Multi-scale modelling of interactions between heat and electricity networks in low-carbon energy systems

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ABSTRACT

Decarbonisation of the heating and cooling sector is critical for achieving long-term energy and climate change objectives. Closer integration between heating/cooling and electricity systems can provide additional flexibility required to support the integration of variable renewables and other low-carbon energy sources. This paper proposes a framework for identifying cost-efficient solutions for supplying district heating systems within both operation and investment timescales, while considering local and national-level interactions between heat and electricity infrastructures. The proposed approach cost-optimises the portfolio of heating technologies, including Combined Heat and Power (CHP) and polygeneration systems, large-scale heat pumps (HPs), gas boilers and thermal energy storage (TES). It is implemented as a mixed-integer linear programming (MILP) optimisation model that minimises net cost of heat supply, taking into account investment and operation cost of heat supply and storage options as well as the impact of local and wider interactions with the electricity system.

KEYWORDS

District heating, polygeneration, combined heat and power, heat pumps, thermal energy storage, system integration

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INTRODUCTION

Together with reducing the carbon impact of the electricity sector through the deployment of low-carbon technologies such as renewables or nuclear generation, decarbonisation of the heating and cooling sector will be critical for achieving EU's long-term energy and climate change objectives. Heating and cooling currently account for half of the EU's energy consumption and a similar proportion of the total carbon emissions [1], with three quarters of energy still being provided by fossil fuels (mostly natural gas). It has been shown that heating and electricity systems can benefit significantly from mutual synergies on their pathways towards decarbonisation [2], by unlocking opportunities for cross-vector flexibility to support the integration of low-carbon generation technologies and to significantly reduce the cost of decarbonisation [3]. Integrated planning and operation of district heating, gas, hydrogen and electricity networks offers interesting opportunities a broad range of technologies, including flexible cogeneration systems, power to gas/H_2 or demand side management options [4,5].

A number of recent studies have shown that district heating can play an important role in the evolution towards sustainable energy systems [6,7,8], but also that the present district heating systems must undergo a radical change to become an integral part of smart energy systems. Various approaches to heat supply planning have been proposed in the literature [9,10]. Another common optimisation problem in this area is district heating network design, for which methods have been proposed based on operational research [11], genetic algorithms [12] and stochastic optimisation [13]. Techno-economic approaches to planning of district heating and energy systems with detailed spatial resolution have been presented in [14] and [15], allowing for the optimisation of the routes and capacities of heat distribution networks, selecting heat loads that will be connected to a district energy system and determining locations for the energy sources.

Recent work in this area has also focused on modelling electricity to heating technologies and the impact of electricity prices on heat supply and the profitability of district heating networks [16], as well as on the impact of fluctuating energy prices on operation strategies of polygeneration systems coupled with energy networks [17]. Energy technologies linking heat and power will play a key role in the integration between heating/cooling and electricity networks, and therefore a lot of research has focused on the optimal design and operation of embedded polygeneration systems and their integration with energy networks, including natural gas and biomass dual source technologies [18,19], hybrid solar-biomass systems [20,21], gas/renewable energy source integrated polygeneration systems [22], different typologies of building-integrated vs. centralised heat pumps [23,24,25], or thermal energy storage options for district heating [26].

Economic comparison of different heat decarbonisation pathways for the UK and the associated impacts on the electricity system were analysed in [2], suggesting that district heating may be economical in urban areas, in particular if its inherent flexibility is utilised to support the decarbonisation of the electricity system. Similarly, the whole-system modelling of the interaction between electricity and heat systems presented in [27] highlighted the benefits of system integration at both local and national level for cost-effective decarbonisation.

Most of the previous research on local district heating systems has focused on the local level infrastructure and cost assessment, with only limited consideration of wider energy system impacts and benefits, which can be substantial as demonstrated through whole-system approaches to integrated heat and electricity system assessment. In that context, the main contribution of this paper is to develop an optimisation framework for choosing a cost-efficient portfolio of heat supply technologies for a given local district heating system, while considering the interactions with a decarbonised electricity system at both national level and within the local distribution grid. The proposed modelling approach allows for an explicit consideration of the impact of increased penetration of renewables and the resulting electricity price patterns, local network constraints and any limits on local carbon emissions. Formulation presented in this paper will be integrated into the open-source application for heat network planning to be developed within the EU-funded THERMOS project [28].

METHOD

The interaction between heating (or cooling) networks and the electricity grid will have both local and national dimensions. At the district level the circumstances in the local distribution network will affect the cost of grid connection of a CHP plant or large-scale HP, while any local network constraints could potentially limit the size of the connection i.e. affect the rate of power consumption or injection that can be accommodated in the existing local grid. On the other hand, interactions with the wider electricity system will be effected through time-varying prices of electricity, which will depend on the national generation mix and in particular on the contribution of variable renewable generation to the electricity supply. Varying electricity prices will have an impact on the attractiveness of different heat supply options, including the installation of dedicated heat storage.

General approach

The model presented here is formulated as a cost minimisation problem for heat supply, finding a solution that results in the lowest (net) cost of supplying a given heat demand, taking into account the cost of investing in heat supply and storage technologies as well as their operating costs. The model uses a mixed-integer linear programming (MILP) formulation.

Four types of heat supply sources are assumed to be available for investment in the model: 1) Combined Heat and Power (CHP) plants, 2) large-scale heat pumps (HP), 3) boilers, and 4) thermal energy storage (TES). Each of these categories can accommodate a variety of technology subtypes and/or fuels such as e.g. gas or biomass boilers, fuel cells or gas turbine CHP plants, or TES in the form of hot water tanks or phase-change materials (PCMs).

