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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

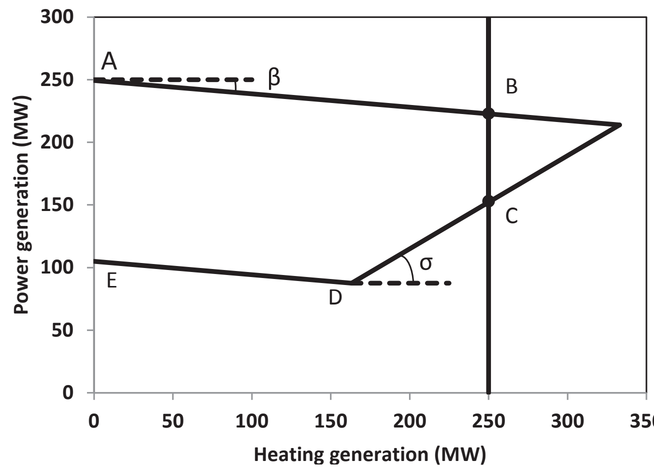

Fig. 2. Feasible operation region for a CHP plant for a given DH input temperature.

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 keeping energy input (Q_{ls}) constant, we obtain a relation between the amounts of electricity produced in both cases, given by Eq. (2),

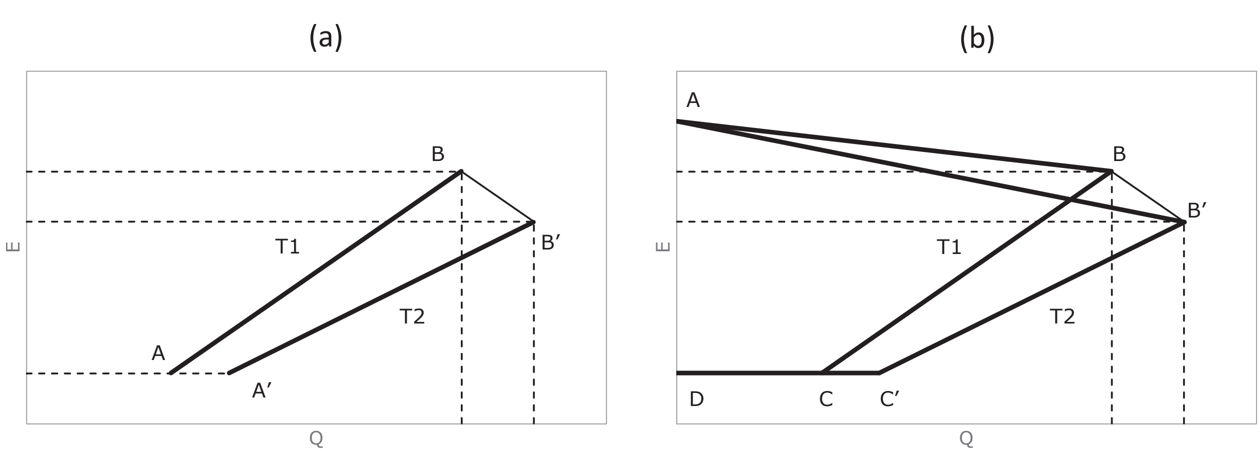

Fig. 1. Feasible operation region for a CHP plant for two given DH supply temperature (T2>T1). (a) Backpressure turbine and (b) extraction-condensing unit [23].

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)

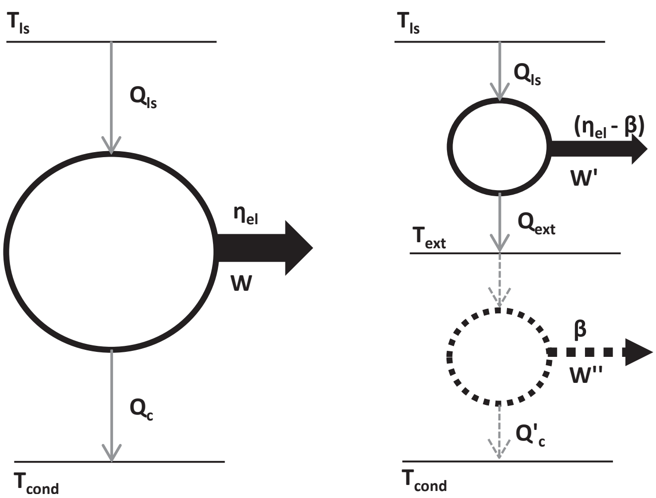

Fig. 3. Steam cycle scheme. No extraction (a) and extraction (b) operations.

