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A system dynamics model for the development and decarbonization of district heating systems

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ABSTRACT

This study evaluates the long-term impact of integrating an energy hub into a district heating system, with a particular focus on system autonomy, CO_2 emissions reduction, and cost dynamics up to 2050. A scenario-based approach was applied to assess three alternative development pathways, combining building renovation measures with different levels of heat supply decarbonization and energy resource diversification. The analysis considers changes in heat production structure, emissions balance, and economic performance under varying technological and market conditions.

The results indicate that by implementing the energy hub, the share of purchased heat energy decreases from approximately 70% in 2023 to 35% in 2050, while the share of self-produced heat energy increases from approximately 30% to 65%. The emission analysis shows that energy efficiency measures in the building sector alone provide limited mitigation potential, achieving only moderate CO_2 reductions. Substantially higher emission reductions, up to 36% by 2050, are achieved when building renovation is combined with a diversified and decarbonized heat supply, including the replacement of natural gas with low-carbon heat sources.

The economic assessment reveals a clear trade-off between cost efficiency and strategic energy independence. Scenarios with lower initial investments and increased reliance on wood-chip-based heat remain the most cost-effective option throughout the analysed period, while technologically advanced solutions with higher upfront costs, such as the integration of an energy hub with synthetic methane production, have higher annual costs despite additional revenues from electricity sales. Sensitivity analysis confirms that natural gas prices remain the dominant cost driver, although the implementation of the energy hub and synthetic methane production progressively reduces the systems vulnerability to gas price volatility.

The findings highlight the necessity of an integrated approach to district heating system transformation, demonstrating that long-term emission reductions, energy security, and economic resilience can only be achieved through the combined approach to building energy efficiency, heat supply decarbonization, and strategic long-term planning.

Keywords

Decarbonization;
District heating;
Energy hub;
System dynamics modelling

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1 Introduction

Globally, the heating and cooling sector remains one of the main sources of CO_2 emissions and plays a critical role in achieving climate neutrality [1,2]. District heating (DH) systems are increasingly recognized as strategic instruments for decarbonizing urban energy systems due to their centralized structure and integration potential [3,4]. Their ability to incorporate large-scale renewable and low-carbon technologies makes them a key component of long-term energy transition strategies [5,6].

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List of Abbreviations

BH	*Boiler house*
CCU	*Carbon capture and utilization*
CHP	*Combined heat and power*
DH	*District heating*
EB	*Eelectric boiler*
HP	*Heat pump*
NIMBY	*Not in my back yard*
TS	*Thermoelectric station*
TES	*Thermal energy storage*

Research demonstrates that substantial reductions in carbon intensity can be achieved through the combined deployment of renewable heat sources, large-scale heat pumps (HP) and thermal energy storage (TES) [5]. Systematic assessments of different heating configurations show that renewable and excess heat-based solutions can achieve very low CO_2 intensities [7]. In contrast, biomass and fossil-based pathways may exhibit greater emission variability and long-term risks [6]. These findings indicate that decarbonization outcomes depend strongly on overall system configuration rather than individual technologies alone.

Technological evolution in DH is commonly framed through the transition from conventional high-temperature systems towards fourth-generation DH (4GDH), characterized by lower supply temperatures and improved compatibility with renewable sources [8]. More recent fifth-generation DH and cooling (5GDHC) concepts introduce bidirectional heat flows and decentralized exchange within the network [9,10]. Integration with the electricity sector via power-to-heat technologies, including large-scale HP and electric boilers (EB), enhances operational flexibility and strengthens sector coupling [11,12]. TES supports this integration by balancing renewable electricity variability and improving system efficiency [13,14].

The system value of flexibility options depends strongly on overall configuration and market conditions. Advanced storage concepts such as Carnot batteries can provide primary energy savings when integrated with electrified DH systems [15]. Probabilistic modelling of highly renewable energy systems further demonstrates that diversified storage portfolios enhance robustness and reduce sensitivity to climatic variability [16]. These results underline the importance of long-term, system-oriented assessments that capture interactions between heat supply, electricity markets and storage technologies.

Spatially explicit planning has emerged as a crucial dimension of sustainable heat transitions. Municipal zoning approaches based on heat density and demand mapping support long-term infrastructure decisions [17]. High-resolution heat atlas methodologies using GIS and building-level data enable detailed evaluation of energy efficiency potentials and DH expansion pathways [18]. Urban scale modelling frameworks combining spatial data with dynamic simulations show that heating and cooling demand trajectories may diverge significantly under climate change scenarios [19,20]. Such findings highlight the need for integrated spatial and temporal planning perspectives.

At the system level, research increasingly moves from sectoral fragmented analyses towards integrated smart energy systems approaches [21,22]. Tools such as EnergyPLAN [23] and related modelling environments enable holistic evaluation of decarbonization pathways and sector coupling strategies [24,25]. Multi-node and multi-period energy hub models demonstrate that market structures and competition influence optimal capacity development and price formation [26]. Nonlinear optimization studies further reveal that demand-side measures may have substantial macroeconomic implications, depending on cross-sectoral allocation strategies [27]. Regional analyses confirm that 100% renewable energy systems are technically feasible but require careful coordination of resource availability and policy frameworks [28,29].

Technological feasibility alone, however, does not guarantee successful transitions. Household-level analysis reveals persistent structural inertia and energy poverty risks without targeted policy support [30]. Participatory decision-making approaches show that stakeholder priorities and social acceptance significantly influence planning outcomes [31]. Comparative assessments across EU member states highlight heterogeneous progress across social, economic and environmental dimensions [32]. Recent syntheses emphasize that DH transformation must be embedded within coherent institutional and governance frameworks [33,34].

Methodological advancements further stress the importance of higher spatial and temporal resolution in carbon accounting and system modelling [35].

Open-source energy hub frameworks improve transparency and reproducibility in district-scale modelling [36]. Operational optimization studies of real DH networks confirm that coordinated generation management can increase profitability while reducing emissions under suitable market conditions [37].

System dynamics modelling has been increasingly recognized as a suitable approach for analysing such complex systems, as it allows the explicit representation of feedback loops, non-linear behaviour, and path dependency. Previous applications of system dynamics in the DH context have demonstrated its potential for assessing long-term transition pathways and policy impacts [38–41]. Thus, such a multi-technology approach, including biomass, HP, waste heat, CHP, and system optimization, together with detailed modelling, has been recognized as one of the most promising strategies to move step by step towards decarbonized and climate-neutral urban heating.

Despite the extensive literature on DH decarbonization, spatial heat planning and integrated energy system modelling, a knowledge gap remains in long-term planning-oriented analyses that explicitly evaluate how the integration of an energy hub into an existing DH system affects system autonomy, emission trajectories and economic performance under evolving technological and market conditions.

By the energy hub in the context of this study is understood a combination of technologies that include electrolysis for green hydrogen production, methanation equipment for synthetic methane production from the green hydrogen and CO_2 captured from industrial processes and the same DH plant, HP, heat and methane storage and CCU technologies. These technologies are installed on the site of the DH plant. Limited attention has been given to the combined assessment of building renovation measures, diversification of heat production technologies and gradual reduction of fossil dependency within a unified scenario-based framework extending to 2050.

The scientific novelty of this study is the extensive analysis of decarbonization pathways by which an existing natural gas combined cycle cogeneration plant can be transformed into an energy hub, offering a potentially transferable solution for a wide range of district heating systems. Unlike the studies reviewed in the literature, in which H_2, synthetic CH_4 and carbon capture are often analyzed as separate solutions, in this work they are integrated into a single energy center chain: renewable electricity → electrolysis → H_2 → methanation with captured CO_2 → synthetic CH_2 → cogeneration. Such approach allows to assess not only the individual potential of each technology, but also their mutual synergy in the context of DH decarbonization.

