is added to the conventional load in EMMA's existing electricity balance equation. A small penalty term is included in the objective function to ensure efficient dispatch of the heating technologies even in times when electricity prices are zero.[6] The heat generation is restricted by maximum thermal capacities (Eq. (8)). Note that a temporally constant thermal capacity is a simplification, but it allows for an intuitive parametrization of the national bivalence threshold, which is the maximum capacity of the actual heat pumps without back-up heaters (see Subsection 3.3).

$$demand_{t,r}^{heat} = \sum_h generation_{t,r,h}^{heat} + storage_{t,r}^{heat,out} - storage_{t,r}^{heat,in} \quad \forall t, r \quad (6)$$

$$generation_{t,r,h}^{heat} = \varepsilon_{t,r,h} \cdot load_{t,r,h} \quad \forall t, r, h \quad (7)$$

$$generation_{t,r,h}^{heat} \leq capacity_{r,h}^{heat} \quad \forall t, r, h \quad (8)$$

2.2.2. Thermal storage

The inter-temporal thermal storage balance (Eq. (9)) relates the amount of stored energy, $storage_{t,r}^{heat,level}$, to the storage level of the preceding hour, considering static losses, λ^{stat} (percent per hour). Storage flows for input and output relate the thermal storage balance to the heat balance, accounting for dynamic storage losses, λ^{dyn} (percent per storage cycle). It is assumed that the heat storage can absorb as much heat as can be generated by the heat pumps (including back-up heaters) and can release sufficient energy to satisfy the entire building demand, hence no additional storage flow constraints are included. Eq. (10) limits the stored heat to the storage capacity in terms of thermal energy, $storage_r^{heat,capacity}$. For the sake of computability, only one aggregated, generic thermal storage is explicitly modelled and subsequently parametrized to represent both active storage in hot water tanks and passive storage in the building structure.

$$\begin{aligned} storage_{t,r}^{heat,level} &= \left(1-\lambda^{stat}\right) \cdot storage_{t-1,r}^{heat,level} - storage_{t,r}^{heat,out} \\ &\quad + \left(1-\lambda^{dyn}\right) \cdot storage_{t,r}^{heat,in} \quad \forall t, r \end{aligned} \quad (9)$$

$$storage_{t,r}^{heat,level} \leq storage_r^{heat,capacity} \quad \forall t, r \quad (10)$$

2.3. Parametrization

This subsection describes the extended model parametrization concerning the heat pumps and thermal storage. The other model parameters are set to the EMMA default, including the CO_2 price (20 €/t) and the discount rate (7%). The complete input data are included in the supplementary material.

[6] By efficient dispatch of heating technologies, we mean that heat pumps are used primarily, and back-up heaters only complement the heat pumps. If there was no penalty term in the objective function, the model would be indifferent on whether to use back-up heaters or heat pumps at times with zero prices, and some results would be arbitrary, including the electricity consumption for heating and renewable curtailment. To avoid this, we penalize back-up heater operation.

2.3.1. Heat demand and generation

Time series parameters for the heat demand and the heat pump COP are obtained from the When2Heat dataset (Ruhnau, 2019; Ruhnau et al., 2019b). The demand profiles from this dataset are based on gas standard load profiles and include space and water heating. The COP time series, $COP_{t,r,source,sink}$, are derived from COP and heating curves for decentralized heat pump technologies with different heat sources and sinks. For the computation of both parameters, spatial reanalysis weather data are used, and national aggregation is performed with respect to population geodata.

For the heat demand, the total demand profile for space and water heating is scaled according to the heat pump shares as described below. For the COP, the profiles for different heat sources and sinks are aggregated into one time series, $COP_{t,r}$, reflecting a mix of various heat pump technologies. Assuming a constant share of heat being supplied by a certain heat pump technology gives[7]:

$$\varepsilon_{t,r,heatpump} = COP_{t,r} = \left(\sum_{source,\, sink} \frac{w_{source} \cdot w_{sink}}{COP_{t,r,source,sink}} \right)^{-1} \qquad \forall t, r \qquad (11)$$

Table 1 displays the weights of different heat sources and sinks, w_{source} and w_{sink}, for three different scenarios. In the base case, a mix of technologies is considered according to statistics from EHPA (2017) and EHI (2017). This scenario can be interpreted as a business-as-usual technology choice. In two consecutive sensitivity runs, the technologies are restricted to ground source heat pumps with mixed heat sinks and with floor heating only, in turn. Because the temperatures of the ground and of a floor heating system are less volatile than the temperatures of the ambient air and of radiators, these technology restrictions flatten the temporal profiles of the COP and of the resulting heat pump electricity consumption. The efficiency of back-up heaters is set to unity.

The thermal capacities of the heat pumps and back-up heaters are defined relative to the national peak heat demand. Air source heat pumps are typically sized for bivalent operation: the heat that exceeds a given threshold is provided by mostly oversized electric back-up heaters. Here, the heat pump and heater capacities are set to 80% and 40% of the peak demand, respectively. The use of less efficient back-up heaters further increases the volatility of the electricity consumption of air source heat pumps as compared to ground source heat pumps. Ground source heat pumps are generally designed for monovalent operation: the actual heat pump can supply the peak demand without a back-up heater. Yet, ground source heat pumps typically include back-up heaters. Here, the capacity is set to 100% and 20% of the peak demand, respectively. The parameters for air and ground source systems are weighted for each country according to Table 1. Note that the oversizing of back-up heaters is only relevant to flexible operation: the heat production can only exceed the peak heat demand if thermal storages are available to absorb the excess heat.

2.3.2. Thermal storage

The thermal storage capacity is likewise parameterized with respect to the national heat demand in terms of hours per peak load. We model one generic type of thermal storage, which represents a mix of active storage in hot water tanks and passive storage in the building mass. In the lower storage scenario, this parameter is set to two hours, which reflects how systems are designed in Germany today, where heat pumps can be interrupted for up to two hours to get a grid tariff discount. In the higher storage scenario, a doubling of capacity to four hours per peak heat load is assumed. This can be achieved through (1) adding active storage capacities, (2) allowing for more passive storage in the building structure, or (3) better insulation, which reduces the peak load per storage capacity. As an average estimate, the dynamic losses λ^{dyn} and static losses λ^{stat} are set to 5% and 1% per hour, respectively, to reflect active storage (Heilek, 2015). On the one hand, additional losses from using active storage will occur in the form of a lower COP for heat pumps supplying heat at higher storage temperatures (Nolting and Praktiknjo, 2019; Patteeuw and Helsen, 2016). On the other hand, passive storage is found to have lower overall losses of up to 5% (Arteconi et al., 2016).

2.3.3. Market shares

By analogy with previous wind value analyses, the wind share is varied between just above 0%[8] and 30% of the total electricity demand in every region (Eq. (2)). The total demand includes the average historic demand from 2008 to 2012 plus the electricity demand of the additional electric heat pumps, where applicable (Eq. (1)).

