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Optimization tool for the sizing of a CCHP plant in the new energy market framework.

Supervisor: Prof. Maurizio Delfanti
Co-Supervisor: Prof. Valeria Olivieri

Graduation thesis by:
Filippo Bovera

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When I heard the learn'd astronomer,
When the proofs, the figures, were ranged in columns before me,
When I was shown the charts and diagrams, to add, divide,
and measure them,
When I sitting heard the astronomer where he lectured with
much applause in the lecture-room,
How soon unaccountable I became tired and sick,
Till rising and gliding out I wander'd off by myself,
In the mystical moist night-air, and from time to time,
Look'd up in perfect silence at the stars.

Walt Whitman [1819-1892]

SOMMARIO

Il presente lavoro di tesi ha come obiettivo la quantificazione delle opportunità economiche derivanti dalla possibilità di partecipazione al Mercato dei Servizi di Dispacciamento (MSD) prevista nel futuro prossimo per la Generazione Distribuita (GD), nonché la stima dell'influenza che tale nuovo assetto di mercato (unitamente alla riforma tariffaria in corso) potrebbe avere sul dimensionamento e sulla conduzione di un impianto di trigenerazione connesso alla rete di distribuzione.
Il lavoro si sviluppa lungo due percorsi principali. Il primo riguarda la definizione di un quadro di riferimento per i prezzi dei servizi forniti su MSD; tale elaborazione, condotta attraverso un codice MATLAB®, consiste nella raccolta, organizzazione e analisi statistica dei dati disponibili per MSD, al fine di fornire dei parametri economici e tecnici (prezzi, probabilità di accettazione delle offerte, fattori di correzione geografica) che tengano conto della complessità e dei molteplici aspetti che caratterizzano questo particolare mercato. Il secondo percorso riguarda lo sviluppo, sempre in ambiente MATLAB®, di uno strumento per l'ottimizzazione del funzionamento di impianti di trigenerazione, che permetta, tra le altre cose, di valutare l'impatto (economico ed operativo) che l'apertura di MSD alla GD avrà su questo tipo di impianti, sulla base delle valutazioni fatte in precedenza, tenendo conto di tutti gli aspetti regolatori che li riguardano, nonché della riforma tariffaria in corso.

PAROLE CHIAVE: trigenerazione, ottimizzazione, risorse di dispacciamento, opportunità di mercato.

SUMMARY

This thesis work aims at assessing the economic opportunities deriving from the possibility for the Distributed Generation (DG) to participate to the Ancillary Service Market (ASM), as well as the influence that the new market framework (together with the charges reform) could have on the sizing and operation of a Combined Cooling, Heat and Power plant connected to the distribution grid.
The work develops along two main axes. The first path defines a reference frame for the prices of the services supplied on the ASM; this elaboration, performed through a MATLAB® code, consists in the gathering, the organization and the statistical analysis of the available data to provide some economic and technical parameters (prices, probability of acceptance of offers, geographic correction factors) that account for the complexity and the many aspects influencing this particular market. The second path concerns the development, again in the MATLAB® environment, of an optimization tool for the operation of Combined Cooling, Heat and Power plants. The tool allows evaluating the economic and operative impact of the participation to ASM for these plants, and is based on the considerations made previously, taking into account all the related regulatory aspects, including the ongoing charges reform.

KEY WORDS: combined cooling heat and power, optimization, dispatching resources, market opportunities.

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ABSTRACT

Modern energy services are crucial to human well-being and to the economy of a country. The effort of developed countries in the next years will be addressed towards the research of sustainable energy provision, able to ensure low levels of pollutants and GHG emissions, high efficiency in the energy consumption, and the possibility of a secure energy provision worldwide.

Maintaining a high level in the quality of service of the electric grid, together with a rapid decarbonisation of the power system, is the key challenge for countries throughout the world.

Electricity can be generated from different energy sources: fossil fuels (coal, oil, gas), nuclear and renewable resources (hydro, wind, solar, tidal, etc.). Each energy resource has its own characteristics from the point of view of the predictability, of the variability, of the environmental and of the social impact. Related to the need to replace ageing capacity, the objective to meet policy targets and the challenges to secure long-term investment in generation assets, OECD countries are adopting policies consisting in the diversification of the fuel mix used to generate electricity, increasing constantly the share of low-emitting sources.

