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An Integrated Approach to Long-Term Fuel Supply Planning in Combined Heat and Power Systems

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Abstract: This paper examines the issue of strategic planning of fuel supplies in combined heat and power systems. This is a major challenge in energy modeling because heating-degree day calculation methods only address short-term horizons and are not suitable for the long-term planning of fuel supplies. In this work, a comprehensive method is proposed for strategic fuel supply planning of independent heat producers. The method considers changes in the market dynamics of residential and commercial properties, the annual rate of customer acquisition by the network operator, customer disconnections, as well as the thermal modernization of buildings for estimating the long-term thermal energy demand of an urban area. Moreover, the method develops a mathematical model to minimize production costs, taking into account the technical constraints of the system. The proposed strategic planning tool, in addition to information on the quantities of fuel consumed for heat and electricity production, also provides valuable management information on the operational costs of the CHP system and its environmental impact. The application of the method is illustrated with the analysis of a large-scale combined heat and power plant supplying heat and electricity to a city with over 500,000 inhabitants. The results indicate that depending on the changes in the primary and secondary heat markets, the demand for energy carriers may range from 107.37 TWh to 119.87 TWh.

Keywords: combined heat and power; fuel supply planning; heat market; strategic heat planning; district heating systems; optimization

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1. Introduction

With the liberalization of energy markets, every economic unit operating in a competitive market setting must have carefully prepared and effectively implemented management strategies. The fundamental objectives of such strategies are to enhance the adaptability of the economic unit to new operating conditions occurring in increasingly volatile market environments.

Over the years, strategic planning has become a valuable tool for effectively managing energy companies. Strategic planning applies not only to generation companies competing in electricity markets but also to companies that actively participate in local heat markets (e.g., energy companies that produce heat and electricity using cogeneration processes) [1]. Since this level of planning deals with allocating resources to attain objectives far into the future (typically involving decisions, actions, or targets on a time scale of decades, e.g., planning periods of 10 to 20 years), strategic planning has been viewed primarily as an analytical process employed by owners and operators of cogeneration plants and district heating systems to determine the best course of action for future investments [2]. Moreover, strategic planning has been used by firms, authorities and policy-makers to optimize resources [3], develop energy infrastructure, and enable the realization of local visions created by different actors (e.g., environmental targets and diversification plans) [4].

Thanks to advances in computational power and the development of integrated tools capable of assisting decision-makers in the energy sector, there is an increasing interest in new instruments and decision support systems capable of developing new strategies for future competitive environments and charting the course of long-term objectives in contract negotiations [5], governance and climate transition [6], fuel purchase and storage [7], as well as carbon capture and storage [8].

Although considerable research effort has been expended on the development of decision-support tools for power-generation investment planning, very little research work has proposed strategic planning tools for long-term contract negotiations and long-term fuel purchase and storage (strategic planning) in combined heat and power (CHP) systems and district heating systems (DHS).

1.1. Related Reserch

Initial research efforts related to the strategic planning of fuel purchase were centered on the shipping and blending of fuel from overseas suppliers for power plants participating in electricity markets. For example, Liu and Sherali [9] developed a heuristic procedure combined with branch-and-bound methods for minimizing the total costs incurred in shipping coal from possible coal contract sources. Huang and Wu [10] developed a model that combined portfolio theory and mathematical programming for the purchase of coal in a Taiwanese state-owned electric utility company. Yucekaya [11] presented a multi-objective optimization model to minimize the fuel supply of coal-fired power units considering multimode transportation and multiple coal products. Shiromaru et al. [12] addressed the problem of coal purchase planning in an electric power plant using a two-level programming approach comprised of a genetic algorithm and a fuzzy satisficing method. Rosyid and Adachi [13] employed a mixed-integer linear programming model to optimize the allocation of coal supply for power generation in Indonesia. In a similar manner, Baskoro et al. [14] presented a multi-objective optimization model using the epsilon-constraint method to secure the long-term supply of coal for coal-fired power plants in Indonesia. Aditya et al. [15] investigated the optimum coal safety stock level in a coal-fired power plant using two policy inventory management processes (continuous and periodic review). More recently, Prasad and Mangaraj [16] proposed a competitive design framework based on a multi-objective optimization technique for fuel procurement in coal-fired power plants in India.

In previous work dealing with strategic fuel supply decisions, little consideration has been given to areas related to heat demand planning and emission costs in CHP plants and DHS—even though emission costs are responsible for a significant share of the total costs incurred by cogeneration companies using fossil fuel energy sources [17,18]. Among the research studies that have targeted the strategic planning of fuel procurement for CHP plants, Bruglieri and Liberti [19] presented two planning models for the optimal running and planning of a biomass-based energy production process comprised of electricity production plants and combined heat and power plants. De Meyer et al. [20] developed a mathematical model to optimize the strategic and tactical decisions of a biomass-based supply chain that includes CHP installations as technologies for heat generation. Chiarandini et al. [21] formulated a mixed-integer linear programming model for the integrated planning of fossil and biomass fuel supply inventory and energy production. Guericke et al. [22] proposed a stochastic optimization model to support biomass supply planning for the optimal operation of a CHP plant directly connected to a district heating network. Palander and Voutilainen [23] presented a decision support system based on a dynamic linear optimization model for the long-term fuel procurement scheduling and storage problem of a Finnish CHP plant. In a more recent work [24], Palander and Voutilainen developed an optimization model to tackle the problem of decentralized fossil, peat and wood-waste fuel procurement in a CHP plant considering the energy content of fuel assortment. Ranta and Korpinen [25] evaluated the maximum availability of forest fuels to CHP plants in Finland using a resource-focused approach and an allocation model.

Despite that recent emphasis on the research of strategic fuel supply planning for cogeneration plants and district heating systems, the studies mentioned above do not consider the impact of future variations in heat demand—mainly due to changes in the residential and commercial property market dynamics, the annual rate of customer acquisition by the network operator, customer disconnections, and thermal modernization of buildings—on the yearly fuel requirements of the systems investigated. In this context, this work develops a comprehensive method for supporting the decision-making process of strategic fuel resource planning in large-scale CHP plants. The method addresses the needs that have emerged in the heating sector as a result of the implementation of decarbonization policies and the actions taken by governments to combat climate change (e.g., the European Green Deal, the U.S. Net-zero 2050 goal). The method differs from the solutions proposed in earlier work in its ability to project the future thermal needs of a district heating market, estimate the demand for fuels (including their type and quantity) taking into consideration various scenarios of technological transformation, and to provide a general production strategy that aims to minimize the total operating costs of the system. Furthermore, the production strategy offers valuable insight into the average variable production costs per unit and the estimated environmental costs of CO_2 emissions and other pollutants.

1.2. Contributions of the Study

The literature review presented in Section 1 shows that only a limited number of studies have proposed methods for supporting the long-term energy planning of cogeneration systems. The current research achievements in the area indicate that the vast majority of research publications address specific elements of the strategic energy planning process in combined heat and power plants or district heating systems such as operational decisions (scheduling of heat and electricity dispatch) and planning for the expansion of capacity. However, there is no comprehensive approach that considers the local heat market dynamics for establishing a long-term fuel procurement strategy in large-scale cogeneration systems.

Considering the abovementioned issues and the fact that the strategic planning of fuel procurement can be combined with the simultaneous minimization of production costs, there is a need to fill the cognitive gap in the area of study by developing a method for optimizing the fuel acquisition requirements and usage in CHP systems connected to district heating networks. Due to the complexity of the existing conditions affecting the functioning of district heating systems (e.g., market, environmental, and technical conditions), it is necessary to construct an adequate framework that considers the key technological and economic elements present in the operation of independent heat suppliers. Moreover, the framework should be able to reliably plan the demand for energy resources over a strategic time horizon. Therefore, this work contributes to the existing literature by:

- Proposing a method for estimating the long-term thermal demand in a district heating system considering district heating market dynamics.
- Developing a mathematical model capable of estimating the long-term fuel demand in a combined heat and power plant while minimizing the cost of energy production (heat and electricity) and considering the key operating constraints of the system.
- Employing the proposed methods to explore the case study of a CHP system connected to a district heating network in a city with more than 500,000 inhabitants. This particular case is relevant for demonstrating the versatility of the method because it includes several market entities and is as an example of a complex competitive heat energy market. Moreover, the case study is a contrasting case to simpler and often vertically integrated utilities found in Poland.
- Showing the impact of potential fuel and emission prices on the tactical and strategic planning of heat sources in an independent producer.