Key links between the heat supply system (which is the subject of optimisation) and the electricity system include: a) CHP plants, which are able to sell their electricity output into the grid at the same time as supplying heat, and b) large HP plants, which produce heat by consuming electricity from the grid at prices that may vary in time.

The model assumes that there is a known annual profile of heat demand, which due to computational efficiency is represented as a set of daily demand profiles for several characteristic days and the associated frequencies of occurrence (e.g. representing peak winter day, normal winter day, spring/autumn and summer days; or workdays and weekends).

Objective function

The objective function implemented in the model is to minimise the net (annualised) cost of building and operating heat sources (including heat storage) to supply a given heat demand profile. The main components of the objective function include:

- Investment cost into new CHP, large HP, heat storage and/or boiler capacity
- Fuel cost of operating CHP and boiler plants
- Revenues from selling electricity generated by CHP
- Electricity purchase cost for large HP operation

- Cost of heat demand curtailment (if any)

The mathematical formulation of the objective function is provided in (1):

$$\begin{aligned}\min z = &\sum_{i=1}^{I} c_{CHP,i} + \sum_{j=1}^{J} c_{HP,j} + \sum_{k=1}^{K} c_{S,k} + \sum_{l=1}^{L} c_{B,l} \\ &+ \Delta \cdot \sum_{d=1}^{D} N_d \sum_{t=1}^{T} \left(\sum_{i=1}^{I} p_{CHP,i,t,d} \cdot \left(B_{CHP,i} - B_{E,t,d}\right) + B_{E,t,d} \sum_{j=1}^{J} p_{HP,j,t,d} \right. \\ &\left. + \sum_{l=1}^{L} \frac{F_{B,l}}{\eta_{B,l}} \cdot h_{B,l,t,d} + C_{VOLL} \cdot h_{curt,t,d} \right)\end{aligned} \tag{1}$$

Note that the objective function does not include the cost of installing the heat network, which will be a function of its topology. There are a number of complexities associated with simultaneously solving both supply and network subproblems, including the disparity in required temporal and spatial representations; the supply problem generally requires a high temporal resolution to accurately account for energy production and cost but only involves a small number of potential heat source locations, whereas the network problem requires rich spatial representation but only needs to consider peak and average heat demand. It is therefore considered more efficient to solve the two subproblems in an iterative fashion, with the heat supply optimised according to the method presented here, and network planning based on the approach presented in [15]. The heat supply subproblem therefore does not consider heat sales revenues, given that both these revenues as well as any network cost would represent a constant term in the objective function.

The variable operating cost of CHPs ($B_{CHP,i}$) and boilers ($F_{B,l}$) can also include the cost of carbon emissions if relevant. Alternative objective functions (e.g. minimising carbon emissions) could be formulated analogously, also taking into account emission factors of CHP plants and/or boilers.

Constraints

Constraints that need to be met in the model include:

- *Heat balance*. The total net heat output of all CHPs, HPs, heat storage and boilers needs to meet the heat demand, also allowing for the possibility of curtailment of demand:

$$\sum_{i} h_{CHP,i,t,d} + \sum_{j} h_{HP,j,t,d} + \sum_{k} \left(h^{+}_{S,k,t,d} - h^{-}_{S,k,t,d}\right) + \sum_{l} h_{B,l,t,d} \geq H_{t,d} - h_{curt,t,d} \tag{2}$$

- *Investment costs*. The cost of building new CHP, HP, TES and boiler capacity for each candidate is expressed as the sum of fixed component (controlled using binary investment variables u) and variable component (controlled using continuous installed capacity variables π):

$$c_{CHP,i} \geq I^{F}_{CHP,i} \cdot u_{CHP,i} + I^{V}_{CHP,i} \cdot \pi_{CHP,i} \tag{3}$$
$$c_{HP,j} \geq I^{F}_{HP,j} \cdot u_{HP,j} + I^{V}_{HP,j} \cdot \pi_{HP,j} \tag{4}$$
$$c_{S,k} \geq I^{F}_{S,k} \cdot u_{S,k} + I^{V}_{S,k} \cdot \pi_{S,k} \tag{5}$$

$$c_{B,l} \geq I_{B,l}^{F} \cdot u_{B,l} + I_{B,l}^{V} \cdot \pi_{B,l} \tag{6}$$

- *Installed capacity limits*. New installed capacity of heat sources is limited by the product of maximum capacity and binary investment decision, as defined in (7)-(10). In case the candidate investment decisions are discrete, i.e. if one can only install the maximum capacity or nothing, the inequalities in these constraints should be converted to equalities.

$$\pi_{CHP,i} \leq u_{CHP,i} \cdot P_{CHP,i}^{MAX} \tag{7}$$
$$\pi_{HP,j} \leq u_{HP,j} \cdot P_{HP,j}^{MAX} \tag{8}$$
$$\pi_{S,k} \leq u_{S,k} \cdot H_{S,k}^{MAX} \tag{9}$$
$$\pi_{B,l} \leq u_{B,l} \cdot H_{B,l}^{MAX} \tag{10}$$

- *Operating limits*. The outputs of CHP, HP, heat storage and boilers are limited by the relevant installed capacity decision variables, as specified in expressions (11)-(14). Depending on the application, the model could also include more advanced operating constraints (especially for CHPs) associated with standard unit commitment problems, such as minimum output, quadratic cost functions, ramping constraints, commitment variables, minimum up and down times etc.

