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

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HIGHLIGHTS

- 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 heterogeneity in settlement types and buildings.
- SNG does not seem economical in the long term, even though it could utilize existing infrastructure in the short term. For most of the investigated combinations of input parameters, either hydrogen or heat pumps are cheaper than SNG.
- There seems to be a limited scope for decentralized hydrogen boilers. According to our results, hydrogen may be economical only at low hydrogen prices in rural settlements.
- Settlements with higher heat densities preferably use heat pumps unless hydrogen prices are very low. High hydrogen prices and hydrogen grid fees can deteriorate the competitiveness of hydrogen boilers.
- The decision between decentralized and centralized heat pumps requires a case-by-case analysis, considering local heating grid costs, energy efficiency of existing buildings, and potential synergies with combined heat and power and industrial waste heat.
- High heating densities in cities and neighborhoods with high supply temperatures favor centralized heat pumps. In contrast, decentralized heat pumps seem more economical in rural areas and neighborhoods with lower supply temperatures.

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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 the uncertainty regarding future energy prices and infrastructure costs. The present article aims to disentangle this complexity by comparing the future costs of various decentralized and centralized climate-neutral heating options. Using Germany as a case study, we calculate the future levelized cost of ten heating technologies for different building and settlement types and a wide range of assumptions for uncertain parameters, including energy prices and grid fees. We find that electric heat pumps are most often the economical choice within the considered range of inputs. Decentralized heat pumps appear to be preferable in rural areas, while heating grids with central heat pumps seem equally attractive in more urban areas. Hydrogen boilers would be cost-efficient only in scenarios with low hydrogen prices and, even then, often limited to rural settlements. Heating with synthetic natural gas seems unlikely to be economical across a broad range of plausible assumptions. Our results allow us to draw conclusions for policymakers in the German context and offer insights for similar policy debates in other countries.

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 globally in curbing these emissions (IPCC, 2022). On the national level, some countries have developed clear strategies for heat decarbonization: for instance, Denmark, Finland, and Sweden use district heating to

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supply low-carbon heat to many households, partially complemented by water or ground-source heat pumps for detached houses, while France and Italy focus on water and air-sourced heat pumps (Kerr and Winskel, 2021; Witkowska et al., 2021; Sovacool and Martiskainen, 2020). Meanwhile, other countries, including Germany and the UK, have witnessed heated policy debates on decarbonization pathways and the corresponding regulation of the heating sector (Thomas, 2023; Meakem, 2023).

In Germany, for instance, where two-thirds of residential buildings are heated with fossil fuels today (c.f. BDEW, 2023), legislators have proposed a minimum renewable energy requirement for new heating systems under the *Law on Building Energy*. This would have effectively banned new combustion boilers and mandated the use of electric heat pumps. Following debates over the high investment costs of heat pumps and the lack of technological openness, the requirement was broadened to include combustion boilers fueled with climate-neutral gases, including electrolytic hydrogen or synthetic natural gas (SNG). Recognizing uncertainties in infrastructure availability, policymakers tied the requirement's implementation to the publication of municipal heat plans, which are to be developed by 2026–2028, depending on municipality size (GEG, 2023; WPG, 2023). This shifts responsibility for determining cost-efficient, climate-neutral heating solutions to the municipalities.

How to cost-efficiently achieve climate-neutral residential heating can be a complex question. Although the majority of existing studies conclude that electric heat pumps are advantageous over climate-neutral gases for residential heating (c.f. Rosenow, 2022), they also reveal that there is great heterogeneity and uncertainty in many of the relevant input parameters. First, buildings vary in size and insulation, and settlements differ by heating density (Kotzur et al., 2020; Heitkoetter et al., 2021). Second, 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). Third, future costs of climate-neutral energy commodities, such as renewable electricity, electrolytic hydrogen, or synthetic natural gas (SNG) (Moritz et al., 2023; Liebensteiner et al., 2023), the future costs of technologies like heat pumps (Chaudry et al., 2015), and the future level of insulation are uncertain. Finally, infrastructure costs and related grid fees are also uncertain for electricity, hydrogen, and district heating due to potential reinforcement, retrofit, and expansion requirements, and for synthetic natural gas due to potentially declining demand (Pena-Bello et al., 2021; Kopp et al., 2022). Previous studies have addressed these factors individually (e.g. Kotzur et al., 2020; Czock et al., 2025; Billerbeck et al., 2024) analyze building heterogeneity, (Chaudry et al., 2015; Knosala et al., 2022; Czock et al., 2025) consider fuel price uncertainty, and (Lux et al., 2022; Billerbeck et al., 2024) model infrastructure (see Appendix A for a detailed literature review). Yet, a systematic approach that jointly analyzes the various heterogeneities and uncertainties is lacking.

This article aims to disentangle the effects of these heterogeneities and uncertainties on the cost efficiency of heating options. Which climate-neutral heating options are cost-efficient under which conditions? What is the joint impact of building and settlement types, energy prices, infrastructure cost, and investment cost on the cost efficiency of different climate-neutral heating options? To answer these research questions, we calculate the future levelized cost of heating (*LCOH*) for a wide range of input assumptions that reflect the heterogeneity of building types, settlement structures, and technology options in great detail. Specifically, we consider different supply temperatures to reflect heterogeneity in building energy efficiency, four different settlement types to reflect heterogeneity in heat density, and ten different heating options. The technology options include decentralized air-to-air (AtA) heat pumps and electric boilers, as well as decentralized and centralized air-to-water (AtW) and water-to-water (WtW) heat pumps, hydrogen boilers, and synthetic natural gas (SNG) boilers (see Methods for the derivation of this selection). Furthermore, we conduct a variety of sensitivity analyses on uncertain future electricity, hydrogen, and SNG prices, as well as grid fees and technology costs. Motivated by the recent policy debate and ongoing heat planning processes, we use Germany as a case study for our analysis. While uncertainty prevents us from drawing definitive conclusions about the future cost efficiency of different climate-neutral heating options, our approach enables us to provide insights into the conditions under which the various options would be most economical.

With this, we make three distinct contributions to the existing literature. First, we capture building heterogeneity and uncertainty regarding fuel prices and infrastructure costs in one analysis. Second, we systematically compile a detailed dataset on heating technology costs by system size, estimated future grid fees or costs by infrastructure and settlement type, and estimated future energy prices by energy carrier, which may prove helpful beyond the present analysis. Third, we conduct extensive sensitivity analyses on the cost efficiency of climate-neutral heating technologies. Our results can help assess the robustness of previous academic results and provide guidance for ongoing heat planning as well as related policy debates in Germany and elsewhere.

The remainder of this article is structured as follows: Section 2 details our methods and data, Section 3 presents results, examines the impact of uncertainties and heterogeneities on the levelized cost of heating for 10 technologies, and discusses limitations, and Section 4 concludes with implications for policymakers.

2. Methods and data

This paper investigates the future cost-efficiency of climate-neutral residential heating technologies in terms of their *LCOH*, which is introduced in Section 2.1 below. Hereby, we consider heterogeneity and uncertainty in relevant input parameters concerning buildings and technology, energy prices, and infrastructure, which are summarized in Table 1. We continue with a brief overview of these heterogeneities and uncertainties and provide more details in the subsections below.

Across buildings, heating system costs are heterogeneous because of variances in equipment costs, 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 Section 2.2 and derive cost functions in Section 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 energy efficiency of heat pumps, as discussed in Section 2.4.

Future fuel prices are highly uncertain for many reasons. Hydrogen and SNG prices depend on the investment costs of renewable energy sources, 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 if transported by pipeline or ship. The uncertainty of electricity prices is related to the costs and availability of renewable energy sources in Germany and interconnected countries, the electricity demand for other applications, and the hydrogen price, which we assume will be used for electricity generation if the renewable electricity supply is insufficient. To include fuel price uncertainty, we calculate the *LCOH* over a range of hydrogen, electricity, and SNG price combinations, derived in Section 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, as described in Section 2.6. Within a settlement type, infrastructure costs are heterogeneous and have variance. Moreover, infrastructure costs depend on uncertain developments in the broader energy system, such as the share of heat pumps or the number and

Table 1
Reasons for heterogeneity and uncertainty of investigated parameters.

Group	Parameter	Heterogeneity	Uncertainty
Buildings and technology	Investment cost	Installed equipment, installation complexity, building sizes	Cost degression 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 degression, available import countries and transport modes
	SNG price		Production cost degression, 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

spatial distribution of renewable energy sources connected to the electricity grid. We present our approach for capturing infrastructure cost heterogeneity and uncertainty in Section 2.7.

2.1. LCOH calculation

The metric of levelized cost of energy is 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. We calculate the levelized cost of heat, i.e., the full costs (in EUR ct 2023) of generating one unit (kWh) of useful heat, for different technologies $tech$, installed capacities c, settlement type st, and supply temperatures T, using the following equation:

$$LCOH_{tech,c,st,T} = \underbrace{\frac{\overbrace{I_{tech,c}\frac{r(1+r)^t}{(1+r)^t-1}}^{\text{CAPEX}} + \overbrace{FOM_{tech,c}}^{\text{fixed OPEX}}}{flh}}_{\text{fixed costs}} + \underbrace{\Big(\overbrace{p_{tech}}^{\text{energy}} + \overbrace{g_{tech,d(st)}}^{\text{grid fees}}\Big)\overbrace{\frac{1}{\eta^{sys}_{tech,T}}}^{\text{conversion efficiency}}\overbrace{\frac{1}{1-L_{st}}}^{\text{heat loss}} + \overbrace{hdc_{d(st)}}^{\text{heat distribution}}}_{\text{variable costs}} \quad (1)$$

Table 2
Units and description of variables in Equation 1.

Variable	Unit	Description
$LCOH_{tech,c,st,T}$	ct/kWh$_{th}$	Lifetime levelized cost of the heating system $tech$ with heating capacity c in a settlement st and buildings with the nominal supply temperature T
$I_{tech,c}$	ct/kW$_{th}$	Specififc investment costs of the heating system $tech$ with the heating capacity c
$FOM_{tech,c}$	ct/kW$_{th}$/a	Fixed operation and maintenance costs of the heating system $tech$ with the heating capapcity c
flh	h/a	Full load hours per year
r	%/a	Interest rate
t	a	Lifetime
p_{tech}	ct/kWh	Energy price for the energy carrier used by the heating system $tech$
$g_{tech,d(st)}$	ct/kWh	Grid fees for heating system $tech$ in a settlemnt st with heating density $d(st)$
$\eta^{sys}_{tech,T}$	%	Conversion efficiency of the heating system $tech$ in a building with the nominal supply temperature T
L_{st}	%	Heat losses of the heating grid in settlement type st
$hdc_{d(st)}$	ct/kWh	Heat distribution cost for a settlement st with the heat density $d(st)$

Table 2 gives an overview of the variables used in Equation (1). $I_{tech,c}$ represents the investment costs of the heating system, which depend on the chosen technology $tech$ and the capacity c. We calculate the investment costs $I_{tech,c}$ as a function of capacity from equipment and installation costs by designing heating systems according to established planning practices. We use the annuity method as described in (VDI, 2012) to transform the capital costs of the initial investment into annual costs. The Python code for the calculations can be found in the supplementary material.[1] p_{tech} is the per kWh energy price for the energy carrier used by $tech$. In the case of SNG, it is expressed as a function of the hydrogen price given the ratio ρ between hydrogen and SNG, i.e., $p_{SNG} = \rho \cdot p_{H_2}$. $g_{tech,d(st)}$ represents estimated future grid fees, which we use to approximate electricity, hydrogen, and SNG infrastructure costs, depending on the heating technology $tech$ and the settlement's energy density d. $\eta^{sys}_{tech,T}$ is the conversion efficiency of the heating system $tech$ depending on the supply temperature T and is calculated in Equation (2). L_{st} represents the heat losses of the heating grid in the settlement type st, and $hdc_{d(st)}$ are the heat distribution costs for a settlement with the heat density d. Both $hdc_{d(st)}$ and L_{st} are equal to zero in the case of decentralized heating. All costs refer to EUR 2023.

