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From hospital to municipal cogeneration systems: An Italian case study

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SUMMARY

A mixed integer linear programming model combined with a more traditional design by scenarios is proposed to optimize facilities size and operation mode of a municipal energy system involving significant civil centres and a hospital. Moving from the need of a new heat and power station for the local hospital due to the construction of new pavilions, the opportunity of involving other centres in the neighbourhood in a distributed cogeneration system is analysed, increasing system complexity step by step.

Smaller cogeneration units tailored to hospital needs are rewarding ventures with relatively low risks but, in a country whose traditional power generation systems heavily rely on fossil fuels and where energy policy and market conditions can make it profitable to sell surplus power, district heating systems foster the installation of larger cogenerators and lead thereby to higher profits and to better performance as for primary energy savings and greenhouse gases emission reduction. Copyright © 2006 John Wiley & Sons, Ltd.

KEY WORDS: optimization models; cogeneration; district heating; hospitals; municipal energy systems

1. INTRODUCTION

Technological evolution and progressive reduction of specific costs of energy conversion units have drastically improved perspectives for cogeneration and distributed energy generation. In Italy, this trend is nowadays fostered by liberalization of energy market, with new competitors coming to light, new investments in power generation and more opportunities to put power surplus on the market than in the past (Ambiente Italia *et al.*, 1999). District heating can play a significant role in enhancing cogeneration facilities profitability, offering an efficient and secure recovery of waste heat.

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As the number of technical and management options for cogeneration and district heating network increases, an attitude to design systems as a whole rather than to optimize single components is more and more required (Wu and Rosen, 1999), and computer-based decision support tools become gradually indispensable. For this reason, optimization models, traditionally used for energy planning at a national (Rath-Nagel and Voss, 1981) and regional (e.g. Pietrapetrosa *et al.*, 2003) level, have been more and more applied to the design of district heating systems, as for instance in Henning (1999), Bojic *et al.* (2000) and Gebremedhin (2003), and even to design cogeneration and energy supply systems for single buildings (see Mavrotas *et al.*, 2003). A widely adopted methodology is mixed integer linear programming (MILP), as seen, e.g. in Bojic *et al.* (2000), Mavrotas *et al.* (2003) and Chinese *et al.* (2004), since it provides a good trade-off between detailed modelling and computational feasibility.

Recently, MILP has been applied to the design of district heating systems supplied by multiple heating sources integrated within the same network (Chinese *et al.*, 2004), rather than by a single centralized station as in more traditional designs. This district heating concept harmonizes well with distributed cogeneration, which makes waste heat from power production available in many different buildings.

An application of this concept in an industrial context has been previously studied (Chinese *et al.*, 2004). However, more interesting perspectives arise in urban areas, where single civil buildings with large heat and power needs can be recognized (e.g. schools, hospitals, swimming pools, etc.), usually having higher fuel expenses and more regular energy demand patterns than industrial buildings of similar size: this is bound to lead to more satisfactory economic performance for district heating systems serving civil customers than in the case of industrial district energy networks (Chinese and Meneghetti, 2005).

Hospitals, in particular, are characterized by large and continuous power demand for medical equipment, by regular heat demand for sanitary processes and extensive space heating and air conditioning needs, depending on season and climate. That is why literature is rich in studies concerning the application of combined heat and power generation (CHP) to hospitals (see e.g. Damberger, 1998; Ambiente Italia *et al.*, 1999; van Schijndel, 2002; Salem Szklo *et al.*, 2004; Renedo *et al.*, 2006; Ziher and Poredos, 2006).

In these studies, a traditional approach based on prior definition and successive comparison of few configuration and operation options is mainly used, while optimization approaches are seldom applied (e.g. van Schijndel, 2002). Moreover, energy systems analysis is restricted to medical centres alone, without examining the surroundings. In principle, however, extending systems boundaries to embrace diverse buildings may enhance performance. Mixing different energy demand profiles may, in fact, even out peak loads and lead to a smoother operation of district energy systems, improving utilization rate and overall efficiency, as reported by Chow *et al.* (2004) in the case of district cooling.

In this framework, the Municipal Energy Plan of the city of Udine (North-Eastern Italy) highlighted that heating demand intensity of the Northwest side of the city, including the major hospital in the Province, could make this area suitable for building a new CHP and district heating system, possibly involving the hospital as a supplier or as a client. Consequently, the Municipal Council directed the University of Udine to carry out the feasibility study. The aim was to compare few different strategies, whose principles were clear to public decision makers and hospital management, thereby designing corresponding technical solutions. To draw a fair comparison, we wanted to identify, among the numerous possible options, the optimal configuration and operation scheme implementing each strategy. To accomplish this task, we developed a methodology based both on MILP and on proceeding by scenarios as in more traditional design practices.

In the following sections, we introduce the case study, describing current energy situation in the area (Section 2) and developing possible scenarios reproducing various strategies (Section 3). In Section 4 the MILP optimization model is presented, while results are discussed in Section 5.

2. CURRENT ENERGY SITUATION OF NORTH-WEST SIDE OF UDINE CITY

The energy usage intensity by the North-West side of Udine city is mainly bound to the requirements by a few large civil centres, which could be connected to a district heating system.

The disposition of analysed buildings in the area is shown in Figure 1, while Table I summarizes current technical and energy features of the building complexes and Table II gives an account of energy costs recently sustained by single centres.

As reported in Table I, which presents brief descriptions of various centres identified and numbered in Figure 1, the area includes, beside the hospital, also three University building complexes and two swimming pools: so, there is a reasonable continuity in heating demand (especially by swimming pools) and a good variety in building usage too.

Currently, most of the examined centres are connected to local gas distribution network and have autonomous natural gas boilers, which were mainly installed in the early 1990s. An exception is represented by the Tomadini foundation (site 6), using quite old boilers fed by heavy fuel oil with limited sulphur content and partially with gas oil, which ought to be replaced in short time with natural gas boilers.

