Energy Flexibility from the Consumer: Integrating Local Electricity and Heat Supplies in a Building [1]

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Abstract: The increasing penetration level of renewable energy requires more flexibility measures to be implemented in future energy systems. Integrating an energy consumer's local energy supplies connects multiple energy networks (i.e., the electrical grid, the district heating network, and gas network) in a decentralized way. Such integration enhances the flexibility of energy systems. In this work, a Swedish office building is investigated as a case study. Different components, including heat pump, electrical heater, battery and hot water storage tank are integrated into the electricity and heat supply system of the building. Special focus is placed on the flexibility that the studied building can provide to the electrical grid (i.e., the building modulates the electricity consumption in response to the grid operator's requirements). The flexibility is described by two metrics including the flexibility hours and the flexibility energy. Optimization of the component capacities and the operation profiles is carried out by using Mixed Integer Linear Programming (MILP).

The results show that the system fully relies on electricity for the heat demand when not considering the flexibility requirements of the electrical grid. This suggests that district heating is economically unfavorable compared with using electricity for the heat demand in the studied case. However, when flexibility requirements are added, the system turns to the district heating network for part of the heat demand. The system provides great flexibility to the electrical grid through such integration. The flexibility hours can be over 5200 hours in a year, and the flexibility energy reaches more than 15.7 MWh (36% of the yearly electricity consumption). The yearly operation cost of the system slightly increases from 62,273 to 65,178 SEK when the flexibility hours increase from 304 to 5209 hours. The results revealed that flexibility can be provided from the district heating network to the electrical grid via the building.

Keywords: Flexibility; Supply Integration; Electrical Grid; District Heating; Optimization

Nomenclature

Symbol	Unit	Description
$C_{DH,y}$	SEK	District heating cost at year *y*
$C_{DSO,y}$	SEK	Electricity cost charged by the DSO at year *y*
$C_{ER,y}$	SEK	Electricity cost charged by the Energy Retailer at year *y*
$C_{O,y}$	SEK	Yearly operation cost
$C_{R,y}$	SEK	Replacement cost at year *y*
$C_{M,y}$	SEK	Maintenance cost at year *y*
Cap_i	-	Capacity of component *i*
COP_t	1	Coefficient of performance at *t*
ELP_t	SEK/kWh	Electricity spot market price at *t*
Inv_i	SEK	Investment cost for component *i*
$P_{c,t}$	kWh	Battery charged electricity at *t*
$P_{d,t}$	kWh	Battery discharged electricity at *t*
$P_{EH,t}$	kWh	Electrical heater electricity consumption at *t*
$P_{ex,t}$	kWh	Exported electricity at *t*
$P_{HP,t}$	kWh	Heat pump electricity consumption at *t*
$P_{im,t}$	kWh	Imported electricity (electricity consumption) at *t*
$P_{L,t}$	kWh	Electricity demand at *t*
$P_{Net,t}$	kWh	Net electricity at *t*
$P_{PV,t}$	kWh	PV electricity production at *t*
$Peak_{\mathrm{m}}$	kWh	Monthly peak of imported electricity
$Q_{c,t}$	kWh	Hot water tank charged energy at *t*
$Q_{d,t}$	kWh	Hot water tank discharged energy at *t*
$Q_{DH,t}.$	kWh	Electrical heater heat output at *t*
$Q_{HP,t}$	kWh	Heat pump heat output at *t*
$Q_{Load,t}$	kWh	Heat demand at *t*
R_y	SEK	Revenue from exported electricity at year *y*
$S_{HWT,t}$	kWh	HWT storage state at the end of *t*
SOC_t	%	State of charge at the end of *t*

Abbreviation

Abbreviations	Description
ASHP	Air Source Heat Pump
CHP	Combined Heat and Power
DH	District Heating
DSM	Demand Side Management
DSO	Distribution System Operator
EH	Electrical Heater
ER	Energy Retailer
GSHP	Ground Source Heat Pump
HP	Heat Pump
HWT	Hot Water Tank
MILP	Mixed Integer Linear Programming
P2G	Power-to-Gas
PV	Photovoltaic
SCR	Self-Consumption Ratio
VAT	Value-Added Tax

1 Introduction

The penetration level of renewable energy is increasing rapidly [1, 2]. Many countries have set ambitious goals towards carbon-neutral societies [3], and thus, an increased amount of variable renewable electricity is expected in future electrical systems [4]. However, as the electrical systems require a balance between supply and demand over time, the variability and uncertainty of renewable energies pose a growing challenge to the stable and secure operation of electrical systems. The ability of an electrical system to cope with uncertainty and variability is usually regarded as the flexibility of the system, which though lacks a unified definition. The flexibility of a system originates from a portfolio of different measures that help maintain the balance between supply and demand over time. These measures are usually collectively called flexibility measures, which were summarized and analyzed by Lund et al. [5]. The increase in renewable energies requires more flexibility measures in future energy systems.

1.1 Energy flexibility measures

A schematic summary of the energy systems and flexibility measures is given in Fig. 1. The electrical system, district heating system, and gas system are distinguished by the energy carriers and showed in different colors. The conversion between different energy carriers is achieved by the energy conversion technologies. In each energy system, the supply units and consumers are connected by the distribution network.

The flexibility measures mainly include supply-side flexibility, demand-side flexibility and the integration of energy networks. Supply-side flexibility is achieved by the coordinated operation of various generation, transmission and distribution units, which are controlled to balance the energy systems. Demand-side flexibility is usually achieved by the demand side management (DSM) [6], which provides various ways to change the energy consumption profiles of a single energy consumer or multiple consumers through aggregation [7, 8]. Energy consumption can be shifted according to the price signals or for higher self-consumption ratio of the on-site renewable energy [9, 10]. Heating, ventilation and air conditioning (HVAC) systems have been demonstrated to have enormous potential in DSM [11, 12]. Arteconi et al. concluded that a heat pump, together with thermal energy storage, can be turned off for 3 hours without losing control of the indoor temperature [13]. Kensby reported that the thermal storage capacity can be 0.1 kWh/m_{Floor}^2 when utilizing the thermal inertia of a building [14]. The concept of 4th Generation District Heating (4GDH) considers controlling the heating demand of a building to be an important technology [15]. Several optimization algorithms and energy management systems have been developed for DSM [16, 17].

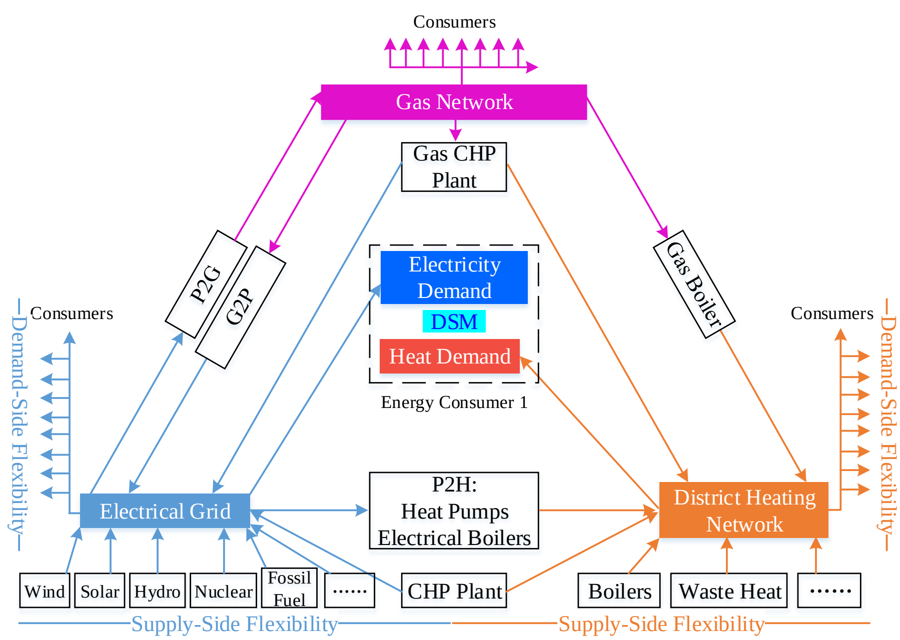

Fig. 1. Flexibility measures in energy systems

The holistic integrating of conventionally separate energy networks (i.e., electrical grid, thermal (heating/cooling) network, and gas network) will also offer significant flexibility. In the UK, there are discussions about the integration of the electrical grid and gas network. An interconnected energy system model was developed in Devlin et al. [18], by which the stress of gas networks under extreme weather events was evaluated. Clegg et al. developed a method to quantify the flexibility that can be provided from the gas network to the electrical network [19]. Integration of the electrical grid and the district heating (DH) network has also been studied. Liu et al. presented a method for the integrated analysis of the electrical grid and the district heating network, which were interconnected through combined heat and power (CHP) units, heat pumps (HP) and circulation pumps [20]. Schweiger et al. estimated the power-to-heat (P2H) potential in Swedish district heating systems to be 0.2–8.6 TWh [21]. Romanchenko et al. introduced an optimization-based model to study the optimal operation of district heating systems in future scenarios with high renewable energy penetration [22]. Nuytten et al. quantified the maximal flexibility potential in operating a CHP system with thermal energy storage (TES) [23]. The integration of multiple energy networks requires more efficient power conversion technologies. Power-to-gas (P2G) technologies are under extensive investigation and further improvements in efficiency, reliability, lifetime and cost are necessary for large-scale implementation. A review of P2G pilots plants can be found in the work of Gahleitner [24].

