Multi criteria dynamic design optimization of a distributed energy system

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Abstract:

Combined heat and power plants (CHP) are highly efficient, but their operation strongly depends on the heat demand and thus, among other parameters, on the ambient temperature. Due to the continuously increasing and highly fluctuating power production of renewable energy sources in Germany, the flexibility of CHP plants should be increased. Heat-storage vessels enable the temporal uncoupling of heat demand and power generation, whereas a district-heating network allows for centralized heat production. In this way, not only can the specific investment costs of a CHP unit be kept low due to the effect of scale economy, but also a higher share of heat production can be generated by the CHP units. The aim of this paper is to analyze the competing components heat storage and district-heating network considering economic and ecological aspects. Therefore a mixed integer linear program (MILP) of a distributed energy system is formulated with a weighted multi-criteria objective function including profit and operational CO_2 emissions. The time horizon of the model, and thus for the input parameters heat demand, ambient temperature and day-ahead electricity prices of the energy exchange, is one year with a temporal resolution of four hours per time interval. The computed designs as well as the operation of the energy system are compared under varying weightings and different technology scenarios. We also conduct a sensitivity analysis of the investment costs associated with heat storages and of the piping costs for the district-heating network. The general results favor the construction of heat-storage devices over a district-heating network. This applies to both environmental impact and cost of energy supply and can be well explained by the decoupling of heat demand and electricity production, which is shown in a correlation analysis.

Keywords:

combined heat and power, design optimization, distributed energy systems, dynamic, mixed integer linear programming.

1. Introduction

The energy concept of the German Federal Government seeks to expand the share of renewable energy to 40 % of the gross electrical power consumption by 2030 (20 % in 2011). By 2050, this proportion shall be further increased to 80 %. Simultaneously, the use of primary energy shall be reduced by 50 %, compared to 2008. To achieve this goal, a significantly more efficient and flexible energy system must be established. Flexibility is vital because the majority of renewable energy production is driven by the supply of volatile factors, such as wind for wind turbines or solar radiation for solar panels, and is fed into the grid independently of the electrical energy demand. One way to achieve this integration while maintaining high fuel efficiency is the development of small, and therefore more flexible, Combined Heat and Power (CHP) plants.

The need for a temporal decoupling of heat and electricity production in CHP plants is emphasized by the results of various renewable energy development studies in Germany. In [1] for example, it is stated that the share of combined heat and power generation must account for 21 % of the gross electricity production in the year 2050, while only 4 % will be provided in conventional power plants in contrast to 67 % provided by volatile renewable energies. This underlines the need for CHP units with a complete regulation of electrical power output.

A flexible, strongly decoupled electricity and heat supply by CHP plants can be achieved with thermal storage facilities. The advantage of heating networks is a higher overall thermal load for the CHP system: This allows for larger energy conversion units to be used, which have lower specific capital costs and a higher electrical efficiency compared to smaller units, due to the effect of scale.

These boundary conditions raise several questions:

- Are heat accumulators and district-heating networks competing or collaborating components?
- How does a district-heating network and heat storage affect the optimal design of the energy system and the unit commitment of the CHP plants? What are its implications for a future power system with a large share of renewable energy sources?
- How much does an optimal system design with respect to profitability differ from one, where the focus is to keep CO_2 emissions low?

To answer these questions, we used a mathematical optimization approach where the design and structure of the energy system as well as the operation of each component are optimized. For this task, a mixed integer linear program (MILP) of a distributed energy system was formulated, consisting of cogeneration units, (heat only) boilers, hot water accumulators, heat pipelines, and heat consumers. By implementing a weighted multi criteria objective function, we were able to consider both profit and operational CO_2 emissions.

1.1. Literature

A comprehensive review of different energy system models is given by Connolly et al. [2] and Keirstead et al. [3]. Whereas Connolly et al. are focusing on the integration of renewable energies, Keirstead et al. give a broad review in diverse areas, i.e. technology design, building design, urban climate, systems design, and policy assessment. The following publications were not mentioned in the reviews, though they have a special focus on combined optimization of district-heating networks and distributed energy conversion units:

In the project Vision of Future Energy Networks (VoFEN) the concept of so called Energy Hubs is developed [4]. With this model, the coupling between different energy carriers (such as electricity, natural gas, and district-heating) was analyzed by energy conversion plants and the optimal mass flows of the different energy carriers were determined. Many different plants can be modeled by coupling multiple energy carriers in a matrix. The coupling matrix is determined in a static optimization. Niemi et al. [5] used a similar approach, but incorporated features of a smart grid, i.e. control functions and network intelligence, among others. Zelmer [6] concentrates on the mathematical difficulties of modeling the transmission losses for the energy carrier gas, electricity and hot water with a high physical accuracy. Due to the resulting complexity, no unit commitment is conducted. In [7], the so called Technology Urban Resource Network (TURN) Model calculates the energy supply system at optimal cost for a whole city. The significant difference to the Energy Hub concept is the modeling of the city through an idealized grid layout, with each cell measuring 400m×400m.

We believe the approach presented in this paper is unique due to the combination of the following aspects:

- Consideration of a full year period and time intervals of 4 h
- Combined optimization of the design and the operation of all system components
- Multi-criteria optimization with respect to economic and ecological aspects and thus determination of Pareto optimal solutions
- More accurate modeling of cogeneration unit and storage characteristics than i.e. in [4-7].

2. Methods – Generic model formulation

The presented model seeks to determine the best possible way to satisfy the time-varying heat demand of distributed sites. Therefore a single optimization program is formulated considering both the choice of technologies and their operation. The supply area is defined by a grid of nodes ($k, kn \in [1..n]$), where coordinates and heat consumption for each node are specified by the user. The developed model will determine how to satisfy these heat demands with the available equipment shown in Fig. 1, i.e. cogeneration units of three different types, a thermal storage facility, a (heat only) boiler and district-heating pipelines, latter able to connect two nodes. Investments into capacities of each component and their operation are decision variables to the model. Cost functions and further information is given in the appendix.

The heat demand must be covered by the optimization in every time interval (τ), which has a length of $\Delta\tau$ = 4h. A further constraint is that the feed flow temperature is adjusted as a function of ambient temperature. As we assume a grid connection is available, the consumers' electrical power consumption is not modeled. Therefore, the incentives for electrical power production are modeled by both a financial benefit, by the power sale in the German energy exchange EEX (real hourly values of the year 2009), as well as an environmental benefit, by effectively reducing greenhouse gas emissions.

