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F A C T O R S O N T H E
D I S T R I C T H E A T I N G
M A R K E T**

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LITHUANIAN ENERGY INSTITUTE

VYTAUTAS DŽIUVĖ

MODELLING THE IMPACT OF
UNCERTAINTY FACTORS ON THE DISTRICT
HEATING MARKET

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LIST OF ABBREVIATIONS AND TERMS

AER – Australian Energy Regulator
BESS – battery energy storage systems
BPIE – Buildings Performance Institute Europe
CEEP – critical excess energy production
CHP – combined heat and power
COP – coefficient of performance
CO₂ – carbon dioxide
CSP – concentrated solar power
DH – district heating
DHC – district heating and cooling
DR – demand response
EU – European Union
FITs – feed-in tariffs
FPCs – flat plate collectors
GAMS – General Algebraic Modelling System
GHG – greenhouse gas
HOB – heat only boiler
HP – compression heat pump
IEA – International Energy Agency
IHP – independent heat producer
LCOE – levelised cost of electricity
LCOH – levelised cost of heat
LHS – Latin hypercube sampling
LP – linear programming
MC – Monte Carlo
MILP – mixed-integer linear programming
NEM – National Electricity Market
PCC – partial correlation coefficients
PEM – proton exchange membrane
PDF – probability distribution function
PRCC – partial rank correlation coefficient
PtX – Power-to-X
RES – renewable energy sources
SA – sensitivity analysis
SRC – standardised regression coefficient
SRRC – standardised rank regression coefficient
TES – thermal energy storage
TPA – third-party access
TTES – tank-type thermal energy storage
WACC – weighted average cost of capital

INTRODUCTION

Relevance of research topic

Energy systems are currently experiencing a major transformation, leading to a sharp increase in the share of intermittent renewables such as solar and wind, which can cause significant curtailment or surplus of energy production. Consequently, new technologies, including those used in district heating (DH), are required to balance energy supply and demand while preventing substantial production curtailments. Because they can integrate electric and other technologies, DH systems play a crucial role in balancing energy supply and demand (Averfalk et al., 2014). DH systems have the potential to enhance the flexibility of energy systems and significantly contribute to the integration of renewable energy technologies into future European energy systems (Averfalk et al., 2014). They may also support the sustainability and security of energy systems, particularly in countries with a high share of DH and renewable energy sources (RES; Münster et al., 2012).

The transformation of DH is expected to be supported by advanced energy solutions, such as Power-to-X (PtX), demand response (DR), and other flexibility and energy storage technologies, which create synergies between electricity and DH (Bloess et al., 2018; Lund et al., 2010). These solutions can facilitate the integration of renewables, reduce CO₂ emissions, and decarbonise energy systems cost-effectively (Lund et al., 2010). Alternatively, the integration of electric vehicles, power-to-gas, and hydrogen (H₂) may further enhance flexible energy management (Parrado-Hernando et al., 2022). Hiltunen and Syri (2021) argue that optimal results are likely when electricity, heating, and transport sectors are combined into a smart energy system. In particular, the integration of hydrogen generation technologies into DH can yield economic benefits by using surplus renewable electricity and recovering hydrogen waste heat into heat networks (Parrado-Hernando et al., 2022). For instance, Mezzera et al. (2021) emphasise the potential to recover waste heat from hydrogen production processes and integrate it into DH networks, thereby helping meet heat demand and improving the overall efficiency of future low-carbon energy systems.

Focusing on the Swedish city of Luleå, Miljanovic and Jonsson (2022) propose a system for integrating hydrogen production waste heat into the DH network and find that doing so could improve the cost-effectiveness of green hydrogen production while supporting sustainable heating supply in the region. Another investigation commissioned by the Embassy of Denmark (Ramboll, 2021) similarly evaluates potential synergies between hydrogen production and waste heat recovery in the UK. The report highlights that large volumes of available heat provide substantial opportunities for integration into heat supply systems.

A large body of scientific research confirms the importance of the energy system, particularly the DH sector, for both the global economy and the energy transition. According to Muncan et al. (2024), DH systems play a significant role in Europe and Central Asia, serving over 70 million people through approximately 17,000 deployed systems. The World Bank (2023) reports that transforming and developing the heat sector can yield multiple benefits, including fuel and cost savings,

improved health outcomes, and social and economic advantages. The report projects that this transition could avoid approximately 8.9 gigatonnes of CO₂ emissions from space heating between 2024 and 2050. The International Energy Agency (IEA, 2019a) emphasises that DH networks enable economies of scale and high efficiency by concentrating demand, providing renewable energy storage solutions, and facilitating the interconnection of heat and electricity. Persson et al.'s (2019) paper is closely related to the work of Lund et al. (2010), highlighting the strategic relevance of DH in improving energy system efficiency, reducing costs, and supporting renewable energy integration. Lund et al. (2010) note that DH with combined heat and power (CHP) can achieve higher cost-effectiveness, compared to individual building heating by using an optimal production technology portfolio and incorporating waste heat from industry and power plants. Persson et al. (2019) also discuss the economic advantages of DH in areas with high heat demand, indicating that economies of scale can reduce supply costs in such regions.

Inadequate planning and investment in DH systems (particularly, expansion reliant on fossil fuel technologies such as gas boilers) can contribute to higher production costs and increased energy poverty. Dahl et al. (2019) present a detailed sensitivity analysis, showing that fossil fuel-based DH systems (e.g., those using gas boilers) are highly sensitive to fluctuations in energy prices, which can increase costs and lead to less reliable and more expensive configurations. According to the authors, the reverse occurs for non-fossil-fuel-based systems using technologies such as heat pumps and heat storage, which exhibit higher cost stability and robustness. Their study highlights the financial risks associated with developing fossil fuel-based DH systems and underscores the importance of strategic planning for cost-effective and sustainable heat production.

Similarly, research on the Polish DH sector emphasises that dependence on fossil fuels, such as natural gas, may increase heat production costs, especially amid rising CO₂ emission prices (Talarek et al., 2023). The study notes that in 2020, many DH companies became unprofitable due to high operating costs associated with fossil fuel use. This financial burden highlights the risks of expanding DH systems without transitioning to renewables.

A geospatial assessment performed by Estonian researchers examined the link between access to heat supply and energy poverty (Kirs & Volkova, 2024). Their study finds that in areas without efficient heat supply systems, lower-income households often face higher energy costs, indicating that inappropriate planning and investment in DH infrastructure can contribute to energy poverty. Similarly, Zach et al. (2019) investigate the synergies between the environmental, technical, economic, and spatial features of DH systems, highlighting that insufficient planning and development can lead to higher installation and operating costs, resulting in more expensive heat for end users. An analysis of small-scale DH systems in Lithuania (Dzenajavičienė et al., 2007) also demonstrates that insufficient planning and investment can lead to higher heat production costs. The study emphasises the importance of addressing long-term operating costs and selecting suitable technologies to ensure economic feasibility.

According to Jiang et al. (2022), effective DH planning involves detailed heat resource mapping, accurate heat demand forecasting, and the strategic integration of

sustainable energy sources. The viability of DH systems is strongly influenced by spatial planning parameters such as building density, land-use composition, and access to suitable heat sources (Zach et al., 2019). While climate change and declining heat demand pose significant challenges to long-term DH sustainability, they can be addressed through lower supply temperatures and a greater reliance on renewable and waste heat (Zach et al., 2019). As systems evolve toward fourth-generation DH, the focus shifts to minimising heat losses, expanding the share of renewable energy, and introducing advanced control and monitoring technologies (Volkova et al., 2020).

Jonynas et al. (2020) highlight the key role of DH in complex energy systems. Based on their findings, Lithuanian DH systems receive significant attention in the national energy strategy, which focuses on reducing dependence on fossil fuels and increasing the use of RES. Lithuania's *National Energy Independence Strategy* emphasises the importance of environmentally friendly thermal energy sources, which are expected to contribute significantly to the national target of achieving a full transition to 100% renewable energy by 2050 (Lithuanian Ministry of Energy, 2024). While innovative heat generation solutions have considerable potential to support the integration of RES, their impact on the DH system remains unclear due to various economic uncertainties. Therefore, proper DH planning is essential to achieve balanced and efficient RES development and meet the national strategy's objectives. More broadly, integrated energy systems require detailed analysis and strategic planning to meet the diverse needs of all sectors and ensure an efficient energy transition (Groppi et al., 2023).

Scientific problem

In conventional DH systems, scientists typically apply deterministic models to simulate energy flows and infrastructure performance based on fixed assumptions, such as constant demand profiles or weather conditions. However, these models often neglect temporal and spatial variations in energy demand, technological efficiency, fuel prices, and climate-related factors, thus potentially leading to inaccurate or biased planning results (Mendes et al., 2011). This lack of flexibility makes them less suitable for long-term strategic planning in rapidly changing energy markets. Scenario-based modelling offers greater diversity; yet, many energy scenarios still represent only a limited range of possibilities and often fail to sufficiently address extreme cases (Wiese et al., 2018). This limited scope can mislead global assessments of potential energy futures and distort comprehensive scientific analysis. In addition, scenarios frequently rely on expert assumptions and may lack probabilistic or sensitivity analyses, complicating the evaluation of the robustness of decisions (Pfenninger et al., 2014). The lack of coverage limits a full assessment of the risks and uncertainties associated with different energy transformation pathways.

The growing complexity of DH systems requires a comprehensive approach to address challenges such as energy price volatility, policy changes, and technology adoption. Tereshchenko and Nord (2016) highlight the relevance of factors such as fuel price volatility and fluctuations in heat load profiles in DH planning. Their study demonstrates that conventional deterministic models often fail to capture these variable dynamics, resulting in suboptimal investment decisions. While conventional

deterministic models can capture the impact of individual economic uncertainties on the energy system, they typically fail to adequately reflect complex techno-economic uncertainties, political-strategic factors, and cross-sectoral factors, all of which are interrelated and relevant to real market dynamics.

Lygnerud et al. (2023) highlight that integrating new technologies and the emergence of different market players are transforming the DH sector, requiring more advanced planning and investment strategies. Researchers have also identified four key challenges in energy modelling over the past decade: (1) handling uncertainty and improving model transparency; (2) managing complexity and optimising at multiple scales; (3) integrating human behaviour and real market factors; and (4) improving the temporal and spatial resolution of optimisation and simulation models to accurately reflect the variability of intermittent RES such as wind, solar photovoltaics, tidal, and wave energy (Parrado-Hernando et al., 2022).

Uncertainties in modelling DH or the entire energy system are generally categorised into three groups: (1) uncontrollable factors, such as volatile electricity, natural gas, CO₂, or biofuel prices and long-term heat demand dynamics (Soroudi & Amraee, 2013; Afzali et al., 2024); (2) controllable factors, including direct investment decisions in emerging renewable energy facilities and capacities (Soroudi & Amraee, 2013); and (3) partially controllable factors, such as renewable energy development targets or subsidy schemes, which depend on future policy decisions and lie between fully controllable and fully uncontrollable (Soroudi & Amraee, 2013). Each category of uncertainty involves specific modelling requirements that increase the complexity of DH sector modelling. For instance, uncontrollable factors, such as market prices and demand variability, require high temporal and spatial resolution; controllable factors, such as investment decisions, require models that include various sector participants; and semi-controllable factors, such as policy measures, are best addressed through multiple iterative scenario analyses (Pfenninger et al., 2014; Wiese et al., 2018). Simplified assessments may reduce computational burden but risk overlooking critical dynamics, whereas enhanced stochastic scenario-based methods systematically capture possible future outcomes across all three uncertainty categories and help evaluate the robustness of strategies (Fan et al., 2022).

Berna-Escriche et al. (2024) examine relevant examples by analysing uncertainties and the applicability of new methods in the electricity sector, considering the Canary Islands' decarbonisation plans for 2040. In this case, uncertainty assessment is used to evaluate the reliability of alternative transition strategies, considering technological, economic, and policy-related uncertainties. Their methodology emphasises the integration of quantitative modelling methods with qualitative scenarios, thereby enabling a more detailed presentation of systemic risks and potential mitigation strategies.

D'Auria (2019) applies a similar approach in the field of nuclear safety, where structured uncertainty analysis forms the basis for decision-making and risk management. The parallels between energy system transformation research and nuclear safety analysis underscore the interdisciplinary significance of uncertainty methodologies, particularly their ability to increase transparency, support adaptive planning, and help stakeholders manage complex social and technical systems.

Despite the importance of uncertainty analysis, its application has been limited across energy topics. The literature suggests that incorporating stochastic methods, which account for uncertainty, variation, and randomness, can yield more robust and reliable outcomes in energy system planning. Therefore, this dissertation raises a fundamental question: what are the potential uncertainties, and how can they be modelled in DH planning, considering the influence of market dynamics?

Research object

The impact of uncertainties on the district heating market.

Research aim

Theoretical identification of uncertainties and establishment of a partial equilibrium methodology that reflects the current auction system by integrating uncertainty factors and identifying optimal investment portfolios for the Vilnius district heating market.

Research objectives

1. To theoretically examine the factors influencing the development of the district heating sector and identify types of uncertainty;
2. To identify the particularities of the most appropriate complex energy modelling tools for district heating systems and their capabilities in uncertainty assessment;
3. To establish a methodology for modelling the district heating market, incorporating global sensitivity and uncertainty analysis;
4. To develop and apply a partial equilibrium economic model for the Vilnius city district heating system;
5. To investigate and identify an optimal investment portfolio for the district heating market, considering the impact of uncertainties;
6. To determine, based on modelling outcomes, the uncertainty factors with the strongest impact on the district heating system market.

Research methods

A wide range of scientific literature has been considered in order to provide a comprehensive analysis of economic modelling methods for the energy system. A detailed investigation of 37 potential energy modelling applications was conducted, from which six of the most appropriate energy modelling tools were purposively selected for comparison. The best modelling tools have been selected to ensure that the chosen model reflects both the electricity and district heating sectors. Priority was given to operational and bottom-up investment optimisation energy modelling tools. In order to better compare the simulation and optimisation model features and differences, two additional most suitable simulation energy tools were selected.

After a comprehensive literature review and the comparison of economic simulation and optimisation models, some limitations were identified, contributing to the incomplete consideration of the dissertation. It has been identified that most of

these models have a lack of capability to reliably manage and manipulate heat auction strategies. Majority of the models examined are based on deterministic systems, which rely on the fixed input parameters and do not take into account the probabilistic behaviour of real-life economic systems. Accordingly, they do not involve Monte Carlo-based uncertainty and sensitivity analysis mechanisms, which are necessary to assess the reliability of the model under uncertain and changing conditions. Therefore, it was decided to establish a self-made partial equilibrium economic model, including DH modelling with Monte Carlo sensitivity and uncertainty analysis. In order to ensure comprehensive planning of the DH system, the deterministic approach of the economic model is broadened by including various controllable, semi-controllable, and uncontrollable uncertainties to realise a stochastic approach. The SimLab software tool helped execute the Monte Carlo-based uncertainty and sensitivity analysis in a complex partial equilibrium model. In addition, in order to test and verify the developed partial equilibrium economic model, the most appropriate simulation tool energyPRO was chosen to evaluate the current DH auction system, which is suitable for the deterministic approach in reducing net production costs.

The partial equilibrium economic model developed in this dissertation realistically represents the DH market by integrating existing IHPs and operator production facilities into the existing heat network. The model operates according to heat auction principles, reflecting competitive interactions that maximise the benefits for end users. It incorporates diverse uncertainties, enabling comprehensive uncertainty and sensitivity analysis to identify financially optimal decarbonisation investment portfolios. The model also provides an opportunity to assess the behaviour of existing operators, IHPs, and potential new market participants under varying market uncertainty conditions. It also helps determine which new energy conversion and production technologies are acceptable and financially viable from an investor's perspective when participating in the DH auction system. The model further enables the analysis of the influence of investment decisions by new potential investors (IHPs or heat operators) on heat auction prices and the effect of these changes on heat production costs associated with the newly installed equipment.

Scientific novelty

Most energy modelling tools are considered deterministic, specifying precise estimates and excluding randomness. A more advanced approach can be achieved by extending deterministic methods with uncertainty techniques (Mendes et al., 2011). Therefore, a new, robust partial equilibrium economic model for assessing DH market performance under uncertainty can support more accurate annual economic planning based on hourly resolution modelling.

The model developed in this dissertation facilitates the assessment of significant changes in the DH environment and the emergence of new market participants. The model captures the operational decisions of existing market participants and incorporates potential new operator and independent heat producer (IHP) investments in heat production and transformation technologies under diverse uncertainty conditions. The novelty of this dissertation lies in the analysis of the integration of

power and other RES-based technologies into DH systems to balance energy supply and demand.

The model extension using Monte Carlo sensitivity and uncertainty analysis supports the identification of an optimal investment portfolio by evaluating scenarios that maximise financial profit, ensure adequate heat auction prices, and reduce CO₂ emissions. The methodology is also unique in its ability to apply and manipulate possible operational strategies for the heat auction system. The modelling of the entire year at hourly resolution demonstrates the feasibility of an hourly auction system, which would enhance the efficiency of the DH market.

The completed partial equilibrium economic model of the Vilnius DH system illustrates a strong potential to utilise and integrate diverse waste heat sources into the DH system to maximise investor profit, ensure adequate heat costs, and replace fossil fuels. This dissertation provides a comprehensive assessment of future DH trends, accounting for technological and economic uncertainties relevant to identifying optimal future solutions. This dissertation also makes a significant contribution to the existing literature, as uncertainty analysis and methods for assessing uncertainty in DH planning and development strategies remain insufficiently addressed.

Research limitations

The heat auction pricing strategy applied in the model is based on the principles of marginal cost, characterising a perfectly competitive market. The model assumes that the heat auction price is based on the marginal variable production costs of the next higher-ranked producer. This approach simplifies the existing heat market structure. Meanwhile, the Lithuanian district heating sector relies on monthly auctions based on price bids from producers, which may be driven by a variety of factors, including irrational behaviour.

The model also assumes no network restrictions on connectivity among production sources. The heat network is not explicitly modelled, implying that the model does not directly reflect the network structure, its components, or their interconnections. Instead of a detailed description of the behaviour of the network, simplified assumptions are used. However, the internal limitations of the heat network may be a risk factor in adapting the developed methodology to large foreign cities by integrating new heat generation sources.

Due to complex uncertainties, the integration of multiple innovative renewable energy technologies, and the need to balance short-and long-term plant operating modes, the analysis focuses on the medium-term horizon of 2030.

The model does not consider longer periods of low solar radiation. Consequently, the required thermal energy storage capacity may be slightly underestimated.

In addition, the model assumes rapid hourly load fluctuations for hydrogen electrolyzers; in reality, this could shorten equipment lifetime, while frequent load shifts could accelerate component deterioration, thereby increasing the need for reinvestment in existing infrastructure.

Finally, only the most significant factors of uncertainty identified in the literature review are assessed; other uncertainty factors that are less relevant to energy planning are not considered.

Practical applications of the developed model and modelling results

The partial equilibrium economic model methodology developed in this dissertation addresses a range of uncertainties and provides a comprehensive approach for setting strategic development directions for DH companies and prioritising the most economically viable solutions. The framework can also help other municipalities identify optimal investment opportunities to meet decarbonisation targets.

Additionally, the model serves as a valuable analytical tool that allows various market participants to assess future scenarios involving new investments in heat conversion and production facilities within an existing DH system in a selected municipality. The methodology also enables evaluation of the financial performance of existing heat and power generation units after additional production capacity is introduced into the DH network.

The ability to assess multiple scenarios, such as policy measures aimed at achieving 100% renewable energy in DH systems or potential EU financial support, enables prediction of changes in heat production costs and auction prices. This assessment can facilitate better planning of future development trends, enhance system reliability and realism, and help reduce heat prices for consumers.

Dissertation structure

This dissertation is structured to examine the role of uncertainty in DH system planning and economic modelling under changing regulatory and market conditions.

Section 1 provides the theoretical foundation. It analyses key features of DH market regulation and planning, including consumer network connection, pricing mechanisms, ownership structures, third-party access (TPA), and policy impacts, such as discount rates. It also discusses uncertainty, provides a classification of uncertainty factors, reviews stochastic assessment and alternative uncertainty characterisation methods, and critically evaluates energy economic modelling approaches and their application in uncertainty assessment.

Section 2 presents the research methodology, including a detailed description of the modelling approach and its verification, the definition of technical and economic parameters, and the specification of the time resolution and planning period. It also describes the data sources used in the partial equilibrium model and outlines the main assumptions related to energy prices, demand trends, discounting, and the technical and economic presentation of conventional and renewable heat generation technologies, storage solutions, heat pumps, and power-to-heat and power-to-hydrogen concepts. Particular attention is given to the application of sensitivity and uncertainty analysis to assess the impact of key uncertainty factors on DH system operation and investment decisions.

Section 3 presents and analyses the modelling results, primarily focusing on the selected DH system. It examines current and future reference scenarios, followed by a detailed assessment of the base scenario. Additional strategic scenarios are also

considered, including plans for the development of a fully renewable DH system, financial support mechanisms for renewable energy production, and fiscal measures to tax fossil fuels. The section concludes with a comparative assessment of the scenarios' uncertainty and sensitivity analysis results, an evaluation of the reliability and applicability of the modelling outcomes, and a discussion of their consistency with findings in the scientific literature. The dissertation closes with general conclusions, a summary of the main results, references, and appendices.

1. CHARACTERISTICS OF THE DISTRICT HEATING MARKET AND THE ROLE OF UNCERTAINTY IN PLANNING AND MODELLING

Energy planning involves the identification of long-term conceptual strategies for future energy systems and is typically undertaken by national and local governments and infrastructure providers (Bush & Bale, 2019). Many factors are considered in planning future energy systems, including the development of renewable technologies, reductions in demand through energy efficiency measures, environmental impacts such as projected carbon footprints, and socio-economic aspects such as population characteristics and investment costs.

Planning low-carbon energy systems is inherently complex, as strategic decisions are influenced not only by the technical and economic viability of technologies but also by broader social factors (Bush & Bale, 2019). In the transition from fossil fuels to intermittent RES, DH systems play a crucial role in increasing the share of renewable energy in the overall energy balance (Blanco et al., 2018). By integrating flexible heat and electricity generation technologies with thermal energy storage facilities, DH systems can contribute substantially to balancing electricity grids.

However, due to the weather-dependent nature of RES, operating and planning electricity and DH systems are highly complex and uncertain, requiring the application of advanced modelling methods (Blanco et al., 2018). Additionally, the increasing RES penetration and the growing cross-country interconnection of electricity markets have increased uncertainty in long-term electricity price forecasts (Blanco et al., 2018). These forecasts strongly influence investment decisions in new heat production technologies. Simultaneously, DH systems must be designed to remain resilient to fluctuating and uncertain energy prices to ensure sustainable investments and system development.

When planning and modelling future DH systems, it is necessary to consider the specific characteristics of DH market regulation, as well as complex uncertainties associated with long-term energy system development. These uncertainties stem from factors such as fuel price fluctuations, evolving policies and regulatory frameworks, technological developments, demand variability, and the increasing integration of RES. Incorporating these factors in modelling systems enhances the accuracy and reliability of system projections, thus enabling more reliable scenario analysis and strengthening the robustness of investment decisions.

In existing energy planning practices, most economic models remain deterministic, ignoring uncertainties and relying heavily on long-term forecasts of key parameters. However, such forecasts are often inaccurate over extended planning periods, leading to excess capacity or underutilisation of installed technologies (Moret et al., 2017). A more detailed and reliable planning approach can be achieved by complementing deterministic methods with stochastic modelling techniques that explicitly account for uncertainty (Nagel et al., 2022).

1.1. Characteristics of District Heating Market Regulation and Planning

DH systems are increasingly recognised across Europe as a key element of sustainable urban energy infrastructure, enabling the integration of renewable and waste heat sources, enhancing energy efficiency, and lowering emissions (Lund et al., 2014). Due to the high capital investment costs required for distribution networks and location-specific infrastructure, DH systems exhibit natural monopoly characteristics, as duplicating pipelines and related infrastructure would be economically inefficient. Investments in insulated underground pipes, pumping stations, and consumer heat substations are significant and largely non-recoverable, while the marginal costs of supplying additional heat consumers are relatively low. Consequently, as the number of connected consumers increases, the average cost per unit of heat supplied decreases, generating substantial economies of scale (Galindo et al., 2016). This cost structure suggests that a single network operator can potentially supply the entire market more efficiently than multiple competing systems, which is a key feature of a natural monopoly. While duplicating heat distribution networks is technically feasible, it is economically inefficient. Constructing parallel networks would require additional excavation, infrastructure investment, and environmental damage, without providing adequate social benefits (Werner, 2017). Therefore, installing alternative heating networks is impractical, particularly in densely populated urban areas where DH systems are often the most rational solution. The physical inseparability of networks and high capital costs create strong natural barriers to competition.

Although the heat supply network is considered a natural monopoly, this does not necessarily apply to other parts of the heat energy chain such as heat production. While technical constraints, particularly in smaller networks, may limit the efficient operation of multiple production units, a competitive heat production market is generally feasible in larger networks (Bürger et al., 2019). Independent heat producers (IHP), such as combined heat and power (CHP) plants, biofuel boilers, waste heat recovery plants, or solar thermal systems, can supply heat to the same network. This structure supports market competition and promotes efficiency and innovation in production technologies (Bürger et al., 2019). To promote effective competition, regulatory separation between heat supply and production is essential. Existing network operators must guarantee non-discriminatory access for independent producers while maintaining transparent pricing and production planning. Without such regulatory separation, vertically integrated operators could favour their own production facilities, making it difficult for new market entrants (such as IHPs) to access the heat market (Werner, 2017). These structural features highlight the need for a clear distinction between the regulation and planning of network and production components to ensure transparency, fair market access, and optimal system performance.

Effective DH system performance relies on clear and fair regulation; as noted by Gatautis (2004), well-defined regulatory frameworks benefit both suppliers and consumers. Consumers benefit from stable prices and reliable heat supply, while producers gain from predictable market conditions and fair grid access when contributing with renewable and waste heat sources. Consequently, all parties:

network operators, heat producers, and consumers, have a shared interest in balanced, efficient, and transparent regulation, which supports both economic efficiency and environmental objectives.

The key forms of regulation in the DH sector are consumer grid connection, price regulation, ownership regulation, and third-party access to heat networks (Billerbeck et al., 2023). In addition, the selection of discount rates as a policy measure is instrumental in regulating the DH sector and planning long-term infrastructure. International experience indicates that discount rates are applied differently across market participants in the energy sector, thereby reflecting variations in regulatory frameworks and risk sharing. Therefore, when considering broader DH market dynamics, it is essential to account for current international DH planning approach, as these regulatory and planning structures directly determine the outcomes for end users by setting user obligations, cost burdens, and the level of influence and participation in the DH system.

1.1.1. Regulation of consumer grid connection

DH systems often face low customer connection rates, which reduce profitability and limit the potential for expansion (European Commission, 2022). To address this, some countries or regions have introduced mandatory network connection and usage regulations, requiring consumers to connect to local DH networks under predefined conditions (European Commission, 2022). Such obligations are typically part of broader energy and environmental policies aimed at supporting decarbonisation, increasing system efficiency, and ensuring the long-term financial stability of heating infrastructure.

However, mandatory connection policies can only be implemented if DH networks meet certain criteria, including a high share of renewable energy or waste heat integration, economic efficiency, and clear societal benefits such as emissions reduction (Billerbeck et al., 2024). Meeting these requirements allows DH operators greater certainty in planning and investment, enabling them to operate with higher load factors and greater economies of scale. This, in turn, can contribute to lower long-term heat prices and encourage additional investment in cleaner technologies.

Meanwhile, mandatory connection strengthens consumers' dependence on a single supplier, making reliable and transparent regulation even more essential. Price regulation is crucial when consumers are required to purchase heat regardless of price, as it prevents monopolistic behaviour and ensures affordability (Billerbeck et al., 2024). As previously mentioned, clearly formulated regulatory frameworks benefit both suppliers and consumers by reducing regulatory uncertainty for suppliers and facilitating long-term investment planning, while providing consumers with stable price structures, confidence in the system, and secure heat supply. Therefore, effective regulation is essential to balance the advantages of mandatory connection with the protection of consumer rights and maintenance of public support for DH systems.

1.1.2. Regulation of prices

A key function of regulatory authorities in the DH sector is heat price setting. Consumers primarily seek low prices, while heat suppliers aim to maximise their

profits. To balance these interests, regulated prices are set to ensure that business remains attractive for suppliers without imposing excessive costs on consumers. Existing literature and practical experience indicate that the most common pricing regimes are regulated and liberalised, where prices are either tightly structured or freely determined (Billerbeck et al., 2024). Billerbeck et al. (2023) identify three main types of regulation: unregulated price formation, regulatory pricing by operators, and regulatory pricing by regulators. Regulated prices follow specific calculation rules, often combined with price controls, whereas liberalised pricing allows greater flexibility, considering supplier costs and market conditions (European Commission, 2022). According to Wissner (2014), prices can also be regulated *ex ante* or *ex post*. An *ex ante* regulation requires approval by public authorities before prices are applied, while an *ex post* regulation involves a retrospective review to determine whether prices charged comply with established rules.

According to Odgaard and Djørup (2020), the choice of price regulation has a significant impact on the development of DH systems. DH prices vary across countries and are strongly shaped by the regulatory framework. Based on European experience, six main types of price regulation can be identified: (1) true-cost principle, (2) true-cost plus investor return principle, (3) market-determined prices, (4) substitution price, (5) price cap, and (6) cost-plus pricing, which has been particularly important in Eastern European countries (Sun et al., 2015; Odgaard & Djørup, 2020). For example, the true-cost principle ensures that consumer prices reflect only the necessary costs of production and distribution. Therefore, consumers do not pay more than is necessary. As prices are essentially non-profit-making, this approach protects consumers from potential abuses by natural monopolies. In Denmark, this mechanism applies to the vast majority of DH systems, while national independent authorities supervise prices and supply conditions (Odgaard & Djørup, 2020). With its collective heat planning, mandatory interconnections, and non-profit principles, the Danish DH sector serves as an example of successful implementation (Johansen & Werner, 2022), illustrating how non-profit rules and regulations determine final heat prices.

This principle is based on the following two rules of Danish municipal law (Danish Energy Agency, 2022):

- Heat supply services must not be used for indirect taxation of consumers; in other words, municipalities are not allowed to increase revenue from the operation of public utilities;
- Heat supply services must not be used to subsidise consumers. This means that municipalities must not provide financial support to users of the utilities.

This process keeps DH prices low for consumers by applying non-commercial financing schemes and adhering to the non-profit or necessary-cost principle (Johansen & Werner, 2022).

Under the non-profit principle, the final heat price is based on the total and cumulative costs of providing the service. The pricing structure ensures that local heat supply companies cannot charge more than the actual cost of producing and delivering heat to consumers (Danish Energy Agency, 2022). End users are charged for the maintenance of heat production infrastructure, fuel costs, distribution networks and

storage facilities, investments, operation and management, servicing, workplace and office costs, legal advice, and general services (Johansen & Werner, 2022). These costs also include asset depreciation and financing expenses to ensure that heat supply companies remain financially stable in both short and long-term (Danish Energy Agency, 2022).

Another method for setting DH prices is to base them on actual costs while allowing higher borrowing costs, enabling investment supported by external capital under market conditions (Odgaard & Djørup, 2020). In Denmark, this approach is applied to industrial waste heat in the DH sector. A real interest rate of around 8% may be introduced to incentivise non-DH companies; however, prices cannot exceed the alternative cost of heat and must be confirmed by independent authorities in case of any dispute. As waste heat is cost-effective for DH, industrial companies are incentivised to sell surplus heat at a reasonable profit (Odgaard & Djørup, 2020).

Cost-plus pricing includes all actual costs incurred by companies in providing heat, as well as a certain profit margin, which can be based on assets, costs, sales, or other criteria. This pricing system is particularly common in Eastern European countries. Its main advantage is that it supports the company's viability by allowing full cost recovery, thus protecting it from variations in the business environment, as costs associated with negative changes are incorporated into the heat price. The primary disadvantage is that it does not encourage efficiency, as businesses do not benefit from reducing costs (Sun et al., 2015).

Another approach is to completely liberalise DH consumer prices, allowing them to be determined by the market in response to supply and demand. The advantage of this approach is that a fully competitive market encourages producers to operate at full capacity, thus promoting efficiency improvements, technological innovation, and cost reductions in heat production. Liberalised pricing can motivate heat producers to optimise their operations, invest in greener or lower-cost technologies, and respond more dynamically to changes in fuel prices or demand.

Studies have demonstrated that when multiple heat producers, such as biomass boilers, waste incineration plants, industrial surplus heat suppliers, large-scale heat pumps, or cogeneration units, supply heat to a single distribution network, competition increases and marginal production costs can be reduced. For instance, Pažeraitė et al. (2022) analyse several Lithuanian municipalities and find that introducing third-party access (TPA) on the supply side and using a one-sided auction can reduce consumer prices when more producers compete. However, the DH network is a natural monopoly, where market power can be abused and used against consumer interests (Odgaard & Djørup, 2020). For example, in Finland, DH pricing is not regulated by specific legislation, but the Competition Act requires uniform pricing for all customers due to prevailing market conditions (Billerbeck et al., 2023). Under this act, the Finnish Competition and Consumer Protection Authority may launch investigations if it suspects abusive pricing practices by DH companies in view of their dominant market position, such as charging unreasonably high prices (European Commission, 2022).

Another approach for regulating DH prices is to align them with the price of heat from individual natural gas boilers. This means that once DH is in use, its price

cannot exceed that of individual gas heating. Its primary benefit lies in the prevention of DH providers exploiting their monopoly position to the detriment of consumers (Odgaard & Djørup, 2020). The Danish experience demonstrates that lower natural gas prices and longer loan repayment terms have made gas heating more competitive than DH. In 2012, only 5.2% of heat consumers were paying more than gas users; however, by 2013, this share had increased to 27.4%. This shows that linking heat supply prices to natural gas is complex, although gas prices remain the benchmark for heat zoning decisions in Denmark (Odgaard & Djørup, 2020).

More advanced incentive pricing focuses on stimulating efficiency improvements rather than recovering a heat supplier's costs and ensuring a fixed level of profit. The most common form of incentive regulation is the introduction of a 'price cap', which sets a maximum price for a specified regulatory period. If a company increases efficiency while the price cap remains unchanged, the benefits of lower costs can be retained by the company or shared with consumers. In this way, enterprises have a clear incentive to reduce costs. However, regulators then face another challenge: ensuring that companies maintain sufficient heat supply quality while minimising costs (Sun et al., 2015).

A similar pricing system currently applied in Lithuania combines features of both 'price cap' and cost-plus pricing methodologies (Lithuanian District Heating Association, 2024). Denmark has also applied a price cap to DH produced from waste-incineration CHP plants, with specific pricing rules for this type of cogeneration plant (Odgaard & Djørup, 2020). In Austria, pricing is also based on the price cap principle: DH companies set prices, while competition authorities only monitor and, if necessary, regulate excessive profits (Pažėraitė et al., 2022).

In general, international experience shows that the choice of price regulation significantly affects the economic performance and long-term development of DH systems. Every regulatory method has strengths and weaknesses. Cost-based systems such as true-cost principles ensure cost coverage and consumer protection, while cost-plus methods, despite the advantage of allowing profit margins, weaken incentives for efficiency. Substitutability-based pricing and price caps create stronger incentives for improved performance but require robust regulatory supervision to prevent inefficient investment or declines in quality. Liberalised pricing can stimulate competition, particularly in heat production, and reduce marginal costs, but it also increases the risk of market power abuse in natural monopoly networks.

As Denmark, Austria, and several Eastern European countries demonstrate, no single model can be applied universally. Instead, regulatory frameworks must be tailored to local institutional capacity, energy market structure, and strategic decarbonisation goals. A growing trend in Europe shows that hybrid systems, combining regulated network tariffs with competitive or partially competitive heat production and supplemented by transparent *ex ante* or *ex post* supervision, can provide a balanced solution that protects consumer interests, maintains investment incentives, and fosters the integration of low-carbon heat sources (Billerbeck et al., 2023).

1.1.3. Regulation of ownership

International experience shows that the nature of regulation in the DH sector is closely related to ownership and the sector's market share. Based on observed ownership models, three main forms can be distinguished: (1) private ownership, (2) public ownership, and (3) consumer ownership (Billerbeck et al., 2024).

Under private ownership, the DH network is owned and operated by a private company, with limited consumer influence. To prevent the abuse of market power, the state imposes rules on the company. In contrast, public ownership refers to a DH network operated by a municipally owned company, giving authorities a degree of control. Consumers can therefore influence the system indirectly by participating democratically in municipal decision-making. Finally, in the case of consumer ownership, DH companies are directly owned by consumers, giving them direct control over operations (Billerbeck et al., 2024; see *Fig. 1*). The need for regulation increases when DH ownership is private and not linked to local communities, and decreases when ownership is cooperative or when DH is less prevalent and consumers have a wide range of heating alternatives.

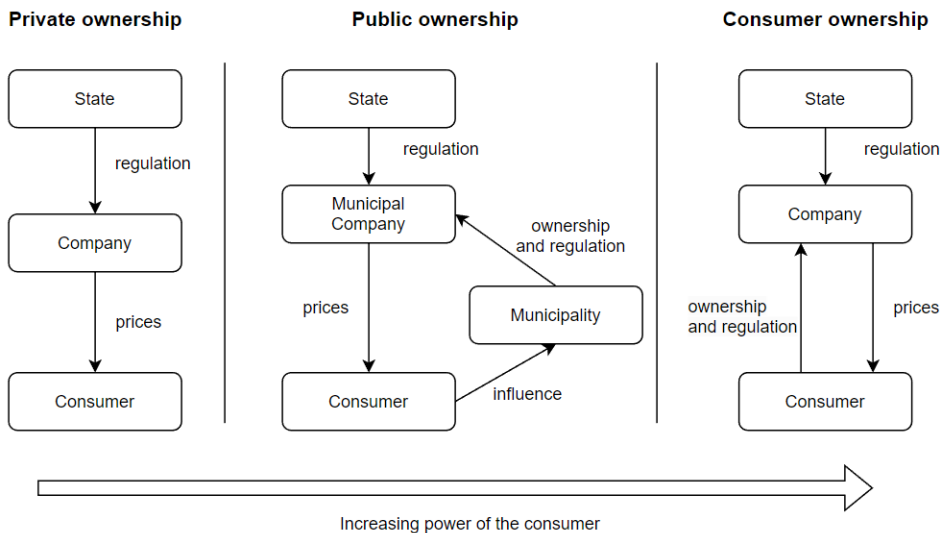


Fig. 1. Structure of ownership regulation models

Source: Created by the author based on Billerbeck et al. (2024)

In many European countries, DH networks are managed by vertically integrated companies, usually owned by municipalities or by private companies in which municipalities hold a significant share. In some countries, such as Poland, Slovakia, and Spain, a combination of public and private ownership is common (Billerbeck et al., 2023). Data indicate that ownership structures vary across the main European DH markets (Bürger et al., 2019).

In Denmark, consumer-owned cooperatives account for the largest share (85%) of ownership, while municipally owned companies and private equity firms represent

a much smaller portion (Bürger et al., 2019). In Sweden, the situation is slightly reversed: more than 70% of ownership is held by municipal companies, with the remainder held by consumer cooperatives and private firms. Germany is unique in its ownership structure, with private companies holding more than 70% of the market (Bürger et al., 2019). By contrast, Estonia's DH ownership structure is dominated by private companies, all of which may be granted monopoly status (Pažėraitė et al., 2022). From a regulatory perspective, monopoly status can be advantageous. However, monopolistic structures tend to reduce incentives to operate optimally and to invest in new technologies and RES.

1.1.4. Third-party access

DH infrastructure exhibits typical natural monopolistic features similar to electricity and gas sectors (Pažėraitė et al., 2022). Despite the monopolistic nature of heat transmission, experience from the liberalisation of electricity and gas markets reveals that heat generation and supply to an integrated network could support competition (Barrett, 2017). During the initial phase of liberalisation, the European Union (EU) established two main methods for introducing competition among electricity producers: regulated TPA or negotiated TPA, and two procurement methods: direct supply or through a single buyer (Pažėraitė et al., 2022).

Under the liberalisation process introducing TPA within the single-buyer electricity market model, the Kaunas DH system, which is the second largest in Lithuania, introduced regulated TPA on the energy supply side in 2012 (Pažėraitė et al., 2022). This was implemented based on the prices offered by auction participants and the technical capabilities of the heat supply system (Parliament of the Republic of Lithuania, 2003). Baltpool was selected to organise the heat auctions.

Regulatory improvements aimed at establishing a more equal competitive environment between heat suppliers and IHPs that are required to account for all heat production costs, not just variable costs, have led to a more transparent auction procedure. These changes have reduced heat production prices and increased the number of DH systems introducing competitive conditions, from one pilot project to 14 in Lithuania by 2021 (Baltpool, 2025b). This transformation was implemented to ensure regulatory transparency, clarity, and non-discrimination. The application of regulated TPA and the one-sided auction system has contributed to a steady decline in DH prices by fostering a competitive environment (Pažėraitė et al., 2022).

Lithuanian heat suppliers are regulated by the National Energy Regulatory Council, which oversees suppliers selling at least 10 GWh of heat per year. The Council sets the heat price components, verifies their annual recalculation, and, if necessary, identifies price violations (Pažėraitė et al., 2022). It also regulates independent heat producers that: (1) have received financial, municipal, or EU support; (2) are subsidised in their electricity tariffs, for example, through public service commitments or fixed tariff measures promoting renewable energy use; and (3) produce more than one-third of the DH system's demand.

The transformation of Lithuania's regulatory system, combining regulated TPA to heating networks, a single-buyer auction model, and supervision by the National Energy Regulatory Council, was a significant step in liberalising DH systems. By

establishing transparent auction rules and cost-reflective price bids, the regulatory framework has reduced uncertainty and increased price transparency. Empirical data indicate that the competitive entry of independent producers has encouraged fuel diversification, improved efficiency, and provided economic benefits to consumers through lower tariffs. However, competition also increases market and investment risks for new entrants and negatively affects existing market participants with established infrastructure. Thus, while consumers and regulators face greater certainty and welfare, existing market players must adapt to increased market and investment risks.

1.1.5. Influence of discount rates on district heating regulation and planning

In energy system planning, discount rates vary by country, reflecting differences in policy and regulatory frameworks. A discount rate is a percentage used to convert future monetary amounts into present-value equivalents, enabling comparisons over time by adjusting for the time value of money (Synapse Energy Economics, 2023). Three main types of discount rates are commonly used in utility cost-benefit analysis:

- (1) The financial weighted average cost of capital (WACC), which reflects the utility cost of capital;
- (2) The discount rate, which reflects a customer's risk tolerance or time preference;
- (3) The social discount rate (Synapse Energy Economics, 2023).

State regulators generally allow utilities to use a private discount rate, typically the WACC, to measure costs and revenues (Institute for Policy Integrity, 2025). The WACC reflects a utility's internal financing costs and investment criteria, making it a private rather than social discount rate. Unlike social discount rates, which capture broader, long-term societal preferences and welfare, private discount rates are based on a company's financial considerations. Consequently, private rates such as the WACC tend to be higher, with typical estimates ranging from 7% to 9% (Institute for Policy Integrity, 2025). Historically, the government of the United States (US) has used a 7% discount rate in evaluating public services that substitute for private-sector investment. This reflects the estimated average pre-tax rate of return on private capital in the US economy. The WACC is often preferred because it reflects the time value of money for utility investors and incorporates the associated opportunity cost of capital. It is a reasonable and analytically robust choice for discounting in risk assessments and cost-effectiveness benchmarks. It is therefore recommended that utilities report the results of their cost-effectiveness analyses using a real WACC, typically ranging from 7% to 8% (Synapse Energy Economics, 2023).

In contrast, the social discount rate reflects how society values future costs and benefits relative to the present (Institute for Policy Integrity, 2025). The application of this rate is appropriate when public regulators require utilities to evaluate costs and benefits from a societal perspective. According to recent evidence, the current risk-free social discount rate is approximately 2% (Institute for Policy Integrity, 2025).

A risk-adjusted rate can also account for the public's evaluation of costs and benefits over time, as well as the perceived risk of investment. The 2023 updated federal guidelines for discounting the costs and benefits for public investments

recommend a risk-adjusted rate of 3.1% (Institute for Policy Integrity, 2025). Considering the methodology used by public agencies to determine social discount rates, researchers of the Buildings Performance Institute Europe (BPIE) estimate that social discount rates in EU Member States range from 1% to 7% (BPIE, 2015).

A comprehensive analysis conducted by Synergies Economic Consulting (2021) identifies an appropriate real discount rate, as well as upper and lower bounds, for private-sector investments in the Australian National Electricity Market (NEM). According to the Australian Energy Regulator's (AER) cost-benefit analysis guidelines, lower and upper discount limits are established. The lower discount rate is based on the most recent regulated WACC for transmission and distribution networks set by the AER. The upper discount rate is a WACC-based estimate representing a more risk-sensitive required return on private investment in the NEM, including investment in generation and storage (Synergies Economic Consulting, 2021).

The authors of the Synergies Economic Consulting report note that the current 7% central discount rate and 10% upper limit (expressed in real pre-tax terms), applied by several Australian government agencies, are excessive in light of systemic risk assessments for private-sector investment in the Australian NEM, as well as prevailing domestic and international financial and stock market conditions. Based on the analysis by Synergies Economic Consulting (2021), a proposed central rate of 5.58% and an upper limit of 7.30% are considered reasonable and methodologically robust. In addition, a lower bound of 2.18% is recommended, which is consistent with recent decisions by the AER.

The International Energy Agency (IEA) examined the impact of discount rates on the levelised cost of electricity (LCOE) in its 2020 publication. While interpretations of discount rates may vary across publications, the IEA generally recognises that lower discount rates correspond to a stable, low-risk investment environment, whereas higher discount rates reflect greater financial, technological, and market risks. The real discount rate (r) used to discount future costs and benefits is typically assumed to be constant, identical for all technologies, and fixed over the entire duration of the assessed project. The 2020 edition of the *Electricity Generation Cost* report applies three real discount rates (IEA, 2020): 3%, reflecting the approximate social cost of capital; 7%, reflecting the typical cost of capital for large utilities operating in deregulated or liberalised markets; and 10%, reflecting the cost of capital in higher-risk investment environments. Nominal discount rates are correspondingly higher when inflation is considered.

The examination of the discount rates applied by Lithuanian DH companies reveals that their WACC has been fluctuating between 5% and 6% in recent years (National Energy Regulatory Council, 2025b). This lower WACC results from the fact that heat supplier production units operate in a regulated competitive environment, where part of the risk is mitigated by the stability of regulated activities.

In contrast, IHPs operate under the same auction-based system but face a significantly higher investment risk profile. This is due to the fact that many of these producers are effectively unregulated and therefore do not benefit from a guaranteed or regulated rate of return on their investments. The profitability of their assets depends entirely on market outcomes, competitive dynamics, and price fluctuations

in heat auctions. Therefore, the remaining regulated independent heat producers typically have a higher WACC compared to regulated entities.

1.1.6. Importance of international experience in planning district heating systems

Drawing on the experience of the Baltic countries, DH remains highly relevant, and the development of this sector is essential for achieving national climate and energy targets. In the context of Estonian DH planning, most regional authorities have engaged energy-planning experts to prepare regional DH development plans. These plans generally include a detailed analysis of the existing situation of consumers, heat networks, and heat production facilities. However, the modelling methods used for scenario analysis often lack clarity and are based on the interpretation of local authorities or individual experts, without a common approach across plans. This results in a limited comparability of analytical outcomes between different plans (Volkova et al., 2020).

The Lithuanian DH sector is managed by local municipalities in accordance with heat-sector specific plans approved by municipal councils. The primary objective of these plans is to meet consumer demand at the lowest possible heat price while minimising negative environmental impacts. In 2023, amendments to the law on the heat sector introduced two levels of planning documents: municipal heat sector plans and 10-year investment plans for the development of the heat sector prepared by heat supply companies (Lithuanian District Heating Association, 2024).

National strategic documents set general guidelines and objectives for DH sector development, while municipalities identify the most cost-effective ways to meet them and plan heat production and energy resource needs. DH system plans are revised at least every 10 years, accounting for developments in heat generation and transmission technologies, environmental pollution, and other factors relevant to urban planning (Lithuanian District Heating Association, 2024).

However, the legal status of heat sector planning is weak, and decisions are often treated as formalities that municipal administrations do not follow. Moreover, a gap exists between national objectives and municipal actions in developing DH infrastructure. National interests, based on international commitments and EU directives, are not translated to municipalities where decision-making is primarily based on economic incentives (Lithuanian District Heating Association, 2024).

The UK government and the UK Committee on Climate Change have recognised DH as a potentially important component of the technology mix and a low-cost option for decarbonising heat, particularly in areas with high heat demand, e.g. cities and towns. However, the widespread availability of natural gas networks and the high upfront costs of DH infrastructure have limited DH penetration in the UK to below 2% of the heat supply mix (Bush & Bale, 2019).

Nevertheless, the ongoing need to decarbonise the heating sector has increased interest among national and local authorities in establishing new DH systems to leverage the potential of renewable heat sources, such as geothermal energy and waste heat, and to improve the efficiency of urban heat supply. To support complex energy planning, a wide range of decision-making mechanisms have been developed, some of which address social and technical contexts. Despite the availability of decision-

making tools, they are often underused. For example, measures in the energy sector are often focused on technical and economic criteria, while policymakers' interests extend beyond simple economic or decarbonisation factors to broader social aspects, such as reducing fuel poverty, alleviating deprivation, and creating jobs (Bush & Bale, 2019).

Denmark was the first country in Northern Europe to introduce DH and remains among the sector's leaders in Europe (Johansen & Werner, 2022). The uniqueness of the Danish DH sector is the rapid integration of RES over a relatively short period. To illustrate, the share of renewables in CHP plants increased from around 20% in 1990 to 63.8% in 2019, while the share of coal in CHP plants declined from around 50% in 1990 to 8.6% in 2019 (Johansen & Werner, 2022). The transition to low-carbon technologies has been primarily driven by the use of biomass and waste in heat and power generation, the integration of solar thermal collectors, the deployment of power-to-heat solutions using green electricity from wind farms, the utilisation of industrial waste heat for heat pumps, and the use of biogas technologies. As RES integration in Danish DH systems has increased over the decades, carbon dioxide (CO₂) emissions have decreased accordingly.

In current Danish practice, local city councils are responsible for approving new heat supply infrastructure projects. They are authorised to evaluate the short and long-term, as well as direct and indirect, impacts of proposed municipal joint heat infrastructure projects through a formal approval or rejection process (Johansen & Werner, 2022). Project proposals typically include socio-economic, consumer economic, company financial, and environmental analyses to compare alternative project options using an established methodology. City councils may then approve the alternative that delivers the highest socio-economic benefits (Danish Energy Agency, 2022). Eikeland & Inderberg (2016) examine the organisation of municipal heat infrastructure planning procedures and the allocation of responsibilities among planning authorities. The findings indicate that comprehensive planning in Denmark has contributed to the establishment of cost-effective DH systems.

Municipalities are also responsible for ensuring that DH developments and system modifications comply with the Heat Supply Act. The Danish energy regulatory authority and the energy appeals board oversee the DH sector and handle complaints related to prices and conditions. CHP plants are required to report information on prices and conditions to the energy regulator, which primarily addresses general issues such as tariffs and conditions of heat supply (Danish Energy Agency, 2022).

1.2. Theoretical Analysis of Uncertainty Factors

DH systems face various uncertainties that affect system performance and planning decisions. In the field of energy planning, uncertainty refers to the limited ability to accurately predict the conditions, parameters, behaviour, and external changes of the system over the long-term planning horizon. In current energy planning practice, most models are deterministic, neglecting uncertainty and relying on long-term forecasts of key parameters. Such projection failures can significantly affect strategic energy planning decisions, potentially leading to overcapacity and underutilisation of deployed technologies (Moret, 2017). However, uncertainty is still

rarely incorporated into energy planning models. In a review of energy system models, Keirstead et al. (2012) report that only three of the 219 papers specifically address uncertainty and sensitivity analysis. Similarly, Goel and Grossmann (2004) note that most of the literature on oil and gas field infrastructure planning relies on deterministic approaches. The combination of long planning horizons and unreliable forecasts exposes the inherent limitations of traditional deterministic energy models and highlights the importance of accounting for uncertainty in energy planning (Moret, 2017). Studies have shown that the incorporation of uncertainty can have a significant impact on energy planning decisions, often favouring renewable and efficient technologies over fossil-based alternatives (Moret et al., 2016). Such approaches support the development of more reliable and robust energy strategies, potentially achieving carbon neutrality and energy self-sufficiency while accounting for uncertainties in the planning process (Li et al., 2022; Moret, 2017). The evolution of energy systems is shaped by multiple factors of uncertainty; therefore, the inclusion of uncertainty analysis in energy system modelling becomes essential for planning future energy systems and allocating resources (Feng et al., 2023).

1.2.1 Classification and investigation of uncertainty factors

Various classifications of uncertainty have been proposed in the literature, but no consensus has been reached. According to Walker et al. (2003), uncertainties can be classified by location, i.e., where the uncertainty occurs within the model set, and by their nature. Based on Stefano Moret's approach (2017), uncertainty factors can be further categorised as epistemic or aleatory: uncertainty is epistemic if it can be reduced by collecting more data or increasing the model's level of detail, whereas it is aleatory if it is considered irreducible.

In strategic energy planning, it is essential to distinguish between present and future uncertainties (Moret, 2017). Existing uncertainties may be reduced by increasing the model's detail, by collecting additional data, or by taking complementary measurements. In contrast, future uncertainties are fundamentally unpredictable and nearly impossible to reduce, e.g., future oil, electricity, natural gas, or biofuel prices.

In contrast, this comprehensive literature review indicates that uncertainties can be classified as physical or economic-regulatory uncertainties (Alonso-Travesset et al., 2023). The authors provide a clear example where potential investments in renewable generation technologies, such as solar PVs and wind turbines, can be sources of physical uncertainties. In both cases, power generation is strongly influenced by weather conditions, making the total annual output of the plants uncertain. Because these facilities generate revenue by selling energy or reducing grid load, fluctuations in production create uncertainty in revenues. According to Andreolli et al. (2022), the introduction of flexibility measures, including energy storage, electric vehicles, and demand response (DR) solutions, can help reduce uncertainties in planning future energy systems. However, questions remain regarding the impact of the utilisation of these technologies on system costs and the financial risks posed by new participants, as analysed at the European level (Ramboll, 2021).

Despite the potential impact of energy generation and transformation technologies on the future energy system, factors such as fluctuations in energy prices and variability in heat load profiles remain critical for DH planning (Miljanovic & Jonsson, 2022). Mu et al. (2022) highlight that natural gas and electricity prices are highly uncertain and constantly fluctuate due to supply and demand, exports and imports, government regulations, extreme weather, and other factors. Sudden fluctuations in natural gas or electricity prices can expose operators to significant operational risks, impose financial constraints beyond their capabilities, and, in severe cases, contribute to bankruptcy or liquidation of energy supply companies. For example, extreme winter storms in 2021 in the south-central US (Texas), caused more than 1,000 generator outages and blackouts, resulting in over a 300-fold increase in the average peak electricity price and a 100-fold rise in natural gas prices (Levin et al., 2022). Similarly, in the European Baltic Nord Pool hourly electricity market prices for 2024, the growing number of RES sources is increasing price volatility, with electricity prices occasionally 10 to 15 times higher than conventional prices (Litgrid, 2025a). High natural gas and electricity prices raise operational costs for energy systems, often exceeding initial planning estimates and placing a higher financial burden on operators (Mu et al., 2022).

For instance, Marx et al. (2023) identify electricity, biofuel, and natural gas prices as key uncertainty factors and quantify the economic risk faced by Austrian heat supply networks under energy price uncertainty. To assess uncertainty in Austrian electricity prices, they analyse the historical monthly average (μ) and standard deviation (σ) using Austrian day-ahead hourly electricity prices for 2015–2022. Over this period, electricity prices varied between 0.63 and 1.37 times the average price. For future hourly electricity prices, they adopt a more conservative range of 0.5–1.5. A similar approach is applied to biomass prices, using historical monthly data (2015–2022) from the Austrian Biomass Association. Since biomass is a major substitute for natural gas in Austria, gas and biomass prices are assumed to be correlated. The study also assesses future natural gas prices using Energy Brain reports, assuming an uncertainty of $\pm 20\%$ and an annual increase of 1.5%. Marx et al. (2023) emphasise the importance of correlation between electricity and natural gas prices given Austria's relatively high dependence on gas-fired generation, limited deployment of balancing and renewable technologies, and a slow progress toward fossil fuel phase-out targets by 2040.

From a broader perspective, the growing penetration of wind and solar in the electricity mix, along with increasing CO₂ prices, could significantly reduce the number of full-load hours for gas power plants. Consequently, market prices may increasingly be driven by more cost-effective technologies, potentially weakening the correlation between electricity and natural gas prices. The uncertainty of CO₂ prices also has a significant impact on DH systems and their decarbonisation strategies.

The expansion of renewable energy solutions, including new generation facilities and infrastructure for DH systems, is increasingly supported by a range of policy measures. The most commonly used instruments to support the DH sector include financing subsidies, feed-in tariffs (FITs), low-interest loans, and tax incentives (European Commission, 2022). The European Commission's (2022)

overview *National Support Schemes and Supporting Measures Regarding District Heating and Cooling* identifies four types of support schemes: subsidies and financial incentives for DH network infrastructure; renewable and efficient DH generation; support for research, technology development, and demonstration of innovative DH systems; and support for connecting end-users to DH networks.

According to Dalby et al. (2018), support schemes can generally be divided into quantity-based or price-based schemes. Quantity-based schemes, such as electricity certificates, reward renewable energy producers with certificates proportional to the amount of electricity supplied to the market. By contrast, price-based schemes include feed-in mechanisms that provide either a price premium on top of the market electricity price or a fixed tariff paid to producers instead of the market price. Fixed tariffs are not affected by fluctuations in electricity prices.

Price-based feed-in schemes are the most widely used form of renewable energy support. As of 2015, nearly 80 countries had adopted FITs as part of their policy frameworks. While FITs are widely regarded as one of the most effective mechanisms for encouraging the rapid deployment of renewable energy technologies, the sudden and retrospective revision of subsidies remains a key challenge for investors. The risk of unexpected subsidy changes has become a source of uncertainty, as the profitability of renewable energy investments largely or entirely depends on consistent government policy (Dalby et al., 2018).

White et al. (2013) emphasise that policy uncertainty is a major challenge for participants in the renewable energy sector. They highlight the importance of clarity and consistency in renewable energy policy and note that many projects rely on loans for financing because they require capital investments that exceed the equity available to households or businesses. If government policy is uncertain and it is unclear whether the necessary conditions for project implementation will be met, access to loans becomes more difficult. Similarly, unclear policy frameworks make it challenging to determine whether government financing is actually available. For example, government subsidies for DH can help utilities overcome entry barriers and sell energy profitably at lower prices, thereby increasing household demand. These measures may encourage the use of RES.

In Finland, policy decisions related to taxes, subsidies, and emissions regulation are instrumental in determining the economic feasibility of different heat supply technologies (European Commission, 2022). The government applies fiscal measures, such as energy and carbon taxes on fossil heating fuels, to encourage a shift toward RES, which are generally exempt from these taxes. One example is the reform of the electricity tax, which aims to improve the cost-effectiveness of heat pump systems by reducing the applicable electricity tax from 22.53 EUR/MWh to 7.03 EUR/MWh (European Commission, 2022).

In Graz, financial incentives support feasibility studies that promote the integration of RES into district heating and cooling (DHC) systems (European Commission, 2022). The city also provides subsidies to encourage private buildings to connect to the DHC network. Graz has established strategic targets to increase the share of RES in DH, with a minimum target of 50% by 2028 and an expected increase to 100% by 2050. Current policy measures already prioritise the integration of

renewable energy supply into the system. In Copenhagen, DHC is promoted through mandatory building connections to the heating network to reduce CO₂ emissions from the building sector (European Commission, 2022). Buildings currently supplied with natural gas are encouraged to switch to DHC systems, since DHC prices are relatively low compared with natural gas prices, which are increased by energy and CO₂ emission taxes.

Policy uncertainty disproportionately influences investment decisions in the energy sector. Ambiguous, inconsistent, or incoherent policy frameworks can increase perceived investment risks, raise capital costs, delay project implementation, and discourage long-term involvement in low-carbon technologies. By contrast, robust and transparent policies are essential for fostering investor confidence, expanding the use of RES, and stimulating innovation. Therefore, recognising and effectively managing policy uncertainty is crucial to ensuring that investment strategies align with broader energy transition goals and that capital is directed toward sustainable, low-risk technologies.

Having examined various classifications and assessed potential uncertainties, it is possible to develop a hierarchical pyramid of uncertainty control (see *Fig. 2*).

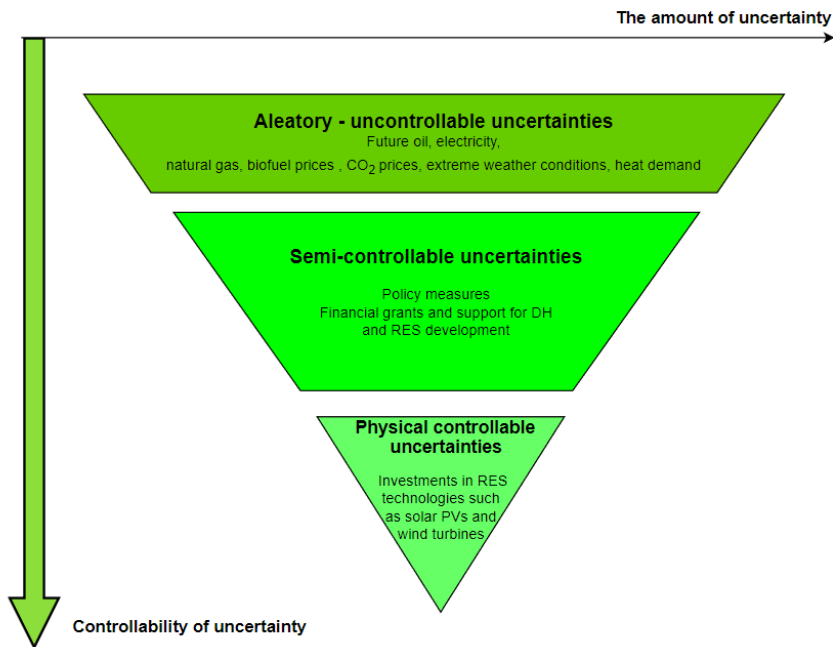


Fig. 2. Hierarchical pyramid of the controllability of uncertainty

Source: Created by the author.

Fig. 2 demonstrates that uncertainties associated with potential investments in new energy technologies are generally relatively low, primarily because investors have considerable control over technical decisions, capital allocation, and the timing of project implementation. This is consistent with findings in the literature, which classifies investments in renewable energy technologies, such as solar and wind

power, as physically controllable uncertainties. These uncertainties can be managed through engineering decisions, technological verification, and financial and economic planning.

By contrast, uncertainties related to future market conditions, such as long-term forecasts for electricity, biofuel, natural gas, and CO₂ prices, are largely unpredictable. These variables are driven by complex global dynamics, including geopolitical changes, macroeconomic fluctuations, and climate change. Consequently, they are generally considered uncontrollable uncertainties that limit investors' ability to mitigate associated risks through internal strategies.

Policy uncertainties occupy an intermediate and highly significant position in this hierarchical pyramid. Measures such as subsidies, tax incentives, FITs, and financial support for the development of DH or RES are categorised as partially controllable uncertainties. This is because they stem from a regulatory environment that may change in response to evolving political priorities, administrative structures, or stakeholder pressure. Although investors and industry representatives may influence policymaking through consultation or lobbying, final outcomes remain only partially in their control.

1.2.2. Uncertainty analysis employing the stochastic method

Most of the analysed energy modelling tools are deterministic, which structure estimations in a precise manner that excludes randomness. A more comprehensive and robust approach can be achieved by complementing deterministic methods with uncertainty methods (Mendes et al., 2011). The best-estimate plus uncertainty approach has been applied in the field of nuclear safety (D'Auria, 2019). This methodology has also been used to forecast electrical balances in isolated grids, with the purpose of decarbonising the Canary Islands by 2040 (Berna-Escriche et al., 2024). Berna-Escriche et al. (2024) model and analyse uncertainty in the key variables affecting proposed electricity mixes intended to meet the Canary Islands' electricity demand in 2040. The authors emphasise the importance of the best-estimate plus uncertainty approach, as it enables the evaluation of uncertainty factors and their effects on output variables. They argue that assessing multiple scenarios using this approach is more reliable than approaches that do not incorporate uncertainty.

Berna-Escriche et al. (2024) present two main methodologies for assessing uncertainty factors: Monte Carlo sampling and the Wilks method. One of the most widely used approaches is the Monte Carlo method that performs a series of simulations by randomly modifying uncertain input parameters (Kalos & Whitlock, 2009). It has been applied in studies of interconnected renewable systems in the Canary Islands (Rivera-Durán et al., 2023; Berna-Escriche et al., 2021). Their study transitions from a deterministic estimation of the energy balance to obtain a generation mix to a stochastic approach that accounts for uncertainty in the input variables. The implementation of this probabilistic analysis is a major novelty, as such analyses are rarely performed in energy balance research (Berna-Escriche et al., 2024).

The second methodology is the Wilks method, established in the 1940s (Wilks, 1941; Berna-Escriche et al., 2024). It determines the required sample size for a two-sided tolerance interval at a fixed confidence level and derives the tolerance range by

running n simulations and taking the minimum and maximum results as the interval boundaries. The number of simulations depends on the preferred coverage and confidence levels. For 95% coverage and confidence, $n = 59$ and $n = 93$ for one-way and two-way intervals, respectively (Berna-Escriche et al., 2024).

Widely applied in nuclear engineering and statistical analysis, the Wilks method is a versatile technique based on probability and statistical theory. However, it does not provide information about the relative contribution of input parameters to output variability and cannot replace global sensitivity analysis methods (Saltelli et al., 2008). In addition, because it focuses exclusively on determining tolerance limits for specified confidence and coverage levels, it does not describe the full probability distribution of the model output, thus limiting its usefulness for detailed risk-based decision-making. Although the Wilks method generally requires fewer simulations than classical Monte Carlo methods, the required sample size increases rapidly when higher confidence or coverage levels are set, reducing its effectiveness in high-dimensional or highly nonlinear systems (Young & Mathew, 2014). Therefore, it should be considered a computationally efficient, limited calculation technique rather than a complete alternative to the Monte Carlo-based sensitivity and uncertainty analysis.

1.2.3. Methods for characterising uncertainty

Methods for characterising uncertainty can be categorised into several distinct groups (Alonso-Travesset et al., 2023). Sensitivity-based methods involve manually modifying uncertain parameters to assess their effects on model outcomes. Probabilistic and possibility-based methods assume that uncertain parameters follow predefined statistical or fuzzy distributions. Time-domain parametric models represent the evolution of uncertainty over time. Other approaches may exist that do not fit neatly into these categories.

When addressing complex energy price uncertainties, three main categories are identified (Mu et al., 2022). The representative scenarios approach characterises energy price uncertainty using a set of representative scenarios. The interval-based method defines upper and lower bounds of uncertain energy prices (Mu et al., 2022). For example, in Zhang et al.'s (2019) case study, uncertainties in natural gas and electricity prices are quantified using the interval approach, treating prices as fluctuating within a specified range. The third category, the probability distribution modelling and scenario-building approach, generates a probability distribution function (PDF) for energy prices (Mu et al., 2022). PDFs support decision-making by providing expected values, volatility, and potential outcomes. They also enable stochastic formulations, which can yield more realistic outcomes than deterministic methods (Alonso-Travesset et al., 2023).

1.3. Economic Modelling Methods and Uncertainty Analysis in DH Systems

1.3.1. Classification of energy system models

The literature presents a wide range of methodologies for classifying energy economy systems models. Models are generally divided into three main types: top-down, bottom-up, and hybrid models (Prina et al., 2020) (see *Fig. 3*). Top-down

models, typically favoured by economists and public administrations, focus on the external linkages between the energy system and the macroeconomy. Because they represent broad and general technological choices, these models are not suitable for assessing sector-specific policies or the synergies between system components (Prina et al., 2019). Their primary purpose is to evaluate the impact of energy and climate policies on socio-economic sectors such as economic growth, public welfare, and employment (Prina et al., 2020).

By contrast, bottom-up models examine in detail the elements and interrelationships within and between different energy sectors. They provide a comprehensive view of the sectors and links between simulated installations (Prina et al., 2019). These models allow users to evaluate the effects of different technologies on the energy system from both technical and economic perspectives and to identify the best options for reducing greenhouse gas (GHG) emissions to meet energy targets.

Hybrid models combine top-down macroeconomic models with at least one bottom-up model for each end sector (Prina et al., 2020). This can be achieved by manually transferring data and parameters between models (soft-linking) or through automated processes (hard-linking). An example of a hybrid model is the Integrated Assessment Model, which connects interlinked modules covering climate impacts, the economy, and energy (Prina et al., 2020). Economic engineering models represent another form of hybrid models that integrate macroeconomic approaches with technological data.

Another possible subdivision of bottom-up models is short-term and long-term models. Static, or short-term, models are designed for a limited time horizon and typically consider the configuration of the energy system and its future scenarios in a single target year (Prina et al., 2019). Long-term models cover a longer period, considering the development of the energy system up to the target year, including variables such as generation capacity, as well as the life cycle, decommissioning, and replacement of power plants during the transition period (Prina et al., 2019). The long-term method endogenously models the entire transition period, whereas the static method focuses only on the end year (Prina et al., 2020).

Further categorisation of long-term models depends on the approach used in the optimisation problem, specifically, the perfect-foresight or myopic approaches. The perfect-foresight approach assumes that decision-makers have detailed knowledge of the entire transition and implements a unique optimisation problem that analyses all periods simultaneously (Prina et al., 2020). In contrast, a myopic approach assumes that decision-makers do not have a complete view of the entire transition. Consequently, decisions made at one stage may not be optimal in light of developments in other stages. While this approach provides a more realistic description of energy system transformation, it generally does not yield a true optimisation, as it does not account for global trends in technology costs. Early-stage decisions may be misguided to limited knowledge, and errors may persist into later stages (Prina et al., 2019).

