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AUTHORS

Michael Moritz, Berit Hanna Czock, Oliver Ruhnau

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Institute of Energy Economics at the University of Cologne (EWI)

www.ewi.uni-koeln.de

Institute of Energy Economics
at the University of Cologne (EWI)

Alte Wagenfabrik
Vogelsanger Str. 321a
50827 Köln
Germany

Tel.: +49 (0)221 277 29-100
Fax: +49 (0)221 277 29-400
www.ewi.uni-koeln.de

CORRESPONDING AUTHOR

Michael Moritz
michael.moritz@ewi.uni-koeln.de

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A heated debate - The future cost-efficiency of climate-neutral heating options under consideration of heterogeneity and uncertainty

Michael Moritz[a,*], Berit Hanna Czock[a], Oliver Ruhnau[a,b]

[a] *Institute of Energy Economics (EWI), University of Cologne, Vogelsanger Strasse 321a, 50827 Cologne, Germany.*
[b] *University of Cologne, Faculty of Management, Economics and Social Sciences, Cologne, Germany*

Abstract

To tackle climate change, residential heating must become climate-neutral. Which technology cost-efficiently achieves this goal is a complex question, given the heterogeneity of buildings and existing infrastructure, as well as uncertainty regarding future energy prices and grid fees. This article aims to disentangle this complexity by comparing the future costs of various decentral and central climate-neutral heating options. Using Germany as a case study, we calculate the future levelized costs of major heating technologies for different building and settlement types and a wide range of assumptions for uncertain parameters like energy prices and infrastructure costs. We find that electric heat pumps are economical most often within the modeled range of inputs, deployed either decentrally in rural areas or centrally with heating grids in more urban areas. Hydrogen boilers can also be cost-efficient, mainly in rural areas and scenarios with low hydrogen prices and grid fees or high electricity grid fees. By contrast, heating with synthetic natural gas seems unlikely to be economical across our broad range of plausible input assumptions.

Keywords: Infrastructure costs, Energy prices, Heat pumps, Hydrogen, Decarbonization, Techno-economic analysis, Levelized costs of heating, Residential heating, Building energy

JEL classification: Q40, Q42, Q48, D61, E61

E-mail addresses: michael.moritz@ewi.uni-koeln.de, berit.czock@ewi.uni-koeln.de, oliver.ruhnau@ewi.uni-koeln.de

[*] Corresponding author: Michael Moritz

1. Introduction

Heating homes is one of the major sources of greenhouse gas emissions in regions with cold climates, and little progress has been made on curbing these emissions globally (Cabeza et al., 2022).

In fact, how to achieve climate-neutral residential heating is a complex question. On the one hand, buildings are heterogeneous in size and in terms of their energy efficiency, and settlements differ by heating density (Kotzur et al., 2020; Heitkoetter et al., 2021). On the other hand, there is a variety of climate-neutral heating technologies based on decarbonized electricity or synthetic fuels (Ruhnau et al., 2019), and the possibility to deploy these technologies either decentrally or centrally, connected to heating grids (Jimenez-Navarro et al., 2020). Finally, the future costs of green energy commodities like electricity, hydrogen, or synthetic natural gas (SNG) (Moritz et al., 2023; Liebensteiner et al., 2023) as well as future costs of technologies like heat pumps are uncertain (Chaudry et al., 2015).

The transition toward climate neutrality challenges both homeowners and infrastructure planning. Homeowners are tasked to determine which heating technology is optimal for their building under the uncertainty of future fuel prices and grid fees. For example, electric heat pumps rely on electricity grids, but future electricity grid costs and grid fees are uncertain due to potential reinforcement requirements for increasing peak loads (Pena-Bello et al., 2021). Hydrogen-based technologies rely on a hydrogen grid, with potentially even more uncertain costs as hydrogen grids are virtually nonexistent today (Kopp et al., 2022). Although district heating grids exist in some places today (Pelda et al., 2021), an expansion would also be subject to substantial cost uncertainty. Hence, infrastructure planners also need to determine what combination of heating technology and infrastructure is cost-efficient.

In countries such as Germany and the UK, this complex situation has led to heated public debates on the decarbonization pathways and corresponding regulation of the heating sector (Thomas, 2023; Meakem, 2023). In Germany, where two-thirds of residential buildings are heated with fossil fuels today (c.f. BDEW, 2023), legislators wanted to accelerate the decarbonization of the heating sector by effectively banning the installation of new fossil systems in the short term.[1] After some debate, however, policy makers have acknowledged the uncertainty regarding the available infrastructure and tied the starting date for the ban of fossil boilers to the publication of a municipal heat plan. As a result, each municipality is now tasked to develop detailed plans for future hydrogen and district heating infrastructure until 2028.[2]

To disentangle the complexity behind the question of cost-efficient heating, we calculate the future levelized cost of heating (LCOH) for the example of Germany. We consider a wide range of input assumptions that reflect the heterogeneity of building types, settlement structures, and technology options in great detail. Furthermore, we conduct a variety of sensitivity analyses on uncertain future electricity, hydrogen, and SNG prices, as well as grid fees and technology costs. While uncertainty prevents us from drawing definitive conclusions on the future cost-efficiency of different climate-neutral heating options, our approach enables us to provide insights into the conditions under which the different options would be most economical.

Related literature and research gap

With this paper, we add to a large body of literature that deals with the question of how to decarbonize residential heating. Researchers approach this question at different scopes, ranging from individual buildings over districts to regional or national energy systems. Furthermore, they use a variety of methods, such as technical simulations and optimization models. Table 1 gives an overview of the relevant literature for the example of Germany. While previous studies have covered the important aspects of building heterogeneity, fuel price uncertainty, and infrastructure individually, none of the studies has captured all of them.

First, Kotzur et al. (2020) and Arnold et al. (2024) focus on representing building sector heterogeneity by applying optimization models for individual buildings to large sets of archetype buildings. Kotzur et al. (2020) show that at least 200 archetype buildings are needed to represent building diversity accurately, and Arnold et al. (2024) use even 770 archetype buildings to reflect building heterogenity including the type and age of existing heating systems. Kotzur et al. (2020) neglect

[1] Technically, this was planned to be implemented by a minimum renewable energy requirement of 65% for newly installed heatings.

[2] 2026 for cities with a population >100,000

Publication	Building sector heterogeneity	Infrastructure heterogeneity and uncertainty	Energy price uncertainty	Heat pump cost uncertainty
Kotzur et al. (2020)	✓			
Arnold et al. (2024)	✓		electricity prices only	
Knosala et al. (2022)		indirectly via end consumer price variation	✓	
Lux et al. (2022)		✓		
Kisse et al. (2020)	for one neighbourhood	✓		
Wuppertal-Institut et al. (2020)	✓	ex-post		
EWI (2021)	✓	ex-post		
Fraunhofer ISI et al. (2021)	✓	✓		
Billerbeck et al. (2024)	✓	✓		
Chaudry et al. (2015)			✓	✓
Our analysis	✓	✓	✓	✓

Table 1: Parameters considered in this study compared to other studies

infrastructure costs and fuel price uncertainty. Arnold et al. (2024) perform a sensitivity analysis on electricity prices but keep other energy prices fixed. Second, using a similar individual building model, Knosala et al. (2022) model uncertainty in energy prices. They calculate optimal energy provision over a range of hydrogen and electricity prices. However, their analysis is limited in terms of the consideration of heterogeneity (only 10 different building types) and infrastructure costs (only current grid fees). Third, Lux et al. (2022) and Kisse et al. (2020) focus on the costs of hydrogen transport and electricity distribution infrastructure, respectively. These studies, on the other hand, simplify the heterogeneity of the building stock and neglect future fuel price uncertainty.[3]

Another set of studies considers both, building sector heterogeneity and infrastructure costs (EWI, 2021; Wuppertal-Institut et al., 2020; Fraunhofer ISI et al., 2021). This is typically done through the coupling of different models. For example, EWI (2021) and Wuppertal-Institut et al. (2020) both soft-couple bottom-up models of the German building stock with energy market optimization models to determine a decarbonization pathway for Germany until 2045. However, infrastructure costs for electricity, hydrogen, and methane are quantified ex-post and not considered in the choice of heating

[3]Kisse et al. (2020) do reflect local heterogeneity in case study for a neighbourhood, however their results cannot be generalized for the German building stock.

technologies. By contrast, Fraunhofer ISI et al. (2021) and Billerbeck et al. (2024) endogenize infrastructure costs. Another difference is that Billerbeck et al. (2024) only consider transmission infrastructure costs, while Wuppertal-Institut et al. (2020) and Fraunhofer ISI et al. (2021) also include costs of distribution grids. Across this type of studies, uncertainty is typically neglected (Wuppertal-Institut et al., 2020) or represented only through a small set of scenarios (EWI, 2021; Fraunhofer ISI et al., 2021; Billerbeck et al., 2024). This can be explained by the modeling being computationally too expensive for a more detailed uncertainty analysis. Scenario variation typically concerns the shares of electricity and hydrogen in decarbonization, and none of the studies explicitly focusses on price uncertainty. Chaudry et al. (2015) incorporate fuel price and technology cost uncertainty and calculate levelized costs of decentralized heating in the UK by running a simple individual building model over a range of inputs. However, they do not consider heterogeneous building types.

Despite the differences in methods, most studies conclude that a mix of decentralized heating with heat pumps and district heating is generally the most feasible option for the building sector. Decentralized hydrogen heating is either viewed as an edge-case at very low hydrogen prices or as a backup option, with the exception of EWI (2021), who assume a slower diffusion of heat pumps and the repurposing of gas grids for hydrogen instead. Centralized hydrogen heating more likely plays a role, especially in energy system studies that model combined heat and power (CHP) plants. This finding is not a German particularity but coherent with a review of international studies on residential building decarbonization (Rosenow, 2022).

Given the question of *cost-efficiency* in heating, researchers mostly opt for optimization-based approaches, which are often computationally expensive. Some studies resort to using heuristic searchers instead. In both types of studies, different methods exist to represent the building stock and to model infrastructure. Fuel price uncertainty, if modeled, is usually represented by varying assumptions and comparing a limited number of scenarios. None of the reviewed studies explicitly model uncertainty, for example, in a systematic Monte Carlo or stochastic approach. Ultimately, there seems to be a trade-off between the level of detail in representing building stock heterogeneity, infrastructure cost (especially distribution level), and fuel price uncertainty. Given the

methodological difficulties, a research gap arises with regard to the robustness of existing results on future optimal heating decarbonization against the relevant heterogeneity and uncertainties.
This article makes three contributions to addressing this research gap. First, using the example of Germany, we systematically compile a detailed dataset including future energy prices as well as heating technology by installed capacity and infrastructure costs across settlement types. Second, we combine this dataset with a computationally inexpensive calculation of the LCOH, which allows for capturing both heterogeneity and uncertainty in heating costs. Third, we conduct extensive sensitivity analyses and present the results in a strucutred and easily accessible. Our results can help assess the robustness of previous academic results and provide guidance for ongoing municipal heat planning as well as related public debates.
The remainder of the paper is structured as follows: section 2 introduces the methods and parametrization for the calculation of LCOH and infrastructure costs, section 3 presents the results, which are discussed in section 4, and section 5 concludes on the findings and provides an outlook for further research.

2. Methods and data

In this paper, we investigate the future cost-efficiency of climate-neutral residential heating technologies in terms of their LCOH (see subsection 2.1). Hereby, we consider heterogeneity and uncertainty in the relevant input parameters, which are summarized in Table 2.
Across buildings, heating system costs differ because of variances in equipment prices, installation complexity, and building sizes. Additionally, heat pump equipment costs may decrease in the future due to learning. We describe how we capture the different technologies in subsection 2.2 and derive cost functions in subsection 2.3. Furthermore, buildings are heterogeneous in terms of their building insulation and the size of radiators. This translates to different required supply temperatures, which are relevant for the efficiency of heat pumps, as discussed in subsection 2.4.
Future fuel prices are highly uncertain for many reasons. Hydrogen and SNG prices depend on the equipment costs of renewable energy, electrolyzers, and methanation, all of which are likely to decrease in the future. Furthermore, prices in Germany will likely depend on import costs, which vary by the country of origin and by the import mode, i.e., via ship or pipeline. The uncertainty

Group	Parameter	Heterogeneity	Uncertainty
Buildings and technology	Heating system investment cost	Equipment prices, complexity of installation, building sizes	Cost digression of heat pumps
	Supply temperature	Building insulation, size of radiators	Building refurbishment
Prices	Electricity price		Cost and availability of renewable energy, other demand, hydrogen price
	Hydrogen price		Production cost digression, available import countries and transport modes
	SNG price		Production cost digression, available import countries and transport modes, hydrogen price
Infrastructure	Electricity grid cost	Density of electricity demand and other settlement properties	Increase due to RES integration and new demand peaks, unclear if utilization de- or increases
	Hydrogen grid cost	Density of hydrogen demand and other settlement properties	Share of newly constructed vs. retrofitted pipelines, utilization
	SNG grid cost	Density of SNG demand and other settlement properties	Increase due to decreased utilization
	Heating grid cost	Density of heat demand and other settlement properties	Increase due to decreased utilization

Table 2: Reasons for heterogeneity and uncertainty of investigated parameters

of electricity prices is related to the costs and availability of renewable energy sources in Germany and interconnected countries, to the electricity demand for other applications, and to the hydrogen price which we assume to be used for electricity generation if renewable supply is insufficient. To include fuel price uncertainty, we calculate the LCOH over a range of hydrogen, electricity, and SNG price combinations, which are derived in subsection 2.5.