This study addresses this gap by evaluating the long-term impact of integrating an energy hub into a DH system, with a particular focus on system autonomy, i.e. decreased reliance on external heat providers, CO_2 emission reduction and cost dynamics up to 2050. By linking district-level transformation strategies with a broader smart energy systems perspective, the study provides planning-relevant insights for utilities, municipalities and policymakers seeking robust and economically viable pathways towards climate-neutral heating systems.

The specific aim of the study was to find out how the implementation of the energy hub in the DH system will impact heat production, energy sources used for the heat production, CO_2 emissions and the total costs of heat. DH plant sites are well-suited to develop energy hubs for smart energy systems since that avoids greenfield developments and the associated NIMBY effect, which is increasingly problematic. The main novelty of the presented study lies in the development of a model, based on the DH system's data at the level of the large city, which can demonstrate the significance of the energy hub in decarbonization of DH while identifying the main challenges and realistic development scenarios. The study evaluates fuel-related pathways, including the transition to renewable energy sources, and provides a long-term cost assessment under different fuel price fluctuation scenarios.

2 Methods

The research methodology is based on a system dynamics modelling implemented with the "Stella Architect" software [42]. The model describes the operational structure of a DH system, considering the annual heat demand of Riga city and the development of heat generation sources until 2050. The operator of the DH system, DH company "Rigas Siltums," serves as the primary data source. The company is the main supplier of heat in the city of Riga and ensures the generation, transmission, and distribution of heat to consumers.

The company uses natural gas and wood chips as fuel for heat production. Five large CHP and several dozen small and medium-scale heat-only boiler houses (BH)

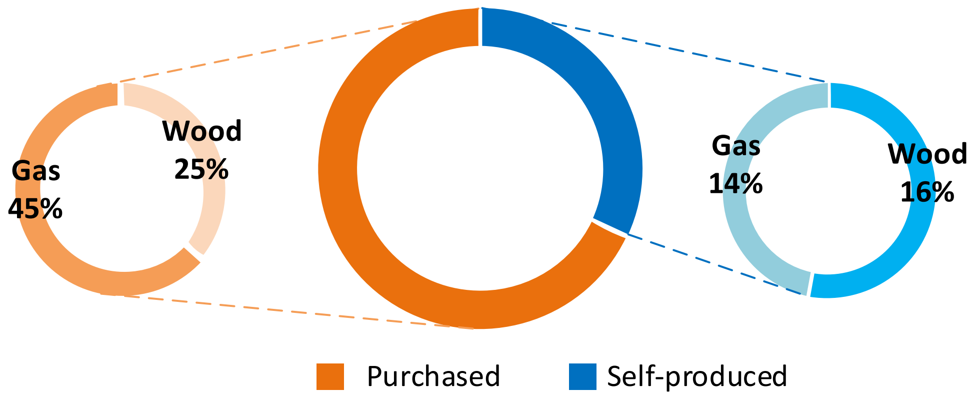

Figure 1: Shares of purchased and self-produced heat, and fuel used in the Riga district heating system.

owned by "Rigas Siltums" collectively produce approximately 30% of the city's total heat demand. External producers supply the remaining 70% of heat (Figure 1), with the larger part of it coming from two natural gas-fired CHPs.

The DH network in Riga extends for approximately 800 km, of which around 689 km are owned and operated by the DH company. The company's heat production facilities are located on both banks of the Daugava River (Figure 3), a factor that reduces flexibility for combining heat generation and distribution since the systems are not connected. On the left bank, the heat supply is entirely ensured by the company's own production sources, whereas on the right bank, a considerable share of heat is purchased from external producers.

It is assumed in the model that DH systems on both banks of the river are connected, ensuring a two-way energy flow across the river. This assumption is because currently such an option is being analysed by the DH company.

The heat demand module (top Figure 2) shows total heat demand influenced by three main elements: renovation subsidies for the renovation of existing buildings, the extent of the renovation of residential and non-residential sectors and the development of new building areas. A detailed description of the heat demand model, which integrates several sub-models to obtain future heat demand forecasts, is provided in [43,44].

The DH heat module (middle) consists of two subsystems. The installed generation capacity in the main subsystem determines the amount of self-produced heat, while the difference between demand and self-produced heat creates a "gap" that affects both the cost of purchased heat and direct CO_2 emissions.

The energy hub module carries out investment, cost, and revenue calculations related to storage equipment (hot water tanks, methane tanks, compressors), and production equipment (electrolyzer, HP, methanation), which results in an increase in self-produced heat. The development of the energy hub sub-model includes TRNSYS [45] optimization and its integration into system dynamics model [46,47].

The external producer module represents independent heat producers operating in parallel with the DH system. The produced heat is transferred to the DH system, thereby supplementing the DH module's self-production volume and reducing the difference between demand and self-produced heat.

Three scenarios (Figure 3, 4, 5) have been developed to evaluate the performance of the potential system, which analyses annual costs and environmental CO_2 emissions. In Scenario 1 (Figure 3) assumed that the DH company continues its current operations, purchasing the required heat throughout the entire modelling period until 2050, without new external producers joining the system.

In Scenario 2 (Figure 4) it is assumed that the DH company continues to operate as before, purchasing heat in the required quantity for the entire modelling period, but new external producers are joining the system. The capacity of external producers participating in the DH market increases almost twice, from 160 to 250 MW. The assumption is based on the already requested permits for the construction of a new wood chip-fired CHP.

In Scenario 3 (Figure 5) it is assumed that the DH company establishes an energy hub at its largest CHP (Figure 6), where hydrogen and subsequently synthetic methane are

