UNIVERSIDAD DE MÁLAGA

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DEPARTAMENTO DE MÁQUINAS Y MOTORES TÉRMICOS

PH.D.THESIS

TECHNO-ECONOMIC ASPECTS OF DISTRICT HEATING AND COOLING NETWORKS SUPPLIED BY COMBINED HEAT AND POWER TECHNOLOGIES

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A mi familia

“Fall in love with some activity, and do it! Nobody ever figures out what life is all about, and it doesn’t matter. Explore the world. Nearly everything is really interesting if you go into it deeply enough. Work as hard and as much as you want to on the things you like to do the best. Don’t think about what you want to be, but what you want to do. Keep up some kind of a minimum with other things so that society doesn’t stop you from doing anything at all.”

Richard Feynman

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A Juanito.

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Nomenclature

CSP	Concentrated solar power
PV	Photovoltaics
EV	Electric vehicles
PLF	Partial load factor
PLR	Partial load ratio
CAPEX	Captial expenditures
DH	District heating
RES	Renewable energy sources
DHC	District heating and cooling
CCHP	Combined cooling, heat and power
CCGT	Combined cycle gas turbine
STP	Science and technology parks
NUC	Nuclear
ICE	Internal combustion engine
FiT	Feed-in-tariffs
SH	Space heating
SC	Space cooling
SO	Single objective

MO	Multi objective
MILP	Mixed integer linear programming
COP	Coefficient of performance

European countries:

AT	Austria
BE	Belgium
BG	Bulgaria
HR	Croatia
CY	Cyprus
CZ	Czech Republic
DK	Denmark
EE	Estonia
FI	Finland
FR	France
DE	Germany
EL	Greece
HU	Hungary
IE	Ireland
IT	Italy
LV	Latvia
LT	Lithuania
LU	Luxembourg
MT	Malta

NL	Netherlands
PL	Poland
PT	Portugal
RO	Romania
SK	Slovakia
SI	Slovenia
ES	Spain
SE	Sweden
UK	United kingdom

Chapter 1

Aim and scope

This thesis focuses on the potential role of district heating and cooling networks fed by combined heat and power technologies in the energy system. District heating and cooling solutions can unlock multiple energy options to decarbonise not only the heating and cooling sector but the power sector, too. They represent an energy solution to achieve the sector coupling that has been acknowledged as a key feature of the future energy system. In this regard, sector coupling allows and enhances the utilisation of larger amounts of renewable sources, the increase of the efficiency of the energy system, and the reduction of CO_2 emissions.

However, due to its inherent complexity, involving technical and economic aspects as well as political and social factors, new methods are required to facilitate the decision-making and promote the deployment of thermal networks. This is especially needed in southern European countries where the penetration of district heating and cooling networks remains limited. On the contrary, northern European countries have a long tradition in the deployment of thermal networks — usually heat driven networks — creating a strong position for future energy challenges. What is more, a common misconception is to link the success of thermal networks to specific climate conditions. On the contrary, successful examples demonstrate that adequate project design guarantees the success of thermal networks despite climatic conditions.

This thesis aims to provide models and methods that can be used to facilitate the penetration of thermal networks fed by combined heat and power technologies. We focus on Southern energy patterns and we consider technical, economic and policy aspects. The proposed methods and results are intended to be relevant to policymakers, energy planners and, energy investors.

Research questions

In this section we introduce the main research question and the four sub-questions defined for this thesis:

What are the methods and models needed to facilitate the penetration of thermal networks, fed by combined heat and power, in South Europe?

The sub-questions are formed as follows:

1. What is the state of the art of district heating and cooling networks and the current modelling approaches followed?

   The first research question aims to present a summary of relevant works that tackle the modelling and analysis of district heating and cooling networks, including different approaches. Since the methods presented in this thesis are based on energy modelling techniques, focus will be given to different approaches followed in current and past literature. (Chapter 3)

2. What is the modelling framework needed for the development of the decision-making process to plan, size, prioritise investments and the operation of district heating and cooling networks in the mid- and long-term?

   The aim of this work was to develop a modelling framework to facilitate the decision-making process regarding the planning, sizing, investment and operation of district heating and cooling networks in the mid-to-long term. This modelling framework focuses on applications with both heating and cooling needs. It is also intended for new urban areas, where the deployment of thermal networks can be done more efficiently from the urban planning phase reducing the cost of the network construction and enabling the design of buildings in the area according to the specific energy supply option. (Chapter 4, Section 4.1)

3. What is the role of feed-in-tariff supporting schemes on the viability of a district heating and cooling production system?

   With this research question we aim to provide a method to design appropriate energy policy support in the form of feed-in-tariffs schemes to guarantee the feasibility of district heating and cooling networks fed by combined heat and power technologies. Put in a different way, the method provides the optimal size of the energy equipment given a fixed feed-in-tariff scheme in place. Thus, both policymakers and energy investors can take advantage of the proposed method that can improve the understanding of the operation of thermal networks at district level, contributing to the establishment of public and private agreements needed to unlock the potential of district heating and cooling solutions. (Chapter 4, Section 4.2)

4. What is the joint effect of centralised cogeneration plants and thermal storage on the efficiency and cost of the power system?

   This chapter was developed in the context of a growing share of energy generation from renewable sources within the power system. This trend is raising the need of sector coupling that enables the utilisation of a wider portfolio of energy technologies and thus accommodating a higher amount of intermittent renewables sources. In this regard, the heating sector — accounting for the 50% of the total final energy used in Europe and characterised by low efficiencies represents a great opportunity to couple with the power sector. This opportunity is highlighted in the European Strategy on Heating and Cooling. In this part of the thesis the conversion of a combined cycle gas turbines (CCGT) into a CHP operation mode in combination with centralised thermal storage option are modelled providing both electricity and heating by the connection to a thermal network. Thus, the model allows the evaluation of the impact of these solutions on the power system, especially regarding the integration of high shares of renewables. The model approach also allows the evaluation of how the new generation of district heating systems contributes to the utilisation of these types of plants. The integration of the proposed model on a power system dispatch model permits the evaluation of the cost reduction brought by the heating and electricity coupling via CHP and thermal storage. (Chapter 4, Section 4.3)

The case studies presented as answer to the proposed research questions aim to support that, even with completely different energy demand profiles and requirements, district heating and cooling networks together with combined heat and power technologies can play an important role in the energy system even in areas with relatively warm winters and hot summers.

Structure of the thesis

The current work has been developed as a compendium of articles published in relevant scientific journals. The original versions of the scientific articles are included in section A of this document.

The thesis is organised in the following chapters:

1. Chapter 2 explains the importance of district heating and cooling networks in the future energy system. The chapter examines the framework and provides the evidence of thermal network solutions. In order to reply to the main research question set, we need to comprehend the nature of these solution and the interest in deploying them.

2. Chapter 3 covers the main trends in literature. An exhaustive review was carried out in order to develop the scientific framework and ensure the contribution's position in the state of the art.

3. Chapter 4 introduces the results obtained from the scientific articles published and further discusses the interpretation of the results.

4. Chapter 5 concludes this doctoral thesis. The findings are brought together to draw conclusions. Moreover, contributions to both policy and practice, and recommendations for future research are discussed.

5. Scientific publications can be consulted in annex A of the document.

Chapter 2

Introduction

Policy background and shifting towards the concept of the smart energy system

The European Commission has defined ambitious energy targets to achieve the decarbonisation of the energy sector in Europe. For 2030 the following goals have been set [1]:

1. A 40% cut in greenhouse gas emissions compared to 1990 levels
2. At least a 32%[1] share of renewable energy consumption
3. At least a 27% energy savings compared with the business-as-usual scenario.

In order to accomplish these goals, a holistic integration of different sectors such as electricity, heating, cooling, buildings and transport has to be achieved, leading to the implementation of the Smart Energy Systems [2]. This shifting approach is an essential step in order to accommodate a growing renewable energy generation — especially wind and solar — and subsequent requirement for a more flexible demand, including demand reduction, demand response strategies and energy storage [3]. In addition to the sustainability of the future of the energy system, this transition will pave the way to promoting local energy investing that can create approximately 10 million jobs in the EU [4]. Thus, the future of the smart energy systems relies on the following elements: new conversion and storage

[1] Recently approved as a provisional agreement that has to be endorsed by the European Council and the European Parliament, raising the previous target by 5%

technologies and a flexible demand. Figure 1 depicts a layout of the future energy system in which fossil fuels are completely replaced by renewable energy sources and bioenergy. Storage solutions play a substantial role in the future energy system.

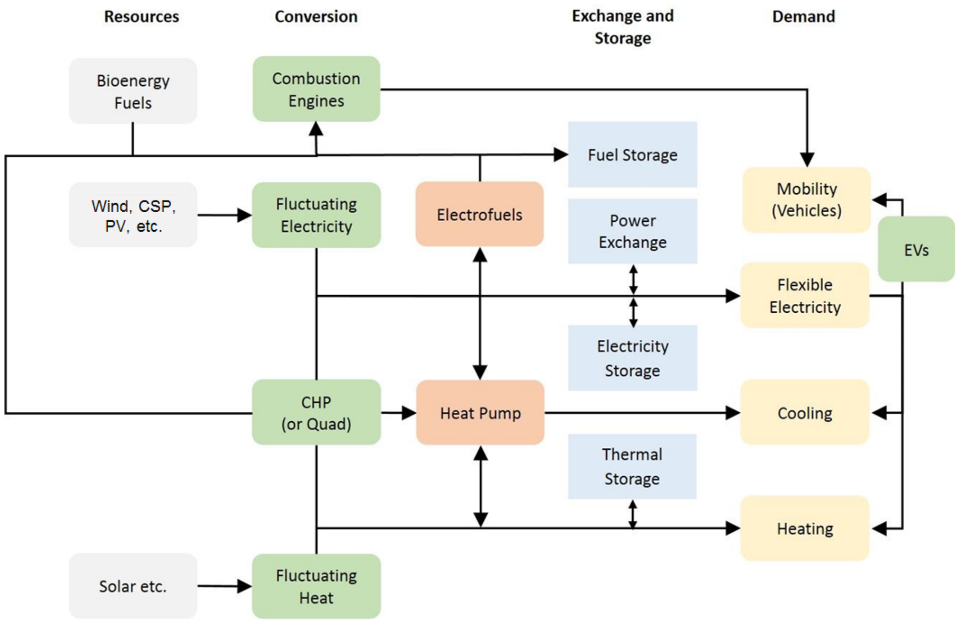

Figure 1: Future smart energy systems layout based on 100% renewable resources [5]

Advantages and disadvantages of thermal networks

Under this new paradigm, energy solutions at a district level have been highlighted as one of the most important key enabling approaches to make the energy transition possible – Heating and cooling strategy!!!.

District solutions aim to take advantage of the synergies between aggregated energy demands and centralised energy generation strategies in a cost-effective way. They could accommodate the aforementioned high shares of renewable generation [6], link centralised energy generation with the demand side increasing the efficiency of the energy system and, enable flexibility options via the deployment of centralised storage solutions. They embrace solutions such as micro-grids, storage options or thermal networks among others.

Concerning thermal networks, which deliver heat and cold, they could play a relevant role in the implementation of the Smart Energy Systems. Thermal networks allow the utilisation of unexploited energy sources such as waste heat deriving from industrial processes. They can enable higher-efficient centralised generation compared to decentralised options. Moreover, thermal networks can level the playing field to the development of flexible energy production strategies enabling the use of centralised thermal storage solutions — 10 times more cost-effective compared to electric storage [7].

In terms of energy efficiency improvements, thermal network solutions provide a more stable operation of the generation systems compared to decentralised systems, in which the frequency of start-ups and shut-downs is higher when supplying individual demands. Aggregated demands enable steady operation and thus limit low efficiency operation. Figure 2 shows the effect of a low capacity factor in the efficiency for a water-to-water heat pump with fixed capacity.

In addition to the efficiency improvement, large energy generation equipment reduces the marginal cost of the installed capacity. Thus, from an economic perspective, the CAPEX of a centralised solution is smaller for a given installed capacity (Figure 3).

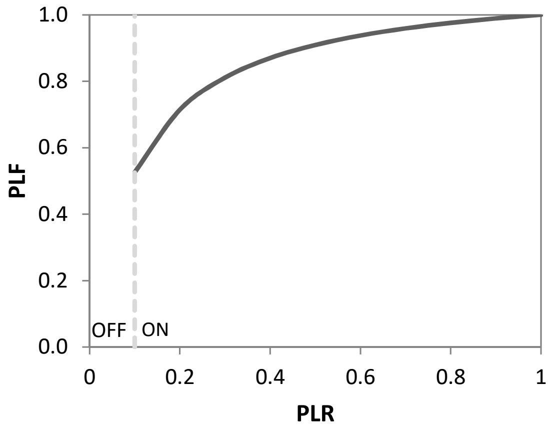

Figure 2: Partial load factor (PLF) as a function of the part load ratio (PLR), assuming fixed temperatures of operation [8]

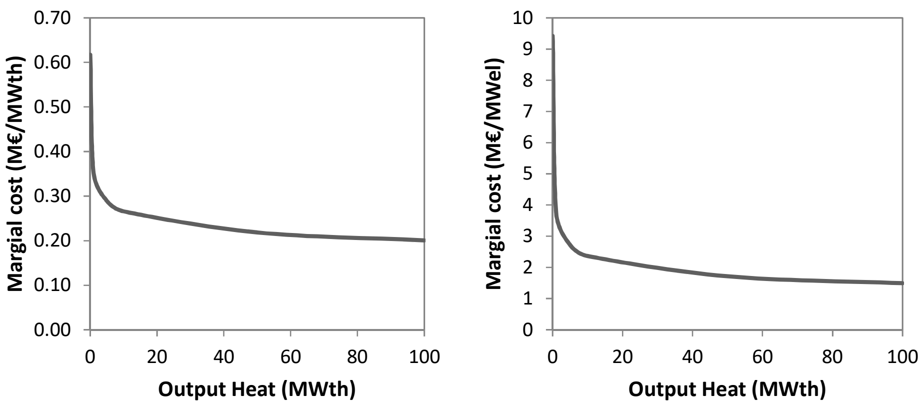

Figure 3: Marginal CAPEX cost of electric heat pumps (left) and natural gas fired turbines in combined cycle configuration (right) [9]

The downside of district heating and cooling networks is that they require an adequate and long-term energy planning strategy as they call for high upfront investments — especially those related to the construction of the network itself, more expensive than electric networks — and, lead to significant thermal transmission losses.

The high upfront investments costs and the characteristics of the energy demand, which are defined by the energy demand density and peak values among others, affect the economics of the thermal networks. Especially because the high dense populated areas are those that offer feasible opportunities for district heating and cooling networks [10]. However an adequate definition of the business case enlarges the adequacy of thermal networks beyond high energy dense areas. In this sense, recent research proves that feasible heat transmission can cover distances beyond 50 km for specific energy market conditions [11].

To provide readers with orders of magnitudes, following the method proposed by Persson and Werner in [12], and given a scenario defined by a building density of 0.4 sq-m of gross floor area per sq-m of land, and specific heat demand of 150 kWh per sq-m of gross floor area and year, the total piping cost is estimated at 8 M€.

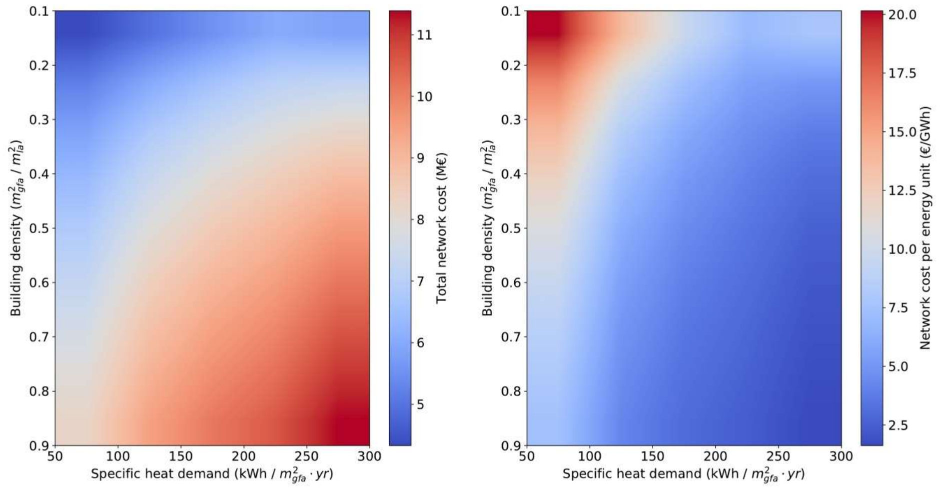

Figure 4: Thermal network investment cost for different building density and specific heating demand [9,12]

Concerning the long-term strategy and according to the literature review performed in this work, thermal networks can be under operation for 60 years [13]. To make the network investment profitable, given the associated high investment shown in Figure 4, the level of energy supplied should be guaranteed. Therefore specific business models have to be defined either by agreements with public administrations or by long term user engagement via attractive conditions. Nowadays, there are few examples in which the networks compete with conventional heat supply, as the case of the city of Barcelona, which also covers cooling needs, with a successful rate of end-user connections. In other cases, the public support is essential at least at the first stages of network deployment, before reaching the critical number of clients.

Regarding thermal transmission losses, many works have shown the benefit of decreasing supply temperatures not only because of the reduction of losses but also because it enables the utilisation of low quality energy sources [11, 14, 15].

In this regard, thermal networks have evolved from grids based on steam as heat carrier to low temperature (30 to 70 °C), grids using water as carrier. From the initial steam based networks, a temperature reduction has been pursued. Thus, the 2nd generation of thermal networks used pressurised hot water over 100 °C, while the 3rd generation operates with temperatures below 100 °C.

The new generation, 4th, of district heating networks are operating with a decreased temperature of supply to the order of 30 to 70 °C minimising inefficiencies in the transmission of energy and also widening the range of supply options and demand requirements, leading to the concept of smart thermal grids that contribute to the implementation of the broader concept of smart energy systems [14, 16, 17].

Overview of district heating networks in Europe

Despite the potential advantages and opportunities that thermal networks bring into the future energy systems, their deployment varies significantly across Europe. In the case of district heating networks, their penetration ranges from countries with no district heating networks to others with a realised capacity of the order of 50% of the thermal demand, as the case of Denmark [18] (Figure 5).

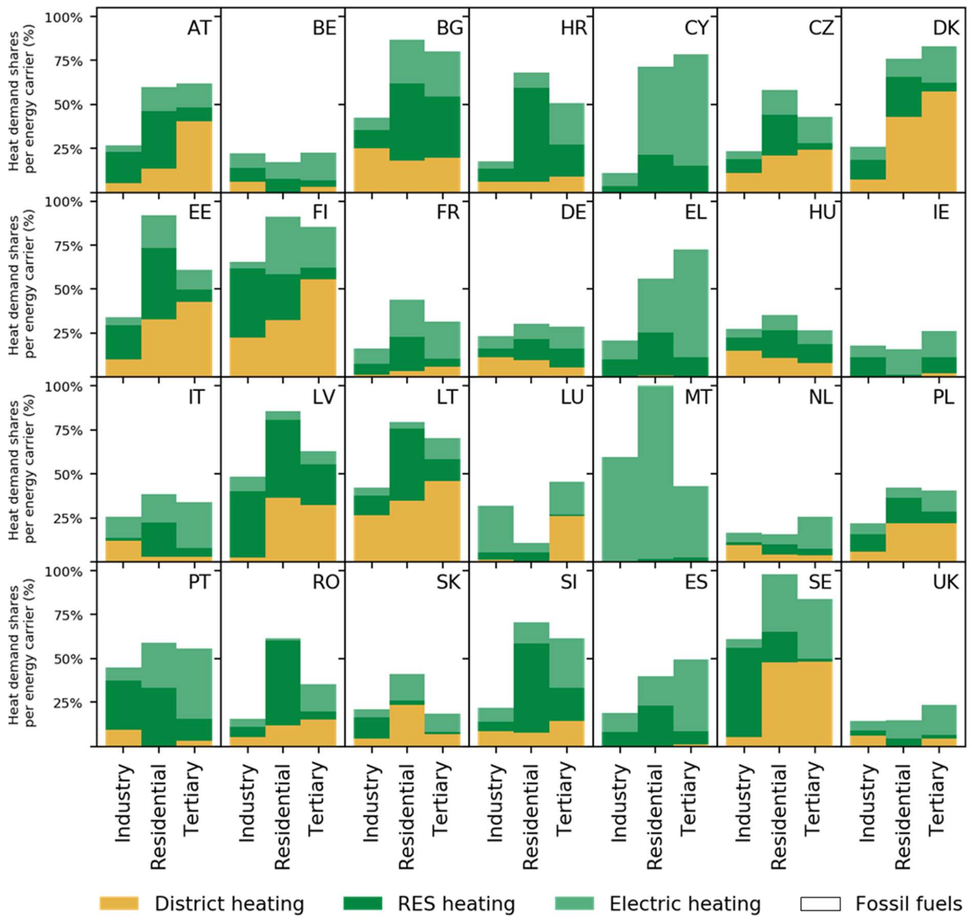

Figure 5: Share of heating demand provided by different energy carriers. 2015 [19]

As presented in Figure 5, countries with warm climate conditions do not show district heating deployment shares — CY, EL, MT and ES. On the contrary, northern countries like DK and FI present shares above 50% of the total heating supply in tertiary applications. It may be inferred that climate conditions determine the level of deployment of district heating and cooling networks. However, it has been demonstrated that climate conditions, despite playing an important role, are not decisive to the feasibility of district heating solutions [20]. As mentioned before, DHC enables the utilisation of multiple energy sources, even those with low quality from an exergy perspective — low temperature sources — within the new generation of district heating and cooling networks. In this regard, although the availability of energy sources may vary depending on the specific country conditions, the existing potential of heat sources is remarkable across Europe. Thus, for the specific case of Spain, which is one of the countries with a low level of DHC deployment, the annual industrial waste heat has been estimated of the order of 100 PJ [21], which roughly represents a 25% of the residential heat demand in the country, 2015 data, according to the profile described in [19].

Concerning cooling thermal networks, it is important to note that the size of cooling sector is 25 times smaller than the heating sector in terms of energy demand [19] and it represents a 12.5% of the total final energy demand in Europe in 2015, although it is expected to grow in the coming years [22]. Contrary to the heating sector, the cooling supply is mostly dominated by decentralised electricity-based technologies, because the portfolio of district cooling networks is limited (Figure 6). Sector wise, the tertiary is the largest, followed by the industrial and the residential (Figure 7).

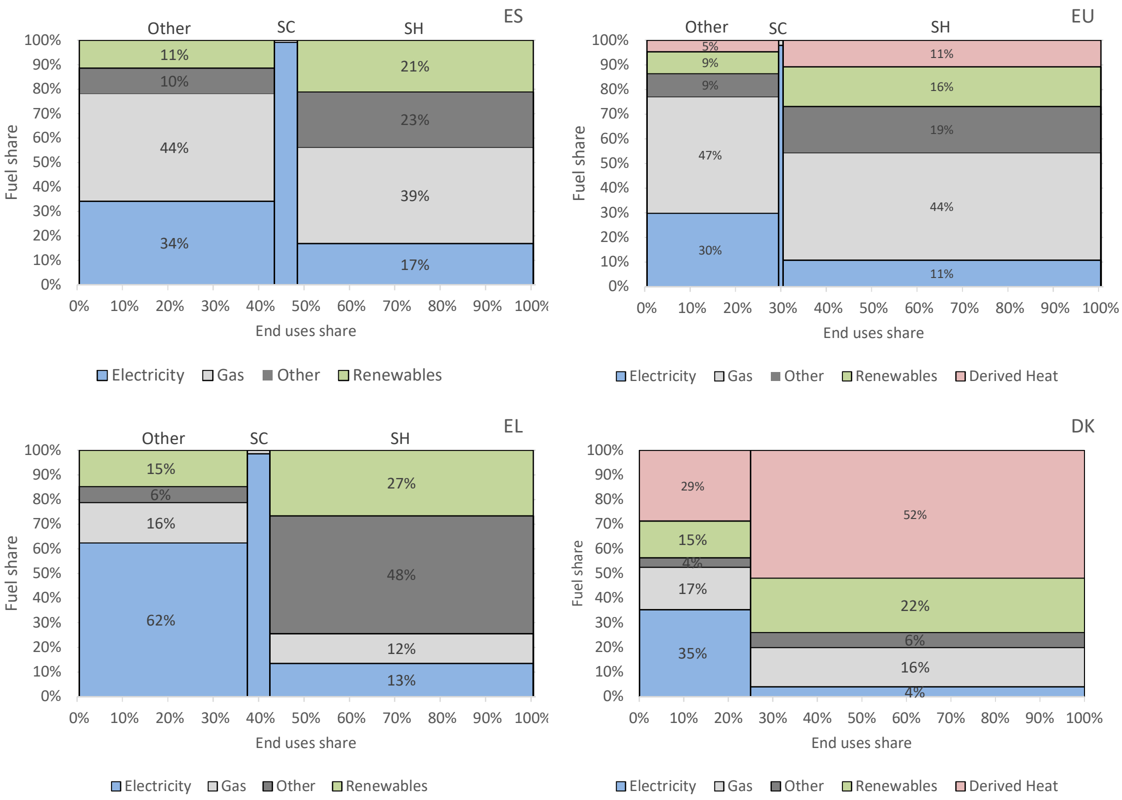

Figure 6: Overview on energy fuel and uses shares, including space heating (SH), space cooling (SC) and other uses [22]

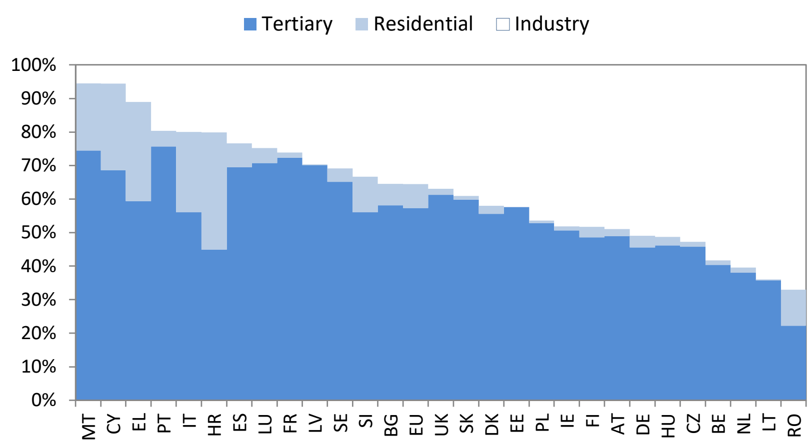

Figure 7: Share of cooling energy demand per sector [22]

Looking at the information available for a country like Spain, where cooling demand is supposed to have a more predominant role compared to other European countries, the deployment of cooling networks remains limited. Based on the latest (2017) available inventory data, in Spain there are approximately 350 thermal networks under operation that provide energy to around 4,400 building, with an aggregated length of more than 600 km and accounting for a total thermal installed capacity of 1.3 GW. Most of the existing networks only provide heat (91%), followed by those providing both heating and cooling (8%). Cooling networks only represent 1% of the total inventory [23]. In general, the European overview of the district heating and cooling networks deployment (DHC) suggests that despite being proven efficient, more efforts are required to unlock the potential of these energy solutions [18].

