Impact of carbon pricing on distributed energy systems planning

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Andrea Bartolini [a,*], Stefano Mazzoni [b], Gabriele Comodi [a], Alessandro Romagnoli [b,c]

[a] *Dipartimento di Ingegneria Industriale e Scienze Matematiche (DIISM), Universita Politecnica delle Marche, Ancona, Italy* ` [b] *Energy Research Institute @ NTU, Singapore* [c] *Department of Mechanical and Aerospace Engineering, Nanyang Technological University, Singapore*

* Corresponding author.
E-mail address: a.bartolini@univpm.it (A. Bartolini).

Abbreviations: AC, Absorption Chiller; CHP, Combined Heat and Power; CCHP, Combined Cooling Heat and Power; EC, Electric Chiller; EES, Electric Energy Storage; CTES, Cold Thermal Energy Storage; MILP, Mixed Integer Linear Programming; PE, Primary Energy; PV, Photovoltaic system; RES, Renewable Energy Source;.

Highlights:

- A MILP model to compute an energy hub's energy systems design is used.
- The impacts of carbon pricing and natural gas prices fluctuations are analyzed.
- High carbon pricing and TES can foster the deployment of distributed CCHP systems.
- Drops in natural gas supply prices can compromise the effectiveness of carbon pricing.
- CO_2 emissions are found to be related to the convenience of CCHP systems usage.

Keywords: Distributed energy systems; Carbon tax; Optimal planning Energy storage; Energy hub design

Abstract:
Carbon pricing is being implemented by several governments to curb CO_2 emissions. This work studies its impact on distributed energy systems design which are powered by both renewable and fossil fuels. In particular, the analyses investigate a real case study situated in Singapore, characterized by cooling and electricity demands.

The goal of the analyses is to determine whether carbon pricing does impact design choices in meeting the energy demands of a user located in a cooling dominated region, and secondly in assessing the effectiveness of carbon pricing as a CO_2 emissions mitigation policy. This is achieved by investigating the optimal design of the energy systems meeting the demands of the test case under different carbon pricing and primary energy supply costs assumptions.

The results indicate that the optimal design under current conditions heavily relies on PV with more than 10 MWp worth of capacity and that an increasing carbon pricing would lead to a lower environmental footprint. But if the supply costs for natural gas were to lower, the optimal design would switch to relying on a combined cooling heat and power-based electricity generation system up to 3 MWe, increasing the primary energy consumptions regardless of the carbon pricing scheme in place. This would also happen even at significantly higher prices than the scheme under evaluation.

1. Introduction

There is an urgent need to address the challenges brought up by climate change, as its consequences are already impacting our societies, with projections of even worse impacts in the near future [1]. For these reasons many countries and organizations worldwide are already committing towards limiting the impacts of our societies on climate and more in general to switch towards more sustainable development models [2].

A huge focus in enhancing sustainability is put on reducing our carbon footprint. From a policy perspective this can be achieved through a diverse set of approaches. Examples of such policies lie in the subsidy of clean energy conversion technologies such as PV and wind, the imposition of meeting fixed shares of the end user demands by means of renewable energy sources (RES) [3], carbon pricing [4] and so on [5,6]. But the way our society produces and consumes energy is also

expected to be disrupted by a set of technological and social paradigm shifts. In fact, there are a set of technologies which are undergoing major development and are by consequence dropping in costs. Some of the mentioned RES in particular, especially photovoltaic solar systems (PV) [7] and wind [8] electricity generation technologies. Moreover, storage technologies are also being increasingly recognized with respect to their beneficial impacts, especially while coupled with intermittent RES, and more in general as measures of flexibility in modern energy systems [9] also considering thermal energy vectors [10].

The two trends, together with specific policy choices (such as incentives and feed in tariffs), contributed to a gradual shift from a centralized energy supply and distribution infrastructure to a more decentralized one [11]. A full switch towards a decentralized structure will though depend on local conditions [12], and in any case will take time to develop, as more renewables go online into the energy mix [11]. Still, there are significant benefits to be gathered from such novel types of structure, which go from economic benefits more oriented at local communities to technical advantages, such as the possibility of effectively and safely welcoming and exploiting large shares of energy systems penetration.

Indeed, a more distributed architecture allows to better tailor the characteristics of an energy conversion system directly to the needs of the end-user, cutting on transmission losses and enabling a degree of interaction between supply and demands of different energy vectors which couldn't be achievable with the traditional large centralized structure [12], potentially a great asset also towards sustainable development [13]. Moreover, distributed energy systems could allow to significantly increase resiliency and flexibility of infrastructures such as power and other distribution networks, which are both mandatory if a deep penetration of non-controllable renewables is sought. Even if as of now almost no country/geographical area is at this stage yet, a credible future scenario for our societies' supply of energy would then have an increasingly larger share of the final energy consumption generated in a distributed way [11]. The literature also highlights how distributed systems can further enhance the decarbonization of our energy systems thanks to a multi-energy system approach [14]. As a matter of fact sector-coupling technologies could allow to even furtherly increase synergies between demands a local level, as highlighted by several authors [15].

For such reasons, the analysis of distributed energy systems garnered significant interest by the scientific community involved in energy systems modeling and analysis. In this sense, a common approach followed in the literature to analyze the design and operation of distributed multi- energy systems is the energy hub modeling and conceptualization approach [16]. An energy hub can be defined as a self-contained entity, which goal is to meet the energy demands of different commodities of a user within its physical boundaries. In order to do so an energy hub can acquire different energy carriers from outside, provided the existence of a connection with an external distributor, such as for example natural gas and/or electricity from the respective distribution infrastructures. Moreover, there can be conversion and storage technologies within its boundaries that can convert such carriers: such as for example a PV or a CHP system, acquiring solar radiation and natural gas respectively to meet an electricity demand.

The abstraction of energy hubs has then been used to tackle several research questions regarding energy systems: from their design to their operation [17] to the assessment of carbon footprint reduction potential, with several approaches [18] and still with several open questions to be addressed in using them [19]. To mention a few examples regarding the design phase: an energy-hub approach has been used to analyze the retrofit of an industrial park in China [20], finding that CO_2 emissions reductions are achievable by deploying PV, heat pumps and distributed CHP . The validity of a long term storage solution is evaluated for a neighborhood energy system in Switzerland [21]. Heat pumps are found to have a significant impact on reducing greenhouse-gases emissions with respect to natural gas based heating in heating and cooling networks with waste heat recovery [22]. The energy-hub approach is also used to analyze decarbonization pathways in Brazilian urban energy systems [23], finding that decarbonization targets are achievable with a moderate economic surplus with respect of current scenarios by using a system-wide perspective. The uncertainty aspect of energy systems operation in taken into account by using a energy-hub approach for the deterministic model definition [24]. The energy-hub approach is finally used to plan multiple low-carbon districts with high penetration of RES in China [25].

In this study the energy hub model is used to assess the potential downstream impact of carbon pricing schemes on the hub's energy systems design choices. Ultimately, the goal is to understand how carbon pricing, which is already emerging as a policy to limit CO_2 emissions, will affect the future configurations of distributed energy systems and storages. This is considered of particular interest, as carbon pricing is increasingly applied throughout the world as an environmental protection policy [26].

Taxing carbon emissions, and thus the usage of certain ways of converting energy at the advantage of others, can potentially impact energy systems design choices. For such reason, many authors investigated the impacts of carbon pricing on energy systems of different scales with the goal of anticipating potential effects of such schemes and the effectiveness towards the goal of mitigating emissions [27]. Such type of analyses have mainly been focused on country/regional-wide scenarios [5] such as a Provence in China [28] and a city in Mexico [29]. Given the small-scale distributed energy systems trend highlighted in the introduction, also smaller district-scale energy systems are garnering interest [30].

1.1. Scope of the paper & contributions

This study contributes to the continuously evolving body of knowledge on energy policy measures regarding distributed energy systems. The subject is deemed relevant given the current discussion on different policy approaches aimed at reducing energy usage and ultimately CO_2 emissions.

It does so by firstly focusing the attention on the impacts of carbon pricing on their design. The goal is to understand whether in a rapidly reconfiguring energy systems scenario pricing carbon emissions is an effective strategy towards obtaining a less CO_2 intensive energy supply. The second contribution regards the object of the analysis, being an urban district located in a tropical region, characterized by a hot and humid climate throughout the year, having by consequence a significant demand for space cooling. This is considered a significant contribution given that the sustainable design of energy systems in these regions is of critical importance as the demand for cooling has more than tripled in the last decades and it's expected to keep growing, generating a significant carbon footprint in the process [31]. Regarding cooling dominated districts, the analysis of energy systems that grant sector-coupling capabilities is also garnering interest in the literature, with highlights of the potential for integrated analysis approaches while analyzing energy systems in tropical regions [32]. It's found that district cooling can potentially save significant CO_2 emissions while coupled with waste-to- energy systems [33]. Some studies also highlight the potential benefic effect that storage systems can have in tropical climates, both chemical [34] and thermal [35]. But, overall, research on the decarbonization of cooling-dominated regions is still lacking [32].

In the year 2018 within a wider effort to reduce the city's carbon footprint a carbon tax has been imposed for all the large emitters within the city-state. As stated by the local government the carbon tax aims at hitting upstream large emitters, such as power stations and large industries [36]. The intended consequences are that businesses, and more in general any energy user, adapts to this framework and is by consequence encouraged to lower its energy consumptions. The tax level is starting as 5 S$ (approximately 3.6 $) per ton of CO_2 until 2023, to be later reviewed in 2023 and potentially increased up to 15 S$/ton$CO_2$ until 2030.

The investigations in this paper are undertaken by analyzing the optimal design for the energy systems that meet the needs of a urban district consisting in large industrial user. The assessment of such question will be achieved by evaluating the optimal mix of energy systems (conversion and storage) for the user, meaning the mix of technologies that guarantees to meet its energy demands following a minimum life cycle costs criterion. In doing so both the impact of increasingly heavier carbon pricing levels and shifts in natural gas supply prices due to evolving market conditions, are considered. Each analysis pursues the minimum cost to meet the energy demands requirements of the district being the case study.

