energies

Article

Opportunities and Challenges of Future District Heating Portfolios of an Austrian Utility

Richard Büchele *, **Lukas Kranzl**, **Michael Hartner** and **Jeton Hasani**

Energy Economics Group, Institute of Energy Systems and Electrical Drives, TU Wien, Gusshausstr. 25-27, 1040 Vienna, Austria; kranzl@eeg.tuwien.ac.at (L.K.); hartner@eeg.tuwien.ac.at (M.H.); hasani@eeg.tuwien.ac.at (J.H.)

* Correspondence: buechele@eeg.tuwien.ac.at

Received: 18 April 2020; Accepted: 10 May 2020; Published: 15 May 2020

Abstract: In this paper, opportunities and challenges of concrete portfolio options of an Austrian district heating (DH) supplier are assessed against the background of current challenges of the DH sector. The following steps are performed: (1) analysis of status quo; (2) analysis of current and possible future economic framework conditions; (3) definition of four concrete future portfolio options for investment planning until the year 2030; (4) modeling of status quo and future portfolios together with the respective framework conditions in a linear dispatch optimization model; and (5) perform techno-economic analysis for each portfolio under the different possible future framework conditions. The expected increase in renewable power generation capacity is likely to increase volatility in future electricity prices with hours of both very low and very high prices. This higher volatility results in higher technical flexibility requirements for the heat generation plants and a need for heat generation portfolios to respond to both high and low electricity prices. The results indicate that the combination of heat pumps and combined heat and power (CHP) plants is well suited to cope with these challenges from a microeconomic point of view. At the same time, we show that a shift to a high share of renewables of more than 60%, implying a complete exit of gas fired CHPs, is also feasible with costs in a very similar range as the current DH generation portfolio.

Keywords: district heating; portfolio options; dispatch optimization; economic framework conditions

1. Introduction

In urban and densely populated areas, district heating (DH) is seen as an important decarbonization option, where it is often the only possible option to integrate large shares of renewable and excess heat into the heating sector. This was found already in various studies, e.g., in [1] or during the second phase of the Heat Roadmap Europe Project [2]. However, the district heating sector is currently in transition and challenged in many ways. One major challenge is the uncertainty in future framework conditions and how these will affect the feasibility of the suppliers' portfolio: e.g., as one important policy framework, the revised directive 2018/2001 [3] on the promotion of the use of energy from renewable sources, for the first time sets concrete targets until 2030 for the annual increase of the share of renewable heat in general and renewable energies in the district heating sector in particular. For many district heating utilities, it is still unclear how to develop the current portfolio to reach this target. Furthermore, a significant increase in costs of European CO_2 emission allowances from an average of 5 EUR/t_{CO2} to around 20–25 EUR/t_{CO2} has taken place in 2018, and additionally fossil energy prices are subject to high fluctuations and affect electricity and heat generation costs. So far, only a few assessments have been published on political framework conditions and its influence on the feasibility of district heating systems: e.g., the assessment in [4] evaluates the impact of different policy frameworks on the future of district heating in a case study city in Romania and shows that energy and climate policy objectives have a big impact on the future of district heating. The work in [5] studies the current and former framework conditions in Nordic DH to project the likely future development of Nordic DH and also finds that fuel prices, tax, and subsidy schemes affect the fuel composition, and the future of Nordic DH relies on CO_2 prices, electricity prices, and energy policy.

Other big challenges for the district heating sector are the integration with the electricity sector, which is rapidly taking place, and the expected heat demand reduction due to thermal building renovation measures and global warming, which will impact the techno-economic parameters of district heating according to the analysis in [6]. Generally, the concept of fourth generation district heating tackles several of the future challenges, and many researches related to this concept have taken place within the last years and have provided various additional insights. For example, the recent status analysis of fourth generation district heating in [7] provides a review of this topic in scientific papers and especially highlights the significant benefits of systems integration and mentions that smart energy systems require innovative planning practices, support tools, and policies facilitating the transformation, including strategic and innovative energy planning considering legal perspectives. One such integrated strategic energy planning process to assess the possible future role of district heating but also the interactions with heat savings and other heat supply options is described in [8]. Regarding current challenges of district heating, [9] provides a perspective on the development of future district heating systems and technologies and their role in future smart energy systems. However, it concludes that the status of the scientific contributions demonstrates a high level of understanding of how to deal with the technical aspects but that the primary current challenge seems to be the understanding of the implementation of these. Furthermore, in [10] it was found that more efforts are required for the identification, assessment, and implementation with the aim to harvest the global benefits of district heating and cooling.

Therefore, this paper adds exactly to this literature gap and focusses on the challenges of transforming the district heating supply from a specific provider's point of view. This viewpoint usually differs from an overall system view, which typically is applied for analysis of the district heating sector. As already pointed out, district heat producers have to deal with uncertainties of future framework conditions and their effect on different concrete investment options they have. District heating suppliers ask themselves how their concrete portfolio options perform under expected bandwidths of these future conditions and how the addition of heat pumps, excess heat, or a biomass combined heat and power plant (CHP) influence the performance of their current supply portfolio. Smaller district heating suppliers usually do not have the know-how and tools to perform assessments like these and—if performed—concrete analyses usually are kept confidential and scientific publications of this kind are hardly available. This paper identifies, describes, and evaluates certain concrete heat supply portfolio options of an Austrian district heating supplier under current and a bandwidth of expected future framework conditions by simulating the status quo and the portfolio options in a district heating dispatch optimization model. Most of the assessed concrete portfolio options are based on prefeasibility studies commissioned by the DH utility. The used values (technical as well as financial) were set in accordance with the utility and may better reflect the effective framework conditions relevant to a DH supplier than other literature values.

2. Materials and Methods

The overall methodology of this work is to first create different consistent sets of input and framework conditions for a dispatch optimization model, which then is used to assess various future portfolio options of an existing Austrian district heating utility in the time horizon to 2030. This includes a holistic view on the main factors affecting the assessed district heating system and their possible future developments by performing the following steps: (1) Analysis of status quo of the district heating system; in this step the current demand for district heating and the technical parameters of the district heating supply portfolio were analyzed. (2) Analysis of current and possible future economic framework conditions; in this step one consistent set of current (2017) and two sets of future (2030) framework conditions (one representing an upper limit and one representing a lower limit within a range of expected future framework conditions) were generated, including energy and carbon prices and charges, taxes, and fees for the different technologies. Each set includes a scenario of hourly electricity prices calculated with a fundamental electricity market model for Germany and Austria fed with the defined framework conditions taking into account expected expansion of renewable electricity generation in these two countries. (3) Definition of realistic future portfolio options; in this step, four concrete portfolio options were developed together with the district heating utility each to enhance the current status quo supply portfolio. Most of these portfolio options are based on prefeasibility studies commissioned by the utility taking into account local actual available potentials and local conditions. (4) Modeling; in this step the status quo and the future portfolios together with the respective framework conditions were implemented in a linear dispatch optimization model, which is described in Section 2.1. (5) Perform techno-economic analysis; in this last step, the dispatch optimization was performed for the status quo and the four portfolio options each for the current and the two sets of possible future framework conditions. For all units, the generated heat and the full load hours of each technology were calculated and indicators like total CO_2 emissions, total share of renewable heat, and resulting levelized cost of heat were compared for the different portfolios and for sensitivities of the most important factors. Figure 1 gives a schematic overview on the methodological framework.