The major barriers that prevent from a larger deployment of thermal networks in those countries with lower penetration are:

- The low participation of the private sector in the ownership of thermal networks. In some countries like Spain, half of the registered thermal networks belong to public administrations.
- Lack of knowledge on the opportunities and options identified in the public entities responsible to promote these types of projects, mainly municipalities and local authorities.
- Uncertainty related to the level of energy demand to be supplied in the long term that may delay the payback of the high upfront investments.
- The need of long term contracts that may be perceived as a burden by public administrations due to the political time frame cycles.
- Unexpected risks derived from the construction, that increases the cost of the networks.
- Lack of urban planning, that makes difficult to deploy networks.
- In public-private partnerships, the impact of the public investment in the corresponding national, regional or local accounts – booked as debt, limiting the participation of public authorities.
- Last but not least, the perception of final users who, in many cases, are not in favour of sharing a common energy infrastructure, or do prefer to cover their needs with traditional means even if they miss potential energy savings, reduces the opportunities for this type of projects.

All in all, in order to realise the potential capacity, available energy sources, business models and energy market conditions including policy measures and user engagement have to be studied in detail.

Overview of combined heat and power technologies in Europe

Combined heat and power technologies (CHP henceforth) technologies have been widely acknowledged as instruments to produce important energy savings and CO_2 emission reductions compared with the individual production of heating and electricity. In addition, CHP technologies can also take advantage of renewable sources, such as geothermal or biogas, alternative fuels and waste heat. Fossil or renewable CHP technologies (waste and biomass) represent two thirds of the heat supply in all the European district heating networks for the period 1990 — 2014 [18]. However, its potential has not been fully realised due to aspects such as the difficulties to comply with electricity, heat and even cooling regulation, the lengthy permitting procedures or eventually high fees to start the operation for such types of plants [3]. Looking at the level of deployment of CHP at the European landscape, same trends as for the DHC case are found. Figure 8 depicts the share of installed capacity of four major energy technology generation groups and the expected evolution of shares until 2030 according to the EU reference scenarios [24]. Southern countries with extremely low penetration of district heating networks — CY, EL, MT and ES — , also show low levels of CHP deployment.

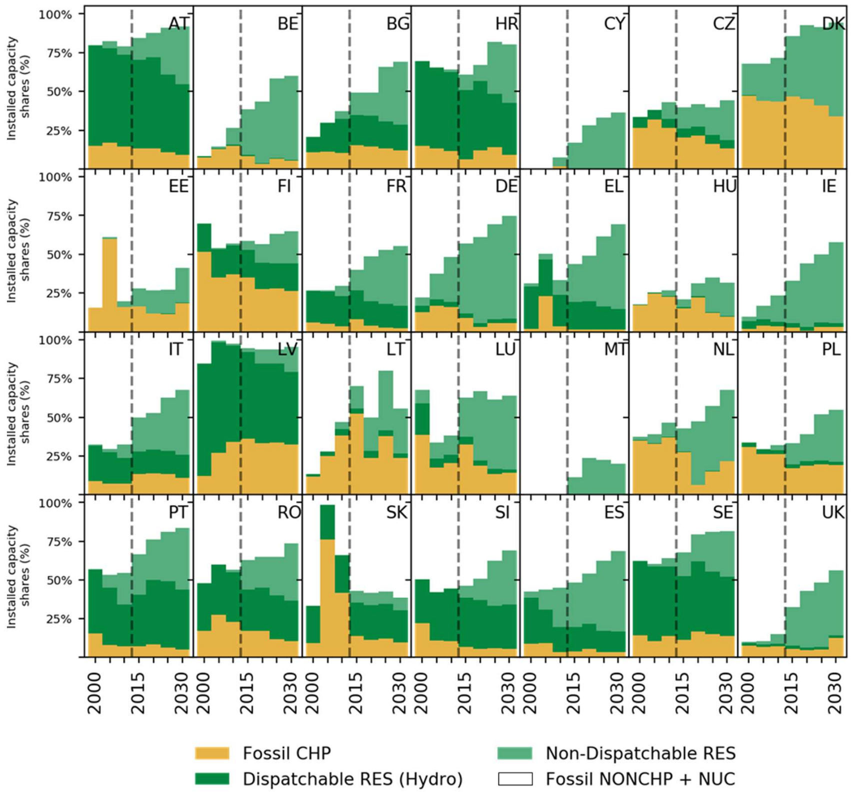

Figure 8: Share of installed net CHP generation capacity per year and Member State according to the EU reference scenario [25][2]

CHP technologies can significantly contribute to the realisation of future of Smart Energy Systems. Centralised CHP production connected to thermal networks links both electricity and thermal sectors by definition.

The importance of flexibility

In the last decade, renewable energy technologies — especially wind and solar — have undergone a sharp price reduction, leading to a greater reduction of the levelised costs of electricity compared with other conventional technologies [26]. This price reduction has resulted in high annual ratios of installed capacities. However, the intermittent nature of renewable energy sources requires the incorporation of technologies and methods that could bring flexibility, such as electric storage systems, into the energy sector, matching supply and demand at all times.

[2] Dotted line separates real historical data from projected values

Despite experiencing an extraordinary price reduction in the last five years [27], electricity storage has not been fully deployed due to economic and reliability aspects. In this sense, by using thermal storage to satisfy energy demand, the heating and cooling sector offers affordable flexibility options while maximising the utilisation of renewable sources via the utilisation of power-to-heat technologies.

Unlocking the coupling of heating and electricity sectors — Power-to-heat concept

As an additional effect, the deployment of the heating and cooling networks may unlock the potential of centralised heat pumps, allowing the conversion of renewable electricity into heat that could be directly used or stored at district level.

Combined heat and power technologies and fossil fuels

It is argued that fossil-fuelled CHP technologies do not contribute to the energy transition that pursues a fossil-free energy sector. However, they can contribute to the energy transition based on two different arguments in the short and medium-to-long term. In the short term CHP technologies increase the overall efficiency of the energy system and more importantly they contribute to the deployment of thermal networks unlocking the advantages presented before. In the long term, CHP technologies can undergo a fuel shift from fossils to biofuels when gas is due to be phased out [28].

Given the current energy sector status, we have considered that gas will be used in a mid-term horizon [29] and thus it is considered as the main energy sources in the studies described in this work. The methods and contributions presented in the following chapters will be still valid if natural gas is replaced by biogas, just by adjusting the economics for the new fuel.

Chapter 3

State of the art

District heating and cooling networks have been extensively studied in the last years from multiple approaches. Due to their complexity, variety of configurations, and uses, thermal networks could be evaluated under different dimensions including technical, economic, environmental, social and policy aspects [30]. The aim of this section is to present a summary of relevant works that tackle the modelling and analysis of district heating and cooling networks including those different approaches. As the methods presented in this thesis rely on energy modelling techniques, focus will be given to the different modelling approaches followed in previous scientific research. From a broad perspective, the literature review performed reveals that in most scientific works, analyses evolve around three major elements that form the district heating and cooling networks: i) the energy sources that feed the network, ii) the energy demand profiles, and iii) the model of the thermal network itself. The modelling of these three elements varies depending on the level of detail pursued in each case [31]. Different approaches for these three major elements are discussed below.

Energy resources

Due to the great amount of sources that district heating and cooling systems can accommodate, previous studies examine a large range of energy sources depending on the case study design in each analysis [30, 32]. Most common energy sources are: gas-based combined heat and power plants (CHP), renewable sources — including biomass [33–35], geothermal and heat pumps [36–40], solar energy [32] and industrial waste to energy [11, 41, 42]. Predominance of gas-based CHP technologies feeding thermal networks has been identified although heat pumps, including geothermal heat pumps [43–47], are gaining momentum endorsed by the foreseen future of the energy system that aims to phase out not only coal but also gas in the medium to long-term.

Energy demand profiles

This element is acknowledged as the most important input data when simulating and optimising energy systems [48]. Yet, different studies follow simplified approaches to calculate the energy needs based on metrics such as the Heating Degree Days (HDD) — defined as the number of degrees that a day's average temperature is below a reference temperate defined as the lowest daily mean air temperature not leading to indoor heating (typically 15 °C), the Cooling Degree Days (CDD) — defined as the number of degrees that a day's average temperature is above a reference temperate defined as the highest daily mean air temperature not leading to indoor cooling (typically 24 °C). Others use the Energy Use Intensity (EUI) defined as the energy demand per unit of surface or the load factor (LF) [49].

To capture the variation of thermal demand that affects the design of the network and the energy production and operation of units, detailed energy demand data, typically with an hourly level of resolution, are widely used. Among others, this approach leads to the utilisation of load duration curves that ultimately has been used to develop sizing methods for combined heat and power plants [50]. Beyond the timescale resolution, regarding the methods used to calculate the actual demand values for a given time step scale, it is common to find complex methods to calculate demand that include a large number of inputs parameters and solve heat balance equations with a high level of detail. In many cases, these approaches rely on detailed energy simulation tools such as Energy Plus [51] or TRNSYS [52]. However, they also account for associated high computation costs and uncertainties on the input data that feed those models. In intermediate approaches, some authors formulate and solve the state-space equations based on the electrical analogy of the thermal problem [53, 54]. In most of the works, these methods are applied to implement building models for residential and commercial uses. Despite enabling more detailed analysis, when the calculation of the hourly demand profile is followed by the resolution of the optimisation problem, some authors have proposed techniques to minimise the computational cost of the problem[55, 56]. In this line of research, identified works rely on clustering techniques that make it possible to select typical days while controlling the associated error [55, 56]. A proposed classification that covers a wide variety of methods to calculate energy demands with increasing complexity, is discussed in [31] and summarised in Table 1.

Table 1: Summary of modelling approaches to compute the energy needs to be satisfied by district heating and cooling networks [31]

Methods Approach	Method
Historical methods	Heating and cooling degree days Energy use intensity and Load Factor Direct measurements Archetype buildings
Deterministic methods	Complex models Simplified models
Predictive time series methods	Predictive models Artificial intelligence

The same study concludes that many of the analyses carried out rely on simplified methods (mainly based on the peak values) have proven to be suitable for sizing the thermal networks. However, these models fail when evaluating the dynamic performance of the district energy system network requiring more detailed analysis. In addition to the above, new methods can be found in recent publications that aim to facilitate the characterisation of the building energy needs at urban level. In this regard, statistical methods based on the urban building energy modelling (UBEM) tool have been used to characterise large building stocks [57]. In another study following the statistical approach, a method is proposed to build hourly demand time series based on cadastral data [58]. Regardless of the method selected, outputs are compared with real data available.

Energy distribution network

Regarding the modelling of the distribution networks, two main approaches are identified according to [31]; the stationary equilibrium and the dynamic models. The first approach is based on the combination of mass flow and energy balances while the latter group could be modelled via dynamic heat transfer equations or state-state equations depending on the temperature of operation of the network [59]. More specific studies have implemented analysis on the optimal operation of the networks [60]. Finally, another group of studies focuses on the geo spatial analysis of the thermal network seeking to identify the optimal spatial development of thermal networks [61, 62].

Modelling approaches

From a holistic approach, which tackles the integrated analysis of the previously presented elements, modelling approaches fall into two main groups: heuristic and optimisation modelling. In the latter, models are designed to evaluate the effect of different parameters in the performance of the energy system. while in the latter, the models calculates the combination of input parameters values that optimise (minimise or maximise) a certain feature of the system such as maximum revenue, energy production or renewable integration, minimum emission, operation costs, or investments [63]. On the other hand, depending on whether models consider uncertainty; deterministic and stochastic models are also identified [32].

Based on the variability of modelling approaches, there are available software tools to model thermal networks, including production, distribution and consumption that pursue different goals. Table 2 presents a list of tools and their applications.

Table 2: Available software tool to simulate district heating systems [32]

Software	Developer	Application
EnergyPlan	Aalborg University, EMD A/S and PlanEnergi	Optimization of energy, environment and economic impact of energy systems
energyPro	EMD International	Modelling package for cogeneration and tri-generation plants of fossil fuels, biomass and other complex energy systems
Homer	National Renewable Energy Agency in USA	Simulation and optimization of stand-alone and grid connected energy resources
LEAP	Community of Energy, Environment and Development	Energy policy application and climate change analysis
MiniCam	Pacific Northwest National Laboratory	Long-term and large-scale changes in global and local energy systems
MODEST	Optensys Energianalys	Cost optimization of energy production
Nems	EIA	Energy/economic/environment of U. S. energy market
NetSim	Vitec	Grid simulation software for district heating/cooling
PRIMES	National Technical University of Athens	Energy supply and demand simulation
RAMSES	Danish Energy Agency	Simulation of electricity and district heat
RetScreen	Natural Resources of Canada	Evaluating energy production, life cycle cost and greenhouse gas emissions of renewable energy sources
SimREN	Institute of Sustainable Solutions and Innovations	Modelling of energy supply and demand
TERMIS	Schneider Electric	Real time planning and optimization of DHS distribution
TRNSYS	University of Wisconsin	Simulation of transient energy systems

The first peer-reviewed paper included in this thesis, entitled "Viability of a district heating and cooling network" (section 4.1) is developed using TRNSYS to model the thermal network. It gives emphasis to the assessment of the opportunities that thermal networks may bring via the implementation of a detailed model. Thus, this work offers a solid framework to evaluate the dual heating and cooling business model.

Optimisation approaches

Studies that evaluate optimal solutions of district energy systems could be classified depending on the optimisation formulation and scope into: the distribution network, the superstructures, the operation and planning and the subsystems building blocks and their interaction with the network [63]. As presented in Table 3, optimisation approaches include technical, economic and environmental aspects as elements of the objective function. When multi-objective functions are considered in many cases a weighted-sum function is computed [63]. The formulation of the different studies includes linear, non-linear and mixed-integer linear programming. However, it is common to use constant efficiencies to avoid non-linear formulations [64–66]. The second contribution to this thesis, entitled "The effect of feed-in-tariff supporting schemes on the viability of a district heating and cooling production system" (section 4.2) falls into the category of superstructures solving a mix-integer linear programme. However, contrary to the objectives identified in the majority of approaches, this optimisation aims to assess supporting schemes — feed-in-tariffs schemes trigger the optimal size and operation of combined heat and power plants.

Table 3: Summary of optimisation approaches [63]

Approach	Opt type	Method/ Algorithm	Objective(s)	DH type	Solver
	SO	MILP	Total annualized cost of micro-grid	Centralized	GAMS CPLEX
	MO	MILP	Both economic and environmental aspects	Decentralized	Not mentioned
Super structures	SO/MO	MILP	Annual cost and carbon dioxide emission	Decentralized	MATLAB/ Gurobi
	SO	MILP	Selection of new users	Centralized	Opti-TLR CPLEX
	SO	MILP	Costs savings and reduction in CO_2 emissions	Decentralized	CPLEX
	SO	NLP	Sum of annual variable costs	Centralized	AIMMS/ W-ECoMP
	SO	MILP	Annual investment, operating and maintenance costs	Combined	Xpress
	SO	MILP	Cost-efficient heating network	Centralized	Xpress

Approach	Opt type	Method/ Algorithm	Objective(s)	DH type	Solver
Operation and planning	SO	MILP	Operating costs for heat production	Centralised	CPLEX
	SO	LP	Costs of the net acquisition for heat power in deregulated power market	Centralised	LP2
	SO	MILP	Dispatching strategy for the different power sources	Centralised	MATLAB
	SO	Newton method	Total mass flow rate / total thermal conductance	Centralised	Not mentioned
	SO	MINLP/MILP	Capital and operating costs	Centralised	CPLEX
	SO	MILP/MINP	Annual CAPEX, O&M cost of CCHP	Centralised	GAMS CPLEX
	SO	MILP/MINLP	System operating costs (fuel and grid)	Centralised	MATLAB/BONMIN
	SO	NLP	Pumping cost and heat loss cost	Centralised	MATLAB
	SO	GSO	Energy consumption	Centralised	MATLAB
	SO	MILP	CO_2 emission and running cost	Centralised	Not mentioned
	SO	Genetic Algorithm	Sum of fuel and pumping cost	Centralised	MATLAB/C++
	SO	MILP	Overall operation costs	Centralised systems integration	CPLEX

Approach	Opt type	Method/ Algorithm	Objective(s)	DH type	Solver
	SO	NLP	cost per unit of thermal energy used	Centralised	Not mentioned
	SO	LP	overall net; acquisition cost for energy	Centralised	LP2; EnergyPro
Distributed integration	SO	MILP	profit of CHP plant by selling electricity	Centralized	GAMS CPLEX
	MO	Kruskal & Genetic algorithms	costs of power & heat supply & CO_2 emission equivalents	Decentralized	Not mentioned
	MO	Kruskal & Genetic algorithms	costs of power & heat supply & CO_2 emission equivalents	Decentralized	Not mentioned
	SO	MILP	Total annual costs including investment and operating	Centralized	GAMS CPLEX
	MO	NLP	total exergetic efficiency and total net power	Decentralized	MATLAB
	SO	Hybrid optimization	Total net present cost	Centralized	HOMER

Approach	Opt type	Method/ Algorithm	Objective(s)	DH type	Solver
Subsystem building blocks	SO	Calculus-based	Pipe investment costs	Centralised & Decentralised	Not used
	SO	Genetic Algorithm	Calibration	Centralized	MATLAB
	SO	Genetic Algorithm	Annual variable cost	Centralized	W-ECoMP
	SO	Genetic Algorithm	investment, depreciation, maintenance, heat loss, and operational cost of circulating pumps	Centralized	Not mentioned
	SO	control vector parametrization (CVP) algorithm	Operation cost	Centralized & Decentralised	gPROMS gOPT
	SO	Genetic algorithm	Annualized price of distribution network	Centralized	Not mentioned

Integration of the heating and the power systems

As highlighted in the introduction, energy sector coupling is gaining momentum as a way to decarbonise the energy sector by increasing the flexibility of the coupled systems, and thus facilitating the penetration of renewable sources [67]. Accordingly, research works are approaching energy sector coupling focusing on the production of combined heat and power. Many of the works that have been analysed in this study consider a set of centralised CHP units and discuss about different modelling approaches to solve the combined operation of the CHP and the power systems. In the literature review, studies that focus on the minimisation of the cost of the power system have been identified. In doing so, authors have worked on the validation of different mathematical approaches [68–71]. Another group of studies focuses on the advantages derived from the integration of both sectors disregarding the effect on the power system operation. This approach includes not only CHP technologies but also heat pumps and renewable energy [44, 72, 73]. Other authors stress the importance of shifting the current smart grids toward the concept of smart energy systems with the aims of incorporating more renewable sources and linking electricity and heat sectors [74]. However, none of the indicated studies tackle the quality of the heat provided and therefore its ability to meet the energy requirements. Regarding the role of storage technologies under this new paradigm and together with the analyses of sector coupling, storage options are more frequently included in the analysis, with thermal storage being predominant compared to electric storage, even though the latter is drawing attention due to its extraordinary price reduction [75–77]. Within this context, the third peer-reviewed article included in this thesis and entitled "The joint effect of centralised cogeneration plants and thermal storage on the efficiency and cost of the power system" (section 4.3) provides a method that determines the optimal dispatch of a combined power plant, the quality of the heat provided in terms of temperature and how this temperature can support the 4th generation of district heating and a better operation of the CHP plants.

Energy policy support

Finally, the last subject tackled in this thesis covers the work done for evaluating measures that enhance the opportunities of district heating and cooling networks. In this matter, previous studies focus on renewable technologies, mostly solar and wind that have traditionally been the beneficiaries of financial supporting schemes — feed-in-tariff and feed-in-premium support. Few examples are identified that assess the impact of those measures in either thermal networks or combined heat and power plants. In more detail, some analyses focus on the competitiveness of district thermal networks compared with conventional gas networks [78]. Others explore the policy measures possibilities to facilitate the upgrade of district heating networks [79]. Lastly, other analyses evaluate the optimal feed-in-tariff support for a given energy generation system [80]. Under this dimension, the contribution to this thesis entitled "The effect of feed-in-tariff supporting schemes on the viability of a district heating and cooling production system" (section 4.2) aims to provide a method to design and size appropriate feed-in-tariff scheme that in one hand attract the interest of investors while in the other do not compromise the long-term feasibility of the energy system, ultimately affecting the price of the energy for final users.

Contribution of thesis

Many studies focus on separate modelling approaches of the different elements required to carry out a comprehensive evaluation of thermal networks namely: heat demand, energy generation technologies and thermal network themselves. Moreover, few studies focus on the assessment of policy options that can contribute to the deployment of these energy solutions.

This thesis brings together different approaches followed in previous works in order to provide methods to support decision-making process when it comes to the deployment of thermal networks from a technical, economic and policy perspective. In other words, we provide a holistic approach to the research of district heating and cooling networks with the end goal of proposing policy recommendations for their deployment in South Europe.

The proposed methods, in this thesis, rely on detailed energy demand assessment and long-term energy planning. The dynamics of the energy demand are needed to carry out detailed evaluations. An hourly resolution demand, as used here, allows the accurate size of equipment and the assessment of thermal storage solutions. Yet, a trade-off between a high detailed energy demand and the computational cost of the optimisation resolution is pursued. Thus, clustering techniques are proposed. Regarding long-term evaluation, a method is proposed to assess how energy demand of new areas could evolve along years.

A sensitivity energy pricing method is proposed to set effective energy policies. The method, in this thesis, identifies the optimal energy tariff schemes to guarantee the feasibility of combined heat and power installations to meet energy needs via thermal networks.

Last, this thesis proposes an integrated detailed model of the coupling of the power and heating sector. It allows the evaluation of the temperature of operation in the network. Therefore, it supports the transition towards the new generation of thermal networks.

Chapter 4

Results and Discussion

This chapter presents the major results derived from the three peer-reviewed scientific articles included in this thesis. The original versions of the articles are included in the appendix A of the document. Thus, this chapter does not discuss in detail the methods and case studies described in the articles but rather focuses on the novelty of these works and their main findings and implications.

Rational behind the set of papers

As explained in chapter 1, the three papers assess the viability of district heating networks. They approach the assessment of their viability from three different approaches; : i) long-term cost-benefit analysis, ii) public-private business case base on supporting schemes, and iii) the utilisation of the available heat in centralised power plants to supply district heating networks, under the sector coupling strategy. Therefore, they could be understood all-together as a compendium of complementary methods that can support the deployment of thermal networks in a cost effective way supporting the energy district planning and the investment decision-making process. Considering the complexity of the topic, one may think that other approaches would serve this purpose. However this multiple approach itself serves as an example of their complexity. In addition to the above, this work aims to demonstrate that thermal networks can be deployed under different climate conditions. Thus, the case studies presented in the three peer-reviewed papers focus on areas with warm winters and hot summers, which can be found in southern European countries.

4.1 Viability of a district heating and cooling network

Juan Pablo Jiménez Navarro, Rogelio Zubizarreta Jiménez, José Manuel Cejudo López
DYNA 87 (2012) 305 - 315

Author attribution

R. Zubizarreta and J.M. Cejudo designed the goals of the study; J.P. Jiménez-Navarro and R. Zubizarreta developed the methodology to characterize the demand and the implementation of the building models used in the study; J.P. Jiménez-Navarro and R. Zubizarreta designed and set up the energy generation models and the techno-economic assessment; J.P. Jiménez-Navarro performed the analysis; J.M. Cejudo validated the results of the study; J.P. Jiménez (with comments from the co-authors) wrote the manuscript.

Context

This work is developed in the framework of the project "Estudio de viabilidad de una red de distrito para el abastecimiento energético de la ampliación del Parque Tecnológico de Andalucía" — Viability of a district heating and cooling network to supply thermal energy demand in the Andalusian Science and Tech¬nology Park (STPs). The project consortium was composed by several research organisations including the University of Málaga and the Andalusian Institute of Technology. The project was funded by the Spanish Ministry of Economy and Competitiveness to foster the modernisation of these areas.

Scope

The aim of this work was is to develop a modelling framework to facilitate the decision-making process regarding the planning, sizing, investment and operation of district heating and cooling networks in the mid-to-long term. This modelling framework focuses on applications with both heating and cooling needs. It is also intended for new urban areas, where the deployment of thermal networks can be done more efficiently from the urban planning phase reducing the cost of the network construction and enabling the design of buildings in the area according to the specific energy supply option. The multi-annual approach of the study aims to determine the investment strategy over years based on the evolution of the heat demand of new areas. Thus, the model evaluates how the energy demand is evolving based on the rate of the occupation of new buildings. Therefore, the final goal of this work is to prevent from over-sizing the energy production systems that supply the district heating and cooling networks as a consequence of real levels of demands lower than expected in the design phase and thus leading the low capacity factors and low efficiencies. Although uncertainty is a major issue when facing new urban areas, this approach aims to identify the appropriate levels of demand required to invest in specific energy generation technologies based on a deterministic demand trend. Based on the long-term vision, this work offers a method to carry out a comprehensive assessment of the techno- economic viability of thermal networks, including a thermal demand forecast, the analysis of the performance of different energy generation technologies available, the size and dimension of the networks and the evaluation of the economic benefits derived from the operation of the network along a time frame — typically 20 years. The modelling framework is implemented by modelling the following elements: the characterisation of the energy demand, the modelling of the energy system and the techno-economic assessment.

Characterization of the energy demand

To characterise the energy demand, a sub-method has been developed based on two steps:

- i) The clustering of the existing building stock leading to the identification of building archetypes and the projection of future buildings to be incorporated in the area of expansion under study.
- ii) The clustering is then followed by the implementation of high detailed models of building archetypes implemented in Energy Plus [52] and validated by the available bibliography on building demand and combined with real data accessible for some of the buildings if available [81].

The incorporation of new building rate is based on the analysis of the building trends and associated economic activity in the area under study, leading to the definition of an annual new building settlement rate. Figure 10 shows the evolution of the additional building surface along the years; meanwhile figure 11 gives an example of a building archetype implemented.

Thus, following a bottom-up approach, buildings — defined by the useful sq-m surface — are incorporated along the coming years. Contrary to traditional cost-benefit analysis that relies on a typical year and then extrapolates the results for the installation lifetime, this work proposes a demand evolution that impacts the operation of thermal networks especially in the first years when new areas are not fully consolidated.