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

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

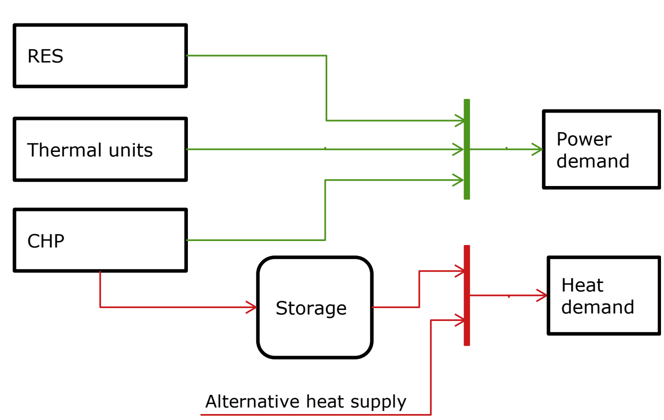

Fig. 4. Integrated energy system for the coverage of specific power and heat demand.

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

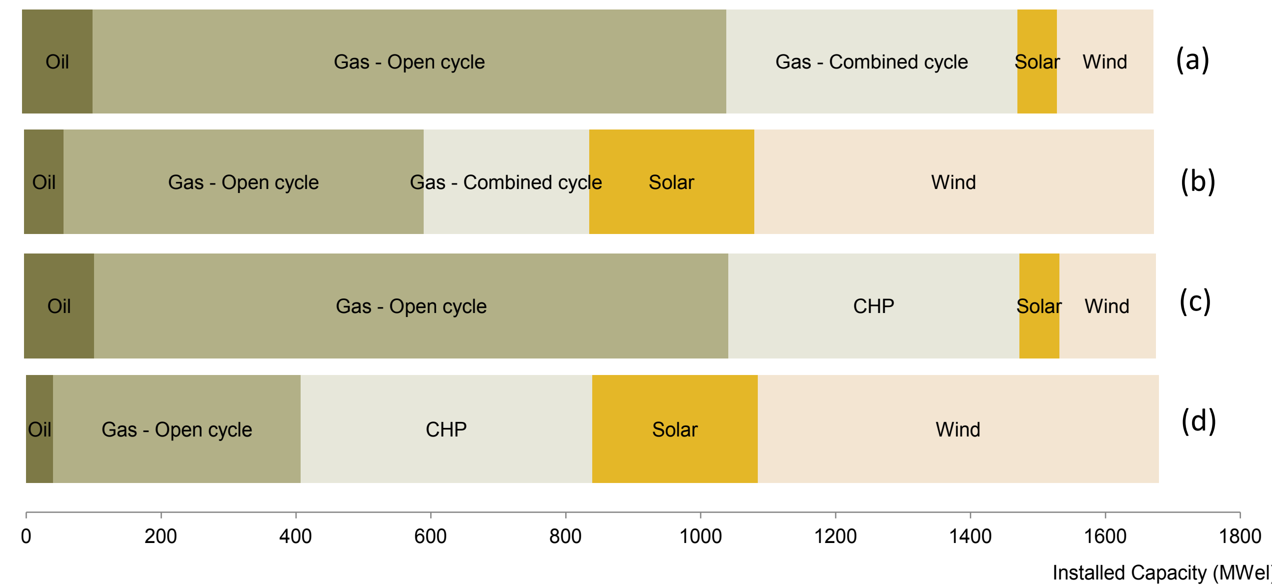

Fig. 5. Energy generation mix for the (a) reference, no CHP | high RES (b), high CHP | low RES (c) and high CHP | high RES (d) scenarios.

