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Design of an Optimization Algorithm for the Distribution of Thermal Energy Systems and Local Heating Networks within a City District

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Abstract:

The linkage of combined heating and power (CHP) systems with local heating networks has the potential to increase energy efficiency on city district scale. First, CHP systems have a high overall efficiency. Second, the usage of CHP systems as heat sources for local heating networks can lead to advantageous economics of scale effects. With an increasing number of buildings the number of possible energy system combinations enlarges tremendously. A manual design approach might lead to a suboptimal solution. This paper describes an approach for the optimized placement of CHP systems, boilers, thermal storages and local heating networks on city district level. A mixed integer linear programming (MILP) problem has been formulated within the General Algebraic Modeling System (GAMS). The objective function is the cost minimization of the overall system under ecological and technical constraints. To reduce the optimization runtime, a k-Medoids demand day clustering and a minimum spanning tree strategy have been implemented. A small city district has been designed as test case. On one hand the algorithm leads to planning solutions with reduced overall costs as well as decreased greenhouse gas emissions. On the other hand a number of 9 buildings leads to 2.5 hours runtime. Therefore, further work on strategies for run time reduction is required.

Keywords:

CHP, local heating networks, MILP, GAMS, energy system distribution, optimized placement, city district

1. Introduction

To deal with the climatic change and its consequences is one of the world's major challenges. This leads to the necessity of greenhouse gas emission reduction. High potential for CO_2 emission diminution can be found on city district scale. The usage of combined heating and power (CHP) systems can increase energy efficiency for building energy supply, especially in combination with local heating networks (LHN). First, CHP systems have a high overall efficiency. Second, they can have positive economics of scale effects due to decreasing specific installation cost with ascending installation power. Therefore, decentralized CHP implementations within city districts are promising. However, the planning process for CHP systems and LHN is challenging. With increasing number of buildings the number of possible options for CHP distribution as well as LHN installations enlarges, too. Furthermore, different target functions, such as cost minimization, greenhouse gas emission reduction or grid stabilization, are possible. The traditional planning approach might lead to suboptimal solutions. Therefore, the usage of mathematical optimization is supportive.

Within this paper the design of an optimization algorithm for distribution of thermal energy systems and local heating networks on city district scale is presented. A mixed integer linear programming (MILP) problem is formulated within the General Algebraic Modeling System (GAMS), which aims at the overall cost minimization of the energy system under different ecological and technical constraints. CHP systems, boilers, LHN and thermal storage systems are taken into account. Two different approaches for runtime reduction were implemented. First, the total number of different daily building load profiles is reduced via k-Medoids-algorithm. Second, the number of binary variables is lowered with the Kruskal algorithm, which sets a minimal spanning tree as a constraint for possible LHN connections. A virtual city district with 9 buildings is designed as test case for the optimization algorithm. First, the required run time for different number of buildings as well as algorithm setups is analyzed. Second, the energy system installation for minimized cost is determined. Finally, a multi-objective optimization via ε–constraint method is performed. Thus, greenhouse gas emission and cost minimization can be taken into account.

2. Fundamentals

2.1. Economic efficiency

The cost calculation is based on the VDI 2067 standard [1] about economic efficiency of building installations. It uses the annuity method to calculate the energy system profitability. It accounts for capital-related costs $A^{N,K}$, demand-related costs $A^{N,V}$, operation-related and other costs $A^{N,B}$ as well as incoming payments $A^{N,E}$. Equation (1) shows the total annual annuity A^N.

$$A^N = -(A^{N,K} + A^{N,V} + A^{N,B}) + A^{N,E} \qquad (1)$$

The system with the lowest cost respectively highest annuity should be selected. The annuity factor ANF is shown in (2), where q is the interest factor and T the observation period in years.

$$ANF = \frac{q^T(q-1)}{q^T-1} \qquad (2)$$

It allows the consideration of non-recurring and regular payments over the observation time T. Furthermore, the VDI 2067 provides factors for calculated service life, efforts on repairs and on operation for relevant components, such as CHP, boiler systems and LHN pipelines.