Based on Equation (1), we understand the $LCOH$ as an approximation of heating costs from a system perspective rather than private costs. Thus, we exclude explicit price components that affect consumer prices but are merely a monetary transfer, such as end-consumer taxes on both energy and investment costs (e.g., VAT or energy-specific taxes). We were unable, however, to exclude implicit taxes, such as labor taxes, the implications of which are discussed in Section 3.4. Furthermore,

[1] File CODE_investment_cost_calculation_heating_systems.py.

Table 3
Technologies and deployment options.

Energy carrier	Decentralized deployment	Centralized 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

we neglect existing heating systems based on the assumption that they will end their lifetime before climate neutrality is reached. By contrast, we assume that existing heat distribution systems inside the buildings (piping and radiators) have longer lifetimes and can be used by radiator-based heating systems without further costs.[2] Similarly, we implicitly consider existing electricity and gas infrastructures, which also have longer lifetimes, because these affect the projections we use for future grid fees to approximate infrastructure costs (see Grid fees and costs below). Hence, our analysis is representative of existing rather than newly built settlements and buildings.

2.2. Heating systems

We calculate the *LCOH* for ten different technology setups that reflect general decarbonization options which are available and scalable everywhere in Germany (see Table 3). Due to limited availability and scalability, we do not consider geothermal or waste heat, although these heat sources provide significant quantities of climate-neutral heat in specific locations already today (e.g., in Munich). We consider four technologies that can be used in centralized and decentralized 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 decentralized deployment only, namely air-to-air (AtA) heat pumps and electric boilers. AtA heat pumps can only be deployed decentrally because they transfer heat directly to indoor air. We do not consider centralized electric boilers because their investment costs are already low when deployed decentrally. Even if investment costs were to decrease to zero in centralized deployment, heat distribution costs and losses would still outweigh the investment cost savings.

System flow sheets for all options are provided in Fig. D.11. The capacity of the decentralized heat generators is designed to provide both heating and hot water, except for 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 smaller than the peak demand, and the difference between the heat pump capacity and the peak demand is covered by an electric heater (cf. Buderus (2019)).[3] For centralized heating, we consider that the capacity of the centralized heat generator is smaller than the sum of the peak heat load of all supplied buildings. This reduction of the aggregated peak is referred to as the simultaneity factor. We use a settlement-type specific simultaneity factor taken from AGFW (2001). Finally, we assume that the temperature of heating grids is aligned with the supply temperature of space heating in the supplied buildings. This reflects the 4th generation of district heating systems. Centralized heating with heat pumps is complemented by decentralized electric heaters for hot water when the grid temperature is too low to achieve a minimum hot water temperature of 55 °C, which is necessary to meet hygiene standards.

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, thereby accounting for scale effects. For the equipment costs, we collected 555 list prices on the relevant heat generators as well as thermal storage from five manufacturers. For the installation costs, we collected 36 data points from eight installation firms in Germany. 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). 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 (see Appendix B for more details). For some cost functions, we were unable to obtain sufficient publicly available 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 add 20 % to the equipment costs to account for the contribution margins of installation firms (see Appendix C). The fixed operation and maintenance costs are parameterized as a function of the installed capacity. Fig. 1 shows the fitted equipment and installation cost functions.

Based on the equipment and installation cost functions, we calculate the investment costs for all heating systems. The investment costs of the heating systems include the costs of the heat generation central inside the buildings in case of decentralized heating. In case of centralized heating, the investment costs include the district heating stations, and the domestic hot water generation system inside the buildings as well as the cost of the heat generation central of the heating grid, which is located outside of the buildings. Fig. D.11 shows flowsheets featuring all components included in the heating system's investment costs (for more details on the investment cost calculation, see Appendix C. Fig. 2 shows the resulting specific investment costs of all heating systems over the installed heating capacity.[4] See Fig. C.10 for the cost structure of the heating system investment costs.

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 yet as widespread as boilers and may benefit from learning effects as 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 conduct a sensitivity analysis with different heat pump equipment cost degressions. We use today's cost (0 % cost degression) as the lower bound for the sensitivity analysis. For the upper bound and baseline values, we calculate cost degression based on heat pump growth factors and learning rates. The upper bound assumes a 60 % cost reduction, derived from a heat pump growth factor of 13 taken from the Net Zero Scenario of the World Energy Outlook (IEA, 2023) and an optimistic 20 % learning rate. The baseline assumes a 30 % cost degression, using a more conservative growth factor of 5 and a 15 % learning rate.

2.4. Conversion efficiency

Equation (2) shows the calculation of the conversion efficiency of fuel to heat for different heating systems. $SPF_{3\,tech,T}$ is the heat pump's seasonal performance factor including the backup heating rod and η^{boiler}_{tech} is the conversion efficiency of boilers. We assume that the conversion

[2] For AtA heat pumps, which are not radiator-based, the cost for installing inside units and refrigerant ducts is included in the installation cost function, as typical existing buildings in Germany have no refrigerant ducts, which could be re-used.

[3] Note that most of the data we use to parameterize heat pump costs and efficiency refers to inverter heat pumps that can operate under partial load and supply high flow temperatures.

[4] The kink in the specific investment costs of SNG and hydrogen boilers is caused by the discontinuous equipment cost function for gas boilers (see Appendix B for explanation).

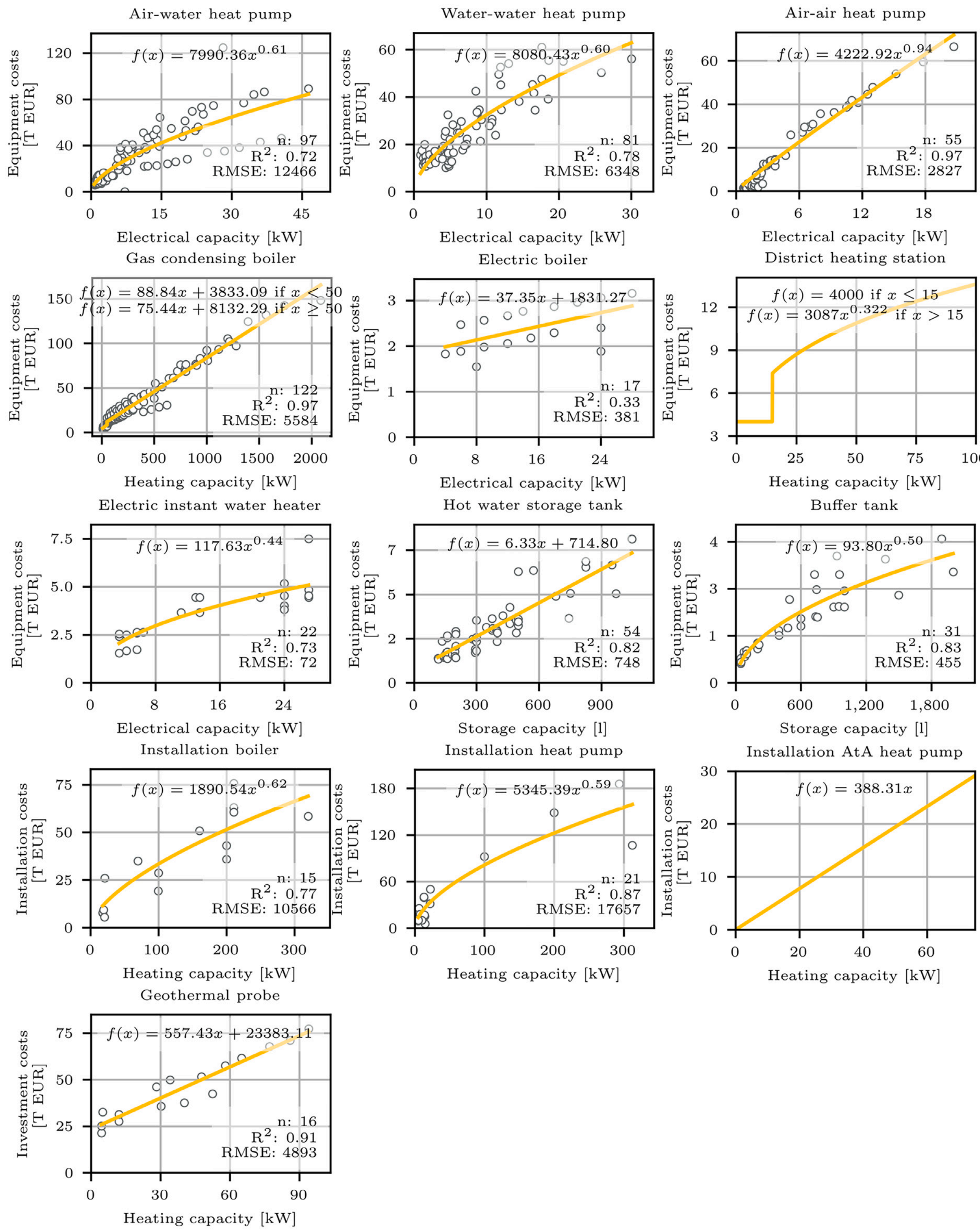

Fig. 1. Equipment and installation cost functions showing the relationship between capacity and costs. n shows the sample size, RMSE is the root mean squared error of the function. Eqipment costs are calculated from manufacturers list prices, installation cost functions are calculated from offers of installation firms and include the costs for installation and small material.

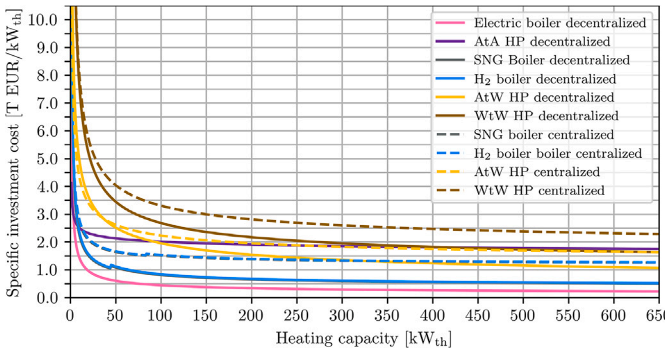

Fig. 2. Specific investment costs of heating systems over installed capacity. Note that the curves for SNG boiler and H_2 boiler costs are almost identical and overlap.

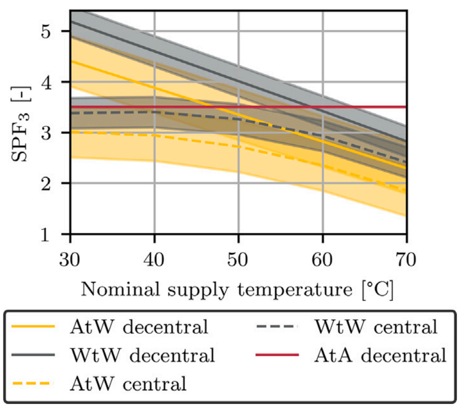

Fig. 3. Relationship between the heat pump's seasonal performance factor SPF_3 and the heating system's nominal supply temperature. Areas reflect ranges in the underlying data.