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.

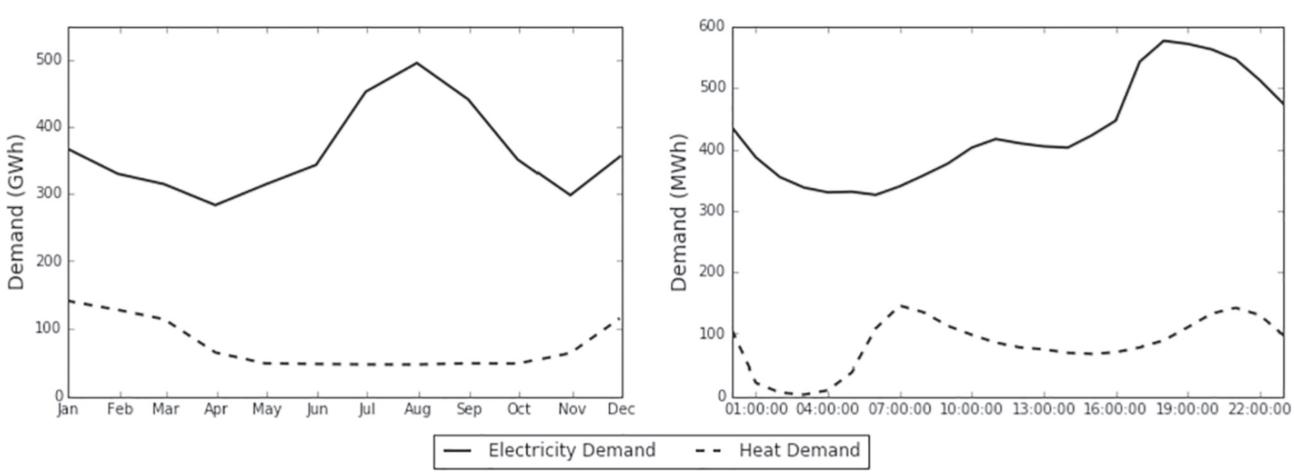

Fig. 6. Electricity and heat demand set for the reference scenario. Monthly demand (left) and hourly demand for a typical winter day (right).

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.

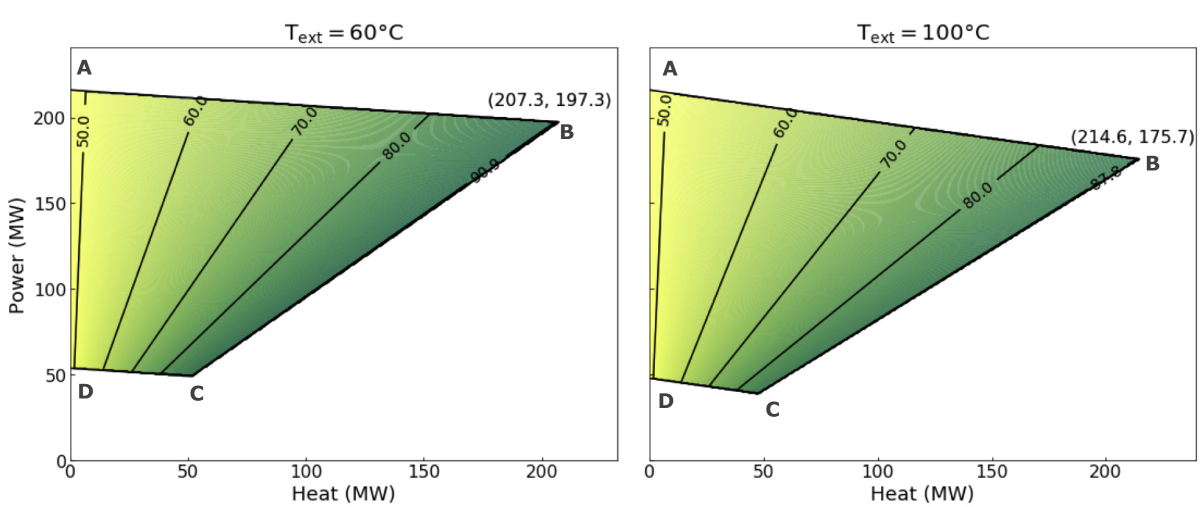

Fig. 7. Feasible operation regions for different extraction temperatures.