2.2. German combined heat and power act

The German act on combined heat and power [2] intents to support decentralized CHP installations and, therefore, increase the share of cogeneration within Germany. Grid operators have to connect efficient CHP systems to their networks and take fed in CHP electricity with higher priority. CHP operators get two kinds of subsidies:

- Surcharge payments for produced electricity, either for own consumption or for grid feed in
- Compensation payments for fed in electricity

The surcharge payment depends on the installed power and number of operational hours. The compensation payment either consists of a price agreement between grid operator and CHP owner or the average base load price of EEX [3] for the most recent quarter plus avoided grid usage fee. Moreover, the CHP act supports LHN development. If the share of CHP heat within the LHN is higher than 60%, the LHN operator gets compensation of 100 €/m for nominal pipeline diameter smaller than 100 mm. Up to 40% of LHN investment cost can be compensated. Furthermore, tax exception is possible (German act on energy taxation [4]). If the CHP annual utilization ratio is higher than 70%, the operator can get a payback of CHP fuel tax (limited to 10 years). Additionally, electric current from CHP systems below 2 MW installed electrical power are tax-exempted.

3. Methodology

3.1. Modeling approach

The following components are modeled within the optimization algorithm:

- Within buildings: CHP systems, boilers, thermal storages, LHN transfer stations
- Between buildings: LHN connections (with heat losses and pressure drop)

If a building is connected to a LHN, every thermal device (CHP, boiler, storage) can supply heat into the grid. Furthermore, a thermal storage can gain heat from the LHN, if a connection exists. Within LHN connections bidirectional heat transfer is possible. The building loads are taken into account via thermal [5] and electrical [6] standardized load profiles for one year. An hourly time step is chosen as step size. Binary variables are used to decide about the installation of components.

3.1.1. Objective function

The optimization aim is the minimization of the overall cost. Therefore, the algorithm has to minimize the total annuity, according to VDI 2067. The objective function is shown in (3).

$$\min\,[z = (A^{N,K} + A^{N,V} + A^{N,B}) - A^{N,E}] \quad (3)$$

3.1.2. Economic constraints

Capital cost

The total amount of capital cost consists of the investment cost for all installed components, as shown in (4):

$$A^{N,K} = A^{N,K,chp} + A^{N,K,b} + A^{N,\mathrm{K},lhn} + A^{N,\mathrm{K},sto} + A^{N,\mathrm{K},ts} \quad (4)$$

Equation (5) shows the capital investment cost for LHN connections

$$A^{0,lhn,total} = \sum_i \sum_j \sum_p Y_{i,j,p}^{lhn} \cdot l_{i,j} \cdot A_p^{0,lhn} (5)$$

with i < j. This constraint prevents the choice of a second pipeline for the same connection between two buildings. Equation (6) shows the annuity of capital cost of each component.

$$A^{N,K} = ANF \cdot (1 + \sum_{rp=1}^{n} b_{rp} - r^{w}) \cdot A^0 \, (6)$$

If the calculated service life T_N is shorter than observation period T, replacement procurements (rp) will be performed. The cash value factor for replacement is shown in (7).

$$b_{rp} = \frac{\mathrm{r}_K^{rp \cdot T^N}}{q^{rp \cdot T^N}} \forall rp \quad (7)$$

The residual value can be calculated with (8).

$$R_W = r_K^{(n \cdot T_N)} \cdot \frac{(n+1) \cdot T_N - T}{T_N} \cdot \frac{1}{q^T} \quad (8)$$

Following, the interest factor q is defined as 1.05 and the observation period T is set to 10 years. Price change factor for capital related cost r_K is defined as 1.017, related to [7]. According to [8], the investment cost of CHP, boiler and thermal storage systems are taken into account via linearized cost functions. The general cost function is shown in (9).

$$A^0 = (a^1 + a^2 \cdot capacity) \quad (9)$$

According to [9], LHN plastic pipes within DN20 to DN40 are assumed to cost 280 €/m. Investment cost of direct transfer stations for LHN are defined as 2000 € per station, related to [10]. Fixed cost as well as capacity dependent cost factors are taken from [11].