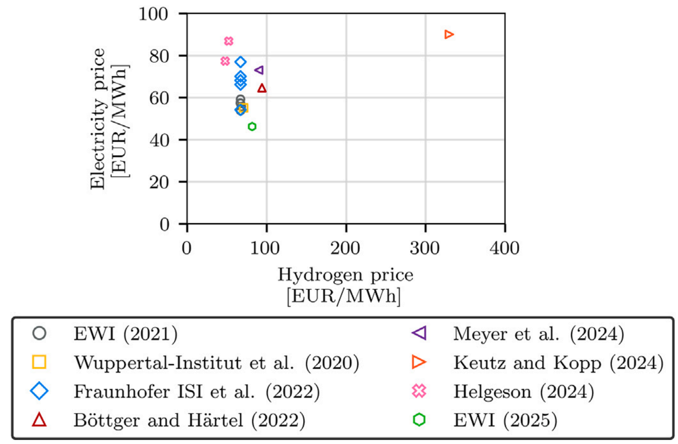

Fig. 4. Hydrogen and electricity prices in climate neutral energy system scenarios for Germany.

efficiency of boilers does not depend on the supply temperature.

$$\frac{1}{\eta^{sys}_{tech,T}} = \begin{cases} \frac{1}{SPF_{3\,tech,T}} & \text{if } tech \text{ is a heat pump} \\ \frac{1}{\eta^{boiler}_{tech,T}} & \text{if } tech \text{ is a boiler} \end{cases} \qquad (2)$$

For heat pump systems, we consider the dependency of the seasonal performance factor SPF_3 on the nominal supply temperature. In the context of this paper, we understand the nominal supply temperature as the minimum necessary supply temperature to enable sufficient heat transfer from the radiators into the room to cover a building's heat load. 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 (see Fig. 3 for typical temperature ranges of different radiator types).

The SPF_3 measures a heat pump's efficiency over an entire year, dividing the annual heat supply by the annual power consumption of the heat pump. It depends on the temporally varying heat source and sink temperatures and heat demands throughout the year. We estimate SPF_3 for AtW and WtW heat pumps according to the Lämmle et al. (2022) and the SPF_3 of AtA heat pumps based on EWI (2025); Eguiarte et al. (2020). A detailed explanation of the assumptions can be found in Appendix H.

2.5. Energy prices

We calculate the *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-induced declines in production costs and uncertainty regarding transport costs and the structure of the hydrogen market that has yet to emerge. Not least, the hydrogen demand for heating may influence the price of hydrogen. To capture all this uncertainty, 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. Data for today's hydrogen production costs vary greatly, 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 is set by the lower end of price projections for 2050 at around 50 EUR/MWh (Merten and Scholz, 2023; Moritz et al., 2023).

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 those of green hydrogen. Contrarily, the transport costs are higher for hydrogen than for SNG due to hydrogen's lower volumetric energy density. We use import costs to calculate the price ratio between SNG and hydrogen. For both fuels, we calculate the average costs of imports to Germany from the 15 origin countries with the lowest import costs for a wide range of production and transport cost scenarios (Moritz et al., 2023; EWI, 2024b). In addition to the import costs, we include a markup for storage costs (see Appendix F). The results are displayed in Fig. 5. It reveals that the SNG-hydrogen 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

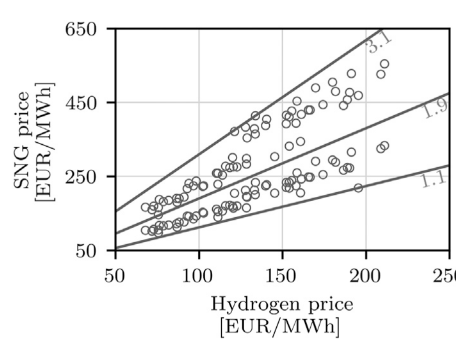

Fig. 5. Hydrogen and SNG costs based on Moritz et al. (2023); EWI (2024b) and the resulting price ratios.

boundaries and set to 1.9 in the baseline scenario, which is the average ratio in the data.

Future electricity prices are inherently uncertain, shaped by demand, the generation mix, and fuel costs. As a baseline, we adopt the mean electricity price (65 EUR/MWh) from recent energy system studies (Fig. 4, y-axis). While real-world electricity prices fluctuate hourly, and the effective cost for heat pumps depends on their consumption profile and flexibility (Ruhnau et al., 2020), we use base prices due to the lack of studies reporting heat-pump-weighted electricity prices in future net-zero energy systems.

Electricity prices will also be influenced by hydrogen prices, a critical factor in heating costs and a key variable in this analysis. The relationship is bidirectional: electricity is converted to hydrogen via electrolysis, while hydrogen powers backup generation. However, Fig. 4 depicts the hydrogen price corresponding to each electricity price (x-axis) and shows that this linkage is not straightforward. To capture the uncertainty in electricity prices driven by hydrogen prices and other factors, we conduct a sensitivity analysis, varying electricity prices between 35 and 95 EUR/MWh, reflecting the range in the referenced studies.

2.6. 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 (types 1, 2, 7 b, and 8). 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 village settlement represents residential areas with detached and semi-detached houses, like larger villages or suburban communities with single- and multi-family dwellings. The primary purpose of rural and village settlements is residential. The urban settlement represents block development, a typical urban building form consisting of large multi-family houses. The typical use of the block development is predominantly residential. 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.

To enable a comparison between centralized and decentralized heating, we analyze standardized districts with a total heat load of 650 kW, corresponding 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 urban and city settlements is scaled accordingly and rounded to whole houses, given the heated area per building. Table 4 shows the characteristics of the four representative settlement types and the corresponding building characteristics. Note that we assume homogeneous buildings within each settlement, except for a sensitivity analysis in which we consider heterogeneous supply temperatures. We discuss the implications of this assumption in Section 3.4.

2.7. Grid fees and costs

Our calculation of future heating costs includes infrastructure costs. Current infrastructure costs exhibit substantial heterogeneity across Germany, some of which can be explained by local heating densities. Additionally, future infrastructure costs are uncertain because they depend on required grid expansion. Residential heating choices themselves may drive part of these expansion costs, but the costs of some infrastructures, e.g., the electricity grid, are influenced by energy system developments that go beyond heating. Here, we use future grid fees to approximate average infrastructure costs within the *LCOH* approach. We do so because current regulation implies that infrastructure costs are distributed to end customers via grid fees. Note that, however, grid fees do not generally reflect marginal grid costs associated with heating technologies (c.f. Hanny et al., 2022).

We employ a two-step approach to derive a baseline assumption for per-kWh grid fees for different settlement types and centralized (district heating) and decentralized (in-building heat generation) distribution cases. First, we use historical data to estimate a functional relationship between infrastructure costs and heating density, which allows for differentiation of grid fees by settlement type. Second, we scale the previously derived cost functions to future levels. To approximate future cost levels, we use estimates of future grid fees for 2045. The estimates of future grid fees are taken from studies that assume that most heating systems use the corresponding infrastructure and consider the corresponding need for infrastructure expansion (e.g., electricity grid fees are estimated for a scenario with a high share of heat pumps and hydrogen

Table 4
Settlement type and building characteristics.

Parameter	Unit	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 decentralized[b]	kW/building	6.5	6.5	34	75
Gross heat load centralized	kW	650	650	646	650
Simultaneity factor[b]	-	0.78	0.74	0.68	0.6
Net heat load centralized[a]	kW	507	481	442	390
Heat distribution loss	%	43[c]	18	8	4
Heat density	MWh/ha/a	51	280	738	1345
Gas density	MWh/ha/a	54	295	777	1416
Electricity density[d]	MWh/ha/a	33	180	475	865
Heat distribution costs	ct/kWh	11.26[e]	3.51	1.80	1.20
Gas grid fees[f]	ct/kWh	3.34/2.83	1.98/1.68	1.47/1.25	1.22/1.04
Hydrogen grid fees[f]	ct/kWh	6.26/5.17	3.72/3.07	2.76/2.28	2.3/1.9
Electricity grid fees[f]	ct/kWh	29.29/26.62	18.59/16.9	14.33/13.03	12.21/11.09

[a] The net centralized heat load is the gross centralized heat load times the simultaneity factor.
[b] The settlement-specific heat load per building and simultaneity factors are based on settlement types by AGFW (2001).
[c] Extrapolated, see Fig. E.12 in the appendix.
[d] 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).
[e] Extrapolated, see Fig. 6.
[f] Decentralized heating / centralized heating.

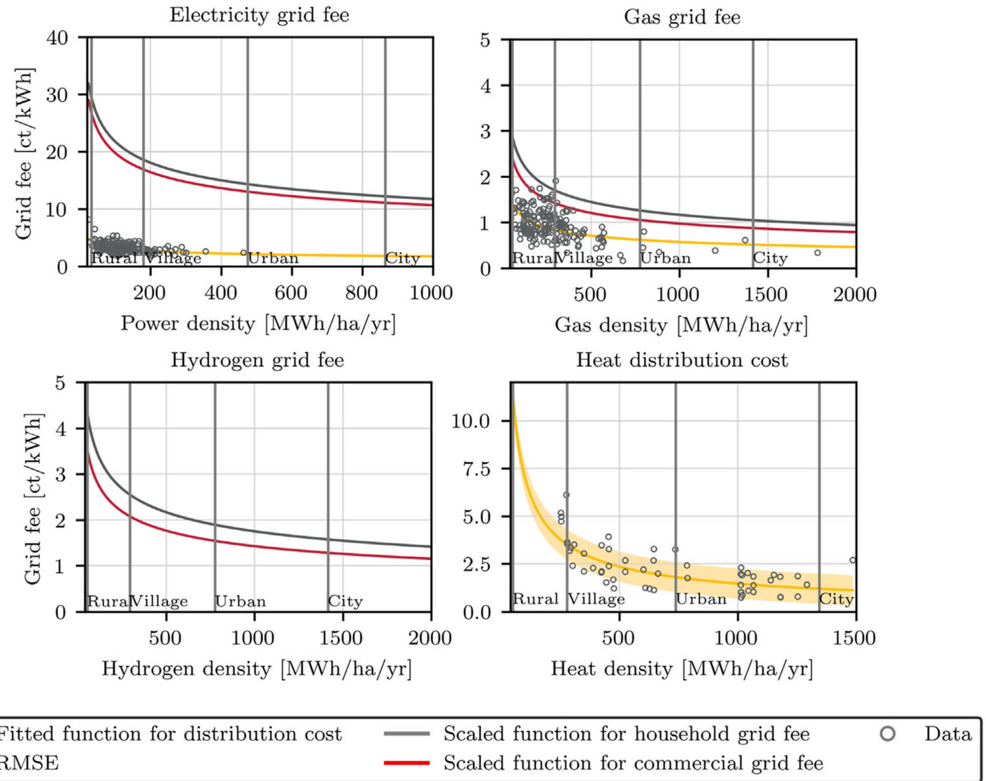

Fig. 6. Reference infrastructure costs for electricity, gas, hydrogen, and heating grids depending on the energy density. The data on electricity grid fees contains an additional data point at a power density of 3,455 MWh/ha/yr.

Table 5
Approximation of future grid fees based on 2045 demand and grid investment cost data in existing studies.

Study	Grid fees decentralized [ct/kWh]	Grid fees centralized [ct/kWh]	Gross electricity demand [TWh]	Grid investment costs [Billion EUR]
ef.Ruhr and EWI (2024)	20–35	14–29	1128	732
Agora Energiewende (2024)	18	16	1267	514
Fraunhofer ISI et al. (2024)	26–27	23	1191–1276	656–681
Bauermann et al. (2024)	27–28	18–22	1080–1300	651

grid fees with a high share of hydrogen boilers). Specifically, we scale the derived cost functions to estimates of future grid fees for households and commercial customers for energy carriers delivered to decentralized and centralized heating systems, respectively. We then use the scaled cost functions to derive point estimates for future grid fees in the different settlement types. The cost functions and resulting assumptions for our baseline scenario are presented in Fig. 6. Note that we vary grid fees in a sensitivity analysis to reflect heterogeneity within settlement types and additional uncertainties. For simplicity, our per-kWh approach neglects the fact that grid fees have fixed and sometimes power-based components in addition to per-kWh components.