Infrastructure costs differ among settlement types as settlement-specific characteristics like the spatial distribution, the annual amount, and the peak load of the energy demand shape the costs. We consider four settlement types that differ in terms of building types and heating density (subsection 2.6). Also, infrastructure costs are heterogeneous and have a variance within the same settlement type. Moreover, infrastructure costs depend on uncertain developments in the broader energy system, such as the share of heat pumps or the quantity and allocation of renewables. We present our approach for capturing infrastructure cost heterogeneity and uncertainty in subsection 2.7.

2.1. Levelized cost of heating

The concept of levelized cost of energy is a metric used to compare the cost of generating energy from different sources or technologies. In this metric, the total costs are normalized per unit of output, discounting over the technology's lifetime. Here, we calculate the levelized cost of heat, i.e. the full costs of generating one unit (kWh) of useful heat, for different technologies, using the following equation:

$$
\begin{aligned}
LCOH_{tech,c,d} = & \underbrace{\frac{\overbrace{I_{tech,c}\frac{r(1+r)^t}{(1+r)^t-1}}^{\text{CAPEX}} + \overbrace{FOM_{tech,c}}^{\text{fixed OPEX}}}{flh}}_{\text{fixed costs}} \\
& + \underbrace{\Big(\overbrace{p_{\mathrm{H}_2} r_{tech}}^{\text{energy}} + \overbrace{gc_{tech,d}}^{\text{grid costs}}\Big)\overbrace{\Big(1 + c_{tech}\big(\frac{1}{\eta_{tech,T}} - 1\big)\Big)}^{\text{conversion efficiency}}\overbrace{\frac{1}{1-L_{st}}}^{\text{heat loss}} + \overbrace{hdc_d}^{\text{heat distribution}}}_{\text{variable costs}}
\end{aligned}
\tag{1}
$$

$I_{tech,c}$ are the investment costs of the heating system $tech$ with the capacity c, r is the interest rate, and t is the economical lifetime or depreciation period. $FOM_{tech,c}$ are the fixed costs for operation and maintenance of the heating system $tech$ of the capacity c, and flh are the annual full load hours of the heat generator. We express energy prices as a function of the hydrogen wholesale price

p_{H_2} and the price ratio r_{tech} between hydrogen and the energy carrier used by the heating system $tech$ (see **??**). This energy carrier is either hydrogen, SNG, or electricity. $gc_{tech,d}$ are the grid fees per unit of energy carrier used by the heating system $tech$ in the settlement with the gas or power density d. c_{tech} is the contribution of the primary heat generator to the total heat demand. c_{tech} equals 1 for all technologies except AtW and WtW heat pumps because we assume that they are combined with an electric heater for peak loads. $\eta_{tech,T}$ is the conversion efficiency of the heating system $tech$, including the annual COP of heat pumps, which depends on the supply temperature T. L_{st} are the heat losses of the heating grid in the settlement type st and hdc_d are the heat distribution cost for a settlement with the heat density d. Both, hdc_d and L_{st} equal zero in case of decentral heating. All costs refer to EUR 2023.

Based on Equation 1 we understand LCOH as an approximation of heating costs from a system perspective rather than private costs. Thus, we neglect any price components that affect consumer prices but are merely a monetary transfer, such as taxes and levies on energy prices. Furthermore, we neglect existing heating systems and their costs based on the assumption that they will reach the end of their lifetime before climate-neutrality is reached. By contrast, we implictly consider existing electricity and gas infrastructures, which have longer lifetimes, because we use grid fees to reflect infrastructure costs in the LCOH (see subsection 2.7 below).

2.2. Considered heating systems

We calculate LCOH for 10 different technology set-ups that reflect major decarbonization options that are currently discussed (see Table 3). We consider four technologies which can be used in central and decentral deployment, namely air-to-water (AtW) and water-to-water (WtW) heat pumps as well as hydrogen and SNG boilers, and two additional technologies for decentral deployment only, namely air-to-air (AtA) heat pumps and electric boilers. System flow sheets for all options can be found in Figure A.8. The capacity of the decentral heat generators is designed to provide both heating and hot water, except for air-to-air (AtA) heat pumps, which are combined with an electric boiler for hot water. AtW heat pumps are designed for bivalent monoenergetic operation, i.e., the installed heat pump capacity is kept at a minimum, and peak demands are covered by an electric heater (c.f. Buderus (2019)). For central heating, we consider that the capacity of the central heat generator is smaller than the sum of the peak heat load of all supplied buildings. This reduction of the aggregated peak is called the simultaneity factor. We use a settlement-type specific simultaneity factor taken from AGFW (2001). Finally, we assume that central heating with heat pumps via low-temperature heating grids are complemented with decentral electric heaters for hot water.

Table 3: Technologies and deployment options

Energy carrier	Decentral deployment	Central deployment
Electricity	Air-to-air heat pump Air-to-water heat pump Water-to-water heat pump Electric boiler	Air-to-water heat pump Water-to-water heat pump
Hydrogen	Hydrogen boiler	Hydrogen boiler
SNG	SNG boiler	SNG boiler

2.3. Investment and fixed costs

As an input to the LCOH calculation, we estimate investment costs as a function of installed capacity, including the costs for equipment and installation. For the equipment costs, we collected 472 list prices on the relevant heat generators as well as thermal storage from four large German manufacturers. For the installation costs, we collected 38 data points from two installation firms. Besides the installed capacity, data points vary due to variations in the installed equipment, the time required for installation due to the building heterogeneity, and the heterogeneity of the cost of different installation firms. We fit linear and power functions to the collected data and select the one with the lowest root mean squared error (RMSE) between function and data. To capture the variance in the observed equipment and installation costs, we generate high-cost and low-cost functions by adding and subtracting 1/3 of the RMSE, respectively.

For some cost functions, we were unable to obtain sufficient primary data and base our assumptions on personal communication with manufacturers and installation firms instead. For instance, we assume that hydrogen boilers are 10% more expensive than natural gas boilers. Furthermore, we increase the estimated equipment cost by 50% to account for the contribution margins of installation firms. The fixed operation and maintenance costs are parametrized as a function of the installed capacity. Figure 1 shows the fitted equipment and installation cost functions for the examples of

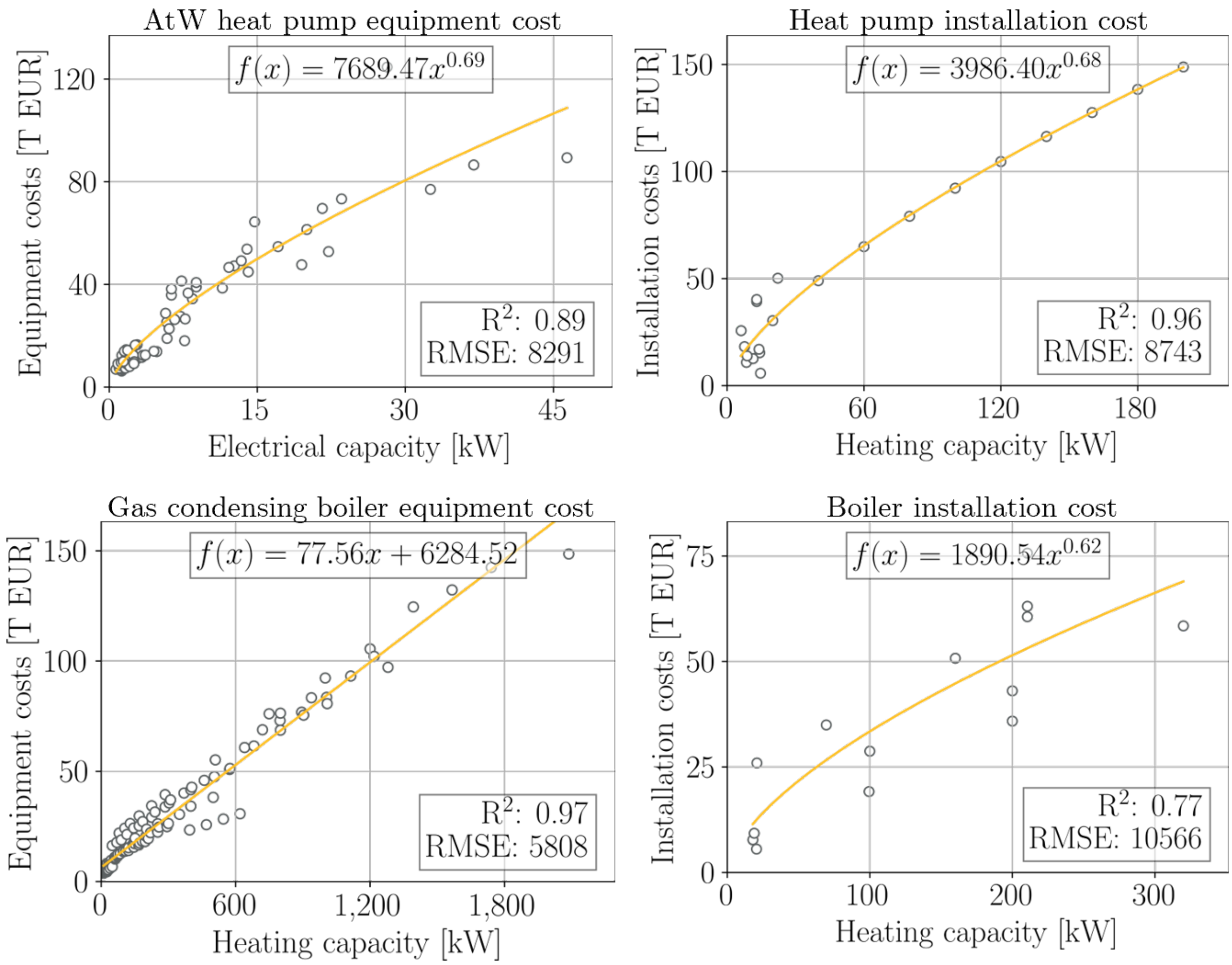

Figure 1: Empirical cost functions for equipment and installation of AtW heat pumps and gas condensing boilers

AtW heat pumps and gas condensing boilers. More details and a visualization of the primary data, as well as the fitted functions for all technology options, are provided in Table B.5 and Figure B.9. As the equipment cost functions are based on historical data, they do not reflect a potential future cost reduction. This is most relevant for heat pumps, which are not as widespread as boilers yet and may benefit from learning effects when deployment increases. The literature reports a wide range of learning rates for heat pumps, with the majority lying between 10 % and 20 % (Heptonstall and Winskel (2023); Henkel (2011); ifeu (2014); Louwen et al. (2018)). To capture the uncertainty in future heat pump costs, we consider cost digressions of up to 75 %. At a learning rate of 20 %, our considered maximum cost digression would require an increase in cumulative deployment of heat pumps of 74 times. Assuming a learning rate of 10 %, an increase of the cumulative production of more than 9,000 times would be necessary.

2.4. Conversion efficiencies

In the context of this paper, we understand supply temperature as the minimal necessary supply temperature to enable sufficient heat transfer from the radiators into the room. The heating system's supply temperature depends on the radiators' heat exchange area and the building's energy efficiency. The higher the area of the radiators, the lower the supply temperature required to transport the same amount of heat into the room. Figure 2 shows temperature ranges in which radiator types typically operate. The better a building is insulated, the more its heat demand decreases. If the heat demand of the building decreases while the area of the radiators remains the same, the supply temperature decreases.

For heat pump systems, we consider the dependency of the annual COP on the supply temperature. The annual COP measures a heat pump's efficiency over an entire year, dividing the annual heat supply by the annual power consumption. It depends on the temporally varying heat source and sink temperatures and heat demands throughout the year. The lower the temperature difference between the heat sink and heat source, the higher the COP. The heat sink represents the supply temperature of the heating system. The heat source is the ambient air temperature in the case of air-source heat pumps and the groundwater temperature in the case of water-source heat pumps. We calculate the annual COP for heat pumps according to the standard VDI 4650 part 1.[4] Detailed explanation of the assumptions can be found in Appendix F.

Figure 2 shows that the annual COP of decentral heat pumps increases linearly with decreasing supply temperature. WtW heat pumps reach the highest annual COPs as the groundwater has a higher temperature than the ambient air during the heating period. The annual COP of central heat pumps is lower than that of decentral heat pumps at the same supply temperature. This is because the heat sink of the central heat pump is the heating grid, whose temperature we assume to be 10 K above the supply temperature of the building's heating system. A temperature difference

[4] This is more precise than the commonly used approach that estimates the COP by $\frac{1}{2}\frac{T_h}{T_h - T_c}$ (c.f. Buderus (2019), where T_c is the heat source temperature and T_h is the heat sink temperature.).

of 10 K is necessary to enable efficient heat exchange between the heating grid and the hydraulically separated heating systems inside the buildings. The slope of the annual COP of central heat pumps decreases for supply temperatures below 60°C because domestic hot water is partially heated via electric boilers with an assumed energy efficiency of 1.

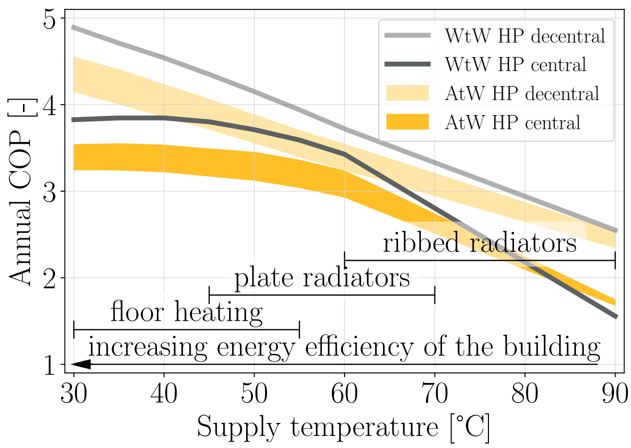

Figure 2: Relationship between the heat pump's annual COP and the heating system's supply temperature according VDI 4650 part 1.