The rest of the paper is organized as follows: Section 2 describes the strategy used to model the optimal design problem of a distributed energy system and the approach used to solve it, Section 3 describes the technical and cost assumptions that are used in solving the problem and the scenarios definition, Section 4 describes the results from the simulations, and finally Section 5 summarizes the conclusions to this study.

2. Distributed energy systems model

This paragraph describes how the energy-hub abstraction is used to define a mathematical optimization problem of the optimal design of a distributed energy system.

2.1. Energy hub approach

The energy-hub abstraction described in the introduction is adapted to the case study at hand: a real industrial district in the city of Singapore and, specifically, a port. For simplicity, the description of the energy needs of the district can be formalized in two distinct energy users: an office building and a set of non-refrigerated warehouses. To function the office building requires cooling power for space cooling purposes and electricity. The warehouses on the other hand are considered to only require electricity, which is used to perform activities such as material handling/lifting, lighting etc. The district, and therefore its hub representation, is connected to both an electricity and a natural gas network distribution infrastructure and can consequently freely purchase the respective commodities from them.

This study analyzes the optimal design for such district, meaning which (and of which size) energy conversion and storage systems allow to optimally achieve the objective of minimal costs for meeting the users demands (both cooling and electricity) over a representative timespan. These costs regard the operational costs (such as for acquiring electricity/natural gas from external suppliers), the investment costs necessary to potentially purchase new equipment and the maintenance costs needed for the proper operation of such equipment. The systems considered in this study are electric chillers (EC), CCHP systems by means of CHP gas engine (CHP) and absorption chillers (AC), PV systems (PV), Lithium-ion battery electricity storage system (BESS) and chilled water tank storage system (CTES). A graphical representation of the energy hub, its external connections, and all the potential conversion technologies to be deployed is shown in Fig. 1.

The figure also shows four energy carriers: electricity, natural gas, cooling and heat. Three of them have a bus within the energy-hub; each bus connects all the technologies related to an energy vector within each timestep of the simulation. As an example, the electricity bus will define a balance of the energy flows for all the technologies dealing with electricity for each timestep: with the positive flows being the output of the assets producing electricity in the hub (purchase from grid, PV, gas engine etc) and the negative flows being the input of the assets consuming it (electricity demand, electric chillers etc.). The balance of such quantities is formulated by means of a set of equations constraining the optimization problem, with additional constraints to model the working of each of the technologies considered in the analysis for each of the considered carriers. In this case, the presence of the heat energy carrier is only needed to balance the heat recovery from a potential CHP gas engine and its feeding into an Absorption Chiller (in the case of trigeneration), given the absence of any type of heat demand by the users.

Given the previously highlighted global research interest in distributed energy systems analysis a wide set of mathematical models, frameworks, up to software tools has been proposed by the literature [37,38]. Such tools cover different domains of energy systems analysis, focusing on modeling variable production systems, distribution networks and sector-coupling capabilities. The goals are diverse and pursuing different objectives: costs and energy supply availability [39], only economic criteria [40], and simultaneous economic and environmental criteria [41]. Among the software tools available there are also diverse accessibility levels, with tools ranging from commercial products such as H.O.M.E.R. [42] and EnergyPRO [43] to freely available such as EnergyPLAN [44] up until completely open source software packages such as Calliope [45], OSeMOSYS [46] and the ones listed in OEMOF [47]. In this study the modeling of the energy-hub functioning is obtained by directly encoding the equations in a mathematical programming language instead of using one of the mentioned tools. While some of the mentioned tools could be adapted to answer the question at hand this approach is followed both for simplicity purposes, leveraging past work of the authors [48,49], but most importantly to provide a clearer description of the methodology in the following paragraph.

2.2. Mathematical model for the distributed system optimization

The mathematical formulation for the optimization problem expressing the optimal design of the energy hub is built by encoding equations using a Mixed Integer Linear Programming approach. All the systems and the hubs collecting the different energy carriers described in the previous paragraph will then be represented by a set of equations. The equations formalize the relations between the parameters of the problem which are provided as external inputs (such as time-dependent energy demands, technology costs etc) and the variables that are to be computed (such as the systems sizes and their time-dependent operational strategy). The deployment of new technologies is modeled by means of both continuous and binary variables. Since performance and specific costs of technologies usually vary with their size, an approach based on size ranges is followed. Computing an optimal design does also need to also compute how the potential systems are scheduled on a high temporal resolution basis in meeting the user energy demands. In this work this is achieved by means of indexing the simulation timespan with an index *h* that represents a particular hour of the whole timespan *T*. Thus, within the h^{th} hour, the energy demands must be met by means of the technologies installed within the energy hub and/or by commodities purchased from outside its boundaries. The equations governing the technical functioning of the various systems, and how the cost attributed to such systems amount to the total cost being objective are defined as in equations (1), (2) and (3); beginning with a generic conversion technology *conv*.

$$P_{min}^{conv} * X^{conv} \leq P_{size}^{conv} \leq P_{max}^{conv} * X^{conv} \tag{1}$$

$$0 \leq P_{convout}(h) \leq P_{convsize} \tag{2}$$

$$\frac{P_{techout}^{tech}(h)}{\eta_{tech}} = P_{in}^{tech}(h) \text{ or } P_{out}^{tech}(h) * COP^{tech} = P_{in}^{tech}(h) \tag{3}$$

Where P^{tech}_{size} is the variable that represents the size (represented by the rated output) of the technology *conv*. The variable is bounded between a lower and upper limit, which are defined for each type of technology and for different size ranges and represented as P^{conv}_{min} and P^{conv}_{max} in equation (1). It's also defined a

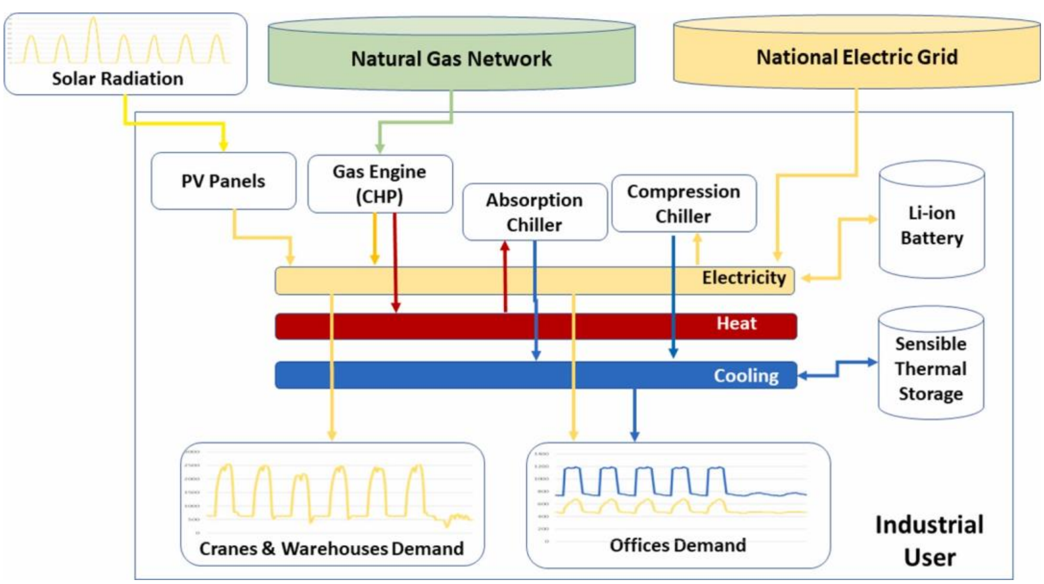

Fig. 1. Energy hub potential configuration, considering all the system that can be deployed.

binary variable X, which allows the size to be equal to zero thanks to the constraint in equation (1). In equation (2) the output power of the technology P^{conv}_{out} is bounded between zero and its rated capacity in each timestep *h*. Finally, equation (3) constrains the input and output power of each technology by means of a single conversion parameter η^{tech} (as an example for a natural gas engine) or COP^{tech} (for an electric/absorption chiller), which is defined for each technology and in each size range.

As an example, the equations (4), (5), (6) and (7) show the model for a CHP system powered by a reciprocating natural gas engine.

$$P_{min}^{CHP-range} * X_{CHP-range} \le P_{size}^{CHP-range} \le P_{max}^{CHP\_range} * X_{CHP\_range} \quad (4)$$

$$0 \le P_{out-el}^{CHP-range}(h) \le P_{size}^{CHP-small} \quad (5)$$

$$\frac{P_{out-el}^{CHP-range}(h)}{\eta^{el}} = P_{in-ng}^{CHP-range}(h) \quad (6)$$

$$\frac{P_{out-th}^{CHP-range}(h)}{(\eta^{tot} - \eta^{el})} = P_{in-ng}^{CHP-range}(h) \quad (7)$$

The size range of the CHP system is highlighted by means of the superscript *range*. Equation (4) bounds the size $P^{CHP}_{size\_}{}^{range}$ of the system, equation (5) its hourly output power $P^{CHP}_{outel}{}^{range}$ (electricity in this case) and equations (6) and (7) represent the relations between the input power (natural gas) with the output electric and thermal powers by means of two conversion efficiency values: η^{el} for input to electricity efficiency and η^{tot} for the total efficiency (electricity + recovered waste heat).

A different strategy is followed for the PV system, which output power is not dispatchable and depends from the hourly yield which is provided as an external parameter. The model is then stated as per equations (8) and (9).

$$0 \le P_{PVsize} \le P_{PVmax} \quad (8)$$

$$P_{PVout}(h) = Y_{yieldPV}(h) * \eta_{PVpar} \quad (9)$$

The size of the system P^{PV}_{size} is represented by its generation capacity in kWp, and the hourly production $P^{PV}_{out}(h)$ directly depends on the total system electricity yield parameter $Y_{yield}{}^{PV}(h)$ which is provided for each hour in kWh/kWp of system capacity as an input to the simulations. The size of the PV does not follow the size ranges approach used for the other conversion technologies and is thus allowed to vary in size maintaining the same performance level. Only an upper bound is applied to consider potential space limitations. Such bound is defined by a maximum system size P^{PV}_{max}. On the amount of electricity defined by the yield an additional loss is added to consider transformers and other auxiliaries' losses by means of equation (9) with the parameter η^{PV}_{par}.