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.

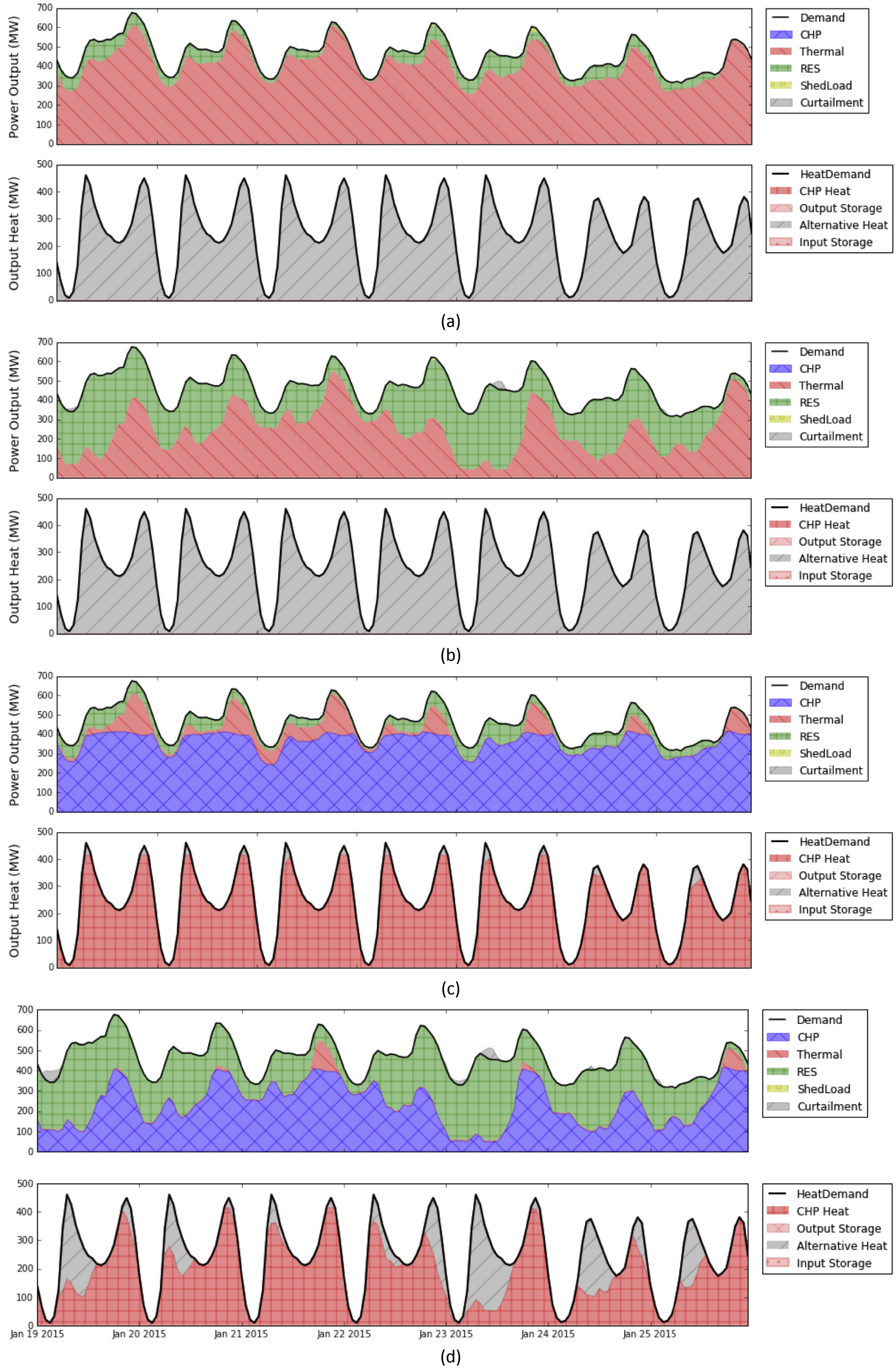

Fig. 8. Power and heating dispatch. High alternative heat supply price scenario and no thermal storage available. (a) No CHP | Low RES, (b) no CHP | high RES, (c) high CHP | low RES and (d) high CHP | High RES. Week in January.