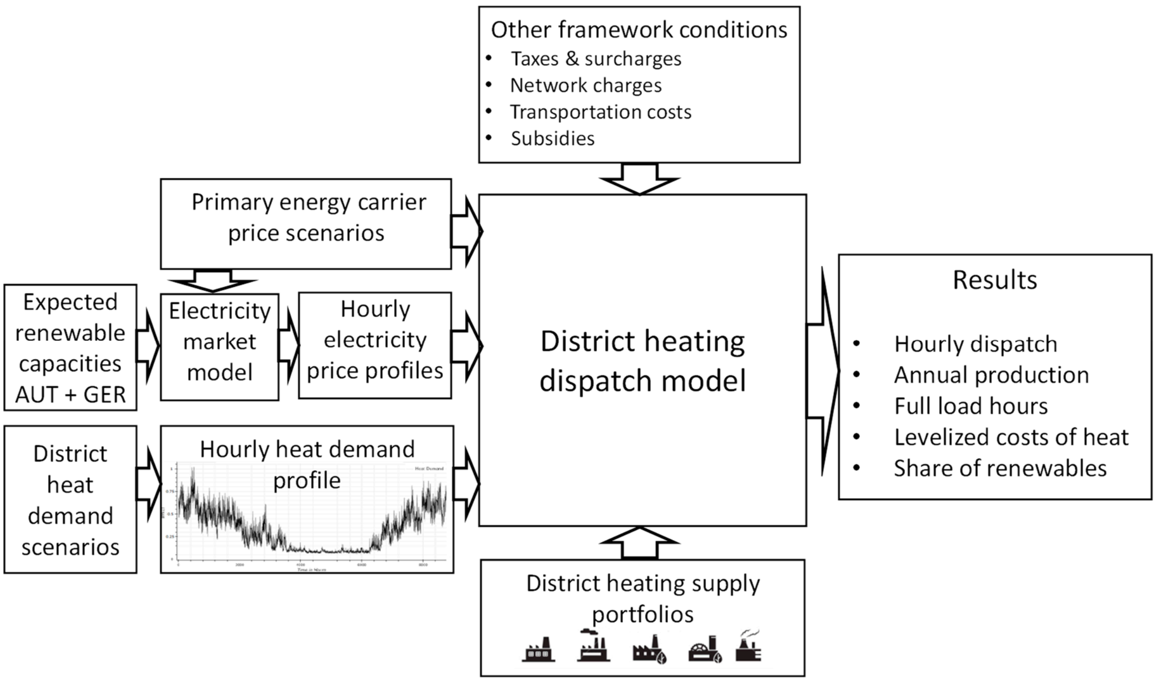

Figure 1. Schematic overview of the methodological framework.

2.1. Dispatch Optimization Model

For the assessment of the different district heating portfolios, a linear dispatch optimization model was used, which was mainly developed within the Hotmaps project [11]. The model is implemented in Python programming language and depicts the essential characteristics and restrictions of the different technologies but does not contain a detailed modeling of the start-up and ramp constraints, the necessary downtime or partial load efficiencies. The model therefore is not suited for very detailed modeling of single technologies but is designed to be able to run several scenarios within reasonable solver time.

The main model inputs are hourly profiles for district heating demand, electricity prices, solar irradiation and outdoor temperature, and the installed heat generation capacities with respective thermal and electrical efficiencies. Each modeled technology is described by its (nominal) thermal power generation and its (nominal) thermal and electrical efficiencies. By means of linear equations, the required (fuel) input and the generated electricity can be calculated for each heat generation operating point at every hour.

The objective function in Equation (1) minimizes the difference from the total costs for heat generation and the revenues from electricity production.

$$min(\ c_{total} - rev_{total}) \tag{1}$$

Under the constraint that the sum of heat generation of all units and the sum of loading and unloading of the heat storages in all hours has to be equal to the heat demand in each hour according to Equation (2).

$$s.t.\ \sum\nolimits_{j,t} x_{th_{j,t}} + \sum\nolimits_{hs,t} \left(x_{unload_{hs,t}} - x_{load_{hs,t}} \right) = demand_{th_t} \tag{2}$$

The total costs of heat generation are calculated according to Equation (3) and consist of the capital costs, the fixed costs, the variable costs, and include for CHP and waste incineration plants the ramp costs.

$$c_{total} = \sum CC + FC + VAR + RAMP \tag{3}$$

With the capital costs calculated according to Equation (4) via the specific investment costs, the installed capacity and the annuity factor from Equation (5) for each heat generation and storage unit can be calculated. The annuity factor is used to calculate the annually equal payments that equal the overall amount considering the lifetime and the interest rate of an investment.

$$CC = \sum\nolimits_{j} Cap_j \cdot i_j \cdot \alpha_j + \sum\nolimits_{hs} sCap_{hs} \cdot i_{hs} \cdot \alpha_{hs} \tag{4}$$

$$\alpha_{j,hs} = \frac{(1+z)^{LT_{j,hs}} \cdot z}{(1+z)^{LT_{j,hs}} - z} \tag{5}$$

The fixed costs are calculated according to Equation (6) via the sum of fixed specific opex costs multiplied by the installed capacity of the respective heat generator or heat storage.

$$FC = \sum\nolimits_{j} Cap_j \cdot opex_{FIX_j} + \sum\nolimits_{hs} sCap_{hs} \cdot opex_{FIX_{hs}} \tag{6}$$

The variable costs are calculated according to Equation (7) for each produced unit of heat in each hour, including the variable opex plus the price of the respective energy carrier and the emission costs considering the efficiency of the technology:

$$VAR = \sum\nolimits_{j,t} x_{th_{j,t}} \cdot (opex_{var_j} + \frac{p_{ec_{j,t}}}{\eta_{th_{j,t}}} + \frac{f_{em_{ec_j}} \cdot p_{CO_2}}{\eta_{th_{j,t}}}) \tag{7}$$

For CHP plants and waste incineration plants, ramp costs are included according to Equation (8).

$$RAMP = \sum\nolimits_{j,t} (x_{th_{jt}} - x_{th_{j,t-1}}) \cdot 100 \frac{}{MWh} \quad \Big| \quad (x_{th_{jt}} - x_{th_{j,t-1}}) > 0 \tag{8}$$

The total revenues from electricity production are calculated via Equation (9) summing the electricity production of each unit and each hour multiplied by the respective electricity price.

$$rev_{total} = \sum\nolimits_{j,t} x_{el_{jt}} \cdot p_{s.el_{j,t}} \tag{9}$$

The electricity generation of each unit and each hour is calculated via Equation (10) using the efficiencies of each production unit.

$$x_{el_{j,t}} = x_{th_{j,t}} \cdot \frac{\eta_{el_j}}{\eta_{th_{j,t}}} \tag{10}$$

As main outputs, the model calculates the levelized heat generation costs, the investment, operation and fuel costs, the heat generation mix per heat generator, CO_2 emissions, full load hours (FLH), etc.

2.2. Electricity Market Model

To generate scenarios of hourly electricity prices as an input for the dispatch model, a fundamental electricity market model of the Austrian and German electricity system is used. A detailed description and formulation of the model can be found in [12]. The model is a linear optimization model that uses hourly resolution to optimize the use of power generation technologies for a given installed capacity of controllable power plants (lignite, coal, nuclear, gas, and oil) and given installed volatility (sun, wind, and running water) in combination with historical feed profiles. Storage power plants are modeled in aggregated form. The used model is a linear dispatch model that minimizes variable generation costs of thermal power plants considering energy demand constraints, feed in of renewables, and installed capacities of hydro storage systems in Austria and Germany. The hourly electricity prices are derived from the shadow price of the demand equation, which demands that the generation in each hour has to exceed the demand.

3. Input Data: Framework Conditions and Portfolio Options

In this section, the used input data and parameter assumptions as well as the portfolio options considered for the district heating system are described in detail. Three different sets of framework conditions (one set of "current" (2017) framework conditions and two sets of "future" framework conditions (2030), which all are described in Section 3.1.) were defined to assess five different portfolio options (status quo plus four alternative portfolios, which are all described in Section 3.2.).

3.1. Framework Conditions

Because there is a high interdependency of different input parameters, sets of consistent framework conditions were created. Each set consists of the assumed energy and CO_2 certificate price and the resulting hourly electricity price determined by the electricity market model described in Section 2.2, as well as the applicable network charges, taxes, and subsidies for each energy carrier and each portfolio. The naming of the three main sets of framework conditions is according to the represented scenario year, the assumed price level of fossil energy carriers ("Hi" ... high, "Lo" ... low), and the respective CO_2 price (30 EUR/t_{CO2}, 60 EUR/t_{CO2}). They are named as follows:

- 2017_current
- 2030_FossilHi_CO2-30
- 2030_FossilLo_CO2-60

3.1.1. Energy and CO_2 Prices

Wholesale primary energy carrier prices and CO_2 prices based on nationally or internationally recognized studies are used which are given in the Appendix A in Table A2. For the "2017_current" scenario average values for the year 2017 are used. For the future scenarios (2030), values from two different energy price scenarios for the year 2030 of the World Energy Outlook 2016 [13] (Current Policies Scenario and 450 ppm Scenario) are used for the fossil energy carriers and corresponding costs of CO_2 emission allowances in the range of the European Reference Scenario defined [14]. The logic behind the combination of fossil energy prices and CO_2 prices within the IEA's World Energy Outlook is that a higher CO_2 certificate price leads to less demand and therefore a lower price for fossil fuels.

For the locally available energy carrier biomass, excess heat and municipal solid waste prices are defined according to national studies [15] and were fixed in accordance with the district heating utility. The price for waste is assumed to be 0 EUR/MWh in the model calculations to represent on the one hand a must run situation for waste treatment and on the other hand not influence the levelized cost of heat of the remaining supply portfolio. For high temperature, excess heat above 100 °C, which can be used directly for the district heating network, an energy price of 15 EUR/MWh, and for low temperature, excess heat at a temperature level of 50 °C an energy price of 5 EUR/MWh is assumed. These values are kept constant for all three price scenarios.

3.1.2. Electricity Prices

Each of the three sets of framework conditions includes a respective scenario of hourly electricity prices, which is generated using the electricity market model described in Section 2.2, which was fed with the energy prices from Section 3.1.1. The marginal costs of the power plants are based on the fossil fuel and CO_2 prices and therefore are different for each scenario. For the calculations, the controllable power plant portfolio of Austria and Germany is represented with the status of the year 2014. Only the capacities of the nuclear power plants were replaced with simple gas turbines, which then operate as back-up capacities at the end of the merit order. The installed renewable capacities were set according to the data in [15] and are listed in Table 1.

Table 1. Electricity demand and installed renewable capacities as input for the electricity market model [15].

	Electricity Demand		**Installed PV Capacity**		**Installed Wind Onshore**		**Installed Wind Offshore**	
Year	**AT [TWh]**	**DE [TWh]**	**AT [GW]**	**DE [GW]**	**AT [GW]**	**DE [GW]**	**AT [GW]**	**DE [GW]**
2017	63.5	493	1	41.1	2.7	47.8	0	4.6
2030	75.9	589.4	12	60.6	7	85	0	28.1

Figure 2 shows the resulting hourly electricity prices sorted by size and the average annual price for the three scenarios as an outcome of the electricity market model. It can be seen that the assumed price developments for the year 2030 lead to significantly higher average electricity prices in both 2030 scenarios compared to the starting year 2017. The results clearly show that the main drivers for these higher electricity prices are the high CO_2 prices as the scenario with the low fossil prices still has the highest average electricity prices (77.6 EUR/MWh) due to higher CO_2 prices. In addition to a rise in the average price level, there is also a clear increase in price volatility. Not only do the shares of hours with prices of 0 EUR/MWh increase (form 400 h in 2017 to 1600 h in the 2030 scenario) but also peaks with high electricity price occur more frequently.

This is a result of the missing nuclear power plants, which allows other power plants with higher marginal costs than in the starting year 2017 come into the merit order at times of high residual loads.

Another reason is that no additional flexibility options have been assumed for the 2030 scenarios in the market model. A strong increase in flexibility in the market would reduce the number of hours with low prices and at the same time reduce price peaks and especially the occurrence of higher price spreads provides incentives for additional flexibility. However, the trend towards increased numbers with lower prices due to strong feed-in peaks from renewable energies would remain.

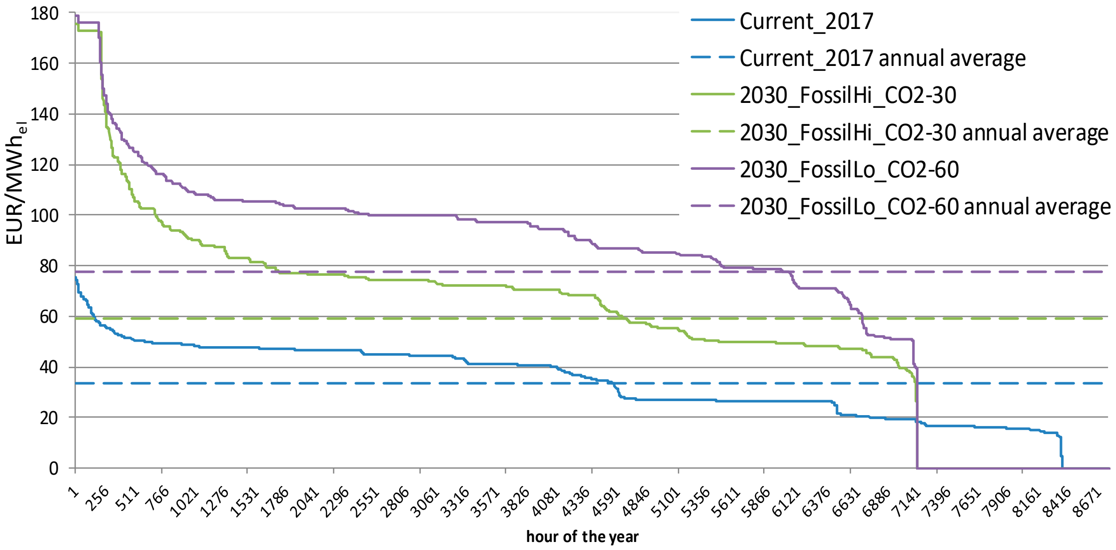

Figure 2. Hourly electricity prices sorted by size and annual average price for the three scenarios as an outcome of the electricity market model.

3.1.3. Network and Transportation Costs

The considered network and transport costs are derived from data from the Austrian network regulator e-control (https://www.e-control.at) and are shown in detail in the Appendix A in Table A3. To feed produced electricity into the public grid, an electricity system charge depending on the network (voltage) level must be paid, which consists of a network service charge, the charge for primary regulation, and the network loss charge of the respective network level. For the assessed district heating utility, there are plants feeding into the grid level 5 and grid level 3 depending on their power generation capacity. The consumption of electricity via public network is also subject to an electricity system charge consisting of network usage and network loss charges at the respective network level. This applies to portfolio options like heat pumps or power-to-heat systems. For rated electrical power consumption below 20 MW_{el}, network level 5 applies and for rated power consumption above 20 MW_{el} network level 4. The natural gas fired power plants are connected to the high-pressure natural gas network (>30 bar), which causes a respective network utilization charge of 0.65 EUR/MWh for customer with annual consumptions over 200 GWh. For the transport of biomass, average transport costs for truck delivery within a radius of 100 km around the power plant are calculated. Assuming uniformly distributed transportation distances within this area resulting in average transport distance of 66 km, fixed costs of 1.1 EUR/MWh and variable costs of 2.49 EUR/MWh occur according to [16]. For the remaining energy carriers (municipal solid waste and industrial excess heat), no direct transportation costs are assumed.

3.1.4. Taxes, Surcharges, and Subsidies

The considered taxes and surcharges are shown in detail in the Appendix A in Table A4. For the consumption of electricity via the public electricity network, e.g., for heat pumps, an electricity consumption tax of 15 EUR/MWh and a network level dependent green electricity support payment applies. Furthermore, the consumption of natural gas via heat only boiler is charged with an energy consumption tax. For natural gas used in CHP plants this tax does not apply. For power plants taking part in the European Emission Allowance Trading Scheme (ETS), a CO_2 certificate price per emitted ton of CO_2 applies. For the use of biomass, municipal waste, or industrial excess heat no tax or surcharge applies. For the generation of green electricity via Biomass CHP plants, a feed-in tariff of currently 103 EUR/MWh_{el} is granted, which is considered in the 2017_current scenario. For the 2030 scenarios, the possible future policy schemes of a fixed market premium of 70 EUR/MWh_{el} in addition to the electricity market price is implemented in the three 2030 scenarios.

3.2. Status Quo of Heat Generation and Assessed Portfolios

In this chapter, each modeled plant of the current supply portfolio and of all assessed future portfolio options are described briefly in Table 2. The respective detailed model parameters, including technical and financial values, are given in the Appendix A in Table A5. All portfolio options and model settings were derived in close cooperation with the corresponding district heating company in order to reflect the actual availability and limitation of resources as well as authentic investment assumptions to support the strategic decision-making process of the DH utility.

Table 2. Description of status quo plant capacities and future portfolio options.

	Plant Name	**Portfolio and Included Plant Capacities** / **Description of Plant**	**P0**	**P1**	**P2**	**P3**	**P4**
Existing plant capacities and storage (Status quo 2017)	WtE CHP	Existing waste-to-energy combined heat and power plant with fuel input of 72 MW, thermal output of 45 MW_{th}, and electrical output of 12 MW_{el}.	X	X	X	X	X
	Bio CHP	Existing biomass CHP plant with fuel input of 36.5 MW, thermal output of 24.8 MW_{th}, and electrical output of 8.1 MW_{el}.	X	X	X	X	X
	CCGT_1	Existing combined cycle natural gas and steam turbine plant with fuel input of 202.8 MW, thermal output of 86.8 MW_{th}, and electrical output of 95.5 MW_{el}.	X	X	X	X	
	CCGT_2	Existing combined cycle natural gas and steam turbine plant with fuel input of 209.1 MW, thermal output of 71.5 MW_{th}, and electrical output of 96.4 MW_{el}.	X	X	X	X	
	GT CHP	Existing natural gas turbine CHP with heat recovery boiler with fuel input of 202.8 MW, thermal output of 132.4 MW_{th}, and electrical output of 68.8 MW_{el}.	X	X	X	X	
	ST CHP	Existing natural gas fired back pressure steam turbine CHP with fuel input of 118 MW, thermal output of 56.8 MW_{th}, and electrical output of 49.2 MW_{el}.	X	X	X	X	
	HOB 1	Existing natural gas fired heat only hot water boiler with thermal output capacity of 124.5 MW_{th}.	X	X	X	X	X
	HOB 2	Existing natural gas fired heat only hot water boiler with thermal output capacity of 10 MW_{th}.	X	X	X	X	X
	HOB 3	Existing natural gas fired heat only hot water boiler with thermal output capacity of 15 MW_{th}.	X	X	X	X	X
	Daily Storage	Existing hot water heat storage with thermal storage capacity of 1300 MWh and loading and unloading power capacity of 60 MW_{th}.	X	X	X	X	X
Additional supply and storage portfolio options	HP_FG	Heat pump using the condensation water from a flue gas condensation unit as heat source (from the biomass CHP and the WtE plant). The heat source is available at a temperature of 50 °C and is cooled by 15 °C to 35 °C. The thermal output power of such a heat pump configuration could be 20 MW_{th}.		X		X	X
	HP _WWC	Heat pump with wastewater channel as heat source. The wastewater is available at a temperature of 35 °C and is cooled by 15 °C to 20 °C. The thermal output power of such a heat pump configuration could be 10 MW_{th}.		X			X
	HP_CW	Heat pump with cooling water from the plant site "Linz Mitte" as heat source. The cooling water is available at around 35 °C and is cooled by 15 °C to 20 °C. The thermal output power of such a heat pump configuration could be 10 MW_{th}.		X			X
	HP_GW	Heat pump with ground water as heat source. The ground water is available at a temperature of 10 °C and is cooled by 4 °C to 6 °C. The thermal output power of such a heat pump configuration could be 5 MW_{th}.		X			X
	HP_RW	Heat pump with river water as heat source. The river water is available at a temperature of 10 °C and is cooled by 4 C to 6 °C. The thermal output power of such a heat pump configuration could be between 10 MW_{th} and 50 MW_{th}.		10			50
	ExH	Integration of high-temperature excess heat of an existing nearby industrial site. This high-temperature excess heat is available at temperatures above 100 °C and can via heat exchanger be used directly for the supply of district heating. The excess heat stream could deliver a power of around 30 MW_{th}.			X		X
	ExH_HP	Apart from the high-temperature excess heat there is a low-temperature excess heat stream, which could be tapped via HP. This excess heat stream is available at around 50 °C and in this option would be used as heat source for a heat pump to be cooled by 15 °C to 35 °C. The thermal output power of such a heat pump configuration could be 30 MW_{th}.			X		X
	Bio CHP_2	Construction of an additional biomass CHP plant with a fuel input of 43.5 MW and thermal output power of 30 MW_{th} and electrical output power of 9.6 MW_{el}.				X	
	HOB 4	Additional heat only boiler for peak load supply with thermal output power of 100 MW_{th}.					X
	Daily Storage 2	Additional daily heat storage with a heat storage capacity of approx. 2000 MWh and loading and unloading power capacity of 80 MW_{th}.		X			
	Weekly Storage	Additional weekly heat storage with a storage capacity of approx. 12,000 MWh and loading and unloading power capacity of 140 MW_{th}.					X

3.2.1. Status Quo

"Portfolio P0 - Status Quo" represents the current heat supply portfolio of the assessed district heating system and consists of the heat generation and heat storage units described in the upper part of Table 2. The current heat generation capacities sum up to 565 MW plus 60 MW heat storage loading/unloading capacity and feed around 1100 GWh into the district heating grid. For some of the existing plant capacities, reinvestment costs of altogether 120 Mio EUR until 2030 are expected and considered in the calculation. These costs are based on actual estimations of the utility due to age and status of the different plants and necessary revisions.

3.2.2. Portfolio Options and Assessed Portfolios

The different portfolio options identified together with the district heating utility are described in the lower part of Table 2. Many of the identified options are based on technical prefeasibility studies performed by the district heating utility and therefore reflect actual availability and limitation of resources and are based on authentic expected investment costs. The future supplied heat demand is assumed to be constant until 2030 because it is expected that expansion of the network and decrease of heat demand due to building refurbishment level out. The different portfolio options are combined to following four possible future portfolios:

- "Portfolio P1—Heat Pump Portfolio": In this possible future portfolio, investments into several heat pump options plus a second daily heat storage are made additionally to the existing status quo capacities as shown in Table 2. For all the heat pump configurations, the temperature rise of the heat sink is assumed to be constant from an average return temperature of 55 °C to a flow temperature of 85 °C without adaptation of the flow temperature according to outside temperature. The resulting efficiencies (coefficient of performance—COP) of the heat pumps result from simulations of different heat pump technologies performed in the Austrian project "Power to heat Potentials" [17]. The expected investments into the additional capacities of 55 MW sum up to 38 Mio EUR.
- "Portfolio P2—Excess heat integration": In this portfolio nearby high- and low-temperature excess heat is integrated in the current system directly and via a heat pump respectively. The expected investments into these 60 MW of capacities sum up to 21 Mio EUR.
- "Portfolio P3—Biomass": In this possible future portfolio, an additional biomass CHP is built together with a flue gas condensation heat pump. The expected investments into these 50 MW of capacities sum up to 45 Mio EUR.
- "Portfolio P4—Renewable": In this portfolio, in contrast to the other portfolios, all fossil CHP plants of the status quo are closed down and thus no longer available. This on the one hand saves the reinvestment costs necessary in all the other portfolios and allows investments into further options but on the other hand removes the possibility of generation of valuable electricity and associated revenues. The following capacities, which are in place in "Portfolio 0—Status Quo" are thus no longer available in Portfolio P4: CCGT_1, CCGT_2, GT CHP, and ST SCHP. To replace the capacities of the closed down plants, investments of 111 Mio EUR are expected for the 255 MW of new heat generation capacity and 140 MW heat storage loading/unloading capacity.

3.2.3. Sensitivities

To investigate the sensitivities of input sets, the following variations of the described scenario sets are assessed:

- Low CO_2 price: in this sensitivity, it is assumed that no increase in the future CO_2 price occurs and that the corresponding CO_2 prices for all four energy price scenarios is 10 EUR/t_{CO2} instead. For each of these sensitivities, again an hourly electricity price is generated using the electricity market model (see Section 2.2).
- Natural gas tax for CHP: in this sensitivity scenario, natural gas used in CHP plants is taxed the same as natural gas use in heat only boiler.

4. Results

In this section, first the results of the effects of the different sets of frameworks on each portfolio are described and then a comparison across all portfolio options is given. In Table A6 in the Appendix A, the detailed results of the analysis can be found.

4.1. Portfolio P0: Status Quo

For the generation capacities of the Status Quo Portfolio, the effects of the different sets of framework conditions can be summarized as follows:

- For the Waste-to-Energy CHP plant, there is almost no difference in the Status Quo Portfolio between the current framework conditions and the different sets of future framework conditions. It supplies around 34% of the heat demand in the current and in all three future scenarios. This is due to the assumed price of 0 EUR/MWh of municipal waste, which leads to very low costs of heat generation fulfilling the requirement that the waste incineration plant operates throughout the year as its primary purpose is the treatment of waste and not the generation of energy.
- The existing Biomass CHP, which in Portfolio P0 is subsidized in all three scenario sets with 103 EUR/MWh$_{el}$, achieves around 5600 full load hours (FLH), which drops to between 3500 FLH and 1800 FLH in the 2030 scenarios, which means a reduction of the supplied heat demand from 12% to between 8% and 4%. This is mainly because the higher average electricity prices in the future scenarios lead to increased economic viability of fossil cogeneration, which reduces the economic viability of the biomass CHP.
- The different fossil CHP plants are operated between 400 FLH and 2200 FLH in the 2017 scenario, depending on the system design with respect to the power to heat ratio of the plant. In the 2030 price scenarios in particular, the plants with high el. efficiency increase their operation to between 3000 to 4000 FLH. On the other hand, the FLH of the CHP plants with lower el. efficiency but higher thermal efficiency drops to between 300 to 700 FLH. In total, this results in an increased economic viability of the fossil CHP plants in the 2030 scenarios compared to the 2017 scenario due to the higher average and higher peak electricity prices, which means higher revenues for electricity production.
- The use of the daily storage increases strongly in all 2030 scenarios compared to the 2017 scenario in order to temporarily store the heat from CHP production in hours of high electricity prices.

4.2. Portfolio P1: Heat Pumps

- For the Waste-to-Energy CHP plant also in this portfolio, the results are very similar as in the Status Quo Portfolio due to the very low costs of heat generation fulfilling the "must run" requirement.
- The Biomass CHP, which is not subsidized in this portfolio, is not economically viable in any of the scenarios and does not generate heat at all.
- Compared to the P0 Portfolio, the natural gas CHP plants are now operated between 500 FLH and 2200 FLH in the 2017 scenario and in the 2030 scenarios between 2800 and 4000 FLH for plants with high el. efficiency and between 500 and 700 FLH with lower el. efficiency but higher thermal efficiency.
- For the different heat pump technologies, the 2017 price scenario allows economic viable use of heat pumps between 2400 and 4700 FLH, producing around 19% of the heat demand. In the 2030 price scenarios, the FLH, in particular of the heat pumps with higher COP, drops compared to the 2017 scenario, but the minimum FLH of all heat pump options in all scenarios are limited to the number of hours with electricity prices close to zero
- The use of the enlarged daily storage increases strongly in all 2030 scenarios compared to the 2017 scenario in order to temporarily store the heat from CHP production in hours of high electricity prices but also the heat generated by heat pumps during hours of low electricity prices.

4.3. Portfolio P2: Excess Heat Integration

- For the Waste-to-Energy CHP plant also in this portfolio, the results are very similar as in the Status Quo Portfolio due to the very low costs of heat generation fulfilling the "must run" requirement.
- Additionally, in Portfolio P2, the Biomass CHP, which is not subsidized in this portfolio, is not economically viable in any of the scenarios and does not generate heat.
- In this portfolio, the different natural gas CHP plants are operated between 400 FLH and 2100 FLH in the 2017 scenario and in the 2030 scenarios between 2700 and 3800 FLH for plants with high el. efficiency and between 200 and 500 FLH with lower el. efficiency but higher thermal efficiency. Overall, this still means an increased economic viability of the fossil CHP plants in the 2030 scenarios compared to the 2017 scenario but lower than in the P0 and P1 portfolio.
- The price scenario 2017 allows integration of direct excess heat with around 5300 FLH supplying 14% of the heat demand. In the 2030 price scenarios, the economic viability of direct waste heat drops to between 2200 FLH and 4600 FLH, supplying between 6% and 12% of the heat demand. This decrease is a result of the increased economic viability of the natural gas CHPs in the 2030 scenarios due to the higher average electricity prices, which reduces the integration of excess heat.
- Additionally, in this portfolio, the use of the daily storage increases strongly in all 2030 scenarios compared to the 2017 scenario in order to temporarily store the heat from CHP production in hours of high electricity prices.

4.4. Portfolio P3: Biomass

- For the Waste-to-Energy CHP plant also in this portfolio, the results are very similar as in the Status Quo Portfolio due to the very low costs of heat generation fulfilling the "must run" requirement.
- In this portfolio, the different natural gas CHP plants are operated between 300 FLH and 2000 FLH in the 2017 scenario and in the 2030 scenarios between 2800 and 3800 FLH for plants with high el. efficiency and between 150 and 400 h FLH with lower el. efficiency but higher thermal efficiency. Overall, this still means an increased economic viability of the fossil CHP plants in the 2030 scenarios compared to the 2017 scenario but lower than in the other Portfolios.
- The new Biomass CHP 2, which in this portfolio is subsidized with a market premium of 70 EUR/MWh$_{el}$ in addition to the electricity price, is economically viable at around 5500 FLH in the 2017 scenario and produces 14.5% of the heat demand. In the 2030 scenarios, the economically viable operation of Biomass CHP 2 decreases to between 4800 and 2400 FLH (13% to 6% of heat demand) because of increased use of fossil CHP due the higher average electricity prices. Although a high electricity price generally benefits the economic viability of Biomass CHPs, a higher electricity price favors fossil CHP more than biomass CHP and therefore reduces the use of biomass CHP in portfolios with fossil CHP.

4.5. Portfolio P4: Renewable

- For the Waste-to-Energy CHP plant also in this portfolio, the results are very similar as in the Status Quo Portfolio due to the very low costs of heat generation fulfilling the "must run" requirement.
- In the renewable portfolio, the unsubsidized Biomass CHP cannot be operated economically in the 2017 scenario but between 2100 and 3100 FLH in the 2030 scenarios supplying 5% to 7% of the heat demand. The absence of fossil CHPs in this portfolio allows the economically viable operation of biomass CHP without subsidies at an electricity price level of the 2030 scenarios.
- Direct excess heat can be integrated in an economically viable manner at around 5000 FLH in the 2017 scenario and to between 5200 and 5300 FLH in the 2030 price scenarios supplying 13% to 14% of the heat demand. The higher electricity prices reduce the economically viable use of heat pumps and thus lead to increased excess heat integration.
- For the different heat pump technologies, the 2017 price scenario allows economical use of heat pumps in between 1700 and 5300 FLH depending on the COP supplying altogether around 39%

of the heat demand. In the 2030 price scenarios with higher electricity prices, the heat pumps still can be operated economically between 1400 and 4700 FLH depending on the COP supplying 33% to 35% of the heat demand. The minimum FLH of the heat pumps with lowest COPs are limited to those hours with electricity prices close to zero.

4.6. Portfolio Comparison

In this section, annual heat generation, levelized costs of heat, and share of renewable generation are compared for the different scenarios across the portfolios. Figure 3 shows the comparison of annual heat generation of the different generation units for each portfolio and for the three assessed price scenarios. In all scenarios, 1100 GWh have to be supplied to the district heating network. The slight overproduction in the different scenarios is due to the losses of the heat storage. Especially in the scenarios with high electricity prices and bigger storage capacities, the losses are slightly higher due to heavy use of the storage by the CHP units and the heat pumps to maximize the revenues from the electricity production.

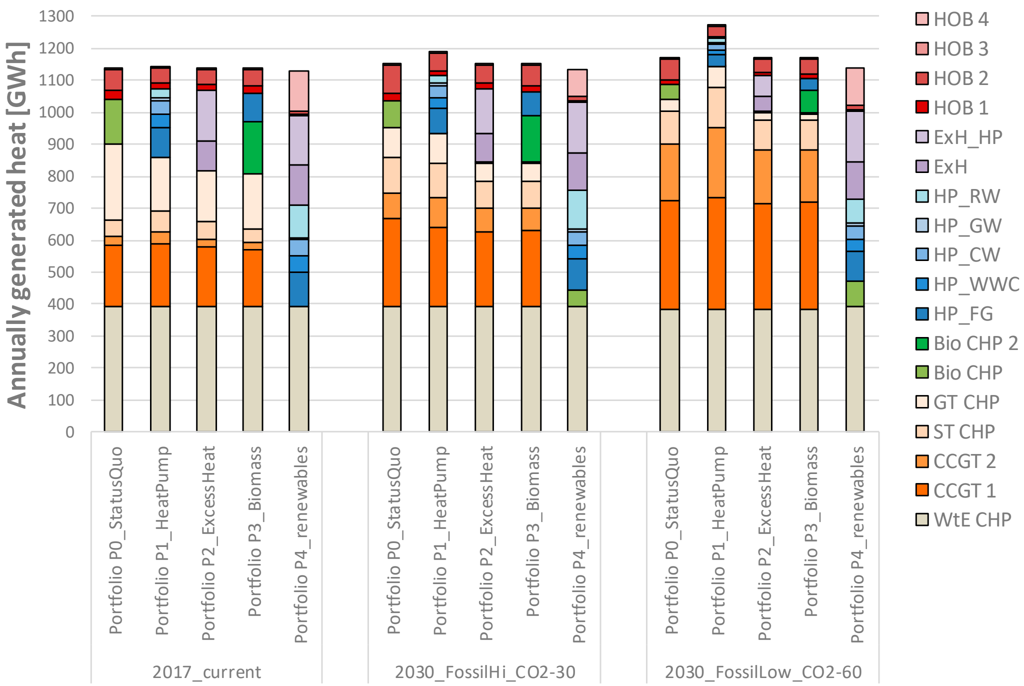

Figure 3. Comparison of annually generated heat of the different generation units for all scenarios and portfolios.

In Figure 4, the levelized costs of heat for each portfolio and all scenarios are shown relative to the scenario "2017_Current" of the Portfolio "P0 Status Quo" (=100%). Additionally, the share of renewables is also shown for each portfolio and for all scenarios. The results show that in the scenario "2017_Current", the "Portfolio P4—Renewable" achieves the by far lowest levelized costs of heat together with the by far highest share of renewables. The second lowest costs of heat can be achieved by the status quo portfolio but at the same time it also has the lowest share of renewables. In the price scenario "2030_FossilHi_CO2-30", still the "Portfolio P4—Renewables" has the lowest cost of heat, together with by far the highest share of renewables. The three portfolios "P0 Status Quo", "P1 Heat Pump", and "P2 Waste Heat Integration" have similar costs of heat with the highest share of renewables in the "P2 Waste Heat Integration" portfolio. If electricity led operation of the CHP plants would be allowed in these model runs, the revenues from produced electricity would lead to a further reduction in levelized costs of heat. In the price scenario 2030_FossilLow_CO2-60, which has the highest electricity prices, the three portfolios "Status Quo", "Heat Pump", and "Waste

Heat Integration" achieve the lowest levelized costs of heat. In these portfolios, the levelized costs of heat are mainly determined by the revenues of CHP on the electricity market. Again, if electricity led operation of the CHP plants would be allowed in these model runs, the revenues from produced electricity would lead to a further reduction in levelized costs of heat.

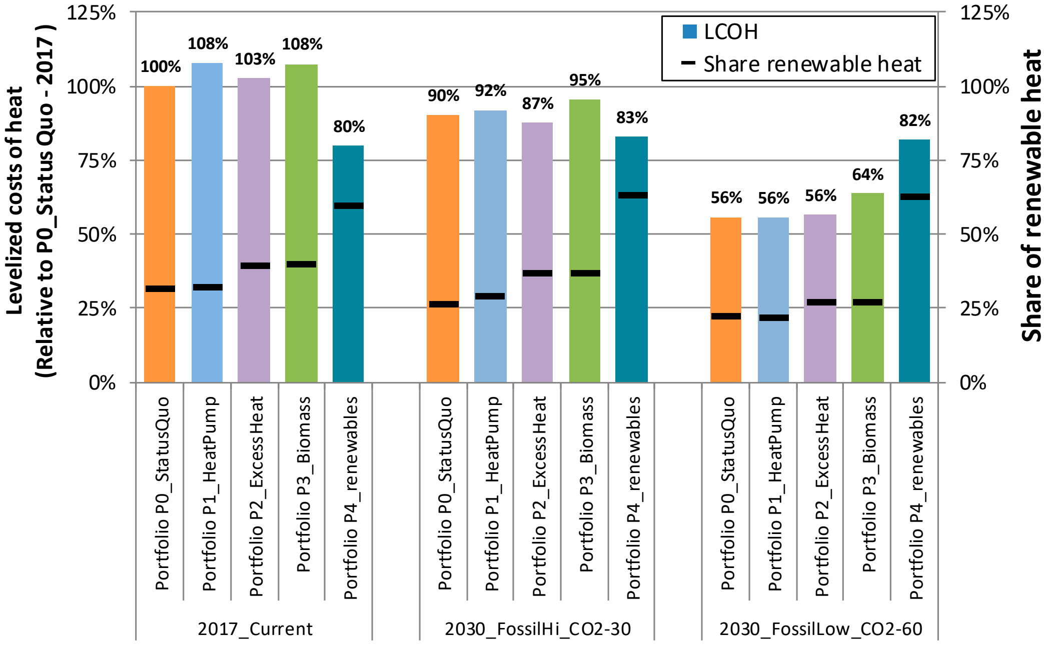

Figure 4. Comparison of levelized costs of heat (relative to Portfolio P0_Status Quo – 2017) and share of renewable heat for all scenarios and portfolios.

4.7. Sensitivities

The sensitivities investigated show the following results:

- Low CO_2 price: The assumption of a low CO_2 certificate price of 10 EUR/t has a big impact on the expected electricity prices and thus on the use of the generation technologies influenced by the electricity price. In this scenario, fossil CHPs are only economical in hours of high electricity prices up to 2500 FLH. However, for heat pump technologies with COPs between 3.5 and 4, in this scenario, an economic operation in more than 4500 FLH per year is possible.
- Natural gas tax for CHP: The introduction of energy taxation, even for natural gas used in CHP plants, leads to a much lower cost-effectiveness of gas-fired cogeneration. The heat generation would then shift towards heat only plants but also to the biomass CHP. In the 2030 scenario with highest electricity prices however, still an economical operation of the gas-fired CHP in up to 3700 h would be possible.

5. Discussion and Conclusions

The results of the electricity market model (see Section 2.2) showed that increased renewable electricity generation capacity is very likely to result in higher volatility of future electricity prices with hours of both very low and very high electricity prices. A crucial question in this context is the number of hours with very high or very low prices and which plants of the merit order will be price-setting in the mid-range. If the current expectations of a strong increase of the future CO_2 price come true, this probably will be the most important factor regarding the future electricity price, which makes future developments very dependent on political decisions and framework conditions. This higher volatility of electricity prices will also result in higher flexibility requirements for the generation plants per se (fast and frequent start-up and shut-down, less nominal operation) but also there is a need for heat generation portfolios to respond to both high and low electricity prices.

The results of the portfolio assessment show that under the assumptions made in this paper, from a microeconomic point of view until the year 2030, the combination of large heat pumps with efficient CHP systems seems to be an effective strategy in order to hedge against different electricity price developments. In this respect, heat pumps are well suited to use periods of low electricity prices and CHP plants for periods of high electricity prices. However, in hours with high electricity prices, the units with highest electricity output are operated, which then even may replace other renewable generation units in the portfolio like biomass CHP or excess heat. Therefore, from a microeconomic perspective (the viewpoint of the district heating utility), and as long as no stringent regulations for an increase in renewable heat generation are in place, a complete withdrawal from the fossil CHP is not the optimal solution according to the model results until 2030, as otherwise periods of high electricity prices and thus potential revenues from the electricity market could not be exploited. Nevertheless, the assessment also showed that by combining heat pumps, integrating waste heat, and generating heat from biomass, an almost CO_2-free district heating supply of the assessed district heating network seems to be possible at reasonable costs in the medium to long term. This scenario of high renewable district heating generation turns out to be most insensitive and resilient subject to the future development of energy and CO_2 prices. In any case, the increase of heat storage capacity turns out to be a no-regret strategy: it is beneficial in all scenarios by allowing the decoupling of electricity generation and the heat demand to optimize the plant dispatch according to electricity prices.

The most recent developments in the context of the Corona crisis and related impacts on global energy demand and prices even more illustrate that the future framework conditions of such analyses are still associated with high uncertainties. This refers in particular to the available fluctuating renewable electricity capacities, future CO_2 price development, the availability of flexibility options, and the future role of conventional electricity generation including from CHP plants. Moreover, the national implementation of EU legislation in Austria (in particular regarding the renewable energy directive [3] and the upcoming further requirements in course of the European Green Deal [18]) is still uncertain and will affect the profitability of investment decisions to be taken now. Overall, it will be essential to take decisions for a heat supply portfolio, which is able to fulfil two requirements: (1) take advantage of different market and price constellations and (2) fulfil the upcoming more and more stringent decarbonization targets. Under the assumptions and portfolio settings considered in this paper, a combination of CHP and heat pumps fulfils the first requirement but most probably not the second one. The presented portfolio with a high share of renewables fulfils the second requirement and seems sufficiently acceptable regarding the first requirement, even though it is less favorable as the portfolio including fossil CHPs.

The analysis shows that the district heating company is able to respond to the different upcoming challenges—as far as they could be considered in our study—by gradually transforming towards a renewable district heat portfolio including heat storages until the year 2030. However, this requires the corresponding investments to be taken within the next few years.

Author Contributions: Conceptualization, R.B., L.K. and M.H.; methodology, R.B., L.K. and M.H.; software, J.H., M.H. and R.B.; validation, R.B.; formal analysis, R.B.; investigation, R.B.; data curation, R.B. and J.H.; writing—original draft preparation, R.B.; writing—review and editing, R.B. and L.K.; visualization, R.B.; supervision, L.K.; project administration, L.K.; funding acquisition, L.K. All authors have read and agreed to the published version of the manuscript.

Funding: This research received funding from Linz AG.

Acknowledgments: This work has been carried out together with Linz AG the district heating utility of Linz, which we especially want to thank to for providing the data and the insights to the challenges they face. Furthermore, the authors acknowledge TU Wien Bibliothek for financial support through its Open Access Funding Program.

Conflicts of Interest: The funders had no role in the analyses, or interpretation of data; in the writing of the manuscript, or in the decision to publish the results.

Appendix A

Table A1. Abbreviations and model parameter.

	Abbreviations	
CHP	Combined heat and power	
FLH	Full Load Hour	
LHV	Lower Heating Value	
	Model Parameter	
Variable	**Description**	**Unit**
c_{total}	total cost for heat generation	EUR
rev_{total}	total revenue from electricity production	EUR
$x_{th_{j,t}}$	Heat generation from the j-Generator at t-hour	MWh_{th}
$x_{el_{j,t}}$	Electricity generation from the j-Generator at t-hour	MWh_{el}
$x_{unload_{hs,t}}$	Thermal energy release from the hs-Storage at t-hour to the grid	MWh
$x_{load_{hs,t}}$	Thermal energy input into the hs-Storage at t-hour	MWh
$demand_{th_t}$	Heat Demand at t-hour	MWh
CC	Capital costs	EUR
FC	Fixed costs	EUR
VAR	Variable costs	EUR
$RAMP$	Ramp costs	EUR
Cap_j	Capacity of the j-Generator	MW
$sCap_{hs}$	Storage capacity of the hs-Storage	MWh
$opex_{FIX_j}$	Fixed operation cost of the j-Generator	EUR/MW
$opex_{FIX_{hs}}$	Fixed operation cost of the hs-Storage	EUR/MWh
i_j	specific investment cost of the j-Generator	EUR/MW
i_{hs}	specific investment cost of the hs-Storage	EUR/MWh
$\alpha_{j,hs}$	annuity of the j-Generator/hs-Storage	1
z	interest rate	1
$LT_{j,hs}$	life time of the j-Generator/hs-Storage	a
$opex_{var_j}$	Variable operational cost of j-Generator	EUR/MWh
$opex_{var_{hs}}$	Variable operational cost of hs-Storage	EUR/MWh
$p_{ec_{j,t}}$	Energy carrier price for j-Generator at t-hour	EUR/MWh
p_{CO_2}	CO_2 Certificate Price	EUR/t_{CO2}
$f_{em_{ec_j}}$	CO_2 emission factor of energy carrier for the j-Generator	t_{CO2}/MWh
$\eta_{th_{j,t}}$	Thermal efficiency for the j-Generator at t-hour	1
η_{el_j}	Electrical efficiency for the j-Generator	1
$p_{s.el_{j,t}}$	Electricity Sale Price for the j-Generator at t-hour	EUR/MWh_{el}

Table A2. Wholesale energy carrier and CO_2 prices for the different scenario sets (Sources: [13–15]).

	Year	2017	2030	2030
Energy Carrier	**Unit**	**Current**	**FossilHi_CO2-30**	**FossilLow_CO2-60**
Natural Gas	EUR/MWh $_{(LHV)}$	20.3	32.1	27.2
Coal	EUR/MWh	5.9	8.3	5.9
Oil	EUR/MWh	25.5	63.4	42.5
CO_2 price	EUR/t_{CO2}	7	30	60
Biomass	EUR/MWh	24.5	32.9	32.9
Waste	EUR/MWh	0	0	0
Excess heat high temp	EUR/MWh	15	15	15
Excess heat low temp	EUR/MWh	5	5	5

Table A3. Network and transportation cost parameter.

Cost Parameter	Value	Unit
Electricity system charge for feed in to network level 3.	1.57	EUR/MWh_{el}
Electricity system charge for feed in to network level 5.	1.93	EUR/MWh_{el}
Electricity system charges for electricity consumption on network level 4.	7.08	EUR/MWh_{el}
Electricity system charges for electricity consumption on network level 5.	9.47	EUR/MWh_{el}
Gas network utilisation charge in high pressure network (consumption > 200 GWh/a).	0.65	EUR/$MWh_{fuel\ (LHV)}$
Biomass transportation with truck within radius of 100 km.	2.80	EUR/MWh_{fuel}

Table A4. Tax and subsidy parameter (Source: e-control: https://www.e-control.at).

Tax Parameter	Value	Unit
Electricity consumption tax (15 EUR/MWh) and green electricity support payments on network level 4 (2.31 EUR/MWh).	17.31	EUR/MWh_{el}
Electricity consumption tax (15 EUR/MWh) and green electricity support payments on network level 5 (2.72).	17.72	EUR/MWh_{el}
Natural gas consumption tax of 6.6 ct/Nm^3 (@11.3 kWh/Nm^3) for natural gas heat only boiler.	5.84	EUR/MWh_{fuel}
CO_2-Certificate price for ETS plants depending on the energy price scenario.	30–60	EUR/t_{CO2}
Subsidy Parameter	**Value**	**Unit**
Feed in tariff for electricity generated by biomass CHP—Current (2017) tariff.	103	EUR/MWh_{el}
Optional fixed market premium additionally to the electricity revenues—Future (2030) tariff.	70	EUR/MWh_{el}

Table A5. Detailed model parameter of heat generation and heat storage units of the status quo and the future portfolio options.

Heat Generation Units							
Plant Name	Cap_j [MW_{th}]	$\eta_{th_{j,t}}$ [-]	η_{el_j} [-]	i_j [EUR/MW_{th}]	$opex_{FIX_j}$ [EUR]	$opex_{var_j}$ [EUR/MWh_{th}]	LT *[a]
WtE CHP	45	0.625	0.167	0	230,000	0	20
Bio CHP	24.8	0.679	0.222	0	23,000	8.2	20
CCGT_1	86.8	0.428	0.471	460,829	50,000	7.7	25
CCGT_2	71.5	0.342	0.461	0	50,000	10.8	25

Table A5. *Cont.*

Heat Generation Units							
Plant Name	Cap_j **[MW$_{th}$]**	$\eta_{th_{j,t}}$ **[-]**	η_{el_j} **[-]**	i_j **[EUR/MW$_{th}$]**	$opex_{FIX_j}$ **[EUR]**	$opex_{var_j}$ **[EUR/MWh$_{th}$]**	LT ***[a]**
GT CHP	132.4	0.595	0.309	415,408	30,000	4.2	25
ST CHP	54.4	0.485	0.426	459,559	25,000	8.8	25
HOB 1	124.5	0.896	0	0	4000	0	25
HOB 2	10	0.833	0	0	4000	0	25
HOB 3	15	0.938	0	0	4000	0	25
HP_FG	20	4	0	750,000	34,000	0	20
HP _WWC	10	3.5	0	430,000	34,000	0	20
HP_CW	10	3.6	0	400,000	34,000	0	20
HP_GW	5	2.1	0	580,000	34,000	0	20
HP_RW	10/50	2.1	0	580,000	34,000	0	20
ExH	30	1	0	267,000	1000	0	25
ExH_HP	30	3.5	0	430,000	34,000	0	20
Bio CHP_2	30	0.69	0.22	1,000,000	23,000	8	20
HP_FG	20	4	0	750,000	34,000	0	20
HOB 4	100	0.94	0	100,000	4000	0	25
Heat Storage Units							
Storage Name	Cap_j **[MW$_{th}$]**	$sCap_{hs}$ **[MWh$_{th}$]**		i_{hs} **[EUR/MWh$_{th}$]**	$opex_{FIX_{hs}}$ **[EUR]**	$opex_{var_{hs}}$ **[EUR/MWh$_{th}$]**	LT **[a]**
Daily Storage	60	1300		0	0	0	25
Daily Storage 2	80	2000		3000	0	0	25
Weekly Storage	140	12,000		2500	0	0	25

* The used lifetimes rather represent a financial depreciation time for the calculation of the annuity of the investment costs than an actual technical lifetime. These values were used in accordance with the district heating supplier who accepts this as a depreciation time for this kind of investment.

Table A6. Detailed results of the portfolio analysis.

Portfolio P0: Status Quo						
	2017_Current		**2030_FossilHi_CO2-30**		**2030_FossilLo_CO2-60**	
LCOH [EUR/MWh]	**42**		**38**		**24**	
RES Share [%]	**32**		**27**		**22**	
	FLH	**Energy [MWh]**	**FLH**	**Energy [MWh]**	**FLH**	**Energy [MWh]**
HOB 1	1760	26,400	1510	22,600	1020	15,300
HOB 2	550	68,900	690	86,400	520	64,800
HOB 3	90	900	230	2300	190	1900
Bio CHP	5580	138,300	3510	87,000	1840	45,600
CCGT 1	2200	190,900	3150	273,200	3920	340,500
CCGT 2	350	25,400	1120	80,100	2440	174,300
WtE CHP	8760	394,200	8730	392,700	8560	385,200
GT CHP	1800	237,900	700	92,800	300	39,200
DT CHP	980	53,500	2050	111,400	1860	101,400

Table A6. *Cont.*

Portfolio P1: Heat Pump						
	2017_Current		2030_FossilHi_CO2-30		2030_FossilLo_CO2-60	
LCOH [EUR/MWh]	**46**		**39**		**24**	
RES Share [%]	**32**		**29**		**22**	
	FLH	**Energy [MWh]**	**FLH**	**Energy [MWh]**	**FLH**	**Energy [MWh]**
HOB 1	1260	18,900	970	14,500	440	6500
HOB 2	390	48,100	440	54,400	250	31,000
HOB 3	70	700	140	1400	100	1000
Bio CHP	0	0	30	700	30	700
CCGT 1	2230	193,500	2820	245,100	4040	350,700
CCGT 2	520	36,800	1300	93,100	3040	217,500
WtE CHP	8760	394,200	8740	393,300	8540	384,300
GT CHP	1270	168,200	720	94,700	490	64,800
DT CHP	1210	66,000	1960	106,500	2310	125,600
HP_RW	2450	24,500	2280	22,800	1200	12,000
HP_GW	2440	12,200	2260	11300	1190	6000
HP_CW	4180	41,800	3520	35,200	1680	16,800
HP_WWC	3980	39,800	3400	34,000	1620	16,200
HP_FG	4720	94,400	3860	77,200	1810	36,200
Portfolio P2: Excess heat integration						
	2017_Current		**2030_FossilHi_CO2-30**		**2030_FossilLo_CO2-60**	
LCOH [EUR/MWh]	**43**		**37**		**24**	
RES Share [%]	**39**		**37**		**27**	
	FLH	**Energy [MWh]**	**FLH**	**Energy [MWh]**	**FLH**	**Energy [MWh]**
ExH_HP	5270	158,200	4630	139,000	2190	65,800
HOB 1	1280	19,100	1140	17,100	690	10,400
HOB 2	370	46,000	460	57,400	340	42,100
HOB 3	70	700	140	1400	120	1200
Bio CHP	0	0	50	1100	40	1100
CCGT 1	2110	183,200	2690	233,500	3770	32,6900
CCGT 2	370	26,500	1010	71,900	2380	170,200
WtE CHP	8760	394,200	8730	392,700	8560	385,200
GT CHP	1180	156,300	440	58,100	180	23,200
DT CHP	1000	54,400	1580	85,900	1730	94,000
ExH	3220	96,500	3000	89,900	1620	48,500

Table A6. *Cont.*

Portfolio P3: Biomass						
	2017_Current		2030_FossilHi_CO2-30		2030_FossilLo_CO2-60	
LCOH [EUR/MWh]	**46**		**40**		**27**	
RES Share [%]	**40**		**37**		**27**	
	FLH	**Energy [MWh]**	**FLH**	**Energy [MWh]**	**FLH**	**Energy [MWh]**
Bio CHP 2	5470	164,100	4840	145,300	2420	72,600
HOB 1	1450	21,700	1280	19,200	800	12,000
HOB 2	430	53,100	530	65,500	390	48,500
HOB 3	80	800	160	1600	130	1300
Bio CHP	0	0	80	2100	80	1900
CCGT 1	2040	176,700	2750	239,000	3830	332,000
CCGT 2	300	21,500	970	69,000	2310	165,300
WtE CHP	8760	394,200	8730	392,700	8560	385,200
GT CHP	1290	171,300	440	58,000	150	20,000
DT CHP	780	42,600	1510	82,300	1700	92,500
HP_FG	4510	90,200	3660	73,100	1890	37,700
Portfolio P4: Renewable						
	2017_Current		**2030_FossilHi_CO2-30**		**2030_FossilLo_CO2-60**	
LCOH [EUR/MWh]	**34**		**35**		**35**	
RES Share [%]	**60**		**63**		**63**	
	FLH	**Energy [MWh]**	**FLH**	**Energy [MWh]**	**FLH**	**Energy [MWh]**
ExH_HP	5030	151,000	5220	156,700	5290	158,800
HOB 1	490	7300	400	6100	490	7400
HOB 2	70	9300	100	12,300	90	10,900
HOB 3	0	0	0	0	0	0
HOB 4	1260	126,100	870	87,100	1170	117,100
Bio CHP	0	0	2110	52,200	3140	78,000
WtE CHP	8760	394,200	8760	394,200	8760	394,200
ExH	4140	124,300	3970	119,000	3790	113,700
HP_RW	2060	102,800	2350	117,500	1520	76,000
HP_GW	1650	8200	1980	9900	1370	6900
HP_CW	5040	50,400	4390	43,900	4120	41,200
HP_WWC	4880	48,800	4280	42,800	4000	40,000
HP_FG	5340	106,900	4690	93,800	4620	92,300

References

1. Werner, S. District Heating and Cooling. In *Reference Module in Earth Systems and Environmental Sciences*; Elsevier: Amsterdam, The Netherlands, 2013.
2. Connolly, D. Heat Roadmap Europe: Combining district heating with heat savings to decarbonise the EU energy system. *Energy Policy* **2014**, *65*, 475–489. [CrossRef]

3. Directive (EU) 2018/ 2001 of the European Parliament and of the Council—of 11 December 2018—on the Promotion of the Use of Energy from Renewable Sources. Available online: https://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX:32018L2001 (accessed on 10 January 2020).
4. Büchele, R.; Kranzl, L.; Hummel, M. What is the impact of the policy framework on the future of district heating in Eastern European countries? The case of Brasov. *Energy Strategy Rev.* **2018**, *19*, 72–75. [CrossRef]
5. Sandberg, E.; Sneum, D.M.; Trømborg, E. Framework conditions for Nordic district heating—Similarities and differences, and why Norway sticks out. *Energy* **2018**, *149*, 105–119. [CrossRef]
6. Andrić, I.; Fournier, J.; Lacarrière, B.; le Corre, O.; Ferrão, P. The impact of global warming and building renovation measures on district heating system techno-economic parameters. *Energy* **2018**, *150*, 926–937. [CrossRef]
7. Lund, H. The status of 4th generation district heating: Research and results. *Energy* **2018**, *164*, 147–159. [CrossRef]
8. Büchele, R.; Kranzl, L.; Hummel, M. Integrated strategic heating and cooling planning on regional level for the case of Brasov. *Energy* **2019**, *171*, 475–484. [CrossRef]
9. Lund, H.; Duic, N.; Østergaard, P.A.; Mathiesen, B.V. Future district heating systems and technologies: On the role of smart energy systems and 4th generation district heating. *Energy* **2018**, *165*, 614–619. [CrossRef]
10. Werner, S. International review of district heating and cooling. *Energy* **2017**. [CrossRef]
11. Hasani, J.; Schmidinger, D. HotMaps/Dispatch_Module. Available online: https://wiki.hotmaps.eu/en/CM-District-heating-supply-dispatch (accessed on 12 May 2020).
12. Hartner, M.; Permoser, A. Through the valley: The impact of PV penetration levels on price volatility and resulting revenues for storage plants. *Renew. Energy* **2018**, *115*, 1184–1195. [CrossRef]
13. IEA Publications. World Energy Outlook, International Energy Agency: France 2016. Available online: https://webstore.iea.org/world-energy-outlook-2016 (accessed on 28 January 2019).
14. European Commission. EU Reference Scenario 2016 Energy, Transport and GHG Emissions Trends to 2050. Available online: https://ec.europa.eu/energy/sites/ener/files/documents/20160713%20draft_publication_REF2016_v13.pdf (accessed on 14 July 2017).
15. Resch, G.; Burgholzer, B.; Totschnig, G.; Lettner, G.; Auer, H.; Geipel, J. Stromzukunft Österreich 2030—Analyse der Erfordernisse und Konsequenzen Eines Ambitionierten Ausbaus Erneuerbarer Energien. 2017, p. 98. Available online: https://www.igwindkraft.at/mmedia/download/2017.07.10/1499698755049626.pdf (accessed on 12 May 2020).
16. Wetterlund, E.; Leduc, S.; Dotzauer, E.; Kindermann, G. Optimal localisation of biofuel production on a European scale. *Energy* **2012**, *41*, 462–472. [CrossRef]
17. Totschnig, G. Potentiale, Wirtschaftlichkeit und Systemlösungen Für Power-to-Heat. Available online: https://nachhaltigwirtschaften.at/resources/sdz_pdf/berichte/schriftenreihe_2018-30-p2hpot.pdf (accessed on 12 May 2020).
18. European Commission. Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions. Available online: https://www.eea.europa.eu/policy-documents/communication-from-the-commission-to-1 (accessed on 12 May 2020).