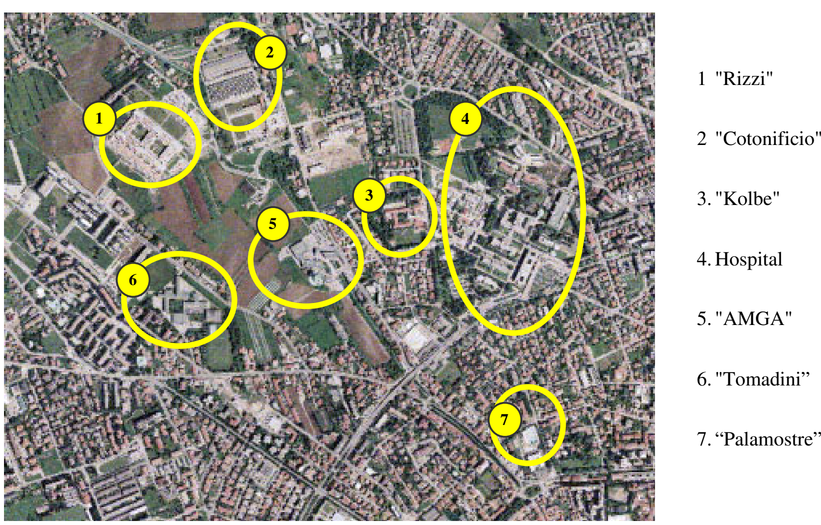

Figure 1. The North-West side of Udine city with energy intensive building complexes.

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Table I. Energy consumption of the analysed centres (year 2003) (TOE = equivalent tons of oil).

Building or building complex	Site number	Description	Total heated volumes (m^3)	Existing heating systems	Total capacity of existing heating system (kW_t)	Fuel type	Fuel quantity (unit $year^{-1}$)	Electric energy (kWh $year^{-1}$)	Total energy demand (TOE $year^{-1}$)
Rizzi	1	University centre for scientific and technological faculties	150 000	Three boilers, providing hot water at 85°C	6050	Natural gas	339 000 m^3	3 900 000	1120
Cotonificio	2	University labs and research departments	62 300	Two boilers, providing hot water at 75°C, two natural gas boilers providing hot water at 70°C	3950	Natural gas	91 500 m^3	778 000	243
Kolbe	3	University conference hall, greenhouse	22 600	Three boilers, providing hot water at 70°C	1230	Natural gas	72 000 m^3	743 000	219
Hospital	4	Large hospital complex including 23 buildings, 14 medical divisions and about 800 beds	520 000	Two steam generators, partially used for process steam, mainly exchanging heat to the hot water distribution system	11 300 (approximate capacity, 17 t/h steam, 45–50 bar, 460°C)	Natural gas	5 396 000 m^3	18 180 000	8370
AMGA	5	Three office buildings, chemical lab, warehouse	45 000	One condensation boiler Four groups of twinned boilers (pairs of boilers regulated to operate alternately in order to guarantee maximum reliability) One traditional boiler	1200	Natural gas	151 000 m^3	818 000	301
Tomadini	6	Boarding school for 270 students, conference hall, church, gymnasium and indoor swimming pool	70 600	Three boilers providing hot water and using heavy fuel oil with low sulphur content and, partially, gas oil	2480	Heavy low-sulphur fuel oil Gas oil	295 000 kg 17 800 l	510 000	354
Palamostre	7	Indoor and outdoor swimming pool, art gallery and theater	20 700	Three hot water boilers	2100	Natural gas	798 000 m^3	570 000	783

Table II. Energy costs of the analysed centres (year 2003).

Centres	Thermal energy			Electric energy		
	Unit cost (c€/m^3)	Tax (%)	Total (€ year^{-1})	Unit cost (c€/m^3)	Tax (%)	Total (€ year^{-1})
Hospital	40.0	20	2 590 000	8.20	20	1 790 000
Rizzi	55.0	20	224 000	9.15	20	428 000
Cotonificio	55.0	20	60 400	10.25	20	95 700
Kolbe	55.0	20	47 500	10.25	20	91 400
Tomadini	52.6	10	188 000	9.70	20	62 600
AMGA	46.0	20	83 500	9.15	20	89 800
Palamostre	57.6	20	552 000	12.50	20	85 500

It should be underlined that all heat distribution systems within various complexes use hot water as a heat carrier. Even at the hospital, where heat is produced by steam generators, heat exchangers are installed so that existing space heating systems and absorption cooling groups are fed by hot water. Hence, hot water could be a suitable energy carrier for a district heating system serving all the sets of buildings.

The hospital is the major energy consumer in the area, as emerges from Tables I and II, and it is also going to increase its energy needs. Within the hospital complex, new edifices for a total volume of 300 000 m^3 are being built, including a new technical and CHP station meant to serve the hospital.

Energy requirements of the enlarged hospital centre will be considered in this study.

Additional winter heating requirements are estimated as a percentage of 20% of current total needs, considering the new volumes and the greater number of indoor air changes requested by present legislation, and taking an indoor temperature of 22°C as reference for the whole day.

Hourly heat demand for a reference day in each month of the heating period has been drawn for the hospital and for all examined centres considering a steady state, dispersion by walls and air change proportional to the difference between indoor and outdoor temperature, but negligible anthropic contribution and dispersion by windows. Theoretical curves have been successively corrected by comparison with actual consumption derived by monthly fuel invoices.

As for the hospital, a significant heat demand over summer months is currently associated with existing hot-water-fed absorption cooling systems.

Since summer heating demand by other centres is comparatively small, future seasonal pattern of thermal energy requirements will strongly depend on the type of refrigeration system that will be adopted at the hospital. If existing absorption groups are maintained and integrated by vapour-compression systems for the new buildings, then thermal requirements can be considered unchanged, while if an absorption system is chosen also for the new buildings, total summer heating demand will be enhanced significantly. Summer thermal energy demand curves of the current configuration have been drawn by adopting a simulation program (Agnoletto *et al.*, 1995) based on response factors and setting a 24 h day^{-1} operating period, reference indoor temperature of 25°C, indoor convective loads equal to 8 W m^{-2}, indoor air changes of 1.32 volumes hour^{-1}. These profiles have been successively updated taking into account refrigeration systems efficiency in order to estimate actual demand curves to be covered by hospital facilities.

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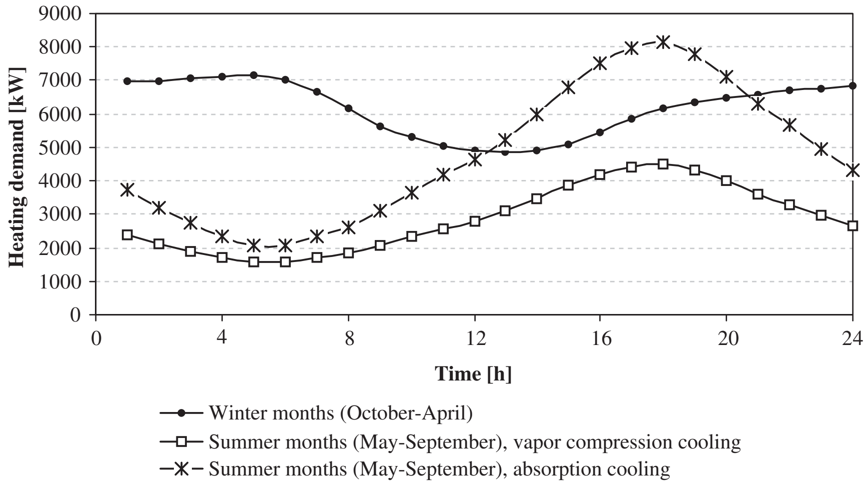

Figure 2. Average daily heat demand profiles of the hospital centre in winter and summer for different cooling options at new hospital buildings.