IEA analysis indicates that the large-scale deployment of low carbon technologies, needed to meet decarbonisation goals, is technically feasible. However, the inherent variability of some of these power sources will lead to less predictable power flows; therefore, the diffusion of new technologies, that are already in place nowadays, requires a greater flexibility of the power system.

Under this light, well-functioning energy markets have a crucial role in helping to deliver electricity in a secure way, and to attract the investments needed to achieve decarbonisations goals. Nowadays 40% of the energy-related CO_2 emissions comes from electricity generation, and the electricity supply costs related to network services varies from 25% to 40% all over the world.

Starting from the above considerations, this thesis work develops a reference framework for the definition of the opportunities coming from a new market and regulatory framework for a crucial technology such as Combined Cooling Heat and Power plants.

Chapter 1 introduces the context of the analysis, providing a description of the energy sector from a global, European and finally Italian point of view. After a brief introduction about the global energy demand and the evolution of the EU policies in the energy sector, the chapter focuses on the Italian situation, presenting the main data about the energy demand and generation, and to the economic flows associated to them. Finally, the main aspects requiring a regulatory intervention are summarized, together with the possible future trends of the Italian energy sector.

Chapter 2 deals with the description of the CHP technology: the basic working principle, the advantages and the drawbacks of cogeneration are presented; then, the main technologies for the CHP are described, with a particular focus on the ICE based CHP plants. This technology is the most suitable for medium and small size applications such as the ones characterizing the Distributed Generation (DG). The second part of the chapter presents the regulatory framework concerning the CHP plants and its evolution in the recent years especially in Italy; the support to the cogeneration technology lead to its widespread all over the Italian territory, especially concerning the industrial and high consumption application. The third part of the chapter presents the evolution of the CHP plant that, equipped with an absorption chiller, can produce cold becoming a CCHP plant.

A detailed analysis of the legislation concerning the CHP technology is reported in Chapter 3. In the first part, the SEU concept is presented, with a description of the regulatory framework and its evolution in the last years; then, the advantages characterizing the self-consumption of electricity are described, together with a presentation of the structure of the Italian electricity bill. The second part of the chapter presents the general system charges reform in place in Italy, with its most recent evolutions, providing a complete picture about the possible scenarios that each reformation hypothesis introduces. The structure of the electricity bill paid by the different customers is a key point to provide an evaluation of the investment worth which is consistent with the actual and the future regulation.

Chapter 4 describes the structure of the Italian Energy Market. In the first part, the Day Ahead and the Intraday Market are presented; then, a full description of the Ancillary Service Market principles is reported: the different phases through which the market activity develops, the dispatching resources that the TSO needs to keep the network in secure conditions, the economic structure of the market and the procedures needed to discipline the negotiations within the market. The second part describes the current reform interesting the ancillary service provision, which is, together with the general system charges reform, one of the main steps for the future evolution of the Italian energy sector. The opportunities presented by the actual market framework for CHP plants connected at a distribution level are reported; in particular, based on the scenarios presented in the DCO 354/2013/R/eel, the new market model hypothesis are described, highlighting the characteristics of each model and associating to each model the possible ancillary services that DG and RES could provide. The last part of the chapter deals with the content of DCO 298/2016, through which the AEEGSI defined the market framework to be adopted in the first phase of the reform.

The statistical elaboration performed on the ASM data, aiming at defining a reference framework for the computations of the economic flows associated to a possible activity of the CHP plants on the ASM, is the core of the thesis, and is reported in Chapter 5. The analysis has been implemented in the MATLAB® environment. The first part describes the gathering and the organization of the data, available on the website of the GME (Gestore dei Mercati Energetici); the data of the whole year 2015 have been collected and organized in order to build a single reference file for each month and for every relevant zone of the Italian grid. The main characteristics of the files obtained are presented under the form of statistic parameters; starting from the organized data, a procedure allowed, thanks to a Kernel Density Estimation (KDE), defining a set of reference prices to be used in the evaluation of the economic flows associated to the ASM. The procedure involved also the definition of a geographic correction factor, to account for the location of a power plant within the Italian network in order to give a real estimation of the actual opportunity represented by the ASM participation. In the last part of the chapter, the results obtained are presented through some examples, highlighting the main aspects that the analysis performed allowed understanding. Even if the elaboration has been carried out for both the upward and the downward reserve services offered on the ASM, the chapter reports the aspects and the results only about the upward services, as they are used in the following chapters to evaluate the impact of the access to the ASM on Combined Cooling, Heat and Power plants.