Against this background, the theoretical contribution of this study is not only to fill the research gap but to provide a practical method for CHP plants to use while experiencing extraordinary financial conditions due to the recent energy price hikes in competitive markets. Compared to previous and recent studies, this paper proposes a novel integrated approach for long-term fuel procurement in complex CHP systems considering the fluctuations in property market dynamics, customer acquisition rate, and the thermal modernization of the building stock. Although this paper concentrates on the fuel procurement of independent heat producers with coal- and gas-based generation portfolios, the proposed optimization model is formulated in a generalized way allowing for its application to any cogeneration or district heating system. It should be noted that the application of the proposed approach is oriented to estimate the long-term thermal energy demand of an urban area considering the fluctuations in the residential and commercial property market dynamics; therefore, it is advisable to use the method for medium- and large-scale district heating systems.

With the above scope in mind, the rest of the article has the following structure. Section 2 presents the method for estimating long-term thermal energy demand in district heating systems as well as the decision to support tools capable of supporting the strategic planning of a combined heat and power system. Section 3 describes a case study of a CHP system owned by an independent heat producer and operating for a local district heating market, including input data and research scenarios. Section 4 presents the results of the case study and research scenarios. Finally, Section 5 summarizes and concludes the article.

2. Materials and Methods

In order to develop a comprehensive method for supporting the strategic decision of fuel procurement of independent heat producers with coal- and gas-based generation portfolios, this study proposes a practical method for estimating the long-term thermal energy demand of an urban area considering the fluctuations in the residential and commercial property market dynamics, the annual rate of customer acquisition by the network operator, customer disconnections, and the thermal modernization of buildings. Moreover, to tackle the issue of the strategic planning of fuel procurement combined with the simultaneous minimization of production costs, this paper develops a computable model with high enough accuracy to allow the capture of the techno-economic characteristics of the heat sources of an independent heat producer. Figure 1 shows a diagram of the method developed in this study.

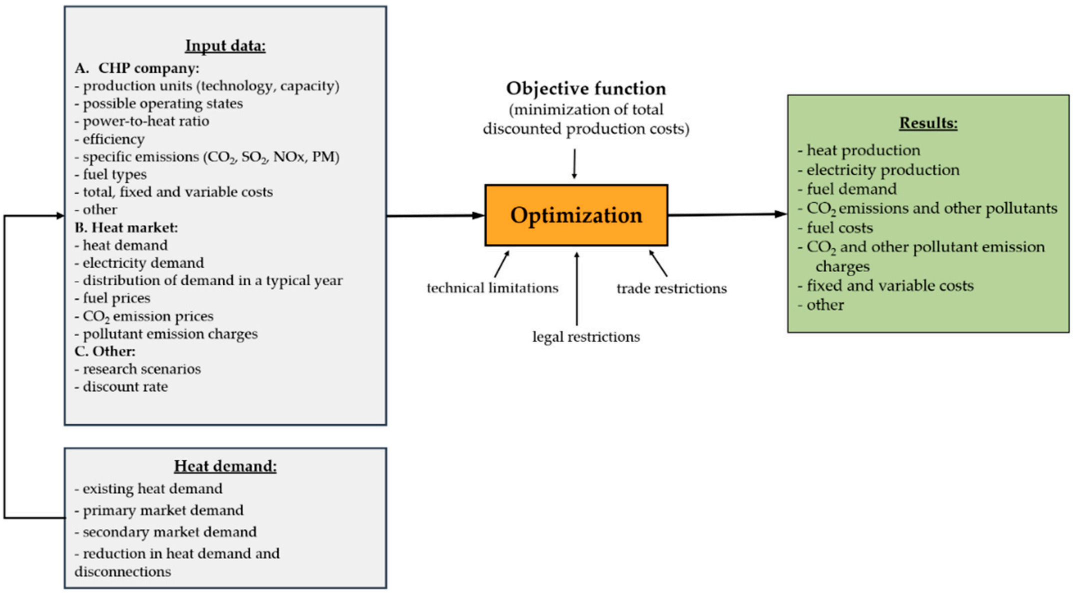


Figure 1. Flowchart of the decision support method.

To the best of the authors' knowledge, no previous study has reported or proposed a practical solution for long-term fuel procurement in complex CHP systems considering the fluctuations in property market dynamics, customer acquisition rate, and the thermal modernization of the building stock. The following sections provide more detailed information on the elements of the proposed method.

2.1. Heat Demand Model

Thus far, the modeling and approximation of changes in thermal energy demand at the city level—mainly due to variation in heat use for space heating and hot water preparation—have been performed using top-down approaches that rely on predictive variables such as heating degree days, number of persons per household, GDP, among others [26,27]. Although these approaches have been essential for developing policies and estimating the use of energy for heating, the existing approaches tend to ignore the future trends of the local property market (e.g., property market development, customer acquisition, improvement in energy performance of residential and commercial units) and the market activity of independent district heating producers.

Therefore, this paper contributes to the state of the art by proposing a practical model for projecting the thermal demand of a defined urban area considering five components:

- Heat demand in the previous year
- Heat demand from the primary market
- Heat demand from the secondary market
- Heat demand reduction due to customer disconnections
- Heat demand reduction due to the thermal modernization of buildings

The proposed heat demand model uses information that is often available to district heating planners and independent district heating suppliers. Moreover, it is a simple and intuitive method for projecting the heat demand of an urban area that can be implemented on a spreadsheet program. Equation (1) describes the relationship between the five components.

$$D_{T(\mathrm{y})} = D_{\mathrm{T(y-1)}} + D_{PM(\mathrm{y})} + D_{SM(\mathrm{y})} - D_{\mathrm{MRD(y)}} - D_{\mathrm{MRM}(y)} \tag{1}$$

where $D_{T(y)}$ stands for the heat demand in year y (MWt), $D_{T(y-1)}$ is the heat demand in the previous year $(y-1)$ (MWt), and $D_{PM(y)}$ is the annual increase in heat demand due to changes in the primary heat market (MWt). The annual increase in heat demand from changes in the secondary heat market is described by $D_{SM(\mathrm{y})}$ (MWt). Moreover, $D_{\mathrm{MRD(y)}}$ represents the annual reduction in heat demand resulting from permanent disconnections of district heating consumers (MWt), and $D_{\mathrm{MRM}(y)}$ is the annual reduction in heat demand resulting from the thermal modernization of existing buildings (MWt).

2.1.1. Primary Heat Market

The overall change in demand in the primary heat market $\left(D_{PM(y)}\right)$ is linked to residential and commercial property market dynamics. This relationship can be disaggregated into three components: annual increase in heat demand due to newly built residential properties $\left(D_{DR(y)}\right)$ (MWt), annual increase in heat demand from newly constructed non-residential buildings $\left(D_{DNR(y)}\right)$ (MWt), and annual increase in demand arising from new products and services offered by the district heating network operator $\left(D_{NP(y)}\right)$ (MWt). The annual increase in the primary heat market can be found as formulated in Equation (2):

$$D_{PM(y)} = D_{DR(y)} + D_{DNR(y)} + D_{NP(y)} \tag{2}$$

For newly built residential and non-residential buildings, the annual increase in heat demand can be estimated from the cadastral data of usable floor area (building typology) and energy performance indicators for heating, ventilation and domestic hot water preparation [28]. The calculations should also take into account the share of district heating in the city's heat demand balance as well as the share of a specific producer in the local district heating market.

The annual increase in heat demand for investments other than residential (office buildings, commercial, cultural and entertainment facilities, etc.) can be computed in a similar way considering the annual increase in the usable area of these types of buildings and their corresponding energy performance indicators.

In the coming years, new products and services offered by the network operator are expected to be available to consumers. Consequently, the proposed heat model may also be expanded to account for the increase in heat demand from new products/services such as the production of cooling for air conditioning. Such services in district energy systems can be achieved using various types of absorption and adsorption chillers and vapor-compression chillers [29].

2.1.2. Secondary Heat Market

The change in the annual thermal demand of a defined urban area can also be attributed to the fluctuation in the yearly rate of customer acquisition by the network operator. In the proposed model, the changes in the structure of the secondary heat market are associated with the market potential of new customers from areas outside the district heating network (i.e., potential customers are in locations where preliminary plans exist to extend the district heating network). It is worth highlighting that the changes in this market segment can also be attributed to the implementation of hot water programs that support the replacement of old boilers and incentivize the utilization of highly efficient heat generation sources such as central hot water installations. New customers in this market segment comprise owners of existing buildings that can connect to the district heating system and are expected to replace their small-scale fuel-powered boilers used to prepare domestic hot water (e.g., individual sources powered by gas or electricity). Therefore, the overall thermal demand in the secondary heat market can be calculated as the sum of the demand from new customers (driven by expansion of the district heating network) and demand through customer acquisition from the replacement of small-scale fuel-powered boilers. These two components are accounted for using Equation (3).

$$D_{SM(y)} = D_{DNE(y)} + D_{DBP(y)} \tag{3}$$

where $D_{SM(y)}$ stands for the heat demand of the secondary market in year y (MW_t), $D_{DNE(y)}$ is the heat demand from new customers due to network expansion (MW_t), and $D_{DBP(y)}$ is the additional demand from replacing small-scale fuel-powered boilers (MW_t).