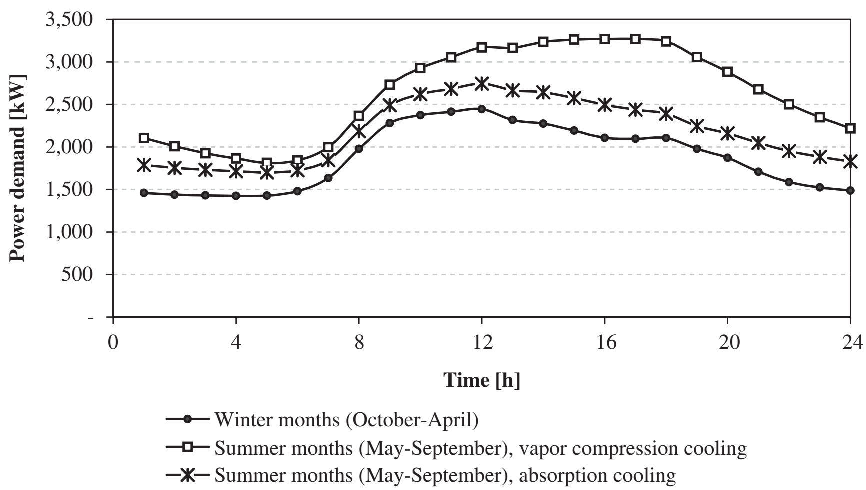

Figure 3. Average daily power demand profiles of the hospital centre in winter and summer for different cooling options at new hospital buildings.

Figures 2 and 3 display average hospital heating and power demand profiles, respectively, for various cooling options at new buildings. For the sake of simplicity, we plot here hourly heating demand (in kW) averaged on a seasonal basis (from October to April for the winter season, i.e. when space heating prevails, from May to September for the summer season, i.e. when air conditioning prevails), which nevertheless show quite clearly how summer consumption patterns are affected by the selected kind of cooling.

As regards electrical energy requirements, all centres are currently served only by the national grid. Recorded demand profiles have been elaborated so that hourly demand curves for the reference day in each month could be drawn.

3. DEVELOPING SCENARIOS FOR A MUNICIPAL COGENERATION SYSTEM

The need of a new heat and power station at the hospital induced public decision makers to evaluate how the strategies by the Municipal Energy Program for a new CHP and district heating system could be put into practice. Discussing with municipal and hospital managers, it emerged that it is either possible to settle for a cogeneration system serving the sole hospital or to pursue the development of a district heating system including the hospital as a major supplier or customer. In the first case, a cogeneration system could be tailored to hospital's power requirements, that is to say possibly avoiding power purchase and surplus power sales, or we could consider the opportunity of putting power surplus on the market and size the system accordingly. In the second case, it is either possible to conceive a central district heating station at the hospital, i.e. within planned hospital CHP station, or to try and conceive an external, distributed cogeneration solution.

In every case, the system should be fueled with natural gas, which is already distributed in the area and used by most buildings, as it is characterized by lower environmental impact, lower costs and higher social acceptability than gas oil or fuel oil.

To carry out the feasibility study, we decided to proceed by creating four different scenarios implementing these strategies, with the objective of identifying for each of them the best technical solution, that is to say, the best size and combination of cogenerators and peak load boilers to be installed and their best operational schedule, taking into account differences in specific capital costs, efficiency and maintenance costs and variations of heat and power demand and of energy price. To this end, an optimization model should be conceived, reflecting constraints and systems boundaries of each scenario. In the following, we define each scenario by qualitatively establishing which constraints it should meet and which costs and reference systems for comparison should be considered in each case.

3.1. Scenario 1: a power station covering hospital energy demand

This scenario reflects the original hospital management preference for an internal CHP station that covers hospital's power demand in a self-sufficiency perspective, avoiding to put power surplus on the market. This choice arises from the need of limiting hospital centre dependency on external power supply, on one hand, and, on the other hand, of maintaining a limited complexity of service facilities so that they could be managed by internal staff. We translate these specifications into constraints to have zero power sales and to cover electrical energy demand by the hospital continuously and completely, which may lead to dissipate waste heat from the engines in case internal power and heating demand do not match.

As for economic variables to be evaluated, only costs pertaining to hospital's facilities will be considered. Thus, capital costs include cogenerators and boilers purchase, engineering and installation costs, operation costs include fuel and maintenance costs.

As a reference scenario for comparison, a base situation with new natural gas hot water boilers for meeting hospital's heating demand, vapour-compression chillers in the new buildings and external power supply is considered.

DOI: 10.1002/er

3.2. Scenario 2: from self-sufficiency to market

In order to allow technical staff to focus on core competences, i.e. medical technical services, hospital managers are also thinking of contracting out the construction and conduction of the cogeneration system to some energy saving company.

Energy saving companies would have the skills to manage technical and administrative issues connected to put surplus power on the market, so they could do it in order to gain extra profits from the liberalized energy market. Thus, there will be no limitation on power sales in this scenario, while other constraints on power demand remain unchanged and heat dissipation is allowed. As size of cogenerators could increase in this case, an upper bound should be imposed to guarantee that energy conversion units fit into the planned hospital's CHP station building. The same is done for integration boilers too. The reference scenario for comparison and the kinds of costs to be considered are the same as in Scenario 1, but incomes from power sales should also be taken into account in this case.

3.3. Scenario 3: introducing a district heating network

In this scenario, we examine the opportunity of providing heating also to nearby building complexes, identified in Section 2, by means of a district heating network departing from the CHP station at the hospital. In this case, the construction and operation of the CHP station at the hospital and of the district heating network built on public grounds would be contracted out on behalf of both the hospital and the municipality.

Besides money flows considered in Scenario 2, costs of the district heating system should be considered now. Total costs of pipes, pumping systems and substations and heat exchangers will be estimated based on full loads by every connected centre and assuming that hot water is fed into the district heating network at a maximum temperature of 99°C, with an available thermal drop of 20–25°C. Annual network operation and management costs will be estimated as a proportion of initial investments in the district heating subsystem. The reference scenario for comparison now embraces all the centres, assuming for simplicity that up to date, independent natural gas boilers meet heating demand by every building complex.

