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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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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 grid fees. This 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 eleven heating technologies for different building and settlement types and a wide range of assumptions for uncertain parameters, such as energy prices and infrastructure costs. We find that electric heat pumps are most often the economical choice within the modeled range of inputs when they are deployed either decentrally, in rural areas, or centrally, with heating grids in more urban areas. Hydrogen boilers can also be cost-efficient, mainly in rural areas and in scenarios with low hydrogen prices and grid fees or high electricity grid fees. By contrast, heating with synthetic natural gas seems unlikely to be economical across our broad range of plausible input assumptions.

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

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

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Main

Heating homes is one of the major sources of greenhouse gas emissions in regions with cold climates, and little progress has been made on curbing these emissions globally (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 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 UK have seen heated public debates on the decarbonization pathways and 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 wanted to implement a minimum renewable energy requirement for new heating systems in the short term as part of a new *Law on building energy.* This piece of legislation, which would have effectively prevented the installation of new fossil systems immediately. After some debate, policymakers acknowledged the uncertainty regarding the available infrastructure and tied the starting date for the requirement to the publication of local heat plans (GEG, 2023), which municipalities shall develop until 2026-28, depending on their size (WPG, 2023).

How to achieve climate-neutral residential heating can be a complex question, due to heterogeneity and uncertainty in many of the relevant input parameters. First, buildings are heterogeneous in size and in terms of their 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 green energy commodities like electricity, 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 unclear. Finally, infrastrucutre costs and related grid fees are 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).

This article aims at disentangling the effect of these heterogeneities and uncertainties on the question of cost-efficient heating. To this end, 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. More specifically, we consider different supply temperatures to reflect heterogeneity in building insulation, four different settlement types to reflect heterogeneity in heat density, and eleven different heating options. The technology options include decentralized air-to-air (AtA) heat pumps as well as decentrally and centrally deployed air-to-water (AtW) and water-to-water (WtW) heat pumps, and electric, hydrogen, 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 on the future cost-efficiency of different climate-neutral heating options, our approach enables us to provide insights into the conditions under which the different options would be most economical.

With this, we make three distinct contributions to the existing literature. First, while previous studies have covered the important aspects of building heterogeneity (Kotzur et al., 2020; Arnold et al., 2024; Billerbeck et al., 2024), fuel price uncertainty (Chaudry et al., 2015; Knosala et al., 2022; Arnold et al., 2024), and infrastructure (Lux et al., 2022; Billerbeck et al., 2024) individually, we are—to the best of our knowledge—the first to capture them all in one analysis (see Appendix A for a detailed literature review). Second, we systematically compile a detailed dataset on heating technology costs by system size, estimated future grid fees by infrastructure and settlement type, and estimated future energy prices by energy carrier, which may prove useful beyond our own 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 public debates in Germany and elsewhere.

Cost-efficient heating options under energy price uncertainty

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 as according to EEX (2023)). The prices of the other energy carriers are initially assumed to vary with the hydrogen price according to a fixed ratio, as previous studies show that future energy prices are likely to be coupled to each other (Ruhnau, 2022; Böttger and Härtel, 2022). Specifically, we assume an electricity-hydrogen price ratio of 0.9, the average across various future energy system scenarios (EWI, 2021; Böttger and Härtel, 2022; Wuppertal-Institut et al., 2020; Meyer et al., 2024; Fraunhofer ISI et al., 2021), and a fixed SNG-hydrogen price ratio of 1.9, the average over various supply options and cost scenarios in Moritz et al. (2023). These price ratios are varied in subsequent sensitivity analyses. Similarly, we initially fix and subsequently vary our assumptions for the other uncertain parameters, namely electricity, hydrogen, and SNG grid fees, as well as heating grid and heat pump equipment costs. All parameters are described in detail in the Methods section.

Figure 1 displays the resulting LCOH as a function of hydrogen prices by settlement type to capture heterogeneity in the density of heat demand. The most salient observation is that the costs decrease from village to city settlements. The reason for this is that grid fees as well as heat distribution costs and losses decrease in settlements with higher energy density.

Focusing on decentralized heating options (left column in Figure 1), AtA heat pumps are often the cheapest option. AtW and WtW heat pumps tend to be more expensive, implying that their higher investment costs cannot be compensated by their improved coefficient of performance (COP). Only in cities and urban settlements with low supply temperatures have AtW and WtW heat pumps similar costs as AtA heat pumps because of the larger average installed capacity per building and related scale effects. Relative to other technologies, the heat pumps' LCOH are less sensitive to rising hydrogen prices because of their higher conversion efficiency and the assumed electricity-hydrogen price ratio of 0.9. Among the other technologies, hydrogen boilers are the cheapest

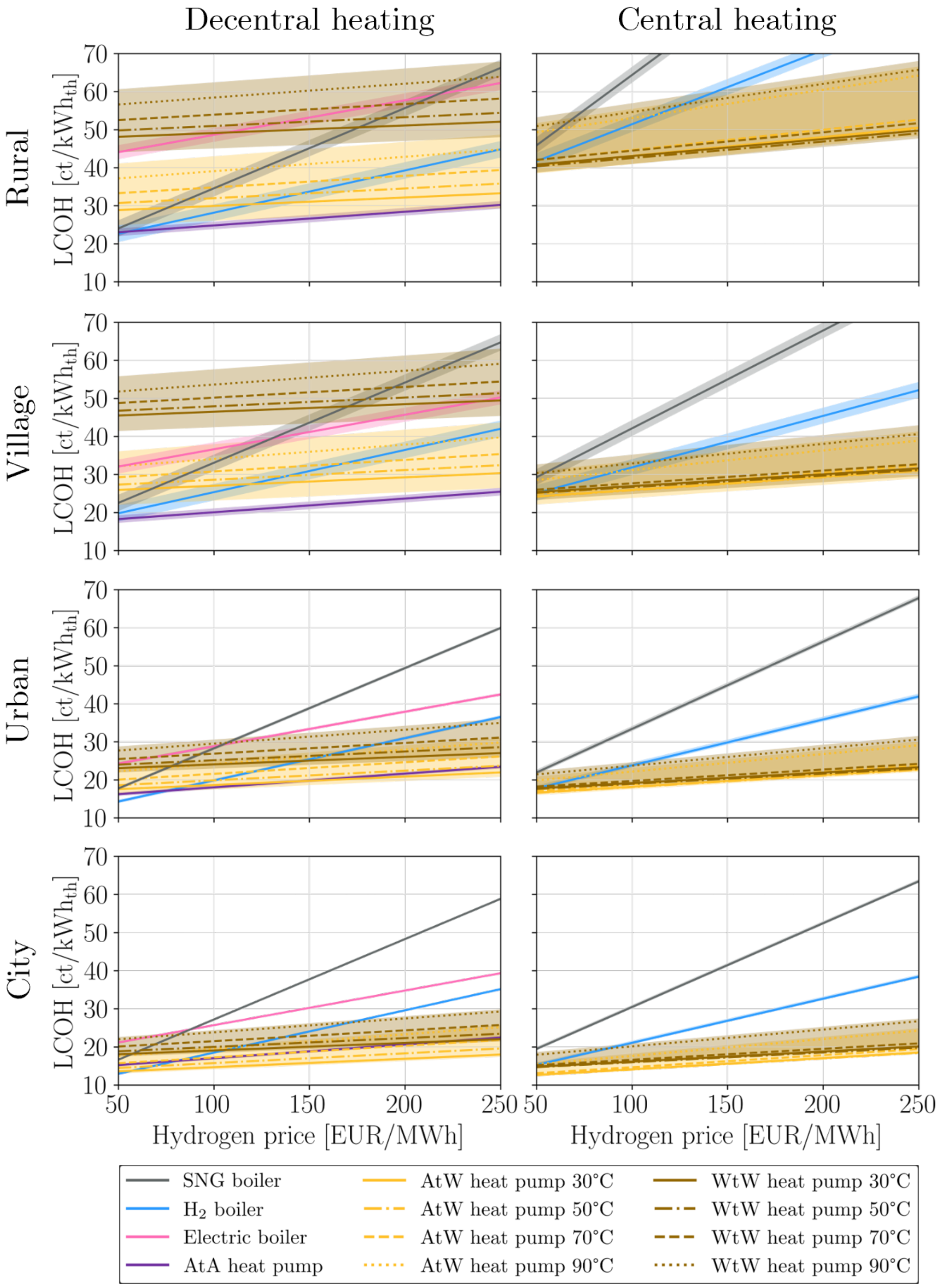

Figure 1: Levelized costs of heating for decentralized heating depending on the hydrogen price and supply temperature of the heating system. The lines reflect average investment costs, and the areas reflect uncertainty in investment costs.

technology. SNG boilers have a similarly low LCOH at low hydrogen prices but diverge with increasing hydrogen prices, as the impact of high SNG prices on the LCOH becomes more important than that of the relatively low SNG grid fees and slightly lower SNG boiler cost. Electric boilers suffer from relatively high power grid fees more than they benefit from the favorable electricity-hydrogen price ratio.