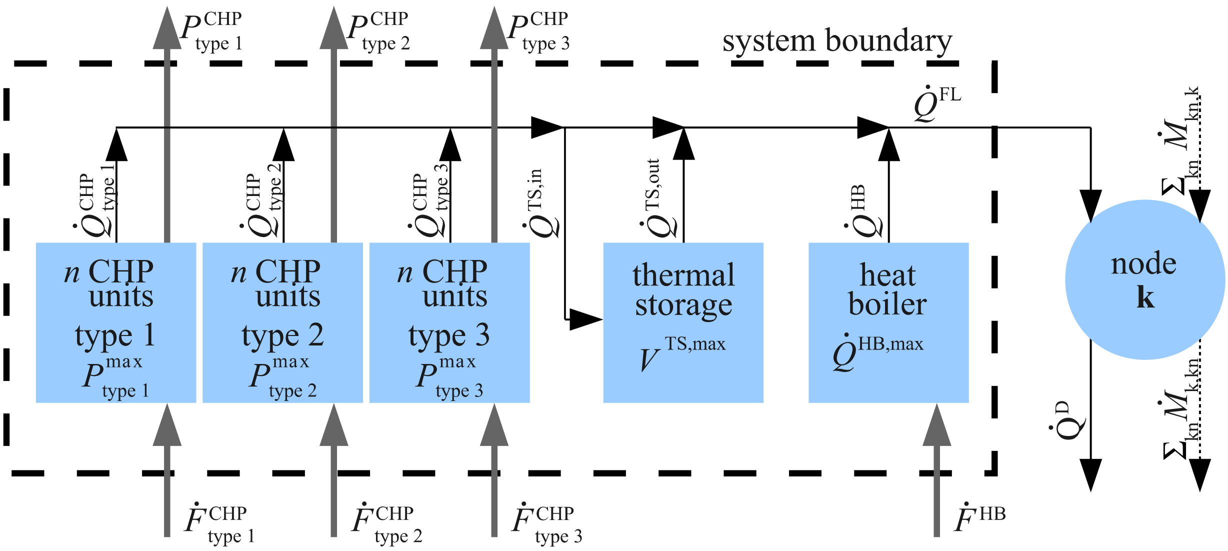


Fig. 1. Energy flow diagram of site k

2.1. Objective function

The best possible solution to meet the given heat demand is calculated by maximizing the annual profit and minimizing the annual CO_2-emissions ($\boldsymbol{M}^{CO_2}$). Therefore the objective function (1) is formulated following the weighted sum model, cf. [8], so that the weighting factor α can be interpreted as the importance of each criterion. For an easier comprehension of the weighting factor's influence, it is advisable to express both terms in the same magnitude; otherwise it is equivalent to "adding apples and oranges". Therefore the absolute values of profit and emission are divided by a respective reference value. Reference state refers to the system with α = 1, i.e. a pure economic optimization. The objective function is constrained by a set of equalities and inequalities describing technical and economical characteristics of the energy system.

$$\max \boldsymbol{O} = \alpha \frac{\boldsymbol{Profit}}{\mathrm{Profit}^{\mathrm{ref}}} - (1-\alpha)\frac{\boldsymbol{M}^{CO_2}}{\mathrm{M}^{\mathrm{CO_2,ref}}} \qquad (1)$$

$$\boldsymbol{Profit} = \sum_{\tau} \left[\boldsymbol{R}_{\tau}\left(\boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}}\right) - \boldsymbol{FC}_{\tau}\left(\dot{\boldsymbol{F}}^{\boldsymbol{HB}}_{\tau,\mathrm{k}}, \dot{\boldsymbol{F}}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}}\right) - \boldsymbol{PC}_{\tau}\left(\dot{\boldsymbol{M}}_{\tau,\mathrm{k,kn}}\right) - \boldsymbol{MC}_{\tau}\left(\boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}}\right)\right] \cdot \Delta\tau$$
$$+ \boldsymbol{S}^{\boldsymbol{CHP}}\left(\boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}}\right) - \sum_{\mathrm{C}} \boldsymbol{A}_{\mathrm{C}}\left(\boldsymbol{P}^{\boldsymbol{CHP,max}}_{\mathrm{k,type}}, \dot{\boldsymbol{Q}}^{\boldsymbol{HB,max}}_{\mathrm{k}}, \boldsymbol{V}^{\boldsymbol{TS,max}}_{\mathrm{k}}, \boldsymbol{y}^{\boldsymbol{connect}}_{\mathrm{k,kn}}, \boldsymbol{d}^{\boldsymbol{max}}_{\mathrm{k,kn}}\right) \tag{2}$$

$$\boldsymbol{M}^{\boldsymbol{CO_2}} = \boldsymbol{M}^{\boldsymbol{CO_2,F}} - \boldsymbol{M}^{\boldsymbol{CO_2,credit}} \tag{3}$$

$$\boldsymbol{M}^{\boldsymbol{CO_2,F}} = \mathrm{m}^{\mathrm{CO_2}} \cdot \sum_{\tau}\sum_{\mathrm{k}} \left(\dot{\boldsymbol{F}}^{\boldsymbol{HB}}_{\tau,\mathrm{k}} + \sum_{\mathrm{type}} \dot{\boldsymbol{F}}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}} \right) \cdot \Delta\tau \tag{4}$$

$$\boldsymbol{M}^{\boldsymbol{CO_2,credit}} = \mathrm{m}^{\mathrm{CO_2,e-mix}} \cdot \sum_{\tau}\sum_{\mathrm{k}}\sum_{\mathrm{type}} \boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}} \cdot \Delta\tau \tag{5}$$

The annual profit (2) is itemized in the following. Sales revenues ($\boldsymbol{R}$) from electricity represent the earnings, while costs for fuel ($\boldsymbol{FC}$), pumping ($\boldsymbol{PC}$) and maintenance ($\boldsymbol{MC}$) make up operational expenditures. Revenues from selling heat are not implemented, since the amount of delivered heat is fixed. In Germany electricity production through cogeneration is subsidized ($\boldsymbol{S}$). A linear depreciation is considered for the investment costs and the annuity associated with each component is calculated by the capital recovery factor, using a discount rate of 10 % over 20 years.

The CO_2 emissions ($\boldsymbol{M}^{\boldsymbol{CO_2}}$) are defined with the aim to calculate CO_2 emissions arising from producing the main product heat. Due to the fact that CHP units generate electrical power as a co-product and thus emit more carbon dioxide than for heat generation solely with boilers, the emissions due to electrical energy production are credited (3). Since we used the German energy system as a reference system, we utilized the average specific CO_2 emissions from German power plants, $\mathrm{m}^{\mathrm{CO_2,e-mix}} = 570\,\mathrm{g/kWh}$ [9]. Equation (4) calculates the emissions ($\boldsymbol{M}^{\boldsymbol{CO_2,F}}$) produced by fuel consumption of all energy conversion units within the system, whereas (5) determines the CO_2-emissions ($\boldsymbol{M}^{\boldsymbol{CO_2,credit}}$) emitted by electricity production in the replaced power plant.