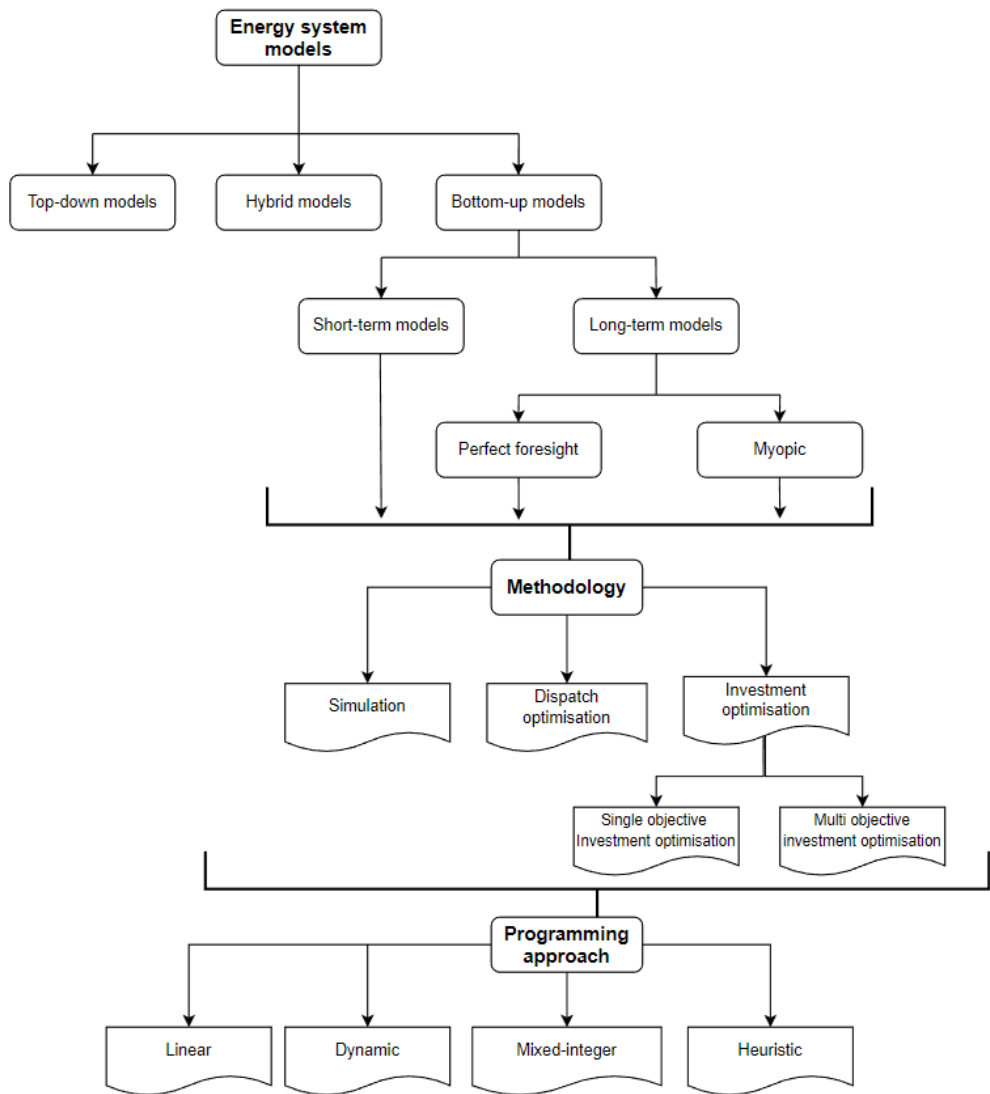


Fig. 3. Classification of energy system models

Source: Created by the author based on Prina et al. (2019)

Another factor that differentiates energy system models is the methodology used. This allows models to be grouped into simulation, dispatch optimisation, and investment optimisation models (Prina et al., 2020). Simulation models validate scenarios for a given energy system configuration and provide the final dispatch, along with characteristics, including total annual costs, yearly CO₂ emissions, primary energy savings, or surplus electricity generation. While this approach does not guarantee an optimal dispatch, it has the advantage of producing a suboptimal solution in a short computational time.

Dispatch optimisation models are typically driven by linear programming (LP), with dispatch determined based on benefit-ranking logic. In contrast, investment optimisation models address not only the annual dispatch of the energy system but also the optimisation of investments in capacity expansion.

A further distinction among energy system models is the programming or mathematical approach (Prina et al., 2020). The most common methods are LP, mixed-integer linear programming (MILP), Dynamic Programming, and heuristic methods. LP focuses on organising activities to maximise or minimise a given target subject to constraints. MILP extends LP by allowing for greater complexity. Dynamic Programming finds the optimal growth path by dividing the problem into subproblems whose optimal solution can be efficiently achieved. Some models use a heuristic approach, which enables problems to be solved in a shorter computing time (Prina et al., 2020).

1.3.2. Importance of energy sector transformation and complex energy system modelling

Connolly et al. (2010) performed a comprehensive investigation of 37 potential energy modelling applications, from which six of the most suitable tools are purposively selected: H2RES, Balmorel, EnergyPLAN, energyPRO, Model of Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE), and TIMES. The selection prioritised models capable of representing both the electricity and DH sectors. Priority was given to operational and bottom-up investment optimisation energy modelling tools.

To facilitate a comparison of the features and differences between the simulation and optimisation models, two additional simulation tools are selected. Temporal and geographical scopes are also considered, with priority given to models capable of regional and national simulation, using hourly time intervals and a simulation horizon of at least 50 years in the heat supply market. Based on the collected data (Connolly et al., 2010), *Appendix 1* summarises the main characteristics of the tools. Solutions that meet the requirements to achieve the objectives are highlighted in green, while features unsuitable for further investigation are shown in grey.

The six selected tools differ in their advantages and disadvantages, but the primary focus is on the economic modelling of DH energy systems with uncertainty assessment capabilities. The following subsections discuss their differences, applicability, modelling approaches, and comparative strengths and weaknesses.

1.3.3. Applicability of modelling methods

H2RES was specifically developed to provide a high degree of flexibility in technological and sectoral coverage. The software incorporates short and long-term energy system planning, with capacity optimisation for each technology, including variable renewables and Power-to-X (PtX) technologies. H2RES also accounts for sectoral intercoupling, including the heat, industrial, electricity, and transport sectors (Feijoo et al., 2022).

Balmorel has been used for the past 23 years for energy scenarios research and policy analysis, with various projections extending to 2060. In addition to evaluating

the feasibility and role of specific technical components (e.g., biogas retrofits, heat storage potential, heat transmission lines), the model assesses interactions between the electricity, heat, gas, and transport sectors. Balmorel analyses ranges from the technical and private economic impacts of heat pumps in a specific DH area to the evaluation of economically optimal energy systems across multiple countries (Bach et al., 2016).

EnergyPRO is the leading software tool for modelling and planning complex energy systems. It is suitable for analysing and simulating technologies, such as Power to Heat, PtX, DHC, and electricity. This modelling tool can also support investment analysis, feasibility studies, and the simulation of advanced energy systems. Supported technologies include cogeneration plants, heat pumps, solar collectors, PtX, sector coupling, solar photovoltaic powerplants, hybrid energy systems, wind turbines, batteries, electrical boilers, absorption chillers, thermal storages, geothermal plants, biofuels, and others (Østergaard et al., 2022).

A slightly different approach can be implemented using the EnergyPLAN model. Its primary objective is to support the preparation of national or regional energy planning strategies by modelling a complex energy system, including the heat and electricity supply, transport, and industry sectors (Connolly et al., 2010).

Greater optimisation from an economic perspective can be achieved with the TIMES and MESSAGE models, which are among the most widely used tools for general-purpose energy system modelling (Pfenninger et al., 2014). TIMES is a particularly valuable resource for identifying the most cost-effective combination of energy sources, incorporating a broad portfolio of renewable, conventional, storage, and transport technologies, as well as existing and emerging technologies, while meeting the demand for energy services and satisfying all constraints imposed on the system (Mendes et al., 2011).

1.3.4. Purpose of economic modelling methods

Long-term integrated energy economy models are essential for identifying economically and technologically viable solutions for sustainable energy systems that reduce heating costs, lower CO₂ emissions, and ensure the self-sufficiency of local energy resources. Each model has a specific structure and a set of objectives. For example, H2RES aims to reduce annual operating and capacity costs of the energy system. It enables modelling over a long-term planning horizon and considers the net present value of future operating and capacity costs. This model also accounts for ramp-up and ramp-down costs, as well as CO₂-related costs (Feijoo et al., 2022).

Similarly, the objective function of Balmorel is to minimise the discounted system costs by fulfilling electricity and heat demands (Wiese et al., 2018). The model divides costs into three categories: investment, variable, and fixed costs. These costs are annual and must be paid throughout the lifetime of the modelled energy producer. Variable costs include fuel costs, operating costs, and CO₂ taxes. In unit commitment planning, start-up, shut-down, and operating costs are also included. Annual fixed costs are associated with the operation of installed capacity. To achieve the objective function, a discount factor is applied as a weighting factor to estimate future costs in

present-term values, thereby reflecting the socio-economic time value (Gea-Bermúdez et al., 2021).

Another complex energy system model, energyPRO, provides the assessments of economic investment alternatives by incorporating detailed technical performance modelling and evaluating economic impacts related to markets, taxes, subsidies, and other activities (Østergaard et al., 2022). EnergyPRO is an input-output model that optimises DH operational strategies by minimising total variable costs in order to meet hourly heat demand (Hast et al., 2018).

A higher-level strategic approach can be implemented using the TIMES model, which optimises operation and investment across the entire EU energy system up to 2100, covering all 27 Member States (Gardumi et al., 2022). The MESSAGE model also provides a high level of complexity by offering an economic engineering optimisation framework for medium and long-term energy system planning, climate policy analyses, and scenario development at national and global scales.

1.3.5. Characteristics of energy modelling methods

1.3.5.1. Temporal resolution

Before proceeding with the analysis and the comparison of the six selected energy models, it is important to emphasise the relevance of a flexible temporal scope. The proliferation of RES has added complexity to energy system modelling. The integration of variable RES, storage, flexibility, and demand-side management requires modelling approaches with higher temporal resolution (Prina et al., 2020).

The MESSAGE energy economic model can represent a time horizon exceeding 100 years (Pfenninger et al., 2014). Similarly, TIMES is a comprehensive general-purpose bottom-up model capable of representing user-defined energy systems and their evolution over periods of up to 100 years. The time-step dimension used in this economic equilibrium model depends on user objectives, with a maximum temporal resolution of one hour. Annual load duration curves and annual variables can be represented using user-defined time periods at three levels: seasons (or months), days of the week or weekends, and hours of the day (Connolly et al., 2010). Compared with the discussed energy optimisation models, the simulation model energyPRO is distinguished by its higher temporal resolution capabilities. Model simulations can range from a few days, during which energyPRO analyses day-to-day operations, to multiple years without time slicing to determine the net present value for investment analysis. The maximum modelling horizon is defined endogenously as 100 years (Østergaard et al., 2022).

Similarly, the Balmorel energy model also demonstrates strong flexibility in the temporal scope, ranging from highly detailed modelling with several time steps per hour to longer-term scenarios with only a few time steps per week or fewer (Wiese et al., 2018). The maximum modelling horizon in Balmorel is up to 50 years at hourly resolution.

The H2RES model considers both short and long-term energy system planning by optimising capacity expansion for each technology, including variable RES and PtX technologies. The model is also beneficial due to its unlimited hourly resolutions

for energy dispatch modelling and its ability to represent complex systems without using time slices (Feijoo et al., 2022). In contrast, the EnergyPLAN also applies a bottom-up approach with high temporal resolution, but it is limited to short-term simulations of one year (Prina et al., 2020).

1.3.5.2. Geographical scope

One of the best-performing models in terms of geographical coverage is Balmorel energy model. It can be applied at city, national, and international levels and under different regulatory frameworks and constraints. Its various operating modes enable optimisation of short-term system performance as well as planning of long-term investments in electricity and heat generation and interconnection capacities across one or more areas or regions (Wiese et al., 2018).

Similar to Balmorel, TIMES and MESSAGE models are suitable for representing the evolution of specific energy and environmental systems at global, multi-regional, national, state or provincial, and community levels (Connolly et al., 2010). As an energy system optimisation tool, MESSAGE has been used for medium and long-term planning, climate policy analysis, and the development of national, regional, and global scenarios (Pfenninger et al., 2014).

The geographical scope of energyPRO focuses on modelling and simulating specific power plants and their associated energy conversion and storage technologies. However, energyPRO has been applied to model energy systems for entire cities and countries (Østergaard et al., 2022). The EnergyPLAN and H2RES are capable of covering geographical scopes ranging from local and regional to national and continental levels.

1.3.5.3. Comparison of the selected energy economy models

One of the most important criteria in evaluating energy models is their methodology. This section provides a detailed comparison of the strengths and weaknesses of the selected energy models.

The first model, H2RES, is an open-source large-scale capacity investment and operation optimisation model developed at the University of Zagreb (Feijoo et al., 2022). H2RES is implemented in Python and solved using the LP solver GUROBI. It is designed for long-term capacity and operational planning of complex energy systems, incorporating PtX and flexibility technologies (Feijoo et al., 2022). However, H2RES does not perform investment optimisation, whereas other energy models, such as TIMES, Balmorel, and MESSAGE, fully support this feature. For example, TIMES performs investment optimisation, while H2RES focuses exclusively on optimising system operation conditions. The model also lacks options for uncertainty and sensitivity analysis, which would allow a stochastic modelling approach.

Another partial equilibrium energy model, Balmorel, allows optimisation of electricity and heat generation, transmission, and consumption in fully competitive markets. It is an open-source, bottom-up, deterministic, flexible-structure, investment optimisation energy system model (Gea-Bermúdez et al., 2021). Balmorel is implemented in General Algebraic Modelling System (GAMS) and designed with an extensible modular structure, allowing new energy services, such as hydrogen or

biogas production and other functionalities, to be incorporated into the core model via add-ons (Wiese et al., 2018).

The Balmorel optimisation process is organised in two consecutive phases: short-term capacity expansion and long-term operational decision optimisation. Optimisation is performed over a full year using a perfect forecast (Gea-Bermúdez et al., 2021), which is a partial limitation compared with other complex energy models. The basic Balmorel model does not directly perform stochastic optimisation or the Monte Carlo-based sensitivity and uncertainty analysis. Therefore, uncertainty analysis can only be conducted using methods outside the basic structure of Balmorel.

A more explicit approach to uncertainty requires a modelling method specifically designed for this purpose, such as stochastic programming. Instead of single deterministic values for all parameters, the modeler can specify distributions for selected parameters, allowing the model to incorporate uncertainty into its solutions. This approach is used in the stochastic version of TIMES, which uses a two-step stochastic programming approach, and in MESSAGE, where the stochastic problem is formulated by expanding the original linear deterministic problem with nonlinear risk functions (Pfenninger et al., 2014).

The integrated MARKAL/EFOM system (TIMES) is one of the most widely used integrated energy modelling platforms in the energy sector, industry, and academia. TIMES was initially a linear optimisation model designed to minimise the total costs of the energy system. More recent modifications include nonlinear and mixed-integer linear formulations (Pfenninger et al., 2014), with a focus on optimising investments. The TIMES model identifies the most appropriate reference energy system for each period by selecting the combination of alternatives that minimises total discounted system costs or total discounted surplus over the planning horizon, while satisfying all political and physical constraints.

MESSAGE, likewise TIMES, can use linear, nonlinear, and mixed-integer optimisation formulations to minimise total energy system costs (Pfenninger et al., 2014). MESSAGE is a free optimisation model that, based on a selected criterion, determines the optimal combination of existing and potential new technologies that can meet different types of energy demand in a given country over the entire study period.

The MESSAGE energy model, which is primarily dedicated to long-term dynamic energy system modelling, often employs a limited number of aggregated time steps to reduce a computational burden. Consequently, its application to energy systems with a high penetration of intermittent RES, storage, flexibility capabilities, and other technologies or demands raises concerns regarding accuracy (Prina et al., 2019). Such technologies and demands exhibit complex seasonal and daily cycles that cannot be aggregated into a limited number of time periods per year (Prina et al., 2019).

In his doctoral dissertation, Neniškis (2023) argues that MESSAGE's long-term time steps and spatial aggregation limit its ability to represent daily DH system operations, local network constraints, and detailed consumer behaviour. Therefore, it is more appropriate to maintain separate probabilistic wind and consumer behaviour

submodules rather than modelling all processes within the main MESSAGE framework.

Another example of MESSAGE-specific application is in the analysis of the integration of a flexible Fischer-Tropsch (FLEXCHX) biofuel process into the Kaunas DH system (Galinis et al., 2024). Because the DH infrastructure is represented in an aggregated form within the electricity system model used, the direct integration of specific technological solutions becomes complicated. This level of aggregation would eliminate many important features of the DH system, particularly those specific to the heat supply network of a given city. Galinis et al. (2024) adopted a flexible two-model integration strategy to maintain the required level of detail and accuracy, enabling adequate representation of the national electricity system alongside detailed modelling of the Kaunas DH system.

The TIMES model has a limited representation of sectoral linkages, non-energy dependencies, and real-world constraints. It primarily focuses on balancing energy supply and demand and modelling technological transformations, but often fails to sufficiently reflect non-energy constraints, cross-sectoral dependencies, and institutional or regulatory barriers. Reviews of energy system modelling indicate that the incorporation of multiple energy sources, multi-sector integration, and interactions among demands remains a major limitation. Consequently, TIMES, like many other widely used models, struggles to address these aspects comprehensively and consistently (Fodstad et al., 2022). It also has other technical disadvantages. For example, the TIMES model requires the use of a commercial solver that can only be run within the CPLEX/GAMS package. In addition, the TIMES model generator requires the Veda 2.0 user interface, which is accessible only for a fixed fee.

EnergyPRO is an input-output scenario simulation tool used to model energy systems, including cogeneration. This software enables users to perform integrated and detailed technical and financial analyses (Fragaki et al., 2008). EnergyPRO employs two main modelling strategies: analytical dispatch mode and MILP dispatch mode. The software also offers two options for the modelling period: monthly and annually. A monthly modelling period allows for a more realistic operational forecast, as it is difficult to predict system behaviour over an entire year, while an annual modelling period better represents the seasonal operation of energy storage and other complex energy production systems (Østergaard et al., 2022).

The analytical dispatch mode considers the entire optimisation period and activates numbers with the lowest priority first, regardless of the chronological order of time steps. Priority numbers can be estimated by energyPRO or specified by the user. When calculated by energyPRO, the objective is to minimise total heat production costs of the modelled energy system, with the priority number corresponding to the short-term marginal heat production cost of each installation in each hour. When users set the priority figures, priority numbers can be determined by additional factors beyond cost minimisation, including values that vary between calculation steps depending on factors, such as electricity prices or energy demand (Østergaard et al., 2022). However, only simple priority numbers or energy resource price trend curves can be entered manually, while more complex manipulations of heat auction strategies remain limited.

In addition to the analytical dispatching approach, energyPRO supports a MILP-based dispatch. The MILP approach treats dispatch optimisation as a fully mathematical problem. One advantage of this method is its ability to incorporate limitations, such as minimum load requirements. This mode enables the solution of optimisation problems involving small thermal storage units, a large number of energy generation units, and variations across different load types. MILP-based dispatch performs particularly well in energy systems where assigning priority numbers to individual energy conversion technologies is complex, and it may even outperform analytical dispatch methods in such cases (Østergaard et al., 2022).

However, based on Østergaard et al. (2022), energyPRO is not capable of the endogenous optimisation of the entire energy system, as it can be achieved using other models, such as Balmorel, H2RES, MESSAGE, and TIMES. Instead, it relies heavily on user involvement and informed modelling choices. Therefore, energyPRO is primarily intended for the analysis of tangible, user-defined alternatives. According to a study using energyPRO (Nielsen et al., 2021), experts confirm that, from a methodological perspective, this approach does not constitute optimisation in the mathematical sense. Instead, it should be regarded as a practical tool based on manual selection of system capacities and outputs. Another limitation of this model is that the software is not open source; it is fully commercial, which may limit its suitability for long-term academic research.

EnergyPLAN, similarly to energyPRO, is a scenario-based modelling tool. It simulates all major energy sectors: electricity, heating, cooling, industry, and transport, over an entire year with hourly resolution. This enables both direct and indirect impacts on the energy system to be captured, including synergies between heating and electricity technologies (Hansen, 2019). Due to its structure based on internally defined priorities, it can perform simulations rapidly, typically within seconds (Prina et al., 2019). However, likewise energyPRO, EnergyPLAN is more suitable for deterministic, non-random method analysis, and is not capable of managing or manipulating heat auction strategies. A key limitation compared with other energy economy models is the restriction of its planning horizon is to a single year.

The structural features of EnergyPLAN have been widely exploited in the context of linking optimisation algorithms (Prina et al., 2019). For example, it was coupled with GenOpt, a single-objective optimisation model, to establish the minimum cost increase required for Serbia's national energy system to meet the EU 2030 targets (Bjelić & Rajaković, 2015). Additional extensions were developed by Mahbub et al. (2016), combining it with the multi-objective evolutionary algorithm, leading to the development of the EPLANopt model. More recently, Mahbub et al. (2017) introduced a long-term model in which EnergyPLAN is coupled with a multi-objective evolutionary algorithm that generates different Pareto profiles for different target years and develops a method to identify the optimal energy transition.

The most advanced and comprehensive application of multi-objective optimisation, described by Prina et al. (2019), provides users with a Pareto front of optimal solutions. The solution is a curve that describes the minimum cost increase associated with reducing CO₂ emissions, which is an achievable adjustment to the

selected decision variables. However, identifying optimal strategies that minimise costs and CO₂ emissions requires the implementation of an external solver (Prina et al., 2019).

In exploring the functions of selected energy optimisation and simulation tools, the H2RES model is distinguished by its ability to incorporate certain policy constraints. H2RES can include three policy approaches, either separately or simultaneously. First, H2RES accounts for different critical excess energy production (CEEP) limits over time. When run over a long-term horizon, the maximum CEEP level can be determined for each year. Second, H2RES allows the setting of renewable energy targets in the energy sector. Similarly to the CEEP target, it can model different renewable energy targets for each year in the long-term planning horizon. Third, H2RES incorporates sectoral boundaries for CO₂ emissions.

Special policy objectives can also be implemented in Balmorel, where users can specify targets for each geographical entity for each year. Examples of policy targets include a maximum level of GHG emissions, a minimum percentage of renewable energy production, restrictions on fossil fuel consumption, or a degree of self-sufficiency (Wiese et al., 2018).

Additionally, TIMES has a climate module that enables detailed analysis of the effects of climate change, such as GHG emissions, changes in atmospheric temperature, and radioactive effects (Mendes et al., 2011). The model can explore a variety of policy scenarios and examine their impacts on a predetermined baseline scenario, including measures to reduce emissions, promote energy efficiency, and increase energy security.

Compared to Balmorel, H2RES has broader modelling capabilities in other sectors, such as PtX and Power-to-Transport. It also allows simulation of the maximum and minimum levels of electricity and hydrogen penetration in the thermal, transport, and industrial sectors (Feijoo et al., 2022). However, H2RES offers limited options for detailed DH modelling and lacks heat storage modelling capabilities. H2RES optimises storage capacity for individual heating systems, hydrogen, and stationary electricity storage, but the heat storage capacities for DH and for electric vehicles are fixed for predefined periods (Herc et al., 2021).

In contrast, the Balmorel energy model comprehensively represents DH and the interaction between heat and electricity markets. As a bottom-up, supply-side model, Balmorel is suitable for analysing energy markets with diverse generation and storage technologies. It also allows modelling of elastic electricity and heat demand, which is generally overlooked in other energy system models. Moreover, its regional structure is well suited for analysing integrated liberalised energy markets. However, Balmorel has limitations in modelling time delays in DH. The software cannot accurately forecast repair or reconstruction periods, nor can it reorganise temperature levels (Wiese et al., 2018).

The main features, advantages, and disadvantages of the selected energy economy models are presented in *Appendixes 2 and 3* (see *Appendices*).

1.3.6. Justification of the selected energy model

The main focus of this dissertation is on modelling uncertainties in DH planning, particularly considering the impact of market dynamics. Accordingly, this dissertation is dedicated to developing and applying a methodology to assess future trends in DH, considering diverse uncertainties and identifying an optimum investment portfolio.

The first criterion under discussion is the methodology. Based on a literature review and an in-depth analysis of selected bottom-up energy economic system models, optimisation models are more suitable than simulation models for modelling long-term energy systems dynamics. They also provide a more comprehensive representation of the entire energy system in order to minimise energy system costs.

However, the focus of this dissertation is not the minimisation of energy costs. Instead, it aims to evaluate the system in a broader, stochastic manner, accounting for diverse uncertainties and identifying the financially feasible investment portfolios by analysing different scenarios. TIMES and MESSAGE are capable of applying stochastic programming by specifying the distribution of certain input parameters, allowing uncertainties to be incorporated into their solutions. They are primarily designed for long-term dynamic modelling, where a detailed annual representation of the energy sector requires additional submodules to maintain high accuracy. Additionally, neither model allows manipulation of heat auction strategies, as they operate according to cost-reduction principles. Because these mathematical models are deterministic cost-minimisation tools, they do not capture endogenous market behaviour, such as strategic pricing, price formation mechanisms, heat auctions, or the decisions of IHPs to maximise profits (Loulou et al., 2005). Therefore, while TIMES and MESSAGE are well-suited for system planning and long-term scenario analysis, they are not appropriate for investigating competitive heat markets, auction mechanisms, or strategic behaviour in DH systems.

Simulation models enable tangible, user-defined analysis of alternatives, which does not produce a fully optimal economic solution but allows a partially optimised solution through iterative computation. EnergyPRO offers several advantages, particularly in the DH sector, such as its ability to model large and complex energy systems, its capacity to include a wide range of heat and electricity generation and storage technologies, its incorporation of balancing services, its inclusion of PtX, hydrogen and methanol, and its consideration of taxes and subsidies. However, energyPRO cannot manage or manipulate heat auction strategies, and can only estimate the costs of individual heat generation sources or the total costs of the heat generation system. Therefore, it is suitable for representing and verifying current DH production.

The software also has limitations regarding the incorporation of uncertainty and sensitivity analysis. Tools such as energyPRO and EnergyPLAN are better suited to deterministic approaches, which provide precise, non-random assessments. EnergyPRO is specifically designed to analyse specific, user-identified alternatives rather than offering a comprehensive, system-wide optimisation perspective.

In contrast, H2RES has greater capabilities in capacity investment and operational optimisation. However, it does not provide full stochastic investment

optimisation and lacks options for uncertainty or sensitivity analysis. It also has limited capabilities for detailed modelling of thermal storage and for specifying temperature parameters in DH systems.

The Balmorel energy model tests all years using perfect forecasting, which is a partial limitation. The basic Balmorel model does not directly implement stochastic approaches or Monte Carlo methods for sensitivity and uncertainty analysis. Therefore, uncertainty analysis must be performed using additional methods outside the basic structure of Balmorel. Furthermore, neither H2RES nor Balmorel can manipulate or manage heat auction strategies. Both models can optimise annual operating and capacity costs, but managing or modifying a potential heat auction mechanism is beyond their scope.

A pivotal criterion for choosing an energy modelling tool is its capability for high temporal and spatial resolution. The selected model should offer flexible geographic and temporal scopes, ideally from hourly simulations to an entire year, enabling the assessment of capacity costs and future trends in the DH market. The highest temporal resolution is offered by models such as Balmorel, TIMES, MESSAGE, and H2RES. For example, H2RES allows simulations with an unlimited time horizon at one-hour resolution, while TIMES, similar to Balmorel, can model up to 100 years. However, scientific examples indicate that additional modelling tools are necessary to capture short-term dynamics when using optimisation tools designed for long-term projections, ensuring higher quality representation at hourly and annual scales.

Importantly, the chosen energy model must be applicable at the city scale and capable of accommodating diverse regulatory frameworks and constraints. Endogenous market behaviour and dynamics pose significant challenges for modelling tools attempting to reflect real market conditions. The economic models examined generally focus on the balance between energy supply and demand and technological change, but often fail to adequately reflect non-energy constraints, cross-sectoral dependencies, and institutional or regulatory barriers.

Despite these considerations, priority should be given to open-source energy modelling programmes, or, if not available, to software that is not excessively expensive. Running TIMES requires a proprietary solver that operates exclusively through the GAMS package. Furthermore, using the TIMES model generator requires the Veda 2.0 user interface, which is accessible only through a fixed financial arrangement. The Balmorel energy model is also available within the GAMS environment, which is not free. EnergyPRO is unique in offering a reduced price for students, intended for academic purposes. Only EnergyPLAN, MESSAGE, and H2RES provide the advantages of open-source optimisation models.

This comprehensive investigation reveals that optimisation models do not consider suboptimal solutions; they primarily generate ideal scenarios that can be unrealistic and may underestimate possible intermediate changes. Additionally, optimisation models are primarily designed for long-term dynamic energy modelling, which may not ensure high simulation quality and or accurately reflect real operating conditions over shorter periods of one year. They also lack the ability to investigate competitive heat markets, auction mechanisms, or strategic behaviour in DH systems.

In contrast, the simulation models allow tangible, user-defined analysis, but are limited to a set of scenarios that often fail to reflect the complex effects of uncertainty. Such models are significantly faster in modelling processes and are suitable for verifying existing energy systems without requiring deep analysis. However, the priority of this dissertation is to conduct a broader and stochastic investigation, accounting for diverse uncertainties and representing optimal investment portfolios in the DH market.

In the evolving DH sector, it is essential to address variable heat and electricity production portfolios, diverse uncertainties, the actions of existing and new market participants, and emerging technologies. Evaluating the ability of energy economic models to address these challenges is crucial. An additional assessment comparing general and partial equilibrium economic models was conducted to select the most appropriate approach.

Recent literature emphasises that general equilibrium models are important for assessing the impact of climate and energy policies on the entire economy, as they capture macroeconomic feedback effects, market interactions, and cross-sectoral linkages (Varga et al., 2022). However, these models rely on aggregated production functions and general technological principles, making them less suitable for detailed energy infrastructure planning. Bottom-up modelling studies indicate that sector-specific planning requires a level of technological and spatial resolution that general equilibrium models cannot provide (Cosmi et al., 2025). In contrast, bottom-up partial equilibrium models offer a high level of technological, spatial, and temporal detail required for planning future energy and DH systems. Focusing on a selected area of the economy, these models incorporate technology-specific costs, efficiency parameters, load profiles, and spatial characteristics, properties that are crucial for evaluating options, such as heat pumps, heat storage, cogeneration, or network expansion.

While the studied energy economy models are applicable for planning future energy systems, many of the selected measures cannot fully capture uncertainties in DH planning or account for the impacts of market dynamics (see *Table 1*).

Table 1. Comparison of complex energy modelling tools

Characteristics of energy modelling tools	energyPRO	EnergyPLAN	H2RES	Balmor-el	MESS-AGE	TIMES	Self-made model
Stochastic approach implementation	No	No	No	No	Yes	Yes	Yes
Long-term dynamic modelling	Yes	No	Yes	Yes	Yes	Yes	No
High temporal resolution and annual-mode quality	Yes	Yes	Yes	Yes	Limited ¹	Limited ¹	Yes
Capability of uncertainty and sensitivity analysis	No	No	No	No	Yes	Yes	Yes
Heat auction strategy formation mechanisms	No	No	No	No	No	No	Yes
Reflection of regulatory barriers, endogenous market behaviour, and dynamics	Limited ²	No	Limited ²	Limited ²	Limited ²	Limited ²	Yes
Detailed DH and TES modelling capabilities	Yes	No	No	Yes	Yes	Yes	Yes
Open-source availability	No	Yes	Yes	No	Yes	No	Yes

Source: Created by the author

The reviewed modelling tools exhibit several limitations. These include the inability to represent alternative heat auction operating strategies that reflect real market conditions, the lack of model extensions for the Monte Carlo-based sensitivity and uncertainty analysis in determining optimal investment portfolios, and the limited capacity to assess significant changes in the DH environment and the entry of new market participants. These participants include potential operators and IHP investments in heat production and conversion technologies under uncertainty.

¹ To model short-term heat market dynamics, an additional tool must be included.

² Model does not capture endogenous market behaviour.

Given these limitations, it would be beneficial to develop an independently designed partial equilibrium economic model of the DH system that incorporates sensitivity and uncertainty analysis. This could yield relevant and timely research outcomes, including optimal investment configurations in the DH market.

2. CONCEPTUAL RESEARCH METHODOLOGY FOR EVALUATING DISTRICT HEATING MARKET UNDER UNCERTAINTIES

A major challenge in planning a district heating (DH) system, or an entire energy system, is the accurate reflection of realistic operating principles while producing reliable projections of future energy production costs. This dissertation establishes a unique partial equilibrium model that simulates a real DH system market, incorporating both independent heat producers (IHPs) and the main heat supplier's production units into the existing integrated heat network. The economic model operates according to realistic heat auction principles, demonstrating competition among heat production units that maximise benefits for end consumers. The model is further enhanced by incorporating economic, strategic, and political uncertainties, enabling uncertainty and sensitivity analysis that identify financially optimal decarbonisation scenarios for DH (see *Fig. 4*).

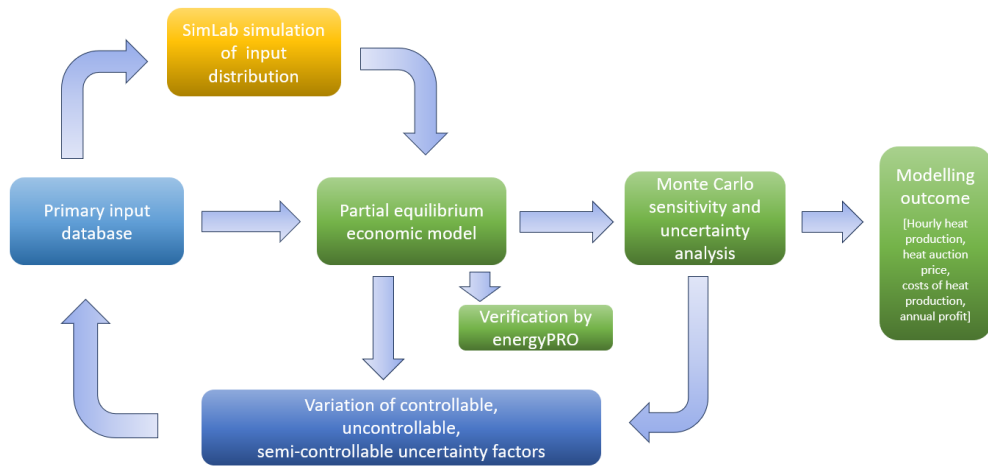


Fig. 4. Simplified methodological framework

Source: Created by the author

The key advantage and distinctive feature of the model developed in this research is that it enables the analysis of existing heat operators, IHPs, and new market participants under changing uncertainties. The model examines which new energy transformation and generation technologies are acceptable and financially viable for investors participating in the DH auction system. Simultaneously, it facilitates the analysis of how the decisions of these potential investors (whether IHPs or main heat operators) affect heat auction prices and how this would influence their own heat production costs associated with new facilities. The model verifies the current structure of the DH market and the potential costs of heat production.

2.1. The Modelling Method

The methodological process begins with the collection of primary data and verification of the existing DH system. The initial structure of the method is based on

existing heat and electricity production data, with a focus on information regarding local water-heating boilers, cogeneration plants, and other production units, including their capacity (MW) and technical efficiency indicators. In addition, all technological, economic, and environmental characteristics of the technologies are considered at this stage, enabling a more precise definition of the existing DH system (see Fig. 5).

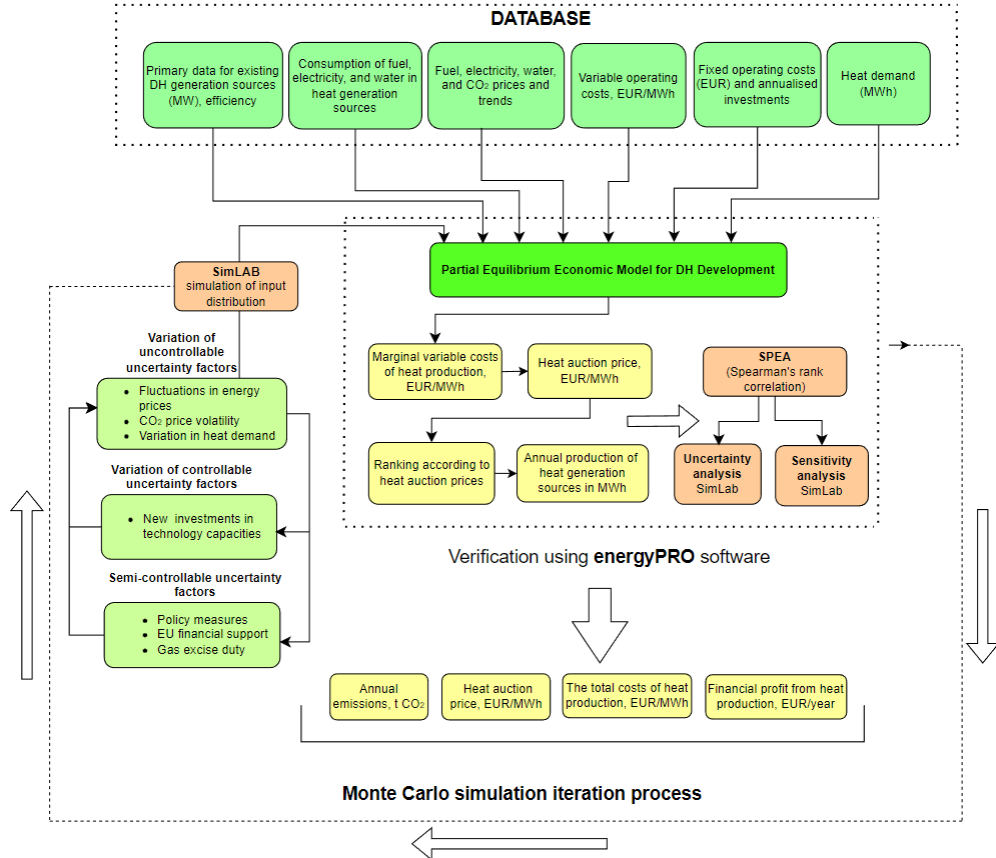


Fig. 5. Methodology

Source: Created by the author

In parallel, information on heat demand is required to represent the current DH system accurately. This can be obtained by collecting all available data on heat networks in the selected city, based on public data or direct communication with the DH company specialists.

Assumptions regarding current electricity, fuel, water, and CO₂ prices are necessary to estimate marginal heat production costs and heat auction prices. By considering electricity consumption ratios (kWh_e/MWh_t), water consumption ratios (m³/MWh_t), fuel consumption ratios (MWh_f/MWh_t), variable operation costs (EUR/MWh_t), electricity generation ratios (MWh_e/MWh_t), CO₂ price factors

(EUR/MWh_t), and actual electricity, fuel, and water prices, the marginal costs of heat production can be determined.

$$P_{Qm} = \frac{El_{cons}}{1000} \cdot El_{pr} + W_{cons} \cdot W_{pr} + F_{cons} \cdot F_{pr} + O_{var} + CO_{2pr} - El_{ratio} \cdot El_{prs} \quad (1)$$

where P_{Qm} is the marginal costs of heat production, El_{cons} is the electricity consumption ratio (kWh_e/MWh_t), W_{cons} is the water consumption ratio (m³/MWh_t), F_{cons} is the fuel consumption ratio (m³/MWh_t), O_{var} represents variable operation costs (EUR/MWh_t), CO_{2pr} is the CO₂ price factor prices (EUR/MWh_t), El_{gen} is the electricity generation ratio (MWh_e/MWh_t), El_{pr} is the electricity purchase price (EUR/MWh), El_{prs} is the electricity sales price (EUR/MWh), W_{pr} is the water price (EUR/m³), and F_{pr} is the fuel price (EUR/MWh).

Equation (1) is deterministic and does not include probabilistic elements, distributional assumptions, or sample variability. Marginal costs are calculated using fixed technical coefficients, such as specific consumption rates, together with established market prices. Therefore, the estimates are not statistical but are instead based on technical and economic assessment. This economic-engineering definition of marginal costs reflects common practice in energy planning models (e.g., energyPRO, TIMES) and in microeconomic analysis. As noted by Li et al. (2021), pricing based on short-term marginal costs focuses on variable costs and therefore best conveys market signals to consumers. From a techno-economic perspective, this formulation captures the essential elements influencing the costs associated with producing an additional unit of heat.

In addition to variable heat production costs, fixed operation and maintenance costs (O&M) and annualised investment costs are included to provide a complete representation of the current DH market structure and to estimate total heat production costs. Data on fixed O&M costs and nominal investment costs for heat generation plants (heat only boilers (HOBs) and combined heat and power (CHP) plants) are obtained from the Danish Energy Agency technology data catalogue (Danish Energy Agency, 2025a).

To reflect a realistic auction system for the total heat supply sector, it is necessary to consider the price of the heat auction for existing generation installations. The auction price is estimated based on marginal variable heat production costs. A 1% tolerance limit is applied hourly to each heat production unit and incorporated into the model to reflect minimal but existing uncertainty. This adjustment allows marginal costs to fluctuate around the base value.

After determining this value, heat generators are ranked according to their estimated marginal heat production costs. For each hour and each heat producer, the heat auction price is assumed to equal the marginal variable costs of the next higher-ranked heat producer. This approach realistically reflects the current structure of the heat market. In reality, this process is managed by the Baltpool auction system, which prioritises production capacity based on price bids submitted by heat production facilities.

These initial factors and parameters, together with their integration into a partial equilibrium economic model, enable the establishment of a reference scenario that reflects the current heat production costs of the selected DH system. Based on the literature (Nielsen et al., 2021; Berna-Escriche et al., 2024), current DH systems can generally be represented using deterministic economic models implemented with common energy economic modelling tools. Therefore, to verify the partial equilibrium model, the energyPRO simulation tool is employed, enabling an accurate assessment of total heat production costs based on the cost-minimisation principle.

2.1.1. Verification procedure with energyPRO

The energyPRO modelling software is selected because of its strong capability to simulate complex energy systems. It offers several benefits, particularly in the DH sector, including the ability to model large-scale energy systems with a wide range of heat and electricity generation and storage technologies. The software also supports balancing services, PtX, hydrogen, methanol, and other technologies. EnergyPRO provides a broad temporal scope, ranging from a few days to a number of years, up to 100 without time slicing. In addition, the tool is flexible in geographical scope, enabling modelling at scales ranging from individual power plants, and energy conversion or storage technologies to entire country-level approaches.

To test and verify the established partial equilibrium economic model, the energyPRO ‘Analytic’ calculation method is adopted. This method is suitable for DH market analysis and operation based on net production cost reduction. The chosen operational strategy ‘minimizing net production costs’ aims to meet the demand of the local DH system at the lowest possible net production costs. This strategy reflects the existing DH auction market with local participants: operator biofuel CHP plants, natural gas water-heating boilers for peak demand, and local IHPs with biofuel water-heating boilers and CHP plants. This operational strategy allows prioritisation of heat production facilities, which depends primarily on electricity market prices, fuel and water costs, and variable operational costs. The software algorithm establishes this prioritisation; for example, cogeneration plants receive the lowest priority, while plants that primarily consume electricity without generation, receive the highest priority. The prioritisation structure is reversible; energyPRO generates first on units with the lowest priority number, then on the next lowest, etc.

Unfortunately, energyPRO does not allow setting heat auction strategies, such as adjusting the heat auction price based on the marginal variable heat production costs of the next higher-ranked heat producer to reflect more realistic auction conditions. The software only estimates the costs of individual heat generation sources using a cost-reduction approach. Moreover, energyPRO is not appropriate for uncertainty or sensitivity analysis. This modelling tool is better suited for deterministic planning, where assessments are conducted in a precise and non-random manner. EnergyPRO is specifically designed to analyse alternatives identified by users, rather than to provide a comprehensive systemic or overall optimisation perspective.

2.1.2. Main technical and economic parameters for current DH system evaluation

The modelling framework established in this dissertation enables a comprehensive assessment of the existing DH system, incorporating a wide range of technical and economic input parameters that describe both performance and cost dynamics under market conditions. The technical parameters define the functional characteristics of heat production technologies, including installed thermal capacities, cogeneration coefficients for CHP plants, and electricity production capacities. They also include performance indicators such as heat production efficiency, coefficient of performance (COP), specific electricity and water consumption rate per unit of heat energy, and fuel-to-heat conversion ratios. System lifetime and temporal availability are represented by the expected asset lifetimes, scheduled shutdown durations, and the annual heat demand of the DH network (see *Table 2*).

Table 2. Main technical and economic input data for the developed partial equilibrium model and key output results

Category	Parameter	Unit / Description
Technical Input Parameters	Heat production unit thermal capacity	MW
	Cogeneration coefficient of CHP unit	–
	Electricity generator electrical capacity	MW
	Heat production efficiency (COP)	–
	Electricity consumption per unit of heat produced	kWh _e /MWh _t
	Water consumption ratio	m ³ /MWh _t
	Fuel consumption ratio	MWh _f /MWh _t
	Lifetime of installed capacity	years
	Scheduled shutdown time	hours per simulation period
	Annual heat demand of DH system	MWh
Economic Input Parameters	Fixed O&M costs	EUR/MW
	Variable O&M costs	EUR/MWh _t
	Investments in heat production unit	EUR/MW _t
	CO ₂ emission allowance price	EUR/MWh _t
	Electricity market price	EUR/MWh
	Electricity transmission and distribution price	EUR/MWh
	Biofuel price	EUR/MWh
	Natural gas raw material price	EUR/MWh
	Natural gas transmission and distribution price	EUR/MWh
	Water price	EUR/m ³
	Waste purchase price	EUR/MWh
	Average total heat auction price	EUR/MWh

Model Output Indicators	Average total costs of heat production	EUR/MWh
	Financial profit of operator	EUR/year
	Financial profit of IHP	EUR/year
	Annual CO ₂ emissions	t CO ₂ /year

Economic parameters include fixed and variable operating and maintenance costs, capital investment per unit of installed thermal capacity, and relevant market prices, such as carbon dioxide (CO₂) emission allowances, electricity market and transmission-distribution prices, biofuel and natural gas prices, water tariffs, and waste procurement costs. Based on this multidimensional data, the partial equilibrium model provides key performance indicators, including the average total heat auction price, average heat production costs, annual financial profit of system operators and independent heat producers, and total annual CO₂ emissions. In summary, this modelling approach enables a reliable and transparent assessment of the technical, economic, and environmental performance of a modern DH system, providing a solid basis for policy analysis and strategic planning.

2.1.3. Time horizon and temporal resolution

Considering the significant potential for integrating intermittent renewables into the existing and future DH system, this model is run for individual years in hourly mode. The modelling period of 2030 is chosen based on realistic projections of future energy prices and the expected remaining amortisation of the existing operator and IHP heat production plants. A longer planning horizon, such as 2040 or 2050, would create unrealistic uncertainties for modelling the DH sector economy and identifying optimal decarbonisation solutions. In hourly mode, the model facilitates the proper assessment of all innovative heat transformation technologies, including seasonal and short-term heat storage, hydrogen electrolyser waste heat recovery, solar collector heat generation, compression heat pump applications, and other power-to-heat solutions.

2.1.4 Sensitivity and uncertainty analysis implementation

The partial equilibrium model uses SimLab software for the Monte Carlo (MC) sensitivity and uncertainty analysis. The MC analysis involves running the model several times with probabilistically selected input values and analysing the results to assess: (1) the uncertainty in model predictions, and (2) which input variables contribute most to this uncertainty.

A typical Monte Carlo analysis comprises five sequential steps to quantify uncertainty and sensitivity (Giglioli & Saltelli, 2003). First, appropriate probability distributions and ranges are assigned to each input variable. Next, a sample of input variable combinations is generated based on these distributions, forming a representative set of scenarios. In the third step, these selected inputs are used to perform multiple model evaluations, establishing a functional mapping from the input space to the output space. This mapping forms the basis for subsequent uncertainty analysis. Finally, a sensitivity analysis determines the relative influence of each input variable on the variability of the model output.

The Monte Carlo process workflow using SimLab is illustrated in *Fig. 6* (Tarantola & Becker, 2016). Green boxes represent data exchange files that store important information, such as the distribution characteristics and correlation structure of the input variables, the generated sample, and the simulation results. Users specify the input variables, including the probability density functions, related parameters, the correlation matrix that defines input uncertainty, and provides the calculation model (marked with blue boxes). Red boxes indicate analytical tools provided by SimLab, including sample generation, uncertainty assessment, and sensitivity analysis procedures for obtaining sensitivity indices.

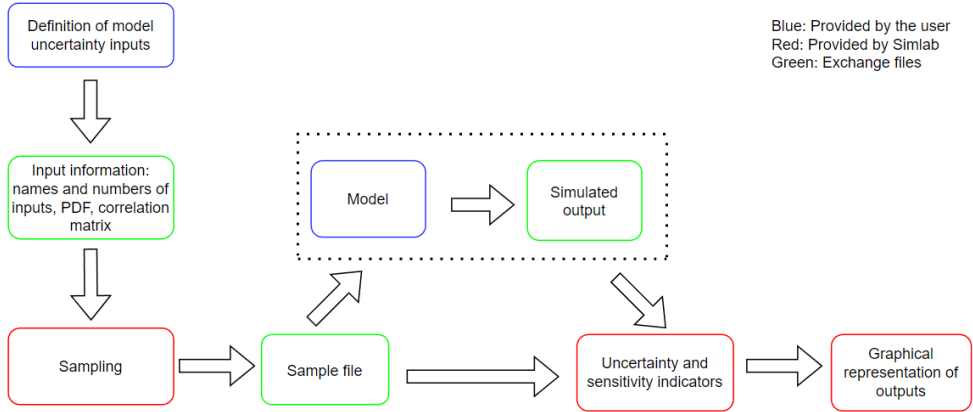


Fig. 6. Principal SimLab data workflow

Source: Created by the author based on Tarantola and Becker (2016)

The partial equilibrium model using the SimLab software package applies an iterative method that allows analysis of multiple scenarios, ensuring the consistency and comparability of each iteration. The evaluation of results follows fundamental rules that provide a structured basis for reliable and repeatable analysis. Firstly, the riskiest and financially unviable options (those with a 100% probability of generating negative financial profit) are eliminated from the model. Applying the established formula, the model then estimates the empirical probability that a value randomly selected from the dataset will be negative.

$$P(\text{Value} < 0) = \frac{N(\text{Values} < 0)}{N(\text{All observed values})} \quad (2)$$

where $N(\text{Values} < 0)$ is the number of observations with negative values and $N(\text{All visible values})$ is the total number of valid observations.

Secondly, by organising iterative processes aimed at maximising profits from the investor perspective, investments in new excessive heat production capacity are reduced. Based on the iteration outcomes, it is concluded that the potential capacity of new investments where the highest financial risk is limited. Capacity reduction and limitation are conducted by systematically evaluating sensitivity analysis diagrams,

which serve as the primary diagnostic tool for determining reliable investment limits. These diagrams are assessed according to two main criteria. First, they should demonstrate that random iterations consistently converge to conditions that lead yielding the highest investor profit, even with high dispersion. This ensures that the recommended capacity restrictions remain resilient under extreme or highly volatile market conditions. Second, sensitivity results should indicate a non-decreasing trend in average values, demonstrating that expected investor profits do not decline when uncertainty is introduced into the system.

Finally, any remaining investment alternatives with a risk greater than 50% from the investor perspective should be eliminated. These three rules ensure that the proposed limitations on heat production capacity do not negatively affect long-term financial expectations and that investment decisions remain consistent with stable or improving average operating results. In this way, the most viable solutions identified in the three stages provide an optimal investment portfolio through diverse scenario analysis options.

2.1.4.1. Identification of uncertainty factors for the partial equilibrium model

To ensure comprehensive planning of the DH system, the deterministic economic model is extended by incorporating controllable, semi-controllable, and uncontrollable uncertainties, thereby adopting a stochastic approach.

Uncontrollable uncertainty factors:

- Variability of electricity market price (EUR/MWh)
- Volatility of biofuel price (EUR/MWh)
- Variability of natural gas price (EUR/MWh)
- Volatility of CO₂ price (EUR/t)
- Volatility of hydrogen price (EUR/kg)
- Heat demand variability (MWh/annually)

Semi-controllable uncertainty factors:

- Policy measures for achieving 100% RES DH system
- EU financial support for RES-based energy production technologies
- Policy measures on the natural gas excise duty

Controllable uncertainty factors:

- Operator investments in wastewater heat pump (HP) capacities
- Operator investments in biofuel HOB capacities
- Operator investments in solar collector thermal plants with TES
- Operator integration of flexibility through investments in electric boiler capacities
- Operator investments in Power-to-Hydrogen and heat solutions
- Operator investments in seasonal PTES-type heat storage capacities
- Operator investments in power-to-heat solutions (air-to-water HPs)
- New IHP investments in biofuel boiler capacities

The classification of different types of uncertainties in the energy sector is crucial for effective planning and decision-making. Accordingly, the partial equilibrium model incorporates uncertainties following the hierarchical framework established and examined in Section 1.2.1 (see *Fig. 2*).

The illustration shows that uncertainty associated with potential investments in various new heat generation technologies is low due to the high level of investor control and well-defined decision-making processes. This is supported by the literature review, which revealed that potential investments in renewable energy technologies, such as solar photovoltaics and wind turbines, are considered physically controllable uncertainties. In contrast, uncertainty is higher when examining future trends and forecasts for electricity, biofuel, natural gas, CO₂, and hydrogen prices. According to the literature reviewed in Section 1, this represents aleatory uncertainties that are inherently unpredictable and uncontrolled.

Meanwhile, policy measures, such as the target of 100% heat from RES, EU financial support, or the introduction of an excise duty on natural gas, are considered partially controllable uncertainties. These measures may be implemented by local or national authorities. Thus, their controllability lies between fully controllable and completely uncontrollable.

Considering these uncertainties, the economic model has an enhanced capability to identify the most financially viable decarbonisation solutions for DH planning. Moreover, the established framework integrates multiple sectors: DH, electricity, and hydrogen markets. This sectoral coupling facilitates broader deployment of renewables in the DH sector while maintaining affordable electricity market prices.

2.1.4.2. Formation of uncertainty factors by probability distribution functions

The process of generating sample data in SimLab commences with defining the uncertainty of each model input, assigning intervals and probability distribution functions (PDF) based on their statistical characteristics. This step is critical for quantitatively assessing how input uncertainties propagate through the model. As described in the SimLab 2.2 software manual (Giglioli & Saltelli, 2003) and in the methodological literature (Saltelli et al., 2004), SimLab supports 12 types of probability distributions, providing a reliable and general methodology for modelling various forms of uncertainty.

The most notable distribution is the uniform distribution, where all values within a certain interval are equally probable. It is particularly applicable in situations characterised by complete uncertainty or the absence of preferences for a specific outcome.

The Normal (Gaussian) distribution, characterised by a symmetrical bell-shaped curve, is defined by the mean and standard deviation and is suitable when input variables fluctuate around the central expected value due to many small, independent factors. It is well suited for modelling measurement errors, natural biological variations, energy price forecasts, and similar phenomena. In contrast, a logarithmic normal distribution is used when the logarithm of a variable is distributed normally, meaning the original variable is strictly positive and skewed to the right. It is particularly suitable for variables such as income, emissions, and reaction times.

When modelling the time between independent events occurring at a constant rate, such as component failures or service waiting times, SimLab uses the exponential distribution. This distribution is based on a memoryless process where past events do not influence future events, making it practical for reliability and lifetime modelling.

Another useful option is Gamma distribution, which, likewise the exponential distribution, simulates positive and skewed data but is more flexible, making it suitable for waiting times when the frequency of events varies over time. The Beta distribution is limited to the interval $[0, 1]$ and is ideal for modelling proportions, probabilities, or variables with natural lower and upper limits.

When detailed datasets are unavailable but expert knowledge can estimate minimum, most probable, and maximum values, a triangular distribution provides a practical solution. For detailed reliability and risk analysis, SimLab offers the Weibull distribution, a highly flexible model for failure time data that can reflect increasing or decreasing failure rates depending on its shape parameter.

In the absence of continuous distributions, SimLab supports discrete distributions, which allow users to assign probabilities to a limited set of categorical or integer values. This is particularly useful for modelling choices or classifications. Constant values are also available, corresponding to deterministic variables without variability and effectively representing fixed parameters. In addition, ratio distributions enable the definition of functional dependencies between input variables, allowing one variable to be calculated as a function of another and directly incorporating correlations into the model.

Finally, the logarithmic uniform distribution is used for scale-invariant situations, where no specific value is preferred in the interval. This distribution is strictly positive and covers values across multiple size classes, which is important when modelling widely different rates, concentrations, or financial values.

Considering the main parameters of this research, particularly those related to future energy prices such as electricity, biofuel, natural gas, and CO₂ prices, the normal distribution is the most appropriate to reflect fluctuations outside set limits, better representing natural market processes. For potential new investment strategies in energy infrastructure and heat production facilities, as well as fluctuating heat demand, a uniform distribution is most suitable, accounting for clear investor decisions on capacity ranges and anticipated changes in heat demand.

2.1.4.3. Identification of sampling generation methods

The next step in organizing a Monte Carlo analysis is selecting the most appropriate sampling generation method from those available in SimLab. The programme offers the following methods: FAST, fixed sample, Latin hypercube, replicated Latin hypercube, Morris, quasi-random LpTau, random, and Sobol (Saltelli et al., 2004).

In the context of low sample sizes, selecting an appropriate sampling method requires balancing statistical efficiency, space coverage, and the ability to handle input correlations. Although random sampling is often criticised for slow convergence and high dispersion, it remains a flexible method when input variables are correlated, as it

enables direct sampling from high-dimensional distributions without structural assumptions.

Latin hypercube sampling (LHS) ensures optimal distribution and space coverage, making it more effective than random sampling when inputs are independent. However, additional processing methods are required to accurately maintain correlations. Quasi-random methods, such as Sobol and LpTau, offer low sequence mismatch and high space coverage but depend on input independence, making them less suitable for strongly correlated inputs unless complex rearrangements are applied. The Morris method is optimal for qualitative screening with a minimal number of tests but also assumes input independence.

For general-purpose low-sample analyses with independent inputs, LHS or quasi-random methods are preferred. However, random sampling is more appropriate when correlations must be preserved directly without additional modelling efforts. Therefore, random sampling is chosen for this Monte Carlo process (see *Table 3*).

Table 3. Characterisation of potential SimLab sampling methods

Sampling Method	Type	Handles Correlation	Key Advantages	Key Limitations
Random Sampling	Unstructured/Monte Carlo	Yes	Simple; directly handles any distribution or correlation	High distribution; poor space filling; slow convergence
Latin Hypercube Sampling (LHS)	Stratified	With post-processing	Well distributed; less dispersion than random; widely used	Requires Iman-Conover or copula correlation; suboptimal for correlations
Sobol Sequences	Quasi-random (low-discrepancy)	Not directly	High uniformity; ideal for dispersion-based sensitivity indices	A high number of cases is required to achieve convergence; challenging with correlated input data
LpTau Sequences	Quasi-random (low-discrepancy)	Not directly	Efficient and space-filling, with less inaccuracy than random	Transformation is essential for correlation
Replicated LHS (r-LHS)	Stratified + Replication	With post-processing	Allows assessment of the uncertainty of sensitivity indices	More efficient when using larger samples, additional post processing necessary for correlation

Morris Method	One-at-a-Time (OAT) Screening	No	Highly effective for qualitative sensitivity screening	Only ranking is provided, not quantitative sensitivity; independence is assumed
FAST	Frequency-domain sensitivity	No	Effective for assessing key effects with fewer samples	Not suitable for correlated inputs; has difficulty coping with higher-level interactions
Fixed Sampling	Deterministic	Manually possible	Regenerable; suitable for comparative analysis	Not probabilistic; lack of quantitative assessment of uncertainty

Source: Created by the author

After generating the uncertainty factors, the next step is to implement the sensitivity and uncertainty analysis in the partial equilibrium model. It is assumed that 100 cases are to run, integrating the various uncertainty factors in each iteration, which allows a 95% confidence level to be achieved.

2.1.4.4. Assessment and selection of linear and nonlinear indicators for sensitivity and uncertainty analysis

In the final stage, the results of the uncertainty and sensitivity analysis are presented using correlation or regression methods selected by the SimLab tool, applying both linear and nonlinear coefficients. The aim of sensitivity analysis (SA) is to identify the most important model inputs and quantify how input uncertainty affects model results (Marino et al., 2008). Various linear and nonlinear SA measures are used to determine the maximum influence of uncertainty factors and to evaluate the overall model results.

For linear relationships between two continuous variables, Pearson's product-moment correlation (PEAR) is commonly used. The Pearson's correlation coefficient is typically applied to normally distributed data (bivariate normal distribution). Similar to Pearson's product-moment correlation, partial correlation coefficients (PCC) are also appropriate for linear trends. PCC estimates the degree of linear relationship between an input variable and the model output after removing the linear effects of all other variables (Manache & Melching, 2008).

Another linear measure is the standardised regression coefficient (SRC), whose primary objective is to assess the effect of different independent variables within the same regression model, particularly when variables are expressed in different units or scales. The standardised regression coefficient indicates how many standard deviations the dependent variable changes in response to a one-standard deviation change in the predictor variable (Song et al., 2015). The benefits of SRC include its simplicity and its ability to assess the sensitivity of each parameter, even when all parameters simultaneously affect the model output. However, SRC is not applicable

when relationships between parameters and model output are nonlinear or non-monotonic, or when correlations exist among variables (Song et al., 2015). Therefore, both PEAR and SRC are applicable to linear numerical models with independent input parameters. When model behaviour is strongly nonlinear or input variables are highly correlated or dependent, SRC is not suitable for quantifying the relative importance of input variables (Wei et al., 2015).

Spearman's rank correlation can be used to measure monotonic association for non-normally distributed continuous data, ordinal data, or data containing significant outliers. Spearman's rank correlation coefficient is calculated using the ranks of data points rather than their actual values, which makes it more robust in the presence of outliers or nonlinear data distributions. Both PEAR and SPEA correlation coefficients range from -1 to +1, where 0 indicates the absence of a linear or monotonic relationship. As the absolute value of the coefficient approaches 1, the strength of the relationship increases and eventually converges toward a straight line in the case of Pearson's correlation or a steadily increasing or decreasing curve in the case of Spearman's rank correlation (Schober et al., 2018).

Rank transformation is often applied when the relationship between input variables and analysis outcomes is nonlinear (Saltelli & Sobol, 1995). In sampling-based approaches, the Standardised Rank Regression Coefficient (SRRC) is a robust and reliable sensitivity measure (Pan et al., 2011). When the input-output ratio is monotonic, the SRRC provides sufficiently accurate and interpretable results (Manache & Melching, 2008). SRRC is similar to SRC, but it is computed using actual ranked input and output values. This rank transforms the data into ordinal values, making SRRC less sensitive to outliers and more suitable for nonlinear or irregular data. However, when input variables are correlated, the SRRC may yield unreliable estimates of parameter importance (Helton et al., 2006).

Likewise PCCs, partial rank correlation performs partial correlation on rank-transformed data. The partial rank correlation coefficient (PRCC) is a reliable measure of sensitivity for nonlinear but monotonic relationships between two variables when correlations among input parameters are low or absent (Marino et al., 2008). However, PRCC is not robust when input variables are highly correlated; they do not significantly indicate the effect of uncorrelated input variables. PRCCs are more commonly used to estimate the association between two variables while controlling additional variables in ordinal data. They measure monotonic, though not always linear, relationships between ranked variable values and are therefore robust to outliers and anomalous data (Marino et al., 2008).

A detailed comparison of linear and nonlinear measures enables the selection of the most appropriate sensitivity indicator SPEA for the sensitivity and uncertainty analysis (Schober et al., 2018). In SA, preference is typically given to nonlinear measures and non-normally distributed continuous data with outliers, as these approaches better identify the maximum influence of uncertainty factors and support the assessment of overall model performance. Consequently, the ranking of data rather than the actual values is prioritised, while preserving correlations among factors.

2.2. Data and Assumptions for the Partial Equilibrium Model

2.2.1. Electricity price assumptions

According to hourly data for 2024 (Litgrid, 2025a), the average electricity spot market price was 87 EUR/MWh. After accounting for additional charges, including electricity distribution and transmission fees, the increased reliability class tax for category II, and excise tax, the total electricity price amounts to 124 EUR/MWh. To reflect more realistic electricity price dynamics, hourly electricity market data from the past six years (since 2019) are analysed and averaged for each hour (see Fig. 7).

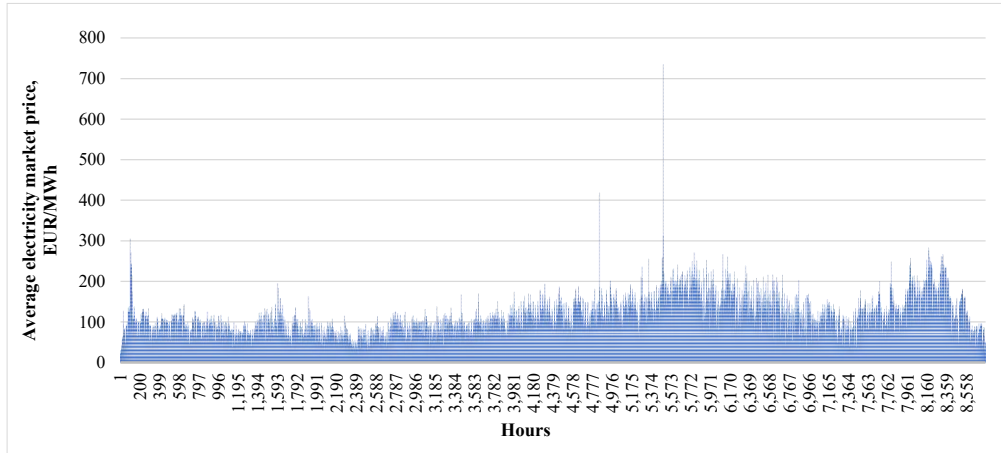


Fig. 7. Average hourly electricity market price for the period 2019–2024

Source: Created by the author

Considering electricity price trends based on the implemented *Power Market Study 2030* (Deloitte, 2018) and *Energy and Electricity Price Scenarios 2020-2023-2030* (Delft, 2017), it is assumed that the average electricity price might be approximately 60 EUR/MWh. In contrast, based on the results from the Lithuanian energy system modelling project, the average electricity market price in 2030 is estimated to be approximately 55 EUR/MWh (Lithuanian Energy Agency, 2024). According to Montel energy experts and analysts, the growth of renewable energy is expected to contribute to lower electricity prices in the future (Montel, 2024). Their forecast suggests that electricity prices will fluctuate between 50 and 70 EUR/MWh in 2030.

Another future electricity price projection for Baltic countries is discussed by Kozlovas et al. (2024). The authors indicate that the final electricity price will primarily depend on the level of local renewable generation at the national level. Their scenario analysis shows that for low, medium, and high levels of renewables and load, electricity price would mostly range between 60 and 70 EUR/MWh. Meanwhile, energy experts at S&P Global (2023) estimate that the average electricity price in Europe will be around 50 EUR/MWh in 2030.

Based on these price forecasts, the appropriate range of uncertainty for the electricity market is assumed to be 50–70 EUR/MWh. This price fluctuation is incorporated as an uncertainty factor in the partial equilibrium model.

2.2.2. Biofuel price assumptions

According to the Lithuania's biofuel price outlook for 2023 and 2024 (National Energy Regulatory Council, 2025a), biofuel prices for both SM2 (higher quality wood chips with lower moisture and impurity level) and SM3 (lower quality wood chips with higher moisture and impurity level) types have not exceeded 25 EUR/MWh since April 2023. In 2024, the average price of SM2 wood chip fuel was 19.61 EUR/MWh, while the average price of SM3 fuel was 18.35 EUR/MWh. Compared to 2023, this comparison represents a significant price decrease of 26.7% for SM2 fuel and 22.3% for SM3 fuel (see Fig. 8).

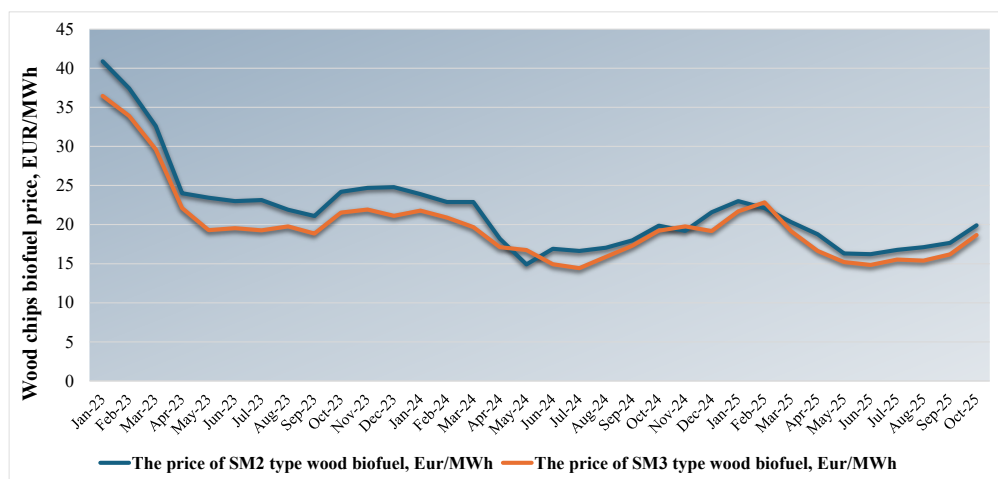


Fig. 8. The average price of biofuel during the period 2023–2025

Source: Created by the author

Meanwhile, in 2025, biofuel prices declined further by 7.5%, reaching average prices of 18.15 EUR/MWh and 16.97 EUR/MWh for SM2 and SM3 wood chip fuel types.

Biofuel price volatility in 2030 was assumed based on the *Heat Roadmap Europe* study on a low-carbon heating and cooling strategy, which provides fuel prices for the periods of 2015, 2030, and 2050. According to this study, biofuel prices may fluctuate between 23 to 28.9 EUR/MWh. In contrast, the Vilnius DH Company's 10-year investment plan (Vilnius DH Company, 2024) suggests that biofuel prices may be around 30 to 33 EUR/MWh. Therefore, a possible biofuel price fluctuation in the range of 23 to 33 EUR/MWh is incorporated as an uncertainty factor in this partial equilibrium economic DH model.

2.2.3. Natural gas price assumptions

According to statistical analysis for 2023 and 2024, the average price of natural gas feedstock in Lithuania decreased from 45.44 to 38.5 EUR/MWh, with a reduction of 15.3%. In 2025, the average price increased to 42.69 EUR/MWh, with an increase of 10%. Additionally, the natural gas distribution component must be considered, with the tax applicable to group No. 7 at 4.26 EUR/MWh (ESO, 2025), as well as the transmission component charged by AB Amber Grid, which is 0.17 EUR/MWh. Excise duty on natural gas consumption in Lithuania amounts to 0.54 EUR/MWh (Vilnius DH Company, 2024). Each of these components contributes to the final consumer price. Therefore, the final price of natural gas for the period 2024–2025 was 43.5–47.66 EUR/MWh, including raw gas, transmission, distribution, and excise duty costs (see Fig. 9).