2.5. Future energy prices

We calculate LCOH across a range of hydrogen, SNG, and electricity prices because future energy prices are uncertain. The future price of green hydrogen is uncertain due to potential learning in production costs and uncertainty regarding transport costs and the structure of the hydrogen market that has yet to emerge. We consider a range of possible future hydrogen prices between 50 and 250 EUR/MWh. The upper limit is set by the pessimistic estimate that hydrogen prices will not decrease from today's hydrogen production costs. Hydrogen production costs have a large variance, for instance, BGC (2023) lists costs in the range of 200 EUR/MWh and 315 EUR/MWh. We use the costs of 250 EUR/MWh from EEX (2023) as a moderate estimate for today's prices. The lower limit of price projections for 2050 (Merten and Scholz (2023); Moritz et al. (2023)) is set by 50 EUR/MWh.

SNG is produced from green hydrogen by catalytic methanation, which requires CO_2 capture via direct air capture. Thus, we assume that the SNG price is linked to the hydrogen price. Due to the additional process step of methanation, the production costs of SNG are higher than the production costs of green hydrogen. Contrarily, the transport costs of hydrogen are higher than for SNG due to the lower volumetric energy density of hydrogen. We use import costs from Moritz et al. (2023); EWI (2024b) to calculate the price ratio between SNG and hydrogen. More precisely, for both fuels, we calculate the average costs of imports to Germany of the 15 origin countries with the lowest costs for a wide range of scenarios. In addition to the import costs, we include a markup for storage costs (see Appendix C). Figure 3 shows that the SNG-H_2 price ratio lies between 1.1 and 3.1, meaning that SNG is 1.1 to 3.1 times as expensive as hydrogen. The SNG-hydrogen price ratio is varied in a sensitivity analysis within these boundaries to determine whether it has an impact on which technology is cost-efficient. We assume a baseline ratio $r_{tech} = 1.5$ for technologies using SNG, which is the average ratio in the data.

Furthermore, in a climate-neutral scenario, hydrogen and electricity prices are interdependent. In many scenarios for the future energy system, green electricity is used to produce hydrogen via electrolysis and hydrogen fuels back-up power generation. In the LCOH calculation, we use annual average energy prices and, therefore, simplify this complex dynamic to a fixed price ratio. Figure 3 lists exemplary studies that published both, electricity and hydrogen prices and illustrates the variation in electricity-hydrogen price ratios, which range from 0.7 to 1.15. We define a base case where the electricity-hydrogen ratio r_{tech} is 0.9, which reflects the average over the ratios found in the literature. In a secondary analysis, the electricity-hydrogen price ratio is varied to determine whether this has an impact on which technology is cost-efficient. Due to the few available data points, we add a margin for additional uncertainty and analyze ratios between 0.5 and 1.3.

2.6. Representative settlement types

We investigate rural, village, urban, and city settlements in order to understand the influence of the settlement type on the levelized cost of heating. We refer to the 13 settlement types introduced by AGFW (2001) and select four types representing a wide range of settlements for the following analysis. The rural settlement represents a scattered settlement consisting of detached buildings with larger plots of land, such as those found in small village settlements or on the outskirts of cities. The main purpose of use is residential, and the settlement refers to settlement type 1. The village settlement represents residential areas with detached and semi-detached houses like larger

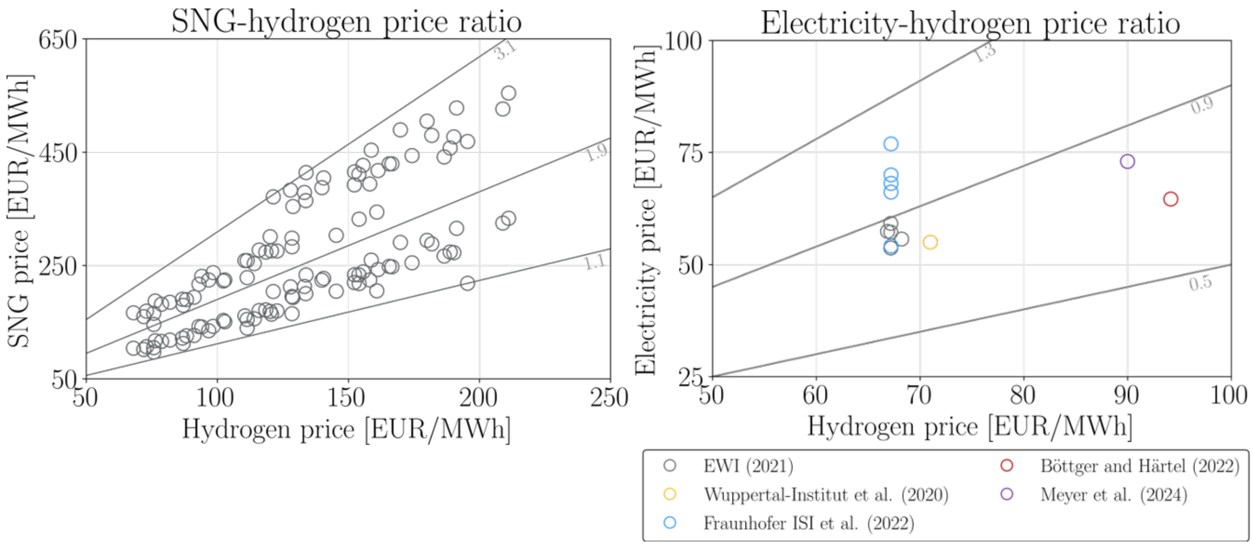

Figure 3: Hydrogen and electricity prices in EWI (2021); Böttger and Härtel (2022); Wuppertal-Institut et al. (2020); Meyer et al. (2024); Fraunhofer ISI et al. (2021) (left) and hydrogen and SNG costs from Moritz et al. (2023); EWI (2024b) (right) and the resulting price ratios

villages or suburban communities consisting of single- and multi-family houses. The main use is residential, and the settlement refers to settlement type 2. The urban settlement represents block development, which is a typical urban building form consisting of large multi-family houses. The typical use of the block development is predominantly residential. The urban settlement refers to settlement type 7b. The city settlement represents the city buildings in the centers of large cities. Similar to urban settlements, the houses in city settlements are arranged in blocks. The buildings tend to be fewer but larger. Typical uses of city buildings are more commercial and less residential. The city settlement refers to settlement type 8.

To enable a comparison between central and decentral heating, we analyze standardized districts with a total heat load of 650 kW, which corresponds to 100 buildings in a rural or village settlement. This heat load can be represented without over-extrapolating our investment cost functions. The heat load of the urban and city settlement is scaled accordingly and is rounded to whole houses, given the heated area per building. Table 4 shows the characteristics of the four representative settlement types.

Table 4: Settlement type characteristics

Settlement type		Rural	Village	Urban	City
Number of buildings	[-]	100	100	19	19
Heated area per building	[m^2]	130	130	680	680
Heated area per household	[m^2]	130	130	92	92
Heat load decentral	[kW]	7	7	34	75
Heat load central	[kW]	650	650	646	650
Simultaneously factor	[-]	0.78	0.74	0.68	0.6
Heat distribution loss	[%]	43^a	18	8	4
Heat density	$[\frac{\text{MWh}}{\text{ha}\cdot\text{yr}}]$	51	280	738	1345
Gas density	$[\frac{\text{MWh}}{\text{ha}\cdot\text{yr}}]$	54	295	777	1416
Electricity density^b	$[\frac{\text{MWh}}{\text{ha}\cdot\text{yr}}]$	33	180	475	865
Heat distribution costs	$[\frac{\text{ct}}{\text{kWh}}]$	11.26^c	3.51	1.80	1.20
Gas grid fees^d	$[\frac{\text{ct}}{\text{kWh}}]$	4.17/2.83	2.48/1.68	1.84/1.25	1.53/1.04
Hydrogen grid fees^d	$[\frac{\text{ct}}{\text{kWh}}]$	6.95/5.72	4.13/3.39	3.07/2.52	2.55/2.10
Electricity grid fees^d	$[\frac{\text{ct}}{\text{kWh}}]$	32.55/25.83	20.66/16.39	15.93/12.64	13.56/10.76

^{a}extrapolated, see Figure E.10 in the appendix, ^{b}the electricity density was approximated based on the heating density given in AGFW (2001) and the historical ratio between energy demands for electricity and heat in 2021 given in AGEB (2022), ^{c}extrapolated, see Figure 4, ^{d}decentral/central

2.7. Grid fees

Our analysis calculates future heating costs, including infrastructure costs, which we approximate via grid fees. Infrastructure costs are heterogenous across Germany. They vary, for example, with local heating densities. Additionally, future infrastructure costs are uncertain because they depend on required grid expansion and on demand, which links them dynamically to future residential heating choices. Finally, the costs of some infrastructures, e.g. of the electricity grid, are influenced by energy system developments that go beyond heating, which adds another layer of uncertainty. We approximate future per kWh infrastructure costs by future grid fees. Today, infrastructure costs are distributed to end customers via grid fees. Thus, we use future grid fees to reflect average infrastructure costs within the LCOH approach.[5]

To derive a baseline assumption for per-kWh grid fees[6] for different settlement types and central (district heating) and decentral (in-building heat generation) distribution cases, we employ a two-step process. First, we use historical infrastructure cost and heating density data that reflect local heterogeneity. Using this data, we estimate cost functions, i.e., a functional relationship between

[5]Note that grid fees do not generally reflect marginal grid costs associated with heating technologies (c.f. Hanny et al., 2022).

[6]In reality, grid fees have fixed and power based components in addition per kWh components. We abstract from this and express grid fees per kWh.

infrastructure costs and heating density. Second, we use estimates of future grid fees for the year 2045 to scale the previously derived cost functions. The estimates of future grid fees are taken from studies which assume that most heating systems use the corresponding infrastructure (e.g., electricity grid fees are estimated for a scenario with a high share of heat pumps). Specifically, we use household grid fees for energy carriers delivered to decentral heating systems and commercial grid fees for delivery to central systems. Heating grid costs are added for the central heating options afterwards. From the scaled cost functions, we derive point estimates for future grid fees in the different settlement types. The cost functions and resulting baseline assumptions are presented in Figure 4. Additionally, we vary grid fees in a sensitivity analysis to reflect heterogeneity within settlement types and additional uncertainties.

In the case of electricity, historical data on local distribution grid costs and corresponding heating densities can be derived from Bundesnetzagentur (2023a). Future electricity grid costs are uncertain and depend on the diffusion and allocation of renewable energy capacity and demand, such as heat pumps. Energy system studies (e.g., EWI (2021), Fraunhofer ISI et al. (2023), Wuppertal-Institut et al. (2020)) and German grid operators (50Hertz Transmission GmbH et al. (2023)) estimate significant investment needs due to renewables and increased peak demands from heat pumps and electric vehicles. However, load flow simulations show that using thermal storage (building inertia (Fischer, 2017) and buffer tanks (D'Ettorre et al., 2019; Steinle et al., 2020)) can reduce the need for heating-related distribution grid expansion and thus cost increases. Additionally, increased demand could lead to lower grid fees, as costs are distributed across a larger base. We derive a baseline assumption for future grid fees based on a recent study estimating infrastructure costs and grid fees, under the assumptions that most homes use electric heat pumps by 2045 and that the targets for the expansion of renewables and the adoption of electric vehicle are reached. The study varies interest rates and power system operation costs (e.g. resulting from different degrees of flexibility utilization). The authors project an average increase in grid fees until 2045 of about 160 % for households and businesses from 9.3 and 7.4 ct/kWh respectively in 2023 (c.f. ef.Ruhr and EWI, 2024) (see Figure 4). Given the uncertainty and heterogeneity that affects future electricity infrastructure costs, we perform a sensitivity analysis where grid fees are varied by -30 % and +45 %.