The heat pump share is increased from just above 0%[9] to 15% of the total regional electricity demand (Eq. (3)), except for France where electric heating is already widespread in the form of resistance heaters. In line with the French electricity transmission system operator (RTE, 2019), we do not explicitly model additional (more efficient) heat pumps in France but assume that their electricity demand is balanced out by the decommissioning of existing electric heaters. Assuming a typical mix of different heat sources and sinks (Table 1), a 15% heat pump share can provide around half of today's building heat supply in the countries considered. Put differently, the 15% heat pump share in *electricity* demand ceteris paribus translates into a 50% heat pump share in *heat* demand. While a 15% heat pump share in electricity is in line with 2050 energy scenarios, the heat share may be even higher due to building retrofit (Ruhnau et al., 2019a). Note that the heat pump share is defined based on inflexible heat pump operation, and the total electricity consumption for flexible operation can differ due to endogenously determined thermal storage losses and back-up heater utilization. Table 2 provides an overview of the absolute electricity demand and heat supply volumes.

3. Results

This chapter investigates the separate adoption of wind power and inflexible heat pumps (Subsection 3.1), the combination of these (3.2), the impact of different heat pump technology (3.3), and the impact of thermal storage (3.4). Wind market values and heat pump load costs are reported as the volume-weighted average of all countries included in the model (Eq. (4) and (5)).

3.1. The separate adoption of wind power and inflexible heat pumps

As a benchmark, Fig. 1 displays the market value of wind power for the adoption of wind power only and the load cost of heat pumps for the adoption of heat pumps only. Heat pumps are assumed to operate inflexibly, without responding to electricity prices. The left graph is in line with the findings of previous studies: as the wind share grows from zero to 30%, the value of wind power declines substantially by 24 €/MWh, which is equivalent to 40% of the initial market value of 59 €/MWh. The right graph reveals a similar effect for heat pumps: as their share rises from zero to 15%, the load cost of heat pumps increases by 21 €/MWh or, in relative terms, 29%. Note that the base price is almost

[7] Note that a constant technology share in *heat generation* implies that the share in the *electricity consumption* will vary over time as a result of technology-specific COP time series.

[8] Zero is avoided to be able to calculate the wind market value, where the wind generation is the denominator (Eq. (4)).

[9] Zero is avoided to be able to calculate the heat pump load cost, where the heat pump load is the denominator (Eq. (5)).

Table 1
Weights of heat sources and sinks in the different scenarios. Mix: diverse heat sources and sinks based on historical data from EHPA (2017) and EHI (2017); GSHP: ground source heat pumps with diverse heat sinks; floor: ground source heat pumps with floor heating only.

Heat pump technology		Mix				GSHP	Floor
		Belgium	Germany	Netherlands	Poland		
Heat source	Air	0.75	0.71	0.57	0.17	0	0
	Ground	0.25	0.29	0.43	0.83	1	1
Heat sink	Radiators	0.55	0.4	0.5	0.7	country mix	0
	Floor heating	0.45	0.6	0.5	0.3	country mix	1

Table 2
Electricity demand and heat supply as of today (average of 2008–2012) and in the scenario with a 15% share of additional heat pumps.

[TWh]	Historic (average of 2008–2012)		15% heat pump share (in total electricity demand)	
Country	Conventional electricity demand	Total building heat supply	Heat pump electricity demand	Corresponding heat supply
Belgium	90	109	16	55
France	495	455	0	0
Germany	570	707	101	325
Netherlands	117	151	21	77
Poland	141	210	25	92

constant at 58–60 €/MWh for various scenarios of wind power and heat pump adoption.[10]

Both the market value decrease of wind power and the load cost increase of heat pumps can be explained by the variability of these technologies: in times of high wind speeds, large volumes of wind power depress the electricity prices and hence the average market value of wind power. The more wind energy is introduced into the market, the more pronounced this value reduction is. Likewise, when the electricity consumption of inflexible heat pumps is high, this drives up total electricity demand and prices in that moment, consequently increasing the average cost of the heat pump load. This effect is exacerbated by the increasing adoption of heat pumps. Just as the decline in marginal value is intrinsic to the power supply of wind farms and unfavorable for wind farm operators, the increase in marginal cost is immanent in the electricity consumption of inflexible heat pumps and disadvantageous for heat pump owners.

To better understand the rise in the heat pump load cost, Fig. 2 provides an insight into changes in the installed capacity of different electricity generation technologies. It can be observed that the total installed capacity grows over-proportionately to the heat-pump-induced increase in electricity consumption: to serve a 15% heat pump share, capacity is expanded by 30%. This includes an increasing portion of the total load being shed at very high prices. In addition, capacity expansion relates mainly to peak-load power plants, namely to open cycle gas turbines, and the full load hours of peak- and mid-load generators decrease.[11] Overall, the opportunity cost of load shedding, additional peak capacity, and a lower utilization of power plants lead to a higher system cost per MWh of electricity consumed. In the long-term equilibrium, this cost is reflected in the heat pump load cost.

More precisely, the cost of peak capacity is reflected in high electricity prices when electricity is scarce. The more heat pumps are adopted, the more this scarcity is driven by their volatile load. As a result, heat pumps over-proportionately consume in times of scarcity, paying the corresponding scarcity price (left plot in Fig. 3). In EMMA, scarcity prices are defined by the cost of load shedding, which is assumed to be 1000 €/MWh by default. A sensitivity analysis with load shedding costs of 500 €/MWh and 2000 €/MWh reveals that the heat pump load costs are robust regarding this assumption (right plot in Fig. 3). This can be traced back to the fact that the number of hours with scarcity prices endogenously decreases inversely proportional to the level of scarcity prices.

While the preceding results are based on time series data from 2010, Fig. 4 compares different weather years. While previous studies show that wind market values are robust to changing meteorological years (Hirth, 2013), it is found that this does not hold true for the heat pump load cost. Their level varies substantially (up to 25 €/MWh), although a substantial cost increase occurs across all sensitivities (19–26 €/MWh). The right plot in Fig. 4 relates this finding to the full load hours of the electricity load profiles of the heat pumps: higher heat pump load costs tend to coincide with lower full load hours. This seems plausible, since low full load hours indicate a peaky load profile, and pronounced peaks are more costly to serve. The low heat pump load cost in 2008 can be explained by a relatively low correlation with the conventional load, i.e. the peaks of the different load profiles coincide less.[12] The remainder of this analysis focuses on the weather year 2010.

3.2. The combination of inflexible heat pumps and wind power

Turning to the interplay between inflexible heat pumps and wind power, Fig. 5 compares their diurnal and seasonal variability. While wind power is almost constant throughout the day, the heat pump load is shaped by a typical lowering at night and peaking in the morning. Seasonally, as expected, both wind power generation and heat pump load are higher in winter than in summer. However, the seasonality of the heat pump load is stronger. The Pearson correlation coefficient for the hourly wind and heat pump electricity time series is 0.11.