Chapter 6 presents the optimization tool, which has been developed in the MATLAB® environment too. The first part of the chapter describes the basic considerations to be done to size a CHP plant and to evaluate the worth of the investment associated. In the second part, the core of the optimization tool is presented: the algorithm followed for the definition of the optimal configuration, the evaluation of the possible operational configuration and the computation of the different energy vectors and of the economic flows associated. In the algorithm presented it is also highlighted the need to distinguish between civil and industrial user: this distinction is necessary because of the different characteristics in terms of consumption profiles and demand features between the two applications, which entail the need to have a different approach for the optimization procedure.
The last part of the chapter focuses on the computation of the main technical and economic parameters that are used for the evaluation of the worth of the investment.

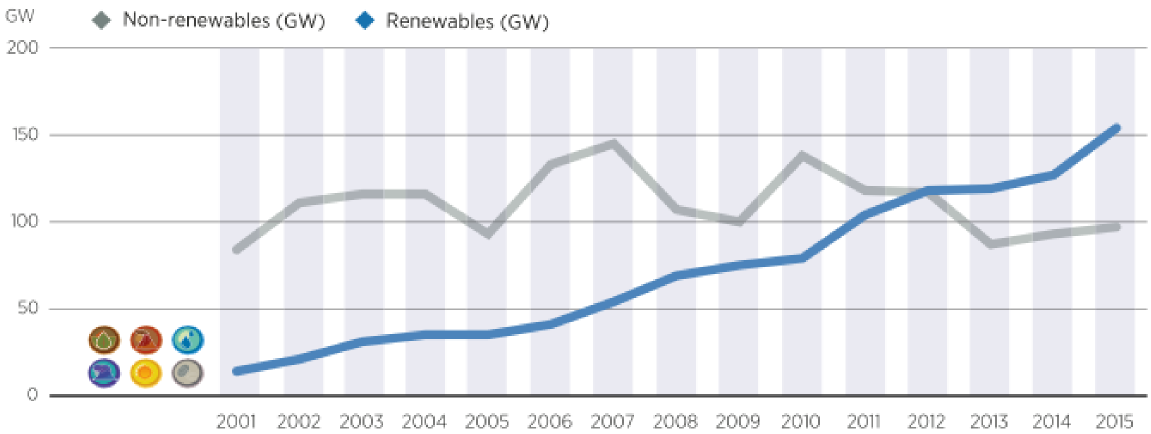
The last chapters are devoted to the analysis of some study cases. The first study case, dealing with the industrial site of Formec Biffi S.p.A. in San Rocco al Porto (LO), is reported in detail in Chapter 7. After listing the main input data, the chapter describes all the main results of the optimization procedure performed on the study case considered considering four different sizes for the CHP plant: 600 kW_{el}, 800 kW_{el}, 1.000 kW_{el} and 1.200 kW_{el}. The management of the electric, thermal and cooling load is described with the help of many diagrams; the main aspects regarding the working operations of the power plant, the economic results and the cash flow are reported. A detailed focus on the Natural Gas (NG) and electricity bills is also presented. For each size analyzed, the role of the market is analyzed; in particular, the effect of the ASM participation on the economic results and on the activity of the plant is described, focusing on the consequences that the ASM opening has on the CHP plant operations depending on the size considered.

Finally, Chapter 8 presents the second study case, dealing with the compus of Bovisa La Masa of Politecnico di Milano. In this study case two different sizes are analyzed: 2.000 kW_{el} and 2.700 kW_{el}. The elaboration performed for this case allowed highlighting the differences between two cases considered: the characteristics of the consumption profiles, the management of the loads, the characteristics of the power plants considered and finally the different opportunities granted by the ASM participation. All these aspects are presented, and allowed comparing the Bovisa La Masa study case with the Formec study case, presenting two very different sets of results.