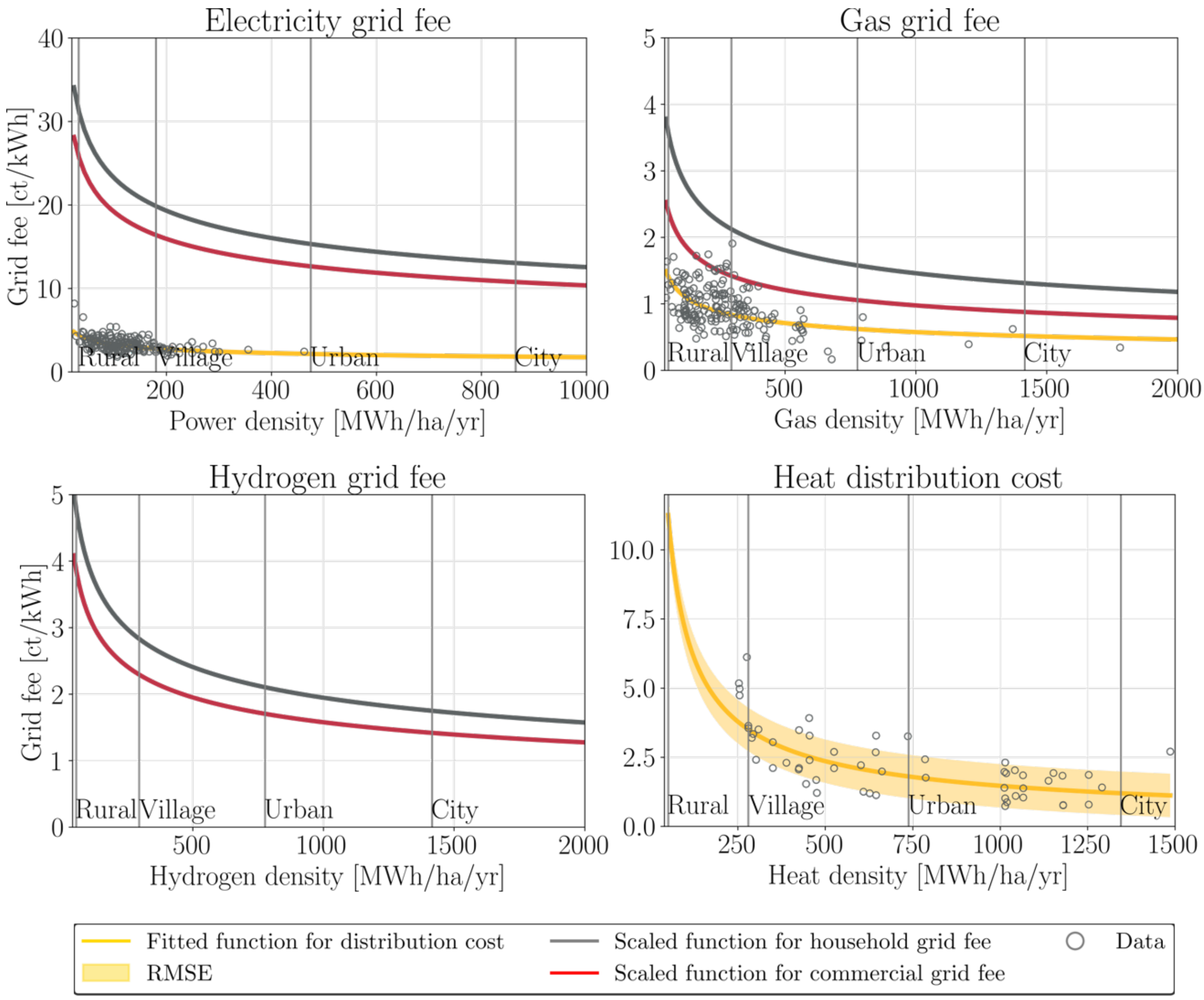

Figure 4: Reference infrastructure costs for electricity, gas, hydrogen, and heating grids depending on the energy density. The data on electricity grid fees contains an additional data point at a power density of 3,455 MWh/ha/yr.

This range includes the variance of grid costs within settlement types found in the historical data (see Figure 4) as well as the scenario range for future grid fees in ef.Ruhr and EWI (2024).

In the case of gas grids, SNG can be transported without modifications through the existing grid. We take historical data on gas distribution costs and energy density Bundesnetzagentur (2023b) to fit the cost functions, which are depicted in Figure 4. The functions are scaled to match future gas grid fees estimated for a 95 % emission reduction scenario with a large share of SNG in residential heating (c.f. EWI), 2018). This study finds an increase of the gas grid fees by 20 % for households and 30 % for businesses by 2050 compared to 1.7 and 1.3 ct/kWh respectively in 2023.

For the case of hydrogen infrastructure costs, we assume that the variance across and within settlement types is similar to existing gas infrastructure. Thus, we apply the same functional form as for SNG. In terms of the cost level, i.e. the scaling of the cost function, hydrogen grid costs are uncertain. It is unclear how demand and supply will develop, and additionally, widespread grid infrastructure does not exist today. Projections range from 4.2 ct/kWh in 2045 (EWI, 2021) on transport level only, to 4.1-4.6 ct/kWh for transport and distribution in 2030 (Cerniauskas et al., 2020) or 2 ct/kWh for transport and distribution in 2050 (Wuppertal-Institut et al., 2020).[7] The large range can be explained by the different time horizons and underlying demand scenarios. For this article, we derive a baseline assumption based on EWI (2024a), a study on potential future hydrogen grid fees in a scenario with widespread hydrogen use in residential heating. On average over all scenarios, hydrogen grid fees in 2045 are about 80 % higher for households and 90 % higher for businesses than 2023 gas grid fees, which are 1.7 and 1.3 ct/kWh respectively in 2023. Due to the high uncertainty related to hydrogen grid costs and the heterogeneity present in the data on today's gas distribution costs, we vary hydrogen grid fees by -30% and +30%. This range includes the scenario range from EWI (2024a) and the variance present in the historical data.

In the case of heating grids, we parameterize grid costs using data on costs for newly built heat distribution grids and heat density. We opt for using this approach instead of a combination of historical distribution costs and estimated future grid fees for existing grids because we would like to provide insights into the expansion rather than the continuation of heating grids. The heat distribution costs in ct/kWh is estimated by the function $f(x) = 166.4505x^{-0.6851}$, where x is the heat density in MWh/ha/yr. Figure 4 shows the data and function taken from Erdmann and Dittmar (2010). We conduct sensitivity analyses within a range of -40% and +40% for heat distribution costs to address the variance present in the data. The full parametrization for all cost functions estimated for infrastructure costs can be found in Appendix D.

3. Results

This article analyzes the future cost-efficiency of climate-neutral heating options. Of the many relevant uncertainties, we start by focusing on the uncertainty of the future hydrogen price while

[7] Cerniauskas et al. (2020) and Wuppertal-Institut et al. (2020) do not consider decentralized hydrogen heating.

assuming average electricity-hydrogen price ratios, average values for technology costs, and expected future grid fees. Subsequently, we investigate the impact of a change in these parameters.

3.1. Varying hydrogen prices

Focusing on decentral heating first, the left column of plots in Figure 5 displays the LCOH of the various options as a function of hydrogen prices. Among the heat pumps, the AtA type is mostly the cheapest option, followed by AtW and WtW. This order follows the order of increasing investment costs, which apparently cannot be compensated by the improved COP of AtW and WtW heat pumps. Relative to other technologies, the heat pumps' LCOH are less sensitive to rising hydrogen prices because of their higher conversion efficiency and the assumed electricity-hydrogen price ratio of 0.9. Among the other technologies, hydrogen boilers are the cheapest technology. SNG boilers have similar LCOH than hydrogen boilers at low hydrogen prices but diverge with increasing hydrogen prices. The higher LCOH are due to high SNG prices, despite SNG boilers having the lowest grid fees of all boiler technologies and slightly lower investment costs than hydrogen boilers. Electric boilers suffer from relatively high power grid fees but benefit from the favorable electricity-hydrogen price ratio. Comparing all technologies, AtA heat pumps are mostly the cheapest option across the entire range of considered hydrogen prices and supply temperatures. However, they may have adverse effects on comfort, which are not accounted for in the LCOH. For this reason, we exclude AtA heat pumps from the following analysis, i.e., look for the cheapest technology under comfort restrictions.

Comparing decentral heating options across settlements, the most salient observation in Figure 5 is that the costs decrease from village to urban settlements. This is for two reasons: first, grid fees decrease in settlements with higher energy density, and second, investment costs decrease due to the larger average heating system sizes in urban and city settlements. The second effect is largest for WtW heat pump systems, as the heat pump itself and the drilling of the groundwater well have significant scale effects.[8] In rural settlements, costs are slightly higher than in village settlements due to higher grid fees, whereas the costs in city settlements are the lowest due to the lowest grid fees, the highest installed capacities, and the largest corresponding scale effects.

[8]AtA heat pump systems show no significant scale effects due to modularity.

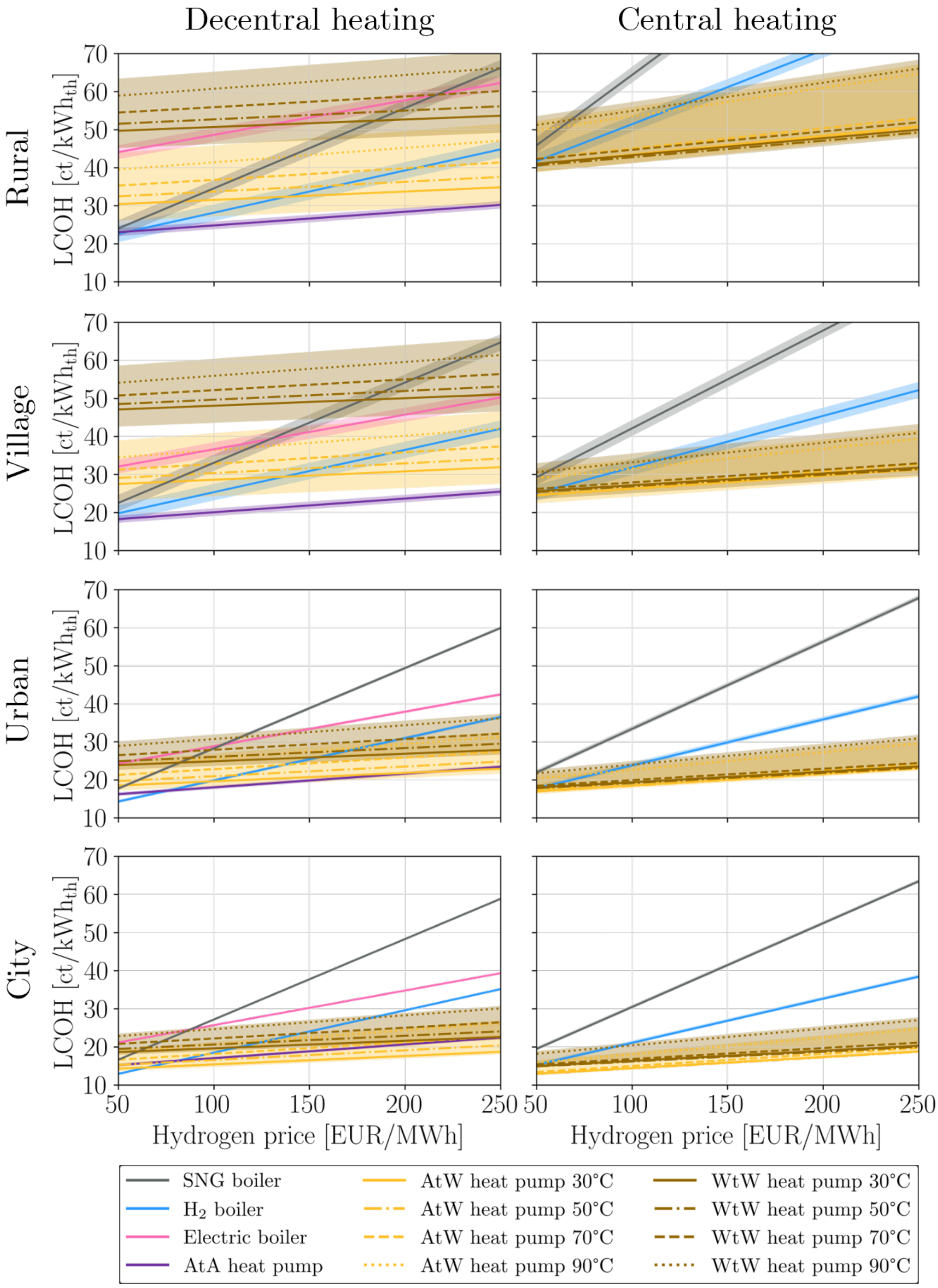

Figure 5: Levelized costs of heating for decentralized heating depending on the hydrogen price and supply temperature of the heating system.

Turning toward central heating (right column in Figure 5, heat pumps are the most cost-efficient. The costs of AtW and WtW heat pump systems converge compared to decentral heating because scale effects reduce the difference in investment costs. The LCOH of central heat pumps for supply temperatures of 70°C or below converge because of the low sensitivity of the COP towards the supply temperature.[9] Boiler technologies have higher LCOH than heat pumps due to higher energy costs. Only for very low hydrogen prices do boilers and heat pumps achieve similarly low LCOH. Put differently, central heating is particularly attractive for heat pumps as significant scale effects outweigh heat distribution costs and heat losses.

Comparing different settlements, the LCOH of central heating options are lower in urban settlements than in villages. This is due to decreasing grid fees, heat distribution costs, and heat losses. Meanwhile, scale effects are absent, as all systems are assumed to have the same installed capacity. These cost trends become more extreme in rural and city settlements with an even higher and lower LCOH compared to the village and urban settlements, respectively.

Across decentral and central heating options, we see that central heat pumps[10] require buildings with supply temperatures of 70°C or below to be economically viable, which corresponds to a heating grid temperature of 80°C or below. In cities, urban and village settlements, central heat pumps are more economical than decentral heat pumps due to significant scale effects on heat pump investment cost. In rural settlements, decentral heat pumps are more economical than central ones due to high heat losses and heat distribution costs. Hydrogen boilers become cost-efficient over heat pumps across all considered supply temperatures if hydrogen prices are below 130 EUR/MWh in rural settlements[11], below 110 EUR/MWh in villages, or below 80 EUR/MWh in urban settlements. In city settlements, even at a hydrogen price of 50 EUR/MWh hydrogen is not economical. The remainder of this section analyzes the sensitivity of the above results to changes in uncertain input parameters other than hydrogen prices.

[9]Note that the LCOH of both central heat pump technologies is quite homogenous for buildings with supply temperatures between 30°C and 70°C because the required complementary direct electric hot water heating leads to similar effective COP (see Figure 2)

[10]Because the costs of central AtW and WtW heat pumps are very similar, we cluster them as central heat pumps.