Fig. 6 translates this correlation into wind market values and the heat pump load cost. Starting with the heat pumps, their load cost indeed falls significantly as wind power enters the electricity system. This effect is greatest at low heat pump shares (almost 10 €/MWh) and decreases with heat pump adoption, being most persistent for high wind shares (stagnating around 6 €/MWh). Apparently, wind power particularly reduces market prices in times of high heat pump electricity consumption. For the wind market value, the results are more ambiguous: in the range of 5–20% of wind power, additional heat pumps tend to attenuate the wind value decrease by up to 2 €/MWh, but this benefit vanishes when reaching 30% wind power. This counter-intuitive finding on the wind market value is scrutinized in the following paragraph.

At this point, it is important to recall that the wind share is defined here in relation to the total electricity consumption, including the growing heat pump consumption. Hence, at a given wind share, the absolute amount of wind power grows with the heat pump share, which is in line

[10] The base price is the (time-weighted) average electricity price. Lamont (2008) shows that, as long as a baseload generator is dispatched in every hour of the year, the base price in the long-term equilibrium should be equal to the levelized cost of electricity of this generator. Indeed, the levelized cost of electricity from lignite power plants, which are continuously dispatched in most of the sensitivities, is equal to 60 €/MWh.

[11] by the following when 15% heat pumps are introduced: 5% for coal-fired steam turbines, 11% for open cycle gas turbines, and 23% for combined cycle gas turbines

[12] The Pearson correlation coefficient for the hourly heat pump and conventional load is 0.26 for 2008 as compared to 0.35 to 0.41 for the other weather years.

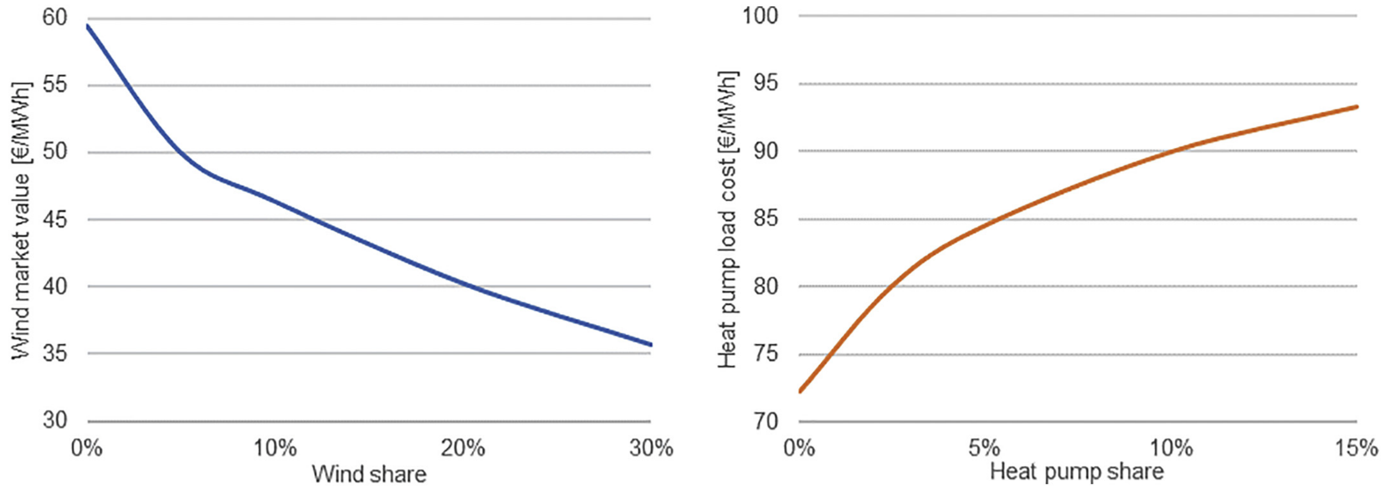

Fig. 1. Wind market value decrease without heat pumps (left) and heat pump load cost increase without wind power (right).

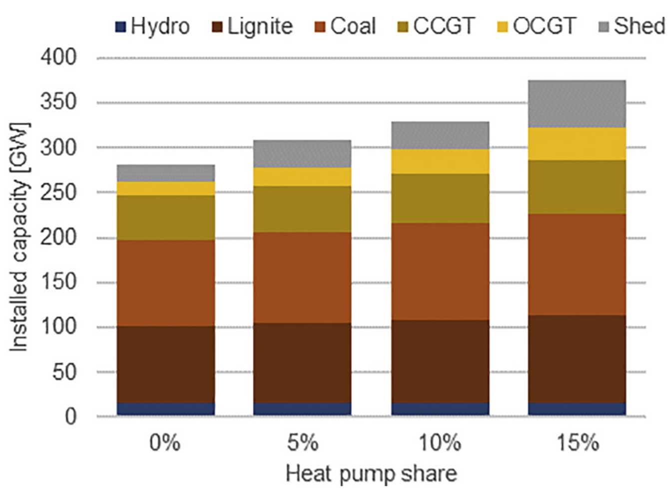

Fig. 2. Installed electricity generation capacity in the overall model region for increasing heat pump shares. CCGT: combined cycle gas turbines; OCGT: open cycle gas turbines; shed: load shedding.

with the decarbonization rationale behind heat electrification. For a better understanding of this, the effect of the absolutely growing wind power is isolated in Fig. 7. When fixing the wind capacity to its levels without extra heat pumps, i.e. exceptionally defining the wind share in relation to the conventional load only, a more pronounced and persistent increase in the wind market value can be observed (2–3 €/MWh or 7%). This leads to the following conclusion: at a constant absolute level of wind power, additional heat pumps raise the wind market value. At the same time, however, more heat pumps need more wind turbines to maintain a certain share of wind in total energy consumption, which in turn reduces the wind market value. At 5–20% wind power, the increase outweighs the reduction. At 30%, the two effects balance out.

3.3. The adoption of system-friendly heat pumps

So far, a business-as-usual mix of heat pumps with different heat sources (air and ground) and different heat sinks (floor and radiators) has been considered. In the two following sensitivity runs, the heat pump configurations are consecutively restricted to ground source systems with different heat sinks and to ground source systems with floor heating only. Both restrictions have a positive effect on the volume and