CHAPTER 1
The Evolution of the Energy Sector

1.1 The International and European Context

Global demand for energy continues to rise, led by developing countries, reflecting an expanding global economy, a rapid industrialization and an overall improved energy access. At the same time, the negative social, economic and environmental impacts resulting from heavy reliance on fossil fuel are forcing governments to look for more sustainable options to meet energy demand. Because of this, governments around the world are rethinking the energy sector strategy and in particular are supporting the development of renewable and low-carbon energy.
The foundations for energy transition already exist: growing maturity of renewable energy market, coupled with technology advancements and policy refinement, provide an opportunity to develop an energy system that is able to hold up sustainable development objectives.
In Figure 1.1 [1], it is possible to see that from the beginning of the new century the installation of new renewable power has shown a strong intensification, firstly thanks to the energy policies of EU and OECD countries, and nowadays thanks to the investments put in place mainly by developing countries.



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Renewables (GW)	14	21	31	35	35	41	54	69	75	79	104	118	119	127	154
Non-renewables (GW)	84	111	116	116	93	133	145	107	100	138	118	117	87	93	97

***Figure 1.1**: Renewable and conventional capacity addition across the world.*

In 2015, the contribution of all renewable energy sources to the global energy mix grew by the largest increment, particularly in the energy sector. Renewable power generation capacity grew by 154 GW, an increase of 9,3% over 2014; most additions were in wind, solar photovoltaic and hydropower. At the end of 2015 renewable capacity represented 61% of all new power generating capacity added worldwide, and accounted for more than 28% of global capacity [1].
Renewables provided an estimated 23,5% of all electricity generated in 2015, equal to 5.660 terawatt-hours (Figure 1.2 [1]). Nevertheless, the world remains heavily dependent on conventional energy technologies: from 1990 to 2014 the share of renewable energy in total final energy consumption has increased from 16,7% up to 18,3%.

