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Heating with wind: Economics of heat pumps and variable renewables

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Abstract

The electrification of heat is discussed as a promising option to integrate a growing share of variable renewable electricity and to decarbonize heating. Wind power potentially benefits from the positive seasonal correlation with heat demand and from thermal storages providing low-cost flexibility. However, intrinsic fluctuations in electric heating may also challenge the power system. This study assesses the impacts of building heat pumps on the economics of wind energy, and vice versa. Using a numerical electricity market model, we estimate the marginal economic value of wind energy and its counterpart, the marginal cost of heat pump load. We find that, just as increasing the wind energy market share depresses its market value, the diffusion of heat pumps implies a rise in their load cost. This rise can be mitigated by synergistic effects with wind power, “system-friendly” heat pump technology, and thermal storage. Additional heat pumps raise the wind value, but this effect vanishes as additional wind energy is needed to serve their load. Thermal storage facilitates wind integration but competes with other flexibility options. We argue that efficient heat pump tariffs should reflect the economic cost of their load.

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1 Introduction

Previous studies describe the decline in the electricity market value of wind and solar energy. The more these variable renewable energy sources (VRE) are introduced into the market, the more prices decline in times of high availability of these sources, and the lower is the average value of that electricity (e.g., Gowrisankaran et al., 2016; Grubb, 1991; Hirth, 2013; Joskow, 2011; Mills and Wiser, 2012). This value drop can be quite pronounced. For example, Hirth (2013) estimates that the value of wind power decreases to 50–80% of the base price at a 30% market share. This value drop challenges the competitiveness of VRE and their planned expansion: without subsidies, a rational investor will install new wind turbines and solar panels only if the market value of their electricity generation exceeds their levelized cost. Thus, the decreasing market value of VRE limits their economically efficient market share. If the penetration is increased beyond that share, the value drop will define the increasingly necessary subsidy for wind and solar power, leading to extra societal cost. In the end, the falling economic value can be related to rising “integration costs” for variable renewables (Hirth et al., 2015).

At the same time, electric heating is expected to play a major role in future clean energy systems (e.g. Barton et al., 2013; Connolly, 2017; Jacobson et al., 2017; Ruhnau et al., 2019a). This expectation is driven by decarbonization targets: electric heating can use the increasing renewable electricity and substitute for fossil-fueled alternatives (e.g., Barton et al., 2013; Connolly, 2017; Jacobson et al., 2017; Ruhnau et al., 2019a). This expectation is driven by decarbonization targets: electric heating can substitute for fossil-fueled alternatives, using increasingly renewable electricity. For example, Ruhnau et al. (2019a) review decarbonization scenarios for Germany 2050 and find that 40–80% of the building heat demand will be served by electric heat pumps (including electric back-up heaters), thereby increasing the overall electricity demand by 10–30%. Like wind power, heat pumps feature their own, potentially challenging, volatility. Their electricity consumption depends on the heat demand and their efficiency, both of which vary over time as a function of the ambient temperature. These fluctuations may impose additional challenges on the electricity system (e.g., Quiggin and Buswell, 2016; Wilson et al., 2013).

Growing VRE and additional heat pumps interact with each other in the electricity system. A positive seasonal correlation between heat demand and wind availability appears promising for both. Furthermore, as a specific type of demand response, heat pumps with thermal storage could provide flexibility to the electricity system by shifting their load towards times with low prices and high availability of renewables. As earlier studies demonstrate, such flexibility options not only support variable renewables but also become more attractive as the penetration of variable technologies, and

Note that this effect is different from 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).
hence the need for flexibility, continues to grow (International Energy Agency, 2014; Mills and Wiser, 2014, 2015). The positive seasonal correlation between heat demand and wind availability, together with the flexibility in heat pump options, potentially increases the economic value of wind energy. Adverse seasonal patterns of heat and solar, however, give less reason to expect benefits for solar power.

This study analyzes the electricity system implications of individual heat pumps in the building sector\(^2\) and potential synergy with wind power. An economic framework is applied from two perspectives. First, the impact of heat pumps on variable renewables is investigated in terms of the wind market value, which is defined here as the marginal value of an additional MWh of temporally varying wind generation to the electricity system. Second, the economics of heat pumps, and the impact of wind power on them, are assessed in terms of the heat pump load cost, which is introduced here as the marginal electricity system cost of covering an additional MWh of the heat pumps’ fluctuating electricity consumption\(^3\). To capture the different degrees of heat pump variability and flexibility, the adoption of different inflexible heat pump types and their flexibilization through thermal storages are considered.

In short, we address the following research questions:

1. How does the heat pump load cost evolve with an increasing heat pump share?
2. What is the impact of heat pumps on the market value of wind power, and vice versa?
3. What is the impact of heat pump technology and thermal storage on the wind value and the heat pump load cost?