Demand related cost

Within this approach only gas and electric energy expenses are taken into account as demand related costs. The annuity of demand related cost is shown in (10):

$$A^{N,V} = A^{V1} \cdot ANF \cdot b^V \quad (10)$$

Price changes can be taken into account via cash value of demand related costs with (11):

$$b^V = \frac{1-\left(\frac{r^V}{q}\right)^T}{q-r^V} \quad (11)$$

According to [7], the annual price change factor r^V for demand related cost is estimated as 1.038. The demand related costs consist of expenses for electric energy and gas, shown in (12) and (13)

$$A^{V1,el} = \sum_i \left(W_i^{grid} \cdot ap_i^{el} + lp_i^{el}\right) + W^p \cdot ap^{el} \quad (12)$$

$$A^{V1,gas} = \sum_i (EE_i^{gas,boiler} \cdot ap_i^{gas} + EE_i^{gas,chp} \cdot (ap_i^{gas} - etg) + lp_i^{gas}) \quad (13)$$

with energy unit price ap and capacity price lp. According to [12], The electric energy unit pricing is assumed to be 26.61 cent/kWh for single family houses and 25.44 cent/kWh for multifamily houses, while the electric capacity price is 111.72 €/a. The gas unit price is assumed to be 6.71 cent/kWh, while the gas capacity price is 142.8 €/a. The annual electric energy and gas demand per building i can be calculated with (14) and (15):

$$EE_i^{gas} = \sum_{tt} nc_{tt} \cdot \Delta t \cdot \sum_t \left(\dot{EE}_{tt,t,i}^{gas,chp} + \dot{EE}_{tt,t,i}^{gas,K}\right) \forall i \quad (14)$$

$$W_i^{grid} = \sum_{tt} nc_{tt} \cdot \Delta t \cdot \sum_t P_{tt,t,i}^{grid} \forall i \quad (15)$$

Operational cost

Operational cost accounts for inspection and repair expenses. Its annuity is calculated with (16):

$$A^{N,B} = A^{0,total} \cdot (f^{Inst} + f^{Insp}) \cdot ANF \cdot b^B (16)$$

Incoming payments

The annuity of incoming payments can be calculated with equation (17).

$$A^{N,E} = \left[\sum_{tt} \left(\left(e_{tt}^{feedin} + aguf\right) \cdot nc_{tt} \cdot W_{tt}^{feedin}\right) + e^z \cdot W^{gen,total}\right] \cdot ANF \cdot b^E \quad (17)$$

with compensation payment factor for fed in electricity e^{feedin}, avoided grid usage fee factor aguf of 0.49 cent/kWh [13], number of demand days nc and surcharge payment factor e^z. The compensation factor e^{feedin} is taken from the EEX electricity price data for 2013 [3].

3.1.3. Technical constraints

The greenhouse gas emission factors of 244 g/kWh (final energy) for gas and 604 g/kWh for electricity are taken from [14]. Thermal and electrical power balance can be found in (18) and (19):

$$\dot{Q}_{tt,t,i}^{b} = \dot{Q}_{tt,t,i}^{chp} + \sum_b \dot{Q}_{tt,t,i,b}^{k} + d\dot{Q}_{tt,t,i}^{sto} + d\dot{Q}_{tt,t,i}^{lhn} \forall tt,t,i \quad (18)$$

$$P_{tt,t,i}^{b} = P_{tt,t,i}^{gen,chp} + P_{tt,t,i}^{grid} - P_{tt,t,i}^{feedin} \forall tt,t,i (19)$$

Boiler system

The boiler can be selected from a continuous power range from 10kW to 100kW thermal power (with constant efficiency of 95% for new installed boilers). If a CHP system is installed within a building, only a peak load boiler can be added, which has a different cost function. The lower and upper power boundaries are defined with (20):

$$\dot{Q}_{b}^{k,lb,min} \cdot \left(Y_{i,b}^{k} + Y_{i,b}^{plb}\right) \le \dot{Q}_{i,b}^{k,n} \le \dot{Q}_{b}^{k,lb,max} \cdot \left(Y_{i,b}^{k} + Y_{i,b}^{plb}\right) \forall i,b \quad (20)$$

