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The effect of feed-in-tariff supporting schemes on the viability of a district heating and cooling production system

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ABSTRACT

Combined cooling, heat and power systems represent an efficient alternative to supply heating and cooling demand compared to conventional boilers and air conditioner systems. However, considering the high level of upfront investment and the relatively long lifetimes, it is important to provide some form of long-term certainty to reduce the risk of deployment of these systems. To overcome this uncertainty, this paper describes a method to calculate an appropriate feed-in-tariff scheme to support investors and public authorities to foster the penetration of this technology in areas with high energy demands. It is subsequently tested in a scientific and technology park located in the south of Spain where different energy prices are studied. The results indicate that a feed-in-tariff is required to support the development of combined heating, cooling, and power systems, which not only improves the economic performance of the system, but also increases the utilisation of more efficient generation technologies such as combined cooling, heat and power systems.

1. Introduction

In the EU, half of the final energy consumed is used to satisfy heating and cooling demand [1]. In particular, cooling requirements are increasing rapidly in recent years [2]. As a result, distributed energy production for heating and cooling production purposes is one of the key elements of the energy strategy in the EU [3]. In this sense, energy solutions at a district level contribute to decentralised energy system and increase its efficiency.

District heating and cooling (DHC) systems are designed to satisfy heating and cooling demand combining local resources [4] and efficient energy generation technologies. In addition, the district approach allows i) a more efficient energy generation portfolio, primarily by utilising excess heat resources [5,6], and ii) higher penetrations of renewable energy technologies [7], a challenge for densely populated areas where little space is available. Therefore, they constitute a key enabling solution to achieve the decarbonisation of the European energy system [8].

However, DHC solutions require high level of investments and are subject to uncertainties concerning conditions of operation [9]. More specifically, their success is tied to changes in the energy demand to be satisfied, energy prices and the regulatory framework in the medium-to long-term [10].

Regulation plays a main role in the penetration of district heating and cooling solutions [11]. Adequate policy combined with financial support set by public bodies could finally enforce the investment decision. Across the EU, different schemes have been put in place based on financial support, market control or energy planning [12] that have been demonstrated effectively. On the contrary, there are examples where lack of policy commitment has led to the termination of district heating and cooling network projects.

Although different supporting mechanisms have already been tailored to promote the deployment of high—efficient energy solutions, this work investigates the optimal design of feed-in-tariffs schemes. They have been proved as the appropriate financial mechanism when technologies or solutions under study have not experiment a significant deployment [13].

Appropriate demand sizing is an additional key factor [14]. A simplified and accurate approach to determine energy demand to be supplied is essential for the final investment decision.

The objective of this paper is to offer a method to facilitate

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investors' decision making. Based on given energy price schemes, the proposed method calculates optimal combined cooling, heat and power (CCHP)/DHC solution providing information on economic indicators including marginal energy prices that ensure the system feasibility.

Thus, the method presented intends to be useful not only for energy investors but also for policymakers. Information on energy and economic performances will allow policy makers to understand DHC business models and then set appropriate supporting schemes to finally contribute to EU energy policies.

This paper is structured as follows: section 2 presents the method developed to get optimal solutions based on economic indicators, and section 3 sets out the case study quantifying the impact of different energy policies. Section 4 covers results derived from the optimal solution under different policy scenarios, and section 5 sets out sensitivity analysis to evaluate the impact of different assumptions concerning prices and performances. Lastly, section 6 presents the main outputs and the discussion about the role of energy policies in the promotion of these types of installations.

2. Method

The proposed method was built around a comprehensive CCHP system (Fig. 1). In real applications, these systems are equipped with back-up energy generation equipment to guarantee a minimum level of energy supply at any time. Therefore, they can potentially operate as a conventional or as a CCHP energy production system.

This dual operation fits the purpose of this work by providing enough flexibility to assess different scenarios. So, for a given set of equipment and energy prices some of the equipment will be selected as part of the optimal solution. Thus, if the optimal solution is conventional generation, then a back-up boiler and mechanical chiller will be part of the solution and sized according to the demand. In this particular case, electricity demand is satisfied by purchased electricity from the grid. On the other hand, if the CCHP is the optimal solution, all the elements included in Fig. 1 will be part of the optimal solution. In this case, electricity supply is managed depending on prices.

Three different types of elements were included in the system: demand, energy generators and storage.

2.1. Energy demand and selection of typical days

Energy demand is the main input when sizing CCHP/DHC installations. As the final objective for any energy system, demand sets the comparison framework to evaluate different energy scenarios. Energy demand influences not only the size of the generation components but also the benefits derived from the system operation. Therefore, an accurate calculation of the energy demand determines the success of any further feasibility study.

According to energy flows that could be potentially delivered by CHP systems, heating, cooling and electricity demand have to be modelled. Thermal energy supply includes heating and cooling demand. In the case of electricity, demand includes not only energy for electric appliances, but also the energy required to operate electric chillers.

To calculate energy demand patterns, a detailed energy simulation program was used [15]. In particular, the selected software allowed the modelling of dynamic effects that may significantly change energy demand compared to other simplified methods [16]. According to the dynamic of thermal behaviour in buildings and considering the level of aggregated demand at district level, a time step of 1 hour was chosen to simulate energy requirements [17].

Hence, the chosen time step led to an 8760-dimension problem on an annual basis. To facilitate the resolution of the optimisation problem, clustering techniques were applied leading to a reduced dimension by selecting a reduced number of typical days [18,19]. In the clustering process, some considerations were taken to ensure that the original demand was estimated accurately. Firstly, those days where demand peak occurred were included in the clustering. Additionally, the selection had to incorporate a number of days that complied with two requirements: i) the error in the load duration curve (ELDC), defined as the relative difference between the original and the estimated load duration curve, is lower than 10% and,