The two storage technologies considered, BESS and CTES, also follow an approach based on a continuous size, thus with no size ranges. The full model for a storage technology is defined as follows with equations (10), (11) and (12).

$$0 \le Cap_{storsize} \le Cap_{stormax} \quad (10)$$

$$Cap_{storsize} * SOC_{min}^{stor} \le E_{storstored}(h) \le Cap_{storsize} \quad (11)$$

$$E_{storedstor}(h-1) - E_{disstor}(h-1) + E_{storch}(h-1) = E_{storedstor}(h) \quad (12)$$

As for Equation (8), Equation (10) constrains the variable representing the storage capacity Cap^{stor}_{size} (defined by a storable energy in kWh) to below its maximum allowed value. Equation (11) bounds the time- dependent stored energy to be between the minimum allowable state of charge (SOC^{stor}_{min}) and the maximum one, defined at the storage capacity itself. Finally, Equation (12) represents the energy balance in time for the storage technology: at any timestep *h* the amount of stored energy equals the amount which was stored at the preceding timestep (*h-1*) plus the amount which was charged and minus the amount that was discharged in that same timestep.

For each energy carrier of the energy hub (cooling, heating, and electricity) an equation represents the balance of energy at every timestep h. The sum of all the inbound energy flows E^{car}_{in} minus the sum of all the outbound energy flows E^{car}_{out} must equal the demand for that specific carrier D^{car} (which is provided as an input parameter) at every timestep *h*.

The general equation for the time-dependent energy balance of a carrier is shown in Equation (13), while the actual balance for an example consisting in the electricity carrier is shown in Equation (14).

$$\sum_{tech} E_{in}^{car}(h) - \sum_{tech} E_{out}^{car}(h) = D^{car}(h) \quad (13)$$

$$D_{ele}(h) = E_{outCHP}(h) + E_{outPV}(h) + E_{dchBESS}(h) + E_{purgrid}(h) - E_{sellgrid}(h) - E_{chBESS}(h) - E_{inEC}(h) \quad (14)$$

In Equation (14), among the inbound flows E^{CHP}_{out} represents the electricity produced by the CHP system, E^{PV}_{out} the one produced by the PV system, E^{BESS}_{dch} the electricity discharged by the local BESS and E^{grid}_{pur} the electricity purchased from the national grid. Among the outbound flows E^{grid}_{sell} is the electricity sold to the grid, E^{BESS}_{ch} the electricity charged in the local BESS and E^{EC}_{in} the electricity absorbed by the local EC. The sum of all the quantities must equal the electricity demand D^{ele} at any hour *h*. Furthermore, an additional constraint on the electricity flows is introduced to limit the amount of electricity sold to the grid to equal at most the production from the PV plus half of the CHP systems generation [50]. This is expressed by means of equation (15).

$$0 \le E_{sell}^{grid}(h) \le E_{out}^{PV}(h) + 0.5 * E_{out}^{CHP}(h) \quad (15)$$

As anticipated, the objective of the optimization is to minimize the total costs sustained to meet the energy demands in the energy hub. These are modeled as a single quantity representing the total costs sustained in one year, both for the operation of the energy systems and a yearly payment consequent in the investment in new technologies deployed within the district. The objective function is shown in Equations (16), (17) and (18) show how the investment, maintenance and operational costs are formulated, and Equation (19) how the investment is considered only by a single payment.

$$min: C_{tot} = C_{inv} + C_{main} + C_{op} \quad (16)$$

$$C_{op} = \frac{8760}{H} * \sum_{h} (E_{gridpur}(h) * c_{gridpur} - E_{sellgrid}(h) * c_{gridsell} + E_{purngas}(h) * c_{purngas}) \quad (17)$$

$$C_{inv} + C_{main} = \sum_{tech} (C_{tech} * S_{tech} * X_{tech}) * (f_{tech} + c_{techmain}) \quad (18)$$

$$f_{tech} = \frac{i * (1+i)^{n_{tech}}}{(1+i)^{n_{tech}} - 1} \quad (19)$$

Where C_{tot} is the total cost to be minimized and C_{inv}, C_{main} and C_{op} the investment, maintenance and operational costs, respectively.

The operational costs are computed as a sum of the electricity purchased from the grid E^{grid}_{pur} plus the natural gas purchased from the natural gas network E^{ngas}_{pur} minus the electricity surplus from the PV sold to the grid E^{grid}_{sell}, with each quantity multiplied for the respective specific purchase/selling price in $/kWh c^{grid}_{pur}, c^{ngas}_{pur} and c^{grid}_{sell}. This sum is computed for a subset of hours the year, which is considered representative, and thus the total yearly costs are obtained by multiplying such costs for a projection factor $\frac{8760}{H}$ where H is the total amount of hours in the simulated timespan. Furthermore, an additional constraint is imposed on the operational costs to forbid the generation of profits from the compensation originated from injecting electricity into the grid. In this way the revenue from selling electricity will at most match the expenses sustained from purchasing electricity from the same grid [51]. This is expressed by the constraint in equation (20):

$$\sum_{h}(E^{grid}_{pur}(h) * c^{grid}_{pur}) = \sum_{h}(E^{grid}_{sell}(h) * c^{grid}_{pur}) \quad (20)$$

The investment and maintenance costs are computed together with respect to the purchase of every system among the ones considered in the study. The purchase of a given system is represented by a binary variable X_{tech} representing its existence and a S_{tech} representing its size (rated power for production systems and storage capacity for storage systems). The size is multiplied for a specific investment cost C_{tech} in $/kW or $/kWh depending on the type of technology and the product of the three quantities represents the total investment. To represent only one yearly payment this cost is multiplied by the factor f_{tech} which considers the interest applied on the investment i and the technical lifetime of the specific technology in years with n_{tech}. The yearly maintenance costs are considered as a fixed fraction of the total investment.

The optimization problem is encoded by means of the Pyomo library for the python programming language [52]. The solution method lies in directly solving the whole MILP problem by means of the Gurobi solver [53] with an integer optimality gap of 1%.

3. Case study definition

This paragraph describes the assumptions and the data that are used as parameters for the optimization problem defined in the previous section. These regards both technical and cost aspects, such as: i) the characterization of the energy needs of the users; ii) the parameters for the energy conversion systems considered for deployment within the energy hub; and iii) the external commodities supply also considering the impacts of the carbon tax and primary energy resources supply price. *3.1. District energy demands parameters*

The two demands of the users in the energy hub, being cooling and electricity, are to be defined on an hourly basis. This is achieved following two different approaches for the office building and the warehouses. For the first, the energy consumption is available as measured data with hourly resolution thanks to smart meters deployed directly in the building. The hourly demands for both electricity and cooling from the available data are shown in Fig. 2.

For the warehouses, the measurements are available with a much lower time resolution (monthly, daily and 12-h total consumption) since the data were collected by an operator on site. Thus, in order to build a realistic hourly profile a warehouse building model is used by referring to a database of prototype building models [54] used for simulation with the EnergyPlus software [55]. A model of a warehouse is simulated, and its electricity consumption is obtained, then once normalized is adapted to obtain a weekly profile following the totals measured. This is considered a valid assumption given that the low-resolution data that is available refers to feeders which as mentioned feed a set of diverse electricity powered devices. The obtained consumption pattern is shown in Fig. 3. The weekly trends showed in Fig. 2 and Fig. 3 are then used to represent the energy demands from the users in the energy hub.

A last time-variant parameter that needs to be represented is the hourly radiation available, which impacts the yield from a potential PV system. The energy hub configuration is tested on the average week obtained from simulated radiation data from the year 2018, available with hourly resolution. The hourly radiation data is retrieved from the web-based model Renewable Ninja [56], which has been extensively used to model renewables production patterns with high spatial resolution [57] and over long multi-decade timespan [58]. The model allows to retrieve simulated timeseries of renewable energy systems (PV and wind) located anywhere in the world by referring to weather data obtained from satellite reanalysis models. An obtained simulated yearly electricity yield for a 1 kWp system is shown in Fig. 4.

The phenomena that generate hourly energy demands and the solar radiation are intrinsically uncertain, and as a consequence such uncertainty propagates in the model while selecting time slices as in the case of this study [59]. In this regards the peculiarities of the case study under analysis help in mitigating the impact of such uncertainties, given the steadiness of the tropical climate throughout the year, with low seasonality characteristics of the weather (e.g temperature and solar radiation). The assumptions that are made of a single week to represent both energy demand and solar radiation availability therefore do include uncertainties given the partial representation of such seasonality trends, but this is considered acceptable given the limited magnitude of such seasonality characteristics (see Tables 1 and 2). *3.2. Technical and cost parameters for the reference case*

To obtain a robust result for the optimal design problem for the distributed energy system the technical and cost parameters needed to characterize each technology are set according to an updated literature. Following the technology sizes modeled in ranges as described in

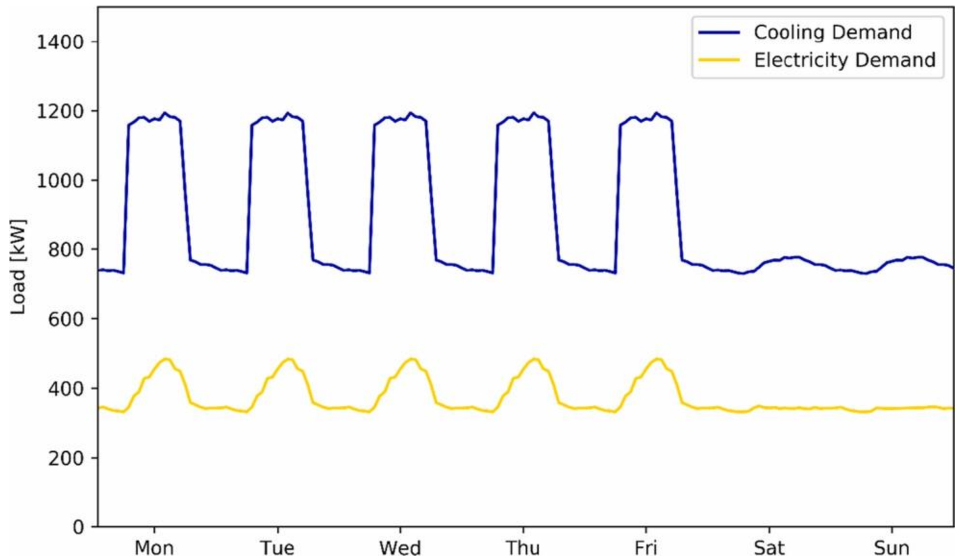

Fig. 2. Cooling and electricity demand for the office building for a week with hourly resolution.