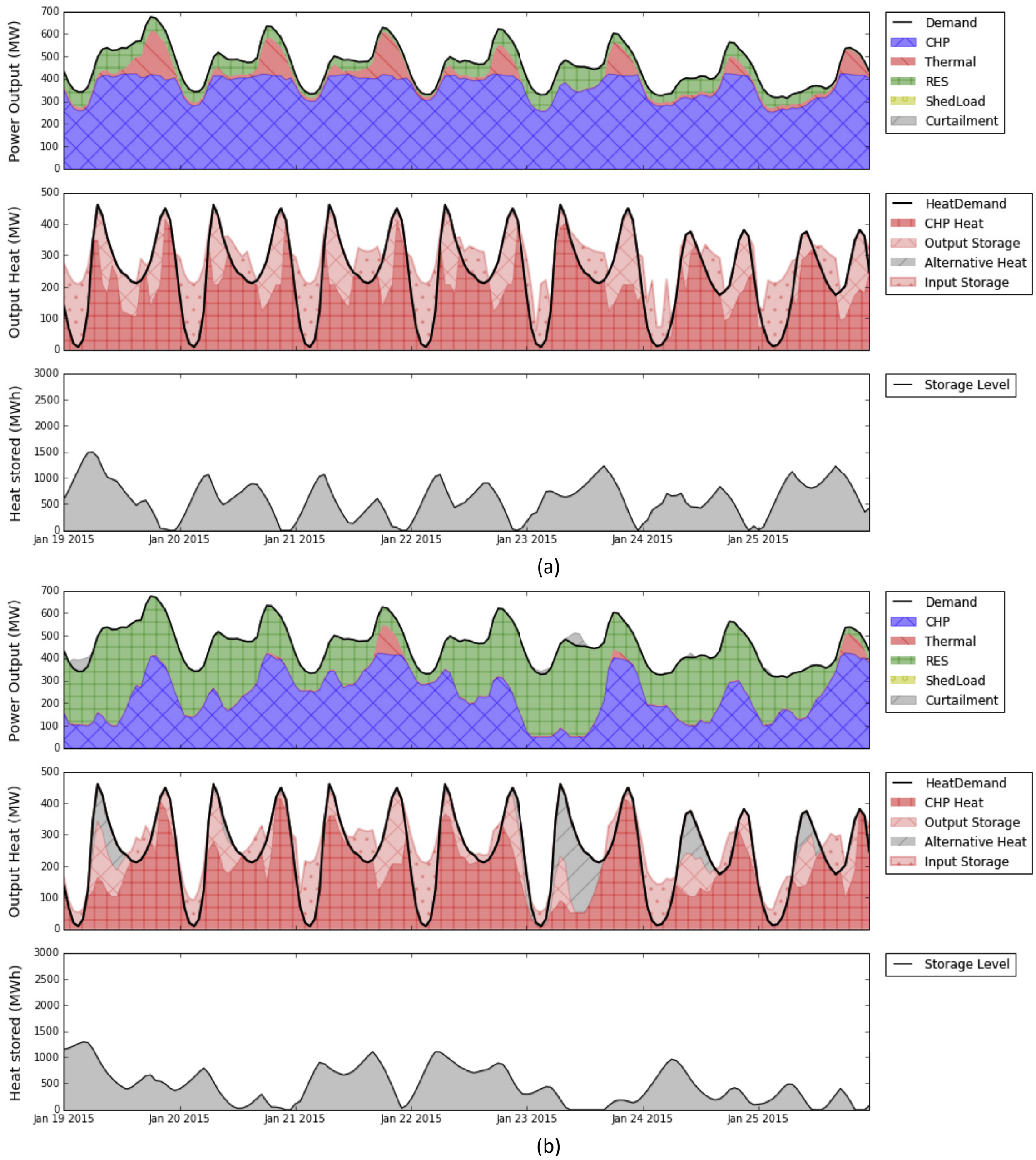

Fig. 9. Power and heating dispatch. High alternative heat supply price scenario. (a) High CHP | Low RES and (b) High CHP | High RES. Week in January with available thermal storage.

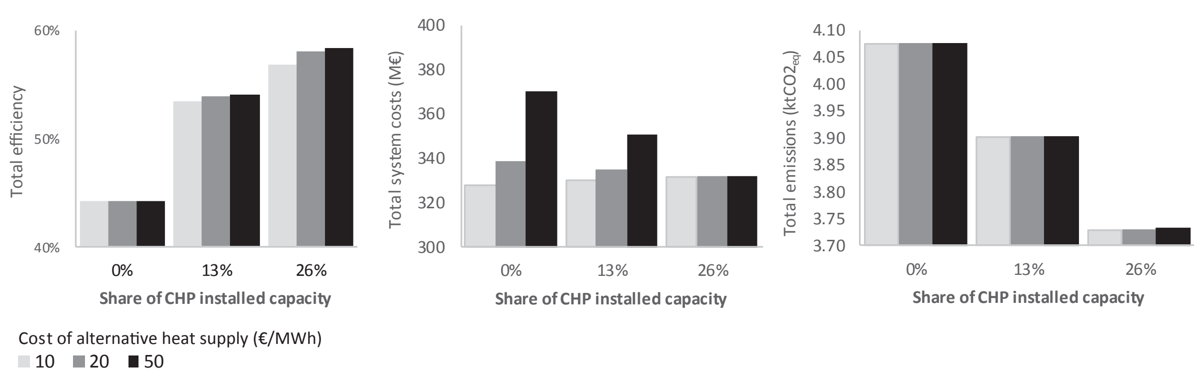

Fig. 10. The effect of increase of CHP installed capacity for different Alternative Heat Supply prices.