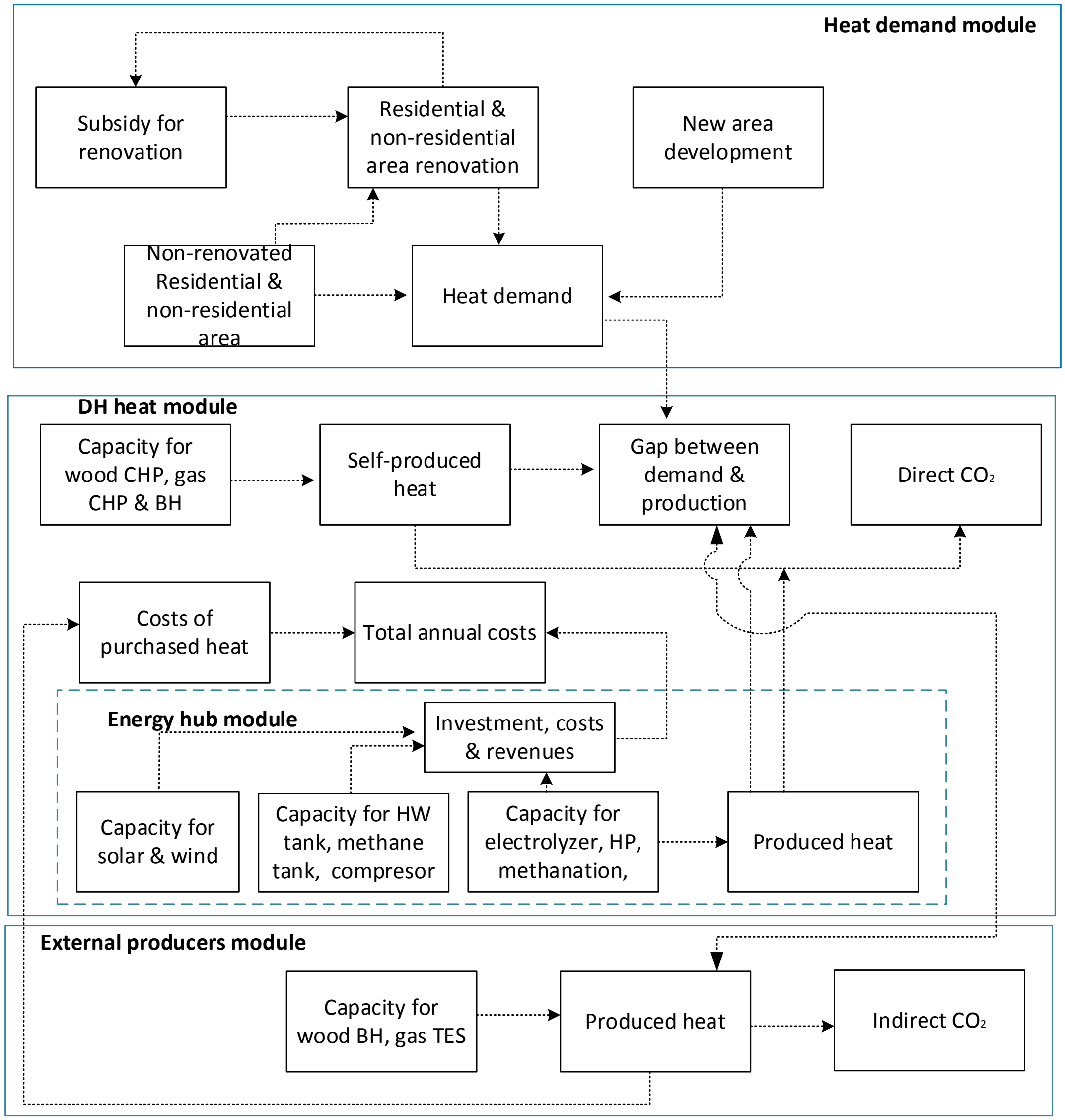

Figure 2: Structure of the system dynamics model characterizing the development and decarbonization of DH systems.

produced and used in the existing gas turbine (GT) for heat and power production. CO_2 generated in the production process is captured and utilized for methanation, while the additionally required CO_2 is collected from the stack of the gas boiler located in the same CHP. The model assumes that the energy hub will begin operating in 2027.

The main parameters used in all scenarios are presented in Table 1.

Integration of the energy hub in the existing CHP plant could potentially avoid the NIMBY effect and would provide necessary utility connections (DH network, gas and electricity). Thus, DH plants are very well suited for energy hub development.

Each technological sub-model (Figure 7) includes a capacity life cycle encompassing new capacity ordering, construction, commissioning, and decommissioning, which together determine long-term changes in available production capacity in operation. This applies to technologies analyzed in the DH module and in the external module, including CHP and BH, as well as all technologies included in the energy hub.

Each capacity sub-model includes two principal capacity groups: capacities under construction and capacities in operation. The interaction between the capacities is governed by flows describing the rates of new capacity ordering, commissioning, and retirement

Figure 3: Scenario 1 – base scenario.

of obsolete units. These processes depend on construction time, operational lifetime, and adaptation coefficients that determine the system's inertia.

Heat production by each technology is calculated based on the maximum available capacity in operation, efficiency, and actual capacity utilization factors. The technical parameters of the existing equipment are summarized in Table 1 and the corresponding parameters of the equipment integrated into the energy hub are summarized in Table 2.

To calculate the costs of purchased heat in all scenarios, it was assumed that the tariff (Figure 8) will be approximately two times higher than the fuel (natural gas and wood chips) costs. This assumption was made by analysing the company's experience over the past five years.

The model also incorporates a submodule, where the total CO_2 emissions generated by the different heat sources are calculated. Emissions are determined using specific emission factors that characterize the CO_2 emission intensity of natural gas and synthetic methane produced with renewable power. Wood is considered to have zero net CO_2 emissions.

Model validation was done by starting with direct structure tests that can be classified as theoretical structure tests, in which, for the structure confirmation, the model structure is compared with the generalized knowledge that can be obtained from various

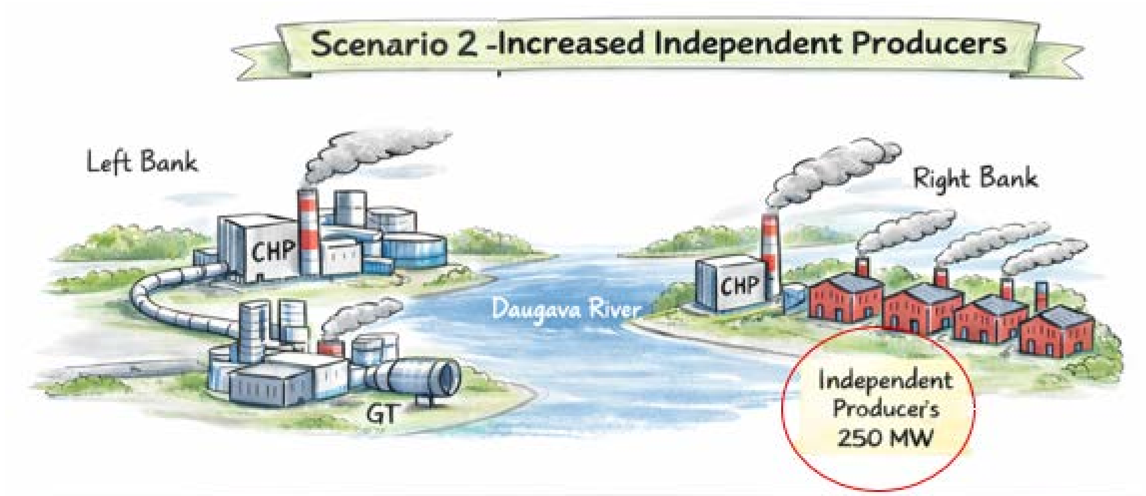

Figure 4: Scenario 2 – increase of external producers.

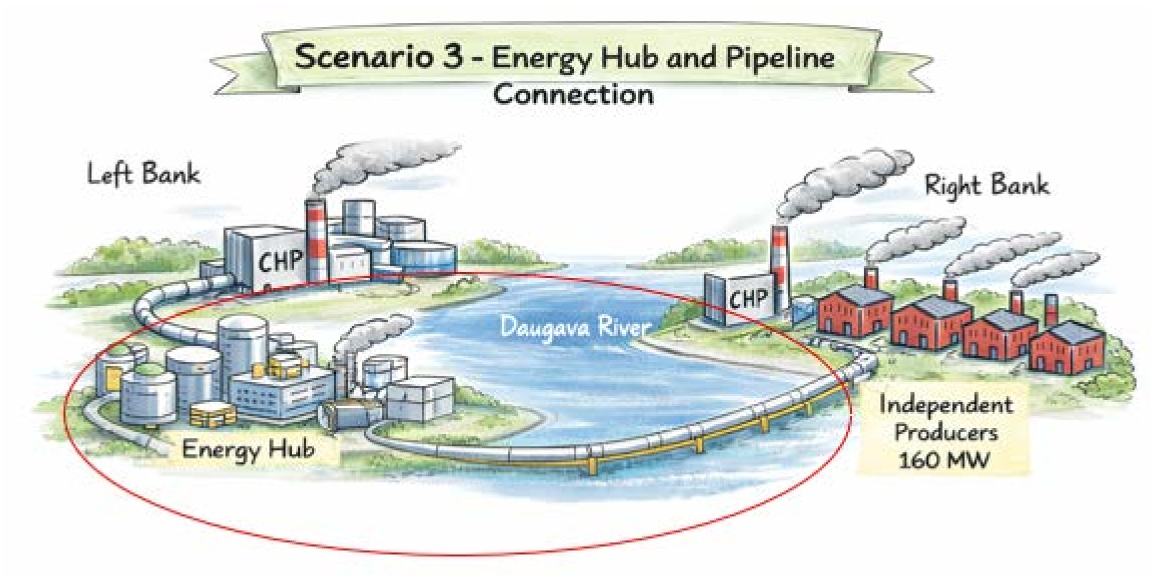

Figure 5: Scenario 3 – energy hub and pipeline connection.

information sources, including scientific publications. A structure-oriented behaviour test was done as the next testing step, using sensitivity analysis that shows that the behaviour of the model in response to changes in some of the important parameters is as would be expected in real life.