Looking at electricity infrastructure costs specifically, historical data on local distribution grid costs and corresponding heating densities are derived from Bundesnetzagentur (2023a). Future electricity grid fees are uncertain and depend on the diffusion and allocation of renewable energy capacity and demand, such as heat pumps. German grid operators (50Hertz Transmission GmbH et al., 2023) and energy system studies such as ef.Ruhr and EWI (2024), Fraunhofer ISI et al. (2024), Agora Energiewende (2024) and Bauermann et al. (2024) expect significant investment needs due to the further deployment of renewables and increasing demand peaks related to heat pumps and electric vehicles. On the other hand, increasing demand could lead to lower grid fees as costs are distributed across a larger base.

For this paper, we estimate future electricity grid fee levels based on projected investment costs and electricity demand from the studies referenced above. Capital costs are derived assuming a weighted average cost of capital (WACC) of 5.5 % and an economic lifetime of 40 years. To approximate full grid costs, we apply a fixed investment-to-operational cost ratio of 1:2 (analogous to ef.Ruhr and EWI (2024)). Per-kWh grid fees are calculated by distributing total grid costs across projected electricity demand in each study. Given that not all sectors contribute equally to grid fees, we account for sectoral exemptions, particularly for certain industrial consumers, and ensure that cost allocation aligns with current voltage-level-based contributions. To do so, sectoral cost-sharing proportions are held constant at today's levels.

The resulting future grid fee levels, which are listed in Table 5 alongside electricity demands and infrastructure costs, range from 16.35 ct/kWh to 27.35 ct/kWh for households (compared to 9.35 ct/kWh today) and 16.42 ct/kWh to 23.42 ct/kWh for businesses (compared to 7.42 ct/kWh today). For the baseline scenario, we adopt the midpoint of projected increases, yielding 21.85 ct/kWh for household customers and 19.92 ct/kWh for business customers. To capture uncertainty, we apply a ±30 % variation around the midpoint, covering the full range of grid fee level estimates, historical variance of grid costs within each settlement type, and additional uncertainty.

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 Fig. 6. 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 (cf. EWI, 2018). This study finds an increase in 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 more uncertain than those of SNG. It is unclear how demand and supply will develop, and a widespread hydrogen 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). Note thatCerniauskas et al. (2020) and Wuppertal-Institut et al. (2020) do not consider decentralized hydrogen heating. The large range can be explained by the different time horizons and underlying demand scenarios. For this article, we derive a baseline assumption from 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 natural gas grid fees, which were 1.7 and 1.3 ct/kWh, respectively. Due to the high uncertainty related to hydrogen grid costs and the heterogeneity in the data on today's gas distribution costs, we vary hydrogen grid fees between −30 % and +30 % in our sensitivity analysis. This 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 depending on the 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. Fig. 6 shows the data and function taken from Erdmann and Dittmar (2010). We conduct sensitivity analyses within a range of −40 % to +40 % for heat distribution costs to address the variance present in the data. The full parameterization for all cost functions estimated for infrastructure costs can be found in Appendix G.

3. Results and discussion

This section examines the impact of uncertainties and heterogeneities on the *LCOH*. We successively focus on uncertainty in the hydrogen price (Section 3.1), uncertainty in other input parameters (Section 3.2), and heterogeneity in supply temperatures (Section 3.3). Finally, we discuss the limitations of our study (Section 3.4). Note that we calculate the *LCOH* for distinct realizations of the uncertain parameters under perfect foresight. Nevertheless, our results can inform decisions under imperfect foresight, as we discuss in Section 4.

3.1. Uncertainty of the hydrogen price

Of the many relevant uncertainties, we first focus on the uncertainty of future energy prices. We investigate this uncertainty by varying the hydrogen price across a range between 50 EUR/MWh (the lowest 2050 cost estimate in Moritz et al. (2023)) and 250 EUR/MWh (today's cost according to EEX (2023)). The price of SNG is assumed to vary with the hydrogen price according to a fixed ratio of 1.9, the average over various supply options and cost scenarios in Moritz et al. (2023). Like hydrogen prices, future electricity prices are uncertain. Initially, we assume an electricity price of 65 EUR/MWh. To account for uncertainty, the electricity price is varied from 35 EUR/MWh to 95 EUR/MWh in a subsequent analysis. This range reflects the projections for net-zero emission scenarios for 2045 in various energy system studies (EWI, 2021; Böttger and Härtel, 2022; Wuppertal-Institut et al., 2020; Meyer et al., 2024; Fraunhofer ISI et al., 2021; EWI, 2025; Keutz and Kopp, 2024; Helgeson, 2024). Additionally, we vary other relevant uncertain parameters, namely electricity, hydrogen, and SNG grid fees, as well as heating grid and heat pump equipment costs. All parameter assumptions are described in detail in the Methods and data section.

Fig. 7 displays the results on *LCOH* as a function of hydrogen prices by settlement type to capture heterogeneity in heat demand density. The most salient observation is that the costs decrease from rural to city settlements, which can be explained by higher energy densities reducing grid fees, heat distribution costs, and heat distribution losses.

Focusing on decentralized heating options (left column in Fig. 7), AtA heat pumps are often the cheapest option, especially in rural and village settlements. AtW and WtW heat pumps tend to be more expensive, implying that their higher investment costs cannot be compensated for by their higher seasonal performance factor. Only in cities and urban settlements with low supply temperatures have AtW and WtW heat pumps *LCOH* close to AtA heat pumps because of the larger average installed capacity per building and related scale effects. WtW heat pumps are particularly expensive in rural and village settlements as the geothermal probe has a high proportion of the costs (see Fig. C.10). The *LCOH* of AtW and WtW converge in urban and city settlements due to larger building sizes. In the following analysis, we refer to the cheapest option among AtW and WtW heat pumps as "decentralized heat pumps". In contrast to hydrogen and SNG boilers, the heat pumps' *LCOH* is unaffected by rising hydrogen prices because we assume electricity and hydrogen prices to be uncorrelated. Among the other technologies, hydrogen boilers are the cheapest. At low hydrogen prices, SNG boilers have low *LCOH* too, but diverge with increasing hydrogen prices, as high SNG prices become more important than the slightly lower SNG grid fees and boiler costs. Electric boilers suffer from relatively high electricity grid fees and prices more than they benefit from low investment costs. Especially in rural areas, the *LCOH* of electric boilers is high due to relatively high electricity grid fees (Fig. 6) and specific investment costs (Fig. 2).

Turning toward centralized heating (right column in Fig. 7), heat pumps are the cost-efficient technology for almost all considered hydrogen prices. Large centralized heat pumps benefit most from scale effects compared to decentralized heating. Scale effects also mitigate the cost difference between AtW and WtW heat pumps, which is why we refer to both as "centralized heat pumps" in the following. Furthermore, the *LCOH* of centralized heat pumps for supply temperatures of 50 °C or below converge because lower supply temperatures do not further reduce the effective seasonal performance factor due to the required complementary direct electric hot water heating (see Fig. 3). Boiler technologies have a higher *LCOH* than heat pumps due to higher energy costs and smaller scale effects. Only for very low hydrogen prices do boilers and heat pumps achieve a similarly low *LCOH*. Put differently, centralized heating is particularly attractive for heat pumps as significant scale effects outweigh heat distribution costs and heat losses.

Across decentralized and centralized heating options, AtA heat pumps are among the cheapest options in all settlements. However, heating with AtA heat pumps may be perceived as less comfortable (c.f. Karmann et al., 2017), and AtA heat pumps may also be used for cooling, which is not accounted for in our *LCOH* comparison. For this reason, we exclude AtA heat pumps from the following analysis. Among the remaining technologies, hydrogen boilers, centralized heat pumps, and decentralized AtW heat pumps are the cheapest options, depending on the settlement type, hydrogen price, and supply temperature. Across settlements, decentralized hydrogen boilers are cost-efficient for lower and heat pumps for medium to high hydrogen prices. In rural settlements, decentralized heat pumps are cost-efficient. In the other settlement types, decentralized or centralized heat pumps can be cheaper, depending on the supply temperature.

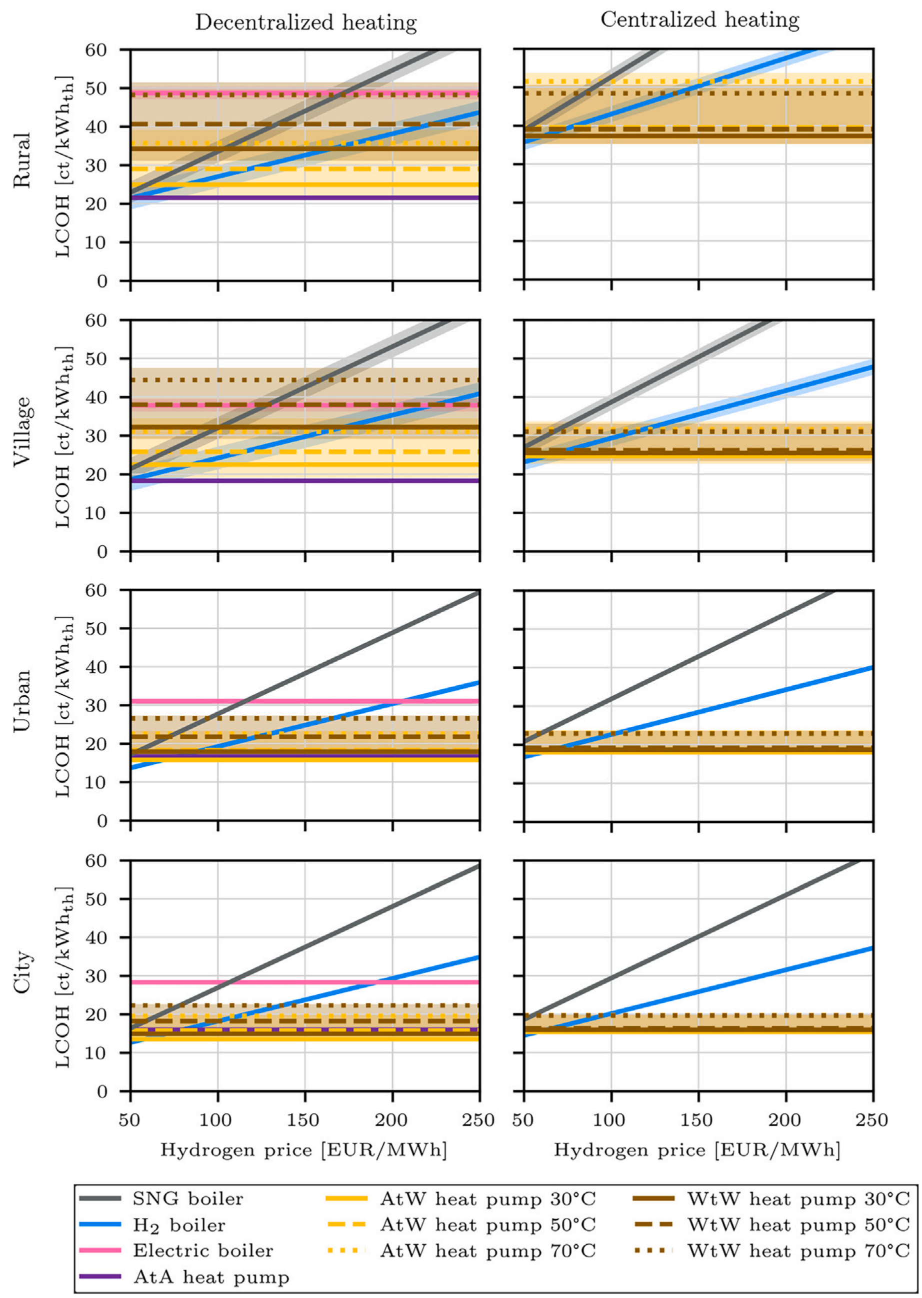

Fig. 7. Levelized costs of heating for decentralized heating depending on the hydrogen price and supply temperature of the heating system. The lines reflect average investment costs, and the areas reflect uncertainty in investment costs.

3.2. Uncertainty in other relevant input parameters

This section analyzes the effect of changes in the previously fixed electricity price, SNG-hydrogen price ratio, grid fees, heating grid costs, and heat pump equipment costs on the cost-efficient heating technology. For these analyses, we consider settlements with heterogeneous supply temperatures. Decentralized options are designed for building-specific supply temperatures, while centralized solutions must cater to the highest supply temperature in the settlement. More precisely, we assume an average supply temperature of 50 °C, the average supply temperature in the current German building stock (Umweltbundesamt, 2023), and a highest supply temperature of 70 °C. Below, we conduct sensitivity analyses for settlements with homogeneous supply temperatures.

Fig. 8 shows the cost-efficient technology and the relative *LCOH* difference between the best and second-best technology for various hydrogen prices and in different settlement types. Each column in the figure represents one settlement type, and each row displays the effect of changing one input parameter.

Overall, we observe that decentralized hydrogen boilers and centralized and decentralized heat pumps are the cheapest technologies for most of the considered parameter variations. In rural settlements (left column), hydrogen boilers or decentralized heat pumps can be cost-efficient, depending on the hydrogen price. In villages, urban settlements, and cities (the other columns), centralized and decentralized heat pumps are most often cost-efficient and almost in cost-parity. Hydrogen boilers become competitive at lower hydrogen prices, and heat pumps do so for some parameter variations when hydrogen prices are higher. The threshold hydrogen price between hydrogen boilers and heat pumps is around 120 EUR/MWh in rural settlements and decreases to around

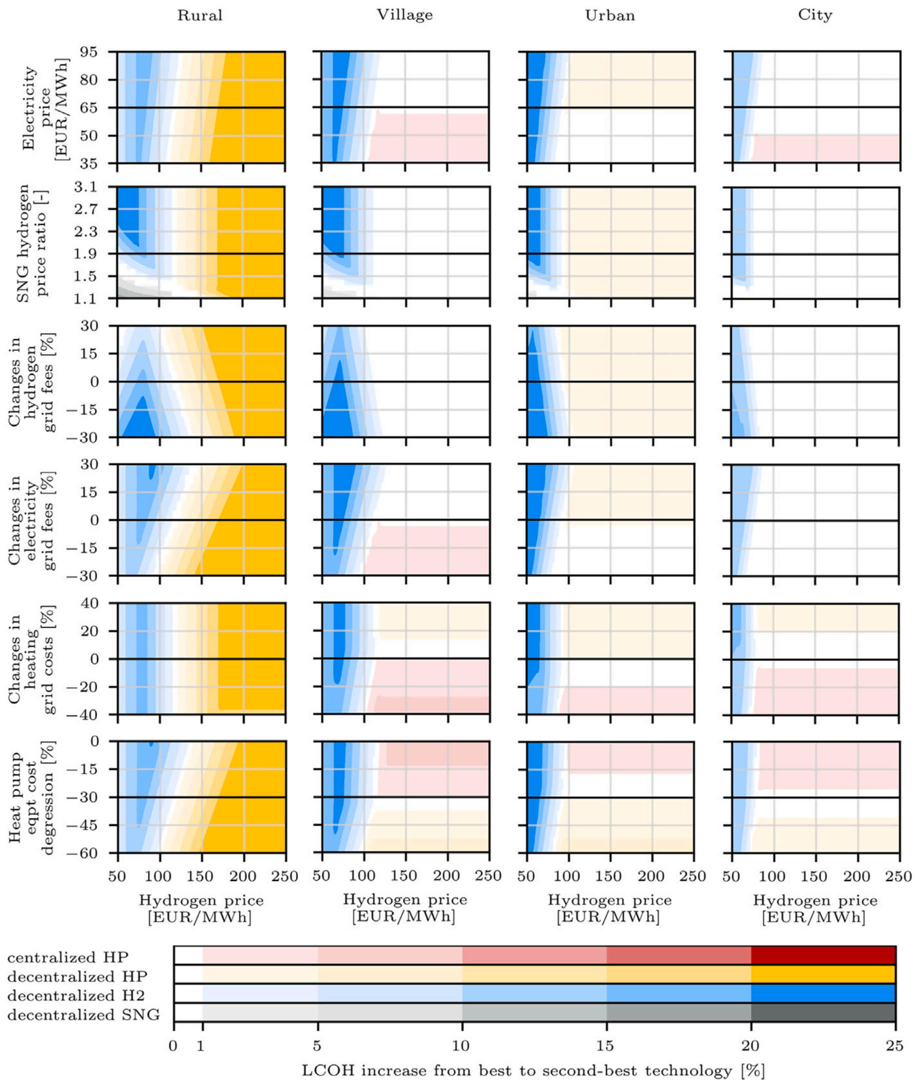

Fig. 8. The impact of uncertain and heterogeneous parameters on the cost-efficient heating technology in different settlement types and buildings with heterogeneous supply temperatures. The maximum supply temperature is 70 °C, the average supply temperature is 50 °C. Color shades indicate the *LCOH* increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article).

80 EUR/MWh in cities. SNG boilers are cost-efficient only if the hydrogen price and the SNG-hydrogen price ratio are at the lower boundary of the investigated parameter ranges.

3.2.1. Varying electricity and SNG prices

The first row of Fig. 8 analyzes the impact of changing the electricity price between 35 and 95 EUR/MWh (our baseline assumption was 65 EUR/MWh). This variation reflects uncertainty about future base electricity prices, which are driven by aspects such as the availability of renewable electricity and changes in the electricity demand for other applications. Furthermore, the heat pump load patterns are uncertain, affecting the effective heat pump load price relative to the base price (Ruhnau et al., 2020). At low hydrogen prices, a high electricity price amplifies the economic viability of hydrogen boilers compared to heat pumps. This effect becomes less pronounced with increasing heat densities due to decreasing heat losses. At high hydrogen prices, a high electricity price favors decentralized heat pumps compared to centralized ones. This is because the higher seasonal performance factor and the absence of heat losses increase the economic attractiveness of decentralized heat pumps.

The second row of Fig. 8 investigates the effect of SNG-hydrogen price ratio variations between 1.1 and 3.1 (our baseline assumption was 1.9). This price ratio is subject to uncertainty due to uncertain future cost degression of electrolyzers, methanation, and a climate-neutral CO_2 source, as well as uncertainty regarding the origin countries of imported fuels. The results show that SNG is hardly cost-efficient in the considered parameter range. If hydrogen is as cheap as 50 EUR/MWh, SNG can compete with hydrogen boilers in rural settlements if the SNG price does not exceed 1.6 times the hydrogen price. For higher hydrogen prices and in more urban settlements, the SNG-hydrogen cost ratio must be even lower to make SNG competitive.

3.2.2. Varying grid fees and grid costs

The third row of Fig. 8 analyzes uncertainty and heterogeneity in hydrogen grid fees. Our baseline assumption for this parameter stems from a future scenario that assumes a relatively high share of hydrogen boilers (EWI, 2024a). We consider a ± 30 % variation relative to this baseline to reflect heterogeneity within the considered settlement types and cost uncertainty. The uncertainty is related to limited experience with hydrogen grids and to the hydrogen demand to which grid costs will be distributed. As expected, we observe that increasing hydrogen grid fees reduces the competitiveness of hydrogen boilers relative to other options. For the example of villages, a 30 % increase in hydrogen grid fees implies that 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 still playing a somewhat larger role in rural settlements and a smaller role in urban settlements and cities.

The fourth row of Fig. 8 examines the effect of varying electricity grid fees. Our baseline assumption of 21.85 ct/kWh represents the average of expected electricity grid fees in 2045, which we derive from several recent studies on grid expansion costs (ef.Ruhr and EWI, 2024; Bauermann et al., 2024; Agora Energiewende, 2024; Fraunhofer ISI et al., 2024). In contrast to the hydrogen grid fees, uncertainty in electricity grid fees is driven not only by future heat demand but also by the diffusion of electric vehicles and renewable generators. Additionally, electricity grid fees can vary within settlements (Bundesnetzagentur, 2023a). We reflect uncertainty and within settlement heterogeneity by a variation of −30 % and +30 % from the baseline. This variation corresponds to the rounded cost range in the studies and includes heterogeneity within the settlements. As expected, we see that higher electricity grid fees favor the economic viability of hydrogen boilers over heat pumps. Furthermore, higher electricity grid fees favor decentralized heat pumps over centralized ones. The competitiveness of the different technologies is more sensitive toward a change in electricity grid fees in rural and village settlements than in urban settlements due to higher baseline grid fees. Overall, increased electricity fees lead to similar effects as higher electricity prices. Among the infrastructure cost sensitivities, electricity grid fees have the highest impact on the cost-efficiency of heat pumps and hydrogen boilers.

The fifth row of Fig. 8 investigates the sensitivity of our results to changes in the heating grid costs. The analysis confirms the intuition that higher heating grid costs promote decentralized technologies, namely hydrogen boilers at low hydrogen prices and decentralized AtW heat pumps at high hydrogen prices. Across settlements, the viability of centralized heat pumps is similarly sensitive toward a change in heating grid costs in villages, urban settlements, and cities. If heating grid costs decrease by 40 %, decentralized heat pumps are cost-efficient in all three settlement types for most considered hydrogen prices, albeit with a cost advantage of less than 10 % compared to decentralized heat pumps. In rural settlements, heating grids remain uneconomical even if heating costs decrease by 40 % due to significantly higher heat distribution costs and heat losses.

3.2.3. Varying heat pump equipment costs

The sixth row of Fig. 8 analyzes the effect of uncertain heat pump equipment costs. In our baseline scenario, we assume that equipment costs decrease by 30 % from today due to learning. We consider a cost reduction between 0 % and 60 % as uncertainty regarding future learning. In rural settlements, decentralized heat pumps intuitively become more competitive relative to hydrogen boilers as heat equipment costs decrease. In the other settlements, the relative cost efficiency of heat pumps compared to hydrogen boilers changes only slightly. Furthermore, we find that equipment cost reductions favor decentralized heat pumps. This is because the share of heat pump equipment costs in the total system costs is larger for decentralized than for centralized heat pumps.

3.3. Heterogeneity in the supply temperatures

The previous sensitivity analyses examined settlements with heterogeneous supply temperatures representing today's distribution with an average of 50 °C (relevant for decentralized heating) and a maximum of 70 °C (relevant for centralized heating). This section looks at settlements with homogeneous supply temperatures.

Fig. 9 shows the sensitivity analysis for a supply temperature of 30 °C, representing a newly developed area with high building energy efficiency. Decreasing the supply temperature improves the economics of both decentralized and centralized heat pumps, but the advantage is larger for decentralized ones. This is because the difference in the seasonal performance factor between decentralized and centralized heat pumps increases at lower supply temperatures (see Fig. 3). As a result, heat pumps become cost-efficient at lower hydrogen prices than in the previous analysis. The threshold hydrogen price between hydrogen boilers and heat pumps is around 80 EUR/MWh in rural settlements and decreases to around 60 EUR/MWh in cities. In rural settlements, decentralized heat pumps have a clear cost advantage of more than 25 % for higher hydrogen prices. In the other settlement types, the cost advantage over centralized heat pumps is mostly less than 15 %. The opposite effect occurs if we assume supply temperatures of 70 °C, e.g., in a settlement with homogeneously low building-specific energy standards (see Fig. I.13 in the Appendix). In this case, centralized heat pumps are favored over decentralized ones. However, centralized and decentralized heat pumps remain almost in cost parity. Also, the threshold hydrogen price between hydrogen boilers and heat pumps shifts to the right and is around 180 EUR/MWh in rural settlements and decreases to around 110 EUR/MWh in cities. Note that, in the future, settlements with lower supply temperatures are likely to occur more often as energetic refurbishment of the existing building stock progresses.

3.4. Limitations

When interpreting these results, several limitations should be considered.

First, to isolate costs from transfers, we excluded explicit taxes, such as VAT, on investment and energy costs. However, we were unable to exclude implicit taxes, such as labor taxes. This may lead to an overestimation of labor-intensive cost components like installation and infrastructure costs and, therefore, a bias in our results toward less labor-intensive heating options.

Second, while our analysis aims to be comprehensive in terms of uncertainties and heterogeneities that affect the future cost-efficiency of heating technologies, we do not investigate possible transition pathways to achieve this future. Potential capital or labor shortages in the context of the system-wide transition may reduce the relative attractiveness of heating options with high implementation effort compared to our analysis, e.g., building new infrastructure.

Third, we do not consider hybrid heating systems. Especially centralized heat pumps could be combined with hydrogen-fired combined heat and power plants or industrial waste heat (c.f. EWI, 2021), which would make heating grids more attractive than our analysis suggests. Similarly, decentralized heat pumps could be combined with existing gas boilers, which could operate as backups based on SNG or biogas. This could reduce peak power demand, heat pump equipment costs, and electricity grid expansion (c.f. Rosenow, 2022; Billerbeck et al., 2024; EWI, 2025). Additionally, we neglect biomass, geothermal, and solar thermal, which could complement both centralized and decentralized technologies, albeit with a (regionally) limited potential.

Fourth, our analysis examines various building and settlement types but assumes homogeneous building stocks within each settlement. We only consider heterogeneity in building supply temperatures within a settlement type. In reality, many settlements have heterogeneous building stocks, which would affect the economics of heating technologies. Larger and less energy-efficient buildings, which have higher heat loads, generally incur greater annual heating costs. In such buildings, decentralized AtW heat pumps tend to have lower *LCOH* due to their large scale effects.

Finally, to be consistent with our exogenous assumptions on grid fees, we only investigate uniform investment decisions, meaning that all buildings in one area use the same heating option. In settlements with heterogeneous buildings, the individual building optimum can differ from the collective optimum. For instance, if the optimal uniform

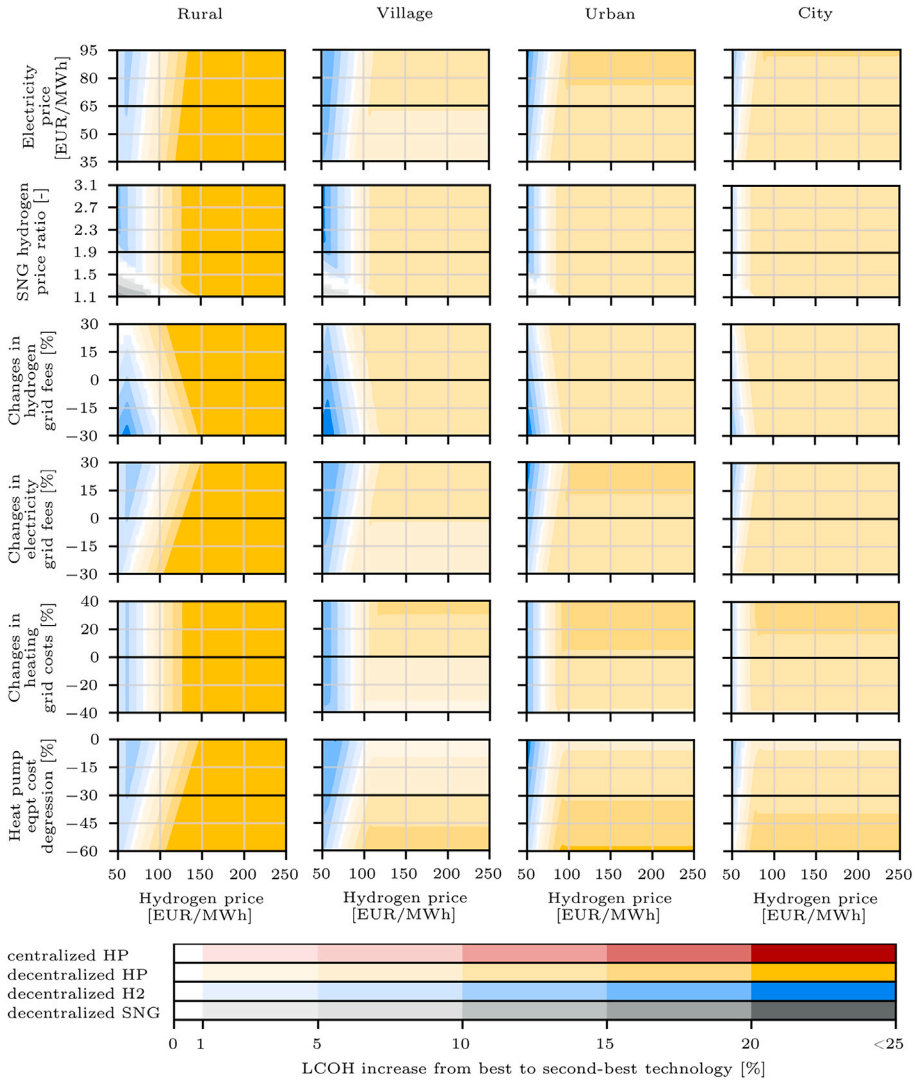

Fig. 9. The impact of uncertain and heterogeneous parameters on the cost-efficient heating technology in different settlement types and buildings with a supply temperature of 30 °C. Color shades indicate the *LCOH* increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article).

decision is to use centralized heat pumps, buildings with low supply temperatures may be incentivized to switch to decentralized heat pumps, increasing the heating grid costs for the remaining consumers. Relative to our results, this may increase the attractiveness of decentralized heat pumps, which use non-heating-exclusive infrastructure, over centralized heat pumps and hydrogen boilers, which use heating-exclusive infrastructure.

4. Conclusion and policy implications

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 heterogeneity in 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, we find that AtA heat pumps are the most cost-efficient technology. While AtA heat pumps may provide additional cooling benefits, their heat may be perceived as less comfortable. If we exclude AtA heat pumps from our technology set, decentralized hydrogen boilers, centralized heat pumps, and decentralized AtW and WtW heat pumps are the most cost-efficient technologies. The relative future competitiveness of these three heating options strongly depends on the settlement type, future hydrogen and electricity prices, infrastructure costs and related grid fees, and potentially decreasing heat pump costs.

Intuitively, hydrogen boilers become less competitive with increasing hydrogen prices, hydrogen grid fees, and heat densities. While hydrogen boilers may be competitive in rural settlements for more parameter combinations, they appear uneconomical in cities across the considered scenarios. Among the heat pump technologies, we find decentralized and centralized heat pumps to be similarly cost-efficient over a wide range of input assumptions. Decentralized heat pumps benefit from higher seasonal performance factors, while centralized heat pumps benefit from significant scale effects on heat pump investment costs. In rural settlements, decentralized heat pumps have a larger cost advantage over centralized ones due to high heating grid costs and heat losses. High electricity prices and grid fees improve the competitiveness of hydrogen boilers, particularly in rural areas, and favor decentralized heat pumps over centralized ones. In settlements with heterogeneous supply temperatures or a homogeneous supply temperature of 70 °C, decentralized and centralized heat pumps are almost in cost parity. In settlements with a homogeneous supply temperature of 30 °C, decentralized heat pumps have a cost advantage over centralized ones.

Our results allow us to draw three main conclusions for policy- and decision-makers in the German context. First, SNG does not seem economical in the long term, even though it could utilize existing infrastructure in the short term. For most of the investigated combinations of input parameters, either hydrogen or heat pumps are cheaper than SNG. Second, there seems to be a limited scope for decentralized hydrogen boilers. According to our results, hydrogen may be economical only at low hydrogen prices in rural settlements. Settlements with higher heat densities preferably use heat pumps unless hydrogen prices are very low. High hydrogen prices and hydrogen grid fees can deteriorate the competitiveness of hydrogen boilers. In this context, a negative feedback loop may emerge in the expectedly small hydrogen market, as potential hydrogen demand for heating may increase hydrogen prices. Given the high uncertainty in hydrogen prices and grid fees, hydrogen boilers also seem to be a riskier option. By contrast, heat pumps are generally less exposed to the risk of increasing energy and infrastructure costs due to their high seasonal performance factor. They may, therefore, be a more economically viable heating choice under imperfect foresight. Third, the decision between decentralized and centralized heat pumps requires a case-by-case analysis, considering local heating grid costs, energy efficiency of existing buildings, and potential synergies with combined heat and power and industrial waste heat. High heating densities in cities and neighborhoods with high supply temperatures favor centralized heat pumps. In contrast, decentralized heat pumps seem more economical in rural areas and neighborhoods with lower supply temperatures. For the example of Germany, making this choice should be the focus of the local heating planning processes, which have just started and are due in 2028.

Next to these immediate conclusions in the German context, our research provides a starting point for further research. Future studies may extend our analysis to other countries. Warmer climatic conditions may reinforce the competitive advantage of heat pumps, while other technologies may benefit in colder climates. In addition, it would be interesting to compare expected future energy prices (including price ratios) and grid fees across countries. In doing so, researchers may build on our proposed method to account for uncertainty and heterogeneity and use and extend our primary dataset of relevant input parameters. Finally, further research could address the above-discussed limitations of our study by investigating the role of transition costs, hybrid heating systems, and non-uniform heating choices.

CRediT authorship contribution statement

Michael Moritz: Writing – original draft, Visualization, Methodology, Conceptualization. **Berit Hanna Czock:** Writing – original draft, Visualization, Methodology, Conceptualization. **Oliver Ruhnau:** Writing – original draft, Conceptualization.

Declaration of competing interest

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. Related literature and research gap

With this article, 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 A.6 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 have captured all of them.

First, Kotzur et al. (2020) and Czock et al. (2025) 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 Czock et al. (2025) use even 770 archetype buildings to reflect building heterogeneity, including the type and age of existing heating systems. Kotzur et al. (2020) neglect infrastructure costs and fuel price uncertainty. Czock et al. (2025) 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 considering 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. On the other hand, these studies simplify the building stock's heterogeneity and neglect future fuel price uncertainty. Note that Kisse et al. (2020) do reflect local heterogeneity in a case study for one neighborhood. Their results cannot be generalized for the German building stock.

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 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 study, 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 focuses 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, except for EWI (2021), who assume a slower diffusion of heat pumps and the repurposing of gas grids for

Table A.6
Parameters considered in this study compared to other studies.

Publication	Building sectorheterogeneity	Infrastructure heterogeneity and uncertainty	Energy priceuncertainty	Heat pump cost uncertainty
Chaudry et al. (2015)			✓	✓
Kisse et al. (2020)	for one neighbourhood	✓		
Kotzur et al. (2020)	✓			
Wuppertal-Institut et al. (2020)	✓	ex-post		
EWI (2021)	✓	ex-post		
Fraunhofer ISI et al. (2021)	✓	✓		
Knosala et al. (2022)		indirectly via end consumer price variation	✓	
Lux et al. (2022)		✓		
Czock et al. (2025)	✓		electricity prices only	
Billerbeck et al. (2024)	✓	✓		
Our analysis	✓	✓	✓	✓

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 searches 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 models 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.

Appendix B. Equipment cost data and functions

We collected list prices for the German market from the manufacturers Buderus, Carrier, Elco, Vaillant, and Viessmann 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. Moreover, we collected data on the installation costs of gas-condensing boilers and AtW heat pumps in Germany from the installation firms Alfons Rott GmbH & Co. KG, E. Altmann GmbH, Guido Schaefer GmbH, König GmbH & Co. KG, Moritz & Barmer GmbH, Octupus Energy, Thermondo, and Wilhöft Heizungsbau GmbH. We fit a cost function to the collected data, with installed capacity as an independent variable. We employ nonlinear least squares fitting using the curve fit function from the SciPy (scipy.optimize) library to estimate the parameters of functions from the data. We 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 represents 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, discontinuous, 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 smaller boilers typically have factory-installed control units 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 Fig. 1.

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 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.

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. We assume identical installation costs for AtW and WtW heat pumps as we calculate the costs of the groundwater well separately. The fixed operation and maintenance costs are parameterized as a function of the installed capacity based on personal communication with Moritz & Bramer GmbH and can be found in C.7. The annual FOM costs of the geothermal probe for WtW heat pumps are calculated as 3 % of the investment costs (cf. 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 % for all major equipment units. Costs for small materials are included in the installation cost functions, which are displayed in Fig. 1.

Regarding energy efficiencies of boilers, gas condensing boilers can have an efficiency of 95 % under optimal conditions (according to manufacturers' information by Buderus, Elco, Vaillant, 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 manufacturers' information by Buderus.

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

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

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 in kW, $P_{out,\max} = 85$ is the largest outside unit available in the manufacturer's price lists, $sc_{branch} = 200$ is the specific cost of a refrigeration line branch in EUR, $bpu = 1$ is the number of refrigeration line branches per inside unit, $sc_{line} = 20$ is the specific cost of a refrigeration line canal in EUR/m, $w = 600$ are the specific wages per person day in EUR/d, $n_{in} = x/P_{in}$ is the number of inside units, $n_{out} = x/P_{out,\max}$ is the number of outside units, where x is the heating capacity of the building in kW, $n_{branches} = n_{in}bpu$ is 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 cost of condensate pump per inside unit in EUR/inside-unit. Equation (C.2) can be simplified to $f(x) = 388.31x$, where x is the heating capacity and $f(x)$ is the installation cost in EUR.

Appendix C. Calculation of heating system investment costs

We design AtW and WtW heat pump systems for bivalent monoenergetic operation. The heat pump is designed to cover the heat load of the building at the bivalence point. The heating rod is designed so that, together with the heat pump, it covers the heating load of the building at the standard outside temperature. The standard outside temperature is defined as the lowest two-day average value reached or fallen below ten times in 20 years. The bivalence point and the standard outside temperature depend on the climate zone. We use the reference climate for Germany in accordance with DIN V 18599–10 (reference location Potsdam). The standard outside temperature in the reference climate is −12.7 °C, and the corresponding bivalence point is −5 °C (according to DIN EN 12831). For the design of AtW and WtW heat pump systems, we approximate the COP of the heat pump as

$$COP^{AtW,WtW} = 0.5\frac{T_{supply}}{T_{supply} - T_{out}}, \quad T \text{ in [K]}, \tag{C.1}$$

where T_{supply} is the supply temperature of the heating system and T_{out} is the outside ambient air temperature. The supply temperature depends on the outside temperature. The maximal T_{supply} is required to provide an inside temperature of 20 °C at the standard outside temperature. We estimate the T_{supply} at the bivalence point, assuming a linear heating curve (c.f. Bader and Ihle (2021)). We design AtA heat pump systems for monovalent operation. The heat pump is designed to cover the heat load of the building at the standard outdoor temperature point. For the design of the AtA heat pump system, we approximate the COP with a formula taken from Eguiarte et al. (2020)

$$COP^{AtA} = 2.85633 + 0.072432T_{out} + 0.000546578T_{out}^2, \quad T \text{ in [°C]}, \tag{C.2}$$

where T_{out} is the outside temperature.

We calculate the investment costs of heating systems, excluding heat distribution outside or within the building. In decentralized heating, these investment costs are the specific investment costs of each building's heating system. In centralized heating, these investment costs are the specific investment costs of the central heat generation system and the decentralized district heating stations in each supplied building. The heat pumps and boilers in most decentralized heating systems are designed to cover heating and hot water demand. Only in AtA heat pump systems is hot water generated by an electric instant water heater. In centralized heating, the heating capacity is designed to be smaller than the heat load of all supplied buildings due to a simultaneity factor. Buffer and hot water storage systems are designed according to typical specific capacities Buderus (2019). Table C.7 shows key assumptions of the investment cost calculation. The calculation details can be found as Python code in the supplementary material (see CODE_investment_cost_calculation_heating_systems.py).

Equipment costs from list prices do not reflect the equipment prices in offers of installation firms. On the one hand, installation firms add a contribution margin to equipment costs to cover their fixed costs. On the other hand, manufacturers often grant a discount to installation firms. Both contribution margin and discounts are not transparent. We are looking for a contribution that calibrates our modeled investment costs well against offers for the installation of heat pumps and gas boilers. We find a contribution margin of 25 %.

Fig. C.10 shows the investment cost structure of the heating systems in different settlement types. The cost structure in the rural and village settlement types is identical because both settlements have the same building type, and the simultaneity factor is very similar. Across settlements, we see that investment costs decrease from the rural to

Table C.7
General techno-economic assumptions.

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 decentralized	[EUR/kW$_{th}$/yr]	25
FOM AtW and WtW heat pumps centralized	[EUR/kW$_{th}$/yr]	2.5
FOM gas and hydrogen boiler decentralized	[EUR/kW$_{th}$/yr]	20
FOM gas and hydrogen boiler centralized	[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 decentralized 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

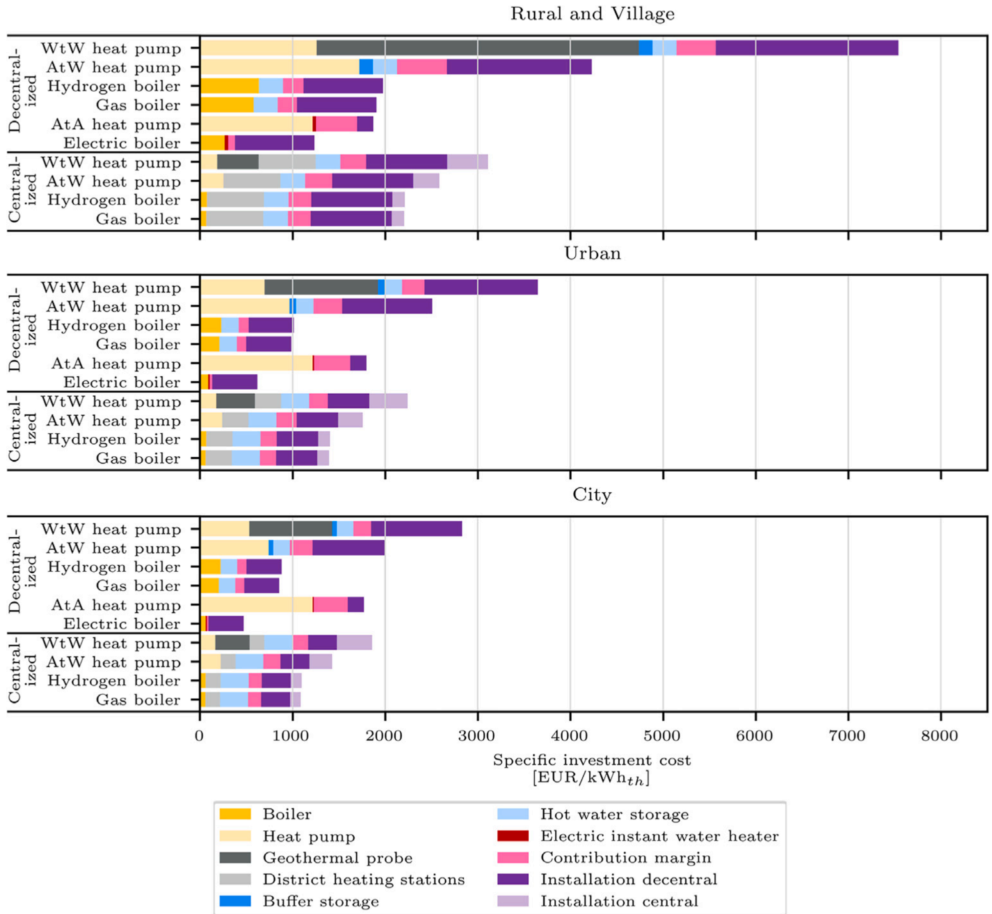
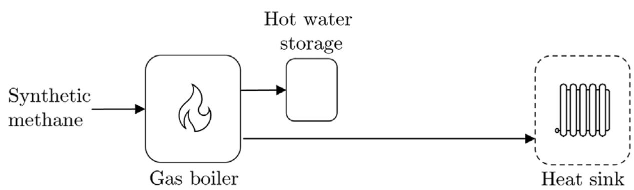


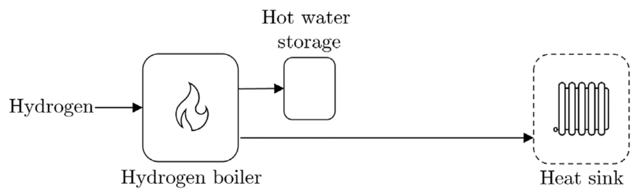
Fig. C.10. Structure of the specific investment costs of different heating systems by settlement type for buildings with a maximal supply temperature of 50 °C.

the city settlement type. For decentralized heating, this decrease is due to scale effects caused by larger buildings. For centralized heating technologies, the decrease is caused by higher simultaneity factors. Across all technologies, installation costs and the contribution margin account for around half of the investment costs. In centralized heating, the majority of the installation costs are for the decentralized district heating stations and hot water storage In decentralized heating, the heat generator most of the equipment costs. In centralized heating, the centralized heat generator accounts for less than half of the equipment costs. Decentralized equipment like district heating stations and hot water storage units make up the remainder of the equipment costs.