[11]Note that, however, this result is affected by our parametrization based on current grid fees, which are often jointly calculated for village and rural settlements. If a hydrogen grid was built to supply a rural area only, costs might be higher than the reference hydrogen grid costs.

3.2. Sensitivity analysis

While the previous analysis assumed fixed energy price ratios, infrastructure costs, and heat pump equipment costs, this subsection analyzes the effect of changes in these parameters on the cost-efficient heating technology for various hydrogen prices and in different settlement types. Figure 6 shows the cost-efficient technology and the relative LCOH difference between the best and second-best technology for buildings with a supply temperature of 70°C. Each column in the figure represents one settlement type, and each row displays the effect of changing one input parameter. In rural settlements (left column), hydrogen boilers and decentral heat pumps are cost-efficient for most of the considered input parameter variations. In village, urban, and city settlements (the other columns), hydrogen boilers and central heat pumps[12] are most often cost-efficient. SNG boilers are cost-efficient only if SNG costs are at the lower boundary of the investigated parameter range.

The changes in input parameters affect the hydrogen price threshold below which hydrogen boilers are cost-efficient. This threshold ranges from 170 to 250 EUR/MWh in rural settlements and decreases with the heat density of settlements. In cities, hydrogen is only cost-efficient in some corners of the parameter ranges. In rural settlements and villages, the cost advantage of hydrogen boilers is the largest between hydrogen prices of 90 to 120 EUR/MWh and can reach up to 25 %. At very low hydrogen prices, hydrogen boilers have only small cost benefits compared to SNG boilers. Central heat pumps are the cost-efficient technology for hydrogen prices above 170 EUR/MWh in villages, 120 EUR/MWh in urban settlements, and 75 EUR/MWh in cities - regardless of variations in the other parameters. The cost gap between central heat pumps and the second best technology increases from village to city settlements and can reach 20 % or higher.

3.3. Varying energy price ratios

This subsection analyses the effect of varying energy price ratios on the cost-efficient technology. First, we analyze the electricity-hydrogen price ratio. This price ratio is subject to uncertainty, depending on the heat pump load patterns and broader aspects of the future energy system, such as the availability of renewable electricity and electricity demand for other applications. We analyze

[12] Because the costs of central AtW and WtW heat pumps are very similar, we cluster them as central heat pumps.

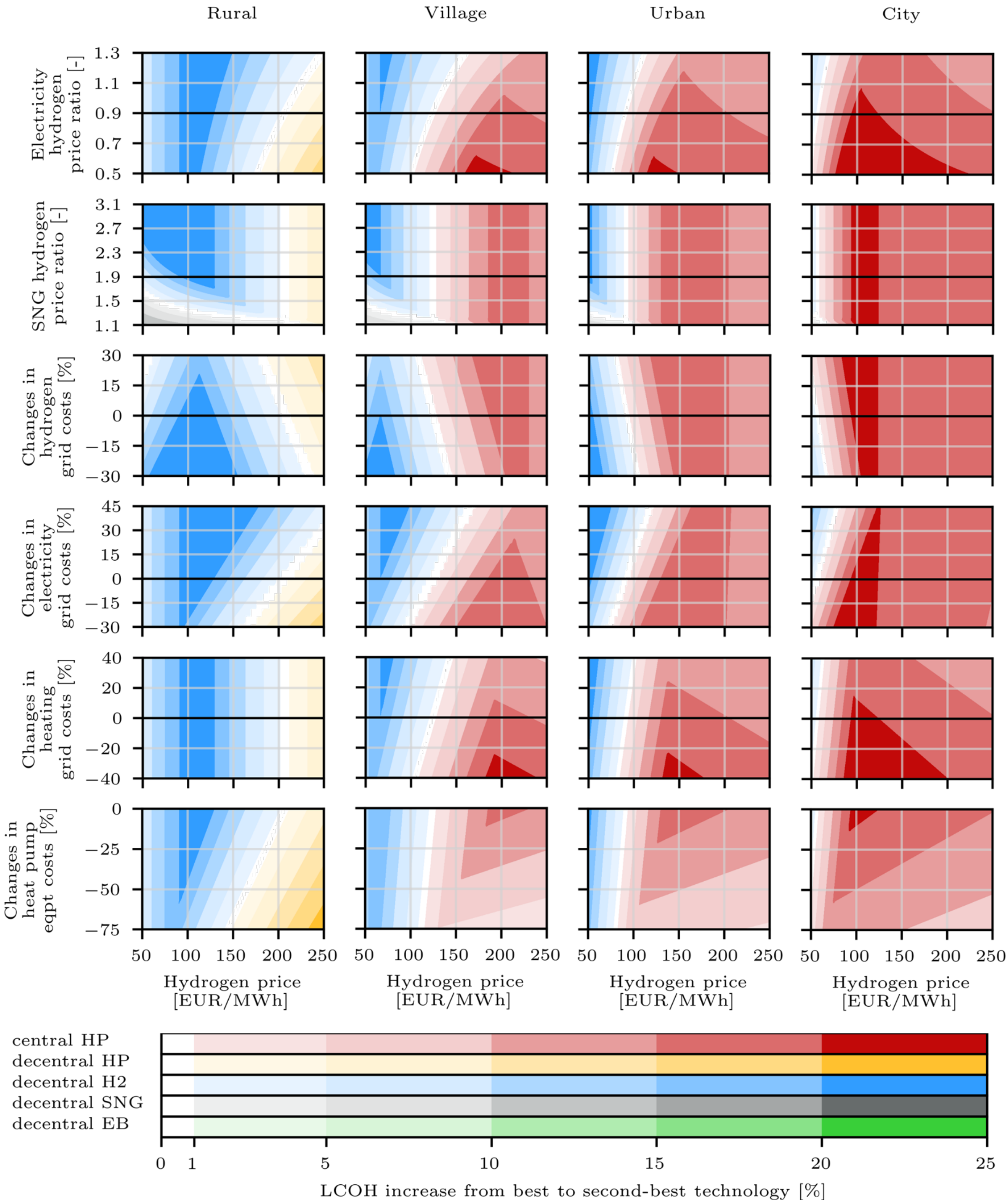

Figure 6: The impact of uncertain and heterogenous parameters on the cost-efficient heating technology in different settlement types for buildings with a supply temperature of 70°C. Colors indicate the cost-efficient technology. Color shades indicate the LCOH increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter.

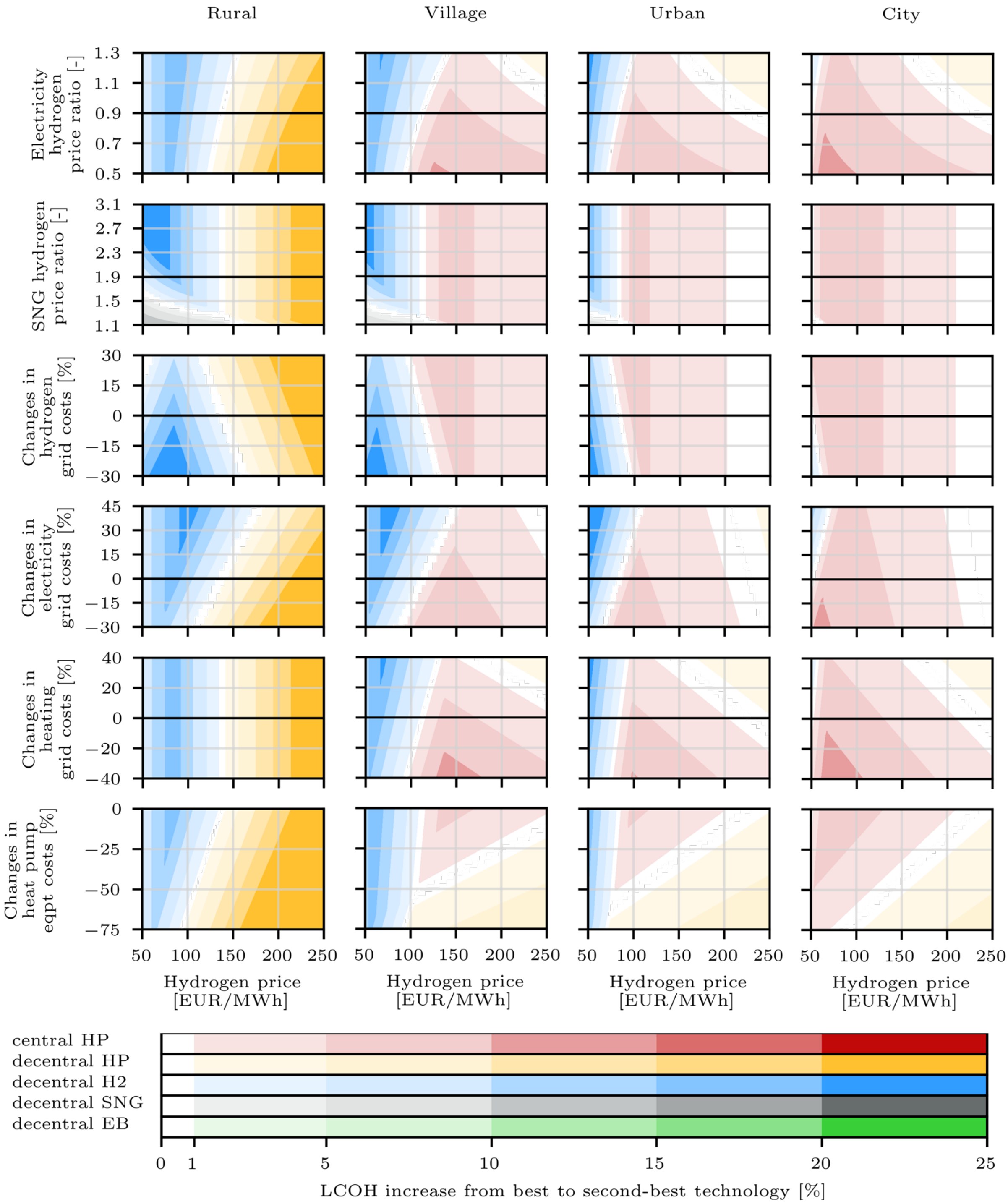

Figure 7: The impact of uncertain and heterogenous parameters on the cost-efficient heating technology in different settlement types for buildings with a supply temperature of 30°C. Colors indicate the cost-efficient technology. Color shades indicate the LCOH increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter.

ratios between 0.5 and 1.3, which includes the range found in the literature plus a margin for additional uncertainty.

The first row of Figure 6 yields two observations: First, at relatively low hydrogen prices, an increasing electricity-hydrogen price ratio favors the economic viability of hydrogen boilers compared to heat pumps. This effect becomes less pronounced with increasing heat densities due to decreasing heat losses. Second, at high hydrogen prices, an increasing ratio reduces the economic advantage of central heat pumps compared to decentral ones, which are the second-best technology. For lower supply temperatures, decentral heat pumps will even become the cost-efficient technology, as discussed in subsection 3.6 below. This is because the higher COP and absence of heat losses increase the economic attractiveness of decentralized heat pumps. If electricity is 1.3 times as expensive as hydrogen, the threshold price at which hydrogen boilers become economical is 160 EUR/MWh in villages and 110 EUR/MWh in urban settlements. For the same electricity-hydrogen price ratio, hydrogen can even be economical at a price of 250 EUR/MWh in rural settlements, whereas it only becomes economical for prices slightly above 50 EUR/MWh in cities.

Second, we analyze the effect of the SNG-hydrogen price ratio on the cost-efficient technology and the cost gap to the second-best technology. This price ratio is subject to uncertainty due to uncertain future cost degression of electrolyzer and methanation plants as well as uncertainty regarding the origin countries of imported fuels. We analyze ratios between 1.1 and 3.1, which is a range derived from EWI (2024b).

The second row of Figure 6 shows that SNG is hardly cost-efficient in the considered range of the price ratio. If hydrogen is as cheap as 50 EUR/MWh, SNG and hydrogen boilers can be in cost parity in rural settlements if SNG costs 60% more than hydrogen. For higher hydrogen prices, the SNG-hydrogen cost ratio must be even lower to make SNG competitive in rural areas. Similarly, SNG boilers become less economical the more urban the settlement becomes.

3.4. Varying grid fees

This subsection investigates the influence of heterogeneity and uncertainty in (future) infrastructure fees on the cost-efficiency of heating technologies for varying hydrogen prices in different settlement types.

First, we analyze hydrogen grid fees. In addition to settlement-related heterogeneities, future hydrogen grid costs may be particularly uncertain due to limited experience with hydrogen grids. Both are reflected by a variation of ± 30 % of the hydrogen grid fee. The third row of Figure 6 shows that increasing hydrogen grid fees reduce the competitiveness of hydrogen boilers relative to other options. This is intuitive as hydrogen grid fees only raise the costs of hydrogen boilers, while other technologies are unaffected.[13] If hydrogen grid fees increase by 30 % in villages, hydrogen boilers would only be cost-efficient at hydrogen prices below 100 EUR/MWh. Similar trends can be observed for the other settlement types, with hydrogen playing a somewhat larger role in rural settlements, a smaller role in urban settlements, and no role in city settlements.

Next, we examine the effect of electricity grid fees on the most cost-efficient heating option. In contrast to the hydrogen grid, the electricity grid is also used for other purposes than heating. Hence, uncertainty in electricity grid fees is driven not only by future heat demand but also by the diffusion of electric vehicles and renewable generators. We reflect related heterogeneity and uncertainty by a variation of -30% and +45 %.