The sensitivity analysis was performed for selected model parameters, including the level of subsidies and the impact of heat tariffs on building renovation rates. Validation of the energy hub system confirmed that the model's dynamic behaviour is insensitive to variations in the time step and to the choice of numerical integration method.

Furthermore, dimensional consistency checks were carried out during the model development process. However, it should be noted that empirical validation of the energy hub model against historical operational data is not feasible, as the energy hub system does not yet exist in practice.

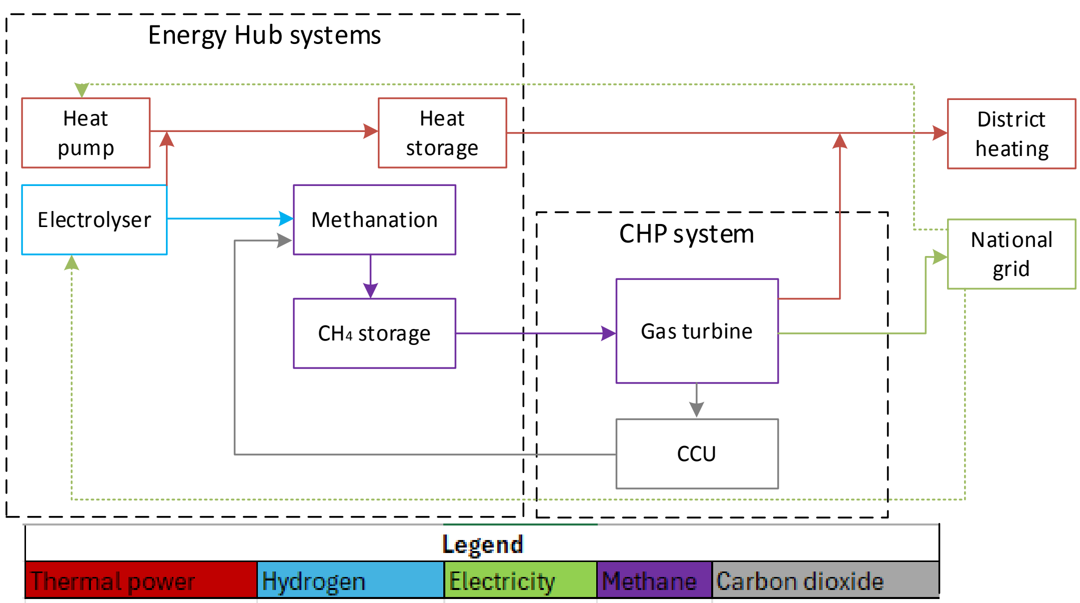

Figure 6: Diagram of energy hub technologies and link with the existing CHP.

Table 1: Parameters used in all scenarios.

Name	Value	Units	Reference
DH heat sources in operation	834	MW	[48]
Average time of construction of capacity	2	years	assumption
Average lifetime of capacity	25	years	assumption
Operating time (DH heat sources) *	5000-8760	hours per year	[48]
Efficiency of DH heat sources*	80-90	%	[48]
Actual capacity/installed capacity (DH heat sources)*	17-75	%	[48]
Total energy demand for DH	3277-2931	GWh/year	[43,44]
CO_2 emission factor for natural gas	224.5	Tons/GWh	
Capacity of independent heat producers' heat sources	160	MW	[48]
Operating time (independent heat sources) **	7303	Hours per year	[48]
Efficiency of independent heat sources)**	85	%	[48]
Actual capacity/installed capacity (Independent heat sources)**	67	%	[48]
Future price of natural gas/wood chips	39-42/ 24-29	MWh/EUR	[49,50]

*The actual capacity is based on average operating time and power, efficiency over the last 5 years. Each technology and source has its own parameter.

**Based on average operating time and power, efficiency over the last 5 years.

Therefore, the results of Scenario 3 reflect scenario-based predictions under assumed conditions, rather than empirically tested results. A similar limitation applies to independent heat producers, which have not commissioned any new wood-chip boiler houses over the past ten years, except for two boiler houses constructed by subsidiaries of the DH company in 2020 and 2024. However, the construction of the new BH envisaged in Scenario 2 is based on the available documentation and issued technical regulations for the construction of new BH of external heat producers.

3 Results and discussion

Results for self-produced heat show that Scenarios 1 and 2 have the same results (Figure 9), as no changes are made to the balance of the company's technical equipment that ensures the production of heat.

In Scenario 3, it can be observed that, although the integration of the energy hub significantly increases the company's self-produced heat starting at 2027, the available heat generation capacity still does not fully cover the city's total heat demand (Figure 9). As a result,

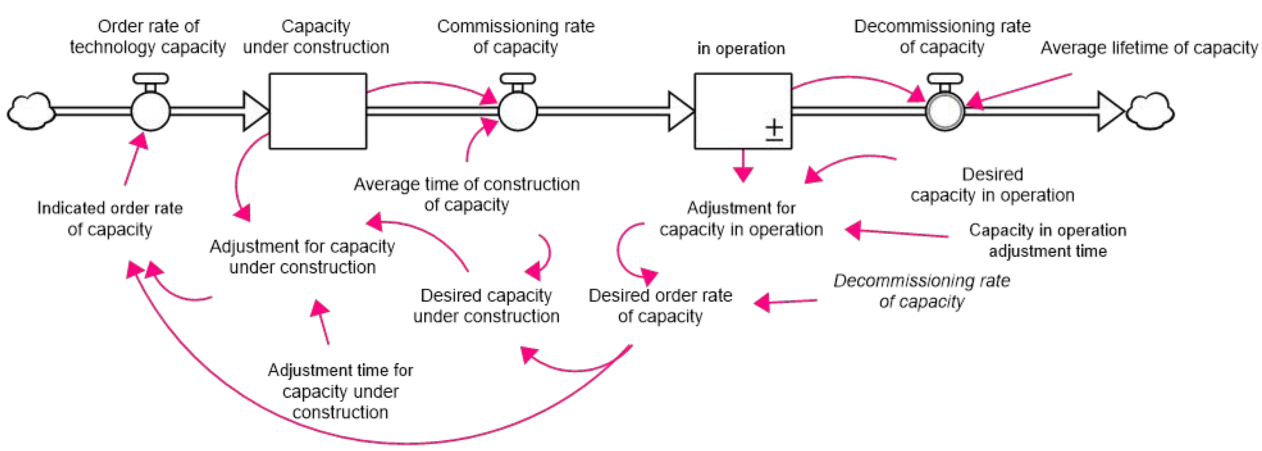

Figure 7: Life cycle sub-model of production capacities based on stocks and flows.

Table 2: Parameters used in Scenario 3.

Name	**Value**	**Units**	**Reference**
Efficiency of GT	0.3016	MWh/MWh	[48]
Electrolyzer efficiency	65	%	[51]
Average lifetime of electrolyzer	16	years	[52]
PHR of GT	65	%	assumption
COP	3,45		assumption
Average lifetime of HP, compressor, wind generations	25	years	[53]
Average lifetime of HWtank	90	years	[52]
Average lifetime of methane tank	100	years	
Specific H_2 requirement	0,25	kg/kg	
LHV of H_2	33,33	MWh/tons	[54]
Specific CO_2 requirement	2,75	kg/kg	
Fraction of CO_2 from GT captured	0,41	kg/kg	
Average lifetime of methanation capacity	50	years	
Indicated capacity utilization time of solar PV	711	Hours/years	
Average lifetime of solar PVs	20	years	[53]
Desired renewable fraction	0,5-1	unitless	assumption
Solar PV capacity in operation	43.2	MW	[48]
Indicated capacity utilization time of wind	1876	Hours/years	
Total costs of compressor	0-164	k EUR/year	[47]
Total costs of electrolyzer	0-43253	k EUR/year	[47]
Total costs of HP	0-1036	k EUR/year	[47]
Total costs of methanation	0-130	k EUR/year	[47]
Total costs of methane tank	0-2740	EUR/year	[47]
Total costs of power production from RES	0-84789	k EUR/year	[47]

procurement of heat from external suppliers remains necessary throughout the period analysed.