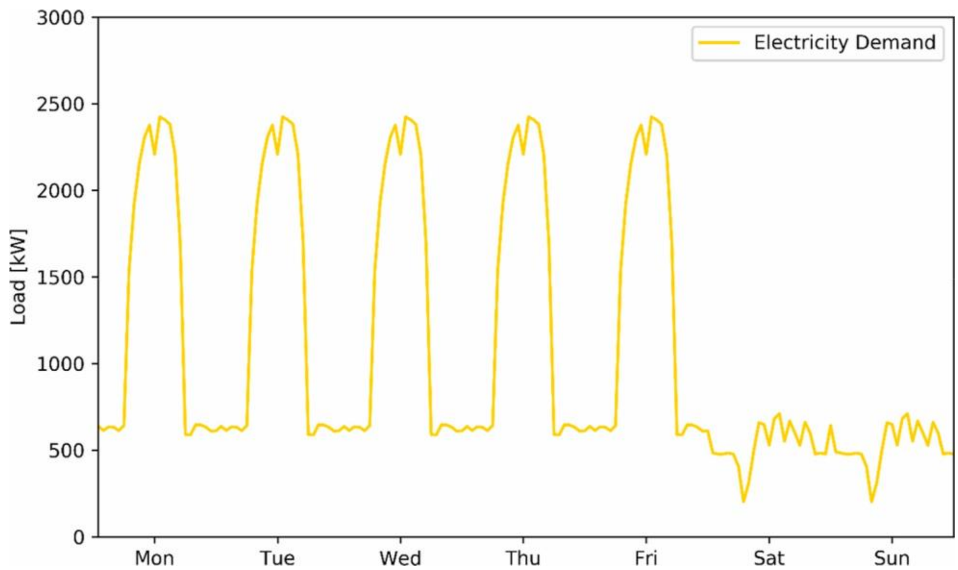

Fig. 3. Electricity demand for the rest of the appliances for a week with hourly resolution.

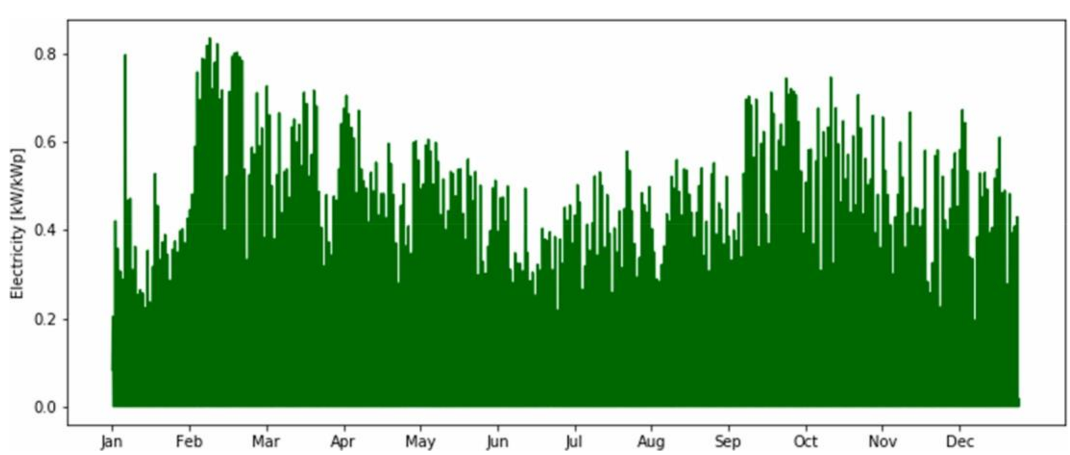

Fig. 4. Hourly electricity production of a 1 kWp system.

Table 1
Technical and cost parameters for the electric chiller.

Electric Chiller (EC) [60–62]	Small	Large
Minimum size [kWc]	0	1500
Maximum size [kWc]	1500	10,000
COP	5.5	6.5
Investment cost [$/kWc]	150	120
Technical lifetime [years]	25	25

Table 2
Technical and cost parameters for the absorpti on chiller.

Absorption Chiller (EC) [60,63]	Small	Large
Minimum size [kWc]	0	1200
Maximum size [kWc]	1200	10,000
COP	1.05	1.2
Investment cost [$/kWc]	560	300
Technical lifetime [years]	25	25

Table 3
Technical and cost parameters for the CHP reciproc ating gas engine.

Gas Engine (CHP) [60,64]	Small	Medium	Large
Minimum size [kWe]	0	750	3000
Maximum size [kWe]	750	3000	10,000
Electric efficiency	0.35	0.38	0.42
Global efficiency	0.83	0.8	0.8
Investment cost [$/kWe]	2800	2000	1400
Technical lifetime [years]	25	25	25

Table 4
Technical and cost parameters for the PV system. The maximum allowable size for the PV system has been estimated by means of an aerial view of the real site.

PV System [8,65]	One size
Minimum size [kWp]	0
Maximum size [kWp]	30,000
Parasitic efficiency	0.98
Investment cost [$/kWp]	860
Technical lifetime [years]	30

Table 5
Technical and cost parameters for the energy storage technologies.

Storage Technologies [34,35,66]	Battery storage systems	Cold thermal energy storage system
Minimum size [kWh]	0	0
Maximum size [kWh]	10,000	10,000
Efficiency charge	0.95	0.85
Efficiency discharge	0.95	0.85
Minimum SOC	0.1	0.3
Investment cost [$/kWh]	1100	30
Technical lifetime [years]	20	35

Paragraph 2.2 the technical and cost parameters are defined in Table 1, 2, 3, 4 and 5, and the costs expressed using USD ($) as currency.
Furthermore, the costs for purchasing electricity and natural gas are set to 0.096 $/kWh and 0.029 $/kWh respectively, which are the tariffs currently imposed on the user being the test case for this study. According to Singapore's regulations the possibility of feeding a potential surplus of renewable electricity into the grid for large producers is compensated according to the time variant wholesale electricity price [67] (still considering the limits defined with Equation (15)), which for 2020 averaged at to 0.048 $/kWh [68]. Such average value as been set as a compensation for feeding electricity surplus into the grid across all the simulated scenarios.

Table 6
Scenarios' features and simulation parameters for Scenario I, Scenario II and Scenario III.

	Carbon tax level [S $/ton$CO_2$]	Natural gas price variation [%]	Grid electricity price (purchase) [$/kWh]	Network natural gas price [$/kWh]
ScenarioI	5	0	0.098	0.03
Scenario II	15	0	0.101	0.03
Scenario III	15	+15	0.108	0.034

As for the time dependent parameters described in the previous paragraph also the ones related to cost and technological assumptions are affected by uncertainty. With regard to the technologies considered for the optimal design of the distributed energy system a distinction can be made by more mature technologies such as cooling and CHP systems, with respect to batteries and PV systems which are still undergoing significant cost reductions due to economies of scale and technological development, as anticipated in the introduction. For these latter two technologies the parameters describing the specific costs can be then confidently expected to lower.

The costs for purchasing electricity and natural gas are also continuously evolving, as they can be assumed as boundary conditions which can be influenced by market forces and policy makers. For these reasons, the sensibility analysis that is undertaken through the proposed scenarios considers as a baseline the electricity and natural gas prices registered in 2019.

3.3. Scenarios definition

The goal of the analyses is investigating the potential impact of carbon pricing on the optimal design of distributed energy systems and, therefore, the CO_2 emissions generated in meeting user energy demand, which ultimately defines the effectiveness of the carbon pricing policy. This is achieved through a set of scenarios, where each scenario entails the solution of the optimal design problem described in Paragraph 2.2 with different values of carbon tax and natural gas price variations, which determine different supply prices for network natural gas and grid electricity.

Firstly, a set of three scenarios is laid down to study how the optimal design of the energy hub varies according to both increasing values of carbon tax level and different levels of natural gas price, as follows:

1. The first depicts the current situation (business as usual scenario), with market prices for grid electricity and natural gas as of 2019, which entail a carbon tax of 5 S$/ton$CO_2$.
2. The second reflects the situation as it could be if the carbon tax is increased to 15 S$/ton$CO_2$ as planned for the year 2023, still maintaining the natural gas price at the same level
3. The third studies how the increase in carbon pricing in 2023 would combine with a shift in natural gas costs. A realistic projection for such cost is made following the projections of the World Bank [69] and set to an increase of 15% with respect to the year 2019. This is a simplifying assumption since natural gas supply costs for regular consumers might not follow such pattern with the same magnitude in relative changes.

Then, a sensibility analysis is performed to investigate how the design choices, and consequently the costs and primary energy usage patterns, of the energy hub would vary in a wider range of carbon tax levels and natural gas supply prices.

The carbon tax levels investigated range from 0 S$/ton$CO_2$ to a value of 100 S$/ton CO_2, which is almost as high as the one of Sweden, that currently has the highest carbon pricing scheme applied worldwide at almost 125 $/ton$CO_2$ [26]. The natural gas price variation levels are varied according to different values in the range of − 50% to +50% with respect to the current price.

In total there are 9 levels for the carbon tax and 9 for the natural gas price variation. Each level of the former is tested against each level of the latter and there are therefore 81 simulations to run, entailing 81 solutions for the optimization problem. The carbon tax and natural gas prices ranges applied within the study are shown in Table 7.

3.4. Model of the impacts of the carbon tax & natural gas price variation

Both the impacts of the carbon tax and the variation in natural gas prices are considered by estimating their impacts on the costs of supply of grid produced electricity and natural gas for CHP purposes.

The carbon tax is considered by assuming increasing pricing levels for the emissions of CO_2 generated by the operation of the energy hub. The tax is designed to hit every large emitter (>2000 ton/year) [36] and within this study it's considered to hit only the large electricity producers which feed Singapore's electric grid, whose mix is mostly composed of large natural gas powered combined cycle plants [70]. No impacts are considered in the case of a distributed CHP system purchased within the energy hub given that even if all its yearly demands would be met by means of a CHP system the emissions would still be below the mentioned threshold of 2000 ton/year.