2.1.3. Customer Disconnections and Thermal Modernization of Buildings

In recent years, numerous studies have reported that the building sector accounts for nearly one-third of total global final energy use [30] prompting governments to roll out ambitious measures to increase the energy efficiency of national stocks of existing buildings. For example, in 2018, the European Commission revised the Energy Performance of Buildings Directive (EPBD) and established the requirement for EU countries to adopt long-term building renovation strategies that include policies and actions to target the renovation of the worst-performing buildings and mobilize the financial institutes to support the transformation of existing buildings into near zero-energy buildings [31]. Consequently, in the proposed heat demand model, the long-term projections consider (a) the reduction in annual demand $\left(D_{\mathrm{MRD(y)}}\right)$ because of the permanent disconnections of customers from the district heating network, and (b) the heat demand reduction resulting from the thermal modernization of the existing building stock $\left(D_{\mathrm{MRM}(y)}\right)$, as presented in Equation (1).

2.2. Optimization Model

In the energy sector, optimization models are often used by decision-makers as normative tools. In other words, they are used in practice to identify the most efficient or optimal path towards achieving an objective while satisfying a set of constraints. This section develops a mathematical program for (1) optimizing the fuel acquisition requirements and usage in large-scale cogeneration systems connected to district heating networks and (2) establishing the long-term operational plan of the constituent elements in the CHP system (peaking boilers and steam turbines).

An important characteristic of cogeneration systems is their ability to satisfy the heat and electricity demand of a specific region of interest. In this context, Equations (4) and (5) present the main assumptions adopted for the definition of the heat and electricity supply–demand requirements. Equation (4) expresses the system's heat supply–demand relationship. This constraint implies that the sum of the thermal energy production of turbogenerators and peaking boilers $\left(Q_{i,s,y}\right)$ must be greater than or equal to the heat demand $\left(DQ_{s,y}\right)$ in time slice s in year y.

$$\sum_i Q_{i,s,y} \geq DQ_{s,y} \qquad \forall s, y \tag{4}$$

In a similar way, Equation (5) expresses the electricity supply–demand requirements. In this case, the electricity demand $\left(DE_{s,y}\right)$ in time slice s in year y must be satisfied by the total electricity generated in production units that are mainly intended for cogeneration processes. The calculation of the electricity output from production units i is based on the power-to-heat ratio $\left(\sigma_{i,y}\right)$. We would point out that this modeling approach has been used extensively to represent the electricity–heat production possibility sets of cogeneration activities [32,33].

$$\sum_i \left(Q_{i,s,y} \cdot \sigma_{i,y}\right) \geq DE_{s,y} \qquad \forall s, y \tag{5}$$

Equation (6) defines the upper bound of the thermal energy production of turbogenerators and peaking boilers $\left(Q_{i,s,y}\right)$ in time slice s in year y. It guarantees that the thermal output of each production unit i is lower than or equal to its maximum continuous rating considering fuel types, grid constraints, and planned/unplanned downtimes, among other factors [34,35]. $AF_{i,s,y}$ is defined as the fraction of time duration that a unit is available to produce heat or electricity at its rated capacity. $Q^{Max}_{i,y}$ is the maximum achievable thermal power output of production unit i in year y, and T_s is the duration of time slice s. It is worth noting that the average availability factors of production unit i can be estimated from historical plant datasets.

$$Q_{i,s,y} \cdot T_s \leq AF_{i,s,y} \cdot Q^{Max}_{i,y} \cdot T_s \qquad \forall i, s, \mathrm{y} \tag{6}$$

Equation (7) defines the upper bound of the electricity generated in cogeneration activities. The electrical output of production unit i, calculated as the product of the thermal power output and power-to-heat ratio $\left(\sigma_{i,y}\right)$, cannot exceed its maximum continuous rating $\left(E^{Max}_{i,y}\right)$ in year y.

$$Q_{i,s,y} \cdot \sigma_{i,y} \cdot T_s \leq AF_{i,s,y} \cdot E^{Max}_{i,y} \cdot T_s \qquad \forall i, s, \mathrm{y} \tag{7}$$

Note that for production units without steam condensation, the power-to-heat ratio can be calculated using Equation (8), while for production units with steam condensation, the power-to-heat ratio can be determined using Equation (9) [36].

$$\sigma = \frac{\eta^E_T}{\eta_0 - \eta^E_T} \tag{8}$$

$$\sigma = \frac{\eta^E_{Non-CHP} - \beta * \eta_0}{\eta_0 - \eta^E_{Non-CHP}} \tag{9}$$

where η^E_T stands for the efficiency of total electricity generation and η_0 for the overall efficiency threshold established for a given technology. The power-to-heat ratio presented in Equation (9) considers the efficiency of the total electricity generation of the CHP equipped with steam condensation $\left(\eta^{E}_{Non-CHP}\right)$ and the loss of electricity generation per unit of heat extracted (β).

To properly reflect the operating characteristics of the turbogenerators and peaking boilers, it is also necessary to model their technical minimum production levels. Equation (10) sets the lower bound of the allowable thermal output of production unit i in time slice s in year y. The lower bound $b^{Min}_{i,s}$ is defined as a percentage of the operational capacity of the production unit [37].

$$Q_{i,s,y} \geq b^{Min}_{i,s} \cdot Q^{Max}_{i,y} \qquad \forall i, s, y \tag{10}$$

In addition to the previously identified technical constraints, combined heat and power systems often face specific limitations imposed by the requirements of the district heating system operator. For instance, the operators may introduce contractual limitations on the maximum flow rate and temperature of the heat carrier injected into the network. As a result, the production capacity of simultaneously operating units equipped with a particular type of steam turbine (e.g., extraction-condensing steam turbines) should be within the permissible range established by the CHP system owner and the district heating network operator. Equation (11) enforces the contractual limitations that preclude the CHP system owner from operating all turbogenerators simultaneously, preventing flow rates of the heat carrier which exceed the allowable levels of the district heating network.

$$\sum_{tg} Q_{tg,s,y} \leq Q^{Max-DHN} \qquad \forall s, y \tag{11}$$

The reduction in pollutants and carbon dioxide emissions has become a major global concern. In this context, EU member states have developed and adopted specific policies and standards to reduce carbon dioxide (CO_2) and other pollutant emissions (SO_2, NOx, PM) [38]. Equation (13) sets the upper bound of the total emissions in a calendar year according to the notifications submitted by the operators of installations covered by the Transitional National Plan (TNP) [39]. In this study, the total quantity of pollutants emitted from the combustion of fossil fuels in year y is calculated as the sum of the products of the thermal power produced $\left(Q_{i,s,y}\right)$, duration (T_s) and emission factors of a given pollutant $\left(Ef_{i,p,y}\right)$. Equation (12) indicates that the total pollutants emitted from the combustion of fossil fuels must be lower or equal to the emission limits set in the TNP for a given year $\left(TE^{Max}_{p,y}\right)$.

$$\frac{\sum_{i,s}\left(Q_{i,s,y} \cdot T_s \cdot Ef_{i,p,y}\right)}{M} \leq TE^{Max}_{p,y} \qquad \forall y, z \tag{12}$$

The objective function minimizes the TC while meeting all the constraints formulated in the optimization model. The total production costs are discounted for the base year using Equation (13). The total discounted production costs (TC) of the CHP system are calculated using Equation (14).

$$Df = \left(1 + r_y\right)^{-y} \tag{13}$$

$$min. \qquad TC = \sum_{y} Df \cdot \left(C^{FX}_{y} + \frac{\left(C^{VR}_{y} + C^{FL}_{y} + C^{E}_{y}\right)}{M} \right) \tag{14}$$

The individual components of the objective function are presented in Equations (15)–(18) and can be described as follows:

- Fixed costs: calculated as the sum of the product of the power output of production unit i and the corresponding fixed cost per unit of installed capacity, Equation (15).
- Variable costs (excluding fuel and environmental costs): calculated as the sum of the product of the power generated by unit i and the variable costs per unit of heat output, Equation (16).