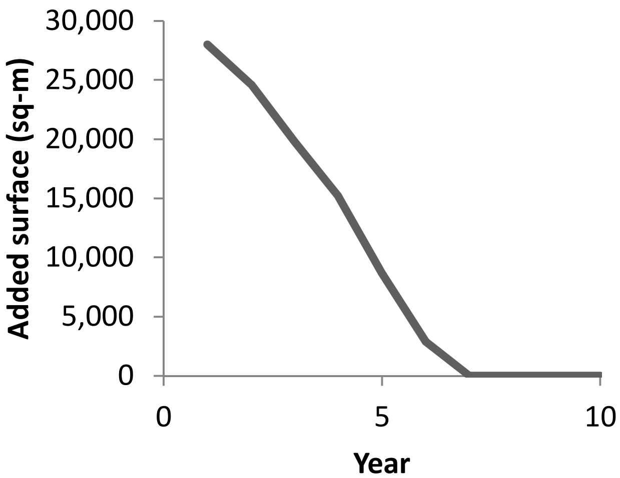

Figure 9: Forecast evolution of new buildings in the expansion area

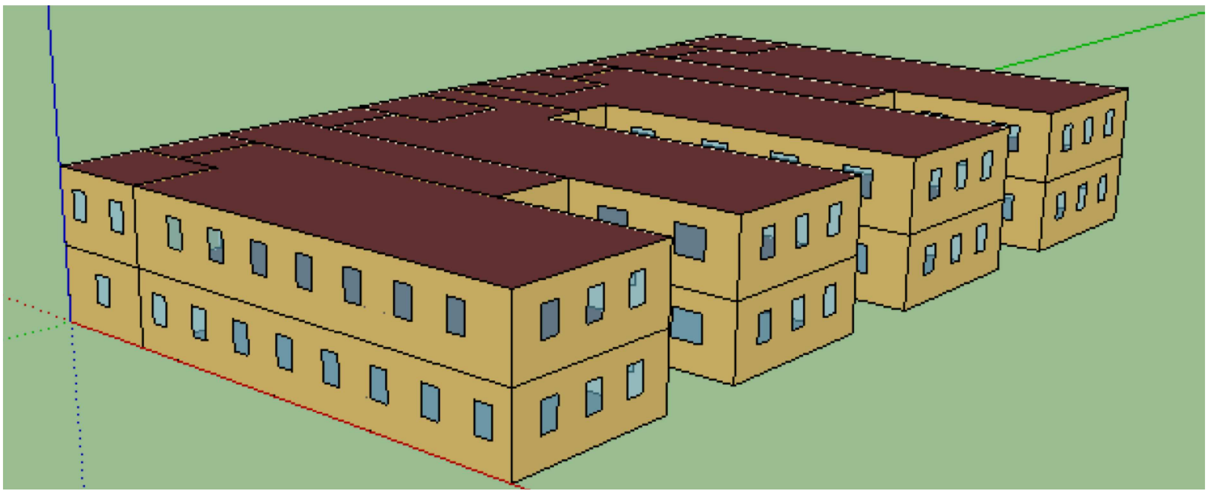

Figure 10: Example of the energy building model. Office building

Modelling of the energy system

The next step in the method is the evaluation of the different energy generation alternatives. To do so, a detailed modelling test-bed is designed and set up. The model allows the evaluation of different energy generation technologies. It also allows setting other aspects such as set-point tem¬peratures, size of the thermal networks or external conditions such as ambient or ground temperatures that can be tuned according to the case study. Thus, this modelling framework is suitable for many other case studies. The model is implemented in TRNSYS [52].

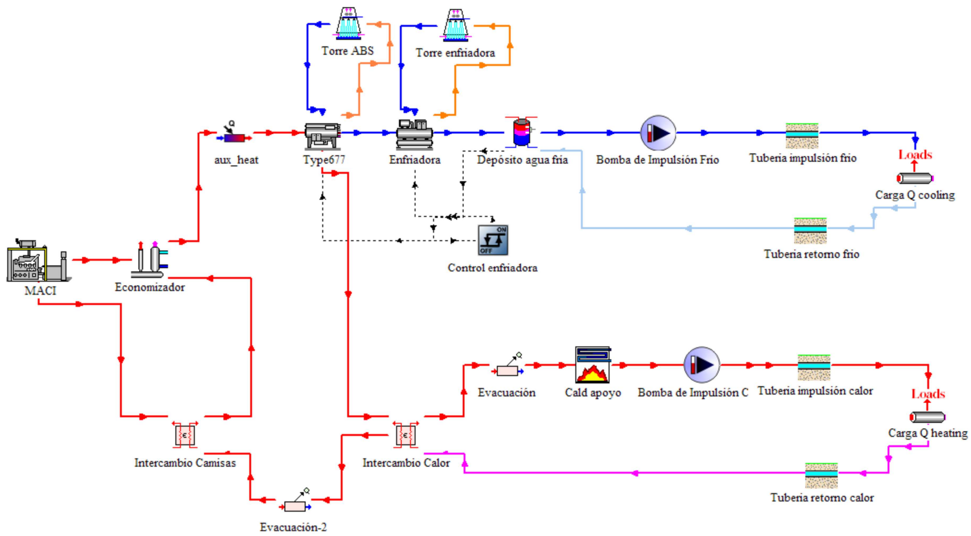

Figure 11: District heating and cooling model. Layout

Together with any potential technology that could be interesting to assess, the model provides alternative supply options based on conventional technologies, offering the opportunity of either comparing the selected technology against conventional ones or to evaluate the convenience of operating in an hybrid approach operating these conventional technologies in the first years and then investing in alternative solutions depending on the annual evolution of the thermal demand.

Techno-economic assessment

Finally, concerning the economic analysis, detailed spreadsheets are developed to evaluate the economic profit derived from the installation. The economic analysis is based on traditional indicators such as pay-back periods and net present value metrics, with the additional feature of considering variable cash flows depending again on the demand evolution and variable revenues linked to the amount of energy provided.

Conclusions

The application of the method to a specific case study indicates that thermal networks require long payback periods, more than 15 years. The analysis stresses the need to make profit from the co-production of electricity. This means that conventional generation of electricity based on mechanical compressor chillers to cover the cooling needs and gas boilers in the case of heating do not provide sufficient incomes. Even more, under the assumed regulatory scenario that offers additional incomes for the electricity co-generated, the continuous operation of the cogeneration unit increases the revenues. The impact of the continuous operation of the cogeneration unit is proven by comparing the steam turbine and internal combustion engines which operation modes were define as non-fixed capacity factor and fixed capacity factor respectively.

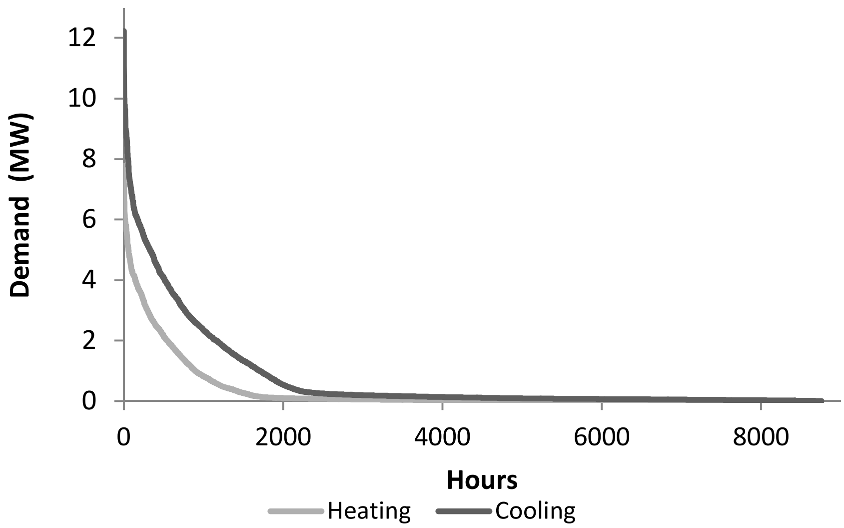

Figure 12: Load duration curves for heating and cooling demands

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

Juan Pablo Jiménez Navarro, José Manuel Cejudo López, David Connolly
Energy 134 (2017) 438 - 448

Author attribution

J.P. Jiménez-Navarro and J.M. Cejudo designed the study. J.P. Jiménez-Navarro developed the optimization model; J.M. Cejudo and D. Connolly validated the model; J.P. Jiménez-Navarro implemented the case study and performed the analysis; J.M. Cejudo validated the results; J.P. Jiménez with comment from the co-authors wrote the manuscript.

Context

This contribution represents a further step in the analysis presented in the previous paper. The conclusion drawn from the techno-economic analysis carried out in the previous study suggested that thermal networks requires supports or guarantees due to their long pay back periods and high level of upfront investments. Additionally, within the Spanish context, the energy policy failed when sizing the feed-in-tariffs support leading to energy costs that exceeded the allocated public budget and therefore to the sudden termination of any supporting schemes for efficient energy generation technologies, including combined heat and power to controlled the debt in the energy sector. This situation suggests that tailored support has to be designed per project, taking into consideration not only the benefit for the energy investor but also for the energy system and the society.

Scope

Therefore, the contribution aims to provide a method to size appropriate energy policy support in the form of feed-in-tariffs schemes in order to guarantee the feasibility of district heating and cooling networks fed by combined heat and power technologies. Put in different way, the method provides the optimal size of the energy equipment given a fixed feed-in-tariff scheme in place. Thus, both policymakers and energy investors can take advantage of the proposed method that will improve the understanding on the operation of thermal networks at district level, contributing to the establishment of public and private agreements needed to unlock the potential of district heating and cooling solutions.

Contributions

The proposed method relies on the implementation of a so-called energy superstructure or poly generation system, which have been studied in previous works [65, 82–84]. These systems include different energy generation technology options that could be combined in order to assess the optimal sizing and operation of the different components, supplying a given demand. For our purpose, the proposed poly generation system is depicted in Figure 13.

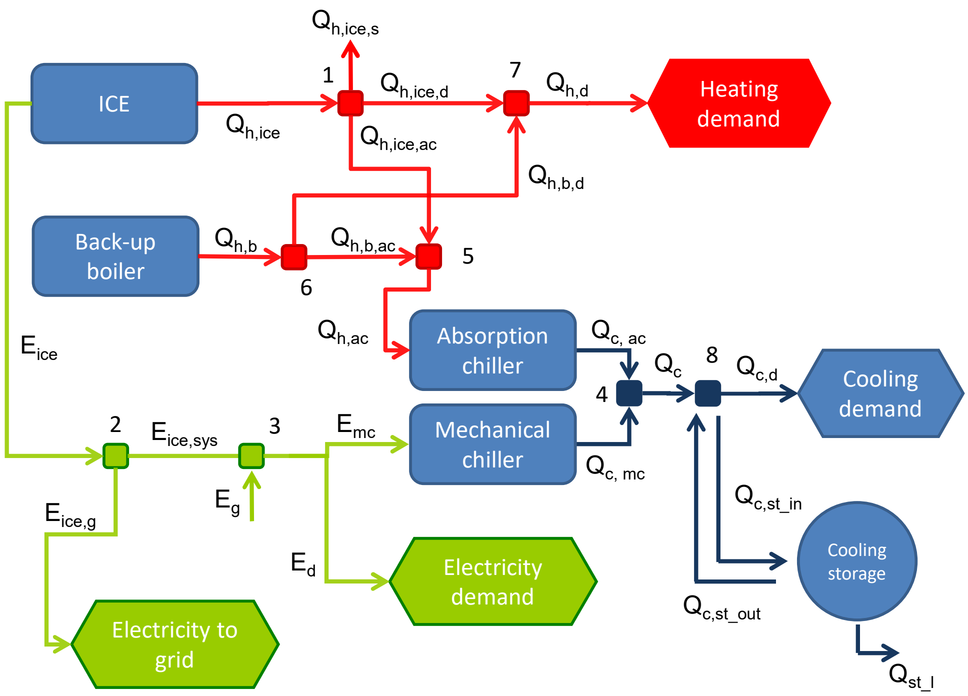

Figure 13: Scheme for a combined heating, cooling and power facility

The model compares two major scenarios; a centralized energy supply scenario based on the operation of CHP plants — internal com¬bustion engine — and, a decentralized energy supply scenario based on the op¬eration of conventional boilers and mechanical chillers. The additional feature of the proposed system, which has not been fully studied previously, is the link to the electricity market retail prices, including the cost of the purchased electricity from the grid and the price of electricity injected in the grid produced by the sys¬tem. This feature enables the possibility of generating electricity and selling it to the grid, or purchasing electricity from the grid to meet both the cooling demand, via mechanical chillers, and the electricity demand itself required for electric appliances. The system operates under a price-taker assumption, which means that the electricity market price is not affected by the potential electricity that could be injected from the system into the grid. This dependency with the electricity market prices allows understanding the impact of policy measures — feed-in-tariffs. Thus, given the electric market conditions and the energy demand, including heating, cooling and electricity, the model determines the optimal size and operation of the different equipment. If the conditions of the electricity market are not attractive enough, the optimal solution will include conventional technologies and electricity will be purchased from the grid to meet the electricity demand required — including the electricity needed to operate the mechanical chillers to supply the cooling needs. In addition, the structure provides the option of evaluating the role of cold storage that 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. Finally, the model includes additional equations to comply with policy regulations. For the case study assessment it is defined as minimum ratio between the electricity generated and the useful heat produced in the cogeneration unit, the so-called 'rendimiento eléctrico equivalente' (equivalent electric performance).

Conclusions

The study suggests that for the given case study (described in detail in section A), specific support is required to guarantee the feasibility of the co-generation system. Under no feed-in-tariff scenario, the optimal solution is based on conventional technologies. In addition it is also observed that the level of support required to provide positive revenues is close to the feed-in-tariffs set in the regulation (0.12 €/kWh). Fig 18 shows the relation between the price for the electricity injected in the grid and the revenues. However, it is clear that the support should be evaluated per project in order to ensure reasonable investment profits. The study shows how the daily thermal storage reduces peak demand. Therefore the required installed capacity decreases and does the upfront investment costs Another interesting conclusion derived from the study is the need for revisiting the conditions that ensure an efficient utilization of the co-generation system as a requisite to take advantage of the feed-in-tariffs. Thus, as defined for the Spanish case, lower COP efficiencies in the absorption chillers turn out to increase the useful heat produced in the cogeneration unit for the same amount of cold produced. This effect allows a higher production of electricity and thus higher economic benefit derived from the electricity injected in the grid. However, the overall efficiency of the system decreases. Therefore, the definition of the REE metric should be based on the final useful energy. So, instead of accounting the input heat in the absorption chillers as useful heat, it should account the useful cold produced in this conversion that takes place in the absorption chillers.

4.3 The joint effect of centralised cogeneration plants and thermal storage on the efficiency and cost of the power system

Juan Pablo Jiménez Navarro, Konstantinos C. Kavvadias, Sylvain Quoilin, Andreas Zucker Energy 149 (2018) 535 – 549

Author attribution

K.C. Kavvadias and S. Quoilin have developed the background model; J.P. Jiménez-Navarro, K.C. Kavvadias and A. Zucker have defined the case study. J.P. Jiménez-Navarro have collected and processed all the input data required in the study; K.C. Kavvadias and J.P. Jiménez-Navarro have launched the simulations; J.P Jiménez-Navarro have processed the simulation results; J.P. Jiménez and K.C. Kavvadias with comment from the co-authors wrote the manuscript.

Context

This contribution is developed in the context of a growing share of energy generation from renewable sources within the power system. This trend is raising the need of sector coupling that enables the utilisation of a wider portfolio of energy technologies and thus accommodating a higher amount of intermittent renewables sources. In this regard, the heating sector — accounting for the 50% of the total final energy used in Europe and characterised by low efficiencies represents a great opportunity to couple with the power sector. This opportunity is highlighted in the European Strategy on Heating and Cooling [3].

To do so, the role of thermal networks becomes essential to connect centralised available energy sources with heating demand hubs [85]. Among others, the deployment of thermal networks may enable the use of waste heat sources and the use of high-efficient CHP technologies that could provide overall efficiencies of up to 90% [86]. Even more, under the new generation of district heating networks paradigm — the so called 4th generation of district heating — in which the operation temperatures are in the range of 30 — 70 C, CHP plants could provide even higher efficiencies.

Scope

Given all the above, in this work the conversion of a combined cycle gas turbines (CCGT) into a CHP operation mode in combination with centralised thermal storage option are modelled providing both electricity and heating by the connection to a thermal network. Thus, this model allows the evaluation of the impact of these solutions on the power systems, especially regarding the integration of high shares of renewables. The model approach also allows the evaluation of how the new generation of district heating systems contributes to the utilisation of these types of plants [14].

The integration of the proposed model on a power system dispatch model permits the evaluation of the cost reduction brought by the heating and electricity coupling via CHP and thermal storage.

Contributions

The major contribution of this work is the implementation of a model that includes the temperature as a parameter of design. This aspect allows the analysis of the benefit derived from the implementation of low temperature networks from the perspective of the CHP operation.

This model is based on the fact that in order to produce heat in the CHP part of the potential electricity produced has to be sacrificed. In this sense the CHP can be understood as a virtual heat pump and can be approximated by using the Carnot cycle expressions. shows the equivalent Carnot cycles for a steam turbine with and without extraction operations.

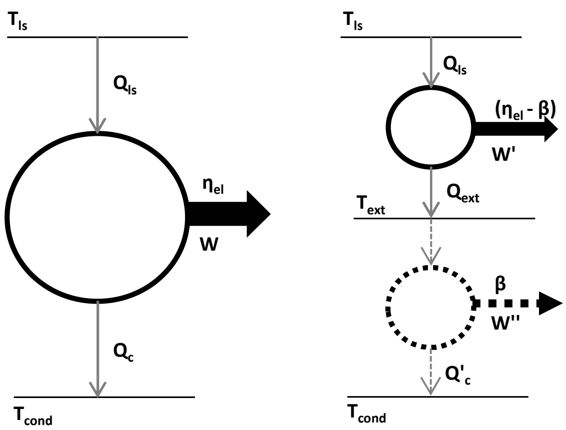

Figure 14: Steam cycle scheme. No extraction (a) and extraction (b) operations

Applying Carnot equations, the operation parameters of the steam turbine can be deducted (Eq. (2 —5) and the region of operation defined.

Table 4: Payback time for the different energy technologies

Parameter	**Mathematical expression**	**Eq.**
Power loss-ratio	$\beta = \dfrac{T_{ext} - T_{cond}}{T_{cond}}$	(3)
Power-to-heat ratio	$\sigma = \dfrac{\eta_{ise} \cdot 1 - \dfrac{T_{ext}}{T_{ls}}}{1 - \eta_{ise} \cdot 1 - \dfrac{T_{ext}}{T_{ls}}}$	(4)

The graphical representation of the region of operation is presented in Figure 15.

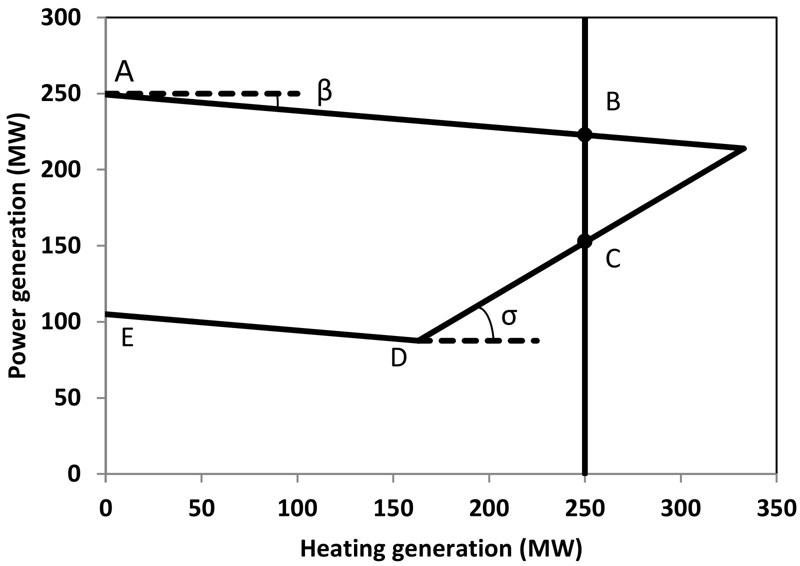

Figure 15: Feasible operation region for a CHP plant for a given DH input temperature

Additionally to the temperature dependant mode of the CHP plant, the model integrated into a power dispatch model — The DISPA-SET model [87] — offers the possibility of analysing how CHP plants can facilitate the penetration of higher share of renewables by assessing both the total cost and total efficiency of the energy power system.

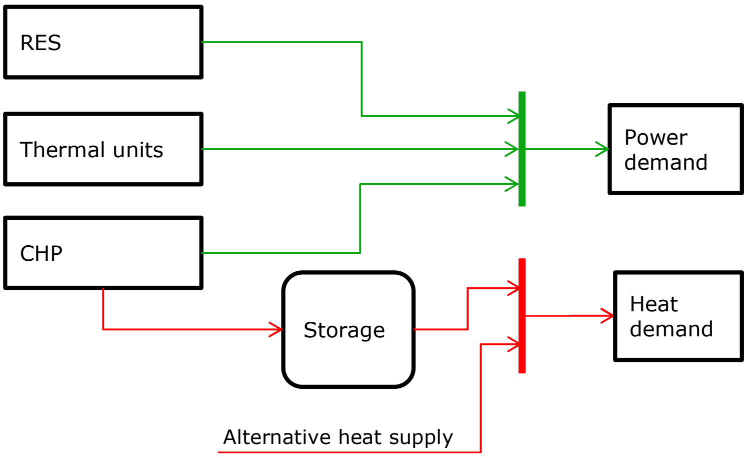

Figure 16: Integrated energy system for the coverage of specific power and heat demand

Contributions

Four different aspects have been evaluated with this study: i) the potential of the conversion of centralised combined cycle plants into centralised combined heat and power, ii) the role of thermal storage in the sector coupling, iii) the benefits provided by low temperatures of operation in thermal networks under the 4th generation of district heating paradigm and iii) the analysis of optimal scenarios by the combination of the aspects mentioned. Regarding the impact of the conversion of COMC into CHP, it brings an in¬crease in the total efficiency of the system and a cost reduction. The thermal storage enables higher capacity factors for the CHP plants and a high efficiency operation. In particular, for the high RES scenarios in which the op¬eration of the CHP is limited by the amount of RES to be incorporated in the system, the role of thermal storage becomes relevant in order to synchronise the heat produced by CHP and the heat demand. Another important contribution of this work is the evaluation of the impact of the temperature of extraction. According to the operation of the model proposed for the CHP plants, high temperatures of extraction in the plant lead to lower efficiencies. It is proven in the analysis that temperatures in the typical range of operation of 4GDH (30 — 70 C) increases the efficiency of the centralised CHP plants, reduces total costs of the system and increases the CO2 emissions. In addition, low temperature of extraction makes the heat provided by the CHP capable of competing with cheaper heat supply alternatives (AHS). In particular for exogenous AHS prices of 10 €/MWh, the share of heat demand supplied by

CHP plants varies from 10% (temperatures of extraction above 100 C) to 90% of the total heat demand for low temperature of extraction of the order of 60 C. Finally, given the implications among the different variables assessed, it was required to analysis the Pareto-optimal solutions in order to understand the trade-off between affordability — system costs — and efficiency. It is concluded that, the optimal scenario in terms of cost and efficiency results from the combination of high CHP penetration, operated at low temperature of extraction, available thermal storage under an scenario of high penetration of renewable energy.

Chapter 5

Conclusions and major contributions

This thesis aimed to explore opportunities and challenges that energy solutions at district level face in order to achieve higher penetration shares of renewable energy sources. The ultimate goal is to contribute to the decarbonisation of the heating sector, which accounts for half of the total final energy consumption in Europe. The research carried out provides energy investors and policy-makers with tools and methods to facilitate the evaluation of energy investments and the adequacy of policy measures.

The major motivation of this work is to contribute to the deployment of thermal networks in Southern European countries where, in contrast to Northern EU member states, these facilities are not widely used despite having a high potential.

The different scientific outputs presented prove that with an appropriate policy support and taking advantage of available energy options and applying them in high energy density areas, the deployment of thermal networks may unlock the benefits derived from a combined production of heating and electricity leading to:

1. an increased efficiency of the energy systems,
2. a more flexible energy system, acknowledged as a key aspect to integrate more renewable sources. In this matter, the research investigates the role of thermal storage in supporting this integration.

More specifically, the major motivations to carry out this study have been:

1. The implementation of a modelling framework and the comprehensive evaluation of the adequacy of thermal networks in non-consolidated areas with high potential energy needs in terms of energy demand density.

2. The development of a method to implement tailor-made measures to guarantee the success of the district heating and cooling business models.

3. The evaluation of the impact of the integration of the heating and cooling sectors in the power system to assess how this integration may accommodate larger renewable installed capacity, as expected in the coming years.

The major outcomes and conclusions derived from this thesis are presented in detail below:

Viability of a district heating and cooling network

This work highlights the importance of certain aspects that are relevant when sizing a thermal network; the existence of a supporting policy that ensures revenues from the electricity produced by the energy system and injected in the electricity grid, such as feed-in-tariffs or feed-in-premium; the impact of the uncertainty and future evolution of the energy demand in the area under consideration; and finally the need to combine different user profiles to level out the daily energy demand profiles and thus the load duration curves, leading to a more efficient operation of the energy generation technologies. Yet the high upfront investment costs, mostly related to construction of the networks themselves — 7,5 M€ for a 4km network considered in our study — have a negative impact on the payback period. Therefore, one of the main conclusions from this analysis is the need of setting public and private partnerships that ensure the operation of the networks and share or minimise the associated financial risks.

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

Combined heat and power systems can satisfy energy demands in a cost-effective way, especially in areas characterised by high intensity energy needs.

Driven by the outcomes obtained in the first scientific article discussed in section 4.1, and 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, the significant increase in the installed capacity of energy technologies that benefited from the energy policies in place jeopardised the economic stability of the energy sector, endangering as well the feasibility of DHCs or even CCHP.

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

As presented in chapter 4, large scale CHP units that supply energy for districts still need policy support to guarantee its penetration in the energy market. However due to the limited financial sources available, it is important to properly design support schemes by ensuring the benefit for both energy investors and the public. In this regard, the method also allows policymakers to define appropriate feed-in-tariffs.

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

Nonetheless, the adequate definition of FiTs varies based on parameters selected for a particular project. In the case study, the coefficient of performance (COP) of mechanical chillers is the most sensitive parameter that may modify economic results by more than 10 c€ per euro invested and 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.

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 can also prevent some investments, 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 (Rendimiento eléctrico equivalente). The effect of the absorption chillers performance supports the definition of legal constraints including the output cold produced by the absorption chillers instead of the input heat in the calculation of the useful thermal energy. Thus, the required ratio between this useful thermal energy and the electricity produced in ensured.