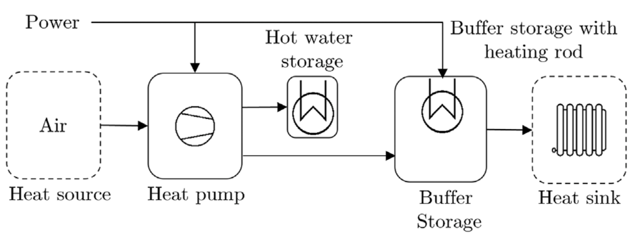
Appendix D. Heating systems



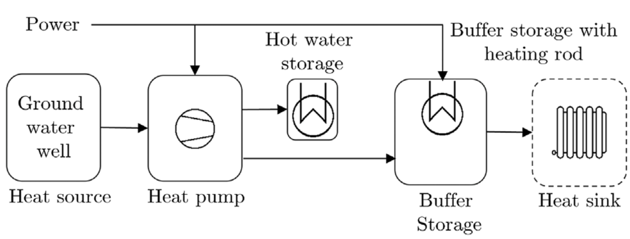
(a) Gas boiler decentral



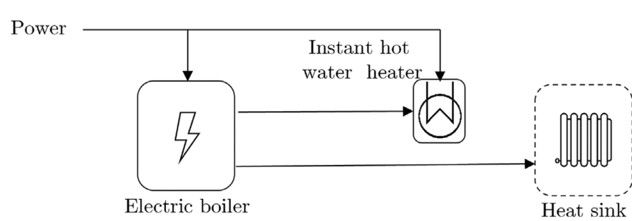
(b) Hydrogen boiler decentral



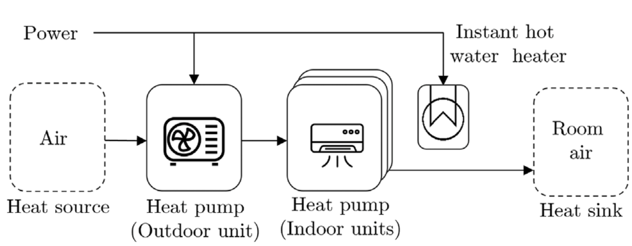
(c) AtW heat pump decentral



(d) WtW heat pump decentral

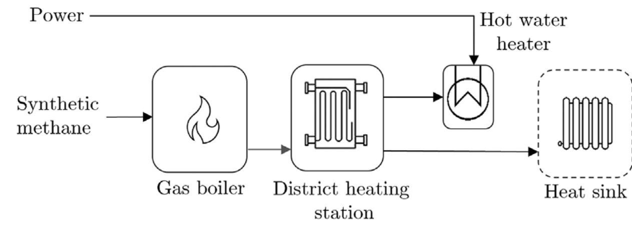


(e) Electric boiler decentral

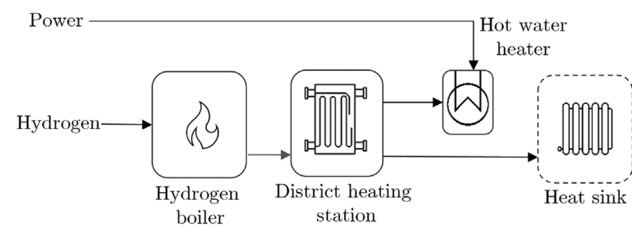


(f) AtA heat pump decentral

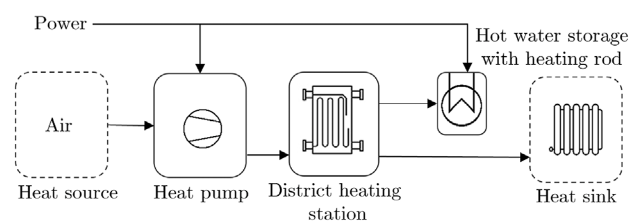
Fig. D.11. (Continued)



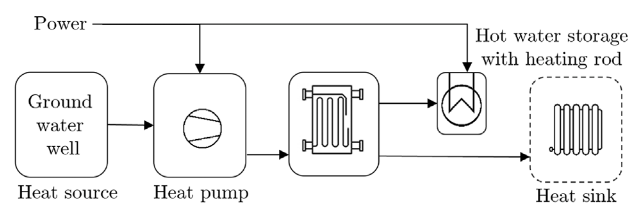
(g) Gas boiler central



(h) Hydrogen boiler central



(i) AtW heat pump central



(j) WtW heat pump central

Fig. D.11. Energy flow charts and major equipment units of the heating systems.

Appendix E. Estimation of heat losses

The heat loss of heating grids depends on the temperature of the grid and the settlement type. The AGFW (2001) provides typical heat losses per settlement type (see Fig. E.12). Due to a lack of information, we assume that these heat losses refer to the average heating grid temperature in Germany. We estimate the grid length weighted average temperature of heating grids in Germany based on data by Agora Energiewende (2023). Further, we assume that heat loss is caused by conduction to the ground with a ground temperature of 10 °C and a temperature spread between supply and return of 20 K. We estimate the heat losses for

Table E.8
Heat losses of a heating grid depending on its supply temperature and the settlement type.

Supply temperature	Rural	Village	Urban	City
40 °C	14 %	6 %	3 %	1 %
60 °C	24 %	10 %	4 %	2 %
80 °C	34 %	14 %	6 %	3 %

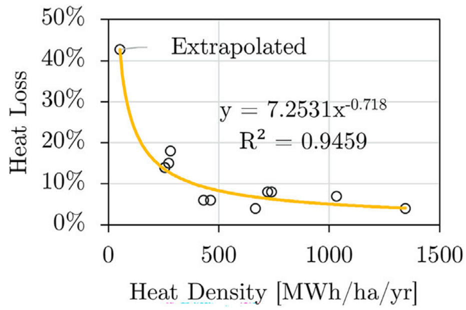


Fig. E.12. Extrapolation of heat loss over heat density for the rural settlement.

different grid supply temperatures based on these assumptions. Table E.8 shows the estimated heat losses. Due to a lack of data, we extrapolate the heat loss for the rural settlement type from existing data according to Fig. E.12.

Appendix F. Hydrogen and SNG price estimation

We use the following scenarios from EWI (2024b) to generate data on import costs for hydrogen and SNG:

- 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 G. Parametrization of grid fees

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

$$f(x) = \left(1 + \frac{(1+a)\overline{gf} - \overline{dc}}{\overline{dc}}\right) b x^c, \tag{G.1}$$

where a is the baseline assumption of future increase in grid fees compared to 2023 levels, $\overline{gf}$ represents the average grid fees for households (decentralized heating) or commercial (centralized heating) in 2023, $\overline{dc}$ denotes the average gas or power distribution cost of the German distribution system operators, and 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 G.9 shows the parameters for the calculation of the grid fees according to Equation (G.1).

Appendix H. Calculation of the seasonal performance factor

Fig. 3 shows the seasonal performance factor SPF_3 of different heat pumps and heating systems. For decentralized heat pumps, the SPF_3 increases linearly with decreasing supply temperature within the considered temperature range. Decentralized WtW heat pumps reach the highest annual COPs as the groundwater has a higher temperature than the ambient air during the heating period. For centralized heat pumps, the SPF_3 is lower than that of decentralized heat pumps at the same supply temperature. This is because the heat sink of the centralized heat pump is the heating grid, whose supply temperature we assume to be 10 K above the supply temperature of the building's heating system. A temperature difference of 10 K is necessary to enable efficient heat exchange between the heating grid and the hydraulically separated heating systems inside the buildings and to compensate for heat losses. We assume that domestic hot water must be heated to 55 °C for hygienic reasons. If the heating grid temperature is too low to provide domestic hot water at a temperature level of 55 °C, centralized heating is complemented with decentralized electric heaters, assuming an energy efficiency of 1. This reduces the slope of the SPF_3 of centralized heat pumps for supply temperatures below 55 °C. Note that considering electric boosters is conservative, as booster heat pumps would be more energy-efficient, although their investment costs would also be higher.

We estimate the seasonal performance factor SPF_3 of AtW and WtW heat pumps using data-based functions. The SPF_3 includes the heat pump, the heating rod, pumps, and ventilators as electrical consumers. Lämmle et al. (2022) provide a functional relationship between the SPF_3 and the mean heat pump temperature based on field measurements in Germany. They also provide the mean heat pump temperature for nominal supply and return temperatures. Based on this data, we derive a linear relationship between the SPF_3 and the nominal supply temperature for the supply temperatures between 30 °C and 70 °C. We also derive an uncertainty range based on the variance in the data. For centralized heating with heat pumps, we assume that the domestic hot water is heated via the heating grid if possible. We assume a temperature

Table G.9
Calculation of scaled grid fee functions.

$f(x)$ $[\frac{ct}{kWh}]$	x $[\frac{MWh}{ha \cdot yr}]$	$\overline{gf}$ $[\frac{ct}{kWh}]$	$\overline{dc}$ $[\frac{ct}{kWh}]$	a [–]	b [–]	c [–]
Gas grid fees decentralized	Gas density	1.89	0.956	0.2	4.7884	−0.307
Gas grid fees centralized	Gas density	1.48	0.956	0.3	4.7884	−0.307
Hydrogen grid fees decentralized	Gas density	1.89	0.956	0.8	$\frac{4.7884}{0.8}$	−0.307
Hydrogen grid fees centralized	Gas density	1.48	0.956	0.9	$\frac{4.7884}{0.8}$	−0.307
Power grid fees decentralized	Power density	9.35	3.275	1.68	11.193	−0.268
Power grid fees centralized	Power density	7.42	3.275	1.34	11.193	−0.268

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 SPF_3 is the weighted average of the heat pump's SPF_3 and the heating rod's efficiency.

For AtA heat pumps, we calculate the SPF_3 for the reference climate in Germany. To that end, approximate the SPF_3 by the heat load weighted average COP. We use an hourly heat load time series from EWI (2025) and estimate the COP of AtA heat pumps based on Equation (C.2).

Appendix I. Sensitivities in settlements with homogeneous supply temperature

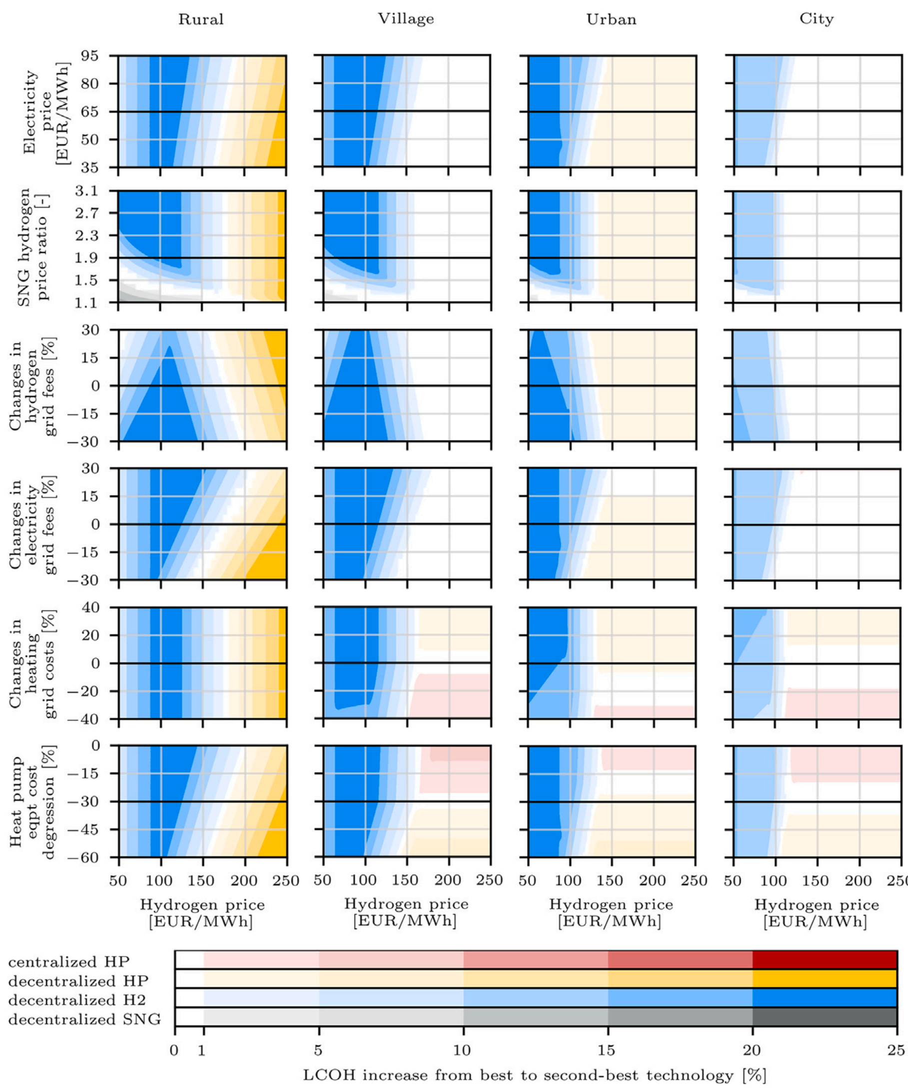


Fig. I.13. The impact of uncertain and heterogenous parameters on the cost-efficient heating technology in different settlement types for buildings with a supply temperature of 70 °C. Colors indicate the cost-efficient technology. Color shades indicate the *LCOH* increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article).

Appendix J. Supplementary data

Supplementary data to this article can be found online at doi:10.1016/j.enpol.2025.114790.

Data availability

Data is available in the supplementary material.

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