- Fuel costs: computed using the amount of heat and electricity produced, power generation efficiency of unit i, and the corresponding prices of the energy carriers f, Equation (17).
- Greenhouse gas emission costs: computed using the amount of heat produced, emission factors of individual pollutants per unit of heat produced, and prices of emission permits for pollutants p, Equation (18).

$$C_y^{FX} = \overbrace{\sum_i C_{i,y}^{UFC} \cdot Q_{i,y}^{Max}}^{Fixed\ costs} \tag{15}$$

$$C_y^{VR} = \overbrace{\sum_{i,s} C_{i,y}^{UVC} \cdot Q_{i,s,y} \cdot T_s}^{Variable\ costs} \tag{16}$$

$$C_y^{FL} = \overbrace{\left(\sum_{i,s} Q_{i,s,y} \cdot \left(1 + \sigma_{i,y}\right) \cdot \left(\frac{\sum_f FP_{f,y} \cdot L_{i,f}}{\eta_{i,y}^{EC}} \right) \cdot T_s \right)}^{Fuel\ costs} \tag{17}$$

$$C_y^{E} = \overbrace{\sum_{i,s} C_{p,y}^{EC} \cdot Ef_{i,p,y} \cdot Q_{i,s,y} \cdot T_s}^{Emission\ costs} \tag{18}$$

3. Case Study

The method developed in Section 2 was applied to the case study of a coal-based cogeneration system connected to a district heating network. The installation is operated by an energy supply company interested in developing a long-term strategy for fuel procurement (2022–2040). Long-term fuel procurement strategies have become critical for the profitability of companies that operate in liberalized energy markets. Often, energy supply companies employ a traditional purchasing approach such as the least-cost method (involving short-term spot market transactions). In such methods, the quantities of coal/gas/oil purchased by the company are determined without a detailed analysis of the risk associated with the price of fuel [10]. Because of the rapid pace of change in short-term spot market transactions, various factors and risks associated with the shipping combinations and quality of fuel tend to be overlooked. In this context, the energy supply company is interested in sourcing diversification (diversifying the portfolio of suppliers) which will enhance its energy security and minimize the risk of short-term supply disruptions.

It is worth highlighting that the city in which the CHP plant is located has a separate ownership system for the generation, transmission, and distribution of heat, as shown in Figure 2. The district heating network in the city is owned by one municipal company, which acts as the operator of the heat transmission and distribution system. In the city, there are three independent heat suppliers—one supplier offering heat using renewable energy and two conventional heat suppliers, including the CHP system investigated. The share of thermal demand met by the CHP system in the municipal heating network is approximately 70%.

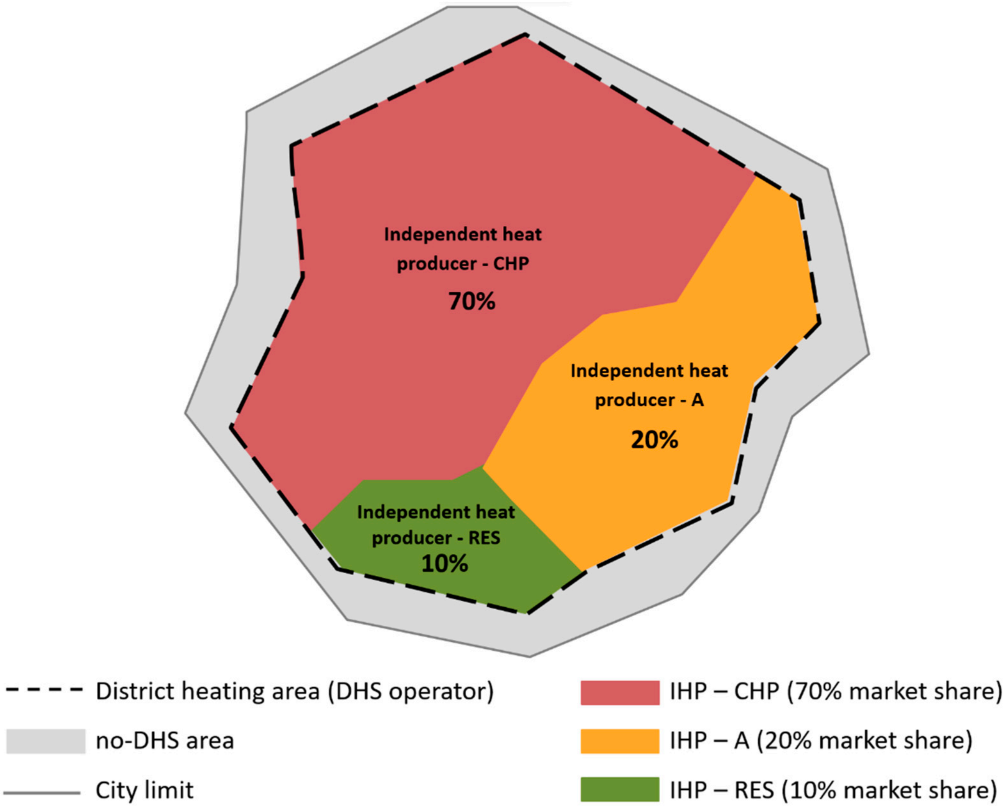


Figure 2. Local heat market.

The cogeneration system supplies heat to the city in the form of hot water (mainly for space-heating purposes and domestic hot water) and simultaneously generates electricity for the needs of the national power system. The electricity is transferred via a 110 kV power transmission line to the local distribution system operator (DSO). The majority of the heat generated by the CHP is sold to the local heat network operator, while direct sales to customers connected to the internal network of the combined heat and power plant make up a negligible share.

The CHP system consists of four turbogenerators and a boiler cascade system. The auxiliary units in the boiler cascade system are only used during periods of maximum heat demand at extremely low temperatures. Currently, the primary fuel used by the system is bituminous coal; however, in years to come, the energy supply company is likely to switch to gas-based power generation technologies (HOB-A:H in 2028, CHP-200 MW_t in 2037, CHP-150 MW_t in 2038), and to using waste heat energy (large water-sourced heat pumps based on cooling water in 2028). Light fuel oil is used to sustain and stabilize the combustion processes, firing up the boilers, as well as in emergency situations. The technical characteristics of the system components are presented in Table 1.

Table 1. Technical characteristics of the CHP system.

Unit Name	Component Technology	Component Type	Thermal Capacity
SB-EC-1	Turbine	Extraction-condensing	158 MW_t
SB-EC-2	Turbine	Extraction-condensing	158 MW_t
SB-BP-1	Turbine	Backpressure	191 MW_t
SB-BP-2	Turbine	Backpressure	191 MW_t
HOB-A:H	Boiler(s)	High-temperature water boiler(s)	280 MW_t

3.1. Input Data

The case study used for demonstrating the functionalities of the proposed method was constructed based on an existing large-scale CHP system located in Poland. In an attempt to decrease the computational complexity of the problem, the annual thermal load of the CHP system was discretized into representative time slices. Discretizing duration curves of a full year is a well-established technique used in linear optimization models constructed for planning, designing, and controlling power and thermal energy systems [40]. In the current work, the yearly time series for heat and electricity were divided into quarters (also commonly referred to as duration curves) and each quarter into 11 bins, as shown in Figure 3. In addition, the annual variations in the heat demand for 2022–2040 were calculated using the method described in Section 2.1.