Turning toward centralized heating (right column in Figure 1), heat pumps are the cost-efficient technology for the largest part of the hydrogen price range. 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 jointly refer to them as "centralized heat pumps" in the following. Furthermore, the LCOH of centralized heat pumps for supply temperatures of 70°C or below converge because lower supply temperatures do not further reduce the effective COP due to the required complementary direct electric hot water heating (see Figure 5). 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 the cheapest option in rural settlements and villages. However, AtA heat pumps may be perceived as less comfortable (c.f. Karmann et al., 2017), which are not accounted for in the LCOH. 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 and hydrogen price. In rural settlements, decentralized hydrogen boilers are the cheapest option for lower and AtW heat pumps for higher hydrogen prices. Here, centralized heat pumps are not economical due to high heat distribution costs and losses. In villages and urban settlements, decentralized hydrogen boilers are cost-efficient for lower and centralized heat pumps for medium to high hydrogen prices. In cities, centralized heat pumps are the cheapest option in our baseline scenario, independent of the hydrogen price.

Uncertainty and heterogeneity in other relevant input parameters

This subsection analyzes the effect of changes in the previously fixed energy price ratios, grid fees, heating grid costs, and heat pump equipment costs on the cost-efficient heating technology. Figure 2 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. We consinder consider settlements with heterogeneous building-specific supply temperatures between 30°C and 70°C. While decentralized options must cater the building-specific supply temperatures, centralized solutions must be designed for the building with the highest temperature in the settlement. In the following, we compute the average costs of decentralized heating at an average supply temperature of 50°C (see Methods section), while we assume a supply temperature of 70°C for centralized heating. The supply temperatures are varied in a sensitivity analysis further below.

Each column in the figure represents one settlement type, and each row displays the effect of changing one input parameter.

Overall, we see that hydrogen boilers, decentralized heat pumps, and centralized 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 prices. In villages, urban settlements, and cities (the other columns), centralized heat pumps are most often cost-efficient, albeit with a relatively small LCOH advantage over the second-best technologies of 5-10 %. Hydrogen boilers become competitive in villages and urban settlements at low hydrogen prices, and decentralized heat pumps do so for some parameter variations when hydrogen prices are high. SNG boilers are cost-efficient only if SNG costs are at the lower boundary of the investigated parameter range.

Varying energy price ratios

The first row of Figure 2 analyzes the impact of changing the electricity-hydrogen price ratio between 0.5 and 1.3 (our baseline assumption was 0.9). This variation reflects uncertainty related to heat pump load patterns, which drive the effective heat pump load price (Ruhnau et al., 2020), and broader aspects of the future energy system, such as the availability of renewable electricity and changes in the electricity demand for other applications. At lower hydrogen prices, an increasing

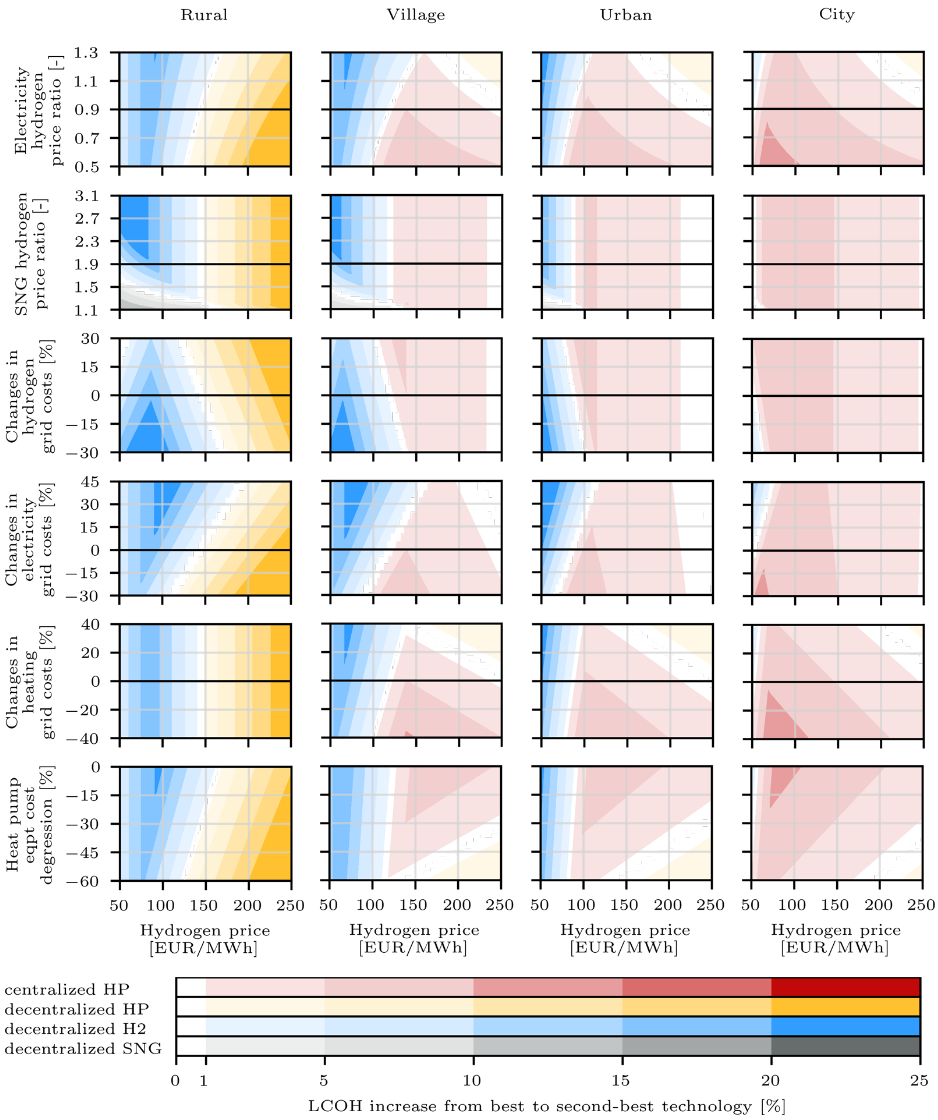

Figure 2: The impact of uncertain and heterogenous parameters on the cost-efficient heating technology in different settlement types and buildings with heterogenous supply temperatures. Color shades indicate the LCOH increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter.

electricity-hydrogen price ratio favors the economic viability of hydrogen boilers compared to heat pumps. This effect becomes less pronounced with increasing heat densities due to decreasing heat losses. At high hydrogen prices, an increasing ratio reduces the economic advantage of centralized heat pumps compared to decentralized ones, which are the second-best technology. This is because the higher COP and absence of heat losses increase the economic attractiveness of decentralized heat pumps.

The second row of Figure 2 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.

Varying grid fees and grid costs

The third row of Figure 2 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 related to limited experience with hydrogen grids and related to the hydrogen demand to which grid costs will be distributed. As expected, we observe that increasing hydrogen grid fees reduce 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, a smaller role in urban settlements, and no role in city settlements.

The fourth row of Figure 2 examines the effect of varying electricity grid fees. Our baseline assumption refers to a recent study that estimates electricity grids in 2045 to be 160 % higher than today (ef.Ruhr and EWI, 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. We reflect related heterogeneity and uncertainty by a variation of -30 % and +45 % from the baseline. As expected, we see that higher electricity grid fees favor the economic viability of hydrogen boilers over heat pumps. Furthermore, higher electricity grid fees reduce the cost advantage of centralized heat pumps over decentralized AtW heat pumps, which are the second-best technology for high hydrogen prices. The competitiveness of the different technologies is more sensitive toward a change in electricity grid costs in rural and village settlements than in urban settlements due to higher baseline grid fees. Overall, increased electricity fees lead to similar effects as a higher electricity-hydrogen price ratio.

The fifth row of Figure 2 investigates the sensitivity of the cost-efficient option to changes in the heating grid costs. The results confirm the expectation that higher heating grid costs promote decentralized technologies, namely hydrogen boilers and decentralized AtW heat pumps at low and high hydrogen prices, respectively. Across settlements, the viability of centralized heat pumps is more sensitive toward a change in heating grid costs in villages than in urban settlements due to higher heating grid costs. Even if heating grid costs increase by 40 %, centralized heat pumps are cost-efficient in cities for most considered hydrogen prices. In rural settlements, heating grids remain uneconomical even if heating costs decrease by 40 % due to significantly higher heat distribution costs and heat losses.

Varying heat pump equipment costs

The sixth row of Figure 2 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 areas, 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 centralized heat pumps and decentralized hydrogen boilers changes only slightly, but decentralized heat pumps outcompete centralized heat pumps at larger cost reductions. This is because the share of heat pump equipment costs in the total system costs is larger for decentralized than for centralized heat pumps.

Varying supply temperatures

The previous sensitivity analyses examined settlements with heterogenous 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 homogenous supply temperatures.