CHP system

The CHP is modeled based on the VDI 2157 report [8] with data of [11]. A total efficiency of 95% is assumed. The algorithm can select CHPs in a discrete range from 2kW up to 50 kW electrical power. From 5 kW to 50 kW electrical power a minimal operation load of 50% is defined. The share between electrical and thermal power output varies according to (21):

$$\dot{Q}_{a}^{chp,n} = \frac{P_a^{el,n} - \gamma}{\alpha + \beta} \quad (21)$$

With α = -0.146, β = 0,66 and γ = -2.62. The part load behavior is included with (22) and (23):

$$\dot{Q}_{tt,t,i}^{chp} = \frac{1}{\beta} \cdot \left(P_{tt,t,i}^{gen,chp} - \sum_a \left(X_{tt,t,i,a}^{chp} \cdot \left(\alpha \cdot \dot{Q}_a^{chp,n} + \gamma\right)\right)\right) \forall tt,t,i \quad (22)$$

$$\sum_a \left(MPL_a^{chp} \cdot P_a^{el,n} \cdot X_{tt,t,i,a}^{chp}\right) \le P_{tt,t,i}^{gen,chp} \le \sum_a \left(P_a^{el,a} \cdot X_{tt,t,i,a}^{chp}\right) \forall tt,t,i \quad (23)$$

Thermal storage system

A capacity model with linear behavior is chosen as storage system. A heat loss rate of 1% per timestep is defined. Its energy balance is shown in (24), the storage capacity in (25):

$$\frac{Q^{sto}_{tt,t+1,i}-Q^{sto}_{tt,t,i}}{\Delta t} = -d\dot{Q}^{sto}_{tt,t,i} - \dot{Q}^{loss}_{tt,t,i} \qquad (24)$$

$$Q^{sto}_{tt,t+1,i} = Q^{sto}_{tt,t,i} \cdot (1-\varphi^{sto}) - \Delta t \cdot d\dot{Q}^{sto}_{tt,t,i} \forall tt, t < t^n, i \qquad (25)$$

To integrate the usage of typical demand days, the amount of thermal energy per storage has to be the same at the start and end of each day, as shown in (26) and (27):

$$Q^{sto,start}_{tt,i} = Q^{sto}_{tt,t,i} \forall tt, t = t^1, i \qquad (26)$$

$$Q^{sto,start}_{tt,i} = Q^{sto}_{tt,t,i} \cdot (1-\varphi^{sp}) - \Delta t \cdot d\dot{Q}^{sto}_{tt,t,i} \forall tt, t = t^n, i \qquad (27)$$

Local heating network

According to [8], LHN pipelines with size DN20, DN25, DN32 and DN40 can be selected. They differ in heat loss and pressure drop factor. The maximal possible heat exchange through pipeline p is shown in (28):

$$\dot{Q}^{lhn,max}_{p} = \frac{\pi}{4} \cdot {d^{lhn}_{p}}^2 \cdot v^{lhn,max} \cdot \rho \cdot c_p \cdot \left(T^{if} - T^{rf}\right) \forall p \qquad (28)$$

The energy balance and losses are defined with (29) and (30):

$$d\dot{Q}^{lhn}_{tt,t,i} = \sum_j \sum_p \left(\dot{Q}^{lhn}_{tt,t,j,i,p} - \left(\dot{Q}^{lhn}_{tt,t,i,j,p} + \frac{\dot{Q}^{lhn,loss}_{tt,t,i,j,p}}{2}\right)\right) \forall tt, t, i \qquad (29)$$

$$\dot{Q}^{lhn,loss}_{tt,t,i,j,p} = U^{lhn}_{p} \cdot l_{i,j} \cdot \left(T^{if} + T^{rf} - 2 \cdot T^{lhn,env}\right) \cdot Y^{lhn}_{i,j,p} \forall tt, t, i, j, p \qquad (30)$$

A high number of LHN operational hours is assumed, therefore, the losses occur over the whole observation period. Furthermore, a linearized pressure drop model for a maximum allowed flow velocity is implemented.

3.2. Runtime reduction methods

k-Medoids method

An approach by [15] is used to reduce the amount of demand days used for the optimization problem. This is done by the selection of typical demand days via k-Medoids method. Comparable demand days are clustered within groups. Every group is assigned to a typical demand day, so that a distance value between original annual demand profile and clustered demand profile is minimized. This leads to another MILP problem. Thus, the amount of demand days can be reduced tremendously, while the clustered demand profiles have a sufficient match with the original profiles.