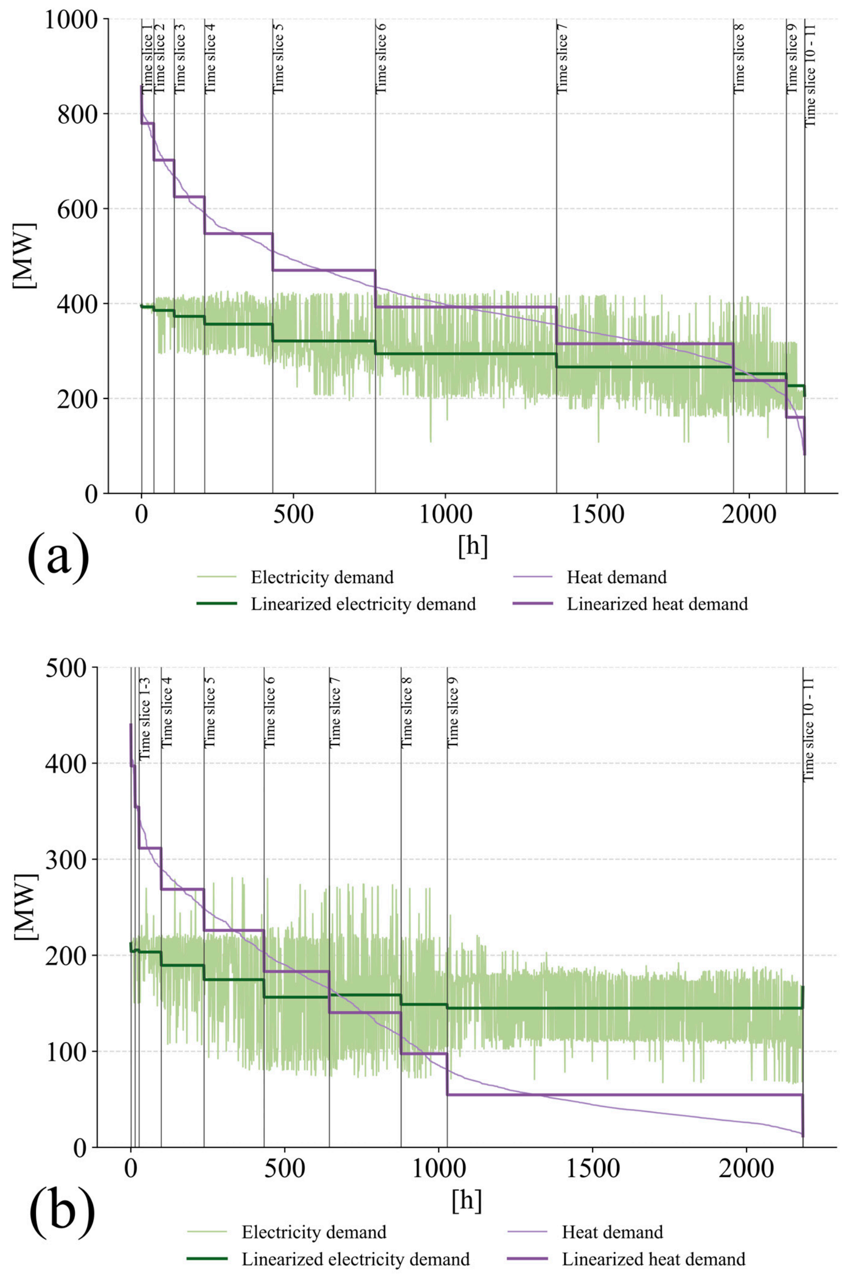


Figure 3. *Cont.*

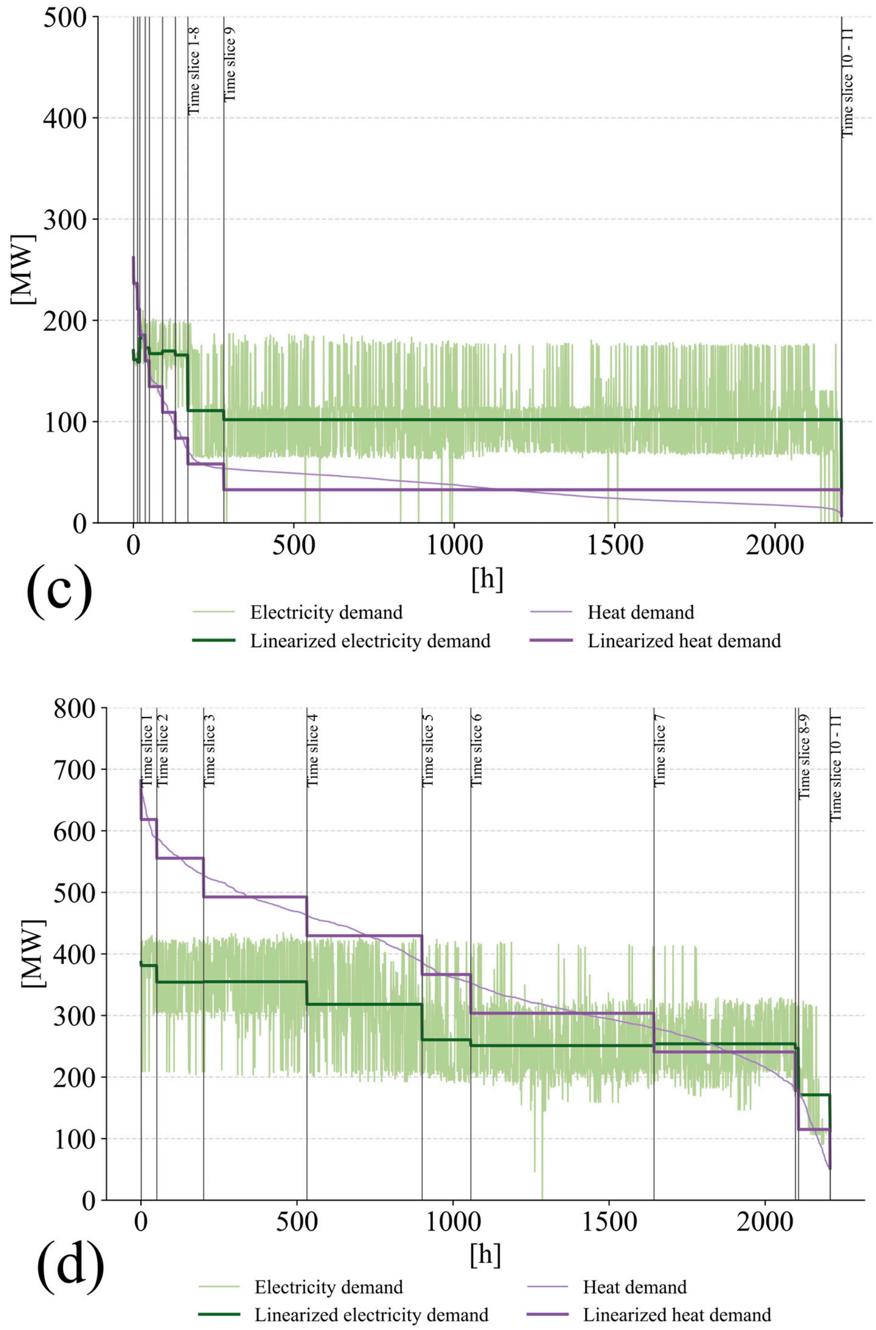


Figure 3. Discretized heat and electricity load: (**a**) 1st, (**b**) 2nd, (**c**) 3rd and (**d**) 4th quarter of the reference year.

The method described in Section 2.1 (heat model) was used to assess the future changes in the thermal energy demand of the city. The data were collected from regional and local reports on the state of the city, housing market, and zoning plans [41]. Furthermore, the data employed in the heat model were supplemented with information gathered from reports analyzing the commercial activity of local independent heat suppliers over the last ten years [42], primary and secondary market development (e.g., real estate development company reports) [43], heat market regulations, and local heat market statistics (e.g., publicly available reports prepared by the network operator) [44].

To demonstrate the general applicability of the method, we consider the case of a CHP system equipped with backpressure and extraction-condensing steam turbines. The boilers can be fired by coal, gas, or heating oil, depending on the primary resource available in the year. It is worth noting that the method uses perfect foresight. Consequently, the future prices of coal, gas, and light heating oil were estimated from the World Energy Outlook 2021 (WEO) [45], and the projections provided in two of its main scenarios: Sustainable Development Scenario (SDS) and Stated Policy Scenario (STEPS).

Carbon prices for 2022–2040 were estimated from the trends reported in the SDS and STEPS of the WEO. This was done to ensure consistency in the calculations and the main assumptions adopted in this study. The emission fees for particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) were taken from the values published in the Announcement of the Minister of the Environment of 11 October 2021 [46]. The main assumptions adopted in the present study are summarized in Table 2.

Table 2. Input data assumptions.

Parameter	Unit	2022	2025	2030	2035	2040
Coal price (Ref)	[€/MWh]	11.71	10.39	8.69	7.62	7.19
Coal price (High)	[€/MWh]	11.71	10.99	10.04	9.41	9.10
CO_2 price (Ref)	[€/Mg]	84.76	85.70	93.20	108.13	130.48
CO_2 price (High)	[€/Mg]	84.76	96.38	121.16	152.73	191.06
Gas price (Ref)	[€/MWh]	91.10	79.46	49.76	31.42	24.41
Gas price (High)	[€/MWh]	91.10	84.99	77.63	72.75	70.36
Oil price (Ref)	[€/MWh]	99.17	76.71	48.04	30.33	23.57
Heat demand (Ref)	[TWh]	2.11	2.13	2.17	2.16	2.16

Source: Own work based on [45].

3.2. Scenarios

Five research scenarios were developed to evaluate the proposed method. The main assumptions adopted in each scenario are shown in Table 3. The scenarios were designed to represent different possible situations that a coal-fired CHP plant or a coal-based district heating system operator may encounter in the years to come. Note that the year 2022 was chosen as the initial year for this study.

Table 3. Scenario assumptions.