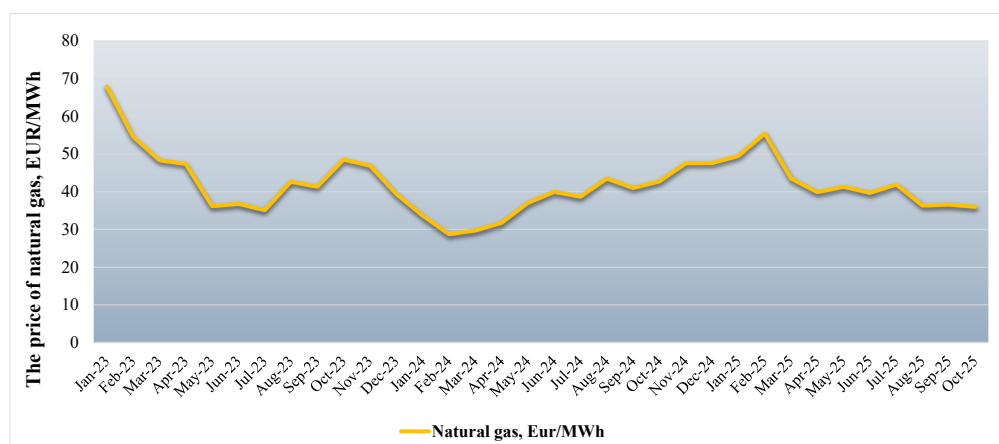


Fig. 9. The average price of natural gas in Lithuania during the period 2023–2025

Source: Created by the author

While there exists a number of uncertainties regarding natural gas price trends and potential variations in future markets, particularly in a geopolitical context, the JRC-EU-TIMES report and *EU Long-term Scenarios 2050* report (Heat Roadmap Europe, 2017) suggest that the price of natural gas in 2030 could be around 30–40 EUR/MWh, excluding additional gas fees. Another report estimates, according to the baseline 2030 scenario, the natural gas price is expected to be around 31 EUR/MWh (Centre on Regulation in Europe, 2024). According to the German consultant Montel (2024), the price is expected to be slightly below 30 EUR/MWh.

It is also necessary to include transmission, distribution, and excise fees. According to the Vilnius DH Company's (2024) 10-year investment plan, these additional fees are projected to total 14.76 EUR/MWh in 2030. Therefore, the price of natural gas, including all additional components, is expected to fluctuate between 44.76 and 54.76 EUR/MWh, which is incorporated as an uncertainty factor in the partial equilibrium economic model.

2.2.4. CO₂ price assumptions

The price of CO₂ is assessed based on the *World Energy Outlook 2023* (IEA, 2023a) and the World Bank report on the state and trends of carbon pricing (The World Bank, 2024). The World Bank's high-level Commission on Carbon Pricing states that, to align with the Paris Agreement and to achieve the $\leq 2^{\circ}\text{C}$ target, the carbon price in 2030 should be approximately 55–115 EUR/t CO₂ in real terms. According to the National Energy and Climate Action Plan of the Republic of Lithuania (Lithuanian Energy Ministry, 2019), the CO₂ price should reach 99 EUR/t by 2030. Meanwhile, the International Energy Agency's (IEA) *World Energy Outlook 2023* forecasts a CO₂ price of 109 EUR/t by 2030 (IEA, 2023a). In its zero emissions scenario, the IEA (2023b) predicts that by 2030, the price of carbon dioxide (CO₂) will be around 120–130 EUR/t CO₂ in advanced economies and 75–85 EUR/t CO₂ in developing markets. These projections are based on ambitious decarbonisation targets, particularly in the electricity and industrial sectors. Therefore, considering these potential trends and the uncertain geopolitical situation in Europe, a CO₂ price range of 55–130 EUR/t is incorporated into the partial equilibrium model.

2.2.5. Hydrogen price assumption

Technological progress, policy measures, and electricity market dynamics are expected to be the key factors influencing hydrogen prices until 2030. Based on a detailed analysis in *Future Costs of Hydrogen: A Quantitative Review*, Frieden and Leker (2024) predict that by 2030, global hydrogen production costs, particularly for electrolysis, will decrease significantly to approximately 4.4 EUR/kg, compared to 5.3 EUR/kg in 2020. The authors note that using proton exchange membrane (PEM)-type electrolyzers, hydrogen production costs can average approximately 4.31 EUR/kg (see Fig. 10).

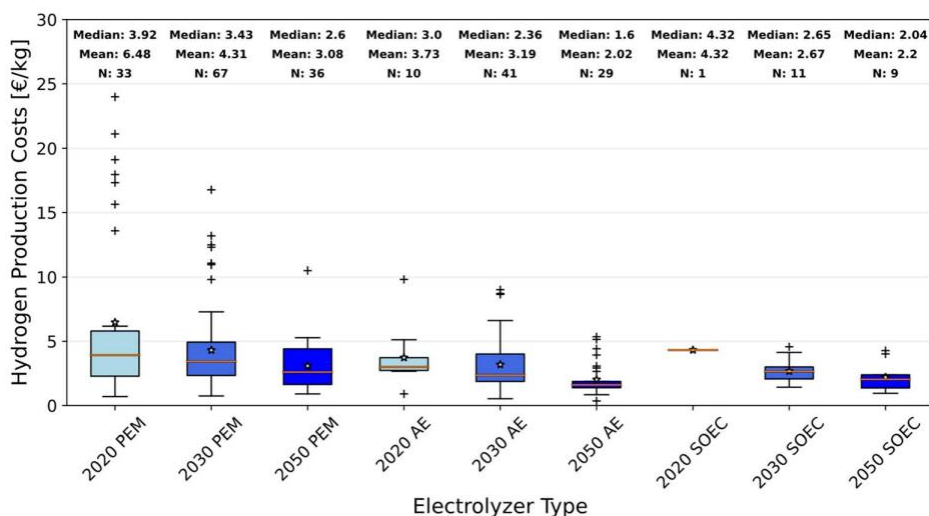


Fig. 10. Forecast of hydrogen production costs for various types of electrolyzers

Source: Created by Frieden and Leker (2024)

According to another comprehensive techno-economic analysis, green hydrogen could benefit from declining renewable energy costs, with prices projected to range between 3–5 EUR/kg by 2030 (Curcio, 2025). Clerici and Furfari (2021) present a prognosis for the levelised cost of hydrogen from electrolysis plants larger than 100 MW in 2030. They emphasise that, depending on the price of renewable electricity and the annual hydrogen production capacity factor, hydrogen prices could range between 3–6 EUR/kg when wind and solar energy are used as the primary electricity sources. Based on this approach and current knowledge of hydrogen production costs, considering the Lithuanian energy market, a hydrogen price range of 3–6 EUR/kg is incorporated as an uncertainty factor for the partial equilibrium economic model.

2.2.6. Heat demand assumptions

In this dissertation, the heat demand analysis is based on actual data from DH systems in Vilnius and Alytus. Evaluating their normalised hourly demand allows for an assessment of seasonal variations in heat consumption and the dynamics of load patterns in cities of different sizes. Both systems exhibit strong seasonal dependence, driven by climatic conditions, which is consistent despite differences in the number of consumers, the layout of the heat production infrastructure, and the network configuration.

During the coldest period of the year, typically from December to February, both DH systems display a consistent increase in heat demand, approaching 0.8–1.0 of normalised values. This indicates that the systems operate near or at maximum capacity. Sudden peaks in demand correspond to the lowest outdoor temperatures and typical morning and evening consumption patterns, reflecting the operating cycles of both domestic and commercial building heating systems. For example, the Vilnius system exhibits larger short-term fluctuations and higher amplitude during the cold season. This is typical of larger systems, where a more heterogeneous consumer portfolio and more complex infrastructure interactions result in more pronounced dynamic changes (see *Fig. 11*).

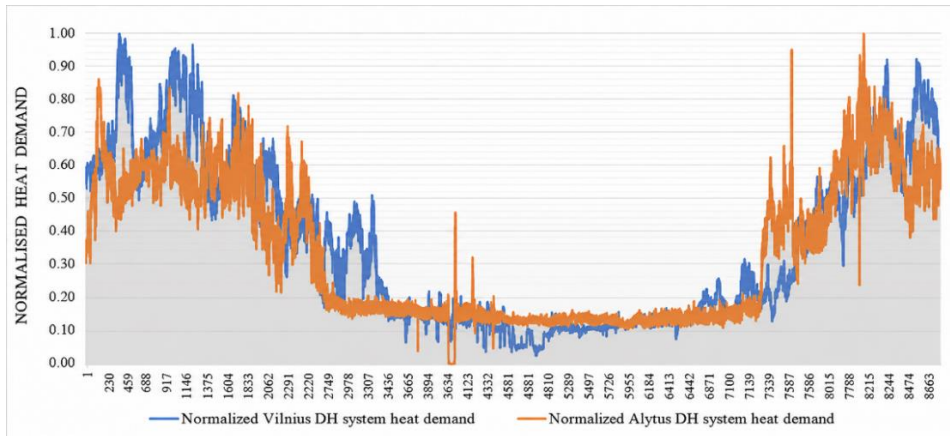


Fig. 11. Normalised heat demand for Vilnius and Alytus DH systems

Source: Created by the author

During the warm season, from May to September, heat demand in both cities stabilises at 0.12–0.20 of the normalised value. This range reflects the base load associated with hot water demand, heat network circulation maintenance, and constant heat losses. Since heating is essentially unnecessary during this period, the heat demand curve becomes much flatter and less influenced by meteorological factors. Both cities demonstrate a similar base load structure, indicating that the heat demand during the non-heating season is primarily driven by technological and domestic processes rather than climatic conditions.

During transitional periods (autumn and spring months), heat demand fluctuates between minimum and maximum values, remaining proportionally sensitive to changes in outdoor temperature. Operational differences between the systems are particularly noticeable during these periods: the Vilnius system exhibits higher intensity fluctuations, whereas the Alytus load profile is smoother and more gradual. This difference can be attributed to the higher inertia of the city network, its more diverse demand structure, and the greater length and complexity of the network and its losses.

The heat demand biodynamics of the Vilnius and Alytus DH systems follow typical seasonal patterns of heat supply systems: during the cold season, demand approaches peak generation capacity, while in the warm season, it stabilises at a low level, corresponding to about one-fifth of peak demand. The analysis of normalised data allows direct comparison between systems and highlights the influence of city scale on the magnitude of heat demand fluctuations while maintaining the overall seasonal structure. This type of analysis is useful for energy production planning and, in this case, for developing a partial equilibrium economic model of the DH system.

2.2.7. Assumptions for discounting factor

This dissertation's partial equilibrium economic model applies different discount rates to annualised investments, assessing the fixed component of heat production costs. It is assumed that, based on the ownership of existing and potential new heat generation facilities, two discount rates can be distinguished: one for operators and one for IHPs.

According to the literature, utility providers are recommended to use the real weighted average cost of capital (WACC), typically ranging from 7% to 8%, when analysing operational efficiency (Borden et al., 2023; Stein et al., 2025). Meanwhile, statistical data from the National Energy Regulatory Council (2025a) indicate that the average WACC in Lithuania in 2024 ranged from 6.0% to 6.3%. Accordingly, the Australian Energy Regulator (AER) considers a 7.30% WACC upper limit reasonable and methodologically appropriate for cost-benefit analysis guidelines (Synergies Economic Consulting, 2021). Furthermore, the 2020 Electricity Generation Cost Forecast report (IEA, 2020) applies a 7% real discount rate, reflecting typical capital costs for large utility providers operating in deregulated or liberalised energy markets.

Therefore, it can be argued that the local DH operator is assumed to have a lower discount rate of 6%, which would apply to existing biofuel CHP plants, older natural gas water boilers, and new capacity investments initiated by operators. Meanwhile,

independent heat production facilities operate in a higher-risk environment due to private ownership and may require a higher discount rate of 7% to compensate for increased investment risk.

2.2.8. Assumptions of modelling the biofuel water heating boilers

According to Danish technology data, investments in new biofuel HOBs are divided into three main groups: small, medium, and large (Danish Energy Agency, 2025a):

- Small capacities [1–20 MW] – 701,825.9 EUR/MW
- Medium capacities [20–50 MW] – 499,785.2 EUR/MW
- Large capacities [50–100 MW] – 446,616.5 EUR/MW

Flue gas condensers are included in the water heating boiler systems to improve heat production efficiency. Efficiency is assumed to be constant at 105%, reflecting uncertainty in biofuel quality. This efficiency is typically observed in most current local IHP biofuel water heating boilers in DH systems. New biofuel HOBs may achieve higher heat production efficiency of up to 115% due to potential integration of absorption or compression heat pumps and second-grade flue gas condensers for deeper heat recovery (see *Table 4*).

Table 4. Techno-economic parameters of biofuel heat-only boilers

Parameters		Units	Biofuel HOB small	Biofuel HOB medium	Biofuel HOB large
Techno-economic parameters	Efficiency	%	114	115	115
	Capacity	MW	[1–20]	[20–50]	[50–100]
	Lifetime	years	25	25	25
	Construction time	years	1	2	2.5
	Investment costs	EUR/MW	701,825.9	499,785.2	446,616.5
	Fixed costs	EUR/MW/year	38,175.1	43,066.6	35,410.3
	Variable costs	EUR/MWh	8.75	7.5	5.07

Source: Created by the author based on the Danish technology data catalogue for electricity and DH (Danish Energy Agency, 2025a).

To estimate potential investments in new biofuel HOB capacities more accurately, the model uses nonlinear regression. The resulting function is as follows:

$$y = 0.4471 + \frac{1.7514}{x} \quad (3)$$

where y is investments (M EUR/MW) and x is biofuel HOB heat capacity (MW).

This function minimises quadratic deviation in the original y space and has a maximum deviation of 3.9% compared with Danish technology data (Danish Energy Agency, 2025a) (see *Fig. 12*).

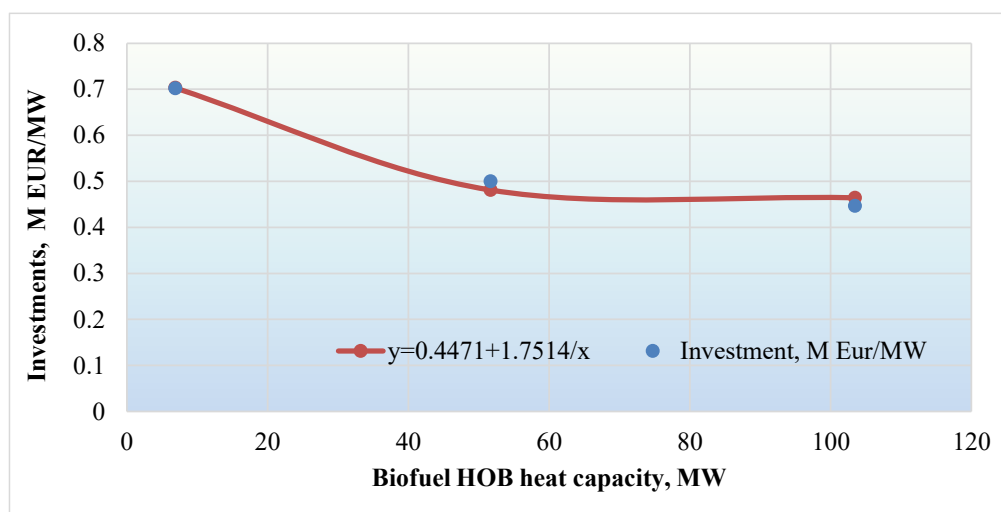


Fig. 12. Nonlinear regression of potential investments in biofuel HOB capacities

Source: Created by the author

2.2.9. Assumptions for modelling the current biofuel and waste CHP units

The partial equilibrium model includes not only HOBs but also existing CHP infrastructure performance. To reflect the current DH systems, the model incorporates inputs from the largest existing Lithuanian CHP facilities, as shown in *Table 5*. *Table 5* presents the existing biofuel cogeneration power plant of the Vilnius DH operator (Vilnius DH Company, 2024), which has been fully modernised with first and second-stage flue gas condensers and absorption heat pumps. To realistically include and integrate new high-power waste and biofuel CHP plants, the model uses one of the largest implemented projects in Lithuania as a benchmark: the Vilnius waste and biofuel cogeneration plant. Based on these assumptions, *Table 5* lists the most relevant technical and economic parameters for inclusion in the partial equilibrium model.

Table 5. Techno-economic parameters of biofuel and waste CHPs

Parameters		Units	Operator bio CHP	IHP waste CHP	IHP biofuel CHP
Techno-economic parameters	Efficiency	%	121	110	109
	Cogeneration ratio		0.231	0.305	0.318
	Capacity	MW	[64.5]	[70]	[170]
	Lifetime	years	25	25	25
	Construction time	years	5	3	5
	Investment costs	EUR/MW	823,529	2,985,714	417,647
	Fixed costs	EUR/MW/ year	62,172	219,055	102,085

Variable costs	EUR/MWh	5.07	5.07	4.26
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Source: Created by the author based on personal communication with a DH operator and IHP producers, and the Danish technology data catalogue for electricity and DH (Danish Energy Agency, 2025a)

Additionally, emission factors should be assessed according to the national greenhouse gas (GHG) inventory report (National Environmental Protection Agency, 2025). For example, a waste incineration plant burning non-renewable municipal waste produces CO₂. According to the National Environmental Protection Agency, the CO₂ emission factor for non-renewable municipal waste in 2024 was 111.65 t/TJ or 0.40195 t CO₂/MWh of heat.

2.2.10. Assumptions for modelling existing natural gas boilers

The model also considers that the DH operator has significant reserves of natural gas boilers. For instance, in the Lithuanian capital, the total potential gas boilers' heat capacity is estimated at approximately 867 MW, which can be used to meet demand during the coldest periods. Although the existing natural gas boiler infrastructure is relatively old, it remains useful for responding quickly to heat demand, particularly when there is a shortage of heat production facilities on the market. *Table 6* presents key technical and economic parameters used in the economic model.

Because natural gas is a fossil fuel, CO₂ emissions must also be considered. According to the National Environmental Protection Agency (2025), the CO₂ emission factor for natural gas in 2024 was 55.4 t/TJ or 0.2 t CO₂/MWh of heat.

Table 6. Techno-economic parameters of natural gas boilers

Parameters		Units	Gas HOB large
Techno-economic parameters	Efficiency	%	92
	Capacity	MW	[50–100]
	Lifetime	years	25
	Construction time	years	1
	Investment costs	EUR/MW	60,000
	Fixed costs	EUR/MW/year	1,967
	Variable costs	EUR/MWh	3.49

Source: Created by the author based on Danish Technology Data catalogue for electricity and DH (Danish Energy Agency, 2025a)

2.2.11. Assumptions on solar collectors and short-term storage

The use of solar energy for water heating is a well-established technology that has been utilised for many years. Currently, more than 580 million square meters of solar collectors are installed worldwide, with a total capacity of 410 GWth. While most of this capacity is used for small domestic hot water systems, the fastest growth is occurring in larger systems (Danish Energy Agency, 2025a).

There are three main types of solar thermal collectors: flat plate collectors (FPCs), evacuated tubular collectors (ETCs), and concentrated solar power (CSP) systems. Large blocks of FPCs are the primary technology used in Denmark's DH systems. Although ETCs provide higher thermal efficiency at high operating temperatures, their elevated cost limits widespread usage. CSP systems can achieve high temperatures suitable for industrial processes. For Lithuanian regions, FPCs are considered the most suitable solar thermal technology due to their cost-effectiveness and compliance with local heat demand profiles.

Ground-mounted FPC fields with storage tanks for district heating are installed in many countries, including Sweden, Denmark, Austria, Finland, and Germany (Danish Energy Agency, 2025a). These collectors are oriented south, with the angle of inclination determined individually based on the location and collector type. The spacing between rows is also determined according to the equipment specifications. Large-area flat-plate solar collector power plants are usually designed in rows of up to 20 collectors. Each collector typically, requires 3–4 m² of ground area.

According to PVGIS software (see *Fig. 13*), annual solar radiation on a horizontal surface inclined at 37–41 degrees in the Vilnius region reaches 1,240 kWh/m² (Photovoltaic Geographical Information System, 2025).

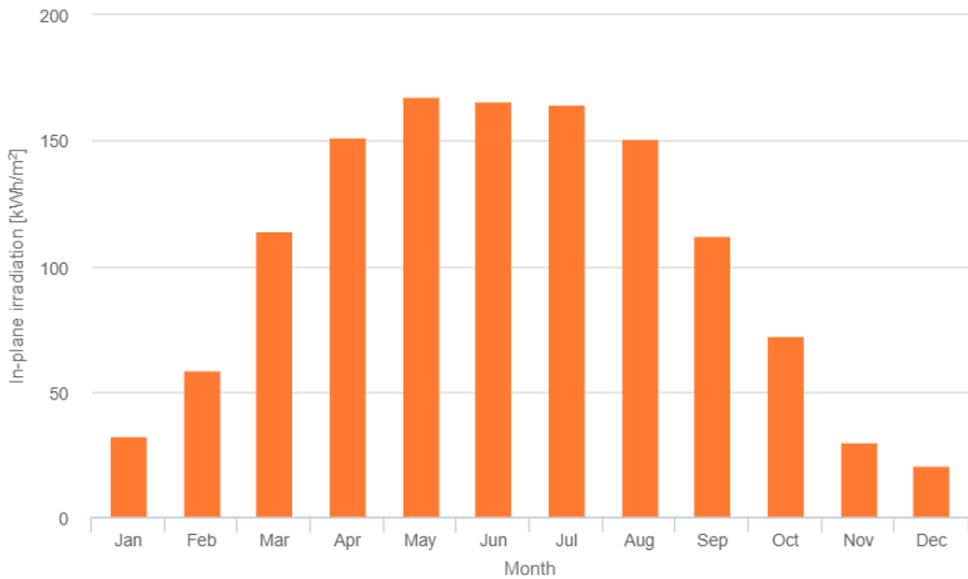


Fig. 13. Monthly solar radiation on a surface inclined at an angle of 37–41 degrees in the Vilnius region

Source: Created by the author

In the partial equilibrium economic model, it is assumed that a high-efficiency FPC-type collector with the following key parameters is applied (see *Table 7*):

Table 7. Efficiency indicators of the assumed solar thermal collectors

Solar collector type	η_0	a_1 (W/(K·m ²))	a_2 (W/(K·m ²))
High-efficiency flat-plate solar collector	0.857	3.083	0.013

where η_0 is the theoretical maximum efficiency of a flat plate solar collector, a_1 is the first-order heat loss coefficient W/(K·m²), and a_2 is the second-order heat loss coefficient, W/(K·m²).

The approximate average annual efficiency of collectors is around 48% to 50% (Danish Energy Agency, 2025a). The highest efficiency of flat-plate solar collectors occurs from May to August, with a calculated coefficient performance exceeding 0.7 (see Fig. 14). Achieving the maximum coefficient of performance is difficult because the final value is influenced by the first and second-order heat loss coefficients. Additionally, the efficiency of solar collectors depends on solar radiation during different seasons (W/m²).

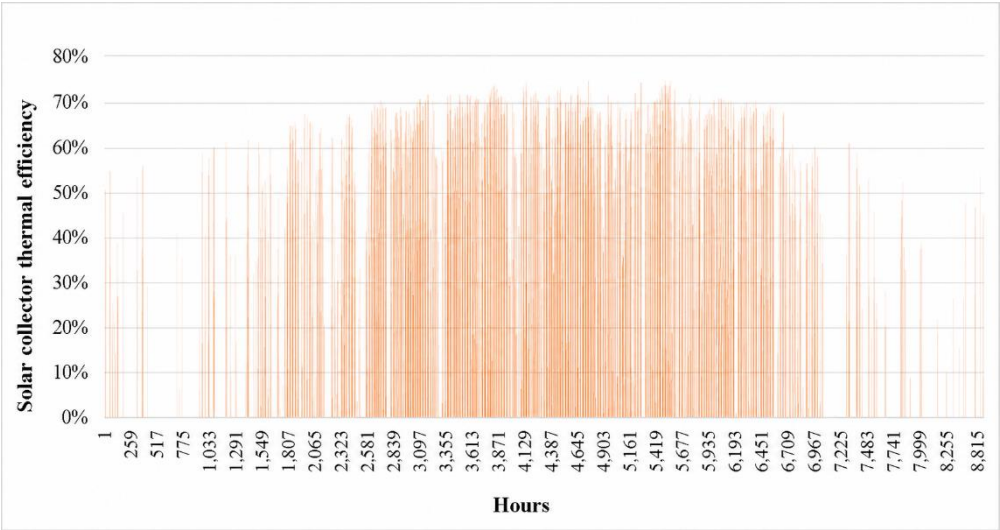


Fig. 14. Average hourly solar collector thermal efficiency

Source: Created by the author

Table 8 presents the key technical and economic parameters used to prepare the partial equilibrium model.

Table 8. Techno-economic parameters of solar collectors

	Parameters	Units	Solar collectors
Techno-economic parameters	Efficiency	%	48
	Area	m ²	[5,000–100,000]
	Lifetime	years	30
	Construction time	years	0.25
	Investment costs	EUR/m ²	[170–216]
	Fixed costs	EUR/MW/year	60.41
	Variable costs	EUR/MWh	0.319

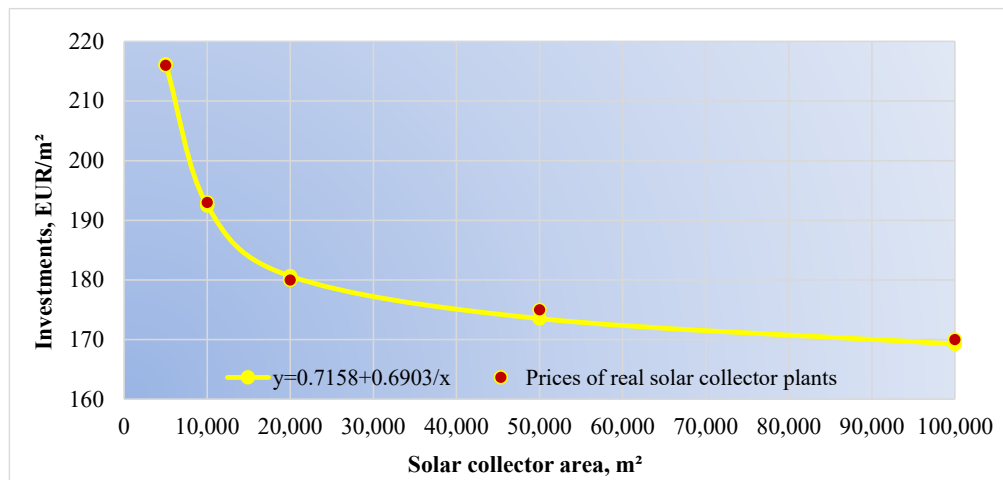
Source: Created by the author based on Danish Technology Data catalogue for electricity and DH (Danish Energy Agency, 2025a)

To more accurately estimate potential investments in solar collector capacities across different areas, nonlinear regression is applied in the partial equilibrium model. The resulting function is:

$$y = 168.789 + \frac{236981.758}{x} \quad (4)$$

where y denotes investments in solar collectors (EUR/ m²), and x represents solar collector area (m²).

This function minimises the quadratic deviation in the original y space and achieves a maximum of 0.84% compared to Danish technology data (Danish Energy Agency, 2025a) (see *Fig. 15*).

**Fig. 15.** Nonlinear regression of potential investments in solar collector capacities

Source: Created by the author

Maximum solar radiation on an inclined solar collector occurs during the warm season. In summer, sunlight is most intense, allowing significantly more thermal energy to be generated. Accumulated excess heat can be stored in thermal storage systems, extending the period of heat production from solar energy. Therefore, solar thermal collectors are typically integrated with short-term tank-type thermal energy storage (TTES).

TTES systems are the most common form of TES. Each tank comprises a cistern, usually located above or below ground, filled with water and connected to supply and return pipes for heating water. Initially, these storage facilities were installed with cogeneration power plants to optimise electricity production and sales. Later, as electricity production increased with the growth of wind energy, the operating life of cogeneration plants began to shorten. Consequently, these storage facilities have largely shifted to use in combination with solar collectors (Danish Energy Agency, 2025c).

TTES systems are usually made of stainless steel, concrete, or glass-fiber-reinforced plastic. Insulation materials are selected based on environmental conditions and the tank's purpose, but 30–45 cm of mineral wool is typically used. Due to their robust construction, these tanks have minimal interaction with the environment and offer excellent technical characteristics. Atmospheric tanks can operate at temperatures up to 98°C (Danish Energy Agency, 2025c).

For solar collectors combined with heat storage, the maximum water temperature is approximately 70–80°C. If the heat is produced in a cogeneration plant, the water temperature can reach 90–95°C, and in pressurised TTES systems, it can reach 100–120°C. The upper and lower temperatures in storage tanks affect not only the stored energy but also heat losses. Other factors influencing heat loss include ambient temperature, TTES operating mode, wind conditions, insulation thickness and properties, and tank shape. Ideally, heat loss is minimised in spherical tanks. Therefore, TTES storage tanks are usually installed with a diameter-to-height ratio of 1.5–2.5 (Danish Energy Agency, 2025c).

The partial equilibrium model is based on the following key technical assumptions. The water temperature at the top of the heat storage tank is assumed equal to the temperature of the water heated in the solar collector (T_1 °C with around 75°C). The temperature at the bottom of the storage tank fluctuates according to the temperature of the return network water T_2 °C. The storage capacity utilisation rate is assumed to be 95%, accounting for additional heat losses, which are variable and depend on the storage volume. The external insulation layer of the TTES is set at 300 mm. According to the Danish Energy Agency (2025a), the required storage size varies, but the typical size is 0.1 m³ of storage per m² of solar collectors. This means that a 10,000 m² solar thermal power plant requires at least 1,000 m³ of daily storage.

Table 9 presents the most important technical and economic parameters used to prepare the partial equilibrium economic model.

Table 9. Techno-economic parameters of TTES

	Parameters	Units	TTES
Techno-economic parameters	Efficiency	%	95–98
	Lifetime	years	40
	Construction time	years	0.5
	Investment costs	M EUR/GWh capacity	3.036
	Fixed costs	EUR/MWh	8.8
	Variable costs	EUR/MWh	0

Source: Created by the author based on Danish Technology Data catalogue for electricity and DH (Danish Energy Agency, 2025a)

2.2.12. Integrating seasonal heat storage with compression heat pumps

A potential option for a DH operator is to invest in seasonal PTES-type heat storage. This is a heat storage tank shaped as a truncated pyramid, installed underground. The tank design depends on its geometry, location, and the terrain. Usually, the walls of the storage facility are insulated to prevent heat from escaping and are lined with a waterproof geotextile polymer membrane. The tank is filled with water, where heat is accumulated, and it is covered by an upper insulating layer. It has two surface types: a floating surface and a solid base (soil or metal). In PTES-type storage tanks, the stored heat energy is between 60–80 kWh/m³ (Danish Energy Agency, 2025c).

It is assumed that the seasonal PTES-type storage should be installed next to existing heat energy production sources that can provide high-parameter surplus heat energy during the non-heating season. In this way, the seasonal storage would be charged to its maximum level during the non-heating season using surplus heat energy. In the intermediate period between gas-demand peaks and the non-heating season, the storage would be gradually charged to compensate for heat losses from the fully charged storage. When the heating season starts and gas boiler reserves begin to be used, the storage would be discharged at maximum capacity, thus covering or partially covering gas peaks. This operating principle would reduce natural gas consumption for heat production and increase the amount of green heat produced in the DH system.

During the heating season, the PTES storage facility becomes sufficiently discharged, and the temperature at the top of the storage facility reaches ~60–70°C, thus the heat storage facility starts to operate together with the compression heat pump, increasing the thermal energy potential to the temperature required for the heating network. In colder periods, when the air temperature remains below zero for a long time and the temperature of the upper layer of the storage tank reaches ~50°C or less, this storage system would only function via a heat pump (see *Fig. 16*).

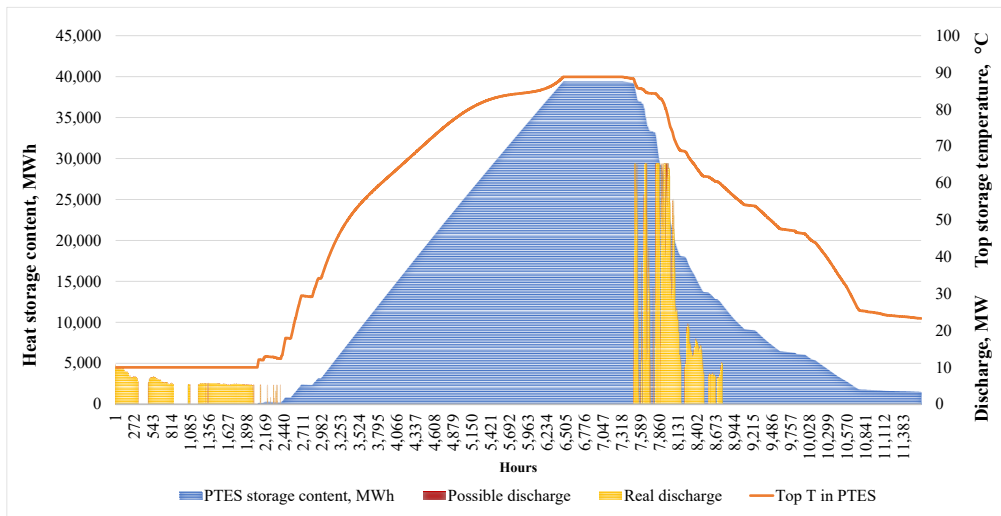


Fig. 16. Operating principle of PTES heat storage

Source: Created by the author

Considering the assumed operating principle of seasonal storage, the partial equilibrium economic model would also account for these essential technical and economic parameters (see *Table 10*).

Table 10. Techno-economic parameters of PTES seasonal heat storage with HPs

Indicator	Value	Assumption
PTES storage volume, m ³	[100,000–1,000,000]	Personal assumption
Useful PTES capacity volume, %	98	Assumption (Danish Energy Agency, 2025c)
Maximum temperature of storage, °C	90	Assumption based on the implemented storage capacities and technical properties of the materials (Danish Energy Agency, 2025c)
Bottom temperature of the storage tank in combination with a heat pump, °C	12	Assumption (Danish Energy Agency, 2025c)
Maximum discharge capacity, MW	[26–126]	Assumption based on an assessment of implemented storage capacities (Danish Energy Agency, 2025c)
Partial discharge capacity with HPs, MW	7	Assumption (Jensen, & Nielsen, 2014)
Thermal conductivity of cover insulation, (W/mK)	0.104	Assumption (Jensen, & Nielsen, 2014)

Cover insulation thickness, m	0.24	Assumption (Jensen, & Nielsen, 2014)
Conductivity of the bottom and sides of the tank (W/mk)	0.5	Assumption (Jensen, & Nielsen, 2014)
Thickness of insulation at the bottom and side walls of the tank, m	2	Assumption (Jensen, & Nielsen, 2014)
Soil temperature, °C	8	Assumption (Jensen, & Nielsen, 2014)
Heat pump efficiency coefficient, %	48	Assumption (Danish Energy Agency, 2025a)
Minimum heat pump performance COP	3	Assumption (Danish Energy Agency, 2025a)
Maximum heat pump operating temperature, °C	90	Assumption (Danish Energy Agency, 2025a)

Source: Created by the author

PTES-type storage technology offers significant economies of scale when larger storage tanks are installed. Based on completed PTES heat storage projects (Danish Energy Agency, 2025c), investment costs range from 24–86 EUR/m³, depending on storage volume.

To more accurately determine potential investments in PTES storage capacities, the model uses nonlinear regression. The resulting function is:

$$y = 15.5465 + \frac{2517298.3371}{x} \quad (5)$$

where y is investments in PTES heat storage (EUR/m³) and x is PTES heat storage volume (m³).

This relationship shows an approximate average investment value, allowing more accurate estimates than the scattered Danish technology data (Danish Energy Agency, 2025c) (see *Fig. 17*).

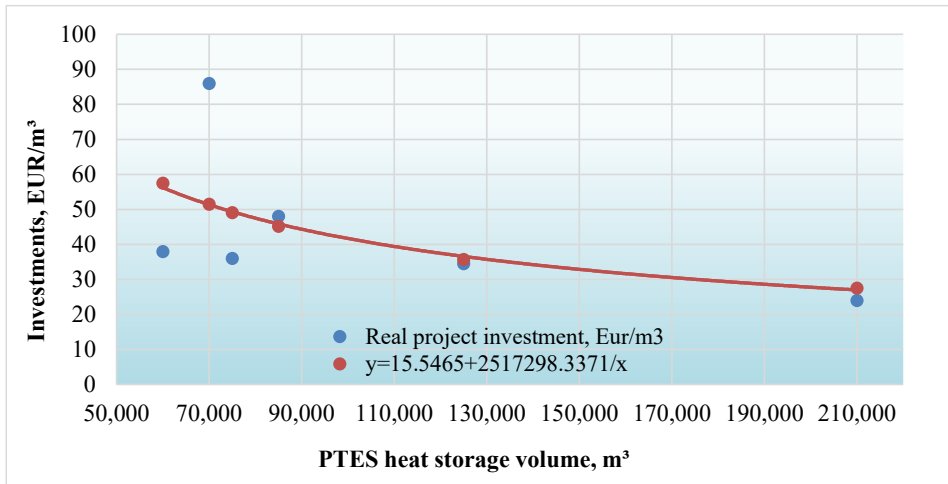


Fig 17. Nonlinear regression of potential investments in PTES heat storage capacities

Source: created by the author

The operating costs of PTES tanks and HPs are typically divided into fixed costs (costs that do not depend on production volumes or the number of operating hours) and variable costs (costs that depend on the amount of energy produced). The fixed costs of PTES capacity include valve inspections, leak repairs, and other minor defects. This is estimated at 3 EUR/MWh of capacity (Danish Energy Agency, 2025c). For compression heat pumps, fixed operating costs include regular maintenance. These fixed costs are typically 2,126.7 EUR/MW of heat (Danish Energy Agency, 2025a). It is assumed that variable costs of heat storage capacity are 0% of the supplied heat energy (Danish Energy Agency, 2025c). While, variable costs for the heat pump are 2.14 EUR/MWh of heat (Danish Energy Agency, 2025a).

2.2.13. Electric boilers

Electric boilers are a mature technology, offering almost 100% efficiency in converting electrical energy into heat. Although, from a thermodynamic perspective, this may seem like one of the least efficient methods of heat production, their ability to respond quickly to power system demands highlights their importance in system operation. Electric boiler construction is simple, ensuring high reliability and easy maintenance. In addition, due to minimal operating costs, these boilers can reach full power in just a few seconds, providing exceptional flexibility in managing electricity supply. Based on the Danish Energy Agency (2025a) catalogue *Generation of Electricity and District Heating*, assumptions are used to assess the economic and technical criteria of electric boilers (see Table 11).

Table 11. Techno-economic parameters of electric boilers

	Parameters	Units	Small boiler	Large boiler
Technical parameters	Efficiency	%	99	99
	Capacity	MW	[2]	[15]
	Lifetime	years	25	25
	Construction time	years	0.5	0.5
Economic parameters	Investment costs	EUR/MW	148,872	63,802
	Fixed costs	EUR/MW/year	1,084.6	1,084.6
	Variable costs	EUR/MWh	1.06	1.06

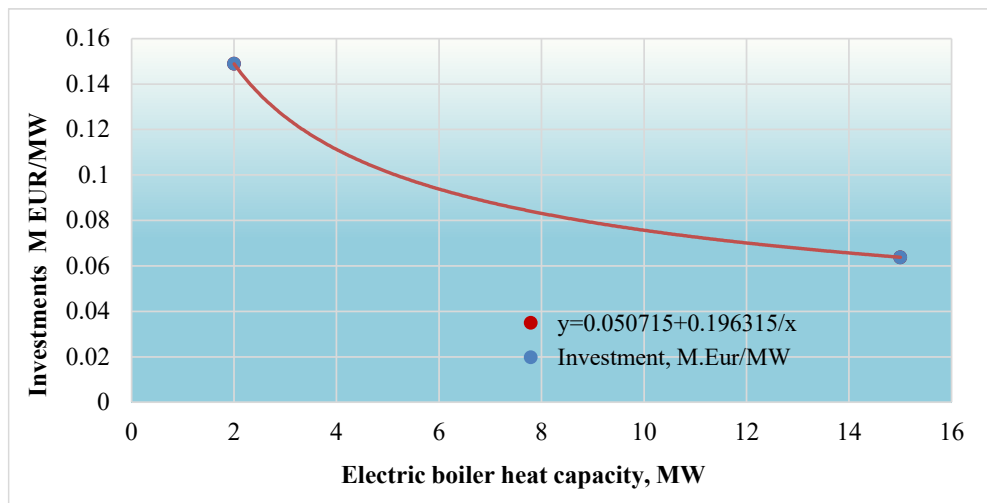
Source: Created by the author based on Danish Technology Data catalogue for electricity and DH (Danish Energy Agency, 2025a)

To more accurately identify potential investments for different sizes of electric boiler capacity, the model uses a nonlinear regression. The resulting function is as follows:

$$y = 0.050715 + \frac{0.196315}{x} \quad (6)$$

where y is investments (M EUR/MW) and x is electric boiler heat capacity (MW).

This function minimises quadratic deviation in the original y space and provides up to 0.0004% deviation compared with the Danish technology data (Danish Energy Agency, 2025a) (see *Fig. 18*).

**Fig. 18.** Nonlinear regression of potential investments in electric boiler capacities

Source: Created by the author

2.2.14. Assumptions on compression air-to-water type heat pumps

A compression heat pump is a heat transformation device that can transfer thermal energy from a lower-temperature source to a higher-temperature source by using an electric compressor and a closed thermodynamic cycle. Different gaseous or liquid streams can be used as the primary energy source (lower temperature). This section considers electrically powered compression heat pumps that use ambient air as a heat source as a potential investment alternative for DH operators.

In Scandinavian countries, this type of equipment has been used in DH systems. Heat pumps do not emit combustion products, which makes them more environmentally friendly and visually preferable. Additionally, heat pumps link heat and power supply systems, allowing participation in electricity market balancing mechanisms and helping stabilise the electricity grid.

Despite these advantages, compression heat pumps also have disadvantages, such as high initial investments, variable efficiency, and dependence on electricity prices. Therefore, they are primarily used to meet the base demand of the heat network. Their efficiency is directly dependent on the temperature difference between the low and high-temperature energy sources, which may limit their use under specific conditions, such as low ambient temperatures (Danish Energy Agency, 2025a).

2.2.14.1. Heat pump investment and operating costs

Heat pump technology can provide fully automatic operation, eliminating the need for regular on-call staff to maintain the equipment. To perform modelling in the partial equilibrium economic DH model, investment and operating costs are taken from the Danish Energy Agency catalogue (Danish Energy Agency, 2025a). Fixed costs are related to heat pump thermal output and are set at 2,126.75 EUR/MW/year. Variable operating costs are associated with heat production volumes and correspond to 1.8 EUR/MWh.

To more accurately identify potential investments in different sizes of compression heat pump capacity, the model applies a nonlinear regression. The resulting function is as follows:

$$y = 0.7158 + \frac{0.6903}{x} \quad (7)$$

where y is investments (M EUR/MW) and x is air-to-water type HP heat capacity (MW).

This function minimises quadratic deviation in the original y space and provides up to 3.4% deviation compared with the Danish technology data (Danish Energy Agency, 2025a) (see *Fig. 19*).

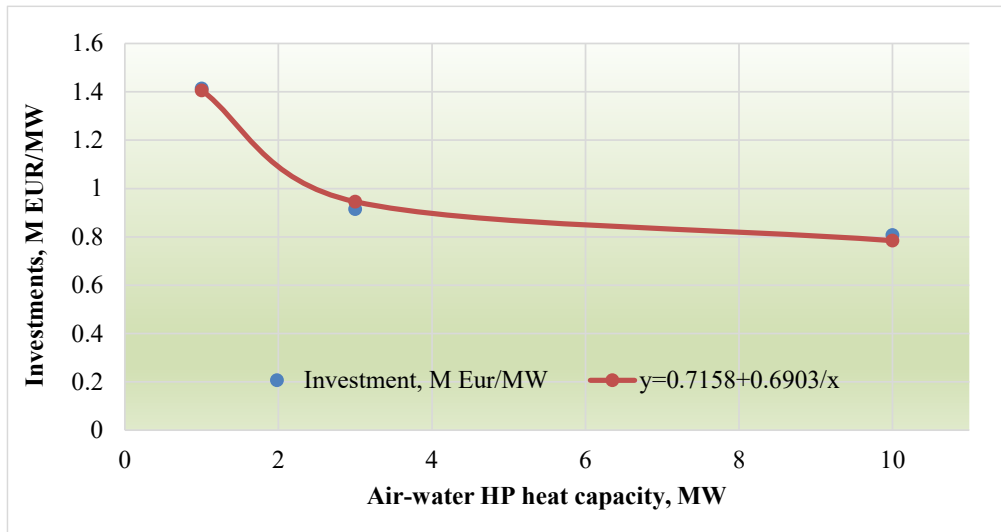


Fig 19. Nonlinear regression of potential investments in air-to-water HP capacities

Source: Created by the author

2.2.14.2. Heat pump efficiency characteristics

In an air-to-water HP system, one of the most important factors influencing HP operation and efficiency is the outside air temperature and the temperature of the heat-transfer fluid supplied to the system. During the summer (non-heating) season, outside air temperatures are higher, resulting in a smaller temperature difference between the cold and hot sides. Based on long-term temperature monitoring data, the outdoor air temperature during summer generally fluctuates between 14°C and 17°C and only occasionally reaches values close to 28–30°C. In contrast, at the beginning of the heating season, the outdoor air temperature drops to between 0–2°C and only rarely drops to -10°C or lower.

HP efficiency is primarily determined by the temperature difference it maintains. Specifically, a higher primary heat source temperature and a lower required outlet temperature reduce the thermodynamic work required to transfer heat, thereby increasing the system's coefficient of performance (COP). The theoretical value of the heat pump cycle efficiency, COP (the ratio of energy transferred to energy consumed), can be calculated using the Carnot or, more commonly, the Lorenz cycle. These cycles relate the work done (or efficiency) to the temperature difference. In the Lorenz cycle, the theoretical COP is calculated according to the following formulas (in °C):

$$COP_{Lorenz} = \frac{T_{lm\ hot}}{T_{lm\ hot} - T_{lm\ cold}} \quad (8)$$

where $T_{lm\ hot}$ is the logarithmic temperature difference on the hot side, and $T_{lm\ cold}$ is the logarithmic temperature on the cold side.

The logarithmic temperature difference is calculated using the following formula:

$$T_{lm} = \frac{T_{in} - T_{out}}{\ln\left(\frac{T_{in}}{T_{out}}\right)} \quad (9)$$

where T_{in} is the temperature of the flow entering the heat exchanger and T_{out} is the temperature of the flow leaving the heat exchanger.

Equations (8) and (9) are used to estimate the theoretical COP, which is based on the laws of physics. Theoretical efficiency is multiplied by the typical cycle efficiency to obtain real efficiency. Thus, the Lorenz cycle efficiency for heat pumps currently available on the market can vary from around 40% for small installations to almost 60% for large industrial HPs. This results in a difference between theoretical and actual efficiency, as the theoretical COP is multiplied by an efficiency factor that reflects the mechanical and thermal losses of the HP.

2.2.15. Assumptions on waste heat recovery from wastewater by integrating HPs

The main technical assumptions for investigating a wastewater compression HP are as follows:

- Temperature of treated wastewater to the evaporator (°C);
- Temperature of treated wastewater after the HP evaporator (°C);
- Treated wastewater flow rate to the HP (m³/h);
- Temperature of supply network water after the HP condenser (°C);
- Temperature of the return network water to the HP condenser (°C);
- Air temperature (°C); the model assumes the temperature for the selected region according to PVGIS data (Photovoltaic Geographical Information System, 2025).

It is assumed that the heat supplier would invest in new heat recovery solutions from treated wastewater by integrating compressor-based industrial HPs into the existing DH system. The primary energy source of the HP would be treated wastewater with an average temperature of 15°C. Optimal waste heat recovery would be achieved by lowering the temperature to 11°C (a temperature difference of 4°C). The waste heat would be recovered into the DH network via an HP condenser, warming the return network water from approximately 45°C to 85°C in the cold heating season. Based on energyPRO modelling and considering the temperature difference between the primary energy source and average supply network water temperature, the average annual COP is estimated at around 3.6 (see *Fig. 20*).

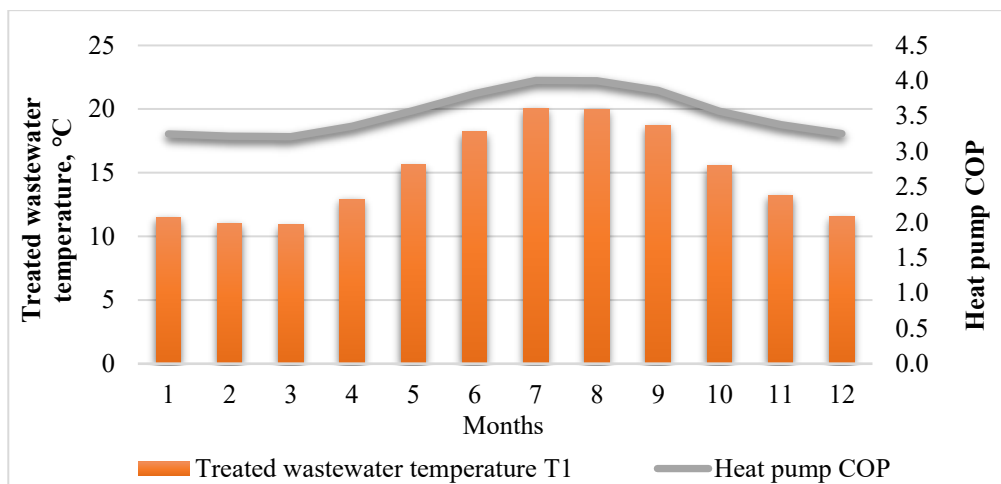


Fig. 20. Correlation between heat pump COP and treated wastewater temperature, °C

Source: Created by the author

The increase in treated wastewater temperature due to higher air temperatures during the warm summer period tends to raise HP efficiency. Correspondingly, during the colder heating season, lower air temperatures also decrease wastewater temperature, resulting in reduced efficiency.

To perform the modelling, investment and operating costs are taken from the Danish Energy Agency (2025a) catalogue *Technology Data for Generation of Electricity and District Heating*. Fixed costs are related to HP thermal output and are set at 2,126.75 EUR/MW/year. Variable operating costs are associated with heat production volumes and correspond to 2.33 EUR/MWh.

To more accurately determine potential investments in compression HPs of different sizes using treated wastewater as the primary heat source, practical assumptions are used, based on a 10-year investment plan for the development of the Vilnius DH sector (Vilnius DH Company, 2024). It is assumed that the total investment in installing a 1 MW thermal-capacity compression heat pump would amount to EUR 1.308 million.

2.2.16. Assumptions on Power-to-Hydrogen and Heat technology concept

Another key innovative solution from operator investment perspective is the Power-to-Hydrogen and Heat concept. It is assumed that a heat supplier could invest in renewable energy generation equipment: a PEM-type electrolyser to produce green hydrogen and industrial compression heat pump to recover waste heat from the electrolyser into the DH network. Customarily, the electrolysis process produces three possible products: oxygen, hydrogen, and waste heat. In this research context, it is assumed that additional equipment for oxygen production would not be included due to the high initial investment. The primary contribution of this technological solution to the heat auction system would be the recovery of waste heat from the electrolyser.

Considering the assumed efficiency of converting electricity to hydrogen via electrolysis, it should be emphasised that this may differ depending on the technology used. For instance, advanced alkaline electrolyzers (AEC) and PEM electrolyzers generally reach efficiencies of 60–75% for the conversion of electricity to hydrogen, depending on the lower heating value of hydrogen, while solid oxide electrolyzers can reach efficiencies of up to 80–90% under high-temperature operating conditions (IEA, 2019b). This research is based on Danish technology data for renewable fuels, which indicates that, using a PEM-type electrolyser, it is possible to extract 58.5% of renewable electricity input (Danish Energy Agency, 2025b).

A comprehensive study by the Danish Board of District Heating (DBDH, 2022) investigated energy losses and waste heat potential in electrolysis, focusing on alkaline (AEC) and PEM systems. The analysis indicates that 10% to 25% of the electrical energy input is lost as waste heat, which is typically of low quality (around 50–80°C). For example, a study in the *International Journal of Hydrogen Energy* on a 2.5 MW PEM electrolyser finds that approximately 20% of electricity is converted to heat at the start of operation (Van Der Roest et al., 2023); after 10 years, this increases to about 30% due to efficiency losses. The waste heat temperature is 57–62°C, corresponding to a low DH temperature class (Van Der Roest et al., 2023). According to DBDH (2022), electrolysis waste heat at 60–70°C may be suitable for DH. However, these temperatures may be insufficient for higher DH temperature regimes during the coldest periods (Bianco & Blanco, 2020). Danish technology data indicate that recovered heat temperature typically fluctuates around 50°C (Danish Energy Agency, 2025b). Therefore, this dissertation assumes that waste heat is approximately 50°C; to extract it and supply it to the heating system, a compression HP is required.

2.2.16.1. Investment costs

Potential investments in hydrogen electrolyser units are based on Danish technology data for renewable fuels (Danish Energy Agency, 2025b). A nonlinear regression is introduced and applied in the partial equilibrium model. The resulting function is as follows:

$$y = 0.6167 + \frac{3.3333}{x} \quad (10)$$

where y is investments (M EUR/MWe) and x is hydrogen electrolyser capacity (MW).

The red curve in *Fig. 21* illustrates intermediate investment points determined from expert estimates for 10 and 100 MW electrolyzers (Danish Energy Agency, 2025b).

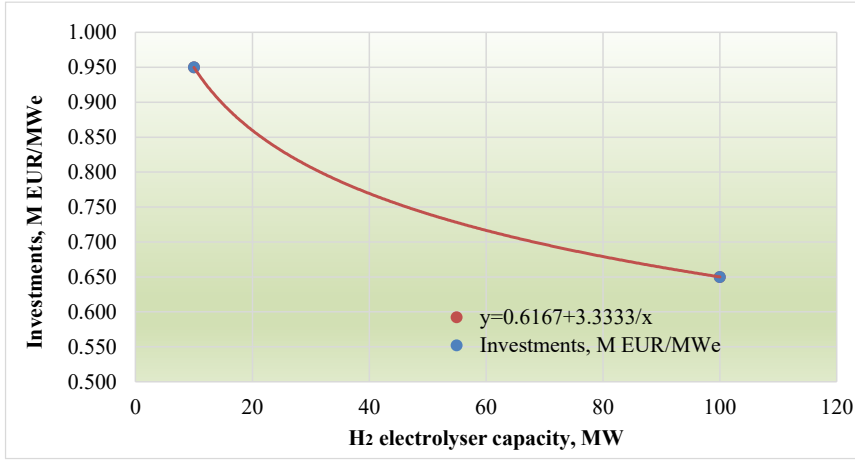


Fig 21. Nonlinear regression of potential investments in H₂ electrolyser capacities

Source: Created by the author

Potential investments in hydrogen electrolyser compression HP units are based on the Danish Energy Agency catalogue (Danish Energy Agency, 2025a). A nonlinear regression is introduced and applied in the partial equilibrium model. The resulting function is as follows:

$$y = 0.5608 + \frac{0.658605}{x} \quad (11)$$

where y is investments in HP capacity (M EUR/MW) and x is hydrogen electrolyser HP thermal capacity (MW).

The red curve in Fig. 22 illustrates intermediate investment points determined from expert estimates for 1 and 10 MW heat pump capacities (Danish Energy Agency, 2025b).

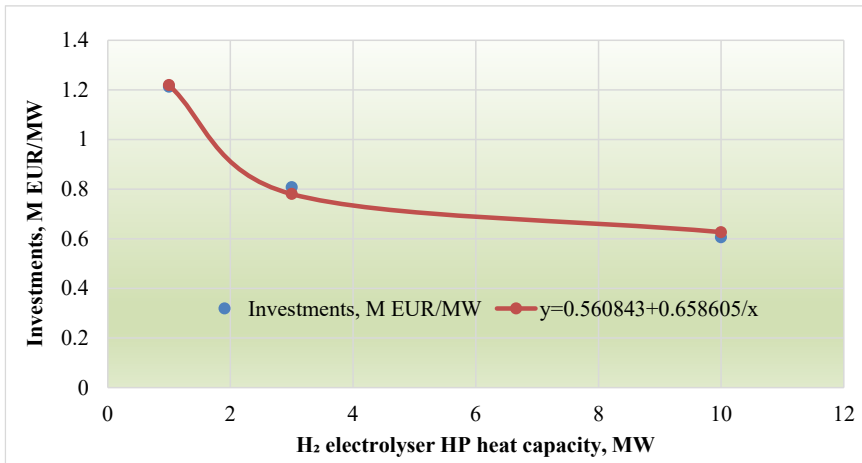


Fig 22. Nonlinear regression of potential investments in H₂ electrolyser heat pump capacities

Source: Created by the author

2.2.16.2. Operational costs

The economic model includes the essential costs for determining the marginal heat variable costs for the hydrogen electrolyser and heat pump. Based on Danish technology data for renewable fuels (Danish Energy Agency, 2025b), it is assumed that electricity consumption for hydrogen production is 1.709 MWh_e/MWh_{H₂}, or that 19.7 kg/h of hydrogen is produced from 1 MW of electricity generated by RES. Required water consumption is assumed to be 178 kg/1kWh_e, or 0.671 m³/MWh, for electrolyser waste heat. To identify total marginal variable costs, additional operation and maintenance costs for the HP are included.

It is assumed that fixed operating costs amount to 2% of the initial electrolyser investment, while variable H₂ operation and maintenance costs are 0 EUR/kWh (Danish Energy Agency, 2025b).

Fixed costs for the compression heat pump are set at 2126.75 EUR/MW/year. Variable operating costs for the heat pump are associated with heat production volumes and correspond to 2.14 EUR/MWh.

2.2.16.3. Revenues

In order to maximise investor profit, it is assumed that hydrogen and waste heat production would be organised using the spot electricity price. Cost volatility would be mitigated by green hydrogen production and sales, which would diversify risks when competing in the DH sector by selling waste heat in the auction system. This concept would generate income from two activities: waste heat and hydrogen sales. This technology investment enables greater financial potential to compete against other market participants in the DH system.

3. RESEARCH FINDINGS AND DISCUSSION OF THE IMPACT OF UNCERTAINTY FACTORS ON THE DISTRICT HEATING MARKET

3.1. Overview of the Selected District Heating System

To practically test the established partial equilibrium economic model, the Vilnius district heating (DH) system in Lithuania is selected. As the capital of Lithuania, Vilnius has the largest DH system in the country.

The integrated heat network of Vilnius comprises eight independent heat producers (IHPs) operating 10 individual heat generation sources that participate in heat auction (Baltpool, 2025a). According to personal communication with a DH operator, since autumn 2024, the total thermal capacity of all installations in Vilnius City has reached 1,417.6 MW. The main heat production capacities are located in the south-western part of the city. In the north, only the operator's district boiler house RK-8 is connected to the integrated DH network. RK-8 has an installed heat generation capacity of 495.44 MW; however, only 58 MW is active. The remaining capacity is reserved or has not been reconstructed to meet environmental requirements. All heat generation plants at RK-8 use natural gas. Based on the collected data and communication with the DH operator, *Table 12* is compiled to show all heat generation sources operating in the integrated network of Vilnius City.

Table 12. Data collection of heat generation facilities in the Vilnius DH network

Heat generation unit (Heat operator and IHP heat generation facilities)	Heat output of the installation, MW	Heat capacity from biofuel or waste, MW	Heat capacity from natural gas, MW	Potential additional capacity from natural gas, MW
IHP8 waste and bio CHPs	240.0	240.0		
Operator: Vilnius DH Company VE-2	892.1	80.8	811.3	116.0
Operator: Vilnius DH Company RK-8	58.0		58.0	407.0
Operator: Vilnius DH Company RK-7	40.7		40.7	-
IHP5 Grigeo	10.0	10.0		
IHP6 Vilniaus Baldai	4.5	4.5		
IHP3 GREN	20.8	20.8		
IHP7 1b Forest Investment	24.3	24.3		
IHP7 2b Forest Investment	24.3	24.3		
IHP2 1b IDEX	25.7	25.7		
IHP2 2b IDEX	25.7	25.7		
IHP1 Zietela	25.0	25.0		
IHP4 IDEX Pakalniškių	26.5	26.5		
Total:	1,417.6	507.6	910.0	523.0

Source: Created by the author according to personal communication data from Vilnius DH Company

The heat-generation capacity in Vilnius City totals 1,417.6 MW, including 507.6 MW from renewable energy sources (RES). This increase results from the implementation of a new biofuel combined heat and power (CHP) unit at the Vilnius CHP plant and the installation of a new absorption heat pump (HP) by the Vilnius DH Company to improve the efficiency of the biofuel steam boiler in 2024 (Vilnius DH Company, 2024; Baltpool, 2025a).

The primary analysis of the heat network demand in this dissertation uses actual heat demand data for the Vilnius city-integrated DH system from January 2019 to December 2021. Based on data provided by the system operator, the actual hourly demand is shown in *Fig. 23*.

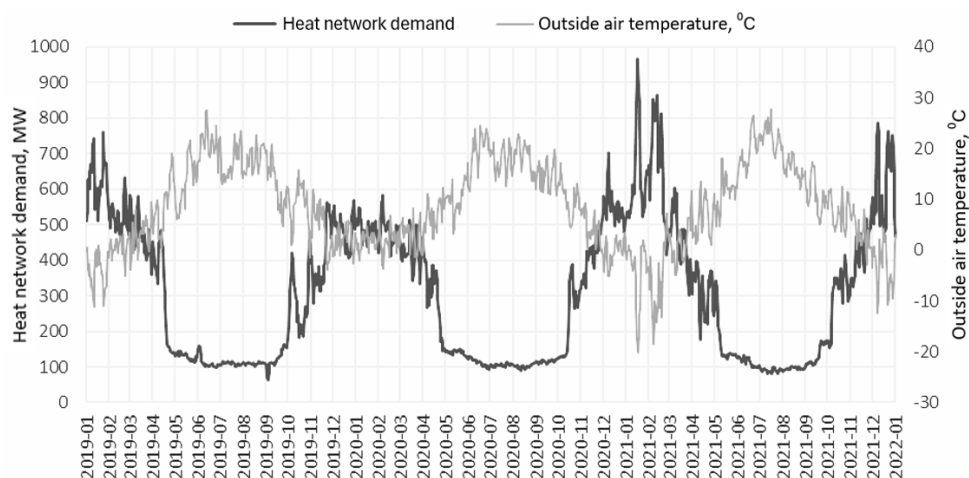


Fig. 23. Heat demand in Vilnius in the period 2019–2021

Source: Created by the author

Analysis of the actual data shows that the highest heat network demand of 999 MW was recorded on 16–17 January 2021. However, the maximum grid demand occurred when the outdoor air temperature was -20.2°C , whereas the design temperature for Vilnius City is -23°C on the coldest five days. Considering annual heat demand over the last five years, 2021 was selected as the year with the coldest weather conditions, reflecting the maximum heat demand of the existing DH system and serving as a reference year.

According to Vilnius DH Company's 10-year investment plan for the development of the DH sector (Vilnius DH Company, 2024), heat demand in 2030 is assumed to be 0.4–0.8% higher due potential growth in new heat consumers in urban areas, despite rapid renovation and improvements in building efficiency. Therefore, heat demand is expected to increase slightly based on hourly heat-demand data for 2021 (see *Fig. 24*).

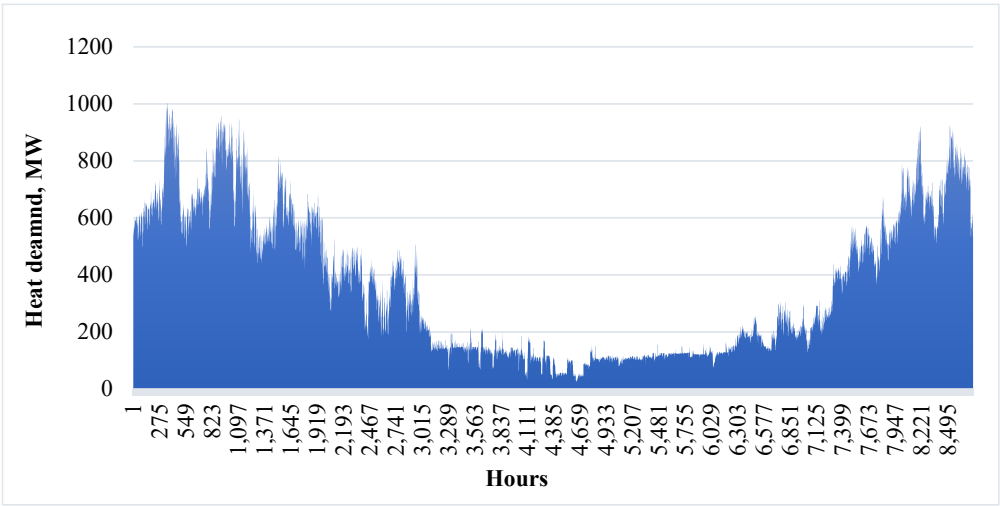


Fig. 24. Forecasted heat demand of the Vilnius DH system in 2030

Based on personal communication with the Vilnius DH Company, the average temperature of the heat network supply line is typically 72–75°C. The maximum temperature recorded in 2021 was 112.9°C, whereas the average temperature of the DH return water is approximately 46°C (see Fig. 25).

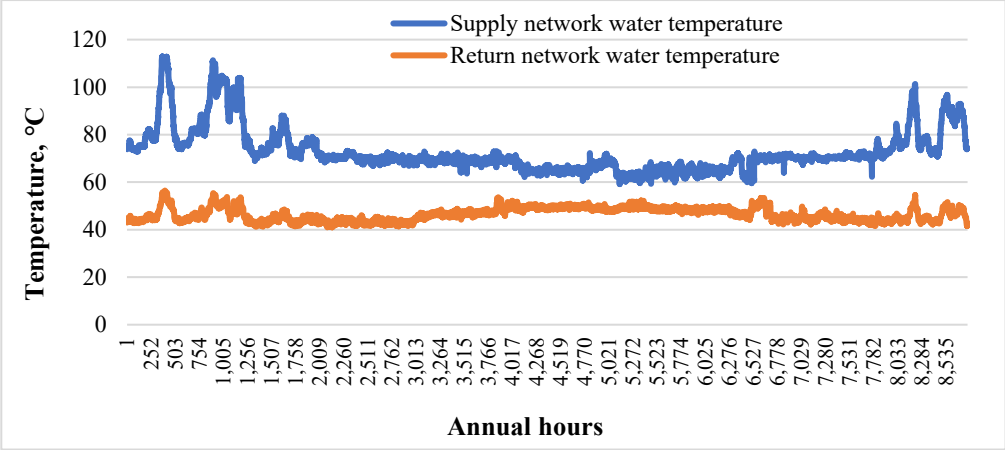


Fig 25. Temperatures of the supply and return network water in the Vilnius DH system

Source: Created by the author

To represent the current situation in the Vilnius DH market, key assumptions on energy source prices are selected. Electricity prices are modelled using hourly Nord Pool data for 2021 (Nord Pool, 2024) because prices in 2022 and 2023 were highly volatile. Biofuel, natural gas, and CO₂ prices are obtained from the National Energy Regulatory Council’s statistical information on the Vilnius DH system. Under these

assumptions, the current Vilnius DH system scenario is developed using a partial equilibrium economic model and verified with energyPRO analytic software for 2023.

Since autumn 2024, new heat generation sources have been incorporated into the Vilnius DH system, including the Vilnius biofuel cogeneration plant (thermal capacity 170 MW) and an absorption HP (thermal capacity 8.5 MW), implemented by the Vilnius DH Company to improve existing heat production facilities. Taking into account the volatility of energy price trends and increased renewable heat production from these new plants, demand coverage and heat production costs in the Vilnius DH system may differ. Therefore, it is essential to plan the economics of the Vilnius DH system for 2030.

3.2. Structure of Scenario Modelling for the Vilnius District Heating Market

The scenario implementation begins with the verification of the Vilnius DH system through the reference scenarios ‘Current 2023’ and ‘Current 2030’. To reflect the DH market structure prior to the latest heat production facilities (the Vilnius biofuel cogeneration power plant (170 MW thermal capacity) and the Vilnius DH system operator’s investment in absorption HP technology (8.5 MW thermal capacity) to modernise existing heat production facilities), the year 2023 was selected to verify the current market situation in the ‘Current 2023’ scenario.

The next phase presents the future prospects of the Vilnius DH system in 2030, expanded with newly built existing heat production sources: the Vilnius biofuel cogeneration plant and the absorption heat pump installed by the operator, representing the ‘Current 2030’ scenario. This scenario illustrates the possible future DH market situation without additional investments by the DH supplier and IHPs.

Considering the prospects for 2030, this dissertation evaluates four scenarios. The first (base) scenario represents a DH economic model that includes all new potential investments by the operator and IHPs. It considers uncontrollable uncertainty factors: electricity, biofuel, natural gas, CO₂, and H₂ prices, and controllable uncertainties, namely, new operator and IHP investments in heat production, flexibility, and storage facilities. A partial equilibrium economic DH model using an iterative approach is used to reflect the optimal development of the DH system (see *Fig. 26*).

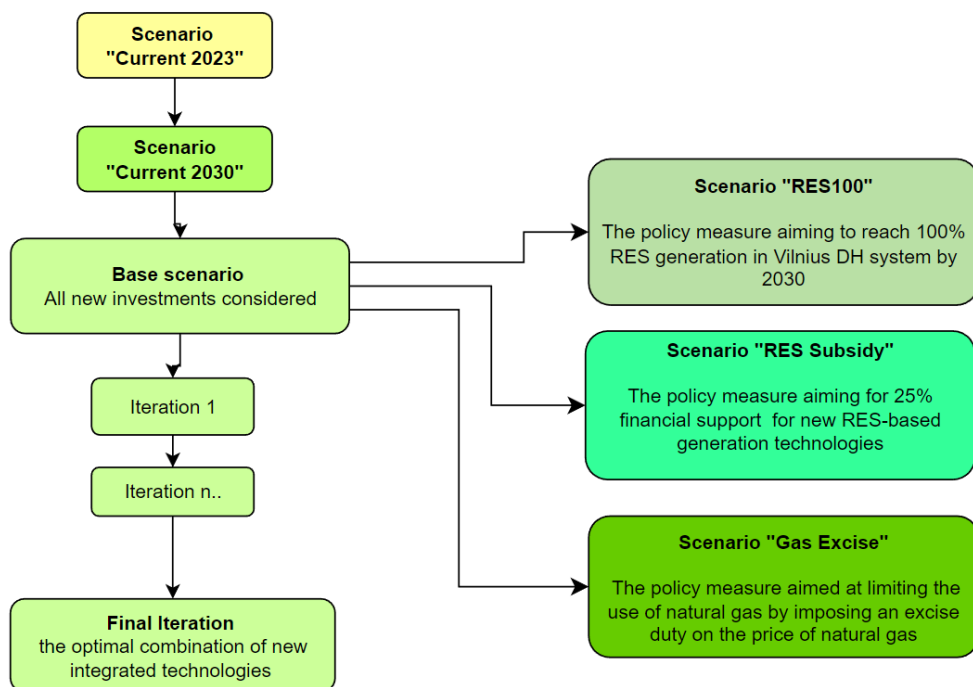


Fig. 26. Structure of scenario modelling

Source: Created by the author

The second scenario, ‘RES100’, represents a policy measure aimed at achieving 100% renewable energy production in the Vilnius DH system by 2030. This alternative prioritises investments under financial profit maximisation, ensuring that heat auction prices do not exceed 5% more than in ‘Current 2030’, under conditions of uncontrollable economic uncertainty, with the aim of eliminating fossil fuels in the DH system.

The third scenario, ‘RES Subsidy’, would be achieved by analysing potential financial support and incentives for new heat production and transformation facilities under financial profit maximisation, ensuring that heat auction prices do not exceed 5% more than ‘Current 2030’. It is assumed that new investments based on RES, except for biomass boilers, can be supported by subsidies of at least 25%. This scenario indicates how additional financial support could change total heat auction prices and helps identify the most financially profitable investments from the perspective of the operator and the IHP.

The fourth scenario, ‘Gas Excise’, considers a policy measure aimed at curtailing natural gas use by imposing an excise duty on the price of natural gas. It is assumed that the excise tax doubles the final price of natural gas. This scenario illustrates how existing and emerging generation sources, both those of the heat supplier and those of the IHP, behave in this changing market environment. It demonstrates the financially optimal portfolio under financial profit maximisation, while ensuring that heat auction prices do not exceed 5% more than ‘Current 2030’.

The additional scenarios ‘RES100’, ‘RES Subsidy’, and ‘Gas Excise’ reflect the assessment of semi-controllable uncertainties in modelling of development of the Vilnius DH system in 2030.

3.3. ‘Current 2023’ and ‘Current 2030’ Scenario Results

Based on the described methodology and data assumptions, the ‘Current 2023’ scenario is developed using a partial equilibrium model and is verified with the energyPRO analytical software to reflect the 2023 heat production costs of the Vilnius DH system. The ‘Current 2023’ scenario analysis covering technological aspects, efficiency indicators, variable marginal heat production costs, fixed heat production costs, and annualised investment costs for existing heat production facilities results in an estimate of heat production costs and the heat demand coverage among the operator and IHP generation sources. *Fig. 27* illustrates the 2023 heat demand coverage of the Vilnius DH network, excluding the most recently installed heat production sources: a 170 MW bio-CHP plant and the operator’s new 8.5 MW absorption HP unit.

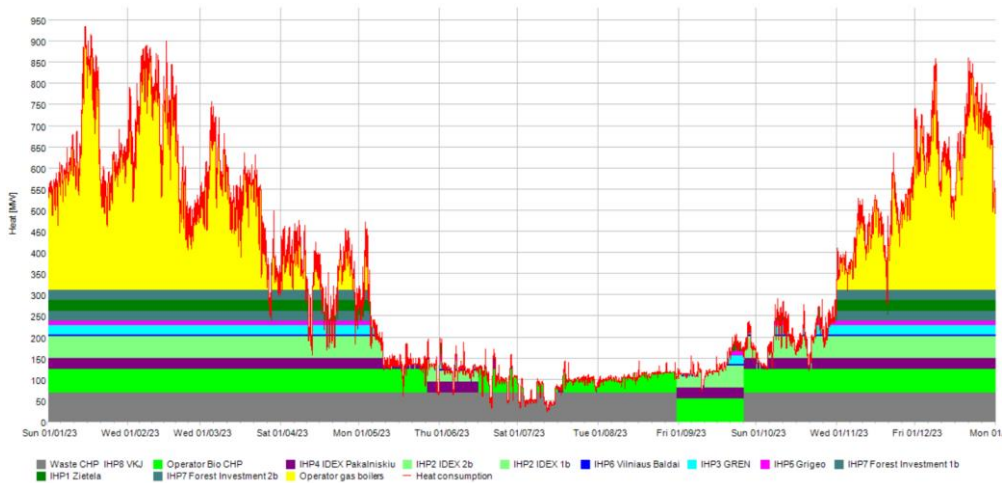


Fig. 27. Heat demand coverage of the Vilnius DH network in 2023

Based on this scenario, the share of heat demand met by natural gas-fired boilers remains at 34.8% (1,033,772 MWh) of total heat demand in the Vilnius DH network, with 224,171 tons of CO₂ in annual emissions. The remaining share is met by green IHPs and operator biofuel heat production facilities. The heat demand duration curve (see *Fig. 28*) and *Table 13* reveal that, in terms of marginal variable heat production costs, the waste cogeneration plant (IHP8) has the highest priority, followed by the operator biofuel cogeneration plant and other biofuel IHPs. Accordingly, the operator would use reserve natural gas boilers only during the coldest periods of the year.

Table 13. Market share of existing heat production facilities in the Vilnius DH system in 2023

Heat market participants	Heat production units	Fuel type	Heat production, MWh	Share in DH, %
IHP	Waste CHP IHP8	Waste	570,446	19.2
Operator	Operator bio CHP	Biofuel	437,184	14.7
IHP	IHP2 IDEX 2b	Biofuel	149,393	5.0
IHP	IHP2 IDEX 1b	Biofuel	151,519	5.1
IHP	IHP4 IDEX Pakalniškių	Biofuel	148,900	5.0
IHP	IHP6 Vilniaus Baldai	Biofuel	18,793	0.6
IHP	IHP5 Grigeo	Biofuel	47,523	1.6
IHP	IHP3 GREN	Biofuel	92,730	3.1
IHP	IHP7 Forest Investment 1b	Biofuel	110,173	3.7
IHP	IHP1 Zietela	Biofuel	107,470	3.6
IHP	IHP7 Forest Investment 2b	Biofuel	105,927	3.6
Operator	Operator Gas boilers	Natural gas	1,033,772	34.8

Source: Created and modelled by the author based on Baltpool and Vilnius DH Company data

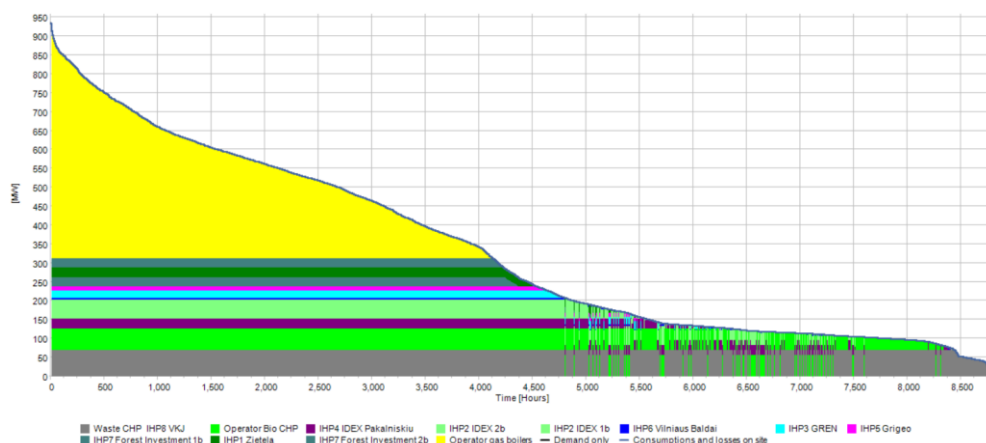


Fig. 28. Heat demand duration curve in 2023

After the ‘Current 2023’ scenario assessment and costs evaluation of each heat generation unit, the total cost of DH production in 2023 is estimated at around 50 EUR/MWh, based on the 2021 heat network demand (see Fig. 29). Considering the comparative heat production costs for Vilnius in 2023 (45–46 EUR/MWh) (National Energy Regulatory Council, 2025a), the final heat price for consumers (75 EUR/MWh), and the actual heat demand in 2023, the obtained results are assumed to be accurate and properly validated.

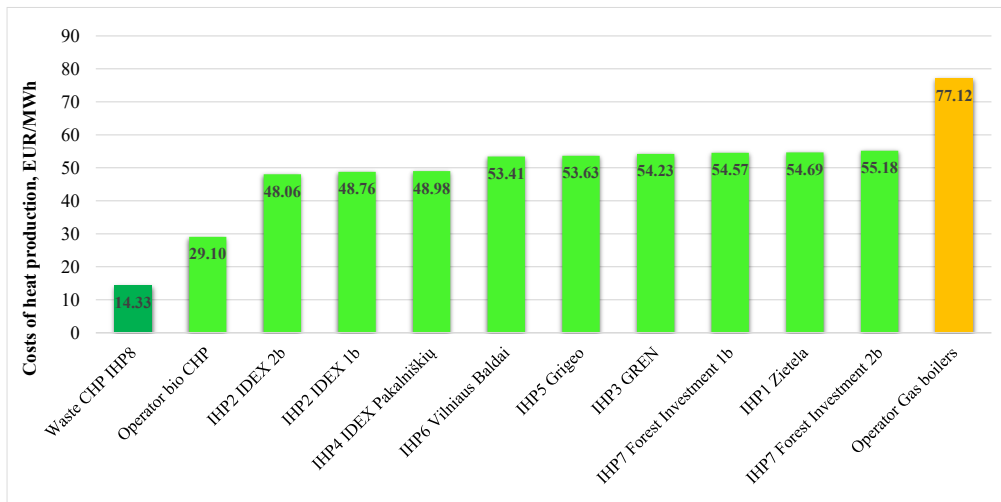


Fig. 29. Heat production costs by producers (EUR/MWh)

For 2030, the ‘Current 2030’ scenario is developed to represent the future Vilnius DH system using a partial equilibrium economic model and verified with the energyPRO software. The scenario demonstrates the DH market situation without any new potential market investments and indicates hourly heat demand coverage in the Vilnius DH network (see Fig. 30).

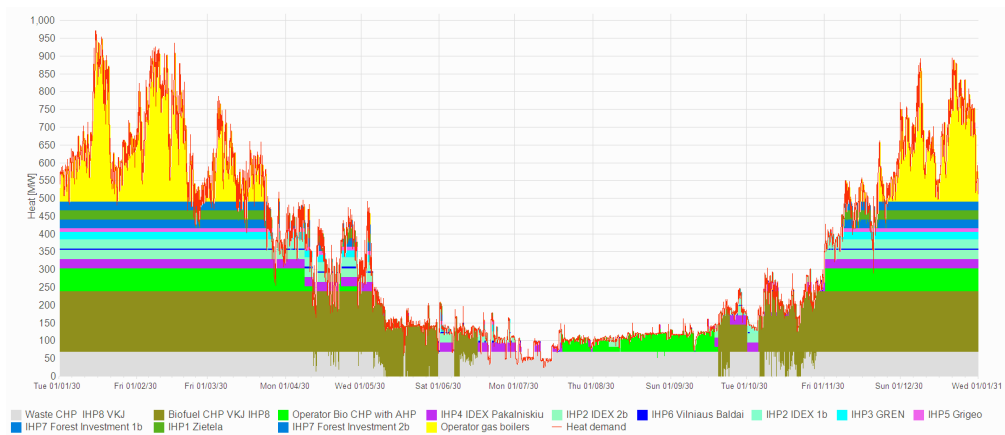


Fig. 30. Heat demand coverage of the Vilnius DH network by 2030

This scenario indicates that natural gas boilers would supply 15.7% (486,303 MWh) of total demand in the Vilnius DH system, and annual CO₂ emissions would total 105,453.8 tons. It also indicates that the new heat generation capacity would increase the share of RES in DH production to 84% through the integration of a 170 MW biofuel CHP plant and improved efficiency of the operator’s biofuel steam boiler via construction of an 8.5 MW absorption HP. Fig. 31 illustrates the heat demand

duration curve and highlights the baseload operation of the lowest-cost heat generation plants: the IHP8 waste-to-energy and biofuel CHP plant, and the operator biofuel CHP plant with an absorption HP.

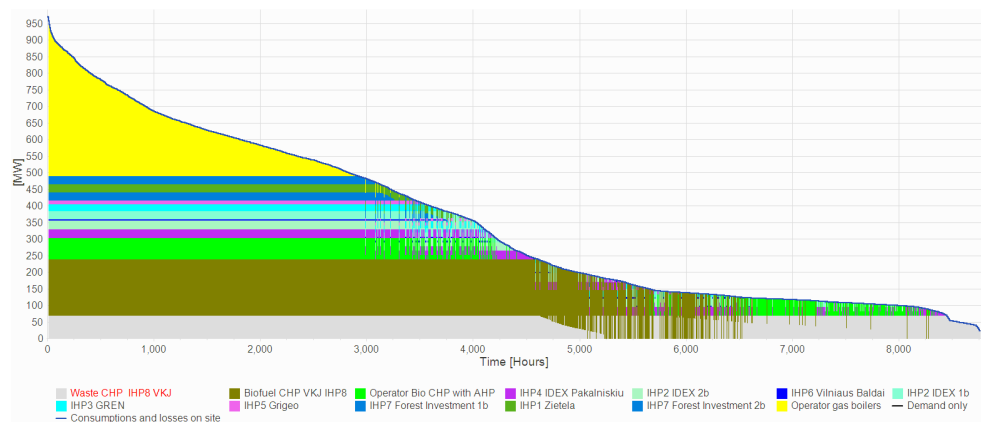


Fig. 31. Heat demand duration curve projected for 2030

Other IHP heat production facilities would constitute a smaller share of total heat demand coverage. It can be observed that the latest waste and biofuel CHP plant would foster stronger competition by reducing heat production quantities from other IHPs (see *Table 14*).

Table 14. Total share of heat production facilities in the Vilnius DH system by 2030

Heat market participants	Heat production units	Type of fuel	Heat production, MWh	Share in DH, %
IHP	Waste CHP IHP8	Waste	537,880.1	17.39
IHP	Biofuel CHP IHP8	Biofuel	1,001,888.3	32.40
Operator	Operator bio CHP with AHP	Biofuel	306,843.5	9.92
IHP	IHP4 IDEX Pakalniškių	Biofuel	142,017.3	4.59
IHP	IHP2 IDEX 1b	Biofuel	121,449.1	3.93
IHP	IHP2 IDEX 2b	Biofuel	112,760.5	3.65
IHP	IHP6 Vilniaus Baldai	Biofuel	17,005.0	0.55
IHP	IHP5 Grigeo	Biofuel	37,389.2	1.21
IHP	IHP3 GREN	Biofuel	81,036.7	2.62
IHP	IHP7 Forest Investment 1b	Biofuel	82,579.8	2.67
IHP	IHP7 Forest Investment 2b	Biofuel	76,727.9	2.48
IHP	IHP1 Zietela	Biofuel	88,829.9	2.87
Operator	Operator Gas boilers	Natural gas	486,303.2	15.72

Source: Created and modelled by the author based on Baltpool and Vilnius DH Company data

Based on the ‘Current 2030’ scenario and considering the heat production costs of each energy source, the average total heat production costs were estimated at 48.5 EUR/MWh under conditions of uncontrollable economic uncertainty (see Fig. 32). Heat auction price would fluctuate around 59.4 EUR/MWh, indicating that, under the stated assumptions, all market players would operate without financial loss.

It is also important to highlight the coefficient of variation, calculated as the ratio of the standard deviation to the mean, which indicates the relative dispersion of the data:

$$CV = \frac{s}{\mu} \cdot 100\% \quad (12)$$

where s is the standard deviation, and μ is the sample mean.

Total heat auction price and heat production costs in DH system would have coefficients of variation of 3.92% and 3.97%, respectively, indicating low dispersion and highly homogeneous data with little variation from the average.

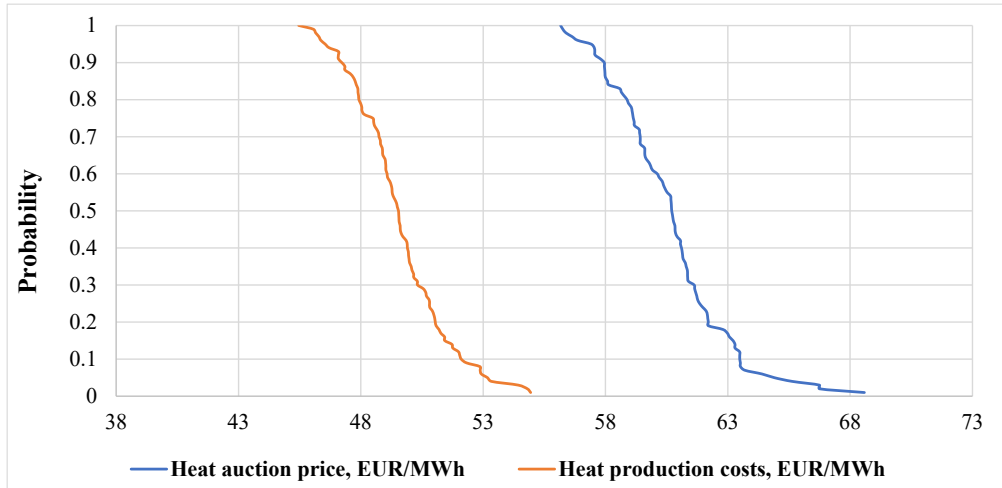


Fig. 32. Impact of uncontrollable uncertainty factors on heat auction and production costs in the Vilnius DH system

Without any new potential investments, the heat supplier’s total financial profit for the period up to 2030 could be around EUR 6.57 million, while IHPs operating existing heat production facilities could reach, on average, EUR 59.36 million (see Fig. 33). The coefficients of variation are 11.02% and 5.14%, respectively, indicating low dispersion and highly homogeneous data with little variation from the average.

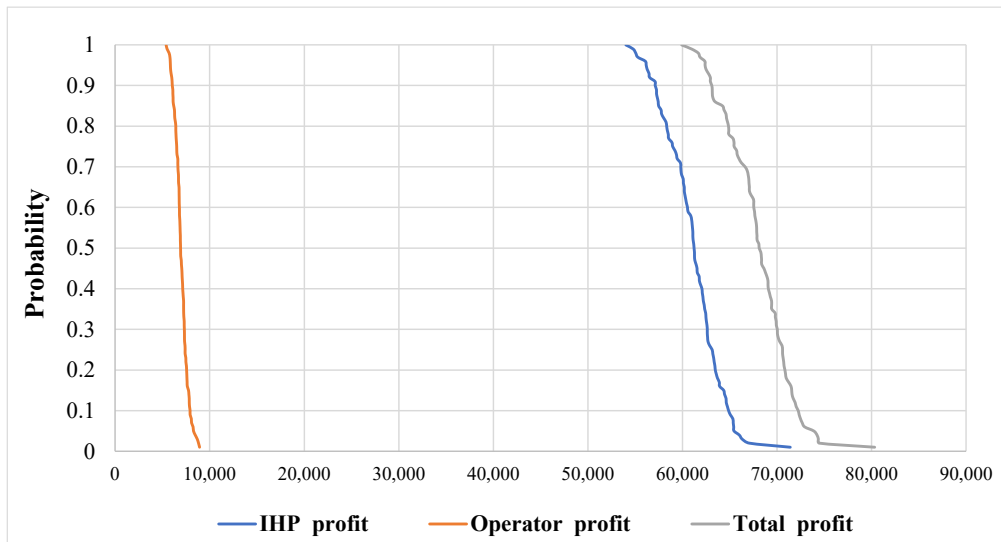


Fig 33. Impact of uncertainty factors on DH market players' profit (thousand EUR)

These results also suggest that local IHP heat production plants could generate 10 times more financial profit than the operator, who would receive profit from only a single biofuel cogeneration plant. Therefore, it is essential to explore potential investments in sustainable heat production and transformation technologies from the operator's perspective to maximise financial profit, strengthen competition in the local DH market, and reduce heat auction price, thereby contributing to the social welfare of heat consumers.

3.4. Characterisation of the Base Scenario

The base scenario comprises existing heat generation facilities (biofuel heat only boilers (HOBs) and CHP plants) and all possible new investments by the operator and IHPs in green energy production and utilisation technologies. Existing heat production infrastructure is primarily based on biomass water heating boilers and biofuel or waste cogeneration plants, while natural gas boilers are needed to meet heat demand only during the coldest periods of the heating season. Looking toward 2030, it is rational to have an appropriate mix of sustainable heat production technologies, with investments covered by operator or other market participants, to make viable choices that contribute to the objectives of the National Energy Strategy by reducing heat auction prices and production costs and phasing out fossil fuels across the heat market.

The base scenario serves as the reference point for all scenarios analysing the 2030 period. It includes existing and emerging market participants, energy price fluctuations, and operator investments in technology development, including the integration of wastewater recovery solutions, investments in biofuel HOBs, integration of solar thermal collectors with short-term storage, integration of flexibility solutions through investments in electric boilers, implementation of Power-to-Hydrogen and Heat solutions, incorporation of seasonal PTES heat storage, and Power-to-Heat solutions as sources of uncertainty.

This first baseline alternative incorporates potential operator investments in treated wastewater heat recovery solutions. The high potential of wastewater is highlighted in the 10-year investment plan for DH sector development (Vilnius DH Company, 2024). Realistic waste heat potential may be around 25 MW over the entire year, due to the constant variation in treated sewage flow of 4,500–5,500 m³/h. Assuming a 4–5°C temperature difference between inlet and outlet treated wastewater and an average heat network supply temperature of 74–75°C, the usable waste heat potential fluctuates from 20.93 MW to 31.98 MW, corresponding to heat production of around 26.75–40.86 MW with an integrated compression HP. Therefore, it is important to include this potential new market participant in the DH system and to investigate how this new generation facility would financially affect other IHP units, as well as the investor-operator itself, and how it would influence the auction and heat production costs across the DH system.

The base scenario also includes a solar thermal collector plant with short-term heat storage, which may be a feasible operator investment to reduce auction price and increase financial profit in the Vilnius DH system. Because the optimal capacity in developing such technologies is uncertain, the potential system-wide impact is assessed for operator investments in solar parks ranging from 10,000 to 1,000,000 m². It is assumed that the solar thermal park includes dedicated short-term thermal storage to utilise surplus heat from the collectors. The storage tank volume (m³) is assumed to be 0.1 of the solar park area (m²) (Danish Energy Agency, 2025a).

The analysis of the Power-to-Hydrogen and Heat concept is an innovative, high-importance solution from the operator's perspective. It is assumed that the heat supplier would invest in renewable energy generation equipment, including a PEM-type electrolyser to produce green hydrogen and an industrial compression heat pump to recover waste heat from the electrolyser into the DH network.

According to the official resolution of the Republic of Lithuania, *Regarding the Approval of the Lithuanian Hydrogen Development Guidelines for 2024–2050*, targets have been set for 2030 to install at least 1.3 GW of electrolysis capacity and produce at least 129,000 tons of green hydrogen annually (Lithuanian Energy Ministry, 2024). Assuming that 1.3 GW of electrolysis capacity must be installed, at least 2.22 GW of renewable electricity capacity is required, using an electrolysis conversion efficiency of 0.585. Potential waste heat generated during the electrolysis process can fluctuate between 444 and 666 MW, depending on the efficiency of the selected electrolyser type. Considering that Vilnius and the surrounding district might produce 70% of the potentially required hydrogen, waste heat therefore could fluctuate from 1 to 350 MW of thermal capacity, which could be used to model a base scenario for the Vilnius DH system.

From the operator's perspective, seasonal heat accumulation is also essential to reduce natural gas use during the coldest periods of the heating season. Seasonal thermal storage (PTES type) can be integrated with an industrial water-to-water type compression heat pump, which would increase the stored energy potential during cold periods. It is assumed that seasonal heat storage would operate in four main regimes. In the beginning, the PTES would be dedicated for the charging process, utilising all surplus renewable heat from existing heat production units. This charging and

accumulation process would continue for at least eight months, until the heat supply system reaches the peak period of fossil fuel use. Therefore, during the coldest periods of the heating season, the seasonal heat storage would be initiated in full discharge mode. After this discharge process, when the storage is partially depleted, and its temperature is below that required for the heat supply network, operation with partial use of a water-to-water type HP would be introduced. Eventually, when air temperature drops significantly below 0°C and the temperature of the upper storage tank layer drops to ~50°C or lower, the storage system would function only via an HP. Considering the uncertainty about the optimal size of the seasonal heat storage tank and its integration with an HP, this baseline scenario assumes that the operator would invest in a seasonal PTES storage tank with a volume in the range of 100,000 to 1,000,000 m³.

Another potential operator's decision is investment in flexibility technology through the installation of electric boilers. Electric boilers are a mature technology that can convert electricity into heat with nearly 100% efficiency. Although this is one of the least thermodynamically efficient ways to generate heat, the ability to respond quickly to system electricity demand underscores their importance in complex systems. In this scenario, electric boiler thermal output is set within an uncertainty range of 1–50 MW, reflecting uncertainty about the financially feasible option.

Compression air-to-water heat pumps may also be relevant in future DH systems. According to the International Energy Agency's (IEA, 2023c) report *The Future of Heat Pumps*, direct conversion of power to heat using industrial HPs provides high overall efficiency, making it a cost-effective and technically simple solution for DH systems. Therefore, this dissertation assumes that the operator might install and apply this technology within a thermal capacity range of 1–200 MW due to uncertainty about the financially feasible option.

Moreover, the development of new biofuel water-heating boilers is a reliable solution to reduce natural gas use across the Vilnius DH system. In this scenario, it is assumed that both the operator and IHPs might invest in this technology. To evaluate optimal capacity, uncertainty ranges of 1–60 MW of thermal capacity are analysed. In addition, this scenario is extended by incorporating accidental non-working hours for existing operator biofuel CHP and the newly built IHP waste and biofuel CHP plant. Each year, cogeneration plants are scheduled to shut down between 16 June and 28 July.

3.5. Base Scenario Results

3.5.1. Uncertainty factors analysis: Iteration 1

The base scenario model results for the Vilnius DH system allow a deeper investigation into the impact of uncertainty factors on operator and IHP total financial profit. The integration of new operator and IHP heat generation units into the Vilnius DH system indicates that the situation of IHPs becomes riskier due to potential financial losses (see *Fig. 34*). The results demonstrate that the new operator heat production infrastructure would negatively affect existing local heat producers (IHPs) with a 13% probability. Meanwhile, the operator position becomes slightly better, with

a 9% probability that the new heat generation facilities would negatively impact the heat supplier’s total financial profit.

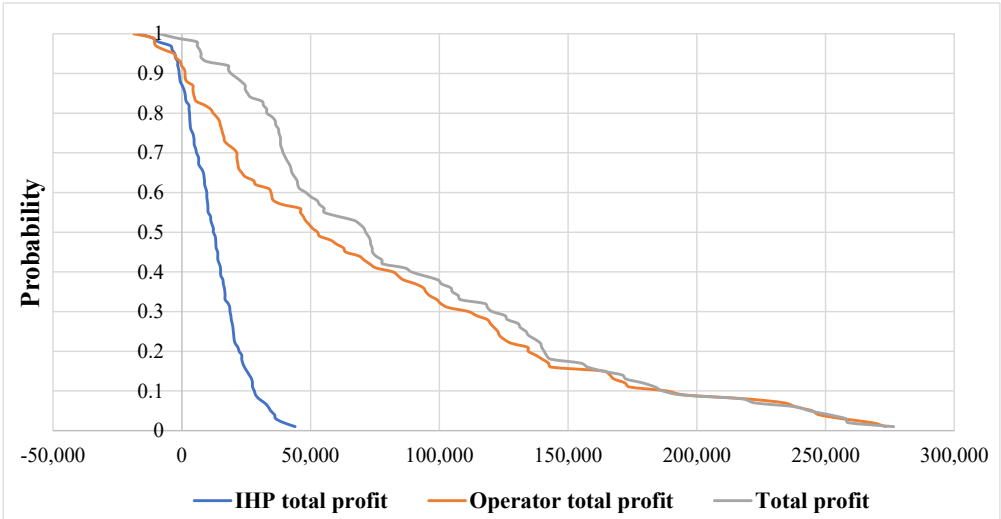


Fig. 34. Impact of uncertainty factors on DH market players’ profit (thousand EUR)

The analysis of the DH system indicates that the operator’s and IPHs potential new investments in new green production solutions would significantly reduce heat auction price by an average of 38.4 EUR/MWh (see Fig. 35). Following the possible investments in green heat facilities, heat production costs are estimated to fluctuate between 17.8 and 63.7 EUR/MWh, with an average of 38.74 EUR/MWh, reflected in a coefficient of variation of 25.98%.

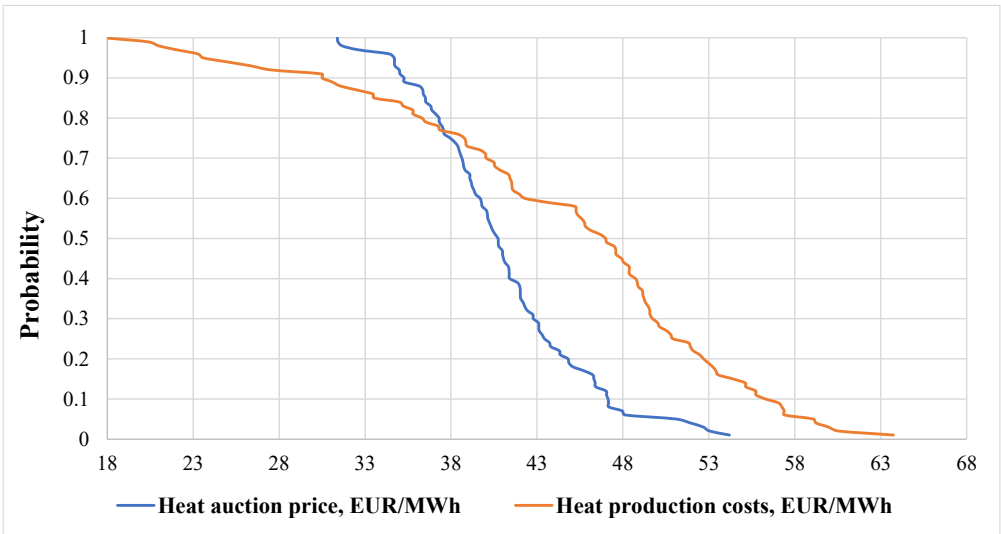


Fig. 35. Impact of uncertainty factors on heat auction and production costs in the Vilnius DH system

Additionally, assumptions regarding a high-capacity hydrogen electrolyser HP, integration of air-to-water compression HP, incorporation of flexibility technologies such as seasonal thermal storage and electric boilers, and expansion of solar parks have a large impact on reducing natural gas share across the DH system. The results indicate that, on average, the operator's gas boilers would supply only 1.19% of total heat demand (see *Fig. 36*).

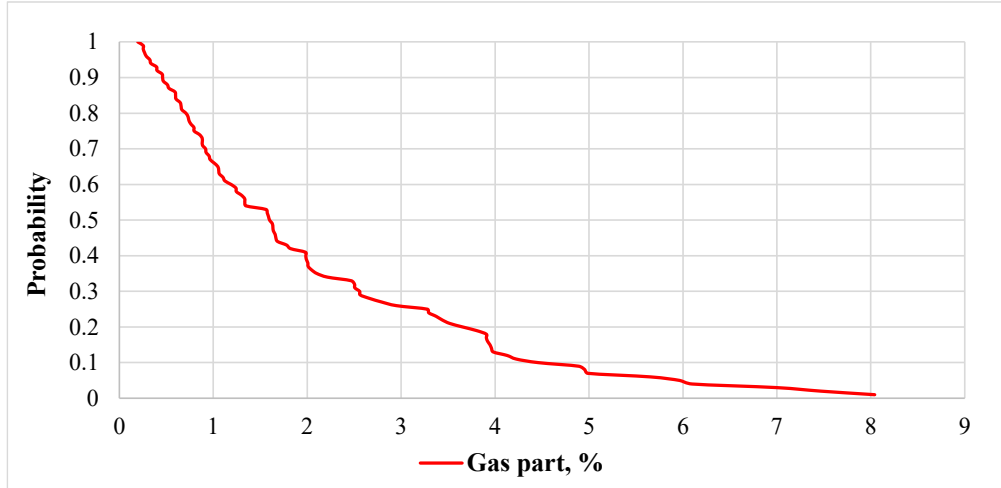


Fig. 36. Share of natural gas boilers in the DH system

Despite these initial results, the uncertainty analysis indicates the need to eliminate the riskiest and least promising investment opportunities that pose the greatest risk to investors.

3.5.1.1. Elimination of the riskiest and non-financially viable options from the model

Based on the uncertainty analysis of the first iteration and the defined scenario assessment methodology, the most financially risky potential investment options are identified and eliminated from further consideration. According to the modelling results presented in *Table 15*, the operator's potential investments in biofuel HOBs and seasonal PTES heat storage facilities are the riskiest and are not financially profitable (see *Fig. 37* and *Fig. 38*). It is assumed that these investments represent a 100% financial risk. Despite the high risk identified during the first stage of assessment, other potential investments are further investigated.

Table 15. Assessment of financial risks for controllable uncertainty factors

Controllable uncertainty factors	Uncertainty factors variability range	Assessment of the financial risk of potential investments, %
Wastewater HP	[26.75–40.86 MW]	88
Biofuel HOB IHP	[1–60 MW]	99
Biofuel HOB OP	[1–60 MW]	100
Solar collectors with TES	[10,000–1,000,000 m ²]	99
Electric boilers	[1–50 MW]	78
Power-to-H ₂ and Heat solutions	[1–350 MW]	3
Seasonal PTES heat storage	[100,000–1,000,000 m ³]	100
Air-to-water HP	[1–200MW]	55

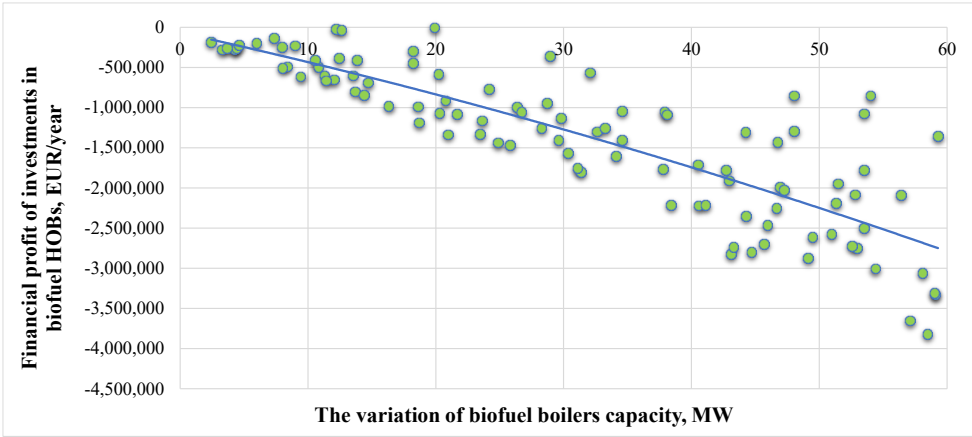


Fig. 37. The impact of biofuel HOBs capacity changes on operator investment profit

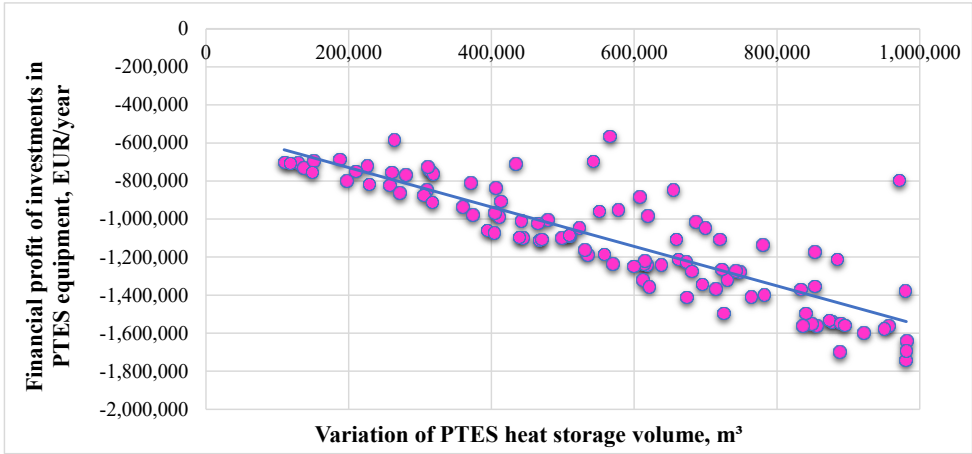


Fig. 38. The impact of PTES heat storage volume fluctuations on operator investment profit

3.5.2. Uncertainty factors analysis: Iteration 2

In the second iteration, the identified uncontrollable uncertainties remain based on the same assumptions for 2030, while only several controllable uncertainties: operator investments in biofuel HOBs and new PTES facilities, are removed from further modelling. Meanwhile, other controllable uncertainties remain unchanged for further investigation (see *Table 16*).

Table 16. Ranges of new uncertainty factors adjusted using the new identification method

Uncontrollable uncertainty factors	Ranges
Electricity price	50–70 EUR/MWh
Biofuel price	23–33 EUR/MWh
Natural gas price	44.76–54.76 EUR/MWh
CO ₂ price	55–130 EUR/t
Heat demand	0.4–0.8%
H ₂ price	3–6 EUR/Kg
Controllable uncertainty factors	Uncertainty factors variability range
Wastewater HP	[26.75–40.86 MW]
Biofuel HOB IHP	[1–60 MW]
Biofuel HOB OP	[0 MW]
Solar collectors with TES	[10,000–1,000,000 m ²]
Electric boilers	[1–50 MW]
Power-to-H ₂ and Heat solutions	[1–350 MW]
Seasonal PTES heat storage	[0 m ³]
Air-to-water HP	[1–200 MW]

The results show that operator investments in solar thermal collectors with short-term heat storage tanks and potential IHP in biofuel HOBs are not sufficiently financially viable (see *Fig. 39*).

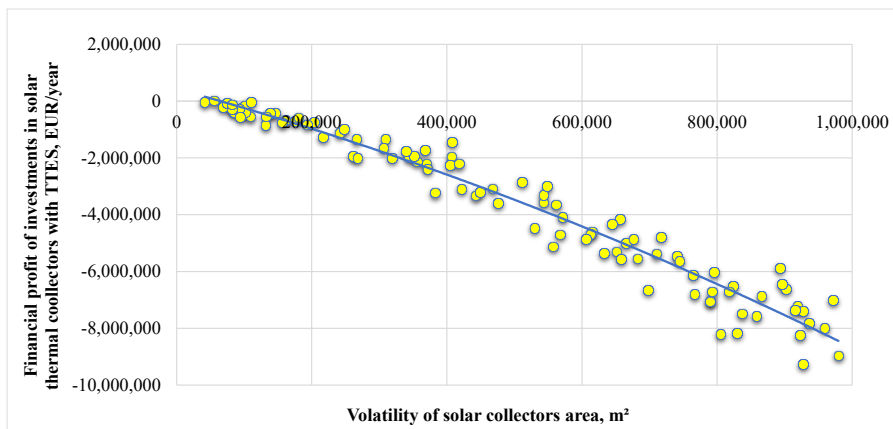


Fig. 39. Effect of solar collector area fluctuations on operator investment profit

The modelling results indicate that these potential investments are irrational and oversized in terms of maximising investor profits, reducing heat auction price and production costs (see Fig. 40).

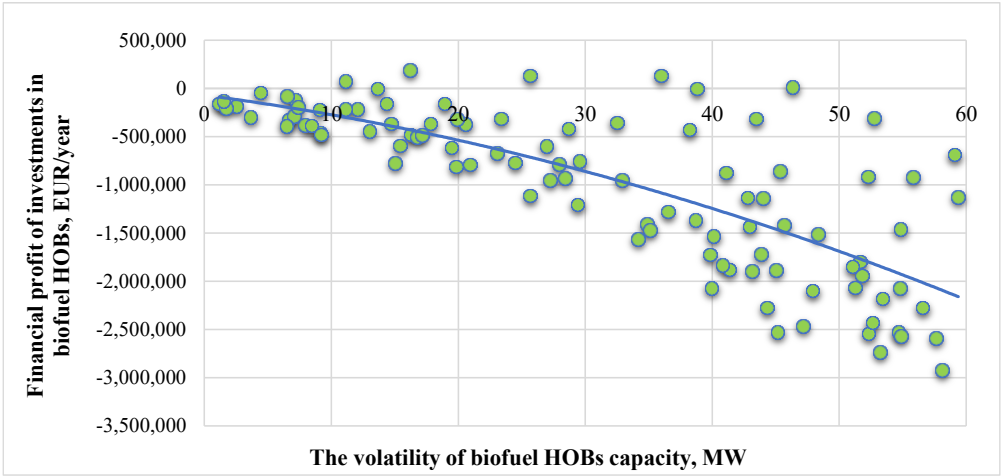


Fig. 40. Impact of biofuel HOBs capacity fluctuations on IHP investment profit

Therefore, in order to verify investment viability and identify options that yield the highest level of investor financial profit, the potential solar collector area can be reduced to 100,000 m², and possible IHP investments in biofuel boiler capacity can be minimised to 16 MW.

Conversely, results for the operator’s planned investment in a hydrogen electrolyser integrated with a heat recovery system (compression HPs) suggest that a capacity of up to 250 MW is sufficient (see Fig. 41).

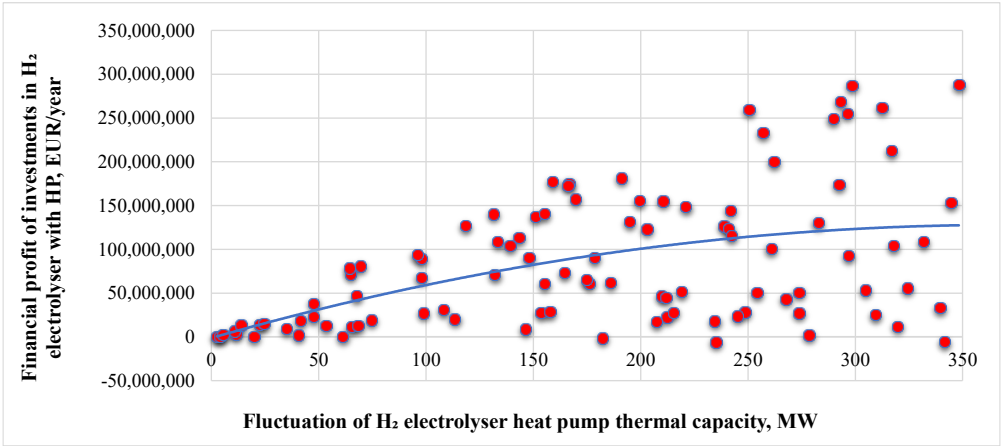


Fig. 41. Impact of H₂ electrolyser HP capacity fluctuations on operator investment profit

The analysis of the potential investment in an air-to-water compression HPs indicates that feasible operating conditions and financial profit may be achieved up to 100 MW (see Fig. 42).

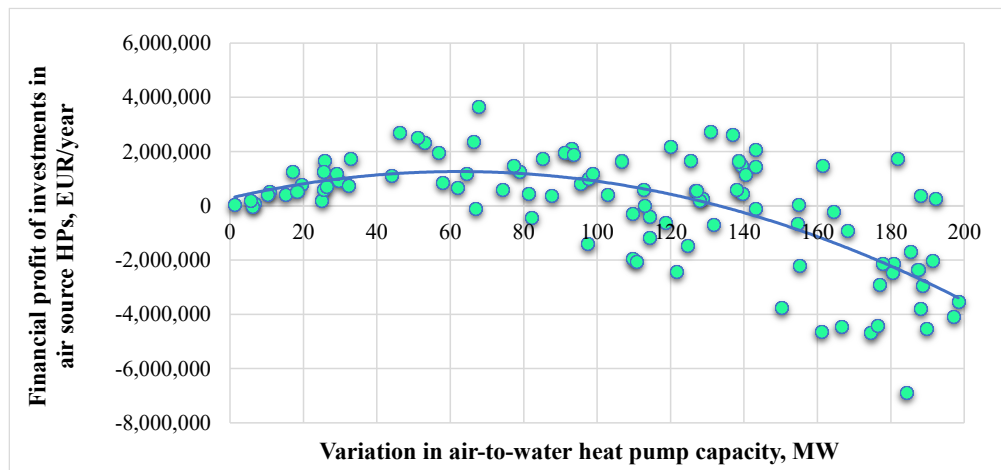


Fig. 42. Impact of air-to-water HP capacity fluctuations on operator investment profit

Accordingly, the results of the second iteration indicate that it is sufficient to invest up to 35 MW of electric boiler thermal capacity (see Fig. 43). This reduction is implemented to ensure that potential investments follow a non-declining trend and deliver the greatest possible financial benefit under anticipated uncertainties.

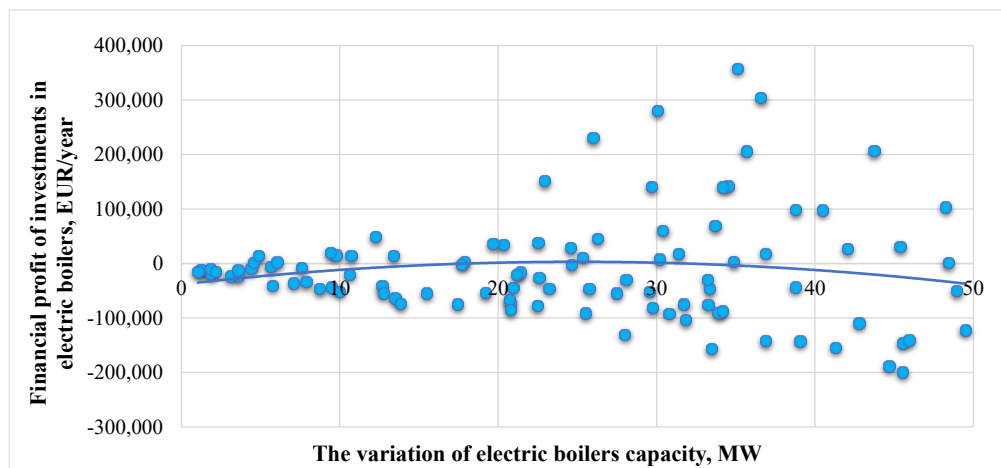


Fig. 43. Impact of electric boiler capacity fluctuations on operator investment profit

For the treated wastewater compression HP, no clear trend is identified; therefore, the capacity range is assumed to remain unchanged.

3.5.3.Uncertainty factors analysis: Iteration 3

The next iterative process is organised to maximise investor profits and reduce heat auction prices by narrowing investments in excess new heat production capacities. In the third iteration, uncontrollable uncertainties remain unchanged, while only controllable uncertainties are adjusted based on the second-iteration results (see *Table 17*).

Table 17. Ranges of new uncertainty factors adjusted using the new identification method

Controllable uncertainty factors	Uncertainty factors variability range
Wastewater HP	[26.75–40.86 MW]
Biofuel HOB IHP	[1–16 MW]
Biofuel HOB OP	[0 MW]
Solar collectors with TES	[10,000–100,000 m ²]
Electric boilers	[1–35 MW]
Power-to-H ₂ and Heat solutions	[1–250 MW]
Seasonal PTES heat storage	[0 m ³]
Air-to-water HP	[1–100 MW]

The results demonstrate that the operator would still overinvest in solar collectors with short-term heat storage due to high financial risks above 40,000 m². Therefore, further research could include additional iterations with variations smaller than 40,000 m² (see *Fig. 44*).

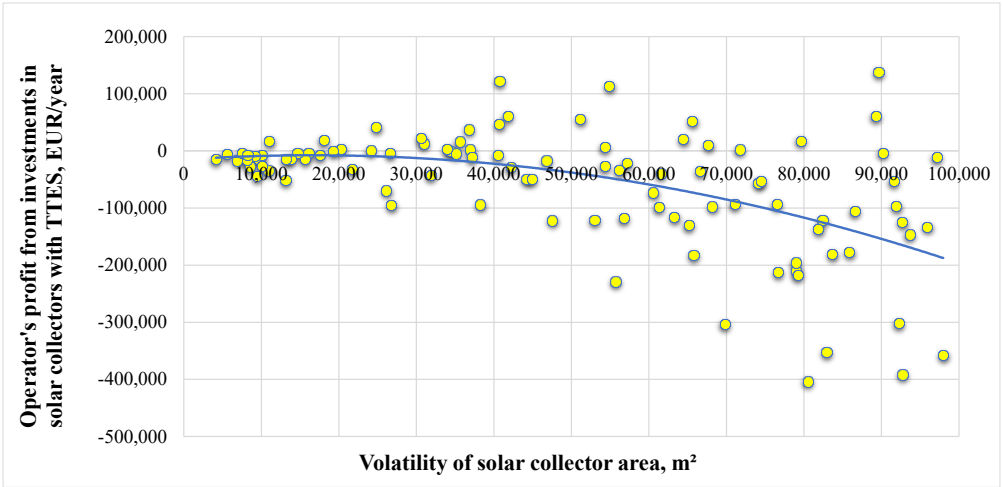


Fig. 44. Effect of solar collector area fluctuations on operator’s investment profit

Meanwhile, the third iteration results in a high proportion (88%) of potential IHP investments in biofuel HOBs being unprofitable (see *Fig. 45*).

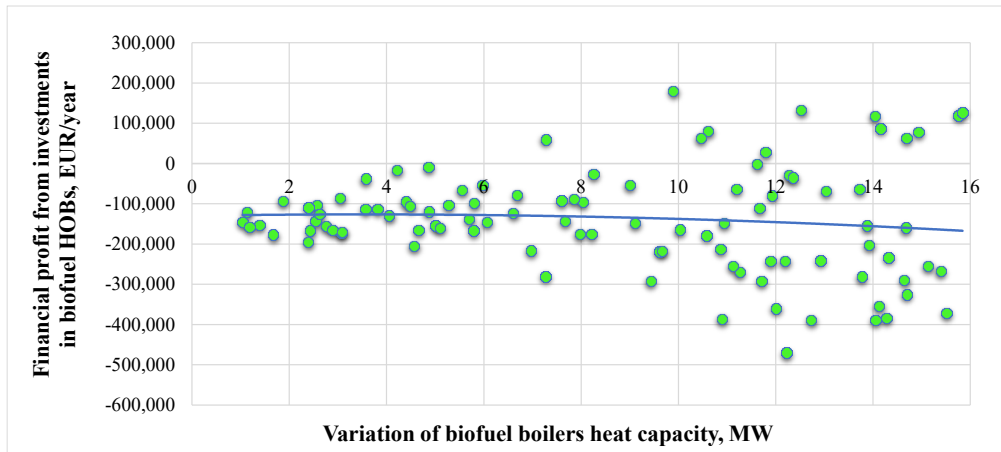


Fig 45. Impact of biofuel HOBs capacity fluctuations on IHP investment profit

Therefore, due to the high potential financial risk for IHPs, this investment is not considered for further investigation.

3.5.4. Uncertainty factors analysis: Iteration 4

The fourth iteration provides additional verification of a narrower investment range for solar thermal collectors, from 1,000 to 40,000 m². Other controllable and uncontrollable uncertainties remain unchanged for further investigation (see *Table 18*).

Table 18. Ranges of new uncertainty factors adjusted using the new identification method

Controllable uncertainty factors	Uncertainty factors variability range	Assessment of the financial risk of potential investments, %
Wastewater HP	[26.75–40.86 MW]	18
Biofuel HOB IHP	[0 MW]	0
Biofuel HOB OP	[0 MW]	0
Solar collectors with TES	[10,000–40,000 m ²]	75
Electric boilers	[1–35 MW]	17
Power-to-H ₂ and Heat solutions	[1–250 MW]	1
Seasonal PTES heat storage	[0 m ³]	0
Air-to-water HP	[1–100MW]	1

The financial risk assessment indicates that the operator would still face particularly high financial risk when investing in solar thermal collectors with short-term heat storage. In this iteration, potential investments in solar collectors are highly likely (75%) to remain unprofitable (see *Fig. 46*). This iteration also suggests that solar collectors are not sufficiently competitive compared with other existing and

future green heat production solutions, and are therefore eliminated under the scenario iteration evaluation rules, where investor risk exceeds 50%.

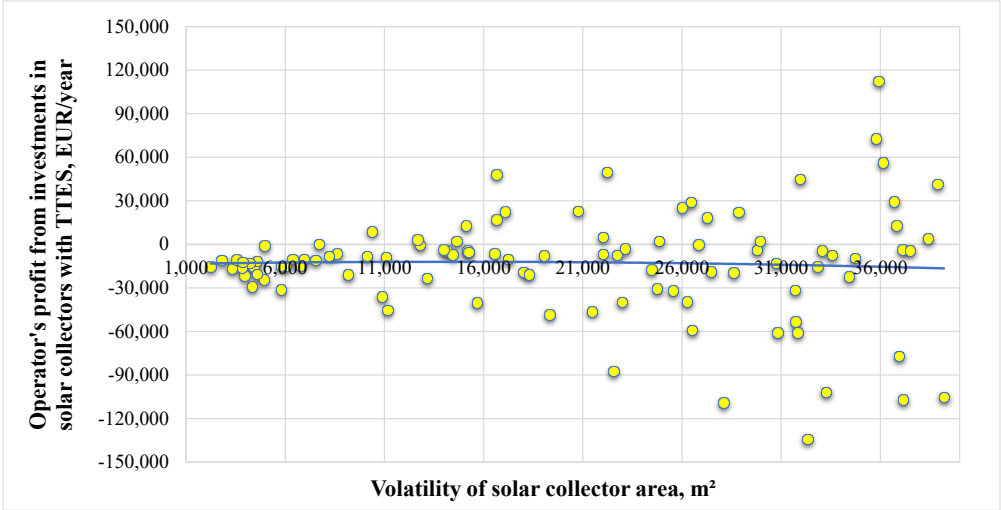


Fig. 46. Effect of solar collector area fluctuations on operator’s financial profit

3.5.5.Uncertainty factors analysis: Iteration 5

Recent decisions to eliminate financially risky alternatives enable identification of an optimal heat production portfolio for the operator’s potential investments, reduction of heat auction and production prices, and maximisation of the operator’s financial profit in the fifth iteration of the base scenario. Under the same uncontrollable uncertainties, the results indicate that the wastewater compression heat pumps, electric boilers, Power-to-Hydrogen and Heat solutions, and air-to-water compression heat pumps would be the most financially profitable options with the lowest investment risk (see *Table 19*).

Table 19. Ranges of new uncertainty factors adjusted using the new identification method

Controllable uncertainty factors	Uncertainty factors variability range	Assessment of the financial risk of potential investments, %
Wastewater HP	[26.75–40.86 MW]	18
Biofuel HOB IHP	[0 MW]	0
Biofuel HOB OP	[0 MW]	0
Solar collectors with TES	[0 m²]	0
Electric boilers	[1–35 MW]	17
Power-to-H ₂ and Heat solutions	[1–250 MW]	1
Seasonal PTES heat storage	[0 m³]	0
Air-to-water HP	[1–100 MW]	1

The partial equilibrium economic model of the Vilnius DH system enables a comprehensive analysis of uncertainty factors in assessing their impact on the total profit of the operator and IHP heat production facilities. Considering the final adjustments to controllable uncertainty factors and assessing the heat supplier's heat production facilities and total IHPs as two separate groups, the final iteration uncertainty analysis indicates a 100% probability of profitable operation (see Fig. 47).

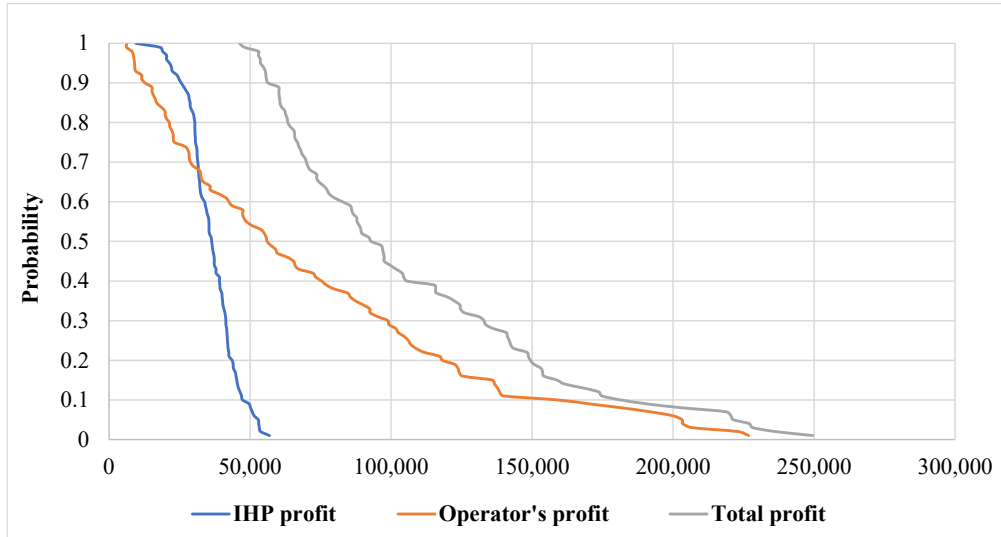


Fig. 47. Impact of uncertainty factors on total DH market players' financial profit (thousand EUR)

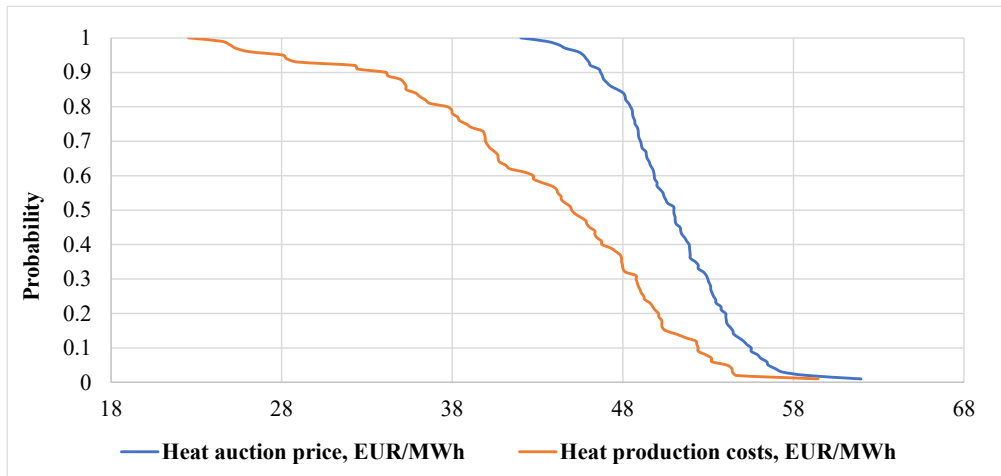
The fifth scenario also shows that in 2030, the operator's total financial profit would increase to an average of EUR 41.05 million, which is six times higher than projected in the 'Current 2030' scenario. However, the coefficient of variation would increase 12.5 times to 138.7%, indicating particularly high level of dispersion in the operator's total financial profit due to expanded competition in the common auction system with other market participants such as IHPs (see Table 20).

Meanwhile, the opposite trend would occur for IHP heat production sources. Total financial profit for existing and new IHPs would decrease by half to an average of EUR 31.45 million compared with the 'Current 2030' scenario. The coefficient of variation would be five times higher (reaching 28%), indicating an average level of dispersion in total IHP financial profit. This coefficient of variation indicates diverse economic uncertainties that drive fluctuations in financial profit due to potential new investments in green sustainable heat production and transformation solutions.

Table 20. Results of uncertainty analysis for iteration 5

Scenario	Strategy/priority	The optimal new investment portfolio by operator and IHPs	Total DH system heat auction price, EUR/MWh	Total DH system heat production costs, EUR/MWh	Total financial profit of operator, M EUR	Total financial profit of IHPs, M EUR	Nat. gas part in DH system, %
Base	All new investments considered	OP wastewater HPs [26.7–40.9 MW]; OP air-to-water HPs [1–100 MW]; OP H ₂ HPs [1–250 MW]; OP el. boilers [1–35MW];	$\mu = 49.02$ EUR/MWh CV = 7.07 %	$\mu = 39.16$ EUR/MWh CV = 19.85 %	$\mu = 41.05$ CV = 138.7 %	$\mu = 31.45$ CV = 28 %	$\mu = 5.46$ CV = 37.5 %

The final iteration also reveals that new operator investments could reduce the total heat auction price by an average of 49.02 EUR/MWh, with a coefficient of variation of 7% (see *Fig. 48*). This coefficient indicates that the obtained auction price is reliable and homogeneous under the assumed uncertainties. The heat production costs are estimated to fluctuate between 22.5 and 59.4 EUR/MWh, with an average of 39.16 EUR/MWh, reflected in a coefficient of variation of 19.85%. Uncertainty analysis demonstrates that heat production costs may fluctuate within wider ranges but remain below the price of the heat auction.

**Fig. 48.** Impact of uncertainty factors on heat auction and production costs in the Vilnius DH system

The uncertainty analysis also reveals that the operator's gas-fired boilers would supply, on average, only 5.46% of total heat demand (see Fig. 49).

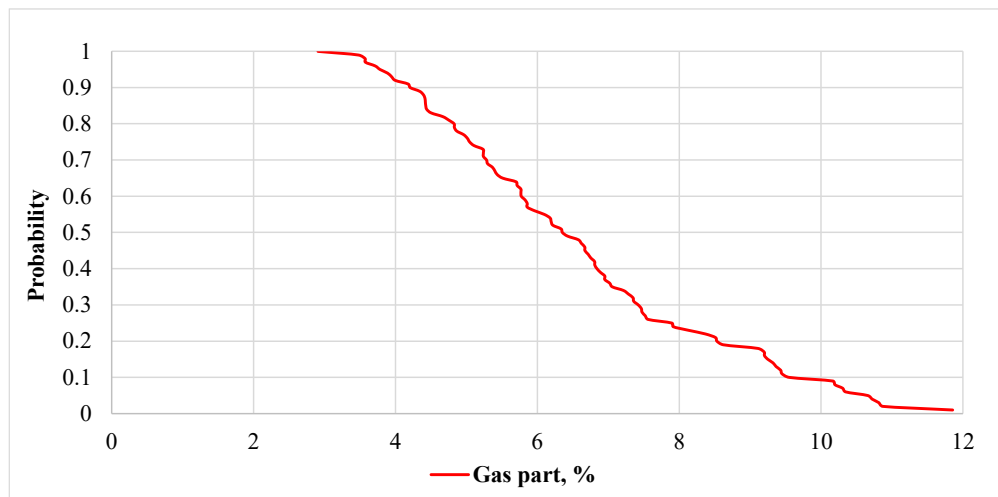


Fig. 49. Share of natural gas boilers in the DH system

Despite substantial potential operator investments, modelling for 2030 still requires fossil fuel heat production facilities during the coldest hours due to an insufficient production portfolio for peak regimes. Therefore, the share of natural gas does not reach 0% under the assumed uncontrollable and controllable uncertainties.

3.5.5.1. SPEA correlation sensitivity analysis: Iteration 5

The Spearman correlation coefficient (SPEA) used in the Monte Carlo sensitivity and uncertainty analysis identifies which uncertainty factors have the greatest impact on model outputs. The correlation analysis demonstrates the effects of uncontrollable factors: electricity, biofuel, natural gas prices, hydrogen prices, CO₂ prices, and heat demand, and controllable factors, such as operator investments in waste heat recovery capacity, flexibility solutions, and other green heat production technologies, on the selected partial equilibrium model results. The results indicate that the largest impact on reducing heat auction price stems from operator investments in a PEM-type electrolyser with compression HP for recovering waste heat from the electrolyser and air-to-water compression HP, with correlation values (-0.59) and (-0.44), respectively (see Fig. 50).

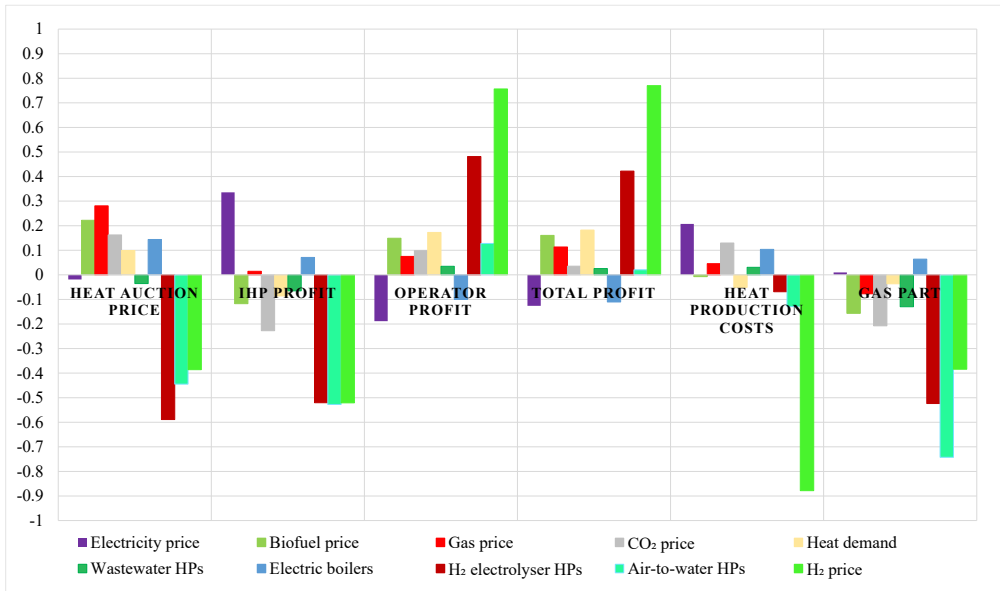


Fig. 50. Impact of uncertainty factors on modelling results using the SPEA correlation

Potential operator investments in a 200–250 MW electrolyser with a HPs would enable a heat auction price of 49 EUR/MWh to be reached in the DH system (see Fig. 51). In addition, the results show that achieving a heat auction price of 49 EUR/MWh would require an installation of 80–100 MW of air-to-water heat pumps (see Fig. 52). In contrast, the strongest direct correlation is between biofuel and gas prices, and higher heat auction prices are associated with an increase in both prices.

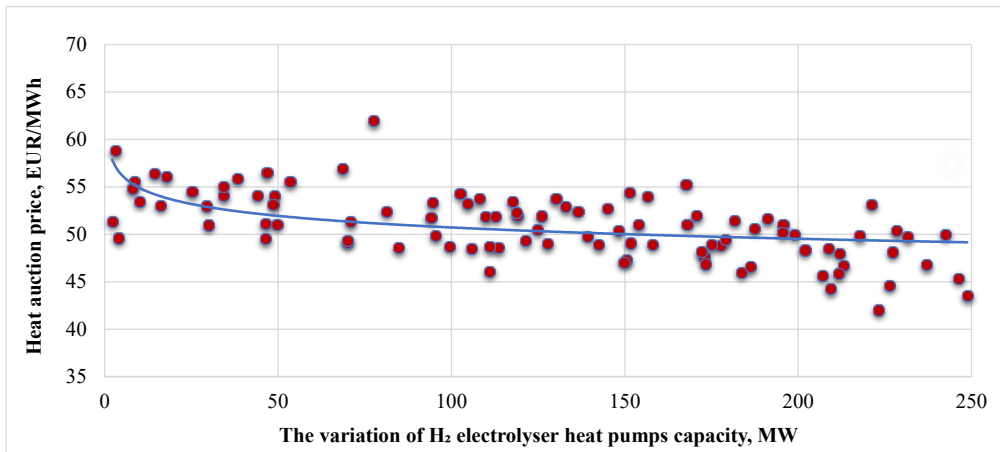


Fig. 51. Impact of H₂ electrolyser HPs capacity variation on DH system heat auction price

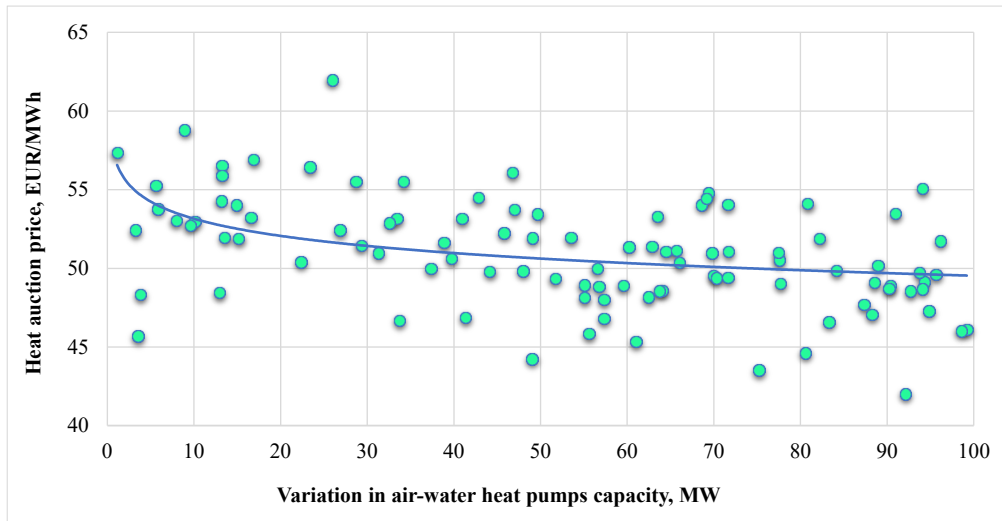


Fig. 52. Impact of air-to-water HPs capacity variation on DH system heat auction price

As shown in *Fig. 51*, the large amount of waste heat from the hydrogen electrolyser, high-capacity industrial air-to-water HPs, and installation of new wastewater HP units negatively affect existing IHP facilities and reduce financial profit due to lower heat production and significantly higher heat production costs in boiler plants. The results indicate that using air-to-water HPs with a thermal capacity of 80–100 MW would most reduce the total financial profit of all IHP plants, including the largest biofuel CHP plants, by 1.5 times (see *Fig. 53*). A similar trend is observed for potential investments in hydrogen electrolyser HP facilities.

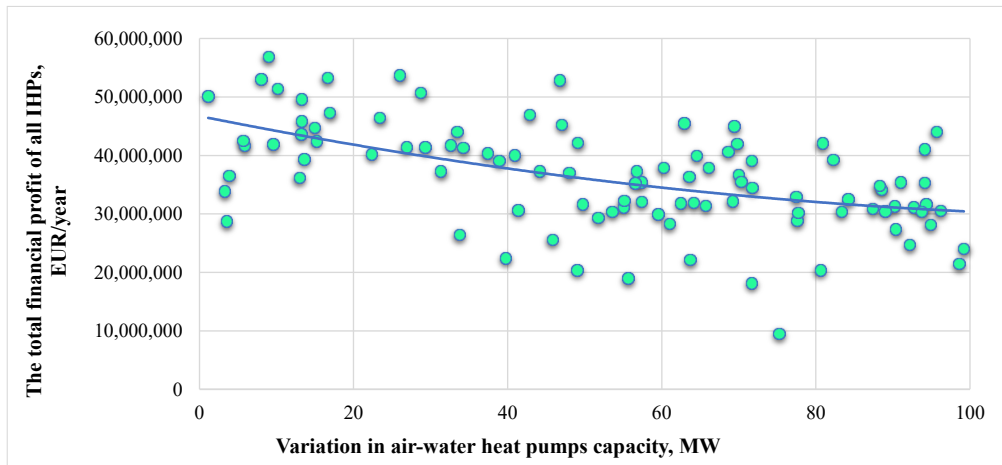


Fig. 53. Impact of air-to-water HPs capacity variation on total IHPs financial profit

Projected electricity prices of 50–70 EUR/MWh increase IHPs financial profit due to the ability to produce electricity flexibly during more expensive periods, using

existing large cogeneration capacities. Future fluctuations in hydrogen prices may negatively affect existing IHP facilities and, conversely, positively affect operator's financial profit (see Fig. 54).

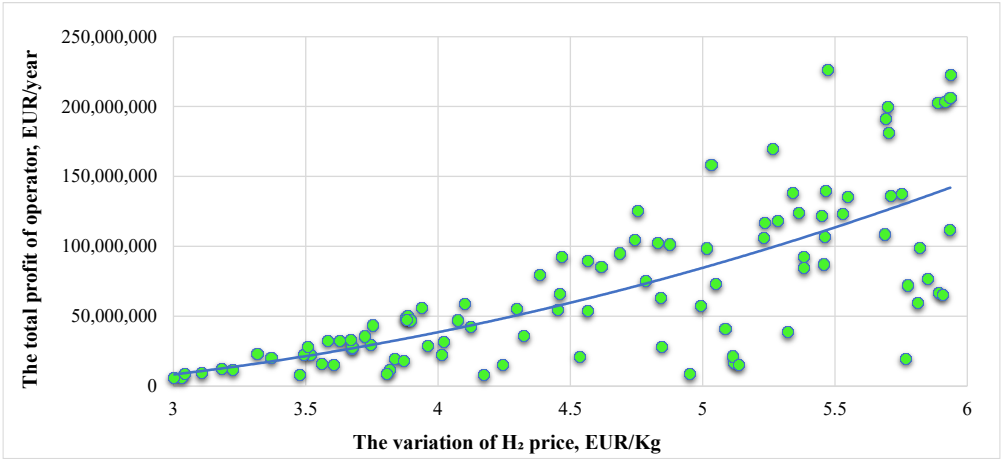


Fig. 54. Impact of H₂ price variation on the total operator's financial profit

For instance, as hydrogen prices increase, the cost of hydrogen waste heat is compensated even more, contributing to lower marginal heat production costs. Therefore, lower heat production costs from the hydrogen waste HP increase its share of heat production and negatively affect local IHP units (see Fig. 55), while supporting rapid growth in operator's financial profit (see Fig. 56).

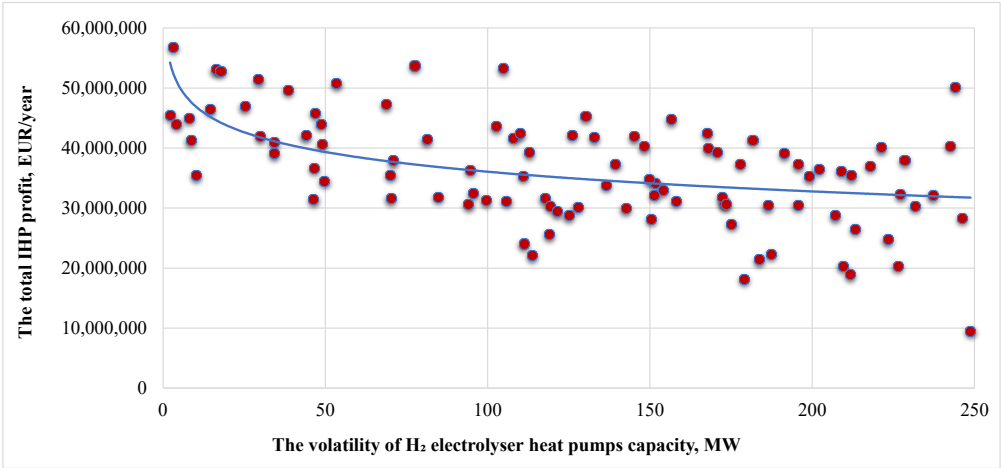


Fig. 55. Impact of H₂ electrolyser HPs capacity variation on total IHP profit

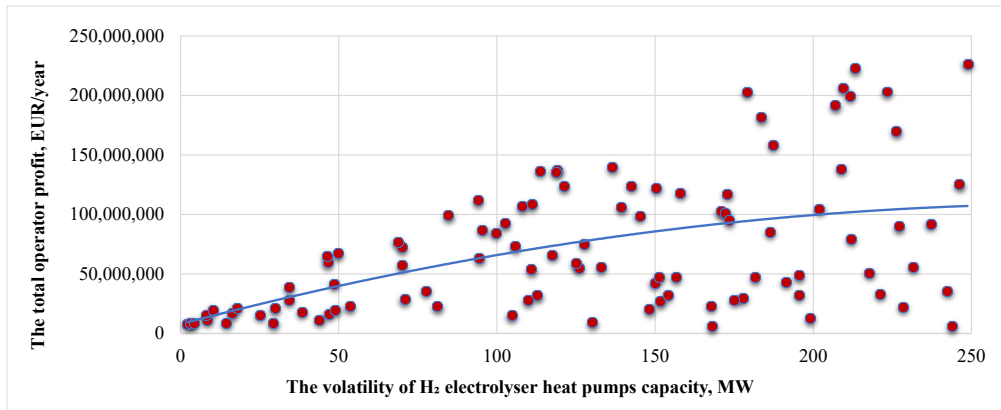


Fig. 56. Impact of H₂ electrolyser HPs capacity variation on total operator profit

In the analysis on total heat production costs, the results show that increases in hydrogen prices have the strongest impact on reducing total heat production costs (see Fig. 57).

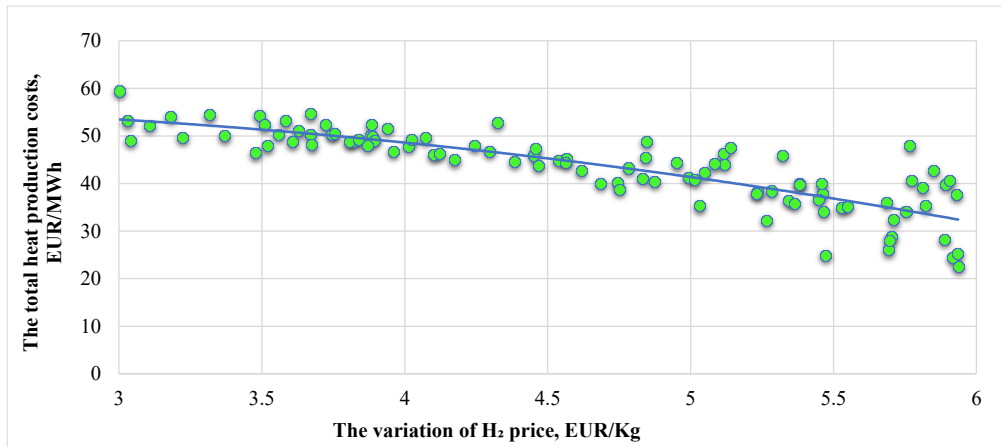


Fig. 57. Impact of H₂ price variation on total heat production costs

Potential investments in hydrogen electrolysis HPs, and air-to-water HPs reduce heat production costs and are also essential for limiting natural gas use in DH networks (see Figs. 58 and 59). Higher electrolyser HPs capacity directly reduces the use of natural gas boilers in the Vilnius DH system. Fig. 58 indicates that, with thermal capacity of up to 250 MW, the gas share in the DH system fluctuates around 5–5.5%.

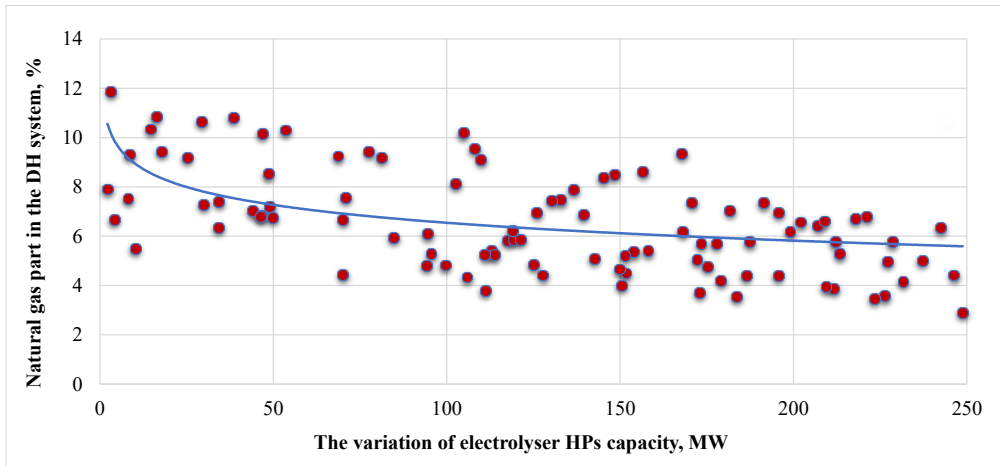


Fig. 58. Impact of H_2 electrolyser HPs capacity variation on the share of natural gas boilers in the DH system

To achieve a similar level of natural gas use in the DH system, it is necessary to integrate 80–100 MW of air-to-water heat pumps (see *Fig. 59*).

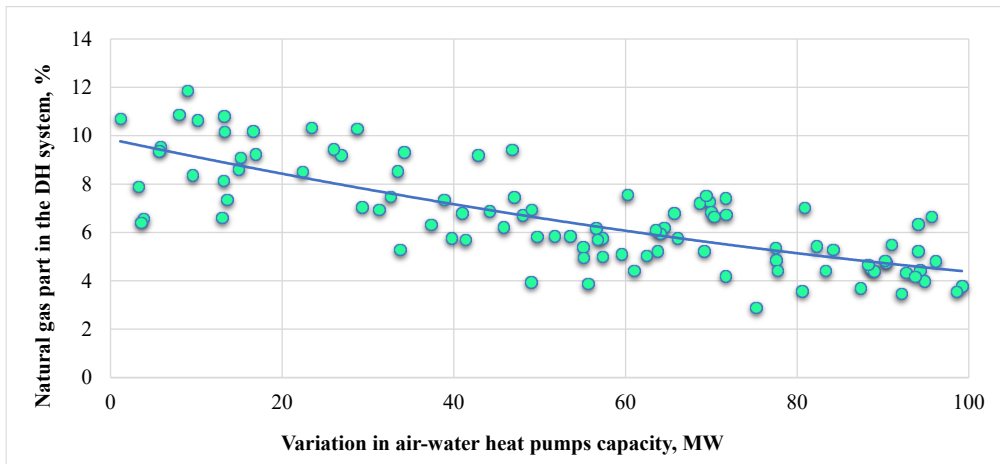


Fig. 59. Impact of air-to-water HPs capacity variation on the share of natural gas boilers in the DH system

The uncertainty and sensitivity analysis of the partial equilibrium model indicates that a detailed iterative process enables identification of potentially financially viable investment opportunities that maximise investor financial profit and contribute to lower heat auction prices.

3.6. Scenario 2 ‘RES100’: Policy Measure Aiming to Achieve 100% RES in the Vilnius DH System by 2030

This scenario examines potential investments by the operator and IHPs in renewable energy technologies, with the aim to fully eliminate fossil fuel use in the existing DH system in Vilnius. The priority of this scenario is not only to achieve 100% energy production from RES, but also to ensure that the selected investments are the most profitable and that heat auction prices do not exceed those of the ‘Current 2030’ scenario by more than 5%. Based on the same assumptions regarding uncontrollable and controllable uncertainty factors applied in the base scenario, a multiple iterative process is conducted to identify the optimal investment portfolio for achieving a 100% RES share in the DH system. Initial investment alternatives are excluded due to their high financial risk from the investor’s perspective. For instance, the first iteration shows that potential operator investments in electric boilers are associated with a 100% risk level, and that the future use of this technology would not be economically justified due to low heat output and high heat production costs (see Fig. 60).

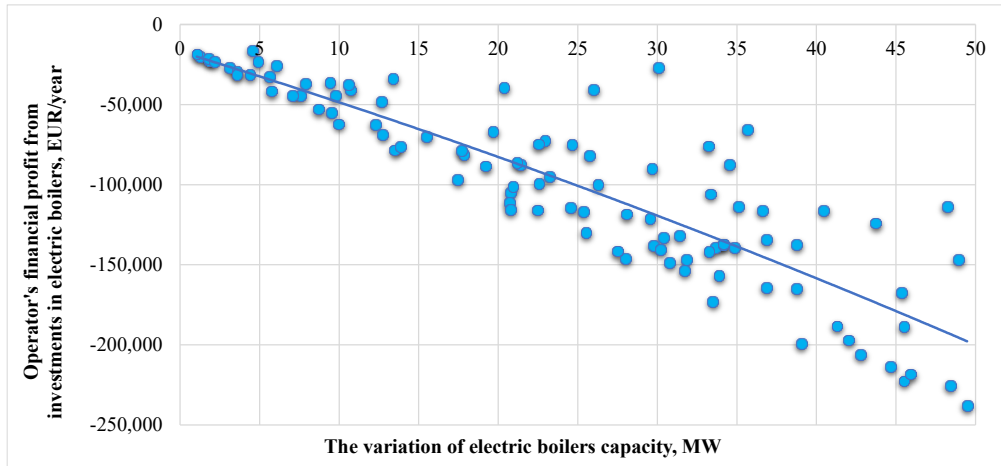


Fig. 60. Impact of variation in electric boilers capacity on the operator’s investment financial profit

The results of the third iteration also demonstrate that seasonal storage is not a suitable choice for the investor. In approximately 90% of the possible cases, the PTES facility would operate at significant losses due to low utilisation of the heat storage system and high production costs, and would therefore be unable to compete with cheaper heat production facilities in the heat auction system (see Fig. 61). This outcome also indicates that the participation of seasonal storage in the auction system would not be operationally feasible.

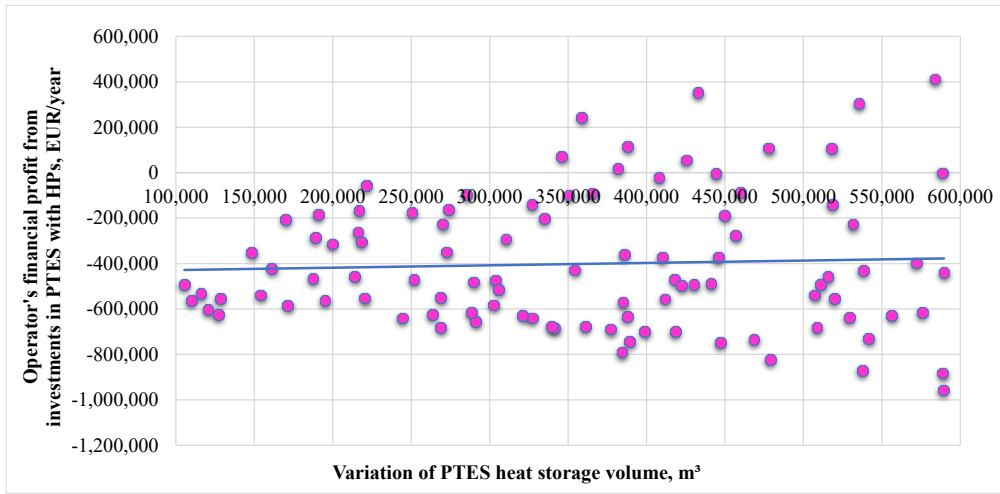


Fig. 61. Impact of variation in PTES heat storage volume on the operator's investment financial profit

Following a detailed investigation and an extensive iterative process, the fourth iteration reveals that potential operator investments in flat plate solar collectors with short-term heat storage are not financially viable, due to an identified financial risk of 65% (see *Fig. 62*).

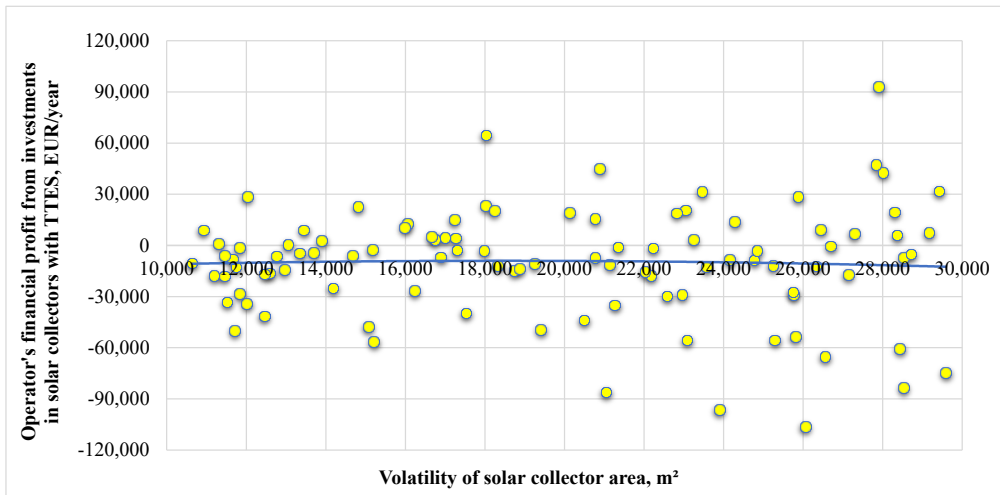


Fig. 62. Impact of volatility in solar collectors area on the operator's investment financial profit

To achieve 100% renewable energy production, maximise investments profit, and obtain adequate heat auction prices, investments in potential biofuel HOB facilities by operators and IHPs remain excessively risky (exceeding a 50% probability of financial loss) and are therefore excluded from further investigation.

After 10 iterations, the partial equilibrium model indicates that priority should be given to green heat production and conversion technologies, specifically through the inclusion of hydrogen electrolyser waste heat utilisation capacities in the range of 150–250 MW and compression air-to-water HPs capacities between 50–150 MW. The final iteration also prioritises the use of wastewater heat recovery solutions through the integration of HPs as potential operator investments. The same wastewater heat recovery potential, ranging from 26.7–40.9 MW, is assumed based on real city limitations and available waste heat output. Therefore, under the given assumptions (see *Table 21*), the final (10th) iteration reveals that the new potential operator investment portfolio is almost 100% profitable, thereby ensuring compliance with the profit maximisation rule. Modelling has also revealed that, due to the variability and instability of renewable energy technologies and taking into account fluctuations of assumed uncontrollable uncertainty factors, an additional 500 MW electric boilers would be needed as back-up to fully cover peak loads during the coldest periods and achieve 100% renewable energy production in the DH market.

Table 21. Ranges of uncertainty factors adjusted using the final identification method

Uncontrollable uncertainty factors		Ranges
Electricity price		50–70 EUR/MWh
Biofuel price		23–33 EUR/MWh
Natural gas price		44.76–54.76 EUR/MWh
CO ₂ price		55–130 EUR/t
Heat demand		0.4–0.8%
H ₂ price		3–6 EUR/kg
Controllable uncertainty factors	Uncertainty factors variability range	Assessment of the financial risk of potential investments, %
Wastewater HP	[26.75–40.86 MW]	7
Biofuel HOB IHP	[0 MW]	0
Biofuel HOB OP	[0 MW]	0
Solar collectors with TES	[0 m ²]	0
Electric boilers	[0 MW]	0
Power-to-H ₂ and Heat solutions	[150–250 MW]	3
Seasonal PTES heat storage	[0 m ³]	0
Air-to-water HP	[50–150 MW]	0

3.6.1. Scenario ‘RES100’ uncertainty analysis

The results obtained for this scenario enable a more detailed examination of the impact of uncertainty factors on the total annual profits of the operator and IHPs. The integration of the optimised portfolio of heat production facilities into the Vilnius DH network indicates that the annual profits of both the operator and IHPs remain positive, with no significant financial losses observed across all cases considered (see *Fig. 63*).

In contrast, the operator's total financial profit (approximately 12 times higher than in the first 'Current 2030' scenario) indicates that newly introduced RES-based heat production facilities, such as hydrogen electrolysis HP capacities, air-to-water HPs, and wastewater heat recovery solutions, constitute the main controllable uncertainty factors capable of competing with existing IHP cogeneration plants. The coefficient of variation increases eightfold, reaching 84%, which reflects a high level of dispersion in the operator's total financial profit due to increased competition in the heat production market.

As a result of the increasing share of renewable energy technologies and the declining production of existing facilities, total IHP profits decrease by half, to EUR 33.5 million annually. The coefficient of variation also increases eightfold, reaching 40%, indicating a high level of dispersion in the total financial profit of IHPs.

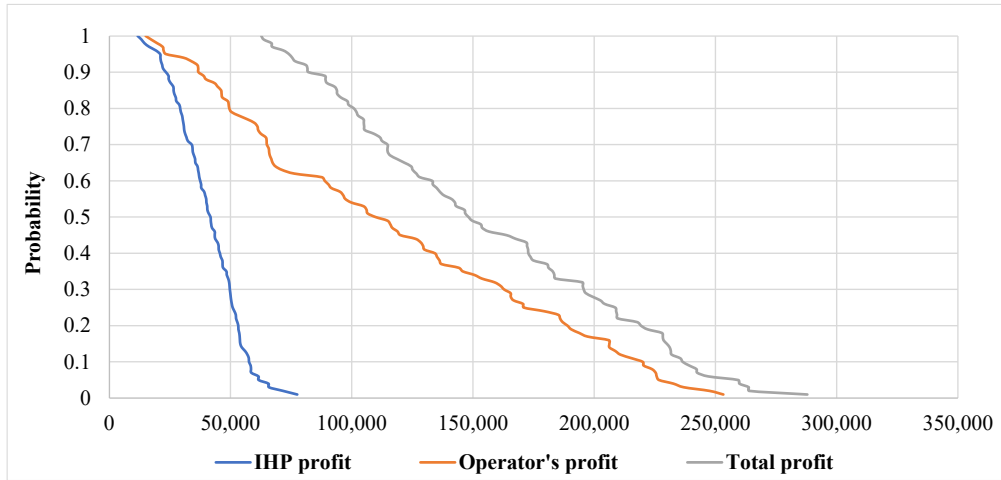


Fig. 63. Impact of uncertainty factors on DH market players' profits (thousand EUR)

The analysis of the impact of the identified uncertainty factors on the variability of heat auction price and total DH system heat production costs demonstrates that a substantial gap exists between total heat auction price and production costs (see Fig 64).

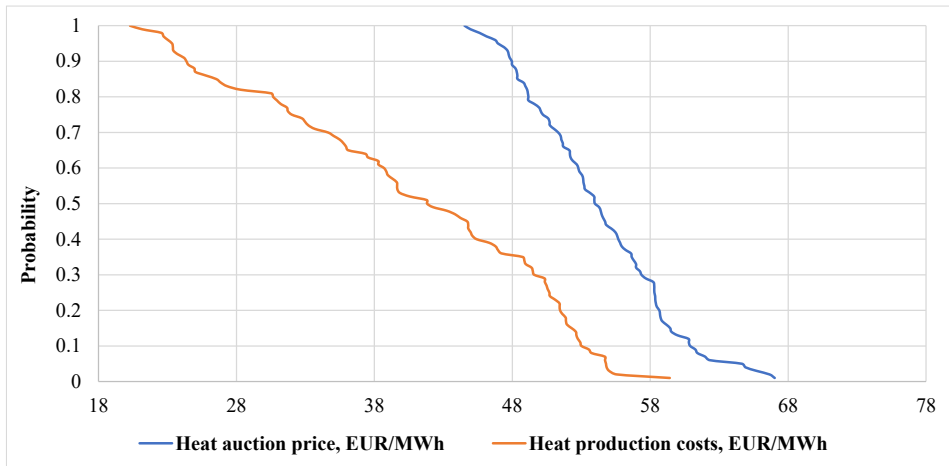


Fig. 64. Impact of uncertainty factors on total heat auction prices and production costs in the Vilnius DH system

The final iteration of the ‘RES100’ scenario indicates that new operator investments result in an average heat auction price of 51.42 EUR/MWh, with a coefficient of variation of 9.97% (see *Table 22*). It should be noted that the use of 100% RES in the DH system does not lead to lower prices compared to the base scenario, due to the initially high investments in high-power hydrogen electrolyzers with HPs, air-to-water HPs, and the inclusion of additional electric boilers as a reserve. Higher auction prices could be slightly reduced if battery energy storage systems (BESS) were integrated alongside electric boilers. The combination of these technologies could enable the use of lower electricity prices.

Table 22. Results of the 10th iteration uncertainty analysis

Scenario	The optimal new investments portfolio by operator and IHPs	Total DH system heat auction price, EUR/MWh	Total DH system heat production costs, EUR/MWh	Total financial profit of operator, M EUR	Total financial profit of IHPs, M EUR	RES based generation in DH system, %	Natural gas part in DH system, %
Scenario RES 100	OP wastewater HPs [26.7–40.9 MW]; OP air-to-water HPs [50–150 MW]; OP H ₂ HPs [150–250 MW]; + El. boilers for reserve	$\mu = 51.42$ EUR/MWh CV = 9.97 %	$\mu = 34.69$ EUR/MWh CV = 30.79 %	$\mu = 79.17$ CV = 84.8%	$\mu = 33.51$ CV = 40.17%	$\mu = 100$	$\mu = 0$

The uncertainty analysis outcomes also indicate that heat production costs fluctuate between 22.3 and 59.4 EUR/MWh, with an average of 34.7 EUR/MWh, thus corresponding to a coefficient of variation of 30.78%. Lower heat production costs allow a profitable operation by covering all necessary annual heat production costs.

3.6.2. SPEA correlation sensitivity analysis

Under the implemented ‘RES100’ scenario, the results of the Monte Carlo sensitivity and uncertainty analysis based on the SPEA correlation coefficient indicate that the optimal solutions comprise operator investments in power-to-heat solutions, including air-to-water HPs, wastewater HPs, and hydrogen waste heat utilisation solutions. From an investor perspective, these options are the most profitable, lead to adequate heat auction prices, and positively contribute to increasing the share of renewable energy production to 100%, with an average electric boiler utilisation of 4% as a green heat reserve (see Fig. 65).

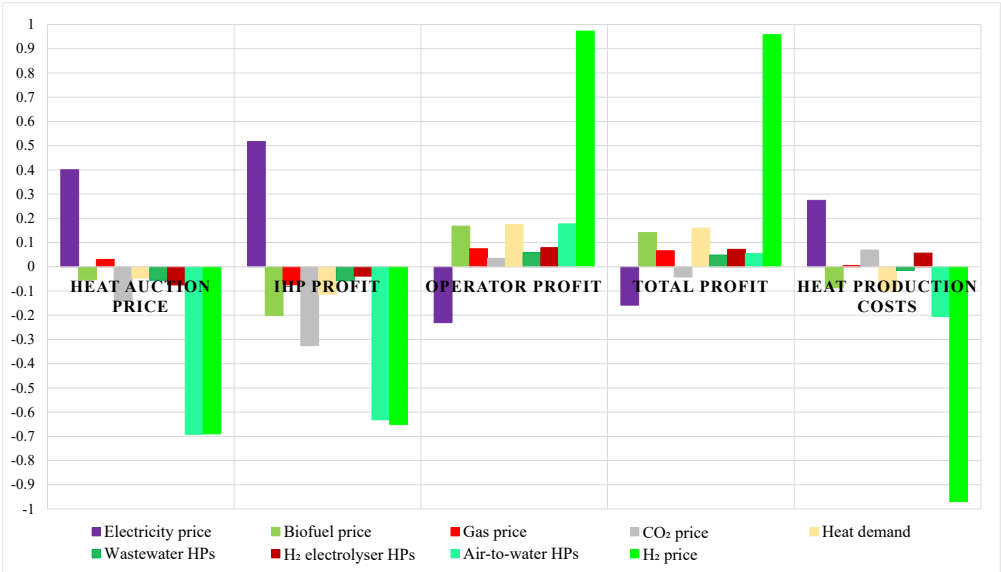


Fig. 65. Impact of uncertainty factors on modelling results using the SPEA correlation

The ‘RES100’ scenario demonstrates that the largest and most significant reduction in heat auction prices is driven by investments in air-to-water HP capacities. The findings indicate that when air-to-water HP capacity exceeds 140 MW, the average heat auction price can reach 50 EUR/MWh (see Fig. 66). In contrast, the strongest direct correlation is observed with electricity prices, which may increase heat auction prices due to possible price spikes.

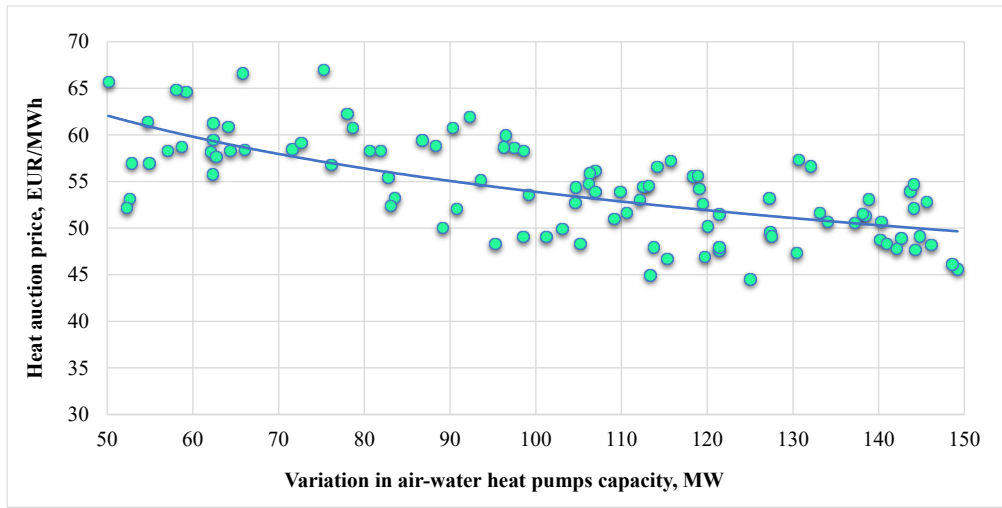


Fig. 66. Impact of variation in air-to-water HPs capacity on heat auction prices

Similarly to the base scenario, volatility in electricity prices also has the strongest positive direct impact on IHP financial profit due to the high share of existing waste and biofuel CHP plants in the DH system. The sensitivity analysis outcomes demonstrate that hydrogen prices and their potential increase predominantly have the most negative effect on existing IHP units, leading to reduced financial profit due to decreased heat production and increased heat production costs in existing IHP boiler plants (see *Fig. 67*).

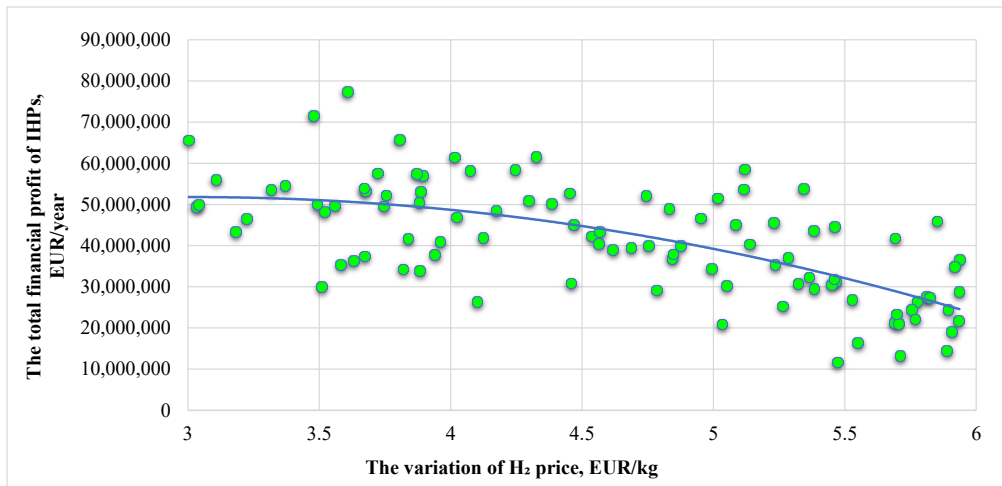


Fig. 67. Impact of H₂ price variation on IHPs total financial profit

The sensitivity analysis of annual operator financial profit reveals that the strongest direct correlation is also associated with fluctuations in hydrogen prices. It should be noted that fluctuations in these prices may have a positive direct financial

impact on operator profits, as rising hydrogen prices would generate more income from hydrogen sales in the Lithuanian market (see *Fig. 68*).

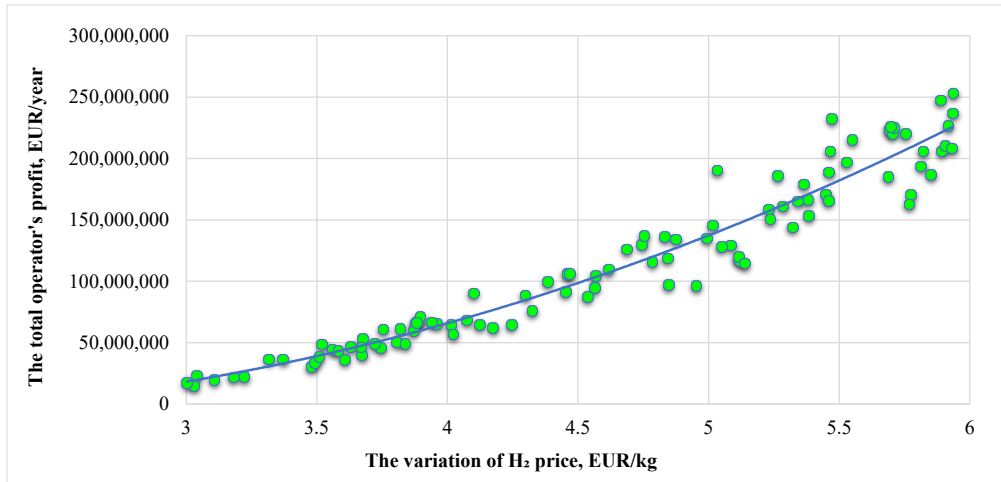


Fig. 68. Impact of variation in H₂ prices on the total operator's financial profit

It should also be noted that rising hydrogen prices result in higher compensation for hydrogen waste heat costs, thereby contributing to a reduction in marginal heat production costs (see *Fig. 69*).

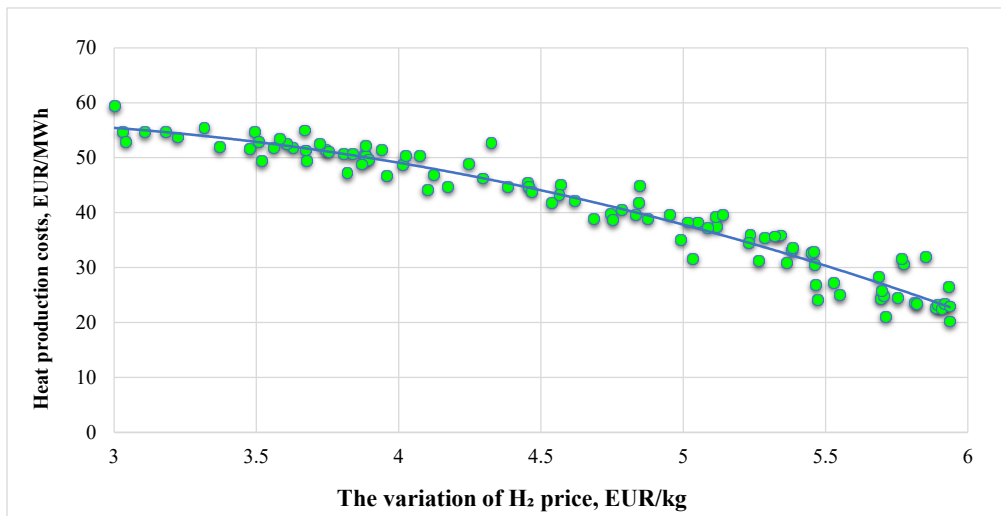


Fig. 69. Impact of variation in H₂ prices on heat production costs

The results of the 'RES100' scenario uncertainty and sensitivity analysis indicate that the target of 100% renewable energy-based heat production can be achieved primarily through the use of electric boilers and HP technologies. While these technologies support profit maximisation for investors, they also lead to higher heat auction prices, thereby affecting end heat consumers.

3.7. Scenario 3: ‘RES Subsidy’

The third scenario, ‘RES Subsidy’, considers potential financial support and incentives for new heat production and conversion infrastructure from the perspectives of the operator and IHPs. It assumes that new investments in renewable energy production, excluding biomass boilers, are eligible for subsidies covering at least 25% of the initial investment costs. This scenario examines how additional financial support may affect heat auction price, total heat production costs, and the overall profit of heat market participants, and identifies the most financially attractive investment portfolio that maximises investors’ profit. Following the iterative methodological process applied in this scenario, the first potential investment alternative is excluded due to its high financial risk from the investors’ perspective. For instance, the first iteration shows that potential operator investments in biofuel HOBs are completely financially unviable (see *Fig. 70*).

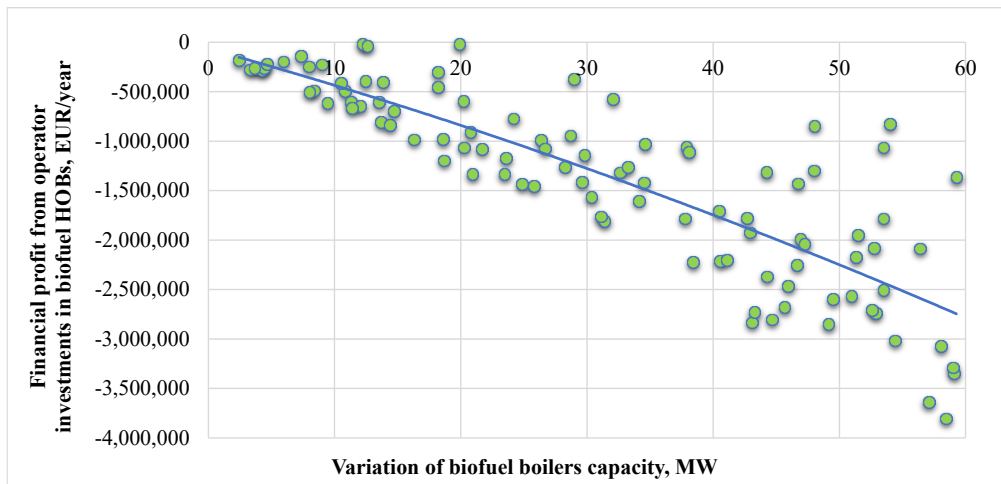


Fig. 70. Impact of biofuel HOBs capacity variation on operator’s profit

In the third iteration, it is found that a seasonal PTES heat storage facility with a HP would not be an economically viable solution for the investor. Despite an efficient 75% to 80% heat charge and discharge cycle and harmonised operating conditions with a water-to-water HP, the high initial investment and annual fixed costs result in a high probability of financial losses. Therefore, even after several iterations narrowing the PTES storage volume, the probability of the operator incurring financial losses is expected to be 96% (see *Fig. 71*). Based on these results, this potential investment alternative has been rejected for further investigation.

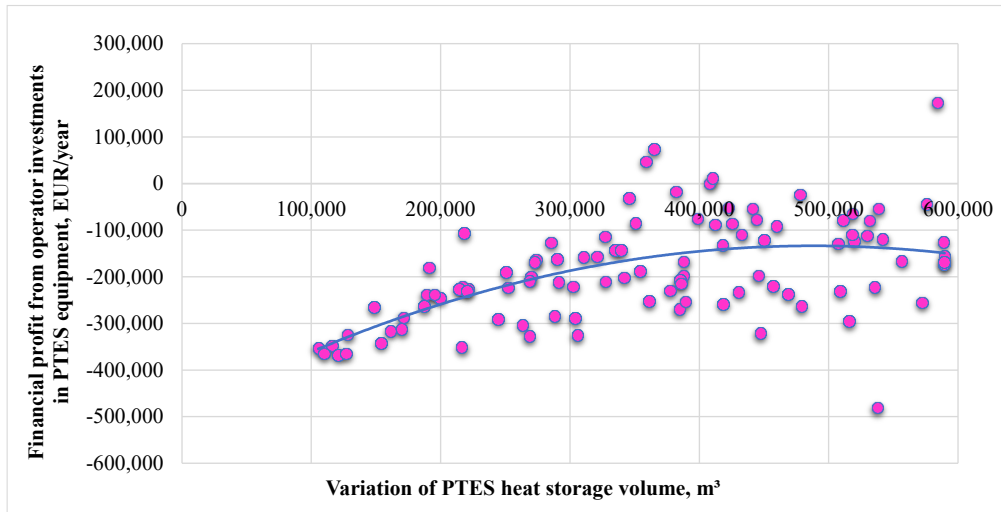


Fig. 71. Impact of PTES seasonal heat storage volume variation on operator's profit

The third iteration also demonstrates a high level of financial risk for IHPs investing in new biofuel water heating boilers. After detailed iterative analysis and a narrowing process, the results indicate that, under complex uncertainty conditions, there is a 90% probability of financial loss for this potential investment (see Fig. 72).

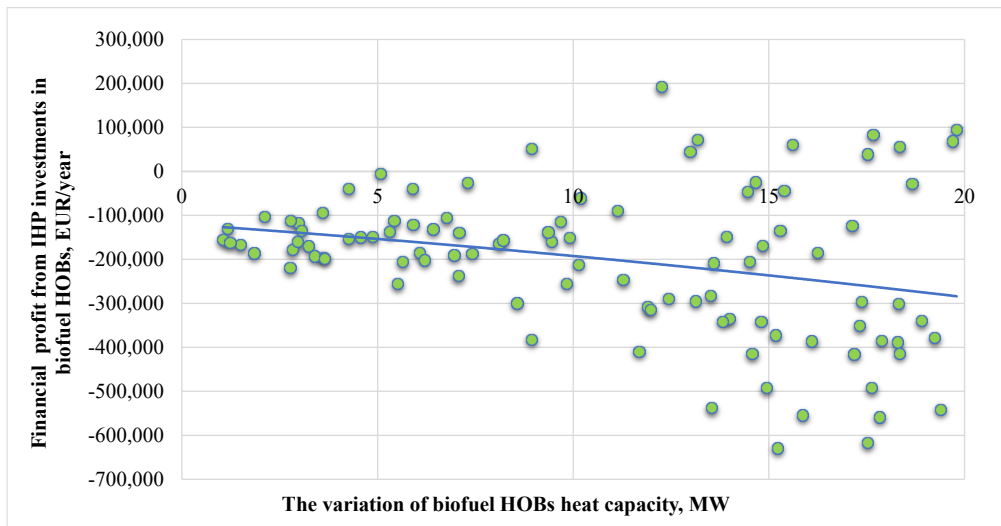


Fig. 72. Impact of variation in biofuel HOBs capacity on IHPs financial profit

After four iterations, the partial equilibrium model reveals that investment priorities should focus on environmentally friendly heat production and conversion technologies. The final iteration emphasises the integration of solar thermal collectors with thermal energy storage (TES) with an area ranging from 10,000 to 100,000 m², electric boilers with capacities of 1 to 35 MW, waste heat utilisation from hydrogen electrolysis of 1 to 300 MW, and air-to-water heat pumps with capacities of 1 to 100

MW. In addition, the scenario highlights the integration of heat pumps for wastewater heat recovery as a realistic investment opportunity for the operator. Based on city constraints and the potential availability of waste heat, it is assumed that 26.7–40.9 MW of energy can be recovered from wastewater. The final iteration's identified uncertainty factor ranges and assessment of financial risks are summarised in *Table 23*.

Table 23. Ranges of uncertainty factors adjusted using the final identification method

Uncontrollable uncertainty factors		Ranges
Electricity price		50–70 EUR/MWh
Biofuel price		23–33 EUR/MWh
Natural gas price		44.76–54.76 EUR/MWh
CO ₂ price		55–130 EUR/t
Heat demand		0.4–0.8%
H ₂ price		3–6 EUR/kg
Controllable uncertainty factors	Uncertainty factors variability range	Assessment of the financial risk of potential investments, %
Wastewater HP	[26.75–40.86 MW]	1
Biofuel HOB IHP	[0 MW]	0
Biofuel HOB OP	[0 MW]	0
Solar collectors with TES	[10,000–100,000 m ²]	11
Electric boilers	[1–35 MW]	9
Power-to-H ₂ and Heat solutions	[1–300 MW]	0
Seasonal PTES heat storage	[0 m ³]	0
Air-to-water HP	[1–100 MW]	0

3.7.1. Scenario 3 ‘RES Subsidy’: Uncertainty analysis

The results of the scenario uncertainty analysis allow a deeper examination of how uncertainty factors affect the annual total profits of the operator and IHPs. After integrating a new portfolio of optimal heat production facilities into the Vilnius DH market, the annual profits of both the operator and IHPs remain positive, with no significant financial losses observed in any of the analysed cases (see *Fig. 73*).

In contrast, the operator's financial profit becomes eight times higher than in the initial ‘Current 2030’ scenario. This indicates that new RES-based heat production facilities, including hydrogen electrolysis HP capacities, air-to-water HPs, wastewater heat recovery solutions, solar collectors, and electric boilers, constitute the main controllable uncertainty factors that may compete with existing IHP cogeneration plants and HOBs. The coefficient of variation increases elevenfold, reaching 125%, which demonstrates a high level of dispersion in the operator's total financial profit due to significantly increased market competition, further amplified by the hourly auction system.

Therefore, with the increasing share of renewable energy technologies and declining production from existing facilities, total IHP profits are reduced by more

than half, to EUR 29.8 million annually. According to the modelled outcome, the coefficient of variation increases nearly sixfold compared with the initial ‘Current 2030’ scenario, reaching 30%, which indicates a high level of dispersion in the financial profit of IHPs, primarily influenced by increased market competition (see Fig. 73).

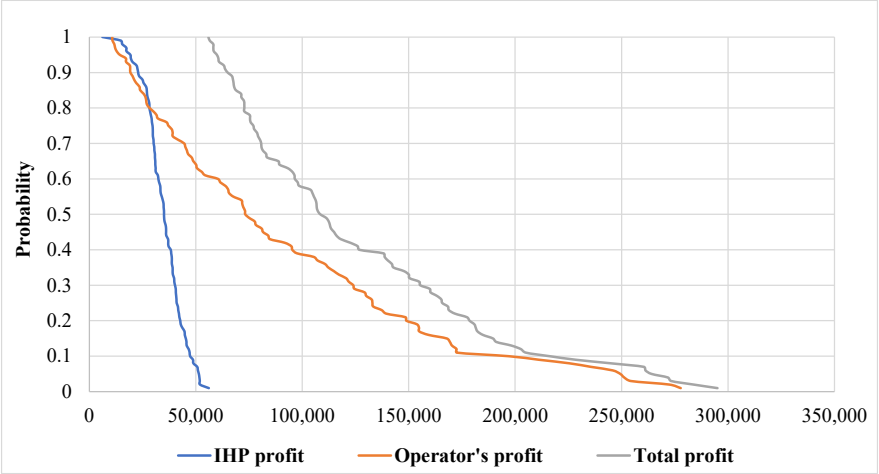


Fig. 73. Impact of uncertainty factors on total profits of DH market players (thousand EUR)

The analysis of the effects of all identified uncertainty factors on the variability of heat auction prices and total DH system heat production costs demonstrates that production costs are approximately 28% lower than heat auction prices (see Fig. 74). This is largely due to reduced initial investments in renewable energy technologies, with a subsidy of 25%, and the rejection of the riskiest alternatives, which pose the highest financial losses for investors.

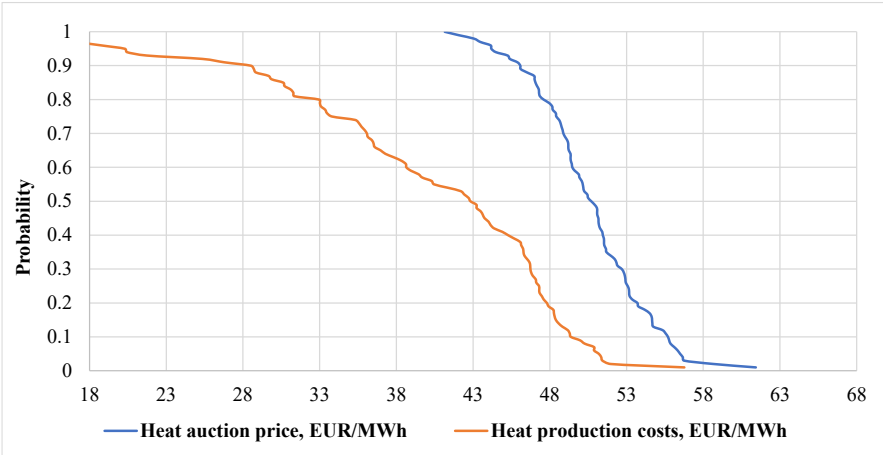


Fig. 74. Impact of uncertainty factors on total heat auction prices and production costs of the DH system

The final iteration indicates that new operator investments could reduce heat auction price to an average of 48.5 EUR/MWh, with a coefficient of variation of 7.6%. This outcome demonstrates that the policy measure, a 25% financial subsidy, is an effective instrument for reducing heat auction prices.

The uncertainty analysis shows that heat production costs are estimated to fluctuate between 14.2 and 56.8 EUR/MWh, with an average of 34.8 EUR/MWh. The coefficient of variation increases nearly sevenfold, reaching 27.1%, which indicates a high level of dispersion in total heat production costs, primarily influenced by increased market competition. In contrast, the uncertainty analysis on the share of natural gas boilers in the Vilnius DH market reveals that, assuming the optimal investment portfolio and accounting for controlled and uncontrolled uncertainties, such as future energy source prices, natural gas boilers would supply only 5.07% of total heat demand on average (see Fig. 75).

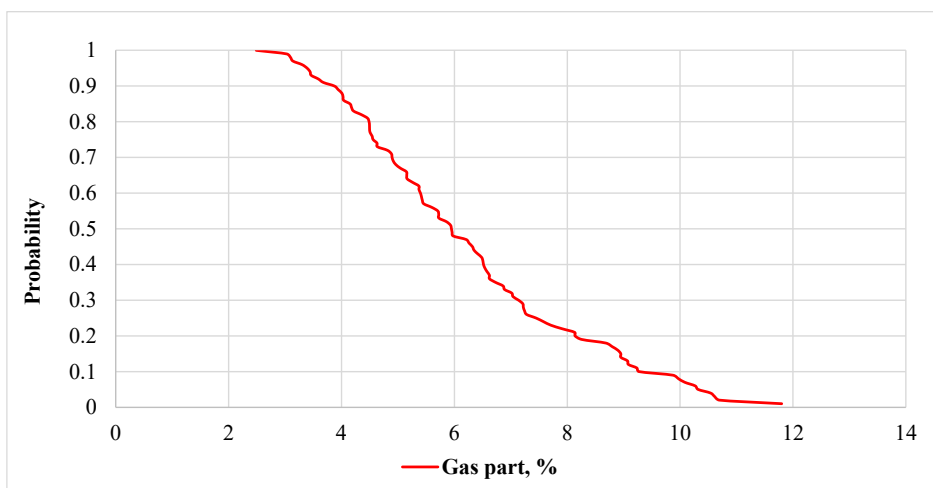


Fig. 75. Share of gas boilers usage in the entire DH system

All key indicators from the ‘RES Subsidy’ scenario uncertainty analysis are summarised in Table 24.

Table 24. Results of iteration four uncertainty analysis

Scenario	Optimal new investments portfolio by operator and IHPs	Total DH system heat auction price, EUR/MWh	Total DH system heat production costs, EUR/MWh	Total profit of operator, M EUR	Total profit of IHPs, M EUR	Natural gas component in DH system, %

‘RES Subsidy’ scenario	OP wastewater HPs [26.7–40.9 MW]; OP air-to-water HPs [1–100 MW]; OP H ₂ HPs [1– 300 MW]; El. boilers [1–35 MW] Solar collectors [1,000–100,000 m ²]	$\mu = 48.5$ EUR/M Wh	$\mu = 34.8$ EUR/MW h	$\mu = 54.85$	$\mu = 29.79$	$\mu = 5.07$
		CV= 7.6%	CV= 27.1%	CV= 125.1%	CV= 30.26%	CV= 41.44 %

3.7.2. SPEA correlation sensitivity analysis

The Monte Carlo sensitivity and uncertainty analysis results for the ‘RES Subsidy’ scenario indicate that the optimal investment portfolio comprises power-to-heat solutions, including air-to-water heat sources, wastewater heat sources, and hydrogen waste heat utilisation solutions, as well as solar collectors and electric boilers. This would yield the highest investor profit, ensure a sufficiently low heat auction price, and positively increase the share of RES production in the DH system (see Fig. 76).

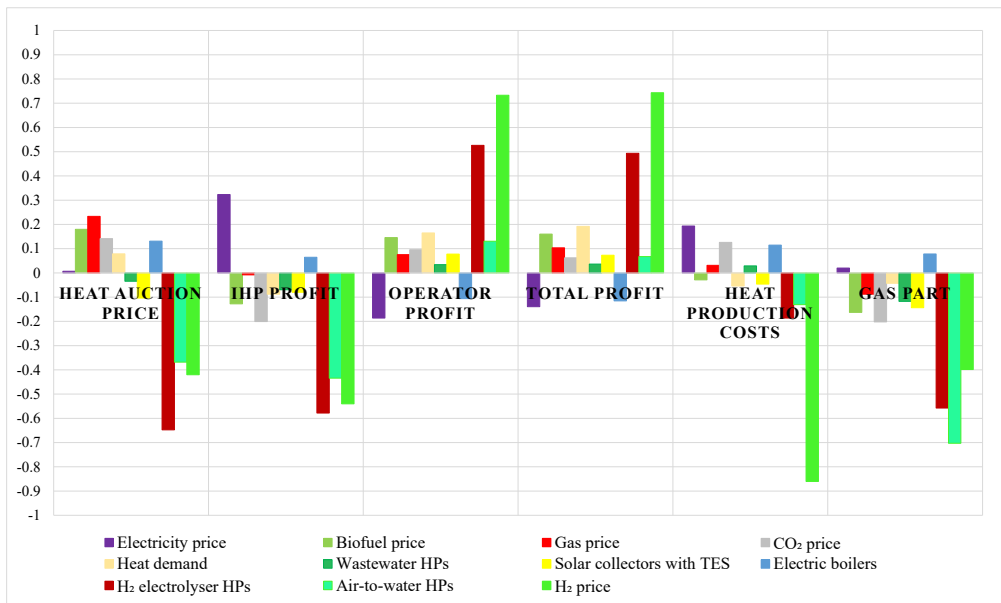


Fig. 76. Impact of uncertainty factors on modelling results using SPEA correlation

In the ‘RES Subsidy’ scenario, the largest and most significant reduction in the heat auction price is driven by investment in a hydrogen electrolyser with HP capacity (see Fig. 76). The findings indicate that when hydrogen HP capacity exceeds 250 MW, the auction heat price could reach an average of 48 EUR/MWh (see Fig. 77). In

contrast, the strongest direct correlation is with natural gas prices, which corresponds to an increase in heat auction prices.

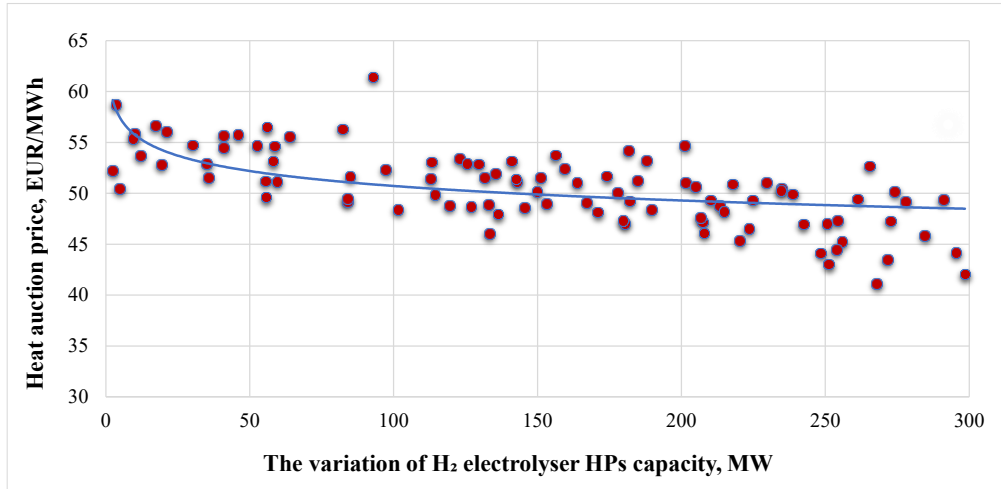


Fig. 77. Impact of H₂ HPs capacity variation on heat auction prices

Similarly to the base scenario, electricity price fluctuations have the strongest direct positive impact on IHPs financial profit, mainly due to the high share of existing waste and biofuel CHP plants in the DH system. However, as shown in *Fig. 76*, the integration of compression air-to-water HPs and hydrogen waste heat utilisation solutions has the strongest negative impact on other existing IHP facilities, resulting in lower profits due to reduced heat production and increased production costs in existing CHP plants and HOBs (see *Fig. 78*).

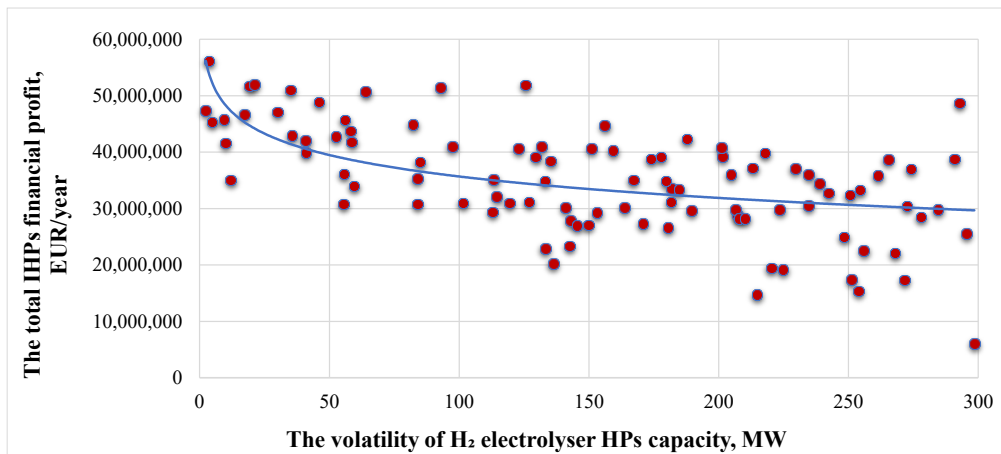


Fig. 78. Impact of H₂ electrolyser HPs capacity variation on total IHPs profit

When new hydrogen electrolysis HPs capacity exceeds 250 MW, the total IHP profit in the DH market is reduced by almost half.

Investigating total operator profit, the hydrogen price and new potential investments in a hydrogen electrolyser with HPs would have the most significant impact (see Fig. 79). Fluctuations in hydrogen prices may have a positive direct financial impact on operator profit, as rising hydrogen prices would increase income from hydrogen sales in the Lithuanian market.

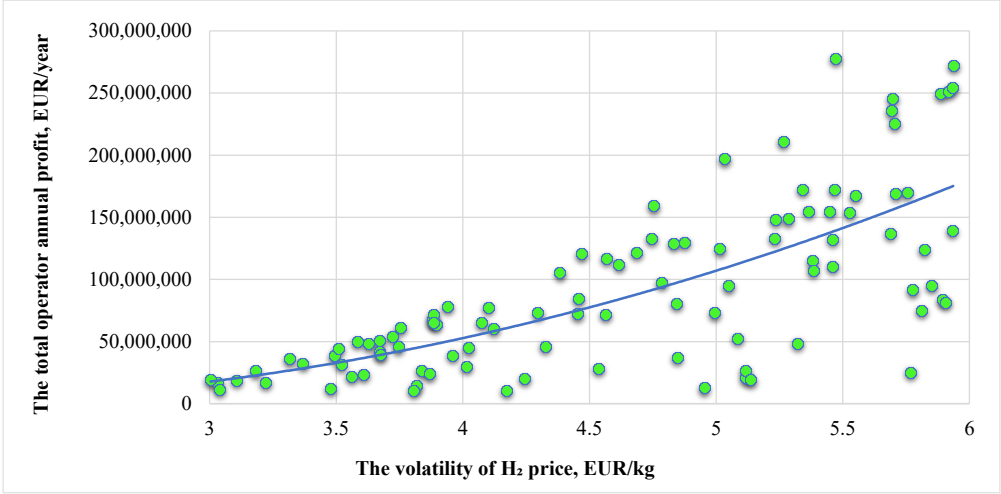


Fig. 79. Impact of H₂ price volatility on total annual operator financial profit

Rising hydrogen prices would also result in higher compensation for hydrogen waste heat costs, contributing to a reduction in marginal heat production costs (see Fig. 80).

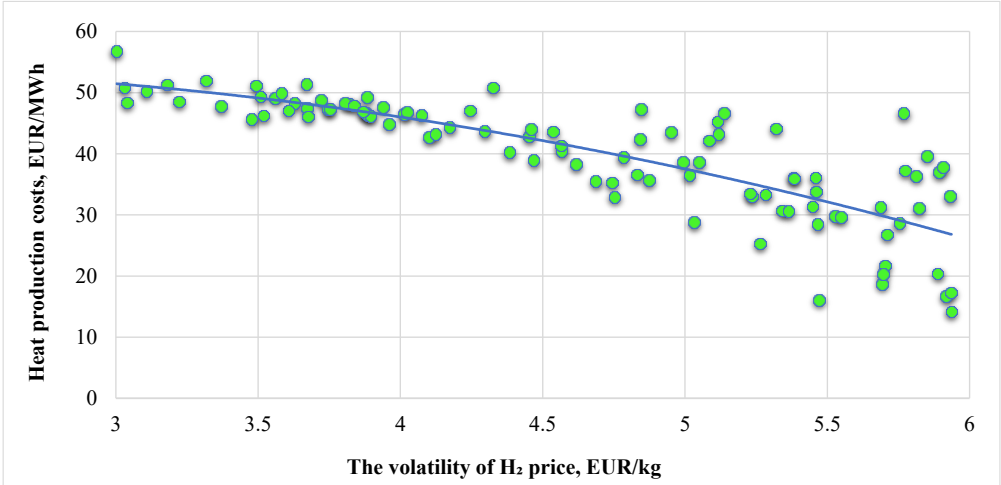


Fig. 80. Impact of H₂ price variation on heat production costs

Potential operator investments in air-to-water HPs have the most positive impact on limiting natural gas use in the market (see Fig. 81). The results indicate that, with

thermal capacity of up to 100 MW, the share of gas in a DH system would fluctuate around 4%.

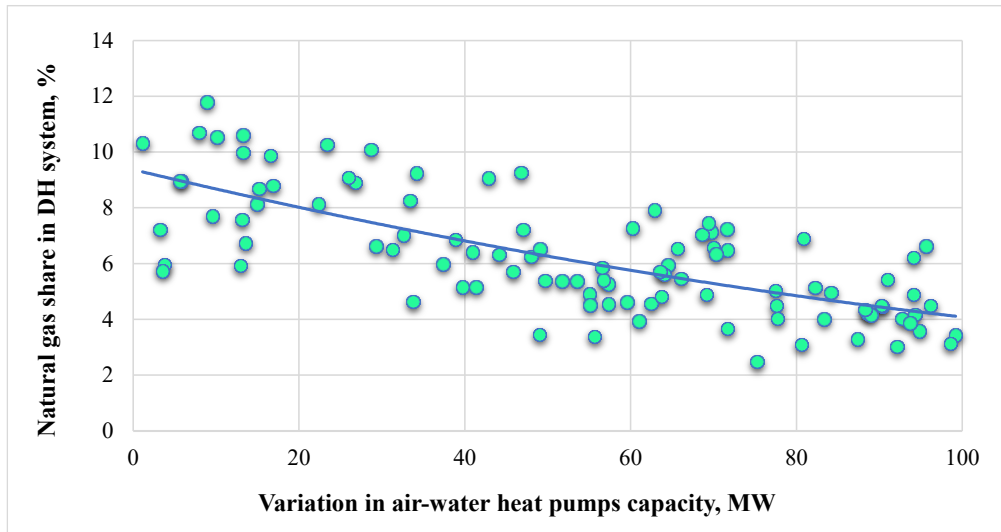


Fig. 81. Impact of air-to-water HPs capacity variation on the natural gas boiler share in the DH system

The ‘RES Subsidy’ scenario demonstrates a diverse green technology investment portfolio which, with the obtained 25% financial subsidy, might reduce heat auction costs by more than 18%. The optimal investment portfolio includes wastewater, air source HPs, hydrogen electrolyzers with compressor HPs, electric boilers, and solar collectors with TES to maximise investor profit. The sensitivity and uncertainty analysis reveals that, with these new potential investments, the DH market would still require approximately 5% natural gas use to meet heat demand during the coldest periods.

3.8. Scenario 4: ‘Gas Excise’

The fourth scenario, ‘Gas Excise’, includes a policy measure aimed at limiting fossil fuel use by imposing an excise tax on natural gas. It is assumed that the excise tax would double the final price of natural gas. This scenario illustrates how all existing and emerging energy production sources, including heat supplier and IHPs, would behave under changing market conditions.

Employing the same methodological procedure, the sixth and final iteration identifies the optimal investment portfolio for new market players. This iteration emphasises seasonal heat storage with a volume of 450,000–470,000 m³, as well as potential investments by IHPs and operator in biofuel HOBs with capacities of 1–40 MW and 1–30 MW, respectively. The optimal portfolio also includes solar thermal collectors with TES with an area of 12,000–35,000 m², electric boilers with a capacity of 1–50 MW, waste heat from hydrogen electrolysis from 1–250 MW, and air-to-water HPs with a capacity of 1–100 MW. In addition, the scenario highlights the importance of integrating HPs for wastewater heat recovery as a realistic investment opportunity

for the operator. Based on city constraints and the potential amount of waste heat, it is assumed that 26.7–40.9 MW of thermal energy can be recovered from wastewater. The uncertainty factors identified in the final iteration and the financial risk assessment are illustrated in *Table 25*.

Table 25. Ranges of uncertainty factors adjusted by the final identification method

Uncontrollable uncertainty factors		Ranges
Electricity price		50–70 EUR/MWh
Biofuel price		23–33 EUR/MWh
Natural gas price		44.76–54.76 EUR/MWh
CO ₂ price		55–130 EUR/t
Heat demand		0.4–0.8%
H ₂ price		3–6 EUR/kg
Controllable uncertainty factors	Uncertainty factors variability range	Assessment of financial risk of potential investments, %
Wastewater HP	[26.75–40.86 MW]	0
Biofuel HOB IHP	[1–40 MW]	6
Biofuel HOB OP	[1–30 MW]	4
Solar collectors with TES	[12,000–35,000 m ²]	40
Electric boilers	[1–50 MW]	0
Power-to-H ₂ and Heat solutions	[1–250 MW]	0
Seasonal PTES heat storage	[450,000–470 000 m ³]	50
Air-to-water HP	[1–100 MW]	0

3.8.1. Scenario 4 ‘Gas Excise’ uncertainty analysis

The uncertainty analysis results enable a more detailed assessment of how uncertainty factors affect the annual profit of the system operator and IHPs. After incorporating the optimised heat-generation portfolio in the Vilnius DH network, the results reveal that the annual profits of both market participants remain positive, and no statistically significant financial losses are identified in the scenario evaluated (see *Fig. 82*).

The operator’s financial profit is expected to be approximately eight times higher than in the ‘Current 2030’ scenario. This reflects the potential of new renewable heat-production technologies, such as hydrogen electrolysis waste heat recovery, air-to-water heat pumps, wastewater heat recovery systems, solar thermal collectors, electric and biofuel boilers, and seasonal heat storage, which are a key set of controllable uncertainty factors that can compete with existing cogeneration plants and HOBs owned by IHPs. In addition, the coefficient of variation increases almost ninefold (to 104%), indicating that the operator profit is significantly more dispersed due to increased heat market competition.

Therefore, as the share of renewable energy technologies increases and production from existing installations decreases, the total annual profit for all IHPs is 142

expected to decline by 20% to approximately EUR 52.1 million. The modelling results also show that the coefficient of variation increases by nearly fivefold to 28.6%, reflecting a significantly greater dispersion in total IHP profit (see *Fig. 82*).

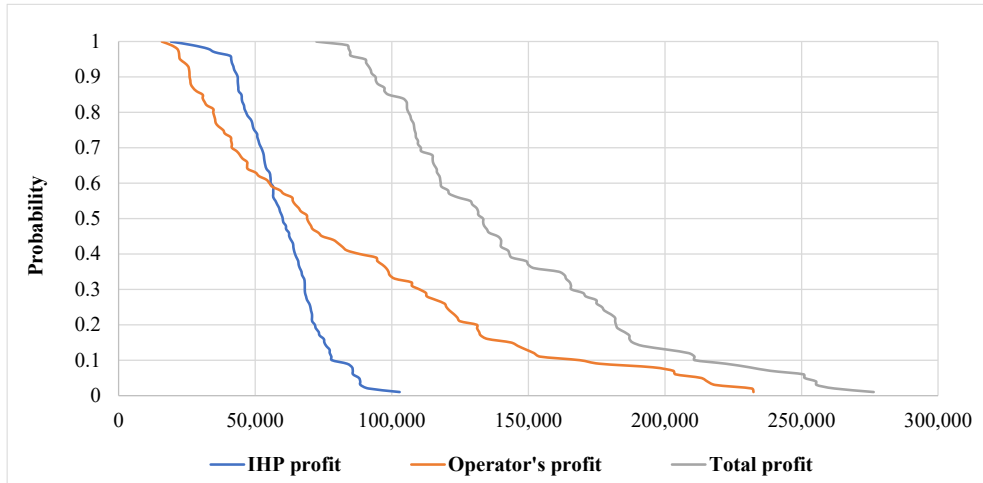


Fig. 82. Impact of uncertainty factors on total profit of DH market participants (thousand EUR)

The final iteration of the ‘Gas Excise’ scenario shows that new operator and IHPs investments would increase the heat auction price by 3.3% compared with the ‘Current 2030’ scenario, reaching an average of 61.45 EUR/MWh. The coefficient of variation is 10.19%, indicating average dispersion (see *Fig. 83*). This is mainly due to the assumption that natural gas prices would rise in response to the introduction of an excise duty as a policy measure, reflecting a realistic situation in the heating market.