2.2. Energy conversion units

Three types of CHP units and a heat only boiler are available to the model as energy conversion units. The boiler is modeled by a constant 95 % thermal efficiency, coupling heat output and fuel consumption, and an upper load limit to be optimized. This upper load limit determines the investment cost.

Equation (6) determines the fuel consumption of any CHP unit type in a simplified manner, assuming constant efficiencies for all operating conditions, as well. Note that this formulation implies a fixed ratio of power and heat production $\sigma = \boldsymbol{P}^{\boldsymbol{CHP}} / \dot{\boldsymbol{Q}}^{\boldsymbol{CHP}} = \eta^{\mathrm{el}} / \eta^{\mathrm{th}}$. All CHP units of a common type at a single site k are grouped together, see also Fig. 1.

$$\dot{\boldsymbol{F}}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}} = \boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}} / \eta^{\mathrm{el}}_{\mathrm{type}} = \dot{\boldsymbol{Q}}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}} / \eta^{\mathrm{th}}_{\mathrm{type}} \qquad \forall \tau, \mathrm{k}, \mathrm{type} \tag{6}$$

In order to consider the different operation modes of cogeneration units, the following characteristics have to be modeled in addition to (6):

1. If all same-type units are shut down, the fuel consumption and the electric and thermal output have to equal zero.
2. The minimum load of all same-type units grouped together has to be equal or greater than the minimum load of one single unit ($\underline{\mathrm{L}}^{1,\mathrm{P}}_{\mathrm{type}}$), which is 50% partial load. This means the operational gap between shut down and minimum load has to be implemented.
3. The maximum load of the grouped CHP units ($\boldsymbol{P}^{\boldsymbol{CHP,max}}_{\mathrm{k,type}}$) has to be defined, since it determines the investment costs.

Since thermal and electrical power are coupled by (6), only expressions related to electrical power are sufficient for the following explanations. The first two characteristics are ensured by (7). The binary variable ($\boldsymbol{y}^{\boldsymbol{P}}_{\tau,\mathrm{k,type}}$) indicates whether the unit is in operation (y=1) or shut down (y=0). Therefore $\boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}}$ is set to zero if cogeneration units are shut down (y=0), and ranges between the lower bound ($\underline{\mathrm{L}}^{1,\mathrm{P}}_{\mathrm{type}}$) and an overestimated upper bound ($\overline{\mathrm{U}}^{1,\mathrm{P}}_{\mathrm{type}}$) if units are running ($y$=1). The value of $\overline{\mathrm{U}}^{1,\mathrm{P}}_{\mathrm{type}}$ is defined as five times the power of one unit, thus far above the expected value of $\boldsymbol{P}^{\boldsymbol{CHP,max}}_{\mathrm{k,type}}$. However, Equation (8) strictly limits the actual electrical power ($\boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}}$) to the maximum load of the grouped CHP units ($\boldsymbol{P}^{\boldsymbol{CHP,max}}_{\mathrm{k,type}}$). That is a somewhat simplified explanation of the so-called Glover's linearization, but for brevity the interested reader is referred to [10] for a more detailed derivation.

$$\overline{\mathrm{U}}^{1,\mathrm{P}}_{\mathrm{type}}\boldsymbol{y}^{\boldsymbol{P}}_{\tau,\mathrm{k,type}} \geq \boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}} \geq \underline{\mathrm{L}}^{1,\mathrm{P}}_{\mathrm{type}}\boldsymbol{y}^{\boldsymbol{P}}_{\tau,\mathrm{k,type}} \qquad \forall \tau,\mathrm{k,type} \qquad (7)$$

$$\boldsymbol{P}^{\boldsymbol{CHP,max}}_{\mathrm{k,type}} \geq \boldsymbol{P}^{\boldsymbol{CHP}}_{\tau,\mathrm{k,type}} \qquad \forall \tau,\mathrm{k,type} \qquad (8)$$

There are two methods of modeling the maximum load limit ($\boldsymbol{P}^{\boldsymbol{CHP,max}}_{\mathrm{k,type}}$) of the sum of CHP units of one type: (a) a straight-forward, but computationally intensive program with integer variables:

$$\boldsymbol{P}^{\boldsymbol{CHP,max}}_{\mathrm{k,type}} = \mathrm{P}^{\mathrm{CHP}}_{\mathrm{type}} \cdot \boldsymbol{x}^{\boldsymbol{CHP}}_{\mathrm{k,type}} \qquad \boldsymbol{x}^{\boldsymbol{CHP}}_{\mathrm{k,type}} \in \mathrm{N}_0,\ \forall \tau,\mathrm{k,type} \qquad (9)$$

where the parameter $\mathrm{P}^{\mathrm{CHP}}_{\mathrm{type}}$ is the power capacity of one cogeneration unit, and (b) a variation of the first approach, with a relaxation of the integer constraints using binary variables allowing not only integer multiples of one unit, but also fractions, as long as one "complete" unit is installed. For this approach, the combined maximum power output of all same-type units at a single site is defined as a semi-continuous variable:

$$\overline{\mathrm{U}}^{1,\mathrm{P}}_{\mathrm{type}} \cdot \boldsymbol{y}^{\boldsymbol{CHP}}_{\mathrm{k,type}} \geq \boldsymbol{P}^{\boldsymbol{CHP,max}}_{\mathrm{k,type}} \geq \mathrm{P}^{\mathrm{CHP}}_{\mathrm{type}} \cdot \boldsymbol{y}^{\boldsymbol{CHP}}_{\mathrm{k,type}} \qquad \forall \tau,\mathrm{k,type} \qquad (10)$$

Here $\boldsymbol{y}^{\boldsymbol{CHP}}_{\mathrm{k,type}}$ is a new binary variable that describes whether one particular CHP unit type is constructed at site (k) or not.