Scenario Name	Heat Demand			Coal and Gas Prices			CO_2 Price		
	Ref	High	Low	Ref	High	Low	Ref	High	Low
CHP-REF	✓			✓			✓		
CHP-M-EX		✓		✓			✓		
CHP-D-LO			✓	✓			✓		
CHP-FP-HI	✓				✓		✓		
CHP-EP-HI	✓			✓				✓	

In the first scenario, also referred to as the reference scenario (CHP-REF), the heat demand projections for 2022–2040 were estimated using the approach described in Section 2 (heat model). Moreover, this scenario assumes the trends for carbon emissions and fossil fuel prices provided in the SDS and STEPS of the WOE (2021). The following two scenarios (CHP-M-EX and CHP-D-LO) explore the effects of potential changes in thermal energy demand at the city level. The changes in heat demand are correlated with a potential expansion of the heat market (CHP-M-EX) and a possible market contraction in 2022–2040 (CHP-D-LO). The expansion of the local heat market is attributed to an additional percentage of heat demand captured from a competing independent heat supplier, as well as the positive changes in the primary and secondary markets. In contrast, the contraction of the local heat market in Scenario CHP-D-LO is attributed to the implementation of long-term building renovation strategies, which cause a reduction in thermal demand. The two scenarios differ in the level of heat demand, which directly affects the total annual heat and electricity production, demand for primary energy resources (hard coal, gas, fuel oil), and emissions of CO_2 and air pollutants into the atmosphere.

The remaining two scenarios (CHP-FP-HI and CHP-EP-LO) assess the impact of higher coal and carbon emission prices on the operation of the energy system. Both scenarios use the same thermal demand as the one projected for the CHP-REF. The Scenario CHP-FP-HI assumes higher fuel prices in 2022–2040, while the Scenario CHP-EP-LO models higher carbon emission prices on the same time horizon. Numerous studies have shown that these two parameters have a substantial effect on the costs of production of coal-fired CHP plants and are essential in the process of strategic planning of an energy supply company. Table 4 provides a summary of the research scenarios.

Table 4. Summary of the research scenarios.

Scenario	Description
CHP-REF	Heat demand: As shown in Table 2, Heat demand (Ref)Electricity demand: proportional to the heat demand and the power-to-heat ratio of the CHP systemFuel prices: As shown in Table 2, coal, gas, oil (Ref)CO_2 prices: As shown in Table 2, CO_2 price (Ref)CHP plant operation according to the characteristics presented in Table 1
CHP-M-EX	High thermal demand due to the company's heat market expansion. Starting from 2028, the CHP system gains a larger share of the market currently served by a competing company (operational capacity of 25 MWt and demand of 56 GWh/year)
CHP-D-LO	Falling heat demand due to a faster pace of energy efficiency improvement, an additional decrease of 1% in heat sales per year starting from 2024
CHP-FP-HI	High fuel prices: As shown in Table 2, coal and gas price (High)
CHP-EP-HI	High CO_2 prices: As shown in Table 2, CO_2 price (High)

The proposed linear programming model was implemented in GAMS (General Algebraic Modeling System) and solved using CPLEX 20.1. All optimization runs were carried out on a high-end desktop computer with an Intel processor i9–12900 K and 128 GB of RAM. Table 5 provides a summary of the model statistics, which illustrates the size and complexity of the optimization model.

Table 5. Model statistics.

Parameter	Value	Parameter	Value
Blocks of equations	10	Single equations	64,153
Blocks of variables	2	Single variables	31,901
Non-zero elements	190,125	Type/Direction	LP/Minimize

4. Results

This section provides a summary of the findings obtained from the application of the method to the case study and research scenarios. The integration of the heat model (described in Section 2.1) with the proposed mathematical program (Section 2.2) allowed the total fuel demand of the system for the years 2022–2040 to be estimated. In addition, the proposed method was used to calculate the yearly production of heat and electricity, as well as the costs associated with the operation of the system.

As mentioned in Section 3.2, the scenarios CHP-M-EX and CHP-D-LO explore the effects of potential changes in thermal energy demand at the city level. The annual heat production by the CHP system ranges from 36.97 TWh in the CHP-D-LO scenario to 41.57 TWh in the CHP-M-EX scenario. It is worth noting that the electricity demand is based on the power-to-heat ratio of the CHP system; therefore, the results related to the electricity production show a similar trend to the heat production. The electricity production ranges from 31.79 TWh in the CHP-D-LO scenario to 35.74 TWh in the CHP-

M-EX scenario. Figure 4 shows the heat (Q) and electricity (E) production for scenarios CHP-REF, CHP-M-EX, and CHP-D-LO (2022–2040).

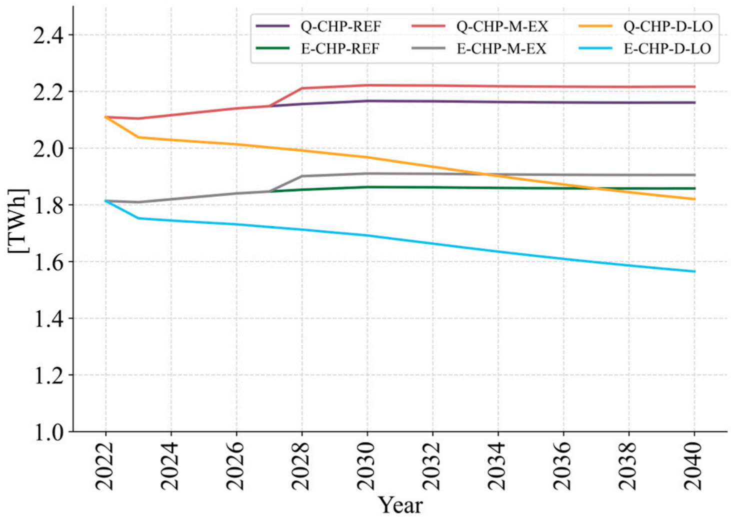


Figure 4. Electricity and heat production in 2022–2040.

As mentioned in Section 2, the proposed method allows the total operational costs of the CHP system to be minimized and enables the development of an optimal operational plan for the years to come. Figure 5 presents the production plan (2022–2040) for electricity and heat in the reference scenario (CHP-REF). The production plan shows that up to the year 2027, the system relies on coal-based technologies to satisfy the thermal demand from customers connected to the district heating network. Nonetheless, because of the high costs of production and the economic pressure that coal-fired CHP plants will face from rising carbon emission prices, additional technologies such as gas- and water-based heat pumps will enter operation starting in 2028. Furthermore, Figure 5 shows the change in the production technology mix for electricity generation. It can be observed that a significant share of the electricity demand will be satisfied using gas-fired CHP units.

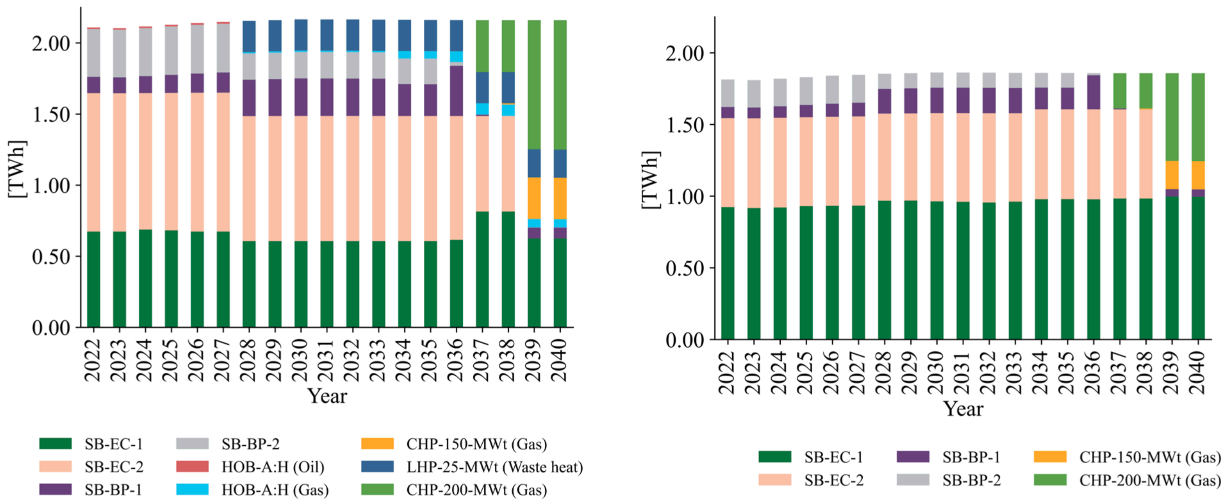


Figure 5. Heat (**left**) and electricity (**right**) production structure for CHP-REF scenario.

Figure 5 shows that the heat produced from the turbogenerator sets equipped with extraction-condensing and backpressure steam turbines meets the largest share of the thermal demand. This is in line with recent studies that have demonstrated the greater flexibility of extraction-condensing steam turbines over backpressure steam turbines; the former are designed to operate over a fixed power-to-heat ratio [47]. The operational plan for 2022–2040 also highlights the importance of backpressure steam turbines (less flexible units) for balancing the electricity demand. In this study, backpressure steam turbines are assumed to operate in full condensation mode in order to maximize their electricity output.