The value of electricity is estimated for several interconnected European countries by using the open-source Electricity Market Model EMMA, which has been developed for estimating VRE market values (Hirth, 2016a). To address our research questions, we introduce into the model a suitable representation of individual building heat pumps that provide space and water heating. Particular attention is paid to the variability and flexibility of the heat pumps by using the demand and efficiency (COP) time series from the When2Heat dataset (Ruhnau, 2019; Ruhnau et al., 2019b) and by considering back-up heaters as well as thermal storage in the model. Focusing on a fundamental economic understanding of the heat-wind interplay in the electricity market, we exogenously vary the shares of wind power and heat pumps and endogenously optimize all other investment and dispatch decisions on a “green field”. Short- and medium-term developments may deviate from this long-term perspective, as we discuss afterwards.

This paper connects and contributes to the fields of wind power integration, heat electrification, and the interaction of the two. On the one hand, we complement the literature on wind market value by

\(^2\) We focus on decentralized heating for space and water heating in buildings and do not consider heat pumps or power-to-heat in centralized district heating systems or for industrial applications.

\(^3\) Note that our definition of the heat pump load cost reflects the competitiveness of the heat pumps, as opposed to the recently proposed concept of “Levelized Cost of Consumed Load”, which values electricity generation (Durmaz and Pommeret, 2020).
estimating the impact of heat electrification and thermal storage. On the other hand, we are – to the best of our knowledge – the first to introduce the concept of the heat pump load cost and to show that unfavorable changes in marginal economics, which are known to decrease VRE values, are also prevalent in increasing the load cost of heat pumps. Looking beyond electric heat pumps, this framework may also be useful for evaluating other increasing loads, such as with electric vehicles. In this context, our numerous sensitivity analyses with respect to wind and heat pump penetration, as well as heat pump volatility and flexibility, contribute to a more comprehensive economic understanding of heat-wind interactions. On this basis, we discuss more generally the substitutional effects among flexibility options and the efficiency of heat pump retail pricing.

The remainder of this paper proceeds as follows. Section 2 gathers and structures the insights of existing studies in the field. Section 3 describes the assessment and modeling methodology applied. Section 4 presents the results in terms of market values and load costs. Section 5 discusses the results and section 6 draws conclusions regarding the competitiveness of heat pumps and wind power.

2 Literature review

From the literature on the impact of building heat pumps on the electricity system, we identify two somewhat opposing lines of argument. A number of authors argue that heat pumps facilitate the integration of VRE, particularly of wind energy (Arteconi et al., 2016; Fehrenbach et al., 2014; Hedegaard et al., 2012; Hedegaard and Münster, 2013; Heinen et al., 2016; Kirkerud et al., 2014; Nabe et al., 2011; Papaefthymiou et al., 2012; Patteeuw et al., 2015; Schaber et al., 2013; Teng et al., 2016; Waite and Modi, 2014). In contrast, several studies identify the challenges of having additional heat pumps, namely an increased peak load and the corresponding need for more dispatchable capacity (Baeten et al., 2017; Cooper et al., 2016; Quiggin and Buswell, 2016; Wilson et al., 2013). In the following, we provide an overview of both arguments and link them to our economic perspective on wind value and load cost. For a more general review of the power-to-heat literature, the reader may refer to Bloess et al. (2018).

While our study evaluates wind market values and heat pump load cost, these metrics are hardly used in the existing literature. One notable exception is Kirkerud et al. (2014), who provide an initial insight into the implications of electric heating for wind market values. In the Norwegian context, their results are highly sensitive to the availability of hydro power. In case of high inflow to the hydro reservoirs, flexible electric boilers in district heating stabilize low wind market values. For a low inflow, inflexible electric building heaters and heat pumps further increase the already high wind values. Note that, in contrast to our green-field analysis, Kirkerud et al. (2014) exogenously fix the power system capacity to the 2012 status quo.
Most of the studies use specific measures to quantify VRE integration (reduced curtailment or endogenous capacity expansion) and conventional capacity requirements (peak capacity and capacity utilization). In addition, many studies observe changes in the specific electricity system cost, that is, system cost per MWh electricity\(^4\). These indicators are linked to each other: reduced curtailment, reduced back-up capacity, and increased full load hours of dispatchable power plants all reduce system costs. The electricity system costs may in turn be connected to the heat pump load cost and the wind market value, because a lower market value reflects higher integration costs (Hirth et al., 2015). However, this connection is not conclusive. If the specific electricity system cost decrease, it remains unclear how much of this benefit is allocated to wind power, in the form of decreasing integration costs and increasing market values, or to heat pumps, in the form of decreasing load costs.

Focusing on the flexibility of the heat pumps, three research settings can be distinguished (Figure 1):

1. The adoption of inflexible heat pumps, i.e. a scenario with inflexible heat pumps is compared to a scenario without or with fewer heat pumps.
2. The flexibilization of heat pumps, i.e. a scenario with flexible heat pumps is compared to a scenario with inflexible heat pumps.
3. The adoption of flexible heat pumps, i.e. a scenario with flexible heat pumps is compared to a scenario without or with fewer heat pumps. This setting can be considered the combination of (1) and (2).

Literature findings for these three settings are summarized in Table 1 and discussed in the following paragraphs.