2.3 Thermal storage and district heating

The hot water accumulator can be charged by a flux of hot water with a temperature of $\mathrm{T}^{\mathrm{CHP}}$ entering at the top and pushing out cold water with a temperature of T^{RL} at the bottom of the vessel, and vice versa for the discharging process. Assuming constant temperatures in the upper, hot layer and the lower, cold layer, the current internal energy of each storage k is determined by an energy balance (11), and is limited by the maximum storage volume (12), as presented in detail in [11].

$$\boldsymbol{U}^{\boldsymbol{TS}}_{\tau+1,\mathrm{k}} = (1-\varphi)\cdot \boldsymbol{U}^{\boldsymbol{TS}}_{\tau,\mathrm{k}} + \left(\dot{\boldsymbol{Q}}^{\boldsymbol{TS,in}}_{\tau,\mathrm{k}} - \dot{\boldsymbol{Q}}^{\boldsymbol{TS,out}}_{\tau,\mathrm{k}}\right)\Delta\tau \qquad \forall \tau,\mathrm{k} \qquad (11)$$

$$\boldsymbol{V}^{\boldsymbol{TS}}_{\tau,\mathrm{k}} = \frac{\boldsymbol{U}^{\boldsymbol{TS}}_{\tau,\mathrm{k}}}{\rho\cdot \mathrm{c_p}\cdot\left(\mathrm{T}^{\mathrm{CHP}} - \mathrm{T}^{\mathrm{RL}}\right)} \leq \boldsymbol{V}^{\boldsymbol{TS,max}}_{\mathrm{k}} \qquad \forall \tau,\mathrm{k} \qquad (12)$$

Heat losses are expressed as a constant ratio (φ) of energy content; disregarding effects on water temperature, as they would lead to nonlinear functions. Hydraulic restrictions due to maximum loading of the pumps have also been neglected. Again the maximum storage capacity determines the investment cost.

Sites can be connected via district-heating pipelines, which can be constructed between the predefined nodes $k, kn \in [1..n]$. A new binary variable ($\boldsymbol{y}^{connect}_{k,kn}$) is introduced, describing whether the considered site (k) is connected or not to the other sites (kn). The same notation is used in the following equations (4). The function of the binary variable is similar to (7).

The pipelines are modeled by mass balances for each node k (13) and diameter restrictions, (15) and (16). When assuming a nominal flow rate of $v^n = 2.5\,m/s$, a quadratic correlation (14) between mass flow rate ($\dot{\boldsymbol{M}}_{\tau,k,kn}$) and minimal needed diameter ($\boldsymbol{d}_{\tau,k,kn}$) can be formulated. To allow the use of a MILP solver, a linearization is conducted for the range of $3\,kg/s \le \dot{\boldsymbol{M}}_{\tau,k,kn} \le 11\,kg/s$, as seen in (15). The diameter of the pipelines, which is relevant for the investment costs ($\boldsymbol{d}^{max}_{k,kn}$), is determined in (16) by assuring that it is higher than the minimal needed diameter ($\boldsymbol{d}^{lin}_{\tau,k,kn}$) for each time step.

$$\sum_{kn} \dot{\boldsymbol{M}}_{\tau,k,kn} + \frac{\dot{\boldsymbol{Q}}^{D}_{\tau,k}}{c_p \cdot \left(T^{FL}_{\tau} - T^{RL}\right)} = \frac{\dot{\boldsymbol{Q}}^{FL}_{\tau,k}}{c_p \cdot \left(T^{FL}_{\tau} - T^{RL}\right)} + \sum_{kn} \dot{\boldsymbol{M}}_{\tau,kn,k} \qquad \forall \tau, k \quad (13)$$

where $\dot{\boldsymbol{M}}_{\tau,k,kn} \le \boldsymbol{y}^{connect}_{\tau,k,kn} \cdot \overline{U}^{1,M} \quad \forall \tau, k, kn$

$$\left(\boldsymbol{d}_{\tau,k,kn}\right)^2 = \frac{4\dot{\boldsymbol{M}}_{\tau,k,kn}}{\pi \cdot v^n \cdot \rho} \qquad \forall \tau, k, kn \qquad (14)$$

$$\left(\boldsymbol{d}_{\tau,k,kn}\right)^2 = \frac{11}{100}\boldsymbol{d}^{lin}_{\tau,k,kn} - \frac{30}{10000} \qquad \forall \tau, k, kn \qquad (15)$$

$$\boldsymbol{d}^{lin}_{\tau,k,kn} \le \boldsymbol{d}^{max}_{k,kn} \qquad \forall \tau, k, kn \qquad (16)$$

The electricity needed for the pumps in the heating network is calculated with respect to the feed flow ($\dot{\boldsymbol{M}}_{\tau,k,kn}$). The maximal pipline diameter and the physical length determine the investment cost.

3. Results

This section presents the computed system designs. By analyzing several indicators, we will be focusing on the cogeneration unit and storage dimensioning, as well as on advantages and disadvantages of district-heating pipelines. Furthermore, the unit commitment for the three base scenarios is examined.

3.1. Experimental design and scenarios

The first attempt to conduct computations with a spatial resolution of $3 \times 3 = 9$ to $10 \times 10 = 100$ nodes, and thus 20 to 342 possible piping sections[1] to be dimensioned by the solver, turned out to be extremely computationally expensive. The computational time for only 9 nodes was more than one week using the solver CPLEX 12 on an ordinary server-PC. The explanation can be found by regarding the combinatorial problem, modeled with the binary variables $\boldsymbol{y}^{connect}_{k,kn}$, whose quantity, in general, increases dramatically the computational effort. Nine nodes with 20 possible piping sections that can be either used or rejected (binary decision) lead to $2^{20} > 10^6$ possible grid

[1] A piping section can be a vertical, horizontal and crosswise connection between two nodes. Thus A * A = B nodes lead to A * (A-1) vertical, A * (A-1) horizontal and $(A-1)^2$ * 2 crosswise possible piping sections.

alternatives, not to mention the amount of possible combinations of heat supplying units and the dynamic character of the model with 2190 time steps. Therefore, we abstained from grid optimization as we focus in this paper on the essential (competing) benefits of district-heating networks and thermal storage facilities.

Akin time requirement occurred to calculations with discrete CHP unit capacity (9). Since these results only barely diverge from the findings of the relaxed modeling of cogeneration units (± 1.5 %), all statements refer to the formulation given in (10).

As it is the aim to inquire the essential distinctions between heat storages and district-heating pipelines, we establish a generalized supply area, consisting of three nodes, each defined as a consumer, which represent apartment blocks with a maximal heat demand of $\dot{Q}_{k=1}^{D,max} = 1MW$, $\dot{Q}_{k=2}^{D,max} = 2MW$ and $\dot{Q}_{k=3}^{D,max} = 3MW$, respectively. For the considered period of one year, we used time series for the heat demand and the ambient temperature, which are representative for Berlin, Germany. The investment costs for the predefined technologies and technical characteristics of the CHP units are given in the Appendix. The three CHP unit types are chosen according to literature recommendation, i.e. minimum 4000 full load hours are necessary for a cost effective operation.