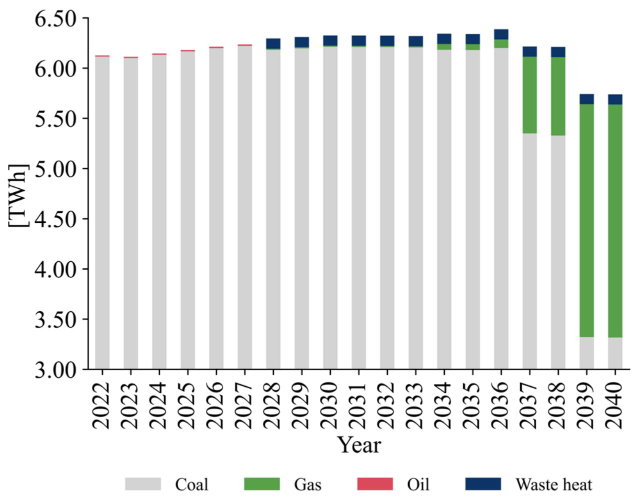
For the market scenarios CHP-M-EX and CHP-D-LO, in which the thermal demand changes depending on the heat market situation, the proposed method allowed an estimate to be made of the annual demand for fuels (energy carriers) within the time horizon investigated. This information is critical for owners and operators since it enables them to find better ways of managing fuel costs. Moreover, the method's capability of exploring different scenarios may help operators develop action plans for diversifying fuel supplies and reducing financial risks. In addition, a greater diversification of fuel supplies may result in a significant reduction in maintenance costs since the use of low-quality fuels can shorten the lifetime of the constituent elements of the CHP system (increasing the number of unplanned stoppages).

As presented in Table 6, the total demand for energy carriers varies depending on the main assumptions adopted in each scenario. The demand for energy carriers ranges from 107.37 TWh (Scenario CHP-D-LO) to 119.87 TWh (CHP-M-EX).

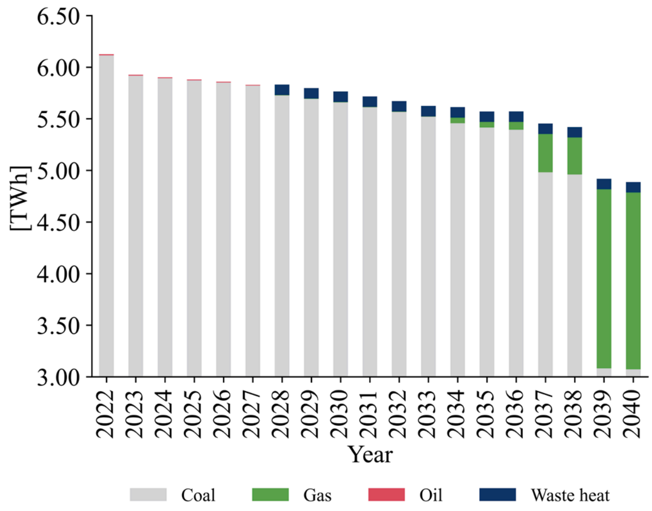
Table 6. Fuel demand in 2022–2040.

Year	Fuel Demand [TWh]											
	CHP-REF				CHP-M-EX				CHP-D-LO			
	Coal	Gas	Oil	Waste Heat	Coal	Gas	Oil	Waste Heat	Coal	Gas	Oil	Waste Heat
2022	6.114		0.012		6.114		0.014		6.114		0.012	
2023	6.101		0.012		6.101		0.014		5.918		0.009	
2024	6.133		0.012		6.133		0.014		5.894		0.009	
2025	6.167		0.013		6.167		0.014		5.872		0.008	
2026	6.200		0.014		6.200		0.014		5.852		0.008	
2027	6.222		0.014		6.222		0.014		5.822		0.008	
2028	6.182	0.01		0.102	6.337	0.014		0.102	5.726	0.004		0.102
2029	6.197	0.01		0.102	6.352	0.014		0.102	5.692	0.004		0.102
2030	6.212	0.01		0.102	6.367	0.014		0.102	5.659	0.004		0.102
2031	6.211	0.01		0.102	6.365	0.014		0.102	5.612	0.003		0.102
2032	6.209	0.01		0.102	6.364	0.014		0.102	5.566	0.003		0.102
2033	6.206	0.01		0.102	6.361	0.014		0.102	5.520	0.003		0.102
2034	6.183	0.06		0.102	6.338	0.059		0.102	5.457	0.054		0.102
2035	6.180	0.06		0.102	6.335	0.059		0.102	5.415	0.054		0.102
2036	6.201	0.08		0.102	6.355	0.084		0.102	5.394	0.076		0.102
2037	5.350	0.76		0.102	5.421	0.833		0.102	4.982	0.371		0.102
2038	5.328	0.78		0.102	5.373	0.873		0.102	4.961	0.358		0.102
2039	3.322	2.32		0.102	3.386	2.399		0.102	3.082	1.735		0.102
2040	3.317	2.32		0.102	3.381	2.401		0.102	3.073	1.713		0.102
Total	110.034	6.453	0.077	1.324	111.673	6.792	0.077	1.324	101.611	4.382	0.054	1.324
	117.888				119.866				107.372			

It is worth noting that results obtained for the five scenarios indicate that thanks to the planned decarbonization process of the system, the adoption of gas as a bridge fuel, the use of waste heat (large industrial-sized heat pumps removing heat from cooling water), as well as the importance of coal diminishes rapidly after 2037, as presented in Figure 6.



(**a**)



(**b**)

Figure 6. Fuel mix for (**a**) scenarios CHP-REF, (**b**) scenarios CHP-D-LO.

The method can also support decision-makers in estimating the total greenhouse gas emissions from the combustion of fossil fuels in the coming years. In this respect, the pollutants considered in this study are sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM). In the scenarios investigated, the emission of greenhouse gases varies from 84.56–104.20 kt for SO_2, 48.22–57.32 kt for NOx, 2.96–3.66 kt of PM, and 25.20–29.54 Mt for CO_2. Figure 7 shows the results of the scenario CHP-D-LO, which demonstrates the effectiveness of fuel switching (from coal to natural gas) and waste heat use in reducing SO_2 and NOx emissions.

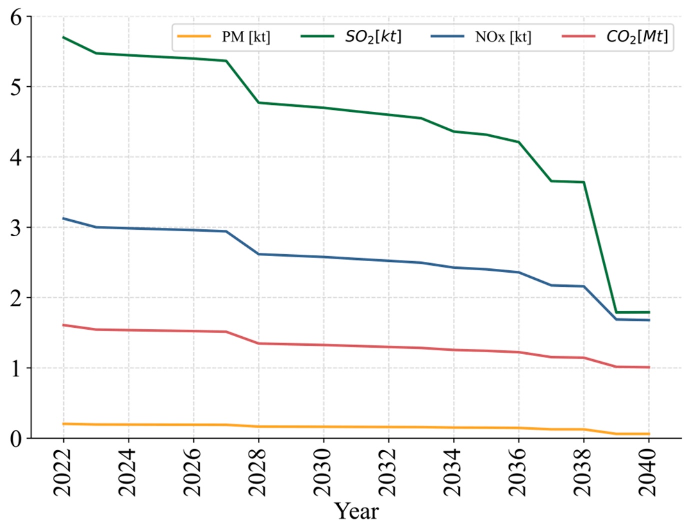


Figure 7. Greenhouse gas emissions in scenario CHP-D-LO.

Table 7 presents the estimated annual production costs of the system for 2022–2040, while Figure 8 illustrates the cumulative cost differences between the scenarios investigated (taking the reference scenario (CHP-REF) as the baseline for comparison). Scenario CHP-EP-HI highlights the need for technological and energy policy measures for decarbonizing district heating systems. In this scenario, CO_2 emission prices could be as high as 191 €/Mg, resulting in total production costs of approximately €4.9 billion, which is 20% or nearly €0.8 billion higher than the reference scenario.

Table 7. The total cost of heat and electricity generation in 2022–2040.