The integration of the energy hub enhances the long-term sustainability of the DH system, while heat demand gradually decreases over time because of building renovations. By 2050, self-produced heat accounts for approximately 65% of the total heat demand, compared to 30% in 2023, demonstrating the considerable impact of the energy hub on increasing the system's autonomy and reducing dependence on external heat sources.

Independence from external conditions is essential to ensure a continuous heat supply, enable the selection of locally available energy resources that are not subject to external global influences and reduce heat tariffs for end users, since the company data show that the cost of self-produced heat is approximately 20 EUR/MWh less, compared to an average purchase price.

Results of heat production by energy sources (Figure 10) show that in Scenario 1 no changes are observed in the structure of energy resources of self-produced heat. At the same time, a significant decrease in the volume of natural gas used for heat production is observed. It is predicted that in 2050, use of natural gas for heat production will be 20% or 346 GWh lower than in 2023. This is explained by the decrease in total heat energy demand, resulting from building renovation.

In Scenario 2 the development trends of self-produced heat remain identical to Scenario 1, however, significant differences are observed in purchased heat. The purchased heat produced from wood-chips increases by 56% or 374 GWh in 2050, compared to 2023, while the volume of the purchased heat produced from natural gas decreases by 42% or 721 GWh in the same period. These changes are related to the entry of new external heat producers into the heat market that use wood chips for heat production.

In Scenario 3 a gradual increase in the shares of HP generation and waste heat utilization can be seen, further

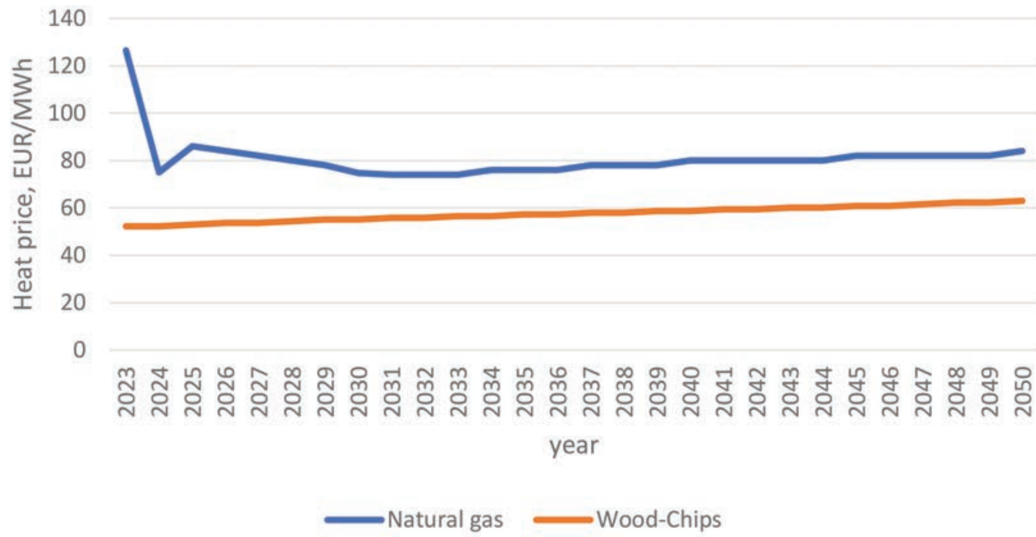

Figure 8: Price of purchased heat from external producers depending on the fuel used for heat production (natural gas, wood chips).

reinforcing the trend towards self-sufficiency. By 2050, the proportion of purchased heat decreases to approximately 35%, compared to 70% in 2023, demonstrating the significant impact of the energy hub integration on improving the system's efficiency and reducing external heat demand. The figure illustrates a clear transition towards a more diversified and internally supported heat supply structure within the DH system.

Direct CO_2 emissions are emissions that originate from sources owned by the company (Figure 11). Indirect CO_2 emissions are emissions that originate from external suppliers that produce and deliver heat for the company's needs.

In Scenario 1 and Scenario 2, direct CO_2 emissions from natural gas remain virtually constant throughout the analysed period, fluctuating between 72 and 73 kt CO_2 per year (Figure 11). This indicates a stable level of natural gas use and limited emission reductions in final energy consumption under these scenarios. In contrast, Scenario 3 shows a pronounced decline in direct CO_2 emissions from natural gas after 2027, decreasing from 73 kt CO_2 to 22 kt CO_2 per year. This can be explained

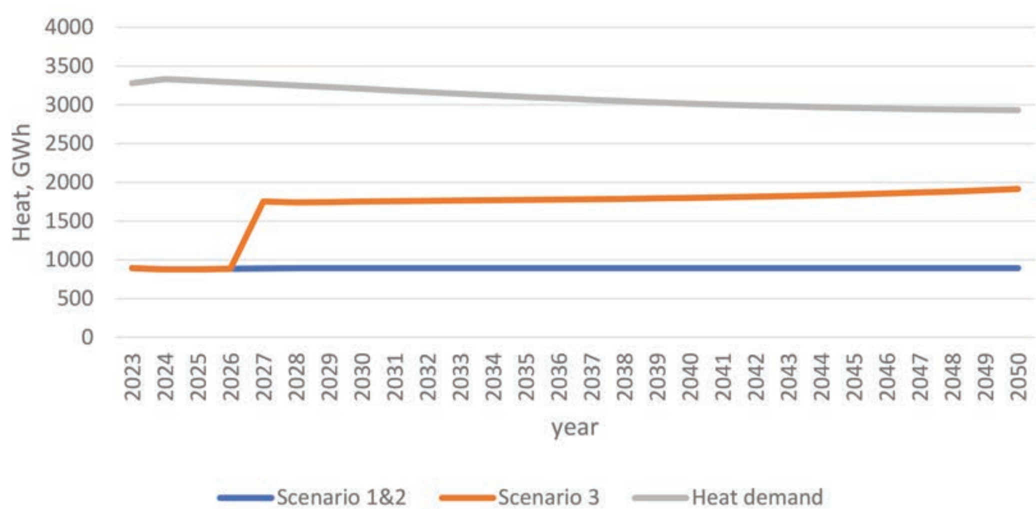

Figure 9: Dynamics of heat demand and self-produced heat in all three scenarios.

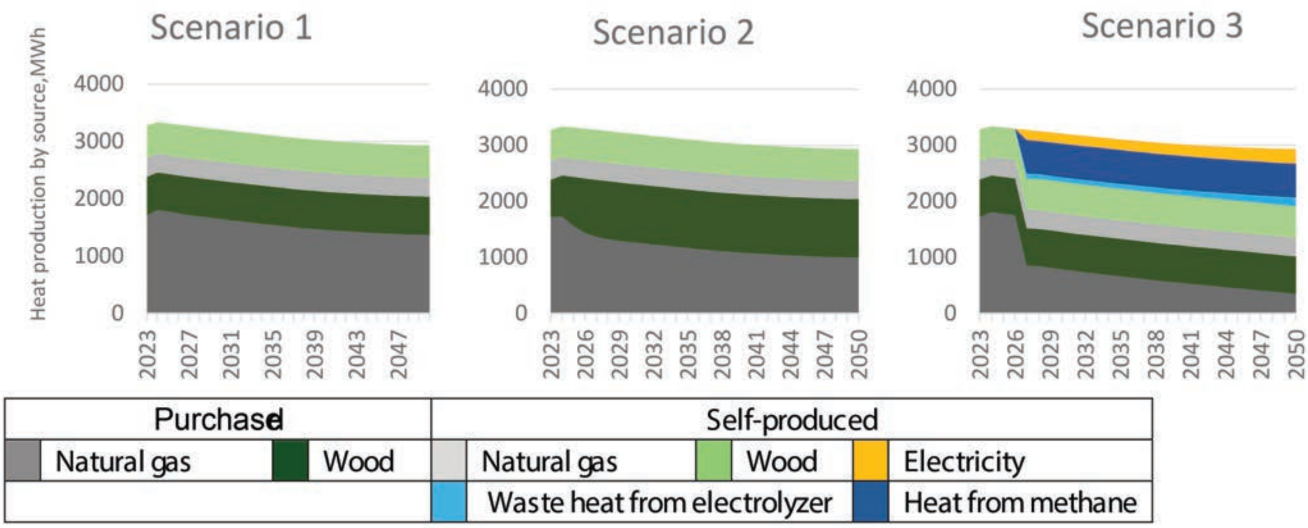

Figure 10: Energy resources used in DH for the production of the purchased and self-produced heat.