Three base scenarios were created to compare design and unit commitment for a system construction employing a green field approach. In each scenario, the following equipment is available:

- **Scenario 1:** cogeneration units, (heat only) boilers, heat-storage vessels, district-heating pipelines
- **Scenario 2:** as scenario 1, excluding storage vessels
- **Scenario 3:** as scenario 1, excluding storage vessels and district-heating pipelines

For every scenario, calculations were performed with the objective function's weighting factor being reduced from 1, where CO_2 emissions are not considered, to 0.5 in one-tenth increments. In order to test the robustness of the results, a sensitivity analysis was conducted by varying the investment costs for heat-storage vessels and heat pipes.

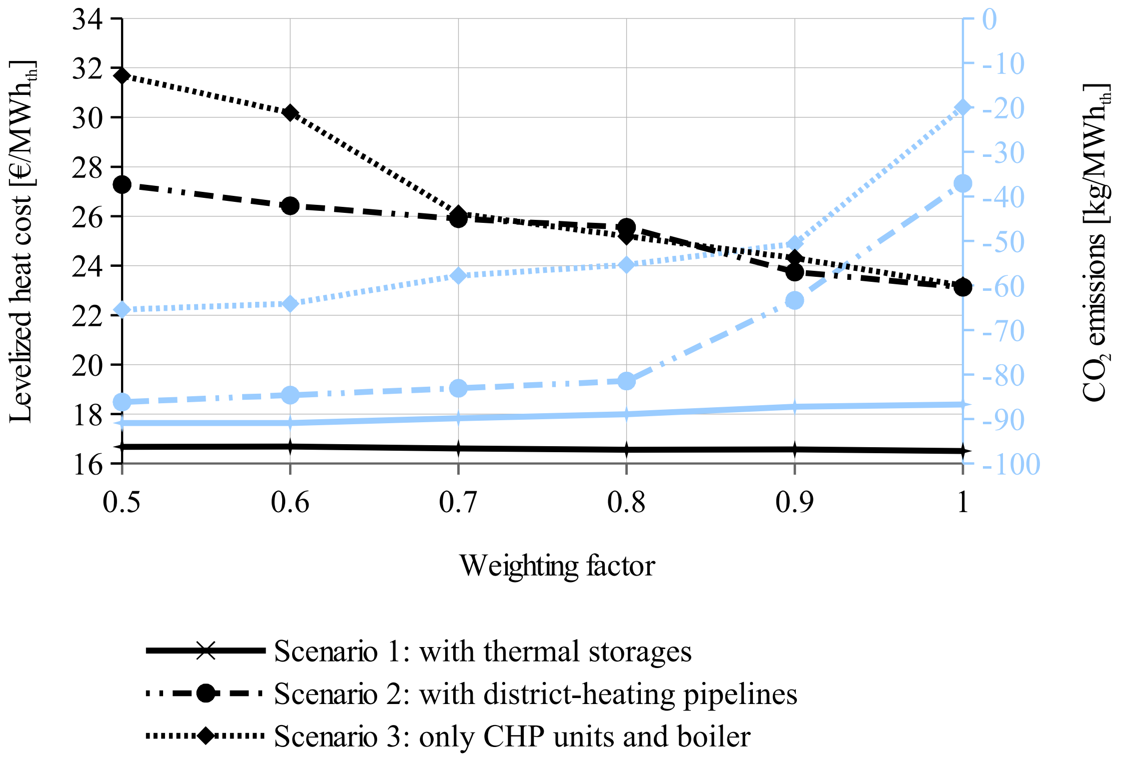


Fig. 2. Results for the two variables to be minimized, plotted against the weighting factor

3.2. Heat storage vs. district-heating pipelines

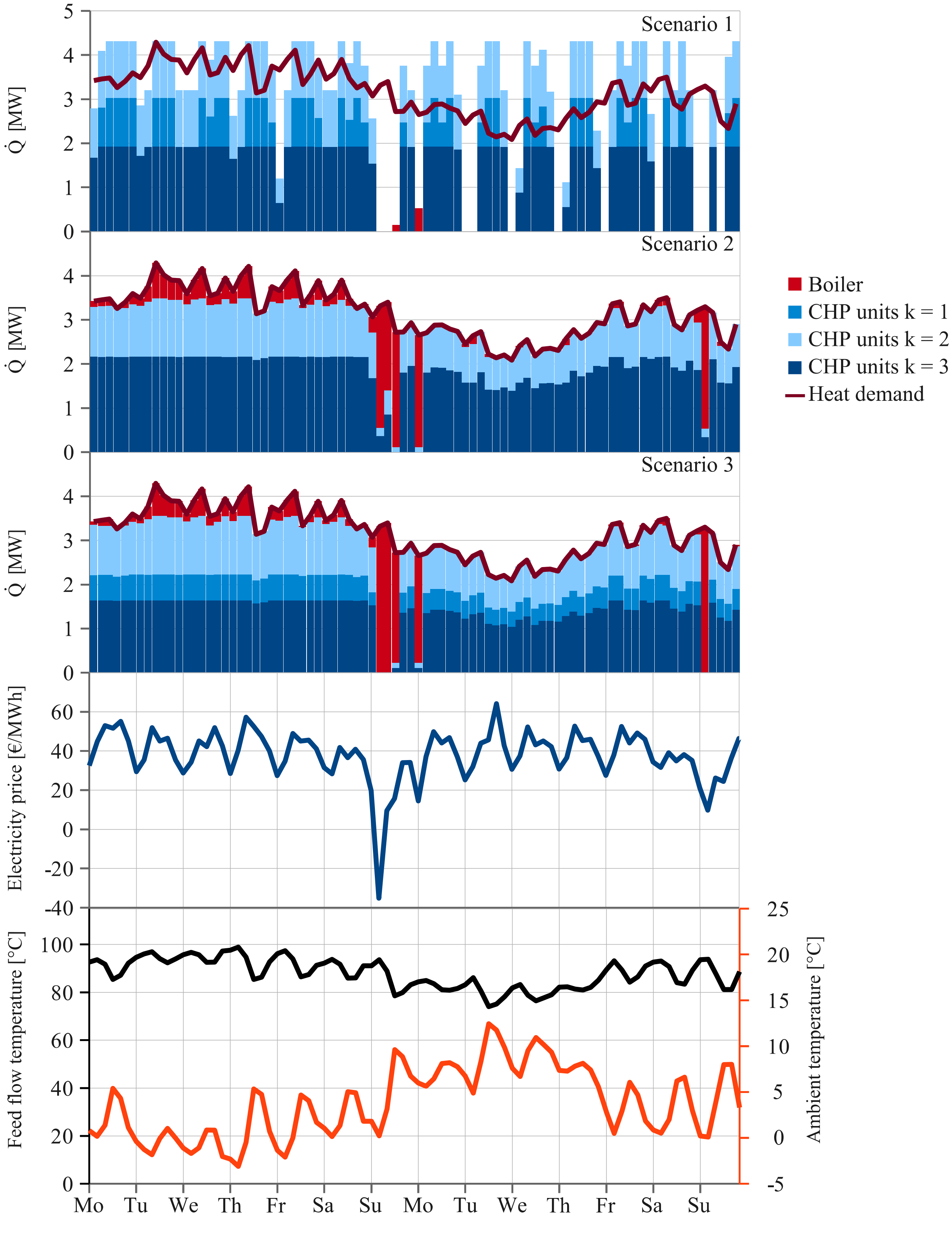
In Scenario 1, the heat-storage vessels enable a monovalent operation of the CHP plants with almost no need for the boilers to be operated, whereas district-heating pipelines are not cost-effective enough to be chosen as part of the energy system. In Scenario 2, where heat storage is not an option, a heat pipeline is constructed between the sites with the highest and lowest heat demand. For a weighting factor less than 0.8, however, a second district-heating pipeline is installed connecting the largest and middle consumer. Figure 2 shows the specific levelized heat cost and carbon dioxide emissions for each scenario. Negative CO_2 emissions illustrate the benefits of cogeneration in contrast to independent production of heat and power, as seen in (3).