Year	Total Costs [M€]				
	CHP-REF	**CHP-M-EX**	**CHP-D-LO**	**CHP-FP-HI**	**CHP-EP-HI**
2022	210.5	210.5	210.5	210.5	210.5
2023	208.6	208.6	202.2	209.3	214.4
2024	209.0	209.0	200.5	210.1	220.5
2025	209.8	209.8	199.5	211.6	227.2
2026	211.2	211.2	199.0	213.5	234.4
2027	212.8	212.8	198.8	215.6	241.8
2028	199.0	204.4	183.1	202.1	230.4
2029	201.2	206.7	183.6	204.8	237.9
2030	204.1	209.6	184.5	208.1	245.9
2031	206.8	212.5	185.4	211.2	253.7
2032	210.1	215.9	186.7	214.7	261.6
2033	213.8	219.7	188.4	218.7	269.7
2034	217.7	223.8	190.2	223.2	278.5
2035	222.3	228.5	192.7	228.1	287.8
2036	227.3	233.7	195.3	233.6	297.6
2037	231.1	236.8	201.7	246.5	299.0
2038	241.1	246.6	210.2	258.2	313.1
2039	236.8	243.5	200.0	281.0	306.0
2040	242.2	249.1	203.3	289.4	312.7
Total	4115.7	4192.7	3715.7	4290.1	4942.6

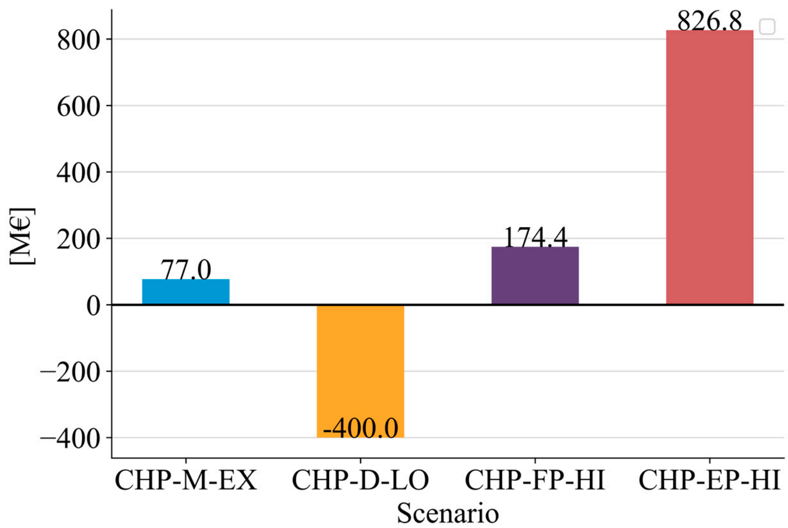


Figure 8. Cumulative cost differences from scenario CHP-REF.

As can be seen from Figure 8, besides providing information on fuel and emission costs, the proposed model allows the unit cost of heat and electricity delivered to the customers to be determined. For example, in the reference scenario the unit cost of heat increases from 99.82 €/MWh$_t$ in 2022 to 112.11 €/MWh$_t$ in 2040. Because of the high volatility and uncertainty of fuel and carbon emission prices, this information has become critical for updating the pricing strategies of CHP plants and district heating systems as well as developing annual operational plans.

5. Conclusions

This study developed a comprehensive method for supporting strategic decision-making for fuel procurement from independent heat producers. Furthermore, the method includes a practical model for projecting the thermal demand of a defined urban area considering five components. In the present study, the proposed method allowed an estimate to be made of the annual demand for fuels (energy carriers) within the time horizon investigated. This information is critical for owners and operators because it enables them to find better ways of managing fuel costs. Moreover, the method's capability of exploring different scenarios may help operators develop action plans for diversifying fuel supplies and minimizing financial risks.

Based on the case study of a CHP system that is operated by an energy supply company interested in developing a long-term strategy for fuel procurement, several key conclusions can be drawn. The heat model allows projections to be made of the thermal demand of the local market. In addition, the method provides valuable information about the future demand for energy carriers. In the reference scenario, the CHP system will require 110.03 TWh of chemical energy from coal, 6.45 TWh of chemical energy from gas, 1.32 TWh of waste energy, and 0.08 TWh of chemical energy of fuel oil. Additionally, the decision-support tool allows an estimate to be made of the emissions of pollutants into the atmosphere in the period 2022–2040.

The main limitations of this work are associated with data collection (which is essential for the construction of case studies) and the need for expert knowledge in CHP plants, district heating systems, and heat markets. Another fundamental limitation is that the optimization model is deterministic, and its computational cost may limit its implementation as a stochastic decision support tool.

Major challenges that should be addressed through further research studies are: (1) the development of new scenarios that will include energy storage technologies, (2) the conceptualization of decentralization paths along with the creation of hybrid systems with novel technologies, (3) the potential incorporation of carbon capture and storage technologies into the system.

In summary, the method developed in this paper is capable of providing detailed information for supporting the implementation of long-term fuel purchasing policies and in the decision-making process of strategic planning. Moreover, the proposed optimization model is formulated in a generalized way allowing for its application to any cogeneration or district heating system. However, considering the findings of this work and the scale of the case study, its use is recommended for medium- and large-scale district heating systems.

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Nomenclature

Abbreviations	
BP	Backpressure
CO_2	Carbon dioxide
CHP	Combined heat and power
DHS	District heating system
EC	Extraction condensing
GDP	Gross domestic product
HOB	Heat-only boiler
NOx	Nitrogen oxides
PM	Particular matter
SB	Steam boiler
SO_2	Sulphur dioxide

Symbols

$\eta^{E}_{Non-CHP}$	Efficiency of total generation of electricity of a CHP equipped with steam condensation
η^{E}_{T}	Efficiency of total electricity generation
$D_{DR(y)}$	Heat demand due to newly built residential properties, (MW_t)
$D_{DBP(y)}$	Heat demand due to the replacement of small-scale fuel-powered boilers, (MW_t)
$D_{DNE(y)}$	Heat demand from new customers due to the expansion of the heating network, (MW_t)
$D_{NP(y)}$	Heat demand from new products and services offered by the district heating network operator, (MW_t)
$D_{DNR(y)}$	Heat demand from newly constructed non-residential buildings, (MW_t)
$D_{PM(y)}$	Heat demand from the primary heat market in year y, (MW_t)
$D_{SM(\mathrm{y})}$	Heat demand from the secondary heat market in year y, (MW_t)
$D_{T(\mathrm{y})}$	Heat demand in year y, (MW_t)
β	Loss of electricity generation per unit of extracted heat
η_0	Overall efficiency
$D_{\mathrm{MRD(y)}}$	Reduction in heat demand due to permanent disconnections of customers, (MW_t)
$D_{\mathrm{MRM}(y)}$	Reduction in heat demand due to the thermal modernization of existing buildings, (MW_t)

Indices and sets

f	Fuel type, $f \in F$
p	Pollutant, $p \in P$
i	Production units (turbogenerators (4) and peaking boilers (8)), $i \in I$
s	Time slices $(\text{time} - \text{of} - \text{year division into quarters})$, $\mathrm{s} \in S$
tg	Turbogenerators, $tg \in TG \subseteq I$
y	Years, $y \in Y$

Parameters

$AF_{i,s,y}$	Average availability factor of production unit i in time slice s in year y
M	Conversion factor
Df	Discount factor
r_y	Discount rate
T_s	Duration of time slice s, (h)
$DE_{s,y}$	Electricity demand in time slice s of year r, (MW_e)
$C^{EC}_{p,y}$	Emission cost of pollutant p in year y, (€/Mg)
$Ef_{i,p,y}$	Emission factor of pollutant p related to the power output of production unit i, (Mg/MWh_t)
$b^{Min}_{i,s}$	Factor indicating the technical minimum power output of production unit i in time slice s
$C^{UFC}_{i,y}$	Fixed cost of production unit i in year y, (M€/MW_t)
$DQ_{s,y}$	Heat demand in time slice s of year y, (MW_t)
$E^{Max}_{i,y}$	Maximum achievable electrical power output of production unit i in year y, (MW_e)
$Q^{Max}_{i,y}$	Maximum achievable thermal power output of production unit i in year y, (MW_t)
$TE^{Max}_{p,y}$	Maximum allowable annual emission of pollutant p, (Mg/year)
$Q^{Max-DHN}$	Maximum thermal power that can be injected into the district heating network, (MW_t)
$\eta^{EC}_{i,y}$	Power generation efficiency of production unit i in year y
$\sigma_{i,y}$	Power-to-heat ratio of production unit i in year y
$FP_{f,y}$	Price of fuel f in year y, (€/MWh)

$L_{i,f}$	Production unit—fuel type incidence matrix (1 if the production unit uses fuel p; 0 otherwise)
$C^{UFC}_{i,y}$	Variable cost of production unit i in year y, (€/MWh$_t$)
Variables	
C^{E}_{y}	Annual emission costs, (M€)
C^{FX}_{y}	Annual fixed costs, (M€)
C^{FL}_{y}	Annual fuel costs, (M€)
C^{VR}_{y}	Annual variable costs, (M€)
$Q_{i,s,y}$	Thermal energy production of production unit i in time slice s in year y, (MW$_t$)
TC	Total discounted production costs, (M€)

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