Kruskal-algorithm

The number of possible LHN connections is quadratic dependent on the number of buildings. Therefore, it offers potential to decrease runtime through reduction of binary variables. Instead of enabling the optimization algorithm to take every LHN connection into account, the possible LHN connections are limited to a minimal spanning tree (MSP). It is generated via Kruskal-algorithm [16], which identifies the shortest path to connect all buildings without generating loops. Thus, the number of possible LHN connections between buildings is reduced.

4. Application and results

Table 1. Building type parameters

Building type	*Acronym*	*Annual heat demand in kWh/a*	*Annual electrical demand in kWh/a*
Single family house	SFH	17600	4400
Duplex house	DH	23400	8000
Multifamily house	MFH	45000	24000

For the analysis 3 different building types are used. Based on specific energy demand values of [17] their parameters are derived and shown in table 1. The optimization is performed with CPLEX 12.

4.1. Influence of number of typical demand days

A virtual city quarter, consisting of 5 residential buildings, is used to analyze the influence of the number of typical demand days on the optimization run time, installation choice and cost. According to [15], the annual profiles are reduced to a number of typical demand days between 4 and 14. Figure 1 shows results for run time and system cost over number of typical demand days. As shown in figure 1, the run time can be decreased around 90% by reducing the amount of typical days from 14 to 4 while generating comparable overall cost values. However, in this example the reduction is critical, because of a change of chosen installation from 8 to 6 typical demand days. While the system installation choice for demand day numbers between 8 and 14 remains the same as the optimal solution for the original profiles, a further reduction leads to another system choice. Therefore, the following analyses are performed with a typical demand day number higher than 7. In comparison to the optimization run with 365 demand days, the run time for a number of 8 typical demand days is reduced around 98%.

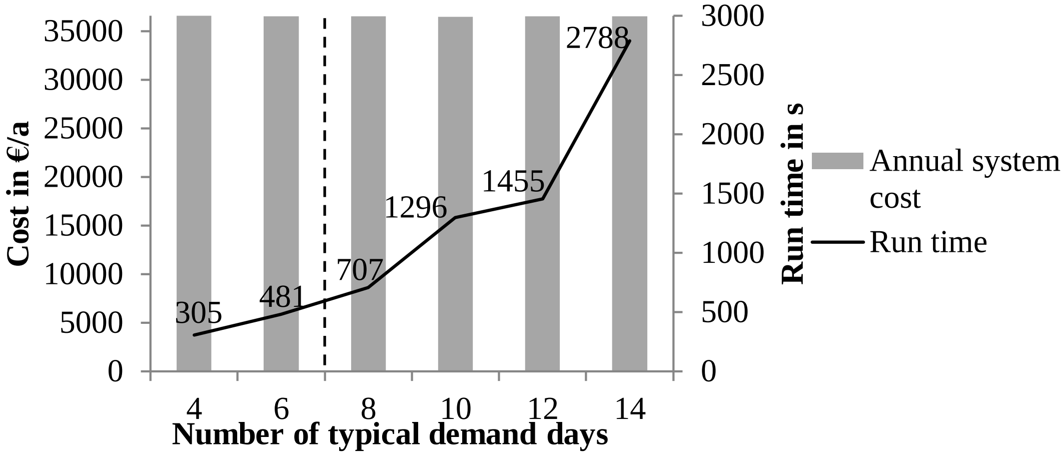

Fig. 1. Cost and run time for different number of typical demand days

4.2. Influence of minimum spanning tree constraint

A run time comparison for optimization runs with and without MST constraint for possible LHN connections is performed for different number of buildings. A number of 9 typical demand days is chosen for k-Medoids clustering. An integrality gap of 2% is accepted for termination of optimization run. Table 2 shows the residential building type and location of a planned city district.

Table 2. Residential building type and location

Building	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Type	SFH	DH	MFH	DH	MFH	SFH	DH	DH	DH
Coordinates (x/y) / m	(0/0)	(0/9)	(10/0)	(12/10)	(20/0)	(20/10)	(5/18)	(28/5)	(25/15)

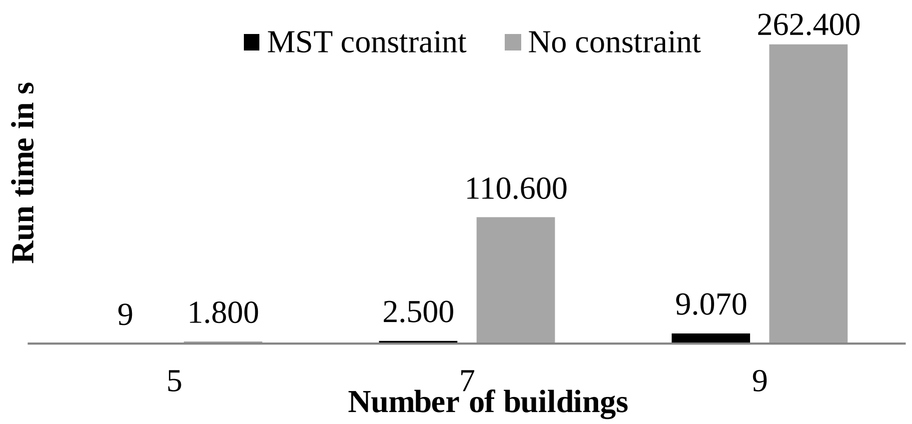

Fig. 2. Required run time for city district optimization with and without MST constraint

Figure 2 shows the optimization results. The run time can be reduced by 96% for an amount of 9 buildings through MST constraint implementation, while resulting in the same chosen configuration. Therefore, the cost optimal solution for 9 buildings (with MST constraint) is identified after 2.5 hours. However, the implementation of the MST constraint does not necessarily lead to the optimal installation choice for every city district structure, but it offers a good solution to reduce run time, especially for the optimization of large amount of buildings. The identification of an optimal energy system distribution for 50 buildings (with 9 typical demand days and MST constraint) requires around 2 week’s runtime.

4.3. Cost optimization of virtual city district

The cost optimal installation for the city district of section 4.2. is identified within this section. Gas boiler installations without LHN connections are chosen as reference system. A number of 9 typical demand days is chosen for k-Medoids clustering. To prevent the MST constraint from affecting the system choice, the MST constraint is not used. The integrality gap is reduced to 0.1%. The lower power limit of boilers is set to 10 kW, the smallest volume of thermal storages to 100 l. Figure 3 shows the identified, optimal configuration. For building 3 a CHP of 5 kW electrical power, a PLB of 23.6 kW thermal power and a thermal storage of 567 l are chosen, for building 5 a CHP of 5 kW electrical power, a PLB of 31.6 kW thermal power and a thermal storage of 675 l. The optimization results are shown in table 3. Furthermore, a minimum spanning tree is generated and compared with the optimal system configuration. All chosen LHN connections are placed within the optimal spanning tree, even without setting a MST constraint. Therefore, the MST constraint is assumed to reduce runtime, while leading to comparable solutions for LHN networks.

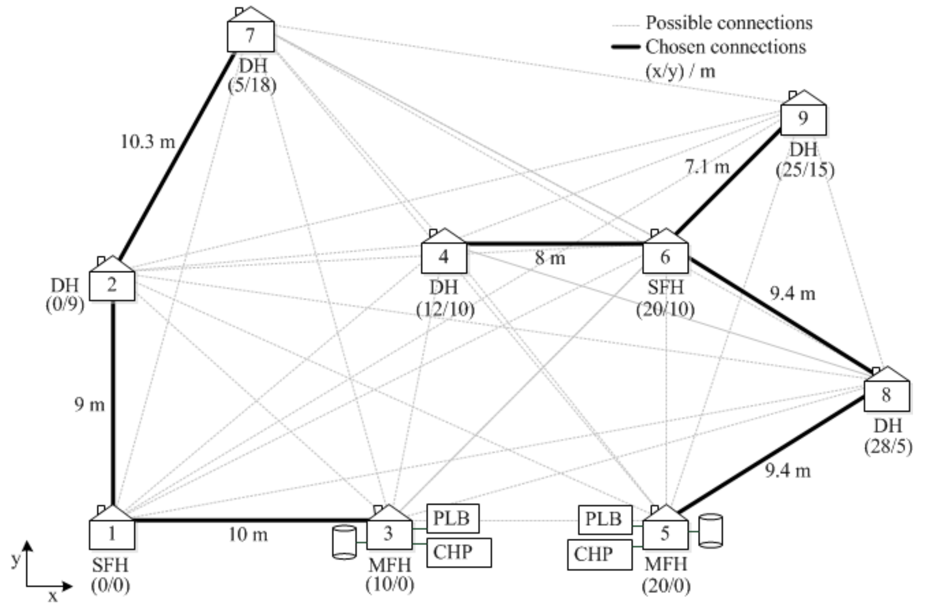

Fig. 3 Optimal system configuration for virtual city district

Table 3. Optimization results

	Reference	*Optimized*	*Difference*
Annual cost in €/a	55616	53719	- 3.41%
Greenhouse gas emission in t/a	115.94	95.45	- 17.60%
Primary energy demand in MWh/a	530.13	433.09	- 18.30%

4.4. Multi-objective optimization of a virtual city district

To take a minimization of greenhouse gas emission and annual cost into account, a multi-objective optimization via ε-constraint method [18] is performed. First, the minimal CO_2 emission value is identified through optimization run with greenhouse gas emissions as objective function. Second, six additional optimization runs with annual cost as objective function are performed. For each of these runs a different, maximal CO_2 emission limit is defined. Furthermore, the optimal cost value should not exceed the annual cost of the reference system (gas boilers only; without LHN). To reduce runtime, only LHN pipes of size DN20 can be installed. This leads to a front of pareto-optimal solutions. Figure 4 shows the pareto front as well as the reference point.

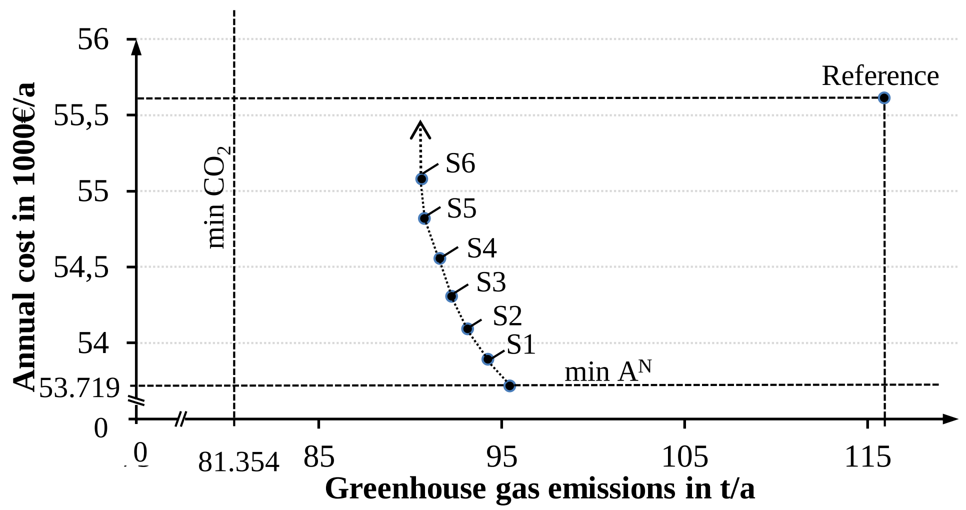

Fig. 4 Pareto-optimal solutions for annual cost and greenhouse gas emissions

In comparison to the cost optimal solution, further greenhouse gas emission reduction can only be achieved with additional payments. The specific cost per reduced amount of greenhouse gas increases progressive, which means that every additional reduced ton of emissions results in increasing, annual cost. The minimal amount of 81.35 t CO_2 emissions could only be reached with total annual cost higher than the reference system cost.

5. Conclusion

This paper describes the development of a mixed integer linear programming (MILP) optimization algorithm in GAMS. It aims at the minimization of annual cost via optimal placement of thermal energy systems on city district scale. Combined heat and power (CHP), boiler, thermal storage systems and local heating networks (LHN) are taken into account. A typical demand day clustering via k-Medoids algorithm as well as a minimum spanning tree (MST) constraint via Kruskal algorithm were implemented for runtime reduction. The influence of runtime reduction methods on system choice and cost is investigated. Furthermore, the algorithm is used to perform a single objective (cost optimization) as well as multi-objective (cost and greenhouse gas emission optimization) operation on a 9 residential buildings district.

First, with the reduction from 365 to 8 typical demand days via k-Medoids method, the runtime can be reduced by around 98%. However, further demand day reduction led to a change in the system installation choice. Therefore, the user has to be aware of the trade-off between runtime and output quality when selecting the number of typical demand days. Second, a runtime reduction around 96% has been achieved through MST-constraint usage, which exclusively enables LHN connection choice within a MST. The optimization run (with demand day clustering and MST-constraint) for 9 buildings required 2.5 hours of runtime. Third, the single objective optimization led to a 3.4% annual cost and 17.6% greenhouse gas emission reduction for the 9 buildings test case. The multi-objective optimization generated a front of pareto-optimal solutions, which showed that a further greenhouse emission reduction was only possible at increasing cost per avoided ton of CO_2 emissions.

However, the shortest, geometrical paths are chosen as LHN connections and, therefore, the algorithm neglects possible barriers, such as unpassable property. Moreover, a newly planned district has been chosen as reference system, where full investments for boiler systems were necessary. Most existing buildings already have a thermal supply system, therefore, the annual cost for a reference system of existing buildings would decrease, what could make CHP-LHN-scenarios disadvantageous. The optimization results are very sensitive to the predefined inputs and constraints. Especially demand profiles and price developments are uncertain. The user has either to make good assumptions or perform multiple optimization runs with different assumed inputs, what would require high runtime. Another critical issue is the increasing runtime for large amount of buildings.

The algorithm will be extended to be applicable to existing city districts, for instance by only enabling LHN connections on street paths. Furthermore, methods for further runtime reduction are reasonable to take larger number of buildings into account. The algorithm is promising to support planners with ex ante solutions for thermal energy system placement and dimensioning. However, the suggested solutions should always be checked under conditions, which were not included within the optimization algorithm.

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Nomenclature

Symbols

a^1	Fixcost investment factor,	€
a^2	Power investment factor,	€/kW
A	Annual cost,	€/a
$aguf$	Avoided grid usage fee,	ct/kWh
ANF	Annuity factor	
ap	Energy unit price,	ct/kWh
c_p	Specific heat capacity	J/kgK
d	Diameter	m
e	Compensation payment,	ct/kWh
EE	Final energy,	kWh
etg	Energy taxation for gas,	ct/kWh
l	Length	m
lp	Capacity price,	€/a
MPL	Minimal part load	kW
nc	Number of demand days	
P	Electrical power,	kW
q	Interest factor	
Q	Thermal energy,	kWh
R_W	Residual value,	€
t	Timestep,	h
T	Observation period,	a
T_N	Calculated service life,	a
U	Heat loss coefficient	W/mK
W	Amount of energy	kWh
X	Binary variable (operation)	
Y	Binary variable (installation)	
z	Total annual cost,	€/a

Greek symbols

α	VDI 2157 CHP factor	
β	VDI 2157 CHP factor	
γ	VDI 2157 CHP factor	
ρ	Density	kg/m^3
φ	Loss factor	

Subscripts and superscripts

0	First period / year
a	Combine heat and power (index)
b	Boiler (index)
B	Operational cost related
chp	Combined heat and power
DH	Duplex house
E	Incoming payment related
el	Electrical
env	Environment
$feedin$	Feed in electric energy
gas	Gas supply / usage
gen	Generated energy
$grid$	Grid connected / usage
i	Building
if	Inlet flow
$Insp$	Inspection and repairs
$Inst$	Installation
j	(Next) building
k	Boiler
K	Capital cost related
lhn	Local heating network
$loss$	Energy loss
max	Maximum
MFH	Multifamily house
MST	Minimum spanning tree
n	Number of components
N	Related to total annual cost
p	Local heating network pipeline
plb	Peak load boiler
rf	Return flow
rp	Replacement procurements
SFH	Single family house
$start$	Start of typical demand day
sto	Thermal storage system
t	Timestep
$Total$	Complete system / all elements
ts	Transfer station (LHN)
tt	Typical demand day
V	Demand cost related

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