Figure 3 presents the economic optimized ($\alpha = 1$) results for the unit commitment at each site for all scenarios. Bars above the red heat load curve are charging procedures of thermal storage facilities and white spaces under the red load curve are discharging procedures, respectively. Note that due to (6) the electrical production is proportional to the thermal power output.

In Scenario 1, the heat storage offers the following two benefits for the system operation, as shown in Fig. 3: 1) Adjustable operation of a CHP unit according to electricity prices, and 2) the stored hot water can cover the heat demand, when the demand is lower than the minimal load of the cogeneration unit. Both reduce the need for peak-load boilers and promote a high share of thermal power output from the CHP units (99 % at $\alpha = 1$). An increased focus on CO_2 reduction affects costs and greenhouse gas emissions marginally, so that it can be said that the economic optimum is equal to the ecologic optimum.

As shown in Fig. 4, emission reductions are achieved by an increased dimensioning of the CHP units, while the full load hours decrease; this leads to higher overall costs. At a weighting factor of $\alpha = 1$, Scenario 2 and 3 differ minimally in regards to levelized heat cost (Fig. 2) and dimensioning of cogeneration units (Fig. 4). However, due to the connecting pipeline, a higher combined heat demand and thus overall higher full load hours (Fig. 4) can be achieved in Scenario 2, reducing CO_2 emissions by 20 kg_{CO2}/MWh_{th} (absolute 300 t_{CO2}/a) in comparison to Scenario 3. As a consequence, CHP plants are running at times with low or even negative electricity prices, as shown in Fig. 3. Due to the construction of a second district-heating pipeline, at $\alpha < 0.8$, emissions are further reduced by approx. 20 kg_{CO2}/MWh_{th} . Additionally, a slight decrease of full load hours can be achieved.

Contrary to the suggested course, it must be mentioned that the graphs given in Fig. 2 and 4 are not continuous but piecewise differentiable functions, due to constraints formulated with binaries. An obvious discontinuity is given between 0.6 and 0.7 in Scenario 3: At weighting factors lower than 0.6 the CHP unit of type 3 (highest nominal rated power) is convenient at the site of the smallest consumer.



Scenario 1: with thermal storages
Scenario 2: with district-heating pipelines
Scenario 3: only CHP units and boiler

Fig. 3. Unit commitment, electricity prices, feed flow temperature and ambient temperature for calendar week 10 and 11 for each scenario at α = 1

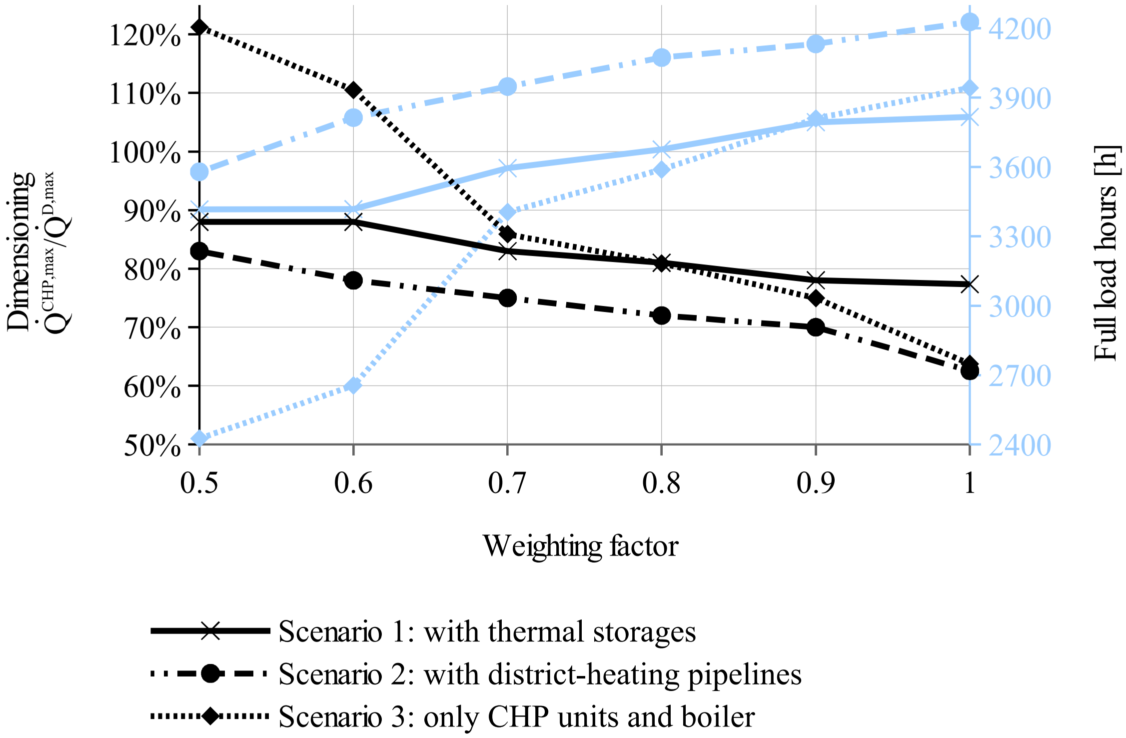


Fig. 4. Dimensioning and full load hours of the CHP units, plotted against weighting factor