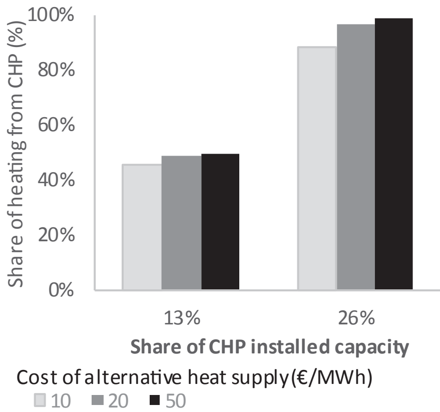

Fig. 11. Fraction of heat demand covered by CHP for different CHP shares and Alternative Heat Supply prices.

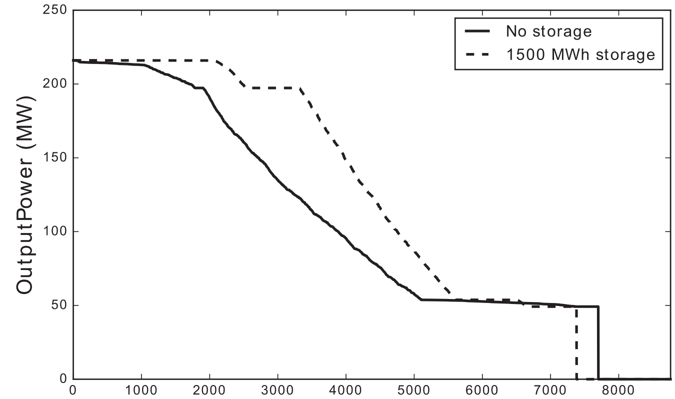

Fig. 13. Load duration curve of a CHP plant and for scenarios with and without storage. Medium CHP | Low RES.