by the installation of a CCU unit on one of the gas boiler flue gas stacks to ensure the amount of CO_2 required for the methanation process.

Indirect CO_2 emissions from natural gas decline in all scenarios, although the rate of reduction differs substantially. In Scenario 1, indirect emissions gradually decrease from 386 kt CO_2 in 2023 to 308 kt CO_2 in 2050, representing a moderate and incremental decarbonization pathway. In Scenario 2, the reduction in indirect CO_2 emissions is more pronounced, falling from 386 kt CO_2 to 224 kt CO_2 by 2050, because of the substitution of natural gas by wood chips. Scenario 3 exhibits the steepest decline in indirect CO_2 emissions after 2027, decreasing from 386 kt CO_2 to 70 kt CO_2 by 2050. This sharp reduction reflects a substantial structural transformation of the DH energy system.

The additional systems integration (energy hub and CCU) to the DH system significantly reduces the amount of natural gas used for heat production in the heat sources of external producers. Direct CO_2 emissions from synthetic methane occur only in Scenario 3, since the energy hub starts operation in 2027, and these emissions increase to approximately 151–154 kt CO_2 per year and remain stable through 2050. This result

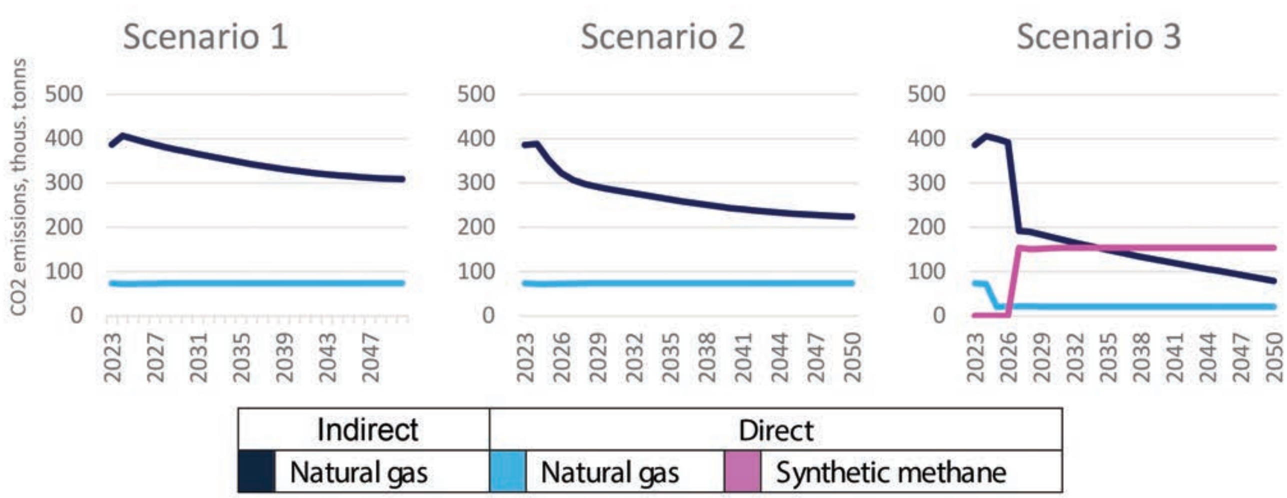

Figure 11: Dynamics of CO_2 emissions associated with purchased and self-produced heat in all three scenarios.

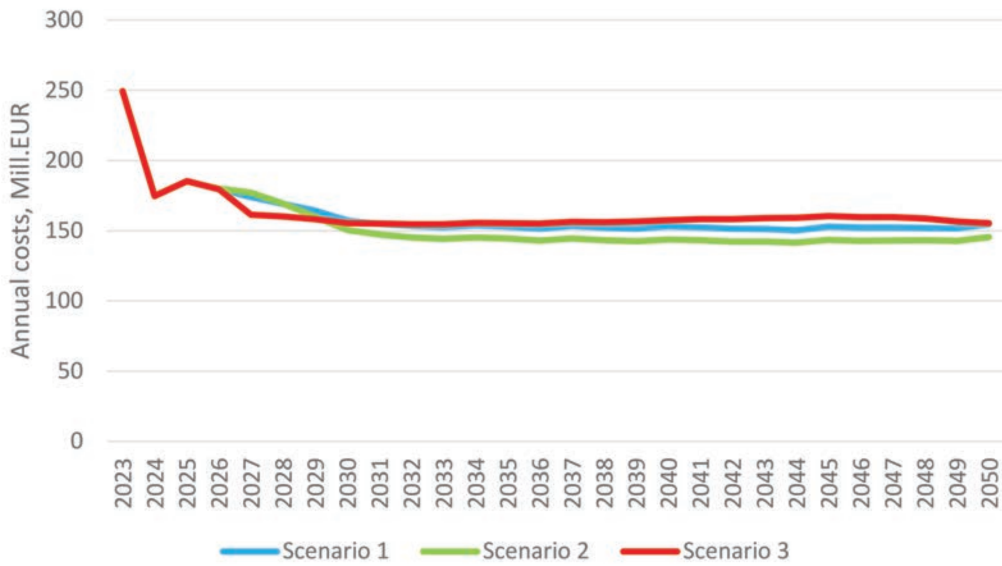

Figure 12: Annual costs for meeting heat demand in DH in all three scenarios.

highlights the significant role of synthetic methane in replacing natural gas.

In all three scenarios the total emissions (direct and indirect), are 459 kt CO_2 in 2023. In 2050, Scenario 1 produced 382 kt CO_2, Scenario 2 produced 298 kt CO_2, and Scenario 3 produced 245 kt CO_2, which means that, from the point of view of CO_2 emissions, the Scenario 3 is the most favourable .

In the cost analysis Scenarios 1 and 2 represent the DH company's costs for purchasing heat from external producers. Scenario 3 presents the total capital, and operation and maintenance (O&M) costs (including the compressor, electrolyzer, HP, HW tank, methane tank, methanation process, solar and wind technologies), electricity costs for electrolysis process and HP, the costs of purchased synthetic methane, as well as the costs of heat purchased from external producers and revenues from net power export (Figure 12).

Across all three scenarios, a significant reduction in costs is observed at the beginning of the period, followed by a relatively stable cost level throughout the medium and long term. The rapid decline in costs during the initial years is explained by a sharp increase in heat prices before 2023, because of the war in Ukraine, which led to a substantial rise in natural gas prices.

During the early period (2023–2026), all three scenarios exhibit nearly identical cost levels, starting at approximately 250 MEUR in 2023 and decreasing to around 175–185 MEUR by 2026, as the scenarios are primarily influenced by the same external energy price dynamics during this phase.