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\(^4\) Note that this study deliberately focuses on a better understanding of electricity system interactions, while many studies report results for integrated energy systems, which cannot always be disaggregated into electricity and heat.
Concerning the system impacts of *adopting inflexible heat pumps*, all relevant studies agree that increasing the number of inflexible heat pumps reduces the curtailment of wind power (Hedegaard et al., 2012; Patteeuw et al., 2015; Waite and Modi, 2014) and increases the need for dispatchable back-up capacity (Baeten et al., 2017; Cooper et al., 2016; Fehrenbach et al., 2014; Hedegaard and Münster, 2013; Patteeuw et al., 2015; Quiggin and Buswell, 2016). As mentioned above, Kirkerud et al. (2014) find that this can raise wind power market values. While decreasing curtailment reduces the electricity system cost, increasing back-up capacity has the opposite effect. Thus, the net effect of inflexible heat pumps on the electricity system cost remains unclear. Furthermore, most studies keep the absolute wind capacity constant when increasing the number of heat pumps. Since the additional heat pumps are not only running during times of wind overproduction, this results in an increasing residual load and a decreasing wind share. Reduced curtailment with increased back-up capacity and wind values are thus not surprising. A notable exception is provided by Waite and Modi (2014), who find that inflexible heat pumps reduce curtailment even when the wind share is kept constant. This can be taken as a positive indication for synergistic effects between wind power and heat pumps.

The insights of the literature into the system implications of *heat pump flexibilization* are unambiguous: wind power curtailment is reduced (Arteconi et al., 2016; Hedegaard et al., 2012; Heinen et al., 2016; Nabe et al., 2011; Papaefthymiou et al., 2012; Patteeuw et al., 2015; Teng et al., 2016), and the need for conventional capacity is also decreased (Arteconi et al., 2016; Baeten et al., 2017; Cooper et al., 2016; 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). Both of these effects have an alleviating effect on the total system cost, which is also explicitly confirmed in the literature (Arteconi et al., 2016; Hedegaard and Münster, 2013; Nabe et al., 2011; Papaefthymiou et al., 2012; Patteeuw et al., 2015; Teng et al., 2016). While Heinen et al. (2016) consider hybrid heat pumps with complementary gas boilers, in all the other studies, flexibilization is implemented with thermal storage in the building structure (passive storage) or in buffer tanks (active storage). Thus, by neglecting changes in the losses from the thermal storages and in the efficiency of the heat pumps, the total electricity demand stays roughly the same in these studies. In consequence, not only the system cost but also the *specific* system cost will decrease. Sensitivity analyses find that flexibility benefits are highest for air-source heat pumps with radiators as compared to air-source heat pumps and ground-source heat pumps with floor heating (Patteeuw et al., 2015). Furthermore, Arteconi et al. (2016) find that increasing the number of flexible heat pumps diminishes the marginal flexibility benefit.
<table>
<thead>
<tr>
<th>Study</th>
<th>Source</th>
<th>Geoscope, horizon</th>
<th>Wind share</th>
<th>Wind value</th>
<th>Renewable curtailment</th>
<th>Dispatchable capacity</th>
<th>Flexibilization of heat pumps</th>
<th>Adoption of flexible heat pumps</th>
<th>Adoption of inflexible heat pumps</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nabe et al. 2011 and Papaefthymiou et al. 2012</td>
<td>Germany 2020</td>
<td></td>
<td>21%</td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
</tr>
<tr>
<td></td>
<td>Germany 2030</td>
<td></td>
<td>28%</td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
</tr>
<tr>
<td>Hedegaard et al. 2012</td>
<td>Denmark 2020</td>
<td></td>
<td>50%</td>
<td></td>
<td>Reduced</td>
<td></td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
</tr>
<tr>
<td>Hedegaard and Münster 2013</td>
<td>Denmark 2020</td>
<td></td>
<td>50-60%</td>
<td></td>
<td>Increased</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Increased</td>
</tr>
<tr>
<td>Schaber et al. 2013</td>
<td>Germany 2020/2050</td>
<td></td>
<td>28-39%</td>
<td></td>
<td>Reduced</td>
<td></td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
</tr>
<tr>
<td>Fehrenbach et al. 2014</td>
<td>Germany 2030/2050</td>
<td></td>
<td>various</td>
<td></td>
<td>Increased</td>
<td></td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
</tr>
<tr>
<td>Kirkerud et al. 2014</td>
<td>Norway 2012/2020</td>
<td></td>
<td>unclear</td>
<td></td>
<td>Increased</td>
<td></td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
</tr>
<tr>
<td>Waite and Modi 2014</td>
<td>New York State/City</td>
<td></td>
<td>various</td>
<td></td>
<td>Reduced</td>
<td></td>
<td></td>
<td>Reduced</td>
<td></td>
</tr>
<tr>
<td>Patteeuw et al. 2015</td>
<td>Belgium 2030</td>
<td></td>
<td>30%</td>
<td></td>
<td>Reduced</td>
<td>Increased</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Increased</td>
</tr>
<tr>
<td>Arteconi et al. 2016</td>
<td>Belgium 2030</td>
<td></td>
<td>15-30%</td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
</tr>
<tr>
<td>Cooper et al. 2016</td>
<td>UK 2020-2050</td>
<td></td>
<td>14-33%</td>
<td></td>
<td>Increased</td>
<td></td>
<td></td>
<td>Reduced</td>
<td>Increased</td>
</tr>
<tr>
<td>Heinen et al. 2016</td>
<td>Ireland 2030</td>
<td></td>
<td>40%</td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Increased or unchanged</td>
</tr>
<tr>
<td>Quiggin and Buswell 2016</td>
<td>UK 2050</td>
<td></td>
<td>various</td>
<td></td>
<td>Increased</td>
<td></td>
<td></td>
<td>Reduced</td>
<td>Increased</td>
</tr>
<tr>
<td>Teng et al. 2016</td>
<td>UK 2030-2050</td>
<td></td>
<td>31-54%</td>
<td></td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Reduced</td>
<td>Increased or unchanged</td>
</tr>
<tr>
<td>Baeten et al. 2017</td>
<td>Belgium 2030</td>
<td></td>
<td>Unclear</td>
<td></td>
<td>Increased</td>
<td></td>
<td></td>
<td>Reduced</td>
<td>Increased or unchanged</td>
</tr>
</tbody>
</table>