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

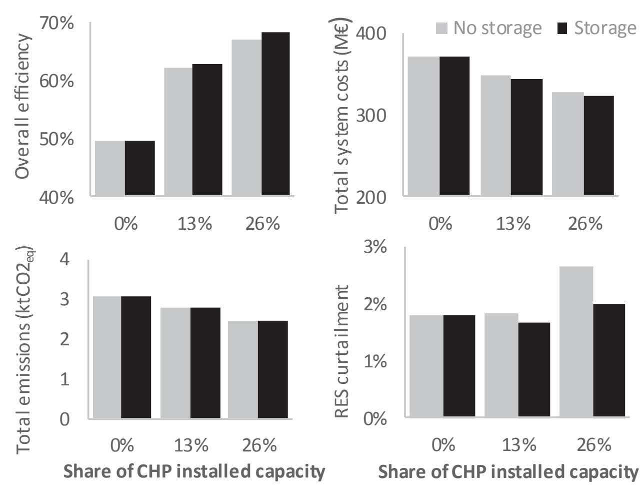

Fig. 14. Effect of thermal storage on the system efficiency for high RES scenarios and high AHS.

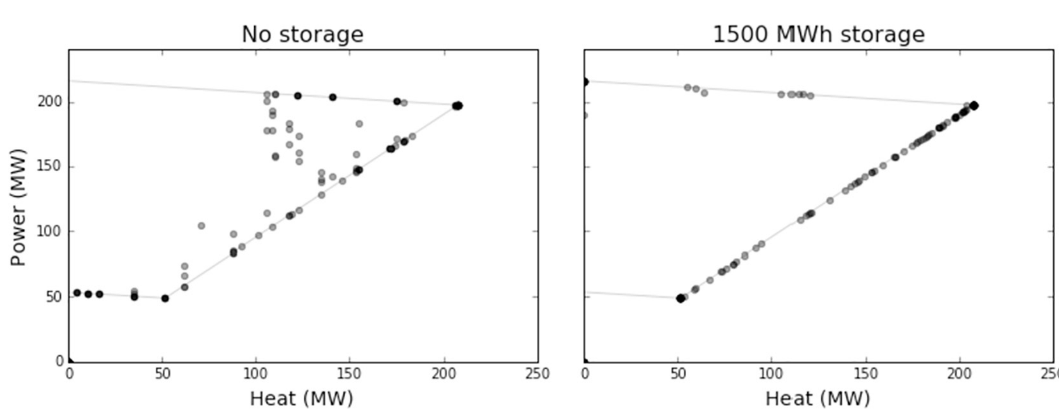

Fig. 12. Hourly CHP operation points for a week in winter. No storage (left) and 1500 MWh (right). Medium CHP | Low RES.

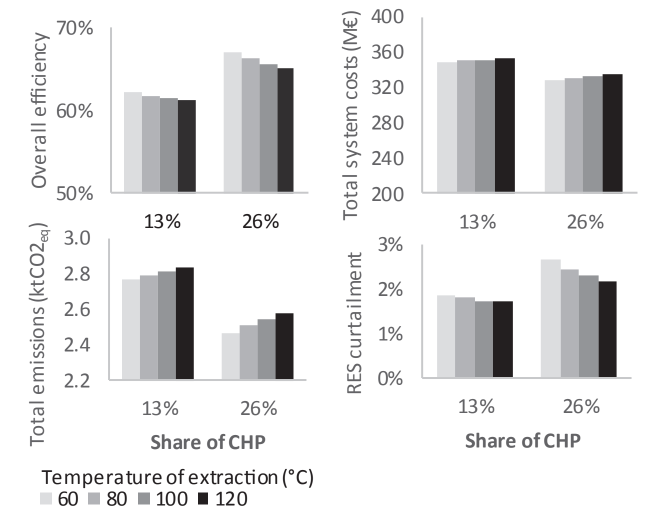

Fig. 15. Effect of the temperature of extraction on the efficiency and cost of the system, total CO2 emissions and the amount of RES curtailed. High RES and high AHS cost scenarios.