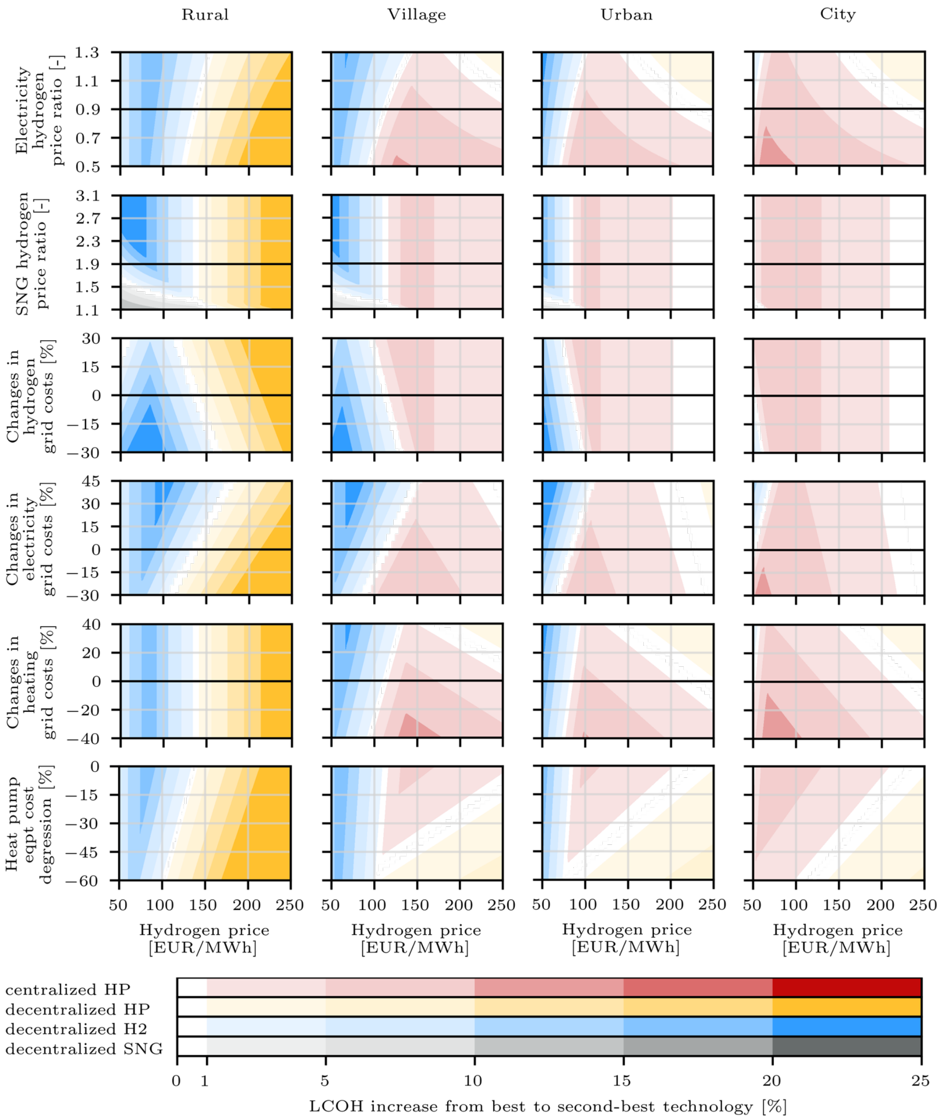

Figure 3: The impact of uncertain and heterogenous parameters on the cost-efficient heating technology in different settlement types and buildings with a supply temperature of 30° C. Color shades indicate the LCOH increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter.

Figure 3 shows the sensitivity analysis for a supply temperature of 30°C, e.g. a newly developed area with high 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 annual COP between decentralized and centralized heat pumps increases at lower supply temperatures. As a result, decentralized heat pumps become the cost-efficient technology at lower hydrogen prices than in the previous analysis. Where centralized heat pumps remain cost-efficient, the cost gap to decentral heat pumps decreases to mostly below 5 % in villages and 10 % in cities. 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 Figure H.11 in the Appendix). In this case, centralized heat pumps have larger advantages of up to 25 % over decentralized ones. Additionally, hydrogen boilers are cost-efficient also for somewhat higher hydrogen prices in rural settlements. Settlements with lower supply temperatures are likely to occur more often in the future as energetic refurbishment of the existing building stock progresses.

Discussion and Conclusion

This article investigates which heating technologies are cost-efficient in a future climate-neutral energy system, given uncertainties in energy, technology, and infrastructure costs and heterogeneous settlement types and buildings. To that end, we calculate the future levelized costs of heating technology options for a set of exemplary buildings and settlement types in Germany and conduct extensive sensitivity analyses. Across the wide range of heterogeneity and uncertainty that we consider, we find that AtA heat pumps are often the most cost-efficient technology. If we exclude this technology because of potentially lower comfort, decentralized hydrogen boilers, centralized heat pumps, and decentralized AtW 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, as well as a potential heat pump cost degression.

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

When interpreting these results, some limitations should be kept in mind. First, while our analysis is very thorough on uncertainties and heterogeneities that affect which heating technologies could be cost-efficient in the future, we do not investigate possible transition pathways to reach this future. Potential capital or labor shortages in the context of the system-wide transition may reduce the relative attractiveness of heating options with a high implementation effort compared to our analysis, e.g., building new infrastructure. Second, 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, thus reducing peak power demand and heat pump and electricity grid costs(c.f. Rosenow, 2022; Billerbeck et al., 2024). Additionally, we neglect biomass and solar thermal which could complement both the centralized and decentralized technologies we investigate, albeit with a limited overall potential. Third, to be consistent with our exogenous assumptions on grid fees, we only investigate uniform investment decision in the sense that all buildings in one area use the the same heating option. In reality, in settlements with heterogeneous buildings, the individual building optimum can differ from the system optimum. For instance, if the optimal uniform decision is to use centralized heat pumps, buildings with low supply temperatures may have an incentive to switch to decentralized heat pumps, which in turn increases 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.

Despite these caveats, our results allow us to draw three main conclusions for decision-makers. First, SNG does not seem economical despite the fact that SNG could utilize existing infrastructure in the short-term. For most of the 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. Hydrogen is mostly economical in rural settlements, while in settlement types with higher heating densities, heat pumps are generally more efficient at moderate or high hydrogen prices. High hydrogen prices and uncertain hydrogen grid costs can deteriorate the competitiveness of hydrogen boilers. Given the high uncertainty in the hydrogen price and grid costs, hydrogen boilers also seem to be a more risky option than heat pumps, which are less exposed to increased energy and infrastructure costs due to their high COPs, when infrastructure investment decisions have to be made today. Third, the decision between 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 favor centralized heat pumps, while in rural areas, decentralized heat pumps seem more economical. For the example of Germany, making this choice should be the focus of the local heating planning processes, which just started and are due in 2028.

Next to these immediate conclusions, our research provides a starting point for further research. Future studies may build on our extensive primary dataset of relevant input parameters and related uncertainty and heterogeneity. Even though part of our data set is specific to the German case, our proposed method could be applied to data from other countries to analyze regional differences. 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.

Methods

In this paper, we investigate the future cost-efficiency of climate-neutral residential heating technologies in terms of their LCOH, which is introduced in the subsection LCOH calculation 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 before we provide more details in the corresponding 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 the subsection Heating systems and derive cost functions in the subsection Investment and fixed

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

Table 1: Reasons for heterogeneity and uncertainty of investigated parameters

costs. 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 the subsection Conversion efficiency.

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, to the electricity demand for other applications, and to the hydrogen price, which we assume to be used for electricity generation if renewable supply is insufficient. To include fuel price uncertainty, we calculate the LCOH over a range of hydrogen, electricity, and SNG price combinations, derived in the subsection Energy prices.

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 the subsection Settlement types. 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 spatial distribution of renewable energies connected to the electricity grid. We present our approach for capturing infrastructure cost heterogeneity and uncertainty in the subsection Grid fees.

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, heat densities d, and supply temperatures T, using the following equation:

$$
\begin{aligned}
LCOH_{tech,c,d,T} = & \underbrace{\frac{\overbrace{I_{tech,c}\frac{r(1+r)^t}{(1+r)^t-1}}^{\text{CAPEX}} + \overbrace{FOM_{tech,c}}^{\text{fixed OPEX}}}{flh}}_{\text{fixed costs}} \\
& + \underbrace{(\overbrace{p_{\mathrm{H_2}} r_{tech}}^{\text{energy}} + \overbrace{g_{tech,d}}^{\text{infrastructure}}) \overbrace{\frac{1}{\eta^{sys}_{tech,T}}}^{\text{conversion efficiency}} \overbrace{\frac{1}{1-L_{st}}}^{\text{heat loss}} + \overbrace{hdc_d}^{\text{heat distribution}}}_{\text{variable costs}}
\end{aligned}
\tag{1}
$$

$I_{tech,c}$ are the investment costs of the heating system, depending 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. The Python code of the calculations can be found in the supplementary material (see `CODE_investment_cost_calculation_heating_systems.py`). r is the interest rate, and t is the economical lifetime or depreciation period. $FOM_{tech,c}$ are the fixed costs for operation and maintenance, depending on the heating technology *tech* and the capacity c, and flh are the annual full load hours of the heat generator. We express energy prices as a function of the hydrogen wholesale price $p_{\mathrm{H_2}}$ and the price ratio r_{tech} between hydrogen and the energy carrier used by the heating system *tech* (see Energy prices). This energy carrier is either hydrogen, SNG, or electricity. $g_{tech,d}$ are estimated future grid fees, which we use to approximate the costs for electricity, hydrogen, and SNG infrastructure, 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} are the heat losses of the heating grid in the settlement type st, and hdc_d are the heat distribution costs for a settlement with the heat density d. Both hdc_d and L_{st} equal 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 neglect any price components that affect consumer prices but are merely a monetary transfer, such as taxes and levies on energy prices. Furthermore, we neglect existing heating systems and their costs based on the assumption that they will end their lifetime before climate neutrality is reached. By contrast, we implicitly consider existing electricity and gas infrastructures, which have longer lifetimes, because we use estimated future grid fees to approximate infrastructure costs (see Grid fees below).