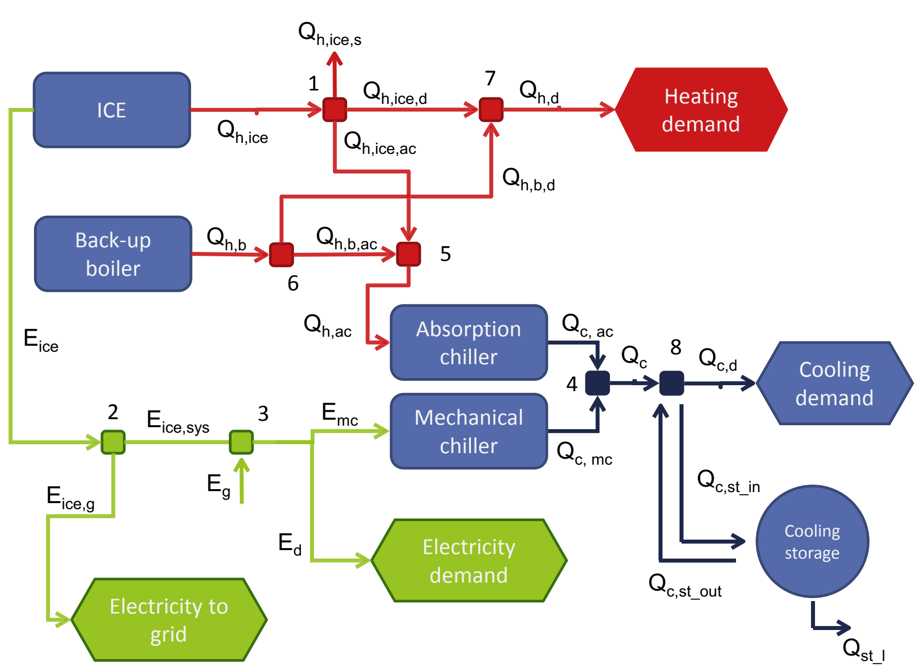

Fig. 1. Scheme for a combined heating, cooling and power facility.

ii) the inclusion of an extra day does not reduce the error by more than 1% (equation (1)).

$$ELDC_{N+1} - ELDC_N \leq 0.01 \quad (1)$$

where $ELDC_N$ was the error in the load duration curve for a N number of typical days (equation (2)):

$$ELDC = \frac{\sum_{t=1}^{8760} |LDC_o(t) - LDC_e(t)|}{\sum_{t=1}^{8760} |LDC_o(t)|} \quad (2)$$

where:

LDC_o ≡ original load duration curve
LDC_e ≡ load duration curve based on a number of typical days

Despite using the clustering technique to reduce the size of the problem, detailed demand of those days was required to ensure an appropriate approximation.

2.2. Generation equipment

A variety of energy generation technologies are considered in this paper, including:

- An internal combustion engine (ICE) for the combined electricity and heat production
- Back-up boiler for heating
- Mechanical chiller for cooling
- Absorption chiller for cooling

Previous studies [20] have shown that the ICE is the most suitable technology as prime mover for these installations. Together with the back-up boiler, the ICE is responsible for both satisfying heating demand and providing heating required to activate absorption chillers. Furthermore, electricity produced by the ICE may also satisfy electric demand – including the mechanical chiller requirements, or be injected in the grid to make a profit. The strategy for the on-site electricity produced is determined by different prices schemes.

Absorption and mechanical chillers have to meet the cooling demand. Both are directly connected with the ICE as explained before. The cooling production may satisfy the cooling demand directly or be stored in a cold storage system in order to balance demand requirements and equipment sizing.

Three parameters are defined for each of the energy generation elements [21,22]:

- Investment cost (€/kW);
- Nominal Power Rate (kW);
- Efficiency (%).

Dynamic performance of generation equipment was not considered. Non-linear behaviour complicated the resolution of the optimisation problem. Therefore, the efficiency represents the typical average performance of the equipment over a year.

2.3. Thermal storage

Based on relevant literature, heating and cooling storage are both included in CCHP optimisation problems [23]. However, the method here only includes cold storage based on the Mediterranean climate conditions for the case study: the cooling demand is predominant due to high temperatures and solar radiation [24] together with the higher cost of producing cooling compared with heating. However, the proposed method could be applied to any application where the flexibility in the cooling demand could contribute to both guaranteeing an optimal supply and reducing the size of the equipment.

The cold storage is expected to i) balance the short-term differences between cold supply and demand, ii) improve the performance of the energy generation technologies by enabling them to operate at better efficiencies and iii) reduce the need for extra generation capacity i.e. by supplying peak demands using the cold storage. The following parameters were considered when modelling storage element:

- Investment cost (€/kW);
- Storage losses (% of total energy stored)

2.4. Optimisation problem

The optimisation problem includes the objective function, parameters and restrictions.

The objective function is the total annual cost of the solution including capital expenditures (CAPEX), operating expenses (OPEX). The objective function could be written as follows;

$$Cost_{total} = fam \cdot \left(\sum_y I_y + C_X \right) + \sum_z C_z \cdot X_z \quad (3)$$

where:

C_X≡ cost of infrastructure including the energy network (€)
C_z≡ energy cost of energy flow z (€/kWh)
fam ≡ Maintenance and amortisation factor (yr^{-1})
I_y ≡ Investment per technology y (€)
X_z ≡ energy flow z (kWh/yr)

It is important to note that the optimisation problem covers a single year. This is the reason why the CAPEX term was affected by the 'fam' factor. This factor distributes initial investment over the lifetime of the installation. According to [21], maintenance and amortisation factors are considered together under the 'fam' factor. Its value was 0.05 yr^{-1} [9]. This means, 20 years is assumed as the lifetime of the installation.

2.5. Decision variables

The optimisation problem is defined to run analysis both based on commercial equipment or based on the aggregation of unitary energy production units. Therefore, the decision variables are the number of units required to satisfy the calculated demand for the different energy generation elements and the size of the cooling storage:

n_{ice} ≡ number of prime mover units
n_{ac} ≡ number of absorption units
n_{mc} ≡ number of mechanical units
n_b ≡ number of back-up boiler units
n_{st} ≡ thermal capacity of the storage (kWh)

Thus, if decision makers are interested in particular commercial models, they would provide power capacity and performance of different units and afterwards, the optimal number of units for each technology will be provided. On the other hand, if they want to know the optimal capacity, then they can set the power capacity to 1 kW and the resulting capacities for the other technologies will provide the optimal capacity for each technology, per kW of power.