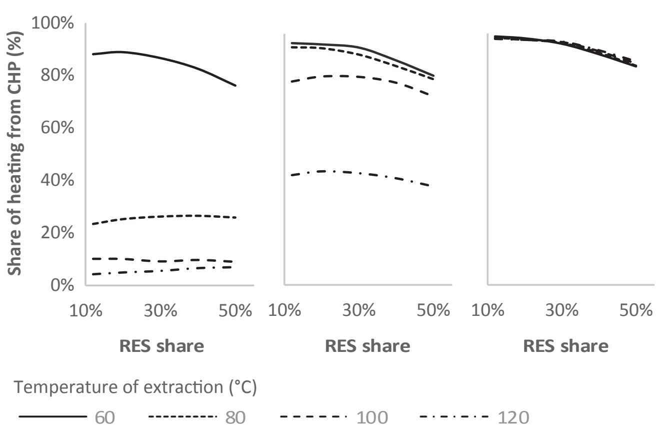

Fig. 16. Fraction of heat demand covered by CHP power plant for different temperatures of extraction, and share of RES installed capacities. (left) low, (mid) medium, (right) high AHS prices.

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

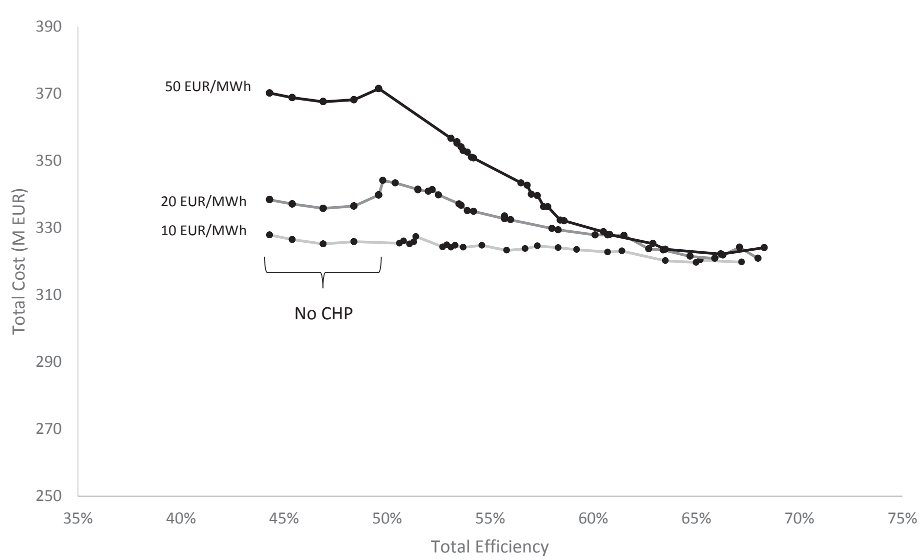

Fig. 17. Comparison of the complete set of scenarios assessed.

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	4th 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.

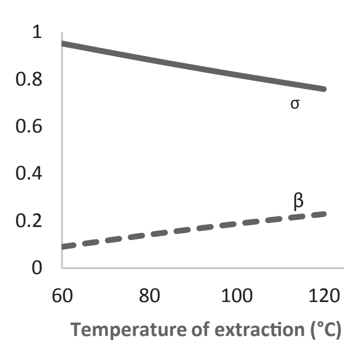

Fig. 18. Effect of temperature of extraction on the value of σ and β parameters for Tls = 580 °C, Tcond = 30 °C and η_{ise} = 0.8.

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