Heating systems

We calculate the LCOH for ten different technology set-ups that reflect major decarbonization options that are currently discussed (see Table 2). 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. Air-to-air 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 decreased to zero in centralized deployment, heat distribution costs and losses would outweigh investment cost savings.

System flow sheets for all options are provided in Figure B.8. The capacity of the decentralized heat generators is designed to provide both heating and hot water, except for air-to-air (AtA) heat pumps, which are combined with an electric boiler for hot water. AtW heat pumps are designed for bivalent monoenergetic operation, i.e., the installed heat pump capacity is kept at a minimum, and peak demands are covered by an electric heater (c.f. Buderus (2019)). For 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 called the simultaneity factor. We use a settlement-type specific simultaneity factor taken from AGFW (2001). Finally, we assume that the temperature of heating grids follows the supply temperature of space heating. Centralized heating with heat pumps is complemented by decentralized electric heaters for hot water if the grid temperature is too low.

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 472 list prices on the relevant heat generators as well as thermal

Table 2: 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

storage from the German manufacturers Buderus, Elco, Vaillant and Viessmann. For the installation costs, we collected 37 data points from five installation firms in Germany, namely E. Altmann GmbH, König GmbH & Co. KG, Moritz & Bramer GmbH, Octupus Energy, and Thermondo. 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.

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 increase the estimated equipment cost by 50% to account for the contribution margins of installation firms. The fixed operation and maintenance costs are parametrized as a function of the installed capacity. Figure 4 shows the fitted equipment and installation cost functions for the examples of AtW heat pumps and gas condensing boilers. More details and a visualization of the primary data, as well as the fitted functions for all technology options, are provided in Table C.5 and Figure C.9.

As the equipment cost functions are based on historical data, they do not reflect a potential future cost reduction. This is most relevant for heat pumps, which are not yet as widespread as boilers and may benefit from learning effects when deployment increases. The literature reports a wide range of learning rates for heat pumps, with the majority lying between 10 % and 20 %

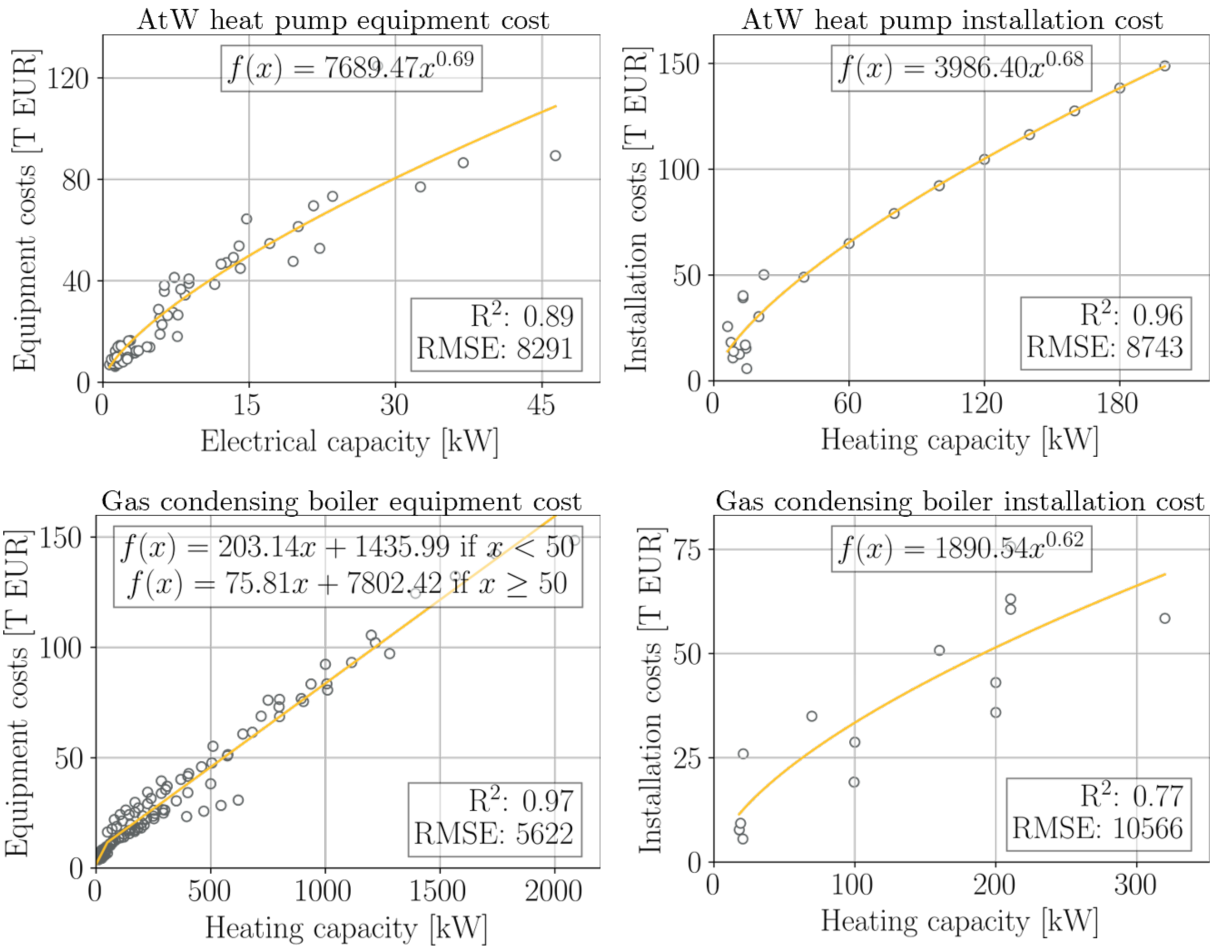

Figure 4: Empirical cost functions for equipment and installation of AtW heat pumps and gas condensing boilers

(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 - International Energy Agency, 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.

Conversion efficiency

Equation 2 shows the calculation of the conversion efficiency of fuel to heat for different heating systems. c_{tech} is the contribution of the heat pump to the total heat demand as we assume that AtW and WtW heat pumps are combined with an electric heater for peak loads. $ACOP_{tech,T}$ is the heat pump's annual coefficient of performance and η_{tech}^{boiler} is the conversion efficiency of boilers. The annual coefficient of performance of AtA heat pumps does not depend on the supply temperature. We assume that the conversion efficiency of boilers does not depend on the supply temperature.

$$\frac{1}{\eta_{tech,T}^{sys}} = \begin{cases} 1 + c_{tech}(\frac{1}{ACOP_{tech,T}} - 1) & \text{if } tech = \text{AtW or WtW heat pump} \\ \frac{1}{ACOP_{tech}} & \text{if } tech = \text{AtA heat pump} \\ \frac{1}{\eta_{tech,T}^{boiler}} & \text{otherwise} \end{cases} \quad (2)$$

For heat pump systems, we consider the dependency of the annual COP on the supply temperature. In the context of this paper, we understand supply temperature as the minimal necessary supply temperature to enable sufficient heat transfer from the radiators into the room. The heating system's supply temperature depends on the radiators' heat exchange area and the building's energy efficiency. The higher the area of the radiators, the lower the supply temperature required to transport the same amount of heat into the room (see Figure 5 for typical temperature ranges of different radiator types). The better a building is insulated, the more its heat demand and the supply temperature decrease (for the same area of the radiators).

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

Figure 5 shows the annual COP of different heat pump types. For decentralized heat pumps, the annual COP 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 annual COP 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 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 60°C for hygienic reasons. If the heating grid temperature is too low to heat hot water to 60°C, hot water heating is complemented with decentralized electric heaters with an assumed energy efficiency of 1. This reduces the slope of the annual COP of centralized heat pumps for supply temperatures below 60°C.

The annual COP of AtA heat pumps in Germany typically lies between 2.4 and 2.8 (Verivox, 2024). We assume an annual COP of 2.5 as a conservative estimate for all buildings.