Table 1: Literature findings on the electricity system implications of building heat pumps (chronological order).
Fewer studies investigate the adoption of flexible heat pumps, finding reduced renewable curtailment (Heinen et al., 2016; Patteeuw et al., 2015; Schaber et al., 2013) and, in some cases, increased back-up requirements (Arteconi et al., 2016; Baeten et al., 2017; Cooper et al., 2016; Hedegaard and Münster, 2013; Heinen et al., 2016; Quiggin and Buswell, 2016). All these studies consider flexibilization with thermal storage, while Schaber et al. (2013) and Heinen et al. (2016) additionally include complementary gas boilers. As argued for the adoption of inflexible heat pumps, both effects are trivial when the renewable capacity is kept constant. However, since the adoption of flexible heat pumps can be considered a superposition of the adoption of inflexible heat pumps and their flexibilization, it is to be expected that the reduction in renewable curtailment will be higher and the dispatchable capacity requirement will be lower for the flexible heat pumps as compared to the inflexible alternative. Nevertheless, the net effect of the advantageous curtailment reduction with the disadvantageous capacity increase on the system cost has yet remained concealed.

Against this background, this paper addresses the following research gaps. First, we aim to quantify the net effect of (beneficial) curtailment reduction and (costly) additional capacity requirement. Second, in contrast to many of the existing studies, we keep the wind share in total electricity consumption constant when analyzing the adoption of heat pumps. As a result, the wind capacity grows as more heat pumps are installed, which we think is in line with the decarbonization rationale behind heat electrification and the policy targets for renewable energy. This allows us to isolate the heat-wind interaction from the mere effect of increasing electric load at a constant wind capacity. Third, we quantify the synergistic effects in terms of the economic value of wind power and the cost of heat pump load. As opposed to curtailment, capacity requirements, and system cost, these metrics allow for direct conclusions to be drawn about the economics of these technologies.

3 Methodology

We analyze the system effects and the interplay of wind turbines and building heat pumps with an extended version of the Electricity Market Model EMMA. More precisely, we exogenously change the penetration of wind power and heat pumps as well as the size of thermal storages. Based on this, we endogenously optimize all other investment and dispatch decisions and calculate the market value of wind power and the load cost of heat pumps. The following subsections discuss the metrics (3.1), the model and its extensions (3.2), and the input parameters to the model (3.3).

3.1 Metrics: penetration rates and economic valuation

Here, penetration rates are defined in terms of yearly electricity. The total electricity consumption is distinguished into the conventional consumption as observed in recent years plus the consumption of
additional building heat pumps. On this basis, the “wind share” and the “heat pump share” are calculated as the percentage of wind electricity generation and heat pump electricity consumption in total consumption, respectively. With these definitions, an increasing heat pump share implies an increase in the total electricity consumption, and eventually, more absolute wind generation is needed to reach the same wind share. This rationale reflects the driver of electric heating: deep decarbonization requires heat electrification to go hand-in-hand with additional renewable electricity generation.

Following Hirth et al. (2015), we define the market value of wind power as the bulk power value minus balancing costs and network costs. In our numerical analysis, we focus on the bulk power value, which we calculate in accordance with Joskow (2011) as the weighted average of the hourly wholesale electricity prices, where the weights are the hourly generation from wind energy:

\[
\text{Wind market value} = \frac{\sum_{t=1}^{T} \text{wind generation}_t \cdot \text{price}_t}{\sum_{t=1}^{T} \text{wind generation}_t}
\]  

(1)

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 revenues, also referred to as capture prices. Recall that balancing and network costs will reduce the wind value if they are internalized.

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

\[
\text{Heat pump load price} = \frac{\sum_{t=1}^{T} \text{heat pump load}_t \cdot \text{price}_t}{\sum_{t=1}^{T} \text{heat pump load}_t}
\]

(2)

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. In contrast to wind farms, building 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. Our numerical analysis focuses on the economic cost perspective, but these issues relating to retail pricing should be borne in mind and will be discussed in section 5. Balancing and network costs will often increase the load cost of heat pumps.