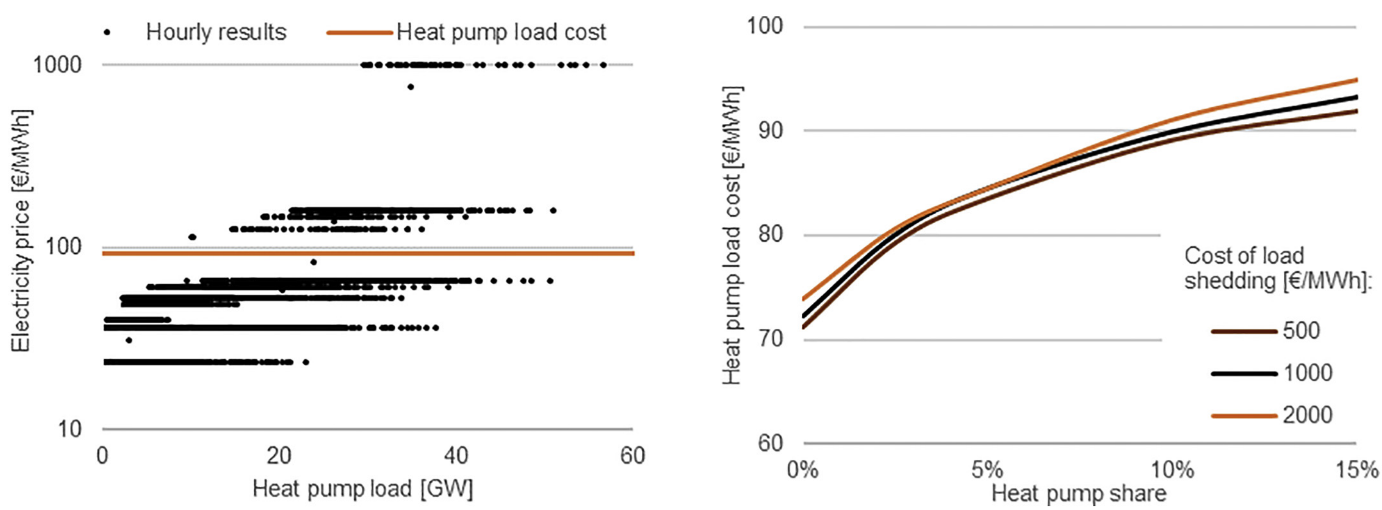

Fig. 3. Hourly model results for the heat pump load and the electricity price in Germany for a 15% heat pump share (left) and heat pump load cost for varying assumptions on the cost of load shedding (right).

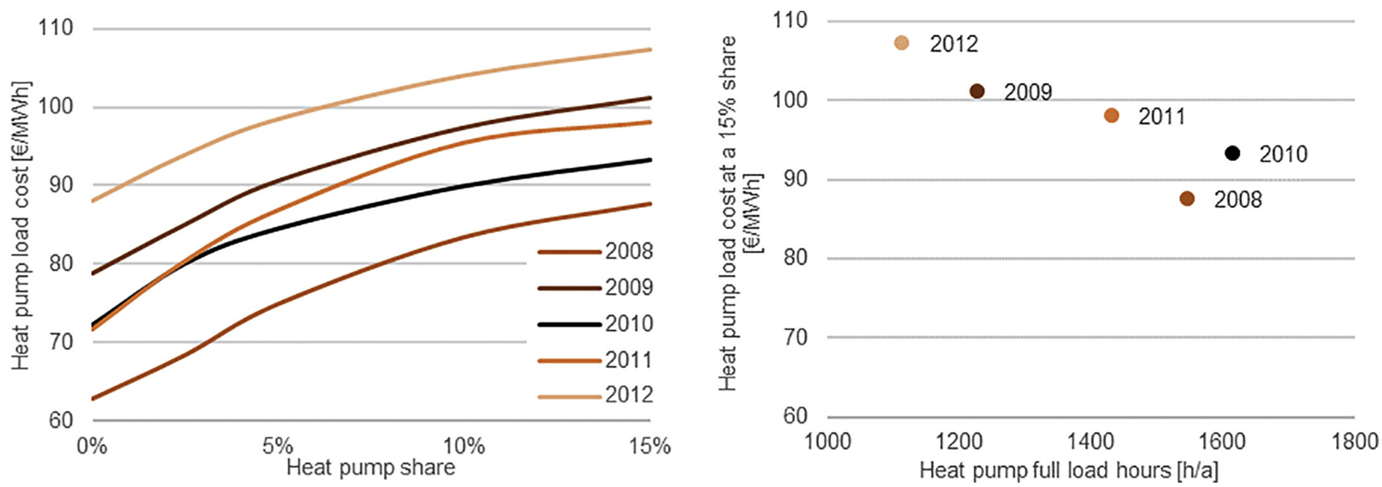

Fig. 4. Weather year sensitivity of the heat pump load cost (left) and its relation to heat pump full load hours (right).

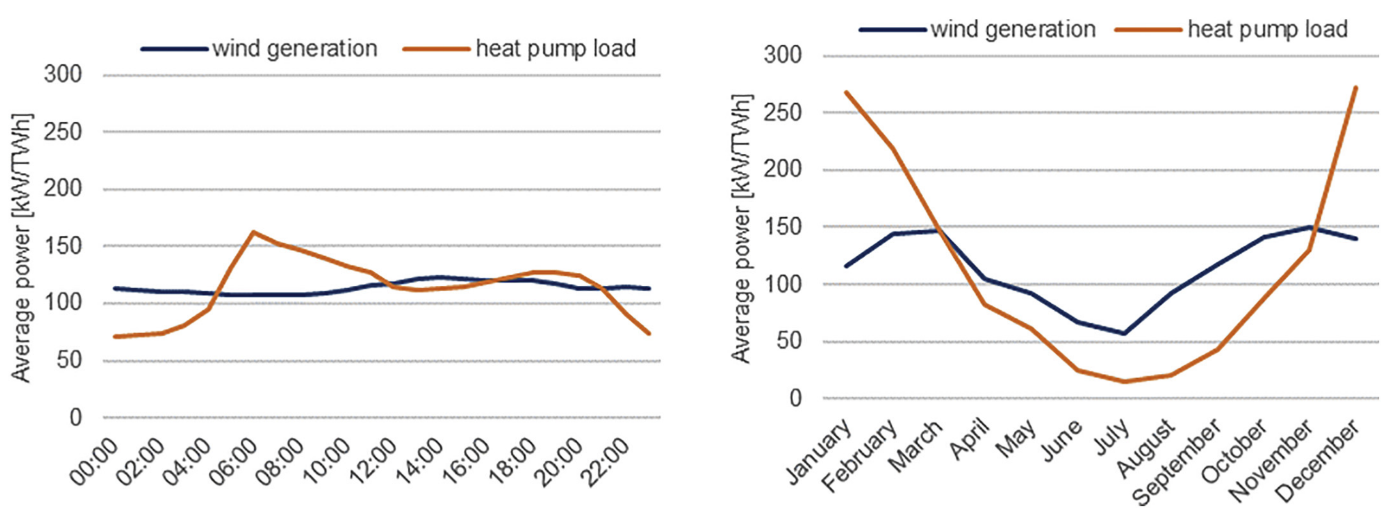

Fig. 5. Diurnal (left) and seasonal (right) pattern of wind generation and heat pump load.

on the profile of the heat pump's electricity consumption: when supplying the same heat demand, the ground source heat pumps consume less electricity with fewer fluctuations than the air source systems, and the heat pumps with floor heating feature smaller and steadier loads than those with radiators.[13]

Fig. 8 translates these positive effects into the load cost of heat pumps. The "mix" curves repeat previous findings, and the technological sensitivity analysis is performed at a wind share of 30%. To capture the profile effect, different technologies can be compared for the same heat pump share, which is defined in terms of the electricity that the heat pumps consume. Apparently, both the restriction to ground source heat pumps and the (additional) restriction to floor heating have positive effects, and these effects increase with the heat pump share. The load cost reductions are higher for floor heating than for ground collectors, reaching a maximum of 3.2 and 1.4 €/MWh, respectively. These results can be explained by the smoother profiles, avoiding high prices and expensive back-up capacity in the electricity system. The additional volume effect can be read from the points depicted for the same heat demand. To supply the heat demand equivalent of a 15% share of mixed heat pumps in the electricity demand, ground- and floor-restricted heat pumps will consume less electricity in absolute terms. This volume corresponds to a 12% and 10% heat pump share, which will reduce the heat pump load cost by another 2.0 and 1.2 €/MWh, respectively. Thus, as compared to the default technology mix, the positive effect of more efficient and less volatile heat pumps with ground source and floor heating add up to 8 €/MWh. By analogy with advanced wind turbines featuring steadier output and higher market values (Hirth and Müller, 2016), heat pumps with ground source and floor sink can be referred to as "system-friendly". Although this system-friendliness of heat pumps reduces their load cost, we find no significant implications for the wind market value.