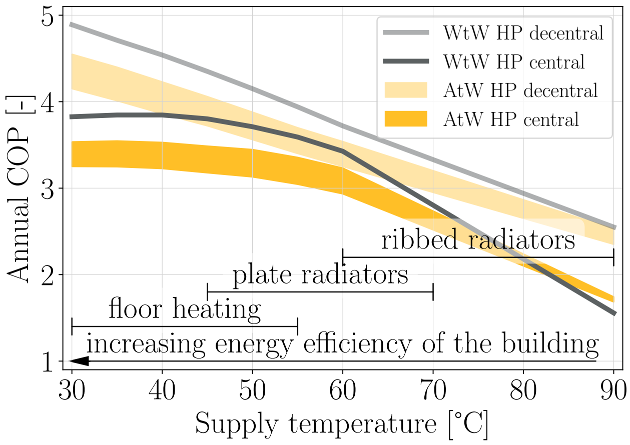

Figure 5: Relationship between the heat pump's annual COP and the heating system's supply temperature according VDI 4650 part 1.

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. 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 of 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 D). The results are displayed in Figure 6. 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 boundaries and set to 1.9 in the baseline scenario, which is the average ratio in the data.

Furthermore, hydrogen and electricity prices are interdependent: In many scenarios for the future energy system, green electricity is used to produce hydrogen via electrolysis and hydrogen fuels back-up power generation. In the LCOH calculation, we use annual average energy prices and, therefore, simplify this complex dynamic to a fixed price ratio. Figure 6 lists exemplary studies that published both, electricity and hydrogen prices and illustrates the variation in electricity-hydrogen price ratios, which range from 0.7 to 1.15. We define a base case where the electricity-hydrogen ratio r_{tech} is 0.9, which reflects the average over the ratios found in the literature. In a secondary analysis, the electricity-hydrogen price ratio is varied to determine whether this has an impact on which technology is cost-efficient. Due to the few available data points, we add a margin for additional uncertainty and analyze ratios between 0.5 and 1.3 in the sensitivty analysis.

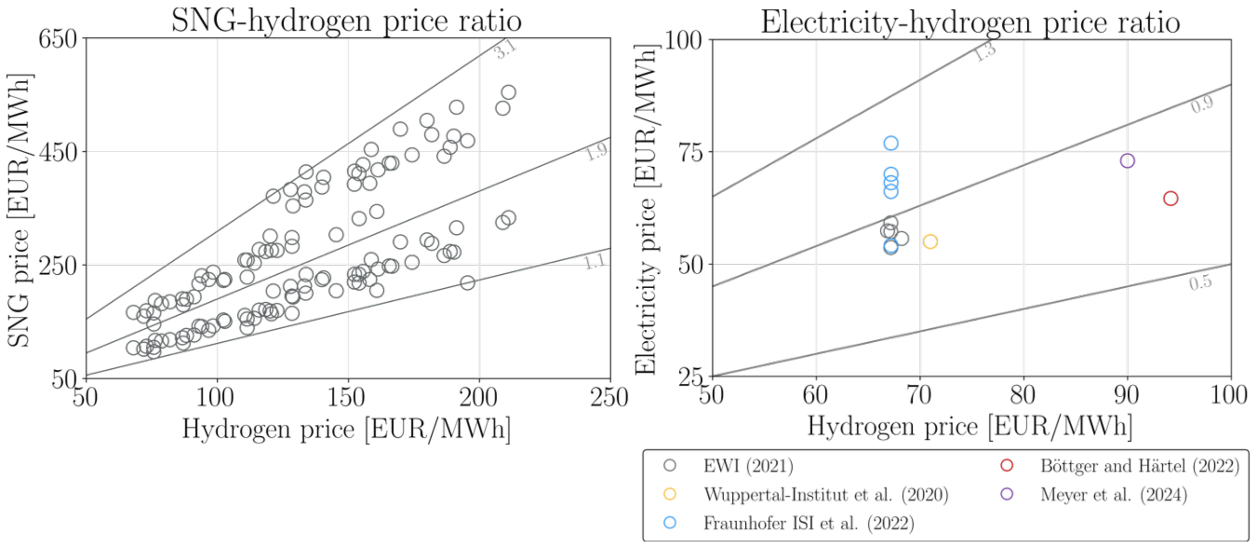

Figure 6: Hydrogen and electricity prices in EWI (2021); Böttger and Härtel (2022); Wuppertal-Institut et al. (2020); Meyer et al. (2024); Fraunhofer ISI et al. (2021) (left) and hydrogen and SNG costs from Moritz et al. (2023); EWI (2024b) (right) and the resulting price ratios

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, 7b, 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 main purpose of use is residential. The village settlement represents residential areas with detached and semi-detached houses like larger villages or suburban communities consisting of single- and multi-family houses. The main use is residential. The urban settlement represents block development, which is a typical urban building form consisting of large multi-family houses. The typical use of the block development is predominantly residential. The 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.

Table 3: Settlement type characteristics

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

[a]extrapolated, see Figure F.10 in the appendix, [b]the electricity density was approximated based on the heating density given in AGFW (2001) and the historical ratio between energy demands for electricity and heat in 2021 given in AGEB (2022), [c]extrapolated, see Figure 7, [d]decentral/central

To enable a comparison between centralized and decentralized heating, we analyze standardized districts with a total heat load of 650 kW, which corresponds to 100 buildings in a rural or village settlement. This heat load can be represented without over-extrapolating our investment cost functions. The heat load of the urban and city settlement is scaled accordingly and is rounded to whole houses, given the heated area per building. Table 3 shows the characteristics of the four representative settlement types.

Grid fees

Our calculation of future heating costs includes infrastructure costs, which are heterogeneous across Germany and vary with local heating densities. Additionally, future infrastructure costs are uncertain because they depend on required grid expansion and, hence, demand, which dynamically links them to future residential heating choices. In addition, the costs of some infrastructures, e.g., the electricity grid, are influenced by energy system developments that go beyond heating. Today, infrastructure costs are distributed to end customers via grid fees. Thus, we use future grid fees to approximate average infrastructure costs within the LCOH approach.Note that grid fees do not generally reflect marginal grid costs associated with heating technologies (c.f. Hanny et al., 2022).

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, we employ a two-step approach. First, we use historical data to estimate a functional relationship between infrastructure costs and heating density. Second, we use estimates of future grid fees for the year 2045 to scale the previously derived cost functions. The estimates of future grid fees are taken from studies that assume that most heating systems use the corresponding infrastructure (e.g., electricity grid fees are estimated for a scenario with a high share of heat pumps and hydrogen 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 use the scaled cost functions to derive point estimates for future grid fees in the different settlement types. The cost functions and resulting baseline assumptions are presented in Figure 7. 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 that grid fees have fixed and sometimes power-based components in addition to per-kWh components.

For electricity, historical data on local distribution grid costs and corresponding heating densities are derived from Bundesnetzagentur (2023a). Future electricity grid costs are uncertain and depend on the diffusion and allocation of renewable energy capacity and demand, such as heat pumps. Energy system studies (e.g., EWI (2021), Fraunhofer ISI et al. (2023), Wuppertal-Institut et al. (2020)) and German grid operators (50Hertz Transmission GmbH et al., 2023) 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. We derive our assumptions for future grid fees from a recent study estimating infrastructure costs and grid fees under the assumption that most homes will use electric heat pumps by 2045 and that the targets for expanding renewables and adopting electric vehicles are reached. In its baseline scenario, the study projects an average increase in grid fees until 2045 of about 160 % for households and businesses from 9.3 and 7.4 ct/kWh in 2023, respectively (c.f. ef.Ruhr and EWI, 2024) (see Figure 7). We use this number in our baseline scenario. Given the uncertainty and heterogeneity that affect future electricity infrastructure costs, we perform a sensitivity analysis where grid fees are varied by -30 % and +45 %. This range includes