3.2 The Electricity Market Model EMMA with building 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. 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 grid restrictions are considered while the copperplate assumption applies within each country. 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. For a detailed description of the original model, the reader may refer to Hirth (2016a).

Here, EMMA is applied to estimate long-term partial equilibria of the interconnected wholesale electricity markets of five European Countries, Germany, France, Belgium, the Netherlands, and Poland. On the supply side, all electricity generation (except for the exogenously fixed wind power) is optimized on a “green field”. On the demand side, so far, the electricity load has 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 for additional heat pumps is introduced into the model.

**Building heat pumps**

The aim of the model is to analyze different quantities of individual building 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 results in an exogenous change in the electricity demand.

By introducing a building heat balance (Eq. (3)), the heat generation is constrained to fulfil a given heat demand for space and water heating at each time $t$ and in every country $r$. To ensure efficient computability, we do not model individual heat pumps but virtually aggregate them into one large heat pump. Furthermore, only one generic heat pump type is explicitly considered, but this is parametrized so as to represent a national mix of various heat pump types with different heat sources and sinks as described in subsection 3.3. The heat pumps are assumed to be operated bivalently, with complementary electric back-up heaters, but mono-energetically, in other words, no fuels besides electricity are used. The bivalent operation is endogenously modelled, which allows for an explicit investigation of the flexible use of both the actual heat pumps and the back-up heaters. Therefore, two heating technologies $h$ are introduced: the actual heat pump and the back-up heater.

The heat generation of the heat pumps and back-up heaters is linked to their electricity consumption by the conversion efficiencies $e_{t,r,h}$ (Eq. (4)). For the heat pumps, these efficiencies refer to the temporally and spatially varying coefficient of performance (COP). For the back-up heaters, a constant efficiency
is assumed. The resulting additional electricity consumption is added to the conventional load in the 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.

\[
\text{demand}_{t,r}^{\text{heat}} = \sum_h \text{generation}_{t,r,h}^{\text{heat}} + \text{storage}_{t,r}^{\text{heat,out}} - \text{storage}_{t,r}^{\text{heat,in}} \quad \forall t, r \tag{3}
\]

\[
\text{generation}_{t,r,h}^{\text{heat}} = \epsilon_{t,r,h} \cdot \text{consumption}_{t,r,h}^{\text{electricity}} \quad \forall t, r, h \tag{4}
\]

\[
\text{generation}_{t,r,h}^{\text{heat}} \leq \text{capacity}_{t,r,h}^{\text{heat}} \quad \forall t, r, h \tag{5}
\]

The heat generation is restricted by maximum thermal capacities (Eq. (5)). Note that a temporally constant thermal capacity is a simplification, but it does allow for an intuitive parametrization of the national bivalence threshold, that is, the maximum capacity of the actual heat pumps (see subsection 3.3).

**Thermal storage**

Heat storage in buildings is modelled analogously to pumped hydro storage in the original version of EMMA. The inter-temporal storage balance (Eq. (6)) relates the amount of stored thermal energy to the storage level of the preceding hour, considering static losses \(\lambda^{\text{stat}}\) (percent per hour). Storage flows for input and output relate the storage balance to the heat balance, accounting for dynamic storage losses \(\lambda^{\text{dyn}}\) (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 it they can release sufficient energy to satisfy the entire building demand, hence no additional flow constraints are included. Eq. (7) limits the stored heat to the storage capacity in terms of thermal energy. For the sake of computability, only one aggregated, generic thermal storage is explicitly modelled and subsequently parametrized so as to represent both active storage in hot water tanks and passive storage in the building structure.

\[
\text{storage}_{t,r}^{\text{heat,level}} = (1 - \lambda^{\text{stat}}) \cdot \text{storage}_{t-1,r}^{\text{heat,level}} - \text{storage}_{t,r}^{\text{heat,out}} + (1 - \lambda^{\text{dyn}}) \cdot \text{storage}_{t,r}^{\text{heat,in}} \quad \forall t, r \tag{6}
\]

\[
\text{storage}_{t,r}^{\text{heat,level}} \leq \text{storage}_{t,r}^{\text{heat,capacity}} \quad \forall t, r \tag{7}
\]

**3.3 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 CO₂ price (20 €/t) and the discount rate (7 %). The complete input data are included in the supplementary material.
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 are derived from COP and heating curves for 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 penetration rates as described below. For the COP, the profiles for different heat sources and sinks are aggregated into one time series reflecting a mix of various heat pump technologies:

\[
\varepsilon_{t,r,\text{heat pump}} = \text{COP}_{t,r} = \left( \sum_{\text{source,sink}} w_{\text{source}} \cdot w_{\text{sink}} \cdot \text{COP}_{t,r,\text{source,sink}} \right)^{-1} \quad \forall t, r \quad (8)
\]

Table 2 displays the weights of heat sources \(w_{\text{source}}\) and heat sinks \(w_{\text{sink}}\) for three different scenarios. In the base case, a mix of technologies is considered according to statistics from EHPA\(^5\) and EHI\(^6\). 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. The efficiency of back-up heaters is set to unity.