The above literature review on flexibility measures can be summarized as follows: at the energy consumer side, research focus was placed on the DSM to match the variable energy supplies; at the energy network side, the integration of different energy networks was discussed to transfer flexibility between networks. However, the increasing penetration level of variable renewable energy will constantly need more flexibility measures. This study aims to introduce a new flexibility measure, which is detailed in the following section.

1.2 Integration of the local energy supplies at the energy consumer side

It is noted from Fig. 1 that one energy consumer can be connected to multiple energy networks. For example, the energy consumer 1 is connected to the electrical grid and the DH network to meet electricity and heat demands, respectively. Integrating different supplies and enabling the conversion between different energy carriers will allow the energy consumer to have coordinated control of their own energy system. This integration has been termed the “Energy Hub” concept [25]. For example, Ottesen et al. employed the rolling horizon planning to solve a daily scheduling problem containing uncertainties [26]. Brahman et al. developed an integrated energy management system for the residential energy hub [27]. Huo et al. developed a hybrid optimization algorithm for the optimal scheduling based on the particle swarm and interior-point approach [28]. Wang et al. proposed an optimal planning method based on graph theory and mixed integer linear programming [29]. Ayele et al. introduced a general approach for the load flow analysis in highly coupled energy networks [30]. Dolatabadi et al. proposed a scheduling strategy based on hybrid stochastic/information gap decision theory optimization [31]. A review paper about energy hubs was published by Mohammadi et al. [32]. In the above studies, the research focus is the operation flexibility of the energy hub to lower the operation cost.

In this study, the “Energy Hub” concept is extended to serve as a flexibility measure for the upper-level energy networks. Because of the local operation flexibility, consumers can modulate the consumption of specific energy carriers according to the energy system operator's request. Thus, the flexibility that originates from the integration of local energy supplies can be transferred to the upper-level networks. Moreover, the integration of local energy supplies builds decentralized connections between the upper-level networks. Flexibility can be transferred between different energy networks through the consumers. The integration of local energy supplies at the energy consumer side can be a new flexibility measure. However, limited work has been done. This study aims at filling the research gap and investigate if the potential can be achieved.

1.3 Technologies that integrate the electricity and heat supplies in buildings

Buildings are large energy consumers (40% of the energy consumption in Europe [33]) and they are commonly connected to multiple energy networks. Thus, the integration of energy supplies in buildings should be studied in the first place on their potential in providing flexibility. In Sweden, DH supplies 55% of the heat demand in buildings and 92% of the heat demand in multi-family residential buildings [34]. It is common for buildings to connect to both the electrical grid and the DH network. To encourage flexibility from energy consumers, the energy providers in Sweden has introduced the flexibility energy costs, which include hourly prices, seasonal prices and peak tariff. However, they are not taken full advantage of by the consumers because the electricity and heat demands remain separately supplied (see energy consumer 1 in Fig. 1). The separate energy demand profiles can hardly be changed at present without changing the energy consumption behavior. The integration of the electricity and heat supplies brings in more operation flexibility and can potentially reduce the consumers' energy costs.

Available technologies to integrate electricity and heat supplies in buildings include heat pumps (HPs), electrical heaters (EHs), and electrical and thermal energy storage. HPs and EHs use electricity to produce heat. The substitution of fossil fuel boilers by heat pumps has great potential for primary energy savings and decarbonization of the housing sector, as the share of renewables in the electricity mix is continuously increasing in many countries [35, 36]. Storage technologies can increase flexibility through scheduled charging and discharging [37]. The capacities of each component and the operation schedules should be optimized and determined simultaneously to achieve the lowest cost [38, 39]. A literature survey indicates that there are several relevant studies. Renaldi et al. proposed an optimization framework that enables the integration of HP and TES in buildings [40]. Khalilpour and Vassallo introduced a method to determine the component capacity and operation schedule of a photovoltaic (PV)–battery system[41]. Beck et al. performed integrated optimization to obtain the optimal system configuration and operation schedule of a residential HP system [42]. Fischer et al. obtained the optimal HP and thermal storage capacities with on-site PV electricity and variable electricity prices [43]. Lindberg et al. summarized a methodology for the optimal system design of zero-energy buildings [44]. All these studies used the mixed integer linear programming (MILP) to obtain the optimal system configuration and operation schedule. In this study, a similar approach is employed with modifications to include more detailed flexible energy costs. Moreover, as MILP is a deterministic approach, sensitivity analysis and Monte Carlo simulation are employed to address the uncertainties in economic assumptions.

1.4 Assessment of the flexibility of the local energy system

Currently, there is no widely accepted methodology or protocol to assess or quantify the flexibility of an energy system. Even definitions of flexibility are quite case-specific. The ongoing Annex 67 project of the International Energy Agency (IEA) aims at a standard definition for energy flexibility [45]. Ulbig et al. defined the operational flexibility as "the technical ability of a power system unit to modulate electrical power feed-in to the grid and/or power outfeed from the grid over time" [46]. The authors proposed the assessment of the flexibility potential over time using three metrics: power provision capacity (π, in MW), power ramp-rate capacity (ρ, in MW/min) and energy provision capacity (ε, in MWh). Stinner et al. employed these metrics to study the flexibility potential of buildings with different types of heat generators and hot water tank capacities. The flexible time intervals, flexible power and aggregated flexible energy were obtained sequentially [47]. D'hulst et al. studied the flexibility potential of smart residential appliances through a large-scale pilot project. The authors suggested that the flexibility potential has a rebound effect in which the exploitation of flexibility at the preceding time step will influence the flexibility of the later time step [48]. Bucher et al. defined the operational flexibility as the capability to absorb system disturbances. Thus, system disturbances were introduced as the system operation constraints and a worst-case-scenario-based robust optimization problem was solved to obtain the lowest system cost [49]. Ampatzis et al. employed a modified robust optimization technique [50] to maximize the short-term operation income of distributed battery storage systems and immunize the systems from electricity price uncertainties. The flexibility requirements were introduced as constraints in the operation schedules [51]. Zhao et al. proposed a unified flexibility definition framework and evaluated the highest uncertainty that a power system could sustain by solving a two-stage robust optimization problem [52]. These previous studies focus on a system's inner flexibility to cope with uncertainties and they seldom include district heating, while this study aims at the flexibility that can be provided from the local system to the upper-level networks. A new method and two metrics are introduced to describe the flexibility of the energy system in a building. The two metrics are the flexibility hours and the flexibility energy. The flexibility hours are the hours in a year that the energy consumer can modulate the electricity consumption. The flexibility energy is the modulated electricity consumption in the flexibility hours.

1.5 Research objectives and contributions

The integration of local energy supplies in buildings can act as a potential flexibility measure to provide flexibility to the upper-level network. Flexibility can also be transferred between different energy networks because the local integration forms decentralized connection between them. A literature survey indicates that there is limited research available on this topic. The major objective of this study is to fill the research gap and investigate if the abovementioned benefits can be achieved. The major contributions and novelties of this study are: 1) the introduction of a new flexibility measure that originates from the integration of local energy supplies, 2) a method to evaluate the flexibility that is provided from the local energy system to the network, and 3) the investigation of the introduced flexibility measure through a case study.

A conceptual summary of the research content is shown in Fig. 2. An investigation on the integration of the electricity and heat supplies in a local energy system as a new flexibility measure is conducted in this study. Because this study focuses on the economic and the flexibility benefits from the integration, demand side management is not included.

The electricity and heat demands are assumed to be met at all simulation steps. Because most of the variable renewable energies exist in the electrical network, which requires more flexibility measures, we have limited the research focus to the flexibility that is provided to the electrical grid from the local energy system and the district heating network (as indicated by the arrow in Fig. 2).