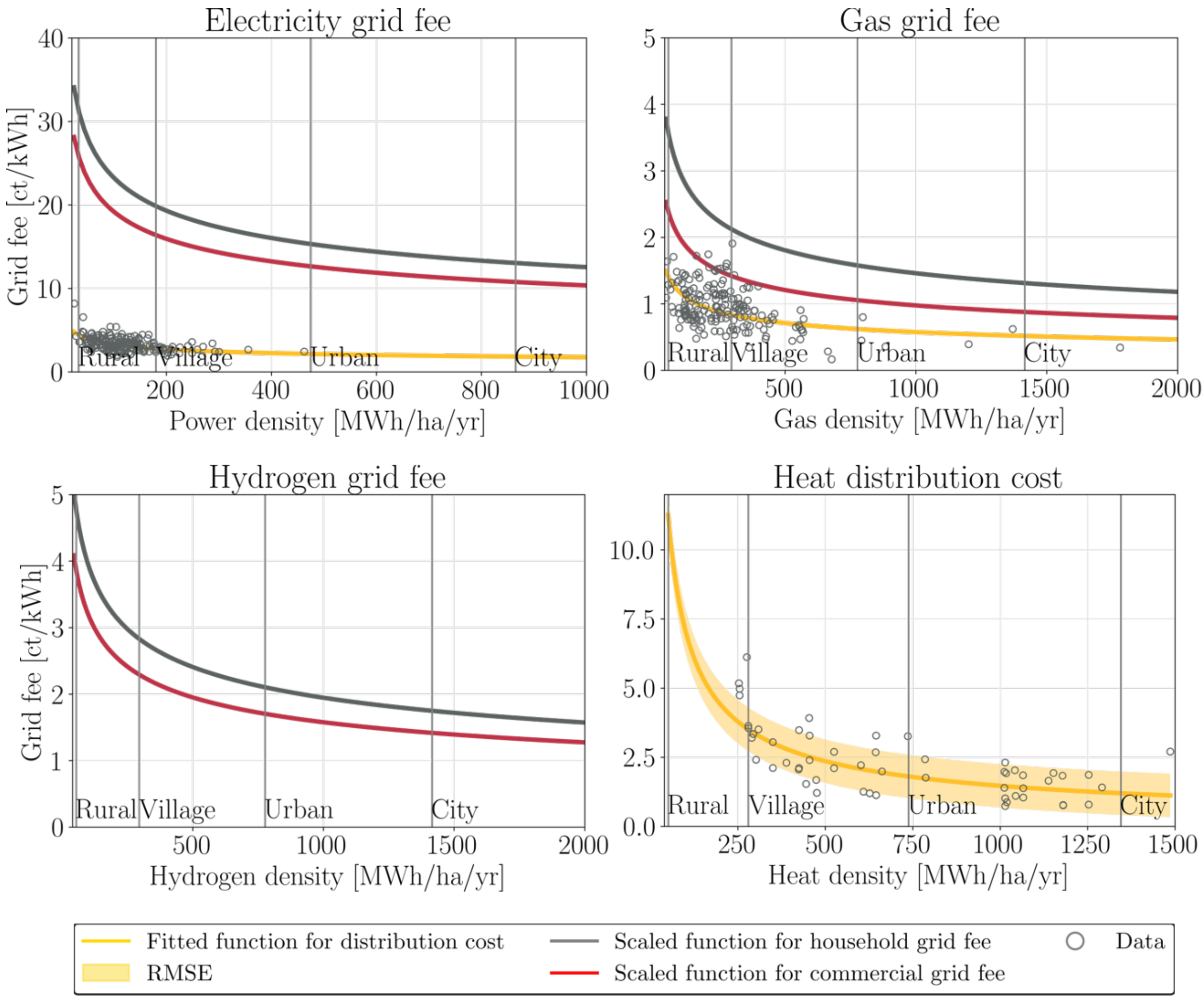

Figure 7: Reference infrastructure costs for electricity, gas, hydrogen, and heating grids depending on the energy density. The data on electricity grid fees contains an additional data point at a power density of 3,455 MWh/ha/yr.

the variance of grid costs within settlement types found in the historical data (see Figure 7) as well as the scenario range for future grid fees in ef.Ruhr and EWI (2024).

In the case of gas grids, SNG can be transported without modifications through the existing grid. We take historical data on gas distribution costs and energy density Bundesnetzagentur (2023b) to fit the cost functions, which are depicted in Figure 7. The functions are scaled to match future gas grid fees estimated for a 95 % emission reduction scenario with a large share of SNG in residential heating (c.f. EWI), 2018). This study finds an increase of the gas grid fees by 20 % for households and 30 % for businesses by 2050 compared to 1.7 and 1.3 ct/kWh, respectively, in 2023.

For the case of hydrogen infrastructure costs, we assume that the variance across and within settlement types is similar to existing gas infrastructure. Thus, we apply the same functional form as for SNG. In terms of the cost level, i.e., the scaling of the cost function, hydrogen grid costs are 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. Figure 7 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 parametrization for all cost functions estimated for infrastructure costs can be found in Appendix E.

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Authors' contributions

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

Competing interests

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

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Appendix A. 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.4 gives an overview of the relevant literature for the example of Germany. While previous studies have covered the important aspects of building heterogeneity, fuel price uncertainty, and infrastructure individually, none of the studies has captured all of them.

Publication	Building sector heterogeneity	Infrastructure heterogeneity and uncertainty	Energy price uncertainty	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)		✓		
Arnold et al. (2024)	✓		electricity prices only	
Billerbeck et al. (2024)	✓	✓		
Our analysis	✓	✓	✓	✓

Table A.4: Parameters considered in this study compared to other studies

First, Kotzur et al. (2020) and Arnold et al. (2024) focus on representing building sector heterogeneity by applying optimization models for individual buildings to large sets of archetype buildings. Kotzur et al. (2020) show that at least 200 archetype buildings are needed to represent building diversity accurately, and Arnold et al. (2024) use even 770 archetype buildings to reflect building heterogenity including the type and age of existing heating systems. Kotzur et al. (2020) neglect infrastructure costs and fuel price uncertainty. Arnold et al. (2024) perform a sensitivity analysis on electricity prices but keep other energy prices fixed. Second, using a similar individual building model, Knosala et al. (2022) model uncertainty in energy prices. They calculate optimal energy provision over a range of hydrogen and electricity prices. However, their analysis is limited in terms of the consideration of heterogeneity (only 10 different building types) and infrastructure costs (only current grid fees). Third, Lux et al. (2022) and Kisse et al. (2020) focus on the costs of hydrogen transport and electricity distribution infrastructure, respectively. These studies, on the other hand, simplify the heterogeneity of the building stock and neglect future fuel price uncertainty. 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.

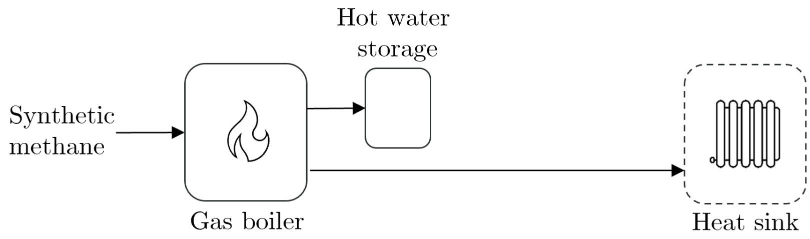
Another set of studies considers both, building sector heterogeneity and infrastructure costs (EWI, 2021; Wuppertal-Institut et al., 2020; Fraunhofer ISI et al., 2021). This is typically done through the coupling of different models. For example, EWI (2021) and Wuppertal-Institut et al. (2020) both soft-couple 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 studies, uncertainty is typically neglected (Wuppertal-Institut et al., 2020) or represented only through a small set of scenarios (EWI, 2021; Fraunhofer ISI et al., 2021; Billerbeck et al., 2024). This can be explained by the modeling being computationally too expensive for a more detailed uncertainty analysis. Scenario variation typically concerns the shares of electricity and hydrogen in decarbonization, and none of the studies explicitly focusses on price uncertainty. Chaudry et al. (2015) incorporate fuel price and technology cost uncertainty and calculate levelized costs of decentralized heating in the UK by running a simple individual building model over a range of inputs. However, they do not consider heterogeneous building types.

Despite the differences in methods, most studies conclude that a mix of decentralized heating with heat pumps and district heating is generally the most feasible option for the building sector.

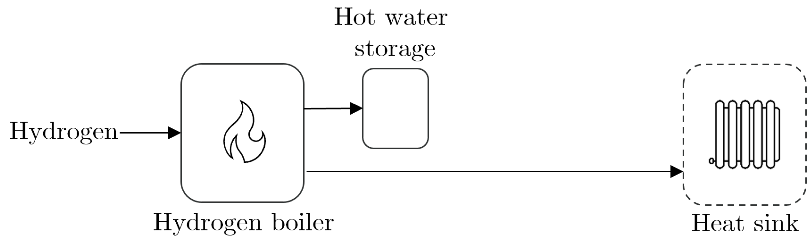
Decentralized hydrogen heating is either viewed as an edge-case at very low hydrogen prices or as a backup option, with the exception of EWI (2021), who assume a slower diffusion of heat pumps and the repurposing of gas grids for hydrogen instead. Centralized hydrogen heating more likely plays a role,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