The joint effect of centralised cogeneration plants and thermal storage on the efficiency and cost of the power system

We present a new method to assess the benefit derived from the conversion of existing steam-based turbine plants into combined heat and power plant has been presented in chapter 4. This method relies on the application of a unit commitment and dispatch model, which includes a detailed representation of the heating system, allowing the assessment of different assumptions such as energy prices, different share of installed capacities for a set of energy technologies and the operation of CHP plants. The ability of the method to link the optimisation of the energy system with the supply temperature delivered by the CHP plant is a valuable asset to evaluate different heat uses, such as the new 4th generation district heating systems characterised by low temperatures of operation, and the derived benefits.

The method has been tested in a small energy system, which offers opportunities to supply heat by the conversion of existing steam-based turbine plants into combined heat and power operation mode.

Results indicate that the conversion into combined heat and power plant leads to an increased efficiency of the energy system, which otherwise is limited to up to 50%. This effect relies on the higher efficiency of the CHP up to 90% for some operation points. However, the deployment of CHP may hinder the utilisation of renewable energy sources leading to renewable energy curtailment. The analysis presented demonstrates that this negative effect could be mitigated by the flexibility provided by thermal storage. However, there is a trade-off between the integration of high CHP and high RES simultaneously.

The analysis of different alternative heat costs reveals that CHP plants could compete with costs in the order of 10 €/MWh. However, for this low cost, the utilisation of the CHP decreases and so does the benefit offered by thermal storage options.

From the CHP operation perspective, low temperature of extraction leads to higher efficiencies and lower costs. Then, the lower the temperature required the better it is for the efficiency of the system. But this increases the amount of RES curtailed by 1% when the temperature of extraction increases from 60 to 120 °C if high RES scenarios are considered. In conclusion, the incorporation of CHP in combination with thermal storage in the energy system leads to high efficiencies and reduced costs. However, in high RES scenarios, this benefit limits the integration of renewables, despite the fact that it still reduces costs.

Table 5 summarizes the major outcomes achieved for the 3 pieces of work

Table 5: Scientific paper highlights

Paper	**Highlights**
Viability of a district heating and cooling network - section 4.1	A detailed dynamic model, including demand and generation, is implemented to assess the viability of thermal networks Long payback times are observed due to the construction of the thermal network that represents 75% of the total investment for the case study
The effect of feed-in-tariff supporting schemes on the viability of a district heating and cooling production system - section 4.2	An optimal sizing method for combined cooling, heat and power projects is proposed Combined cooling, heat and power projects at district level still require support Public support has to be specifically designed per project
The joint effect of centralised cogeneration plants and thermal storage on the efficiency and cost of the power system - section 4.3	Model of centralised cogeneration plants with varying heat temperatures Co-optimization of heat and power using a unit commitment model CHP plants increase the affordability and the overall energy efficiency of the system Thermal storage reduces the curtailment of renewable while increasing the overall system efficiency CPH plants become more competitive by supplying heat to low temperature networks

Limitations of the thesis

When it comes to research for energy systems, the characterisation of the energy demand is a complex task. It requires assumptions on user and occupant behaviour. As a result, it is difficult to predict the actual energy needs. In this thesis, we approach the matter in a deterministic way. However, the conclusions could benefit from the use of stochastic approaches. We expect that new results using this type of stochastic approach could shed light on the statistical significance and representativeness of the results.

Recommendations for policy and practice

In terms of policies and applications on the future energy system, based on this work, three main recommendations can be formulated.

First, the deployment of thermal networks should be investigated in detail to connect demand and supply from centralised power plants. Geo spatial evaluation of feasible heat supply from real existing power plants to high density demand areas could provide a view of the actual potential of thermal networks. An analysis like this, across Europe, can stimulate the provision of input for energy policies that incorporate the use of available heat from centralised power plants.

Second, the need of supporting schemes, such as feed-in-tariffs, should be re-evaluated in current energy policies. The subsidy of specific energy solutions has proven not to always be beneficial. However, based on this work, in the deployment of thermal networks in the South of Europe, a feed-in-tariff scheme could guarantee the viability of these solutions. Feed-in-tariff schemes should be deployed carefully as they are not "one size fits all" solution.

Last, electrification is gaining attention in the energy policy scene. Heat pump technologies, defined by high efficiency ratios, can contribute to the decarbonisation of the heating sector. In this matter, the combined evaluation of two different pathways in the heating sector, the use of heat from centralised power plants and the electrification at the demand side are worth investigating.

Recommendations for future research

As future research lines, according to the expected evolution of the energy systems, many options are available to evaluate different technology portfolios in the process to integrate more options such as heat pumps or electric storage.

More specifically, 3 main lines are pursued;

1. The role of electric storage in the supply of thermal energy needs and its competitiveness against thermal storage. Electric storage costs have plunged in the last years. Its feasibility may unlock many more opportunities such as

the large deployment of heat pumps fed by renewable energies. However, the issue concerning the reliability of its performance has to be explored and considered when assessing energy systems. In this regard, some preliminary works have been already completed under the title "Optimal Home Battery Sizing and Dispatch in EU Countries Taking Into Account Battery Degradation and Self-Consumption Incentives" that was presented in the 11th International Renewable Energy Storage Conference (IRES 2017) [88].

2. The second research line concerns the evaluation of the operation of centralised CHP plants in combination with decentralised heat pumps, also known as booster heat pumps. The aim of this working line is the evaluation of how high-efficient heat pumps may expand the utilisation of low temperature sources and how they can be operated in combination with centralised extraction/condensing turbines to maximise efficiency and minimise costs.

3. Finally the third line focuses on the definition of a metric for thermal storage, analogous to the levelised cost of energy for generation technologies, to facilitate the analysis of the convenience of incorporating thermal storage in different district heating and cooling applications and promote its utilisation. Literature review only shows some studies for electric storage.

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Appendix A

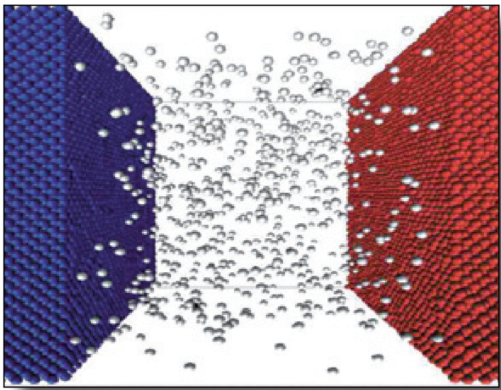
Scientific output

Viability of a district heating and cooling network
Juan Pablo Jiménez Navarro, Rogelio Zubizarreta Jiménez, José Manuel Cejudo López
DYNA 87 (2012) 305 - 315

Author attribution

R. Zubizarreta and J.M. Cejudo designed the goals of the study; J.P. Jiménez-Navarro and R. Zubizarreta developed the methodology to characterize the demand and the implementation of the building models used in the study; J.P. Jiménez-Navarro and R. Zubizarreta designed and set up the energy generation models and the techno-economic assessment; J.P. Jiménez-Navarro performed the analysis; J.M. Cejudo validated the results of the study; J.P. Jiménez (with comments from the co-authors) wrote the manuscript.

Viabilidad de una red de distribución de calor y frío



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DISTRICT HEATING AND COOLING FEASIBILITY

ABSTRACT

- The purpose of this paper is to present the results of the feasibility study for a district heating-cooling network to cover the energy demand in a Scientific and Technological Park under Mediterranean climate conditions.
This study consists of three phases: energy demand, technology analysis and economic study.
To evaluate the energy demand a bottom-up strategy has been followed: a building inventory has been carried out to define several building types according to use, envelope and glazing. Energy + has been used to obtain heating and cooling demand profiles for each building type and orientation. According to municipal development plans for PTA and forecast in business growth, the energy demand evaluation in a 10-years timeframe has been carried out.
Most appropriate technologies has been analyzed and evaluated: cogeneration (gas turbine and alternative internal combustion engines), biomass boiler and conventional technologies have been evaluated with TRNSYS to obtain consumption profiles, consumption rates, efficiency indicators and energy losses.
Finally an economic analysis has been done to technologies in a 20 years period to evaluate technology that better economic results address.
The main objective of this work is the promotion of the efficient and effective energy supply in areas with high energy consumption. DCH technology is widely used in the North of Europe and this paper tries to demonstrate that this technology could be applied in Mediterranean areas successfully.

- Keywords: district heating cooling (DHC), building energy analysis. technical and feasibility study, district energy, thermal energy generation.

RESUMEN

El objetivo de este artículo es presentar los resultados del estudio de viabilidad de una red de distribución de calor y frío para satisfacer la demanda de energía en un Parque Tecnológico y Científico bajo condiciones climáticas Mediterráneas.

El estudio ha sido desarrollado en tres fases: *evaluación de la demanda, análisis de la tecnología y estudio económico.*

Para cuantificar la demanda de energía se ha seguido una estrategia "*bottom-up*" basada en la identificación de edificios tipo. Mediante el SW de simulación Energy + se han obtenido las curvas de demanda de calor y frío de cada edificio tipo, teniendo en cuenta múltiples orientaciones. De acuerdo a los planes de desarrollo urbanísticos y a las previsiones de crecimiento del Parque Tecnológico de Andalucía, se ha realizado una evaluación de demanda en un horizonte temporal de 10 años.

Una vez caracterizada la demanda, han sido evaluadas las tecnologías más apropiadas para esta aplicación mediante SW de simulación TRNSYS: cogeneración (turbina de gas y motor alternativo de combustión interna), biomasa y tecnología convencional.

Finalmente se ha realizado un análisis económico para las distintas tecnologías en un

horizonte temporal de 20 años a fin de valorar la opción que mejor se adapte a esta aplicación concreta.

Este estudio avala que la tecnología de distribución de calor y frío, muy extendida en el norte de Europa, puede ser aplicada en zonas mediterráneas, apoyando así a la promoción de suministros de energía eficientes en áreas con una alta demanda energética.

Palabras clave: redes de distribución de calor y frío (DHC), análisis energético en edificios, viabilidad técnico-económico, energía de distrito, generación de energía térmica.

1. INTRODUCCIÓN

Teniendo en cuenta el marco energético actual, las redes de distribución de calor y frío, DHC en adelante, constituyen una alternativa para mejorar tanto los procesos de distribución de energía como los procesos de generación a nivel local, permitiendo incorporar diferentes fuentes de energía (combustibles, valorización de residuos energéticos o energía solar), que mejoren la eficiencia del ciclo completo *"generación-distribución-consumo"*.

Experiencias existentes en latitudes europeas más septentrionales han demostrado que las redes de distribución de calor representan una alternativa que, además de cubrir las necesidades energéticas, constituyen una solución de alta eficiencia para el suministro de energía. La producción de energía térmica a gran escala repercute positivamente en los rendimientos de los equipos de producción frente a una producción atomizada en la que las demandas son intermitentes, provocando que los equipos generadores funcionen a regímenes muy variables.

Este artículo presenta el estudio de viabilidad de una red de distribución de calor y frío para el abastecimiento de un determinado número de entidades que se establecerían en la futura ampliación del Parque Tecnológico de Andalucía ubicado en Málaga (España), analizando la adaptación de esta tecnología a los climas mediterráneos, caracterizados por temperaturas suaves, así como su adaptación en zonas industriales y tecnológicas.

2. METODOLOGÍA

El estudio se ha llevado a cabo en tres fases claramente diferenciadas: caracterización de la demanda, estudio de las mejores tecnologías disponibles y análisis económico.

2.1 CARACTERIZACIÓN DE LA DEMANDA DE ENERGÍA

La evaluación de la demanda de energía es el aspecto más crítico, puesto que determinará cuáles son las necesidades de calor y frío que deben ser satisfechas, lo que repercutirá de manera directa tanto en la elección de la mejor tecnología disponible como en el nivel de explotación económico de la red.

La complejidad en la determinación de la demanda de climatización de un grupo de edificios reside en el propio modelado de los edificios, ya que la caracterización de éstos está sujeta a múltiples variables (tales como climatología, localización, orientación, epidermis, usos, etc.); más aún si tenemos en cuenta que los edificios objeto todavía están por construir. Varios autores como Gustafsson [4], Heiple [5], Huang [6], Pedersen [7] o Segen [8] han desarrollado diferentes métodos para resolver estas dificultades. En el presente estudio, inicialmente se han considerado dos estrategias para la caracterización de la demanda de energía:

1. *Estrategia Top-down:* está basada en métodos estadísticos para la predicción de la demanda de un conjunto de edificios a partir de valores de demanda agregados para grandes núcleos de consumo (ciudades o regiones).

2. *Estrategia Bottom-up*: esta metodología es opuesta a la anterior, ya que como punto de partida toma "*edificios tipo"* resultando la demanda total como la suma de las demandas de cada uno de los edificios considerados. Para emplear esta metodología es requisito indispensable realizar un inventario de edificios del área objetivo de estudio de forma que todo edificio pueda ser asignado a uno de los edificios tipo definidos. Matemáticamente, esta metodología puede expresarse como sigue:

$$Demanda = \sum_{i=1}^{N}\left[A_i \cdot (\sum_{j=1}^{M} EUI_j \cdot P_{ij})\right] \quad [1]$$

donde A_i es la superficie neta de cada edificio, EUI_j es la demanda de energía anual para cada tipo de edificio (M tipos diferentes) y P_{ij} es la matriz que establece la relación entre el tipo de edificio y su superficie.

Apoyado en los trabajos propuestos por Chow [9], para el estudio se ha elegido una estrategia *bottom-up*. A pesar de no conocer el uso y tipo de cada edificio que se establecerá en la ampliación del PTA, se dispone de la superficie total de la ampliación (651.334 m^2), el porcentaje de esta área dedicado a cada uso según el plan urbanístico y el área neta de cada parcela. Para dar solución a la incertidumbre relativa al desconocimiento de la tipología de cada edificio, se asume que los nuevos edificios que ocuparían las nuevas parcelas mantendrán características similares a los ya existentes en el propio parque.

Por ello y con el objetivo de caracterizar con exactitud los edificios presentes en el PTA y poder modelar edificios tipos, se ha realizado un estudio pormenorizado de las características constructivas y de uso de cada uno. En dicho estudio se han tenido en cuenta las siguientes propiedades:

- **Características envolventes:** debido a la gran variedad constructiva presente en el PTA, se han tomado los valores mínimos normativos recogidos en el *Código Técnico de la Edificación* (CTE), ya que los nuevos edificios deberán cumplir los mínimos exigidos en este documento.

- **Superficie acristalada:** se han clasificado los edificios según tres niveles de acristalamiento respecto a la superficie de cerramiento exterior total: poco acristalados (<10%), acristalamiento medio (10-75%) y muy acristalados (>75%).

- **Orientación de los edificios:** caracterizados para las orientaciones predominantes.

- **Uso:** se han considerado las empresas actuales presentes en el PTA y el reparto de usos recogido en el plan de ordenación urbanística.

Teniendo en cuenta los aspectos anteriores, se han modelado los siguientes edificios tipo:
- Hotel con centro comercial
- Guardería
- Industria ligera
- Edificio de oficinas

En el caso de edificios de oficinas se ha detectado una gran variabilidad en cuanto a la superficie acristalada, por los que se han distinguido en el modelo de oficinas los tres niveles de acristalamiento indicados anteriormente.

En la siguiente figura se muestra el aspecto exterior de los edificios modelados:

Para validar el desarrollo de dichos modelos se han tomado valores de referencia procedentes de diversos análisis de consumo en viviendas [10], [11], [12].

De cara a cuantificar la tasa de implantación de nuevos empresas se han utilizado técnicas de extrapolación a partir de los datos históricos registrados desde la apertura del PTA según se muestra en la siguiente figura:

Fig. 1: Características de los edificios existentes en el actual PTA

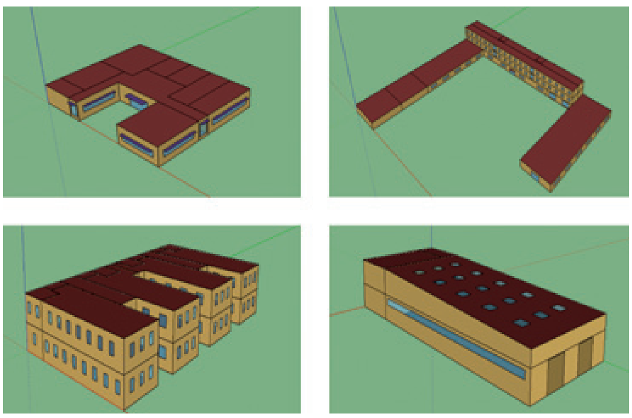

Fig. 2: Modelado de los edificios en Energy Plus

Fig. 3: Evolución del número de empresas instaladas en el PTA

La curva polinómica que sigue la evolución de crecimiento del PTA es de orden 4, con la que se obtiene un coeficiente de correlación de 0,9978.

$$y = -0{,}0031 \cdot x^4 + 0{,}0482 \cdot x^3 + 1{,}853 \cdot x^2 - 1{,}2072 \cdot x + 14{,}605 \quad [2]$$

A través de la evolución de empresas, considerando el número de empresas por edificio y la superficie por empresa en el año 2009, 751,9 m²/empresa, se obtiene la evolución equivalente en lo que a superficie se refiere para los próximos 10 años.

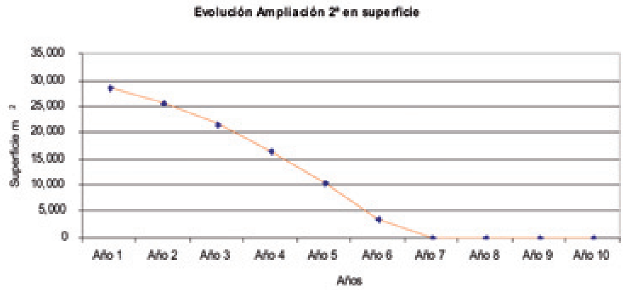

Fig. 4: Evolución de los m² edificados para nuevas empresas en los próximos 10 años.

Con esta curva de evolución de la superficie edificada y considerando como superficie de los edificios la de los modelos desarrollados, la ubicación de edificios en la nueva ampliación del PTA es la que se muestra:

Fig. 5: Ubicación de los edificios considerados en la ampliación 2ª del PTA

siendo:

- Edificio industrial
- Edificio de oficinas con acristalamiento medio
- Hotel
- Guardería
- Edificio de oficinas muy acristalado
- Edificio de oficinas poco acristalado

Así, año tras año se van incorporación edificios modelados siguiendo la curva de superficie presentada en la figura 4, generando una curva de demanda energética en continuo crecimiento hasta el año 7.

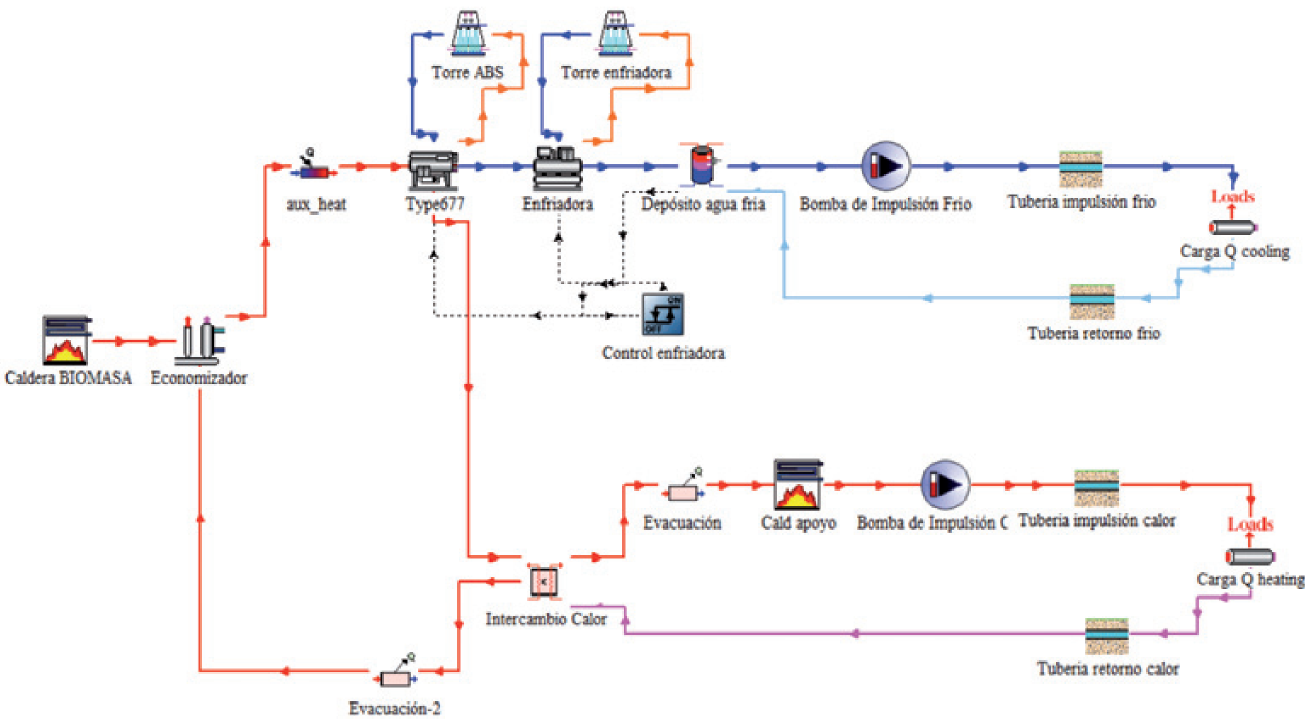

Fig. 6: Modelo TRNSYS. Caldera de biomasa

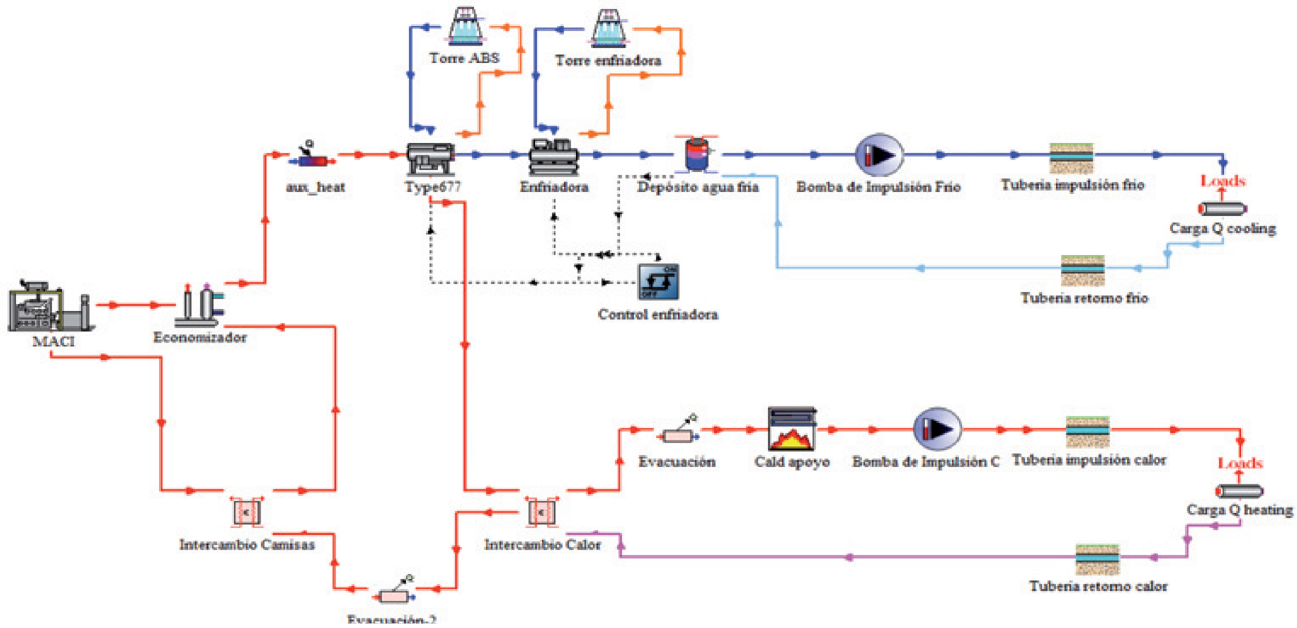

Fig. 7: Modelo TRNSYS. Motor alternativo de combustión interna

2.2 TECNOLOGÍAS DE GENERACIÓN DE ENERGÍA

Para el análisis de tecnologías, se ha hecho uso del SW de simulación TRNSYS que permite realizar simulaciones dinámicas evaluando la eficiencia y los parámetros de consumo.

Previo al desarrollo de los modelos, ha sido analizado un amplio abanico de tecnologías basado en los trabajos de Cardona [13], Marimon [14], Ortiga [15] y Söderman [16]. Se ha optado por:

Caldera de biomasa para aprovechamiento de residuos leñosos: en este caso la tecnología incluye una caldera de biomasa de 20 MW para el calentamiento de agua que alimenta a la red de distribución de calor y al sistema de generación de frío.

Cogeneración (CHP-*Combined Heat and Power*): las dos tecnologías de generación consideradas han sido la tecnología de turbina de gas (TG en adelante) y la tecnología de motor alternativo de combustión interna (MACI en

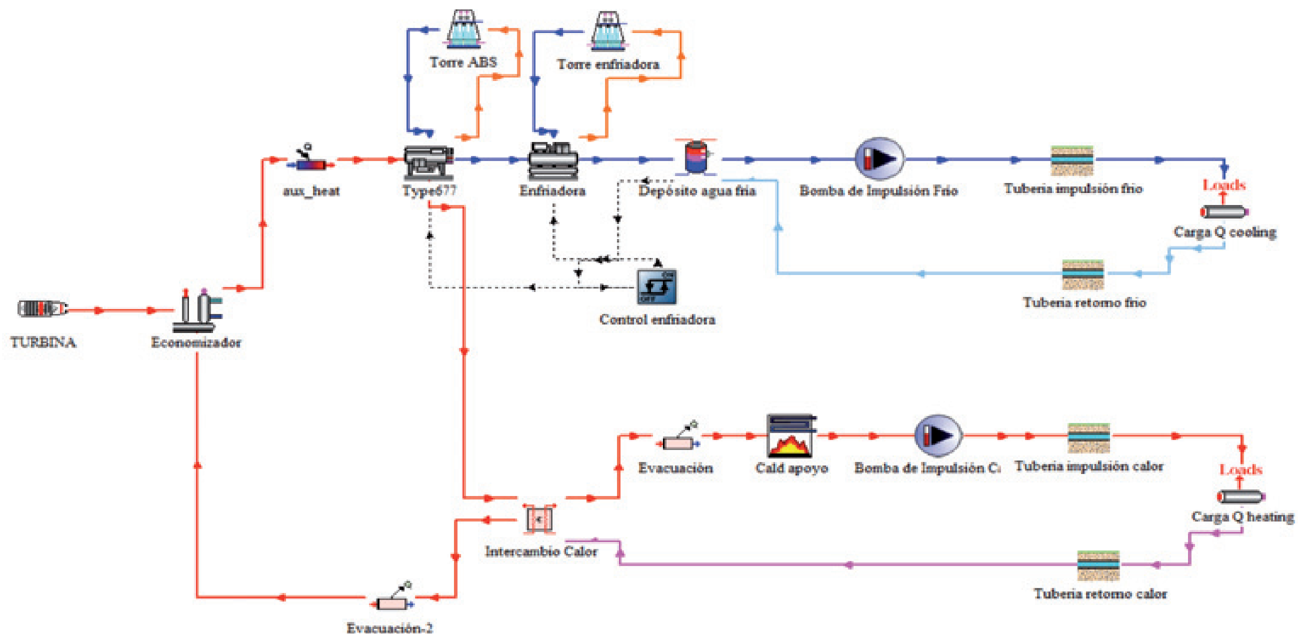

Fig. 8: Modelo TRNSYS. Turbina de gas.

adelante). El dimensionado de los equipos en cada caso se ha realizado siguiendo las recomendaciones aportadas por Cardona [13], Ortiga [15] y Söderman [16], y teniendo en cuenta el marco normativo de aplicación [18].