To illustrate the significance of these results, we compare the savings in terms of load cost to the investment cost of air and ground source heat pumps for an exemplary single-family house with 10 MWh/a annual and 5 kW peak thermal demand. The air source heat pump will consume about 3.2 MWh/a electricity, and its annualized investment cost is approximately 370 €/a.[14] A ground source heat pump consumes about 2.4 MWh/a electricity which saves 82 €/a in load cost, mostly due

[13] The electricity consumption of the heat pumps is inversely proportional to the COP of the heat pumps (Eq. (4)), which in turn depends on the temperature difference between the heat source and sink – the smaller the difference, the higher the COP. As compared to air and radiators, soil and floor temperatures are less volatile, and their difference is smaller.

[14] Assuming 784 €/kW investment cost (De Vita et al., 2018), 20 years lifetime, and a 7% discount rate.

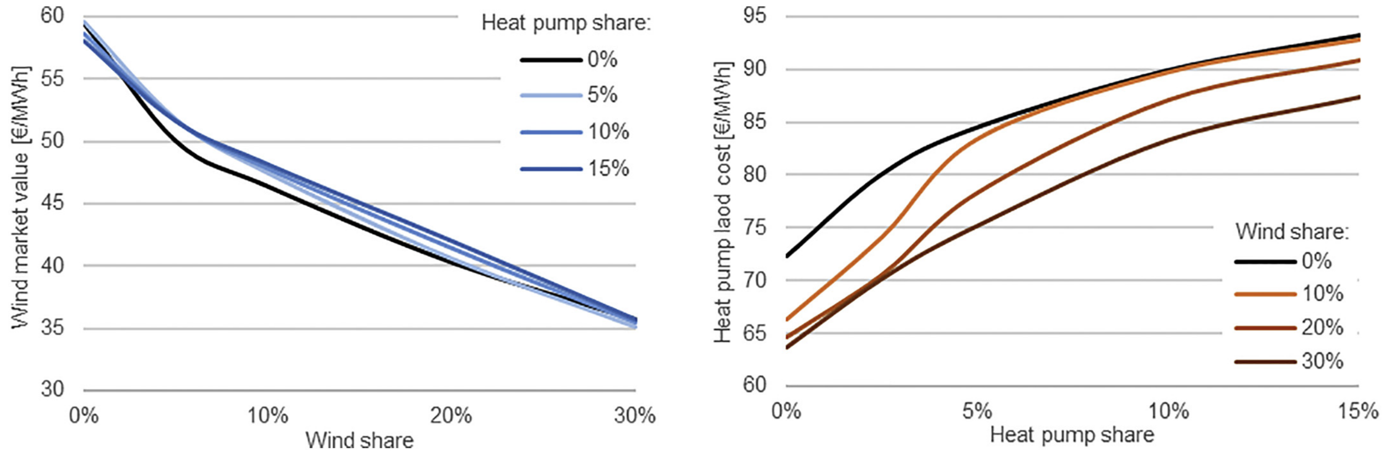

Fig. 6. Wind market values (left) and heat pump load cost (right) at different combinations of wind power and heat pumps.

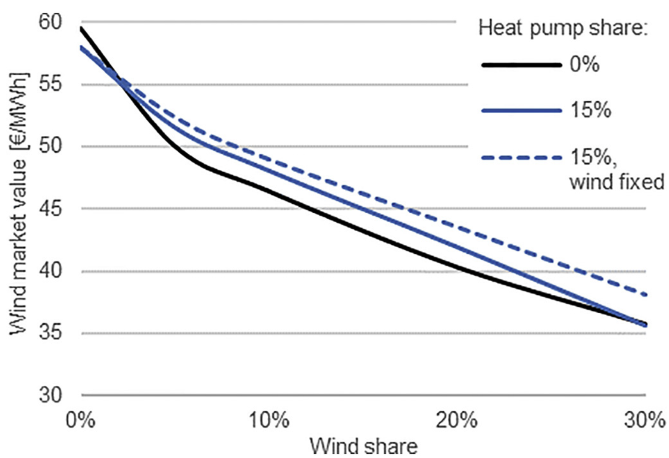

Fig. 7. Wind market values for the adoption of heat pumps, with a sensitivity run where the wind capacity does not grow with the increasing heat pump electricity consumption but is fixed to no-heat-pump levels (i.e. the wind share is exceptionally defined in relation to the conventional load, not total load, for the "wind fixed" scenario).

to the higher efficiency (74 €/a) and less due to reduced load cost per MWh (8 €/a). The average annualized investment cost of a ground source heat pump is about 489 €/a,[15] which is 119 €/a higher than for the air source type and outweighs the 82 €/a reduction in load cost. However, the costs of individual projects may differ from these average values. In addition, grid costs and other mark-ups on the wholesale electricity price amplify the reduction in load cost of ground source heat pumps from a retail-price perspective. As a result, ground source heat pumps are sometimes preferred over air source heat pumps already today (Table 2). With higher heat pump shares and increasing heat pump load cost, the role of ground source heat pumps may hence increase relative to this status quo.

3.4. The flexibilization of heat pumps with thermal storage

In the preceding analyses, the heat pumps were constrained to strictly follow the heat load, as defined by the exogenous input time series. The storage capacity in the model was set to zero. In the following, the heat pumps with ground source and floor sink are equipped with thermal storage to enable their flexible, price-responsive operation.

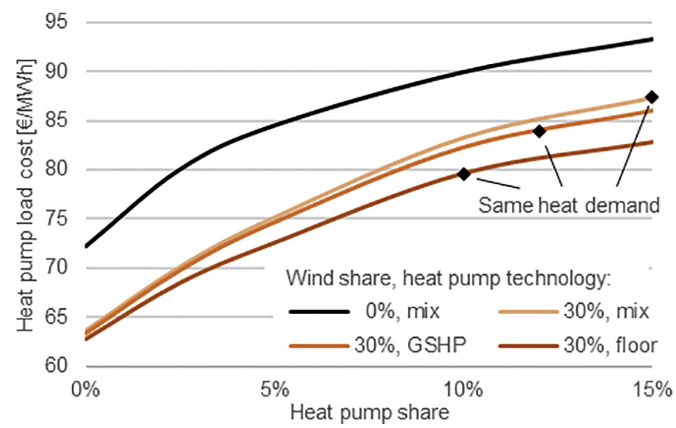

Fig. 8. Heat pump cost increase for different heat pump technologies. Mix: diverse heat sources and sinks; GSHP: ground source heat pumps with diverse heat sinks; floor: ground source heat pumps with floor heating only.