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

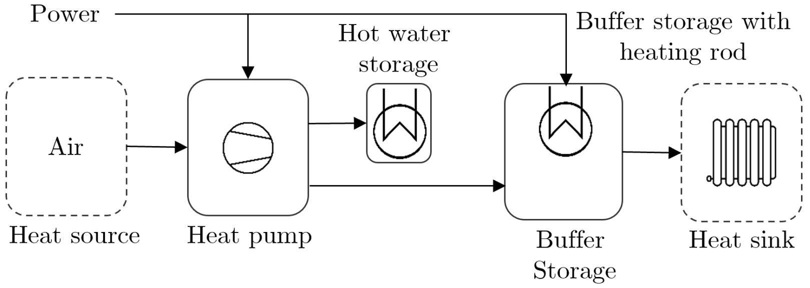
Appendix B. Heating systems



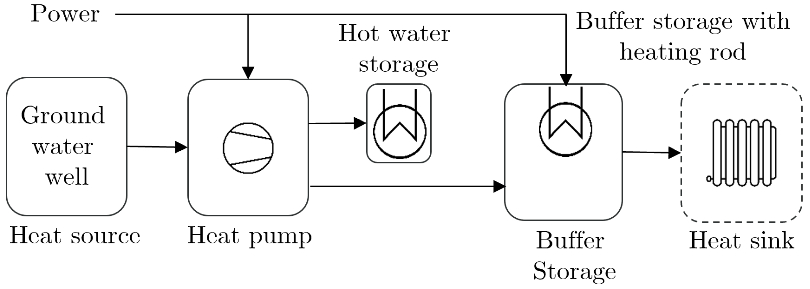
(a) Gas boiler decentral



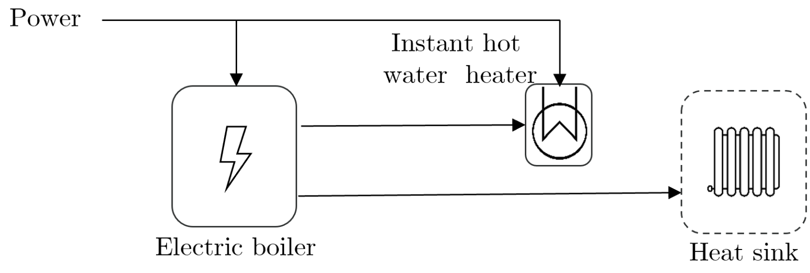
(b) Hydrogen boiler decentral



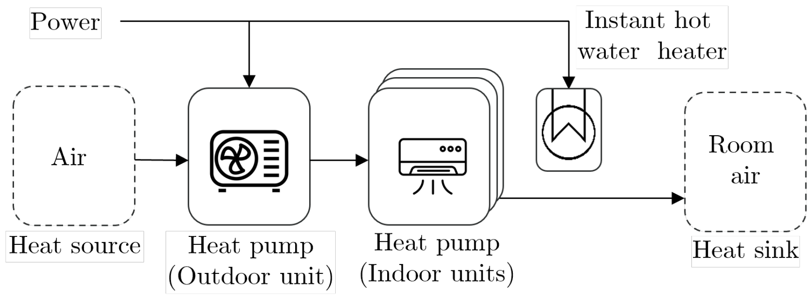
(c) AtW heat pump decentral



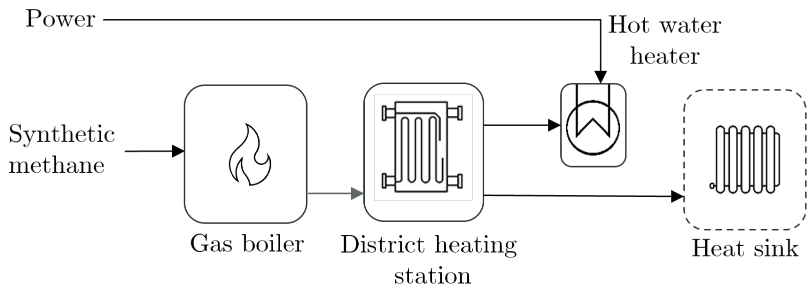
(d) WtW heat pump decentral



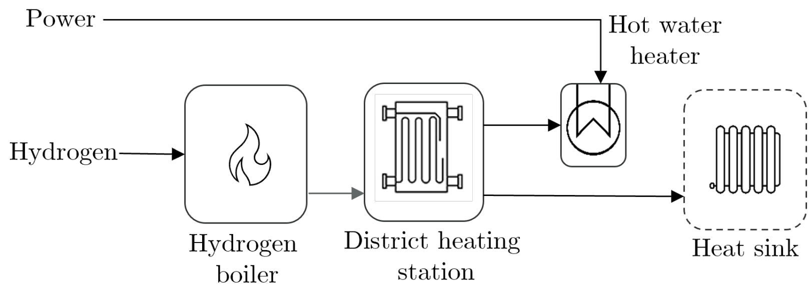
(e) Electric boiler decentral



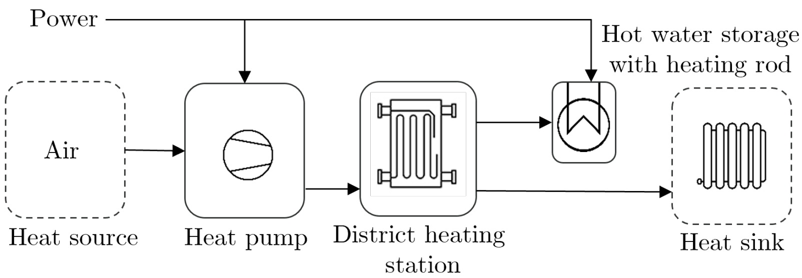
(f) AtA heat pump decentral



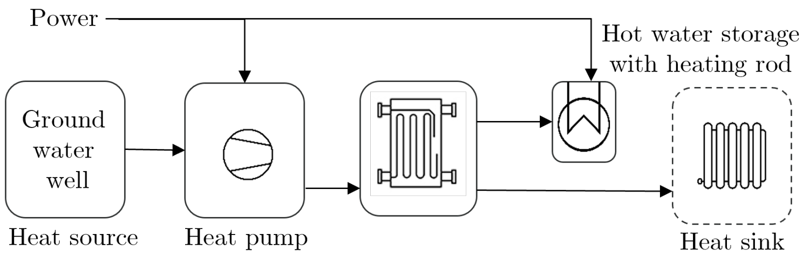
(g) Gas boiler central



(h) Hydrogen boiler central



(i) AtW heat pump central



(j) WtW heat pump central

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

Appendix C. Equipment cost data and functions

We collected cost data from manufacturers Buderus, Elco, Vailaint, and Viessman for the following components: air-to-air heat pumps, air-to-water heat pumps, water-to-water heat pumps, gas-condensing boilers, electric boilers, electric instant water heaters, buffer tanks, hot water tanks, and heating rods.Table C.5 summarizes the data scope for the calculation of the cost functions. Moreover, we collected data on the installation costs of gas-condensing boilers and AtW heat pumps from Moritz & Bramer GmbH and Octopus Energy. We fit a cost function to the collected data, with installed capacity as an independent variable. Table C.5 shows the scope of the collected primary data. We use least squares regression to fit linear functions without intercept ($f(x) = mx$), linear functions with intercept ($f(x) = mx + b$), and power functions ($f(x) = ax^b$), where $f(x)$ represents the costs, and x represent the installed capacity. We choose the one with the lowest RMSE from the three fitted functions. In the case of gas condensing boilers, a 2-step piecewise-linear function resulted in the best fit. This function reflects that boilers with a heating capacity below 50 kW are relatively cheaper than larger boilers because they typically have factory-installed control and are produced in larger numbers. In the case of district heating stations, we assume equipment costs of 4000 EUR for a heating capacity of up to 15 kW as these are off-the-shelf products. This assumption is based on personal communication with the manufacturer Pewo Energietechnik GmbH. Based on personal communication with Habo Wärmetechnik GmbH & Co. KG, district heating stations with larger capacities are typically individually designed. We use a power function provided by Blesl et al. (2023) for district heating stations with larger capacities. In order to be able to reflect the variance in the data, we generate high-cost and low-cost functions. High-cost functions are the fitted functions plus 1/3 of the standard error, and low-cost functions are the fitted functions minus 1/3 of the RMSE. The primary data and fitted functions are shown in Figure 4 and Figure C.9.

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

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

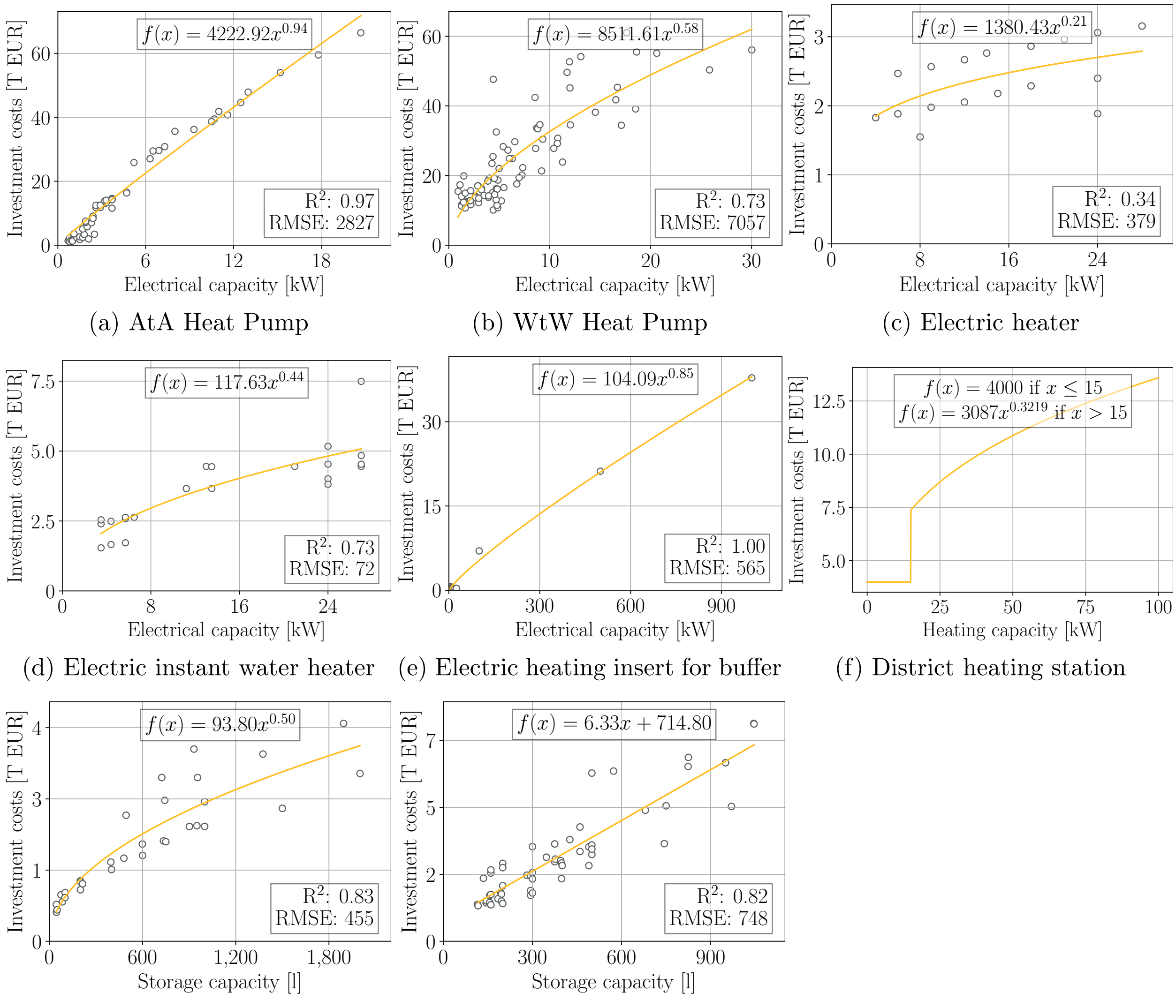
Investment costs	Number of data points
Air-to-air heat pumps	55
Air-to-water heat pumps	67
Buffer tanks	31
Heating rod for buffer storage	24
Electric boilers	17
Electric instant water heaters	22
Gas condensing boilers	122
Hot water storage tanks	54
Water-to-water heat pumps	81
Installation costs	
Gas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