The impact of natural gas prices fluctuations is accounted for by estimating the consequent increase on the electricity tariff, and by considering the shift in the price of the natural gas purchased to feed potential CHP systems. The variation in natural gas price is modeled as a relative variation with respect to the price applied for the base scenario. In the case of the natural gas-powered CHP system potentially deployed in the energy hub this reflects as an increase with respect to the current tariff.

The impact of both carbon tax and natural gas price variation on electricity price has been modeled by assuming that a fixed fraction of the base electricity tariff, representing the energy costs, increases of a fixed relative amount accordingly to the magnitude in variation of the natural gas costs.

The shift in costs for the natural gas withdrawn from the network and the grid electricity cost is shown in the equations (22) and (23):

$$c_{ngaspur} = c_{ngasbase}*(1 + *v_{ngas}) \qquad (22)$$

$$c_{gridpur} = c_{gridbase}*(1 + k_{ngasctax}*v_{ctax} + k_{ngasngvar}*v_{ngas}*g_{ngas}) \qquad (23)$$

Where c^{ngas}_{pur} and c^{grid}_{pur} are the cost parameters used to compute the operational costs in Equation (17), and c^{ngas}_{base} and c^{grid}_{base} the value for the same parameters in 2019. v_{ngas} is the degree of relative variation of the price with respect to the 2019 price and v_{ctax} is the value of the carbon tax in S $/ton$CO_2$, as shown in Table 7. k^{ctax}_{ngas} is used to quantify the impact of the carbon tax on the grid electricity price; and it is assumed by considering the CO_2 emissions of the national energy mix which in 2018 amounted to 0.4192 kgCO_2/kWh of electricity generated in Singapore [70].

It is assumed that the carbon tax related costs associated to the production of a given quantity of electricity are entirely sustained by the user that consumes it: Thus, for the consumption of electricity purchased from the grid the user will sustain an additional cost of 0.031 ¢$/kWh for each S$ of carbon tax. It must be noted that this is a worst-case assumption, as in the idea of the policymakers the increased costs associated to the consumption of grid produced electricity would also encourage energy efficiency both on the supply and demand side, thus having only a part of the costs reflected on the electricity bill.

The impact of shifts in natural gas prices on grid electricity prices is also accounted for by estimating the costs increase sustained by the large producers that feed into the grid, and by consequence the shifts in costs on downstream users. This achieved by means of two parameters. g_{ngas} quantifies the share of the electricity bill that is due to the actual cost of the energy being supplied, and it's set to 75% [71]. The parameter k^{ngvar}_{ngas} represents the relative increase in energy production costs due to an increase in primary energy supply costs, this is set to 0.7% per each 1% of increase in natural gas costs [72] assuming that the electricity is entirely produced by means of natural gas combined cycle plants [70].

The natural gas supply prices and grid electricity supply prices for the energy hub which are considered in this study and shown in Table 7 determine a set of grid electricity and natural gas prices shown in Fig. 5 for all the cases analyzed. The compensation for feeding renewable surplus into the grid is left unaltered across all the simulations, equaling the value of 0.048 $/kWh obtained as described in paragraph 3.2.

3.5. Model of environmental footprint of the energy hub

In order to evaluate the environmental impact of the designs computed by the algorithm a metric based on an estimate of the primary energy consumption needed to meet the energy needs of the district over a year is computed for each simulation. Thus, the primary energy consumption of a given scenario is computed through equation (24).

$$PE_{cons} = \sum_{h}^{8760} \left(E^{ngas}_{pur}(h) + \frac{E^{grid}_{pur}(h) - E^{grid}_{sold}(h)/\eta^{grid}_{trasm}}{\eta^{grid}_{el}} \right) \qquad (24)$$

Where PE_{cons} is the total amount of primary energy consumed by the energy hub, E^{ngas}_{pur}, E^{grid}_{pur} and E^{grid}_{sold} are the amounts of natural gas purchased, electricity purchased, and electricity sold to the respective distribution infrastructures. η^{grid}_{el} the electric efficiency of the national grid's energy mix and η^{grid}_{trasm} the transmission and distribution efficiency for the mix in the city [70]. In this way the primary energy consumption of the district accounts for both the energy that is consumed in meeting the energy needs of the district, and for the surplus which is considered as a primary energy saving generated elsewhere.

Thus, according to Equation (24), the energy hub can reduce its carbon footprint by exporting electricity to the grid, which is accounted for as if such energy production is taken off from the national energy system mix production.

4. Results & comments

This section highlights the results from all the performed simulations. In Section 4.1 the optimal system configurations and performance indicators for the three scenarios representing Scenarios I, II, and III are shown. The results are expressed both in terms of the optimal design, meaning the size for each technology that is used within the energy hub, a set of relevant performance metrics such as total yearly costs, primary energy consumption and so on.

Sections 4.2 and 4.3 highlight the results of the sensitivity analysis on a wider span of carbon tax levels and natural gas price variations according to the parameter values shown in Table 7.

4.1. Results of Scenario I, Scenario II and Scenario III

This subsection reports the results of the Scenario I, Scenario II and Scenario III, which are summarized in three tables, showing summary quantities describing the results obtained from the simulations both in terms of systems design, energy usage patterns and costs sustained. Table 8 shows the results for the optimal design of the energy hub's systems, for each of the technologies included in the analyses. Table 9 shows the yearly overall electricity production and consumption. Table 10 the results in terms of total yearly costs (being the objective quantity to minimize) and the total primary energy consumed.

The results show that the optimal design is almost unaltered, except for an increase in the PV system size, by increasing both the carbon tax level as of 2023 and consequently to a realistic natural gas price

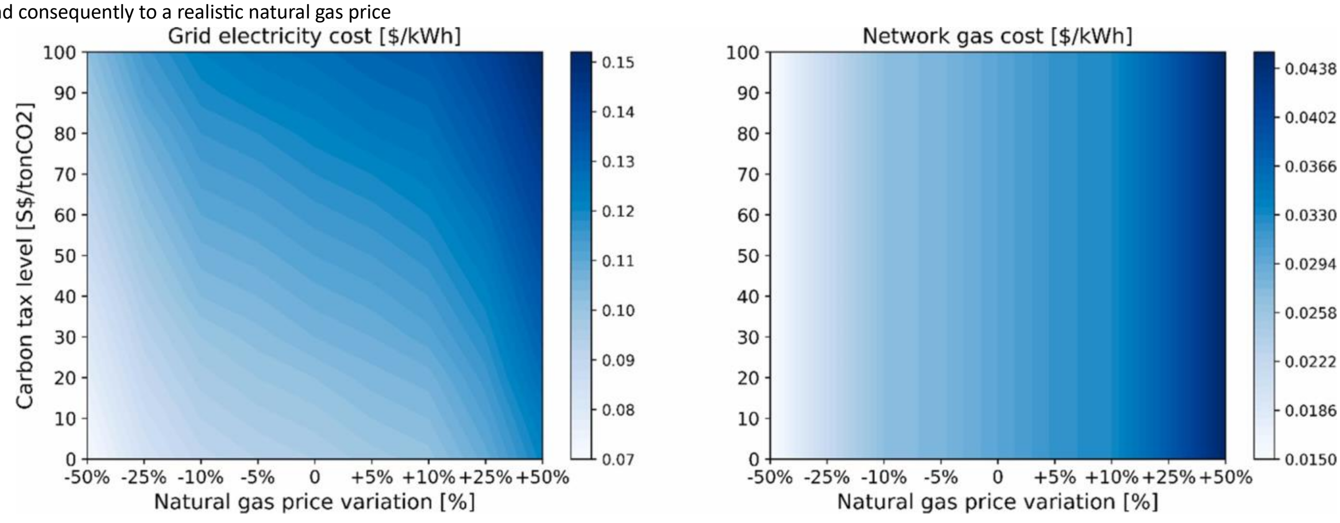

Fig. 5. Variation of the grid electricity purchase price across all the scenarios.

Table 7
Teste levels for the carbon tax and natural gas prices variation.

Carbon Tax level [S$/ton$CO_2$]	0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100
Natural gas price variation [%]	− 50%, − 25%, − 10%, − 5%, 0, +5%, +10%, +25%, +50%

Table 8
Energy hub design results in Scenario I, Scenario II and Scenario III.

	Tot EC size [kWc]	Tot AC size [kWc]	Tot CHP size [kWe]	Tot PV size [kWp]	Tot CTES size [kWh]	Tot BESS size [kWh]
Scenario I	1500	0	0	10,570	0	0
Scenario II	1500	0	0	10,574	0	0
Scenario III	1500	0	0	11,439	0	0

Table 9
Yearly energy usage results in Scenario I, Scenario II and Scenario III.

	Tot PV prod [GWh]	Tot CHP prod [GWh]	Tot Grid pur [GWh]	Tot Grid sell [GWh]
Scenario I	11.75	0	7.46	2.59
Scenario II	11.76	0	7.46	2.6
Scenario III	12.72	0	7.3	3.38

Table 10
Costs and yearly primary energy consumption.

	Total yearly costs [M $]	Tot PE cons [GWh]	Total CO_2 emissions [kt]
Scenario I	1.34	11.21	2.08
Scenario II	1.36	11.20	2.08
Scenario III	1.41	9.11	1.7

variation. With respect to the as-is scenario (represented by Scenario I) the PV system capacity grows by 242 kWp (a 2% increase) consequently to the carbon tax increase, while adding the increase on natural gas prices this grows by 1492 kWp (a 15% increase). All the rest of the system design does not change, thus with no need to use neither CHP/ CCHP and without the need for storage systems (see Tables 4 and 5).

The absence of CHP/CCHP is to be attributed to the cost of purchasing electricity versus the cost for purchasing natural gas from their respective distribution networks, which are shown in Table 6. In Scenario I, producing 1 kWh of electricity with a CHP engine would cost between 0.086$ and 0.071$ (depending on which one of the considered gas engine sizes from Table 3 is considered) versus spending 0.098 $/kWh by purchasing from the grid. The production with a CHP then comes at a cheaper price, but clearly not enough to justify the purchase of the CHP system given the given the similar values in the ratio between producing electricity by means of a CHP system and purchasing it from the grid [73], and this is true even by considering the availability as a resource of the recovered heat, which would need an additional investment in an absorption chiller system to be used in this context. The results are the same in Scenario II and Scenario III given the similar values in the just described ratio.