The fourth row of Figure 6 shows that higher electricity grid fees favor the economic viability of hydrogen boilers over heat pumps. Also, higher electricity grid fees promote decentral AtW heat pumps over central heat pumps due to higher energy efficiency, but AtW heat pumps become cost-efficient only at lower supply temperatures (see below). The competitiveness of the different technologies is more sensitive toward a percentage increase in electricity grid costs in rural and village settlements than in urban settlements due to higher baseline grid fees. If electricity grid fees increase by 45 %, hydrogen is cost-efficient for hydrogen prices below 160 EUR/MWh in villages and 120 EUR/MWh in urban settlements. If electricity grid fees decrease by 30 % and hydrogen prices are low, central heat pumps are cost-efficient in villages at a hydrogen price of 100 EUR/MWh and urban settlements at 70 EUR/MWh. The results are more extreme in rural and city settlements, with the highest sensitivity being in rural areas and the lowest sensitivity being in city settlements. Overall, increased electricity fees lead to similar effects as a higher electricity-hydrogen price ratio.

[13]Note that we neglect the potential effect of rising hydrogen grid fees on the electricity price through hydrogen power plants. We justify this by the assumption that large-scale power plants are connected to the transmission grid with much lower fees than the distribution grid.

Finally, we investigate the sensitivity of the cost-efficient option to changes in the heating grid costs. The fifth row of Figure 6 confirms the expectation that higher heating grid costs promote decentral technologies. At low hydrogen prices, increasing heating grid costs promote hydrogen boilers. At high hydrogen prices, increasing heating grid costs promote decentral AtW heat pumps. Decentral heat pumps become viable for buildings with low supply temperatures, while heating grids remain viable for the remaining buildings. When comparing across settlements, the viability of central heat pumps is more sensitive toward a percentage increase in heating grid costs in villages than in urban settlements due to higher heating grid costs. Even if heating grid costs increase by 40 %, central heat pumps are cost-efficient in villages if hydrogen prices are higher than 140 EUR/MWh or in urban settlements if hydrogen prices are higher than 100 EUR/MWh. If heating grid costs increased further, decentral heat pumps would gradually become economically viable in both village and urban settlements. In rural settlements, heating grids are not economical due to significantly higher heat distribution costs and heat losses. In city settlements, there is no case for hydrogen if hydrogen prices are higher than 60 EUR/MWh, regardless of the heating grid costs. However, increasing hydrogen prices and heating grid costs favor decentral heat pumps over central heat pumps.

3.5. Heat pump equipment cost digression

This subsection analyzes the effect of uncertain heat pump equipment costs on which heating technology is cost-efficient at different hydrogen prices. Future heat pump equipment costs may decrease due to learning effects when deployment increases. Based on learning rates reported in the literature, we reflect this uncertainty by a decrease of up to 75 % from the baseline equipment costs.

The sixth row of Figure 6 shows that the hydrogen price at which heat pumps and hydrogen are in cost parity decreases only slightly if heat pump investment costs are reduced. This is because hydrogen boilers compete with central heat pumps, and heat pump equipment costs only account for a small fraction of the total system costs of central heat pumps. In decentral heat pump systems, the share of heat pump equipment costs is larger, and the COP is higher than in central heat pump systems.[14] Thus, decreasing heat pump equipment costs and high hydrogen prices promote the economic viability of decentral heat pumps over central ones. Nevertheless, even a heat pump investment cost reduction of 75 % only reduces the cost gap but does not lead to a cost advantage of decentral over central heat pumps in villages, urban settlements, and cities. The reason is that the investment costs of the decentral systems remain significant, especially due to high installation costs. In rural settlements, decreasing heat pump equipment costs lead to a significant shift from hydrogen boilers to decentral heat pumps.

3.6. Lower supply temperatures

While the previous subsections analyzed buildings with a supply temperature of 70°C, this subsection investigates the influence of the supply temperature on which technology is cost-efficient and the cost gap.[15] Comparing Figure 6 and Figure 7 reveals that decentral heat pumps become more economical compared to all other technologies at lower supply temperatures. Among heat pump technologies, the relative cost difference between central and decentral heat pumps decreases from supply temperatures of 70°C to 30°C. At 30°C, the difference in annual COP between central and centralized heat pumps is larger than at 70°C (see Figure 2), making decentral heat pumps more economical. Across settlement types, lower supply temperatures result in decentral heat pumps becoming cost-efficient at lower hydrogen prices. Despite decentral heat pumps being more economical at lower supply temperatures, central heat pumps remain cost-efficient for medium hydrogen prices in villages, urban, and city settlements. However, the cost gap to decentral heat pumps, which reaches up to 25% at a supply temperature of 70°, decreases to 15 % or lower. If hydrogen prices are higher than 150 EUR/MWh, the cost gap is less than 5 % in most cases.

4. Discussion

This section discusses the assumptions and the limitations of our analysis and their implications for the interpretation of our results.

[14] We assume that the percentage cost reduction applies equally to all heat pumps in the kW range as these are typically off-the-shelf products.

[15] Supply temperatures correspond to the building type and age. Typically, existing buildings with smaller radiators and medium to low energy efficiency have supply temperatures of up to 70°C, while newly constructed buildings with high energy efficiency and larger radiators have supply temperatures of down to 30°C.

4.1. Technology options

Our technology set does not include hybrid systems that combine different heat sources. Combined heat and power plants are the dominant technology in current heating grids and may also be relevant in the future: hydrogen-fired gas turbines are likely needed for periods with low RES availability, and excess heat could be available for district heating at negligible cost. The same is true for industrial waste heat. Moreover, heating grids can provide flexibility to the power sector through the inertia of the grid itself and through the integration of large-scale thermal storage. In sum, there are significant synergies between hybrid technologies and heat-pump-powered heating grids, which further enhance the case for this technology.

Furthermore, we neglect decentral hybrid systems that integrate rooftop PV and batteries. Such additional technologies could lower electricity costs (including grid fees) and improve the economics of heat pumps. Further, we disregard solar thermal, which would lower the residual heat demand for the technologies considered here. Thus, solar thermal could improve the case for technologies with high energy costs. Finally, we do not consider pellet and biogas heating because the potential for biofuels in Germany is limited, and the classification of biofuels as fully climate neutral is debated (c.f. Öko-Institut (2023)).

4.2. Future energy prices

We consider a wide range of hydrogen prices to reflect the high uncertainty of future hydrogen prices. Nevertheless, there are several reasons why hydrogen prices may emerge rather in the higher part of our considered range: First, the current levelized cost of hydrogen lies at the upper end of the considered price range or even higher (BGC, 2023; EEX, 2023). Hydrogen costs below this upper end would require substantial degression of electrolyzer investment cost. While declining costs can be expected due to economies of scale and learning (EWI (2023)), the extent of the cost degression is hardly predictable, as it depends on the development of global hydrogen demand. Second, many studies projecting lower future hydrogen prices do not account for the storage costs necessary to balance hydrogen production from volatile RES (Moritz et al. (2023)). In consequence, projected hydrogen prices might be underestimated (Breuning et al. (2023)). Finally, the cost of hedging against uncertain hydrogen prices (e.g., through additional storage or take-or-pay clauses) would increase the effective hydrogen price. Third, our assumed price range is based on the assumption that hydrogen can be imported via pipeline. If (additional) imports via ship were required, this would substantially increase import costs and resulting market prices.

Regarding future electricity prices, our analysis assumes a fixed electricity-hydrogen price ratio, which is derived from ratios of hydrogen and electricity base prices found in the literature. However, this neglects the interactions between heat pumps and electricity markets. Heat pump load tends to be positively correlated with electricity prices, and thus they can be expected to pay a higher weighted average price than the base price (Ruhnau et al. (2020)). Not least, relatively high heat pump electricity prices may reflect the increased electricity generation capacity requirements to cover heat-pump-driven peak loads (EWI (2021)). On the other hand, thermal storage could be used to enable the shifting of heat pump load to times with lower electricity prices and hence lower the weighted average price to be paid by heat pumps.

4.3. Future grid fees

Our analysis is based on estimated future grid fees for electricity, hydrogen, and (synthetic) natural gas. These estimates are based on current rules for allocating grid costs and reflect average infrastructure costs rather than marginal costs associated with heating. Thus, they might not fully reflect the true system-level costs associated with each of the heating options. In particular, they do not reflect the effect that the operation of heat pumps has on related electricity grid costs. Inflexible heat pumps may cause above-average grid costs by increasing the peak load on cold days in the distribution grid. By constrast, flexible heat pumps that shift consumption toward times with low grid utilization may cause below-average grid costs. Depending on the heat pumps' flexibility, they may be more or less economical than suggested by our results.[16]

4.4. Supply temperature

The results show that central heat pumps require buildings with supply temperatures of 70°C or below to be economically viable. While some buildings currently require higher supply temperatures, nearly all existing buildings can achieve such lower temperatures with little to no effort.

[16]Current German regulation offers reduced grid fees to interruptible loads such as heat pumps or electric vehicles if their owners grant the grid operators flexible operation rights. However, we do not consider this reduction in our analysis as it is unclear to what extent the reduction alingnes with actual cost savings.

In fact, flow temperatures below 70°C can be achieved in more than 90 % of the German building stock without modifications because existing radiators are often oversized (Umweltbundesamt (2023); Østergaard and Svendsen (2019)). If modifications are necessary, most buildings can achieve supply temperatures below 70°C by replacing 30 % or less of the existing radiators (Pehnt et al. (2023)). Also, supply temperatures can be decreased by using existing radiators more efficiently through new pump control, radiator valves, and thermostats (Østergaard and Svendsen (2019)).

Moreover, we investigate settlements with homogenous buildings. In reality, buildings in settlements are heterogeneous. The heating grids' temperature is limited downwards by the supplied building with the highest supply temperature. Heterogenous supply temperatures of the buildings disfavor the economics of central heat pumps compared to decentral heating. Buildings with lower supply temperatures than the buildings with the highest supply temperature cannot benefit from their low supply temperature. Consequently, decentral AtW heat pumps may be more economical than our results suggest for buildings with low supply temperatures in heterogeneous settlements.

Furthermore, we only consider the effect of heating grid temperatures on the annual COP of central heat pumps. In reality, lower grid temperatures also lead to lower heat losses. The reference losses used in our calculations are for heating grids with supply temperatures above 90°C. As we do not consider the grid temperature's influence on the heating grid's energy losses, we overestimate the cost of heat losses. Consequently, central heat pumps might be more economical for low grid temperatures than our results suggest.

4.5. Parallel grid infrastructures

We calculate the LCOH assuming that an entire settlement is heated by the same heating technology using the same grid. A single grid has a higher utilization than parallel grids, which allows for the distribution of fixed costs onto more shoulders, thus keeping grid fees low. Nevertheless, parallel infrastructures exist today, for example, where CHP or industrial waste heat can be used in heating grids next to decentral heating with gas. According to several studies, parallel infrastructure could play a role during transition times. The scenario analysis in Billerbeck et al. (2024) makes a case for exhausting existing electricity grids with baseload heat pumps while new hydrogen infrastructure and boilers provide peak heat in the future. Similarly, Rosenow (2022) discusses that utilizing existing boilers could reduce the peak electrical demand of the heat pumps and hence decrease investment costs for the heating system and for a potential electricity grid expansion. In the long term, gas or hydrogen infrastructure that is parallel to district heating may not be economical because heat from CHP and industrial waste heat could be integrated into heat-pump-powered heating grids, which are cost-efficient in many cases. In any case, electricity grids will always exist in parallel to other infrastructure because they serve non-heating purposes, which further enhances the case for heat pumps.

4.6. Transitional challenges

Our analysis focuses on the cost-efficiency of technologies in the future and does not investigate possible transition pathways to reach this future. Implementation challenges need to be considered in real-world infrastructure planning and may as well be an interesting topic for further research. For instance, while central heating appears to be very attractive in our analysis, the expansion of heating grids may be subject to long planning horizons and limited planning and building capacities. The financing of increased investment costs may be challenging, in particular for long-lived technologies with high up-front cost. As all net-zero technologies are capital-intensive (considering upstream costs for hydrogen and SNG), it is not obvious which technologies would be most affected.

4.7. Generalization

While our method is widely applicable and some of the qualitative results may be generalized, our quantitative estimates are specific to Germany because a part of the input data is country-specific. This includes data for investment, installation, and infrastructure costs. Moreover, the relationship between the supply temperature and the annual COP of AtW heat pumps is based on German climate conditions.

5. Conclusion

This article investigates which heating technologies are cost-efficient in a future climate-neutral energy system, given uncertainties in energy, technology, and infrastructure costs and heterogeneous settlement types and buildings. To that end, we calculate the future levelized costs of heating technology options for a set of exemplary buildings and settlement types in Germany and conduct extensive sensitivity analyses.

Across the wide range of heterogeneity and uncertainty that we consider, AtA heat pumps turn out to be economically very attractive and may provide additional cooling services. However, their heating may be perceived as less comfortable compared to the radiator-based systems used today. Among radiator-based systems, we find that decentral hydrogen boilers, central heat pumps, and decentral AtW heat pumps are the most cost-efficient technologies. The relative future competitiveness of these three heating options strongly depends on the settlement type and the hydrogen price but also on the electricity-hydrogen price ratio, infrastructure costs, and a potential heat pump cost degression.

Intuitively, hydrogen boilers become less competitive with increasing hydrogen prices, but also with increasing hydrogen grid costs and higher heating densities. While hydrogen boilers may be competitive in rural settlements for more parameter combinations, they are not found to be economical in cities across our considered scenarios. Among the heat pump technologies, central heat pumps are cost-efficient over a wide range of input assumptions due to significant scale effects on heat pump investment costs in cities, urban settlements, and even villages. Only in rural settlements and for specific parameter combinations with low supply temperatures do decentral heat pumps emerge as the most cost-efficient heat pump technology. High electricity-hydrogen price ratios and electricity grid costs improve the economics of hydrogen boilers relative to heat pump technologies. At higher heating densities, central heating is economical and is less sensitive to electricity grid costs.

From these results, we draw three main conclusions for decision makers. First, SNG does not seem economical despite the fact that SNG could utilize existing infrastructure in the short-term. For most of the many combinations of uncertain and heterogeneous input parameters that we investigated, either hydrogen or heat pumps are cheaper than SNG. Second, there seems to be a limited scope for decentral hydrogen boilers. Hydrogen is mostly economical in rural settlements, while in settlement types with higher heating densities, heat pumps are generally more efficient at moderate or high hydrogen prices. High hydrogen prices and uncertain hydrogen grid costs can deteriorate the competitiveness of hydrogen boilers. Given the high uncertainty in the hydrogen price and grid costs, hydrogen boilers also seem to be a more risky option than heat pumps, which are less exposed to increased energy and infrastructure costs due to their high COPs, when infrastructure investment decisions have to be made today. Third, the decision between decentral and central heat pumps requires a case-by-case analysis, considering local heating grid costs, energy efficiency of existing buildings, and potential synergies with CHP and industrial waste heat. High heating densities in cities favor central heat pumps, while in rural areas, decentral heat pumps seem more economical. For the example of Germany, making this choice should be the focus of the municipal heating planning processes, which just started and are due in 2028.

Further research may benefit from our extensive primary dataset of relevant parameters to analyze climate-neutral heating options further. The dataset and our proposed methods could be further extended to include hybrid heating systems, CHP, industrial waste heat, solar thermal, and biomass. Additionally, our proposed method could be applied to data from other countries to analyze regional differences. Finally, our analysis may be updated as some of the uncertainties on the future costs of novel heating technologies and infrastructures narrow down.

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Authors’ contributions

M. Moritz came up with the initial idea. M. Moritz and B.H. Czock designed and performed research, and analyzed data. All authors discussed the results and wrote the final manuscript.

Competing interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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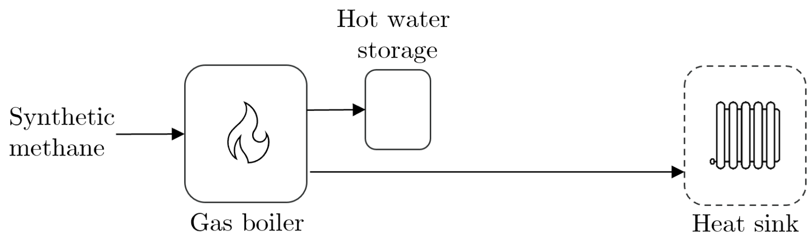
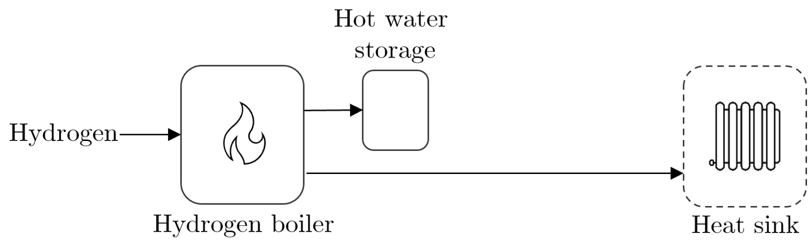
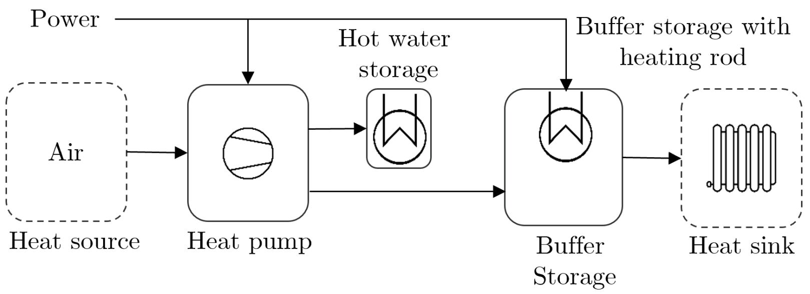
Appendix A. Heating systems



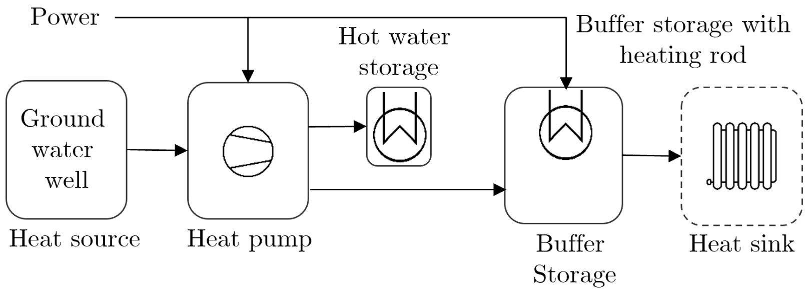
(a) Gas boiler decentral



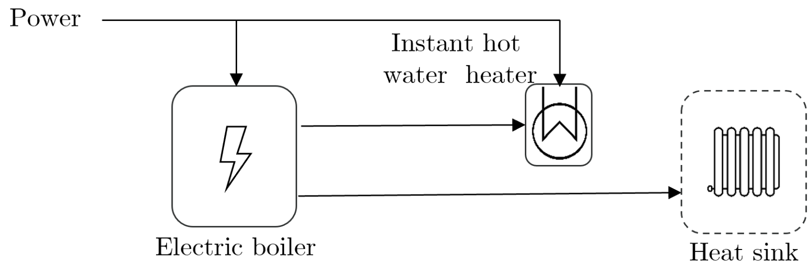
(b) Hydrogen boiler decentral



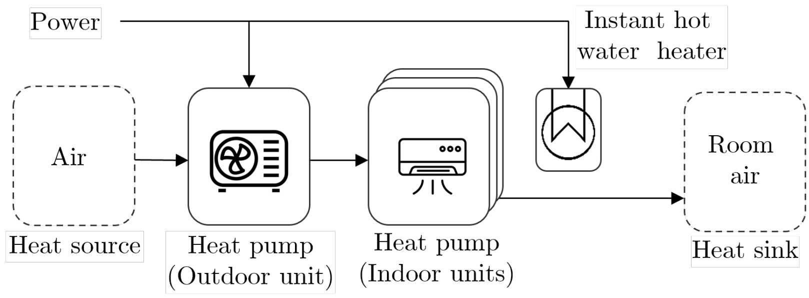
(c) AtW heat pump decentral



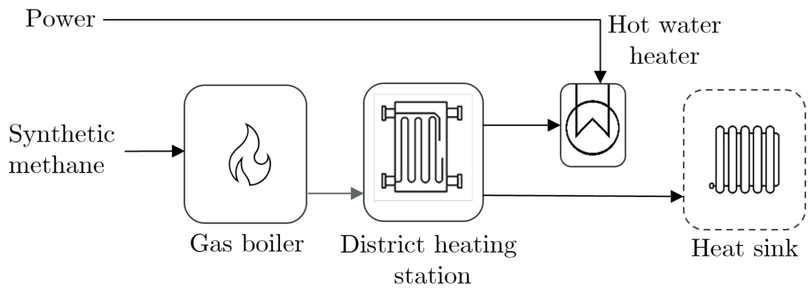
(d) WtW heat pump decentral



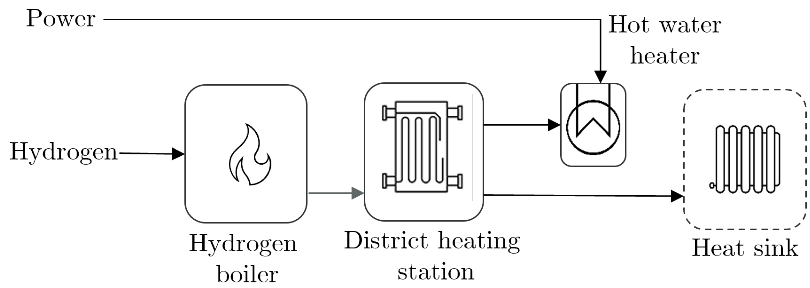
(e) Electric boiler decentral



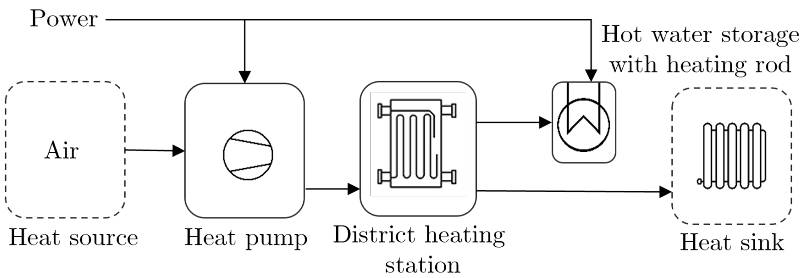
(f) AtA heat pump decentral



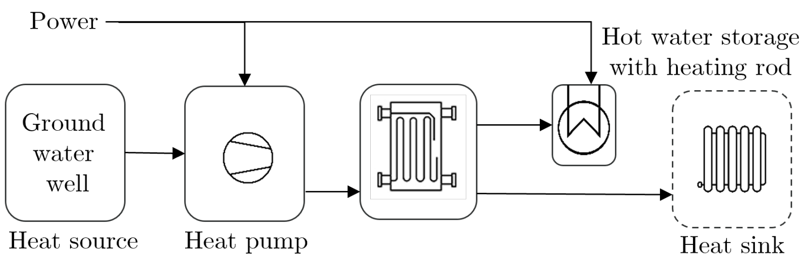
(g) Gas boiler central



(h) Hydrogen boiler central



(i) AtW heat pump central



(j) WtW heat pump central

Figure A.8: Wnergy flow charts and major equipment units of the heating systems

Appendix B. Equipment cost data and functions

We collected cost data from manufacturers Buderus, Elco, Vailaint, and Viessman for the following components: air-to-air heat pumps, air-to-water heat pumps, water-to-water heat pumps, gas-condensing boilers, electric boilers, electric instant water heaters, buffer tanks, hot water tanks, and heating rods.Table B.5 summarizes the data scope for the calculation of the cost functions. Moreover, we collected data on the installation costs of gas-condensing boilers and AtW heat pumps from Moritz & Bramer GmbH and Octopus Energy. We fit a cost function to the collected data, with installed capacity as an independent variable. Table B.5 shows the scope of the collected primary data. We use least squares regression to fit linear functions without intercept ($f(x) = mx$), linear functions with intercept ($f(x) = mx + b$), and power functions ($f(x) = ax^b$), where $f(x)$ represents the costs, and x represent the installed capacity. We choose the one with the lowest RMSE from the three fitted functions. In the case of gas condensing boilers, a 2-step piecewise-linear function resulted in the best fit. This function reflects that boilers with a heating capacity below 50 kW are relatively cheaper than larger boilers because they typically have factory-installed control and are produced in larger numbers. In the case of district heating stations, we assume equipment costs of 4000 EUR for a heating capacity of up to 15 kW as these are off-the-shelf products. This assumption is based on personal communication with the manufacturer Pewo Energietechnik GmbH. Based on personal communication with Habo Wärmetechnik GmbH & Co. KG, district heating stations with larger capacities are typically individually designed. We use a power function provided by Blesl et al. (2023) for district heating stations with larger capacities. In order to be able to reflect the variance in the data, we generate high-cost and low-cost functions. High-cost functions are the fitted functions plus 1/3 of the standard error, and low-cost functions are the fitted functions minus 1/3 of the RMSE. The primary data and fitted functions are shown in Figure 1 and Figure B.9.

Some cost functions cannot be directly derived from data. Hydrogen boilers are not yet available commercially. According to personal communication with the manufacturer Viessmann, the sales prices of hydrogen boilers will be around of 10 % higher than those of natural gas boilers. Thus, our investment cost function for hydrogen-condensing boilers is the cost function of gas-condensing boilers multiplied by 1.1.