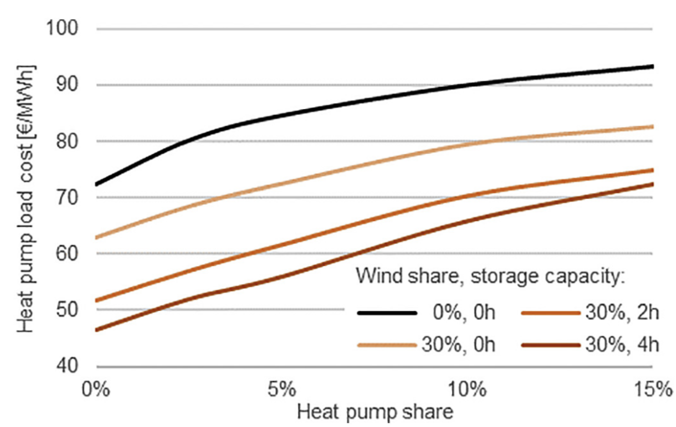

Fig. 9. The impact of heat pump flexibilization with thermal storage on the heat pump load cost.

Hence, the impacts of such heat pump "flexibilization" is assessed in addition to the impact of system-friendly heat pump technology.

Fig. 9 compares the heat pump load cost for a 30% wind share in combination with different heat pump shares and thermal storage capacities (zero, two, and four hours of the national peak heat load). The heat pump cost without wind power is also displayed to serve as a

[15] Assuming 1036 €/kW investment cost (De Vita et al., 2018), 20 years lifetime, and a 7% discount rate.

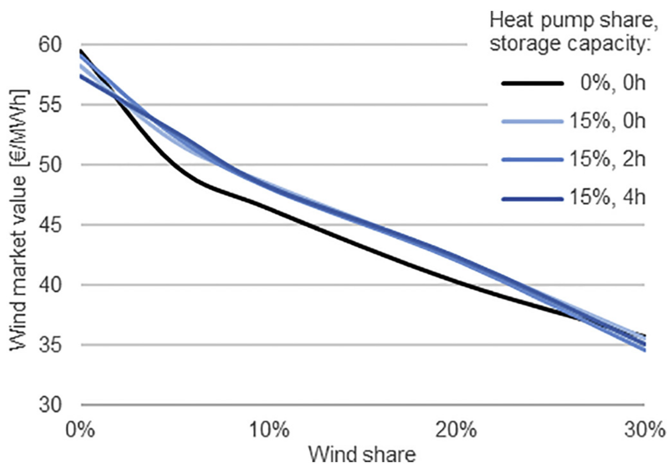

Fig. 10. The impact of heat pump flexibilization with thermal storage on the wind market value.

benchmark. The results reveal significant benefits from thermal storage for heat pumps. With a four-hour storage capacity, the heat pump cost is reduced by 16 €/MWh (26%) and by 10 €/MWh (12%) at low and high heat pump shares, respectively. At the same time, the total electricity consumption of heat pumps grows by 1–3% because of higher storage losses (implicitly including lower heat pump efficiencies) and increased usage of back-up heaters. When compared to the two-hour storage, the marginal benefit of increasing from two to four hours storage capacity decreases. Note that, even though the load cost of heat pumps still rises with their market share, it now partly falls below the cost of the conventional load, which is around 65 €/MWh. The reductions in the heat pump load cost can be easily traced back to the target of optimized storage dispatch, that is, to shift the electricity consumption for heating from times with high prices to those with lower prices. Note that the incremental value of storage is lower at higher heat pump shares than at lower heat pump shares. This can be explained by the strong seasonal pattern of the heat pump load (Fig. 5), while the thermal storage considered here can shift heat only for some hours because of the limited storage capacity (up to four hours per peak load) and because of static losses (1% per hour). The more the heat pump load drives electricity prices, the more the seasonal variability of prices increases and the diurnal variability decreases. This reduces the benefit of short-term thermal storage.

For perspective, we compare this reduction in the heat pump load cost to the investment cost of thermal storage, reconsidering the exemplary single-family house with 10 MWh/a annual and 5 kW peak thermal demand (Subsection 3.3). An active thermal storage of two hours corresponds to a hot water tank with about 500 l. The investment cost of such a tank is about 85 €/a,[16] which exceeds the savings of 19–35 €/a. There are, however, economical alternatives to installing a new hot water tank: most heating systems already include an active thermal storage as a buffer for space heating, water heating, or both. To enable flexible heat pump operation, this existing storage may be used as is, or a larger storage size may be chosen at small additional cost (26 €/a[17]). In addition, passive thermal storage in the building structure can be an economically attractive option: the potential is about two to four hours of peak load (Sperber et al., 2020) and the investment cost of electric thermostats, which are a prerequisite for passive thermal storage, is about 29 €/a[18] – if electric thermostats are not already included in modern buildings.

Fig. 10 focuses on the wind market value at a 15% heat pump share in combination with variously sized thermal storage. Apparently, the introduction of thermal storage has no significant or even negative implications for the wind market value. At 30% of wind power, its value *decreases* by up to 1 €/MWh. These results are counterintuitive against the background of previous studies finding that adding flexibility to the electricity system supports the integration of wind power.

With the aim to resolve this apparent contradiction, Fig. 11 evaluates the different scenarios in terms of wind power curtailment and the installed capacity of other flexibility options, namely interconnectors and pumped hydro storage. Focusing first on the 20% wind share, it can be observed that curtailment is indeed reduced when introducing thermal storage. Thus, flexible heat pumps shift their load towards hours with excess wind production. The fact that this does not affect the wind market value may have the following reasons: (1) the shifting may not always affect prices, for instance, it could be less than the amount of otherwise curtailed electricity that is shifted such that prices remain zero, and (2) the positive wind value effect of increased prices in times of increased heat pump consumption could be compensated for by the negative effect of decreased prices in times of reduced heat pump consumption. However, turning to the 30% wind share, Fig. 11 reveals that thermal storage does not generally reduce wind curtailment. In fact, it reduces the optimal capacity of interconnectors and pumped hydro storage. This can be explained by the volatility of electricity prices: as with other flexibility options, thermal storage tends to reduce price volatility, which at the same time, is the driver for investing in flexibility. Only if spatial and temporal price differences are high enough, will interconnectors and pumped hydro storage be competitive. At 30% of wind power, the pronounced reduction of these flexibility options has a negative effect on the wind market value which outweighs the positive effect of thermal storage, as apparent from Fig. 10.

To substantiate this finding, Fig. 12 isolates the positive effect of additional thermal storage from the negative effect of declining pumped hydro storage. The dashed line represents a sensitivity run at 15% heat pumps with four-hour thermal storage where the pumped hydro capacity is fixed to the level without thermal storage. Indeed, thermal storage provides an incremental wind value benefit of around 1 €/MWh at 30% wind power. Note that the exogenously defined amount of pumped hydro storage is not cost-effective in this long-term sensitivity run. In the short and medium term, however, the investment costs of existing pumped hydro power are sunk, and a combination with thermal storage is conceivable. In this case, wind power will benefit from the additional flexibility.

4. Discussion and limitations

This study finds that, just as the marginal value of electricity from wind turbines drops with an increasing market share, the marginal cost of electricity for heat pumps rises with their adoption. Numerical estimates suggest a cost increase of 21 €/MWh (29%) when introducing heat pumps with 15% of total electricity consumption. Put differently, the more heat pumps there are, the higher the long-term costs to serve their load. This finding is related to an increasing need for dispatchable back-up capacity, which is in line with previous studies (Baeten et al., 2017; Cooper et al., 2016; Fehrenbach et al., 2014; Hedegaard and Münster, 2013; Patteeuw et al., 2015; Quiggin and Buswell, 2016). Wind power can attenuate the rise in heat pump cost by around 6 €/MWh (all numbers at 15% heat pump market share), which may be taken as evidence for the complementary nature of heat pumps and wind power. Heat pumps with ground source and floor sink, which consume electricity more steadily than those with air source or radiator sink, can reduce load cost by another 8 €/MWh. This confirms the findings of Patteeuw et al. (2015) and leads us to apply the term "system-friendly" to this heat pump technology. Such technology reduces challenges and costs in the overall electricity system. As expected from the existing literature (Arteconi et al., 2016;

[16] Assuming investment costs of 1138 € for a 500 l water tank (Hedegaard et al., 2012), 40 years lifetime, and 7% discount rate.

[17] Assuming additional investment costs of 347 € for a 1000 l water tank as compared to a 500 l tank (Hedegaard et al., 2012), 40 years lifetime, and 7% discount rate.

[18] Assuming investment costs of 265 € (Hedegaard et al., 2012), 15 years lifetime, and 7% discount rate.

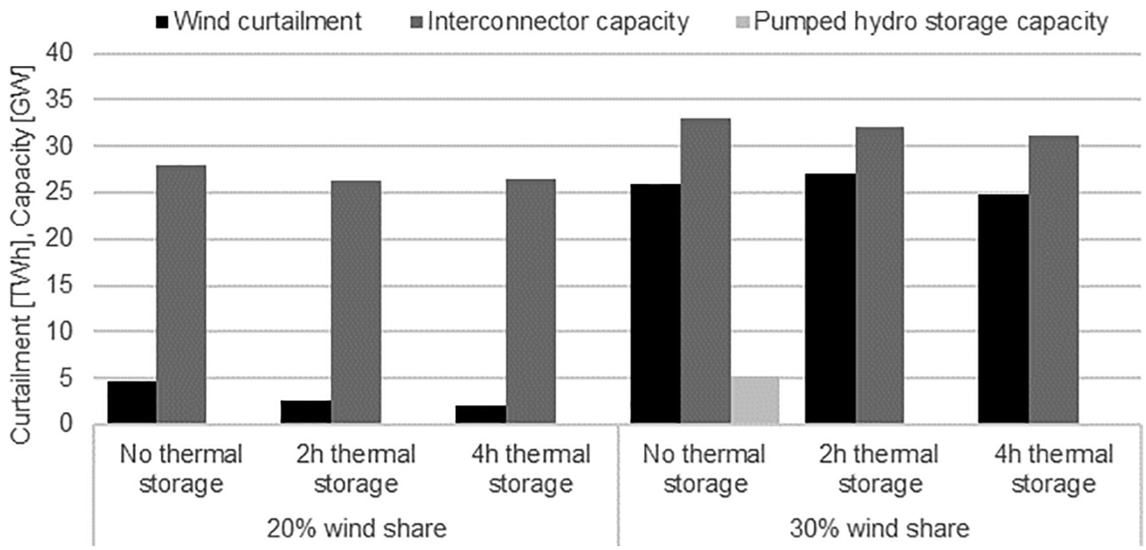

Fig. 11. Wind power curtailment and endogenous deployment of flexibility options for different levels of thermal storage and wind power.

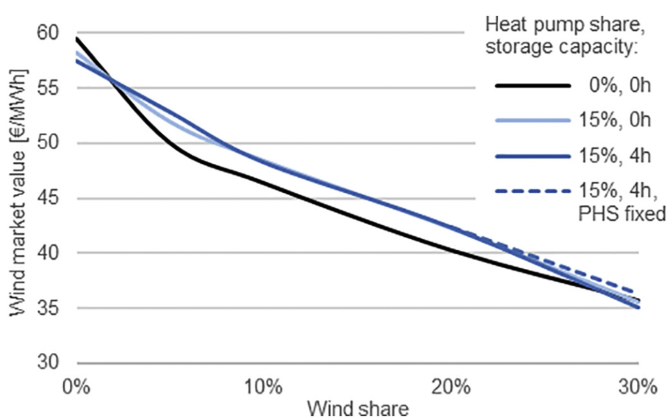

Fig. 12. Wind value decrease with flexible heat pumps and fixed pumped hydro storage (PHS) capacity.

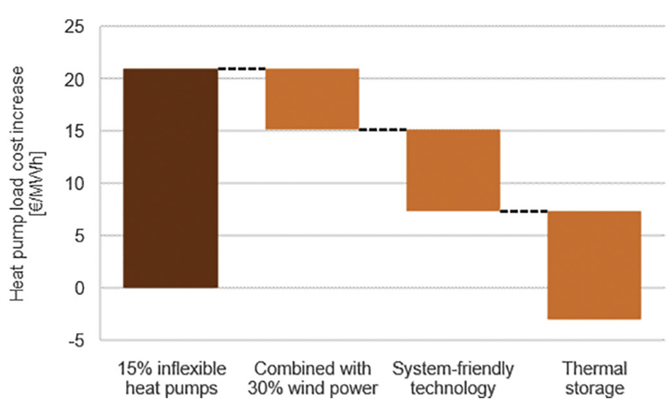

Fig. 13. The heat pump load cost increase and its mitigation options.

Baeten et al., 2017; Cooper et al., 2016; Hedegaard et al., 2012; Hedegaard and Münster, 2013; Heinen et al., 2016; Nabe et al., 2011; Papaefthymiou et al., 2012; Patteeuw et al., 2015; Quiggin and Buswell, 2016; Teng et al., 2016), a flexible heat pump operation using active or passive thermal storage implies further benefits, which is quantified at 10 €/MWh in terms of reduced heat pump load cost. Altogether, as summarized in Fig. 13, the combination of wind power, system-friendly heat pump technology, and thermal storage can overcompensate the heat pump load cost increase.

Furthermore, we show that additional heat pumps have only a minor impact on the market value of wind power. If inflexible heat pumps are adopted at a constant *absolute* level of wind power (fixed GW), the wind value will increase by 2–3 €/MWh or 7%. However, this merely reflects the increase in electricity demand. If instead the *relative* wind level is held constant (fixed percentage), the benefit for wind power diminishes. The flexibilization of heat pumps has similarly limited implications for the wind value. In the long-term equilibrium, thermal storage reduces the profitability and hence the efficient adoption of interconnectors and pumped hydro storage. Only if such a market-based substitution for other flexibility is prohibited, will a net benefit for wind power materialize. This contains more general lessons: the electrification of heat and transport is often sought to support the integration of variable renewables, provided these sectors are seasonally correlated or flexibly operated. However, because they also increase overall demand for electricity, the correlation effect is attenuated by the expansion of renewable capacity necessary to keep up with the additional electricity consumption. Moreover, the finding that thermal storage substitutes for interconnectors and pumped hydro storage may be exemplary for the concurring nature of various flexibility options, including battery electric storage (not least in electric vehicles), more flexible residual generation, and alternative demand-side flexibility (e.g., Hirth, 2016b; Mills and Wiser, 2015; Praktiknjo, 2016).

These model results should be interpreted with the assumptions and limitations in mind. In the present study, one key influencing factor is the representation of the heat pump variability, which is co-determined by variations in the building heat demand and the heat pumps' COP. As summarized in Table 3, a large number of the factors influencing this variability were included, but some were not. For example, the thermal load time series from the When2Heat dataset are based on gas standard load profiles, and the replacement of gas heating with heat pumps may slightly change the load profile. Furthermore, changes in building stock and climate are not considered. When buildings are better insulated, the yearly heat demand decreases faster than the maximum demand, and the load volatility in terms of peak per annual volume increases (Harrestrup and Svendsen, 2015). Climate change implies higher average outdoor temperatures, probably leading to a concentration of the thermal load on fewer days.

This study focuses on variable electricity generation from wind turbines and variable consumption from heat pumps. In the real world,

Table 3
Modeling the variability of heat pumps.

	Impacts on the variability considered	Impacts on the variability not considered
Heat demand	Exogenous (When2Heat dataset based on gas standard load profiles): • Temperature-dependence • Location windiness • Diurnal profile (night lowering) • Weekdays for commercial buildings • Actual building stock characteristics (Germany)	• Heat pump particularities (compared to gas heating) • Improved insulation of future buildings • Global warming
COP	Exogenous (When2Heat dataset): • Temperature-dependence • Heat pump technologies (sources and sinks) Endogenous (EMMA): • Back-up heaters • Heat and efficiency losses when shifting thermal load	

further fluctuations will increasingly arise from solar power and electric vehicles. Additional flexibility, including alternative forms of demand side management, could attenuate the heat pump cost increase and the wind value decrease but may also be subject to substitutional effects.

Long-term equilibria are analyzed here to better understand the fundamental economic characteristics of wind turbines and heat pumps and to provide guidance for the distant future. In the short term, however, in the light of the current dynamics of the energy transition and ambitious political targets, decarbonization technologies may rather appear to be economic shocks. The existing generation capacity has been found to further depress the short-term market value of variable renewables (Hirth, 2013). Regarding heat pumps, the load cost can likewise be expected to be lower in the short than in the long run. The positive impact of storage will probably decline as price peaks are less likely to occur.

Furthermore, electricity is valued here under the assumptions of perfect foresight and "copperplate" electricity transmission within countries. In the real world, both wind power and heat pumps will cause balancing costs due to forecasting errors and grid costs. However, heat pumps may also provide balancing services, which would imply balancing revenues (Teng et al., 2016). In the context of grid costs, heat pumps may challenge distribution grids (Protopapadaki and Saelens, 2017), but further synergistic effects with wind power may arise from spatial proximity, as shown by Schaber et al. (2013). In contrast, flexible heat pumps downstream a constrained transmission line cannot help integrate upstream renewable oversupply, but may even further aggravate grid congestion and drive up system costs and carbon emissions.

Real price signals may deviate from the economic value and cost of electricity as estimated in this study. This is less the case for wind farms: fixed feed-in tariffs are replaced by more market-oriented renewable energy policies, such as market premium schemes, contracts for difference, portfolio standards, and power purchase agreements. Therefore, wind farm revenues usually depend on wholesale electricity market prices (capture prices). In contrast, individual heat pumps are typically charged at fixed retail tariffs that do not differentiate between different heat pump technologies and different degrees of flexibility. In Germany, for instance, utilities mostly procure the electricity for heat pump customers based on standard load profiles. In this setting, the cost and benefit of volatility and flexibility are not internalized but socialized across all heat pumps. A more innovative tariff design, such as real-time pricing, would be needed to incentivize the choice of system-friendly heat pump systems and the provision of flexibility (Ruokamo et al., 2019). Moreover, retail prices include taxes, levies, and grid charges. Not only may these mark-ups act as a disadvantage to electric heating as opposed to non-electric options (Barnes and Bhagavathy, 2020), but they also penalize thermal losses, potentially impeding an economically efficient flexible heat pump operation.

5. Conclusions

The market value of wind power and the load cost of heat pumps can be interpreted as indicators for their long-term competitiveness. Wind farms will only be economically viable if their electricity value is above their levelized cost, and heat pumps will only be cost-efficient if their load cost plus investment outperform the total cost of alternative heating technologies. Against this background, this study's findings lead to conclusions regarding the economics of heat pumps and wind power.

Just as previous studies have raised concerns about the future expansion of wind power because of its drop in value, rising heat pump load costs might decelerate or even prevent the continuing adoption of heat pumps. At the same time, we find that the simultaneous expansion of wind power, the choice of system-friendly heat pump technology, and flexible heat pump operation with thermal storage could mitigate this rise in load cost and hence support the competitiveness of heat pumps.

Our finding that heat pumps raise wind market values at fixed wind capacity supports the rationale of *heat* decarbonization through electrification: on a market basis or at a given subsidy level, the increase in the wind market value incentivizes additional wind power investment. Consequently, the load of the additional heat pumps will at least partly be supplied by additional wind power. The small value rise, if any, at constant wind shares yet suggests that heat pumps may not necessarily facilitate *electricity* decarbonization: heat pumps may not incentivize an over-proportionate investment into wind power. Finally, the substitutional effect we find between thermal storage and pumped hydro storage may be exemplary for various flexibility options: they may not simply add up but compete among themselves to supply the increasing flexibility demand of variable renewables.

Adequate price signals are essential for the economically optimal deployment of wind power and heat pumps, including different heat pump technologies and thermal storage. For this reason, we argue that heat pumps should turn away from collective standard load profiles towards individual settlement with smart meters that considers variable wholesale prices.

Further research can be built on this work. Using the example of heat pumps, we introduced the concept of the heat pump load cost, identified the key drivers of this cost, and observed substitution effects between different flexibility options. This framework and analysis could be transferred to other types of variable and flexible load. In the context of energy end-use electrification and sector coupling, additional electricity consumption is expected not only from heat pumps but also from the transport sector. What will be the cost of that new load?

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2020.104967.

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