$$p_{CHP,i,t.d} \leq \pi_{CHP,i} \tag{11}$$
$$p_{HP,j,t,d} \leq \pi_{HP,j} \tag{12}$$
$$h_{S,k,t,d}^{+}, h_{S,k,t,d}^{-} \leq \pi_{S,k} \tag{13}$$
$$h_{B,l,t,d} \leq \pi_{B,l} \tag{14}$$

- *Heat storage balance*. The state of charge (SoC) of heat storage at time t is equal to the SoC at time $t-1$ plus the net effect of charging and discharging also accounting for roundtrip losses (15). SoC is also limited from above by the product of thermal power rating and duration of heat storage (16):

$$w_{S,k,t,d} = w_{S,k,t-1,d} - \Delta \cdot \left(h_{S,k,t,d}^{+} - \eta_{S,k} \cdot h_{S,k,t,d}^{-}\right) \tag{15}$$
$$w_{S,k,t,d} \leq \pi_{S,k} \cdot D_{S,k} \tag{16}$$

- *Heat to power ratios*. Power generation/consumption and heat production for CHPs and HPs are linked via proportionality constraints:

$$h_{CHP,i,t,d} = R_{CHP,i} \cdot p_{CHP,i,t,d} \tag{17}$$
$$h_{HP,j,t,d} = R_{HP,j} \cdot p_{HP,j,t,d} \tag{18}$$

- *Local electricity grid*. Constraints associated with the local power network (assuming any CHP plants or large HPs would connect to the same network substation) need to ensure that the aggregate effect of baseline power demand, CHP generation and HP consumption does not exceed substation capacity (19). This constraint also accounts for limits on any reverse power flows (i.e. power injections into the grid) using a coefficient $\alpha < 1$, given that for technical reasons the substations can normally accommodate slightly lower power flows in the reverse than in the default direction.

$$-G_{cap} \cdot \alpha \leq D_{t,d}^{el} + \sum_{j} p_{HP,j,t,d} - \sum_{i} p_{CHP,i,t,d} \leq G_{cap} \tag{19}$$

- *Emission constraints*. Total annual carbon dioxide (CO_2) emissions from CHP plants and boilers can be constrained so as not to exceed a pre-specified carbon emission limit for the heat supply system:

$$\Delta \cdot \sum_{d=1}^{D} N_d \sum_{t=1}^{T} \left(\sum_{i=1}^{I} p_{CHP,i,t,d} \cdot E_{CHP,i} + \sum_{l=1}^{L} h_{B,l,t,d} \cdot E_{B,l} \right) \leq E_{CO_2} \tag{20}$$

Implementation

The model formulation presented here has been implemented in the FICO Xpress optimisation software [29]. This allowed for the calculation of illustrative case studies presented in the remainder of the paper.

Common assumptions

Note that the numbers and assumptions used in these examples are for illustration only and are not intended to be representative of a specific technology or location. For simplicity, all case studies assume that only one candidate of each technology (gas-fired CHP, large-scale HP, TES and gas-fired boiler) is available for installation.

One characteristic day was assumed to represent the heating season, with 48 half-hourly intervals for heat demand values. It was further assumed that this day repeats itself 150 times during a year (representing the length of the heating season), and that no heating is required during the rest of the year. No cooling demand was considered in this example.

Default assumptions used in case studies for annualised investment cost and maximum installed capacities are presented in Table 1. Annualised investment cost are obtained from overnight investment costs by applying the appropriate discount rate and the economic life of the asset. Note that in some case studies the input assumptions from Table 1 were modified to evaluate their impact on the optimal solution.

Table 1. Assumptions on investment cost and maximum capacities for heat supply technologies

Parameter	Technology			
	CHP	Large HP	TES	Boiler
Fixed cost (€/yr)	5,000	10,000	1,000	2,000
Variable cost (€/kW/yr)	50	100	10	20
Max. capacity (MW)*	2	2	5	5

* Note: Capacities of CHP and large HP are expressed as electrical power (in MW_{el}), while those of TES and boilers refer to thermal capacities (in MW_{th}).

The operating cost of the CHP plant per unit of electricity output was assumed to be €80/MWh. The fuel (i.e. gas) cost for operating the boiler was assumed at €30/MWh, and its efficiency was 95%. The emission factor per unit of output for CHP was 0.5 tCO_2/MWh_{el}, and for boilers 0.2 tCO_2/MWh_{th}. The assumed heat-to-electricity (H-E) ratio was 2 for CHPs and 3 for HPs. Heat storage duration (ratio between rated energy and power) was assumed to be 4 hours, and the assumed roundtrip efficiency of TES was 90%.

Several daily electricity price profiles have been assumed in the case studies presented in the next section, as illustrated in Figure 1, in order to simulate different possible realisations of electricity price patterns in the future electricity system (without making any judgment as to the likelihood of these price profiles being sustained over the course of the heating season):

- *Flat*: Fixed electricity price (€50/MWh) throughout the representative day. It can also represent a situation where a CHP or a large HP have a power purchase or supply agreements in place with fixed prices.

- *Variable*: Profile with price variations representing a typical day, varying between €36/MWh (overnight) and €65/MWh (peak demand hours).

- *Low Peak*: Price scenario reflecting a downward pressure on prices during peak hours due to abundant wind output (being a plausible scenario for the UK system).

- *Extreme Peak*: A future price scenario that reflects scarcity pricing, pushing the electricity prices to a very high level during peak demand periods as the result of high demand levels and low renewable (wind) output.

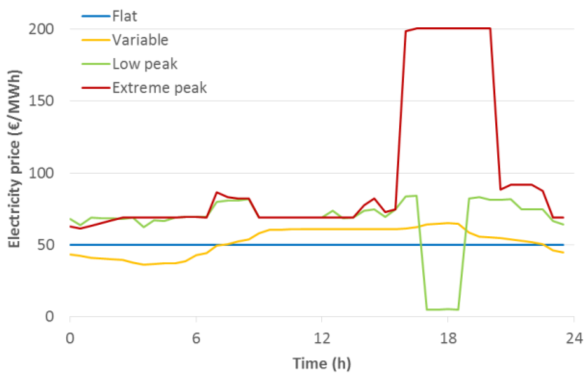

Figure 1. Electricity price profiles used in case studies

Heat demand profile for the characteristic day used in the study was assumed to peak at just over 2.5 MW_{th}, with morning and evening peaks as shown in Figure 2 (left-hand vertical axis). Baseline electricity demand profile (before including power generation or consumption by CHP and HP installations) at the local substation was assumed to follow the pattern also depicted in Figure 2 (right-hand vertical axis), with peak demand level just above 3 MW_{el}. The capacity of the local electricity substation was assumed to be 4 MW_{el}.

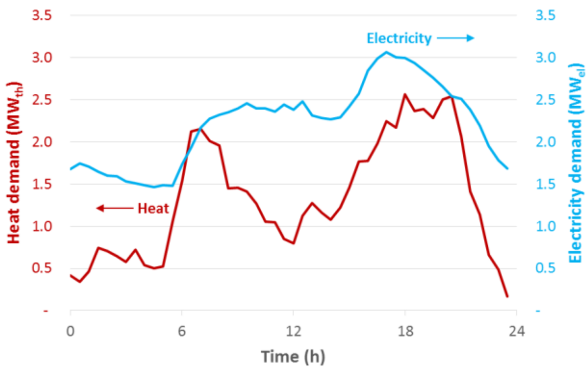

Figure 2. Daily heat demand and local electricity demand profiles

RESULTS AND DISCUSSION

The model presented in the previous section was applied to a number of illustrative case studies that highlight the capability of the model to make cost-efficient trade-offs when investing in portfolios of heat supply technologies in different scenarios characterising the interaction between heat and electricity systems. Table 2 provides an overview of the main assumptions and variations from default assumptions across different case studies. A total of 8 case studies have been run in order to illustrate the impact of the following key drivers on decisions to invest in heat supply options: 1) electricity price profiles, 2) investment cost of heat supply technologies, 3) constrained electricity grid, and 4) constrained carbon emissions.

Table 2. Overview of main assumptions across different case studies

No.	Electricity price profile	CHP cost	TES cost	Boiler cost	Network constraint	CO_2 constraint
1	Flat	Default	Default	Default	-	-
2	Variable	Default	Default	Default	-	-
3	Low Peak	Default	Default	Default	-	-
4	Extreme Peak	Default	Default	Default	-	-
5	Flat	4x higher	Default	Default	-	-
6	Flat	Default	10x higher	2x lower	-	-
7	Flat	4x higher	Default	Default	Active	-
8	Flat	Default	Default	Default	-	Active

Note: ‘Default’ investment cost assumptions (fixed and variable) are given in Table 1.

Key model outputs reported for each case study include: a) installed capacities of CHP, HP, thermal storage and boilers, b) total annual cost of supplying heat, and c) average cost of heat supplied to customers. In all case studies the reported results for installed capacities for CHP and HP refer to their electrical power (in MW_{el}), while those for TES and boilers refer to thermal capacities (in MW_{th}).

Impact of electricity prices

Figure 3 shows the daily diagram of heat supply and demand for the Flat electricity price profile (shown in Figure 1), as well as the optimal investment choices for heat sources.

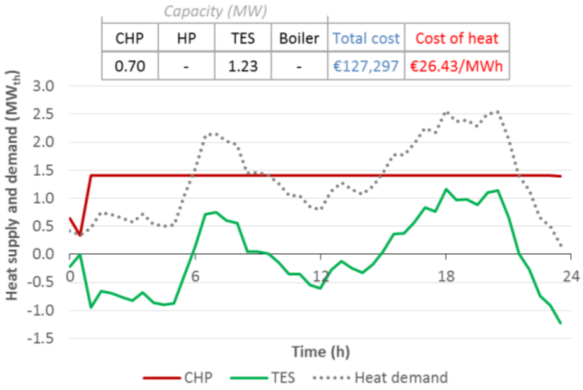

Figure 3. Heat supply profile and investment decisions for Flat electricity prices

The cost-optimal supply mix in this case is achieved by a mix of 0.7 MW_{el} of CHP and 1.2 MW_{th} of heat storage. This combination allows the CHP plant to operate at almost constant output, producing around 1.4 MW_{th} of heat. The remainder of heat demand during peak periods is supplied by releasing heat from TES, and this heat is then replenished during off-peak periods, while still allowing CHP to operate at full output. Despite the flat electricity prices seen by the CHP plant, it is still justified to build some heat storage alongside the CHP. Building any additional CHP capacity above the optimal 0.7 MW_{el} would reduce its utilisation factor and make the total cost higher than for the combination of CHP and TES.

CHP produces electricity at €80/MWh_{el} while earning a revenue of €50/MWh_{el}. The difference of €30/MWh_{el}, when applied to the 2 MWh of heat produced simultaneously with 1 MWh of electricity results in a net heat cost of €15/MWh_{th}. The heat output cost of large HPs would be 1/3 of the electricity price, or €16.7/MWh_{th}, which combined with a higher investment cost of HPs explains why CHP is preferred to HP. Gas boiler on the other hand can produce heat at €30/MWh / 0.95 = €31.6/MWh, which is significantly higher than CHP, so even the lower investment cost of boilers does not justify choosing them as a supply source. The average cost of supplying heat in this example, after accounting for all operating costs as well as the investment cost of CHP and heat storage capacity, is around €26/MWh_{th}.

Daily changes in the State of Charge (SoC) of TES are shown in Figure 4. A positive gradient of SoC is observed during off-peak periods, when TES is charged with heat produced by the CHP in excess of current heat demand, while negative gradients occur during peak demand periods when heat storage output is used to top up the heat supplied by the CHP. The model ensures that TES is fully charged before the beginning of morning and evening peaks.

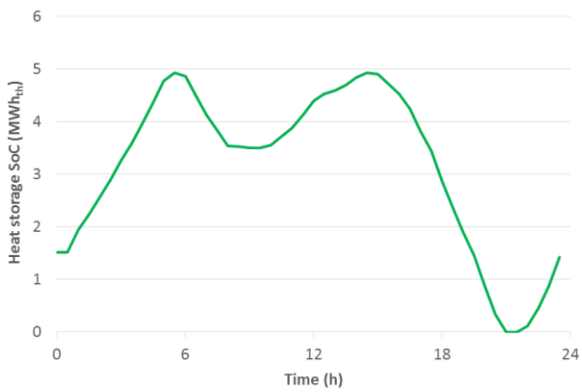

Figure 4. Daily variation of energy stored in TES

The impact of other electricity price profiles (Variable, Low Peak and Extreme Peak) on investment decisions, total net annual cost and daily diagrams of heat supply is shown in Figure 5.

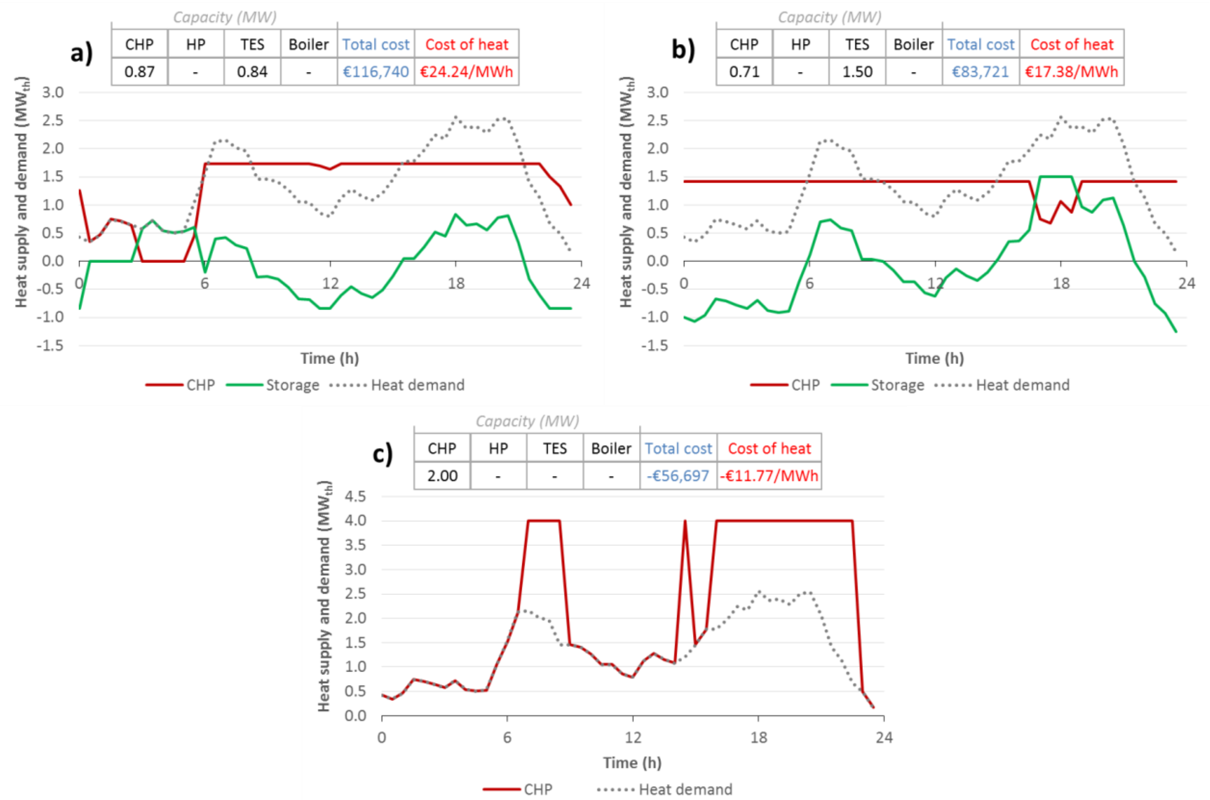

Figure 5. Heat supply profiles and investment decisions for a) Variable, b) Low Peak and c) Extreme Peak electricity prices

The cost-optimal mix of heat sources with Variable electricity prices (Figure 5a) includes more CHP capacity (0.87 MW$_{el}$) and less TES capacity (0.84 MW$_{th}$) than with Flat prices. The overall net cost decreases by 8%, with the average heat supply cost of €24.2/MWh$_{th}$. Although the peak heat demand still requires both CHP and TES to be used, higher CHP capacity allows it to run at higher output during high price periods. TES is mostly charged during the mid-day low-demand hours and late evening, and this heat is again released to help meet the morning and evening peak demand. The CHP operates at a lower level during the night when the electricity prices and hence the available net revenues are lower.

The scenario with Low Peak electricity prices (Figure 5b) emulates a price drop during peak demand periods, e.g. due to high output of wind generation, while outside these periods the prices are relatively higher (Figure 1). The optimal volume of CHP capacity is similar to Flat prices scenario (0.71 MW_{el}), but the optimal TES capacity is now higher (1.50 MW_{th}). Thanks to high electricity prices outside the peak demand window, the overall net cost of heat supply is significantly lower than in previous case studies, with the average cost of heat of only €17.4/MWh. In the daily diagram CHP operates at full output outside the low-price window, taking advantage of relatively high electricity prices compared to its operating cost. Conversely, when power prices drop between 5pm and 6.30pm, the CHP operation is no longer profitable, and hence most of the heat in that period is released from TES.

Finally, in the Extreme Peak price scenario (Figure 5c), acknowledging the low likelihood of such a scenario persisting over the entire heating season, the optimal solution includes only CHP capacity at the maximum allowed level of 2 MW_{el}. Due to extremely high revenues from selling power, the net annual cost of supplying heat becomes negative in this example (-€11.8/MWh_{th}). Note that this scenario assumes that heat dumping is allowed i.e. that any heat produced by CHP in excess of actual heat demand could be released into the environment if economically justified. This is also reflected in constraint (2) that is formulated as inequality rather than equality. (Had the option for heat dumping been disabled, CHP would be installed at the level of 1.28 MW in order to meet peak heat demand, while the net cost of heat would be -€3.3/MWh_{th}.) The CHP operating strategy in this case is to produce heat equal to the demand if the electricity price is below its operating cost (€80/MWh), and operate at maximum output if the price exceeds €80/MWh, while dumping any excess heat.

Impact of investment cost assumptions

Figure 6 shows the investment decisions, net annual cost and daily diagrams of heat supply for case studies with high CHP investment cost (case #5 in Table 2), and high CHP and TES but low boiler cost (case #6 in Table 2).

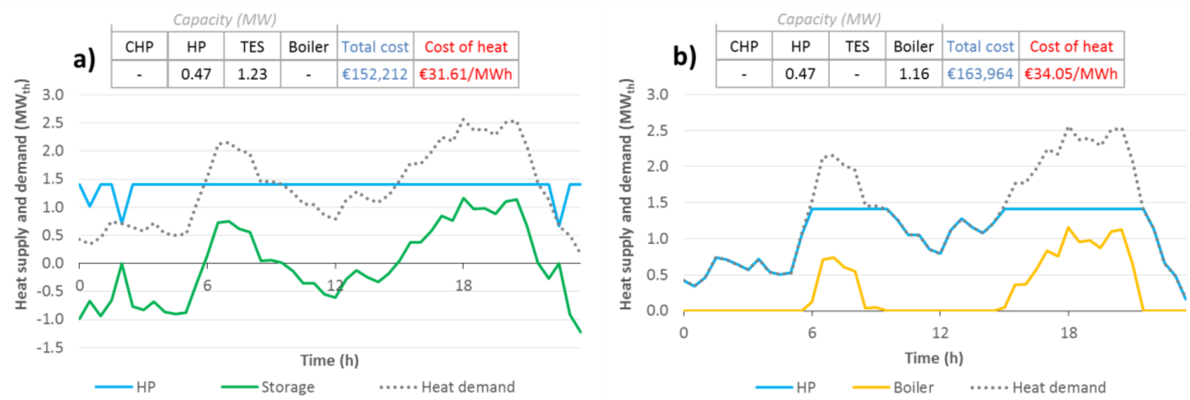

Figure 6. Heat supply profiles and investment decisions for a) high CHP cost (case #5) and b) high CHP, high TES and low boiler cost (case #6)

Higher investment cost of CHP (Figure 6a) changes the optimal technology mix, now consisting of 0.47 MW_{el} of large-scale HP capacity and 1.23 MW_{th} of TES. This also results in about 20% higher total net cost and the average cost of heat of €31.6/MWh_{th}. Daily operating patterns of

HP and heat storage are similar to Figure 3, except that the 1.4 MW_{th} of baseload heat is now supplied by large-scale HP. This also means that the local electrical substation will see an increase in electricity demand, including an increase in peak demand by 0.5 MW_{el} (which is still below the assumed substation rating of 4 MW).

With higher CHP cost combined with higher TES cost and lower boiler cost (Figure 6b) the optimal solution no longer includes heat storage, but a combination of a large HP (0.47 MW_{el}) and boiler (1.16 MW_{th}). The total annual net cost is now about 8% higher than in Figure 6a, and the average cost of heat is €34.1/MWh_{th}. In the daily heat supply diagram the HP supplies heat demand up to the level of 1.4 MW_{th}, and gas boiler tops up the HP output whenever the heat demand exceeds this level.

Impact of constraints in local electricity grid

This example considers the interdependencies with the local electricity network by assuming that in addition to the assumptions made in case #5 there is a constraint on total active power that can be supplied through the local substation, at the level of 3.2 MW_{el}. This means that the large HP can no longer be operated in the same way as in Figure 6a, as this would overload the substation during peak demand hours. The optimal solution, shown in Figure 7a, includes a similar volume of large HP capacity as before (0.50 MW_{el}), but a significantly higher volume of TES (1.97 MW_{th}), which allows for the HP output during peak hours to be partly replaced by heat released from TES. The local grid constraint gives rise to a 7% net cost increase, with the resulting cost of heat of €33.9/MWh_{th}. Daily output diagram for this case shows that higher TES capacity is required to enable HP output to reduce sufficiently during the evening peak (from 4pm to 7.30pm) to avoid overloading the local electrical substation.

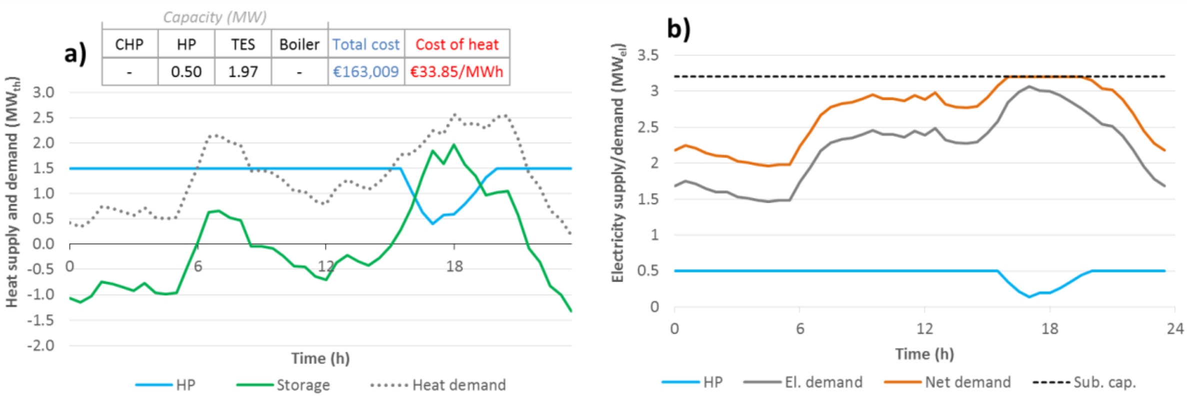

Figure 7. a) Heat supply profiles and investment decisions, and b) electricity demand profile at local substation for high CHP cost and constrained local grid (case #7)

The loading profile for the local substation is presented in Figure 7b. The power demand of large HP is reduced during the peak period in order to maintain the aggregate substation loading (baseline demand plus HP consumption) at the level of substation capacity (3.2 MW_{el}). In this case it becomes justified to increase the size of TES beyond the requirement of the heat network itself in order to ensure a more flexible interaction between the district heating system and the local electricity grid.

Impact of constrained carbon emissions

Case #8 is the same as case #1 except that it has an explicit limit on annual carbon emissions from the heat supply system, at the level of 500 tCO_2. Figure 8 shows the daily heat supply pattern and optimal investment decisions for this scenario.

Only gas-fired CHP and boilers were assumed to be direct CO_2 emitters, while large HPs were not assumed to produce any direct emissions (it would be relatively straightforward to also consider grid emissions associated with HP electricity demand). Without the emission constraint (case #1) the optimal solution only included CHP and TES capacity, and the resulting annual carbon emissions from the CHP were 1,230 tCO_2. Restricting the carbon emissions, however, limits the output that can be provided by the CHP, and therefore its capacity is reduced from 0.7 to 0.3 MW_{el}. To compensate for that, the model adds about 0.27 MW_{el} of large HP capacity. Instead of CHP continuously providing 1.4 MW_{th} of heat on its own as in case #1, the heat output is now split between CHP (0.6 MW_{th}) and large HP (0.8 MW_{th}). If the carbon constraint is tightened further, even more of the low-cost CHP will be replaced by higher-cost HP (at zero-carbon target all CHP capacity would be replaced by HPs).

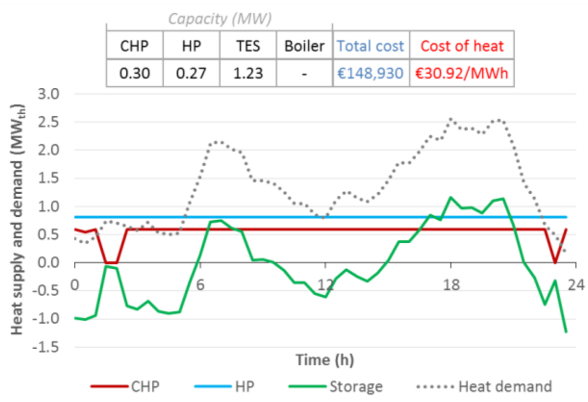

Figure 8. Heat supply profiles and investment decisions with constrained carbon emissions

CONCLUSION

This paper describes a multi-scale approach to modelling both local and system-wide interactions between thermal energy networks and the electricity grid. Decarbonisation of electricity and heat supply presents numerous challenges, but also opportunities for system integration between the two sectors, taking advantage of flexibility in the heat sector to support a more cost-effective decarbonisation of the electricity sector. The modelling approach presented in this paper shows that certain flexible options in the heating system (such as CHPs or TES) could have significant whole-system value that materialises outside the local district heating application. For instance, as shown in the case studies, it may be beneficial to increase the size of TES beyond the requirement of the local heat network in order to provide additional flexibility in the interactions with the electricity grid and managing local network constraints. It is therefore crucial to reflect the whole-system value of flexible heating technologies in the underlying cost-benefit analysis of heat networks.

Future work on improving the model will focus on: adding cooling demand and supply, moving from annualised cost to Net Present Value (NPV), considering the CO_2 intensity of electricity grid for carbon impact assessment of HP, refining the operating parameters of CHP and HP plants (e.g. by considering minimum output, ramping, start-up cost, variable H-E ratio and

COP, limited number of starts per day etc.), and including the provision of ancillary services (e.g. frequency regulation) as a potential additional source of revenue for CHP and HP assets. Another area to be explored is linking the heat supply and network subproblems.

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NOMENCLATURE

Indices

t	Time interval
d	Characteristic day
i	CHP plant candidate
j	Large-scale HP candidate
k	Heat storage candidate
l	Boiler candidate

Parameters

T	Number of time intervals in a characteristic day (typically 24 or 48)
Δ	Duration of the unit interval (in hours)
D	Number of characteristic days used in the study
N_d	Frequency (number of occurrences) of characteristic day d within a year
I	Number of CHP candidates
J	Number of large-scale HP candidates
K	Number of heat storage candidates
L	Number of boiler candidates
C_{VOLL}	Value of Lost Load (VOLL), cost associated with unserved heat demand (in €/MW_{th})
$H_{t,d}$	Heat demand profile at time t for day d (including losses) (in MW_{th})
$D_{t,d}^{el}$	Baseline electricity demand profile at local substation at time t for day d (in MW_{el})
$B_{E,t,d}$	Electricity price profile at time t for day d (in €/MWh_{el})
E_{CO_2}	Annual limit on CO_2 emissions from the heat supply system (in tCO_2)
G_{cap}	Capacity of local electricity grid (substation) (in MW_{el})
α	Factor for constraining reverse power flows at substation
$P_{CHP,i}^{MAX}$	Maximum installed capacity of CHP candidate i (in MW_{el})
$P_{HP,j}^{MAX}$	Maximum installed capacity of large HP candidate j (in MW_{el})
$H_{S,k}^{MAX}$	Maximum installed capacity of heat storage candidate k (in MW_{th})
$H_{B,l}^{MAX}$	Maximum installed capacity of boiler candidate l (in MW_{th})
$I_{CHP,i}^{F}$	Fixed component of (annualised) investment cost for CHP candidate i (in €/yr)
$I_{HP,j}^{F}$	Fixed component of (annualised) investment cost for large HP candidate j (in €/yr)
$I_{S,k}^{F}$	Fixed component of (annualised) investment cost for heat storage candidate k (in €/yr)
$I_{B,l}^{F}$	Fixed component of (annualised) investment cost for boiler candidate l (in €/yr)

$I^V_{CHP,i}$ Variable component of (annualised) investment cost for CHP candidate i (in €/kW$_{el}$/yr)
$I^V_{HP,j}$ Variable component of (annualised) investment cost for large HP candidate j (in €/kW$_{el}$/yr)
$I^V_{S,k}$ Variable component of (annualised) investment cost for heat storage candidate k (in €/kW$_{th}$/yr)
$I^V_{B,l}$ Variable component of (annualised) investment cost for boiler candidate l (in €/kW$_{th}$/yr)
$B_{CHP,i}$ Variable electricity generation cost of CHP candidate i (in €/MWh$_{el}$)
$F_{B,l}$ Fuel cost of boiler candidate l (in €/MWh)
$R_{CHP,i}$ Ratio between heat and electricity output for CHP candidate i
$R_{HP,j}$ Ratio between heat output and electricity input (COP) for large HP candidate j
$D_{S,k}$ Duration (ratio between energy and power rating) for heat storage candidate k (in hours)
$\eta_{S,k}$ Roundtrip efficiency of heat storage candidate k
$\eta_{B,l}$ Combustion efficiency of boiler candidate l
$E_{CHP,i}$ Emission factor per unit of electricity output of CHP candidate i (in tCO_2/MWh$_{el}$)
$E_{B,l}$ Emission factor per unit of heat output of boiler candidate l (in tCO_2/MWh$_{th}$)

Decision variables

$c_{CHP,i}$ Investment cost into CHP candidate i (in €/yr)
$c_{HP,j}$ Investment cost into large-scale HP candidate j (in €/yr)
$c_{S,k}$ Investment cost into heat storage candidate k (in €/yr)
$c_{B,l}$ Investment cost into boiler candidate l (in €/yr)
$u_{CHP,i}$ Binary decision on investment into CHP candidate i
$u_{HP,j}$ Binary decision on investment into large HP candidate j
$u_{S,k}$ Binary decision on investment into heat storage candidate k
$u_{B,l}$ Binary decision on investment into boiler candidate l
$\pi_{CHP,i}$ Installed capacity of CHP candidate i
$\pi_{HP,j}$ Installed capacity of large HP candidate j
$\pi_{S,k}$ Installed capacity of heat storage candidate k
$\pi_{B,l}$ Installed capacity of boiler candidate l
$p_{CHP,i,t,d}$ Electrical output of CHP candidate i at time t for day d (in MW$_{el}$)
$p_{HP,j,t,d}$ Electrical input of large HP candidate j at time t for day d (in MW$_{el}$)
$h_{CHP,i,t,d}$ Heat output of CHP candidate i at time t for day d (in MW$_{th}$)
$h_{HP,i,t,d}$ Heat output of large HP candidate j at time t for day d (in MW$_{th}$)
$h^+_{S,k,t,d}$ Heat output (discharging) from heat storage candidate k at time t for day d (in MW$_{th}$)
$h^-_{S,k,t,d}$ Heat input (charging) into heat storage candidate k at time t for day d (in MW$_{th}$)
$h_{B,l,t,d}$ Heat output of boiler candidate l at time t for day d (in MW$_{th}$)
$w_{S,k,t,d}$ State of charge of heat storage candidate k at time t for day d (in MWh$_{th}$)
$h_{curt,t,d}$ Curtailed heat demand at time t for day d (in MW$_{th}$)

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