3.2.1. Interpreting the weighting factor as CO2 abatement cost

Of particular interest is the question: How much does it cost to avoid a certain amount of CO_2 emitted to the environment? The answer can be provided by the so-called abatement cost for CO_2 emissions. Abatement costs are here defined as additional costs divided by the avoided CO_2 emissions referred to the value of $\alpha = 1$ for each scenario. As we used a "credit" system for the allocation of emissions by electrical energy production (3), the emission reduction is related to the national energy system, calculated in the sense of a national economic approach. As shown in Table 1, the abatement costs in Scenario 1 are low, but so are the related avoided CO_2 emissions. Therefore it can be stated that the results are very robust to changes in prices for CO_2 emission allowances. In Scenarios 2 and 3 we have higher abatement costs, but with an even higher impact on avoided emissions. However, Scenario 3, where heat storage and district-heating pipeline are not an option, has an inferior ratio of cost and avoided amount of greenhouse gases.

The absolute avoided CO_2 emissions tend to a horizontal asymptote, given by the ecological optimum of operation, see also Fig. 2. This optimum strongly depends on the pre-selected technologies.

Table 1. Abatement cost and avoided CO_2 emissions referred to the value at $\alpha = 1$.

Weighting factor α	Scenario 1 Abatement cost [€/t]	Scenario 1 ΔM [t_{CO2}]	Scenario 2 Abatement cost [€/t]	Scenario 2 ΔM [t_{CO2}]	Scenario 3 Abatement cost [€/t]	Scenario 3 ΔM [t_{CO2}]
0.8	21.83	36.95	54.51	739.37	56.45	589.54
0.5	42.61	69.40	84.66	817.82	186.74	757.06

To align these costs, two examples are given: 1) In the Phase II (2008-2012) of the European Union Emissions Trading System (EU ETS), the prices for CO_2 emission allowances were constantly smaller than 17 €/t_{CO2} and 2) technologies of Carbon Capture and Storage (CCS) are cost-effective at a prices of about 30 – 90 €/t_{CO2} [12, p. 43].

3.2.2. Correlation analysis

Using correlation coefficients between time-varying values, the flexibility of the designed systems[2] can be analyzed. Selected results are presented in Table 2. There are three time-variant input parameters: heat demand Q^D, ambient temperature T^{amb}, and day-ahead electricity price on the stock exchange p^{el}.

In Scenarios 2 and 3, a strong dependency can be observed between heat demand and electrical power output. Simultaneously, the correlation between electrical power output and market price of electricity has a rather low value of 0.4 to 0.27: Nearly the same dependency as for the pair of heat demand and electricity price. There is, therefore, no special uncoupling of heat production and demand in scenarios with district-heating pipelines as well as without both heat pipelines and storage vessels. In contrast, computations with thermal storages show a high uncoupling of heat demand and power output.

Since heat demand and ambient temperature are correlated in opposite directions, the influence of the time-variant input parameters on the objective function decreases with reduced weighting factor, and thus the need for a flexible system design.

Table 2. Selected correlation coefficients of time-varying values.

	Scenario 1		Scenario 2		Scenario 3	
Correlation	$\alpha = 1.0$	$\alpha = 0.8$	$\alpha = 1.0$	$\alpha = 0.8$	$\alpha = 1.0$	$\alpha = 0.8$
Q^D - P^{CHP}	0.665	0.646	0.925	0.986	0.922	0.997
P^{CHP} - p^{el}	0.544	0.552	0.403	0.291	0.383	0.267
Q^D - p^{el}	0.260					
Q^D - T^{amb}	-0.887					
p^{el} - T^{amb}	-0.169					

3.3. Sensitivity analysis

In order to survey the robustness of the results, a sensitivity analysis was conducted by varying investment costs for heat-storage vessels and heat pipelines. The scaling factors f^{TS} and f^{Pipe} are formulated. Table 3 displays factor combinations where exact one district-heating pipeline is profitable. Computations were aimed at maximizing profits ($\alpha = 1$).

Table 3. Factor combination f^{TS} and f^{Pipe}, specific costs and capacities for $\alpha = 1$.

f^{TS}	f^{Pipe}	Thermal storage			District-heating pipeline	
[-]	[-]	[€/kWh$_{th}$]	[€/m³]	$\sum_k V_k^{TS,max}$ [m³]	[€/kW$_{th}$]	d^{max} [cm]
1.0	0.40	4.065	236	702	85.50	4.116
1.5	0.50	6.632	385	473	100.65	4.206
2.0	0.50	9.354	543	383	94.28	4.312
2.5	0.55	11.937	693	357	103.73	4.312
3.0	0.62	15.023	872	308	117.43	4.305

In these computations, the district-heating pipeline is constructed between the complex with the smallest and the complex with the largest heat demand. Due to the installation of heat pipelines and storage devices, the cogeneration unit at site 1 is able to cover the demand at peak hours for both sites.

The scaling Factor f^{Pipe} leading to a cost-effective use of one pipeline has to be very small (0.4 to 0.6). A variation of this factor can be interpreted as change of both distance between nodes and specific investment cost of constructing a pipeline. The cost-effectiveness of a district-heating

[2] cf. [13]

network only depends on the absolute cost per transmitted power. For the assumed cost functions, the factor $f^{Pipe} = 0.4$ is in accordance with a distance of 200 m.

4. Conclusions

Within an energy system consisting of CHP units, boilers, multiple heat consumers, and the possibility to sell electricity on the spot market, the components heat storage and district-heating network were analyzed considering profit and operational CO_2 emissions. Therefore, a mixed integer linear program (MILP) of a distributed energy system was formulated with a weighted multi criteria objective function. This function enabled both the maximization of profit and the minimization of operational CO_2 emissions.

Based on the assumptions made, district-heating networks cannot compete with thermal storages:

1. Thermal storage vessels enable an uncoupling of unit operation and heat demand (correlation coefficient lower than 0.67) and thus offer two main benefits: 1) Adjustable operation of CHP unit according to electricity prices, and 2) stored hot water can cover heat demand, when the demand is lower than the minimal load of the units. As a consequence, less carbon-intensive cogeneration covers a high share of heat demand, and thus CO_2 emissions are reduced.
2. Due to a connecting pipeline, a higher combined heat demand and thus overall higher full load hours are achieved, reducing CO_2 emissions in comparison to a case excluding both storage vessels and heat pipes. However, the connection of sites leads to an unit operation determined by the heat demand.