Energía solar térmica: esta tecnología no ha sido considerada como alternativa de apoyo a la generación de energía debido a dos razones fundamentales: el alto coste de adquisición de la tecnología y las grandes superficies requeridas para el establecimiento de éstas que no la hacen competitiva desde una perspectiva económica. (Bruno [17]).

Tecnología de generación de frío: para la producción de frío se ha elegido una máquina de absorción de doble efecto LiBr para cubrir la demanda de frío considerada. Esta elección se ha realizado teniendo en cuenta las ventajas y desventajas presentadas en los trabajos de Marimon [14]. Es importante señalar que si bien la tecnología de doble efecto proporciona rendimientos superiores requiere unas temperaturas de activación mayores que en el caso de simple efecto. Este mayor nivel térmico supondrá adecuar el régimen de funcionamiento tanto de la TG como del MACI para asegurar el nivel exergético del flujo energético. En todos los casos, se ha elegido una máquina con una potencia de 5,8 MW. Adicionalmente se ha elegido un depósito de acumulación de frío de 15.000 m^3.

Es muy importante destacar que en todos los casos se ha acoplado en paralelo tecnologías convencionales compuestas por enfriadoras eléctricas y calderas de gas escalables (hasta 6 y 9 MW respectivamente). Esto se ha hecho con un doble objetivo, en primer lugar garantizar el suministro de energía ante cualquier eventualidad y en segundo lugar evitar que durante los primeros años los sistemas de producción estén funcionando a muy bajos niveles haciendo que en muchos casos estén parados.

Para evaluar las prestaciones de cada tecnología, se han considerado los siguientes parámetros:

- **Rendimiento eléctrico equivalente (REE)** definido como:

$$REE = \frac{E_{el}}{E_{input\_by\_fuel} - \dfrac{H}{\eta_{boiler}}} \qquad [3]$$

siendo:
E_{el}: energía eléctrica generada.
$E_{input\_by\_fuel}$: energía necesaria para activar el sistema.
H: producción de calor útil.
η_{boiler}: valor de referencia del rendimiento para la producción separada de calor.

- **Consumo neto de energía primaria (CNEP):** definida para comparar los consumos de energía en cada caso. La expresión matemática para el consumo de energía primaria es:

$$CNEP = (E_{el\_cons} - E_{el}) \cdot C_1 + (E_{input\_by\_fuel}) \cdot C_2 + (E_{input\_by\_biomasa}) \cdot C_3 \qquad [4]$$

donde
C_1: factor de conversión de energía final eléctrica
C_2: factor de conversión de energía final para gas natural
C_3: factor de conversión de energía final para biomasa

Estos valores son 2.28, 1.07 y 1.25 respectivamente [19].

- **$COP_{instalación}$** definido como:

$$COP_{instalación} = \frac{E_{térmica}}{E_{combustible} - E_{producida}} \qquad [5]$$

siendo
$E_{térmica}$: energía térmica (calor y frío) producido por el sistema y puesta en servicio en los puntos de consumo.
$E_{eléctrica}$: energía eléctrica generada por el sistema consumida por el sistema.

- **Ahorro de energía primaria (PES)** definido como:

$$PES = \left[1 - \frac{1}{\dfrac{CHPH_\eta}{RefH_\eta} + \dfrac{CHPE_\eta}{RefE_\eta}}\right] \cdot 100 \qquad [6]$$

siendo:

PES: porcentaje de ahorro de energía primaria respecto de la que se hubiera consumido en generación separada de calor y electricidad y/o energía.

$CHPH_\eta$: es la eficiencia térmica de la producción mediante la cogeneración definida como la producción anual de calor útil procedente de la cogeneración dividida por la aportación de combustible utilizada para generar la suma de la producción útil de calor y electricidad procedentes de la cogeneración.

$CHPE_\eta$: es la eficiencia eléctrica de la producción mediante cogeneración definida como la electricidad anual producida por cogeneración dividida por la aportación de combustible utilizada para generar la suma de la producción de calor útil y electricidad procedentes de la cogeneración.

$RefH_\eta$: es el valor de referencia de la eficiencia para la producción separada de calor. [24]

$RefE_\eta$: es el valor de referencia de la eficiencia para la producción separada de electricidad. [24]

Estos parámetros permitirán por un lado asegurar que se cumplen los requisitos establecidos en el RD 661/2007 [18] y por otro lado, conocer el funcionamiento global del sistema. Asimismo, a partir de estos parámetros se llevará a cabo el estudio económico.

2.3 DIMENSIONADO DE LA RED DE DISTRIBUCIÓN

El dimensionado de la red ha sido realizado empleando los valores pico de demanda de energía de forma que la red pueda abastecer a los consumidores finales en cualquier circunstancia. El diseño se ha realizado considerando la demanda pico en el horizonte temporal de 10 años, ya que una vez se acometa la infraestructura relativa a la red, ésta no podrá ser modificada. Bajo estas premisas se han dimensionad: tuberías, depósitos de acumulación y equipos de impulsión.

Para definir el trazado de la red se ha optado por definir el caso más desfavorable siendo éste aquel en el que la central de producción de energía se encuentra en uno de los límites del área de estudio. Esta situación, si bien no afecta directamente a la longitud total de la red, sí afecta a los caudales a tratar y a las pérdidas de carga y energía asociadas. En la siguiente imagen se muestra el trazado de la red propuesta:

Fig. 9: Trazado de la red de distribución de calor y frío

Con este esquema no se pretende hacer una descripción exhaustiva de la red. De cara al diseño en esta fase de estudio, la importancia reside en la definición de la longitud máxima de la red, es decir la distancia entre los extremos del esquema presentado en la figura anterior. Bajo este enfoque, consideramos que la central de producción podría estar en uno de los dos extremos de la red presentada.

En cuanto a las características operativas se han fijado los siguientes valores:

- Temperatura red de calor: 95/65 ºC
- Temperatura red de frío: 5/13 ºC
- Criterio de pérdidas de presión: 1-2 bar/km.
- Criterio de pérdidas de temperatura en la red de calor: 0,2 ºC/km
- Criterio de pérdidas de calor en la red de frío: 0,5 ºC/km

Si bien, en la mayoría de los casos las necesidades de los clientes en lo que a calefacción se refiere no van a ser superiores a 95 ºC, se ha elegido esta temperatura para asegurar la posible necesidad. Una vez más se ha optado por un criterio conservador ya que producir a temperaturas elevadas es costoso y las pérdidas en la red son mayores.

2.4 ANÁLISIS ECONÓMICO

El análisis económico se ha realizado considerando los siguientes aspectos:

- Costes de adquisición
- Costes de mantenimiento
- Costes de amortización
- Costes de operación (energía, recursos humanos, costes globales)
- Ingresos derivados de la venta de energía

Estos aspectos permiten evaluar las inversiones en términos de retornos de inversión, valor actual neto (VAN en adelante), payback y cash flow acumulado.

3. RESULTADOS

Los resultados obtenidos del desarrollo de las tres fases anteriores: demanda de energía, tecnologías de producción y evaluación económica son los siguientes:

3.1 DEMANDA DE ENERGÍA Y DISEÑO DE LA RED DE DISTRIBUCIÓN

Los resultados obtenidos para los modelos una vez ajustados a los valores de referencia [10], [11], [12] son los que se muestran en la siguiente Tabla:

Uso	Ratio consumo (kWh/m^2)	Refrigeración %	Calefacción %	Iluminación %	Equipamiento %	ACS %
Oficinas	131,57	42	4	39	15	-
Guardería	43	5	60	17	15	3
Industria ligera	214,66	33	15	34	18	-
Hotel	312,66	28	12	29	24	7

Tabla 1: Valores teóricos de demanda de energía

A partir de estos modelos agregando año a año la incorporación de nuevos edificios se obtienen los perfiles horarios de demanda para calefacción y refrigeración para la ampliación objeto de estudio considerando la evolución de demanda a lo largo de los 10 próximos años en la que se aprecia un crecimiento constante debido a la ocupación de nuevas parcelas.

La evolución mensual de la demanda de calefacción y refrigeración a lo largo de los primeros 6 años son los que se muestran en las siguientes figuras. Tal y como se muestra en la Fig. 4, se ha considerado que la totalidad de edificios se establecerá en los 6 primeros años, por lo que, para el resto de años sucesivos la demanda de energía no sufrirá modificaciones.

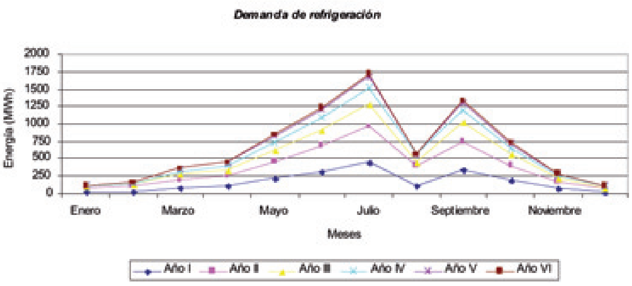

Fig. 10: Evolución de la demanda de refrigeración

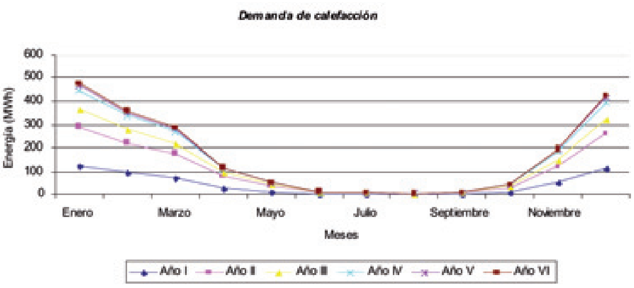

Fig. 11: Evolución de la demanda de calefacción

Como puede observarse, la demanda de refrigeración se reduce drásticamente en el mes de agosto ya que se ha considerado este mes como el período vacacional predominante.

En las figuras 12 y 13, se presentan las curvas agregadas de demanda tanto de calefacción como de refrigeración para el año 10. Estas curvas son muy útiles para dimensionar los equipos de cogeneración según [13].

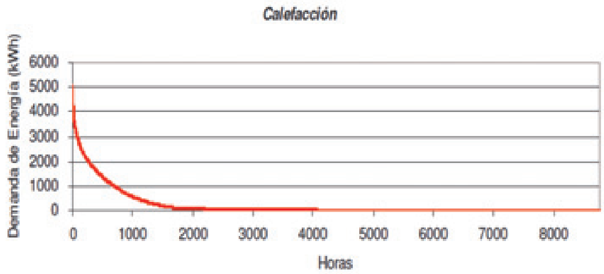

Fig. 12: Curva de demanda agregada. Calefacción

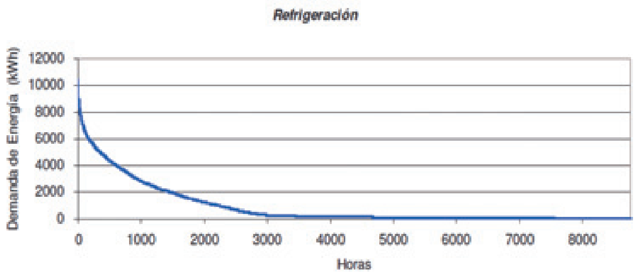

Fig. 13: Curva de demanda agregada. Refrigeración

Las gráficas de demanda agregada no es más que la representación de los valores de demanda ordenados de mayor a menor. Así por ejemplo para el caso de la Figura 13, observamos como un nivel de demanda de 2000 kWh o superior tiene lugar aproximadamente durante 1.500 horas al año.

Como se muestra en las figuras anteriores, la demanda pico para el año 10 queda fijada en 7,7 MW para calefacción y 12,22 MW para refrigeración.

Con estos valores de potencia máxima y considerando unos saltos de temperatura de 30ºC para calefacción y 8ºC para refrigeración, el caudal máximo para cada red son: 61,8 kg/s en calefacción y 364,6 kg/s para refrigeración. Estos valores de caudal garantizan aseguran unas pérdidas tanto de presión como de temperaturas adecuadas [23].

En la Tabla 2 se muestran los valores característicos de la red.

Es importante destacar la diferencia de tamaños entre la red de distribución de calor y la red de distribución de frío. Este hecho se debe a los niveles térmicos de cada una frente a los niveles térmicos de la demanda. Es decir, la diferencia de temperaturas en la red de calor es aproximadamente de 60 ºC mientras que en la red de frío el salto térmico es de unos 10 ºC, lo que hace que el caudal en este último caso tenga que ser mayor.

	DN tuberías (mm)	Espesor de aislamiento (mm)	Potencia de bombeo (kW)	Volumen de acumulación (m^3)
Cooling	600	7,1	315	15.000
Heating	350	5,6	75	-

Tabla 2: Parámetros de diseño de la red

3.2 EVALUACIÓN DE TECNOLOGÍAS

Una vez presentadas las características de los modelos y su simulación correspondiente, el desglose de resultados es el que se muestra en la siguiente Tabla resumen. En ella se muestran los cuatros aspectos fundamentales sobre cómo está teniendo lugar el aprovechamiento energético en cada caso.

	Consumo de energía primaria (MWh)	Ahorro de energía primaria	COP instalación	REE
Tecnología convencional	16.118,15	-	1.14	-
Caldera de biomasa	15.989,36	-	0,747	-
Turbina de gas	22.763,06	7,07 %	0,571	0,541
Motor alternativo de combustión interna	26.999,38	3,88 %	0,570	0,528

Tabla 3: Parámetros globales de las distintas tecnologías

De los resultados presentados en la tabla anterior, se pueden obtener diversas conclusiones de cara a discernir qué tecnología se adapta mejor a la aplicación objeto de estudio:

- En lo que respecta a flujos energéticos de entrada en los sistemas (consumo de energía primaria) es evidente cómo en los casos de trigeneración el consumo de energía de entrada es mayor, debido a que se está produciendo una doble generación eléctrica y térmica, lo que hace que el sistema sea más eficiente pero que también se requiera mayor cantidad de energía en el sistema.
- Si analizamos el parámetro de ahorro de energía primaria, en los dos primeros casos no aplica, ya que no existe producción de energía eléctrica. En los resultados obtenidos para las dos últimas alternativas vemos que, para la tecnología de TG, el ahorro de energía primaria es mayor debido al régimen de funcionamiento modelado. Así, para el caso de TG, se ha modelado un régimen de operación acorde al nivel de demanda, mientras que el MACI opera a carga constante. El comportamiento adaptativo a la demanda hace que se optimice el consumo de energía (mejor PES), pero disminuye la cantidad de energía eléctrica que como veremos en el siguiente punto penaliza la cuenta de resultados de la explotación.
- En cuanto al parámetro definido como COP de la instalación que representa el cociente entre energía térmica producida y la energía consumida (bien eléctrica o bien gas), es superior en los casos convencional y biomasa. Esto se debe a que mediante estas dos estrategias de suministro de energía se prioriza el consumo de energía térmica, mientras que, en los casos de MACI y TG, la producción de energía térmica y eléctrica simultanea hace disminuir este parámetro.
- Finalmente, el REE es un parámetro importante desde un punto de vista normativo. Así según el RD 661/2007 el REE equivalente mínimo en el caso de Gas Natural y GLP en motores térmicos es de 0,55, mientras que en el caso de Gas Natural y GLP en turbinas de gas es de 0,59. No obstante, si la potencia instalada es menor o igual a 1 MW, el rendimiento eléctrico equivalente se reduce un 10%, arrojando unos valores mínimos de 0,495 y 0,531. Como observamos, en el caso de la turbina de gas, dado el control modelado sobre la misma, el REE obtenido es ligeramente superior que en el caso del motor alternativo de combustión interna. Es importante señalar que para garantizar el cumplimiento normativo se han requerido equipos de producción más pequeños de los obtenidos mediante métodos de selección habituales. Esto, se debe a la propia naturaleza de la demanda de energía (curva de demanda inestable en el tiempo de acuerdo al horario de edificios de oficinas). De esta forma se han elegido dos motores de 514 kW_e y una turbina de gas de 1.000 kW_e ambos en el límite de instalaciones inferiores a 1 MW_e.

3.3 ANÁLISIS ECONÓMICO

La siguiente tabla muestra el análisis económico para cada tecnología evaluada mientras en la Figura 14 se muestra el *cash flow* acumulado en cada caso.

	Payback (años)
Tecnología convencional	> 20
Caldera de biomasa	>20
Turbina de gas	16,23
Motor alternativo de combustión interna	12,97

Tabla 4: Análisis económico

Desde una perspectiva económica, vemos cómo la variable producción de electricidad es la que dictamina cómo de buena será la inversión en términos monetarios. Como era de esperar, no es posible obtener un rendimiento positivo en las instalaciones de producción mediante

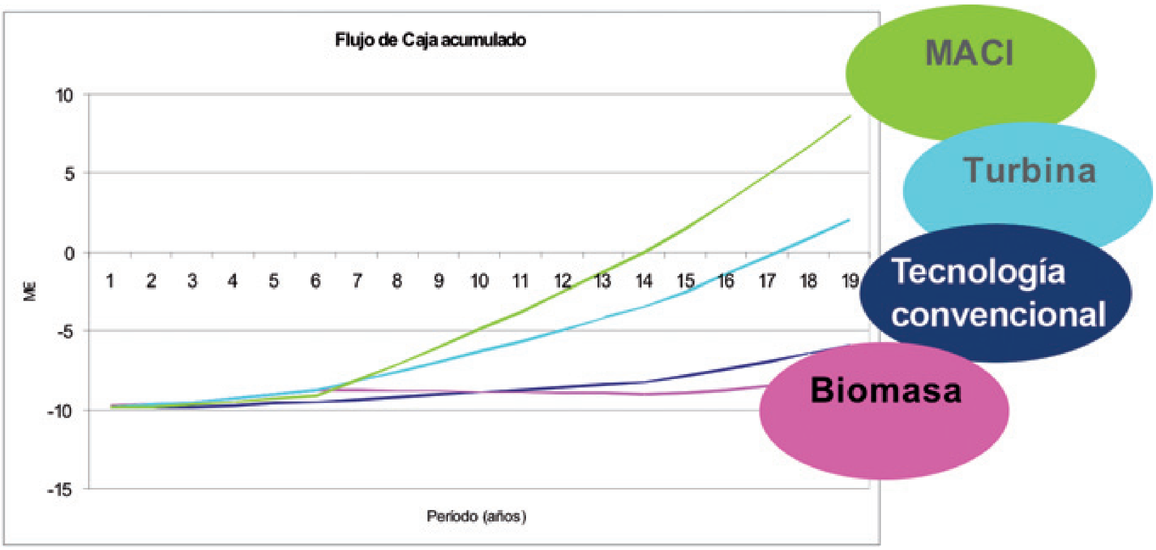

Fig. 14: Flujo de caja acumulado para cada tecnología estudiada

tecnología convencional o biomasa. El objetivo de estas instalaciones es suministrar energía térmica suficiente al parque edificatorio objeto de estudio. Esta situación no se da en el caso de las instalaciones de trigeneración, ya que en este caso la explotación del sistema reportará beneficios debido fundamentalmente a la venta de energía eléctrica. Idealmente desde el punto de vista del explotador de la instalación, éste desearía vender la mayor cantidad de energía eléctrica posible, si bien este hecho entra en conflicto directo con el cumplimiento normativo recogido en el RD 661/2007 en cuanto al rendimiento eléctrico equivalente y ahorro de energía primaria.

Teniendo en cuenta que el modelado del motor se ha hecho de forma que éste opera de manera continua, mientras que la turbina se adapta a la demanda de cada instante, implica que los resultados de explotación sean más favorables en el caso del MACI.

4. CONCLUSIONES

Como puede observarse en la Tabla 4, la tecnología que ofrece un menor período de retorno de inversión es el Motor Alternativo de Combustión Interna seguido de la Turbina de Gas. Este hecho es consecuencia directa de los ingresos derivados de la venta de energía eléctrica. Para el caso del MACI, los beneficios comienzan a ser positivos a partir del año 13.

Es evidente que los costes de adquisición e implantación de la red de distribución son muy elevados y que es crucial garantizar un adecuado nivel de demanda en el futuro, pero bajo las hipótesis de trabajo consideradas, la tecnología MACI resulta atractiva dado el volumen de ingresos si bien el *payback* es muy elevado para este tipo de inversiones.

A modo de resumen las conclusiones derivadas del estudio son las siguientes:

- Como se ha expuesto una curva de *demanda diaria intermitente* dificulta la viabilidad de este tipo de instalaciones, siendo más adecuada en aquellas situaciones donde la curva de demanda diaria es uniforme. El hecho de que la demanda de energía sea intermitente implica que sea necesario recurrir a equipos de producción más pequeños.

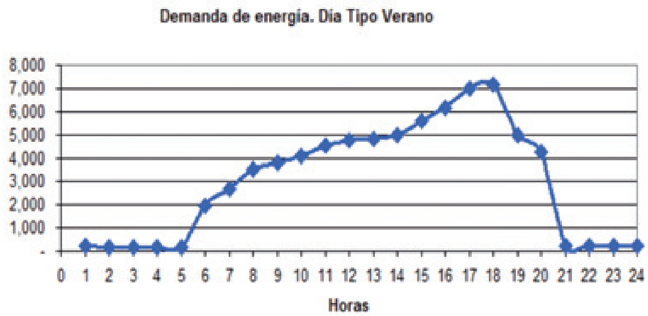

Fig. 15: Curva de demanda de refrigeración. Día tipo de verano

En la gráfica se observa cómo en horario fuera de oficinas la demanda cae drásticamente repercutiendo negativamente en el REE de la instalación y obligando a ésta a reducir su régimen de funcionamiento.

- Gran dependencia con la tasa de establecimiento de nuevas empresas. El estudio realizado está sujeto a la velocidad de establecimiento de nuevas empresas ya que de otra forma las inversiones realizadas no se recuperarán en un plazo de tiempo razonable. Por esta razón se propone en los primeros años de evolución de la demanda un suministro de energía convencional que sea modulable a la demanda y que finalmente constituya un sistema de apoyo en el caso de dificultades de suministro. Por esta razón se contemplan enfriadoras y caldera de elevada potencia (6 y 9 MW).

- Necesidad de grandes inversiones → elevados períodos de recuperación de inversión.
- CHP: MACI y TG son las MEJORES opciones técnicamente y económicamente.
- La venta de energía eléctrica es decisiva de cara a garantizar la viabilidad económica.
- Modelo de negocio: necesidad de colaboración público-privada para hacer frente a las fuertes inversiones iniciales. Es importante tener en cuenta que para una red como la planteada con una longitud de 4 kilómetros el coste de la misma asciende a 7,5 M€ según el precio de mercado.
- La posibilidad de integración de energía solar ha sido descartada debido a dos factores fundamentales, en primer lugar los elevados niveles térmicos requeridos para la activación térmica de la máquina de absorción, lo que implicaría por un lado la necesidad de recurrir a tecnologías de última generación y, en segundo lugar, los elevados niveles energéticos puestos en juego suponen la implementación de instalaciones de gran superficie con la consecuente ocupación de suelo necesaria que las hace inviable desde un punto de vista económico.

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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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Energy 134 (2017) 438 - 448

Author attribution J.P. Jiménez-Navarro and J.M. Cejudo designed the study. J.P. Jiménez-Navarro developed the optimization model; J.M. Cejudo and D. Connolly validated the model; J.P. Jiménez-Navarro implemented the case study and performed the analysis; J.M. Cejudo validated the results; J.P. Jiménez with comment from the co-authors wrote the manuscript.

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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,

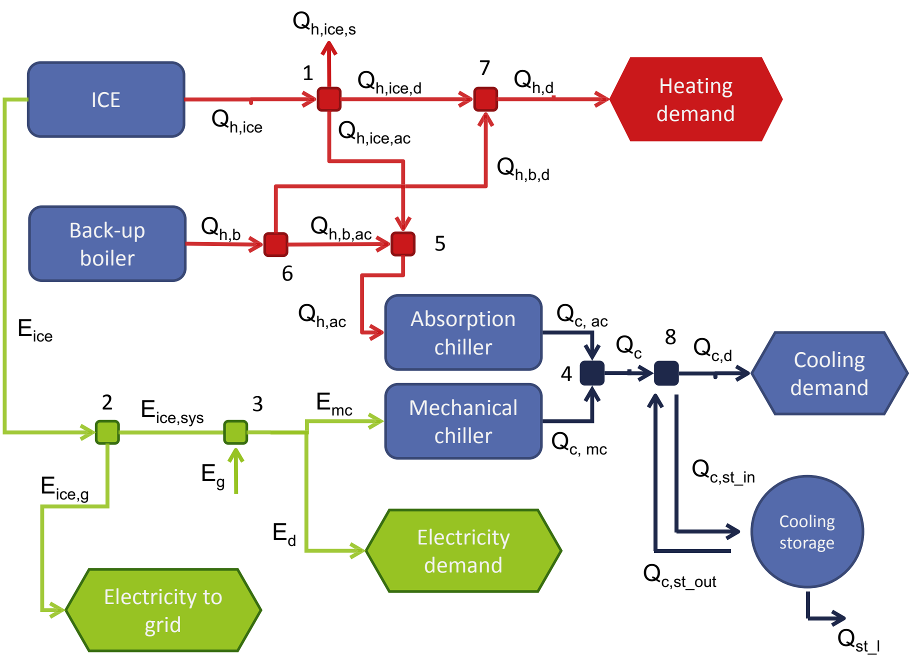

Fig. 1. Scheme for a combined heating, cooling and power facility.