In the transition period (2027–2030), the scenarios begin to diverge. The costs in Scenarios 1 and 2 continue to decline, reaching approximately 150 MEUR by 2030, while Scenario 3 stabilizes at a slightly higher level of around 160 MEUR. The cost reduction in Scenario 2 is achieved by increasing the share of purchased heat from lower-cost wood chip-fired CHP. Scenario 3 represents the highest cost option throughout this period, as it involves investment in energy hub technologies.

In the period from 2030 to 2050, costs across all scenarios remain relatively stable, with only minor fluctuations. Scenario 2 consistently demonstrates the lowest cost level throughout this period, remaining around 145 MEUR, because the price of wood chips is lower than the price of natural gas. Scenario 1 maintains a slightly higher yet stable cost level of approximately 150–155 MEUR, primarily influenced by wood chip costs and natural gas prices. Scenario 3 continues to exhibit the highest annual costs throughout the period, remaining around 155–160 MEUR, exceeding those of the other scenarios by a consistent margin.

This difference is primarily explained by the fact that, although electricity generated from the GT and surplus solar energy is sold, the resulting revenue is insufficient to offset the maintenance and capital costs associated with the new energy hub technologies. By 2050, Scenario 2 remains the most cost-effective option (~145 MEUR),

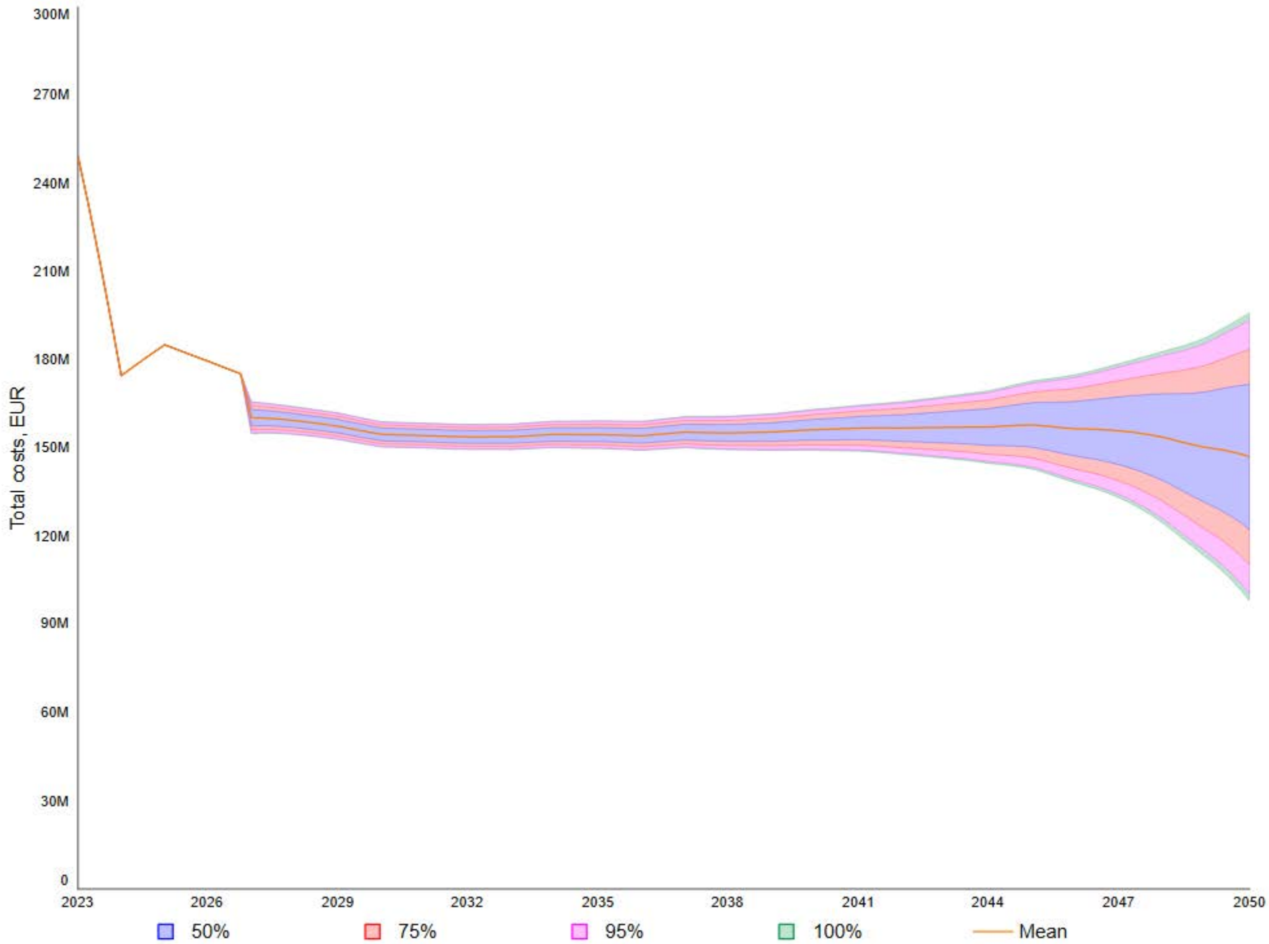

Figure 13: Probabilistic confidence intervals of the sensitivity analysis of the total costs depending on electricity price.

followed by Scenario 1 (~150 MEUR), and Scenario 3 as the highest-cost alternative (~155 MEUR).

Sensitivity analysis was performed for Scenario 3 using Monte Carlo simulation. In each simulation iteration, parameter values were randomly generated according to their defined distributions. Each simulation run represents a possible combination of energy resource prices in the specified interval. The mean curve (mean) reflects the average value of the total costs in all Monte Carlo simulations, while the coloured confidence intervals characterize the range of possible cost variations (Figure 13). Electricity and natural gas prices were varied from 50 to 150 EUR/MWh in the runs.

The probabilistic confidence bounds for the total costs depending on electricity prices (Figure 13) are relatively narrow during the medium-term period (2027–2041), remaining within a range of approximately 150–165 MEUR. However, confidence intervals progressively widen toward the end of the period, expanding considerably after 2044 and reaching the widest range by 2050, where the 100% confidence interval extends from approximately 100 MEUR to 190 MEUR. This widening reflects the increasing influence of electricity price variability on total costs in the long term, as the volume of electricity sold from the energy hub grows over time.

When the natural gas prices are varied (Figure 14), the confidence intervals are considerably wider than for the electricity prices throughout the period, demonstrating high sensitivity to gas price fluctuations.

During the initial period (2023–2026), the 100% confidence interval extends from approximately 110 MEUR to 300 MEUR, with a mean value of around 210 MEUR, indicating substantial uncertainty in total costs driven by gas price variability. A pronounced structural break is observed in 2027, related to the implementation of the energy hub and the start of synthetic methane

Figure 14: Probabilistic confidence intervals of the sensitivity analysis of the total costs depending on natural gas price.

production, after which both the mean total costs and the confidence intervals decrease significantly.

From 2027 onward, the mean total costs gradually decline from approximately 180 MEUR to around 150 MEUR by 2050, while the confidence intervals progressively narrow over time, since the natural gas is phased out by the energy hub, with the 100% confidence interval ranging from approximately 130 MEUR to 200 MEUR by the end of the period.

Sensitivity analysis with combined variation of electricity and natural gas prices (Figure 15) shows that the confidence intervals of the total costs are narrower than for the gas prices alone and wider than for the electricity prices alone.

During the initial period (2023–2026), the 100% confidence interval extends from approximately 120 MEUR to 305 MEUR, with a mean value of around 210 MEUR, reflecting substantial uncertainty driven by the combined variability of both energy resource prices. From 2027 onward, the mean total costs gradually decline from approximately 175 MEUR to around 165 MEUR, while the confidence intervals progressively narrow over time, converging to a single point of approximately 165 MEUR around 2046–2047.