3.4. Scenario 4: a municipal cogeneration system

In line with the fourth strategy, a more innovative district heating and distributed cogeneration solution with at least one CHP station external to the hospital should be conceived. According to public and hospital managers, in fact, building a CHP station out of hospital grounds could generate several long term and administrative advantages. District heating pipes and at least one feeding station could be built on public grounds and thus be finally owned by the municipality, which would hence possess a functionally complete system. In this way, the municipality expects to achieve a better bargaining position and higher flexibility in managing tenders and contracting procedures. Actually, more restrictive requirements are likely to characterize the central district heating station located within the hospital centre.

As explained in Scenario 2, a space bound limits the size of cogenerators and boilers which could be installed at the hospital: this could represent an heavy restriction from the perspective of further expansion of the district heating network. Smaller buildings in the same area and

DOI: 10.1002/er

other neighbouring quarters of the city could, in fact, be served by the district heating system after the initial connection of the core buildings identified in this study. Secondarily, higher safety assurance and more efficient pollution and noise abatement systems could be required by local health, safety and environment protection authorities for energy conversion systems located within a medical complex, which could result in unexpectedly high investments. Mentioned uncertainties and strategic issues could be hardly monetized, but still they induce public decision makers to consider this solution as a valid alternative, provided its economic feasibility can be proved. On the other hand, hospital managers would also appreciate a solution enabling the hospital to own and operate an internal cogeneration system designed according to hospital's original plans (Scenario 1) and to purchase peak load heat at a favourable price from a district heating network rather than self-produce it.

To mirror these views, we conceived a system where the role of major energy producer and controller of the system is shifted outside the hospital centre towards the local water and natural gas provider named AMGA (see Figure 1 and Table I). AMGA is, in fact, sited in a barycentric position with respect to the other centres to be served and can provide skilled personnel to control the whole system.

Therefore, AMGA energy station is charged with the main cogenerator and integration boilers, while a second cogenerator is sited in the hospital power station and sized for hospital electrical energy demand. This choice allows to satisfy the request of power self-sufficiency expressed by hospital management, while, as to thermal energy, the hospital could get heat from the district heating network during hospital's high demand periods and supply the system with its exceeding cogenerated heat when internal heating demand is low.

We developed two versions (a and b) of Scenario 4, to consider the different organizational forms the venture can take. In particular, in Scenario 4a the hospital cogenerator is treated as a separated investment, and its configuration and operation schedule are those designed in Scenario 1, while the external cogenerator design is based on integration heating requirements by the hospital and on heating demand of the other buildings. Only capital costs of the external system (district heating network and second cogeneration group) are considered in this case, and, similarly, operation costs and savings bound to power production at the hospital are not taken into account. In Scenario 4b, instead, the hospital cogenerator is recognized as part of the venture and the system is designed and optimized as a whole. Therefore, all capital costs, operational costs, savings and incomes from power sales are taken into account. In Scenario 4a, the reference system for comparison is represented by all the examined buildings but the hospital plus hospital integration heating demand as calculated in Scenario 1, while in Scenario 4b the comparison system is the same as in Scenario 3.

4. THE OPTIMIZATION MODEL

A MILP model has been conceived to optimize the size and operation mode of the described cogeneration system in its different levels of complexity (from Scenarios 1 to 4). The model is time-dependent, in that it allows energy demand variations along the day and the year and hourly power sale price differentiation as proposed by the Italian Energy Bureau (AEEG, 2004). Data on hourly energy demand in working days and weekends averaged on a monthly basis have been grouped according to power tariff levels. By adding short periods to model peak

DOI: 10.1002/er

loads, 41 time periods have been obtained and power and heating demand profiles have been discretized accordingly (Gustafsson, 1998).

In the following subsections, model elements are described.

4.1. Variables

The main variables of the model are:

- Thermal capacities *CapTh* (kW_t) for each heat technology *techTh* and production unit uTh_z selected in each centre *z*.
- Electrical capacities *CapEl* (kW_e) for each production unit uEl_z selected in each centre *z* with electrical energy technology *techEl*.
- Thermal power *PowTh_prod* (kW_t) and electrical power *PowEl_prod* (kW_e) produced by each unit uTh_z and uEl_z, respectively.
- Electrical power *PowEl_sale* (kW_e) produced for sales by each unit uEl_z.
- Thermal power *PowTh_diss* (kW_t) which is dissipated when it is necessary or profitable to generate power even in the absence of a corresponding heating demand.
- Natural gas amounts *GasQty* needed to produce energy flows for different uses *us*. Different energy destinations (internal consumption, sales,...) imply different gas prices due to current tax system, which encourages cogeneration and district heating.
- Electrical energy *ElQty* purchased by each centre, including the hospital (if we relax the constraint of meeting internal requirements) and—in Scenario 4—the AMGA centre, in case it is more convenient to buy electricity than to produce it locally.

Binary variables (*bin*) are introduced as needed to model scale economies and Italian tax system.

4.2. Parameters

The following parameters are taken into account:

- Investment costs, characterized by a variable component *CostVarInv* proportional to facility sizes and a size-independent component *CostFixInv*.
- Costs related to district heating: pipeline installation *CostDHpipe* and operation costs *CostDHop* (pumping, personnel, maintenance) of the network.
- Costs of fuel, *CostGas*, dependent on the kind of final use *us* and cost of purchased electrical energy *CostEl*.
- Operation costs of electrical (*El*) and thermal (*Th*) facilities *CostOp*, including personnel, administration and maintenance.
- Dissipation cost *CostDiss*, related to costs of electrical energy consumed by dissipators.
- Electrical energy sale price *PriceEl*, function of time period *t* (AEEG, 2004).
- Thermal and electrical energy demand of each centre in every time period *t*, calculated for each centre *z* by multiplying the duration of the time span in hours h by the required heat flow *PowTh_dem* (kW_t) and the required power flow *PowEl_dem* (kW_e), respectively, both averaged on time span *t*.
- Technical performance measures related to each technology such as efficiency, power to heat ratio (α), dissipation coefficient and so on.

DOI: 10.1002/er

4.3. The objective function

The objective function is minimized and represents the total cost per year of the energy system in each previously identified configuration (see paragraph 3); its simplified form is

$$\min\left\{\begin{array}{l} annDHpipe\cdot CostDHpipe + CostDHop + \sum_t CostEl_t\cdot ElQty_t\cdot h_t \\ \quad + \sum_{z,uTh_z,techTh} ann_{uTh_z,techTh}\cdot\begin{pmatrix} CostVarInv_{uTh_z,techTh}\cdot CapTh_{uTh_z,techTh} \\ + binTh\cdot CostFixInv_{uTh_z,techTh}\end{pmatrix} \\ \quad + \sum_{z,uEl_z,techEl} ann_{uEl_z,techEl}\cdot\begin{pmatrix} CostVarInv_{uEl_z,techEl}\cdot CapEl_{uEl_z,techEl} \\ + binEl\cdot CostFixInv_{uEl_z,techEl}\end{pmatrix} \\ + \sum_{us,z,uTh_z,techTh,t} CostGas_{us,uTh_z}\cdot GasQty_{us,uTh_z,techTh,t} \\ + \sum_{us,z,uEl_z,techEl,t} CostGas_{us,uEl_z}\cdot GasQty_{us,uEl_z,techEl,t} \\ + \sum_{z,uEl_z,techEl,t} CostDiss_t\cdot PowTh\_diss_{uEl_z,techEl,t}\cdot h_t \\ + \sum_{z,uTh_z,techTh,t} CostOp_{uTh_z,techTh,t}\cdot h_t + \sum_{z,uEl_z,techEl,t} CostOp_{uEl_z,techEl,t}\cdot h_t \\ - \sum_{z,uEl_z,techEl,t} PriceEl_t\cdot PowEl\_sale_{uEl_z,techEl,t}\cdot h_t \end{array}\right\} \quad (1)$$

Investment costs are expressed on yearly basis by introducing the annuity factor *ann* depending on expected life of each facility. Positive cash flows from electrical energy sales are then taken into account by related incomes.

4.4. Constraints

From a functional point of view, two main types of constraints can be recognized:

- energy flow balances, which relate fuel amounts and purchased electrical energy to energy forms produced by the analysed system and to energy demand to be covered;
- capacity constraints, which relate operation modes and electrical and thermal power produced in each time period to installed capacities in system centres and guide facility size selection on the basis of actual commercial ranges.

Most important energy flow constraints are reported below and discussed in the following:

$$\sum_{uEl_z,techEl}(PowEl\_prod_{uEl_z,techEl,t} - PowEl\_sale_{uEl_z,techEl,t}) = PowEl\_dem_{z,t} - ElQty_{z,t}\forall z,\forall t \quad (2)$$

$$\begin{aligned}\sum_{z,uEl_z,techTh} PowTh\_prod_{uTh_z,techTh,t} + \sum_{z,uEl_z,techEl}\frac{PowEl\_prod_{uEl_z,techEl,t}}{\alpha_{techEl}} \\ = \sum_z PowTh\_dem_{z,t} + \sum_{z,uEl_z,techEl,t} PowTh\_diss_{uEl_z,techEl,t}\ \forall t\end{aligned} \quad (3)$$

DOI: 10.1002/er

$$GasQty_{self,uEl_z,techEl,t} + GasQty_{sales,uEl_z,techEl,t} \leqslant 0.25 \cdot PowEl\_prod_{uEl_z,techEl,t} \cdot h_t \quad \forall z,\ \forall uEl_z, \forall techEl, \forall t \tag{4}$$

$$\sum_{uEl_z,techEl,t} PowEl\_prod_{uEl_z,techEl,t} \cdot h_t \geqslant 0.1 \left[\begin{array}{l} \sum_{uTh_z,techTh,t} PowTh\_prod_{uTh_z,techTh,t} \cdot h_t \\ + \sum_{uEl_z,techEl,t} \dfrac{PowEl\_prod_{uEl_z,techEl,t}}{\alpha_{techEl}} \cdot h_t \end{array} \right] \forall z \tag{5}$$

Electrical energy flow balance (Equation (2)) is imposed at every centre to model self-sufficiency as in the hospital case. Heat flow balance is, on the contrary, set at a global level as shown in Equation (3), where demanded power has been properly increased to take into account losses along the pipeline.

Depending on the scenario being analysed, constraints are introduced to model characteristics of that configuration; for example, in Scenario 1, only the hospital centre is analysed and both electrical power purchase and sale are excluded, *ElQty* and *PowEl_sale* are set to zero.

A peculiarity of Italian energy system is its taxation, which requires the introduction of special constraints that differentiate our model from others in literature (Mavrotas *et al.*, 2003; Sundberg and Henning, 2002). In particular, natural gas taxes vary depending on adopted technology and final use of energy produced; special reductions are established for cogeneration (with slightly higher discounts for self consumed power—*self* in Equation (4)—than for sold power—*sales* in Equation (4)) and for district heating. Fuel quantity with reduced tax is limited to $0.25\ \mathrm{N\,m^3\,kW^{-1}\,h^{-1}}$ (see Equation (4)), and a reduction is also granted to district heating peak load boilers coupled with cogeneration systems, provided that a minimum power to heat ratio is satisfied over the year (see Equation (5)).

While Equation (4) promotes higher electric efficiency of cogenerators, Equation (5) requires a minimum annual amount of produced electrical energy, actually setting a very relaxed bound: the required power to heat ratio is just 10% and thus the difference between the overall efficiency of the CHP system and of a traditional system could be very small. This seems to foster the installation of cogenerators in order to take advantage from discounts on fuels for heating systems rather than to efficiently generate power; this disadvantage is, however, limited by high specific costs of cogeneration units.

Beside usual capacity constraints (see e.g. Chinese *et al.*, 2004), obliging energy flows by single equipments not to exceed equipment capacity and installed capacities to be comprised within commercially available ranges, a site-specific capacity constraint was introduced, imposing upper bounds to total power generation or, respectively, heat generation capacity at each site. In this way, the same model can be used to reflect different scenarios by modifying the values of capacity bounds at different sites: in Scenario 3, we allow large boilers and cogenerators to be installed at the hospital, while in Scenario 4, to model the construction of an external CHP station at the AMGA, we limit power generation capacity at the hospital to minimum values meeting averaged peak demand and inhibit installation and use of boilers at the hospital station.

Finally, it should be observed that modelling fiscal incentives also requires to express logical conditions and limitations (e.g. some benefits apply to cogeneration units only in the periods of local consumption, constraint 5 only applies when and where power is produced). These logical

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conditions are modelled by adding auxiliary binary variables, working as flags which drop constraints that do not hold (we refer to Williams (1990) about modelling logical conditions in MILP).

5. RESULTS AND DISCUSSION

The model was implemented in AMPL® (Fourer *et al*., 2003) and solved with the commercial solver CPLEX™ (ILOG, 2002). Up to date natural gas boilers are adopted as heat generation technology. As power generation technologies, we consider three classes of gas engines, depending on the number of revolutions per minute and size (from slow engines, 750 rpm and a minimum capacity of 5000 kW_e, to fast engines, 1500 rpm and a maximum capacity of 2400 kW_e, with medium engines at 1000 rpm and capacities from 2400 to 5000 kW_e). Gas turbines (minimum capacity of 1500 kW_e) were initially tested, but they were never selected by the optimization procedure, mainly because of their high specific cost and limited part load operation capabilities.

The total number of variables and constraints increases when progressing from an independent CHP system with no sale opportunities (Scenario 1) to a market oriented but independent cogeneration system (Scenario 2) up to a district heating system firstly involving a single cogenerator (Scenario 3 and 4a), then two cogenerators located in different sites (Scenario 4b). Problem size thus varies from 1259 variables—thereof 49 binary—and 2107 constraints in Scenario 1 up to 3385 variables—thereof 100 binary—and 5078 constraints in Scenario 4b.

5.1. Sizing and overall performance

Results of the optimization model are summarized in Tables III and IV. As for cogenerator sizing (see Table III), it should be stressed that, although the model allowed to install more units at the same site, e.g. to better manage part load operation, the optimization procedure always settles for a single engine, thereby increasing heat dissipation levels if required.

It can also be observed that larger engines are preferred, because of their lower specific and maintenance costs and partly because fuel detaxation makes an intense use of cogenerators for meeting heat requirements a cost effective option. For example, a capacity of 5000 kW_e is installed in Scenario 1 and is always operated at partial load, as peak power demand of the hospital is about 3200 kW_e. The size of cogenerators installed at the hospital grows in Scenario 2 and 3, whereas in Scenario 4b the joint optimization of distributed cogeneration units leads to install a smaller engine at the hospital than in Scenario 1.

Table III. Optimal facility sizes for each scenario.

	Hospital centre cogenerator (kW_e)	Hospital centre integration boiler (kW_t)	AMGA centre cogenerator (kW_e)	AMGA centre integration boiler (kW_t)
Scenario 1	5000	8300	—	—
Scenario 2	7400	1000	—	—
Scenario 3	8500	8500	—	—
Scenario 4a	5000	—	7900	7600
Scenario 4b	3300	—	8000	7600

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Table IV. Investments and performances for each scenario (tCO_2Eq = equivalent tons of CO_2).

	Investment (kEuro)	Net Present Value (NPV) (kEuro)	Pay-back period (years)	Energy savings (TOE year^{-1})	Avoided emissions (tCO_2Eq year^{-1})	Dissipated heat (MWh year^{-1})
Scenario 1	2874	13 860	2.08	3366	7391	1183
Scenario 2	4244	20 450	1.84	6000	12 740	6443
Scenario 3	6524	23 560	2.46	7573	16 090	4812
Scenario 4a	5805	5806	5.74	4645	9259	11 390
Scenario 4b	8371	19 680	3.48	7866	16 200	10 960

Considering overall performances (see Table IV), it can be observed that all scenarios achieve positive performances both from an economic and a primary energy saving and Greenhouse Gas (GHG) emission reduction perspective. Scenario 1 proves to be a low risk scenario (small cogenerator, small pay-back period, very high ratio between Net Present Value (NPV) and investment), with little heat dissipation but also with limited reduction of energy consumption and GHG emissions and relatively small NPV. Better performances obtained in Scenario 2 are associated with higher risks, since a larger cogenerator is installed and economic results largely depend on putting power on the market, which can be a source of uncertainty. Emission reduction and primary energy savings are remarkably better, in spite of large heat dissipation, because in Italy average GHG emissions and fossil fuel consumption per unit of traditionally generated power are anyway higher (values were obtained from ENEL, 2002 and from Regione Friuli Venezia Giulia, 2003).

Thanks to district heating, heat dissipation is significantly reduced in Scenario 3, which appears the best one looking at NPV, GHG emission and primary energy consumption reduction and also considering the small increase in pay-back time compared to Scenario 1. This suggests how the need of a new hospital power station, if analysed from the wider perspective of service to municipality rather than to hospital centre only, can lead to a real application of urban Facilities Management and be a chance of technological and economical development for local community. Scenario 4 is economically sub-optimal, mainly due to investment duplication, yet its overall performance is positive, and, as to the 4b variant, comparable with Scenario 3 especially from an emission reduction perspective.

The main role played by hospital centre to foster a new energy system in the North-West side of Udine city is highlighted by the high pay-back period achievable in Scenario 4a, where hospital acts as a heat buyer for integration only. Power demand of hospital buildings represents a key element for profitability of the whole venture and variant 4b is definitely more practicable than variant 4a.

Because of very high heat dissipation, large size of cogenerators and high dependence on power sales, Scenario 4 is likely to be the most sensitive to internal and external sources of uncertainty, which have not been dealt with so far as the model is deterministic. In view of that and of the strategic importance that decision makers placed to this scenario (see Section 3.4), we will briefly present a sensitivity analysis for Scenario 4b.

5.2. Sensitivity analysis for Scenario 4b

Five main sources of uncertainty have been identified, which arise in all scenarios.

DOI: 10.1002/er

Two of them are internal, depending on errors in estimating internal properties and behaviour of the system:

1. Possible variations of values of thermal and electric peak load, to be carefully considered because our dimensioning criterion was to fully cover hospital's power demand.
2. Design choices which will be made for air conditioning of new hospital buildings, as the final proportion of vapour-compression and of absorption cooling is still unknown.

On the other hand, three main sources of uncertainty are associated with external conditions, represented by:

1. Actual levels of power buy-back tariffs, which may be linked to traders' remuneration percentage.
2. General levels of energy prices.
3. Equipment grants that can be obtained by local authorities. Many Italian regions, in fact support district heating and cogeneration projects through equipment grants, which improve pay-back periods of investments; however, the availability and the proportion of equipment costs covered by such grants is not fixed.

As for peak load variations, we have analysed robustness of solutions to variations of electric and thermal loads in the most critical time periods, that are January for heating demand, June and July for power demand in the vapour-compression air conditioning case and December for power demand in the absorption cooling case.

As can be seen in Figure 4(a), the optimal cogenerator size located in AMGA power station is basically robust and only the size of the integration boiler changes. Demand variations have more significant effects on the cogenerator to be installed at the hospital centre; as highlighted in Figure 4(b), however, peak load fluctuations have small impact both on NPV and pay-back period (note that pay-back period axis values range from 3 to 4).

Although the original view of hospital technical management was to adopt a compression conditioning system for the new buildings, results of the analysis reported in Table V clearly show that chilling also new buildings with an absorption cooling system in summer is the better choice. The increased exploitation of waste heat in summer and the opportunity to produce and sell extra power in that season, when power tariffs reach their peak, fully compensate for additional investments in absorption cooling groups, leading to a 23% increase of NPV, compared to the vapour-compression option, and to a better pay-back period, too. It is interesting to note that, in the absorption cooling option, larger cogenerators would be installed at AMGA power station, whereas hospital cogenerator size needed to cover internal energy requirements would decrease because electrical demand in summer would be smaller than in the vapour-compression case.

The variability of buy-back tariffs is considered by augmenting the remuneration share by energy traders. The reference value of the percentage on electrical energy price required by traders used in the model was 4% and the corresponding net wholesale tariffs were, on average, about 65% of end user tariffs. We have gradually increased remuneration percentage up to 20%, which means an average buy-back tariff of about 54% of power end user tariffs.

As highlighted by Figure 5 increasing percentages lead to smaller and smaller optimal size of the main cogenerator at AMGA power station, while larger peak load boilers are selected. Reduced profit by electrical energy sales are, in fact, counterbalanced by limited investments in

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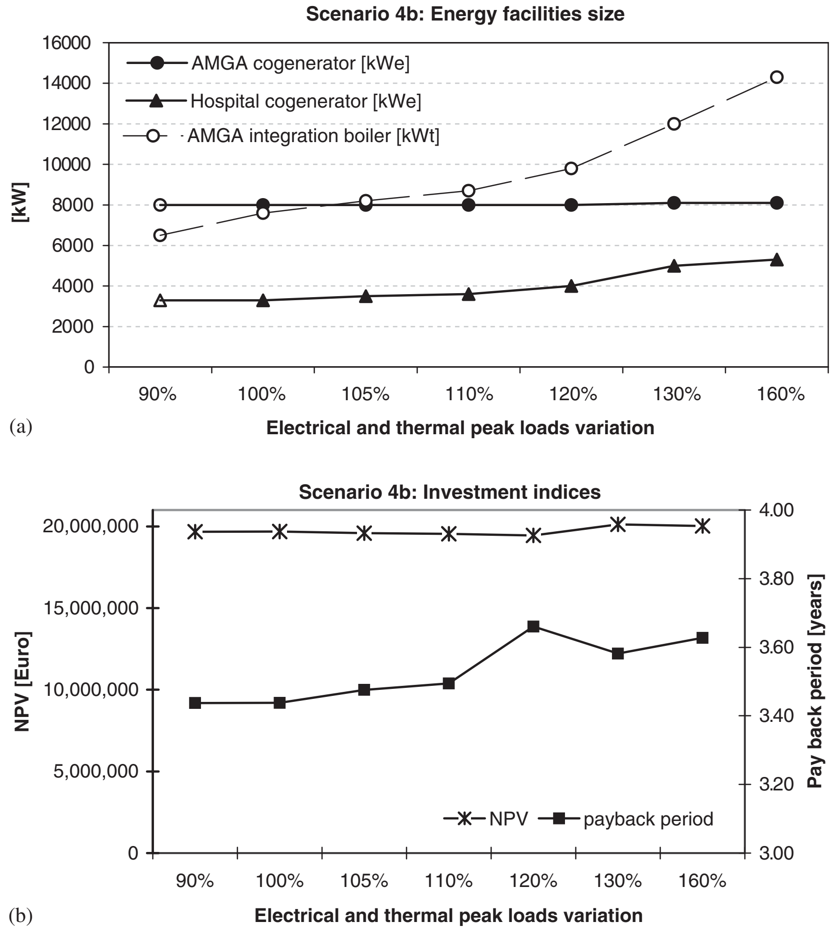

Figure 4. Sensitivity to thermal and electric peak loads variations: (a) effects on facilities size; and (b) investment indices.

order to control NPV decrease, which is nevertheless notable, while pay-back periods remain almost unchanged.

Considering future fluctuations of costs and sale price of fuels and electrical energy, we performed sensitivity analysis assuming natural gas costs and electrical energy costs and prices to be mutually linked, since they all depend on oil cost. It was observed that optimal energy facility sizes are robust for small negative variations of energy costs and prices, while more powerful cogenerators and smaller integration boilers are selected by the model when increases of those parameters are recorded. A positive trend of energy costs and prices leads to improved economical performances (see Figure 6), with potentials fully exploited by adapting facility sizes to follow electrical energy incomes.

Concerning the availability and amount of public subsidies, we have examined the possibility to receive such grants in a variable proportion (up to 30%) of total investment. Table VI shows how such non-repayable equipment subsidies induce the model to select greater sizes for the

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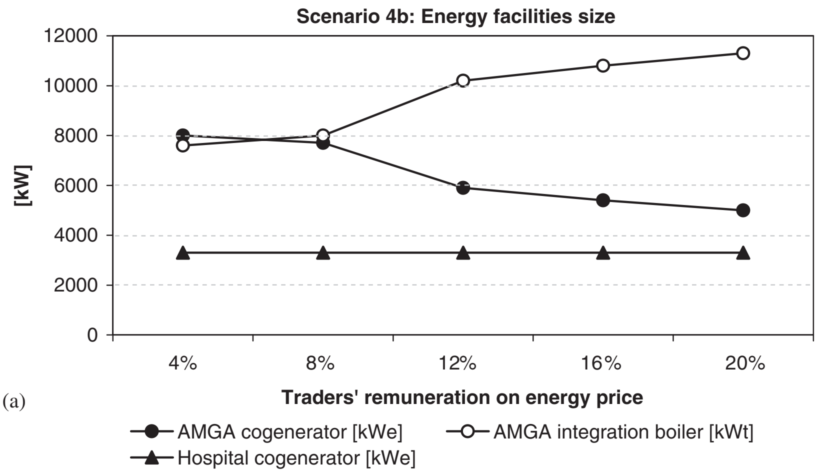
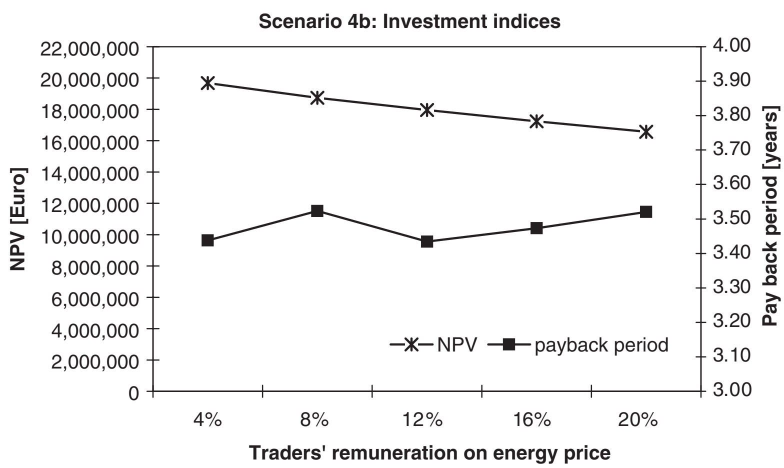
Table V. Sensitivity to air conditioning system type: effects on facilities size and investment indices.

Cooling technology	Vapour compression	Absorption
Capacity of cogenerator at AMGA (kW_e)	8000	8500
Capacity of integration boiler at AMGA (kW_t)	7600	7000
Capacity of cogenerator at the hospital (kW_e)	3200	2600
NPV (k€)	19 680	24 280
Simple pay-back period (years)	3.44	2.93



(a)



(b)

Figure 5. Sensitivity to traders' remuneration percentage on electrical energy price: (a) effects on facilities size; and (b) investment indices.

main cogenerator, stabilizing the choice at 8500 kW_e. Public grants enable the municipal energy system to gain better performances, due to enhanced capacity of producing and selling electrical energy. This improves GHG emission reduction by further substituting electrical energy

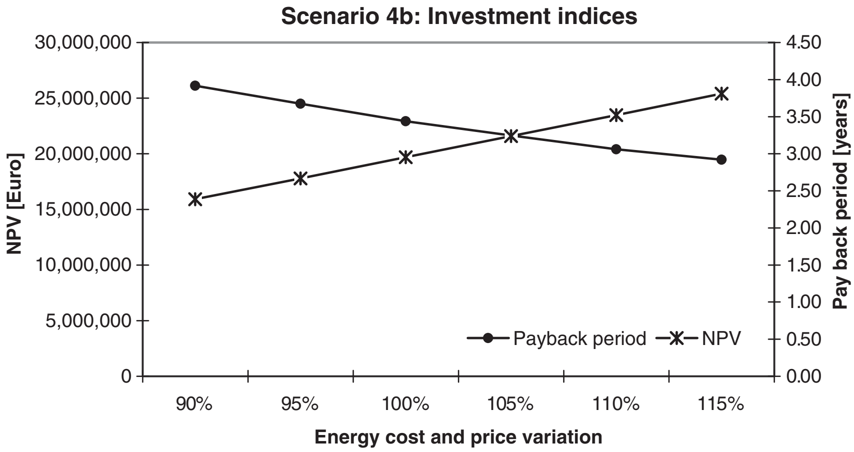


Figure 6. Sensitivity to fuel and electrical energy costs and prices: effects on investment indices.

Table VI. Sensitivity to equipment grants: effects on facilities size and investment indices.

Percentage of subsidy on equipment costs (%)	0	10	20	30
Capacity of cogenerator at AMGA (kW_e)	8000	8100	8500	8500
Capacity of integration boiler at AMGA (kW_t)	7600	7500	7000	7000
Capacity of cogenerator at the hospital (kW_e)	3300	3300	3300	3300
NPV (k€)	19 680	20 630	21 590	22 560
Simple pay-back period (years)	3.44	3.10	2.79	2.44

produced by traditional power stations with power from cogeneration, but it is bound to lead to larger local heat dissipation, as heat demand profiles are unchanged.

5.3. *General applicability and international context*

Sensitivity analysis has shown that economic performance of cogeneration and district heating significantly depends on external elements such as equipment subsidy and fuel and power costs, and especially on power buy-back tariffs, because sizing and operation of the system are basically determined by power sales. Sizing and operational practices similar to the obtained optimization results are confirmed by distributed generation literature. Strachan and Dowlatabady (2002), who compare the diffusion of distributed generation in the Netherlands and in the U.K., point out that, where power buy-back tariffs are attractive and fuel incentives for CHP exist, equipment subsidies, originally meant to reduce the economical threshold size for CHP installation, actually result in the installation of larger capacities. These exploit both economies of scales and an innovative, power sales oriented utilization of DG, even if this may lead to more heat dissipation (Strachan and Dowlatabady refer to 20% rejection of available heat, in our case the sizeable value of 11 390 MWh year^{-1} rejected in Scenario 4b corresponds to about 15% of heat available from cogenerators). This typically happens when profit maximization objectives are pursued, as can be deduced from van Schijndel (2002), who presents the case of a hospital trigeneration system in the Netherlands. On the other hand, opposite results are obtained if power sale tariffs are low, especially if cogenerated power costs are high. Downsizing may then be the right option, as, for instance, in the Spanish case presented by Renedo *et al.* (2006), where better investment yield is obtained with minimum diesel engines designed to work always at full load, rather than with larger engines meeting maximum electrical demand. In that case, there might even be an intermediate optimal solution, which could be disclosed by adopting an optimization approach instead of the traditional one. Concerning the opportunity of developing district heating systems moving from hospital cogeneration or trigeneration systems, it has been shown that better energy and environmental performances can be achieved in this way. Whether this improves profitability and in what measure depends on the investments required for district heating networks (shorter networks will perform better) and on how well do heat demand profiles match so that overall demand becomes as uniform as possible throughout the year.

6. CONCLUSIONS

The study has highlighted that all the proposed cogeneration and district heating solutions have positive economic performances and lead to better results in terms of GHG emission reduction and of primary energy savings. Profitability of cogeneration at the hospital boosts the profitability of the whole venture and may draw capitals to the district heating project, which would be less attractive as a stand alone project. Where energy policy and market conditions make it profitable to sell electricity from distributed cogeneration, district heating may lead to the installation of larger engines and to the production of more cogenerated power with less heat dissipation. Also where external conditions and internal heating demand profiles are such that smaller CHP systems, designed to meet only a fraction of internal power demand, are preferred, satisfying an external heating demand allows to efficiently generate more power to reliably cover an higher percentage of internal needs. Especially in the case of hospitals, this should encourage designers and public decision makers to broaden systems boundaries and consider also the surroundings of such energy intensive buildings when designing new energy facilities.

As to methodology, the development and application of an optimization model to design the described energy system has shown to be a powerful instrument for the identification of the most suitable solutions in terms of facility sizes and operation mode, especially because a joint optimization takes account of interdependence between design and operational choices. By introducing proper constraints, different scenarios, related to different managerial perspectives, could be analysed and compared. The automation of procedure lets easily perform sensitivity analyses on the most critical parameters, overcoming the deterministic approach typical of such models. Based on these arguments, we promote a wider use of optimization methodologies especially in hospital energy systems design, where they have been less frequently applied up to now but where the variety of types of energy demand and of possible technical solutions enhances the complexity of designer decisions.

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