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:

$LDC_o \equiv$ original load duration curve
$LDC_e \equiv$ 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:

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

$n_{ice} \equiv$ number of prime mover units
$n_{ac} \equiv$ number of absorption units
$n_{mc} \equiv$ number of mechanical units
$n_b \equiv$ number of back-up boiler units
$n_{st} \equiv$ 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.

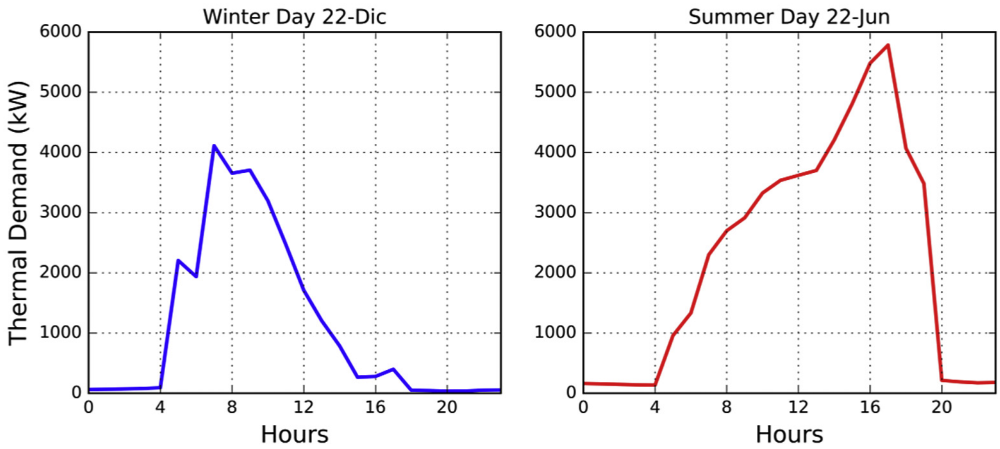

Fig. 3. Load profile for a winter day (left) and a summer day (right).

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

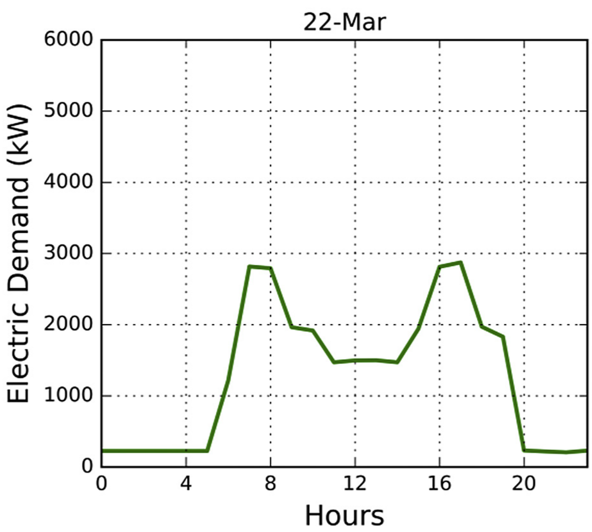

Fig. 4. Daily electric load profile.

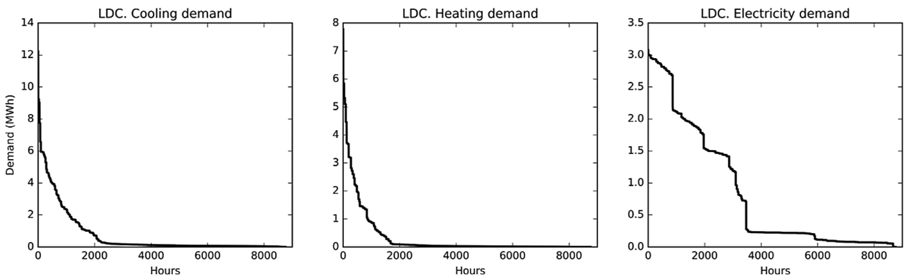

Fig. 5. Generated load duration curves (LDC) for the selected number of typical days. Cooling demand (a), heating demand (b) and electricity demand (c).

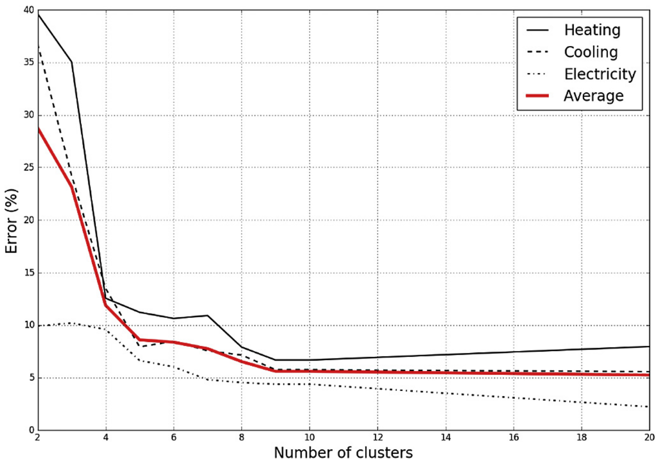

Fig. 6. Analysis of clustering exercise to reduce sampling data in the optimisation problem.

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

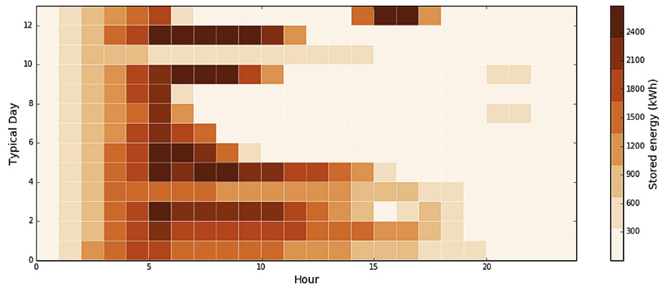

Fig. 7. Stored energy. FiT scenario.

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 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%.

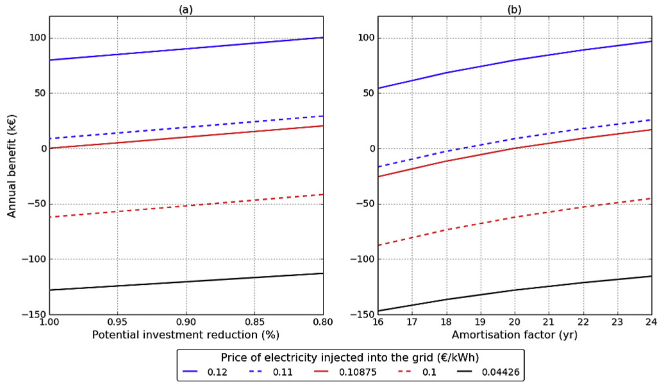

Fig. 9. Effect of the potential investment reduction (a) and amortisation factor (b) on the annual benefit.

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

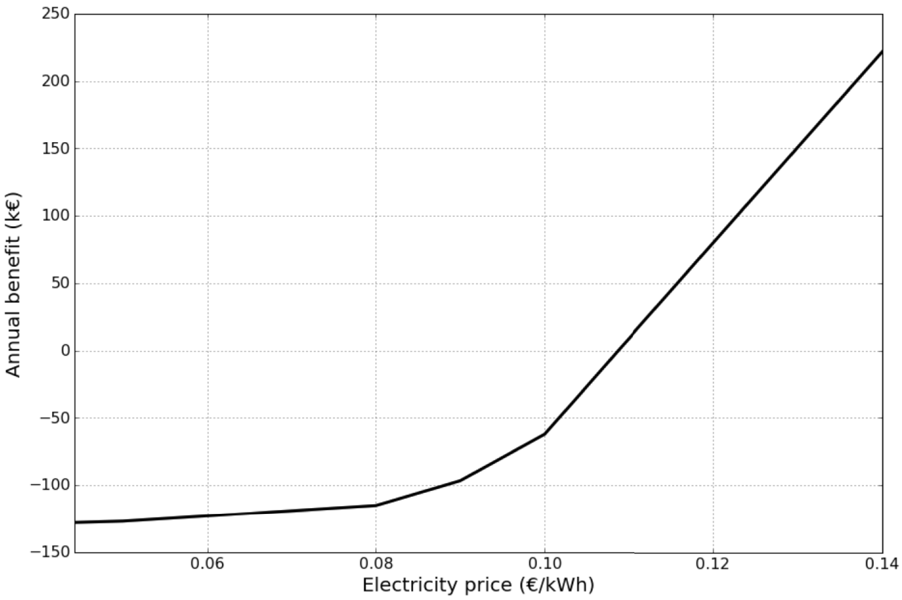

Fig. 8. Effect of the electricity price on annual benefits.

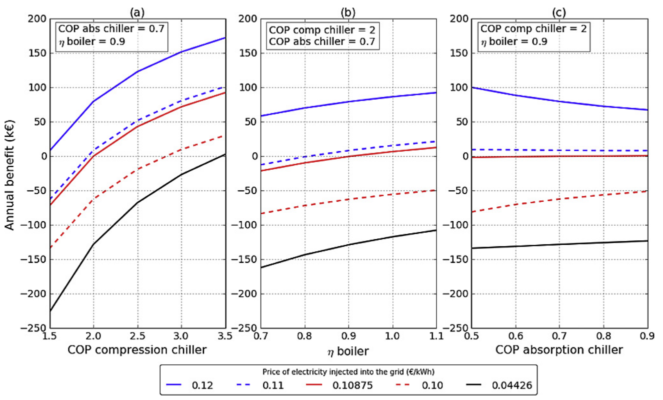

Fig. 10. Changes in the annual benefit according to different energy performances for (a) compression chiller, (b) back-up boiler and (c) absorption chiller.

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.

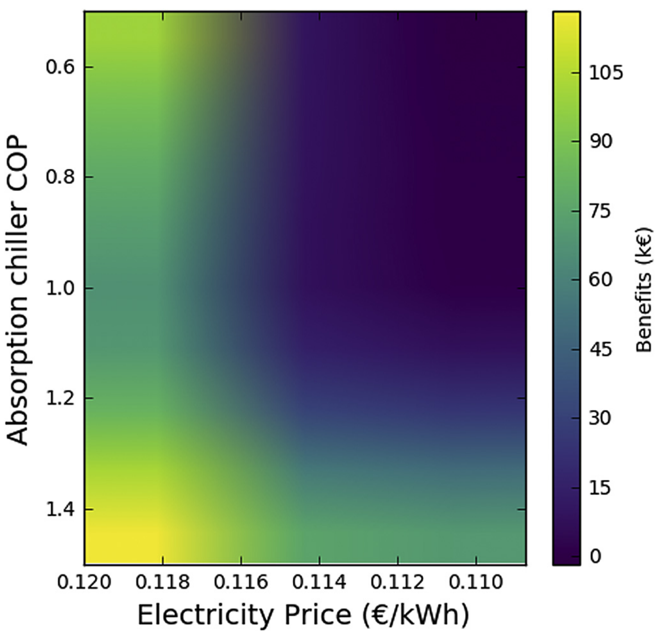

Fig. 11. Evolution of benefits by modifying absorption chiller COP and the price of the electricity injected in the grid.

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.

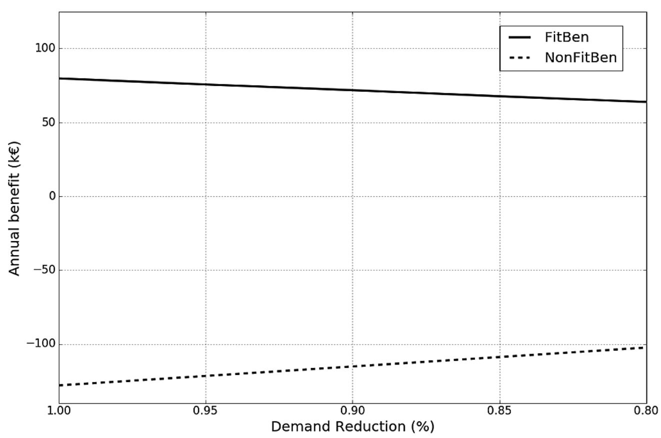

Fig. 12. Effect of demand reduction.

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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Author attribution K.C. Kavvadias and S. Quoilin have developed the background model; J.P. Jiménez-Navarro, K.C. Kavvadias and A. Zucker have defined the case study. J.P. Jiménez-Navarro have collected and processed all the input data required in the study; K.C. Kavvadias and J.P. Jiménez-Navarro have launched the simulations; J.P Jiménez-Navarro have processed the simulation results; J.P. Jiménez and K.C. Kavvadias with comment from the co-authors wrote the manuscript.

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The joint effect of centralised cogeneration plants and thermal storage on the efficiency and cost of the power system

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The coupling of the heating and the electricity sectors is of utmost importance when it comes to the achievement of the decarbonisation and the energy efficiency targets set for the 2020 and 2030 in the EU. Centralised cogeneration plants connected to district heat networks are fundamental element of this coupling.

Despite the efficiency benefits, the effects of introducing combined generation to the power system are sometimes adverse. Reduced flexibility caused by contractual obligations to deliver heat may not always facilitate the penetration of renewable energy in the energy system. Thermal storage is acknowledged as a solution to the above.

This work investigates the optimal operation of cogeneration plants combined with thermal storage. To do so, a combined heat and power (CHP) plant model is formulated and incorporated into Dispa-SET, a JRC in-house unit commitment and dispatch model. The cogeneration model sets technical feasible operational regions for different heat uses defined by temperature requirements.

Different energy system scenarios are used to assess the implications of the heating–electricity coupling to the flexibility of the power system and to the achievement of the decarbonisation goals in an existing non interconnected power system where CHP plants provide heating and electricity to nearby energy dense areas.

The analysis indicates that the utilisation of CHP plants contributes to improve the overall system efficiency and reduce total cost of the system. In addition, the incorporation of thermal storage increases the penetration of renewable energy in the system.

1. Introduction

Renewable energy has experienced a rapid growth in the past years supported by energy policies that pursue the decarbonisation of the energy system and thus contributing to the climate change mitigation. The energy transition, from traditional fossil-fuel and nuclear based energy systems to sustainable energy systems, requires the integration of large-scale of intermittent renewable sources [1]. For this reason, future energy systems should rely on the "smart energy system" concept based on the integration of multiple energy sectors [2].

In the particular case of the heating and cooling sector, its integration with the electricity sector enables the utilisation of available technologies such as heat pumps or combined heat and power (CHP) plants [3].

To achieve a large scale integration, the deployment of thermal networks, recognised as a cost effective way of decarbonising the energy system [4], becomes fundamental.

In the European context, the heating and cooling sector has been recently recognised as a priority to achieve decarbonisation targets. Accounting for half of the EU energy consumption, the sector is characterised by low efficiencies and large amounts of waste heat [5].

While there is room for energy efficiency improvements

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especially in the European residential and tertiary sectors, a holistic energy system approach is required, meaning the aforementioned integration of different sectors such as transport, electricity and heating sector itself [6]. This not only allows the evaluation of all potential options for a future sustainable energy system, but also the assessment of its feasibility and the identification of operational bottlenecks. One such bottleneck is the lack of flexibility of the power system with high shares of variable renewable energy sources. Based on this approach, the study of the heating and electricity sector coupling is of outmost importance given the size of the heating sector on one hand and the opportunity of their linkage to integrate more renewable power generation via different thermal energy solutions offers on the other [7,8].

Among other advantages, this linkage may enable thermal energy storage, widely acknowledged as a key enabling technology to decarbonise power systems [9,10]. Off-peak electricity can be used to heat water in storage tanks to perform daily load shifting. Compared to electrical energy storage, thermal energy storage is 100 times cheaper in terms of investment per unit of storage capacity, which makes it an attractive solution to increase flexibility and maximise the use of available energy sources [11].

Combined heat and power (CHP) plants, which can reach an overall efficiency of up to 90% [12], are important elements of this linkage. They have been recognised in the EU as the most efficient way to generate useful energy from fossil-fuelled energy sources [13].

However, despite this high efficiency, the integration of CHP in energy systems with high share of renewable sources may bring negative effects without available thermal storage leading to a reduction of the overall system efficiency [14]. Obligations to satisfy a given heat demand reduces the flexibility of the CHP operation and limits the integration of RES sources. For this reason, thermal storage is not only an attractive solution but also essential to achieve flexible energy systems [15].

The utilisation of CHP and thermal storage with new generation of district heating networks could even maximise the utilisation of both electricity and heating. These new district heating networks, also known as 4th generation district heating systems (4GDH) and characterised by low temperatures (30–70 °C), facilitates the integration of multiple energy sources, even those with low quality from an exergy perspective. The transition to these new 4GDH is expected to take place within the timeframe 2020–2050 [1].

The reduction of the temperature allows the CHP plant to extract heat in a late stage of the expansion process in the steam turbine, reducing the amount of electricity that is lost and consequently increasing the overall CHP efficiency.

To sum up, combined heat and power technologies in combination with efficient district heating networks and competitive thermal storage, set the ground for achieving more flexible and efficient energy systems [3]. All these opportunities may unlock the full potential of district heat networks, which currently have only reached a ten percent share of the total heat supply worldwide, but with high discrepancies between countries [16].

In the literature, a set of studies on the optimal operation of CHP plants have been focused on the minimisation of the power system costs. Under this approach some authors have worked on the validation of different mathematical approaches using linear, mixed-linear or non-linear programming methods [17–20] regardless of the quality of the heat produced and its adequacy to meet specific heat applications. Other authors have studied thermo-economic aspects of the operation of CHP plants to optimise their operation such as temperature and pressure of the input steam flow and mass flows rates from an energy and exergy economic approach [21].

To a certain extent, and driven by the evolution of modern thermal networks that allows a wide range of operating temperatures, this work focuses on both aspects: the minimisation of the power system costs including the cogenerated heat and the analysis of the quality of the heat based on the demand side temperature requirements. This approach allows a more thorough analysis of the benefits derived from low-temperature heat networks when operating a CHP plant. Thus, the scope of this work is to present a method to co-optimise and analyse the operation of a power and heating system combined with thermal storage under different energy market assumptions and thermal requirements.

This method is based on a detailed model of the short-term operation of large-scale power systems and the results are presented and discussed via a comprehensive scenario analysis of a case study.

The paper is organised as follows: section 2 presents the model implemented, and section 3 sets out the experimental design including the baseline power systems. Section 4 covers results derived from the different scenarios and section 5 present the conclusions of the benefits derived from the linkage between heating and cooling sectors.

2. Methods

2.1. Model background

This work is built upon the Dispa-SET model, an open source unit commitment and dispatch model of the European power system. The aim of this model, implemented as a mixed-integer linear programming, is to optimise, at an hourly time step resolution and with a high level of detail, the short-term operation of large-scale power system, solving the unit commitment problem. The objective function of this model minimizes the total power system costs, which are defined as the sum of different cost items, namely: start-up and shut-down, fixed, variable, ramping, transmission-related and load shedding (voluntary and involuntary) costs. The results include the optimal mix of power plants production, including renewable sources, that satisfies electricity demand at minimum cost over one year. All the modifications performed for this paper are released as version 2.2, which is available online[1] [22].

To assess the interaction between heating and electricity sectors, a heating module has been developed and integrated into the existing model. It includes two main elements; the formulation of cogenerated steam-driven plants module that produce both power and heat and the thermal heat storage module. In the following section a detailed explanation of the CHP and storage models is provided.

2.2. CHP model

In this section the background for the proposed CHP model and its mathematical formulation are presented.

2.2.1. CHP categories and operation regions

In order to model the different operation alternatives provided by CHP, we have taken advantage of the pioneering work developed in [23]. Accordingly, steam-based CHP plants fall into two categories: plants with a backpressure turbine and plants with an extraction/condensing turbine.

In the first group, the different energy production options are given by a bundle of fixed relations between the electricity and the heat production depending on the required output temperature of

[1] www.dispaset.eu.

the heat flow that feeds a certain DH. Thus, for a required output temperature (T1) these turbines could operate along a unique line A-B. (Fig. 1a).

In the latter, the heat production is more flexible, due to the availability of a cold condensing unit at the end of the steam expansion — cold-condensing tail. For this types of turbines the feasible operation region (FOR) is defined by the area ABCD, for a required output temperature (T1) (Fig. 1b).

The flexible operation provided by the extraction-condensing units is modelled as a two-dimensional (E-Q) feasible operation region (FOR). This approach enables a robust formulation of the dispatch optimization problem from a mathematical perspective as it leads to a convex optimization area. Thus, this type of turbines is considered for the proposed analysis.

In the study, it is also assumed a fixed DH supply temperature — selected as design temperature — for each configuration. Under these assumptions, for each scenario the FOR is described by the power-loss line at maximum power (line A-B) and the power-loss line at minimum power (line E-D) as defined by the power-loss factor (β), and the line of maximum heat that, for a given fuel input, could be extracted guaranteeing the minimum required temperature at the end of the expansion process (line D-C). This line is defined by a fixed power-to-heat ratio (σ). Finally, the maximum heat extracted could also be limited due to technical constraints (line B-C) related to the minimum flow that has to pass through the last stages of the turbine (Fig. 2).

Hence, a CHP power plant can be defined by three parameters (β, σ, Q_{max}) in addition to the technical minimum and maximum power limits (P_{max} and P_{min}) (Table 1).

2.2.2. The effect of temperature of extraction in the operation of the CHP plants

As described in the previous section, β and σ depend on the design of the supply temperature required in the thermal network [24,25] while P_{max} and P_{min} are given by technical limits of the turbine.

Based on these two parameters (β and σ), for a range of DH supply temperatures, the FOR is modified leading to a trade-off between power and heat outputs. Thus, the higher the extraction temperature is, the lower the limit for the maximum electricity production and the higher the amount of heat that could be extracted.

In addition, the selection of these DH supply temperatures determines the maximum efficiencies and the point of maximum heat and power at which the plant can operate.

To mathematically describe the relation between the DH supply

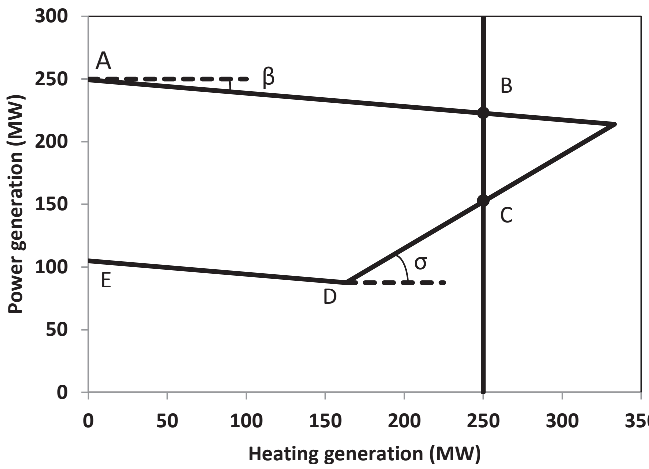

Fig. 2. Feasible operation region for a CHP plant for a given DH input temperature.

temperature and the two parameters, we have approximated the CHP plant as a virtual steam cycle heat pumps [26]. Based on this concept, electricity is sacrificed in order to deliver heat at a higher temperature. Under this assumption the parameter β is equal to the efficiency of a virtual steam cycle between T_{ext} — DH supply temperature — and T_{cond}. For the temperature range under consideration (<120 °C) we can safely use the Carnot cycle with minimum loss in accuracy (less than 5%).

Then if we assume that the CHP plant operates without heat production, its efficiency, equals to the electric efficiency (Fig. 3a), is given by Eq. (1)

$$\eta = \frac{W}{Q_{ls}} \approx 1 - \frac{T_{cond}}{T_{ls}} \tag{1}$$

where:

T_{ls} ≡ Temperature of the life steam input flow
T_{cond} ≡ Condensing temperature, typically assumed as 10 °C higher than the ambient temperature to guarantee heat transfer in the condenser.

Applying the same expression for the two-steps Carnot cycle between the temperatures T_{ls} and T_{ext} (Fig. 3b) while keep-ingenergy input (Q_{ls}) constant, we obtain a relation between the amounts of electricity produced in both cases, given by Eq. (2),

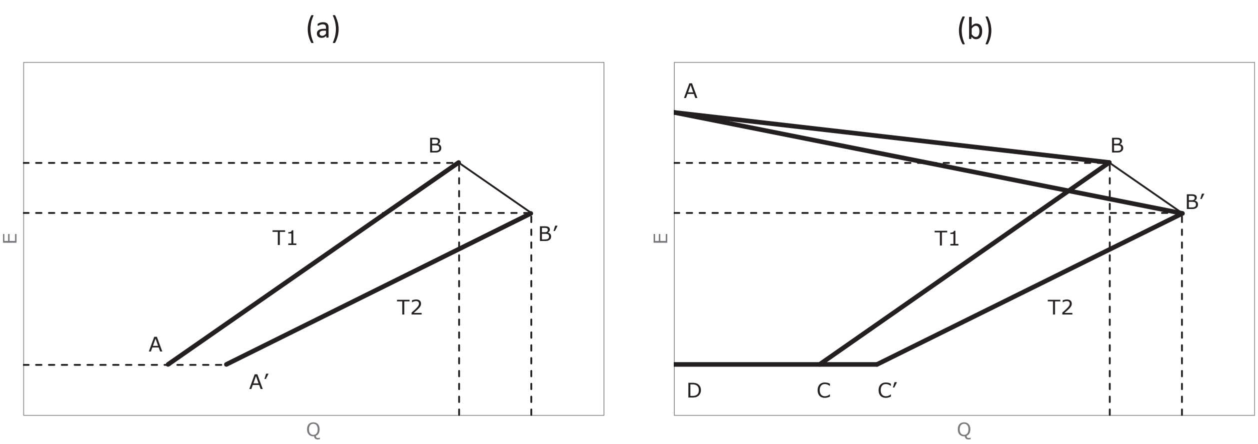

Fig. 1. Feasible operation region for a CHP plant for two given DH supply temperature (T2>T1). (a) Backpressure turbine and (b) extraction-condensing unit [23].

Table 1
CHP plant model parameters.

Parameter	Description
β	Ratio between lost power generation and increased heating generation. Power-loss factor
σ	Back-pressure ratio. Power-to-heat ratio per type of technology
P_{max} ($Q=0$)	Maximum power generation when no heat extraction is considered
P_{min} ($Q=0$)	Minimum power generation when no heat extraction is considered
Q_{max}	Maximum heat generation (minimum condensation constraint)

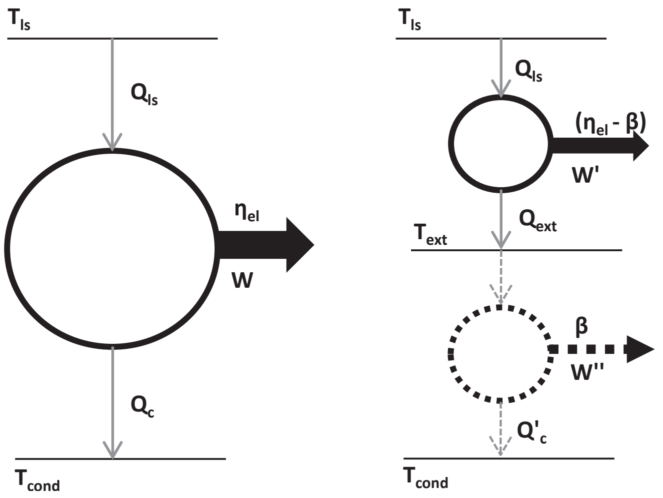

Fig. 3. Steam cycle scheme. No extraction (a) and extraction (b) operations.

$$\beta = \frac{T_{ext} - T_{cond}}{T_{cond}} \tag{2}$$

where β stands for the power-loss ratio, T_{ext} the desired extraction temperature and T_{cond} the condensing temperature, which is assumed 10–15 °C higher than the ambient temperature.

The power-to-heat ratio, defined by Eq. (3), is calculated by applying Carnot efficiency – Eq. (1) and the energy balance of the system – Eq. (4).

$$\sigma = \frac{W'}{Q_{ext}} \tag{3}$$

$$F = Q_{ls} = W' + Q_{ext} \tag{4}$$

With these two relations and the Carnot efficiency, σ is given by Eq. (5)

$$\sigma = \frac{\eta_{ise} \cdot \left(1 - \frac{T_{ext}}{T_{ls}}\right)}{1 - \eta_{ise} \cdot \left(1 - \frac{T_{ext}}{T_{ls}}\right)} \tag{5}$$

where σ stands for *the* power-to-heat ratio, T_{ls} the live steam temperature, typically of the order of 500–600 °C, and η_{ise} the isentropic efficiency (90–95% in modern steam turbines) [26]. A literature review has been carried out to compare typical values for the assumed parameters of β and σ (Annex A).

Fuel consumption and overall CHP efficiency are defined by Eq. (6)–(7). It is assumed a linear relationship between the fuel consumption and the power load [27].

$$F = \frac{P + \beta \cdot Q}{\eta_{el}} \tag{6}$$

$$\eta = \frac{P + Q}{F} \tag{7}$$

where F is the Fuel (MW), P is the power produced (MW), Q is the heat produced (MW), and η_{el} is the reference electric efficiency of the single-purpose plant.

This formulation, which captures the effect of temperature in the design of a CHP plant, allows the study of the role of the CHP plants supplying heat at different DH supply temperatures in different energy system scenarios and thus the benefits derived from the utilisation of 4GDH networks.

2.3. Thermal storage model

The thermal storage model assumes well-mixed conditions (no stratification) and is thus expressed as a 1-node model. Energy balance and maximum capacity equations are written as follows:

$$Q_{st}(t) = Q_{st,in}(t) - Q_{st,out}(t) - Q_{l}(t) + Q_{st}(t-1) \tag{8}$$

$$Q_{st}(t) \leq Q_{st,max} \quad \forall t \tag{9}$$

2.4. System integration

The complete system including the heating module developed for this study is presented in Fig. 4. In addition to the CHP model presented in a previous section, an alternative heat supply (AHS) energy vector is considered in order to capture individual heat supply options. This energy flow allows studying the behaviour of systems for different heating cost scenarios. This energy vector allows the analysis of marginal heat costs from which heat supplied

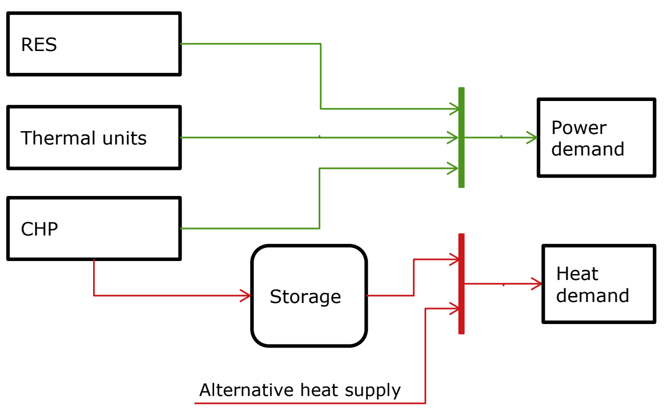

Fig. 4. Integrated energy system for the coverage of specific power and heat demand.

by CHP plants combined with the thermal storage become cost-effective. Depending on this cost, the system can choose the most cost efficient source of heat supply. Thus, by selecting high costs, must-run plants (e.g. CHP plant that have the contractual obligation to satisfy a specific amount of heat at specific time as defined by the heat demand curve) can be simulated.

2.5. Evaluation of system performance

In order to compare different scenarios, the system was examined in three different dimensions:

- **Affordability**: Operational cost (OPEX), investment costs applicable for those scenarios in which the power capacity is modified (CAPEX);
- **Efficiency and environmental impact**: Efficiency of the system, RES curtailment and CO2 emissions;
- **Reliability**: Share of electricity demand that cannot be provided due to intermittent renewable energy supply, shed load.

The definition of the CAPEX indicator relies on the development of the different scenarios under investigation. To compute this indicator, two costs are considered; additional power capacity compared to the reference scenario, and the investment related to additional storage capacity.

Eq. (10)–(12), show the mathematical formulation for the overall system efficiency, OPEX, and CAPEX.

$$\eta = \frac{\sum_i \sum_t P(i,t) + \sum_i \sum_t Q(i,t)}{\sum_i \sum_t F(i,t) + \frac{\sum_t AHS\ (t)}{\eta_h}} \tag{10}$$

$$OPEX = \sum_i \left(\sum_t F(t,i) \right) \cdot C_f + \sum_t AHS(t) \cdot C_{AHS} \tag{11}$$

$$CAPEX = \left(\sum_{Tech} \cdot Cap_{Tech} \cdot I_{Tech} \right) \cdot crf \tag{12}$$

where the capital recovery factor (crf) is given by Eq. (13)

$$crf = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \tag{13}$$

3. Case study

The analysis conducted in this work compares the optimal dispatch of a combined heat and power system for different energy generation technology mixes and operational variables, namely the cost of alternative heat supply and the extraction temperature of the CHP plants. The system is defined by given heating and electricity demands and by a fixed total power installed capacity, thereby establishing the reference scenario.

Alternative scenarios are defined based on the share of available installed capacity per energy generation technologies: renewable energy sources including wind and photovoltaic (RES), thermal generation, through steam turbines (STUR), through internal combustion engines (ICEN) and through combined cycles (COMC), and finally on the share of CHP when considered the replacement of steam-based power plants by CHP. In addition, for the scenarios that include CHP plants, two additional variables are investigated; the availability of thermal storage and the temperature of the heat delivered by the CHP plants.

For this case study we have selected a small island energy system that faces the substitution of two combined cycles (COMC) power plants enabling the opportunity of replacing these plants either by new combined cycles or by CHP plants. In addition, the system has a thermal network fed by centralised gas boilers that deliver heat demand to a nearby energy dense area. The energy system also shows a high renewable energy potential.

This case was selected to demonstrate the desired effects because (a) there are no interconnections (b) the full potential share of CHP plants on the power system can be significant (up to 26%). The base scenario has 24 power plants of a total capacity of 1681 MW_{el}.

3.1. Reference scenario

The reference scenario is defined by the replacement of existing COMC plants by new ones with the same capacity. Thus no large scale CHP plants are considered. Thus, this scenario sets the baseline to compare and assess the benefits derived from the combined utilisation of heat and power and the incorporation of thermal storage. For this reference scenario, the RES contribution in terms of installed capacity is 12% and the rest (88%) is provided by thermal units that use natural gas (STUR, COMC) and oil (ICEN) as input fuels. In this reference scenario, RES installed capacity constitutes a low RES scenario according to the definition of scenarios described in the following section. Hence this reference scenario is labelled as 'no CHP | *low RES*'. Fig. 5 shows four indicative scenarios, including the reference scenario (Fig. 5a), corresponding to the extreme capacity values for the different group of technologies. The full range of scenarios is described in Table 2.

In this study, the proposed model considers the CHP units as the only available technology to link heat and electricity. This means that the electricity and thermal problems are decoupled in the reference scenario as no CHP plants are considered. In that case, potential power capacity replaceable by CHP (432 MW of COMC) are only delivering electricity and grouped within the thermal generation group while, the heat is provided via existing centralised gas boilers, which are modelled as virtual conventional boiler with an efficiency of 85% — alternative heat supply vector.

These different combinations of energy technology have to meet fixed electricity and heating demands. These demands correspond to a climate zone characterised by warm winters and hot summers. Thus, August is the month with the highest power demand reaching a total sum of almost 500 GWh, while for the heat demand, January corresponds to the peak consumption, with a value of 140 GWh. Total annual demands for both electricity and heating demands are 4350 and 900 GWh respectively (Fig. 6).

3.2. Alternative scenarios

The different scenarios are defined based upon the flexibility provided by the thermal generation. They are implemented by combining various levels of renewable and CHP penetration, availability and capacity of thermal storage, different cost for the AHS energy vector and the temperature of extraction in the CHP units (Table 2). In summary, three specification variables (share of renewables, share of CHP, cost of alternative heat supply) and two design variables (size of storage, temperature of extraction) explicitly define a scenario.

In all the scenarios, we considered a fixed capacity given by the reference scenario (1681 MW_{el}). In this way, if the share of renewable power capacity or the replacement of steam turbine plants by CHP increases, the capacity of remaining thermal units is reduced to maintain the total capacity of the system (Fig. 5). This approach ensures a fair comparison between scenarios as allows

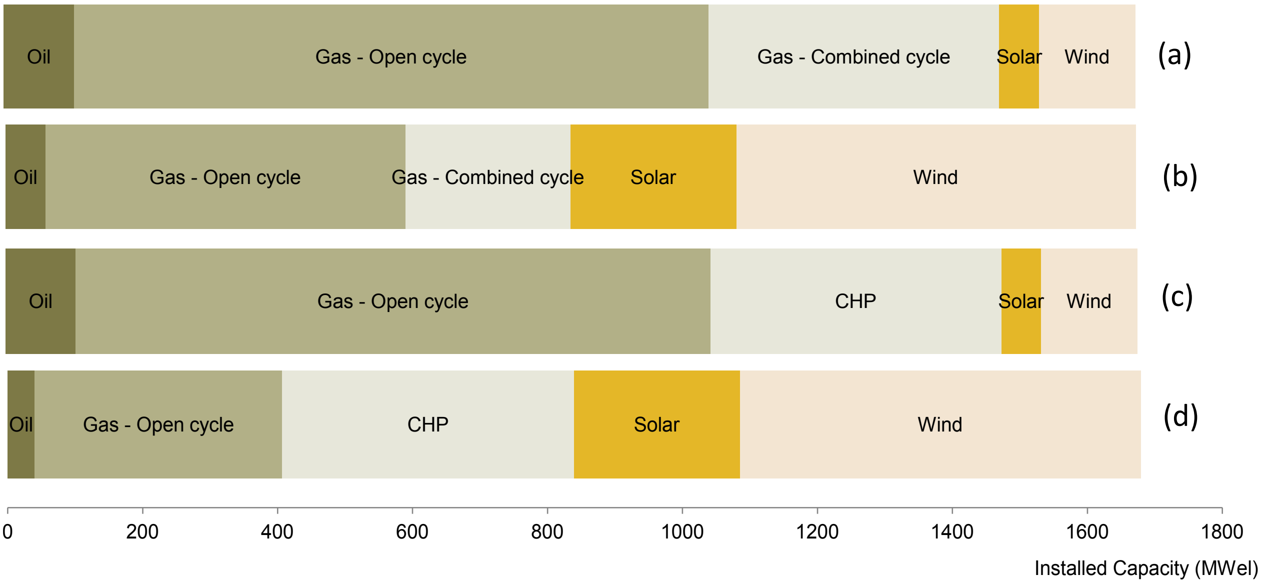

Fig. 5. Energy generation mix for the (a) reference, no CHP | high RES (b), high CHP | low RES (c) and high CHP | high RES (d) scenarios.

Table 2
Variation range of the model parameters.

AHS prices (€/MWh)			Share of RES (% of total capacity)		Share of CHP (% of total capacity)			Temperature of extraction (°C)[a]		Storage availability[a,b]	
Low	Medium	High	Low	High	Low	Medium	High	Low	High	No	Yes
10	20	50	12%	50%	–	13%	26%	60	120	–	1500/3000

[a] These parameters only applies to scenarios that consider CHP.
[b] In case thermal storage is available, the size will be determined by the share of CHP. 1500 MWh of storage capacity corresponds to a medium CHP share while 3000 MWh corresponds to high CHP share. The size of the thermal storage has been selected based on the maximum daily heat demand over the year.

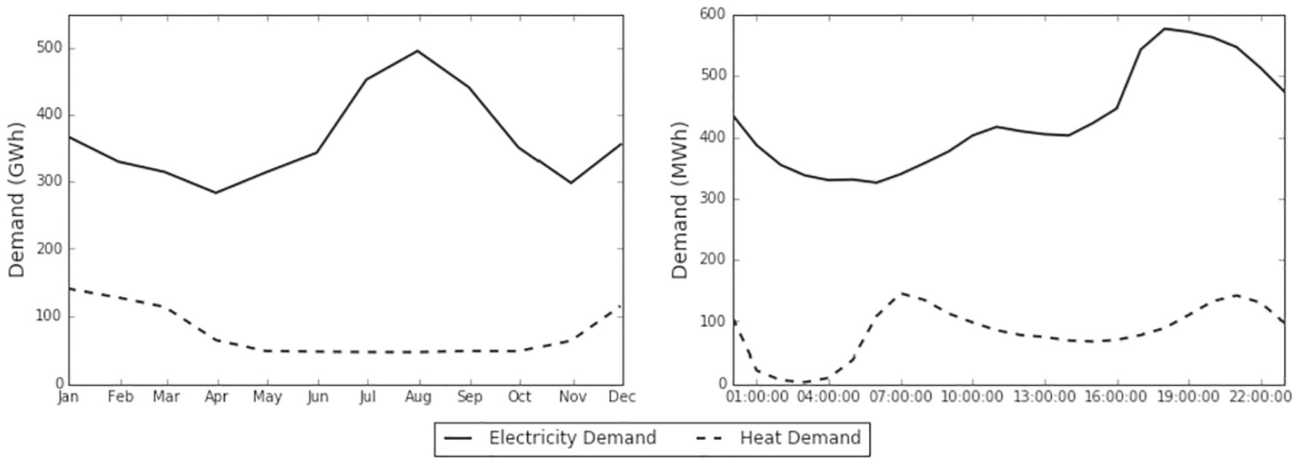

Fig. 6. Electricity and heat demand set for the reference scenario. Monthly demand (left) and hourly demand for a typical winter day (right).

examining the structural changes of the generation mix.

To build different CHP penetration scenarios, we assume that the total COMC capacity of 432 MW is covered by two power plants. The medium CHP scenario assumes the replacement of one of this COMC plants (216 MW) by CHP and the replacement of both for the high CHP scenario. The storage penetration level is linked to the CHP level: medium storage refers to one plant replacement scenario and high to both plants replacement.

Table 2 shows the summary of the ranges considered for the parametric analysis. A total of 435 scenarios were created and run on an hourly resolution. The total simulation time was 20 h in a high performance cluster.

In order to carry out the economic assessment of the different energy generation alternatives, it is assumed that investments in the existing energy system have been previously covered. This means that existing installed capacity and alternative heat supply capacity do not bring additional investment costs into the energy system. Only the additional RES capacity compared to the reference scenario and the additional CHP plants investment costs compare to the COMC investment costs are considered.

Concerning operational costs, mainly input fuel costs, these have not been modified along the different scenarios. Cost of natural gas and oil has a fixed value of 20 and 35 €/MWh respectively, typical average wholesale prices in EU for the last years [28]. In the definition of the scenarios, it would be expected a common price evolution for the CHP and AHS operational costs. However, the AHS energy carrier is just a formulation of an alternative heat source. Thus, we want to assess the competitiveness of the CHP plants in a wide range of heat market prices, taking into account any potential alternative.

3.3. CHP parameters characterisation

As described in previous sections, the CHP plant model proposed is defined by 5 parameters (β, σ, P_{max}, P_{min} and Q_{max}). In our analysis we have assumed that there is no restriction for the used heat meaning that the cogenerated heat is not truncated. Then, the parameter Q_{max} is neglected and the Q_{max} point is given by the intersection of the power-loss line at maximum power (line A-B) and the line of maximum heat (line D-C), as described in Fig. 2. Concerning power capacity parameters, P_{max} is given by the size of the existing steam-turbine based plants meanwhile P_{min} has been calculated based on a fixed minimum capacity factor of 40% [17,20,29,30].

Regarding σ and β parameters, they have been calculated based on Eq. (2)–(5). To determine the values of the power-loss parameter (β) a condensing temperature of 30 °C has been considered.

Finally and following Eq. (5), to calculate the values of the power-to-heat ratio parameter (σ) we have assumed a typical life steam temperature (T_{ls}) of 580 °C and a conservative isentropic efficiency (η_{ise}) of 0.85 [26].

The feasible operation regions for the extraction/condensing turbine CHP units considered in our power system for two different extraction temperatures are presented in Fig. 7. It is shown that, when the temperature of extraction is set at 60 °C, values for β and σ are 0.09 and 0.95, while if the temperature of extraction increase to 100 °C, values are 0.18 and 0.82 respectively. Therefore, when the extraction temperature increases, the maximum heat that could be delivered increases, the electricity decreases, while the total overall CHP efficiency decreases.

Table 3 summarizes the values considered for the different scenarios based on the design DH supply temperatures proposed in the study. This range of temperatures is aligned with the new generation of district heating (4GDH).

3.4. Cost and environmental data

To produce indicators that allow the comparison among different scenarios (section 2.5), additional input data related to investments is needed. Since scenarios are built based on different combination of installed power capacity, unitary costs for the different energy generation technologies are required. As indicated in a previous section, it is assumed that the available capacity in the reference scenario already exists. Therefore, only the additional RES power capacity replacing existing thermal capacity is considered in the investment cost indicators. For the same reason, the investment cost related to CHP only refers to the additional cost compared with the investment cost of COMC plants. This assumption also applies for the capacity available to deliver alternative heat. Additionally, to calculate investments on annual basis, life of investment and interest rate are required (Table 4).

Table 5 shows the conversion factor for the input fuel that the system under study requires.

4. Results

In this section, outputs from different scenarios are presented to quantify the impact of incorporating CHP plants, which replace steam-turbine based plants, in the performance of the power system.

As explained in the previous section, three main aspects are worth to be investigated; the incorporation of the CHP plants, the effect of thermal storage in combination with CHP plants, and the effect of the DH input temperature linked to the new district heating paradigm (4GDH). These three aspects are compared against the reference scenario and also for different RES levels and cost of alternative heat supply prices. The variables of comparison are: the total system cost and efficiency, RES curtailment and CO2 emissions. Concerning this last indicator, despite AHS carrier is conceived as a virtual energy flows, conventional boiler has been considered to compute associated emissions.

At the end of the section, all the scenarios are jointly assessed to understand the interrelations between the different variables and to identify the optimal cases.

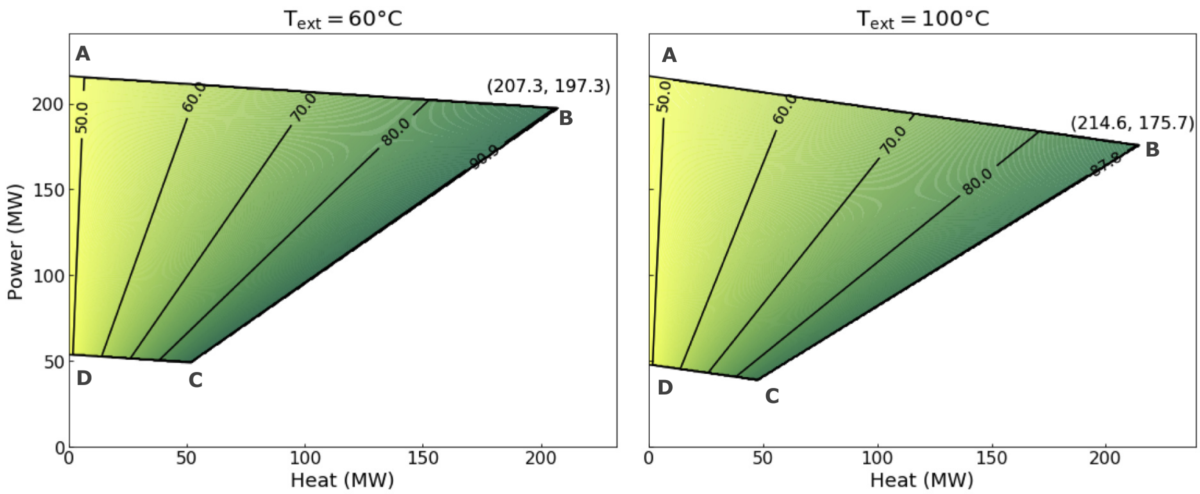

Fig. 7. Feasible operation regions for different extraction temperatures.

Table 3
CHP model parameters for different temperatures of extraction.

T_{ext} (°C)	T_{cond} (°C)	P_{max} (Q = 0) (MW)	P_{min} (% of P_{max})	β	σ	Q_{max} (MW)
60	30	216	40	0.09	0.95	207.3
80	30	216	40	0.14	0.88	210.8
100	30	216	40	0.19	0.82	214.6
120	30	216	40	0.23	0.76	218.7

Table 4
Investment-related parameters [31,32].

Parameter	Units	Value
Wind (CAPEX)	M€/MW	2
Solar (CAPEX)	M€/MW	1
$CAPEX_{CHP}$ - $CAPEX_{COMC}$	M€/MW_{el}	0.3[a]
Thermal storage capacity (CAPEX)	€/kWh	3
Financial lifetime	yr	20
Interest rate	%	5

[a] Unitary capacity costs have been calculated by the following expressions: $CAPEX_{CHP}$ (M€/MW_{el}) = $4.59x^{-0.2}$, $CAPEX_{COMC}$ (M€/MW_{el}) = $3.75x^{-0.2}$.

Table 5
CO2 emissions factors [33].

Fuel	Units	Value
Natural gas	gCO2/kWh	405
Gas/Diesel oil	gCO2/kWh	715

4.1. Reference scenario and detailed hourly dispatch samples

In the no CHP scenario, the total cost of the system ranges from 327 to 369 M€ on an annual basis. This cost range depends on the value of the price set for the AHS. The efficiency, not affected by the AHS cost, reaches a value of 44.3%. No RES curtailment is observed and CO2 emissions are slightly above 3000 tCO2-eq.

Based on the reference scenario, the introduction of different elements and the changes in the operational conditions modify the hourly dispatch of the system. Fig. 8 shows the comparison of the power and heat dispatch for a week in winter on an hourly basis for the indicative cases presented in Fig. 5. The introduction of CHP plants in the power system (Fig. 8b) leads to the replacement of AHS by cogenerated heat, except for the peak hours in which small contribution from AHS is required. From the power dispatch perspective, the utilisation of CHP also increases, limiting the use of other thermal units. However, when the level of RES is high, CHP production is reduced and a considerable fraction of the heat demand is delivered by the AHS (Fig. 8d).

In Fig. 9, two cases are presented to illustrate the effect of thermal storage. It is observed that thermal storage contributes to increase the utilisation of the CHP plants from both power and heat perspective. For low RES penetration (Fig. 9a), the incorporation of thermal storage allows meeting the heat demand without any contribution from the alternative heat supply vector.

All these implications are further assessed in the coming sections including the analysis of global parameters such as total costs and global efficiencies.

4.2. The effect of centralised CHP deployment

The first effect derived from the replacement of COMC plants by CHP is the increase in the utilisation of these plants limiting the use of the conventional thermal units.

As result of the high utilisation of the CHP plants, the total efficiency of the system rises from 44.3% in the reference scenario up to 58.4% reached for high level of CHP combined with high AHS price (Fig. 10). As mentioned, this effect is explained by the high overall CHP efficiency, up to 90% for some specific operational conditions. For all the AHS scenarios, efficiency increases, however low AHS price leads to a lower efficiency improvement as it limits a high CHP utilisation. The fraction of heat demand supplied by CHP is reduced for the low AHS scenario decreasing from 98% showed in the high AHS cost scenario to 88% (Fig. 11). When AHS is set at the level of 10 €/MWh CHP plants turn less profitable, although still leading to higher global efficiency as it operates driven by the electricity demand. It is also observed that the higher the AHS price, the higher the reduction of costs and the higher the efficiency of the system when increasing the share of CHP (Fig. 10). Overall, compared to the reference scenario, in all CHP scenarios a considerable efficiency increase is observed.

Concerning CO2 emissions, CHP leads to a considerable reduction of 8.5% but no differences are observed for different AHS.

4.3. The effect of thermal storage

Heat storage is of particular interest as it allows the combined benefit of high RES and CHP deployment by increasing the flexibility of the system and thereby facilitating the integration of both energy sources. The benefit derived from the incorporation of thermal storage becomes relevant when high RES electricity production has to be incorporated in the systems, reducing curtailed energy. In the low RES scenario, the effect of thermal storage is limited because CHP can deliver electricity while meeting the required heating demand without competing with renewable energy.

In low RES scenarios, thermal storage allows maximising the efficiency of the CHP plants. As indicated in Fig. 7, the efficiency of the CHP plants increases with the amount of heat released. Ideally, without any limitation, the CHP should operate on the D-C line of the feasible operation region (Fig. 2) in which efficiencies reaches values higher than 80%. However, the coupling of power and heating production forces the CHP to adjust power and heat released and thus limiting its efficiency. For a given power production requirement, the option of storing heat allows a higher heat production and therefore higher efficiencies. Fig. 12 shows how the flexibility provided by thermal storage allows moving the CHP operation to the line of maximum efficiency. In addition to the increase of the overall CHP efficiency, the capacity factor of the CHP plants, defined as the ratio between the sum of the electricity produced and the maximum potential electricity output over the year, increases from 0.48 to 0.56 (Fig. 13).

As indicated, in the high CHP | high RES scenarios, storage plays a key role leading to a reduction of the system costs and higher overall system efficiencies for high AHS prices. Under this scenario, efficiency and cost are improved by 4 and 2% respectively. This outcome is due to the higher amount of RES that could be integrated in the system via a more flexible operation of the CHP. The assessment of curtailed RES reveals that thermal storage could increase the utilisation of RES by approximately 1% when high CHP installed capacity is assumed (Fig. 14). This effect is subject to AHS prices that affects the utilisation of the heat supply from CHP.

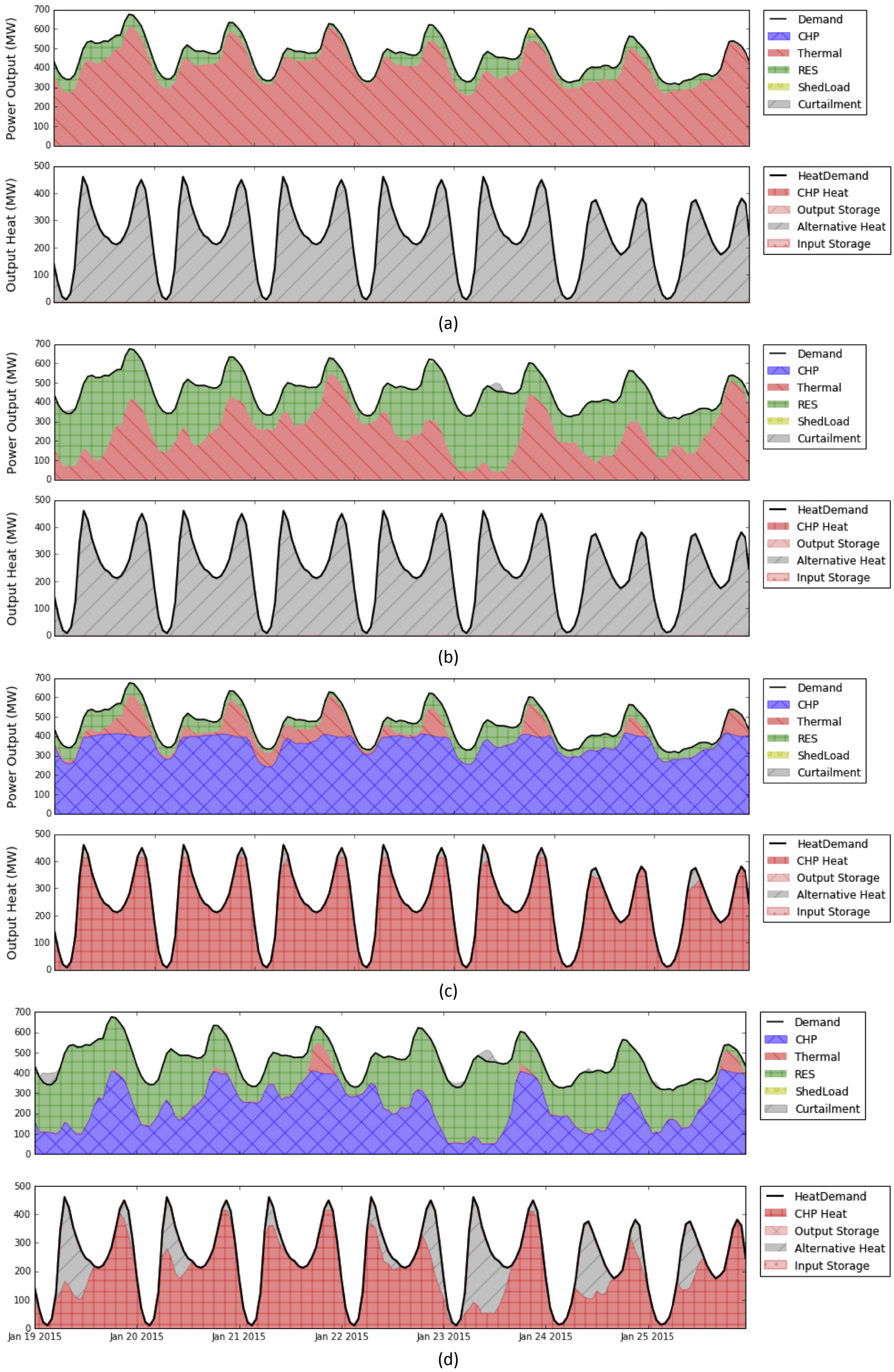

Fig. 8. Power and heating dispatch. High alternative heat supply price scenario and no thermal storage available. (a) No CHP | Low RES, (b) no CHP | high RES, (c) high CHP | low RES and (d) high CHP | High RES. Week in January.

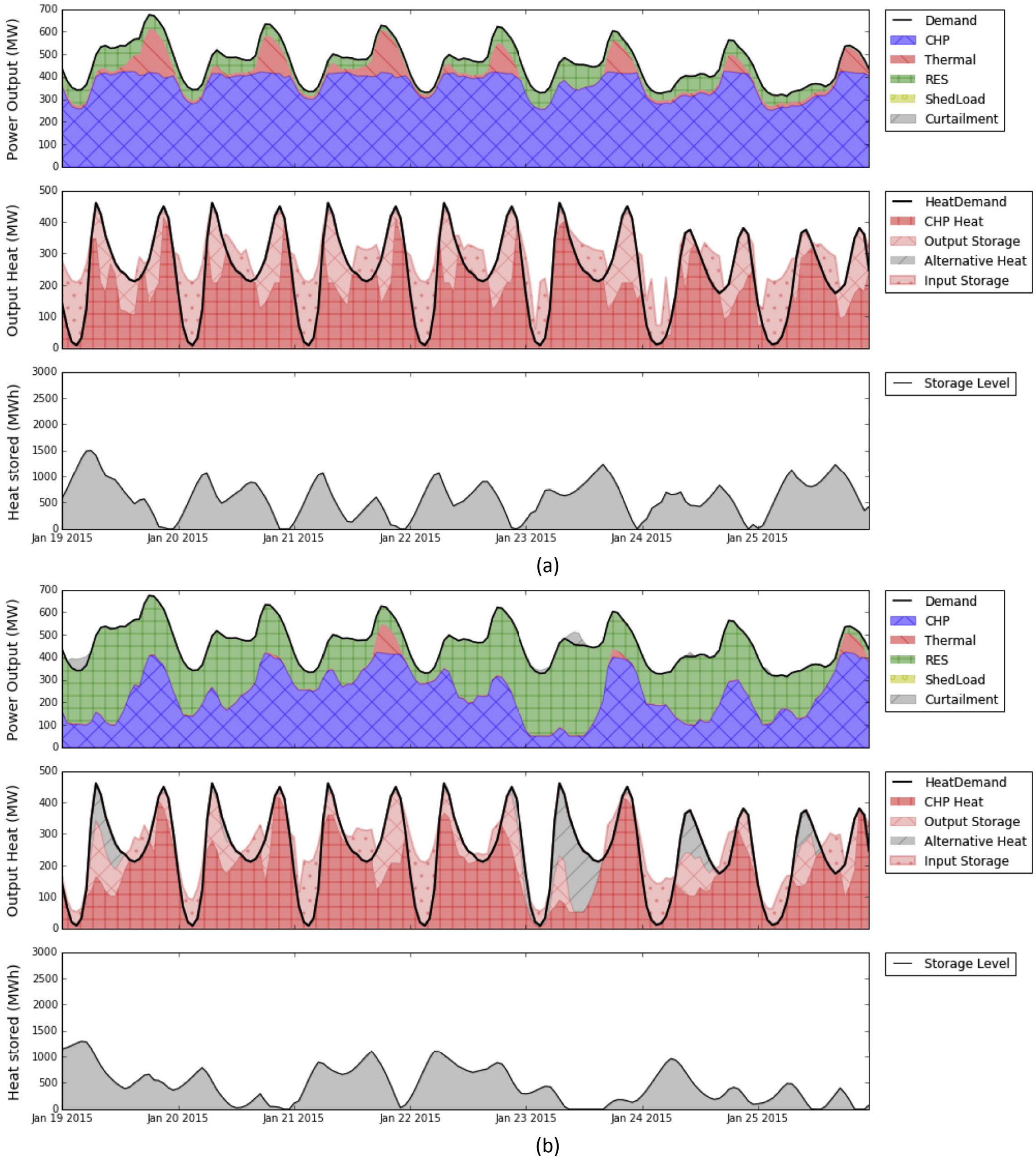

Fig. 9. Power and heating dispatch. High alternative heat supply price scenario. (a) High CHP | Low RES and (b) High CHP | High RES. Week in January with available thermal storage.

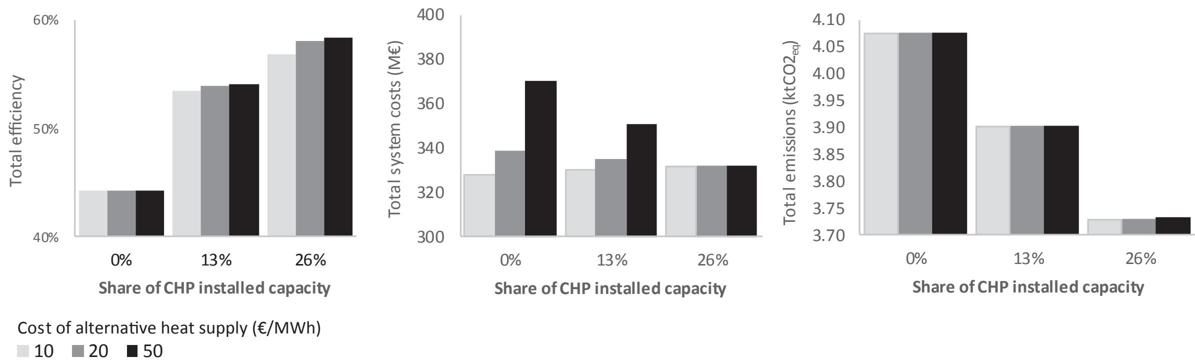

Fig. 10. The effect of increase of CHP installed capacity for different Alternative Heat Supply prices.

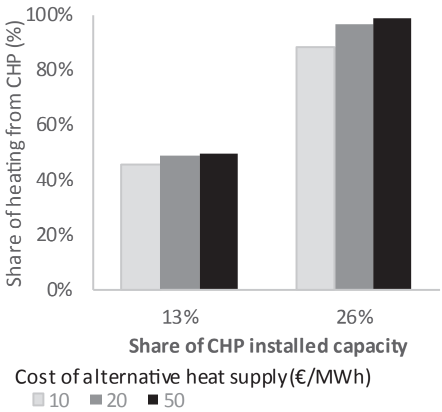

Fig. 11. Fraction of heat demand covered by CHP for different CHP shares and Alternative Heat Supply prices.

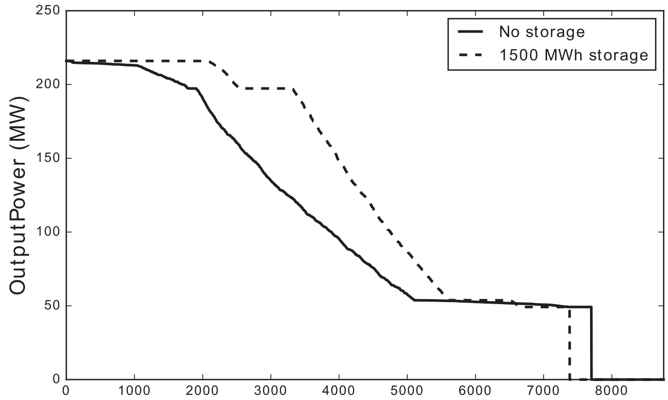

Fig. 13. Load duration curve of a CHP plant and for scenarios with and without storage. Medium CHP | Low RES.

Hence, if low AHS prices are given, the system takes advantage of these low prices, limiting both the use of heat from the CHP and the operation of the thermal storage and therefore RES are prioritised from the power supply perspective.

For the intermediate cases (low CHP | high RES or vice versa) storage improves the efficiency of the system and the economic impact remains limited.

To sum up, thermal storage becomes beneficial when high RES and high penetration of CHP are given under a scenario of high AHS prices. In these scenarios, thermal storage increases the overall system efficiency and reduces curtailed RES. If AHS prices are low or the share of RES limited, its impact remains marginal.

4.4. The effect of the heat extraction temperature

As described in previous sections, the final use of the heating demand determines the output temperature in the CHP plants. This decision modifies the FOR and thus the optimal operation points within the FOR as shown in section 2. The simulations indicate that high temperatures of extraction lead to lower overall system efficiencies and slightly higher system costs and CO2 emissions (Fig. 15).

The increase of the efficiency, driven by lower temperature of extraction, is higher when low-cost AHS is considered. This effect is explained by the fact that CHP can only compete with low AHS costs when its extraction temperature is low and therefore its efficiency high. As shown in Fig. 16, for low AHS costs, only the lowest temperature of extraction considered (60 °C) leads to a share of heating supply higher than 50%. For this case, the share of heat supply is affected by the amount of RES capacity considered. If high AHS costs are assumed, the utilisation of heat from CHP is not affected by the output temperature but by the amount of RES available in the system.

Besides the effect on the fraction of heat provided by CHP for different the temperature of extraction, in scenarios with high RES

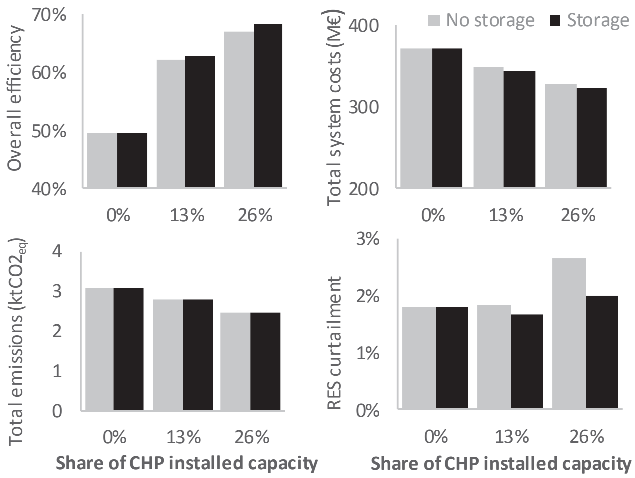

Fig. 14. Effect of thermal storage on the system efficiency for high RES scenarios and high AHS.

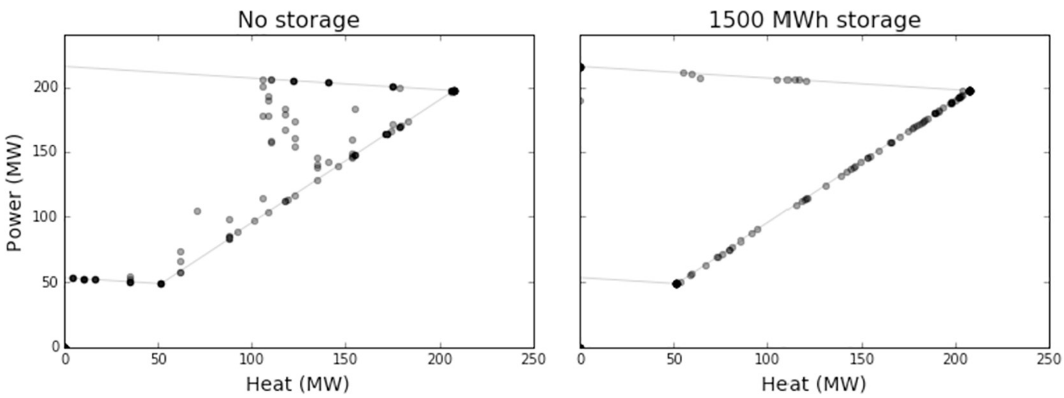

Fig. 12. Hourly CHP operation points for a week in winter. No storage (left) and 1500 MWh (right). Medium CHP | Low RES.

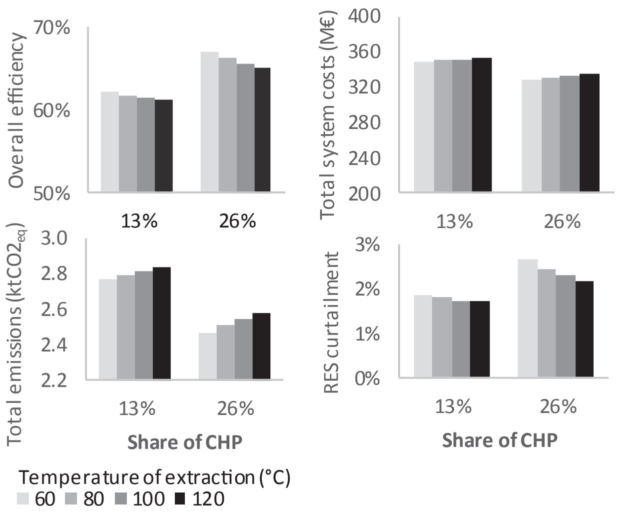

Fig. 15. Effect of the temperature of extraction on the efficiency and cost of the system, total CO2 emissions and the amount of RES curtailed. High RES and high AHS cost scenarios.

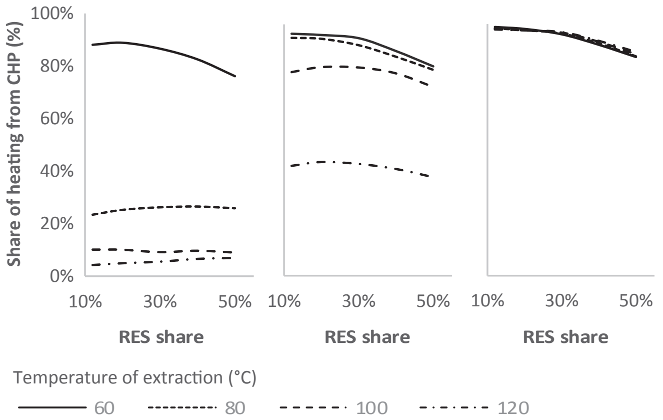

Fig. 16. Fraction of heat demand covered by CHP power plant for different temperatures of extraction, and share of RES installed capacities. (left) low, (mid) medium, (right) high AHS prices.

installed capacity and high AHS costs, low temperatures of extraction increase both the overall efficiency of the system but also the amount of RES curtailed. The effect on the total cost of the system is limited (Fig. 15).

It can be therefore concluded that, for low exergy heat requirements, heat produced by CHP could potentially compete with extremely low-cost thermal sources leading to higher efficiencies and lower costs. However it also impacts negatively the curtailment in the high RES case. Therefore, a trade-off exists between the overall efficiency and cost of the systems, and the integration of RES.

4.5. Optimum scenario selection

In this section, and given the implications among the different variables assessed, we present the pareto optimal solutions for three different alternative heat supply prices examined in order to understand the trade-off between affordability and efficiency. One of the first outcomes is that with no integration of CHP in the system, overall system efficiency is limited up to 50%. It is also observed that the system cost converges to a value of 320 M€ (Fig. 17). As presented in previous sections, CHP plants delivering heat at low temperatures (60 °C) could compete with low alternative heat supply prices, providing between 60% and 90% of the total heat demand depending on the penetration of RES (Fig. 16). This explains the convergence of scenario in terms of cost. In other words, under specific operational conditions, CHP plants can lower the heat cost down to values close to those considered in the low AHS cost scenarios.

Finally, the optimal scenario in terms of cost and efficiency results from the combination of high CHP penetration, operated at low temperature of extraction, available thermal storage and high level of RES (up to 50%).

Table 6 shows a summary for the indicative scenarios presented in previous sections. The optimal scenario is also included. It shows an overall efficiency of 66.9% and an OPEX of 233 M€.

5. Conclusions

A method to assess the benefit derived from the conversion of existing steam-based turbine plants into combined heat and power plant has been presented in this work. This method relies on a unit commitment model, which includes heating features, allowing the

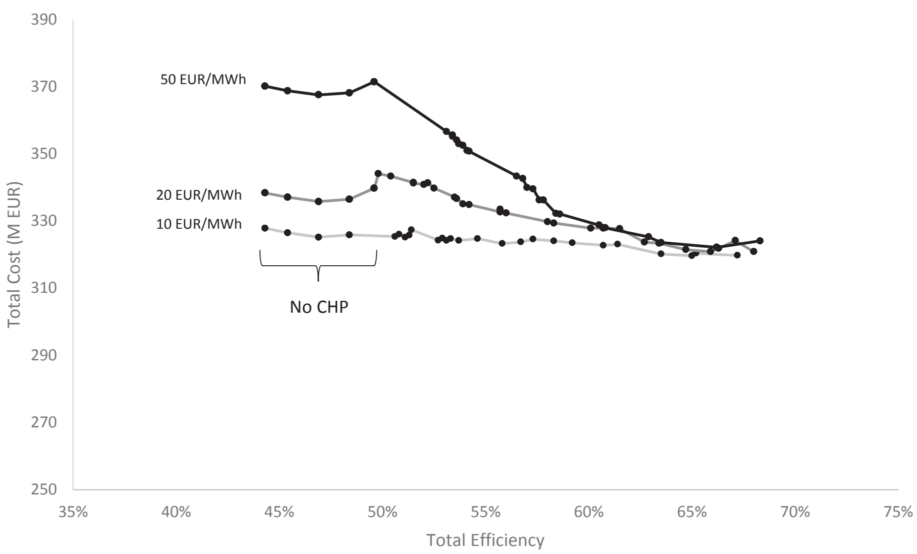

Fig. 17. Comparison of the complete set of scenarios assessed.

Table 6
Summary results on indicative scenarios.

Scenarios	Design parameters			Operational parameters		Results				
	RES level (%)	CHP level (%)	Storage (Y/N)	AHS price (€/MWh)	T_{ext} (°C)	CAPEX (M€)	OPEX (M€)	Overall system efficiency (%)	RES curtailment (%)	CO2 emissions tCO2-eq
No CHP | Low RES	12	–	–	50	–	–	370	44.3	–	4076
No CHP | High RES	50	–	–	50	–		284	49.6	1.8	3074
High CHP | Low RES	12	26	N	50	60	6.9	325	58.4	–	3732
			Y		60	7.7	324	58.6	–	3727
			N		120	6.9	337	56.5	–	3869
			Y		120	7.7	335	56.8	–	3851
High CHP | High RES	50	26	N	50	60	94.4	233	66.9	2.6	2469
			Y		60	95.2	229	68.3	2.0	2463
			N		120	94.4	241	65.2	2.2	2572
			Y		120	95.2	237	66.4	1.9	2566

assessment of different assumptions such as energy prices, different share of installed capacities for a set of energy technologies and the operation of CHP plants. The capacity of the method to link the optimization of the energy system with the temperature of heat delivered by the CHP plant is a valuable asset to evaluate different heat uses, such as the new 4th generation district heating systems characterised by low temperatures of operation, and the derived benefits.

The method has been tested in a small energy system, which offers opportunities to supply heat by the conversion of existing steam-based turbine plants into combined heat and power operation mode.

Results indicate that the conversion into combined heat and power plant leads to an increase of the efficiency of the energy system, which otherwise is limited up to 50%. This effect relies on the higher efficiency of the CHP up to 90% for some operation points. However, the deployment of CHP may prevent from the utilisation of renewable energy sources leading to renewable energy curtailment. The analysis presented demonstrates that this negative effect could be mitigated by the flexibility provided thermal storage. However, there exist a trade-off between the integration of high CHP and high RES simultaneously.

The analysis of different alternative heat cost reveals that CHP plants could compete with costs on the order of 10 €/MWh. However, for this low cost, the utilisation of the CHP decreases and so the benefit offered by thermal storage options.

From the CHP operation perspective, low temperature of extraction leads to higher efficiencies and lower costs. Then, the lower the temperature required the best for the efficiency of the system, but increases the amount of RES curtailed by 1% when the temperature of extraction increases from 60 to 120 °C if high RES scenarios are considered.

In conclusion, the incorporation of CHP in combination with thermal storage in the energy system leads to high efficiencies and reduced costs. However, in high RES scenarios, this benefit limits the integration of renewables, although still reducing costs.

Disclaimer

The views expressed in this paper are purely those of the writers and may not in any circumstances be regarded as stating an official position of the European Commission.

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Nomenclature

Abbreviations

4GDH	4^{th} generation District Heating
AHS	Alternative heat supply
Cap	Energy generation capacity
CAPEX	€ Capital expenditure
CHP	Combined heat and power
COMC	Combined cycles
Crf	Capital recovery factor
DH	District heating
FOR	Feasible operation regions
ICEN	Internal combustion engines
JRC	Joint Research Centre
OPEX	€/yr Operational expenditure
RES	Renewable energy sources
STUR	Steam turbine

Roman letters

C	€ Cost
F	kW Fuel
I	€/kW Unitary capacity cost
P	kW Power energy flow
Q	kW Heating energy flow
T	Temperature

Greek letters

σ	(–) Back-pressure ratio (Power-to-heat ratio per type of technology)
β	(–) Power-loss factor. Ratio between lost power generation and increased heating generation
η	(–) Efficiency

Subscripts

f	fuel
i	Power plant unit
st	Storage
l	losses
t	Time step simulation
in	Input energy flow
out	Output energy flow
max	Maximum
min	Minimum
ls	Live steam
cond	Condensing
ext	Extraction
el	Electric

c	Cooling
ise	Isentropic
tech	Energy generation technology
AHS	Alternative heat supply
h	Heating from conventional boiler
CHP	Combined heat and power

Annex A. A literature review on simplified CHP 5-parameter models

In this section, a collection of typical values for the parameters that characterise CHP power plants following the 5-parameter model approach is presented. Even though for some of the references included in the collection, CHP plants are defined based on other features, they allow calculating the 5 parameters proposed in our model (β, σ, P_{max}, P_{min} and Q_{max}).

Table 7
List of typical values of parameters to characterise simplified CHP models.

P_{max} (Q = 0)	Pmin (%)	β	σ	Qmax	Qmin	Ref
247	0.4	0.177	1.78	180		[17]
60	0.33	0.272	2.33	55		[17]
125.8	0.35	0.115	0.86	135.6		[17]
250	0.42	0.106	1	332.9		[27]
247	0.4	0.177	1.78	180		[29]
125.8	0.35	0.115	0.86	135.6		[29]
125.8	0.35	0.115	1.158	135.6		[20]
247	0.4	0.177	1.78	180		[20]
12.58	0.35	0.115	1.158	13.56		[30]
24.7	0.4	0.177	1.78	18		[30]
250		0.140	0.65	330		[34]
425		0.165	1.55	90		[34]
575		0.139	0.73	485		[34]
			0.27	250		[34]
			0.75	330		[34]
			0.6	244		[34]
			1	78		[34]
			1	60		[34]
			1.33	31		[34]
		0.12	0.68			[34]
		0.13	0.75			[34]
		0.18	1			[34]
		0.1	0.58			[34]
		0.05	0.27			[34]
		0.13	0.73			[34]
263	0.2	0.15	0.64	331	0	[35]
215	0.14	0.15	0.28	500	70	[35]

To complement the information in the annex, Fig. 18 shows the dependency of the σ and β parameters with the temperature of extraction under the operational conditions assumed in the case study.

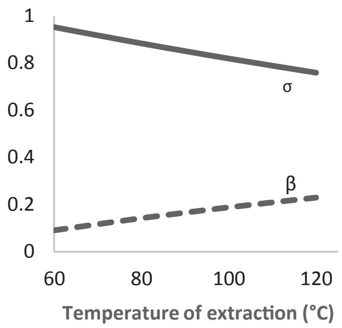

Fig. 18. Effect of temperature of extraction on the value of σ and β parameters for Tls = 580 °C, Tcond = 30 °C and η_{ise} = 0.8.

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