4 Conclusions

This study demonstrates that the integration of an advanced energy hub into the district heating system provides substantial long-term technical and environmental benefits, significantly enhancing energy autonomy and resilience against fossil fuel price volatility, even though it represents the highest-cost option over the analyzed period due to significant upfront capital investments.

In Scenarios 1 and 2, with no energy hub, self-produced heat remains largely unchanged, as no modifications are introduced to the existing technical infrastructure. Although Scenario 2 achieves partial decarbonization through increased procurement of wood-chip-based heat, both scenarios remain significantly dependent on external suppliers. By contrast, Scenario 3 fundamentally alters the system's structure. The integration of the energy hub from 2027 onward

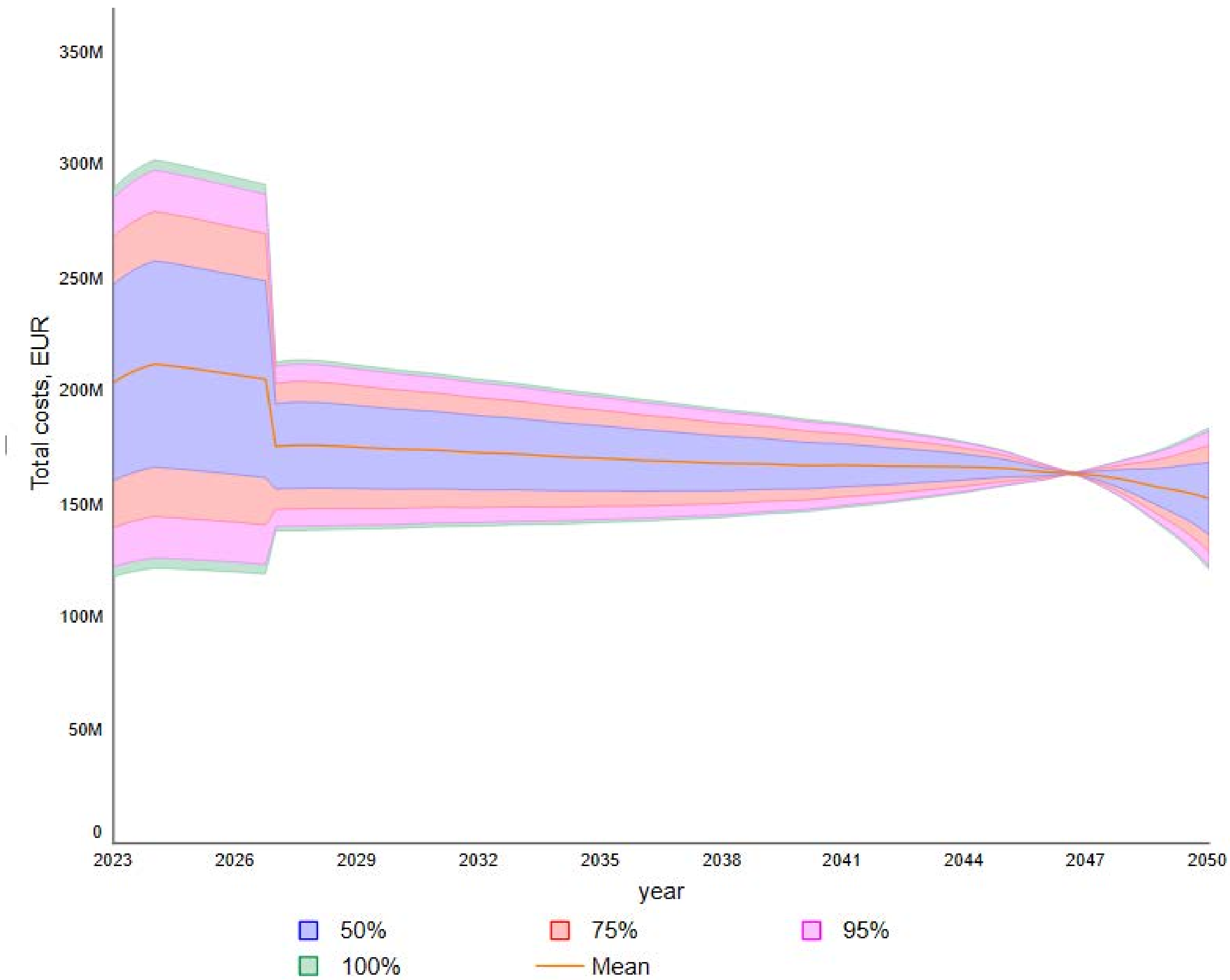

Figure 15: Confidence intervals of the sensitivity analysis of the total costs depending on the simultaneous variation of electricity and natural gas prices.

significantly increases self-produced heat, raising its share from approximately 30% in 2023 to about 65% by 2050. While external heat procurement remains necessary, the system's autonomy and diversification are markedly improved. This transition strengthens energy security, reduces exposure to geopolitical risks, and enables greater use of locally available energy resources.

From an environmental perspective, Scenario 3 delivers the most pronounced emission reductions. While Scenarios 1 and 2 show only moderate decline in indirect CO_2 emissions and nearly constant direct emissions from natural gas, Scenario 3 achieves a pronounced reduction in both direct and indirect emissions after 2027. Despite the introduction of direct emissions from synthetic methane, overall emissions decrease most significantly. By 2050, Scenario 2 results in a 22% reduction relative to Scenario 1, while Scenario 3 achieves a substantially larger reduction of approximately 36% compared to Scenario 1. Consequently, Scenario 3 constitutes the most effective decarbonization pathway.

The economic analysis reveals differentiated cost dynamics over time. In the short term (2023–2026), all three scenarios exhibit nearly identical cost levels, as they are primarily influenced by the same external energy price dynamics. From 2027 onward, the scenarios begin to diverge, with Scenario 2 emerging as the most cost-efficient option throughout the analysed period due to increased reliance on comparatively cheaper wood-chip-based heat.

Scenario 1 maintains a slightly higher yet stable cost level, while Scenario 3 represents the most expensive alternative throughout the period because of high capital investments in energy hub technologies. Although electricity generated from the GT and surplus solar energy is sold in Scenario 3, the resulting revenue is insufficient to fully offset the maintenance and capital expenditures associated with the new energy hub technologies. By 2050, the cost ranking remains unchanged, with Scenario 2 as the most cost-effective option, followed by Scenario 1, and Scenario 3 as the highest-cost alternative.

The implementation of the energy hub and the start of synthetic methane production in 2027 result in a pronounced structural break, after which both the mean total costs and the confidence intervals decrease significantly, indicating reduced system vulnerability to gas price volatility in the long term.

It should be emphasised that the results for Scenario 3 represent scenario-based projections of a prospective transformation pathway rather than empirically validated forecasts. As the energy hub does not yet exist in operational form, the reported share of self-produced heat (~65% by 2050), emission reductions (~36% relative to Scenario 1) and cost dynamics are conditional on the technical and economic assumptions specified in Table 2 and the modelling framework described in Section 2.

By contrast, the parameters underlying Scenarios 1 and 2 are anchored in observed historical data and publicly available documentation, including the issued technical regulations for the construction of new boiler houses by external producers. The robustness of the Scenario 3 projections has been examined through Monte Carlo sensitivity analysis on the dominant uncertain parameters (electricity and natural gas prices), as reported in Figures 13–15.

Overall, the results demonstrate that incremental changes (Scenarios 1 and 2) provide the most cost-effective pathway in purely economic terms, with Scenario 2 consistently delivering the lowest annual costs throughout the analysed period. However, only systemic integration of advanced technologies, such as the energy hub combined with CCU and synthetic methane production (Scenario 3), enables a substantial transition toward a more autonomous, diversified, and low-carbon DH system.

Despite higher annual costs, Scenario 3 delivers significant non-monetary benefits in terms of energy security, emission reduction, and reduced dependence on imported natural gas, making it a strategically important development pathway toward 2050, particularly when broader decarbonization and energy independence objectives are considered.

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