2.6. Constraints

Constraints are determined by the balance in each node (Fig. 1), power capacity and related performance ratio constraints and any legal restrictions in case further case studies require them.

a. Balance equations in nodes

Following the scheme introduced in (Fig. 1), nine balance equations are defined:

$$\text{Node 1}: \ Q_{h,ice} = Q_{h,ice,s} + Q_{h,ice,d} + Q_{h,ice,ac} \tag{4}$$

$$\text{Node 2}: \ E_{ice} = E_{ice,g} + E_{ice,sys} \tag{5}$$

$$\text{Node 3}: \ E_{ice,sys} + E_g = E_{mc} + E_d \tag{6}$$

$$\text{Node 4}: \ Q_{c,ac} + Q_{c,mc} = Q_c \tag{7}$$

$$\text{Node 5}: \ Q_{h,ice,ac} + Q_{h,b,ac} = Q_{h,ac} \tag{8}$$

$$\text{Node 6}: \ Q_{h,b} = Q_{h,b,d} + Q_{h,b,ac} \tag{9}$$

$$\text{Node 7}: \ Q_{h,ice,d} + Q_{h,b,d} = Q_{h,d} \tag{10}$$

$$\text{Node 8}: \ Q_c + Q_{c,st\_out} = Q_{c,st\_in} + Q_{c,d} \tag{11}$$

b. Power capacity constraints related to the total capacity of the elements

For different energy-generation units the power delivered has to be lower than the maximum power capacity. As an example, power capacity constraint for prime mover units is expressed as follows;

$$n_{ice} \cdot E_{ice} \geq E_d(i,j) \forall (i,j) \tag{12}$$

c. Legal restrictions; defined depending on the regulatory framework in each country

The conditions in the case study are set accordingly. They are only applied when non-FiT prices are considered for the electricity production.

d. Performance equations of different equipment that correlate energy inputs and outputs for every single element. In the case of absorption chillers.

$$Q_{h,ac}(i,j) \cdot COP\_Absorption = Q_{c,ac}(i,j) \tag{13}$$

e. Cooling Storage; the following equation models the storage [21];

$$Q_{st}(j,i-1) + Q_{c,st\_in}(j,i-1) - Q_{c,st\_out}(j,i-1) - Q_{st\_l}(j,i-1) = Q_{st}(j,i) \tag{14}$$

$$Q_{st}(j,1) = Q_{st}(j,24) \tag{15}$$

$$Q_{st}(j,1) = Q_{st}(j-1,1) \tag{16}$$

Eq. (14) models balance equation in the deposit. Eqs. (15) and (16), ensure continuity throughout the annual simulation. These two equations guarantee that the amount of energy is the same at the beginning and at the end of every typical day. Then, under any different typical day set, continuity is ensured. Under this approach, storage operates on a daily basis. Losses from the thermal storage are set at 1% of the energy in the storage.

All constraints equations are expressed in kWh and they have to be satisfied for every time step (every hour i during the typical days j).

The system has been solved with GAMS [25].

2.7. Other parameters

Further to the equations and associated variables and parameters, economic prices of energy flows have to be given. Prices required are:

- price of natural gas (€/kWh),
- prices of electricity acquired from the grid and sold to final users (€/kWh),
- price of heating sold to final users (€/kWh),
- price of cooling sold to final users (€/kWh)

As a summary, the proposed optimisation problem is composed by:

- 1 economic objective function (Eq. (3)),
- 5 decision variables,
- 19 constraint equations (Eqs. (4)–(16)),
- potential additional constraint equation related to legal requirements,
- 17 parameters related to energy flow prices (5), energy performance of the generation equipment (5) and storage system losses (1), unitary cost of the generation equipment and storage system (5) and the unitary cost of the network per linear meter,
- in case commercial units are tested, nominal capacities have to be provided as well (4).

2.8. Sensitivity analysis

Once the system is set, multiple sensitivity studies could be assessed. Thus, potential technology improvement and/or cost reduction can be studied by modifying the associated parameters [26].

Particularly interesting is the analysis of energy prices. So, the proposed system allows the study of feed-in-tariff schemes by modifying the value of the electricity injected into the grid. This analysis may lead to two different exploitation approaches: i) by purchasing energy from the grid to meet electrical demand and the electricity required to produce thermal demand, but also ii) by selling electricity to the grid if the price is favourable (typical under feed-in-tariff schemes). Furthermore, this study could be used to determine the marginal prices for electricity, i.e. those that make the CCHP system more attractive than the conventional solution.

3. Case study

The method is applied to a science and technology park located in Málaga, Spain (36.76 N, −4.40 W). The area brings together companies working in the technology sector. In the area, office buildings are the predominant type of building. The location is characterised by a high energy intensity demand because of the large amount of office buildings with a high occupation rate in a

Fig. 2. Andalusian technology Park extension. Area under study.

limited area. In terms of thermal demand, cooling is prevalent due to the local weather conditions and high internal gains as a result of high occupancy ratios in the buildings.

The analysis of potential integration of the CCHP/DHC facility is performed for an extension area hosting new companies within the park. The total surface of this new area is above 100 ha.

The case study is based on the current and future growth expectations and the urban planning definition [20] (Fig. 2). According to the quantity of companies per unitary area of surface in the consolidated areas of the park, 142 companies are expected to be installed. This means 42 occupied buildings and 10^5 m^2 of conditioning surface.

It is important to note that new areas represent the ideal situation to deploy CCHPs integrated in a district heating and cooling network (DHC) as network costs are lower than in the case of existing urbanised areas. In our case study, it is assumed that the network has already been installed when the area was developed. So, what it is assessed is the viability of the CCHP installation.

When applying the method, it is also assumed that all of the companies are present in the business park. Two strategies can be applied for those years before reaching total expected demand:

a. Provide energy from conventional technologies that will be used as back-up suppliers afterwards;
b. Increase power capacity by adding units as the demand increases.

3.1. Parameters

According with the definition of the optimisation problem, values of parameters selected for the study case are presented for the categories: energy price (Table 1), generation equipment (Table 2), and the cold storage (Table 3).

Heating and cooling prices have been set as discussed in [27]. In particular, prices have been set based on the cost of producing an energy unit from conventional technologies. For the case of Spain, final electricity price is set around 0.2 €/kWh. Assuming a coefficient of performance for individual heat pumps between 3 and 5, cost for final user ranges between 0.067 and 0.04 €/kWh$_{th}$. If heating is produced by natural gas boilers, the cost for final users is 0.067 €/kWh$_{th}$ considering a boiler performance of 0.9 and natural gas price of 0.06 €/kWh. Based on these pricing assumptions, prices are selected to ensure competitiveness of the installation (Table 1).

Electricity prices are explained in detail in the section dedicated to the regulatory framework as it is affected depending on the policy scenario considered.

Table 1
Energy cost parameters.

Parameter	Value	Unit
Heating sold to final users	0.04	€/kWh
Cooling sold to final users	0.04	€/kWh
Natural gas	0.042	€/kWh

Table 2
Generation equipment. Performance ratios & unitary costs.

Equipment	Parameter	Value	Unit
ICE units	Investment cost	800	€/kW
	Ratio fuel/electricity	2.56	–
	Ratio Heat/Electricity	1.05	–
Natural gas back-up boiler	Investment cost	37.5	€/kW
	Ratio fuel/heat	0.905	–
Electric chiller	Investment cost	90	€/kW
	Coefficient of Performance	2	–
Absorption chiller	Investment cost	125	€/kW
	Coefficient of Performance	0.7	–

Table 3
Cold storage system. Losses rate & unitary costs.

Equipment	Parameter	Value	Unit
Storage	Investment cost	48	€/kWh
	Losses rate	1	% of stored energy

3.2. Spanish regulatory framework

Spain is an interesting country for testing the proposed method. Before 2013, supporting schemes for sustainable production were in place [28], After that year, existing FiT schemes were cancelled to guarantee the stability of the national energy sector [29]. From this energy policy transition, two main scenarios emerge.

3.3. FiT scenario

FiT schemes were available for co-generation installations. According to [28], the remuneration set in Spain for electricity produced by co-generation systems was 0.12 €/kWh. This price could vary slightly depending on the total installed capacity in case of installations larger than 0.5 MW$_{elec}$. In this study, the indicative reference price is used.

3.4. Non-FiT scenario

Under this scenario, the energy produced is sold in the free market with no FiT associated, being the electricity price established at 0.04426 €/kWh according to the average value during the reference year 2013 [30] (Table 4).

Based on internal communication from energy retail companies and taking into consideration the mix of uses in the studied area, as well as the size of the installation, the price of electricity acquired from the network has, as a result of a potential negotiation, been

Table 4
2013 Electricity prices in Spain [31].

Electricity prices	FiT	Non-FiT
a. Electricity produced and injected into the grid (€/kWh)	0.12	0.04426
b. Purchased electricity		
Industrial (€/kWh)	0.09	0.09
Residential (€/kWh)	0.15	0.15
Considered weighted price (€/kWh)	0.10	0.10
c. Delivered electricity[a]	0.10	0.10

[a] Delivered electricity has been established as the same as that purchased from the network to simplify the understanding of the impact of FiT schemes.

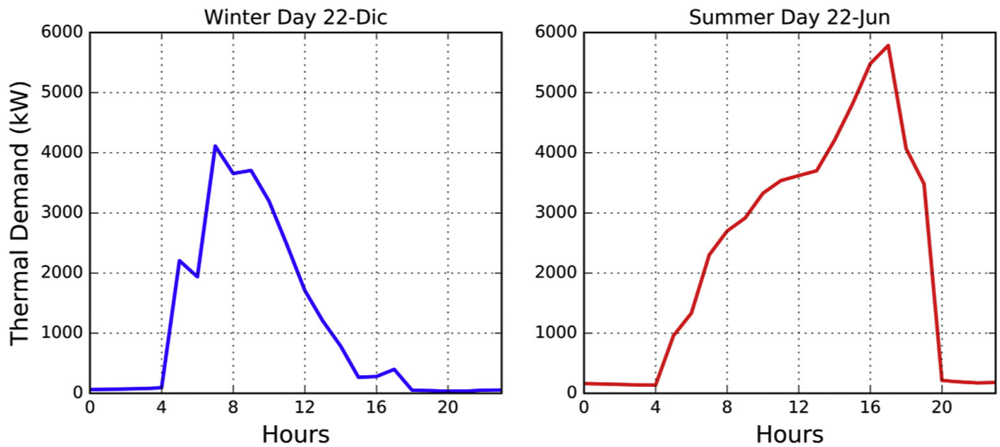

Fig. 3. Load profile for a winter day (left) and a summer day (right).

established at 0.10 €/kWh. It has been assumed that, based on market prices, the price of the electricity purchased from the network is the same as the purchasing cost for final users, so electricity does not produce any additional benefit if installation managers act as electricity retailers. In any case, the method allows setting different energy prices for purchased and retail electricity. In this case, the method is applied to specifically assess FiT impact.

FiT scenario requires an additional constraint equation, set by Spanish regulator to guarantee efficiency and avoid deliberate production of electricity. Specifically, installation under the FiT regime has to comply with the so-called electric equivalent performance to guarantee a balance between electricity production and heating and cooling utilisation [28]. The indicator, called 'equivalent electric performance' (REE), is defined in Eq. (15). For this type of installation REE lower limit value is 0.55.

$$REE = \frac{E}{Q - \frac{V}{RefH}} \geq 0.55 \tag{17}$$

where:

REE ≡ electric equivalent performance
E ≡ electricity generated (kWh)
Q ≡ heat of combustion from fuel (kWh)
V ≡ useful heat production
RefH ≡ Typical heating efficiency

4. Results

In this section, outcomes from the method presented in section 2, including energy demand and selection of typical days and the resolution of the optimisation problem for the base case scenarios, are presented when applied to the case study described.

4.1. Energy demand

The models used to simulate energy demand were developed by authors in previous works [20]. The estimated energy demand is based on the current mix of uses in the consolidated area. Mainly office and industrial buildings have been modelled. In particular, 62.38% of the built area is occupied by office buildings. This fact leads to an energy demand pattern characterised by a high variance in a daily basis (Fig. 3).

This energy behaviour, which is typical for office buildings, is expected to lead to a combined production where CCHP system covers base load demand while boiler covers the difference.

This pattern, characterised by high peak demand for a limited number of hours, is also reflected in the load duration curves. These curves show a rapid decrease to less than 10% of peak values within 2000 h (Fig. 5). Ideal scenarios for CCHP present steadier load duration curves that maximise the performance of the production units. For that reason, common strategies try to cover load-based demand in order to guarantee the maximum number of hours during the year with the CCHP in operation [32]. An alternative option is to provide energy for residential areas. Residential demand patterns — low demand during the middle of the day and high early in the morning and at nights — are complementary to the tertiary sector [33]. Thus, the final demand pattern may stabilise demand curves on a daily basis. However, the area initially covered by the DHC facility is a long way from the closest residential (~2 km) so it is unlikely to be an affordable solution.

Concerning electricity demand, it has been calculated according with typical electric appliances used for the tertiary sector. This electricity demand does not include demand derived from HVAC systems (Fig. 4).

After obtaining the detailed energy demand patterns for every

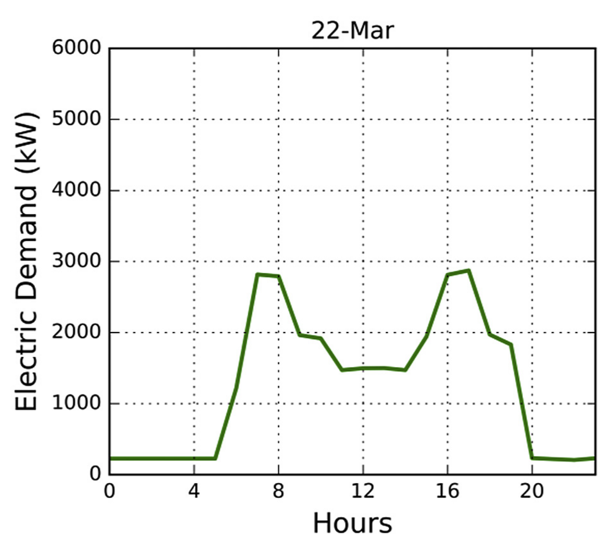

Fig. 4. Daily electric load profile.

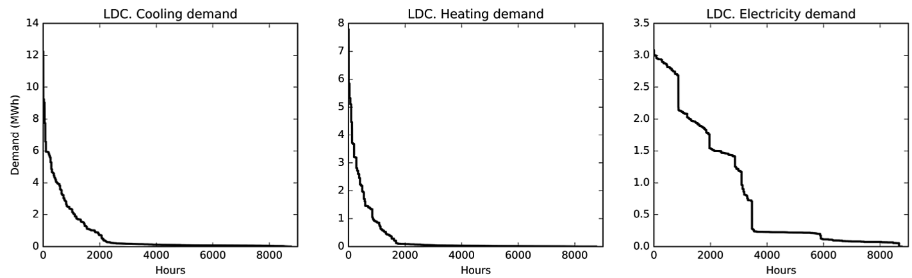

Fig. 5. Generated load duration curves (LDC) for the selected number of typical days. Cooling demand (a), heating demand (b) and electricity demand (c).

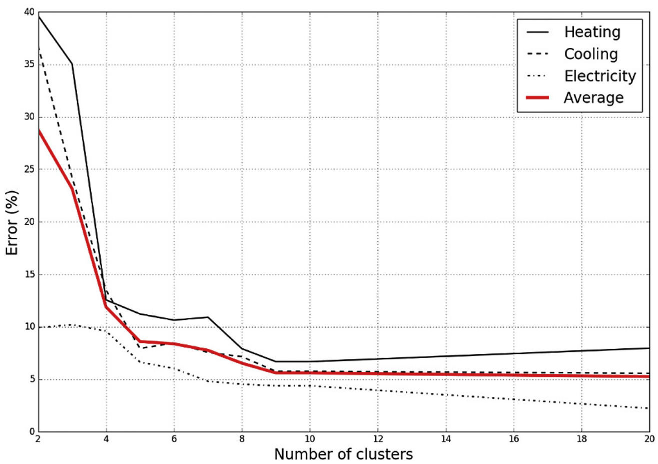

Fig. 6. Analysis of clustering exercise to reduce sampling data in the optimisation problem.

energy vector: electricity, heating and cooling, clustering techniques are applied. The requested number of typical days is 10 plus the 3 days where peak demand occurs. This number guarantees an error lower than 10% of the original demand. In particular, for each energy demand; heating, cooling and electricity, the error is 7%, 6% and 4% respectively (Fig. 6).

With these 13 typical days, the final dimension of the optimisation problem is 312 instead of the original 8760.

4.2. Base case scenarios

Once the demand has been calculated, the results from the two base case scenarios are obtained solving the optimisation problem for the different energy pricing schemes introduced in section 3.

4.3. FiT scenario

The optimal solution is driven by maximising electricity production according to the high price of the electricity injected into the network ($E_{ice,g}$) compared with the electricity price purchased from the grid (E_g) (Fig. 1).

According to the model assumption, annual operation has not been limited. Potential maintenance operations have been modelled via the 'fam' factor introduced in previous sections. This means equipment is allowed to operate for 8760 h per year. Thus, in this scenario ICE is delivering energy every hour of the year, producing a total amount of 7.1 GWh per year, being all this electricity injected into the grid.

To take advantage of the energy produced by the ICE, absorption technology is included in the solution. Total energy produced by

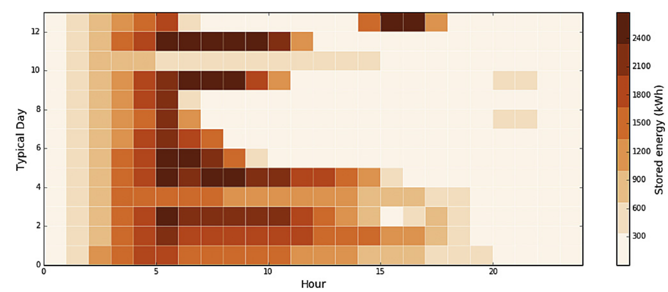

Fig. 7. Stored energy. FiT scenario.

absorption chiller is 2.3 MWh, which represents 35% of total cooling demand.

Concerning storage, it shows a capacity of 600 kWh, which is a higher value compared with the non-FiT case. It stores energy especially in the first hours of the day to reduce peak summer demand (Fig. 7).

Regarding heating demand, ICE produces 47% of heating demand. However, the boiler power capacity required is 90% of peak heating demand. Therefore, ICE is covering base load heating demand while the boiler is covering the peak demand, which is the typical case in a district heating system.

It is worth mentioning that the optimal solution reaches the legal restriction (REE = 0.55). This behaviour was expected since this condition limits the production of electricity, which is the largest source of income for the system.

In the case of cooling demand, 35% is covered by absorption chillers and 65% by mechanical chillers.

In terms of peak demand, the mechanical chiller power capacity represents 85% of peak cooling demand, while the absorption chillers only 5%. Thus, the effect of the storage is a reduction of 10% of capacity based on the peak cooling demand.

Table 5
Optimal solutions for the base case scenarios.

Parameter	Non-FiT	FiT
Incomes from the electricity injected in the grid (k€)	7.7	851
Electricity demand incomes (k€)	737	737
Heating demand incomes (k€)	119	119
Cooling demand energy incomes (k€)	263	263
Opex (k€)	1179	1788
Capex (k€)	76	102
Installed capacity (MW). Back- up boilers	7.6	6.9
Installed capacity (MW). ICEs	0.15	0.8
Installed capacity (MW). Absorption chillers	0.1	0.6
Installed capacity (MW). Compression chillers	12	10.4
Storage size (MWh)	0.6	2.7
Annual profits (k€)	**−128**	**80**

4.4. Non-FiT scenario

Under this scenario, the price of the electricity injected in the grid is lower than the cost of purchasing electricity from the grid. This fact modifies the optimal solution. Then, the investment in CCHP elements is reduced (ICEs and absorption). Thus, mechanical chiller provides 90% of the cooling demand and the boiler 84% of heating demand.

In terms of power capacity, mechanical chillers represent 97% of the peak cooling demand (absorption chiller 1%) and the boiler 98% of the peak heating demand. In this case, the storage system reduces the installed capacity by 2% of the peak cooling demand.

Concerning revenues, as shown in Table 5, they are negative for the non-FiT scenario but positive for the FiT scenario. Then from an energy policy perspective, the question is what the price of the FiT should be to ensure positive revenues and then the penetration of these solutions. To determine price evolution, the optimal solution is calculated for electricity prices ranging from a non-FiT price (0.04426 €/kWh) to 0.14 €/kWh (Fig. 8).

The minimum electricity price that makes the benefit positive is 0.108 €/kWh. Therefore, for this particular case, energy incentives are required to guarantee the feasibility of the installation. It is also important to mention that the marginal price which makes the benefit equal to zero is close to the FiT price set in this study case. Therefore, it could be stated the FiT is already set at an appropriate level.

5. Sensitivity analysis

Beyond the results presented, to evaluate future energy policy support, it is important to understand the impact of parameters and assumptions considered in the model. The main assumptions relate to the investments, operational parameters and amortisation periods. Variations in these parameters modify the marginal price of the electricity that makes the CHP installation feasible.

5.1. Investment analysis and amortisation period

To evaluate the impact of the investment, the total sum of

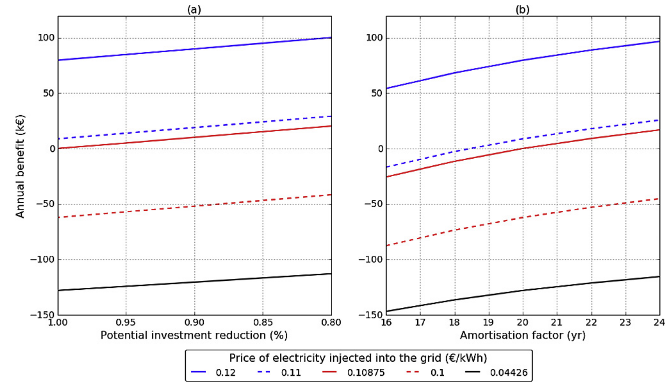

Fig. 9. Effect of the potential investment reduction (a) and amortisation factor (b) on the annual benefit.

elements included in the investment term has been reduced by a factor between 0.8 and 1 (base case scenario) affecting all the purchased elements. This range was selected according to reviewed projections [34]. The investment effect is decoupled from the energy performance although a combined effect in the long term could be expected. The income increases by ~100 k€ when the investment diminishes by 1%.

However as displayed in Fig. 9, under non-FiT schemes, even with an investment reduction of 20%, the CCHP is still not profitable.

In the case of the amortisation period (Fig. 9b), its value (yr^{-1}) has the same impact as a global reduction of the investment. One additional year of lifetime represents an increase of 10 k€ of yearly benefits.

5.2. Operational parameters

To understand the impact of the assumptions concerning the performance of the different units, parameters related to absorption, compression chillers and back-up boilers have been modified based on the commercial performance rates. It should be noted that

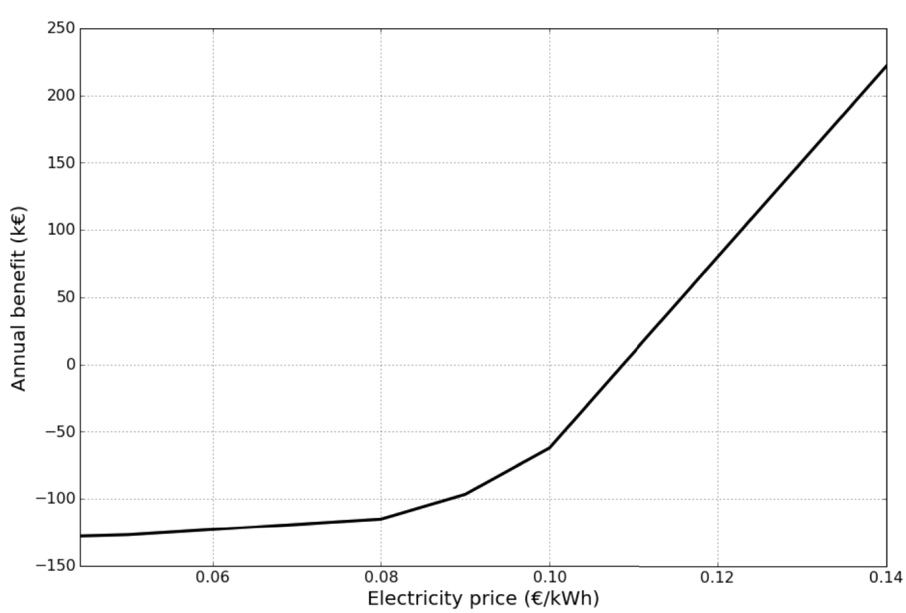

Fig. 8. Effect of the electricity price on annual benefits.

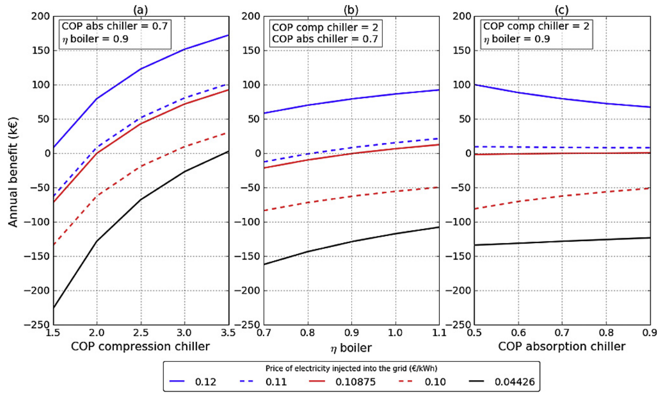

Fig. 10. Changes in the annual benefit according to different energy performances for (a) compression chiller, (b) back-up boiler and (c) absorption chiller.

investment cost is fixed. Thus, the results reflect only energy performance improvements.

The improvement in the performance of compression chiller increases the annual benefit (Fig. 10a). In particular, for those scenarios with FiT prices (electricity price different from 0.04426 €/kWh) the benefit increases by 56 k€. This high impact in the benefit is because cooling is mainly produced by compression chillers (90%).

In the case of the boiler (Fig. 10b), optimal solutions follow the same pattern as the compression chiller cases. However the impact is lower. For FiT schemes, the benefit increases by 8.5 k€. In the non-FiT case (electricity price equals to 0.04426 €/kWh) the benefit increases by 13.5 k€ because energy production relies mainly on boilers (84% of heating demand).

Particularly interesting is the case of the absorption chillers (Fig. 10c). For the scenario where electricity is set at 0.12 €/kWh, an increase of the absorption chiller performance produces lower benefits. This effect is the result of the combination of capital costs and operation costs together with the REE restriction.

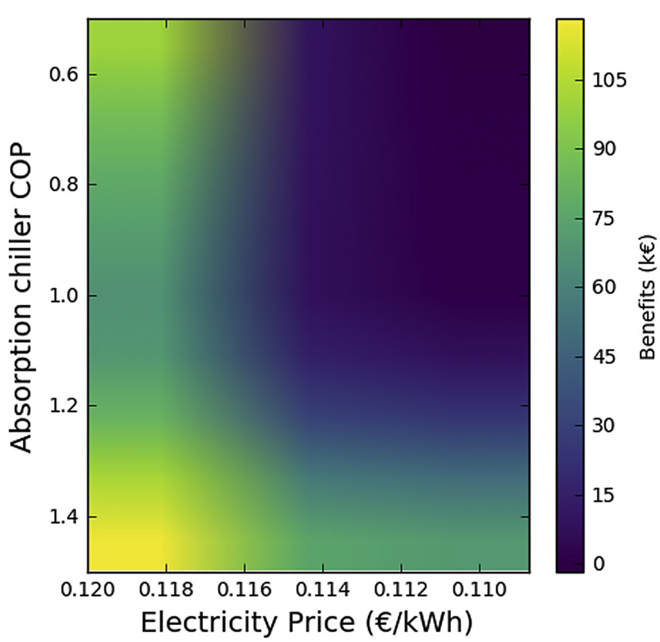

Fig. 11. Evolution of benefits by modifying absorption chiller COP and the price of the electricity injected in the grid.

Regardless of investment costs, producing thermal energy is cheaper by conventional technologies. Thus, the benefit of producing heating from a boiler is more than two times cheaper compared with the ICE (0.9 $€_{income}/€_{opex}$ vs. 0.4 $€_{income}/€_{opex}$). In the case of cooling, compression chiller production is 4 times cheaper than an absorption chiller (0.8 $€_{income}/€_{opex}$ vs. 0.2 $€_{income}/€_{opex}$). This fact, combined with the highest CAPEX derived from the ICE acquisition and legal constraints, produces negative effects in the benefits even if some parameters are improved.

If the performance of the absorption chiller is increased even further, to a level that is typical for double effect absorption, then the annual economic balance becomes positive after a COP of 0.9 (Fig. 11).

As it can be observed, once the COP of the absorption chiller is higher than 1, the global benefit of the installation raises again. Then, legal constraints have to be properly designed in order to avoid the promotion of low efficient equipment.

5.3. Changes in demand

The long-term stability of energy demand is essential to define appropriate FiT schemes and to guarantee energy systems feasibility. In most cases, but especially in science and technology hubs, the economic environment affects companies in terms of the number of employees and also their long-term presence in the area, which then affects energy demand.

Steady demand is essential to design district heating and cooling business models in the long term. There are cases where CHP systems have been sized to provide energy for areas with deployment expectations that finally were not met. For those cases, economic losses were considerable. Thus, it is also important to assess the impact of potential energy demand reduction to set useful contingency plans within business models.

To assess the impact of a potential decrease in energy, the initial demand values are used to solve the optimisation problem and therefore, sizing equipment based on this initial demand as well. Having this initial investment fixed, lack of incomes derived from the demand decline, both to the users in the area and the potential electricity injected in the grid, are deducted.

To cover this analysis, the same potential reduction is applied to heating and cooling demand as well as the electricity demand. As a result, there is a linear relation between the demand evolution and annual benefits (Fig. 12).

In the non-FiT scenario, the benefit increases by 20%. This improvement is derived from a lower CAPEX and OPEX as a result of lower demands. The opposite effect takes place for the FiT scenario.

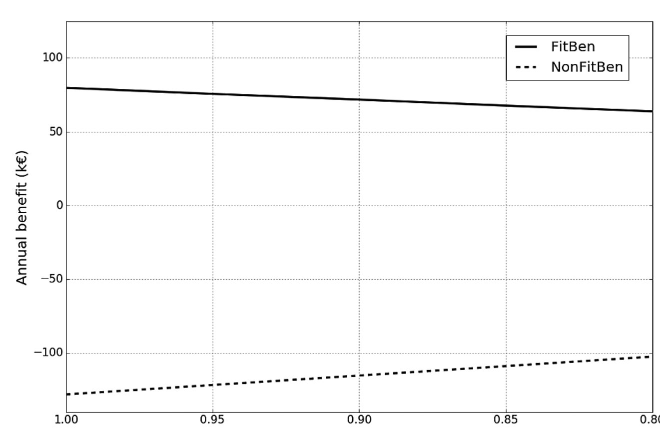

Fig. 12. Effect of demand reduction.

A reduction of 20% in the benefits is observed due to the smaller ICE required, which in turn reduces the income from electricity injected in the grid.

For this reason, investors initially prefer to invest in consolidated areas, where energy demand is well known. However, these areas usually require higher network construction costs.

6. Conclusion

Combined heat and power systems are an efficient solution to satisfy energy demands, especially in areas characterised by high intensity energy requirements.

Traditionally, taking into consideration the high-risk investment required because of the cost of the installation and the stability of the energy demand in the long term, energy policies have been designed to promote the penetration of these installations. However, various energy market issues meant that supporting policies were cut, jeopardising the feasibility of DHCs or even CCHP.

To facilitate energy investor decision making, this paper presents a method to optimise the size of potential DHC/CCHP projects.

As it has been presented in this work, CCHP still needs policy support to guarantee its penetration in the energy market. However due to limited financial sources available, it is important to properly design any support scheme by guaranteeing the benefit for both energy investors and the public. In this regard, the method also allows policymakers to define appropriate feed-in-tariffs.

In this paper, the analysis of support schemes in the case study demonstrates it was well-defined. In addition, it is also demonstrated that FiTs improves economy and efficiency of local systems by promoting the implementation of CCHP together with thermal storage.

Nonetheless, the adequate definition of FiTs varies based on parameters selected for a particular project. In the case study, coefficient of performance of mechanical chillers is the most sensitive parameter that may modify economic results by more than 100 k€ per unitary COP increment. On the contrary, in the case of heating production, an improvement in the boiler performance has 4 times less impact compared to mechanical absorption chillers. These effects are linked to demand patterns.

Concerning energy demand, it plays an important role in achieving feasibility as it has been demonstrated. Firstly, for cases where the energy demand varies significantly on a daily basis, the only opportunity for CCHP systems relies on the production of a base load demand to guarantee the installation's steady performance. Secondly, demand evolution uncertainty may also prevent some investment, especially in tertiary areas linked to economic activities where demand may vary significantly.

Finally, the case study proves that under specific investment and operational cost schemes, legal constraints defined to foster efficiency may have a negative effect. The effect on the absorption chillers recommends defining ad-hoc legal constraints for every project.

Therefore, even if energy technologies prices and performances improve, public-private cooperation is essential to accomplish new CCHP/DHC projects.

Disclaimer

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Nomenclature

C_X	cost of infrastructure including the energy network (€)
C_z	energy cost of energy flow z (€/kWh)
E	Electricity generated (kWh)
E_d	Electricity available to meet electricity demand (kWh)
E_g	Electricity purchased from the grid (kWh)
E_{ice}	Electricity produced by ICE units (kWh)
$E_{ice,g}$	Electricity injected in the grid (kWh)
$E_{ice,sys}$	Electricity to meet system requirements (kWh)
E_{mc}	Input electricity for mechanical chillers (kWh)
ELDC	error in the duration load curve
fam	Maintenance and amortisation factor (yr^{-1})
i	hours
I_y	Investment per technology y (€)
j	number of typical days
LDC	Load duration curve
Q	Heat of combustion from fuel (kWh)
Qc	Total cooling produced (kWh)
$Q_{c,\ ac}$	Cooling produced by absorption chillers (kWh)
$Q_{c,\ d}$	Cooling to cover demand (kWh)
$Q_{c,\ mc}$	Cooling produced by mechanical chillers (kWh)
Q_{c,st_in}	Cooling to energy storage (kWh)
Q_{c,st_out}	Cooling from energy storage (kWh)
$Q_{h,ac}$	Heating supplied to absorption chiller (kWh)
$Q_{h,b}$	Heating produced by back-up boiler (kWh)
$Q_{h,b,ac}$	Heating produced by back-up boiler to supply absorption chiller (kWh)
$Q_{h,b,d}$	Heating produced by back-up boiler to cover heating demand (kWh)
$Q_{h,d}$	Heating to cover demand (kWh)
$Q_{h,ice}$	Heating produced by ICE units (kWh)
$Q_{h,ice,ac}$	Heating supply to absorption chiller (kWh)
$Q_{h,ice,d}$	Heating produced by the ICE units to cover heating demand (kWh)
$Q_{h,ice,s}$	Surplus heating produced by ICE units (kWh)
Q_{st}	Cooling energy stored (kWh)
Q_{st_l}	Storage losses (kWh)
REE	Equivalent electric performance (−)
RefH	Typical heating efficiency (−)
n_{ac}	number of absorption units
n_b	number of back-up boiler units
n_{ice}	number of prime mover units
n_{mc}	number of mechanical units
n_{st} c	thermal capacity of the storage (kWh)
V	Useful heat production (kWh)
X_z	energy flow z (kWh/yr)

Subscript

ac	absorption chiller
b	boiler
c	cooling flow
d	demand
e	typical days base
g	grid
h	heating flow
ice	internal combustion engine
mc	mechanical chiller
o	original
s	surplus

st	storage
st_in	to storage
st_l	storage losses
st_out	from store
th	thermal
y	technology
z	energy flow

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