[a] Experience-based cost function

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

Typically, installation companies add a contribution margin to the material costs to cover their administrative expenses. We assume a contribution margin of 50 % to all major equipment units. Costs for small materials are included in the installation cost functions, which are displayed in Figure 4.

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



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

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

(g) Buffer tank (h) Hot water storage

Figure C.9: Equipment costs of components

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

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

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

Parameter	Unit	Value
Energy efficiency of gas and hydrogen boilers	[-]	0.90
Energy efficiency of electric boilers	[-]	0.99
Interest rate	[%]	5
Depreciation period	[yr]	20
Full load hours of heating technologies	[h/yr]	2000
FOM AtW and WtW heat pumps 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

Table C.6: General techno-economic assumptions

Appendix D. 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 E. Parametrization of grid costs

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

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

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

Table E.7: Calculation of scaled grid fee functions

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

Appendix F. Extrapolation of heat losses for rural settlements

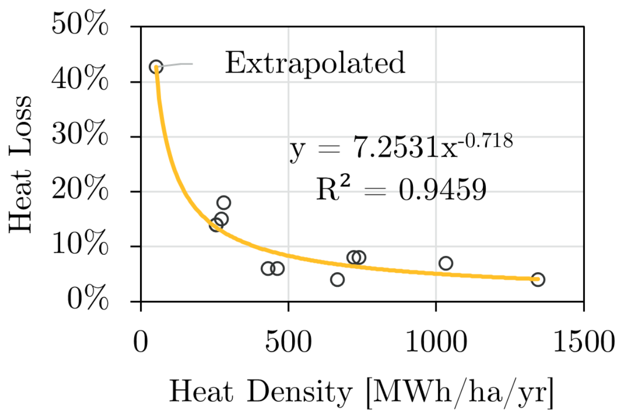


Figure F.10: Extrapolation of heat loss over heat density for the rural settlement

Appendix G. Calculation of the annual COP

We calculate the annual COP for power-controlled heat pumps with inverters in bivalent mono-energetic operation according to the standard VDI 4650 part 1. The temperature spread between the supply and return of the heating systems is 10 K. The domestic hot water temperature is 60°C. For decentralized heating, we assume that the heat pump is used for space heating and domestic hot water heating. The annual COP of AtW heat pumps for decentralized heating is represented by a range based on German climate conditions. The minimum and maximum values of the range are calculated with standard outdoor temperatures of -8°C and -14°C. The standard outdoor temperature (German: Normaußentemperatur) is the lowest temperature of a cold period, which must have been maintained 10 times within 20 years over a period of at least two consecutive days. The range of -8°C and -14°C represents the majority of regions in Germany. Only islands or places in the Alps can have lower or higher standard outdoor temperatures (BWP (2023)). The annual COP of WtW heat pumps for decentralized heating is calculated assuming a constant groundwater temperature of 10°C. The energy consumption of the well pump is taken into account. For centralized heating with heat pumps, we assume that the domestic hot water is heated via the heating grid. We assume a temperature spread of 10 K between the heating grid and the supply temperature of the building. Suppose the domestic hot water temperature is higher than the temperature of the heating grid minus the temperature difference of 10 K. In that case, the remaining domestic hot water heating is done via a heating rod. The annual COP is the weighted average of the heat pump's annual COP and the heating rod's efficiency. The VDI 4650 is defined for supply temperatures up to 60°C. Annual COP for supply temperatures larger than 60°C are linearly extrapolated.

Appendix H. Sensitivities in settlements with homogenous supply temperature

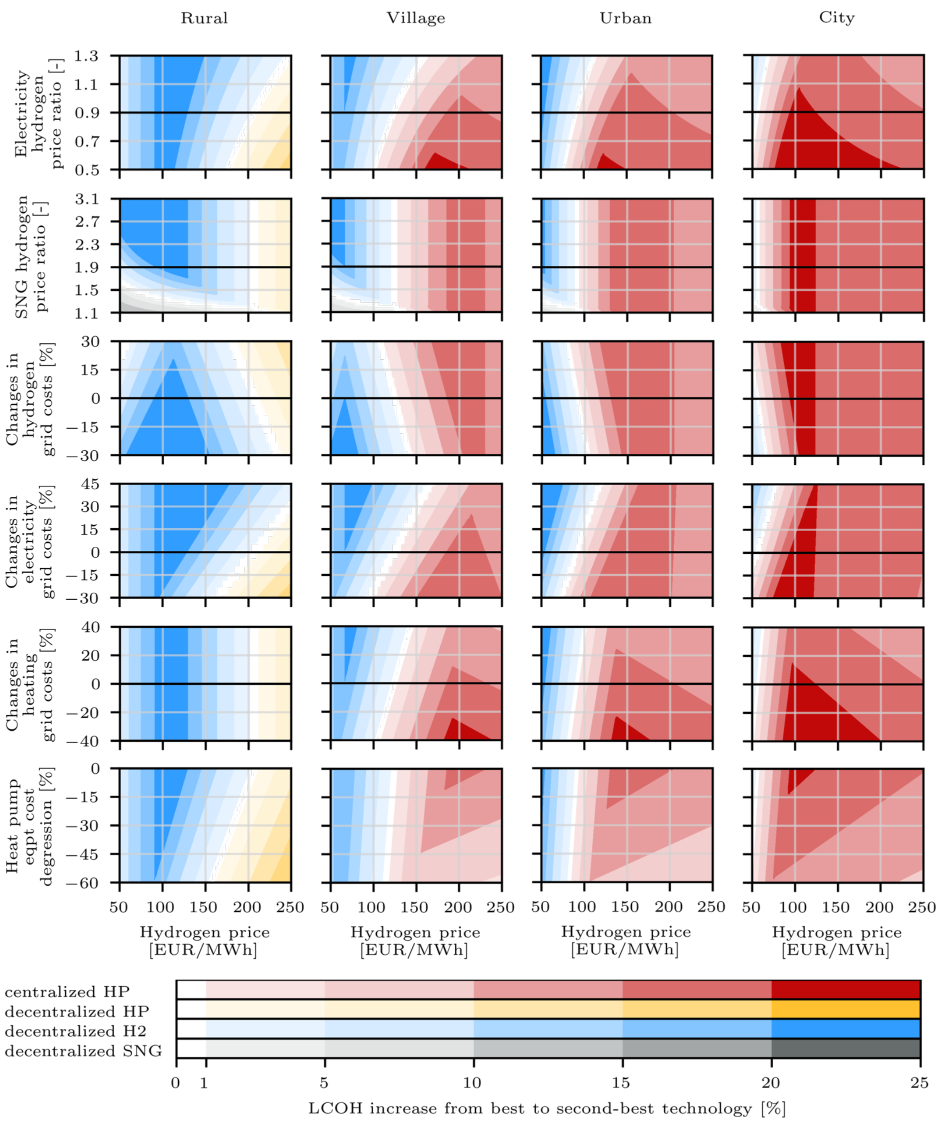


Figure H.11: The impact of uncertain and heterogenous parameters on the cost-efficient heating technology in different settlement types for buildings with a supply temperature of 70°C. Colors indicate the cost-efficient technology. Color shades indicate the LCOH increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter.