Renewable Energy Integration in German District Heating Systems

A Case Study of Schwäbisch Hall Municipal Utility

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Abstract

In order to decarbonise the heating sector, district heating is seen as an efficient and potentially environmentally friendly approach to achieving the sector's climate targets. Currently, German district heating systems rely predominantly on fossil fuels and utilise combined heat and power plants, which are efficient but not climate neutral. Therefore, the integration of renewable energy sources (RES) is crucial to further reduce the carbon footprint of these systems. To promote this development this year Germany enacted a new law that sets targets for municipal utilities for the future to increase the share of RES. This legislation has an impact on their business models and therefore requires an analysis of its impact on economic feasibility and system operation. District heating systems in Germany are diverse and depend on local energy potentials for the integration of renewable energy. Therefore, an individual assessment of these systems is necessary to evaluate the economic feasibility and the potential to increase the share of renewable energy. The aim of this work is to analyse the integration of renewable energies into the district heating system of Schwäbisch Hall municipal utilities. In particular, it is analysed how different pricing scenarios affect the system's production plan, operating costs and their implications on investment decisions. In addition, it is investigated how the sensitivity of the system to electricity and gas prices changes with the integration of renewable energies, as well as the sensitivity to other input parameters. The system is analysed, modelled and simulated using Energy Optima 3, an energy supply optimisation software. The results show that the economic feasibility varies in the different scenarios, ranging from very favourable to similar performance to the current system. In addition, the new system shows greater resilience to changing input prices compared to the current system and has the potential to achieve a RES share of up to 95% based on the local energy potential.

Keywords: District Heating, Renewable Energy, Modelling, Optimisation, Pricing Scenarios, Sensitivity Analysis

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Contents

List of Abbreviations

CCS .... *Carbon Capture and Sequestration*
CF .... *Cash Flow*
CHP .... *Combined Heat and Power*, *combined heat and power*
DH .... *District Heating*
dyn. IB .... *Dynamic Income Balance*
el. prices .... *Electricity Prices*
EO3 .... *Energy Optima 3*
EWI .... *Institute of Energy Economics at the University of Cologne*
GHG .... *Greenhouse Gas*
HP .... *Heat Pump*
LCOE .... *Levelized Cost of Energy*
NPV .... *Net Present Value*
RES .... *Renewable Energy Sources*
RNG .... *Renewable Natural Gas*
SDH .... *Solar District Heating*
SWSHA .... *Schwäbisch Hall Municipal Utilities*
TC .... *Total Costs*
TES .... *Thermal Energy Storage*
UBA .... *Umweltbundesamt - Federal Environment Agency*

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1 Introduction

In 2022 global greenhouse gas (GHG) emissions continued to rise again and have almost returned to pre-Covid levels, indicating that global emissions have not yet peaked. The continued rise in emissions will further deplete the carbon budget available to achieve the 1.5° C or 2° C target set in the Paris Agreement. In the scenarios without exceeding the target, emissions in 2022 accounted already for 10.0 % of the 1.5°C budget. If the rate of emissions growth continues, the 1.5°C budget could be exhausted in just 7.1 years. Countries must therefore take further actions now to reduce their greenhouse gas emissions [1].

The first steps towards reducing global greenhouse gas emissions have already been taken with the signing of the Paris Agreement in 2015, which is probably the most important agreement in this context. As the first binding agreement that unites 196 parties to jointly combat climate change, it laid an important foundation stone on the path to carbon neutrality and towards peaking global greenhouse gas emissions. According to the agreement, emissions must peak before 2025 to constrain global warming to 1.5° C [2], a target that the IPCC does not anticipate reaching by then [3]. Thus, further efforts must be made by the global community to mitigate climate change. As a signatory to the Paris Agreement and with the fourth largest economy in the world and the largest in Europe [4], [5], Germany has a major responsibility as an important global player in the fight against climate change and the reduction of greenhouse gas emissions.

Germany is actively committed to tackling climate change, as shown by recent announcements emphasising its continued efforts to reduce greenhouse gas emissions. According to a recent press release, Germany has maintained its course to reduce greenhouse gas emissions and has successfully met the European emission reduction targets. Detailed data on greenhouse gas emissions for 2022 shows that around 750 million tonnes of CO_2 equivalents were emitted in Germany, a decrease of 9.6 million tonnes or 1.3 percent compared to 2021 and a 40 % reduction since 1990, as the German Federal Environment Agency (UBA) informed the European Commission [6]. These achievements underline the progress Germany has made towards carbon neutrality until now.

While being on the right path there are sectors that still need improvement. Looking closer at the emission profile of Germany reveals that energy-related emissions accounted for around 84 % of German greenhouse gas emissions in 2021, of which 37 % of those the main source was the energy industry, i.e. primarily public electricity and heat generation in power plants and refineries [7].

Germanies energy consumption for heating and cooling accounts for a good half of total final energy consumption. Heat is largely generated and consumed directly in the three end consumption sectors "Private households", "Industry" and "Trade, commerce and services". In addition, just under a tenth of the heat demand is covered by district heating from the general supply conversion sector. The shares of the various energy sources in the heat supply have hardly changed in recent years and are still dominated by fossil fuel sources. Although renewable energy sources (RES) for heating were continuously rising they only account for about 18 % of the total heat energy supply, compared to RES in the electricity production which makes a share of 46 % [8], [9]. Therefore, there is significant potential for improvement in the heating sector.

The IEA considers district heating to be a promising technology to provide low carbon heating in the future on a larger scale [10]. In addition to numerous advantages including economic aspects, district heating (DH) is seen as the only feasible option for decarbonising densely populated areas in terms of heating [11], [12].

Concluding, while global emissions are still on the rise many countries have decided to take action against climate change by signing the Paris Agreement with the intention to contribute to global GHG reduction. Germany as a big player in the economic world can provide a role model in achieving climate goals. While Germany showed positive development in the past there are still many sectors to be decarbonised, one of them the heating sector. District heating as a promising technology in reducing the carbon footprint plays a crucial role in future scenarios of achieving net zero emission.

1.1 Motivation

In the following further motivation is given, as well as the objective of this thesis and structure are presented.

In Germany the challenge remains to further expand and decarbonize the district heating sector to provide low carbon heating. Although there has been changes in the energy source over the years, natural gas remains the biggest chunk of energy source used for district heating provided by power plants, followed by hard coal and lignite. Renewable energy sources for district heating only make for about 21,7 % in 2021 (mainly biomass and renewable municipal waste) [9].

In order to drive forward the development of the heating sector, particularly in the area of district heating, it is essential to enact relevant legislation. On the roadmap to become climate neutral Germanys next milestone is the Climate Action Program, planning to reduce GHG emissions by 65 % compared to 1990 [13]. Thus, to further decrease 25 % compared to now. The centrepiece of the Climate Action Programme 2030 was the introduction of a price for the emission of CO_2 for transport and heating from 2021 onwards. The price, which will rise over the years, is intended to create more incentives for climate protection in the economy and among consumers [14]. For the district heating sector, the government is proposing to further expand and modernise combined heat and power (CHP) generation. Modern CHP systems should replace coal-fired CHP power plants in the future, secure the supply of electricity and heat and support the integration of RES through flexible and system-friendly operation[1]. Furthermore, the German government recently passed the "Heat Planning and Decarbonisation of Heating Networks Act", which stipulates that 30 % of heating networks must be supplied with heat from renewable energies or unavoidable waste heat by 2030 and 80 % by 2040 [15]. The enactment of the Heat Planning and Decarbonisation of Heating Networks Act represents a crucial advancement in the ongoing efforts to decarbonize the district heating sector.

This represents a challenge for the district heating industry, as new investments need to be made and suitable technologies integrated into their systems. The integration of renewable energies into a district heating system can be achieved, for example, by using technologies such as bioenergy, heat pumps, solar thermal energy, heat storage or the utilisation of unavoidable industrial waste heat (as third-generation renewable energy) [16].

1.2 Objective of this work

In view of the newly adopted laws, the aim of this work is to investigate the integration of RES into an existing district heating system in Germany as an exemplary case study. The goal is to increase the total share of heat supplied with renewable energies and investigate the economic

[1] https://www.bundesregierung.de/resource/blob/974430/1679914/c8724321decefc59cca0110063409b50/2019-10-09-klima-massnahmen-data.pdf?download=1

feasibility of the investments into selected RES. More specific objectives for the thesis are as follows:

- Identifying the current state of DH systems in Germany
- Examination and explanation of latest and future legislative standards for district heating systems in Germany regarding climate-neutrality.
- Investigation of existing and state-of-the-art technologies for district heating systems with minimal or no GHG emissions.
- Develop price scenarios for the integration of renewable energy technologies into an existing district heating system in Germany.
- Evaluation of pricing scenarios regarding the production plan, share of heat supplied by renewable energies, and various economic parameters.
- Sensitivity analysis for changes in input data, i.e. different fuel prices such as the natural gas price, electricity price, biomethane, etc. as well as the district heating load.

1.3 Thesis Structure

Following this introduction, this work will cover the foundation necessary to understand the conducted results. It provides insights into DH systems in general, the heating landscape in German, as well as presenting the newly enacted law and its implications for German municipal utilities. Furthermore, different DH generation technologies are explained, including CHP systems and various RES. To place this work in the context of the academic world, previous conducted research is presented in the field of renewable energy integration for DH systems, followed by the research questions which are answered in this work. The following chapter presents the methodology, providing details on how this work was conducted, the research design, the pricing scenarios used, and the limitations imposed by the methodology. The main part of this work will be shown in the results section where the scenario analysis and the sensitivity study are presented, followed by the discussion of the results.

2 Foundations

This chapter exhibits the foundation upon which this thesis is based. Next to DH in general, the recently passed laws are presented in detail, highlighting relevant aspects and marginal considerations. Moreover, it explains how basic generation technologies work and how they can be integrated into district heating networks. In addition, the chapter provides a short insight into current research of the most important technologies and their integration into district heating networks. To place this work in the current state of research, a literature review is presented which examines what published research has found in integrating RES into DH systems. Consequently, the research questions for this work are presented.

2.1 District Heating

The Authors Frederiksen and Werner (2013) [12], and Wiltshire (2015) [17] provided an overview of district heating and cooling systems and described the system as follows.

District heating systems are a cost-effective alternative to conventional heating methods such as boilers, air conditioning or direct electric heating and offer greater resource efficiency. These systems play a crucial role in providing heat for domestic hot water, heating, and industrial processes. The basic mechanism is the circulation of heat and cold through networks that usually contain pressurised water in insulated pipes. District heating systems essentially comprise four areas: Supply units or heat sources, distribution networks, customer stations and customer heating and cooling systems.

Traditionally, the primary heat sources for district heating systems have been thermal power stations, waste incineration plants or industrial processes such as those found in cement production and oil refineries. However, today's hot water systems can be adapted to a wide range of technologies and heat sources. These include processed waste heat from thermal power stations, so-called CHP plants, biomass, heat pumps, geothermal energy, solar thermal energy and even fuel cells. A key contemporary approach is to utilise local fuels and heat sources, such as industrial heat, which would otherwise remain unused to exploit synergy effects and maintain cost efficiency. The integration of heat storage systems increases the flexibility of hot water systems, as the energy generated can be stored for later use. This not only improves the overall efficiency of the system, but also reduces costs as peak demand is avoided. Economic feasibility is paramount in today's landscape of DH systems, as competitive heat sources are required to offset the significant investment required for such infrastructure

The distribution system within the district heating infrastructure consists of insulated double pipes that run parallel to different locations and have one pipe for the heat supply and another for returning the circulating water. The insulation serves to minimise heat loss during transport. An important operational aspect is the maintenance of a constant heat supply through a continuous supply of heat in line with customer demand. Each customer station is equipped with a heat exchanger that takes heat from the distribution system and passes it on to the individual heating systems.

Achieving a systematic heat balance is an essential prerequisite for the effective functioning of the system. This balance is maintained by the continuous supply of heat corresponding to the amount extracted at each customer station. This process is facilitated by maintaining a predetermined temperature flow to the customers commonly referred to as the forward temperature. This dynamic mechanism ensures the optimisation of heat distribution and utilisation within the district heating network [12], [17].

Figure 1 shows a principal concept of a district heating system, depicting the interconnected elements of supply, distribution, and customer components within the system framework.

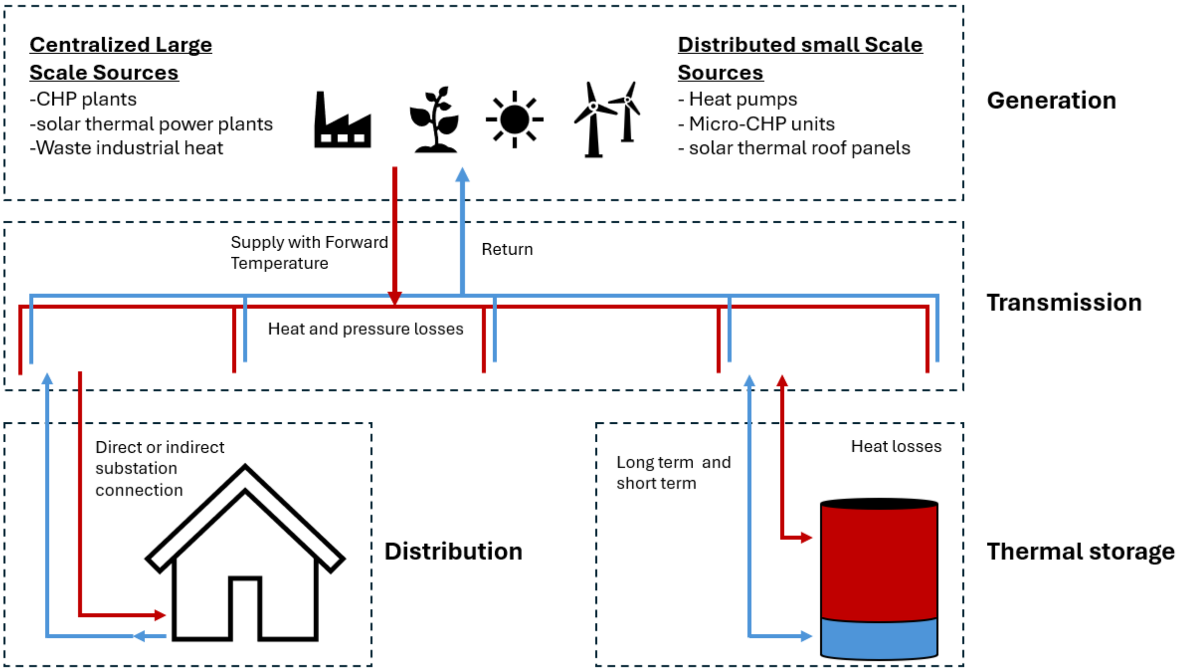

Figure 1: Principal concept of a district heating system, adapted from Mazhar, Liu and Shukla, (2018)

Throughout history District heating system have evolved and can be further categorized depending on their average forward temperature, as seen in Table 1. Over time the temperature decreased gradually and currently the 3rd generation distribution systems are most commonly in use, having temperature levels of 70<120°C [12], [16].

Table 1: Different Generation District Heating Systems

Generation	Medium	Forward Temperature	Primary Operational Period
1st Generation	Steam	>150° C	Before 1930, a few still operating
2nd Generation	Liquid Water	>120° C	Dominating between 1930 and 1980
3rd Generation	Liquid Water	70<120° C	Dominating since 1980
4th Generation	Liquid Water	40<60° C	Emerging technology

The implementation of a 4th generation district heating system, characterised by a low temperature distribution network, offers a significant advantage in reducing energy losses due to a lower temperature difference. This lower operating temperature not only minimises heat losses during distribution, but also has a positive impact on production and storage technologies. In addition, the introduction of lower temperatures increases the potential for utilising the excess heat generated by the industry, both through direct application and indirectly using heat pumps. In addition, the 4th generation of water heating provides significant support for the integration of renewable energy sources. The lower temperature requirements fit well with the characteristics of various renewable energy technologies and facilitate the integration of sustainable energy into the heating system [18]. In the literature, there is also mention of 5th generation district heating systems characterized by low flow temperatures ranging from 10 to 40° C. These systems capitalize on the benefits of an even lower operating temperature, aiming to further optimize energy efficiency [19].

2.2 Heating Landscape in Germany

This subchapter provides an overview of the heating sector in Germany, providing insight into the share of heating in the total energy consumption, the used energy sources for heating in general as well as which renewable energy sources are used for heating. Furthermore, the share of energy sources is specifically shown for the district heating sector.

Firstly, taking a closer look at the heating landscape of Germany reveals, that the final energy consumption for heating and cooling accounts for about half of total final energy consumption. In 2021 Space heating has a share of 28 % alone followed by process heating having just over 22 % of the total final energy consumption respectively. Domestic hot water and cooling applications follow behind with 8,3 % in 2021 [9].

Final energy consumption by energy source and application in the heating sector has been dominated by gas for several years now, while the share of renewable energies and district heating combined increased by just under 3 % between 2012 and 2022, from 20 % to 22,9 %. The share of district heating alone has fallen by 0.4 percentage points (Figure 2) [20].

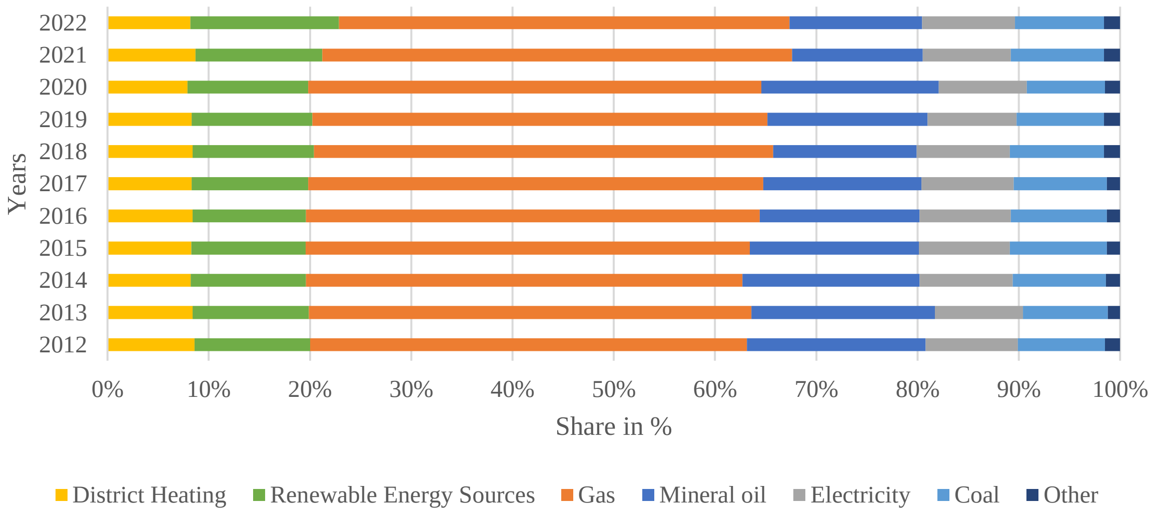

Figure 2: Final energy consumption by energy carrier and application in the heating sector. Data from [20]

The shares of renewable energy sources and district heating combined here are dominated by solid biomass, which is mainly wood (66,4 %), followed by shallow geothermal energy (9,4 %). Solar thermal energy for instance has a share of 4,6 %. A more detailed overview can be found in Figure 3 [9].

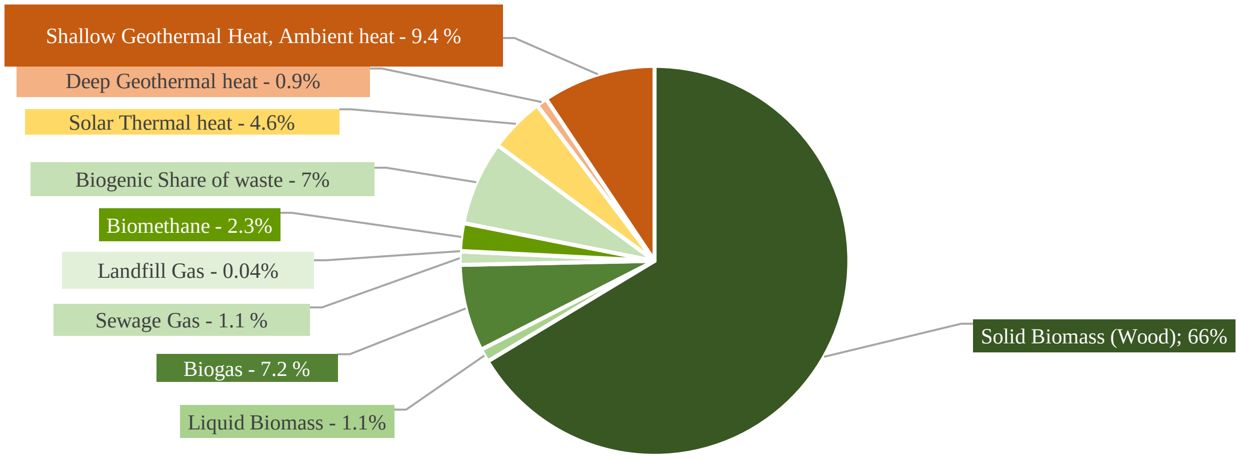

Figure 3: Renewable Energy for Heat and Cold Supply in 2022. Data from (Umweltbundesamt, 2024c)

Zooming in on the energy carriers used for District Heating alone, shows the same dominance of fossil fuels as for the total heating sector. Gas is the most widely used source for heat generation for district heating, followed by coal. Looking at the development between 2003 and 2021 shows, that the use of gas has barely changed, while the use of coal has significantly decreased. The use of biomass and waste has increased steadily in recent years (Figure 4). This is partly because in 2005, untreated municipal waste began to be utilised as an energy source instead of being deposited in landfills [9]. The share between CHP plants and heating only plants for district heating here is 86% to 14% [21]**.**

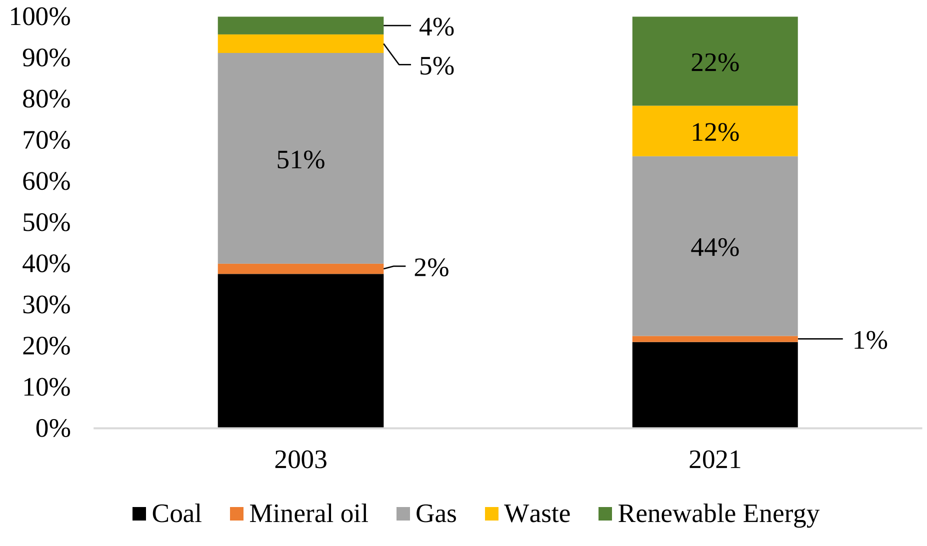

Figure 4: Energy use for district heating generation in power plants for general supply

In summary, both the heating sector in general and the district heating sector in particular remain predominantly reliant on fossil fuels, highlighting the challenges and potential for future decarbonisation efforts. The urgency to accelerate this transition emphasises the essential role of well-designed policies within the sector. The following chapter looks at the current policy landscape of the German energy market and offers insights into the existing frameworks and regulations that are shaping the course of decarbonisation initiatives. Understanding and implementing effective policy measures in this context is crucial for steering the heating sector towards a sustainable and low-carbon future.

2.3 Heating Legislation in Germany

The following chapter describe the relevant legislative landscape in Germany. It will offer an overview of past legislation aimed at climate protection and examine how recent laws, especially those pertaining to the heating and district heating sectors, contribute to these efforts.

In 2019, the Climate Protection Act (Klimaschutzgesetz) set binding climate protection targets in Germany for the first time. Permissible annual emission levels were set for individual sectors such as industry, the energy sector, transport and buildings up to 2030 [22]. The purpose of the Climate Protection Act is to ensure the fulfilment of national climate protection targets and compliance with European targets. The basis for this is the obligation under the Paris Agreement based on the United Nations Framework Convention on Climate Change. This states that the increase in the global average temperature should be limited to well below two degrees Celsius and, if possible, to 1.5° Celsius compared to pre-industrial levels in order to minimise the effects of global climate change. This is also intended to support Germany's commitment at the UN Climate Summit in New York on 23 September 2019 to pursue greenhouse gas neutrality as a long-term goal by 2050 [23]. In 2023 the German government has launched the new version of the Climate Protection Act and presented the new climate protection programme. The draft stipulates that in future, multi-year and cross-sectoral overall calculations will be used as a basis for measuring climate targets, instead of calculating individual sectors and their targets. Emissions should be reduced in particular where there is the greatest potential for savings. Specifically, the law states, that by 2030, GHG emissions are to be reduced by at least 65 % compared to 1990 levels and by at least 88 % by 2040, and until 2045 Germany should be climate neutral [13].

To support the reduction of emissions, the Renewable Energy Sources Act (EEG) enacted in the year 2000 has already successfully contributed to the reduction of greenhouse gas emissions in the electricity sector by promoting electricity generation from renewable energies. It has been updated too in 2023 and adjusted targets were formulated [24]. The German government is currently trying to repeat this success by extending support for a similar development in the heating sector and aims to have climate-neutral heating by 2045 [15].

The decarbonisation of the heating sector should be driven forward through the enactment of the so-called Heat Planning Act. The law has two major parts, firstly the heat planning which should be provided by municipal heating companies to inform citizens and businesses whether they can expect a district heating connection or should opt for another climate-friendly heating option. Secondly, the law also sets the target of generating half of district heating-based heat in a climate-neutral way on a nationwide average by 2030 (§2 (1) WPG). This corresponds to the requirement that 30% of every heating network must be supplied with heat from renewable energies or unavoidable waste heat by 2030 and 80% by 2040 (§29 (2), Nr 1., Nr.2 WPG). In addition to the Heat Planning Act, the Building Code is being amended to as well as the Environmental Impact Assessment Act. [25].

To be more specific a closer look is taken at the Heating Planning Act. Important information for this work is mentioned and clarified here. They are reproduced in the same sense, and it is indicated where additional information is given in the law. Initially, the process involves three distinct time steps, each requiring the attainment of specific goals:

Paragraph 2, Section 1 of the WPG:
The share of heat from renewable energies, from unavoidable waste heat or a combination thereof in the annual net heat generation in heating networks shall amount to 50 percent on a nationwide average from 1 January 2030.

This is supplemented with,

Paragraph 29 Section 1 WPG:

The annual net heat generation for each heating network must be supplied from the following heat sources from the specified dates:

1. from 1 January 2030, a share of at least 30 percent from renewable energies, unavoidable waste heat or a combination thereof,

2. from 1 January 2040, a share of at least 80 percent from renewable energies, unavoidable waste heat or a combination thereof.

With the final step:

Paragraph 31 Section 1 WPG:

Every heating network must be supplied entirely with heat from renewable energies, unavoidable waste heat or a combination thereof by 31 December 2044 at the latest.

Paragraph 31 Section 1 WPG:

Every heating network must be supplied entirely with heat from renewable energies, unavoidable waste heat or a combination thereof by 31 December 2044 at the latest.

Furthermore, it is described how renewable energy and unavoidable heat are defined. This is defined by the following paragraphs.

Paragraph 3 Section 1 WPG:

Definitions for the purposes of this Act,

Number 13:

"unavoidable waste heat" means heat that is generated as an unavoidable by-product in an industrial plant, an electricity generation plant or in the tertiary sector and that would be discharged unused into the air or water without access to a heat network; waste heat is considered unavoidable if it cannot be utilised in the production process for economic, safety or other reasons and cannot be reduced with reasonable effort.

Number 15: "Heat from renewable energies" Heat:

a) from geothermal energy […].
b) from environmental heat […].
c) from waste water […].
d) from solar thermal energy […].
e) from biomass […] and from category III waste wood, from untreated residual wood, from residual wood from woodworking and wood processing, from sawmill residue or from industrial wood in waste wood categories I, II and III […], with the exception of biomass from raw materials with a high risk of indirect land-use change in accordance with Article 3 of Delegated Regulation (EU) 2019/807 […]; Solid biomass fuels, gaseous biomass fuels and liquid biofuels must fulfil the sustainability requirements of the Biomass Electricity Sustainability Ordinance, as amended, […].

f) from green methane in the sense of biomethane, that fulfils the requirements for gaseous biomass fuels in accordance with letter e […].
g) from a heat pump […].
h) from electricity […] that fulfils the average renewable energy share.
i) from green hydrogen […].
j) from a heat storage.

Additionally, to limit the share of biomass:

Paragraph 31 Section 2 WPG:
The share of biomass in the annual amount of heat generated in heating networks with a length of more than 50 kilometres shall be limited to a maximum of 15 percent from 1 January 2045. § Section 30 (2) sentences 2 and 3 shall apply accordingly.

These sections of the Heat Planning Act form the basic framework within which this work is carried out and the objectives to be achieved.

The subsequent chapter offers an overview of the operational principles of the technology mentioned suitable by the Heat Planning Act and explores its potential integration into district heating systems. Taking into consideration the constraints imposed by the geographical location of Schwäbisch Hall municipal utilities (SWSHA) only a selection of technologies are presented in the following.

2.4 District Heating Generation Technology

In the following chapter different heat generation technology is presented to give an overview of how they function. They are discussed in which way they can or do contribute to making district heating more climate neutral and current insights into research is given in short where applicable. Firstly, cogeneration as a conventional heating source is presented, following RES suitable for district heating integration, and lastly waste incineration is shortly described.

2.4.1 Combined Heat and Power

The basic principle of CHP is to utilise the combustion of fuels, which takes place in various engines such as gas turbines or reciprocating engines, to drive a shaft connected to a generator to produce electricity. At the same time, the residual heat contained in the exhaust gases is channelled through a heat exchanger, commonly referred to as a recovery boiler, to heat water for district heating purposes. This concept can be referred to as a motor/gas turbine CHP.

Another form of cogeneration is a steam turbine power plant, in which water is vaporised using various fuels. The steam produced drives a steam turbine to generate electricity, with the excess heat being transferred to the district heating sector. In scenarios with higher district heating demand, the steam turbine can be bypassed to utilise the steam for additional heat to the district heating system. This arrangement could be referred to as a steam turbine CHP.

A key difference between these two cycles is the location of the combustion process: in the engine CHP, combustion takes place inside the thermodynamic cycle, whereas in the steam turbine CHP cycle, combustion takes place outside the thermodynamic cycle to protect the turbine from combustion by-products. Consequently, the steam turbine CHP shows flexibility in the choice of fuel making it highly adaptable. This includes difficult to burn fuels such as municipal waste or other renewable waste which cannot be used in an combustion engine [17].

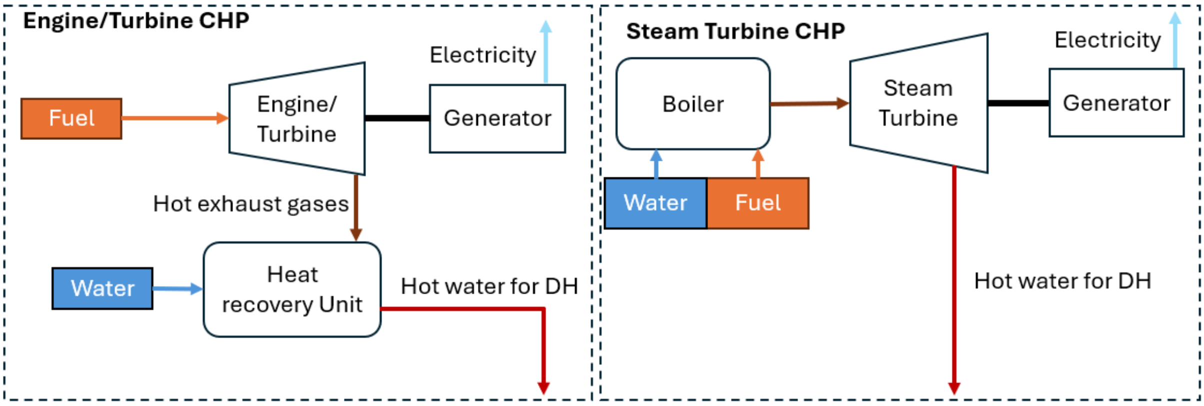

Figure 5: Main CHP concepts

From thermodynamic perspective, CHP plants can be considered more sustainable than conventional heating technology such as thermal plants as they maximize the use of exergy content in a fuel. In a CHP the exergy content used for heating is adapted to the temperatures used for the district heating system and the bigger share of exergy is used for. Thus, the overall use of exergy is maximised compared to a heating only power plant where the high-level exergy is completely used for low temperature heating [12].

Considering the higher efficiency, CHP plants offer especially an advantage if they replace thermal power plants that did not produce electricity. Since there are still many thermal power plants in Europe, replacing those with CHP plants can have a positive impact on the overall energy system towards more sustainability. The transition of CHP facilities enhances efficiency while concurrently decreasing operational expenses and mitigating the environmental footprint of the energy systems [26], [27].

But even though CHP plants are efficient and cost-effective solutions, CHP plants cannot be considered sustainable if natural gas or other fossil fuels are burnt. They can help to reduce emissions and save energy by providing energy-efficient electricity and heat, as efficiencies can exceed 90 %. Nevertheless, they can only be considered more sustainable in terms of energy efficiency compared with systems that have a higher CO_2 footprint. However, when integrated with renewable energy sources like solar systems, heat pumps, or replacing fossil fuel with for example biomass, CHP systems can attain a sustainable status [28].

While biomass is considered a viable option for increasing the share of renewable energies in district heating and energy systems [29], there are other options for decarbonising the CHP sector. Renewable alternatives such as renewable natural gas (RNG), hydrogen and biomass-derived biogas will replace natural gas, which is currently the main fuel used. RNG for example, derived from upgraded biogas, can simply be integrated into the existing natural gas infrastructure. Additionally, biogas and biomass are already being utilized in CHP plants, further contributing to their potential for sustainable energy production [30].

The majority of research concerning CHP plants primarily deals with enhancements, hybrid configurations, fuel diversification, and analytical studies, reflecting the maturity of this technology [16].

In conclusion, CHP plants is reliable, applicable, and cost-effective solution that can be very beneficial, especially when replacing systems that do not utilize the whole range of the exergy content of a fuel. However, in prospect of zero emissions, CHP must undergo a transition and need to shift away from fossil fuels completely. Solutions are emerging, utilizing biomass, biogas or hydrogen, offering alternatives to fossil fuels. Until this transition is completed CHP plants can still offer an efficient low carbon alternative to thermal power plants.

2.4.2 Renewable Energy Sources

In the following section RES suitable for the integration into district heating systems are presented. This includes an alternative energy source such as biomass, power-to-heat technology such as heat pumps, but also classical known technology as for instance solar thermal power, thermal storages, and industrial waste heat as third generation renewable energy.

Biomass

The term "biomass" encompasses materials derived from the growth of plants or animal manure or generally speaking, it is material from organic sources. Bioenergy currently constitutes the primary source of renewable energy globally and is anticipated to play a significant role in meeting a substantial portion of the world's energy demand in the coming century. Properly managed biomass systems have the potential to contribute significantly to carbon emissions reduction efforts. Solid biomass and renewable waste serve as the principal sources of bioenergy. There exist five categories of biomass which are:
Wood from various sources, crops that are grown for energy uses, waste from agriculture, food waste, and industrial waste.
Biomass can be processed into various forms to be used as fuel. This can either be solid, such as wood chips, liquid, for example like bio-diesel, or gaseous as biogas. Solid biomass and biogas play an important role when it comes to heat generation for district heating as both types of fuels can be used either in thermal power plants or CHP plants. While solid biomass such as

woodchips are burned in a boiler to heat water or steam, biogas can be burned in engines directly. Biogas is a specific form of biomass as it is generated by anaerobic micro-organisms that produce methane and carbon dioxide. It is thus considered a renewable fuel since it is generated by utilising biomass that was grown from atmospheric carbon. Another form to process biomass is to use wood waste which can be processed into wood pellets which are easier to transport and can even have a higher energy content when pretreated by torrefaction. However, it comes with higher costs to produce those. Other processing methods exist to produce biodiesel, which is rather used for the transport sector, or for instance, renewable natural gas, which is biogas that is cleaned from residue compounds i.e. water vapor, nitrogen, etc., and can be used in the natural gas infrastructure [12].

Biomass offers several advantages but also has drawbacks as a renewable energy source. Benefits are that it is widely available and can be considered a constant source of energy. Moreover, biomass is often viewed as carbon neutral since the carbon released during combustion was initially captured from the atmosphere during the relatively short growth period of the biomass, thus completing a closed carbon cycle. However, there are also drawbacks associated with biomass utilization. Depending on how biomass is cultivated, it may have negative effects on the climate, such as using fossil fuel-based fertilizers or machinery for harvesting. Additionally, extensive biomass utilization can lead to issues related to land use change, indirect land use change, and deforestation. To ensure the sustainability of biomass as a renewable energy source and avoid compromising the future, it is essential to manage biomass resources in a sustainable manner. This includes considering socioeconomic and ecological factors in biomass production and utilization practices [31].

Biomass can be a good energy source for district heating as a study shows how it is implemented in Sweden. Biomass plays an important role in Swedish district heating systems and accounts for around half of total heat production. This substantial use of biomass is largely supported by policies aimed at increasing the share of renewable energy sources in district heating. Local wood fuels serve as the primary biomass source, although imported biomass also contributes to the supply chain. The integration of biomass into the district heating industry is supported by the forestry industry, which further increases its importance. Currently, biomass is mainly used in boilers or CHP plants, which emphasises its central role in the modern heating infrastructure in Sweden [32].

Although biomass for district heating system can be a good solution for providing low to no carbon emissions heat it still has to overcome several barriers and needs specific implementation. A study from Soltero *et al.* (2022) showed that efficient biomass powered thermal systems for district heating including other renewable energy sources can help to mitigate climate impact of the heating sector, but the implementation of the technology however lacks wide use due to barriers in policies, technical aspects as well as social acceptance [33]. Rezaei, Sameti and Nasiri (2021), suggest that in order for biomass CHP plants be environmentally friendly, life cycle assessment and supply chain analysis should be included to provide a holistic picture of the environmental impact. Although biomass is commonly regarded as a carbon-neutral fuel, it is important to realise that harmful by-products can still be produced during combustion, which requires careful monitoring. Furthermore, the degree of carbon neutrality of biomass is highly dependent on how quickly it is grown and harvested. Moreover, the financial viability of biomass as an energy source depends on local policies, including subsidies, which should be thoroughly assessed as part of a sensitivity analysis [34].

Looking at the Germany heating sector, biomass is the predominant renewable heat source in the German heating sector, as mentioned before, with heat generation from biomass accounting for almost 90 % of renewable heat generation. Biomass is also the most important energy source among the renewable alternatives in the district heating sector. Woodchips, which are obtained from wood waste, green waste or waste wood, are predominantly used to generate heat [35].

To summarise, bioenergy derived from biomass can be an important source for phasing out fossil fuels and plays a crucial role in the district heating sector as it can replace fuels such as natural gas for combustion processes. When produced from renewable waste and other sustainable sources, it creates added value that can benefit society. However, biomass sources need to be closely managed and monitored to ensure their sustainability. Due to several drawbacks that can occur if handled irresponsibly, this source is prone to having no environmental benefits, which can undermine its position as a renewable energy source.

Heat pumps

Heat pumps (HP) are designed to utilise the natural flow of heat by extracting heat from low-temperature sources and transferring it to a medium at a higher temperature. This process makes it possible to heat a medium using energy from sources with lower temperatures. The fundamental operating principle of a HP relies on the widely employed vapor compression cycle, which can be adapted for both heating and cooling purposes. This cycle utilises a designated fluid called 'refrigerant' as its working fluid. The vapor compression refrigeration cycle comprises four primary stages: evaporation, compression, condensation, and expansion. In the evaporation stage, low-pressure refrigerant absorbs heat from its surroundings, transitioning into a low-pressure vapor. The compressor then pressurizes this vapor, raising its temperature and energy level through compression. Next, in the condensation stage, the high-pressure vapor releases heat to the environment, condensing back into a liquid. Finally, the expansion valve reduces the refrigerant's pressure and temperature, preparing it to restart the cycle. By cyclically circulating refrigerant through these stages, HPs can transfer heat from a low-temperature source to a higher-temperature space, providing both heating and cooling functions. This process enables HPs to extract heat from outdoor air, water, or the ground to warm indoor spaces, and conversely, to remove heat from interiors and release it outside for cooling purposes [36]. Figure 6 shows the operating principle of a HP and a corresponding T-s diagram.

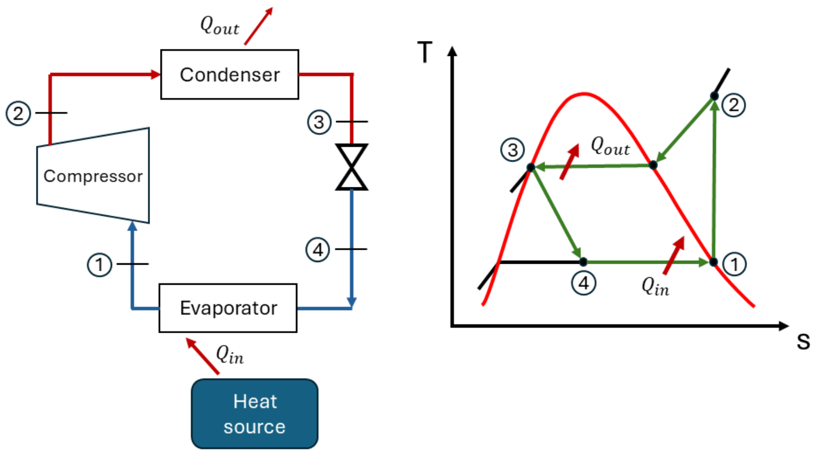

Figure 6: Operating principle of a heat pump and T-s diagram, adapted from Cengel, Boles and Kanoglu, (2019)

The performance of a HP is expressed through the coefficient of performance:

$$COP = \frac{Desired\ output\ (Heating\ or\ Cooling)}{Required\ input} \tag{1.1}$$

Or:

$$COP = \frac{Q_H}{W_{net,in}} = \frac{Q_H}{Q_H - Q_L} \tag{1.2}$$

Where Q_H is the heat supplied to the warm side and Q_L is the amount of heat extracted from the cold side, whereas the difference between Q_H and Q_L is the net-work needed. Nowadays HPs have usually an average COP of two to three [36].

More aspects are important when integrating HPs into DH system and are addressed in the following.

While HPs have been mainly known for small scale applications, they are not limited to such. HPs are commonly known for the building level but can also be deployed at the network or plant level. While large scale HPs are well suited for network and plant level, though their optimization and operational management present challenges due to the complexity of these systems. Today, large scale HPs are seen as a major way to reduce carbon emissions and increase the efficiency of district heating systems [37].

Looking at the technology readiness, David *et al.* (2017) found that the technology of large-scale HPs is now mature enough to be employed on a large scale in DH systems and identified that sewage water, and ambient waters, such as the sea, lakes or rivers, as potential main heat sources. They provide a long-term stability and are usually closely located to cities and municipalities. Even 3rd generation DH system can be supplied with current HPs but the suggest that lower temperature DH systems would increase the efficiency significantly and is paramount for future DH systems [38].

Not only the desired system performance can be achieved, but also the economic feasibility has been proved and investigated by Pieper *et al.* (2019). Additionally, they found that for their case study sewage water and river water had the highest capacity [39].

The placement and supply of HPs can vary when integrating them into DH systems. Large scale HPs for DH system can be either placed centrally close to a CHP unit, or locally depending on the heat source. There two versions of supply, either feeding the supply pipe directly or increasing the temperature of the return pipe. Both options have a positive impact of environmental and performance aspects of the system [40].

Furthermore, energy storage systems are proving to be key components in HP implementation, enabling the balancing of the electricity system and, in combination, making a significant contribution to reducing greenhouse gas emissions [41].

Moreover, Volkova, Koduvere and Pieper, (2022) and David *et al.* (2017) both concluded that currently policies are lacking for the widespread of HPs in DH systems.

In conclusion, HPs represent a mature technology that is ready for the large-scale employment and has proven to be economically viable in many regions. Ambient water and sewage waters have proven to be stable and reliable heat sources for HPs. Especially beneficial is the implementation in combination with thermal storages to provide flexibility to the electricity grid supporting the integration of fluctuating RES. The integration of HPs itself can be realised through different ways by either providing the main heat supply or raising the temperatures of the return waters, either way HPs are capable of providing the needed temperatures for DH systems. Overall, the implementation of HPs is a crucial technology in helping to reduce GHG emissions in the district heating sector when power with green electricity. The main barrier however is the lack in supporting policies.

Thermal Energy Storage

Thermal Energy Storages (TES) systems are integral components of DH systems, primarily aimed at optimizing heat production to enhance economic efficiency and balance the heat demand-supply dynamics. By storing excess heat during periods of low costs and releasing it during times of high costs. Moreover, TES systems play a crucial role in mitigating peak loads, thereby ensuring system stability and reliability. Typically, a TES comprises a large container utilizing water as the thermal storage medium, well insulated to minimize heat losses. While water remains the predominant storage medium due to its favourable thermodynamic, chemical, and environmental properties, alternative materials such as rocks or molten salts can also be employed [17].

Depending on the storage medium used, TES systems can be categorised into sensible, latent, and chemical storage systems. Sensible heat storages utilised the temperature change of a material to store heat. Usually, water is used due to its low costs, simplicity, and good thermal properties, as well as for the case of district heating the medium for storage and transportations remains the same. Latent heat storages utilise the phase change of a material to store heat. The main advantages are the higher energy density; hence less volume is needed, and fewer losses. On the other hand, latent heat storages are more complex systems due to an additional medium used, which required additional heat exchanger. Chemical energy storages use reversible chemical reactions to store heat. For instance, a reversible endothermic reaction is used to store heat in the reaction products. For releasing the heat, the reaction is reversed, and heat is released again. The main advantages are of chemical energy storages are high energy density, which can be as much as double the amount of water as well as low heat losses. However, this technology is still in research state. Sensible heat storage systems continue to be the most widely utilized due to their well-established technology and straightforward design [42].

TES systems can be further categorised according to the duration of their use, namely short-term storages and long-term storages. While short term storages are primarily used to balance out intraday variations, long term storages are used within weeks or even months to shift mismatched production and supply. This is especial the case for solar thermal power where a lot of heat is produced during summer, where at the same time the demand is low, and vice versa, in winter the production is low and the demand high. This can also be utilised for HPs when an excess of electricity is available to generate heat and store it. Today, mainly three different long-term storages are used, namely Tank-Pit-, Borehole-, and Aquifer-storages. Tank-Pit storages are essentially big storage tanks filled with hot water, above ground or underground. Borehole storages utilise pipes buried in the ground to store the heat in the soil. Aquifer storages use geological formation and actually pumps water into the ground and used the ground water as a storage medium [12], [17]. An overview of the storage types is depicted in Figure 7.

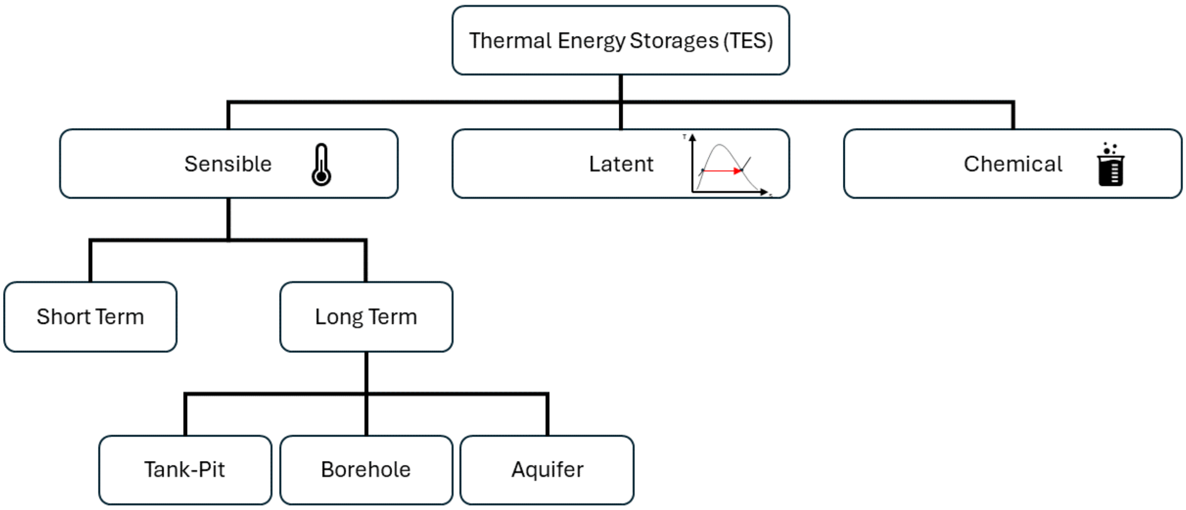

Figure 7: Thermal energy storage categories, Figure adapted from [42]

Solar thermal

Solar thermal power is well developed, economically feasible technology which has been widely used for domestic household hot water supply. It can be utilised even in cold climates today and produce up to 100°C of heat supply. While most of the solar thermal power is built on a small scale on rooftops, for district heating solar thermal heat is usually utilised using centralised large-scale systems having big areas of collector fields. These large-scale systems are also called solar district heating (SDH) systems and can have ranging capacities from 350kW to 50MW. These collector fields can be either installed on the ground or on building rooftops. There are two mainly used types: glazed flat plate and evacuated tube collectors, both utilising solar radiation to heat water. When combined with heat storages, solar thermal power can provide a large share of heat for DH systems demand and significantly increase the share of renewable energy heat supply. With seasonal storages, heat demand can be covered to up to 50% of the total annual heat demand. Seasonal storage would save up heat produced in summer and it would be used in autumn or winter [43]**.**

Solar district heating can also be combined with small scale rooftop mounted solar collectors and combining both systems. Decentralised solar thermal systems here can serve as importers or exporters of heat to increase flexibility of the system. However, such configurations are hard to manage efficiently.

For centralised plants, the bigger the collector surface area the lower the specific costs become, as well as inter-seasonal storges also help to reduce the specific costs and heat losses. The size of the storages needs to be scaled according to the size of the district heating system and connected consumers [17].

SDH is a well-established in Europe and seen as a good opportunity to increase the RES share for heating and decrease the dependence on fossil fuels. Today 80% of the SDH capacity is installed in Europe, with Denmark as a leader followed by Sweden, Germany, and Austria. These countries showed the applicability of large scale SDH system in Europe, even in colder climates of the northern Hemisphere. SDH can fully cover the heating need in summer, and when combined with seasonal storges even support a distinct share in winter. From an economic perspective SDH can provide a stable levelized cost of heat for the lifetime of the system which is estimated to be 20-25 years. Levelized costs of heat vary between 18 to 33€/MWh for instance for a 110 MW system, as it was investigated for different location in Europe. However, SDH must be evaluated for each geographic locations as costs parameters, such as installation costs and system performance vary significantly [44].

Industrial waste heat

Historically and presently, unused heat generated by industries holds significant potential for integration into DH systems. This potential is largely attributed to the straightforward technology required for heat recovery, particularly when the available heat matches or exceeds the temperature requirements of the DH supply. Heat recovery involves the installation of a heat exchanger at the outlet of the heat stream, connected to the DH systems. However, even low-grade heat can be harnessed by employing heat pumps to elevate the temperature level, further expanding the scope of heat utilization in DH systems [17]. Church, (2016) refers to this type of energy source as an "unused resource," highlighting that this heat is a by-product of primary production processes and will be generated regardless. Despite the simplicity of the technology, the author emphasizes two crucial considerations for high-grade temperature heat: the composition of the heat source and its condensation point. The condensation point plays a significant role in determining the recoverable energy, as a substantial amount of energy is stored in latent heat [45].

Industries offering such high-temperature waste heat include sectors such as cement, steel, pulp and paper, and various chemical industries. Although internal recovery methods can repurpose some of this waste heat for secondary processes, there is often an excess of high-quality waste heat remaining. This surplus heat can then be effectively utilized in DH systems. [46], [47].

The utilisation of industrial waste heat is a key factor in the development of low-emission district heating systems. By reusing these heat flows, district heating systems can significantly reduce their greenhouse gas emissions. By integrating such waste heat streams, district heating systems not only increase their environmental friendliness, but also their self-sufficiency, as these heat sources are reliably available. This approach increases the reliability and resilience of the system [48]. In combination with other RES such as green electricity and biomass, industrial waste heat has a crucial role to play in shaping the future energy mix of DH systems [49].

2.4.3 Waste Incineration

Although not defined as a renewable energy source according to the Heat and Planning Act, waste incineration will temporarily be used by Schwäbisch Hall municipal utilities to generate heat. Thus, the principal technology is shortly described.

Waste-to-energy, the oldest and simplest technology for generating heat or electricity from waste, remains a controversial process in the energy landscape. Municipal solid waste serves as the primary energy source for this process and offers options for heat-only, electricity-only or CHP generation to increase efficiency. Although the fossil fuel content of waste generally remains below 10% and methane emissions are reduced compared to landfill, waste incineration plants require extensive flue gas cleaning to reduce pollutants, toxins and emissions which is challenged with constantly changing composition [17].

2.5 Previous Scholarship

The following chapter provides an overview of previous research done in the area of optimising district heating systems with RES. This overview serves to place this work in the context of the wider research landscape. The literature reviewed in this chapter dealt mostly with optimisation from both economic and environmental perspectives, reflecting the prevailing goals of increasing efficiency and reducing emissions. The studies discussed here cover several key areas and are organised according to the technologies examined. The presentation begins with research that may be more distant from the present work and then moves on to studies that are more closely related to the present investigation.

There are many studies in the area of identifying potentials and theoretical frameworks for the optimising DH system as for example Pelda, Stelter and Holler (2020), who investigated the which extend industrial waste heat and solar thermal power could be used in DH systems in Germany and developed a methodology for identifying these potentials. This kind of research is not further presented in this chapter to limit the content but is worth mentioning since it often provides a theoretical foundation for applied research which is presented here [50].

While many studies focus on the integration of renewable energies and the supply side only, other studies additionally include parameters of the distribution systems and the demand side. Barone *et al.* (2020) focused on optimization including the sizing of the distribution systems piping using their own developed MATLAB tool [51]. Vesterlund, Toffolo and Dahl (2017), also included temperature and pressure as variables into their developed optimization scheme [52]. Furthermore, Ancona *et al.* (2019) compared a conventional fossil fuel DH system with a RES DH system, focusing on low temperature distribution systems [53].

In order to reduce the ecological footprint of DH systems, attempts are usually made to increase efficiency or increase the proportion of renewable energy. One technology that is not yet widely used, is the application of carbon capture and sequestration (CCS) technology. Lerbinger *et al.* (2023), investigated optimal decarbonisation strategies for an existing DH system including the potential of CCS on a central waste incineration CHP plant. They mention that their approach could also be applied to biomass CHP plants. Additionally, they investigated the influence of building level optimisations [54].

Sector coupling and interconnecting DH systems is another investigated strategy to improve DH systems. Schindler *et al.* (2023) investigated the coupling of the electricity and heating sector by connecting RES like wind directly to HPs [55]. Dominković *et al.* (2020) investigated interconnecting DH system from two cities and was able to improve the system performance [56].

A still very common and efficient technology for DH systems are CHP plants. Roberto *et al.* (2019) investigated the optimisation only based on a CHP and distributed storage units [57]. Wang *et al.* (2017) focused on optimising a CHP DH system but included solar thermal power and short-term TES [58].

TES are going to play a crucial role in integrating intermittent RES into DH systems. It has to be differentiated between short-term and long-term storages. Quaggiotto, Vivian and Zarrella (2021) focused on short-term TES and investigated their influence on a DH system utilising a CHP plant, a HP and gas boilers [59]. Fiorentini, Heer and Baldini (2023) on the other hand studied the combination of long-term TES (BHTES), HPs, and solar thermal power [60]. These two storage types can also be combined as Lamaison *et al.* (2019) did. They investigated the storage influence while having a focus in the specific sizing of the TES [61].

As already mentioned, heat pumps and solar thermal energy are promising renewable energy technologies that are often analysed regarding their possible integration into district heating systems. More studies focused on these technologies only. Fink *et al.* (2015) only looked at optimal operation of HPs combined with a biogas CHP plant [62]. Wang and Blondeau (2022) [63] and Carpaneto, Lazzeroni and Repetto (2015) [64] investigated solar thermal power including short-term storages and Buoro, Pinamonti and Reini (2014) [65] investigated solar thermal power with long term storages.

An even more comprehensive approach by optimising a DH system can be conducted by taking into account various RES technologies, local energy potentials and even political goals and frameworks. Lazzeroni *et al.* (2019) optimised a polygeneration according to EU directives and looked at different RES individually and combined. They included CHP plants, HPs, solar thermal power, and short-term TES, also focusing on district cooling [66]. Kersten *et al.* (2021) conducted a similar study for a municipality in Germany, taking federal subsidies into account [67]. Additionally, to Lazzeroni et al. they also considered geothermal heat and waste water as a heat source.

Studies from Alberg Østergaard *et al.* (2010) and Yuan *et al.* (2021) ([68], [69]) conducted more comprehensive research and considered a 100% RES DH system also including the electricity network. Both studies used the software EnergyPlan to plan an optimal energy system, included even more renewable energy sources and took local energy potentials and political frameworks into account. Alberg Østergaard *et al.* (2010) conducted a case study only, focusing on low temperature geothermal heat, wind power and biomass. Yuan *et al.* (2021) developed an own methodology framework to decide on optimal planning and investigated the trade-off between HPs and industrial excess heat.

2.6 Research Questions

Given the contextualisation of this study to the specific use case and the company's strategic decisions in relation to the assessment of local energy potential, this work does not contribute to the existing body of knowledge as a classic research work, but offers a detailed analysis tailored to a particular scenario. Although it does not fill a clear research gap, it provides a pragmatic approach to mitigating, quantifying, and assessing the environmental impacts associated with incorporating renewable energy technologies into the economically viable framework of a real-world case study. The resulting research questions addressed in this study are as follows:

- How do different price scenarios influence the cost structure of district heating systems when integrating RES?
- How do different price scenarios influence the integration of RES into the production plan of district heating systems based on a cost-effective operation?
- How can renewable energy technologies contribute to an increase in RES share and what share of heat supply from renewable energies can be achieved considering cost-effective operation?
- How sensitive are district heating system that use renewable technology to changes in input parameters of various fuel types and district heating loads?

3 Methodology

This section describes the methodology of this study. Firstly, the research design is presented, which consists of four steps: Analysis, Modelling, Simulations and Evaluation. Within the research design, the primary analyses are also presented, which are the scenario analysis and the sensitivity study. Following, the price scenarios applied in the scenario analysis are described in detail. Finally, the limitations resulting from the methodology that apply to this thesis are explained.

3.1 Research Design

In this section the individual steps of the research design are presented in detail. In the analysis phase, the district heating system under investigation is analysed, the current status is presented and future plans for the integration of new technologies are outlined. In the modelling phase, the new technology is incorporated into the software and the necessary boundary conditions are defined to realistically model the operation of the system. In addition, the modelling includes the adjustment of input parameters such as prices and DH loads as well as the inclusion of other boundary conditions such as the availability of units. During the simulation phase, various scenarios are simulated to obtain data for different pricing scenarios. In the evaluation phase, the simulations are analysed using economic parameters and the production plan is evaluated. To depict different scenarios, the steps from modelling to evaluation are iterated to change input parameters and generate new data. A visual representation of this process is shown in Figure 8.

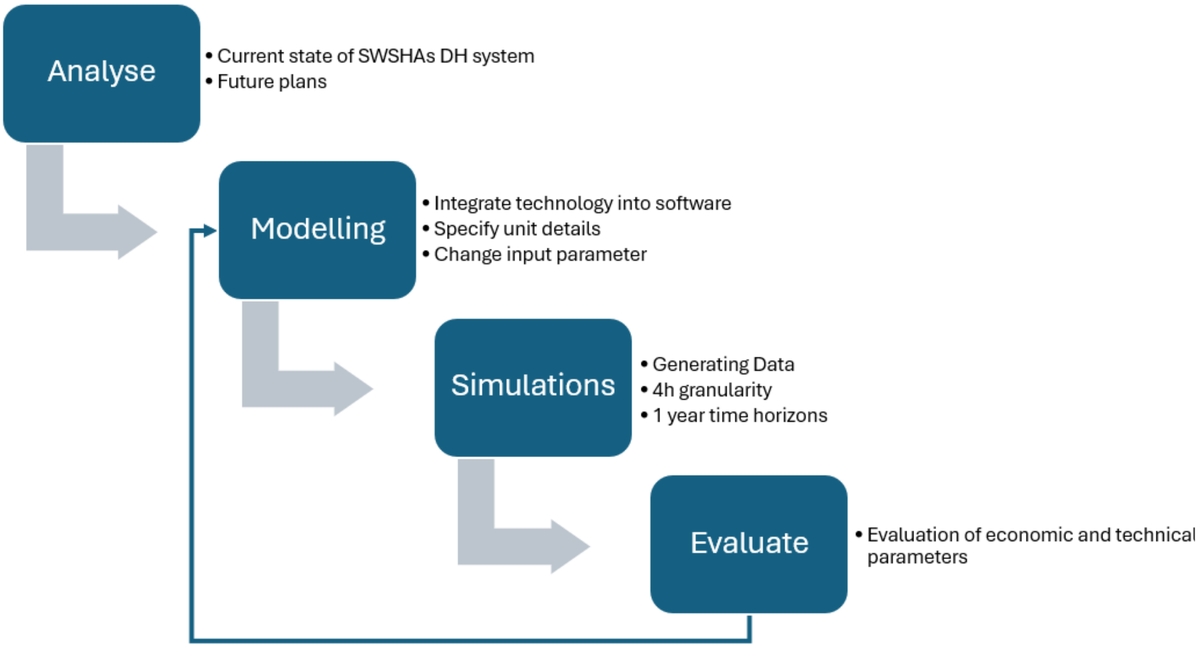

Figure 8: Research Design

3.1.1 Analysis

This subsection presents the use case on which this work is based, presenting its current state and future plans. The DH system investigated in this thesis is the system of the Schwäbisch Hall municipal utilities (SWSHA) which are located in the northeast of Baden-Württemberg in south-Germany. They supply their community not only with heat, but also with electricity from various RES such as wind, solar and hydropower, as well as conventional electricity generation based on natural gas and biomethane CHP plants. The heat is partly generated by their CHP plants, but also by thermal power stations and conventional gas boilers. At present, they can already provide 60% of their heat from renewable energies, which is due to their high proportion of biomethane used. The rest of the heat is provided through natural gas, covering 40% of their heat. An overview of their current heat supply during the year is shown in Figure 9 for 2023. The figure shows the typical characteristic of the heat supply of a district heating system during the year. While in summer the demand is low, which here is covered almost only by the biomethane units, in winter the demand is much higher having several peaks which are covered by gas CHP and gas boilers.

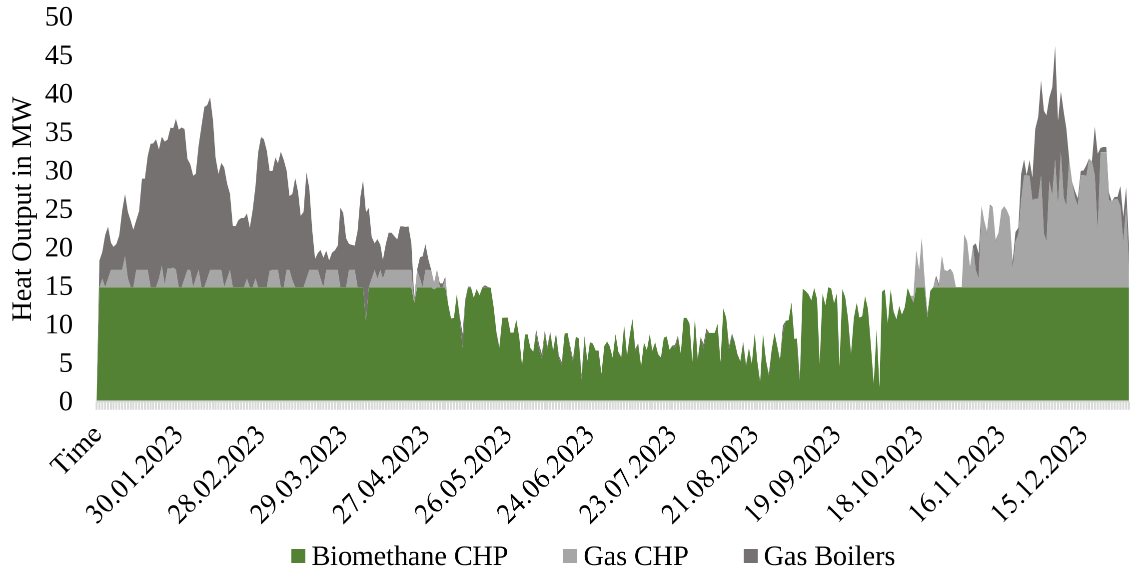

Figure 9: Heat supply by source units - current system

For the upcoming years SWSHA has defined a roadmap up to 2030 as to which new technology for heat production are to be introduced, in what size (power) and at what time. Their new production units will be implemented successively starting in the year of 2025 until 2029. This includes woodchip biomass thermal power plants (only heat production), heat from an external waste incineration plant (only heat supply), a solar thermal power plant in two expansion steps, a river HP, a biomethane CHP (heat and electricity), as well as industrial excess heat from a dairy plant. The planned technologies and timeframe are provided in Table 2

In addition, SWSHA is planning to expand its DH system in the upcoming years by connecting additional customers, which will lead to an expected increase in DH load of 8,000 GWh per year. As a result, the amount of heat will be increased annually from 2025.

Table 2: Roadmap 2030 of SWSHA

Planned year of implementation	Technology
2025	Thermal plant - woodchips Heat from external waste incineration
2026	Solar thermal power expansion state 1
2027	River heat pump Biomethane CHP plant Industrial waste heat – diary plant
2028 2029	Solar thermal power expansion state 2 Thermal plant - woodchips

3.1.2 Modelling

This sub-section provides details of how the DH system was modelled and adapted to create a functional system and run simulations. It consists of four sub-sections: Optimisation Software - Energy Optima 3, Validation, Unit Integration and Price Modelling. First, a brief introduction to the software is given, explaining how it works. The validation of the base case is then presented. The integration of new energy converters explains how the new units have been implemented in the software. In particular, further details are given for solar thermal power and heat pump, as additional inputs and calculations were required. Finally, the modelling of prices is described.

Optimization Software - Energy Optima 3

In order to answer the posed research questions, the system of SWSHA is adapted, simulated, and analysed utilising the software Energy Optima 3 (EO3) from Energy Opticon. Energy Optima 3 is a linear optimisation simulation tool in which energy systems can be modelled and possible production plans simulated and optimised. It is designed to achieve a cost optimal production based on input parameters such as prices for fuels and electricity, different cost factors from energy converters, energy loads, as well as weather forecasts. It can be used for different time horizons ranging from hours to several years. The main energy converters are represented as "black boxes", meaning that and no internal processes are considered by the software. For instance, for a CHP unit, only the input energy flow, efficiency, output energy flow are considered for the energy balance equation. The concept is depicted in Figure 10, showing potential fuels, production units, the connection to the electricity grid and to a DH grid. After running a simulation, the software provides optimized variables for each production unit, based on the provided/projected forecasts.

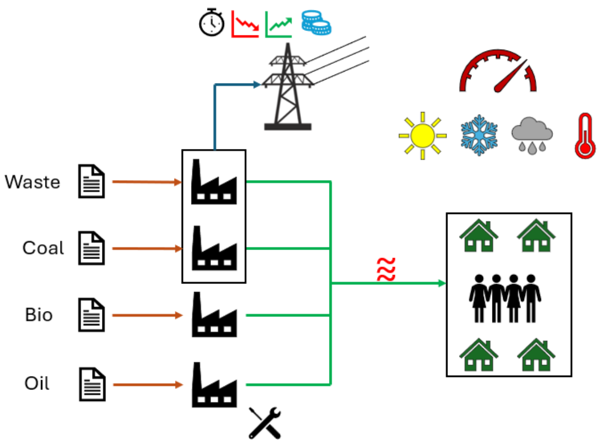

Figure 10: Energy Optima 3 concept, Source: Energy Opticon

Validation

Before new technologies were added to the software and simulations could be run, the simulation was validated to ensure that it accurately represented the current system. This was needed since before no one-year time horizon simulations have been conducted for SWSHA with EO3. Due to privacy policies SWSHA was unable to provide data for publication, and hence the validation was carried out internally by employees. The validation was conducted by running one-year simulations with historic inputs from 2023 (Prices, DH-load, availabilities), which were then compared to the data from SWSHA. In particular, it was compared how much heat is provided by which unit, during the course of the year. This process was iterated, and adaptions were made to the software by employees from Energy Opticon until the results were approved by SWSHA. The validated system corresponds to the base system presented in section 3.1.1, which shows SWSHA's heat supply in 2023.

Unit Integration

SWSHA's current system with all its operating units was already implemented in the software, so only the new units had to be integrated. To analyse SWSHA's future plans, the defined technologies were added to the software. This was done using the 'Topology Editor', a two-dimensional visual interface of the system, which can be used to add, connect and modify relevant parts of the system, such as energy converters, valves, interconnecting piping, etc. Each unit of the system can be specified with further details relevant to energy balance, performance intervals and costs. Relevant details for the production units are the possible load interval in MW, the efficiency of the unit and, if applicable, further cost details. Relevant cost details are start costs, stop costs, load change costs and maintenance costs. However, these cost categories do not apply to solar thermal power, external heat supply from waste incineration and industrial waste heat.

While the software has standard units such as various engines or boilers, for solar thermal and heat pump further details on the potential heat supply had to be determined and are presented below.

<u>Solar Thermal power</u>

For solar thermal power there is no standard unit available in the software, hence it was modelled as an external heat source, which should mimic the heat production of a solar thermal power plant only has a heat output based on a forecast. This energy forecast was based on a specific solar collector, the outside temperature, and the global radiation. Equation 3.1 provided by Perers and Bales (2002), was used to estimate a potential heat output based on a CPC INOX[2] vacuum tube solar collector as a reference, which represents a state of the art collector suitable for DH systems. The relevant characteristics of the collector are shown in Table 3.

$$P_{out} = A_{ap} \left(\eta_0 G - a_1(t_m - t_a) - a_2(t_m - t_a)^2\right) \tag{3.1}$$

P_{out}: Power output in Watt
A_{ap}: $Aperature\ area\ of\ collector$
η_0: $Zero\ loss\ efficiency\ for\ global\ radiation\ at\ normal\ incidence$
G: $Global\ solar\ radiation\ =\ historic\ forecast$
a_1: $First\ order\ heat\ loss\ coefficient$
a_2: $Second\ order\ heat\ loss\ coefficient$
t_m : $Arithmetic\ mean\ temperature\ between\ collector\ inlet\ and\ outlet$
t_a: Ambient air temperature close to collector

[2] https://ritter-energie.de/wp-content/uploads/2023/03/KollUebers_OEM_DE.pdf

Table 3: Solar collector characteristics

Collector characteristics	CPC INOX 6/12 XL
$Zero\ loss\ efficiency\ \eta_0$	0.644
$First\ order\ heat\ loss\ coefficient\ \ a_1\ (W/m^2K)$	0.75
$Second\ order\ heat\ loss\ coefficient\ a_2(W/m^2\ K^2)$	0.005

The collector area is 45.000 m^2 for the first expansion state in 2026 and again 45.000 m^2 for the second expansion state in 2028. Furthermore, in correspondence with SWSHA, the arithmetic mean temperature of 65° C was assumed, based on an outlet temperature of 80° C and an inlet temperature of 50° C. The global solar radiation and ambient outside temperature is based on historic values measured by SWSHA from 2023 and was used for upcoming years too.

River Heat Pump

Whilst there is a standard unit for a heat pump, it was necessary to estimate the potential energy in the river to ensure that the 7MW heat pump could deliver the required energy. First, the heat extraction potential was calculated from the river data using the fundamental heat transfer of a fluid (Equation 3.2)

$$\dot{Q} = \dot{m}\ c_p \Delta T \tag{3.2}$$

with

$$\dot{m} = \ \rho\ \dot{V} \tag{3.3}$$

Further parameters assumed are the density with $\rho = 1000\ \frac{kg}{m^3}$, the specific heat capacity with $c_p\ =\ 4.19\ \frac{kJ}{kg\ K}$, as well as it was assumed, that a temperature difference of 2°C can be achieved between the inlet and the outlet of the HP. The potential average volume flow of the river is assumed $\dot{V}\ =\ 26.2\frac{m^3}{s}$, which represents the annual mean value measured between 1980 and 2003[3]. Since technically not all the volume flow can be used, the minimum necessary volume flow is calculated based on an equation from Marguerite *et al.* (2019) (Equation 3.4).

$$\dot{m} = \frac{P_0 \cdot 3600}{c_p \Delta T} \tag{3.4}$$

$$P_0\text{: }the\ cooling/heating\ capacity\ of\ the\ heat\ pump\ in\ kW$$

With, P_0 of 7MW and a ΔT of 2° C the needed mass flow would be $\dot{m}\ =\ 3007\ \frac{kg}{h}$ which corresponds to $\dot{V} = 0.835\ \frac{m^3}{s}$. This represents 3.18 % of the annual mean available volume flow and thus assumed a reasonable to achieve, independent of a specific HP model. Furthermore, based on historic data, SWSHA defined that the HP cannot be used in January and December since the temperatures of the river will fall below 4°C to 5°C and becomes prone to freezing, as well as between mid-June and mid-September the water levels are too low to use

[3] https://de.wikipedia.org/w/index.php?title=Kocher_(Fluss)&oldid=242477480

water from the river. Outside these time frames it is assumed that the HP can in provide 7 MW of heat. It is modelled to be able to buy electricity from the market, based on the pricing scenarios presented later, as well as a biomethane2 CHP unit.

Other Energy Sources

For the thermal power plants utilising woodchips, standard units could be used and a new fuel type, woodchips, was created. The same was done for the biomethane CHP plant. The external waste heat incineration plant was modelled as an external heat source with a potential heat output based on 1.6 MW. The same applies to the industrial excess heat with a potential power output of 2 MW.

To provide further details on the newly added technology, Table 4 gives an overview of the maximum possible power outputs for each energy converter/heat source.

Table 4: Energy converters and its max. power outputs

Technology	Maximum Power Output in MW
Thermal Plant – Woodchips 1 & 2	5
Heat from Waste Incineration Plant	1.6
Solar Thermal Power	Based on formular
River Heat Pump	7
Biomethane CHP plant	4
Industrial Excess Heat	2

Price modelling

This subsection explains how the modelling of prices was done. It provides an overview of how the volatile prices of gas and electricity in particular are modelled. It also explains which prices are treated statically. Since the main purpose of EO3 is to economically optimize the production plan, the prices for energy sources are one of the most important input parameters for the software. While certain energy sources such as biomethane and wood chips are defined to have a fixed price in this work, other energy sources such as natural gas and electricity are subject to constant change and, especially in the recent past, have a volatile price structure over the course of the year. In order to map these constant changes during the year for the future, the price structure for 2023 was used for both natural gas and electricity in order to model the price structure for the years 2025 to 2031. For this purpose, the prices history for gas and electricity of 2023 were used and was scaled up or down based on the annual average price. This was done by multiplying the prices throughout the year with one factor to match the new desired annual average price.

The prices for biomethane and woodchips are assumed to remain constant in these years. Further details on the prices are presented in Chapter 3.2 . For the sensitivity analysis all input prices (plus the DH heating load) are varied in 2030, to investigate the sensitivity of these input parameters on the systems costs and the production plan. Details about the sensitivity study are presented in Chapter 3.1.4.

3.1.3 Simulations

This subsection describes details about how the simulations were carried out. After setting up the model and having all input parameters set, simulations could be run. The simulations have been carried out with a four-hour granularity to have a balance between accuracy and computational time. The one-year simulations timeframe was set to start at the 1st of January of each year at midnight to the 31st of December at midnight. Simulations were run for each year from 2025 to 2030. The main output data used were the total costs per year as well as the production plan, detailing which unit provides how much energy in a four-hour granularity in the given timeframe. The total costs are a sum of all fixed and variable costs of the energy converters including the fuel costs. In addition, the total costs include the income from the sale of electricity, which is also based on electricity prices and applies to the CHP units.

The data was extracted from the software using "csv" files and Excel files. The production plan was analysed using a Python script and then exported to Excel to further process and visualise. The costs were directly exported to excel and then postprocessed there. The Python script was used to pre-sort the data, remove empty columns, and finally categorise the data.

3.1.4 Evaluation

This subsection describes the evaluation carried out for the different analyses presented here. The analyses evaluated include the Scenario Analysis and the Sensitivity Study. The Scenario Analysis is assessed using economical parameters, and the production plan is examined. For the sensitivity study, variations in total cost are investigated.

Scenario Analysis

For the scenario analysis, two timelines from 2025 to 2030 were simulated. One timeline could only use existing units to provide heat. The other timeline used the new technology according to the roadmap presented in Chapter 3.1.1. The economic analysis is based on the total costs for each timeline, which were compared for each year to obtain a cost difference and hence a theoretical cash flow (CF) from which different economic parameters could be derived (Equation 3.5). After the year 2030 it is assumed that the cash flow remains constant until 2050.

$$CF_t = Toal\ costs_{current\ system,t} - Total\ costs_{new\ system,t} \tag{3.5}$$

CF_t: Cash flow in year t

$Toal\ costs_{current\ system,t}$: Total cost of the timeline using the existing systems units in year t

$Total\ costs_{new\ system,t}$: Total costs of the timeline using additionally new units in year t

The production plan for each scenario was evaluated in 2030 to provide a picture of the new system, including all new technologies. This was done to show how an optimal production plan could look like in 2030 based on the price scenarios presented. The scenario analysis concept is shown in Figure 11.

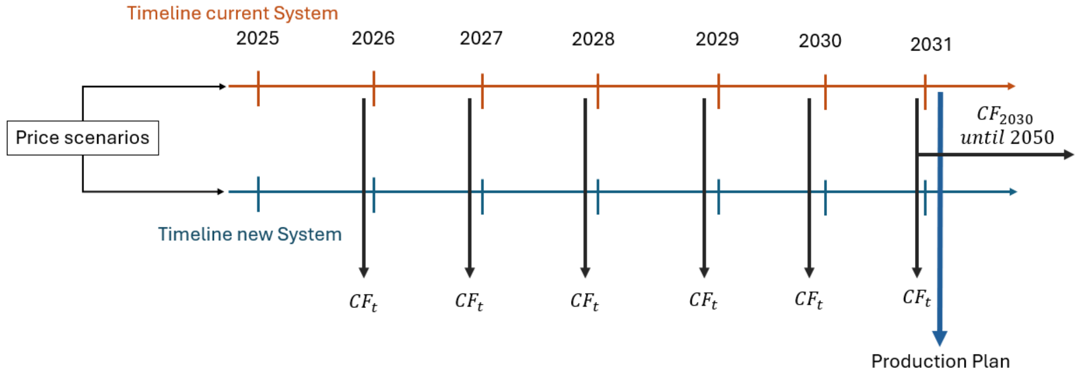

Figure 11: Concept and timelines for the Scenario Analysis

The economic parameters evaluated in the scenario analysis include the Dynamic Payback Period, the Net Present Value (NPV) and the Levelized Cost of Energy (LCOE). The methodology for calculating these parameters is described below.

Economic Parameter

To calculate the dynamic payback period and the NPV, the present value of future cash flows is determined together with the investment expenditures of the technologies in year t (Equation 3.6).

$$Present\ value\ cash\ flow = \frac{CF_t - \sum_{t=1}^{L} I_t}{(1+r)^t} \tag{3.6}$$

CF_t: Cashflow in year t

I_t: represents the Investment expenditure in year t

r: discount rate

t: year

For this study, the current European Central Bank base rate was used, which is 4.5% (September 2023). Furthermore, the lifetime is assumed to be 25 years.

The dynamic payback period is determined by identifying the point at which the sum of all present value cash flow accumulation reaches zero (this includes the investment expenditures). Meanwhile, for the net present value, all cash flows over the lifetime are included and summed up (Equation 3.7).

$$NPV = \sum_{n=1}^{N} \frac{CF_t - \sum_{t=1}^{L} I_t}{(1+r)^t} \tag{3.7}$$

Since there is no initial investment the investment expenditures are included in the corresponding year as before.

The LCOE are calculated based on Equation 3.8.

$$LCOE = \frac{sum\ of\ costs\ during\ lifetime}{sum\ of\ heat\ output\ over\ lifetime} = \frac{\sum_{t=1}^{N} \frac{I_t + TC_t}{(1+r)^n}}{\sum_{t=1}^{N} \frac{E_n}{(1+r)^n}} \tag{3.8}$$

I_t: represents the investment expenditures

TC_t: represents the total expenditures for operation of the system including maintenance and fuel expenditures in year t

E_n: represents the heat energy that is provided in year t

r: discount rate

t: year

While LCOE is usually used to assess the cost of electricity generation, this thesis looks at the energy output of heat.

Production Plan Assessment

To assess the production plan, the energy output of each energy converter is considered. Energy converters using the same energy source are grouped together, allowing to analyse the systems heat supplied by each energy source relative to the total production. This is later presented in percentage for each source per year for the year 2030.

Sensitivity Study

For the sensitivity study, the price of each fuel type/energy source, as well as the energy output of the DH load, is varied by ±10% and ±20% to assess their influence on the total costs of the system and the production plan. This is done to identify the most critical parameters of the system and investigate their influence on the production plan.

3.2 Price Scenarios

As already mentioned, the first analysis conducted in this work was to evaluate the investment decision for the roadmap provided by SWSHA. Since prices of the future are unknown and prospect of many influences, different price scenarios have been created and used as input parameters to depict potential future scenarios. These price scenarios have been based on an analysis from the Institute of Energy Economics at the University of Cologne (EWI) [72]. This analysis provides potential price scenarios for electricity and gas until 2030, based on current economic and geopolitical developments in Europe. Main influential factor for this analysis were the potential electricity and gas demand/supply in Europe, the war in Ukraine and the resulting geopolitical changes (hence the availability of Russian gas imports), as well as the expansion of renewable energies in Europe. Based on these main influence factors the analysis from EWI proposes 8 different price scenarios. Which are used for this thesis. Details about the different price scenarios are presented in Figure 12 as well as the abbreviations are described in Table 5. The scenarios are firstly differentiated, based on the electrification of end consumer sectors and gas demand. Following, for each of those scenarios either no Russian gas imports are assumed or low availability of Russian gas imports. In the final step, it is assumed for each scenario that either a strong or a moderate expansion of renewable energies takes place. Eight electricity price scenarios have been created from these factors (Figure 13).

Table 5: Scenario Attribute description, adapted from EWI 2022

Main Uncertainty	Abbreviation	Description
Electricity and gas demand	mEL	moderate electrification, constant gas demand
	hEL	high electrification, decreasing gas demand
Availability of Russian gas	oRI	without availability of Russian gas
	sRI	with little (small) availability of Russian gas
Expansion of renewable energies	hRE	High expansion path for renewable energies
	mRE	moderate expansion path for renewable energies

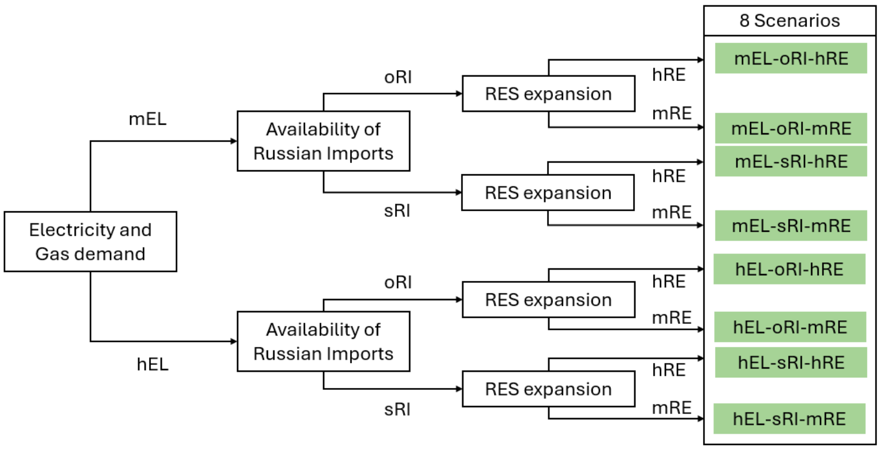

Figure 12: Price Scenarios from EWI, Figure adapted from EWI (2022)

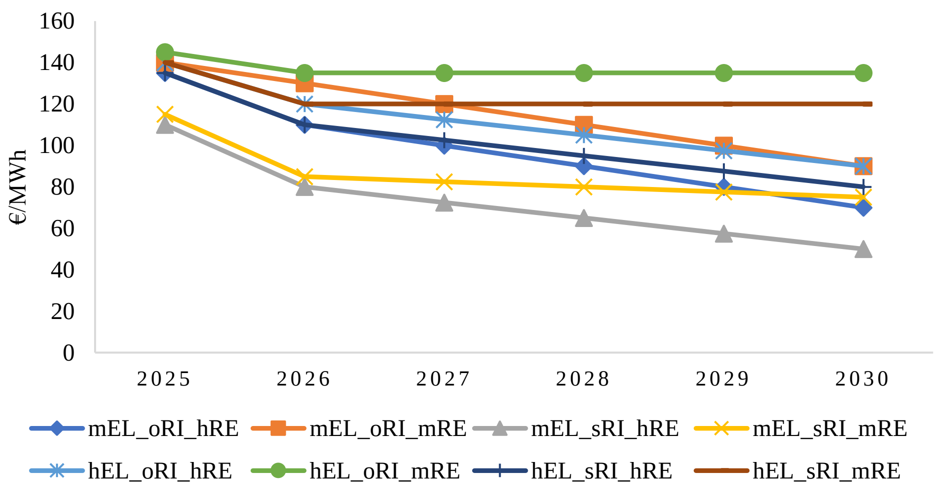

Figure 13: Electricity price scenarios from EWI

Furthermore, the Analysis of EWI proposes 4 different gas price developments which are based on the development of the electricity and gas demand and the availability of Russian gas. The report estimated one average gas prices for the year of 2026 and one average gas price for 2030 for each of those 4 scenarios. These average prices are the "model result" in their analysis (blue triangles in Figure 14). For each model result they provide an uncertainty based on the global LNG infrastructure expansion (grey area in the figure). While for hEL-oRI, hEL-sRI, and mEL-nRI the uncertainty is low, the uncertainty for the scenario mEL-oRI is rather high compared to the other scenarios. Due to this, a fifth gas price scenario is added in this work to include this uncertainty.

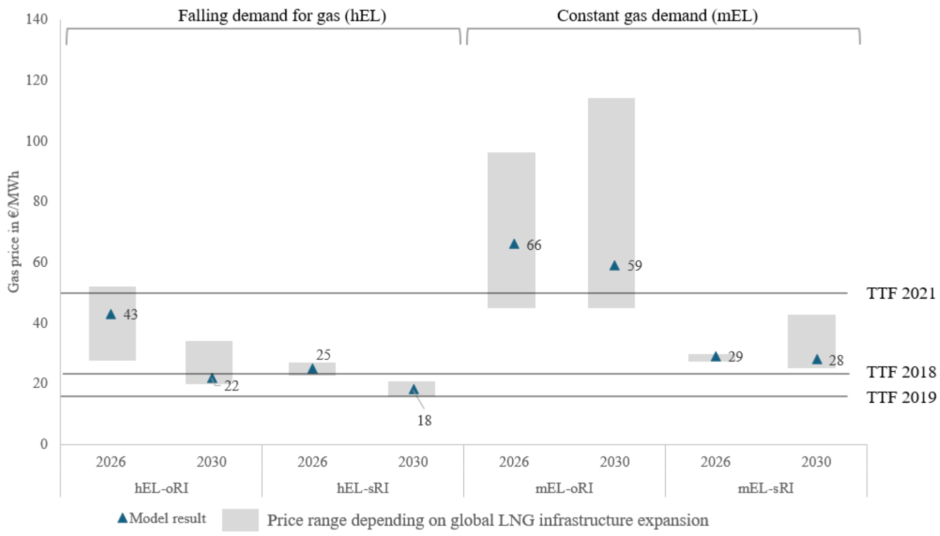

Figure 14: Gas price scenarios from EWI, Figure adapted from EWI (2022)

To have an average gas price for each year between 2025 and 2030, it was assumed the gas price in 2025 is the gas price from 2026 and for the years between 2025 and 2030 the values were interpolated linearly. The used average gas prices and interpolated values are presented in Figure 15.

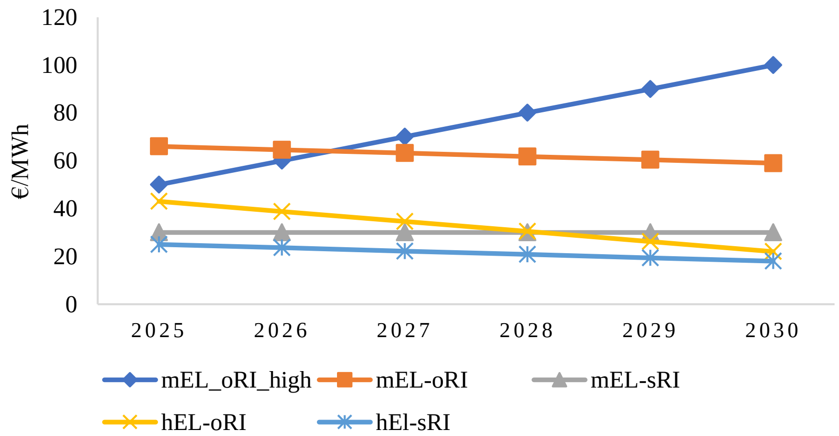

Figure 15: Interpolated average gas prices, based on EWI (2022)

The additional scenario for the high uncertainty of the mEL-oRI-Scenario was named "mEL-oRI_high" and was selected to start at 50€/MWh and rise until 100€/MWh. It was chosen this way to not have the absolute boundary values of the uncertainty but still cover a wide range of it. It was chosen to start smaller and then grow to depict a price increase, which could represent rising CO_2 prices for instance and poses a counter development to the other scenarios which are all decreasing or remaining constant. The values for scenario mEL-sRI were kept at a constant average value of 30 €/MWh since model prices varied very little. The other model values were kept as proposed by the EWI report and linearly interpolated as mentioned above. Furthermore, the price structure of the gas prices from 2023 were used and scaled to match the corresponding average gas price for each year.

Other prices for fuels and heat supply are as mentioned considered constant for the Scenario Analysis and are presented in Table 6 based on data from SWSHA.

Table 6: Fuel/Heat source prices

Fuel/Source	Price in €/MWh
Biomethane	79.95
Woodchips	5
Industrial Excess Heat	20
Waste incineration external heat supply	20

3.3 Limitations

As mentioned above, a number of assumptions have been made which have led to limitations in this thesis and the data generated. These limitations are briefly outlined here.

One limitation relates to the modelling of the DH systems and their boundary conditions in terms of functionality. The assumption of a static increase of 8000 GWh per year in the DH load is a calculation made by SWSHA. Like all projections of the future, it is subject to change. However, it provides a general trend of increasing DH load. In addition, the sensitivity study examines the variance of the DH load to assess its influence.

Another limitation is the use of temperature and global radiation data from 2023, which may affect the assessment of solar thermal energy production. Furthermore, the availability of the heat pump and the assumed flow rate need to be critically examined, as future changes in river temperatures and extreme flood levels could affect their availability. However, the availability of the heat pump is provided by SWSHA and is not further analysed in this thesis.

For the economic analysis, other critical input parameters need to be considered. Firstly, the base rate of 4.5% is chosen according to the European Central Bank but should be carefully chosen depending on the industry or investment alternatives. In addition, the chosen prices and price structure impose further constraints. The price structure of recent years, including 2023, shows considerable price volatility and the same price structures have been assumed for each year from 2025 to 2031, which may not reflect future trends. In addition, negative prices are hardly included in the current price structure, and it is uncertain whether more negative prices will occur in the future. Therefore, the price structure needs to be critically examined and carefully assessed. However, the average prices chosen are based on a detailed analysis that includes different scenarios of interest. Furthermore, it is assumed that the cash flow for the NPV remains constant after 2031 which has a significant influence on its outcome.

In addition, the gas prices are subject to more limitations, as it has been assumed that model prices from 2026 are already used in 2025 due to the unavailability of model prices for this year. However, these prices are still linked to the analysis used for electricity prices. Finally, another limitation is the assumption of static prices for the remaining fuels and energy sources, which is addressed in the sensitivity study by investigating their impact on the system.

4 Results

The following section shows and visualises the data generated during the simulation and explains the initial implications of the data. The results consist of two main analyses: the scenario analyses and the sensitivity study.

4.1 Scenario Analysis

The scenario analyses provides insight into how different price structures of electricity and gas influence the systems performance in terms of costs, the presented economic parameters, as well as the corresponding optimal production plan. As described before two systems are compared on two timelines, having the same price structures as inputs. These are named in the following as the current system (without new technology) and the new system (new technology implemented according to roadmap). While there is a separate sensitivity study, the scenario analysis already provides insights into how both systems react to changes in electricity prices and gas prices during the years, comparing the two systems behaviour.

Firstly, an overview of the results is given to illustrate the range of parameters and the variety of possible results. Following, the results of the individual scenarios are presented in three steps. Firstly, the cost development between 2025 and 2030 is analysed to explain the impact of changing price structures on the system while the system itself changes (new technologies are constantly being introduced). Secondly, the optimal production plan is presented for all scenarios in 2030, providing an overview about how the price structure influences the optimal use of production units. Lastly, the evaluated economic parameters are presented in detail for each scenario.

Overview of Results

In the following the overview of the results are provided. The table below shows all economic outcomes from the analysed scenarios. Goal is not present each scenario in detail, but provide a short overview of the potential outcomes, range, and boundaries of the results. The table consists of eight columns, from left to right: the scenario names, which is then separate for each scenario into the current systems (C) results and the new systems (N) results, providing the total cost (TC) of each system in 2030 (in million €), their corresponding price difference (hence theoretical cash flow), and the LCOE are shown for each system. Finally, the payback time based on the theoretical cash flow and its NPV is shown. In the last column, the scenarios allocation to the gas prices is given. Important to highlight here is the range of potential outcomes. The first scenario serves as upper limit of the results, having the highest costs, highest cash flows, shortest payback times and highest NPVs. The results from 01 to 10 then progressed with decreasing total costs in 2030, lower cash flows, decreased LCOE, increasing payback time and decreased NPVs. Hence while the costs for both systems fell over the course of the scenarios, the economic parameters for the new system became less favourable. The last four scenarios were not economically viable based on the economic parameters, as they had low cash flows, the payback periods were not achieved within 25 years and the NPVs were negative. At the same time, these scenarios have all lower total costs and lower LCOE compared to the economic favourable scenarios. This can be seen in the table by following each column from top to bottom seeing its continuous rise or fall for each parameter. Since the systems total cost and their difference is crucial for all parameters analysed in the table, those values are visualised and can be found in Figure 16. Here also the decrease in cost and cash flow can be observed for the scenarios from left to right.

Table 7: Results economic parameters

Scenario	System	TC (M €) 2030	CF in 2030 (M €)	LCOE €/MWh	Dyn. Payback	NPV (M €)	Gas price scenario
01_mEL_oRI_hRE	C	29.37	12.29	122.78	7	117.43	mEL_oRI_high
	N	17.08		86.45			
02_mEL_oRI_mRE	C	26.57	11.01	109.74	8	100.54	
	N	15.56		78.63			
03_mEL_oRI_hRE	C	24.21	8.08	104.60	9	68.12	mEL_oRI
	N	16.14		83.52			
04_mEL_oRI_mRE	C	20.81	6.37	89.38	10	46.35	
	N	14.44		75.04			
05_mEL_sRI_hRE	C	20.86	5.20	90.25	14	26.58	mEL_sRI
	N	15.65		82.03			
06_mEL_sRI_mRE	C	16.80	2.87	74.33	Not reached	-1.53	
	N	13.94		74.80			
07_hEL_oRI_hRE	C	11.76	0.48	52.48	Not reached	-29.94	hEL-oRI
	N	11.28		61.75			
08_hEL_oRI_mRE	C	2.96	-0.97	17.82	Not reached	-47.98	
	N	3.93		32.67			
09_hEL_sRI_hRE	C	12.42	0.54	47.66	Not reached	-32.75	hEL-sRI
	N	11.88		56.82			
10_hEL_sRI_mRE	C	4.74	-1.01	22.82	Not reached	-51.33	
	N	5.76		38.70			

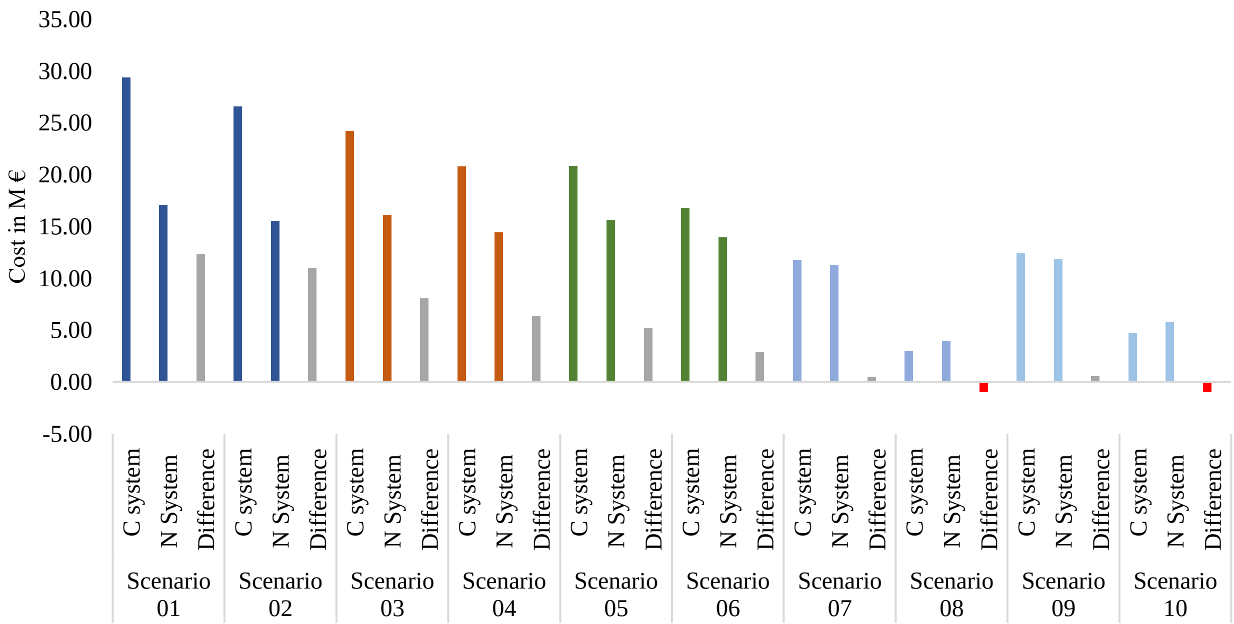

Figure 16: Total cost and cash flow in 2030 - current system vs. new systems

This overview shows already that the different input prices have a crucial influence on the outcome and performance of the new system, when compared to the current system. Results vary from the new system being very beneficial compared to the current one, to both systems performing very similar. The price structure from scenario 01 to 10 follows in principle the structure of high gas prices and lower electricity prices in scenario 01 to low gas prices to higher electricity prices in scenario 10. However, the price structure between 2025 and 2030 is more complex and needs an in-detail analysis before conclusions can be drawn.

4.1.1 Cost Development 2025 to 2030

In the following, the scenarios for the years 2025 to 2030 are analysed in detail to examine the influence of the gas and electricity price on the systems as well as the influence of the newly introduced technology on the system. Scenarios based on the same gas price are analysed together to specifically examine the influence of the electricity price. The detailed analysis starts with scenarios 01 & 02 and ends with 09 & 10. Three things are considered, firstly the overall cost development and the resulting cash flow between the systems. Secondly, the sensitivity towards the electricity price of the current and new systems over the years for the different scenarios is analysed. And finally, the dynamic income balance from 2025 to 2030 is also considered for each scenario analysis, which includes the investment expenditures and discounted cash flows.

Scenario 01 and 02 – Development 2025 – 2030

In the following the scenarios 01 and 02 are analysed from 2025 to 2030, and the development of the cost and the production plan is looked upon. Figure 17 shows the price structure the scenarios are based on. These scenarios have the highest gas price progression, rising from 50 €/MWh to 100 €/MWh. Electricity prices are moderate and continuously falling over the course of time, ranging from 140/135 €/MWh to 90/70 €/MWh.

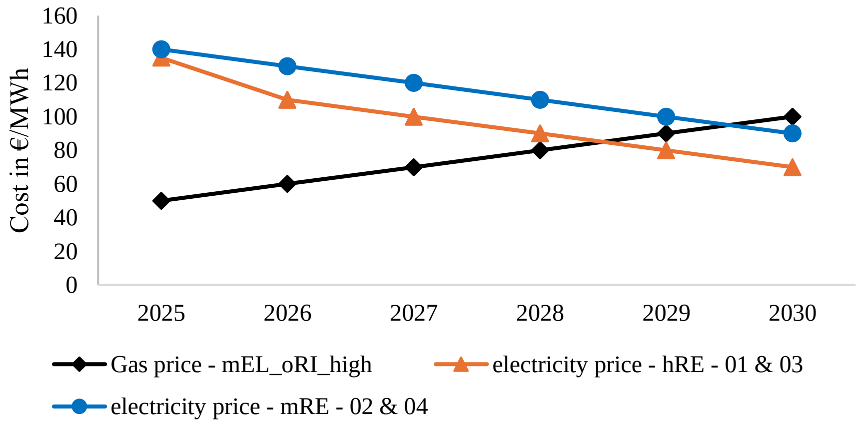

Figure 17: Price Development of Scenario 01 & 02

<u>Cost Development 2025-2030</u>

To analyse the influence of gas and electricity prices (el. prices), the total costs and the cash flow between the systems are examined for both scenarios. The total costs and cash flow over time can be seen in Figure 18. On the left the total cost over time for each system and scenario, and on the right the cost difference between the current and the new system for each scenario is shown. The current system is abbreviated with a “C” and the new system with an “N”. The orange colour represents scenario 01 (lower electricity prices) and the blue colour scenario 02 (higher electricity prices). The colour code is kept as in Figure 17.

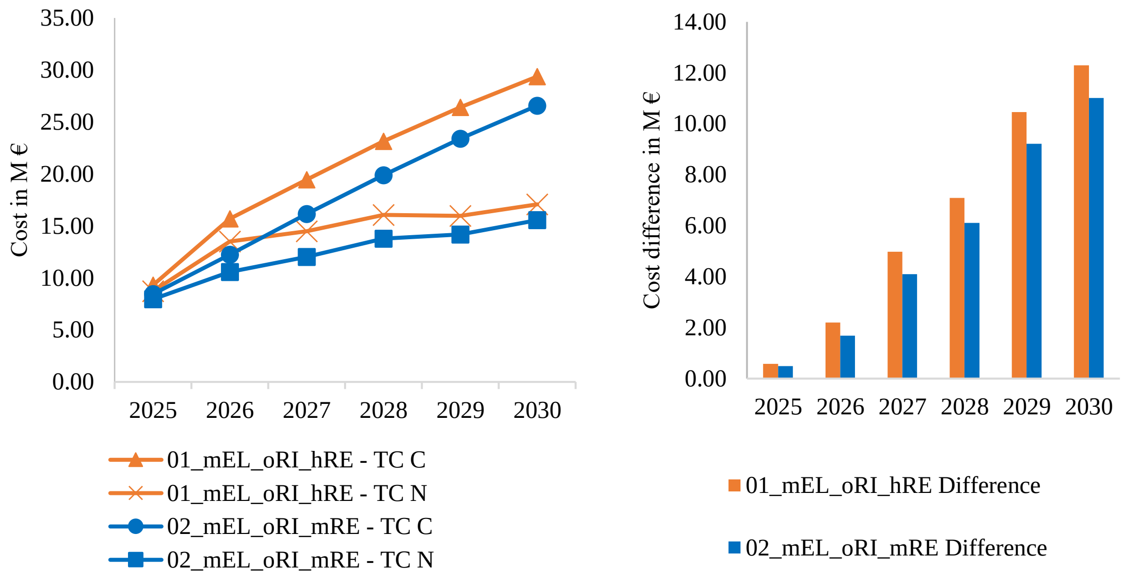

Figure 18: Scenario 01&02 Cost development 2025-2030

The left graph shows, that for the underlying cost structure the absolute total costs rise, for both systems and scenarios over time. While for the current systems the price increase is almost constant, the price increase for the new systems flattens out over time. Thus, the costs are diverging between the systems. The right graph shows the diverging behaviour of the two systems by showing the cost difference in each year. The cost difference for both scenarios increase over time and are smaller for the scenario 02 with higher el. prices. Comparing the two scenarios, the absolute total costs are higher for scenario 01 (lower el. prices) and lower for scenario 02 (higher el. prices).

Three conclusions can be made from this data. Firstly, that an increase in el. prices leads to lower costs (comparing scenario 01 and 02). This is due to the system's ability to sell electricity for a higher price and thus the costs are lower. Secondly, due to this decrease in costs, the cash flow resulting from the cost difference between the systems decreases too. Lastly, the cost development on the left side indicates that the current system reacts more sensitive to the price changes compared to the new system, which also applies to both scenarios. This can be derived from the diverging cost behaviour between the systems. While from 2025 to 2026 the two systems rise similarly in costs, after 2026 the systems diverge. This can be attributed to newly introduced technology which is more independent from natural gas (woodchips thermal power plants, biomethane CHP, solar power, industrial waste heat, HP). This applies to both scenarios investigated here, however this characteristic is visually better illustrated by scenario 01.

Sensitivity

Since between scenario 01 to 02 only the el. prices change, the sensitivity to el. prices can be investigated for each system (C and N) over the course of the years. The relative price change for each system is investigated based on scenario 01. This is done for each year from 2025 to 2030, thus, the relative cost change in relation to the first scenario can be seen per year (Equation 4.1). The equation shows the index for the current system comparing scenario 02 and 01. "S" being the systems index as described before and "N", being the scenarios index. A graph of was plotted and shown in Figure 19, providing the relative cost change for each system and the relative el. price change.

$$Relative\ cost\ change_{S,N} = \frac{TC_{S,N} - TC_{S,N-1}}{TC_{C,N-1}} = \frac{TC_{C,2} - TC_{C,1}}{TC_{C,1}} \tag{4.1}$$

S: System index – current (C) or new system (N)

N: Scenario index – number of scenario

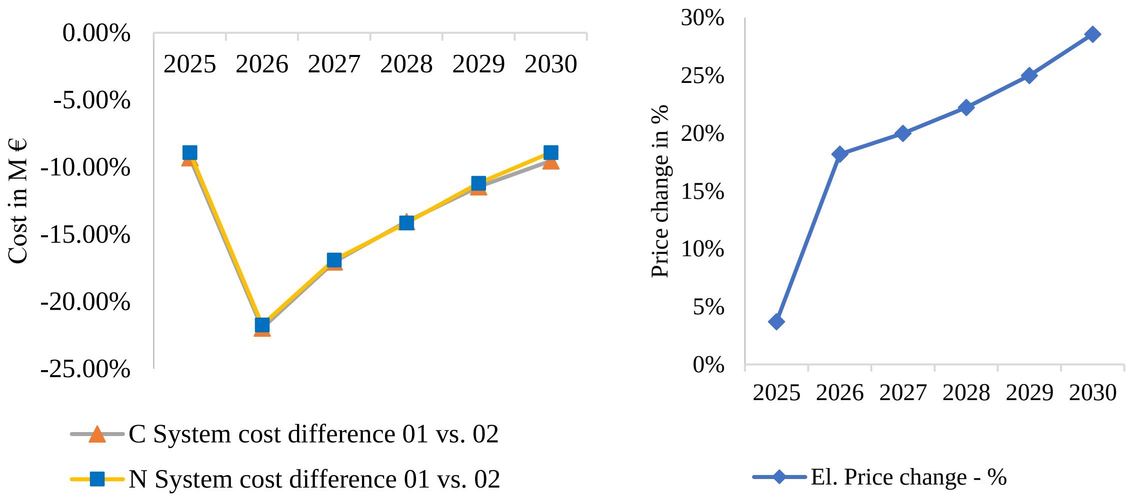

Figure 19: Cost-sensitivity of current system vs. new system

On the left-hand side, the relative cost change is shown for the current and the new system and on the right-hand side the relative el. price change between scenario 01 and 02, based on scenario 01. The graphs show that for an increase in el. price both systems (C and N), lead to total costs decrease. The diagram on the left shows a cost change between -9% and -22%. From this graph it can be concluded that both systems react almost identically to price changes for the given gas price. There are slight differences in 2029 and 2030, and the current system has lower relative costs compared to Scenario 01.

<u>Dynamic Cash Flow</u>

Next to the total cost development, the dynamic cash flow needs to be considered. The dynamic cash flow represents the current balance of the NPV, in principle taking the investment expenditures into account and accumulating the cash flows. Or in other words the current dynamic income balance. The income balance from scenario 01 and 02 can be seen in Figure 20. It shows that scenario 01 has a better performance due to higher absolute cash flows. The income balances in 2030 being -5.36 M. € for scenario 01 and -9.47 M. € for scenario 02.

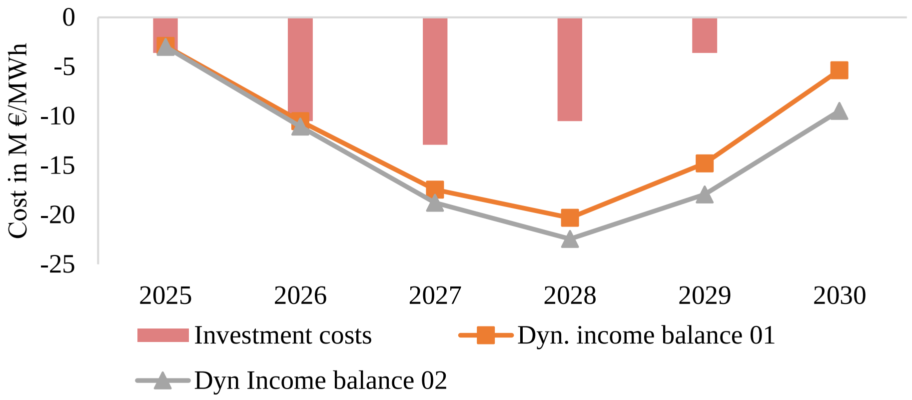

Figure 20: Dynamic income balance for scenarios 01 & 02

Scenario 03 and 04 – Development 2025 – 2030

Following, the analysis for scenario 03 and 04 is presented. Like before the years from 2025 to 2030 are looked upon. For the price development for these scenarios the only difference compared to scenario 01 and 02 is the underlying gas price. The prices for electricity are the same as for scenario 01 and 02. The gas price here is moderate and falling from 66 €/MWh to 59 €/MWh on average. The prices can be seen in Figure 21.

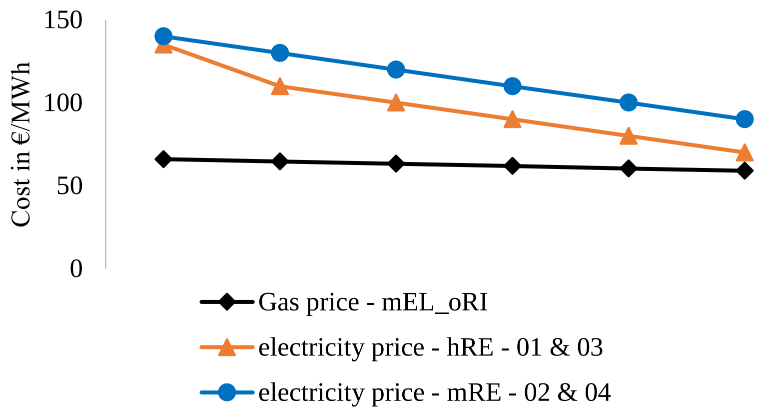

Figure 21: Price Development of Scenario 03 & 04

<u>Cost Development 2025-2030</u>

Comparing with scenario 01 and 02, a similar development for the total costs and cost difference, can be seen in Figure 22. For both scenarios and systems, the total costs are rising, while the total costs of the systems are diverging. This is also illustrated by the bar chart on the right where the cost difference between the systems per scenario can be seen. With progressing years, the cost difference increases for both scenarios. However, compared to scenario 01 and 02 the absolute total costs as well as the absolute cost difference is smaller, and the systems converge.

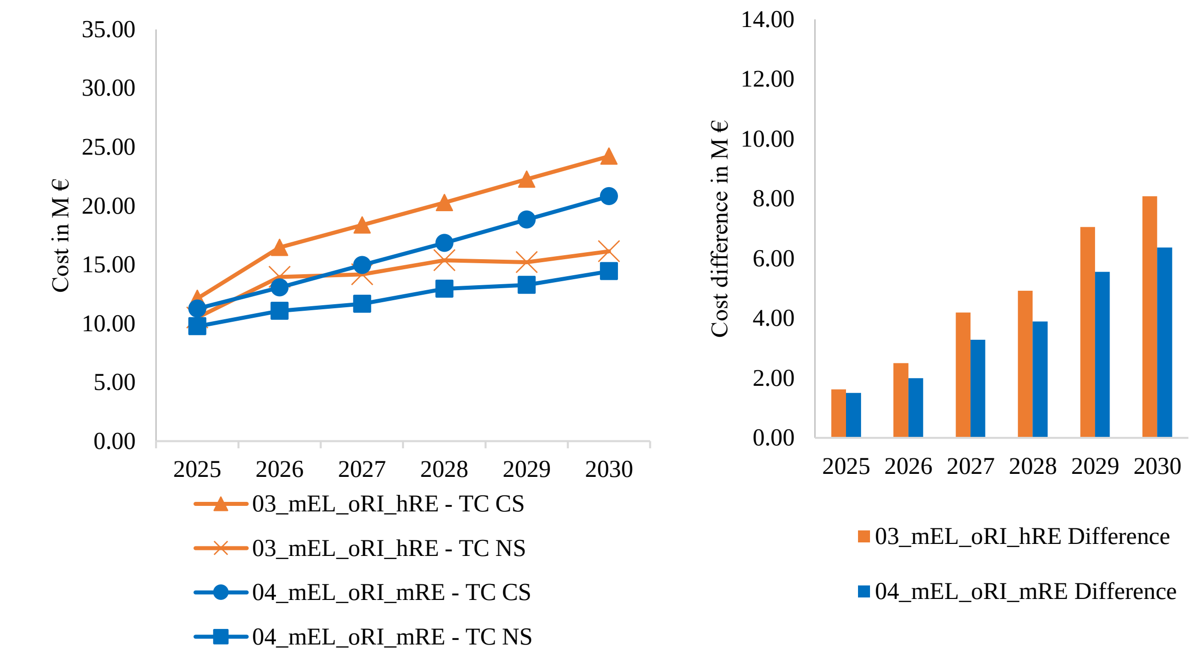

Figure 22: Scenario 03 & 04 Cost development 2025-2030

The same conclusions as before can be drawn. The higher el. prices lead to lower costs, lower cash flow, as well as the current system show a higher sensitivity to the price change in gas and electricity compared to the new system. The higher sensitivity of the current system is again visible through the divergence of the total cost development, shown in the right bar chart of Figure 22.

<u>Sensitivity</u>

In addition, the sensitivity of each system to electricity prices over the years is also analysed by comparing the costs for scenario 03 and 04 for the current and the new system. Figure 23 shows the relative cost change based on scenario 03 for the current and the new system. On the right, the relative el. price change is shown.

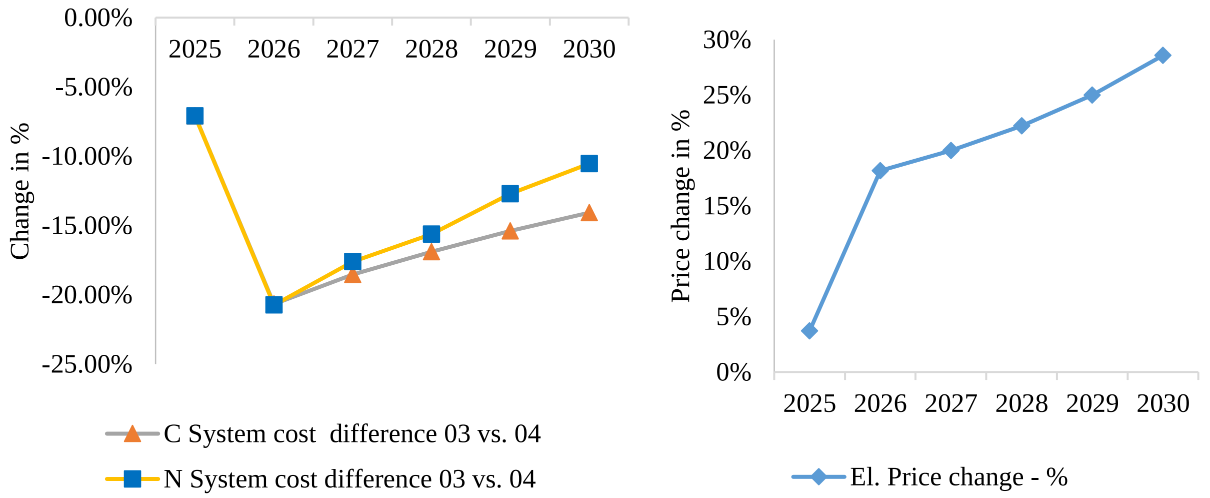

Figure 23: Cost-sensitivity of current system vs. new system - Scenario 03&04

Although the electricity price change between the two scenarios analysed (03 and 04) was the same as previously, the systems react differently. The current system reacts stronger to the electricity price change than the new system compared to the previous scenarios. This indicates that the sensitivity to electricity prices increases for the current system compared to the new system for lower gas prices. While in 2025 and 2026 the systems react similar, after the systems relative cost change diverges.

Dynamic Cash Flow

The dynamic income balance development for scenario 03 and 04 is shown in Figure 24, together with income balances from scenarios 01 and 02. The income balances from scenarios 03 and 04 are shown in yellow and blue. Here it can be seen that due to the lower cost difference between the systems, the dynamic income balance is becoming more negative. Thus, the investment costs are not recovered as fast and the income balance in 2030 is more negative. The income balance for scenario 03 is -12.56 M € and for scenario 03 -17.3 M €. This already shows that the lower gas price reduces the system performance difference and influences the cumulative dynamic income balance.

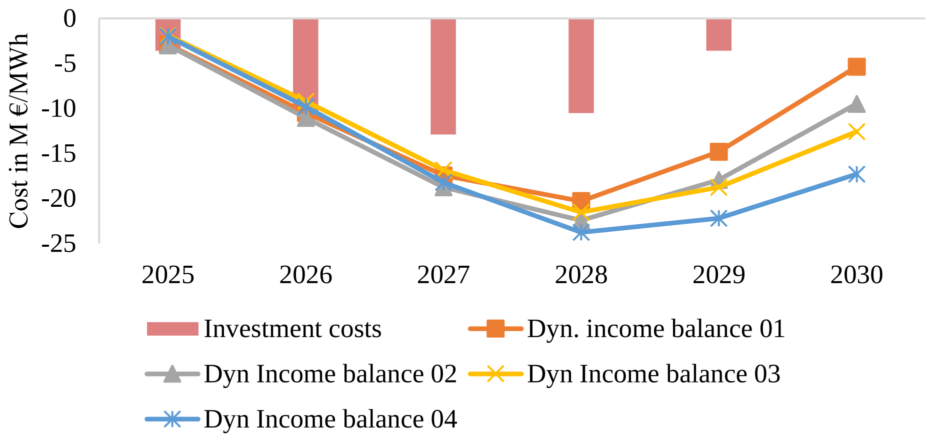

Figure 24: Dynamic income balance for scenarios 03 & 04

Scenario 05 and 06 – Development 2025 – 2030

The price development of scenarios 05 and 06 represent constant low gas price of 30 €/MWh and strong decreasing low electricity prices. El. prices range from 115/110 €/MWh to 75/50 €/MWh. The price structure is shown in Figure 25.

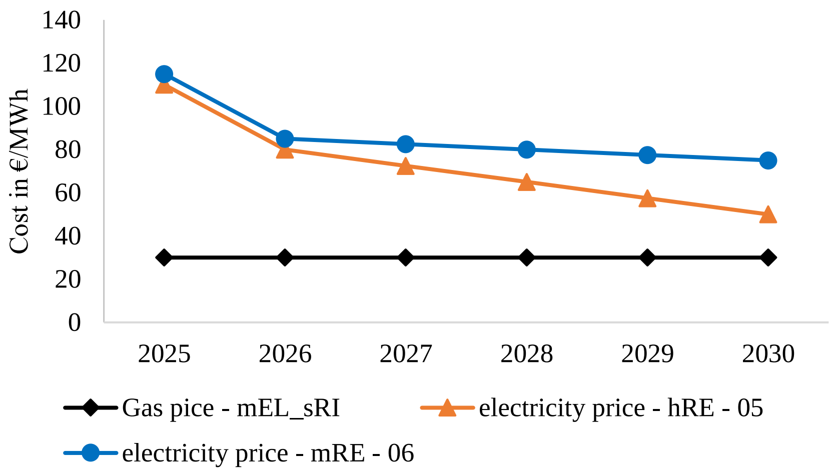

Figure 25: Price development of Scenario 05&06

Cost Development 2025-2030

With gas prices even lower and electricity prices falling quite sharply, the cost trend between the systems is beginning to converge further. In Figure 26 the cost development and cost differences are shown for scenario 05 and 06. For both scenarios and both systems the increase in costs from 2025 to 2026 is clearly visible, which is due to the sharp decrease in el. prices and thus the costs rise from one year to another. After 2026 the total cost development flattens out especially for scenario 06 for both systems.

Although there is still a cost difference between the systems, this is becoming significantly smaller over the years and the differences are becoming smaller in absolute terms. Additionally, for the year 2025 the cost difference is even negative, which means that the current system performed better compared to the new one. Furthermore, a stronger difference between the cost difference can be seen in the right bar chart between the scenarios. This shows that the higher el. prices here have a strong influence on the current systems performance. While the new systems performance does not change a lot between scenarios, the difference between the current systems is higher.

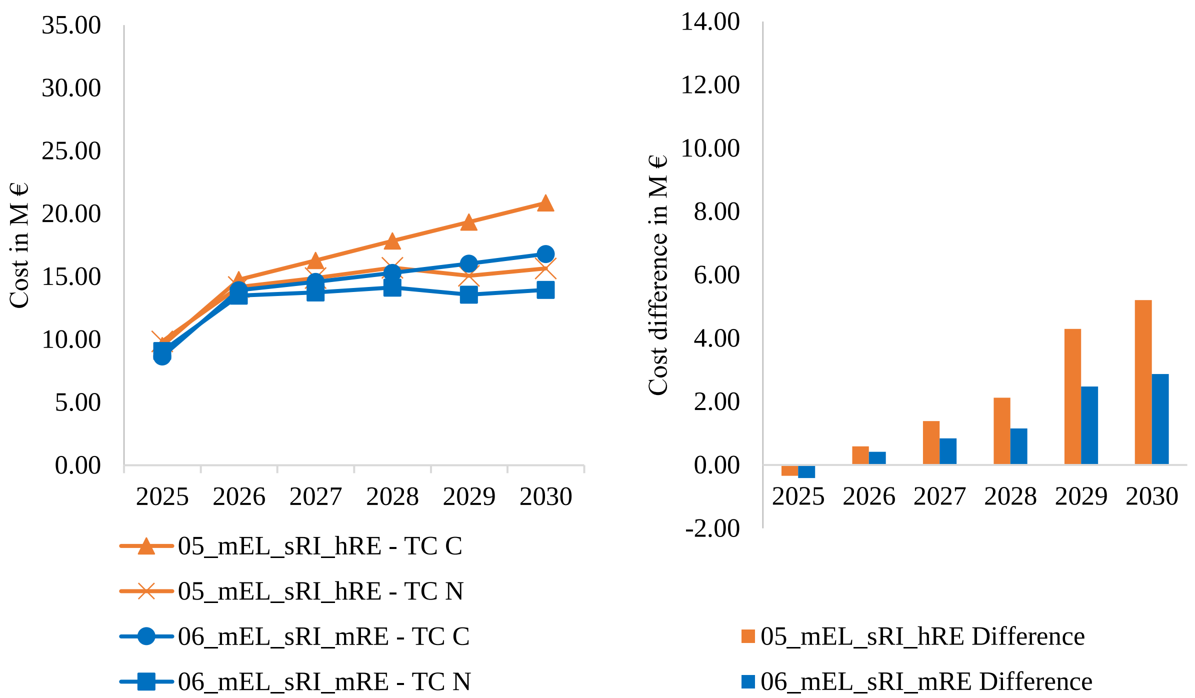

Figure 26: Scenario 05 & 06 Cost development 2025-2030

Sensitivity

In Figure 27 the sensitivity of the new and current system is shown. In 2025 and 2026 the system reacts more similarly, which then diverges until 2030, showing a similar behaviour compared to the previous scenarios. However, the deviation here is higher than before for the current system, which indicates an increased sensitivity. The electricity price change is continuously rising for these scenarios and shown again on the right side.

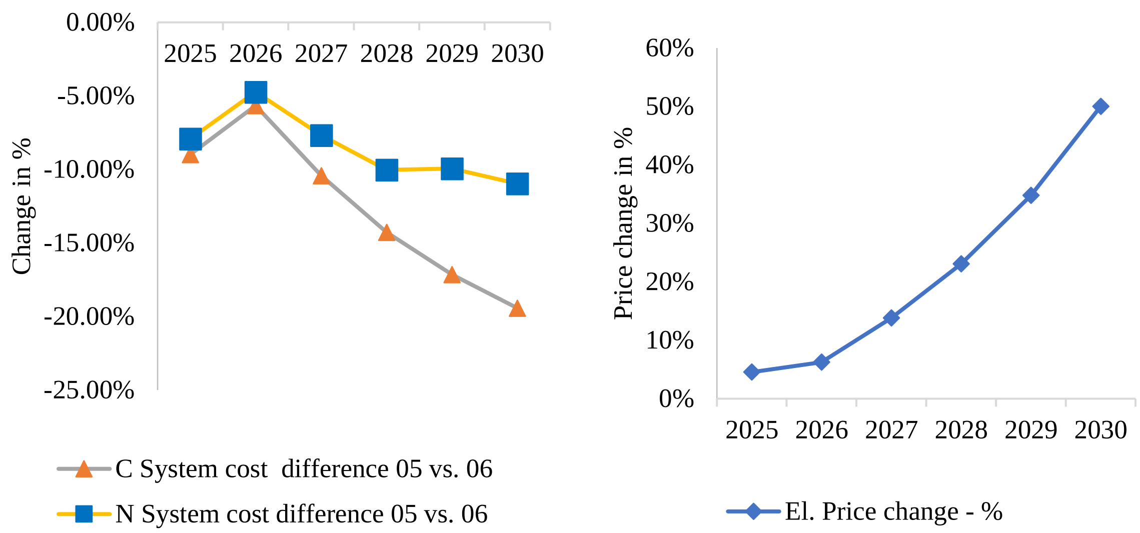

Figure 27: Cost-sensitivity of current system vs. new system - Scenario 05&06

<u>Dynamic Cash Flow</u>

The dynamic income balance of scenario 05 and 06 is added to the figure before and plotted in Figure 28. Through the further decrease in cost difference the dynamic income balance also recovers slower from the investment expenditure as seen in the figure. The dynamic income balances from scenarios 05 and 06 is shown in green and blue. The income balances in 2030 are -25.41 M € for scenario 05 and -30.18 M € for scenario 06.

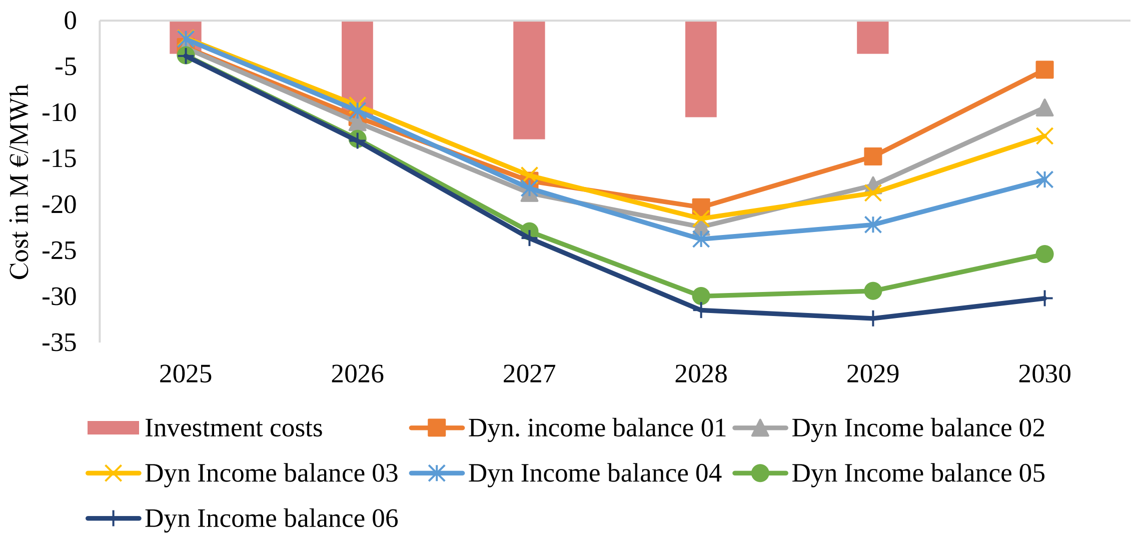

Figure 28: Dynamic income balance for scenarios 05 & 06

Scenario 07 and 08 – Development 2025 – 2030

Scenarios 07 and 08 represent the highest el. prices of all scenarios, starting with 140/145 €/MWh in 2025 and ending with 90/135 €/MWh in 2030. The gas price here is falling over time and can be categorised low with 43 €/MWh in 2025 and 22 €/MWh in 2030. The price structure is depicted in Figure 29.

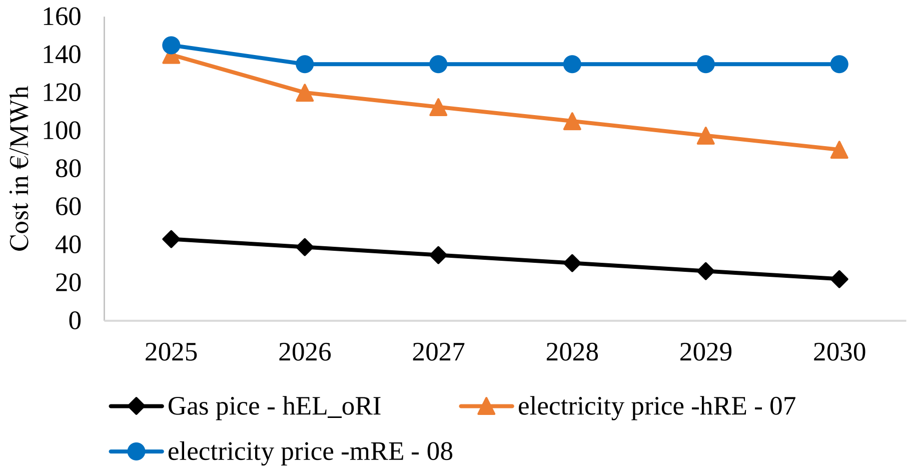

Figure 29: Price Development of Scenario 07&08

<u>Cost Development 2025-2030</u>

The cost development for the scenarios 07 and 08 are presented in Figure 30. For the underlying price structure, the systems now become very similar in terms of total costs. For scenario 07 (lower el. prices) the two systems perform almost identical with small cost advantages for the new system and no diverging behaviour that can be observed. While for scenario 07 the total cost still rise for both systems it is almost constant after 2026. For scenario 08 (higher el. prices) the cost even decreases after a peak in 2026, as well as the current system performs better than the new system, shown by the negative cost difference in the right graph. In terms of sensitivity, both systems seem to react in a similar manner to the price changes. What remains as characteristics, is that an increase in el. prices lead to lower total costs when comparing the two scenarios. The influence here is so strong that the total costs even decrease, which can be attributed to the very high el. prices for scenario 08.

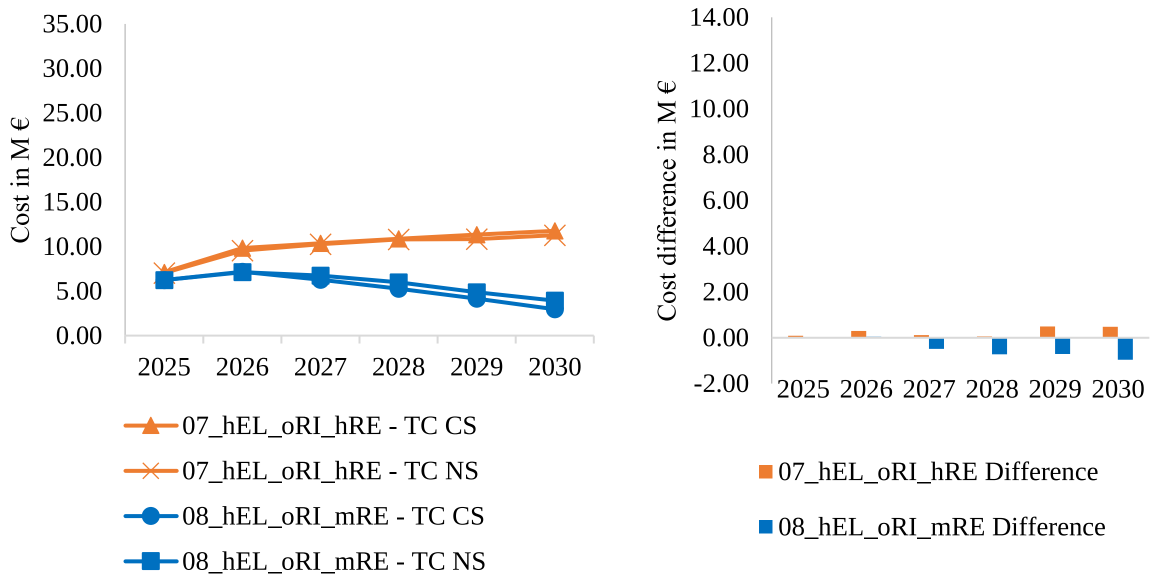

Figure 30: Scenario 07 & 08 Cost development 2025-2030

Sensitivity

For the sensitivity to el. prices for each system is shown again in Figure 31. While we have a similar el. price change progression as before the relative cost change looks different. The sensitivity of both systems converges compared to the scenarios before but are still diverging. Again in 2025 and 2026 the systems behave similar which then diverges with the current system being more sensitive and having higher cost changes. The relative price change is very high for both systems ranging from around -10% to around -70%. This can be attributed to the strong difference in el. prices between the scenarios in 2030.

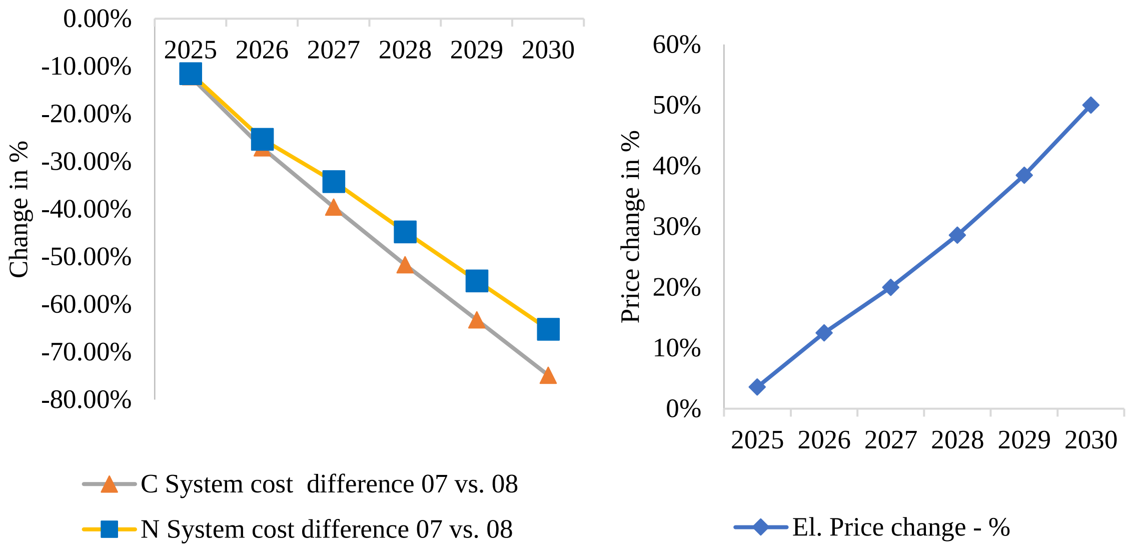

Figure 31: Cost-sensitivity of current system vs. new system - Scenario 07&08

Dynamic Cash Flow

Adding the dynamic income balances to the figure as before, shows that the income balances for the scenarios further decrease, due to the lower differences and even negative differences in total costs. Scenario 07 is shown as red line without markers, and scenario 08 is shown as grey line without markers in Figure 32. The income balances in 2030 are -34.77 M € and -38.32 M € respectively.

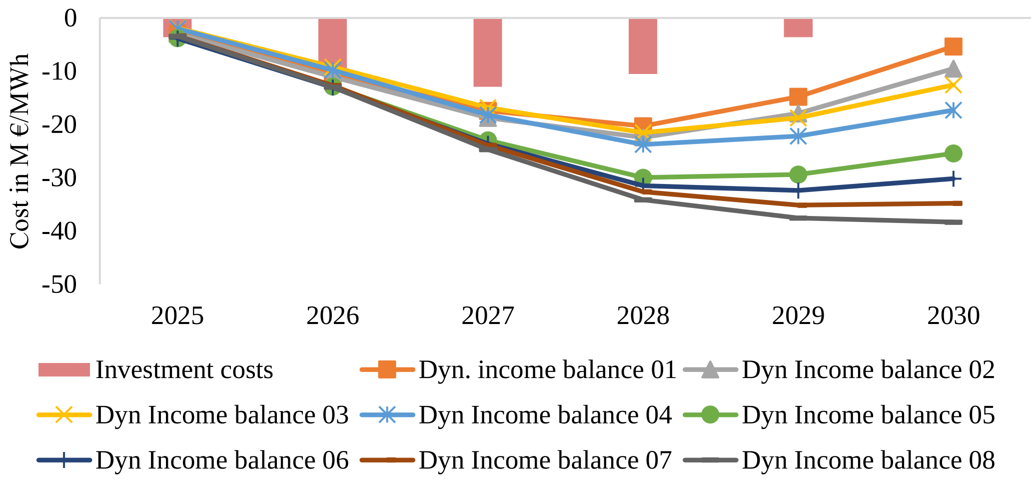

Figure 32: Dynamic income balance for scenarios 07 & 08

Scenario 09 and 10 – Development 2025 – 2030

The following scenarios have the lowest here investigated gas price and like the previous scenarios rather high el. prices. The gas price ranges from 25 €/MWh in 2025 to 18 €/MWh and the el. prices range from 135/140 €/MWh to 80/120 €/MWh for scenario 09 and 10 respectively. The price structure can be seen in Figure 33.

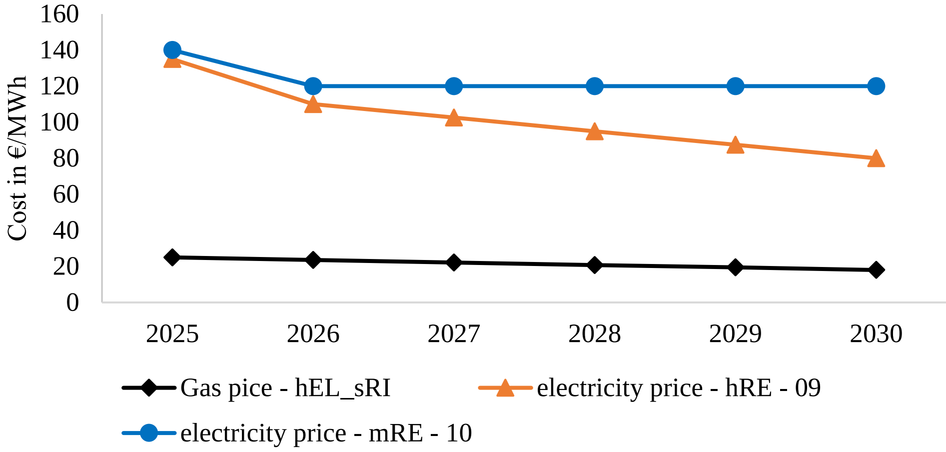

Figure 33: Price Development of Scenario 09&10

Cost Development 2025-2030

The cost structure for scenarios 09 and 10 are very similar to the previous scenarios and show that the systems have a very similar total cost development. Again, for the lower el. prices both systems total cost increase but very little and for the higher el. prices the cost even decrease after a peak in 2026. Other than before, the new system here has higher total cost throughout the years which results in a negative cost difference, except for scenario 09 (lower el. prices) in the years 2029 and 2030, where the new system is slightly more cost efficient. For scenario 10 the negative cost difference increases until 2028 and then decreases again. The cost development is shown in Figure 34. As for scenario 07 and 08 there a divergence in cost cannot be observed. The influence of increasing el. prices between scenarios applies here too, showing lower costs for higher el. prices.

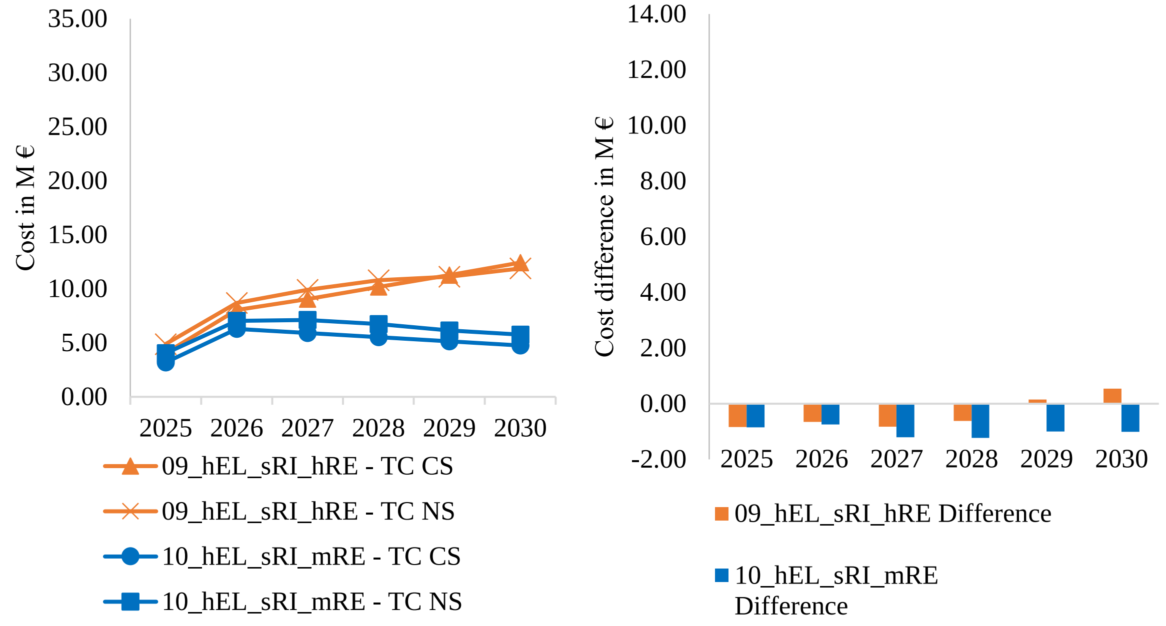

Figure 34: Scenario 09 & 10 Cost development 2025-2030

Sensitivity

The sensitivity of scenarios 09 and 10 are shown in Figure 35. The cost difference her again is higher for the current system compared to the new system. Important to note it that the difference occurs right from the beginning with the systems having a different sensitivity for all years. The el. price change is as before constantly rising.

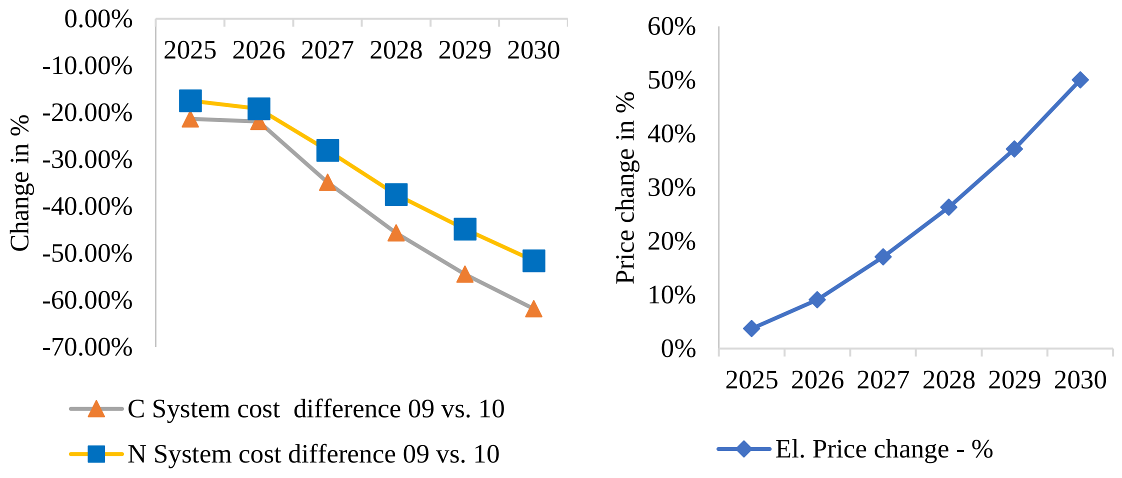

Figure 35: Cost-sensitivity of current system vs. new system - Scenario 09&10

Dynamic Cash Flow

Adding the final scenarios to the dynamic income balance shows, that scenarios 09 and 10 provide the least favourable income balances for the new system. The scenarios are depicted in Figure 36, with scenario 09 in brown with diamond marks and scenario 10 in light blue with square marks. The dynamic income balance in 2030 are -38.17 M € and -41.22 M € for scenario 09 and 10 respectively.

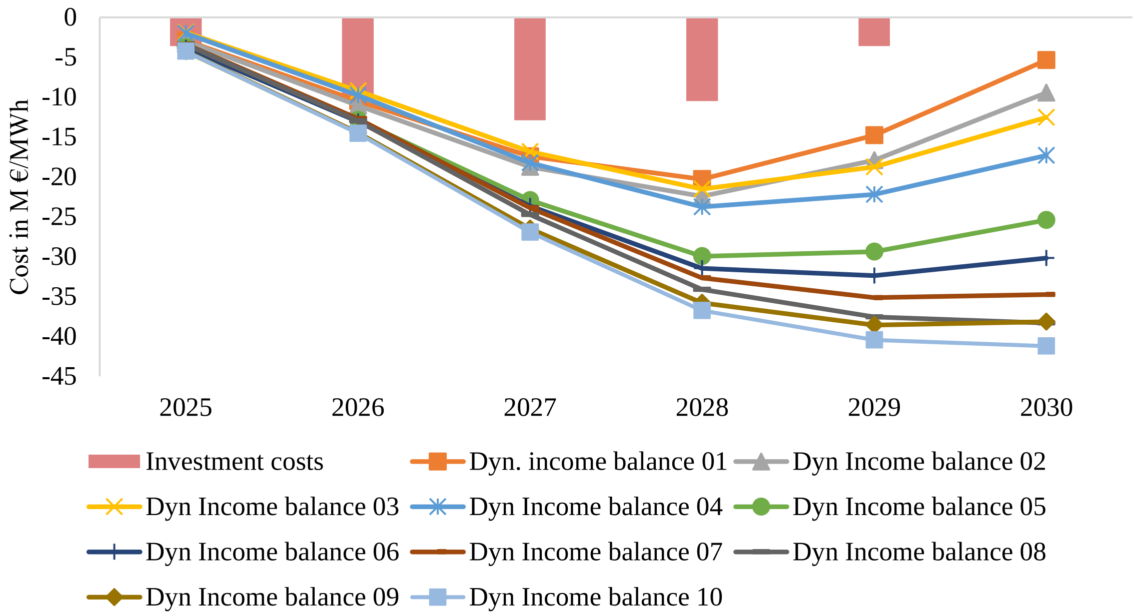

Figure 36: Dynamic income balance for scenarios 09 & 10

Scenario comparison 01 & 03 – Gas price sensitivity

Due to the same el. prices in scenario 01/02 and 03/04, the sensitivity of both systems to gas prices can additionally be investigated to show how it changes between 2025 and 2030. To show this, the relative cost change for each system for scenario 01 and 03 is compared, having scenario 01 as a base. The results are shown in Figure 37, showing the relative cost change per system in the left graph and the relative gas price change in the right graph.

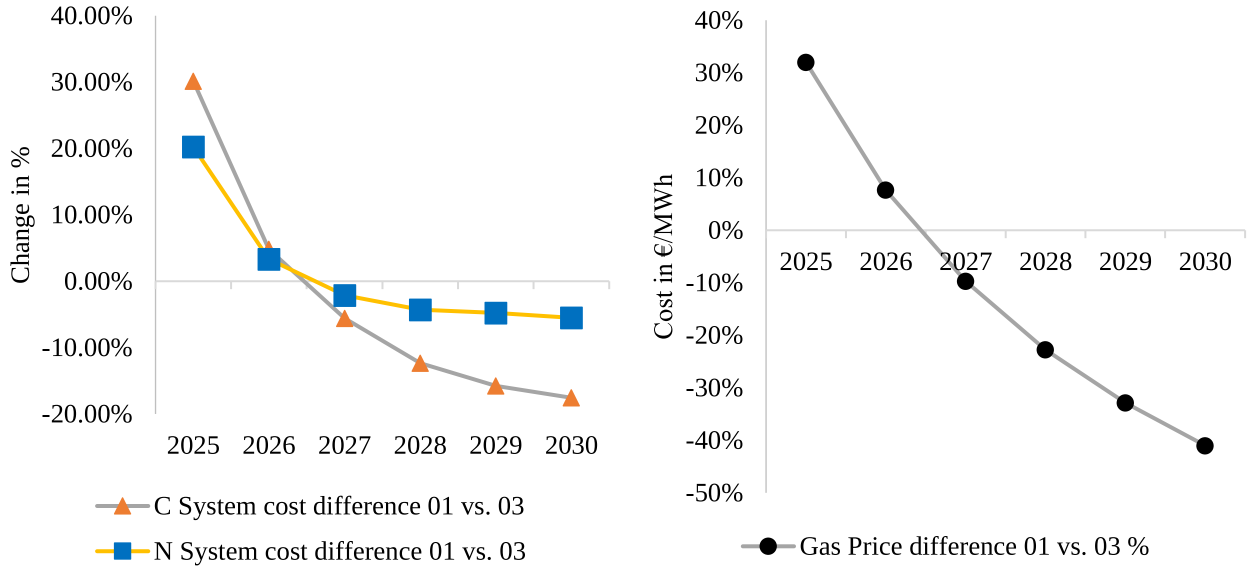

Figure 37: Gas Price Cost-sensitivity - 01&03

The diagram on the left shows that the current system reacts stronger to the gas price change than the new system, both at higher and lower gas prices. While the new system reacts quite strongly in 2025, its reactivity decreases over the years compared to the current system. The same behaviour can be observed in scenarios 02 and 04 and is therefore not shown here.

Summary

In summary, the decrease in gas price showed a continuously decrease in total costs and lead to the systems converging together in terms of cost performance. At the same time the el. price showed a crucial influence decreasing costs for higher el. prices. For the scenarios 07/08 and 09/10 it showed that the el. price can be a deciding factor in whether the new or the current system performed better in terms of costs. Generally, a higher sensitivity could be seen for the current system especially towards 2030 for both el. price and gas price. Depending on the exact prices, both systems start generally with similar sensitivities and then diverge, the new system showing less sensitivity to electricity, as well as gas prices. The dynamic income balance showed a decrease in performance for the new system with lower gas prices, having higher negative income balances in 2030.

To further analyse why the systems cost change, as just presented, the production plan is analysed in the following.

4.1.2 Production Plan 2030

This subchapter presents and analyses the production plans for the various scenarios. To analyse the production plan for the newly planned system, the year 2030 is examined in conjunction with the prices prevailing in 2030. This allows the correlation between gas/electricity prices and the production plan to be clearly shown. The prices for gas and electricity for the year 2030 are shown in Figure 38. From scenarios 01 and 02 to scenarios 09 and 10, the figure shows a continuous decline in gas prices from left to right. For electricity prices, the trend initially remains constant for scenarios 01 to 04, is lower for scenarios 05 and 06 and then rises, with scenarios 07 and 08 showing the highest electricity prices, followed by 09 and 10 with slightly lower electricity prices. The here shown prices are the annual average prices.

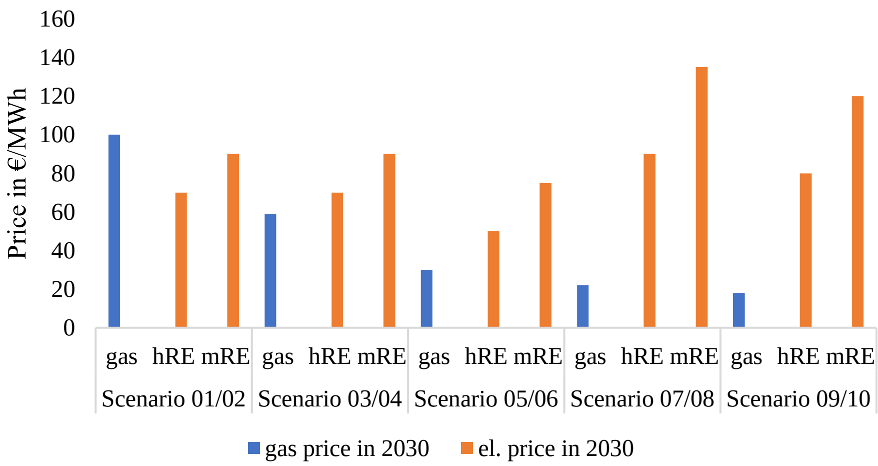

Figure 38: Price structure in 2030

Based on this price structure the production plans are analysed to identify the influences of both the gas and el. price. The production plans are presented as a bar charts showing the share of production by units and fuel types. It needs to be mentioned, that only the biomethane units and gas CHP units provide both heat and electricity, while the remaining units only provide heat.

The use of the heat from the industrial excess heat is not discussed explicitly since it is set in the software so all the heat available is used, and hence does not change.

Production Plan 2030 - Scenario 01 and 02

The production plan for scenario 01 and 02 is shown in Figure 39 together with the current systems optimal production plan in 2030. The current systems production plans are shown on the left and the new systems production plan on the right. The figure shows that the new system avoids using natural gas almost completely in 2030, only providing 3% (gas CHP + gas boilers) of the total energy through natural gas for scenario 01 and 02. Furthermore, comparing between the scenarios shows that the higher el. price for scenario 02 leads to an increased use of the CHP plants utilising biomethane and reducing the use of non-electricity producing units, i.e. the woodchips thermal power plants, solar thermal power, and the heat pump. The influence of the el. prices between scenario 01 and 02, can also be seen on the current system, where EO3 opts for a higher use of boilers for the lower el. prices.

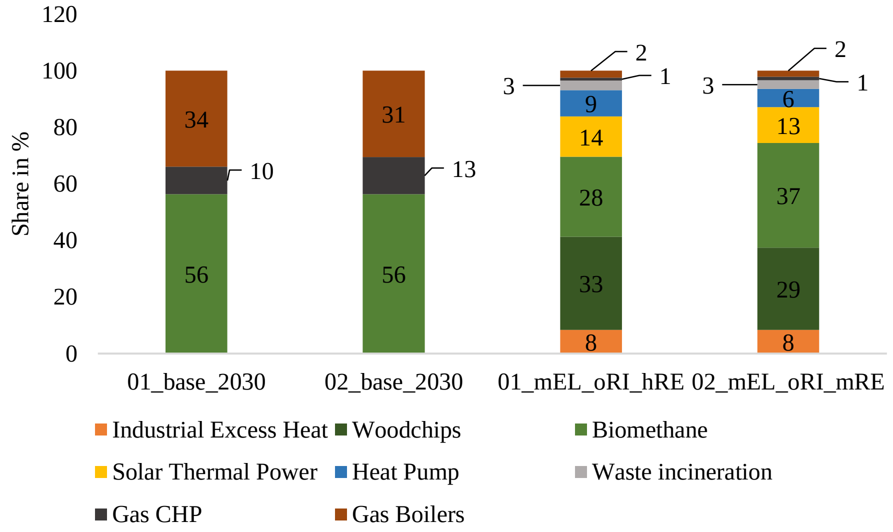

Figure 39: Production plan 2030 – Scenario 01 and 02

Production Plan 2030 Scenario 03 and 04

Investigating the production plan of scenario 03 and 04 only shows minor changes compared to the previous scenarios. Interesting to compare is the scenario 01 and 03 since the same el. price is used. The main change here is that the use of natural gas was increased and the use of biomethane was reduced, the remaining energy sources changed little, to not at all. Gas CHP changed from one to five percent and gas boilers from two to three percent. The use of biomethane was reduced from 28 % to 26 %. Comparing scenario 02 and 04 shows the same development. An increase in the use of gas and decrease in the use of biomethane mainly. Comparing scenarios 03 and 04, shows the same development as for scenario 01 and 02. Due to the higher el. prices the use of units providing electricity was increased, that is the biomethane CHPs and natural gas CHPs. The use of other technology, i.e. woodchips, solar thermal power, and the heat pumps, have been reduced.

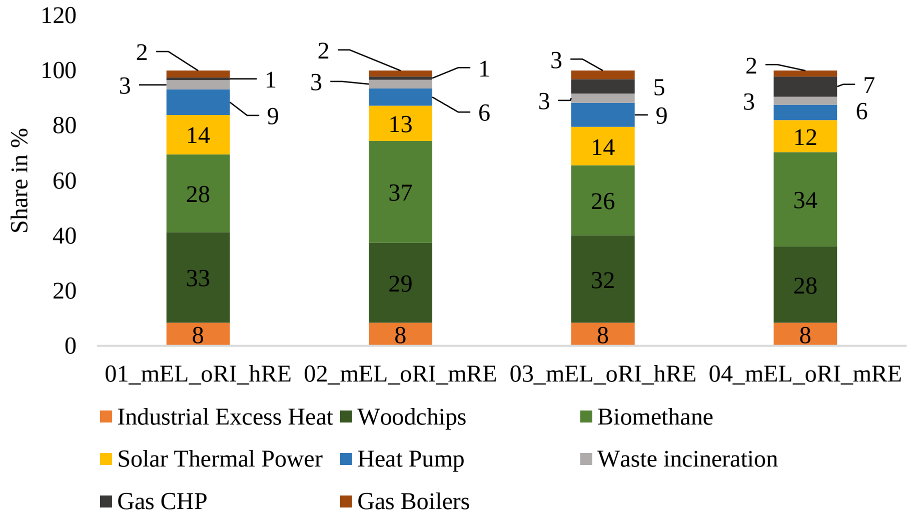

Figure 40: Production plan 2030 - share of energy sources – Scenario 01-04

Production Plan 2030 Scenario 05 and 06

Comparing the production plan of scenario 05 and 06 to the scenarios 03 and 04, shows a further increase in the use of natural gas due to the lower gas price. Furthermore, the very low el. price of scenario 05 in 2030 has further influence on the system. The use of biomethane is strongly reduced, the use of woodchips is increased, and the use of the heat pump is increased. This contrasts with scenario 06 where the el. price in 2030 is comparatively high which has the opposite effect, increasing the use of biomethane CHPs again and decreasing the use of the heat pump.

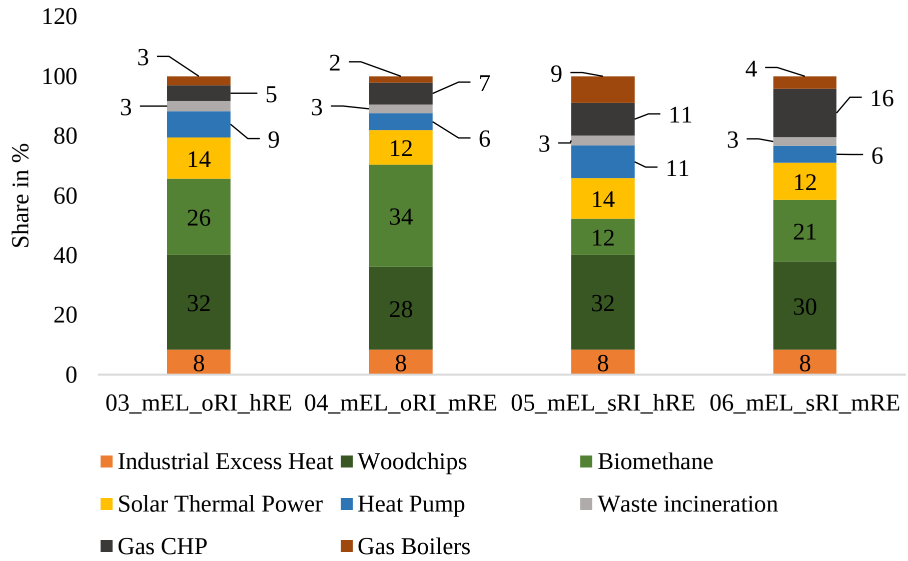

Figure 41: Production plan 2030 - share of energy sources – Scenario 04-06

Production Plan 2030 Scenario 07 and 08

Through a further decrease in gas price in 2030 and increase in el. price in scenarios 07 and 08 the production plan now changes noticeably compared to the previous scenarios (Figure 42). There is a further increase in the use of natural gas, and for the first time, solar thermal energy is also significantly reduced, although the heat from it does not cause any additional costs per MWh. As before, the higher electricity prices in Scenario 08 lead to increased use in the electricity-producing units compared to Scenario 07. Compared to the previous scenarios the use of woodchips, solar thermal power and heat pump is dramatically reduced, and the main energy source used is natural gas and biomethane. This especially applies to scenario 08, where woodchips are down to 9%, solar thermal to 3% and the HP to 1%.

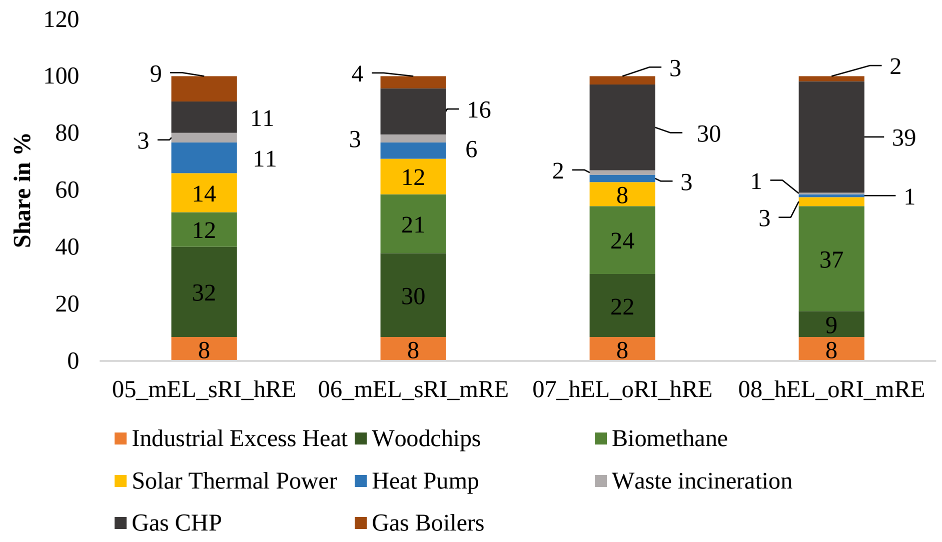

Figure 42: Production plan 2030 - share of energy sources – Scenario 05-08

<u>Production Plan 2030 Scenario 09 and 10</u>

For the even lower gas price, the production plan continues to develop to higher use of natural gas. The production plan is very similar to the scenarios presented above, with slightly higher shares of natural gas for both scenarios when comparing the low (07 and 09) and high (08 and 10) electricity prices. The share of solar thermal energy increases by a further 1% with similar price developments (07 and 09 + 08 and 10) (Figure 43).

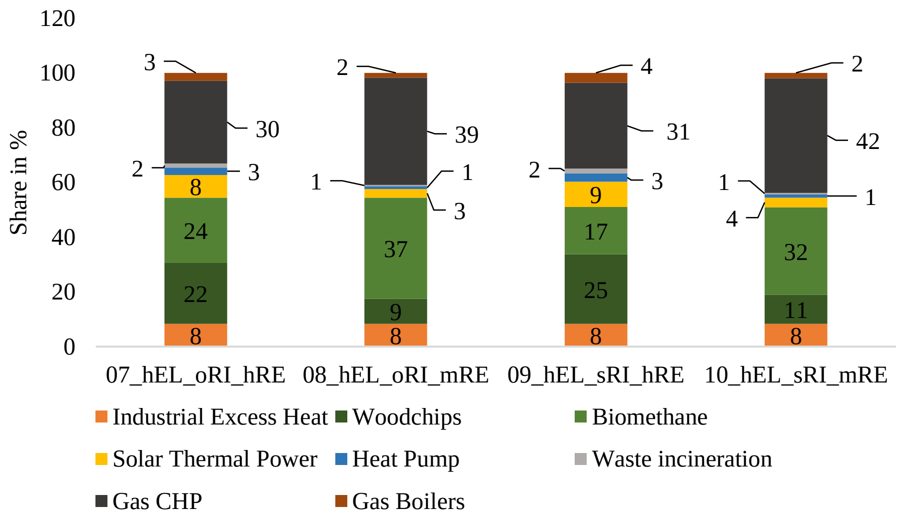

Figure 43: Production plan 2030 - share of energy sources – Scenario 07-10

Production Plan – RES vs. Fossil fuels

If we look at the production plan in terms of the ratio between renewable energies and fossil fuels (RES as defined in the Heat Planning Act), we can see how different price developments can influence this ratio with regard to the underlying goal of cost efficiency. The shares of RES compared to fossil fuels are shown in Figure 44 for all scenarios. The current share of the system in 2023 is shown on the left-hand side, followed by all scenarios from 01 to 10. It can be seen from the figure that the scenarios are very different, from scenario 01 with a 93 % share of renewable energy to scenario 10 with a 56 % share of renewable energy. The scenarios in between show different fluctuations between these numbers and follow the same trend as previously seen. The use of natural gas increases as natural gas prices falls. The influence of electricity prices is not as clear between the scenarios with the same gas price. The electricity price changes for the 07/08 and 09/10 scenarios further increase the use of fossil fuels, while the ratio does not change in the other scenarios.

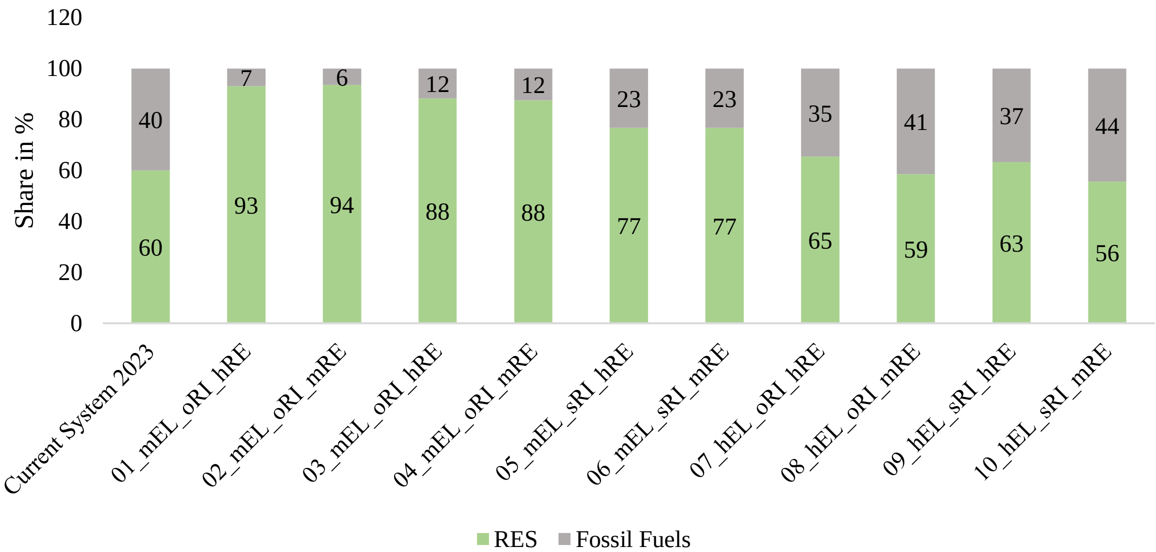

Figure 44: RES and Fossil Fuel share for Scenarios 01-10

Used Solar Thermal Power and Heat Pump Potential

Zooming in on the potentials used from the HP and the solar thermal power shows, that there is still unused potential for both implemented technology for the scenario 01, where the share of RES is very high. Figure 45 shows the HP potential for 2030 for the price structure for scenario 01. The black line indicates the available power based on the assumption mentioned in Chapter 3.1.2, and the blue area the used power during the year.

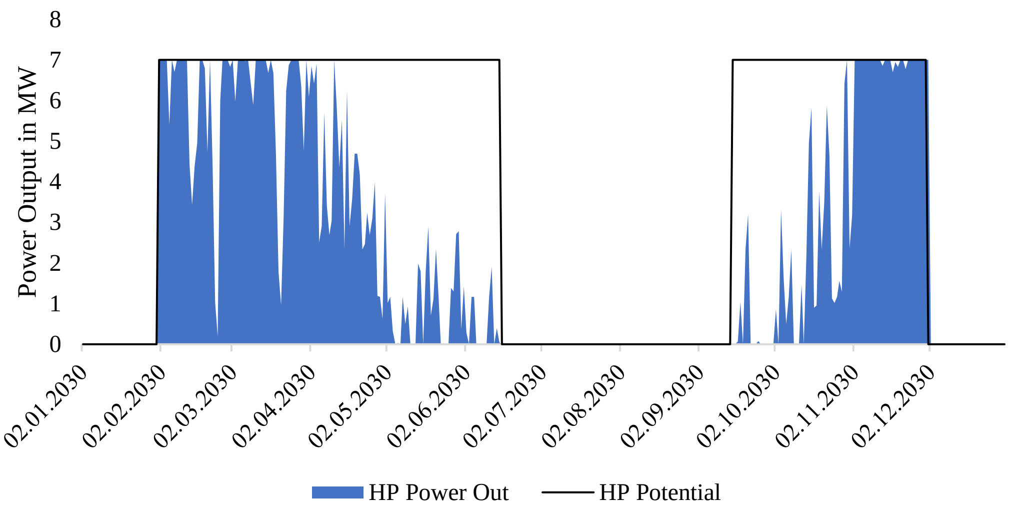

Figure 45: Heat Pump Potential - used vs available

The same applies to the solar thermal power. In Figure 46 the available and used power, based on the solar radiation and temperature is shown. In summer, and some peaks in fall, where production is high, the potential of the available power is not used entirely, due to demand being too low or other units being more cost efficient.

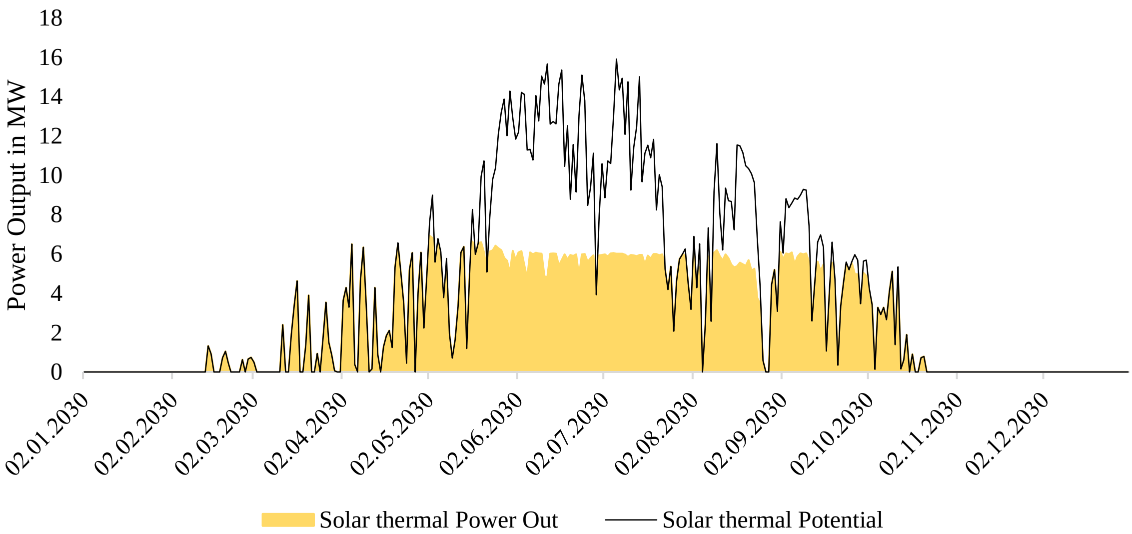

Figure 46: Solar Thermal Potential - use vs. availability

Summary

In conclusion, the gas price has a major influence on the use of natural gas which can be seen throughout the scenarios. The el. price especially influences the use of electricity producing units and displaces the non-electricity producing units for higher el. prices. Combining lower gas prices with high electricity prices leads to an increased use of the natural gas and biomethane units. Vice versa for the higher gas prices and generally lower el. prices, EO3 opts for the new technology which is independent of both the gas and el. price. If the results shown here are combined with the cost development between 2025 and 2030, it becomes clear why the scenarios with lower gas prices have similar cost structures for both systems. EO3 opts for more natural gas and biomethane, and the production plan of the new system is more similar to the production plan of the current system. The same trend can be seen when analysing the share of renewables versus fossil fuels for each scenario. In addition, the potentials of HP and solar thermal were analysed, showing that the energy potentials are not fully tapped. However, it is not being utilised for economic reasons and due to a mismatch between production and demand.

In order to further investigate how the different price structures and production plans will influence the profitability of the new system in 2030, the economic parameters are presented and analysed below.

4.1.3 Economic Parameters

In this sub-chapter the economic parameters for the scenarios are presented in detail. The total cost and cost difference of 2030 are shown here due to its projection into the future and significance for the here evaluated parameters. Due to the focus on 2030, it is once again referred to the prices in 2030, which were presented in Figure 38, showing the fall in gas price and increase in el. price ranging from scenario 01 to scenario 10.

Scenario 01 and 02

Scenarios 01 and 02 are the most economic beneficial scenarios compared to the current system. They have the highest cash flows in 2030, the lowest payback times, and have the highest NPVs. At the same time, they have the highest total costs in 2030 and highest LCOE, compared to the other scenarios for both systems. The values for both scenarios can be seen in Table 8.

In 2030 for scenario 01 the cash flow results from a 42 % total cost reduction between the systems and for scenario 02 the cash flow results from a 41 % total cost reduction. This leads to a cash flow of 12.29 M € for scenario 01 and 11.01 M € for scenario 02. For the underlying prices in 2030 the new system has a large cost advantage for both scenarios. The LCOE for the new system in scenario 01 is 36 €/MWh lower, compared to the current system over the lifetime of 25 years. The payback time is 7 years and the NPV is 122 M. €. Scenario 02 has slightly lower values and the LCOE for the new system is 31 €/MWh lower, the payback time is 8 years and the NPV is reduced to 105 M €.

Table 8: Economic parameters Scenario 01&02

Abbreviation	System	Total Costs (M. €) 2030	Cashflow in 2030 (M€)	LCOE €/MWh	Dyn. Payback	NPV in M €	Gas price
01_mEL_oRI_hRE	Old system	29.37	12.29	122.78	7	122.66	mEL_oRI_high
	New System	17.08		86.45			
02_mEL_oRI_mRE	Old system	26.57	11.01	109.74	8	105.02	
	New System	15.56		78.63			

The change in el. price here leads to noticeable differences in total costs, which then influences the cash flow, the LCOE, the payback time and NPVs. The higher total costs lead to higher LCOE, and higher cash flows to higher NPVs, as well as it reduces the payback time.

Scenario 03 & 04

By further reducing the gas price, a decrease in total costs and cash flow can be observed for the following scenarios, as shown before in the 2025-2030 analysis. This influences the economic parameters, leading to a decrease in LCOE and NPV, and an increase in payback time. The values are shown in Table 9. The cash flows here result from a 33 % and 31 % reduction in total costs for scenario 03 and 04 respectively. The LCOE is reduced since the total cost decrease for both systems and scenarios. The differences between the scenarios for the LCOE also decrease compared to the previous scenarios. For scenario 03 the difference reduces to 21 €/MWh and for scenario 04 to 14.34 €/MWh. Payback times are increased to 9 and 10 years, while NPVs decreases to 71 M € and 48 M €.

Table 9: Economic parameters Scenario 03&04

Abbreviation	System	Total costs (M. €) in 2030	Cost difference	LCOE €/MWh	Payback dynamic	NPV in M. €	Gas price
03_mEL_oRI_hRE	Old system	24.21	8.08	104.60	9	71.15	mEL_oRI
	New System	16.14		83.52			
04_mEL_oRI_mRE	Old system	20.81	6.37	89.38	10	48.41	
	New System	14.44		75.04			

Also here, the decreased gas price leads to lower costs and the systems performances converges in terms of total costs (comparing scenario 01/02 and 03/04). Also, the higher el. prices led to the systems converge together (comparing scenario 03 and 04). However, the new system still performs better compared to the current system.

Scenario 05 & 06

For the underlying prices in scenario 05 and 06 the new system continuous to perform less beneficial compared to the current system. The total costs between systems reduce to 25 % and 13 % difference, leading to cash flows of 5.2 M € and 2.87 M € for scenarios 05 and 06 respectively. The difference in LCOE reduces to 8 €/MWh for scenario 05 and becomes negative for scenario 06, the new system being 0.47 €/MWh more expensive over the course of the lifetime. The payback time increases to 14 years for scenario 05 and is not reached within 25 years for scenario 06. The NPV becomes 27.75 M € and -1.62 M €.

Table 10: Economic parameters Scenario 05&06

Abbreviation	System	Total costs (M. €) in 2030	Cost difference	LCOE €/MWh	Payback dynamic	NPV in M €	Gas price
05_mEL_sRI_hRE	Old system	20.86	5.20	90.25	14	27.75	mEL_sRI
	New System	15.65		82.03			
06_mEL_sRI_mRE	Old system	16.80	2.87	74.33	Not reached	-1.61	
	New System	13.94		74.80			

While the new system is still advantageous in scenario 05, scenario 06 shows that the new system no longer outperforms the current system. While there is still an absolute cost advantage for scenario 06 in 2030, the discounted cash flow is not sufficient to cover the investment costs.

Scenario 07 & 08

In Scenarios 07 and 08 the systems become very similar in terms of total cost in 2030. For Scenario 07 the total costs are slightly lower for the new system and vice versa for scenario 08. The LCOE are higher for the new systems for both scenarios, being 9 €/MWh and 14 €/MWh in difference for scenario 07 and 08 respectively. The payback times are not reached for both scenarios, as well as both NPVs are negative. The values are shown in Table 11.

Table 11: Economic parameters Scenario 07&08

Abbreviation	System	Total costs (M. €) in 2030	Cost difference	LCOE €/MWh	Payback dynamic	NPV in M €	Gas price
07_hEL_oRI_hRE	Old system	11.76	0.48	52.48	Not reached	-31.29	hEL-oRI
	New System	11.28		61.75			
08_hEL_oRI_mRE	Old system	2.96	-0.97	17.82	Not reached	-50.13	
	New System	3.93		32.67			

Scenario 09 & 10

Scenarios 09 and 10 perform very similar to the previous scenarios. Total cost slightly increases for both scenarios and systems, but the cash flow remain similar, being 0.54 M € cost difference and -1.01 M € for scenario 09 and 10 respectively. The LCOE are again higher for the new systems being 9 €/MWh and 16 €/MWh higher for scenarios 09 and 10 respectively. Also, the payback times are not reached and the NPVs are negative.

Table 12: Economic parameters Scenario 09&10

Abbreviation	System	Total costs (M. €) in 2030	Cost difference	LCOE €/MWh	Payback dynamic	NPV in M €	Gas price
09_hEL_sRI_hRE	Old system	12.42	0.54	47.66	Not reached	-34.22	hEL-sRI
	New System	11.88		56.82			
10_hEL_sRI_mRE	Old system	4.74	-1.01	22.82	Not reached	-53.63	
	New System	5.76		38.70			

Dynamic Income Balance

In the following the projection of the accumulated cash flows in 2030 and hence the dynamic income balances (dyn. IB) of the presented scenarios are shown. The presentation of the economic parameters showed that from scenario 01 to scenario 10 the cash flows decreased continuously between the systems. Figure 47 shows dyn. IB for all scenarios, which include the investment expenditures of the new technology. On the y-axis the dyn. IB is shown and on the x-axis the years until 2050. It is shown that the high cash flows lead to the highest income balance curves for scenarios 01 and 02. The curves continue to become less and less beneficial for the new systems throughout the scenarios. Scenario 06 (green line with circles as markers) is the first scenario where the dynamic income balance does not reach zero and hence the NPV becomes negative. The following scenarios are all performing worse. This shows that the discounted cash flows between the systems are not sufficient to recover the investment expenditures.

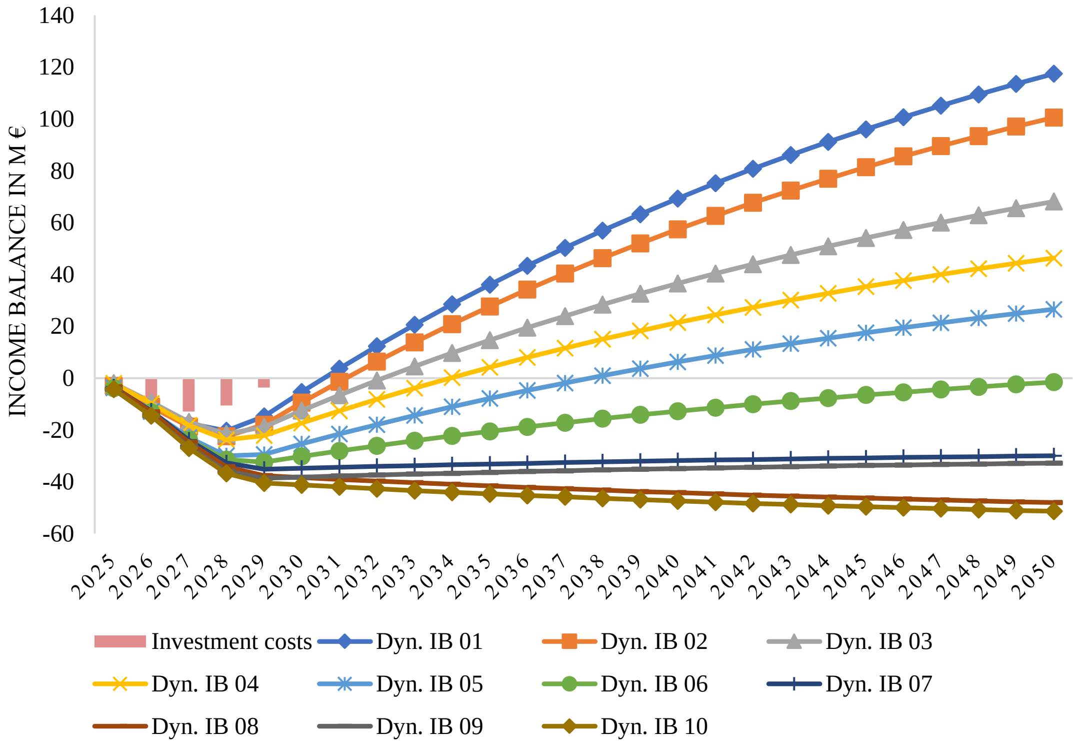

Figure 47: Dynamic Income Balance 2050 - Scenario 01 to 10

Summary

Overall, the presentation of the economic parameters showed that the performance of the new system decreases with the fall in the price of gas. In addition, the increased electricity prices also supported the performance of the current system. While the total costs for both systems decreased during the scenarios, the cash flow between the systems also decreased. As a result, the economic parameters were less favourable for the new system, while the total costs of the systems converged. The LCOE was lower for the new system compared to the current with higher gas prices, and with decreasing gas prices both systems converged until scenario 06. In the following scenarios, the LCOE of the new system became higher compared to the current system. The payback periods decreased with the decline in cash flow and were not reached before 2050 for scenarios 06 to 10. The same applies to the NPV, which showed negative values for scenarios 06 to 10. The influence of the reduced cash flow was visualised with the dyn. IB which shows the development of the payback period and the NPV. This analysis showed how different price structures can influence the economic performance of the two systems and identified critical price thresholds.

4.2 Sensitivity Analysis

The sensitivity analysis was conducted to investigate how sensitive the new system is to key input parameters. The key input parameters investigated are the prices for the main fuel types, namely biomethane, woodchips, gas, electricity, as well as the price for the industrial excess heat and waste incineration. Additionally, the DH load sensitivity is also investigated. For each parameter the input parameters are changed by -20 %, -10 %, +10 %, and +20 % to investigate the influence on the total costs of the system and identify the most critical input parameters.

Scenario 04 was chosen as the basis for adjusting the input parameters because it represents a moderate example of prices, costs and production schedule and is not one of the extreme scenarios. It was also chosen because it reflects a scenario in which the new system is favourable and includes a moderate proportion of new units in the production plan, so that the response of the new system that includes these units can be observed.

In Table 13 the results of the sensitivity study are shown. The different changes in input parameters are shown on the left of each table with the relative change in total costs on the right. Biomethane is shortened with “Biom”, Woodchips with “Wood”, electricity prices with “EP”, gas prices with “GP”, the DH load with “DH”, the industrial excess heat with “IEH”, and the waste incineration with “waste”. The data has a colour code to easier see the changes in total costs. Increases in costs are marked yellow when being close to zero, orange and red for small to strong increase in costs and light green to dark green for small to strong decrease in costs. The data shows that price fluctuations for woodchips, waste incineration and industrial excess heat have a minimal impact on the total costs of the system. The gas price then proves to be a more influential factor with fluctuations of between +2.9 % and -4.2 % of the total costs. The changes in the DH load have greater influence on the total costs, ranging between +12.6 % and -8 %. Electricity prices represent the second largest sensitivity, with changes ranging from -13.8 % to +10.6 % of total costs resulting from fluctuations in electricity prices. Biomethane proves to be the most influential input parameter, with fluctuations in total costs ranging from an increase of +13.2 % to a decrease of -21.3 %.

Linking these results to the production plan of scenario 04 (Figure 48) can explain why the system is most sensitive to biomethane and electricity. Both input parameters influence a big share of units involved in the production plan and hence change the total cost significantly. Biomethane, makes up 35% of the production plan of scenario 04. Electricity also involves the natural gas CHP additionally to the biomethane CHPs having influence of 41% of the production plan. The DH load also influence the complete system and thus has a higher influence which the system reacts more sensitive too. The same pattern can then be seen for the gas price influence since it makes 9% of the total production plan and is thus less sensitive to it, while still having a noticeable influence on the total costs. Surprising is that the change in woodchips price does not have a significant influence although woodchips make 28% of the production plan. This can be attributed to the small absolute price of 5 €/MWh, and hence the absolute change of the price is neither significant. This shows that the start price of the fuel has significant influence on the sensitivity too. In contrast industrial excess heat and the waste incineration only make small portions of the production plan and hence has less influence on the total costs.

Table 13: Sensitivity Analysis Results

Scenario Name	Change in %	Scenario Name	Change in %
01_Biom_+10	7.4%	05_DH_+10	5.6%
01_Biom_+20	13.2%	05_DH_+20	12.4%
01_Biom_-10	-9.6%	05_DH_-10	-4.5%
01_Biom_-20	-21.3%	05_DH_-20	-8.0%
02_Wood_+10	0.1%	06_Dairy_+10	0.2%
02_Wood_+20	0.5%	06_Dairy_+20	0.5%
02_Wood_-10	-0.3%	06_Dairy_-10	-0.2%
02_Wood_-20	-0.5%	06_Dairy_-20	-0.5%
03_EP_+10	-6.5%	07_Waste_+10	0.1%
03_EP_+20	-13.8%	07_Waste_+20	0.1%
03_EP_-10	5.8%	07_Waste_-10	-0.1%
03_EP_+20	10.6%	07_Waste_-20	-0.1%
04_GP_+10	1.7%		
04_GP_+20	2.9%		
04_GP_-10	-1.9%		
04_GP_+20	-4.2%		

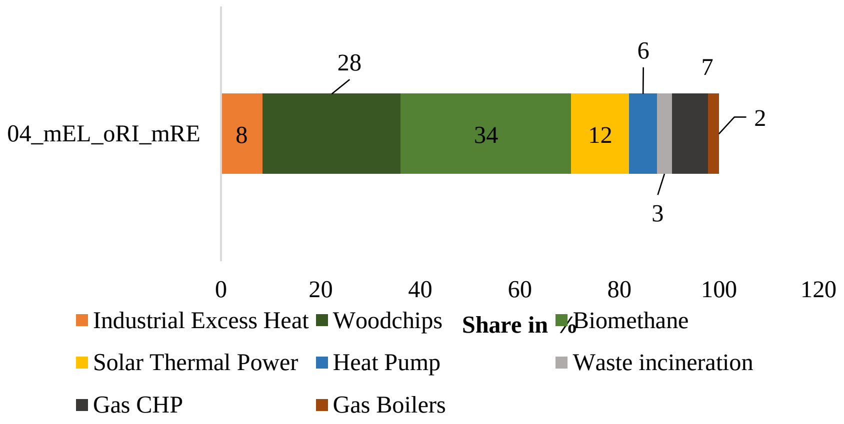

Figure 48: Production Plan Scenario 04

5 Discussion

In the following section the before presented results are discussed. The research problem and major findings are first reiterated and then followed by a discussion for each major finding.

The research problem posed in this work was to investigate the integration of renewable energy into district heating systems with the objective to understand the influence of different input factors. The main objective was to assess how the implementation of renewable energy in a district heating system is affected by different pricing scenarios, focussing on the cost structure, production planning and the share of renewable energy while maintaining cost efficiency. In addition, this work aimed to analyse the sensitivity and resilience of the new system in relation to key input parameters. The analysis provided several important findings. In particular, five of the ten scenarios analysed for the new system were found to be economically viable compared to the current system, showing its potential for cost efficiency under specific conditions. In particular, the new system showed economic advantages in scenarios with higher gas prices and lower electricity prices, while its advantage decreased with low gas prices and high electricity prices. In addition, this work found that the share of RES compared to fossil fuels varies greatly based on the pricing scenarios, ranging from 93% to 56% RES share. All values are within the legal limits set for 2030 by the German government. Delving deeper showed, the optimal production plan showed significant fluctuations under different price scenarios. However, despite the high share of renewable energy, the full potential of the planned solar thermal and heat pump systems was not utilised completely. Insights into the influence of electricity and gas prices revealed different patterns, showing how both systems react to price changes, in relation to each other. Furthermore, the specific influence of other input parameters for the new system could be investigated. Overall, this work showed the potential economic performance of the new system and how the new system reacts do different input prices in comparison with the current system. It showed the complex dynamics when integrating renewables into DH systems.

A major discussion point for this work is how the analysis for the economic evaluation is conducted and which limitations apply to it. As mentioned, five of ten scenarios are evaluated as economically viable, and the others are deemed as economically unviable. In the economic analysis, the new system is compared with the current system with a theoretical cash flow based on the total cost differences between the systems for each year. This limits the informative value of the results. The analysis gives only credit to the new system, if it has significant lower costs compared to the current system leading to a “cash flow” that recovers the investment expenditures on a discounted level. For the scenarios when the system costs are comparably equal, the economic analysis concludes that the new system is not economically viable. Nevertheless, with the exception of two scenarios, the new system still performs better in terms of total costs, a factor that is not fully taken into account in this analysis.

Another point of discussion for the economic analysis is that there are no investment costs considered for the current system, which would inevitable be necessary for the current system too, especially when investigating the economic performance until 2050. This would influence the LCOE of the current system significantly.

While it cannot be evaluated which scenario is most likely, the CO_2 price will most likely increase significantly in the years until 2050 leading to additional costs of the current system, which would deem the low gas price scenarios as rather unrealistic [73]. It needs to be mentioned that CO_2 prices are not considered in this analysis could be investigate in future works.

Additionally, it must be added to the economic analysis, that the implementation of the new technology is in principle independent of the economic outcome. The law is enforcing this development with the higher goal of climate protection. Nevertheless, this work serves as an outlook to how the new system could perform compared to the current one with an economic comparison and showing the boundaries of the new and current system.

The second point of discussion addresses the variety of potential shares for RES, and variety in different production plan outcomes. The range for the RES share between 93% and 56% implicates that the current plan from SWSHA is sufficient to be within the legal limits for 2030, even for the “worst” scenario. Based on scenarios 01 to 04 even the 80% goal of RES can be achieved for the 2040 goal. For the 2045 goal the use of biomass would need to be reduced dramatically, since currently 62% are provided by biomethane which is limited by law to be 15% by 2045. The variety in potential outcomes for the production plan is an expected outcome but shows that the specific optimal production plan is very dependent on the specific pricing structure. It shows how the specific system of SWSHA behaves for different price scenarios and how a cost-efficient production looks like with the new technology. In this relation it needs to be mentioned, that scenarios with high use of natural gas and low use of solar thermal power and HP do not reflect reality very well since solar thermal power most likely will be utilized when available, according to SWSHA. Furthermore, the availability for certain fuels or the amount of possible electricity that can be sold were not limited in this work too, which also does not reflect reality, but are simplifications done for this work. Furthermore, the optimal production plan does not consider emissions of the system or is tailored to increased use of RES but is set to increase economic efficiency. This could be additional objectives investigated in future works to see how the systems performs adding these objectives.

In relation to the production plan and shares of RES used, the unutilised potential of the solar thermal power and HP must be addressed. This unused potential could be used to further increase the share of RES. Solar thermal usage could be further increased by adding short term TES and long-term TES. Especially a seasonal storage could be used to shift the mismatch in production and demand from summer to later in the year. This was already investigated by various literature ([17], [43], [44], [60], [64], [65], [66]). The same applies to heat pumps which can utilise low or negative el. prices to produce heat and store it. Ultimately this could help to reach the 2045 goal and could be part of future research for the system of SWSHA.

Another point of discussion are the insights into the influence of electricity and gas prices which revealed different patterns. The direct influence of gas prices and electricity prices to both systems (lower gas prices - lower costs and higher el. prices - lower costs) were an expected outcome. However, it was unclear too which extent for instance lower gas prices and higher electricity prices influence the performance between the systems. It provided specific insights into the system of SWSHA and the border of “economic feasibility” comparing the systems, considering the above-mentioned limitations of the analysis. More unexpected in this relation was the converging behaviour between the system for decreasing gas and increasing electricity prices. That showed that especially for high gas prices and low el. prices the new system could perform better and illustrate an independence from natural gas and el. prices, while both systems performed similar for low gas prices and high el. prices. This pattern shows the resilience and flexibility of the new system, proving that the new system can adapt very well to fluctuating pricing structures, and could even profit from negative prices.

Addressing the sensitivity study, the new system showed the highest sensitivity toward the biomethane price due to its high share in the production plan. This price has not been investigated in terms of fluctuations for the future and thus poses a limitation of the results.

This price might rise or fall in the future and thus will change the cost structure, the economic outcomes as well as the production plan. Future work could be conducted to address this issue for the here analysed system. The third strongest influence as shown from the sensitivity study is the DH load. The DH load was assumed to increase from 2025 to 2030, however higher generation DH systems can help reducing the DH load and thus could be an additional point to consider in future work. The assumption of an increased DH load was given from SWSHA and is most likely to happen due to their calculation of expanding their DH system and adding more customers. However, the exact value for and DH load increase is unknown.

Additionally, what has not been investigated in this work is how negative price would affect the analysis conducted in this work. The new system has the ability to opt for non-electricity producing units as well as the HP can benefit from negative electricity prices in combination with a TES. Especially because the HPs potential is not entirely used and its potential to utilise negative prices, future work could investigate how these influences different parameters in comparison to the current system.

Overall, this analysis has shown potential outcomes for the integration of RES into a given district heating system, taking into account aspects such as cost structure, production plan, RES shares and potential economic impacts compared to the current system. Despite the limitations mentioned, the results provide detailed insights into the behaviour of the new system under certain price structures and show their implications for investment decisions. Although certain scenarios may not appear theoretically favourable compared to the current system, the analysis has shown numerous results that are not only beneficial from an economic perspective, but also show improved performance in terms of environmental impact of the system and are in line with future regulatory requirements. Furthermore, the new system showed a comparatively high resilience to fluctuating prices in gas and electricity which could be a crucial factor in navigating the intermittent electricity supply from RES and uncertainty of gas prices of the future.

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