The absence of the two storage systems considered is still to be attributed to the type of supply of electricity. The CTES is not needed since the entire cooling production is met by an electric chiller, which is fully dispatchable depending on the load in real-time. A second reason lies in the fact that in the case of availability of excesses in solar electricity production the choices of the algorithm exploit the possibility of injecting in the distribution grid in exchange for a compensation, instead of storing it for later consumption which would imply both the losses in the round-trips through a storage system, and also the costs related to its purchase. The latter is also the reason explaining the absence of a BESS as well. As described in the introduction one of the applications of batteries is to increase self-consumption from renewables. But if there is a grid that can welcome any amount of surplus electricity and compensate it appropriately their usage is made unnecessary by the capital expenditures that would be needed to purchase them.

Regarding the distribution grid usage, the increase in the PV system size implies a slight decrease in the electricity that is purchased from it, but more significantly an increase on the amount that is injected which increases by 0.79 GWh per year (a 30% increase) considering both the higher carbon tax and the natural gas price shift. This ultimately leads to a significant reduction in primary energy usage in Scenario III, with a reduction of 2.1 MWh per year, a 18.7% decrease with respect to the situation as-is described by Scenario I. The shift from Scenario I to Scenario II on the other hand is less significant, as the total yearly primary energy consumption drops of an almost negligible 0.01 GWh. It is also worth noticing that in all the three Scenarios a great share of the PV generated electricity that is produced has to be exported, ranging from 22% in Scenario I to 26.5% in Scenario III. This suggests that a shift in the availability of the grid asset to inject electricity surpluses (as an example due to congestions) would probably have a significant impact on the system design, as an example encouraging energy storage.

Regarding costs the shift from Scenario I to Scenario II is worth 20 k$ per year, being a 1.5% increase, while shifting to Scenario III the costs increase of 70 k$, for a total relative shift of 5.2%.

These results already suggest a set of preliminary conclusions. Both two phenomena analyzed, being the shift in natural gas costs and the progressive increase in carbon pricing, contribute to increasing the supply costs for both natural gas and grid electricity, even though to a different extent. This is reflected in the results of Scenario I, II and III, which show that the shift in the cost for natural gas has a much greater effect on the design of the energy hub meeting the energy demands of the industrial user under study. The changes in the design, being substantially a larger PV system, are in fact more pronounced following the shift in natural gas costs rather than the carbon tax increase.

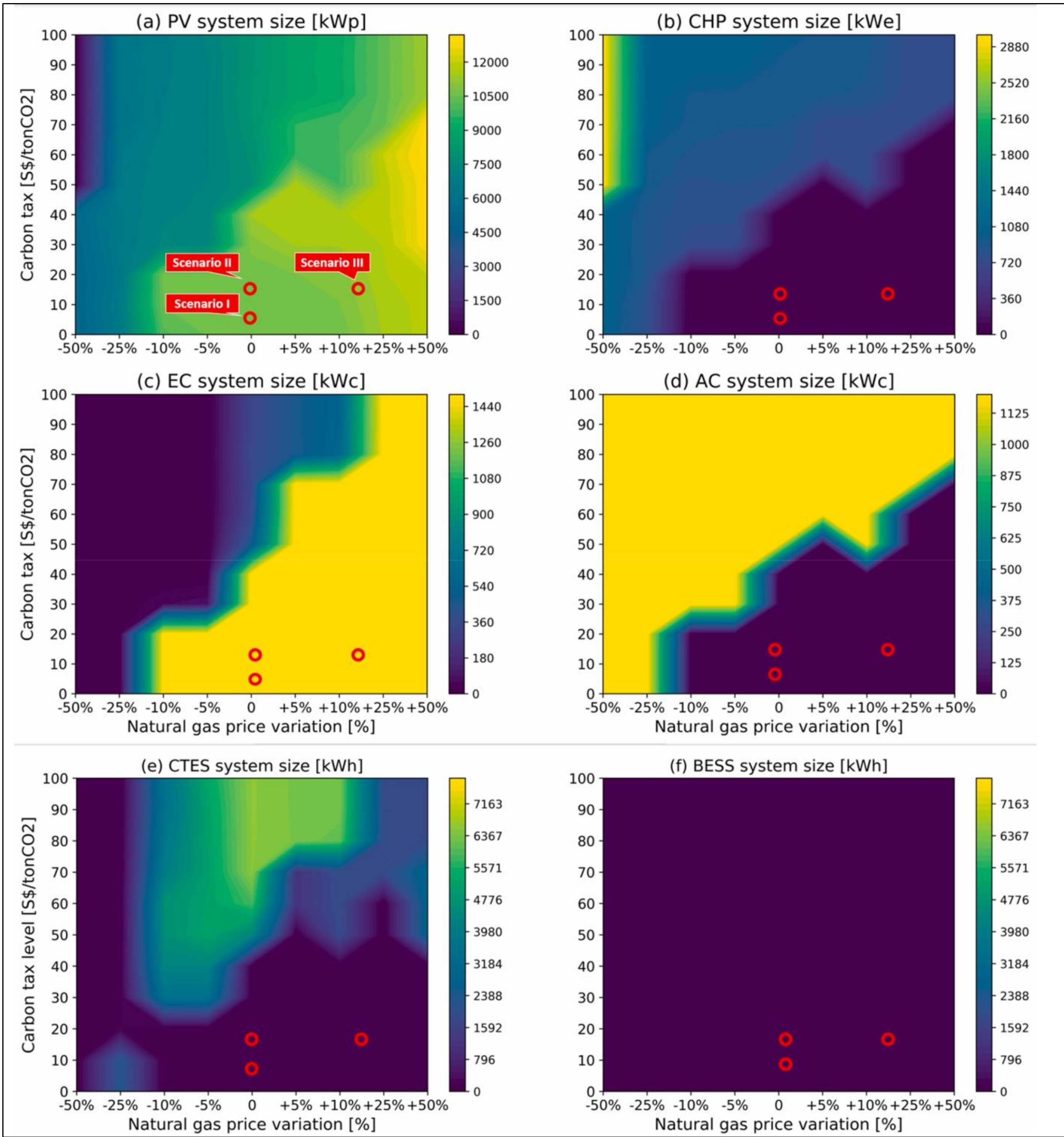

Fig. 6. Results for the optimal systems design in the sensibility analysis. Subfigure (a) shows the PV system size, (b) the CHP system size, (c) the EC system size, (d) the AC system size, (e) the CTES system size and (f) the BESS system size

This suggests that the increase in the carbon tax level from 5 to 15 S $/ton$CO_2$ has an almost negligible effect towards its goal for the case study at hand, which is to lower the CO_2 emissions. This is confirmed by Table 10, which shows that the emissions only decrease in Scenario III, which with respect to the other two has an increase of 15% in the natural gas supply costs.

4.2. Sensitivity analysis: energy hub design and energy use

The results in this paragraph furtherly explore the impacts of the carbon tax and the natural gas price over the range described in paragraph 3.3.

The results are shown in 2d color plots with the same matrix configuration of Fig. 5, with the natural gas variation parameter on the x-axis and the carbon tax level on the y-axis. The quantity encoded by the color represents the value of the quantity of interest computed in the optimal solution in each scenario. Such quantity changes in each plot and ranges from the size of a system to relevant quantities determined on a yearly basis: such as the total amount of primary energy consumption generated, total yearly costs, total PV production and so on.

Fig. 6 shows the energy systems design choices across all the simulations in terms of the size for each of the systems considered in the analyses, having a subfigure for each system. Fig. 8 shows how the electricity is produced in the energy hub and eventually exchanged with the distribution grid, each subfigure shows one of such quantities.

The position of the three Scenarios described in the previous paragraph are highlighted in each subfigure of both Fig. 6 and Fig. 8 so to indicate how their design and electricity usage patterns compare with the rest of the sensibility analysis.

Fig. 6 focuses on the optimal sizes of four energy systems considered in the simulations: (a) PV system; (b) CHP gas engine (thus summing the sizes for the small, medium and large), (c) EC system, (d) AC system, (e) CTES and (f) BESS storage systems.

In Fig. 6(a) it is possible to see the importance of the PV system in the optimal design. The optimal capacity gradually increases with both the cost of natural gas and the carbon tax, reaching its largest values in the right part of the plot, where the natural gas prices are at their highest. The size on the other hand gets smaller by moving towards the top-left corner of the plot where, according to Fig. 5, the natural gas to be used as fuel for the local CHP system is at its cheapest and the grid electricity already has a high price due to the carbon tax. In this area the optimal size of the CHP system, shown in Fig. 6(b), gradually increases at the expense of the PV system, up to the point where the latter is not chosen at all, in the top-left corner. This is to be attributed to the fact that the carbon tax only affects the national power mix, while a distributed CHP system that can keep producing electricity at the same cost for a given level of natural gas price.

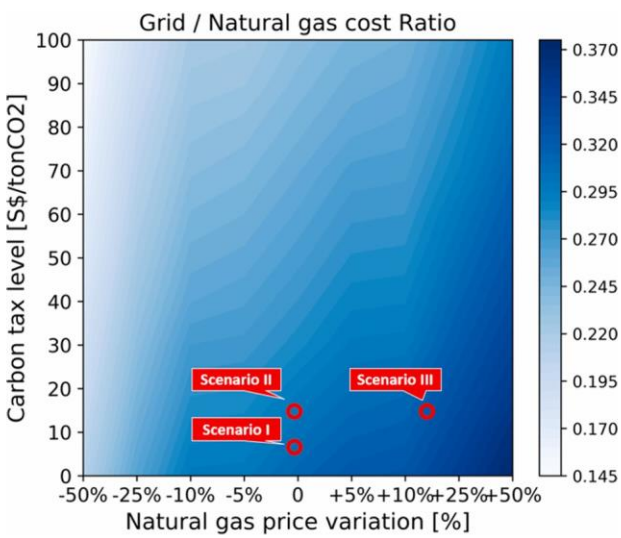

Fig. 6(c) and (d) show the optimal size of the two cooling production systems being considered (electric and an absorption chiller), showing how such size varies with a trend correlated with the PV system size in the first case (seen by confronting with Fig. 6(a)) and with the CHP system in the second (by confronting with Fig. 6(d)). In the first case this is due to the presence of large amounts of electricity from the PV system in the central hours of the day, when the cooling demand is at its peak (as in Fig. 2), that allow to meet such demand with electricity being produced at the same time. In the second case, when the cooling system is mostly based on an absorption chiller, the cooling production is driven by the waste heat recovered from the CHP engine.

It has also to be noticed that the areas where there is a presence of a CTES system, shifting towards yellow in Fig. 6(e), overlap in a region between a design which cooling production fully relies on an electric chiller towards the ones where the same production fully relies on an absorption chiller. This suggests that the CTES system can have a role, which is to act as a buffer for cooling production systems which cannot follow the cooling load on an hour-by-hour basis.

Overall, the results suggest that there are two broad types of designs distinguished by the type of the predominant distributed electricity generation device: one mostly based on generation by means of PV in the bottom-right corner and one mostly based on generation by means of CHP in the top-left corner. An increasing carbon tax, which only weighs on the electricity purchase price under the assumptions made, favors the switch towards a design based on a CHP/CCHP system, and the effect is increasingly stronger with the supply cost for the natural gas resource being increasingly smaller.

The results regarding the size of the BESS system, which are shown in Fig. 6(f), highlight that batteries were not selected in any of the scenarios, the same as for Scenarios I, II and III as described in Table 8. This happens also in the scenarios with the highest grid electricity prices, which according to Fig. 5 are up to 38% higher than the highest price considered in the first three scenarios. Thus, the considerations that can be drawn are also the same: under the current electricity pricing and surplus compensation schemes (even considering the additional impact of carbon pricing and shifts in natural gas supply costs) the investment in batteries to increase electricity self-consumption is not an economically optimal choice. Though, it must be noticed that the typical issues generated by uncontrolled electricity injection (grid instability) are not considered within this study. As a matter of fact, massive injection of surplus electricity, especially from solar PV systems, is already a well- known issue in urban districts characterized by large PV capacities penetration [74,75]. Broadening the point of view of the analysis beyond the single district under consideration it appears that a solution allowing any surplus from distributed generation sources to be exported

Fig. 7. Ratio between the cost for purchasing grid electricity versus for purchasing natural gas.

is not viable within the scope of a technically sustainable and resilient electricity distribution infrastructure, and consequently the city. As a consequence some policymakers are already proposing the concept of local energy communities (even enclosed within larger urban systems) with dedicated compensation schemes to ensure the safe operation of large penetration of distributed renewable generation systems [76]. With such schemes in place only the constraint of self-consumption within the community would be promoted, and batteries systems could become key assets in accessing the incentives.

The criteria being the main driver of the two designs (PV versus CHP dominated) appears to be the dimensionless ratio between the cost for purchasing electricity from the distribution grid (in $/kWh), and the equivalent cost for purchasing natural gas from its respective distribution network [73], such ratio is shown graphically in Fig. 7 following the same graphical representation used in Fig. 5. As the ratio increases the optimal system design leverages more a PV system, while as the ratio decreases (meaning the natural gas being supplied at a progressively lower cost with respect to grid electricity) the optimal system switches towards an electricity production driven by a CHP system. In both cases anyway there is an important role of distributed electricity generation systems, both to drive the production of cooling but also to meet the

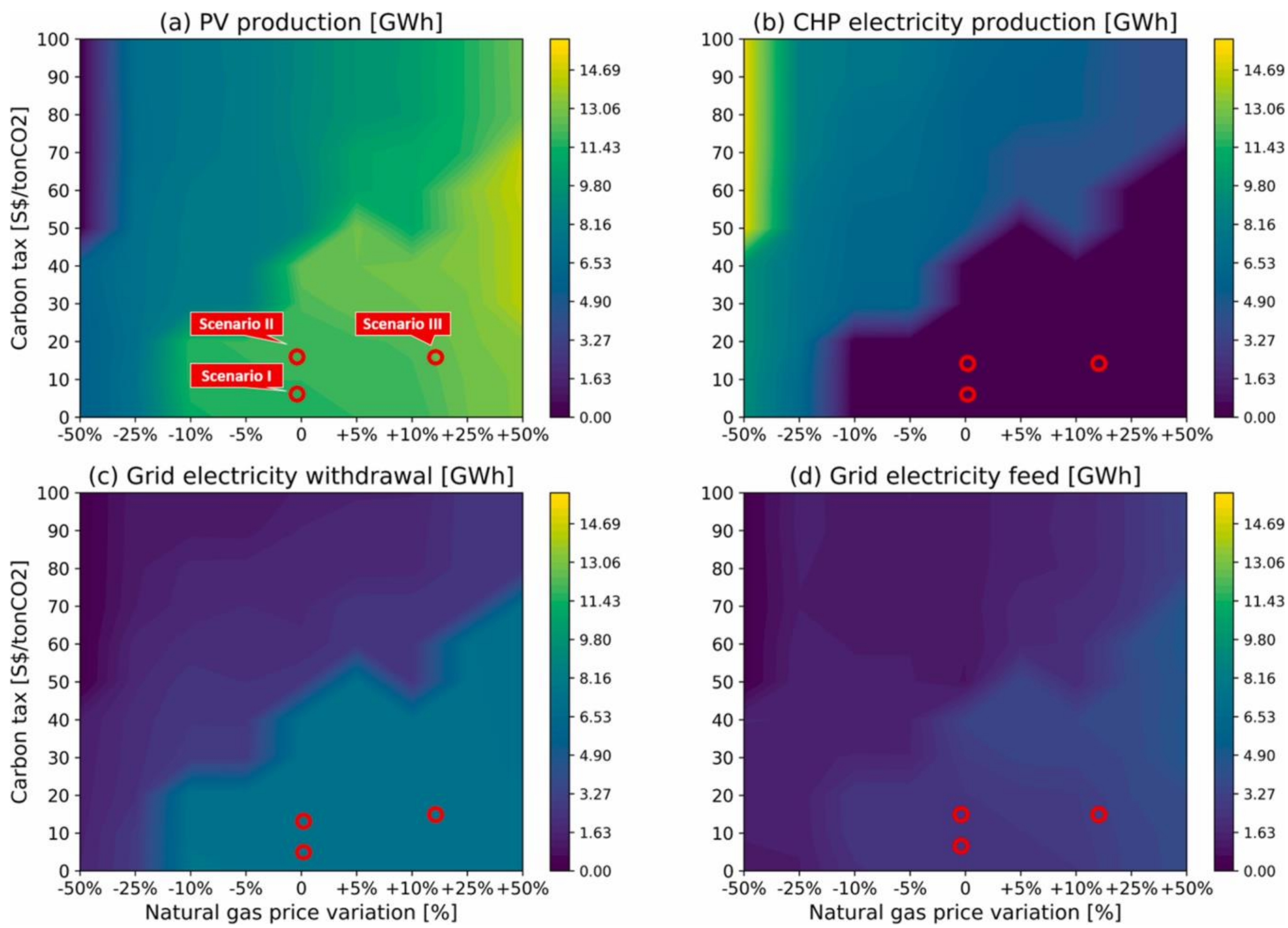

Fig. 8. Results in electricity usage patterns in the sensibility analysis. Subfigure (a) shows the total yearly PV production, (b) the total yearly CHP electricity production, (c) the electricity withdrawn from the grid and (d) the amount that is fed into the grid.

onsite electricity demand itself.

Fig. 8, which is also split in subfigures, shows the yearly electricity distributed production and usage pattern of the distribution grid in GWh. In particular, Fig. 8.a shows the yearly electricity produced with PV, Fig. 8.b the one produced by means of CHP, Fig. 8.c the yearly withdrawal from the electricity grid and Fig. 8.d the yearly electricity injection. It is immediately possible to see that the patterns are like some of the results coming from the optimal design shown in Fig. 6. As expected, larger sizes of the PV system, as in Fig. 6a, coincide with the larger amounts of electricity produced by means of PV shown in Fig. 8a. And the same is true comparing Fig. 6b with Fig. 8b regarding the CHP system. The distribution grid electricity withdrawal and feed are also correlated with the system design. First, it can be noticed that both the two subfigures representing the exchanges with the grid, being Fig. 8c and Fig. 8d, show darker colors with respect to the first two that represent the electricity being produced onsite by the distributed generation systems. The withdrawal shown in Fig. 8c shows its maximum values in the bottom-right corner, which coincides with designs having PV as the only distributed electricity generation system. During the evening and the night, when there is no electricity being produced by such systems, and both the electricity and cooling demands must still be met the grid is used to cover for such energy. Fig. 8(d) shows the trends for the feeding of the surplus electricity into the grid which, even if in relatively smaller amounts with respect to the withdrawal, shows a trend which matches the one of the PV system size shown in Fig. 6(a). This suggests that feeding is mostly related to the non-controllable production pattern of a PV system and, even if that is partially allowed for the CHP system as per Equation (15). Thus, the export of electricity produced by the CHP system is not performed under any of the costs settings simulated in this study. A particular mention has also to be made regarding the configuration in the top-left corner of all the subfigures in Fig. 6 and Fig. 8. In these the optimal design for the energy systems fully relies on distributed generation to meet both the electricity and cooling demand, showing no need to either withdraw or feed electricity from/intro the grid. In particular it can be seen that no PV system of any capacity is deployed, as in Fig. 6(a), and a CHP system for a total electricity generation capacity of approximately 3 MW_e is deployed, with 3 MW being approximately the peak electric load by adding the two loads shown in Fig. 2 and Fig. 3. Also, the cooling demand is met by a fully schedulable AC system, since no CTES is deployed as well. This shows that under a particular set of conditions, in this case related to a relatively very cheap natural gas supply cost, even a system as large as an industrial user could entirely rely on a distributed energy system approach to meet its energy needs, without the need for an electricity distribution grid.

4.3. Sensitivity analysis: energy hub costs and primary energy usage towards "nearly zero" and "net positive" energy districts

This subsection finalizes the results of the study by showing the impacts on the total costs sustained to obtain the optimal designs investigated, and their environmental impact expressed in terms of total amount of primary energy consumed. These are shown in Fig. 9, where the first subfigure shows the total yearly costs in thousands of USD, the second the total yearly amount of primary energy in GWh and finally the third the CO_2 emissions generated annually, being the real objective of the carbon pricing policy. Regarding the costs it is showed that they increase both with the increase of the supply cost of the natural gas and also with the carbon tax, but the former has a much greater impact since, as seen in the previous paragraph, it shifts the optimal design towards having an increasing capacity for electricity generation with CHP. Thus, the possibility of self-producing electricity thanks to a cheap supply of natural gas is shown to be the main pathway towards a significant decrease in the total costs to be sustained by the industrial user, at least with respect to the costs related to the current conditions, which are shown in Table 10. The total primary energy consumption, which is shown in Fig. 9b, shows trends which are similar to the ones shown by the PV and CHP system sizes highlighted in Fig. 6(a) and (b). The consumption gradually lowers while moving towards the right/bottom-right of the plot (where the PV system size it is at its largest) and grows while moving towards the upper-left corner (where the CHP is dominating the optimal design). This is the figure which gives insights regarding the effectiveness of the carbon tax, being the actual end-goal towards which it is designed. Qualitatively, it is possible to see that the darker areas are confined in the bottom-right part of the plot, and that are also correlated with the areas having no CHP generation capacity (as per Fig. 6(b)). The trend is confirmed also by analyzing Fig. 9(c), CO_2 emissions do decrease by increasing carbon pricing but only until CHP enters the mix of technologies in the energy hub. This suggests that a switch towards a CHP-based electricity generation, which is these simulations is driven by an economic criterion, can increase the primary energy consumption, and this happens at lower carbon tax values with a progressively decreasing natural gas supply cost. The designs leading to the lowest primary energy consumptions are the ones which show the highest electricity generation capacity from PV. It is important to remind, here, that under the hypotheses made for this study all the surplus electricity that is generated is exported and successfully consumed elsewhere, offsetting the carbon footprint of the district. Finally, several conclusions can be drawn from the results of this study. Regarding the optimal planning of the energy systems for the test case investigated it can be concluded that there is a tradeoff between a design predominantly using grid electricity and PV, versus another increasingly relying on electricity generated locally through fossil fired solutions. In particular, the latter takes advantage of the sector coupling capabilities provided by combined heat and power and absorption chillers in CCHP mode.

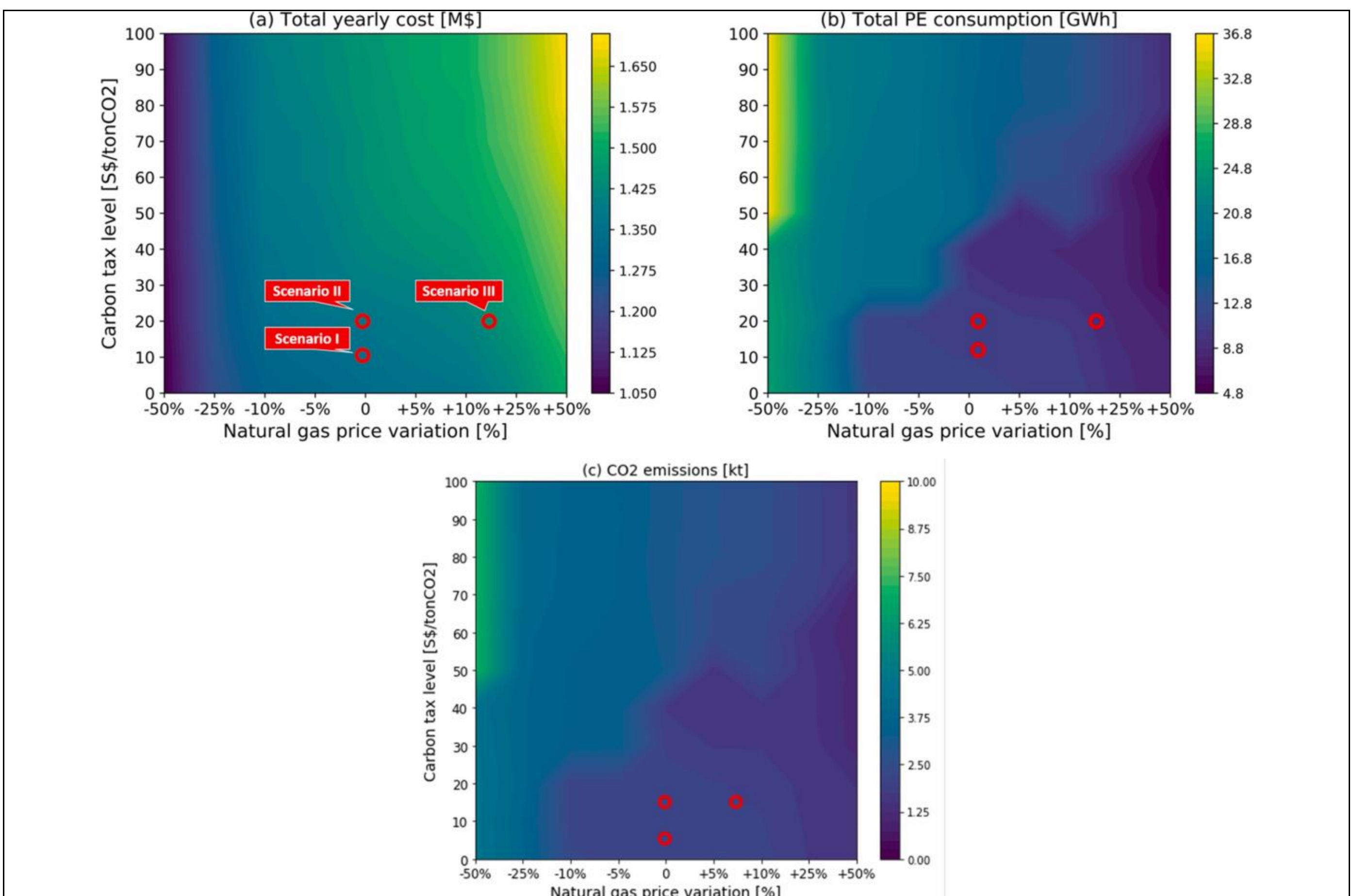

Fig. 9. Results for the energy hub costs and primary energy consumption in the sensibility analysis. Subfigure (a) shows the total costs sustained in one year, (b) the total primary energy consumption.

A first conclusion lies in assessing that carbon pricing does have an impact in reducing primary energy, but this is only limited to contexts where systems design does not use distributed CHP technologies for electricity generation. The switch towards such solutions appears to be driven by the relative increase in grid electricity purchase price with respect to the supply cost for natural gas from the distribution network, which directly determines the cost for electricity production with CHP.

Even accounting for the limitations in this study it is highlighted how, under certain conditions, carbon pricing can have only a limited effect on CO_2 emissions, up to delivering opposite effects if the supply cost for natural gas were too low.

Deploying more PV is effective in reducing primary energy consumptions, and ultimately CO_2 emissions. But this is an approach which most probably could not be followed on larger scales due to common issues in having large injections of non-programmable and variable renewable electricity within local distribution grids. The beneficial effects of the increased RES capacities could also be increased and made more technically sustainable with the usage of an electricity storage system such as batteries, which under the hypothesis made are not a part of an economic driven optimal design.

For such reasons, and in a wider and more general sense, it is suggested that policymakers also take into considerations subsidizing renewable energy sources with the aim of encouraging self- consumption, towards which storage systems such as batteries are a key asset. Carbon pricing, especially within the ranges that are currently in consideration can have limited if not negligible effects depending on the case study being analyzed.

The proposed analysis framework and the results obtained in this study are also transferable to other case studies, in different places and with different energy consumption patterns. Moving from an industrial/ commercial user to a residential one, where usually energy consumption is less intensive during the central hours of the day. In such case with a renewable energy supply mostly based on solar encouraging self- consumption would be even more important and policies would have an important role in such sense. Regarding applicability to other case studies most of the data used in this paper is available from open access databases and tools, except for the data regarding the user's energy demands which is proprietary and not openly released. But realistic building energy consumption data could be generated leveraging a continuously evolving set of frameworks and software tools [77,78].

While the proposed framework could analyze such different portfolio of end-use of energy, it could be enhanced with additional equations to correctly account for incentives regarding only the renewable energy which is self-consumed, as an example.

5. Conclusions

This paper analyzes the impact of carbon pricing on the design of distributed energy systems, and the effectiveness towards the goal of reducing energy consumption. This is achieved by analyzing a test case situated in Singapore, which needs cooling and electricity as energy- related commodities to sustain its operation. The satisfaction of such needs is investigated by considering both a carbon tax scheme in place and a potential shift in primary energy sources prices by studying how the optimal design would vary consequently to such shifts.

To do so a model that represents the optimal design for an energy hub is formulated by means of MILP programming techniques. After modeling the impacts of both a carbon tax and shifts in primary energy sources prices (natural gas in this case) the optimal design problem is solved for a wide set of values for the two parameters. Such results are divided in scenarios that represent the situation as it is now, and as its projected to be following a moderate increase of the carbon pricing scheme already in place. Afterwards a sensitivity analysis on the two parameters aimed at better understanding the impacts of the two external factors is performed.

The results show that the optimal design heavily relies on photovoltaic technology to meet the energy needs of the user under analysis, both now and with moderate changes to the current supply price for the natural gas and the carbon pricing scheme. Also, a potential increase in the supply cost for natural gas could have much greater effects on the amount of primary energy that is being consumed with respect to an increase in the price for carbon emissions.

An additional insight regards the impacts that a potential different switch towards a distributed energy system design, with electricity generation relying on a combined heat and power system, which could lead to increased primary energy consumptions if the supply costs for natural gas were to lower too much. The drivers for such switch are to be found in an increasingly expensive grid electricity, with respect to the cost for the supply of natural gas.

Overall, it is shown that increasing carbon pricing is an effective approach in lowering primary energy usage only if the optimal design does not rely on distributed CHP, a decision which is driven to a set of external conditions such as the supply costs for natural gas analyzed in this study. Consequently, it is also shown that the main driver towards reducing primary energy usage is the size of the PV system being part of the optimal design. Given the hypotheses made, granting the possibility of unlimited injection of surplus electricity within the local distribution grid, it is suggested that incentivizing self-consumption (as an example with increased storage systems capacities) with ad-hoc policies could also be an effective strategy in carbon footprint reduction.

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