Table B.5: Scope of the primary data collected for investment and installation costs for heating systems

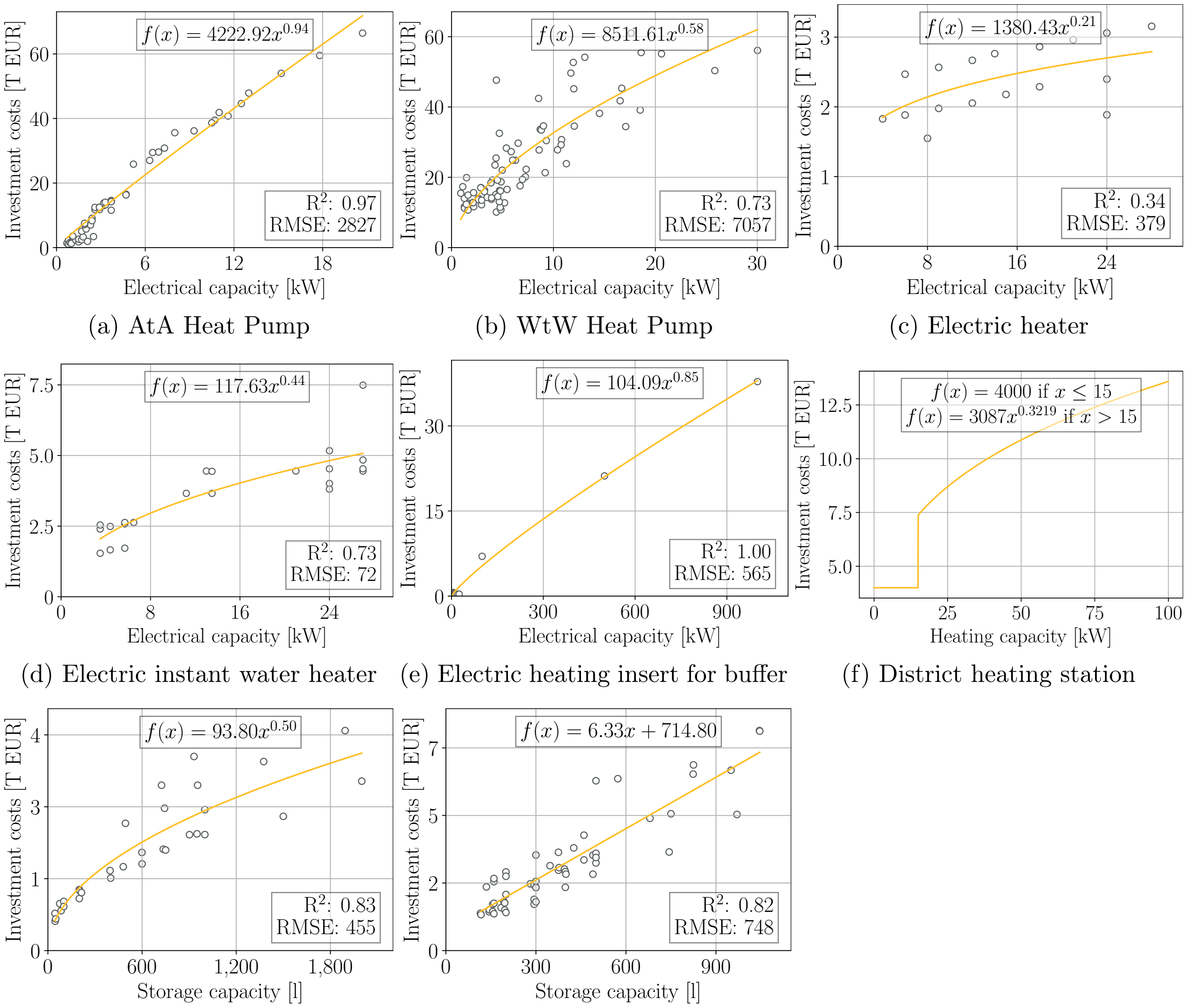
Investment costs	Number of data points
Air-to-air heat pumps	55
Air-to-water heat pumps	67
Buffer tanks	31
Heating rod for buffer storage	24
Electric boilers	17
Electric instant water heaters	22
Gas condensing boilers	122
Hot water storage tanks	54
Water-to-water heat pumps	81
Installation costs	
Gas condensing boilers	15
Water-sink heat pumps	22
Air-to-air heat pumps	1[a]

[a] Experience-based cost function

In the same fashion, we calculate the installation costs of district heating stations and electric boilers based on the installation costs of gas-condensing boilers. According to personal communication with the heating company Moritz & Bramer GmbH, the installation of a district heating station costs 10 % less than the installation of a gas condensing boiler since no chimney system is necessary. Installing an electric boiler costs 20 % less since neither a chimney system nor gas piping is necessary. The fixed operation and maintenance costs are parametrized as a function of the installed capacity based on personal communication with Moritz & Bramer GmbH and can be found in B.6. The annual FOM costs of the geothermal probe for WtW heat pumps are calculated as 3 % of the investment costs (c.f. npro energy (2023)).

Typically, installation companies add a contribution margin to the material costs to cover their administrative expenses. We assume a contribution margin of 50 % to all major equipment units. Costs for small materials are included in the installation cost functions, which are displayed in Figure 1.

Regarding energy efficiencies of boilers, gas condensing boilers can have an efficiency of 95 % under optimal conditions (according to manufacturer's information by Buderus, Elco, Vailland and Viessmann). However, a detailed in-situ study in the United Kingdom showed that average efficiencies are 82 % (GASTEC, 2009). A reason for lower efficiencies is that return temperatures are too high to condense the water in the boiler exhaust gas fully. For our analysis, we assume an efficiency of 90 % for gas and hydrogen condensing boilers and neglect the effect of the supply temperature on the boiler efficiency. For electric boilers, we assume an energy efficiency of 99 % according to manufacturer's information by Buderus.



(a) AtA Heat Pump (b) WtW Heat Pump (c) Electric heater

(d) Electric instant water heater (e) Electric heating insert for buffer (f) District heating station

(g) Buffer tank (h) Hot water storage

Figure B.9: Equipment costs of components

The calculation of installation costs for AtA heat pumps is based on personal communication with Aircon-Technik GmbH. We calculate the installation costs depending on the heating capacity by:

$$f(x) = w(t_{out}n_{out} + t_{in}n_{in} + t_{line}l_{line}) + l_{line}sc_{line} + n_{in}sc_{cond} + n_{branches}sc_{branch} \quad \text{[EUR]} \quad \text{(B.1)}$$

, where $t_{in} = 0.5$ are person days per inside unit, $t_{out} = 1$ are person days per outside unit, $t_{line} = 1/48$ are person days per meter of refrigeration line, $P_{in} = 2$ is the average power of an inside unit kW, $P_{out,max} = 85$ is the largest outside unit available in the manufacturer's price lists, $sc_{branch} = 200$ is are the specific costs of a refrigeration line branch in EUR, $bpu = 1$ are the number of refrigeration line branches per inside unit, $sc_{line} = 20$ are the specific costs of a refrigeration line canal in EUR/m, $w = 600$ are the specific wages per person day in EUR/d, $n_{in} = x/P_{in}$ are the number of inside units, $n_{out} = x/P_{out,max}$ are the number of outside units, where x is the heating capacity of the building in kW, $n_{branches} = n_{in} bpu$ are the number of branches, and $l_{line} = n_{in} sl_{line}$ is the total length of refrigeration line. We generate ranges for the installation costs by varying the costs for the condensate pump and the length of the refrigeration lines. $sl_{line} = [2.5; 7.5]$ is the range for the specific average refrigeration line length per inside unit in m/inside-unit, and $sc_{cond} = [0 - 100]$ is the range for the specific costs of condensate pump per inside unit EUR/inside-unit.

Parameter	Unit	Value
Energy efficiency of gas and hydrogen boilers	[-]	0.90
Energy efficiency of electric boilers	[-]	0.99
Interest rate	[%]	5
Depreciation period	[yr]	20
Full load hours of heating technologies	[h/yr]	2000
FOM AtW and WtW heat pumps decentral	[EUR/kW$_{th}$/yr]	25
FOM AtW and WtW heat pumps central	[EUR/kW$_{th}$/yr]	2.5
FOM gas and hydrogen boiler decentra	[EUR/kW$_{th}$/yr]	20
FOM gas and hydrogen boiler central	[EUR/kW$_{th}$/yr]	2.5
FOM of district heating stations	[EUR/kW$_{th}$/yr]	20
FOM of ground water well	[% of CAPEX/yr]	3
Specific heat load of buildings	[W/m^2]	50
Specific hot water demand	[kWh/occupant/yr]	500
Heated area per occupant	[m^2]	30
Specific heat load for domestic hot water	[W/occupant]	200
Specific buffer storage capacity for decentral heat pumps	[l/kW$_{th}$]	200
Heating capacity of heat pumps at bivalent point	[kW$_{th}$/kW$_{th}$ specific heat load]	0.73
Heating capacity of the heating rod at bivalent point	[kW$_{th}$/kW$_{th}$ specific heat load]	0.36
Contribution margin of HPs in bivalent monoenergetic operation	[%]	0.98

Table B.6: General techno-economic assumptions

Appendix C. Hydrogen and SNG price estimation

We use the following scenarios to generate import cost the data from EWI (2024b):

- 2025, baseline cost scenario, high cost new hydrogen pipelines, greenfield gas pipelines, CO_2 from DAC
- 2050, baseline cost scenario retrofitted hydrogen pipelines, brownfield gas pipelines, CO_2 from DAC
- 2025, optimistic cost scenario, high cost new hydrogen pipelines, greenfield gas pipelines, CO_2 from DAC
- 2050, optimistic cost scenario retrofitted hydrogen pipelines, brownfield gas pipelines, CO_2 from DAC
- 2025, baseline cost scenario, high cost new hydrogen pipelines, greenfield gas pipelines, biogenic CO_2
- 2050, baseline cost scenario retrofitted hydrogen pipelines, brownfield gas pipelines, biogenic CO_2
- 2025, optimistic cost scenario, high cost new hydrogen pipelines, greenfield gas pipelines, biogenic CO_2
- 2050, optimistic cost scenario retrofitted hydrogen pipelines, brownfield gas pipelines, biogenic CO_2

We assume that biogenic CO_2 is available for 50 USD/t. In addition to the import cost, we add a markup for storage costs of 5.2 EUR/MWh for hydrogen and 3.3 EUR/MWh for SNG. The storage costs are derived from model results by Keutz and Kopp (2024), who calculate hydrogen and natural gas storage requirements for climate neutrality scenarios and different weather years. We levelize the storage costs by dividing them by the annual demand.

Appendix D. Parametrization of grid costs

Equation D.1 specifies the calculation of the baseline grid costs for gas, hydrogen, and electricity grids depending on the energy density of the settlement type by:

$$f(x) = \Big(1 + \frac{(1+a)\overline{gf} - \overline{dc}}{\overline{dc}}\Big) b x^{c} \tag{D.1}$$

, where a is the baseline assumption of future increase of grid fees compared to 2023 levels, $\overline{gf}$ are the average grid fees for households (decentral heating) or commercial (central heating) of 2023, $\overline{dc}$ are the average gas or power distribution cost of the German distribution system operators, b and c are parameters of a power function fitted to the distribution cost over energy density data of the German distribution system operators. Table D.7 shows the parameters for the calculation of the grid fees according to Equation D.1

Table D.7: Calculation of scaled grid fee functions

$f(x)$ $[\frac{\text{ct}}{\text{kWh}}]$	x $[\frac{\text{MWh}}{\text{ha}\cdot\text{yr}}]$	$\overline{gf}$ $[\frac{\text{ct}}{\text{kWh}}]$	$\overline{dc}$ $[\frac{\text{ct}}{\text{kWh}}]$	a [-]	b [-]	c [-]
Gas grid costs decentral	Gas density	1.89	0.956	0.5	4.7884	-0.307
Gas grid costs central	Gas density	1.48	0.956	0.3	4.7884	-0.307
Hydrogen grid costs decentral	Gas density	1.89	0.956	1	$\frac{4.7884}{0.8}$	-0.307
Hydrogen grid costs central	Gas density	1.48	0.956	1.1	$\frac{4.7884}{0.8}$	-0.307
Power grid costs decentral	Power density	9.35	3.275	1.5	11.193	-0.268
Power grid costs central	Power density	7.42	3.275	1.6	11.193	-0.268

Appendix E. Extrapolation of heat losses for rural settlements

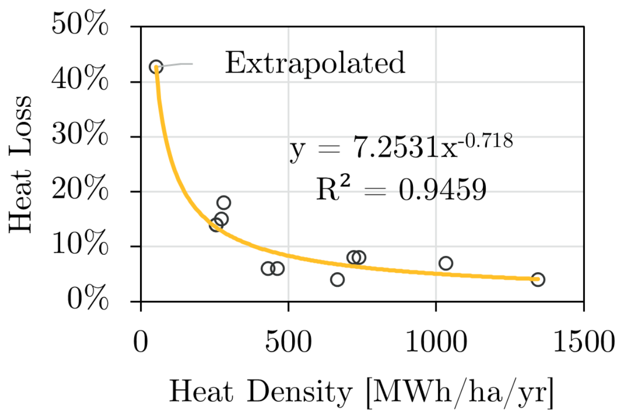


Figure E.10: Extrapolation of heat loss over heat density for the rural settlement

Appendix F. Calculation of the annual COP

We calculate the annual COP for power-controlled heat pumps with inverters in bivalent monoenergetic operation according to the standard VDI 4650 part 1. The temperature spread between the supply and return of the heating systems is 10 K. The domestic hot water temperature is 60°C. For decentralized heating, we assume that the heat pump is used for space heating and domestic hot water heating. The annual COP of AtW heat pumps for decentralized heating is represented by a range based on German climate conditions. The minimum and maximum values of the range are calculated with standard outdoor temperatures of -8°C and -14°C[17]. The annual COP of WtW heat pumps for decentralized heating is calculated assuming a constant groundwater temperature of 10°C. The energy consumption of the well pump is taken into account. For central heating with heat pumps, we assume that the domestic hot water is heated via the heating grid. We assume a temperature spread of 10 K between the heating grid and the supply temperature of the building. Suppose the domestic hot water temperature is higher than the temperature of the heating grid minus the temperature difference of 10 K. In that case, the remaining domestic hot water heating is done via a heating rod. The annual COP is the weighted average of the heat pump's annual COP and the heating rod's efficiency. The VDI 4650 is defined for supply temperatures up to 60°C. Annual COP for supply temperatures larger than 60°C are linearly extrapolated.

[17]The standard outdoor temperature (German: Normaußentemperatur) is the lowest temperature of a cold period, which must have been maintained 10 times within 20 years over a period of at least two consecutive days. The range of -8°C and -14°C represents the majority of regions in Germany. Only islands or places in the Alps can have lower or higher standard outdoor temperatures (BWP (2023)).