Table 2: Weights of heat sources and sinks in the different scenarios. Mix: diverse heat sources and sinks; GSHP: ground source heat pumps with diverse heat sinks; floor: ground source heat pumps with floor heating only.

<table>
<thead>
<tr>
<th>Heat pump technology</th>
<th>Mix</th>
<th>GSHP</th>
<th>Floor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Belgium</td>
<td>Germany</td>
<td>Netherlands</td>
</tr>
<tr>
<td>Heat source</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Air</td>
<td>0.75</td>
<td>0.71</td>
<td>0.57</td>
</tr>
<tr>
<td>Ground</td>
<td>0.25</td>
<td>0.29</td>
<td>0.43</td>
</tr>
<tr>
<td>Heat sink</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Radiators</td>
<td>0.55</td>
<td>0.4</td>
<td>0.5</td>
</tr>
<tr>
<td>Floor heating</td>
<td>0.45</td>
<td>0.6</td>
<td>0.5</td>
</tr>
</tbody>
</table>

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. Ground source heat pumps are generally designed for monovalent operation, yet they 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

\(^5\) http://stats.ehpa.org/
\(^6\) http://www.ehi.eu/page/surface-heating-and-cooling
source systems are weighted for each country according to Table 2. Note that the oversizing of back-up heaters is only relevant to flexible operation.

**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 2 h, 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 4 h per peak heat load is assumed. This can be achieved through (1) adding active storage capacities, (2) allowing for 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 $\lambda_{dyn}$ and static losses $\lambda_{stat}$ are set to 5% and 1% / h, 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).

**Penetration rates**

By analogy with previous wind value analyses, the wind share is varied between 0% and 30% of the total electricity demand in every region. The total demand includes the average historic demand from 2008–2012 plus the electricity demand of the additional electric building heat pumps, where applicable.

The heat pump share is increased from 0% to 15% of the total regional electricity demand, 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 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 2), 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 would ceteris paribus translate into a 50% heat pump share in heat demand. While this electricity share 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, while the total electricity consumption for flexible operation can differ due to endogenously determined thermal storage losses and increased/decreased back-up heater utilization. Table 3 provides an overview of the absolute electricity demand and heat supply volumes.
Table 3: Electricity demand and heat supply as of today (average of 2008–2012) and in the scenario with a 15% share of additional heat pumps.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Conventional electricity demand</td>
<td>Total building heat supply</td>
</tr>
<tr>
<td>Belgium</td>
<td>90</td>
<td>109</td>
<td>16</td>
</tr>
<tr>
<td>France</td>
<td>495</td>
<td>455</td>
<td>0</td>
</tr>
<tr>
<td>Germany</td>
<td>570</td>
<td>707</td>
<td>101</td>
</tr>
<tr>
<td>Netherlands</td>
<td>117</td>
<td>151</td>
<td>21</td>
</tr>
<tr>
<td>Poland</td>
<td>141</td>
<td>210</td>
<td>25</td>
</tr>
</tbody>
</table>

4 Results

This chapter investigates the separate adoption of wind power and heat pumps (subsection 4.1), the combination of these technologies (4.2), the effects of system-friendly heat pump technology (4.3), and the effects of thermal storages (4.4). Wind market values and heat pump load costs are reported as the volume-weighted average for the different countries included in the model.

4.1 The separate adoption of wind power and inflexible heat pumps

As a benchmark, Figure 2 displays the wind market value for the adoption of wind energy only and the heat pump load cost for the adoption of heat pumps only. The left plot 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 plot 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 constant at 58-60 €/MWh for various wind and heat pump penetrations.7

Both the value drop of wind power and the 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 at this time and hence the average market value of wind power. The more wind energy is introduced into the market, the more pronounced this unfavorable 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 aggravated by the adoption of heat pumps. Just as the value drop is intrinsic and unfavorable to the wind

7 The base price is the (time-weighted) average electricity price. Lamont (2008) show 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, 60 €/MWh is equal to the levelized cost of electricity from lignite power plants, which is continuously dispatched in most of the sensitivities.
power supply, this cost increase is immanent and disadvantageous to the electricity consumption of inflexible heat pumps.

Figure 2: Wind value drop without heat pumps (left) and heat pump cost increase without wind power (right).

To better understand the rise in heat pump cost, Figure 3 provides an insight into changes in the installed capacity of different electricity generation technologies. First, 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%. Note that this includes an increasing portion of the total load being shed at very high prices. Second, apart from the substantial increase in load shedding, capacity additions relate mainly to peak-load power plants, namely to open cycle gas turbines. Third, we find that the full load hours of peak- and mid-load generators decrease 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. In total, these observations indicate a lower utilization rate of the overall power plant fleet, which explains the higher load cost.

Figure 3: Installed electricity generation capacity for increasing heat pump shares. CCGT: combined cycle gas turbines; OCGT: open cycle gas turbines; shed: load shedding.
While the preceding results are based on time series data from 2010, Figure 4 analyzes the weather year sensitivity. While previous studies show that wind market values are robust to changing meteorological years, we find that this does not hold true for the heat pump load cost. Their level varies substantially (up to 25 €/MWh), although a substantial rise in cost occurs across all sensitivities (19–26 €/MWh). The right plot in Figure 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 higher peaks are more costly to serve.