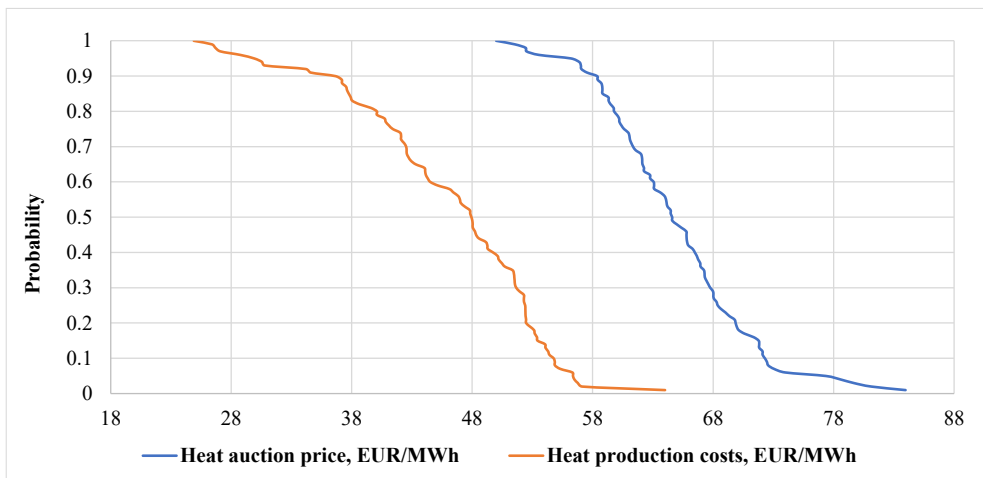


Fig. 83. Impact of uncertainty factors on the total Vilnius DH system heat auction and production costs

The uncertainty analysis yields average heat production costs of 41.66 EUR/MWh, with a coefficient of variation of 19.2%. Despite higher heat auction price across the DH system, heat production costs would be lower, allowing all DH market participants to operate profitably.

Based on the uncertainty analysis of the share of natural gas boilers in the Vilnius DH market, the results show that, assuming the optimal investment portfolio and future energy source prices as controlled and uncontrolled uncertainties, natural gas boilers would account for only 2.9% of the total heat demand on average (see *Fig. 84*).

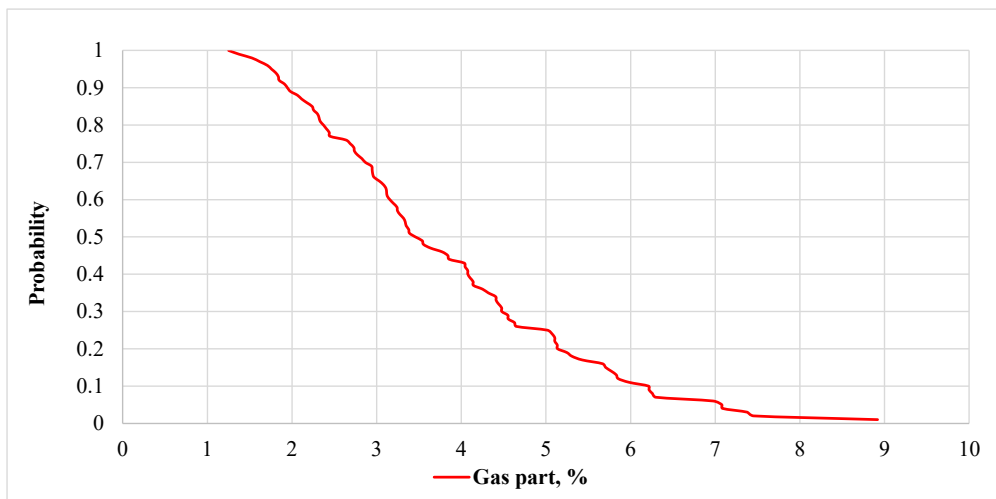


Fig. 84. Share of gas boilers use across the DH system

All key outcome indicators of the uncertainty analysis for the ‘Gas Excise’ scenario are summarised in *Table 26*.

Table 26. Results of iteration six uncertainty analysis

Scenario	Optimal new investment portfolio of operator and IHPs	Total DH system heat auction price, EUR/MWh	Total DH system heat production costs, EUR/MWh	Total operator profit, M EUR	Total IHPs profit, M EUR	Natural gas component in DH system, %
'Gas Excise' scenario	OP wastewater HPs [26.7–40.9 MW]; OP air-to-water HPs [1–100 MW]; OP H ₂ HPs [1–250 MW]; El. boilers [1–50 MW] Biofuel OP [1–30 MW] Biofuel IHP [1–40 MW] Solar collectors [12,000–35,000 m ²] PTES storage [450,000–470,000 m ³]	$\mu = 61.45$ EUR/MWh $CV = 10.19\%$	$\mu = 41.66$ EUR/MWh $CV = 19.2\%$	$\mu = 53.75$ $CV = 103.93\%$	$\mu = 52.09$ $CV = 28.58\%$	$\mu = 2.9$ $CV = 54.1\%$

3.8.2. SPEA correlation sensitivity analysis

The Monte Carlo sensitivity and uncertainty analysis results for the 'Gas Excise' scenario indicate that the optimal investment portfolio comprises power-to-heat solutions, including air-to-water HPs, wastewater HPs, and hydrogen waste heat utilisation solutions, as well as solar collectors, electric boilers, seasonal PTES heat storage, and biomass HOBs. This portfolio would yield the highest investor profit, ensure a sufficiently low heat auction price, and positively increase the share of RES production in the DH system under an additional excise duty on natural gas prices, considering the expected semi-controllable uncertainties (see *Fig. 85*).

The results also show that the most significant impact on heat auction price is driven by operator investments in renewable energy infrastructure, particularly PEM-type electrolyzers integrated with compression HPs designed to recover electrolyser waste heat, as well as air-to-water compression HPs (see *Fig. 85*).

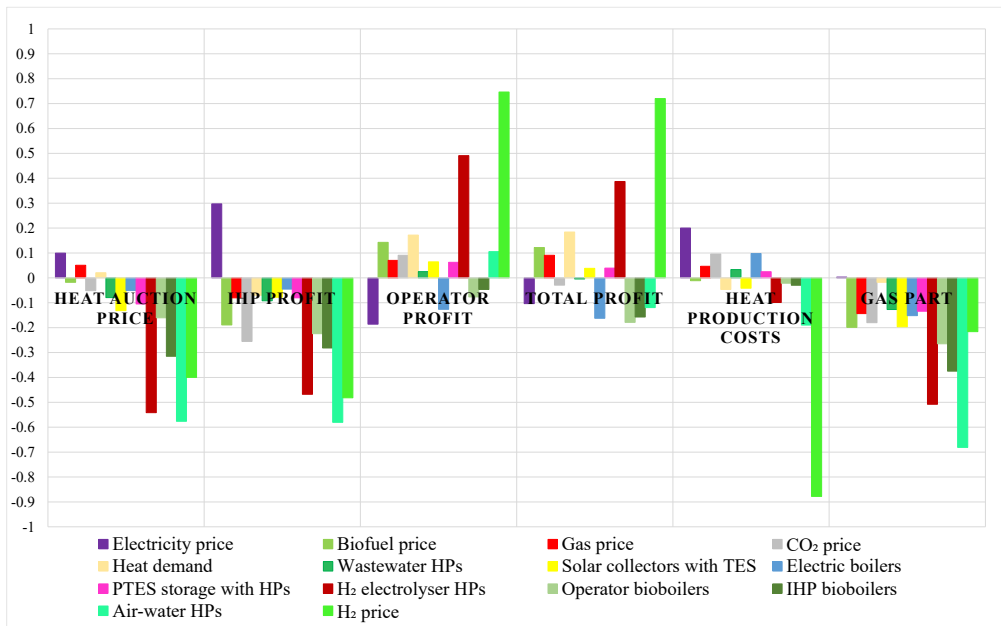


Fig 85. Impact of uncertainty factors on modelling results using SPEA correlation

Potential investments in hydrogen electrolyzers coupled with HPs of 250 MW thermal capacity would allow the DH system to achieve an average heat auction price of 61 EUR/MWh (see Fig. 86).

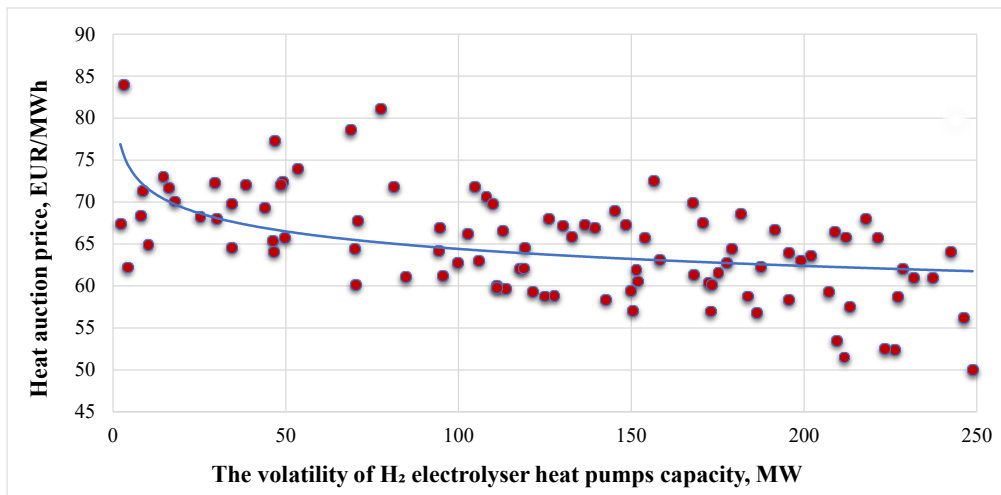


Fig. 86. Impact of H₂ HPs capacity variation on the heat auction price

Furthermore, to achieve the same auction price of 61 EUR/MWh, approximately 80–100 MW of air-to-water HPs require installation (see Fig. 87).

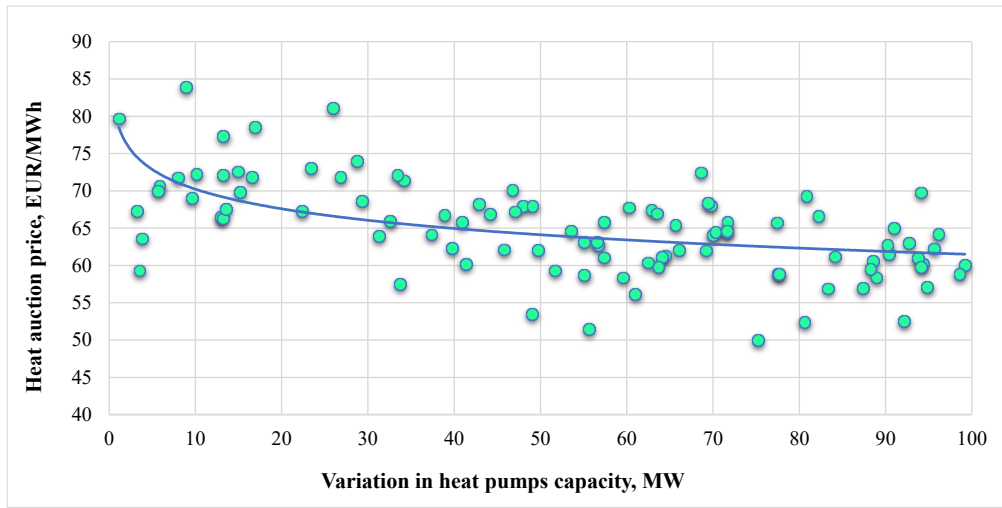


Fig. 87. Impact of air-to-water HPs variation on the heat auction price

Similarly to the base scenario, an increase in electricity prices has the strongest direct positive impact on total IHPs profit, mainly due to the high share of existing waste and biofuel cogeneration plants in the DH system. However, as shown in *Fig. 85*, integrating compression air-to-water HPs, utilising hydrogen waste heat, and fluctuations in hydrogen prices are expected to have the strongest negative financial impact on the performance of existing IHP plants. This negative impact is driven by reduced heat production and the associated increase in heat production costs, which decreases the profit of existing IHP units (see *Fig. 88*).

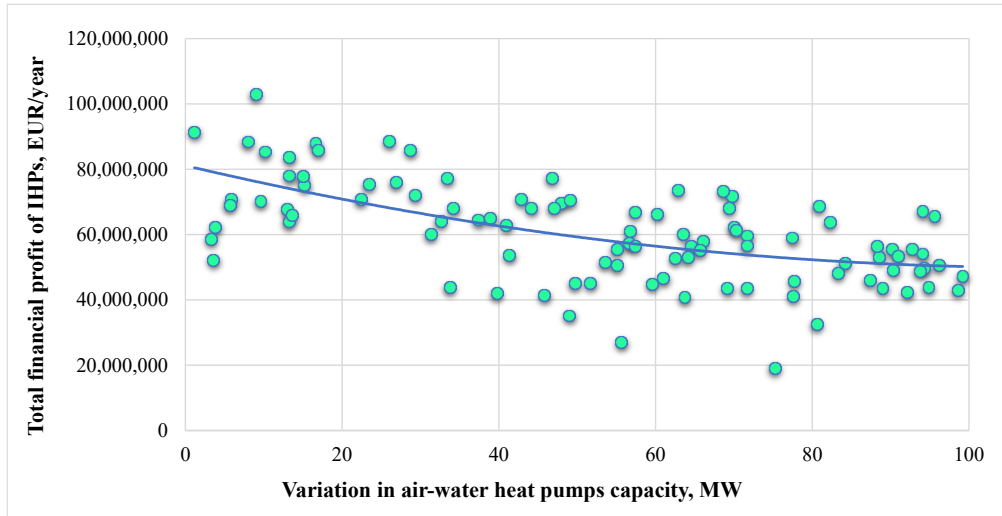


Fig. 88. Impact of air-to-water HPs capacity variation on IHPs financial profit

When examining total operator profit, the results indicate that the price of hydrogen and new potential investments in hydrogen electrolyzers with HPs have the

most significant effect (see *Fig. 85*). The higher hydrogen prices lead directly to an increase in operator total financial profit, as rising hydrogen prices would increase income from hydrogen sales in the Lithuanian market (see *Fig. 89*).

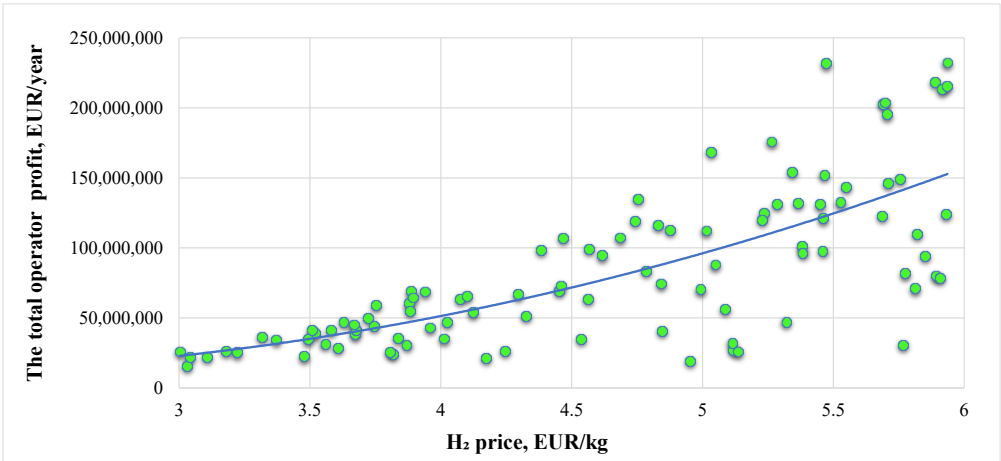


Fig. 89. Impact of H₂ price volatility on total annual operator profit

Rising hydrogen prices would also result in higher compensation for hydrogen waste heat costs, contributing to a reduction in marginal heat production costs (see *Fig. 90*).

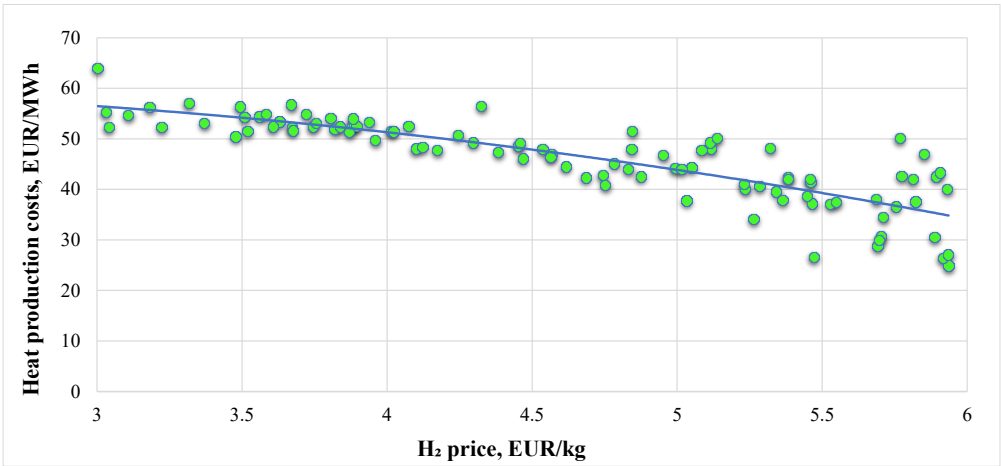


Fig. 90. Impact of H₂ price variation on heat production costs

It is observed that potential operator investments in air-to-water heat pumps have the most positive impact on limiting natural gas use in DH networks (see *Fig. 91*).

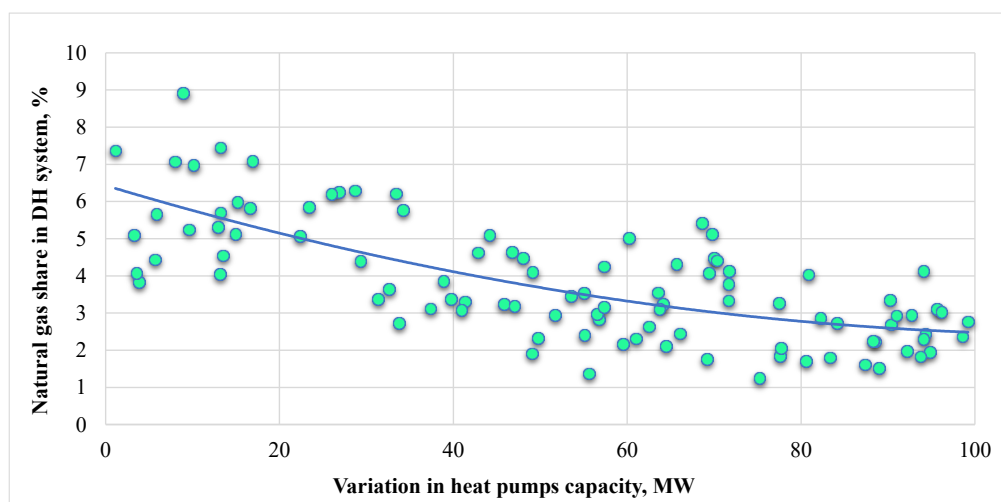


Fig. 91. Impact of air-to-water HPs on the natural gas boiler share in the DH system

The results indicate that, with thermal capacity of up to 100 MW, the share of gas in the DH system would fluctuate around 2.9%. Therefore, the ‘Gas Excise’ scenario shows that the policy measure, which is an excise duty on natural gas that would double the price of gas, would be most unfavourable for final heat consumers, due to a 3.3% increase in the heat auction price, compared with the ‘Current 2030’ scenario.

3.9. Comparative Review of Uncertainty Analysis Outcomes

The uncertainty analysis across all scenarios for 2030 indicates that policy measures have diverse effects on investor profit and the DH market heat auction price. The ‘RES100’ scenario has the greatest potential to maximise financial profit. By integrating compression HPs, significant investments in new hydrogen electrolysis facilities and waste heat utilisation, as well as power-to-heat conversion solutions and investments in treated wastewater and air-source HPs would maximize investor-operator profit, which would be 12 times higher than in the ‘Current 2030’ scenario.

Although the operator’s existing and new production sources show increased profit in this scenario, with the coefficient of variation exceeding 84%, competition with local IHPs is expected to intensify. This competitive pressure would, in turn, reduce the total IHP profit by half compared with the ‘Current 2030’ scenario. The most favourable financial outcome for IHPs (an average exceeding EUR 66 million per year) would occur without additional new operator investments, as indicated by the ‘Current 2030’ scenario. However, maximising financial profit and achieving 100% renewable heat production would not result in the lowest heat auction prices, making this outcome a less desirable scenario for end heat users.

Based on the analysis of the Vilnius DH market structure in the ‘Current 2023’ scenario and projected uncontrollable uncertainties until 2030, the heat auction price is expected to increase by approximately 22% to 59.36 EUR/MWh. In the ‘RES100’ scenario, investments in renewable heat production technologies could reduce auction

prices by 13%, compared with the ‘Current 2030’ alternative, reaching an average of 51.42 EUR/MWh. By contrast, introducing an excise duty on natural gas is associated with a slight increase in heat auction prices, to an average of 61.45 EUR/MWh. The ‘Gas Excise’ scenario indicates that an excise tax on natural gas could increase auction prices by 3.5%, compared with the ‘Current 2030’ scenario, despite the integration of a significant share of new RES. This effect is primarily related to the persistence of natural gas, which is projected to account for an average of 2.9% of heat production during the coldest periods in the Vilnius DH system.

Among the simulated scenarios, ‘RES Subsidy’, which allocates 25% financial support to new renewable heat production technologies (excluding biofuel boilers), results in the lowest auction price (48.5 EUR/MWh), which is 18.34% lower than in the ‘Current 2030’ scenario. This scenario shows that targeted financial measures would strongly encourage development of an optimised portfolio of new energy investments aimed at maximising operator profit. The final investment portfolio would mainly comprise high-temperature compression HPs using treated wastewater, with thermal capacity of 26.7–40.9 MW, as well as air-to-water HPs with a capacity of 1–100 MW. It would also include waste heat recovery from hydrogen electrolysis, integrating compression HPs with a capacity of 1–300 MW, and investments in electric boilers with thermal capacity of 1–35 MW. The portfolio would be complemented by solar thermal collector fields with an area of 1,000–100,000 m². Together, these investments would supply heat at the lowest possible auction price while ensuring operators’ financial viability (see *Table 27*).

Table 27. Summary table of uncertainty analysis for all scenarios

No.	Scenario	Strategy/priority	Optimal new investment portfolio by operator and IHPs	Total DH system heat auction price, EUR/MWh	Total DH system heat production costs, EUR/MWh	Total financial profit of OP, M EUR	Total financial profit of IHPs, M EUR	Gas share in DH system, %
1	‘Current 2023’	Current situation of Vilnius DH system in 2023	OP Biofuel CHP IHP-8 Waste CHP IHP1-7 Biofuel HOBs OP Gas boilers	48.56	49.36	14.92	36.98	34.8
2	‘Current 2030’	Vilnius DH system in 2030 without any new investment	OP Biofuel CHP + AHP[8.5MW] IHP-8 Waste CHP IHP-8 Biofuel CHP [170MW] IHP1-7 Biofuel	$\mu=59.39$ CV=3.92 %	$\mu=48.54$ CV=3.97%	$\mu=6.57$ CV=11.0%	$\mu=59.36$ CV=5.14 %	$\mu=16.2$ CV=

		ts by OP and IHP	HOBs OP Gas boilers					3.25 %
3	Base	All new investments considered toward profit maximisation	OP wastewater HPs [26.7–40.9 MW]; OP air-to-water HPs [1–100 MW]; OP H ₂ HPs [1–250 MW]; OP El. boilers [1–35 MW]	$\mu=$ 49.02 $CV=$ 7.07 %	$\mu=$ 39.16 $CV=$ 19.85 %	$\mu=$ 41.05 $CV=$ 138.7 %	$\mu=$ 31.45 $CV=$ 28%	$\mu=$ 5.46 $CV=$ 37.5 %
4	‘RES100’	To reach 100% RES generation by 2030 with profit maximisation	OP wastewater HPs [26.7–40.9 MW]; OP air-to-water HPs [50–150 MW]; OP H ₂ HPs [150–250 MW]; El. boilers for reserve [500 MW]	$\mu=$ 51.42 $CV=$ 9.97 %	$\mu=$ 34.69 $CV=$ 30.79 %	$\mu=$ 79.17 $CV=$ 84.8%	$\mu=$ 33.51 $CV=$ 40.17 %	0
5	‘RES Subsidy’	25% financial support for new RES-based generation technologies	OP wastewater HPs [26.7–40.9 MW]; OP air-to-water HPs [1–100 MW]; OP H ₂ HPs [1–300 MW]; El. boilers [1–35 MW] Solar collectors [1,000–100,000 m ²]	$\mu=$ 48.5 $CV=$ 7.6%	$\mu=$ 34.8 $CV=$ 27.1%	$\mu=$ 54.85 $CV=$ 125.1 %	$\mu=$ 29.79 $CV=$ 30.26 %	$\mu=$ 5.07 $CV=$ 41.44%
6	‘Gas Excise’	Limited use of natural gas by imposing an excise duty on the natural gas price	OP wastewater HPs [26.7–40.9 MW]; OP air-to-water HPs [1–100 MW]; OP H ₂ HPs [1–250 MW]; El. boilers [1–50MW] Biofuel OP [1–30 MW] Biofuel IHP [1–40 MW] Solar collectors [12,000–35,000 m ²] PTES storage [450,000–470,000 m ³]	$\mu=$ 61.45 EUR/MWh $CV=$ 10.19 %	$\mu=$ 41.66 EUR/MWh $CV=$ 19.2%	$\mu=$ 53.75 $CV=$ 103.93 %	$\mu=$ 52.09 $CV=$ 28.58 %	$\mu=$ 2.9 $CV=$ 54.1 %

Based on the uncertainty analysis scenario results, optimal new investment portfolios for the operator and new IHPs would substantially reduce heat production costs. The analysis indicates that the ‘RES100’ scenario, in which 100% of the DH system is supplied by RES, yields the lowest total heat production costs (34.69 EUR/MWh). Operator investments in new environmentally friendly heat production solutions: wastewater HPs, air-to-water HPs, hydrogen waste heat HPs, and electric boilers, would reduce total heat production costs by 28.5% compared with the ‘Current 2030’ scenario (see Fig. 92).

Similarly, the ‘RES Subsidy’ scenario produces a comparable outcome, with average heat production costs of 34.8 EUR/MWh. By contrast, the base scenario has slightly higher total heat production costs (39.16 EUR/MWh) than ‘RES Subsidy’ and ‘RES100’, mainly due to a higher average share of natural gas in the DH market (about 5.5%). The ‘Gas Excise’ scenario, assuming an excise duty that doubles the final price of natural gas, indicates that the total costs of heat production would be the highest under these uncertainty conditions.

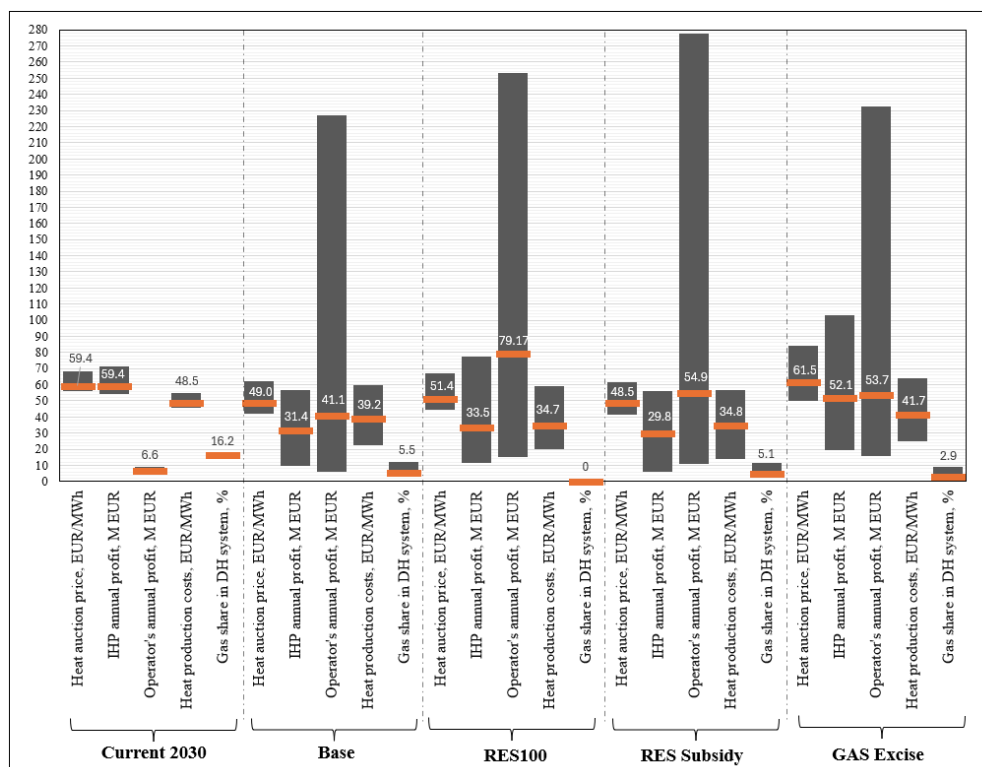


Fig. 92. The uncertainty analysis outcomes of the implemented scenarios

Furthermore, the uncertainty analysis indicates that, in 2030, heat production from natural gas could account from 0% to 5.5% of total heat production in the Vilnius DH system. Although the ‘RES100’ scenario ensures a complete transition to RES, a broader assessment of heat auction prices and consumer benefits indicates that the

‘RES subsidy’ scenario is more favourable for heat consumers. In this scenario, natural gas accounts for an average of 5.07% of heat production while delivering the lowest auction price for end consumers.

Such extensive modelling of future DH systems under a wide range of uncertainties offers a unique advantage for municipal DH strategic planning. For instance, the established partial equilibrium model can be applied not only in Lithuanian cities, where the operator and IHP heat production units primarily participate in the heat auction system, but can also be adapted on a broader scale by integrating the DH systems of foreign cities. The DH economic model is flexible and can be adapted to existing DH market structures and operating principles. Therefore, applying uncertainty analysis and evaluating diverse scenarios enables better planning of future energy systems.

3.10. Comparative Review of Sensitivity Analysis Outcomes

The partial equilibrium model sensitivity analysis identifies which uncertainty factors have the strongest effects on the selected model results, using the SPEA correlation coefficient ranging from -1 to 1. With an optimal portfolio of new technologies in all scenarios, hydrogen price dynamics is the most significant factor in reducing heat production costs and increasing total DH operator profit. All analysed scenarios confirm that, considering the financial compensation for waste heat generated during hydrogen production, higher hydrogen prices encourage a reduction in total heat production costs. This, in turn, reduces auction prices and maximises the total operator profit.

Operator investments in electrolyser waste heat utilisation equipment (compression HPs) with a capacity of 225–300 MW and in air-to-water HPs with thermal capacity of 100–150 MW could deliver the largest reduction in auction prices while maximising investor profit. For instance, the ‘RES100’ scenario demonstrates that achieving 100% RES production in the Vilnius DH system would require substantial operator investments in air-to-water HPs, hydrogen electrolysis waste heat HPs, and electric boiler units. This would have a positive effect on the final heat price for consumers but a negative effect on existing IHP facilities due to increased competition and potential financial difficulties (see *Table 28*).

Table 28. Summary table of sensitivity analysis for all scenarios

Scenario	Strategy/ priority	Highest uncertainty factor (UF) impact on total DH system heat auction price	Highest UF impact on total DH system heat production costs	Highest UF impact on total operator profit	Highest UF impact on total IHPs profit	Highest UF impact on gas component in DH system
Base	All new investments considered toward profit maximisation	Investments in H ₂ electrolyser HPs [225–250 MW] (h.a.price reduction up to 42 EUR/MWh)	H ₂ price increase toward 6 EUR/kg (h.p.costs reduction to ~30 EUR/MWh)	H ₂ price increase toward 6 EUR/kg (Increase the total operator profit in av. EUR 150 M)	Air-to-water HPs decrease profit [EUR -20 M] by investment in 100 MW	Air-to-water HPs decrease gas component [3.7%] by investment in 100 MW
RES100	To reach 100% RES generation by 2030 with profit maximisation	Air-to-water HPs (h.a.price reduction) [up to 45.9 EUR/MWh] by investment in 150 MW	H ₂ price increase toward 6 EUR/kg (h.p.costs reduction to ~23 EUR/MWh)	H ₂ price increase toward 6 EUR/kg (Increase the total operator profit in av. EUR 226 M)	H ₂ price increase toward 6 EUR/kg (decrease the total IHPs profit to EUR -25 M)	-
RES Subsidy	25% financial support for new RES-based generation technologies	H ₂ electrolyser HPs (h.a.price reduction) [up to 41.2 EUR/MWh] by investment in 270–300 MW	H ₂ price increase toward 6 EUR/kg (h.p.costs reduction to ~27 EUR/MWh)	H ₂ price increase toward 6 EUR/kg (Increase operator profit EUR 170–190 M)	H ₂ electrolyser HPs decrease profit [EUR -20 M] by investment in 300 MW	Air-to-water HPs decrease gas component 3.3% by investment in 100 MW
Gas Excise	Limitation in the use of natural gas by imposing an excise duty on the natural gas price	Air-to-water HPs (h.a.price reduction) [up to 59.4 EUR/MWh] by investment in 100 MW	H ₂ price increase toward 6 EUR/kg (h.p.costs reduction to ~32.5 EUR/MWh)	H ₂ price increase toward 6 EUR/kg (Increase operator profit EUR ~155.5 M)	Air-to-water HPs decrease profit [EUR -30 M] by investment in 100 MW	Air-to-water HPs decrease gas component 2.57% by investment in 100 MW

By contrast, the sensitivity analysis suggests that investments in air-to-water HPs could contribute most to reducing dependence on natural gas. The scenario results indicate that operator expansion through investment in up to 100 MW air-to-water HPs would reduce natural gas usage in the Vilnius DH market by approximately 2.6–3.7%. However, developing new HPs is also associated with a decrease in total IHPs profit, reflecting potential financial risks. The analysis also indicates that new investments in hydrogen waste heat recovery units and fluctuations in hydrogen prices have the most significant negative impact on existing IHP units, causing financial losses due to reduced heat production in existing IHP boiler plants. The ‘RES Subsidy’ and ‘RES100’ scenarios show that large operator investments in heat recovery from hydrogen electrolysis (300 MW) and a corresponding increase in hydrogen costs to 6 EUR/kg would reduce total IHP profit due to significantly increased competition.

Policy measures such as subsidies for renewable technologies and excise taxes on natural gas can accelerate decarbonisation and reduce gas dependency, but they also make it harder to balance system-wide cost savings with the financial sustainability of smaller producers. Subsidies can create strong investment incentives for large-scale hydrogen and HP projects, thereby reducing average production costs and supporting long-term competitiveness of DH systems. However, they may increase market concentration by disproportionately benefiting operators with more capital, while IHPs may face lower profits and reduced market participation. Similarly, excise taxes on natural gas can reduce fossil fuel use and support climate goals, but they may raise auction prices in the short term and distribute costs unevenly across market participants. National targets to achieve 100% RES-based heat production in DH systems may also be impractical for final heat consumers and IHPs, due to increased auction complexity as production sources become less competitive than new market entrants.

3.11. Applicability of Model Results and Their Correlation to Similar Scientific Findings

This dissertation evaluates complex DH sector performance under diverse uncertainties. The results indicate that treated wastewater and ambient air heat recovery, as well as green hydrogen waste heat utilisation, may be beneficial and have significant potential to improve DH systems. These solutions could increase competition among heat producers and reduce heat costs. This research develops new methods using a partial equilibrium economic model to improve DH economic planning accuracy. Extending the model with Monte Carlo sensitivity and uncertainty analysis enables optimal solutions for maximising investor profits, ensuring adequate heat auction costs, and lowering CO₂ emissions.

Hiltunen and Syri (2021) conduct a similar economic study, but with a narrower scope focused on improving the Espoo DH system in Finland. Their research assesses feasible scenarios to replace coal-fired heat generation with biofuel CHP and HOBs, as well as compression HPs using waste heat from data centres and wastewater. They identify data centre waste heat recovery as an appropriate solution for reducing heat production costs and CO₂ emissions. The authors report that recovering waste heat from operating data centres can reduce production costs below the baseline and emissions to one-quarter of the baseline level (Hiltunen & Syri, 2021). Their study indicates that using waste heat from the data centres reduced average production costs from 34.89 EUR/MWh to 33.34 EUR/MWh and lowered annual CO₂ emissions to 128 ktOE CO₂, compared with the baseline of 545.5 ktOE CO₂.

The research on the Vilnius DH system demonstrates that new high-capacity compression-based HPs utilising waste heat from green hydrogen might reduce emissions by up to 66%, considering the complex economic uncertainties. A case study of the Vilnius DH model also suggests that under the ‘RES100’ and ‘RES Subsidy’ scenarios, an investment portfolio including treated wastewater HPs, air-to-water HPs, hydrogen electrolysis waste heat compression HPs, solar collectors, and electric boilers could reduce heat production costs by 28–28.5%, compared with the ‘Current 2030’ scenario, while accounting for energy price volatility as an uncertainty in the 2030 projections.

In their comprehensive analysis, Hiltunen and Syri (2021) indicate that the waste heat recovery rate is considerably high, at around 64–65%. High electricity prices are a key factor limiting waste heat use because they increase HP operating costs. The authors conclude that pauses in waste heat recovery tend to occur when electricity prices are extremely high. Conversely, this condition increases electricity sales and encourages CHP electricity production. Wahlroos et al. (2017) argue that waste heat recovery is financially profitable and reduces heat production costs, but it can also reduce electricity generation profits because waste heat can replace other CHP units. They argue that waste heat is valuable at the DH system level, with potential annual operating cost savings of 0.6–7.3% when waste heat potential is 18.7–58.5 MW (Wahlroos et al., 2017). The Vilnius economic model supports these findings that increasing new compression HP capacities reduces the financial profit of existing IHP

units and lowers IHPs heat production due to higher competition in the local DH market.

Similarly, Ali et al. (2024) conduct a comprehensive study emphasising the importance of integrating seawater HPs into DH systems in Estonia and Norway. For Estonia, their scenario comparison assesses a near-shore seawater HP combined with an electric boiler and a stand-alone offshore seawater HP integrated into the Estonian DH system. For Norway, their study investigates three scenarios: a seawater HP system combined with waste heat from electrolysis plants, a stand-alone seawater HP, and an individual electric heating system. Their analysis considers key parameters, including heat pump coefficient of performance (COP), electricity consumption, CO₂ emissions, and heat production costs.

The Estonian results indicate that stand-alone seawater HPs provide increased economic benefits due to more stable seawater temperatures, higher COP, lower electricity consumption, and lower CO₂ emissions. The Norwegian results demonstrate that greater use of seawater HPs could achieve a 71% reduction in annual electricity consumption for heating. The authors also report that combining seawater HPs with electrolyser waste heat could reduce heat production costs by nearly fourfold (Ali et al., 2024).

Building on the partial equilibrium economic model of the Vilnius DH system and the international examples discussed, the findings highlight the strong potential of waste heat utilisation in DH systems to improve efficiency, reduce heat production costs, maximise profit, and replace fossil fuels. The newly developed model, which covers diverse strategic, policy, and economic uncertainties, supports a comprehensive approach to setting development directions for DH companies and prioritising the most economically viable solutions. The framework can also assist other municipalities in identifying optimal investments to achieve decarbonisation targets. For instance, the developed methodology was applied to the smaller-scale Alytus DH network through a sensitivity and uncertainty analysis, aiming to integrate optimal size renewable heat and flexibility technologies. The study explores the behaviour of existing and new market participants, considers energy price fluctuations and the operator's potential investments in the development of new heat generation facilities, e.g., air-to-water HP solutions, flexibility solutions related to investments in short-term TES for the utilisation of excess heat from industrial heat sources, as well as investments in solar collectors integrated with TES as sources of uncertainty. The research reveals that the existing Alytus DH market is almost full, and the implemented investigation proved that only air-to-water compression HPs might be financially feasible for operator investments and heat costs reduction in the Alytus DH system. The results indicate that, with the introduction of new HPs with a capacity of 2.5–2.7 MW, the heat auction price might be 10–20% lower than in the baseline scenario, reaching 39–44 EUR/MWh, taking into account all economic uncertainties. The established model can also assess multiple scenarios that include diverse policy measures, e.g., transitioning to 100% RES-based heat production in the local DH system, introducing additional taxes for fossil fuels, or integrating potential EU financial support, and demonstrate how total heat production costs and auction price may change.

The achieved dissertation findings have relevant implications for Lithuanian and European energy policy. For instance, the conducted ‘RES100’ scenario indicates that large-scale investments in hydrogen production and the utilisation of its waste heat, power-to-heat technologies, and the use of ambient waste heat by HPs can significantly increase investor profits and reduce total heat production costs. This corresponds to the direction of Lithuanian national energy independence strategy, which highlights carbon-neutral local energy production, electrification, green hydrogen, heat pumps, and renewable energy technologies as key elements of the national energy transition towards 100% renewable energy by 2050 (Lithuanian Ministry of Energy, 2024). At the European Union (EU) level, the research results are in line with the latest Energy Efficiency Directive (European Parliament and Council of the European Union, 2023a), in particular Article 26, which emphasises the role of efficient district heating and cooling by imposing stricter decarbonisation criteria and fostering the integration of renewable energy and waste heat. These outcomes are also consistent with the updated Renewable Energy Directive (European Parliament and Council of the European Union, 2023b), which enhances the role of renewable energy and waste heat in district heating and cooling systems by raising the annual growth target for the integration of renewable energy and waste heat into district heating and cooling networks from 1.0 to 2.2 percentage points for the period 2021–2030.

However, a comparison of the ‘RES100’ and ‘RES subsidy’ scenarios reveals that the most profitable path for investors is not always the most beneficial for end heat users or IHPs. Although 100% renewable energy targets can accelerate decarbonisation, they may also increase the complexity of heat auctions, reduce the competitiveness of existing cogeneration power plants and boiler facilities, and shift market power to more capital-intensive operators capable of investing in hydrogen and large-scale power-to-heat technologies. This issue is consistent with the guidelines of the European Commission (2022) on aid for climate, energy, and environmental protection, which emphasise that state support for climate and energy investments should be proportionate and limit distortions of competition. Thus, national subsidy schemes for the decarbonisation of district heating should include competition-preserving instruments, such as open auctions and monitoring of market concentration.

The impact of natural gas excise taxes also deserves careful policy consideration. Higher taxation of fossil fuels may contribute to the achievement of climate goals by increasing the competitiveness of renewable heat, hydrogen-based waste heat, and electrified heat production. This research finding is directly supported by the proposal of the European Commission (2021) on restructuring the EU framework for the taxation of energy products and electricity, where the Commission clearly indicates that the aim of the reform is to increase taxes on fossil fuels, thereby enhancing the competitiveness of lower-carbon energy technologies. However, research findings demonstrate that gas excise taxes may increase heat auction prices in the short term and place a disproportionate burden on market participants. Therefore, the taxation of fossil fuels should be implemented gradually, combined with consumer protection measures, transitional support for vulnerable heat consumers, and rules preventing excessive price increases in district heating auctions.

The sensitivity analysis conducted in the dissertation reveals that hydrogen price trends and large-scale hydrogen and heat pump projects are the most significant sources of uncertainty that reduce the total costs of heat production. This means that hydrogen policy should not be formulated separately from DH sector policy. Lithuanian and EU green hydrogen strategies should clearly recognise that DH systems are potential users of waste heat from electrolyzers. Such integration would increase system efficiency, reduce heat auction prices, and strengthen the economic viability of green hydrogen.

Additionally, the partial equilibrium model can assess the future financial condition of existing IHPs and operator heat and electricity generation facilities, considering projected economic uncertainties when additional heat generation capacity is introduced into the DH market. This model capability is valuable for identifying future market risks and planning decisions to avoid financial losses. It is worth noting that a comprehensive assessment of the entire DH sector can support better planning of future development trends by enabling a more reliable and realistic DH system and contributing to lower heat prices for consumers.

CONCLUSIONS

1. The theoretical analysis shows that the development of the district heating (DH) sector is strongly influenced by the regulatory framework, market structure, and various types of uncertainties. Key regulatory factors, such as consumer network connections, price regulation, ownership regulation, and third-party access to heat networks, significantly affect investment incentives, market stability, and system development. A detailed assessment of uncertainties in DH has led to the establishment of a hierarchical pyramid of uncertainty control. This pyramid provides a structured system for differentiating the level and degree of control over uncertainties in the context of the energy transition. The classification highlights the importance of distinguishing between controllable, partially controllable, and uncontrollable uncertainties, enabling decision-makers to plan future investments more effectively, prioritise risk mitigation measures, and enhance adaptive capacity during systemic energy transitions.
2. The literature review on energy modelling tools indicates that simple deterministic approaches using energy simulation or optimisation tools are insufficient to fully characterise the DH environment under uncertainty. Optimisation models do not address suboptimal solutions, often producing idealised scenarios that are unrealistic and underestimate intermediate changes. By contrast, simulation models allow user-defined sensitivity analyses but are restricted to a set of scenarios that do not adequately reflect the complex effects of uncertainty. The reviewed modelling tools also exhibit additional limitations, including the inability to manage different strategies for heat auction system performance that reflect real heat market conditions, insufficient extensions for Monte Carlo-based sensitivity and uncertainty analysis when determining optimal investment portfolios, and limited capacity to assess significant changes in the DH environment. The increasing complexity of DH systems requires a multidisciplinary stochastic approach to address economic, strategic, and political challenges.
3. The methodology developed in this dissertation employs a stochastic approach and enables an analysis of DH sector performance under diverse uncertainties. It reflects the DH market structure, in which new market participants are emerging, and a dynamic environment is evolving. The methodology integrates economic (uncontrollable), strategic (controllable), and political (semi-controllable) uncertainties within uncertainty and sensitivity analyses. The extension of the deterministic approach with these analyses allows for the identification of new optimal investment portfolios for operators and independent heat producers in order to maximise investment profits, ensure adequate heat auction prices, and contribute to carbon emission reduction.
- 3.1. This methodology is also applicable for assessing the financial condition of existing market participants by considering various policy measure scenarios and including diverse new heat production and transformation facilities. It supports

long-term DH development planning across municipalities of different sizes and has unique benefits in its ability to manipulate alternative operational strategies for the heat auction system.

4. This dissertation demonstrates the application of a partial equilibrium economic model and an energyPRO-based verification to the selected Vilnius city DH system. The developed framework is designed to operate according to the principles of a realistic heat auction system, illustrating competition among heat production units that generates the greatest benefits for final heat consumers. The implementation of the partial equilibrium economic model for the Vilnius DH system under different types of uncertainty reveals significant potential to integrate various waste heat sources to maximise investor profit, ensure adequate heat auction prices, and reduce CO₂ emissions. A key advantage and distinctive feature of the model is its ability to analyse the behaviour of existing heat operator, independent heat producers (IHPs), and new market participants under changing uncertainties. The framework also demonstrates the feasibility of an hourly auction system, enabling more reliable and efficient operation of the Vilnius DH market.
5. The uncertainty analysis indicates that the 'RES100' scenario, where the entire DH system is supplied by renewable energy sources (RES), results in the lowest total heat production costs and the highest potential financial profit for the investor. In this scenario, operator investments in advanced, environmentally friendly technologies, such as treated wastewater heat pumps (HPs) (26.7–40.9 MW), air-to-water HPs (50–150 MW), H₂ electrolyzers with waste heat utilisation compression HPs (150–250 MW), and electric boilers (500 MW), enable a 28.5% reduction in total heat production costs, compared with the 'Current 2030' baseline scenario. These large-scale investments in hydrogen and power-to-heat conversion technologies also generate financial profits 12 times higher than the 'Current 2030' scenario. Although the 'RES100' scenario achieves full reliance on renewable energy, a detailed assessment of heat auction prices and consumer benefits shows that the 'RES Subsidy' scenario is more favourable for final heat consumers. Under this scenario, the optimal investment portfolio includes treated wastewater and air-to-water HPs, H₂ electrolyzers with HPs, electric boilers, and solar thermal collectors with short-term heat storages. Under the 'RES Subsidy' scenario, the share of natural gas in the DH mix is limited to an average of 5.07%, while the lowest consumer auction price (48.5 EUR/MWh) may be achieved under the assumed 2030 economic uncertainties.
- 5.1. Subsidies can provide strong investment incentives for large-scale hydrogen and heat pump projects, thereby reducing average production costs and supporting the long-term competitiveness of DH systems. However, they may also increase market concentration by disproportionately favouring operators with more capital, while IHPs may face reduced profits and lower market participation.

- 5.2. Similarly, excise duties on natural gas can support climate objectives by reducing reliance on fossil fuels; however, in the short term, they may increase auction prices and lead to an unbalanced cost burden among market participants.
 - 5.3. National targets aimed at achieving 100% RES-based heat production in DH systems may also be inefficient, not only for end consumers but also for IHPs, due to increased auction complexity and declining competitiveness of existing production sources relative to newer market participants.
 - 5.4. The results of the uncertainty analysis are not limited to the Vilnius DH system and provide valuable information applicable to the planning and modelling of DH systems in other cities.
-
6. The sensitivity analysis shows that, across all investigated scenarios with optimal investment portfolios in new technologies, hydrogen price dynamics is the most influential uncertainty factor in reducing heat production costs and maximising investor profit. The scenario outcomes further demonstrate that, when financial compensation for waste heat generated during hydrogen production is considered, higher hydrogen prices stimulate reductions in total heat market production costs. Combined with increased competition, this effect leads to lower heat auction prices and creates favourable conditions for maximising investor-operator profits through the production and sale of green hydrogen in the local market.
 - 6.1. The results of the Monte Carlo sensitivity analysis also demonstrate that, under optimal combinations of new technologies, H₂ electrolysis waste heat units and air-water heat pumps may have the greatest impact on DH system development and contribute most to the reduction in heat auction price.
 - 6.2. Conversely, across all scenarios, investments in air-to-water heat pumps may contribute most to reducing natural gas dependence but are also strongly associated with decreased IHP profitability, reflecting substantial financial risks to future profits.
 - 6.3. The analysis also indicates that new investments in hydrogen waste heat recovery facilities, along with fluctuations in hydrogen prices, may have the most significant negative impacts on existing CHP facilities and may cause substantial financial losses due to reduced heat production in existing IHP boiler houses.

SANTRAUKA

IVADAS

Tyrimo aktualumas

Energetikos sistema šiuo metu išgyvena didžiulius pokyčius, susijusius su sparčiu atsinaujinančių energijos išteklių, ypač saulės ir vėjo, dalies padidėjimu, o tai gali lemti reikšmingą pagaminamos energijos apimčių apribojimą arba perteklių. Todėl, siekiant užtikrinti tinkamą elektros energijos pasiūlos ir paklausos balansą bei išvengti didelio gamybos apimčių apribojimo, reikalingos naujos technologijos, apimančios ir centralizuoto šilumos tiekimo (CŠT) technologijas. Dėl CŠT sistemų gebėjimo integruoti elektros ir kitas technologijas, jos gali atlikti reikšmingą vaidmenį balansuojant elektros energijos pasiūlą ir paklausą (Averfalk et al., 2014). CŠT gali padidinti energetikos sistemos lankstumą ir reikšmingai prisidėti prie atsinaujinančiųjų energijos technologijų integravimo į būsimą Europos energetikos sistemą (Averfalk et al., 2014). Ateityje šios sistemos galėtų būti naudingos užtikrinant energetikos sistemų tvarumą ir saugumą, ypač šalyse, kuriose didelę dalį sudaro centralizuotas šilumos tiekimas ir atsinaujinančiųjų energijos išteklių naudojimas (Münster et al., 2012).

Prognozuojama, kad centralizuoto šilumos tiekimo transformacija bus įgyvendinama įdiegiant pažangius energetikos sprendimus, tokius kaip „Power-to-X“, paklausos reagavimo ir kitas lankstumo bei energijos saugojimo technologijas, kurios sukuria sinergiją tarp elektros energijos ir centralizuoto šilumos tiekimo sektorių (Bloess, Schill ir Zerrahn, 2018), (Lund ir kt., 2010). Šie sprendimai galėtų prisidėti prie atsinaujinančiųjų energijos išteklių integravimo, CO₂ išmetimo mažinimo ir energetikos sistemos dekarbonizavimo ekonomiškai pagrįstu būdu (Lund et al., 2010). Kita vertus, deklaruojama, jog elektromobilių bei elektros energijos pavertimo vandeniliu per elektrolizę panaudojimas galėtų prisidėti prie lankstesnio energijos valdymo (Parrado-Hernando et al., 2022). Tyrėjai (Hiltunen, Syri, 2021) teigia, kad optimalūs rezultatai galėtų būti pasiekti, kai elektros, šilumos ir transporto sektoriai yra integruoti į bendrą pažangią energetikos sistemą. Reikšmingas ekonominis efektas galėtų būti pasiekiamas integravus vandenilio elektrolizės įrenginius šilumos sektoriuje, nes atsirastų galimybė lanksčiai naudoti atsinaujinančiosios energijos perteklių ir vandenilio atliekinę šilumą panaudoti šilumos tinkluose (Parrado-Hernando et al., 2022). Tyrimas (Mezzera et al., 2021) išryškina didelį potencialą panaudoti vandenilio gamybos procesų metu susidarančią atliekinę šilumą. Ši atliekinė šiluma gali būti efektyviai integruota į centralizuoto šilumos tiekimo tinklus, taip ženkliai prisidedant prie šilumos poreikio tenkinimo. Vandenilio gamybos metu susidarančios atliekinės šilumos panaudojimas yra esminis veiksnys, didinantis bendrą ateities, mažai anglies dioksido į aplinką išskiriančių, energijos sistemų efektyvumą. Nagrinėjant Švedijos miestą Luleå (Miljanovic ir Jonsson, 2022), buvo pasiūlyta sistema, leidžianti integruoti vandenilio gamybos metu susidarančią atliekinę šilumą į centralizuoto šilumos tiekimo tinklą. Tyrimas parodė, kad šios atliekinės šilumos panaudojimas galėtų padidinti žaliojo vandenilio gamybos ekonominį efektyvumą ir paskatinti tvarius šilumos tiekimo sprendimus regione.

Kitas, Danijos ambasados iniciatyva, atliktas tyrimas (Ramboll, 2021) panašiai vertina galimas sinergijas tarp ateities vandenilio gamybos ir atliekinės šilumos panaudojimo Jungtinėje Karalystėje. Ataskaitoje pabrėžiama, kad didžiuliai atliekinės šilumos kiekiai, susidarantys gaminant vandenilį, atveria plačias galimybes integruotis į šilumos tiekimo sistemas.

Dauguma mokslinių tyrimų patvirtina energetikos sistemos, ypač CŠT sektoriaus, svarbą pasaulio ekonomikai ir jo lemiamą vaidmenį energetikos pereinamajame procese. Tuo tarpu (Muncan et al., 2024) tyrimas parodė, kad centralizuoto šilumos tiekimo sistemos yra svarbios ne tik Europoje, bet ir Centrinėje Azijoje – jos aprūpina šildymu daugiau nei 70 milijonų gyventojų, o regione veikia apie 17 000 tokių sistemų. Pasaulio banko ataskaitoje (The World Bank, 2023) teigiama, kad šilumos tiekimo sektoriaus transformacija ir plėtra gali suteikti daug pranašumų, pavyzdžiui, degalų ir išlaidų taupymą, geresnes sveikatos sąlygas, socialinę ir ekonominę gerovę. Tyrime prognozuojama, kad toks perėjimas 2024–2050 m. laikotarpiu leistų išvengti apie 8,9 Gt CO₂ emisijų, susidarančių dėl patalpų šildymo. Pavyzdžiui, Tarptautinė energetikos agentūra (IEA, 2019a) pabrėžia, kad centralizuoti šilumos tiekimo tinklai sudaro palankesnes sąlygas masto ekonomijai ir didesniai efektyvumui, nes koncentruoja paklausą, diegia atsinaujinančiosios energijos kaupimo sprendimus ir leidžia lengviau sujungti šilumos ir elektros energijos sistemas. Tuo tarpu mokslininkų (Persson et al., 2019) ir (Lund et al., 2010) tyrimai akcentuoja CŠT strateginę reikšmę didinant energijos sistemos efektyvumą, mažinant sąnaudas ir skatinant atsinaujinančių energijos šaltinių plitimą. Lund et al. (2010) pabrėžia, kad centralizuotas šilumos tiekimas gali būti ekonomiškesnis nei individualus pastatų šildymas, naudojant optimizuotus gamybos šaltinių technologijų profilius ir pramonės bei elektrinių atliekinę šilumą. Persson et al. (2019) savo ruožtu aptaria CŠT ekonominius privalumus vietovėse, kuriose yra didelis šilumos poreikis, nurodant, kad masto ekonomija tokiose vietovėse gali sumažinti tiekimo sąnaudas.

Neracionalus CŠT plėtros planavimas ir investicijos į naujas sistemas grindžiamas iškastinio kuro technologijomis, pvz., gamtinių dujų katilais, kurie gali prisidėti prie didesnių energijos gamybos sąnaudų ir energijos nepritekliaus. Mokslininkų (Dahl, Brun ir Andresen, 2019) tyrime pateikiama išsami jautrumo analizė, kurioje pabrėžiama, kad iškastiniu kuru pagrįstos šilumos energijos sistemos, naudojančios dujų katilus, yra labai jautrios energijos kainų svyravimams, kurie gali didinti sąnaudas ir dėl to gali tapti mažiau patikimos ir atitinkamai brangesnės. Autorių nuomone, įvyksta priešingas reiškinys, kai ne iškastiniu kuru pagrįstos veikiančios sistemos, kuriose naudojamos tokios technologijos kaip šilumos siurbiai ir šilumos saugyklos, yra stabilesnės ir patikimesnės. Tyrime pabrėžiami finansiniai rizikos veiksniai, susiję su iškastiniu kuru pagrįstų šilumos tiekimo sistemų plėtra, ir akcentuojama strateginio planavimo svarba užtikrinant ekonomišką ir tvarią šilumos gamybą. Panaši situacija matoma ir kitame tyrime apie Lenkijos centralizuoto šilumos tiekimo sektorių (Talarek, Knitter-Piątkowska ir Garbowski, 2023). Tyrime pabrėžiama, kad priklausomybė nuo iškastinio kuro, pavyzdžiui, gamtinių dujų, gali padidinti šilumos gamybos sąnaudas dėl augančio CO₂ emisijų apmokestinimo. Tyrime nurodoma, kad 2020 m. daugelis centralizuoto šilumos tiekimo įmonių tapo nuostolingos dėl išaugusių kintamųjų eksploatacinių išlaidų, susijusių su iškastinio

kuro naudojimui. Ši finansinė našta pabrėžia riziką, susijusią su centralizuoto šilumos tiekimo sistemų plėtra nepereinant prie atsinaujinančiųjų energijos išteklių. Kita vertus, Estijos mokslininkų (Kirs ir Volkova, 2024) atlikta geoerdvinė analizė atskleidžia ryšį tarp prieinamumo prie šilumos tiekimo ir energijos nepritekliaus. Tyrimas parodė, kad vietovėse, kuriose nėra efektyvių šilumos tiekimo sistemų, mažesnes pajamas gaunantys namų ūkiai dažnai patiria didesnes energijos sąnaudas. Šis ryšys rodo, kad netinkamas planavimas ir investicijos į centralizuoto šilumos tiekimo infrastruktūrą gali prisidėti prie energijos nepritekliaus. Mokslininkų (Zach, Erker ir Stoeglehner, 2019) tyrime taip pat nagrinėjama šilumos tiekimo sistemų aplinkos, techninių, ekonominių savybių ir erdvinės struktūros sinergija. Jie pabrėžia, kad nepakankamai gerai apgalvotas plėtros planas ir netinkamas planavimas gali lemti didesnes pradinės įrengimo ir eksploatacijos išlaidas, dėl kurių galutiniai vartotojai patirtų didesnes šilumos išlaidas. Lietuvoje atliktas mažų šilumos tinklų sistemų tyrimas (Dzenajavičienė et al., 2007) atskleidžia panašius rezultatus – nepakankamas planavimas ir investicijos gali padidinti šilumos gamybos sąnaudas. Tyrime pabrėžiama būtinybė atsižvelgti į ilgalaikes eksploataavimo sąnaudas ir užtikrinti tinkamų technologijų pasirinkimą, kad būtų užtikrintas ekonominis pagrįstumas.

Pavyzdžiui, pagal (Jiang, Rindt ir Smeulders, 2022), įgyvendinant patikimą centralizuoto šilumos tiekimo planavimą reikalinga atlikti išsamią šilumos energijos išteklių analizę, tiksliai prognozuoti šilumos poreikį ir strategiškai integruoti tvarius energijos šaltinius. CŠT sistemų gyvybingumą labai lemia teritorijų planavimo parametrai, įskaitant pastatų šilumos vartojimo tankį, žemės paskirties sudėtį ir prieigą prie tinkamų šilumos šaltinių (Zach et al., 2019). Nors klimato kaita ir mažėjantis šilumos poreikis kelia didelius sunkumus ilgalaikiam CŠT tvarumui, juos galima įveikti žeminant šilumos tiekimo temperatūrą ir plačiau naudojant atsinaujinančius ir atliekines energijos šilumos šaltinius (Zach et al., 2019). Vystantis ketvirtosios kartos centralizuoto šilumos tiekimo (4G DH) sistemoms, dėmesys sutelkiamas į šilumos nuostolių mažinimą, atsinaujinančių energijos išteklių dalies didinimą ir pažangių valdymo bei stebėsenos technologijų diegimą (Volkova et al., 2020).

Mokslininkai (Jonynas et al., 2020) 2020 m. tyrime pabrėžia CŠT svarbą kompleksinėse energetikos sistemose. Remiantis jų išvalgomis, Lietuvos CŠT sistema sulaukia didelio dėmesio nacionalinėje energetikos strategijoje, kurioje pagrindinis dėmesys skiriamas priklausomybės nuo iškastinio kuro mažinimui ir atsinaujinančių energijos išteklių (toliau – AEI) naudojimo plėtrai. Lietuvos nacionalinėje energetinės nepriklausomybės strategijoje (Lietuvos energetikos ministerija, 2024) pabrėžiama aplinkai nekenksmingų šilumos energijos gamybos šaltinių svarba. Tikimasi, kad šie šaltiniai reikšmingai prisidės prie nacionalinio tikslo iki 2050 m. visiškai pereinant prie 100 % atsinaujinančiosios energijos. Dauguma šiuolaikinių šilumos gamybos sprendimų gali turėti milžinišką potencialą prisidėti prie AEI integravimo, tačiau jų poveikis CŠT yra nežinomas dėl daugybės ekonominių neapibrėžtumų. Siekiant subalansuotos ir efektyvios atsinaujinančiųjų energijos išteklių plėtros bei nacionalinių strateginių tikslų įgyvendinimo, būtina užtikrinti tinkamą CŠT planavimą. Kita vertus, žvelgiant iš platesnės energetikos perspektyvos, integruotos energetikos sistemos reikalauja detalios analizės ir strateginio planavimo, kad būtų

patenkinti įvairūs visų sektorių poreikiai ir užtikrintas tinkamas bei efektyvus energijos transformavimo procesas (Groppi et al., 2023).

Mokslinė problema ir jos ištirimo lygis

Įprastinėse CŠT sistemose mokslininkai energijos srautus ir infrastruktūros veikimą modeliuoja taikant deterministinius modelius, pagrįstus fiksuotomis prielaidomis, tokiomis kaip pastovūs paklausos profiliai ar oro sąlygos. Tačiau šie modeliai dažnai neatsižvelgia į energijos paklausos, technologinio efektyvumo, kuro kainų ir su klimatu susijusių veiksnių kintamumą laike ir erdvėje, o tai gali lemti netikslus ar potencialiai neobjektyvius planavimo rezultatus (Mendes, Ioakimidis ir Ferrão, 2011). Šis lankstumo trūkumas riboja jų tinkamumą ilgalaikiam strateginiam planavimui sparčiai kintančiose energijos rinkose. Scenarijais pagrįstas modeliavimas suteikia daugiau įvairovės, tačiau pastebima, kad daugelis energetikos scenarijų atspindi tik ribotą galimų scenarijų spektrą, dažnai nepakankamai atsižvelgiant į ekstremalius scenarijus (Wiese et al., 2018). Ši ribota aprėptis gali klaidinti atliekant galimų energetikos ateities scenarijų bendrą vertinimą ir iškreipti išsamią mokslinę analizę. Be to, scenarijai dažnai grindžiami ekspertų prielaidomis ir juose gali trūkti tikimybės ar jautrumo analizės, todėl sunku įvertinti pasirinkimų patikimumą (Pfenninger et al., 2014). Dėl ribotos aprėpties sudėtinga visapusiškai įvertinti įvairių energetikos transformacijos kelių riziką ir neapibrėžtumus.

Dėl didėjančio CŠT sistemų sudėtingumo reikalingas kompleksinis požiūris, leidžiantis spręsti tokius iššūkius kaip energijos kainų svyravimai, politikos pokyčiai ir naujų technologijų įdiegimas. Tereshchenko ir Nord (2016) pabrėžia tokių veiksnių kaip kuro kainų svyravimai ir šilumos apkrovos profilių pokyčiai svarbą planuojant CŠT. Jų tyrimas demonstruoja, kad tradiciniai deterministiniai modeliai paprastai nepakankamai atspindi šių kintamųjų dinamiką, todėl investicijų pasirinkimai nėra optimalūs. Vis dėlto įprasti deterministiniai modeliai leidžia įvertinti atskirų ekonominių neapibrėžtumų poveikį energetikos sistemai, tačiau paprastai jie nepakankamai atspindi kompleksinius techninius ir ekonominius neapibrėžtumus, politinius ir strateginius veiksnius bei tarpsektorinius veiksnius, kurie yra tarpusavyje susiję ir svarbūs realioms rinkos dinamikos sąlygoms. Autoriai (Lygnerud et al., 2023) pabrėžia, kad naujų technologijų integravimas ir įvairių rinkos dalyvių atsiradimas keičia CŠT sektorių ir reikalauja pažangesnių planavimo ir investavimo strategijų. Tuo tarpu mokslininkai (Parrado-Hernando et al., 2022) pabrėžia, kad per pastarąjį dešimtmetį išryškėjo keturi pagrindiniai energijos modeliavimo iššūkiai: neapibrėžtumo ir modelių skaidrumo užtikrinimas, kompleksiško valdymas ir optimizavimas skirtingais masteliais, efektyvus žmoniškųjų ir realių rinkos elgsenos veiksnių integravimas bei optimizavimo ir simuliacinio modelių laiko ir erdvės skiriamosios gebos gerinimas, siekiant tiksliai atspindėti nepastovių AEI, įskaitant vėjo, saulės fotoelektros, potvynių, bangų ir kitus, kintamumą. Visi šie veiksniai didina centralizuoto šilumos tiekimo sistemų planavimo ir investicinių sprendimų sudėtingumą ir aiškiai rodo, kad paprastas deterministinis arba scenarijais pagrįstas požiūris nėra pakankamas išsamiam vertinimui.

Paprastai neapibrėžtumai, susiję su centralizuoto šilumos tiekimo ar visų energetikos sistemų modeliavimu, skirstomi į tris grupes: nekontroliuojami veiksniai,

tokie kaip nepastovios elektros, gamtinių dujų, CO₂ ar biokuro kainos ir ilgalaikės šilumos paklausos dinamika (Soroudi ir Amraee, 2013), (Afzali, Hosseini ir Peyghami, 2024), kontroliuojami veiksniai, įskaitant tiesioginius investicinius sprendimus į naujus AEI įrenginius ir pajėgumus (Soroudi ir Amraee, 2013), ir iš dalies kontroliuojami veiksniai, pvz., AEI plėtros tikslai ar subsidijų schemos, kurios priklauso nuo būsimų politinių sprendimų ir todėl yra tarp visiškai kontroliuojamų ir visiškai nekontroliuojamų (Soroudi ir Amraee, 2013). Kiekviena neapibrėžtumo kategorija yra susijusi su konkrečiomis modeliavimo sąlygomis, kurios didina CŠT sektoriaus sudėtingumą. Pavyzdžiui, nekontroliuojami veiksniai, tokie kaip rinkos kainos ir paklausos svyravimai, reikalauja didelės laiko ir erdvės skiriamosios gebos, kontroliuojami veiksniai, tokie kaip investiciniai sprendimai, reikalauja modelių, apimančių skirtingus sektoriaus dalyvius, o iš dalies kontroliuojami veiksniai, tokie kaip politikos priemonės, geriausiai sprendžiami scenarijų analize (Pfenninger et al., 2014), (Wiese et al., 2018). Kita vertus, paprastesnė vertinimo metodika galėtų sumažinti skaičiavimo apimtis, tačiau išliktų rizika ignoruoti kritinius dinamikos aspektus, o pažangios stochastinės scenarijais pagrįstos metodikos suteiktą sistemiską būdą įvertinti galimas ateities perspektyvas visose trijose neapibrėžtumo kategorijose ir padėtų nustatyti strategijų geresnį patikimumą (Fan et al., 2022).

Aktualūs pavyzdžiai nagrinėjami analizuojant neapibrėžtumus ir naujų metodų taikymo galimybes elektros energetikos sektoriuje, atsižvelgiant į Kanarų salų dekarbonizacijos planus iki 2040 m. (Berna-Escriche et al., 2024). Šiame tyrime neapibrėžtumo vertinimas taikomas alternatyvių pereinamojo laikotarpio strategijų patikimumui įvertinti, atsižvelgiant į technologinius, ekonominius ir su politika susijusius neapibrėžtumus. Metodikoje pabrėžiamas kiekybinių modeliavimo metodų integravimas su kokybiniais scenarijais, taip sudarant galimybę išsamiau pateikti sisteminės rizikas ir galimus jų mažinimo būdus. Panašus požiūris yra taikomas ir branduolinės saugos srityje, kur struktūrizuota neapibrėžtumo analizė yra sprendimų priėmimo ir rizikos valdymo pagrindas (D'Auria, 2019). Energetikos sistemos transformacijos tyrimų ir branduolinės saugos analizių panašumai pabrėžia tarpdisciplininę neapibrėžtumo metodikų reikšmę, ypač jų gebėjimą didinti skaidrumą, skatinti lankstų planavimą ir padėti suinteresuotosioms šalims valdyti kompleksines sistemas.

Nepaisant neapibrėžtumų analizės svarbos, iki šiol ji buvo taikoma tik ribotam skaičiui energetikos srities šaltinių. Literatūroje akcentuojama, kad yra platesnės galimybės gauti tikslesnius ir patikimesnius rezultatus, įtraukiant stochastinius metodus, kurie leistų atsižvelgti į neapibrėžtumus, svyravimus ir atsitiktinumus planuojant energetikos sistemą. Todėl ši disertacija kelia pagrindinį klausimą: kokie yra galimi neapibrėžtumai ir kaip juos modeliuoti planuojant centralizuotą šilumos tiekimą, atsižvelgiant į rinkos dinamikos poveikį?

Tyrimo objektas

Neapibrėžtumų poveikis centralizuoto šilumos tiekimo rinkai.

Tyrimo tikslas

Teoriškai identifikuoti neapibrėžtumus ir sukurti dalinės pusiausvyros metodiką, skirtą atspindėti dabartinę aukcionų sistemą, integruojant neapibrėžtumo veiksnius ir identifikuojant optimalius investicijų portfelius Vilniaus centralizuoto šilumos tiekimo rinkai.

Tyrimo uždaviniai

1. Teoriškai išnagrinėti veiksnius, darančius įtaką centralizuotos šilumos tiekimo sektoriaus plėtrai, ir nustatyti neapibrėžtumo rūšis.
2. Nustatyti labiausiai tinkamų kompleksinių energetikos modeliavimo priemonių, skirtų centralizuoto šilumos tiekimo sistemoms, savybes ir jų galimybes vertinant neapibrėžtumus.
3. Sukurti metodiką, integruojančią centralizuotos šilumos rinkos modeliavimą su globalia jautrumo ir neapibrėžtumo analize.
4. Sukurti ir pritaikyti dalinės pusiausvyros ekonominį modelį Vilniaus miesto centralizuoto šilumos tiekimo sistemos atvejui.
5. Išnagrinėti ir nustatyti optimalų investicijų portfelį centralizuoto šilumos tiekimo rinkai, atsižvelgiant į neapibrėžtumų poveikį.
6. Remiantis modeliavimo rezultatais ištirti didžiausią identifikuotų neapibrėžtumo veiksmų poveikį centralizuotos šilumos tiekimo sistemos rinkai.

Tyrimo metodai

Siekiant kompleksiškai išanalizuoti energetikos sistemos ekonominio modeliavimo metodus, buvo išnagrinėta plataus spektro mokslinė literatūra. Atliktas išsamus 37-ių potencialių energetikos modeliavimo taikomųjų programų tyrimas, kurio metu palyginamajai analizei buvo atrinkti šeši tinkamiausi energetikos ekonomikos modeliavimo įrankiai. Šie modeliavimo įrankiai pasirinkti siekiant užtikrinti, kad ekonominis modelis apimtų tiek elektros energetikos, tiek centralizuoto šilumos tiekimo sektorius. Prioritetas suteiktas veiklos ir investicijų optimizavimo energetikos modeliavimo priemonėms. Siekiant geriau palyginti simuliacinio ir optimizavimo modelių savybes bei skirtumus, išskirtos dvi tinkamiausios energetikos simuliacinio modelių priemonės.

Po išsamios literatūros apžvalgos ir ekonominių simuliacinio bei optimizavimo modelių palyginimo buvo nustatyti tam tikri apribojimai, dėl kurių disertacijoje numatytų tikslų nebūtų galima pasiekti visa apimtimi. Buvo nustatyta, kad daugumai šių modelių trūksta patikimų šilumos aukcionų strategijų valdymo ir reguliavimo galimybių. Nagrinėti modeliai yra pagrįsti deterministinėmis sistemomis, kurios remiasi fiksuotais įvesties parametrais ir neatsižvelgia į realistinių ekonominių sistemų atsitiktinumą. Atitinkamai, jie neturi Monte Carlo metodo principu pagrįstų neapibrėžtumo ir jautrumo analizės mechanizmų, kurie yra būtini modelio patikimumui įvertinti neapibrėžtomis ir kintančiomis sąlygomis. Todėl buvo nuspręsta sukurti savarankiškai parengtą dalinės pusiausvyros ekonominį modelį, CŠT

modeliavimui su Monte Carlo jautrumo ir neapibrėžtumo analize. Kompleksiniam CŠT sistemos planavimui užtikrinti, ekonominio modelio deterministinis požiūris buvo išplėstas, įtraukiant įvairius kontroliuojamus, iš dalies kontroliuojamus ir nekontroliuojamus neapibrėžtumus, kad būtų įgyvendintas stochastinis požiūris. SimLab programinė įranga padėjo atlikti Monte Carlo metodu pagrįstą neapibrėžtumo ir jautrumo analizę kompleksiniame dalinės pusiausvyros modelyje. Be to, siekiant išbandyti ir patikrinti sukurta dalinės pusiausvyros ekonominį modelį bei įvertinti pastarųjų metų CŠT sistemos šilumos gamybos kainą, tinkamiausia simuliacijos priemonė pasirinkta energyPRO. Ši priemonė, taikydama deterministinį metodą geba atvaizduoti atskirų šilumos gamybos šaltinių sąnaudas ir optimizuoti šaltinių veikimą remiantis sąnaudų minimizavimo principu.

Naujai sukurtas dalinės pusiausvyros ekonominis modelis realistiškai atspindi CŠT rinką, kuri integruoja esamus nepriklausomus šilumos gamintojus (toliau – NŠG) ir operatoriaus gamybos įrenginius į esamą šilumos tinklą. Modelis veikia pagal šilumos aukciono principus, atspindėdamas konkurencines sąveikas, kurios maksimaliai padidina naudą galutiniams vartotojams. Jis gali integruoti įvairius neapibrėžtumus, leidžiant atlikti išsamią neapibrėžtumo ir jautrumo analizę, kuri padeda nustatyti finansiškai optimalų dekarbonizacijos investicijų portfelį. Modelis taip pat suteikia galimybę įvertinti esamų operatoriaus, NŠG ir potencialių naujų rinkos dalyvių elgesį įvairiomis rinkos neapibrėžtumo sąlygomis. Modeliavimas padeda nustatyti, kurios naujos energijos transformavimo ir gamybos technologijos būtų priimtinos ir finansiškai perspektyvios investuotojų požiūriu, dalyvaujant CŠT aukcionų sistemoje. Tuo pačiu metu šis modelis suteikia galimybę analizuoti, kaip šių naujų potencialių investuotojų (NŠG arba šilumos operatoriaus) sprendimai paveiktų šilumos aukcionų kainas ir kaip tai paveiktų jų pačių šilumos gamybos sąnaudas, susijusias su naujos įrangos įrengimu.

Darbo mokslinis naujumas

Didžioji dalis energetikos modeliavimo priemonių laikomos deterministiniais modeliais, kurie tiksliai pateikia rezultatą ir eliminuoja atsitiktinius faktorius. Išsamesnis ir pažangesnis metodas pasiekiamas deterministinius metodus išplečiant neapibrėžtumo kriterijais (Mendes, Ioakimidis ir Ferrão, 2011). Todėl galima teigti, jog, sukūrus naują ir patikimą dalinės pusiausvyros metodiką, skirtą CŠT veiklos vertinimui esant neapibrėžtumams, tiksliau planuojama CŠT sistemos ekonomika visų metų perspektyvoje valandiniu režimu.

Kita vertus, sukurta metodika yra siejama su reikšmingai besikeičiančia CŠT aplinka ir naujų rinkos dalyvių atsiradimu. Išsamus modeliavimas atliekamas atsižvelgiant į esančių rinkos dalyvių veiklos sprendimus, įtraukiant naujausias potencialias operatoriaus ir NŠG investicijas į šilumos gamybos ir transformavimo technologijas esant įvairiems neapibrėžtumo veiksnių svyravimams. Disertacijos naujumas taip pat atsiskleidžia analizuojant galimybes integruoti elektros energijos ir kitas atsinaujinančiųjų energijos išteklių technologijas į CŠT sistemas, siekiant subalansuoti elektros energijos pasiūlą ir paklausą.

Metodologijos išplėtimas, naudojant Monte Carlo jautrumo ir neapibrėžtumo analizę, leidžia nustatyti optimalų investicijų portfelį, įvertinant įvairius scenarijus ir

siekiant maksimaliai padidinti investuotojo finansinį pelną, užtikrinti pagrįstas šilumos aukciono kainas ir sumažinti CO₂ išmetimus.

Sukurta metodika taip pat yra unikali dėl galimybės taikyti ir modifikuoti galimas šilumos aukcionų sistemos veiklos strategijas. Be to, demonstruojama galimybė taikyti valandinių aukcionų sistemą, kuri užtikrintų patikimesnį ir efektyvesnį CŠT rinkos veikimą.

Realizuotas Vilniaus CŠT sistemos dalinės pusiausvyros ekonominis modelis iliustruoja didelį įvairių atliekinės šilumos šaltinių panaudojimo ir integravimo į CŠT sistemą potencialą, siekiant maksimaliai padidinti investuotojų finansinį pelną, užtikrinti ekonomiškai pagrįstas šilumos gamybos sąnaudas ir mažinti priklausomybę nuo iškastinio kuro. Įgyvendintas išsamus kompleksinis tyrimas leidžia įvertinti ateities tendencijas CŠT srityje, atsižvelgiant į įvairius technologinius ir ekonominius neapibrėžtumus, kurie yra svarbūs ir vertingi ieškant optimalių ateities sprendimų.

Ši disertacija reikšmingai prisideda prie esamos mokslinės literatūros, kurioje nepakankamai nagrinėjama neapibrėžtumo analizė bei neapibrėžtumo vertinimo metodai CŠT planavimo ir plėtros strategijose.

Tyrimo apribojimai

Modelyje taikoma šilumos aukciono kainodaros strategija grindžiama ribinių sąnaudų principais, būdingais tobulos konkurencijos rinkai. Modelyje daroma prielaida, kad šilumos aukciono kaina nustatoma remiantis aukštesnėje reitingo vietoje esančio gamintojo ribinėmis kintamosiomis gamybos sąnaudomis. Šis metodas supaprastina esamą šilumos rinkos struktūrą. Tuo tarpu Lietuvos centralizuoto šilumos tiekimo sektoriuje taikomi mėnesiniai aukcionai, grindžiami gamintojų pateiktais kainų pasiūlymais, kuriuos gali lemti įvairūs veiksniai, įskaitant ir neracionalų elgesį.

Modelyje laikomasi prielaidos, kad gamybos šaltinių prijungimui prie šilumos tiekimo tinklo netaikomi jokie apribojimai. Šilumos tiekimo tinklas nėra tiesiogiai modeliuojamas, o tai reiškia, kad modelis neatspindi tinklo struktūros, jo komponentų ar jų tarpusavio ryšių. Užuoat detaliam nusakant tinklo sandarą, naudojamos supaprastintos prielaidos. Tačiau šie vidiniai modelio apribojimai gali tapti rizikos veiksniais pritaikant sukurta metodiką didmiesčiams, integruojant naujus šilumos gamybos šaltinius.

Dėl kompleksinių neapibrėžtumų ir įvairių novatoriškų atsinaujinančiosios energijos technologijų integravimo į ekonominį modelį, taip pat siekiant subalansuoti trumpalaikius ir ilgalaikius jėgainių veikimo režimus, prioritetas teiktinas vidutinės trukmės laikotarpiui – iki 2030 m.

Modelis taip pat neatsižvelgia į ilgesnius saulės spinduliavimo sumažėjimo laikotarpius. Dėl šios priežasties modeliuojami šilumos akumuliacinių talpų tūriai galėtų būti nepakankamai tiksliai įvertinti.

Tuo tarpu vertėtų paminėti, kad vandenilio elektrolizeris turėtų staigius valandinius apkrovos svyravimus, kurie realybėje galėtų sutrumpinti įrangos tarnavimo laiką, o dažni darbo režimo pokyčiai pagreitinėtų komponentų nusidėvėjimą, kas paskatintų inicijuoti reinvesticijas į esamą infrastruktūrą. Šios reinvesticijos disertacijoje nėra vertinamos.

Taip pat reikėtų pažymėti, kad remiantis literatūros apžvalga buvo įvertinti ir analizuoti tik labiausiai reikšmingi neapibrėžtumo veiksniai, neatsižvelgiant į kitus būdingus neapibrėžtumo veiksnius, kurie nėra esminiai energetikos planavimui.

Galimas praktinis sudaryto modelio ir modeliavimo rezultatų pritaikymas

Naujai sukurta dalinės pusiausvyros ekonominio modelio metodika, apimanti įvairius neapibrėžtumus, leidžia taikyti kompleksinį požiūrį nustatant strategines CŠT įmonių plėtros kryptis, teikiant pirmenybę ekonomiškai perspektyviausiems sprendimams. Sukurtas modelis gali padėti vietos savivaldybėms bei tarptautiniams miestams nustatyti optimalias investicijas, siekiant dekarbonizacijos tikslų.

Kita vertus, modelis yra labai vertingas vertinant ir tiriant galimus ateities scenarijus, susijusius su įvairių rinkos dalyvių, NŠG ir šilumos tiekėjo, investicijomis į naujus šilumos transformavimo ir gamybos įrenginius, integruotus į pasirinkto miesto esamą šilumos rinką. Šiame kontekste metodika galėtų padėti įvertinti esamų NŠG šilumos ir elektros gamybos įrenginių bei pačio šilumos tiekėjo potencialią būsimą finansinę padėtį, jei nauji papildomi pajėgumai būtų integruoti į CŠT tinklą.

Dalinės pusiausvyros modelis leidžia įvertinti įvairius scenarijus, pavyzdžiui, politikos priemonės, skirtas pereiti prie 100 % atsinaujinančios energijos naudojimo CŠT sistemoje, arba potencialią ES finansinę paramą, galima prognozuoti, kaip keistųsi šilumos gamybos sąnaudos ir aukcionų kainos. Šis išsamus visos CŠT sektoriaus vertinimas galėtų padėti geriau planuoti plėtros tendencijas, užtikrinant patikimesnę ir realistiškesnę CŠT sistemą, o tai galėtų prisidėti prie šilumos kainų mažėjimo galutiniams vartotojams.

Disertacijos struktūra ir apimtis

Ši disertacija yra metodiškai struktūruota, siekiant išsamiai išnagrinėti neapibrėžtumo vaidmenį CŠT sistemų planavime ir ekonominiame modeliavime kintančiomis reguliavimo ir rinkos sąlygomis. Pirmoje dalyje pateikiama teorinė apžvalga, analizuojamos CŠT rinkos reguliavimo ir planavimo ypatybės, nagrinėjant vartotojų prijungimo prie tinklo, kainodaros mechanizmus, nuosavybės struktūras, trečiųjų šalių prieigą ir politikos priemonių, pvz., diskonto normų, poveikį. Šioje skyriaus dalyje toliau nagrinėjami teoriniai neapibrėžtumo veiksniai, pateikiama neapibrėžtumo veiksnų klasifikacija, stochastiniai vertinimo metodai ir alternatyvūs neapibrėžtumo charakterizavimo metodai, taip pat išsamiai bei kritiškai vertinami energetikos ekonomikos sistemų modeliavimo metodai ir jų taikymas kompleksiniam energetikos sistemų transformavimui.

Antrajame skyriuje pateikiama tyrimo metodika, išsamiai aprašomas pasirinktas modeliavimo metodas ir jo patikrinimas, apibrėžiami techniniai ir ekonominiai parametrai, konkretizuojama pasirinkta laiko skiriamoji geba ir planavimo laikotarpis. Šioje dalyje taip pat aprašomi dalinės pusiausvyros modelyje naudotini duomenų šaltiniai ir pagrindinės prielaidos, susijusios su energijos kainomis, paklausos tendencijomis, diskontavimu, taip pat įprastų ir atsinaujinančių šilumos gamybos technologijų, saugojimo sprendimų, šilumos siurblių, elektros energijos į šilumą ir elektros energijos į vandenilį konversijos koncepcijų techninis ir ekonominis aptarimas. Ypatingas vaidmuo tenka jautrumo ir neapibrėžtumo analizės taikymui,

siekiant įvertinti svarbiausių neapibrėžtų veiksnių poveikį CŠT sistemos veikimui ir investiciniams sprendimams.

Trečiajame skyriuje pateikiami ir analizuojami modeliavimo rezultatai, pirmiausia apžvelgiant pasirinktą centralizuoto šilumos tiekimo sistemą. Skyriuje pateikiama dabartinių ir būsimų referencinių scenarijų analizė, po kurios pateikiamas išsamus bazinio scenarijaus vertinimas. Apsvarstomi papildomi strateginiai scenarijai, įskaitant planus sukurti visiškai atsinaujinančią centralizuoto šilumos tiekimo sistemą, finansinės paramos mechanizmus atsinaujinančios energijos gamybai ir finansines priemones, skirtas apmokestinti iškastinį kurą. Skyrius užbaigiamas scenarijų neapibrėžtumo ir jautrumo analizės rezultatų lyginamuoju vertinimu, modeliavimo rezultatų patikimumo ir taikymo vertinimu bei jų atitikties panašioms mokslinės literatūros rezultatams aptarimu. Disertacija pabaigiama apibendrinančiomis išvadomis, pagrindinių rezultatų apžvalga, patvirtinančiomis nuorodomis ir priedais.

CENTRALIZUOTO ŠILUMOS TIEKIMO RINKOS PLANAVIMO IR MODELIAVIMO YPATYBĖS BEI NEAPIBRĖŽTUMO VAIDMUO

Energetikos planavimas yra ilgalaikis strateginis procesas, apimantis techninių, ekonominių, aplinkosaugos ir socialinių aspektų subalansavimą kuriant ateities energetikos sistemas (Bush & Bale, 2019). Šiame kontekste centralizuotas šilumos tiekimas (CŠT) tampa vis svarbesnis, nes šalys pereina nuo iškastinio kuro prie atsinaujinančiųjų energijos išteklių (AEI). Dėl savo gebėjimo integruoti lanksčias gamybos technologijas, šilumos kaupimą ir atliekinės šilumos utilizavimą, CŠT gali padėti didinti nepastovių AEI dalį energijos gamybos struktūroje ir prisidėti prie elektros tinklų balansavimo (Blanco et al., 2018). Tačiau dėl AEI priklausomybės nuo oro sąlygų CŠT veikla ir investicijų planavimas tampa vis sudėtingesni ir neapibrėžti, todėl reikalingi pažangūs modeliavimo metodai. Be to, vis didėjantis AEI naudojimas ir stiprėjantis elektros rinkų tarpvalstybinis sujungimas didina ilgalaikių elektros kainų prognozių neapibrėžtumą (Blanco et al., 2018). Šios prognozės turi didelę įtaką investiciniams sprendimams dėl naujų šilumos gamybos technologijų. Todėl, siekiant užtikrinti tvarias investicijas ir sistemos plėtrą, centralizuoto šilumos tiekimo sistemos turi būti atsparios energijos kainų svyravimams ir neapibrėžtumams.

Planuojant ir modeliuojant būsimas CŠT sistemas, taip pat būtina atsižvelgti į vyraujančias rinkos reguliavimo ir planavimo ypatybes bei kompleksinius neapibrėžtumus, susijusius su ilgalaikie energetikos sistemos plėtra. Šie neapibrėžtumai siejami su kuro kainų svyravimais, politikos ir reguliavimo sistemų pokyčiais, technologijų plėtra, paklausos svyravimais ir AEI integracijos didėjimu. Įtraukiant tokius kompleksinius veiksnius į energetikos sistemų modeliavimą, padidėja būsimų sistemų prognozių patikimumas ir tikslumas, o tai leidžia atlikti objektyvesnę scenarijų analizę ir sustiprina investicinių sprendimų patikimumą ir teisingumą.

Dauguma dabartinių planavimo modelių yra deterministiniai ir remiasi ilgalaikėmis prognozėmis, kurios dažnai pasirodo esančios netikslios, o tai gali lemti neefektyvumą, pavyzdžiui, perteklinį pajėgumą ar nepakankamą šaltinių išnaudojimą (Moret et al., 2017). Šiai problemai spręsti vis dažniau rekomenduojami stochastiniai

modeliavimo metodai, kurie apimtų neapibrėžtumų įvertinimą (Nagel, Kirkerud & Bolkesjø, 2022).

Centralizuotos šilumos sektoriaus rinkos reguliavimo ir planavimo ypatybės

CŠT sistemos visoje Europoje vis labiau pripažįstamos kaip pagrindinis tvaraus miestų energetikos infrastruktūros elementas, leidžiantis integruoti atsinaujinančius ir atliekinės šilumos šaltinius, didinti energijos vartojimo efektyvumą ir mažinti išmetamųjų teršalų kiekį (Lund et al., 2014). Dėl didelių kapitalo investicijų, reikalingų perdavimo tinklams, CŠT sistemos turi natūralios monopolijos požymių, nes investicijos į vamzdynų ir susijusios infrastruktūros replikavimą būtų ekonomiškai neefektyvios. Investicijos į izoliuotus požeminius vamzdynus, siurbines ir vartotojų šilumos punktus yra didelės, o papildomų šilumos vartotojų aprūpinimo ribinės sąnaudos yra palyginti mažos. Todėl didėjant prijungtų vartotojų skaičiui, vidutinė vieno šilumos vieneto kaina mažėja, o tai lemia reikšmingą masto ekonomiją (Galindo et al., 2016). Ši sąnaudų struktūra rodo, kad vienas tinklo operatorius gali potencialiai efektyviau aprūpinti visą rinką nei kelios konkuruojančios sistemos, o tai yra pagrindinis natūralios monopolijos bruožas. Be to, šilumos perdavimo tinklų dubliavimas būtų techniškai įmanomas, bet ekonomiškai neefektyvus. Lygiagrečių tinklų įrengimas pareikalautų papildomų kasimo darbų, investicijų į infrastruktūrą ir padarytų žalą aplinkai, tačiau nesuteiktų pakankamos socialinės naudos (Werner, 2017). Todėl alternatyvių centralizuotos šilumos tiekimo tinklų įrengimas yra iš esmės neįmanomas, ypač tankiai apgyvendintose miesto vietovėse, kur CŠT sistemos yra racionaliausias sprendimas. Fizinis tinklų neatskiriamumas ir didelės kapitalo sąnaudos sudaro dideles natūralias kliūtis konkurencijai.

Nors šilumos tiekimo tinklas laikomas natūralia monopolija, tai iš esmės netaikoma kitoms šiluminės energijos grandinės dalims, pavyzdžiui, šilumos gamybos daliai. Nors techniniai apribojimai, ypač mažesniuose tinkluose, gali trukdyti efektyviai eksploatuoti daugiau nei vieną gamybos vienetą, didesniuose tinkluose paprastai galima sukurti konkurencingą šilumos gamybos rinką (Bürger et al., 2019). Nepriklausomi šilumos gamintojai (NŠG), pavyzdžiui, kogeneracinės elektrinės, biokuro katilai, atliekinės šilumos atgavimo įrenginiai ar saulės šiluminės kolektorių sistemos, gali tiekti šiluminę galią į tą patį tiekimo tinklą. Tokia struktūra palengvina konkurenciją rinkoje ir skatina gamybos technologijų efektyvumą bei inovacijas (Bürger et al., 2019). Tačiau, kad ši konkurencinė aplinka veiktų efektyviai, reikalingas reguliavimo atskyrimas tarp šilumos tiekimo ir gamybos. Esamas tinklo operatorius privalo užtikrinti nediskriminacinę prieigą NŠG ir kartu užtikrinti skaidrią kainodarą ir gamybos planavimą. Nesant tokio reguliavimo atskyrimo, šilumos tiekėjas galėtų teikti pirmenybę tik savo gamybos įrenginiams ir apsunkintų naujiems rinkos dalyviams (NŠG) patekti į šilumos rinką (Werner, 2017). Šios struktūrinės ypatybės pabrėžia būtinybę aiškiai atskirti tinklo ir gamybos dalių reguliavimą bei planavimą, siekiant užtikrinti skaidrumą, sąžiningą prieigą prie rinkos ir optimalų sistemos veikimą, kuris būtų naudingas tiek vartotojams, tiek tiekėjams.

Tinkamas CŠT sistemų veikimas priklauso nuo efektyvios ir teisingos reguliavimo sistemos. Kaip pažymėjo (Gatautis, 2004), skaidrios ir aiškiai suformuluotos reguliavimo sistemos yra naudingos tiek tiekėjams, tiek vartotojams.

Vartotojai gali naudotis stabiliomis kainomis ir užtikrintu šilumos tiekimu, o gamintojai – iš anksto numatomomis rinkos sąlygomis ir sąžininga prieiga prie tinklo, prisidedant prie atsinaujinančių energijos bei atliekinės šilumos šaltinių integravimo. Todėl visos suinteresuotosios šalys – tinklo operatorius, NŠG ir vartotojai – yra suinteresuotos subalansuotu, efektyviu ir skaidriu CŠT reguliavimu, kuris prisideda prie ekonominio efektyvumo ir aplinkosaugos tikslų įgyvendinimo.

Išskirtinos pačios svarbiausios CŠT sektoriaus reguliavimo formos: vartotojų prisijungimo prie šilumos tinklo reguliavimas, kainų reguliavimas, nuosavybės reguliavimas ir trečiųjų šalių prieigos prie šilumos tinklų reguliavimas (Billerbeck et al., 2023). Be to, diskontų normų pasirinkimas kaip politikos priemonė vaidina svarbų vaidmenį CŠT sektoriaus reguliavime ir ilgalaikiame infrastruktūros planavime. Tarptautinė patirtis rodo, kad diskonto normos energetikos sektoriaus rinkos dalyviams taikomos labai skirtingai, atspindėdamos reguliavimo sistemų ir rizikos pasidalijimo įvairovę. Todėl, žvelgiant į platesnę CŠT rinkos dinamiką, labai svarbu atsižvelgti į esamą tarptautinių CŠT sistemų planavimo praktiką, kadangi šios reguliavimo ir planavimo priemonės tiesiogiai lemia galutinių vartotojų padėtį, nustatydamos vartotojų pareigas, patiriamus kaštus ir įtakos bei dalyvavimo CŠT sistemoje lygį.

Vienas iš dažniausiai pasikartojančių iššūkių CŠT sistemose yra mažas vartotojų prisijungimo lygis, kuris mažina operatorių finansinį pelną (Europos Komisija, 2022 m.). Siekiant išspręsti šią situaciją, kai kurios šalys taiko privalomą prisijungimą prie šilumos tinklų, ypač tais atvejais, kai tinklai yra efektyvūs arba pagrįsti AEI šaltiniais (Billerbeck et al., 2024). Nors tokios priemonės apsaugo investicijas ir gali padėti stabilizuoti kainas, jos taip pat didina vartotojų priklausomybę, todėl sustiprina poreikį taikyti patikimą kainų reguliavimą.

Taigi kainų formavimas yra pagrindinis CŠT reguliavimo veiksnys, o jo metodai svyruoja nuo griežtai reguliuojamų, sąnaudomis pagrįstų sistemų iki liberalizuotų rinkų (Odgaard & Djørup, 2020). Pavyzdžiui, Danijos pelno nesiekiantis sąnaudų principas užtikrina, kad vartotojai mokėtų tik būtinas sąnaudas, taip apsaugant juos nuo piktnaudžiavimo monopoline padėtimi (Johansen & Werner, 2022). Priešingai, Rytų Europoje neretai vyrauja sąnaudų su priedu kainodara, kuri garantuoja sąnaudų susigrąžinimą, bet silpnina paskatas didinti efektyvumą (Sun, Zhang & Wallin, 2015). Liberalizuoti modeliai, pavyzdžiui, Suomijoje, leidžia taikyti rinkos sąlygomis nustatytas kainas, bet didina piktnaudžiavimo riziką, atsižvelgiant į CŠT monopolistinį pobūdį (Billerbeck et al., 2023).

CŠT nuosavybės struktūra reikšmingai lemia reguliavimo intensyvumą. Dėl viešosios arba vartotojų nuosavybės didėja skaidrumas ir vartotojų įtaka, o dėl privačios nuosavybės atsiranda poreikis taikyti griežtesnius reguliavimo reikalavimus, siekiant užkirsti kelią piktnaudžiavimui rinka (Billerbeck et al., 2024). Kaip pavyzdį galima paminėti Daniją, kurioje dominuoja vartotojų nuosavybės kooperatyvai (85 %), Švediją, kurioje dominuoja savivaldybių viešoji nuosavybė, ir Vokietiją, kurioje dominuoja privačios įmonės (Bürger et al., 2019). Šie skirtumai rodo, kad valdymo modeliai yra labai svarbūs nustatant, kokio lygio yra reikalinga vartotojų apsauga.

CŠT infrastruktūra turi bendras natūralias monopolistines savybes, kaip ir elektros bei dujų sektoriai (Pažeraitė et al., 2022). Nepaisant šilumos perdavimo monopolinio pobūdžio, elektros ir dujų rinkų liberalizavimo patirtis rodo, kad šilumos gamybos dalis integruotame tinkle gali būti palanki konkurencijai (Barrett, 2017). Pasitelkiant elektros ir dujų rinkų liberalizavimo patirtį, kai kurios CŠT sistemos, ypač Lietuvoje, įgyvendino reguliuojamą trečiųjų šalių prieigą per šilumos aukcionus (Pažeraitė et al., 2022). Tai padidino skaidrumą, sumažino kainas ir padidino konkurencingų šilumos gamintojų skaičių (Baltpool, 2025b). Tokios reformos rodo, kad konkurencija gali būti išplėta šilumos gamybos dalyje esant tinkamai reguliavimo priežiūrai.

Diskonto norma taip pat yra svarbus politikos elementas CŠT sektoriaus reguliavime, nes ji nustato, kaip ateities patiriamos sąnaudos ir nauda yra vertinamos dabartinėmis sąlygomis. Praktikoje taikomi trys pagrindiniai tipai: finansinė svertinė vidutinė kapitalo kaina (WACC), atspindinti komunalinių paslaugų finansavimo sąnaudas; individualios diskonto normos, susijusios su vartotojų rizikos lūkesčiais, ir socialinės diskonto normos, atspindinčios platesnę visuomenės gerovę (Synapse Energy Economics, 2023). Reguliavimo institucijos dažnai remiasi WACC, paprastai 7–9 %, siekdamos užtikrinti komunalinių paslaugų finansinį gyvybingumą, nors šis požiūris teikia pirmenybę privačių investuotojų perspektyvoms, o ne ilgalaikiam visuomenės naudai (Institute for Policy Integrity, 2025). Tuo tarpu socialinės diskonto normos paprastai yra mažesnės, apie 2–3 %, ir jos rekomenduojamos vertinant viešąją infrastruktūrą ir dekarbonizacijos projektus (BPIE, 2015; Institute for Policy Integrity, 2025). Tarptautinė patirtis rodo didelius skirtumus: Australijoje analizės rodo, kad 5,6 % centrinė diskonto norma su 2,2–7,3 % ribomis geriau atspindi sisteminės rizikas nei istoriškai taikoma 7–10 % norma (Synergies Economic Consulting, 2021), o IEA (2020) taiko 3 %, 7 % ir 10 % orientacines diskonto normas, kad atspindėtų mažos, vidutinės ir didelės rizikos investicijų aplinką. Paprastai pasirinkimas tarp privačių ir socialinių diskonto normų turi didelę įtaką CŠT sistemos veikimui, nes didesnės normos trukdo ilgalaikiam atsinaujinančiosios energijos integravimui, o mažesnės normos remia ekonomiškai efektyvius dekarbonizacijos būdus.

Tarptautinė patirtis atskleidžia skirtingus nacionalinius požiūrius. Baltijos valstybėse CŠT yra ypač svarbus klimato ir energetikos tikslams, tačiau planavimas yra nenuoseklus, savivaldybės rengia šilumos ūkio planus be vieningos metodikos, o tai riboja palyginamumą (Volkova et al., 2020). Lietuva neseniai įvedė dviejų lygių planavimą – savivaldybių šilumos ūkio planus ir dešimties metų investicijų šilumos ūkio plėtros investicijų planus, kuriuos rengia šilumos tiekėjai, – tačiau tarp nacionalinių tikslų ir vietos savivaldos planų įgyvendinimo vis dar yra neatitikimų (Lietuvos šilumos tiekėjų asociacija, 2024). Jungtinėje Karalystėje CŠT sistemų naudojimas tebėra mažesnis nei 2 % dėl plačiai paplitusio dujų vartojimo ir didelių pradinių infrastruktūros išlaidų, tačiau politikos sistemose vis labiau pripažįstamas CŠT potencialas siekiant mažinti anglies dioksido išmetimą, ypač didmiesčių teritorijose (Bush & Bale, 2019). Danija išsiskiria kaip lyderė, kurioje savivaldybės prižiūri CŠT planavimą pagal šilumos tiekimą reglamentuojančius teisės aktus. Atlikus struktūrizuotas socialines, ekonomines, vartotojų bei aplinkos analizes, Danijos savivaldybės sėkmingai integravo AEI generavimo šaltinius į CŠT sistemas,

padidindamos AEI dalį kogeneracinių elektrinių gamybos apimtimis nuo 20 % 1990 m. iki beveik 64 % 2019 m., tuo pačiu sumažindamos anglies naudojimą iki mažiau nei 9 % (Johansen & Werner, 2022). Ši visapusiška planavimo sistema, kurią palaiko nacionalinių institucijų reguliavimo priežiūra, leido užtikrinti ekonomišką, mažai anglies dioksido išmetančią CŠT plėtrą (Eikeland & Inderberg, 2016; Danijos energetikos agentūra, 2022).

Neapibrėžtumo veiksnių teorinė analizė

CŠT sistemas vis labiau veikia įvairūs neapibrėžtumai, kurie apsunkina tiek esamos sistemos funkcionavimą, tiek ilgalaikį planavimą. Energetikos planavimo srityje neapibrėžtumas apibūdina ribotą galimybę tiksliai numatyti sistemos būklę, parametrus, elgseną ir išorinius pokyčius ilguoju laikotarpiu. Literatūros šaltiniuose išskiriamos skirtingos neapibrėžtumo rūšys. Mokslininkai (Walker et al., 2003) siūlo klasifikuoti neapibrėžtumus pagal lokaciją modelyje ir pobūdį, tuo tarpu autorius (Moret, 2017) išskiria episteminius (grindžiamus duomenimis ar žiniomis, potencialiai mažinamus) ir aleatorinius (iš prigimties kintamus, nemažinamus) neapibrėžtumus. CŠT planavime esami neapibrėžtumai gali būti sumažinti renkant duomenis arba tobulinant modeliavimą, o ateities neapibrėžtumai, pavyzdžiui, iškastinio kuro ar biokuro kainų tendencijos, iš esmės yra nenuspėjami.

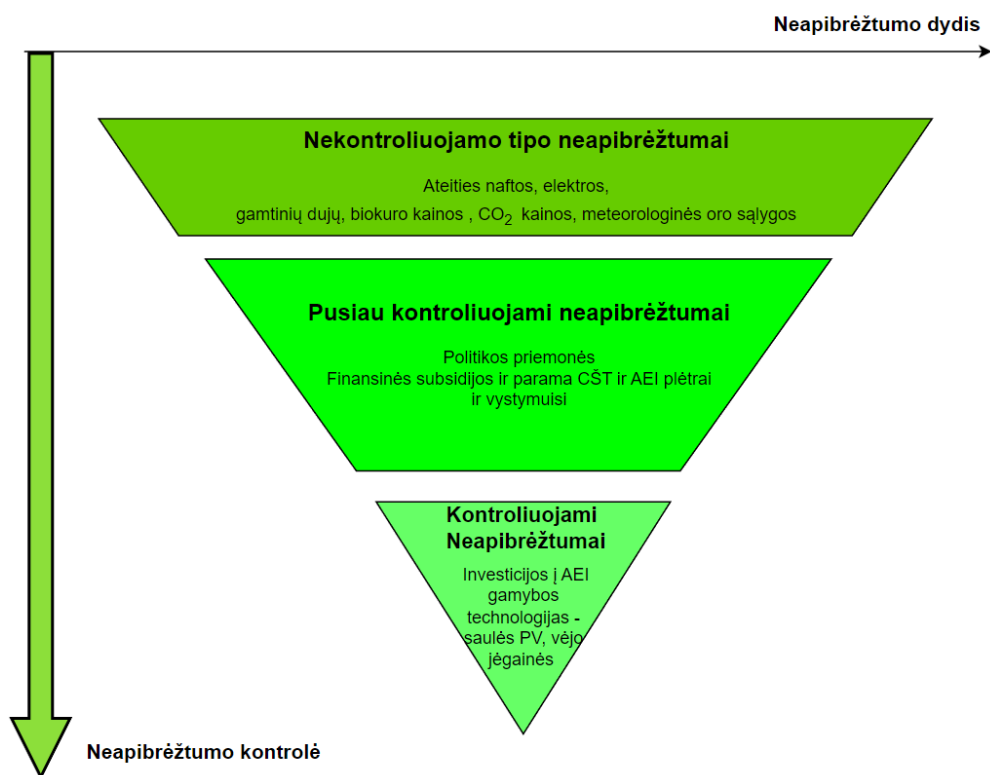
Pasak autorių (Alonso-Travesset et al., 2023) galėtų būti išskiriami fiziniai neapibrėžtumai (pvz., atsinaujinančios energijos generacijos svyravimai) ir ekonominiai bei reguliavimo neapibrėžtumai. Pavyzdžiui, dėl oro sąlygų kintantis vėjo ir saulės energijos gamybos generavimas daro poveikį tiek energijos prieinamumui, tiek pajamoms, todėl energijos tiekimo sistemos tampa nestabilios (Alonso-Travesset et al., 2023). Lankstumo priemonės, tokios kaip akumuliacijos, paklausos reagavimas ar elektriniai automobiliai, gali sumažinti kai kurias iš šių rizikų, tačiau jų poveikis sąnaudoms ir pelningumui lieka neapibrėžtas (Andreolli, Alpaos & Moretto, 2022; Ramboll, 2021).

Ekonominiai ir su rinka susiję neapibrėžtumai yra ypač svarbūs CŠT sistemoms. Dėl gamtinių dujų ir elektros kainų svyravimų operatoriai patiria eksploataavimo ir finansines rizikas, kurios gali viršyti jų galimybes. Netikėti kainų šuoliai, tokie kaip 2021 m. Teksaso žiemos audra, dėl kurios elektros kainos išaugo daugiau nei 300 kartų, o dujų kainos – 100 kartų (Levin et al., 2022), rodo energetikos sistemų pažeidžiamumą ekstremalių įvykių atveju. Europoje augantis AEI diegimas „Nord Pool“ rinkoje sustiprino kainų svyravimus, o valandinės elektros kainos pasiekė 10–15 kartų didesnę nei įprastą lygį (Litgrid, 2025a). Panašūs Austrijos tyrimai rodo, kad elektros kainos svyruoja ± 50 % nuo vidurkio, tuo tarpu biomasės kainos yra stipriai koreliuojančios su gamtinių dujų kainomis, o CO₂ kainos yra labai neapibrėžtos. Visi šie veiksniai turi tiesioginės įtakos šilumos tiekimo dekarbonizacijos strategijoms (Marx et al., 2023).

Politinės priemonės sukelia papildomą neapibrėžtumo lygį. Subsidijos, supirkimo tarifai, mokesčių lengvatos ir dotacijos yra kritiškai svarbūs instrumentai CŠT plėtrai (Europos Komisija, 2022), o staigūs ar retrospektyvūs pokyčiai neskatina investuoti į inovacijas (Dalby et al., 2018). Dėl politikos priemonių neapibrėžtumo sudėtinga užtikrinti finansavimą, nes projektai dažnai priklauso nuo ilgalaikių

valdžios institucijų išsipareigojimų (White et al., 2013). Europos šalių pavyzdžiai rodo teikiamas politinių priemonių galimybes: Suomijoje energijos ir anglies dioksido mokesčiai už iškastinį kurą bei elektros mokesčių reformos paskatino atsinaujinančios energijos ir šilumos siurblių naudojimą (Europos Komisija, 2022). Tuo tarpu Graz mieste subsidijos remia atsinaujinančios energijos šaltinių integravimą ir tinklų jungtis, siekiant iki 2050 m. užtikrinti 100 % atsinaujinančios energijos naudojimą centralizuotam šilumos tiekimui. Tuo tarpu Kopenhagoje privalomos centralizuoto šilumos tiekimo jungtys skatina pastatų sektoriaus dekarbonizaciją (Europos Komisija, 2022).

Išnagrinėjus įvairias klasifikacijas ir nuodugniai įvertinus galimus neapibrėžtumus, sukurama hierarchinė neapibrėžtumo kontrolės piramidė (93 pav.). Šiame paveiksle pabrėžiama, kad neapibrėžtumai, susiję su potencialiomis investicijomis į įvairias naujas technologijas, yra nedideli dėl aukšto investuotojų kontrolės lygio ir aiškių sprendimų priėmimo procesų. Priešingas efektas pastebimas tiriant ateities tendencijas ir prognozes dėl elektros, biokuro, gamtinių dujų, CO₂ kainų. Literatūros analizė parodė, jog tai susiję su nuspėjamais ateities neapibrėžtumais, kurių negalima kontroliuoti. Tuo tarpu įvairios politikos priemonės, pvz., finansinė parama ir subsidijos, laikomos iš dalies kontroliuojamais neapibrėžtumais, nes jas gali priimti kai kurios vietos ar nacionalinės institucijos.



93 pav. Hierarchinė neapibrėžtumo kontroliuojamumo piramidė

Ekonominio modeliavimo metodų palyginimas ir pasirinkimo pagrindimas

Pirmasis nagrinėjamas vertinimo kriterijus yra metodologija. Remiantis apžvelgta literatūra bei išsamiau pasirinktų „iš apačios į viršų“ energetikos sistemos ekonominių modelių vertinimu, galima teigti, kad optimizavimo modeliai yra tinkamesni nei simuliacijos modeliai ilgalaikės energetikos sistemos dinamikos modeliavimui ir geriau tinka kompleksiskai pavaizduoti visą energetikos sistemą, siekiant sumažinti energetikos sistemos sąnaudas. Kita vertus, šios disertacijos prioritetas nėra ieškoti būdų, kaip sumažinti energijos sąnaudas, o atlikti tyrimą ir vertinti platesniu stochastiniu požiūriu, atsižvelgiant į įvairius neapibrėžtumus, ir pateikti optimalų investicijų portfelį, nagrinėjant įvairius scenarijus. Tuo tarpu TIMES ir MESSAGE energetikos modeliai gali taikyti stochastinio programavimo metodą, specifikuodami tam tikrų įvesties parametrų pasiskirstymą ir leisdami įtraukti šiuos neapibrėžtumus į savo sprendimus. Tačiau jie yra skirti daugiausia ilgalaikiam dinaminiam modeliavimui, kur detalus, metinis kompleksiškas energetikos sektoriaus vaizdavimas skatintų naudoti papildomus modulius, siekiant išlaikyti didesnę tikslumą. Be to, abu modeliai neturi galimybės modifikuoti šilumos aukciono strategijų, neapima kainų formavimo mechanizmų, nes jie yra modeliuojami pagal sąnaudų mažinimo principus. Todėl TIMES ir MESSAGE yra tinkami sistemos planavimui ir ilgalaikiams scenarijų tyrimams, bet nepritaikyti konkurencinių šilumos rinkų, aukcionų mechanizmų CŠT sistemose tyrimams.

Tuo tarpu simuliacijos modeliai suteikia galimybę atlikti konkretų, vartotojo apibrėžtą alternatyvų analizę, kuri neleidžia pasiekti visiškai optimalaus ekonominio sprendimo, bet tik iš dalies optimizuoti sprendimą, atliekant keletą iteracinių skaičiavimų. EnergyPRO turi daug privalumų, ypač CŠT sektoriuje, pvz., galimybė modeliuoti dideles ir kompleksines energetikos sistemas, įskaitant platų šilumos ir elektros energijos gamybos bei saugojimo technologijų spektrą, balansavimo paslaugų, Power-to-X, vandenilio ir metanolio integravimą bei įtraukiant įvairius mokesčius ir subsidijas. Deja, energyPRO neturi galimybės valdyti ir modifikuoti šilumos aukcionų strategijas, tačiau gali įvertinti atskirų šilumos gamybos šaltinių sąnaudas arba bendras šilumos gamybos sistemos sąnaudas. Todėl ji gali būti tinkama dabartiniam centralizuoto šilumos tiekimo gamybos pavaizdavimui ir tikrinimui. Be to, ši programinė įranga turi ribotas galimybes taikyti neapibrėžtumo ir jautrumo analizę. Modeliavimo įrankiai, tokie kaip energyPRO ar EnergyPLAN, yra labiau pritaikyti deterministiniam metodui, kuriuo vertinimas organizuojamas tiksliai, neatsitiktinai. EnergyPRO yra specialiai pritaikyta analizuoti konkrečias alternatyvas, kurias nustato patys vartotojai, užuot siūlant holistinę sisteminių ar bendrą optimizavimo požiūrį.

Kita vertus, H2RES turi platesnes galimybes optimizuoti investicijas į pajėgumus ir veiklą. Tačiau šis modelis neatlieka visiškos stochastinės investicijų optimizacijos ir neapima neapibrėžtumo ir jautrumo analizės galimybių. Jame taip pat trūksta išsamių galimybių modeliuoti šilumos talpyklas ir detalizuoti CŠT temperatūros parametrus. Tuo tarpu, tyrinėjant Balmorel energijos modelio panaudojimą, matyti, kad jis apima visų metų modeliavimą su tobula prognoze, o tai yra dalinis apribojimas. Pats pagrindinis Balmorel modelis tiesiogiai netaiko

stochastinio ar Monte Carlo metodų jautrumo ir neapibrėžtumo analizei. Todėl neapibrėžtumo analizė gali būti atliekama tik naudojant papildomus metodus, nepriklausančius nuo pagrindinės Balmorel modelio struktūros. Be to, nei H2RES, nei Balmorel modeliai neturi jokių galimybių modifikuoti ar valdyti šilumos aukciono strategiją. Abu modeliai gali optimizuoti metines eksploatacijos ir pajėgumų sąnaudas, tačiau galimų šilumos aukciono mechanizmų valdymas ir modifikavimas nėra šių modelių taikymo sritis.

Vienas iš pagrindinių kriterijų renkantis energijos modeliavimo įrankį yra jo gebėjimas užtikrinti aukštą laiko ir erdvės skiriamąją gebą. Pasirinkto modelio geografinė ir laiko aprėptis turėtų būti pritaikoma, idealiau atveju apimanti nuo valandinių simuliacijų iki visų metų laikotarpio, siekiant įvertinti energijos gamybos pajėgumų sąnaudas ir ateities tendencijas CŠT rinkoje. Aukščiausią laiko skiriamąją gebą gali užtikrinti tik šie modeliai: Balmorel, TIMES, MESSAGE, H2RES. Pavyzdžiui, H2RES turi visiškai neribotą simuliacijos laikotarpį su vienos valandos skiriamąja geba. Tuo tarpu TIMES, panašiai kaip Balmorel, gali modeliuoti iki 120 metų laikotarpio. Kita vertus, apžvelgti moksliniai pavyzdžiai rodo, kad modeliuojant trumpalaikę dinamiką ir naudojant optimizavimo įrankius, skirtus ilgalaikių ateities perspektyvų modeliavimui, būtini papildomi modeliavimo įrankiai aukštesnei kokybei ir valandinio metinio režimo vaizdavimui užtikrinti.

Labai svarbu, kad pasirinktas energetikos modelis būtų pritaikomas miestų mastu, atsižvelgiant į įvairias reguliavimo sistemas ir apribojimus. Tuo tarpu vidiniai rinkos veiksniai ir dinamika kelia didelių iššūkių modeliavimo priemonėms, kuriomis siekiama atspindėti realią rinkos situaciją. Nagrinėjami ekonominiai modeliai paprastai orientuoti į energijos pasiūlos ir paklausos bei technologinių pokyčių pusiausvyrą, tačiau dažnai nepakankamai atspindi ne energetikos srities apribojimus, tarpsektorines priklausomybes ir institucines ar reguliavimo kliūtis.

Nepaisant visų minėtų siekių, pirmenybė turėtų būti teikiama atvirojo kodo energijos modeliavimo programoms arba, kitaip tariant, programinė įranga neturėtų būti labai brangi. Galima pastebėti, kad tik EnergyPLAN, MESSAGE ir H2RES ekonominiai modeliai demonstruoja didžiausią atvirojo kodo optimizavimo modelių pranašumą.

Po išsamaus tyrimo galima teigti, kad optimizavimo modeliai neatsižvelgia į suboptimalius sprendimus, jie dažniausiai veda prie idealių scenarijų, kurie kartais gali būti nerealistiški ir nepakankamai įvertinti galimus tarpinės pakopos pokyčius. Be to, optimizavimo modeliai daugiausia skirti ilgalaikiam dinaminiam energetikos modeliavimui, kuris kartais negali užtikrinti aukštos simuliacijos kokybės ir atspindėti realių eksploataavimo sąlygų trumpesniais nei vienerių metų laikotarpiais. Be to, jiems stinga gebėjimo tirti konkurencingas šilumos rinkas, aukcionų mechanizmus ar strateginį elgesį CŠT sistemose.

Kita vertus, simuliacijos modeliai leidžia atlikti konkrečią vartotojo apibrėžtą analizę, kuri apsiriboja scenarijų rinkiniu, dažnai neatspindinčiu kompleksinių neapibrėžtumo veiksnių. Tokie modeliai yra ženkliai sparčiau modeliuojami ir gali būti tinkami esamų energetikos sistemų patikrai be gilios analizės. Tuo tarpu šioje disertacijoje prioritetas teikiamas platesnio stochastinio pobūdžio tyrimui,

atsižvelgiant į įvairius neapibrėžtumus ir pateikiant finansiškai gyvybingus investicijų portfelius CŠT rinkoje.

Kintančioje CŠT sektoriaus aplinkoje labai svarbu atsižvelgti į kintamą šilumos ir elektros energijos gamybos portfelį, įvairius ekonominius neapibrėžtumus, esamų ir naujų rinkos dalyvių veiksmus bei naujas technologijas. Todėl ištirti energetikos ekonomikos modeliai galėtų būti taikomi planuojant ateities energetikos sistemas, tačiau daugelis pasirinktų priemonių neatspindėtų aptartų galimų neapibrėžtumų planuojant CŠT sistemas, atsižvelgiant į rinkos dinamikos poveikį (29 lentelė).

29 lentelė. Kompleksinių energetikos modeliavimo priemonių palyginimas

Energetikos modeliavimo priemonių savybės	Energy PRO	Energy PLAN	H2RES	Balmer	MESS AGE	TIME S	Sukurtas modelis
Stochastinio metodo realizavimas	Ne	Ne	Ne	Ne	Taip	Taip	Taip
Ilgalaikis dinaminis modeliavimas	Yes	Ne	Taip	Taip	Taip	Taip	Ne
Aukšta laiko skiriamoji geba ir kokybė modeliuojant metinius režimus	Taip	Taip	Taip	Taip	Ribota ¹	Ribota ¹	Taip
Galimybė atlikti neapibrėžtumo ir jautrumo analizę	Ne	Ne	Ne	Ne	Taip	Taip	Taip
Šilumos aukcionų strategijos formavimo mechanizmai	Ne	Ne	Ne	Ne	Ne	Ne	Taip
Reguliavimo kliūčių, vidinės rinkos elgsenos ir dinamikos poveikis	Ribota ²	Ne	Ribota ²	Ribota ²	Ribota ²	Ribota ²	Taip
Išsamios CŠT ir akumuliacinio technologijų modeliavimo galimybės	Taip	Ne	Ne	Taip	Taip	Taip	Taip
Atviras ekonominis modelis	Ne	Taip	Taip	Ne	Taip	Ne	Taip

Šaltinis: sudaryta autoriaus

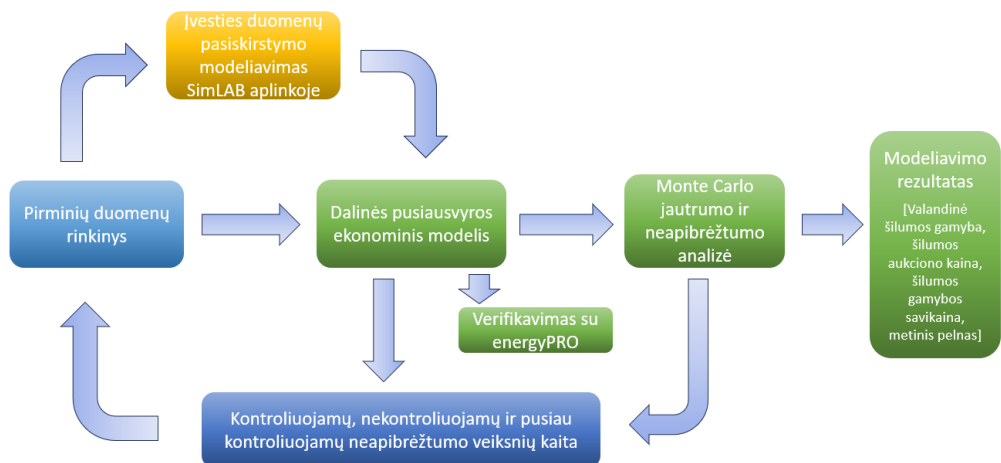
¹ Modeliuojant trumpalaikę šilumos rinkos dinamiką, būtina įtraukti papildomą įrankį

² Modelis neatsižvelgia į vidaus rinkos pokyčius

Dėl apžvelgtų modeliavimo priemonių esamų apribojimų, pavyzdžiui, modifikuoti šilumos aukcionų sistemos veikimo strategijas, atspindinčias realią padėtį šilumos rinkoje, nepakankamų modelių funkcijų, leidžiančių atlikti Monte Carlo jautrumo ir neapibrėžtumo analizę, nustatant optimalų investicijų portfelį, taip pat ribotų galimybių įvertinti reikšmingus reguliavimo pokyčius CŠT sistemoje bei naujų rinkos dalyvių - NŠG ir operatoriaus - atsirandančioms investicijoms į naujas šilumos gamybos ir transformavimo technologijas, esant įvairiems ekonominiams neapibrėžtumams, yra tikslinga sukurti savo dalinės pusiausvyros CŠT sistemos ekonominį modelį su integruota jautrumo ir neapibrėžtumo analize. Šis strateginis sprendimas galėtų padėti pasiekti reikšmingus ir aktualius tyrimo rezultatus, kurie leistų rasti optimalų būsimų investicijų portfelį CŠT rinkoje.

METODOLOGINĖS STRUKTŪROS APIBŪDINIMAS

Pagrindinis iššūkis planuojant CŠT ar visą energetikos sistemą yra atspindėti realius veikimo principus ir pateikti tikslas, patikimas ateities energijos gamybos ar energijos sąnaudų prognozes. Šiame tyrime sukuriamas unikalus dalinės pusiausvyros modelis, galintis atspindėti realią CŠT rinką, kurioje į esamą integruotą šilumos tinklą įtraukiami įvairūs NŠG ir pagrindiniai šilumos tiekėjo šilumos gamybos įrenginiai. Ekonominis modelis yra sukurtas veikti pagal realistiškos šilumos aukciono sistemos principus, parodant konkurenciją tarp šilumos gamybos įrenginių, kuri sukuria didžiausią naudą galutiniams šilumos vartotojams. Modelis yra išplėstas integruojant ekonominius, strateginius bei politinius neapibrėžtumus, siekiant atlikti jautrumo ir neapibrėžtumo analizę, kuri leidžia sukurti finansiškai optimalius centralizuoto šilumos tiekimo dekarbonizacijos scenarijus (94 pav.).



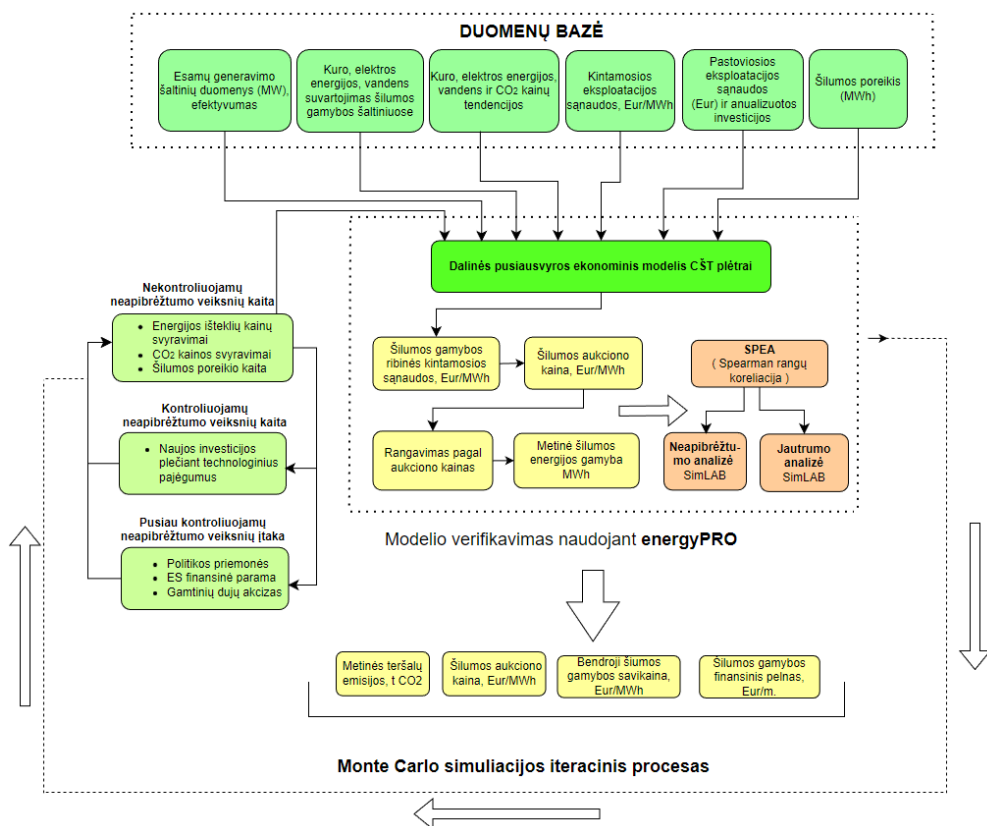
94 pav. Supaprastintas ekonominio modelio metodinis principas

Sukurta metodika išsiskiria tuo, kad ja remiantis galima tirti esamų operatoriaus, NŠG ir naujų rinkos dalyvių elgseną esant kintančioms neapibrėžtumų sąlygoms. Modelis tiria, kokios naujos energijos transformavimo ir gamybos technologijos galėtų būti priimtinos ir finansiškai perspektyvios investuotojų požiūriu, dalyvaujant

CŠT aukcionų sistemoje. Tuo pačiu metu ši metodika suteikia galimybę analizuoti, kaip šių naujų potencialių investuotojų (NŠG ar šilumos operatoriaus) sprendimai paveiktų šilumos aukcionų kainas ir kaip tai paveiktų jų pačių šilumos gamybos sąnaudas, susijusias su naujų įrenginių įdiegimu. Sukurtas modelis leidžia patikrinti dabartinę centralizuoto šilumos tiekimo rinkos struktūrą ir potencialias šilumos gamybos sąnaudas.

Modeliavimo metodo identifikavimas

Tyrimo metodika pradedama nuo pirminių duomenų surinkimo ir esamos CŠT sistemos verifikavimo. Pradiniame etape apžvelgiami esami šilumos ir elektros energijos gamybos šaltinių duomenys, surenkama informacija apie vietinius vandens šildymo katilus, kogeneracines jėgaines ir kitus gamybos įrenginius, jų galią (MW) ir techninio efektyvumo rodiklius. Taip pat yra atsižvelgiama į visas technologines, ekonomines ir aplinkosaugos charakteristikas, kurios leidžia geriau apibrėžti konkrečią esamą CŠT sistemą (95 pav.).



95 pav. Sukurto dalinės pusiausvyros ekonominio modelio metodika

Be to, informacija apie šilumos poreikį taip pat yra būtina norint pateikti esamą CŠT sistemos padėtį. Tai galima atlikti surinkus visą turimą informaciją apie

pasirinkto miesto šilumos tinklus, remiantis viešaisiais duomenimis arba asmenine komunikacija su CŠT įmonės specialistais.

Tuomet apskaičiuojamos ribinės šilumos gamybos sąnaudos, taikant techninę-ekonominę lygtį. Atsižvelgiant į informaciją apie elektros energijos suvartojimo santykį ($\text{kWh}_e/\text{MWh}_s$), vandens suvartojimo santykį (m^3/MWh_s), kuro suvartojimo santykį ($\text{MWh}_k/\text{MWh}_s$), kintamas eksploataavimo sąnaudas (Eur/MWh_s), elektros energijos gamybos santykį ($\text{MWh}_e/\text{MWh}_s$), CO_2 faktoriaus kainas (Eur/MWh_s) ir turint faktines elektros energijos, kuro, vandens kainas, galima nustatyti šilumos gamybos ribines sąnaudas. Šis deterministinis metodas, dažnai taikomas tokiuose modeliuose kaip TIMES ir energyPRO, atspindi trumpalaikes ribines sąnaudas ir fiksuoja esminius rinkos signalus (Li, Hakvoort & Lukszo, 2021). Išsamiam savikainos įvertinimui gauti įtraukiamos fiksuotos eksploataavimo ir priežiūros sąnaudos bei metinės investicijų sąnaudos, remiantis Danijos energetikos technologijų katalogu (Danish Energy Agency, 2025a).

Tuo tarpu, siekiant atspindėti realistišką aukcionų sistemą visam šilumos sektoriui, būtina atsižvelgti į esamų gamybos šaltinių šilumos aukciono kainą. Aukciono kaina apskaičiuojama remiantis ribinėmis kintamosiomis šilumos gamybos sąnaudomis. Taip pat, visiems nagrinėjamiems šilumos gamybos šaltiniams kiekvieną valandą papildomai įvertinama 1 % paklaidos riba, atspindinti minimalų, bet esamą neapibrėžtumą ir leidžiant ribinėms sąnaudoms svyruoti aplink bazinę vertę. Nustačius šią vertę, procedūra organizuojama reitinguojant šilumos gamintojus pagal apskaičiuotas ribines šilumos gamybos sąnaudas. Atsižvelgiant į visus reitingus kiekvienai valandai ir kiekvienam šilumos gamintojui, priimama prielaida, kad šilumos aukciono kaina turėtų būti apskaičiuojama remiantis kito aukštesnio reitingo šilumos gamintojo ribinėmis kintamosiomis šilumos gamybos sąnaudomis. Toks metodas realistiškai parodo esamą šilumos rinkos struktūrą. Realybėje šį procesą reguliuoja „Baltpool“ aukcionų sistema, kuri rinkos dalyvių pajėgumus prioritetizuoja pagal šilumos gamybos įrenginių pateiktus kainų pasiūlymus.

Šie pirminiai rodikliai ir parametrai, taip pat jų kompleksinis integravimas į dalinės pusiausvyros ekonominį modelį, leidžia sukurti bazinį scenarijų, atspindintį pasirinktos CŠT sistemos esamas šilumos gamybos sąnaudas. Remiantis literatūros duomenimis (Nielsen et al., 2021; Berna-Escriche et al., 2024), esamas CŠT sistemas paprastai galima pavaizduoti deterministiniais ekonominiais modeliais, kuriuos galima įgyvendinti naudojant įprastas energetikos ekonomikos modeliavimo priemones. Todėl, siekiant patikrinti ir verifikuoti dalinės pusiausvyros modelį, įtraukiama patikima modeliavimo priemonė energyPRO, kuri leidžia tiksliai įvertinti bendras šilumos gamybos sąnaudas, taikant sąnaudų mažinimo principą.

Pagrindiniai techniniai ir ekonominiai rodikliai, taikomi CŠT sistemos vertinimui

Sukurta metodika leidžia atlikti išsamų esamos CŠT sistemos vertinimą, įtraukiant įvairius techninius ir ekonominius parametrus, apibūdinančius sistemos veikimą ir sąnaudų dinamiką, lemiamą rinkos sąlygų. Techniniai parametrai apibrėžia šilumos gamybos technologijų funkcines charakteristikas, įskaitant įrengtą šiluminę galią, kogeneracinių elektrinių (CHP) kogeneracijos koeficientą ir elektros gamybos

pajėgumus, taip pat veiklos rodiklius, pvz., šilumos gamybos efektyvumą (COP), specifinį elektros ir vandens suvartojimą vienam šilumos energijos kiekio vienetui, kuro ir šilumos konversijos koeficientus. Numatomo gamybos šaltinio tarnavimo laikas ir prieinamumas nustatomas pagal turto nusidėvėjimo laiką, planuojamą sustabdymo trukmę ir metinį tinklo šilumos poreikį (30 lentelė).

30 lentelė. Pagrindiniai techniniai ir ekonominiai įvesties duomenys, naudojami sukurtam dalinės pusiausvyros modeliui bei pagrindiniai išvesties rezultatai

Kategorija	Parametrai	Vnt. / Aprašymas
Techniniai įvesties parametrai	Šilumos gamybos įrenginio šiluminė galia	MW
	Kogeneracijos koeficientas	–
	Elektros gamybos įrenginio elektrinė galia	MW
	Šilumos gamybos šiluminis efektyvumas (COP)	–
	Elektros energijos suvartojimas vienam pagamintam šilumos vienetui	kWh _e /MWh _s
	Vandens suvartojimo santykis	m ³ /MWh _s
	Kuro suvartojimo koeficientas	MWh _k /MWh _s
	Gamybos šaltinio tarnavimo laikas	metai
	Planuojamas jėgainės sustabdymo laikas	valandos per simuliacijos laikotarpį
	Metinis CŠT sistemos šilumos poreikis	MWh
Ekonominiai įvesties parametrai	Fiksuotos eksploatacijos ir priežiūros sąnaudos	Eur/MW
	Kintamosios eksploataavimo ir priežiūros sąnaudos	Eur/MWh _s
	Šilumos gamybos įrenginių investicijos	Eur/MW _s
	CO ₂ teršalų emisijos kaina	Eur/MWh _s
	Elektros energijos biržos kaina	Eur/MWh
	Elektros energijos perdavimo ir skirstymo kaina	Eur/MWh
	Biokuro kaina	Eur/MWh
	Gamtinių dujų žaliavos kaina	Eur/MWh
	Gamtinių dujų perdavimo ir skirstymo kaina	Eur/MWh
	Vandens kaina	Eur/m ³
	Atliekų pirkimo kaina	Eur/MWh
Modelio išvesties rodikliai	Vidutinė bendroji šilumos aukciono kaina	Eur/MWh
	Vidutinė bendroji šilumos gamybos savikaina	Eur/MWh
	Operatoriaus finansinis pelnas	Eur/m.
	NŠG finansinis pelnas	Eur/m.
	Metinis CO ₂ emisijos kiekis	t CO ₂ /m.

Ekonominiai parametrai apima fiksuotas ir kintamas eksploataavimo ir priežiūros išlaidas, kapitalo investicijas į vieną įrengtą šiluminės galios vienetą ir atitinkamas rinkos kainas, įskaitant CO₂ emisijos leidimų kainą, elektros biržos ir perdavimo-skirstymo kainas, biokuro ir gamtinių dujų kainas, vandens tarifus ir atliekų pirkimo išlaidas. Remiantis šiais daugialybiais duomenimis, dalinės pusiausvyros modelis nustato pagrindinius veiklos rodiklius, pvz., vidutinę bendrą šilumos aukciono kainą, vidutinės šilumos gamybos sąnaudas, sistemos operatoriaus ir nepriklausomų šilumos gamintojų metinį finansinį pelną ir bendrą metinį CO₂ išmetimą. Taigi, šis modeliavimo metodas leidžia patikimai ir aiškiai įvertinti modernios CŠT sistemos technines, ekonomines ir aplinkosaugos charakteristikas, taip sudarant tvirtą pagrindą politikos analizei ir strateginiam planavimui.

Laiko intervalas ir skiriamoji geba

Atsižvelgiant į reikšmingą potencialą integruoti kintamąją atsinaujinančią energiją į esamą ir būsimą CŠT sistemą, numatoma modeliuoti atskirus metus valandiniu režimu. 2030 m. modeliavimo laikotarpis pasirinktas remiantis realistiškomis ateities energijos kainų prognozėmis ir aiškia vizija dėl esamų operatoriaus ir NŠG šilumos gamybos įrenginių liekančios amortizacinės vertės. Ilgesnis planavimo laikotarpis, pvz., 2040 m. ar 2050 m., sukeltų pernelyg didelį neapibrėžtumą, norint modeliuoti patikimą CŠT sektoriaus ekonomiką ir nustatyti optimalius dekarbonizacijos sprendimus.

Valandiniame režime modelis leidžia įtraukti ir tinkamai įvertinti visas novatoriškas šilumos transformavimo technologijas, įskaitant sezoninius ir trumpalaikius šilumos kaupimo sprendimus, vandenilio elektrolizės atliekinės šilumos atgavimo technologijas, saulės kolektorių šilumos generavimą, kompresorinių šilumos siurblių panaudojimą ir kitus novatoriškus elektros energijos į šilumą konvertavimo sprendimus.

Jautrumo ir neapibrėžtumo analizės realizavimas

Dalinės pusiausvyros modelis naudoja SimLab programinę įrangą Monte Carlo (MC) neapibrėžtumo ir jautrumo analizei atlikti. MC analizė apima daugkartinį modelio paleidimą su tikimybiškai atrinktais įvesties duomenimis ir rezultatų analizę, siekiant įvertinti 1) modelio numatomų rezultatų neapibrėžtumą ir 2) kokie įvesties kintamieji labiausiai prisideda prie šio neapibrėžtumo.

Tipinė MC analizė susideda iš penkių nuoseklių etapų, skirtų neapibrėžtumui ir jautrumui kiekybiškai įvertinti (Giglioli ir Saltelli, 2003). Iš pradžių kiekvienam įvesties kintamajam priskiriami atitinkami tikimybiniai pasiskirstymai ir intervalai. Vėliau, remiantis šiais pasiskirstymais, generuojama įvesties kintamųjų derinių imtis, taip sudarant reprezentatyvią scenarijų grupę. Trečiajame etape šie atrinkti įvesties duomenys naudojami modelio daugkartinėms iteracijoms atlikti, taip nustatant funkcinį atvaizdavimą iš įvesties erdvės į išvesties erdvę. Šis atvaizdavimas yra pagrindas tolesnei neapibrėžtumo analizei. Galiausiai atliekama jautrumo analizė, siekiant įvertinti kiekvieno įvesties kintamojo santykinį poveikį modelio rezultatų kaitai.

Dalinės pusiausvyros modelis, naudojantis SimLab programinės įrangos paketą, taiko iteracinį metodą, leidžiantį analizuoti įvairius galimus scenarijus. Rezultatų vertinimas grindžiamas pagrindinėmis taisyklėmis, kurios sudaro struktūrizuotą pagrindą užtikrinti patikimą ir atkartojamą iteracinę analizę. Pirmiausia iš modelio pašalinami rizikingiausi ir finansiškai negyvybingi variantai, kurie su 100 % tikimybe būtų nuostolingi. Taikant nustatytą formulę, apskaičiuojama empirinė tikimybė, rodanti potencialios investicijos finansinio nuostolio rizikingumą nuo 0 iki 1.

$$P(Vertė < 0) = \frac{N(Vertės < 0)}{N(Visos nagrinėjamos vertės)} \quad (1)$$

čia: $N(Vertės < 0)$ simuliacijų skaičius su neigiamomis investicijos finansinio pelno vertėmis; $N(Visos nagrinėjamos vertės)$ visų atliktų investicijos finansinio pelno simuliacijų skaičius.

Antra, organizuojant iteracinį procesą, siekiama maksimaliai padidinti investuotojų pelną, mažinant investicijas į naujus perteklinius šilumos gamybos pajėgumus. Remiantis iteracijų rezultatais, daroma išvada, kad būtina sumažinti naujų investicijų, susijusių su didžiausia finansine rizika, potencialius pajėgumus. Pajėgumų mažinimo ir ribojimo procesas vykdomas sistemingai vertinant jautrumo analizės diagramų rezultatus, kurie yra pagrindinė diagnostinė priemonė, padedanti nustatyti patikimas investicijų ribas. Šios diagramos vertinamos pagal du pagrindinius kriterijus. Pirmia, jos turi parodyti, kad atsitiktinės iteracijos nuosekliai priartėja prie sąlygų, kurios lemia didžiausią investuotojų finansinį pelną, net ir esant dideliui sklaidos lygiui. Šis kriterijus užtikrintų, kad rekomenduojami pajėgumų apribojimai išliktų atsparūs ekstremalioms ar labai nepastovioms rinkos sąlygoms. Antra, jautrumo rezultatai turėtų rodyti nemažėjančią vidutinių verčių tendenciją, taip parodydant, kad numatomas investuotojų pelnas nesumažėja, kai sistemoje atsiranda neapibrėžtumai.

Galiausiai, bet kokia likusi investavimo alternatyva, kuri investuotojo požiūriu keltų didesnę nei 50 % finansinio nuostolio riziką, būtų atmetama. Šios trys taisyklės užtikrintų, kad taikomas naujų šilumos gamybos šaltinių apribojimas neturėtų neigiamos įtakos ilgalaikiams investuotojų finansiniams lūkesčiams ir kad investavimo sprendimai atitiktų stabilius arba gerėjančius veiklos rezultatus. Tokiu būdu, per tris etapus nustatyti perspektyviausi investiciniai sprendimai užtikrintų optimalų investicijų portfelį, analizuojant įvairius pasirinktus scenarijus.

Dalinės pusiausvyros modelio neapibrėžtumo veiksnių identifikavimas

Siekiant užtikrinti kompleksinį CŠT sistemos planavimą, ekonominis modelis yra išplečiamas įtraukiant įvairius kontroliuojamus, iš dalies kontroliuojamus ir nekontroliuojamus neapibrėžtumus, kad būtų įgyvendintas stochastinis modeliavimo požiūris.

Nekontroliuojami neapibrėžtumo veiksniai:

- Elektros energijos biržos kainos svyravimas, Eur/MWh;
- Biokuro kainos svyravimas, Eur/MWh;

- Gamtinių dujų žaliavos kainos svyravimas, Eur/MWh;
- CO₂ kainos svyravimas, Eur/t;
- Vandenilio kainos svyravimas, Eur/kg;
- Šilumos paklausos svyravimas, MWh/per metus.

Iš dalies kontroliuojami neapibrėžtumo veiksniai:

- Politinės priemonės, skirtos pasiekti 100 % iš AEI šilumos tiekimo sistemą;
- ES finansinė parama AEI naudojančioms energijos gamybos technologijoms;
- Politinė priemonė, susijusi su gamtinių dujų akcizo mokesčiu.

Kontroliuojami neapibrėžtumo veiksniai:

- Operatoriaus investicijos į nuotekų atliekinės šilumos atgavimą diegiant šilumos siurblių pajėgumus;
- Operatoriaus investicijos į biokuro vandens šildymo katilines (VŠK);
- Operatoriaus investicijos į saulės kolektorių jėgaines su šilumos akumuliacijos talpomis (ŠAT);
- Operatoriaus investicijos į lankstumo sprendimus - elektrinių katilų pajėgumus;
- Operatoriaus investicijos į Power-to-H₂ and Heat sprendimus;
- Operatoriaus investicijos į sezoninio šilumos akumuliacijos sprendimus;
- Operatoriaus investicijos į Power-to-Heat sprendimus (oro-vandens tipo šilumos siurbliai);
- NŠG investicijos į biokuro VŠK pajėgumus.

Skirtingų tipų neapibrėžtumų klasifikavimas energetikos sektoriuje yra labai svarbus efektyviam planavimui ir sprendimų priėmimui. Todėl dalinės pusiausvyros modelis apima neapibrėžtumus pagal hierarchinę sistemą, nustatytą ir išnagrinėtą 1.2 skyriuje (1 pav.). Iliustracija parodo, kad neapibrėžtumai, susiję su potencialiomis investicijomis į įvairias naujas šilumos gamybos technologijas, yra maži dėl aukšto investuotojų kontrolės lygio ir aiškių sprendimų priėmimo procesų. Tai taip pat galima pagrįsti literatūros apžvalga, kuri atskleidė, kad potencialios investicijos į AEI technologijas, pvz., saulės fotoelektros ir vėjo jėgaines, yra laikomos fiziškai kontroliuojamais neapibrėžtumais.

Priešingas reiškinys pastebimas analizuojant ateities tendencijas ir prognozes dėl elektros energijos, biokuro, gamtinių dujų, CO₂ ir H₂ kainų. Remiantis ankstesniuose skyriuose analizuota literatūra, tai susiję su nenusipėjamais ateities neapibrėžtumais, kurių negalima kontroliuoti.

Tuo tarpu tokios politikos priemonės kaip ES finansinė parama, skatinanti pasiekti 100 % šilumos gamybą iš AEI, ar akcizo mokesčio už gamtines dujas įvedimas laikomos iš dalies kontroliuojamais neapibrėžtumais. Jas gali priimti kai kurios vietos ar nacionalinės valdžios institucijos, todėl jų kontrolės laipsnis galėtų būti tarp visiškai kontroliuojamų ir visiškai nekontroliuojamų neapibrėžtumų.

Atsižvelgiant į šiuos aptartus neapibrėžtumus, ekonominis modelis suteikia platesnes galimybes rasti optimalius ir finansiškai perspektyvius dekarbonizacijos sprendimus, planuojant CŠT sistemų plėtrą. Kita vertus, sukurta sistema apima kelis

sektorius: centralizuoto šilumos tiekimo, elektros energijos ir vandenilio rinkas. Tokia sektorių sąveikos struktūra palengvina didesnę atsinaujinančiųjų išteklių naudojimą CŠT sektoriuje už prieinamą elektros energijos rinkos kainą.

REZULTATAI

Pasirinktos centralizuoto šilumos tiekimo sistemos apžvalga

Sukurto dalinės pusiausvyros ekonominio modelio išbandymui buvo pasirinkta Vilniaus centralizuoto šilumos tiekimo sistema (Lietuva). Lietuvos sostinė Vilnius turi didžiausią centralizuoto šilumos tiekimo sistemą šalyje.

Vilniaus miesto integruotą šilumos tinklą sudaro 8 NŠG, eksploatuojantys 10 atskirų šilumos gamybos šaltinių, kurie dalyvauja šilumos aukcionuose (Baltpool, 2025a). Remiantis Vilniaus šilumos tiekėjo pateikta informacija, nuo 2024 m. rudens visų Vilniaus miesto įrenginių bendra šiluminė galia siekė 1417,6 MW. Pagrindiniai šilumos gamybos pajėgumai yra įsikūrę Vilniaus miesto pietvakariuose. Šiaurinėje miesto dalyje prie integruoto Vilniaus šilumos tinklo yra prijungta tik operatoriaus katilinė RK-8. RK-8 įrengtoji šilumos gamybos galia siekia 495,44 MW, tačiau eksploatuojama tik 58 MW šios galios, o likusi gamybos galia yra atsarginė arba neatitinka aplinkosaugos reikalavimų, nes nėra rekonstruota. Visos RK-8 įrengtos šilumos gamybos katilinės naudoja gamtines dujas. Remiantis surinktais duomenimis ir komunikuojant su šilumos tinklų operatoriumi, buvo sudaryta 31 lentelė, kurioje pateikiami visi Vilniaus miesto integruotame tinkle veikiantys šilumos gamybos šaltiniai.

31 lentelė. Duomenys apie esamus šilumos gamybos įrenginius Vilniaus CŠT tinkle

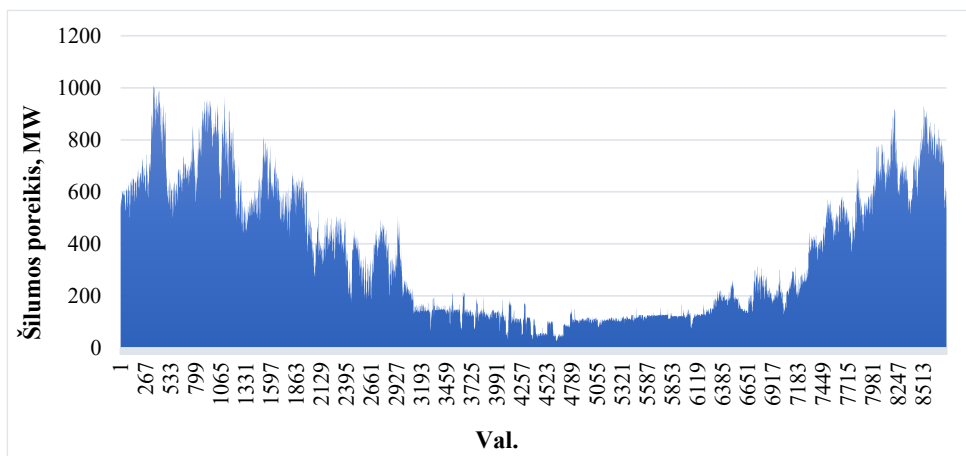
Šilumos gamybos šaltinis (šilumos tiekėjo ir NŠG šilumos gamybos įrenginiai)	Įrenginio šiluminė galia, MW	Šiluminė galia iš biokuro ar atliekų, MW	Šiluminė galia iš gamtinių dujų, MW	Galimas papildomas gamtinių dujų pajėgumas, MW
NŠG8 atliekų ir biokuro kogeneracinė jėgaine	240,0	240,0		
Operatoriaus- termofikacinė elektrinė VE-2	892,1	80,8	811,3	116,0
Operatoriaus- RK-8 katilinė	58,0		58,0	407,0
Operatorius- RK-7 rajoninė katilinė	40,7		40,7	-
NŠG5 „Grigeo“	10,0	10,0		
NŠG6 „Vilniaus baldai“	4,5	4,5		
NŠG3 GREN	20,8	20,8		
NŠG7 1b „Forest Investment“	24,3	24,3		
NŠG7 2b „Forest Investment“	24,3	24,3		

NŠG2 1b IDEX	25,7	25,7		
NŠG2 2b IDEX	25,7	25,7		
NŠG1 „Zietela“	25,0	25,0		
NŠG4 IDEX Pakalniškių	26,5	26,5		
Iš viso	1 417,6	507,6	910,0	523,0

Šaltinis: sudaryta autoriaus, remiantis asmenine komunikacija su Vilniaus šilumos tiekimo bendrove

Šilumos gamybos pajėgumas Vilniuje siekia 1 417,6 MW, iš kurių 507,6 MW gaunama iš AEI. Šis padidėjimas pasiektas įdiegus naują biokuro kogeneracinį bloką Vilniaus kogeneracinėje jėgainėje ir Vilniaus šilumos tinklų bendrovei įrengus naują absorbcinį šilumos siurblių, skirtą biokuro garo katilo efektyvumui pagerinti 2024 m. (Vilniaus šilumos tinklų bendrovė, 2024 m.), (Baltpool, 2025a).

Faktinių duomenų analizė parodė, kad didžiausias šilumos tinklo poreikis – 999 MW – buvo užregistruotas 2021 m. sausio 16–17 d. Tačiau reikėtų pažymėti, kad didžiausias tinklo poreikis buvo pasiektas dieną, kai lauko oro temperatūra buvo – 20,2 °C, o Vilniaus miesto projektinė temperatūra laikoma šalčiausia penkiadienio temperatūra, kuri yra –23 °C. Atsižvelgiant į metinį šilumos poreikį per pastaruosius penkerius metus, 2021 m. buvo pasirinkti kaip šalčiausi metai, atspindintys didžiausią esamos CŠT šilumos poreikį ir galintys būti naudojami kaip atskaitos metai. Remiantis Vilniaus šilumos tiekimo bendrovės dešimties metų investiciniu planu šilumos tiekimo sektoriaus plėtrai (Vilniaus šilumos tiekimo bendrovė, 2024 m.), daroma prielaida, kad 2030 m. šilumos poreikis bus 0,4–0,8 % didesnis dėl galimo naujų šilumos vartotojų skaičiaus augimo miesto zonose, nepaisant sparčios renovacijos ir pastatų efektyvumo didinimo. Todėl, remiantis 2021 m. valandinio šilumos poreikio duomenimis, tikimasi, kad šilumos poreikis šiek tiek išaugs (96 pav.).



96 pav. Prognozuojamas Vilniaus CŠT sistemos šilumos poreikis 2030 m.

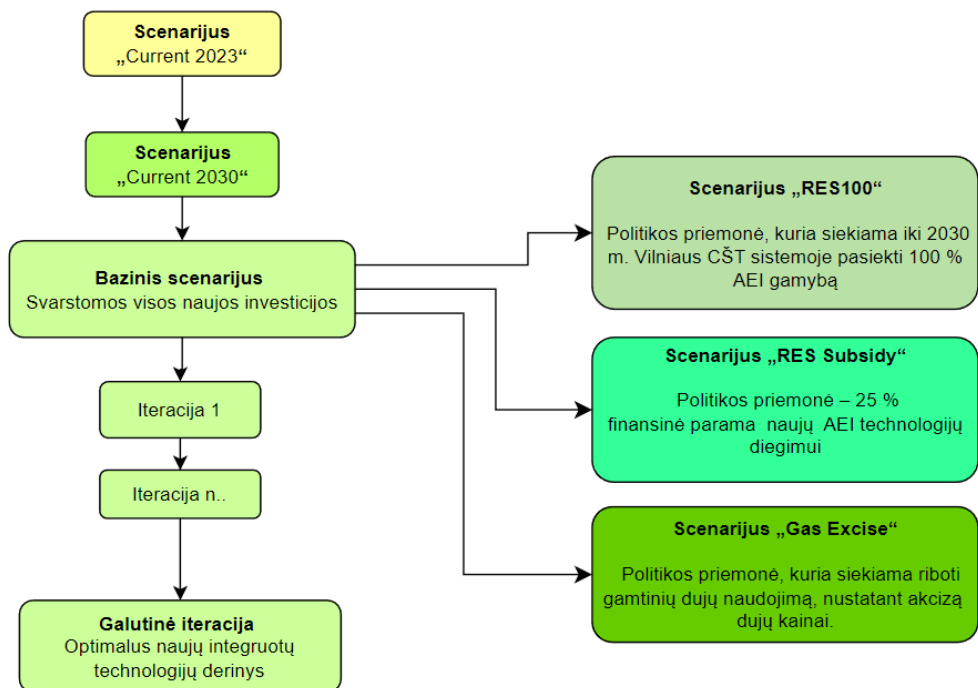
Scenarijų modeliavimo struktūra Vilniaus centralizuoto šilumos tiekimo rinkai

Kompleksinis modeliavimo tyrimas pradedamas verifikuojant Vilniaus CŠT sistemą, formuojant du referencinius scenarijus „Current 2023“ ir „Current 2030“. Siekiant atspindėti CŠT rinkos struktūrą be naujausių šilumos gamybos šaltinių – Vilniaus biokuro kogeneracinės jėgainės, kurios šiluminė galia yra 170 MW, ir Vilniaus šilumos tiekėjo investicijų į absorbcinius šilumos siurblius (8,5 MW šiluminės galios) esamos šilumos gamybos infrastruktūros modernizavimui, šilumos rinkos padėties verifikacijai, vertinant scenarijų „Current 2023“, pasirenkami 2023 metai.

Toliau pateikiamos Vilniaus CŠT sistemos perspektyvos 2030 m., atsižvelgiant į naujai pastatytus esamus šilumos gamybos šaltinius – Vilniaus biokuro kogeneracinę jėgainę ir operatoriaus įrengtą naują absorbcinį šilumos siurblių, kurie atspindėtų scenarijų „Current 2030“. Šis scenarijus parodo galimą CŠT rinkos padėtį ateityje be jokių naujų papildomų šilumos tiekėjo ir NŠG investicijų.

Atsižvelgiant į ateities perspektyvas iki 2030 m., šioje disertacijoje bus įvertinti keturi skirtingi scenarijai. Pirmasis bazinis scenarijus yra atspindintis pilnai išplėstą CŠT ekonominį modelį, kuriame atsižvelgiama į visas naujas potencialias operatoriaus ir NŠG investicijas. Bazinis scenarijus susideda iš esamų šilumos gamybos įrenginių – biokuro VŠK ir kogeneracinių jėgainių – bei operatoriaus ir NŠG visų galimų naujų investicijų į žaliosios energijos gamybos technologijas. Esama gamybos infrastruktūra šilumos sektoriuje daugiausia grindžiama biokuro vandens šildymo katilais ir biokuro arba atliekų kogeneracinėmis jėgainėmis, o gamtinių dujų katilai reikalingi šilumos poreikiui patenkinti tik šildymo sezono šalčiausiais laikotarpiais. Žvelgiant į 2030 m., racionalu turėti tinkamą tvarių šilumos gamybos technologijų derinį, kurio investicijas finansuotų šilumos tiekėjas ar kiti rinkos dalyviai, siekiant maksimizuoti finansinį pelną, prisidedant prie Nacionalinės energetikos strategijos tikslų įgyvendinimo, šilumos aukcionų kainų ir gamybos sąnaudų mažinimo bei iškastinio kuro naudojimo atsisakymo visoje šilumos rinkos struktūroje.

Bazinis scenarijus yra atskaitos taškas visiems scenarijams, analizuojantiems 2030 m. laikotarpį, kuris apima esamus ir naujus rinkos dalyvius, energijos kainų svyravimus, kaip nekontroliuojamus neapibrėžtumo veiksnius, bei kontroliuojamus neapibrėžtumo veiksnius, tokius kaip, operatoriaus ar NŠG investicijas į naujų technologijų plėtrą, pvz., išvalytų nuotekų šilumos atgavimo sprendimus, investicijas į biokuro VŠK, saulės kolektorių pajėgumus su trumpalaikio saugojimu, lankstumo sprendimų integraciją investuojant į elektrinius katilus, „Power-to-H₂“ ir „Heat“ sprendimų įgyvendinimą, sezoninio PTES šilumos saugojimo įtraukimą, „Power-to-Heat“ sprendimus (97 pav.).



97 pav. Scenarijų modeliavimo struktūra (sudaryta autoriaus)

Antrojo scenarijaus „RES100“ atveju būtų taikoma politikos priemonė, kuria siekiama iki 2030 m. Vilniaus C&H sistemoje pasiekti 100 % šilumos gamybą iš atsinaujinančių energijos išteklių. Šis scenarijus numato investicijų prioritizavimą, atsisakant iškastinio kuro naudojimo C&H sistemoje, orientuotą į finansinio pelno maksimizavimą, kartu užtikrinant, kad šilumos aukcionų kainos, esant nekontroliuojamiems ekonominiais neapibrėžtumams, nevirsytų daugiau kaip 5 % lyginant su scenarijumi „Current 2030“.

Tuo tarpu trečiasis scenarijus „RES Subsidy“ būtų įgyvendintas analizuojant galimą finansinę paramą ir paskatas naujoms šilumos gamybos ir transformavimo technologijoms finansinio pelno maksimizavimo kontekste, užtikrinant pagrįstas šilumos aukciono kainas, kurios nevirsytų daugiau nei 5 % lyginant su scenarijumi „Current 2030“. Daroma prielaida, kad naujos investicijos, pagrįstos AEI gamyba, išskyrus biokuro katilus, gali būti finansiškai remiamos 25 % subsidijomis. Scenarijus parodytų, kaip papildoma finansinė parama galėtų pakeisti bendrąsias šilumos aukciono kainas, ir padėtų nustatyti finansiškai pelningiausias investicijas iš operatoriaus ir NŠG perspektyvos.

Ketvirtasis scenarijus „GAS Excise“ apimtų politikos priemonę, kuria siekiama sumažinti gamtinių dujų naudojimą, nustatant akcizą gamtinių dujų kainai. Daroma prielaida, kad akcizas padidins galutinę gamtinių dujų kainą dvigubai. Šis scenarijus iliustruotų, kaip esami ir nauji energijos gamybos šaltiniai, tiek paties šilumos tiekėjo, tiek NŠG, elgtųsi šioje kintančioje rinkos aplinkoje. Scenarijus parodytų finansiškai optimalų portfeli, įgyvendinant finansinio pelno maksimizavimo sąlygą, taip pat

užtikrintų adekvačias šilumos aukciono kainas, kurios neviršytų daugiau nei 5 % scenarijaus „Current2030“ kainų.

Papildomų scenarijų „RES100“, „RES Subsidy“ ir „Gas Excise“ identifikavimas atspindėtų iš dalies kontroliuojamų neapibrėžtumų vertinimą modeliuojant Vilniaus CŠT sistemos plėtrą 2030 m.

Visų analizuotų scenarijų neapibrėžtumo analizės rezultatai

Išsami visų nagrinėtų scenarijų neapibrėžtumo analizė, vertinant 2030 m. laikotarpį, rodo, kad politikos priemonės daro įvairų poveikį investuotojų finansiniam pelnui ir bendrosioms CŠT rinkos šilumos aukcionų kainoms. Tyrimas parodė, kad didžiausią poveikį finansinio pelno maksimizavimui turėtų scenarijus „RES100“. Reikšmingos investicijos į naujus vandenilio elektrolizės įrenginius ir jų atliekinės šilumos panaudojimo sprendimus, integruojant kompresorinius šilumos siurblius (ŠS), taip pat elektros energijos į šilumą konversijos sprendimus, investuojant į išvalytų nuotekų ir oro šaltinio ŠS, maksimaliai padidintų investuotojo - operatoriaus finansinę naudą, kuri būtų vidutiniškai 12 kartų didesnė nei vertinant scenarijų „Current 2030“. Nors operatoriaus esami ir nauji gamybos šaltiniai šiame scenarijuje skatintų didesnę finansinę pelną, tikėtina, kad konkurencija vietiniams NŠG sustiprėtų dėl atsiradusių naujų energetiškai efektyvių gamybos šaltinių. Šis konkurencinis poveikis sumažintų bendrą NŠG patiriamą finansinę pelną dvigubai, lyginant „Current 2030“ scenarijų. Atliktas modeliavimas demonstruoja, kad palankiausia visų NŠG finansinė padėtis būtų pasiekama pagal scenarijų „Current 2030“ be visų papildomų naujų potencialių operatoriaus investicijų, kur vidutinė finansinio pelno vertė viršytų 66 mln. Eur per metus. Kita vertus, verta pažymėti, kad maksimalus finansinis pelnas ir 100 % AEI naudojimas šilumos gamybai nesudarytų sąlygų mažiausioms šilumos aukciono kainoms, ir tai nebūtų palankiausias scenarijus galutiniams šilumos vartotojams.

Remiantis atlikta Vilniaus CŠT rinkos struktūros analize pagal scenarijų „Current 2023“ ir prognozuojamais nekontroliuojamais neapibrėžtumais iki 2030 m., galima tikėtis, kad šilumos aukciono kaina padidėtų maždaug 22 % iki 59,39 Eur/MWh. Tuo tarpu „RES100“ scenarijaus tyrimų rezultatai rodo, kad investicijos į atsinaujinančiosios energijos šilumos gamybos technologijas galėtų prisidėti prie 13 % aukciono kainų sumažėjimo, lyginant su scenarijumi „Current 2030“, ir pasiekti 51,43 Eur/MWh vidutinę vertę. Kita vertus, galima pastebėti, jog akcizo mokesčio už gamtines dujas įvedimo politinė priemonė skatintų nežymų šilumos aukciono kainų padidėjimą, pasiekiantį vidutiniškai 61,45 Eur/MWh arba 3,5 % aukciono kainos padidėjimą, lyginant su scenarijumi „Current 2030“, nepaisant didelės dalies naujų AEI šaltinių integravimo. Šis poveikis daugiausia susijęs su gamtinių dujų naudojimu, kurios, kaip prognozuojama, vidutiniškai sudarytų 2,9 % šilumos gamybos per šalčiausius laikotarpius Vilniaus CŠT sistemoje. Iš simuliuotų scenarijų „RES Subsidy“, numatantis 25 % finansinę paramą naujoms atsinaujinančiosios energijos šilumos gamybos technologijoms (išskyrus biokuro katilus), užtikrina mažiausią šilumos aukciono kainą (48,5 Eur/MWh), kuri yra 18,34 % mažesnė nei demonstruoja scenarijus „Current 2030“. Šis atvejis rodo, kad tikslinės finansinės priemonės labai paskatintų plėtoti optimalų naujų energetikos investicijų portfelį, orientuotą į šilumos

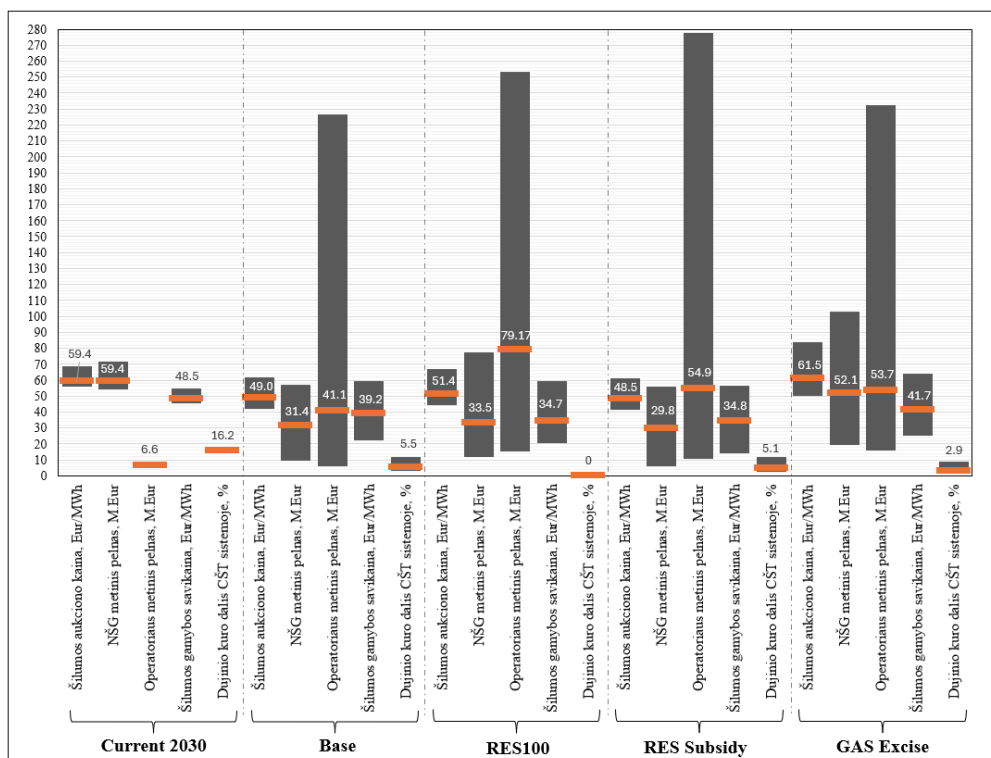
aukciono kainų mažinimą, užtikrinant investicijų finansinio pelno maksimizavimo sąlygas. Scenarijaus investicijų portfelį daugiausia sudarytų aukštos temperatūros kompresoriniai ŠS, naudojančys išvalytas nuotekas, kurių šiluminė galia galėtų svyruoti nuo 26,7 iki 40,9 MW, taip pat oro-vandens tipo ŠS, kurių galia svyruotų nuo 1 iki 100 MW. Portfelis taip pat apimtų atliekinės šilumos iš vandenilio elektrolizės procesų panaudojimą, integruojant kompresorinius ŠS, kurių galia galėtų svyruoti nuo 1 iki 300 MW, taip pat investicijas į elektrinius katilus, kurių šiluminė galia svyruotų nuo 1 iki 35 MW. Investicijų portfelį papildytų galimos investicijos į saulės šiluminius plokščiųjų kolektorių laukus su trumpalaikėmis akumuliacinėmis talpomis, kurių plotas būtų nuo 1 000 iki 100 000 m². Kartu šios investicijos leistų tiekti šilumą mažiausiomis įmanomomis aukciono kainomis, kartu užtikrinant operatoriaus finansinį gyvybingumą (32 lentelė).

32 lentelė. Visų scenarijų neapibrėžtumo analizės suvestinė lentelė

Nr.	Scenarijus	Strategija / prioritetas	Optimalus naujų investicijų portfelis pagal operatorių (OP) ir NŠG	Bendroji CŠT sistemos šilumos aukciono kaina, Eur/MWh	Bendrosios CŠT sistemos šilumos gamybos savikaina, Eur/MWh	Bendras OP finansinis pelnas, mln. Eur	Bendras NŠG finansinis pelnas, mln. Eur	Dujų dalis CŠT sistemoje, %
1	Current 2023	Esama 2023 m. Vilniaus CŠT sistemos padėtis	OP biokuro CHP NŠG-8 atliekų CHP NŠG1-7 biokuro VŠK OP dujiniai katilai	48,56	49,36	14,92	36,98	34,8
2	Current 2030	2030 m. Vilniaus CŠT sistema be naujų OP ir NŠG investicijų	OP biokuro CHP + AŠS [8,5MW] NŠG-8 atliekų CHP NŠG-8 biokuro CHP [170MW] NŠG1-7 biokuro VŠK OP dujiniai katilai	$\mu=59,39$ CV= 3,92 %	$\mu=48,54$ CV= 3,97 %	$\mu=6,57$ CV= 11,02%	$\mu=66,08$ CV= 5,34 %	$\mu=16,2$ CV= 3,25%
3	Bazinis	Visos naujos investicijos, skirtos pelno maksimizavimui	OP nuotekų ŠS [26,7–40,9 MW]; OP oro-vandens tipo ŠS [1–100 MW]; OP H ₂ ŠS [1–250 MW]; OP El. katilai [1–35MW]	$\mu=49,02$ CV= 7,07 %	$\mu=39,16$ CV= 19,85 %	$\mu=41,05$ CV= 138,7%	$\mu=31,45$ CV= 28%	$\mu=5,46$ CV= 37,5%

N r.	Scenarijus	Strategija / prioritetai	Optimalus naujų investicijų portfelis pagal operatorių (OP) ir NŠG	Bendroji CŠT sistemos šilumos aukciono kaina, Eur/MWh	Bendrosios CŠT sistemos šilumos gamybos savikaina, Eur/MWh	Bendras OP finansinis pelnas, mln. Eur	Bendras NŠG finansinis pelnas, mln. Eur	Dujų dalis CŠT sistemoje, %
4	RES 100	Pasiekti 100 % iš AEI gamybą iki 2030 m. ir maksimaliai padidinti pelną	OP nuotekų ŠS [26,7–40,9 MW]; OP oro-vandens tipo ŠS [50–150 MW]; OP H ₂ ŠS [150–250 MW]; OP El. katilai rezervui [500MW]	$\mu=51,43$ CV=9,97 %	$\mu=34,69$ CV=30,79 %	$\mu=79,17$ CV=84,8%	$\mu=33,51$ CV=40,17 %	0
5	RES Subsidy	25 % finansinė parama naujų AEI pagrįstų gamybos technologijų diegimui	OP nuotekų ŠS [26,7–40,9 MW]; OP oro-vandens tipo ŠS [1–100 MW]; OP H ₂ ŠS [1–300 MW]; El. katilai [1–35 MW] Saulės kolektoriai [1000–100 000 m ²]	$\mu=48,5$ CV=7,6 %	$\mu=34,8$ CV=27,1 %	$\mu=54,85$ CV=125,1%	$\mu=29,79$ CV=30,26 %	$\mu=5,07$ CV=41,44 %
6	Gas Excise	Gamtinių dujų naudojimo apribojimas, nustatant akcizą gamtinių dujų kainai	OP nuotekų ŠS [26,7–40,9 MW]; OP oro-vandens tipo ŠS [1–100 MW]; OP H ₂ ŠS [1–250 MW]; El. katilai [1–50MW] BioVŠK OP [1–30 MW] BioVŠK NŠG [1–40 MW] Saulės kolektoriai [12 000–35 000 m ²] PTES sez. talpykla [450 000–470 000 m ³]	$\mu=61,45$ CV=10,19 %	$\mu=41,66$ CV=19,2 %	$\mu=53,75$ CV=103,93 %	$\mu=52,09$ CV=28,58 %	$\mu=2,9$ CV=54,1%

Remiantis gautaisiais neapibrėžtumo analizės scenarijų rezultatais, galima pastebėti, kad optimalūs nauji investicijų portfeliai su operatoriaus ir NŠG naujais šilumos gamybos šaltiniais padėtų ženkliai sumažinti šilumos gamybos sąnaudas. Neapibrėžtumo analizė atskleidė, kad scenarijus „RES100“, pagal kurį 100 % CŠT sistemos būtų aprūpinamos iš AEI, lemtų mažiausias bendrąsias vidutines šilumos gamybos sąnaudas (34,69 Eur/MWh). Operatoriaus investicijos į naujus aplinkai draugiškus šilumos gamybos sprendimus, pvz., išvalytų nuotekų ŠS, oro-vandens tipo ŠS, H₂ atliekinės šilumos ŠS ir elektrinius katilus, leistų 28,5 % sumažinti bendrąsias šilumos gamybos sąnaudas, lyginant su scenarijumi „Current 2030“. Tuo tarpu scenarijus „RES Subsidy“, taip pat kaip ir „RES100“, atspindi politikos priemonės, kurių poveikis yra panašus pasiekiant vidutines šilumos gamybos sąnaudas – 34,8 Eur/MWh. Kita vertus, bazinis scenarijus pasižymi šiek tiek didesnėmis bendrosiomis šilumos gamybos sąnaudomis (39,16 Eur/MWh) nei scenarijai „RES Subsidy“ ir „RES100“, daugiausia dėl didesnės vidutinės gamtinių dujų dalies CŠT rinkoje, kuri sudaro apie 5,5 %. Vertinant scenarijų „Gas Excise“ ir numatant, kad gamtinių dujų kainas paveiks akcizas, dėl kurio galutinė dujų kaina padidės dvigubai, matyti, kad bendrosios šilumos gamybos sąnaudos būtų didžiausios esant tokioms neapibrėžtumo sąlygoms (98 pav.).



98 pav. Įgyvendintų scenarijų neapibrėžtumo analizės rezultatai

Be to, neapibrėžtumo analizė indikuoja, kad 2030 m. šilumos gamyba naudojant gamtines dujas galėtų sudaryti tik 0–5,5 % visos Vilniaus CŠT sistemos. Nors scenarijus „RES100“ užtikrina visišką perėjimą prie AEI, išsamesnis šilumos aukcionų kainų ir vartotojų naudos vertinimas rodo, kad scenarijus „RES Subsidy“ yra palankesnis šilumos vartotojams. Pagal scenarijų „RES Subsidy“ gamtinių dujų naudojimas CŠT sistemoje vidutiniškai sudarytų 5,07 %, tuo pačiu užtikrinant mažiausią aukciono kainą galutiniams vartotojams.

Verta pažymėti, kad toks išsamus ateities CŠT sistemų modeliavimas, atsižvelgiant į platų neapibrėžtumų spektrą, suteiktų unikalią galimybę strateginiam savivaldybių CŠT planavimui. Pavyzdžiui, sukurtas dalinės pusiausvyros modelis galėtų būti taikomas ne tik Lietuvos miestuose, kur operatoriaus ir NŠG šilumos gamybos šaltiniai daugiausia dalyvauja šilumos aukcionų sistemoje, bet ir pritaikytas platesniu mastu, integruojant užsienio miestų CŠT sistemas. Ekonominis modelis yra lankstus ir gali būti pritaikomas pagal esamą CŠT rinkos struktūrą ir pagrindinius veiklos principus, todėl neapibrėžtumo analizės taikymas ir įvairių scenarijų tyrimas suteikia unikalias galimybes efektyviau planuoti ateities energetikos sistemas.

Visų analizuotų scenarijų jautrumo analizės rezultatai

Dalinės pusiausvyros modelio jautrumo analizė atskleidžia, kurie neapibrėžtumo veiksniai daro didžiausią įtaką modeliavimo rezultatams, naudojant SPEA rangų koreliacijos koeficientą, kuris parodo poveikį tarp -1 ir 1. Galima pastebėti, kad turint optimalų naujų technologijų portfelį visais scenarijais, vandenilio kainos dinamika yra svarbiausias veiksnys šilumos gamybos sąnaudų mažinimui ir CŠT operatoriaus bendrojo finansinio pelno didinimui. Visi analizuoti scenarijai patvirtina, kad, atsižvelgiant į finansinę kompensaciją už vandenilio gamybos metu susidariusią atliekinę šilumą, didesnė potenciali H₂ kaina skatina bendrosios šilumos gamybos savikainos mažinimą, o tai lemia šilumos aukciono kainų mažėjimą ir operatoriaus bendro finansinio pelno maksimizavimą.

Tuo tarpu nustatyta, kad operatoriaus potencialios investicijos į 225–300 MW elektrolizės atliekinės šilumos panaudojimo įrangą – kompresorinius ŠS ir investicijos į 100–150 MW šiluminės galios kompresorinius oro-vandens tipo ŠS – galėtų lemti didžiausią aukciono kainų sumažėjimą, užtikrinant investuotojo pelno maksimizavimą. Pavyzdžiui, scenarijus „RES100“ rodo, kad, siekiant pasiekti 100 % šilumos gamybą iš AEI Vilniaus CŠT sistemoje, operatoriaus požiūriu būtų reikalingos reikšmingos investicijos į oro-vandens tipo ŠS, H₂ elektrolizės metu susidarančios atliekinės šilumos panaudojimo ŠS bei elektrinius katilus. Tokios investicijos galėtų turėti teigiamą poveikį galutinei šilumos kainai vartotojams, tačiau kartu didintų konkurencinį spaudimą esamiems NŠG, dėl mažėjančių šilumos gamybos apimčių galintį lemti finansinius sunkumus (33 lentelė).

33 lentelė. Visų scenarijų jautrumo analizės suvestinė lentelė

Scenarijus	Strategija/prioritetas	Didžiausia NF įtaka bendrai CŠT sistemos šilumos aukciono kainai	Didžiausia NF įtaka bendroms CŠT sistemos šilumos gamybos sąnaudoms	Didžiausias NF poveikis bendram OP finansiniam pelnui	Didžiausias NF poveikis bendram NŠG finansiniam pelnui	Didžiausias NF poveikis dujų daliai CŠT sistemoje
Bazinis	Visos naujos investicijos, skirtos pelno maksimavimui	Investicijos į H ₂ elektrolizerio ŠS [225–250 MW] (š. a. kainos mažėjimas iki 49 Eur/MWh)	H ₂ kainos augimas iki 6 Eur/kg (š. g. kainų mažėjimas iki ~30 Eur/MWh)	H ₂ kainos augimas iki 6 Eur/kg (bendras OP pelnas padidėja iki 223 mln. Eur)	Oro-vandens tipo ŠS žemina pelną [–20 mln. Eur] investuojant į 100 MW	Oro-vandens tipo ŠS mažina dujų dalį [3,7%] investuojant į 100 MW
RES100	Pasiekti 100 % iš AEI gamybą iki 2030 m. ir maksimaliai padidinti pelną	Oro-vandens tipo ŠS (š. a. kainos mažėjimas) [45,9 Eur/MWh] investuojant į 150 MW	H ₂ kainos augimas iki 6 Eur/kg (š. g. kainų mažėjimas iki ~23 Eur/MWh)	H ₂ kainos augimas iki 6 Eur/kg (bendras OP pelnas padidėja iki 226 mln. Eur)	H ₂ kainos augimas iki 6 Eur/kg (NŠG pelno sumažėjimas – 25 mln. Eur)	-
RES Subsidy	25 % finansinė parama naujų AEI pagrįstų gamybos technologijų diegimui	H ₂ elektrolizerio ŠS (š. a. kainos mažėjimas) [46 Eur/MWh] investuojant į 270–300 MW	H ₂ kainos augimas iki 6 Eur/kg (š. g. kainų mažėjimas iki ~26 Eur/MWh)	H ₂ kainos augimas iki 6 Eur/kg (bendras OP pelnas padidėja iki 176,5 mln. Eur)	H ₂ elektrolizerio ŠS mažina pelną [–20 mln. Eur] investuojant į 300 MW	Oro-vandens tipo ŠS sumažina dujų dalį iki 3,3% investuojant į 100 MW
Gas Excise	Gamtinių dujų naudojimo apribojimas, nustatant akcizą gamtinių dujų kainai	Oro-vandens tipo ŠS (š. a. kainos mažėjimas) [59,4 Eur/MWh] investuojant į 100 MW	H ₂ kainos augimas iki 6 Eur/kg (š. g. kainų mažėjimas iki ~32,5 Eur/MWh)	H ₂ kainos augimas iki 6 Eur/kg (bendras OP pelnas padidėja iki ~155,5 mln. Eur)	Oro-vandens tipo ŠS mažina pelną [–30 mln. Eur] investuojant į 100 MW	Oro-vandens tipo ŠS mažina dujų dalį iki 2,57% investuojant į 100 MW

Kita vertus, jautrumo analizė atskleidžia, kad investicijos į oro-vandens tipo šilumos siurblius galėtų labiausiai prisidėti prie priklausomybės nuo gamtinių dujų naudojimo mažinimo. Gauti scenarijų rezultatai rodo, kad nauja operatoriaus plėtra, investuojant į iki 100 MW oro-vandens tipo ŠS, skatintų gamtinių dujų naudojimo mažinimą Vilniaus šilumos energijos rinkoje iki maždaug 2,6–3,7 %. Tačiau naujų ŠS plėtra taip pat susijusi su bendro NŠG finansinio pelno sumažėjimu, atspindinčiu potencialius finansinius rizikos veiksnius. Galima pastebėti, kad naujos investicijos į H₂ atliekinės šilumos atgavimo įrenginius, vandenilio kainų svyravimai taip pat daro didžiausią neigiamą poveikį esamiems NŠG šaltiniams ir sukelia finansinius nuostolius dėl sumažėjusios šilumos gamybos esamose NŠG katilinėse. Scenarijai „RES Subsidy“ ir „RES100“ iliustruoja, kad ypač didelės operatoriaus investicijos į šilumos atgavimo įrenginius iš vandenilio elektrolizės (300 MW) ir atitinkamas vandenilio kainos padidėjimas iki 6 Eur/kg turėtų stipriausią neigiamą poveikį visų NŠG bendrajam finansiniam pelnui dėl žymiai padidėjusios konkurencijos.

Politikos priemonės, tokios kaip parama AEI technologijų plėtrai ir akcizo mokesčiai už gamtines dujas, spartina dekarbonizaciją ir veiksmingai mažina priklausomybę nuo dujų, tačiau jos taip pat kelia sunkumų siekiant subalansuoti sistemos lygio sąnaudų taupymą ir mažesnių gamintojų finansinį tvarumą. Parama gali sukurti stiprią investicinę paskatą didelio masto vandenilio ir šilumos siurblių projektams, taip sumažinant vidutinės gamybos sąnaudas ir remiant ilgalaikį CŠT sistemų konkurencingumą. Tačiau šie mechanizmai kelia rinkos koncentracijos didėjimo riziką, nes suteikia neproporcingą pranašumą operatoriams, turintiems daugiau kapitalo, o nepriklausomi šilumos gamintojai gali susidurti su pelningumo sumažėjimu ir mažesniu dalyvavimu rinkoje. Panašiai, akcizo mokesčiai už gamtines dujas padeda mažinti iškastinio kuro naudojimą energijos gamybai ir prisideda prie klimato tikslų įgyvendinimo, tačiau jie gali padidinti aukcionų kainas trumpuoju laikotarpiu ir sukelti nevienodą sąnaudų naštą skirtingiems rinkos dalyviams. Tuo tarpu nacionaliniai tikslai pasiekti 100 % iš atsinaujinančiųjų išteklių energijos šilumos gamybą CŠT rinkos sistemose taip pat gali būti neracionalūs ne tik galutiniams šilumos vartotojams, bet ir NŠG, nes dalyvavimas aukcionuose tampa sudėtingesnis, o gamybos šaltiniai tampa mažiau konkurencingi už naujus rinkos dalyvius.

IŠVADOS

1. Teorinė analizė atskleidžia, kad CŠT sektoriaus plėtrą didžiąja dalimi lemia reguliavimo sistema, rinkos struktūra ir įvairūs neapibrėžtumai. Pagrindiniai reguliavimo veiksniai, tokie kaip vartotojų prijungimas prie tinklo, kainų reguliavimas, nuosavybės reguliavimas ir trečiųjų šalių prieiga prie šilumos tiekimo tinklų, yra pagrindiniai elementai, darantys įtaką investicijų paskatoms, rinkos stabilumui ir sistemos plėtrai. Išsamus įvairių neapibrėžtumo veiksnių, darančių įtaką CŠT plėtrai, vertinimas ir identifikavimas leido sukurti hierarchinę neapibrėžtumo kontrolės piramidę, kuri vaizduoja struktūrizuotą sistemą, leidžiančią diferencijuoti neapibrėžtumų dydį ir kontrolės laipsnį energetikos transformacijos kontekste. Ši klasifikacija pabrėžia, kaip svarbu atskirti kontroliuojamus, iš dalies kontroliuojamus ir nekontroliuojamus neapibrėžtumus, kad sprendimų priėmėjai galėtų efektyviau planuoti būsimas investicijas, nustatyti rizikos mažinimo priemonių prioritetus ir lanksčiau prisitaikyti sisteminės energetikos transformacijos sąlygomis.
2. Išsami energetikos modeliavimo priemonių literatūros analizė parodė, kad deterministinis metodas, naudojantis energetikos simuliacinio ar optimizavimo modeliavimo priemonės, nėra pakankamas, siekiant visapusiškai įvertinti CŠT aplinką esant neapibrėžtumams. Buvo pastebėta, kad optimizavimo modeliai neatsižvelgia į galimus tarpinės pakopos pokyčius, kurie dažnai veda prie idealizuotų scenarijų. Kita vertus, simuliacijos modeliai leidžia atlikti konkrečią, vartotojo apibrėžtą jautrumo analizę, kuri apsiriboja scenarijų rinkiniu, dažnai neatspindinčiu kompleksinių neapibrėžtumo veiksnių. Nustatyta, kad apžvelgtos modeliavimo priemonės turi ir kitų trūkumų, pavyzdžiui, negali valdyti įvairių galimų šilumos aukcionų sistemos veikimo strategijų, atspindinčių realią padėtį šilumos rinkoje, modeliai nepakankamai išplėsti, kad būtų galima atlikti Monte Carlo jautrumo ir neapibrėžtumo analizę nustatant optimalų investicijų portfelį, taip pat neturi visų galimybių įvertinti reikšmingų pokyčių CŠT aplinkoje. Dėl didėjančio centralizuoto šilumos tiekimo sistemų sudėtingumo reikia daugiadisciplinio stochastinio požiūrio, kad būtų galima spręsti su ekonominiais, strateginiais ir politiniais aspektais susijusias problemas.
3. Sukurta metodika remiasi stochastiniu požiūriu ir leidžia analizuoti kompleksinę CŠT sektoriaus veiklą esant įvairiems neapibrėžtumams. Metodika atspindi šilumos rinkos struktūrą, kurioje atsiranda nauji rinkos dalyviai ir vystosi dinamiška aplinka. Metodas yra patobulintas integruojant ekonominius – nekontroliuojamus, strateginius – kontroliuojamus ir politinius – iš dalies kontroliuojamus neapibrėžtumus, skirtus neapibrėžtumo ir jautrumo analizei atlikti. Deterministinio požiūrio išplėtimas jautrumo ir neapibrėžtumo analizei leidžia nustatyti naujus optimalius operatoriaus ir NŠG investicijų portfelius, siekiant maksimaliai padidinti investicijų pelną, užtikrinti adekvačias šilumos aukciono kainas ir prisidėti prie anglies dioksido išmetimo mažinimo.
- 3.1. Naujoji metodika taip pat demonstruoja galimybes vertinti kitų esamų rinkos dalyvių finansinę padėtį, taikant įvairius galimus politikos priemonių scenarijus

ir įtraukiant skirtingus naujus šilumos gamybos ir transformavimo šaltinius. Metodika pasižymi platesniu požiūriu, kuris gali būti vertingas planuojant ilgalaikę CŠT sistemų plėtrą įvairaus dydžio savivaldybėse. Ji taip pat yra unikali ir naudinga dėl savo gebėjimo modifikuoti įvairias galimas šilumos aukcionų sistemos veiklos strategijas.

4. Disertacijoje pristatomas sukurtas dalinės pusiausvyros ekonominis modelis ir energyPRO grindžiama verifikavimo priemonė, skirta pasirinktai Vilniaus miesto centralizuoto šilumos tiekimo sistemai. Sukurtas modelis yra skirtas veikti pagal realistiškos šilumos aukciono sistemos principus, atspindint konkurencinę aplinką tarp šilumos gamintojų, kurie teikia didžiausią vertę galutiniams šilumos vartotojams. Dalinės pusiausvyros ekonominio modelio, taikomo Vilniaus centralizuoto šilumos tiekimo sistemos analizei, įgyvendinimas, atsižvelgiant į įvairių tipų neapibrėžtumus, parodė didelį įvairių atliekinės šilumos šaltinių panaudojimo ir integravimo į CŠT sistemą potencialą, siekiant maksimaliai padidinti investuotojų finansinį pelną, užtikrinti adekvačias šilumos aukciono kainas ir sumažinti anglies dioksido išmetimą. Sukurto modelio esminis privalumas ir unikalumas yra jo gebėjimas tirti esamų šilumos operatoriaus, NŠG ir naujų rinkos dalyvių elgseną kintančių neapibrėžtumų sąlygomis. Ši sukurta sistema demonstruoja galimybę naudoti valandinio aukciono sistemą, kuri užtikrintų patikimesnį ir efektyvesnį Vilniaus centralizuoto šilumos tiekimo rinkos sistemos veikimą.
5. Neapibrėžtumo analizė leidžia daryti išvadą, kad scenarijus „RES100“, pagal kurį visa CŠT sistema būtų aprūpinama iš AEI, užtikrina mažiausią bendrąją šilumos gamybos savikainą. Pagal šį scenarijų operatorius turėtų investuoti į pažangias, aplinkai draugiškas technologijas, tokias kaip išvalytų nuotekų šilumos siurbliai (26,7–40,9 MW), oras-vanduo šilumos siurbliai (50–150 MW), H₂ elektrolizeriai ir jų atliekinės šilumos panaudojimo įranga – kompresoriniai šilumos siurbliai (150–250 MW) bei elektriniai katilai (500 MW), kurie leistų 28,5 % sumažinti bendrąsias šilumos gamybos sąnaudas, lyginant su referenciniu scenarijumi „Current 2030“. Be to, šios didelės reikšmės investicijos leistų pasiekti 12 kartų didesnę finansinį pelną nei vertinant scenarijų „Current 2030“ be naujų rinkos dalyvių atsiradimo. Nors scenarijus „RES100“ numato visišką perėjimą prie atsinaujinančiosios energijos, išsamus šilumos aukcionų kainų ir vartotojų naudos vertinimas rodo, kad scenarijus „RES Subsidy“ yra palankesnis galutiniams šilumos vartotojams. Optimalus investicijų portfelis apimtų ne tik išvalytų nuotekų ir oro-vandens tipo šilumos siurblius kartu su H₂ elektrolizės įrenginiais, bet ir saulės kolektorius su trumpalaikėmis šilumos saugyklomis. Scenarijus atskleidė, kad operatorius kaip investuotojas galėtų finansiškai įgyvendinti 1000–100 000 m² ploto saulės kolektorių projektą. Remiantis scenarijumi „RES Subsidy“, gamtinių dujų dalis centralizuoto šilumos tiekimo sistemoje būtų ribojama iki vidutiniškai 5,07 %, tuo tarpu būtų pasiekiamas žemiausia šilumos aukciono kaina vartotojams (48,5 Eur/MWh) atsižvelgiant į numatomas 2030 m. ekonominius neapibrėžtumus.

- 5.1. Verta pabrėžti, kad subsidijos gali būti rimta investicinė paskata didelio masto vandenilio ir šilumos siurblių projektams, taip sumažinant vidutines gamybos sąnaudas ir remiant ilgalaikį centralizuoto šilumos tiekimo sistemų konkurencingumą. Tačiau šie mechanizmai kelia rinkos koncentracijos didėjimo riziką, nes suteikia neproporcingą pranašumą operatoriams, turintiems daugiau kapitalo, tuo tarpu NŠG gali susidurti su pelningumo sumažėjimu ir mažesniu dalyvavimu rinkoje.
- 5.2. Atitinkamai, akcizas už gamtines dujas prisideda prie klimato kaitos švelninimo tikslų įgyvendinimo, mažindamas priklausomybę nuo iškastinio kuro energijos gamybai, tačiau trumpalaikiu laikotarpiu jis gali padidinti šilumos aukcionų kainas ir sukelti nevienodą išlaidų našta skirtingiems rinkos dalyviams.
- 5.3. Tuo tarpu nacionaliniai tikslai, siekiant 100 % AEI paremtos šilumos gamybos CŠT sistemose, taip pat gali būti neracionalūs ne tik galutiniams šilumos vartotojams, bet ir NŠG, dėl išaugusio aukcionų sudėtingumo, nes gamybos šaltiniai tampa mažiau konkurencingi nei naujausi rinkos dalyviai.
- 5.4. Neapibrėžtumo analizės rezultatai neapsiriboja Vilniaus CŠT sistema ir suteikia vertingos informacijos, kuri gali būti panaudota planuojant ir modeliuojant kitų miestų CŠT sistemas.
6. Jautrumo analizė parodė, kad visais tirtais scenarijais, esant optimaliam naujų technologijų investicijų portfeliui, vandenilio kainų dinamika yra svarbiausias veiksnys, lemiantis šilumos gamybos sąnaudų sumažėjimą ir finansinio pelno maksimizavimą investuotojams. Tirtų scenarijų rezultatai rodo, kad, atsižvelgiant į finansinę kompensaciją už vandenilio gamybos metu susidarantią atliekinę šilumą, didesnės potencialios vandenilio kainos skatina bendrą šilumos rinkos gamybos sąnaudų mažėjimą, o tai kartu su didesne konkurencija lemtų mažesnes bendrąsias šilumos aukciono kainas ir sudarytų sąlygas maksimaliai padidinti investuotojo-operatoriaus pelną dėl vietinėje rinkoje pagaminto ir parduoto žaliojo vandenilio.
- 6.1. Monte Carlo jautrumo analizės rezultatai taip pat patvirtina, kad, atsižvelgiant į scenarijuose numatytą optimalų naujų technologijų derinį, H₂ elektrolizės atliekinės šilumos įrenginiai ir oro-vandens tipo šilumos siurbliai galėtų turėti didžiausią poveikį CŠT sistemos plėtrai ir prisidėti prie reikšmingiausio šilumos aukcionų kainų sumažėjimo.
- 6.2. Kita vertus, visų scenarijų jautrumo analizė atskleidžia, kad investicijos į oro-vandens tipo šilumos siurblius galėtų labiausiai prisidėti prie gamtinių dujų naudojimo mažinimo, tačiau tuo pačiu tai sumažintų NŠG gaunamą finansinį pelną, kas reikštų didelę riziką ateities veiklai.
- 6.3. Taip pat galima teigti, kad naujosios investicijos į H₂ atliekinės šilumos panaudojimo įrenginius ir vandenilio kainų svyravimai turėtų didžiausią neigiamą poveikį esamiems NŠG gamybos šaltiniams ir sukeltų didelius finansinius nuostolius dėl sumažėjusios šilumos gamybos esamose katilinėse.

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LIST OF SCIENTIFIC PAPERS AND SCIENTIFIC CONFERENCES

Scientific articles

1. Džiuvė, V., Lekavičius, V. (2025). Planning the development of district heating in the face of uncertainty. *Energy*. Oxford: Elsevier. Vol. 335, 137894, pp. 1–20. ISSN 0360-5442.
2. Ziemele, J., Volkova A., Latošov, E., Murauskaitė, L., Džiuvė, V. (2023). Comparative assessment of heat recovery from treated wastewater in the district heating systems of the three capitals of the Baltic countries. *Energy*. Oxford: Elsevier, Vol. 280, 128132, pp. 1–11. ISSN 0360-5442.

Scientific conferences

1. Ziemele, J., Volkova, A., Latošov, E., Murauskaitė, L., Džiuvė, V. (2022). Comparative assessment of treated wastewater heat recovery into district heating system of the three Baltic capital cities. *Book of abstracts 17th Conference on sustainable development of energy, water and environment systems November 6–10 2022 Paphos, Cyprus*. Zagreb: Faculty of Mechanical Engineering and Naval Architecture, pp. 348–348. ISSN 2706-3690.
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6. Džiuvė, V. (2025). Modeling the Impact of Uncertainty Factors on the Development of District Heating. The International Conference of Young Scientists on Energy and Natural Sciences, CYSENI, 2025.



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APPENDICES

Appendix 1. The complex comparison of the most common energy modelling tools

No	Tool	Simulation	Scenario	Equilibrium	Top - Down	Bottom-up	Operation optimisation	Investment optimisation	Geographical area	Scenario time frame	Time-step	Electricity	DH sector or
1	AEOLIUS	YES	-	-	-	YES	-	-	National/state /regional	1 year	Minutes	YES	-
2	BALMOR EL	YES	YES	Partial	-	YES	YES	YES	Local/regional/state/international	Max 50 years	Hourly	YES	YES
3	BCHP Screening Tool	YES	-	-	-	YES	YES	-	Single project investigation	1 year	Hourly	-	-
4	COMPOSE	-	-	-	-	YES	YES	YES	Single project investigation	No limit	Hourly	YES	YES
5	E4cast	-	YES	YES	-	YES	-	YES	National/state /regional	Max 50 years	Yearly	YES	YES
6	EMCAS	YES	YES	-	-	YES	-	YES	National/state /regional	No limit	Hourly	YES	-
7	EMINENT	-	YES	-	-	YES	-	-	National/state /regional	1 year	Yearly	YES	YES
8	EMPS	-	-	-	-	-	YES	-	International	25 years	Weekly	YES	-

9	EnergyPLAN	YES	YES	-	-	YES	-	-	-	National/state /regional/International	1 year	Hourly	YES	YES
10	EnergyPRO	YES	YES	-	-	YES	-	-	-	Single project investigation, local, regional	100 years	Hourly	YES	YES
11	ENPEP-BALANCE	-	YES	YES	YES	-	-	-	-	National/state /regional	75 years	Yearly	YES	YES
12	GTMax	YES	-	-	-	-	YES	-	-	National/state /regional	No limit	Hourly	YES	Partly
13	H2RES	YES	YES	-	-	YES	YES	YES	-	Local/regional/national	No limit	Hourly	YES	YES
14	HOMER	YES	-	-	-	YES	YES	YES	YES	Local/ community	1 year	Minutes	YES	YES
15	HYDROGEMS	-	YES	-	-	-	-	-	-	Single project investigation	1 year	Minutes	YES	-
16	IKARUS	-	YES	-	-	YES	-	YES	YES	National/state /regional	Max 50 years	Yearly	YES	YES
17	INFORSE	-	YES	-	-	-	-	-	-	National/state /regional	Max 50 years	Yearly	YES	YES
18	Invert	YES	YES	-	-	YES	-	YES	YES	National/state /regional	Max 50 years	Yearly	YES	YES
19	LEAP	YES	YES	-	-	YES	YES	-	-	National/state /regional	No limit	Yearly	YES	YES

20	MARKAL /TIMES	-	YES	YES	-	YES	-	YES	Local/regional/national/international	100 years	Hourly	YES	YES
21	Mesap PlanEt	-	YES	-	YES	-	-	National/state/regional	No limit	Any	Any	YES	YES
22	MESSAG E	-	YES	Partial	YES	YES	YES	Global	Up to 120 years	5 years	5 years	YES	YES
23	MiniCAM	YES	YES	Partial	YES	YES	-	Global and regional	50 years	15 years	15 years	YES	Partly
24	NEMS	-	YES	YES	-	-	-	National/state/regional	50 years	50 years	Yearly	YES	YES
25	ORCED	YES	YES	YES	-	YES	YES	National/state/regional	1 year	Hourly	Hourly	YES	-
26	PERSEUS	-	YES	YES	-	YES	-	International	50 years	Based on typical days with 36-72 slots for 1 year	Based on typical days with 36-72 slots for 1 year	YES	YES
27	PRIMES	-	-	YES	-	-	-	National/state/regional	50 years	Yearly	Yearly	YES	YES
28	ProdRisk	YES	-	-	-	-	YES	National/state/regional	Multiple years	Hourly	Hourly	-	-
29	RAMSES	YES	-	-	-	YES	YES	International	30 years	Hourly	Hourly	YES	Partly
30	RETScreen	-	YES	-	-	YES	-	User-defined	50 years	Monthly	Monthly	YES	YES
31	SimREN	-	-	-	-	-	-	National/state/regional	No limit	Minutes	Minutes	YES	YES

32	SIV/AEL	-	-	-	-	-	-	-	-	-	National/state /regional	1 year	Hourly	YES	Partl y
33	STREAM	YES	-	-	-	-	-	-	-	-	National/state /regional	1 year	Hourly	YES	YES
34	TRNSYS1 6	YES	YES	-	-	YES	YES	YES	YES	YES	Local/commu nity	Multiple years	Seconds	YES	YES
35	UniSud3. 0	-	YES	YES	-	YES	-	-	-	-	National/state /regional	50 years	Bi-weekly	YES	Partl y
36	WASP	YES	-	-	-	-	-	-	-	YES	National/state /regional	50 years	12 load duration curves for a year	YES	-
37	WILMAR Planning Tool	YES	-	-	-	-	-	YES	-	-	International	1 year	Hourly	YES	Partl y

Appendix 2. The comprehensive comparison of the advantages and disadvantages of selected energy system models

No	Energy modelling tool	Objective	Appropriateness	Advantages	Disadvantages
1	H2RES	H2RES aims to reduce annual energy system operating and capacity costs	The software incorporates short and long-term planning of the energy system, with capacity optimised for each technology, including variable renewables and Power-to-X technologies	* It is a long-term capacity investment and operational energy planning model with power-to-X and flexibility technologies * Possibility to incorporate some policy constraint options (CEEP, RES targets for each year in the long-term planning horizon, sectoral boundaries for CO₂ emissions) * H2RES has wider modelling capabilities in other sectors as Power-to-X, Power-to-Transport * Simulation of the level of electricity and hydrogen penetration (maximum and minimum) in the heat, transport, and industrial sectors	* H2RES does not provide a stochastic investment optimisation; * The model does not have wide option possibilities to have detailed DH modelling * Lack of heat storage modelling capabilities in DH sector * Lack of uncertainty and sensitivity analysis possibilities * It does not apply heat auction manipulation mechanisms * It does not consider suboptimal solutions, leading to ideal scenarios that can be unrealistic
2	BALM OREL	To minimise the discounted costs of the system by fulfilling the demand for electricity and heat	A partial equilibrium energy model, which optimises the generation, transmission, and consumption of electricity and heat in fully competitive markets	* Can be used at city, national, and international levels * Flexible geographical and temporal scope * Capable for analysing energy markets consisting of different generation and storage technologies * Strong side on global optimisation of operation and investment * Extensible modular structure, so that new energy services, e.g., hydrogen	* A deterministic energy system model and presumes perfect forecasting * Lack of capabilities in setting up district heating for time delays and temperature levels * The software is not appropriate to forecast the periods for repairs or reconstruction * Lack of uncertainty and sensitivity analysis possibilities * Does not apply heat auction manipulation mechanisms

				and other functionalities, can be incorporated *The user can specify diverse policy objectives	* The model requires to use a commercial GAMS package * It does not consider suboptimal solutions, leading to ideal scenarios that can be unrealistic
3	ENERGYPLAN	The tool allows the assessment of the costs for a global energy system analysis	To support the preparation of national or regional energy planning strategies by modelling a complex energy system, including the heat and electricity supply, transport, and industry sectors	* User-friendly energy model * It has the uniqueness to implement very fast simulations * The model simulates all energy sectors (electricity, heating, cooling, industry, transport) for the entire year at hourly resolution * EnergyPLAN can model all thermal, renewable, storage, conversion, transport technologies	* It is only a scenario-based deterministic modelling tool, not an optimisation model * Short-term modelling horizon, only up to one year * In order to find out the long-term optimisation strategies that minimise costs and CO₂ emissions, a solver (multi-objective evolutionary algorithm (MOEA) has to be incorporated * Lack of uncertainty and sensitivity analysis possibilities * Does not apply heat auction manipulation mechanisms
4	ENERGYPRO	To evaluate the investment alternatives in the energy sector, taking into account detailed modelling of the technical performance and economic impact on business	* The scenario simulation tool used to model complex energy systems * Enables the user to perform extensive, integrated, and detailed technical and financial analysis	* Capability to simulate large and complex energy systems * Suitability to model relevant markets and its complexity to fully incorporate taxes and subsidies * Flexible in geographical scope; suitable and can be used to model from specific powerplant, energy conversion, storage technologies to entire country-level approaches * High temporal scope: from a few days to many years, up to 100 without any time slices * Two options for the optimisation period: by month and by year	* It is a scenario-based deterministic modelling tool * EnergyPRO is designed for the analysis of tangible user-defined alternatives * It does not have the capability to describe heat auction strategies * The software is not open-source; the model is commercial * Lack of uncertainty and sensitivity analysis possibilities

5	TIMES	To achieve a least-cost energy system, optimised for a given set of consumer constraints in the medium and long term	Valuable in identifying the cheapest combination of energy sources incorporating a broad portfolio of energy generation, storage, and transport technologies that meet the needs of energy services and satisfy all the constraints imposed on the energy system	* A general-purpose energy planning model that is able to represent the evolution of a specific energy and environmental system over a 20–50 or 100-year time horizon at global, multi-regional, national, state/provincial, or community level * TIMES can simulate all thermal, renewable energy, storage/conversion, and transport technologies * It can be used as a scenario assessment tool * It has a climate module that permits a detailed analysis of the effects of climate change * Stochastic programming integration possibility (incorporation of uncertainty)	* TIMES model requires to use a commercial solver that can only be run with the CPLEX/GAMS package * To reflect the detailed and complex energy sector, it is necessary to use additional submodules to maintain higher accuracy * The model does not include endogenous market behaviour, such as strategic pricing and heat auction price formation mechanisms * It does not consider suboptimal solutions, leading to ideal scenarios that can be unrealistic	
6	MESS AGE	The model dedicated to minimise the total costs of the energy system	* Used for medium and long-term planning of energy systems * MESSAGE identifies cost-effective portfolios of GHG emission reduction and mitigation instruments	* It is free of charge and intended for academic purposes * The entire range of technologies and inputs for thermal power generation, renewables, storage/conversion, transport can be modelled * Stochastic programming possibility (incorporation of uncertainty)	* To reflect the detailed, complex energy sector, it is necessary to use additional submodules to maintain higher accuracy * The model does not include endogenous market behaviour, such as strategic pricing and heat auction price formation mechanisms * It does not consider suboptimal solutions, leading to ideal scenarios that can be unrealistic	

Appendix 3. Characterisation of the bottom-up energy models considered in terms of methodological approach, temporal and spatial resolution

No	Energy modelling tool	Source	Approach	Programming language	Coverage sectors	Methodology approach	Programming approach	Term info	Temporal resolution	Modelling horizon	Geographical coverage
1	H2RES	Open-source	BU	H2RES is designed in Python (programming language) and solved using the linear programming optimisation solver GUROBI	Sectoral intercoupling, including the heat, industrial, electricity, and transport sectors	Dispatch optimisation (large-scale capacity investment and operation optimisation model)	Linear programming	Unlimited	Hourly scale resolution	Unlimited (most likely up to 2050)	Local region → national modelling
2	BALMOR EL	Open-source code, but GAMS needs to be installed	BU Partial Equilibrium Perfect foresight	Balmorel is written in GAMS (General Algebraic Modelling System) modelling language and built in a generic, extensible modular structure	District heating, gas networks, electricity networks with all possible RES, industry, sectors, extensions with hydrogen technologies	Dispatch operation optimisation and single objective investment optimisation	Linear programming or mixed integer programming with unit commitment	Short and long term	Detailed modelling with a few time steps per hour to longer-term scenarios with a few time steps per week/month/year	Up to 50 years	Regional → National → International

3	ENERGY PLANNING	Open-source	BU Perfect foresight	Simulation model based on heuristic technique	All energy sectors	Simulation	-	Short-term	Hourly resolution (EnergyPLAN analyses 1 year in steps of 1 hour)	Modeling horizon - up to one year	Regional → International
4	ENERGY PRO	Commercial	BU	EnergyPRO implemented in Delphi Pascal	All energy sectors	Simulation (analytical dispatch mode and MILP dispatch mode)	-	Short and long term	Hourly resolution, multiple years	Up to 100 years	Local → Regional → National
5	TIMES	Commercial	BU Perfect foresight and stochastic approach	Written in GAMS mathematical programming language	All energy sectors, including transport sector	Multi objective investment optimisation	Linear optimisation method and nonlinear/mixed-integer linear method	Medium to long-term	Hourly resolution, multiple years - with UD time-slices	Up to 100 years	Local → Regional → National → International
6	MESAGE	Open-source	BU Perfect foresight and stochastic approach	Written in GAMS mathematical programming language	All energy sectors, including transport sector	Dispatch operation optimisation and single/multi objective investment optimisation	Linear optimisation method and nonlinear/mixed-integer linear method	Long-term	Hourly resolution, multiple years - with UD time-slices	Up to 120 years	For national and global regional scenarios

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