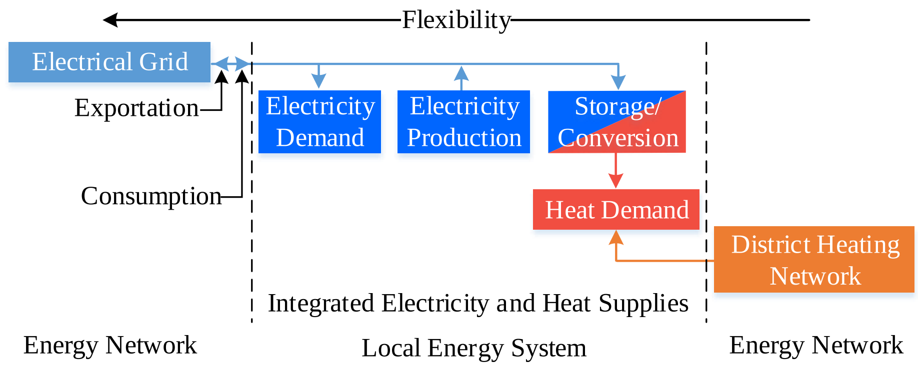

Fig. 2. Integration of the electricity and heat supplies in a local energy system

The paper is organized as follows: Section 1 is the introduction, Section 2 describes the studied system and detailed energy costs, Section 3 presents the methods, Section 4 presents the results and discussion, and Section 5 draws the conclusions.

2 Energy system and energy costs of the studied building

A Swedish rental office building in Västerås (N 59.62°, E16.56°) is studied. The current energy system is used as the reference system and is described in Section 2.1. The energy costs of the building are detailed in Section 2.2. The system that integrates the supplies is described in Section 2.3.

2.1 The reference system

The schematic layout of the current local energy system is shown in Fig. 3. A photovoltaic (PV) system with a capacity of 30 kW_p is installed on the building roof. In 2016, the electricity production ($\sum_{t=1}^{8760} P_{PV,t} = 26.1$ MWh) was slightly higher than the electricity demand ($\sum_{t=1}^{8760} P_{L,t} = 25.6$ MWh). However, because of daily and seasonal mismatches between the production and demand, the self-consumption ratio (SCR) was only 43%. The net electricity profile ($P_{Net,t} = P_{L,t} - P_{PV,t}$) is shown in Fig. 4 (a). The electricity demand shows a weekly pattern, and the PV panels generate most of the electricity during the warmest and sunniest months. The building is connected to the local DH network that supplies all the heat demand. The district heating profile is shown in Fig. 4 (b).

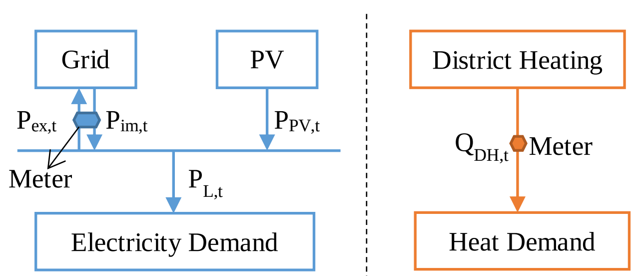

Fig. 3. Schematic layout of the current energy system (the reference system)

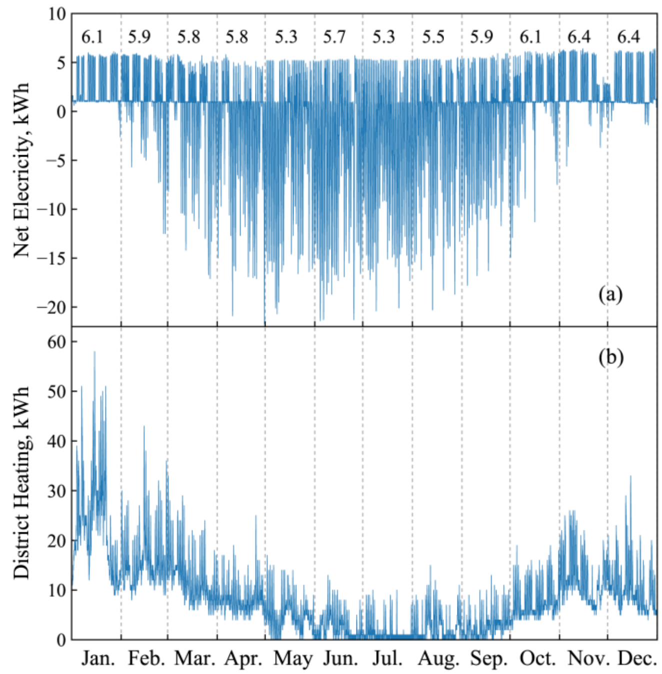

Fig. 4. (a) Net electricity and (b) district heating profiles of the reference system (a negative value indicates exported electricity)

2.2 Electricity and district heating costs

The electricity costs are charged by both the Distribution System Operator (DSO) and the Energy Retailer (ER) based on the imported electricity ($P_{im,t} = \max\left(P_{Net,t}, 0\right)$). The costs from the DSO and ER are calculated by Eqs. 1 and 2, respectively. The cost from the DSO includes three parts: the yearly fixed cost, the monthly peak cost, and the transmission cost. The cost from the ER also includes three parts: the yearly fixed cost, the energy cost with variable price, and the energy cost with fixed price. The variable price is the day-ahead electricity spot market price (ELP_t). The revenue (R_y) from the exported electricity ($P_{ex,t} = \left|\min\left(P_{Net,t}, 0\right)\right|$) is calculated with Eq. 3, which assumes that there are no subsidies. Because the average ELP_t is much lower than the average cost of imported electricity (0.275 SEK/kWh vs. 1.78 SEK/kWh in the studied case in 2016), the economic value of the exported electricity is lower than the imported electricity.

$$C_{DSO,y} = \left(C_{YF,DSO} + C_{P,DSO} \cdot \sum_{m=1}^{12} Peak_{\mathrm{m}} + C_{T,DSO} \cdot \sum_{t=1}^{8760} P_{im,t}\right)(1 + VAT) \quad (1)$$

$$C_{ER,y} = \left(C_{YF,ER} + \sum_{t=1}^{8760}\left(ELP_t + C_{F,ER}\right) \times P_{im,t}\right)(1 + VAT) \quad (2)$$

$$R_y = \sum_{t=1}^{8760} ELP_t \cdot P_{ex,t} \quad (3)$$

The district heating cost is calculated by Eq. 4. Three major parts are included: the yearly fixed cost, the yearly peak cost and the seasonal energy cost. Seasonal prices (WS: warm season; MS: middle season; CS: cold season) are employed. The energy price during cold season is higher. $C_{YF,DH}$and $C_{P,DH}$ are dependent on the yearly peak power (Table 1) [53].

$$C_{DH,y} = \left(C_{YF,DH} + C_{P,DH} \cdot max\left(Q_{DH,t}\right) + C_{WS} \sum Q_{DH,t \in WS} + C_{MS} \sum Q_{DH,t \in MS} + C_{CS} \sum Q_{DH,t \in CS}\right)(1 + VAT) \quad (4)$$

The energy cost parameters are summarized in Table 2. The electricity and district heating costs in 2016 are calculated, and the breakdown of the costs is shown in Fig. 5. It should be noted that the Value-Added Tax (VAT) are included in the costs, because VAT are paid by the building owner. However, VAT can be deducted for companies, and the calculation method can be changed accordingly.

Table 1. District heating yearly fixed cost and peak cost

$max\left(Q_{DH,t}\right)$	$C_{YF,DH}$, SEK (DH Yearly Fixed Cost Parameter)	$C_{P,DH}$, SEK/kW (DH Yearly Peak Cost Parameter)
0	0	0
(0, 10)	6000	0
[10,24)	2000	370
[24,49)	3600	330
[49,199)	6000	330

Table 2. Values of the energy cost parameters

Energy Cost Parameter	Description	Unit	Value
$C_{YF,DSO}$	DSO Yearly Fixed Cost Parameter	SEK	5556
$C_{P,DSO}$	DSO Monthly Peak Cost Parameter	SEK/kW	58.5
$C_{T,DSO}$	DSO Transmission Cost Parameter	SEK/kWh	0.0535

$C_{YF,ER}$	ER Yearly Fixed Cost Parameter	SEK	336
$C_{F,ER}$	ER Fixed Energy Price	SEK/kWh	0.3879
ELP_t	Electricity Spot Market Price (Variable Energy Price)	SEK/kWh	Variable
C_{WS}	Warm Season DH Energy Price	SEK/kWh	0.236
C_{MS}	Middle Season DH Energy Price	SEK/kWh	0.44
C_{CS}	Cold Season DH Energy Price	SEK/kWh	0.5
VAT	Value Added Tax	%	25

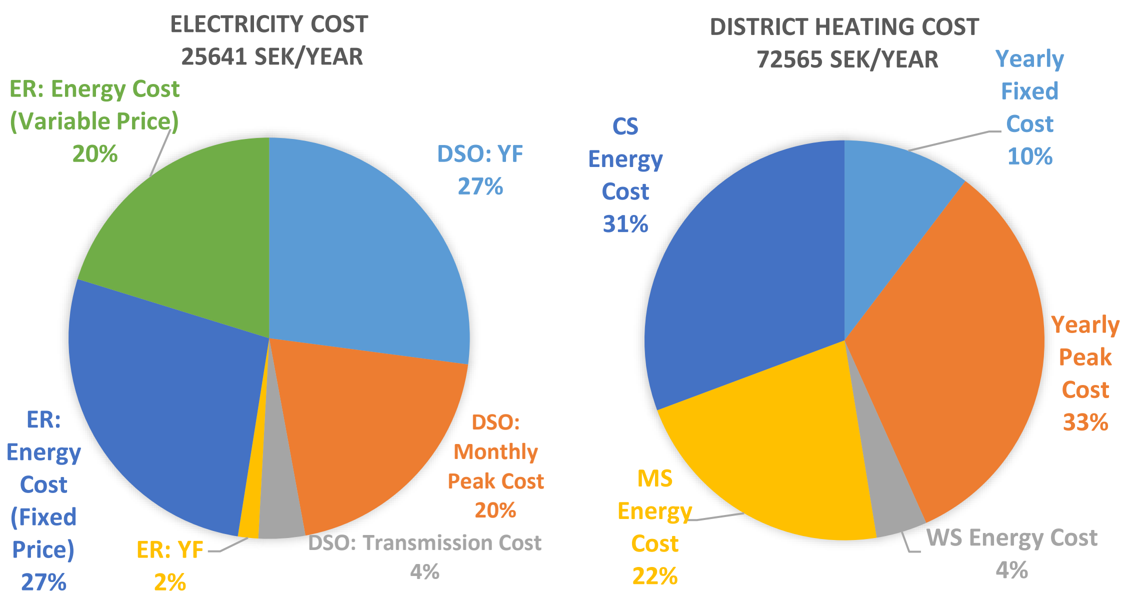

Fig. 5. The electricity cost and district heating cost breakdown of the reference energy system in the investigated building (YF: Yearly Fixed)

2.3 Integrating the electricity and heat supplies

Integrating the electricity and heat supplies enables the consumer to have more control over the building's energy system. A schematic layout is provided in Fig. 6. Four components, including a battery, heat pump (HP), electrical heater (EH) and hot water tank (HWT), can be used to integrate the supplies. In this study, the system boundaries are drawn between the building and the electrical grid and the district heating network. The electricity and heat demands must be met at all simulation steps because DSM is not included. It should be noted that electricity consumption is defined as the imported electricity ($P_{im,t}$), which is different from the electricity demand ($P_{L,t}$).

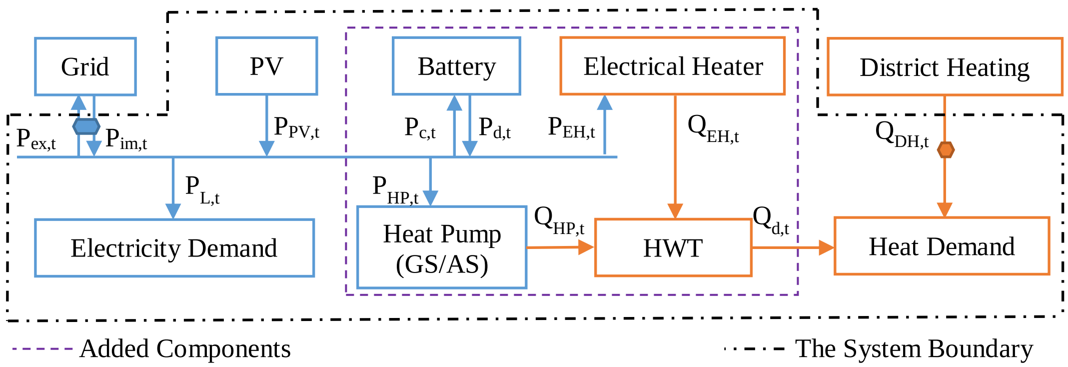

Fig. 6. Schematic layout of the system with integrated electricity and heat supplies

3 Methodology

As discussed in Section 1.2, Mixed Integer Linear Programming (MILP) is widely employed to determine the optimal component capacities and operation profiles. It is also employed in this work using CPLEX solver [54] with the Python interface.

3.1 Optimization objectives and decisional variables

3.1.1 Net present cost

The optimization objective in Sections 4.1 and 4.2 is to minimize the net present cost (NPC) over the project lifetime. The project lifetime is assumed to be 30 years because the lifetime of PV panels is usually 30 years [55] and 30 years is also an integer multiple of the lifetimes of the components (Table 3). As shown in Eq. 5, the NPC includes investment cost (*Inv*), maintenance cost ($C_{M,y}$), replacement cost ($C_{R,y}$), electricity cost ($C_{DSO,y}$ and $C_{ER,y}$, Eqs. 1 and 2), electricity revenue (R_y, Eq. 3), and the district heating cost ($C_{DH,y}$, Eq. 4). The discount rate (d_r) is chosen as 6%, considering the current loan rate [56, 57] and the financial expectations of the owner of the building.

$$\min\left\{\sum_{y=1}^{30}\frac{(C_{DH,y}+C_{DSO,y}+C_{ER,y}-R_y+C_{M,y}+C_{R,y})}{(1+d_r)^y}+Inv\right\} \quad (5)$$

The system investment cost (Inv) is the sum of the individual component investments (Eq. 6). The lifetimes of the components are given in Table 3. The maintenance cost ($C_{M,y}$) is calculated as a ratio ($r_M = 1\%$) of the investment cost.

$$Inv = \sum_{i=1}^{n} Inv_i \quad (6)$$

$$C_{M,y} = Inv \cdot r_M \quad (7)$$

Like other studies on system planning [42, 44], the input data for the optimization model are usually for one year (or several years) instead of for the project lifetime. A common assumption is that the yearly costs and revenues are the same in each year. The optimization objective in Eq. 5 is then transformed to the form in Eq. 8.

$$\min\left\{\sum_{y=1}^{30}\frac{(C_{DH,1}+C_{DSO,1}+C_{ER,1}-R_1+C_{M,1})}{(1+d_r)^y}+\sum_{y=1}^{30}\frac{C_{R,y}}{(1+d_r)^y}+Inv\right\} \quad (8)$$

When the optimization objective is NPC, the decisional variables include the capacity of each component (Cap_i) and the system operation profiles, which further include electrical energy flows ($P_{ex,t}$, $P_{im,t}$, $P_{c,t}$, $P_{d,t}$, $P_{HP,t}$, and $P_{EH,t}$), thermal energy flows ($Q_{HP,t}$, $Q_{EH,t}$, $Q_{d,t}$, and $Q_{DH,t}$), and storage states ($S_{HWT,t}$ and SOC_t). The optimization horizon is one year ($t \in [1, 8760]$), and the time step is one hour.

3.1.2 Yearly operation cost

In Sections 4.3 and 4.4, the optimization objective is the yearly operation cost (Eq. 9). The decisional variables are the system operation profiles.

$$C_{O,1} = C_{DH,1} + C_{DSO,1} + C_{ER,1} - R_1 \quad (9)$$

3.2 Optimization constraints

The constraints are shown in Eqs. 10-25. The constraints include HP and EH operation constraints (Eqs. 10-14), HWT operation constraints (Eqs. 15-17), battery operation constraints (Eqs. 18-21) and the system energy balances (Eqs. 22-25).

The coefficient of performance (COP_t) represents the dynamic performance of HP and is dependent on the lift temperature (T_L) [43, 58, 59]. The lift temperature is the temperature difference between the source and the outlet. The outlet temperature is assumed to be constant at 50 °C. The source temperature is the ambient air temperature in the air source heat pump (ASHP) and the earth temperature in the ground source heat pump (GSHP) [60].

$$Q_{HP,t} = P_{HP,t} \times COP_t \tag{10}$$

$$COP_{AS,t} = 6.81 - 0.121 \cdot T_L + 0.000630 \cdot T_L^2 \tag{11}$$

$$COP_{GS,t} = 8.77 - 0.15 \cdot T_L + 0.000734 \cdot T_L^2 \tag{12}$$

A binary value ($\delta_{HP,t}$) is introduced in Eq. 13 to ensure that the HP works above the load factor (LF_{HP}) and below the HP capacity.

$$LF_{HP} \cdot \delta_{HP,t} \cdot Cap_{HP} \leq Q_{HP,t} \leq \delta_{HP,t} \cdot Cap_{HP} \tag{13}$$

The EH electricity consumption is below the EH capacity. This constraint is described in Eq. 14.

$$P_{EH,t} \leq Cap_{EH} \tag{14}$$

The HWT operation constraints are described in Eqs. 15-17, which establish the energy balance in the HWT and the storage limit. $Q_{c,t}$ and $Q_{d,t}$ are the charged and discharged energies of the HWT. ΔT_{HWT} is the maximal temperature difference in the HWT and is assumed to be 10 °C [40].

$$S_{HWT,t} = S_{HWT,t-1} + Q_{c,t} - Q_{d,t} \tag{15}$$

$$Q_{c,t} = COP_t \cdot P_{HP,t} + \eta_{EH} \cdot P_{EH,t} \tag{16}$$

$$0 \leq S_{HWT,t} \leq \frac{Cap_{HWT} \times \rho_w \times c_p \times \Delta T_{HWT}}{3600} \tag{17}$$

The battery operation conditions are constrained by Eqs. 18-21. The charged ($P_{c,t}$) and discharged ($P_{d,t}$) electricity at time t are constrained to be below a specific ratio of the battery capacity ($R = 0.33$). The charged and discharged energy cannot both exceed zero at the same time (Eq. 19). The energy balance and storage limit of the battery are shown in Eqs. 20 and 21.

$$P_{d,t}, P_{c,t} \leq R \cdot Cap_{Batt} \tag{18}$$

$$\left(P_{d,t} = 0\right) + \left(P_{c,t} = 0\right) \geq 1 \tag{19}$$

$$SOC_t = SOC_{t-1} + \left(P_{c,t} - P_{d,t}\right)/Cap_{Batt} \tag{20}$$

$$20\% \leq SOC_t \leq 100\% \tag{21}$$

The electrical energy balance is shown in Eq. 22. A fixed battery discharge efficiency (η_{Batt}) is employed. $P_{im,t}$ and $P_{ex,t}$ are the imported and exported electricity from and to the grid, respectively. They cannot both exceed zero at the same time (Eq. 23). The peak of imported electricity is calculated for each month (Eq. 24).

$$P_{PV,t} - P_{c,t} + \eta_{Batt} \cdot P_{d,t} + P_{im,t} - P_{ex,t} = P_{L,t} + P_{HP,t} + P_{EH,t} \tag{22}$$

$$\left(P_{im,t} = 0\right) + \left(P_{ex,t} = 0\right) \geq 1 \tag{23}$$

$$Peak_{\mathrm{m}} = \max_{t \in Month_m} \left(P_{im,t}\right) \tag{24}$$

The thermal energy balance is described in Eq. 25.

$$Q_{d,t} \cdot \eta_{HWT} + Q_{DH,t} = Q_{Load,t} \tag{25}$$

Because of the introduced binaries and logical expressions, some constraints are non-linear, and their transformation to linear expressions follows the method described by Chen et al. [61].

3.3 Investment costs of different components

The component capacity and investment costs are linearly correlated in Eq. 26. Cap_i is the capacity of component *i*. The parameters a_i and b_i are listed in Table 3. The capacity unit for each component is listed in the first column. The costs are presented with the Swedish currency, Swedish Kronor (SEK). The exchange rate from Euro to SEK is approximately 9.9 at the time of writing this paper (Dec. 2017).

$$Inv_i = \begin{cases} a_i \cdot Cap_i + b_i, & Cap_i > 0 \\ 0, & Cap_i = 0 \end{cases} \tag{26}$$

Table 3.Lifetime and investment costs for different components

Component/ Capacity Unit	Lifetime (Year)	a (SEK/Unit Capacity)	b (SEK)	References
Battery / kWh	10	4,757	-	[62]
Heat Pump / kW	15	1,909	30,649	[59] [63]
Borehole / kW	30	10,000	-	[59]
Electrical Heater / kW	15	570	-	[43]
Hot Water Tank (HWT) / L	15	24	11,184	[40]

The battery storage investment follows the Tesla Powerwall price, which is the benchmark in the market. Staffell et al. developed an equation that shows the relationship between the heat pump capacity and the investment cost [59]. That equation is linearized within the range of 5-45 kW. The obtained equation shows good agreement with some available products in the Swedish market. Compared to the ASHP, the GSHP is assumed to have an additional borehole cost of 10,000 SEK/kW [59, 64].

3.4 Sensitivity analysis and Monte Carlo simulation

As MILP is a deterministic approach and the optimization is carried out based on many economic assumptions, it is necessary to study the influence of these assumptions on the optimization results.

Sensitivity analysis is carried out to study the influence of the component investment parameters (a_i and b_i in Table 3) on the NPC and the system configuration. Their values are varied between 0.5 and 2.5 times of the base value. The results are presented in Section 4.2.

The changes in future energy costs can influence the system operation cost. However, it is usually troublesome to give a precise long-term prediction of the energy costs, especially the prediction of different cost parameters. Because the energy costs are influenced by many factors including the technology development and social and political issues. The data from the Swedish Energy Agency indicate that the electricity and district heating prices for the residential sector are within ±35% of the average value between 1996 and 2014 [65]. In this study, we adopt the conservative assumption that all the energy cost parameters (Table 1 and Table 2), including $C_{YF,DSO}$, $C_{P,DSO}$, $C_{T,DSO}$, $C_{YF,ER}$, ELP_t, $C_{F,ER}$, $C_{YF,DH}$, $C_{P,DH}$, C_{WS}, C_{MS}, and C_{CS}, can vary within ±50% of the original values and have uniform distributions. Monte Carlo simulations are used to study the influence of energy cost parameters on the yearly operation cost. The simulations are repeated 2000 times. For each simulation, optimization is carried out to obtain the lowest yearly operation cost. The results are presented in Section 4.3.

3.5 Assessing flexibility

An optimization-based method is introduced to assess the system's flexibility that can be provided to the electrical grid. It should be noted that this method cannot be used for quantifying the full flexibility potential of the system or scheduling the real operation. However, it aims at intuitively comparing the difference in the flexibility of the energy systems. Random hours (RD) are introduced to represent the hours with flexibility requirements (i.e., DSO or aggregators require energy consumers to increase or decrease their electricity consumption). The number of RD is termed the intended flexibility hours. It is assumed that the electricity consumption is either decreased or increased by 30% of the reference electricity consumption. These flexibility requirements are formed as constraints in the optimization, as shown in Eqs. 27-28. RD_d and RD_i are the random hours to decrease or increase the electricity consumption, respectively.

$$P_{im,t} \leq 0.7 \cdot P_{ref,t} \mid \mathrm{t} \in RD_d \quad (27)$$

$$P_{im,t} \geq 1.3 \cdot P_{ref,t} \mid \mathrm{t} \in RD_i \quad (28)$$

However, some constraints in Eqs. 27-28 will violate the energy balance constraint in Eq. 22. To ensure feasible solutions, these constraints are modified. The flowchart for the detailed process is shown in Fig. 7. In RD_d (shown in blue), if the inequality in the diamond is established, the right side of Eq. 27 is modified. A similar process is carried out for RD_i (shown in red). Additional comparison with $Peak_{\mathrm{m}|t \in m}$ is conducted to ensure monthly peaks of $P_{ref,t}$ are not exceeded.

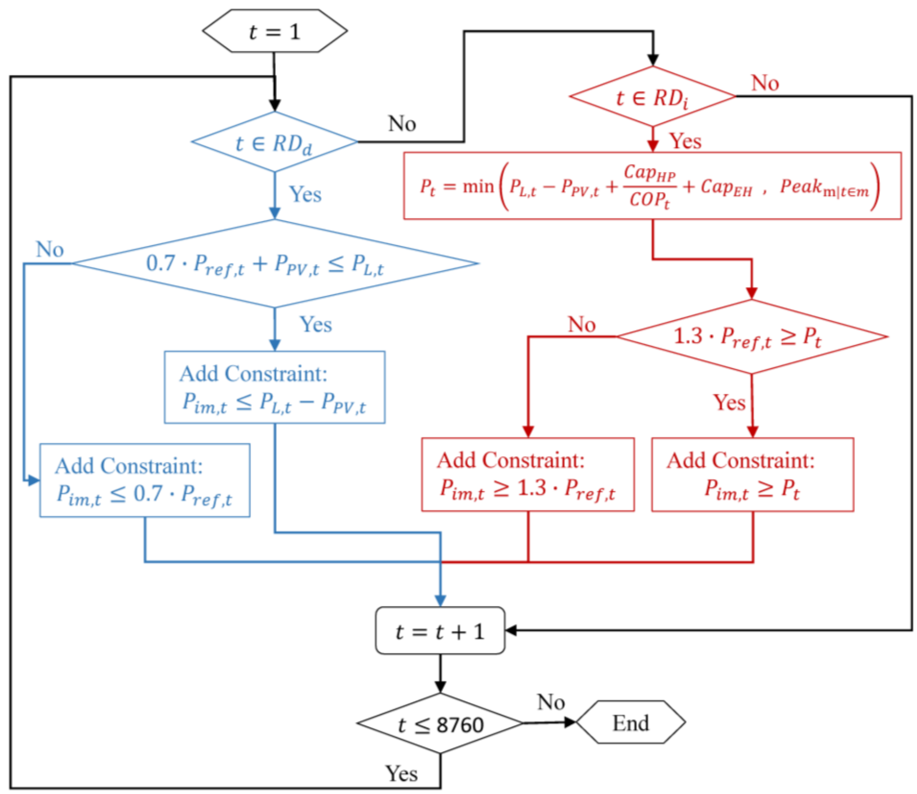

Fig. 7. Flowchart of the process to modify constraints in Eqs. 27-28

The optimization objectives are the yearly operation costs (Eq. 9). After the optimization, the time steps that have followed the flexibility requirements and modulated the electricity consumption are counted and referred to as the flexibility hours. The modulated electricity consumption is called the flexibility energy.

3.6 Limitations

Though the developed methodology is general and can be applied to other case studies, this work is based on several local economic assumptions, which might not be applicable to other cases. More cases should be studied to reach more general conclusions for the Swedish market. A similar limitation is valid for other countries. Sensitivity analysis and Monte Carlo simulations are employed to address the uncertainties in component costs and energy costs. However, as the energy market is under such rapid change, it cannot be guaranteed that the future energy and equipment costs are within the studied variation range.

The study is based on MILP, which linearizes the system and can lead to errors in the results. Moreover, MILP assumes perfect forecasting of demand and production. The obtained optimal operation schedule cannot be guaranteed in real applications because there are always forecast uncertainties. Thus, the system might have higher operation cost than following the ideal operation schedule. Future studies are needed to quantify the difference between the ideal NPC and practically achievable NPC.

4 Results and discussion

The comparison between the reference system and the system with integrated supplies is carried out in Section 4.1. The sensitivity study and Monte Carlo simulation are presented in Sections 4.2 and 4.3, respectively. The flexibility of the system is discussed in Section 4.4.

4.1 Comparison between the reference system and four scenarios

The net present cost (NPC) and the accumulated cash flow of the reference case are shown in Fig. 8. Optimizations of the component capacities and operation profiles are carried out with the method and the economic assumptions stated in Section 3. Four scenarios are studied, including an air source heat pump (ASHP) scenario, ground source heat pump (GSHP) scenario, GSHP with low borehole cost scenario and ASHP with high maintenance cost scenario. The differences between different scenarios are the heat pump type and specific economic assumptions. In the GSHP with low borehole cost scenario, the borehole cost is reduced by 50%, and in the ASHP with high maintenance cost scenario, the maintenance cost ratio (r_M) is 5%. The NPCs and the accumulated cash flows of these four scenarios are also shown in Fig. 8.

All studied scenarios achieve a lower NPC than the reference system. The ASHP scenario has a lower NPC than the GSHP scenario. However, the GSHP with low borehole cost scenario has a lower NPC than the ASHP scenario. Though the ASHP with high maintenance cost scenario has the highest NPC among the four scenarios, its NPC is still lower than that of the reference system. Because the ASHP scenario has a lower investment cost and is easier to realize in existing buildings, the following part of the study will focus on the ASHP scenario.

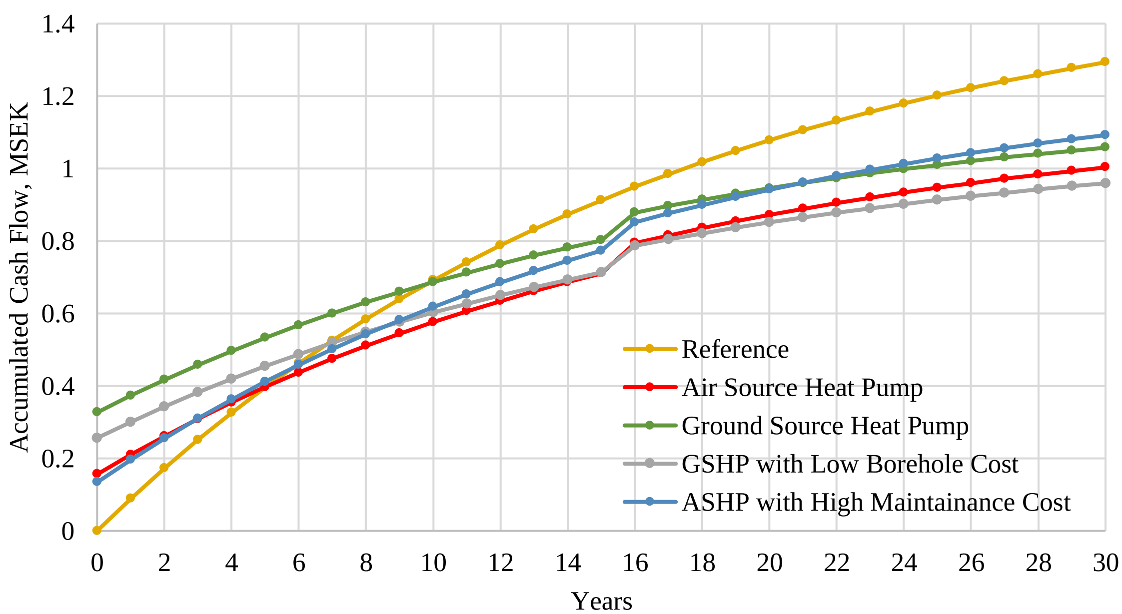

Fig. 8. Accumulated cash flow and NPC of the reference system and four different scenarios

The optimal HP, EH, HWT, and battery capacities in the ASHP scenario are shown in Table 4. In the following part of the study, this configuration is referred as "the optimal system". The NPC of the optimal system is 1.0 MSEK, which is 22% less than that of the reference system. The yearly electricity cost of the optimal system is shown in Fig. 9.

Compared with the electricity cost of the reference system (in Fig. 5), the percentages of DSO and ER yearly fixed costs decrease, while the energy cost with fixed price has the highest increase.

Table 4. The component capacities in the optimal system

Component	Capacity	Unit
Battery	0	kWh
Heat Pump	29	kW
Electrical Heater	19	kW
Hot Water Tank (HWT)	2000	L
District Heating	None	-

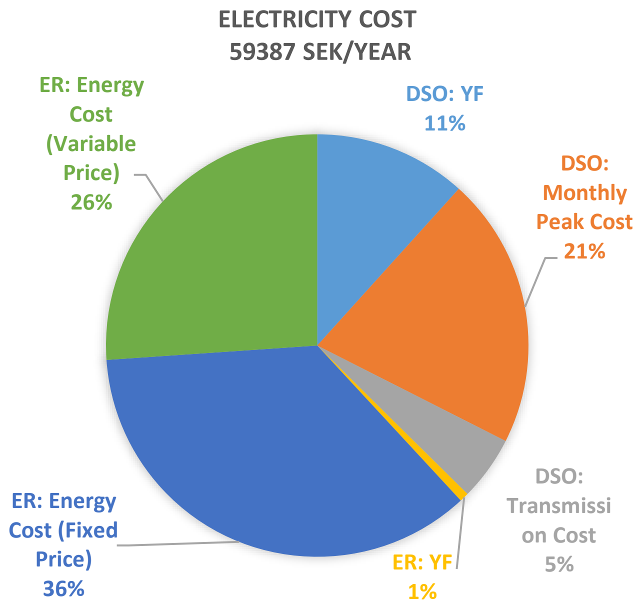

Fig. 9. The electricity cost breakdown of the optimal system in the investigated building (YF: Yearly Fixed)

When not including VAT, the accumulated cash flows for the reference system and the optimal system are shown in Fig. 10. The NPC of the optimal system is 0.84 MSEK, which is 17.6% less than that of the reference system. It indicates that the optimal system can achieve lower NPC than the reference system, whether VAT is included in the cost or not.

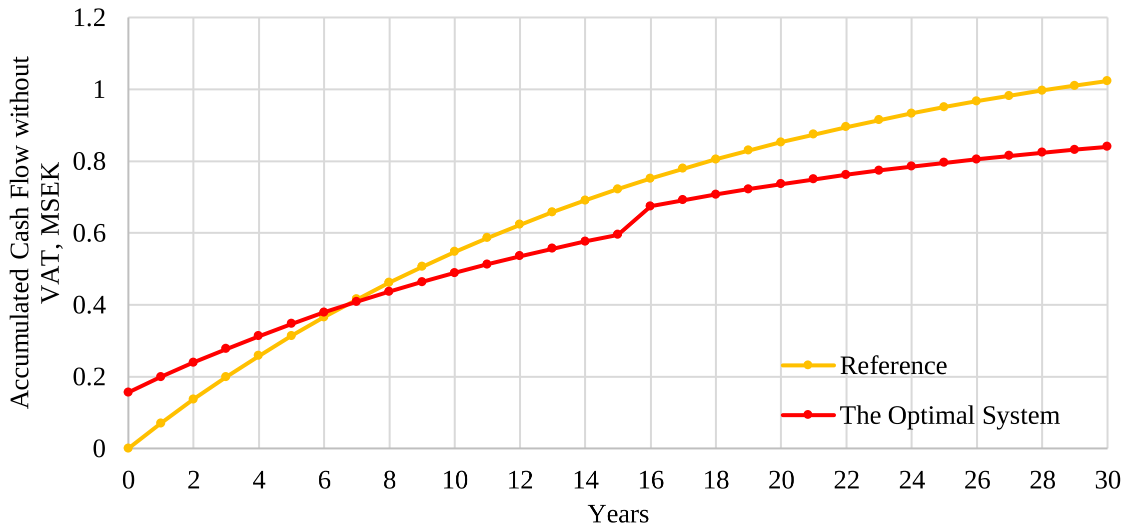

Fig. 10. Accumulated cash flow and NPC of the reference system and the optimal system without VAT

The net electricity profile and the HP and EH heat output profiles are shown in Fig. 11. Compared with the reference system, the electricity consumption peaks increase significantly during the cold period. The yearly electricity exportation is reduced from 14.9 MWh to 10.3 MWh. The corresponding self-consumption ratio increases from 43% to 61%. This suggests that the optimal system makes better use of the surplus PV electricity through scheduling the HP and EH operations. As shown in Fig. 11 (b) and (c), HP supplies most of the heat demand, and EH works mostly in January. It is also noted that the EH produces heat during warm months, because the EH works to consume the surplus PV electricity.

In the optimal system, the battery was not chosen by the optimization algorithm, suggesting that the battery investment is too high for implementation in the studied case. The district heating network is not used for the heat supply. This suggests that with the current electricity and district heating costs, it is economically more favorable for energy consumers to use electricity to meet the heat demand. However, if large numbers of energy consumers shifted from district heating to electrical heating, the regional or national energy system would be greatly impacted in terms of stable operation, energy price, primary energy saving, carbon emission [35, 66, 67]. A detailed regional/national analysis of the impact is important in future studies.

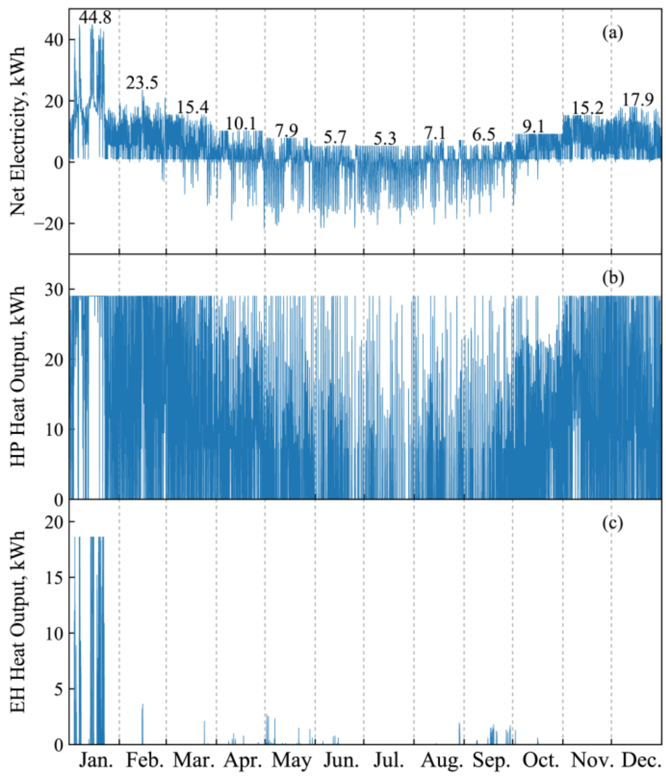

Fig. 11. (a) Net electricity, (b) HP heat output, and (c) EH heat output profiles of the optimal system (a negative value indicates exported electricity)

4.2 Sensitivity analysis of the component investment costs

The economic assumptions about the component investment costs (a_i and b_i in Table 3) can influence the optimization results, leading to different NPCs and component capacities. A sensitivity study is carried out to determine the most influential parameter. The NPCs and optimal component capacities under different sensitivity parameter values are shown in Fig. 12 and Fig. 13.

As indicated in Fig. 12, the NPC of the system increases with all studied parameters, except a_{Batt}. The results indicate that a_{HP} has the most influence on the NPC. The relationship between the sensitivity parameter and NPC is not linear, indicating that the optimization algorithm can adjust the system configuration. Moreover, the highest NPC from the sensitivity analysis is lower than that of the reference system, which further guarantees the economic performance of the optimal system.

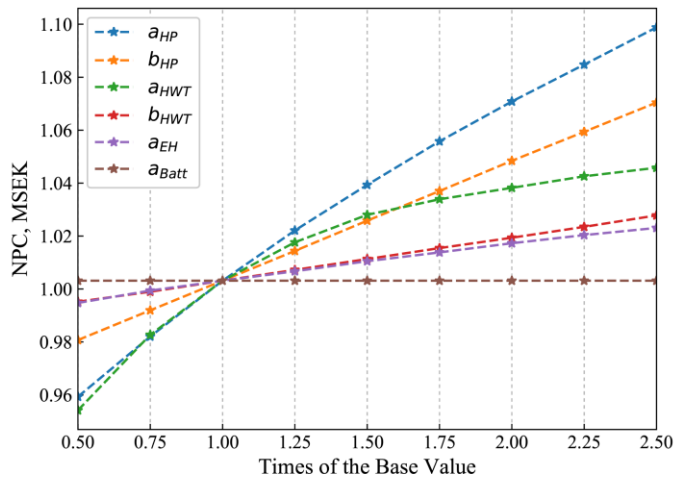

Fig. 12. The NPCs under different values of the sensitivity parameters (Batt: Battery)

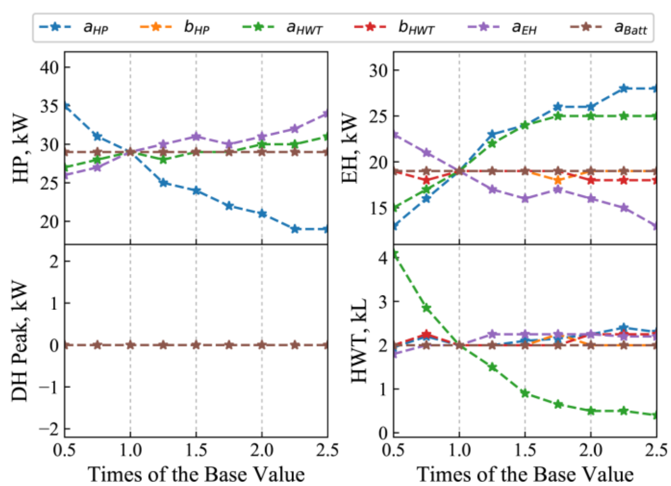

Fig. 13. The optimal component capacities under different values of the sensitivity parameters

As the optimal battery capacities remain zero in the sensitivity analysis, the battery capacity is not shown in Fig. 13. District heating is also not selected by the optimization algorithm in the sensitivity analysis. The optimal capacities of other components generally decrease with their investment cost parameters. Some parameters, including b_{HP}, b_{HWT}, and a_{Batt}, have minor effects on the optimal configuration. The most influential parameter for the HP capacity is a_{HP}. The optimal EH capacity is mostly influenced by a_{HP}, but it is also largely influenced by a_{HWT} and a_{EH}. The optimal HWT capacity is quite sensitive to a_{HWT} and less sensitive to the other parameters.

It can be concluded that the component investment costs have moderate influences on the NPC and more significant influences on the optimal system configuration. Two parameters, a_{HWT} and a_{HP}, have greater influences than the other parameters. These two parameters should be carefully determined when deciding the right component capacities.

4.3 Monte Carlo simulations on energy cost uncertainties

As the energy market in undergoing rapid change, it should be studied whether the optimal system (Table 4) can achieve a lower NPC than the reference system when future energy costs change. Monte Carlo simulation is employed, and all the energy cost parameters are studied with unified distributions (Section 3.4).

A histogram of the yearly operation cost differences between the reference system and the optimal system is shown in Fig. 14. The yearly operation cost difference is always positive, indicating that the optimal system always has a lower yearly operation cost than the reference system. It is calculated that the yearly operation cost difference must be higher than 21,120 SEK to ensure the optimal system results in a lower NPC. It is thus estimated that the optimal system has a 93% probability to achieve a lower NPC than the reference system.

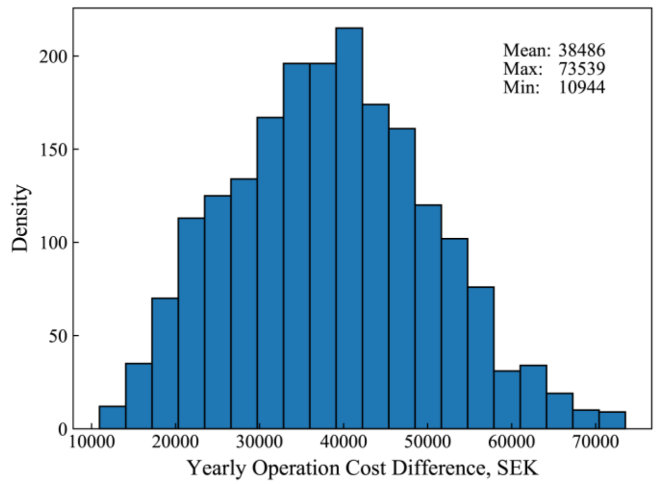

Fig. 14. Histogram of differences in the yearly operation costs of the reference system and the optimal system

The distribution of the yearly operation cost differences is shown in Fig. 15. The value of the yearly operation cost difference is represented by the dot color. The x-axis is the electricity cost ratio of the reference system, which is the ratio of the electricity cost with the Monte Carlo simulation parameters to the electricity cost with the original parameters. The y-axis is the DH cost ratio of the reference system, which is calculated in a same way. As shown in this figure, the simulations with high yearly operation cost differences are located at the upper left corner of the figure, while the simulations with the low values are at the opposite location. It indicates that the optimal system will be more economically favorable than the reference system when the DH cost increases and the electricity cost decreases.

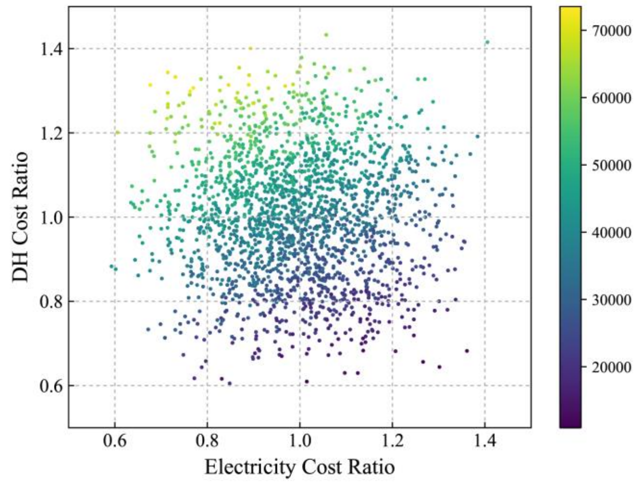

Fig. 15. Distribution of the yearly operation cost differences against the electricity and DH cost ratio of reference system.

4.4 Flexibility from the optimal system

The flexibility that the optimal system (Table 4) can provide to the electrical grid is tested and the results are shown in Fig. 16. Random hours are chosen as intended flexibility hours (x-axis). The intended flexibility hours cannot exceed the hours that consume electricity (i.e., $P_{im,t} > 0$), which are 6880 hours in a year. In this work, the intended flexibility hours are examined from 0 to 6800 hours with an interval of 400. The method in Section 3.5 is used to calculate the flexibility hours, flexibility energy, and yearly operation cost, which are shown on different y-axes. The fill patterns of the bars distinguish whether the electricity consumption is modulated to increase or decrease. As shown in the figure, the flexibility hours with increased consumption are more than the hours with decreased consumption. The flexibility energy increases with the intended flexibility hours. The highest flexibility hours are 5209 (decrease: 2022 hours, increase: 3187 hours), and the highest flexibility energy is 15767 kWh in one year (decrease: 8250 kWh, increase: 7517 kWh).

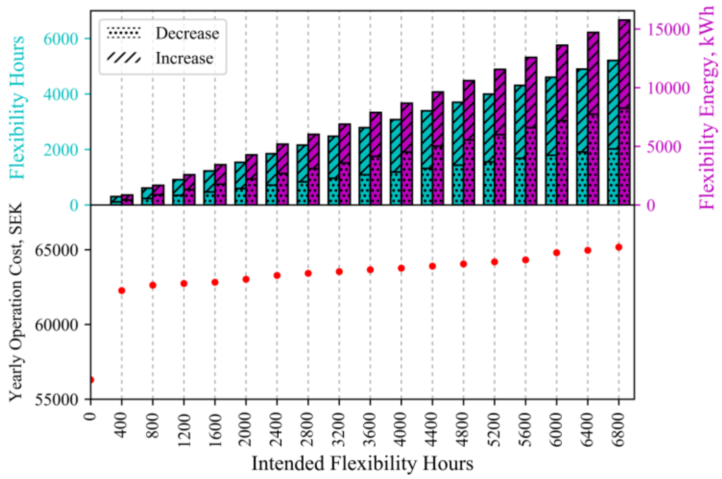

Fig. 16. Flexibility from the optimal system (cyan bars: left axis; magenta bars: right axis)

This indicates that the system can provide great flexibility to the electrical grid. However, the flexibility comes at a cost. The yearly operation cost increases suddenly to over 62000 SEK when the intended flexibility hours are only 400, since the district heating network is used to provide part of the heat demand when the system provides flexibility to the grid. The operation cost increases mainly because the DH yearly fixed cost and yearly peak cost are added. The yearly operation cost increases slightly with the intended flexibility hours. It should be noted that the economic value of the provided flexibility is not included in this work, as the current market does not allow the consumer to trade flexibility with the grid.

Another flexibility test is carried out considering a larger HWT (3000 L). The flexibility test results are shown in Fig. 17. The intended flexibility hours can reach 1200 hours without obviously increasing the yearly operation cost. However, district heating is required when the intended flexibility hours reach 1600. This indicates that increasing the HWT capacity helps the local energy system provide more flexibility; however, its effectiveness is lower than that of the district heating network.

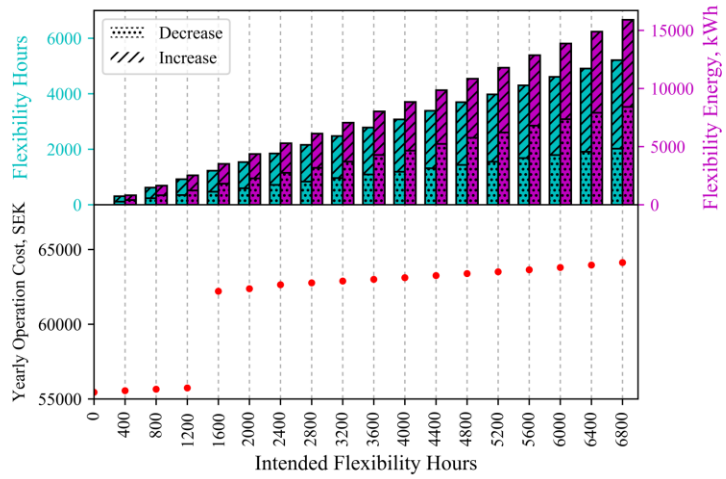

Fig. 17. Flexibility from the system with a 3000 L HWT (cyan bars: left axis; magenta bars: right axis)

The electrical grid and district heating network are connected through integration of the electricity and heat supplies in the building. It should be noted that only flexibility requirements from the electricity grid are considered in this study. The building provides flexibility to the grid because the building can utilize the DH supply. In future studies, constraints in the DH supply, such as the heat supply ramp rate, can be introduced. Flexibility requirements from the DH network operators can also be introduced, and thus, flexibility can be transferred between different networks via the energy consumer.

The integration of energy supplies at the consumer side enables the connection of upper-level energy networks. This connection appears in a localized and distributed form. Compared with the centralized connections between different energy networks, some advantages can be expected. It saves space for large centralized infrastructures. The distributed on-site renewable energy is closer to the consumption, reducing the transmission loss. The integrated energy supply system can share the energy management system with DSM. Expected disadvantages include the high investment cost and the requirement of the active participation of consumers. A detailed comparison between the centralized and decentralized integration of multiple energy networks should be done in future works. It should be noted that the thermal inertia of the building can be used to provide flexibility. However, it is not included in this study due to the limitations of the research scope. Moreover, the research method of this study is based on historical heat demand, which cannot give enough information about the thermal inertia. More efforts are required to include the flexibility from the thermal inertia in future studies.

In the current DH network, CHP plants provide large share of the heat supply. The integration of consumer's local supplies helps the CHP plant synchronize its heat and electricity production. For example, when the grid faces an electricity shortage, energy consumers can lower electricity consumption and turn to DH for heat supply. For CHP plants, there are simultaneous electricity and heat demands. Thus, the electricity and heat production from CHP plants can be more synchronized, which helps CHP plants lower operation cost.

5 Conclusions

This work focuses on the integration of electricity and heat supplies in buildings. As one building can connect to multiple energy networks, integrating the local energy supplies and enabling the conversion between different energy carriers allow more control of the energy system of the building. Thus, the building can turn to different energy networks as its energy supply. The energy system of a Swedish office building is taken as the case study. Its energy system is optimized under given economic assumptions, and the net present cost can be decreased by 22%. The district heating network is disconnected, and it is economically more favorable to supply the heat demand through a heat pump and an electrical heater. The sensitivity analysis suggests that the net present costs of the optimal systems are lower than that of the current energy system despite changes in the investment cost of the components. Monte Carlo simulations indicate that the optimal system has a 93% possibility to achieve a lower net present cost than the current system in the facts of uncertainties related to future energy costs.

The integration of electricity and heat supplies allows the building to provide flexibility to the electrical grid. The flexibility from the optimal system is tested through an optimization-based method. The results suggest that the district heating network must be connected when there are flexibility requirements from the electrical grid. The yearly operation cost slightly increases with the flexibility hours. The flexibility hours can be over 5200 hours and the flexibility energy can be over 15.7 MWh (36% of the yearly electricity consumption). The results indicate that the integration of electricity and heat supplies can offer great flexibility to the electrical grid.

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