Under the given assumptions high shares of thermal energy produced in co-generation alongside with a strong development of renewable energy sources suggest uncoupling of heat demand and power output through thermal storages – at least for energy systems like the one under consideration in this paper.

The resulting dimensioning of the CHP units strongly varies in accordance to adopted technology, i.e. storage vessel, heat pipeline or none of these. This suggests that a combined optimization of conversion units, thermal storages and heat pipes, as well as a unit commitment is necessary for reasonable dimensioning of equipment. Note that this only holds for energy systems large enough, that an every day unit commitment with respect to electricity prices is done in the real world operation.

The use of a weighting factor between a profit maximization and emission minimization in such a large range offers more scientific than practical conclusions. However, by implementing more technologies (e.g. heat pumps and renewable energies) as well as different types of fuels (biogas and other renewable resources), a Marginal Abatement Cost (MAC) curve can be calculated for different heat demand constellations.

A drawback of the established model is that security issues, such as security of supply through redundancy are not considered.

Therefore, further research will focus on the following aspects:

- Analyzing the impact of reference scenario used in the objective function, since profit and CO_2 emissions are not independent, but coupled by the fuel consumption
- Analyzing the impact of time dependent input parameters, i.e. heat demand and electricity prices, and
- Implementation of a broader field of technologies and several structures of heat consumers.

Based on the previous aspects, long-term investments should be analyzed with special regard to changing general requirements (e.g., demographic change and better thermal insulation)

Appendix

Cost functions [14] for

1. Heat boiler

$$\boldsymbol{I}^{\boldsymbol{HB}} = 1056\,\tfrac{€}{\mathrm{MW_{th}}} \cdot \dot{\boldsymbol{Q}}_{\mathrm{k}}^{\boldsymbol{HB,max}} \exp(-0{,}4736261422)$$

   This equation is linearly interpolated between

$$\boldsymbol{I}^{\boldsymbol{HB}}\left(\dot{\boldsymbol{Q}}_{\mathrm{k}}^{\boldsymbol{HB,max}} = 0\right) = 0€\ ,$$

$$\boldsymbol{I}^{\boldsymbol{HB}}\left(\dot{\boldsymbol{Q}}_{\mathrm{k}}^{\boldsymbol{HB,max}} = 0.02\right) = 10000€\ ,$$

$$\boldsymbol{I}^{\boldsymbol{HB}}\left(\dot{\boldsymbol{Q}}_{\mathrm{k}}^{\boldsymbol{HB,max}} = 0.5\right) = 27818.34€\ ,$$

$$\boldsymbol{I}^{\boldsymbol{HB}}\left(\dot{\boldsymbol{Q}}_{\mathrm{k}}^{\boldsymbol{HB,max}} = 1\right) = 40066.88€\ ,$$

$$\boldsymbol{I}^{\boldsymbol{HB}}\left(\dot{\boldsymbol{Q}}_{\mathrm{k}}^{\boldsymbol{HB,max}} = 3\right) = 71438.06€\ .$$

2. Thermal storage

$$\boldsymbol{I}^{\boldsymbol{TS}} = 10000€ + 193{,}33\,\tfrac{€}{\mathrm{m}^3} \cdot \boldsymbol{V}_{\mathrm{k}}^{\boldsymbol{TS,max}} \quad \forall \boldsymbol{V}_{\mathrm{k}}^{\boldsymbol{TS,max}} < 0$$

3. District-heating pipelines

$$\boldsymbol{I}^{\boldsymbol{pipeline}} = \boldsymbol{I}^{\boldsymbol{construction}} + \boldsymbol{I}^{\boldsymbol{material}}$$

$$\boldsymbol{I}^{\boldsymbol{construction}} = \sum_{\mathrm{k}} \sum_{\mathrm{kn}} \left[200{,}000\,\tfrac{€}{\mathrm{km}} \cdot \mathrm{s}_{\mathrm{k,kn}} \cdot \boldsymbol{y}_{\mathrm{k,kn}}^{\boldsymbol{connect}}\right]$$

$$\boldsymbol{I}^{\boldsymbol{material}} = \sum_{\mathrm{k}} \sum_{\mathrm{kn}} \left[\left(29.71€ \cdot \boldsymbol{y}_{\mathrm{k,kn}}^{\boldsymbol{connect}} + 0.093\,\tfrac{€}{\mathrm{m}}\,\boldsymbol{d}_{\mathrm{k,kn}}^{\boldsymbol{max}}\right) \mathrm{s}_{\mathrm{k,kn}} \cdot 1000\,\tfrac{1}{\mathrm{km}}\right]$$

Here $\mathrm{s}_{\mathrm{k,kn}}$ is the distance between node k and node kn, Table 4 presents the coordinates of each node.

Table 4. Coordinates of nodes and maximal heat demand.

	North [km]	West [km]	$Q^{D,max}$ [MW]
node 1	0	0.5	1
node 2	0	1	2
node 3	0	0	3

Table 5. Parameters of CHP unit types [15].

		CHP unit of		
	unit	Type 1	Type 2	Type 3
P^{el}	[MW]	0.14	0.42	1.00
σ	[-]	0.65	0.71	0.90
η^{el}	[-]	0.35	0.36	0.43
η^{th}	[-]	0.54	0.51	0.47
I	[€]	121,244	247,560	490,000
K^{WTG}	[ct/kWh]	1.54	1.15	0.91
K^{GU}	[€/kW]	186	127	93

Nomenclature

Constants are printed normally and variables are printed in italics. If possible, the nomenclature for physical quantities is used. Superscripts are used to attach the name of a component and other describing features. Subscripts represent arguments spanning a vector space.

A	annuity, €/a
c	specific heat, J/(kg K)
CHP	combined heat and power
d	diameter, m
$\dot{\mathrm{F}}$	fuel consumption, MW
FC	fuel cost, €/h
$\underline{\mathrm{L}}$	lower bound of Glover's linearization
$\dot{\mathrm{M}}$	mass flow rate, kg/s
MC	maintenance cost, €/h
P	electrical power, MW
PC	pump cost, €/h
$\dot{\mathrm{Q}}$	thermal power, MW
R	revenue, €/h
S	subsidy, €/a
T	temperature, °C
U	internal energy, MWh
$\overline{\mathrm{U}}$	upper bound of Glover's linearization
V	volume, kg/m^3
x	integer variable
y	binary variable

Greek symbols

α	weighting factor
Δτ	number of hours per time interval, h
η	efficiency
φ	heat loss in storage vessel

Superscripts

CHP	combined heat and power unit
D	demand
el	electrical
FL	feed line
HB	heat boiler
RL	return line
th	thermal
TS	thermal storage

Subscripts

C	component
k	node

kn node

τ time interval

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