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

4.2 The combination of inflexible heat pumps and wind power

Turning to the interplay between inflexible heat pumps and wind power, Figure 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 heat pump load is more concentrated in fewer winter months. The Pearson correlation coefficient for the hourly wind and heat pump electricity time series is 0.11.

Figure 5: Diurnal (left) and seasonal (right) pattern of wind generation and heat pump load.
Figure 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 penetration rates (almost 10 €/MWh) and decreases with larger heat pump shares, 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, our results are more ambiguous: in the range of 5–20% of wind power, additional heat pumps tend to attenuate the wind value drop by up to 2 €/MWh, but this benefit vanishes when reaching 30% wind power. We scrutinize this counter-intuitive finding on the wind market value in the following paragraph.

![Figure 6: Wind market values (left) and heat pump load cost (right) at different combinations of wind power and heat pumps.](image)

At this point, it is important to recall that we defined the wind share 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 with the decarbonization rationale behind heat electrification. For a better understanding of this, we isolate the effect of the absolutely growing wind power in Figure 7. By fixing the wind capacity to its levels without extra heat pumps, we observe a more pronounced and persistent increase in the wind market value (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.
4.3 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 restricted to ground source systems and to ground source systems with floor heating only. Both restrictions have a positive effect on the volume and 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 heat pumps with floor heating feature smaller and steadier loads than those with radiators⁸.

Figure 8 translates these positive effects into heat pump load cost. The “mix” curves repeat our 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 heat pump cost reductions are higher for floor heating than for ground collectors, reaching a maximum of 3.2 and 1.4 €/MWh, respectively. 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

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⁸ 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.
turbines featuring steadier output and higher market values (Hirth and Müller, 2016), heat pumps with ground source and floor sink could 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.

Figure 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.

4.4 The flexibilization of building heat pumps with thermal storage

Until now, 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, thermal storages are added to the system-friendly heat pumps with ground sources and floor sinks. The impact of this flexibility option is assessed in terms of both the heat pump load cost and the wind value.

Figure 9 compares the heat pump load cost for scenarios with a 30 % wind share in combination with thermal storages of different capacities (zero, two, and four hours of the national peak heat load). As a benchmark, the heat pump cost without wind power is also displayed. 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 storages, 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 as their penetration grows, 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.
Figure 9: The impact of heat pump flexibilization with thermal storages on the heat pump load cost.

Figure 10 focuses on the wind market value at a 15% heat pump share in combination with variously sized storages. Apparently, the introduction of thermal storages 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’ findings that adding flexibility to the electricity system supports the integration of wind power.

Aiming to resolve this apparent contradiction, Figure 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 toward hours with excess wind production. The fact that this does not affect the wind market value can be explained as follows: (1) the shifting may not always affect prices, for instance, it could be only the amount of otherwise curtailed electricity that is shifted, 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, Figure 11 reveals that thermal storages do not generally reduce wind curtailment, but they
do reduce the optimal capacity of interconnectors and pumped hydro storage. The substitution of thermal storages for these flexibility options can be explained by the volatility of electricity prices: as with other flexibility options, thermal storages tend 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 storages be competitive. Apparently, at 30% of wind power, the negative wind value effect from the pronounced reduction of these flexibility options outweighs the positive effect of thermal storages.

![Figure 11: Wind power curtailment and endogenous deployment of flexibility options for different levels of thermal storage and wind power.](image1)

To substantiate this finding, Figure 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 storages provide 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 storages is conceivable. In this case, wind power would benefit from the additional flexibility.

![Figure 12: Wind value drop with flexible heat pumps and fixed pumped hydro storage (PHS) capacity.](image2)
5 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 as their penetration grows. Numerical estimates suggest a cost increase of 21 €/MWh (29%) when introducing heat pumps with 15% of total electricity consumption. We exemplarily relate this finding 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 save another 8 €/MWh. This confirms the findings of Patteeuw et al. (2015) and leads us to introduce the term “system-friendly” heat pump technology. As expected from the existing literature (Arteconi et al., 2016; 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 storages implies further benefits, which we quantify at 10 €/MWh in terms of reduced heat pump load cost. Altogether, as summarized in Figure 13, the combination of wind power, system-friendly heat pump technology, and thermal storages can almost completely mitigate the heat pump cost increase.

Figure 13: The heat pump cost increase and its mitigation options.

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 constant absolute levels of wind power (fixed GW), wind values will increase by 2-3 €/MWh or 7%. However, this merely reflects the increase in electricity demand. If instead the relative wind levels are held constant (fixed percentage), the benefit for wind power diminishes. The flexibilization of heat pumps has similarly limited implications for the wind
value. In our model, thermal storage reduces the profitability and hence the efficient adoption of interconnectors and pumped hydro storage. Only if we prohibit such a market-based substitution for other flexibility, 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, our finding that thermal storages substitute 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 4, a large set of the factors influencing this variability was 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 heaters 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.

<table>
<thead>
<tr>
<th>Impacts on the variability considered</th>
<th>Impacts on the variability not considered</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Heat demand</strong></td>
<td>• Heat pumps particularities (compared to gas heaters)</td>
</tr>
<tr>
<td>Exogenously (When2Heat dataset based on gas standard load profiles):</td>
<td>• Better insulation of future buildings</td>
</tr>
<tr>
<td>• Temperature-dependence</td>
<td>• Global warming</td>
</tr>
<tr>
<td>• Location windiness</td>
<td></td>
</tr>
<tr>
<td>• Diurnal profile (night lowering)</td>
<td></td>
</tr>
<tr>
<td>• Weekdays for commercial buildings</td>
<td></td>
</tr>
<tr>
<td>• Actual building stock characteristics (Germany)</td>
<td></td>
</tr>
<tr>
<td><strong>COP</strong></td>
<td></td>
</tr>
<tr>
<td>Exogenously (When2Heat dataset):</td>
<td></td>
</tr>
<tr>
<td>• Temperature-dependence</td>
<td></td>
</tr>
<tr>
<td>• Heat pump technologies (sources and sinks)</td>
<td></td>
</tr>
<tr>
<td>Endogenously (EMMA):</td>
<td></td>
</tr>
<tr>
<td>• Back-up heaters</td>
<td></td>
</tr>
<tr>
<td>• Heat and efficiency losses when shifting thermal load</td>
<td></td>
</tr>
</tbody>
</table>

Table 4: Modeling the variability of building heat pumps.
This study focuses on variable electricity generation from wind turbines and variable consumption from heat pumps. In the real world, 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 drop but may also be subject to substitutional effects.

We analyze long-term equilibria to better understand the fundamental economic characteristics of wind turbines and heat pumps and to provide guidance for the distant future. In the short run, however, in the light of the current dynamics of the energy transition and ambitious political targets, these 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, which would increase the optimal penetration. The positive impact of storages will probably decline as price peaks are less likely to occur.

Furthermore, electricity is evaluated here under the assumptions of perfect foresight and copperplate transmission within countries. In addition, both wind power and heat pumps will cause balancing costs due to forecast 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).

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: because market premium schemes, contracts for difference, renewable portfolio standards, and power purchase agreements substitute for fixed feed-in tariffs, wind farm revenues usually depend on wholesale electricity market prices (capture prices). In contrast, building heat pumps are typically charged at fixed retail tariffs that do not differentiate between different heat pump technologies and different degrees of flexibility. At least in Germany, 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. Hence, there is no monetary incentive to opt for system-friendly technologies or thermal storages. 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, but they also penalize thermal losses, potentially impeding the economically efficient flexibilization of heat pumps.
6 Conclusions

The 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 economical if their electricity value is above their levelized cost, and heat pumps will only be efficient if their load cost plus investment outperform the total cost of alternative heating technologies. Against this background, our findings lead us to conclusions regarding the economics of heat pumps and wind power.

On the one hand, we find that the load cost of building heat pumps increases as their penetration grows. Just as previous studies have raised concerns about the future expansion of wind power because of its value drop, rising heat pump load costs might decelerate or even prevent the continuing adoption of heat pumps. At the same time, we identify options that could, in total, almost completely mitigate this rise in cost. A higher wind share lowers the heat pump load cost, which can be taken as evidence for synergy between the seasonally correlated wind power generation and heat pump consumption. In addition, ground source heat pumps with floor heating, which feature less volatile electric load, and thermal storages, which enable flexible heat pump operation, can further reduce the heat pump load cost. More generally speaking, the cost of the heat pump load is driven by its volatility and attenuated by its flexibility. However, to draw conclusions about the economic efficiency of such system-friendly technologies, their benefits need to be contrasted with their investment costs (e.g., Felten and Weber, 2018).

On the other hand, we find that heat pumps increase the wind value at fixed wind capacity, but not necessarily at fixed wind shares, implying a growing wind capacity to serve the additional heat pumps. The substantial value rise at constant wind capacities indicate that heat pumps may ease the integration of more wind power in absolute terms, which supports the rationale of heat decarbonization through electrification. The small value rise, if any, at constant wind shares yet suggests that heat pumps may not necessarily facilitate electricity decarbonization. Thermal storages for heat pump flexibilization will increase the wind value if they do not replace endogenous interconnector and pumped hydro storage investment. This substitution effect may be exemplary for various flexibility options. They may not simply add up but may 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 storages. As discussed in section 5, fixed and undifferentiated heat pump tariffs do not incentivize system-friendly investment and operation. Since the volatility and flexibility of their load apparently matters, heat pumps should turn away from collective standard load profiles towards individual settlement with smart meters. Based on real-time pricing, or on tariffs that implicitly consider variable wholesale electricity prices, the heat pump owners
could monetarize the benefits of system-friendly technology and thermal storages. Furthermore, taxation and levies in retail electricity prices may distort the economic equilibrium. For example, if losses due to flexible operation are disproportionally penalized on the demand side as compared to electricity supply and storage, this will lead to a less-than-optimal deployment of demand side flexibility options. In addition, if taxes on different heating fuels vary, the resulting heat pump share will not be efficient.

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?

References