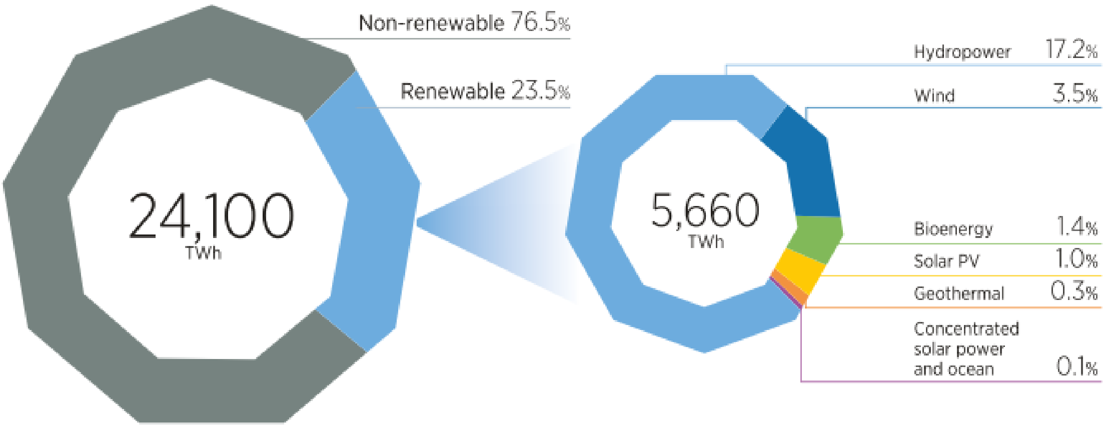


Figure 1.2*: Global electricity generation by source, 2015.*

As of 2015, 173 countries had established renewable energy targets at a national or state level. The need for pushing energy transition was firstly acknowledged by the European Union, which set the "20-20-20" targets in 2007; the path marked by EU culminated in the decisions and the commitments taken in the COP21 held in Paris in 2015.
The EU policy has been built on the aim of reaching three main targets: the creation of an internal energy market that allows a free and economically efficient flow of electricity all over Europe, the increase in the security of supply for electricity granted at low price to all EU citizens, and the development of a sustainable and environmental friendly energy system. Nowadays the main effort of EC in the direction of the development of the energy system aims at: establishing a common power market across the EU ensuring the adequacy of the system, promoting a better integration of electricity produced from renewable sources, increasing the energy efficiency and cleanliness for all the activity sectors and implementing rules on the governance of the energy in the EU [2].
The new power market design is intended to better fit the future electricity markets, which will be characterized by more variable and decentralized production, an increased interdependence between systems cross-border and opportunities for consumers to participate in the market through demand-side response, auto-production, smart metering and storage.
Under this light, it is possible to gather the objectives of the EU policy that directly influence the Italian legislation in the following points [3]:

- completion of the process of market coupling among neighboring countries and integration between DAM and Intraday Market;
- capacity remuneration mechanism and capacity market to ensure a strategic reserve;
- achievement of all the targets fixed regarding RES development;
- development of an integrated electricity grid shared among different member states;
- redesign the role of TSO and DSO dealing with the grid and the electricity flows management.

1.2 The Italian Situation

1.2.1 Energy demand and offer

The liberalization process of the electrical energy sector and the unbundling among the different activities of generation, transmission, distribution and retailing started in 1999 by the so-called "Decreto Bersani", which defined a new market architecture and allowed to acknowledge the EU directives.

During the first decade after the decree, Italy knew a strong increase in the electricity demand, with a U-turn in the following decade, mainly because of the macro-economic conditions at a global level.

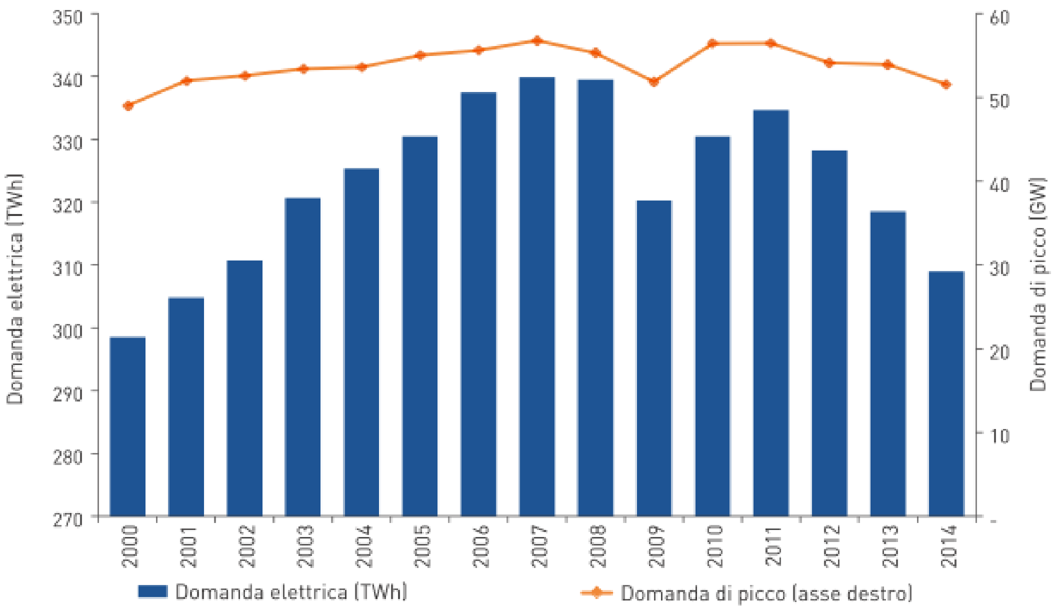


Figure 1.3: *Electricity demand evolution in Italy.*

The decrease in the electricity demand has been linked to: the drop of the GDP and of all the industrial activities, the favorable climatic conditions, the high electricity prices for small and medium industries with a negative impact on the economic recovery, the continuous increase of the energy efficiency in all the sectors due to revamping intervention and also the still limited incidence of electricity demand for heating and EV application. Figure 1.3 [4] shows the evolution of the electricity demand in terms of overall and peak demand, while Figure 1.4 [4] correlates the GDP and electricity demand grow rate and shows the division of the demand among the different zones of Italy.

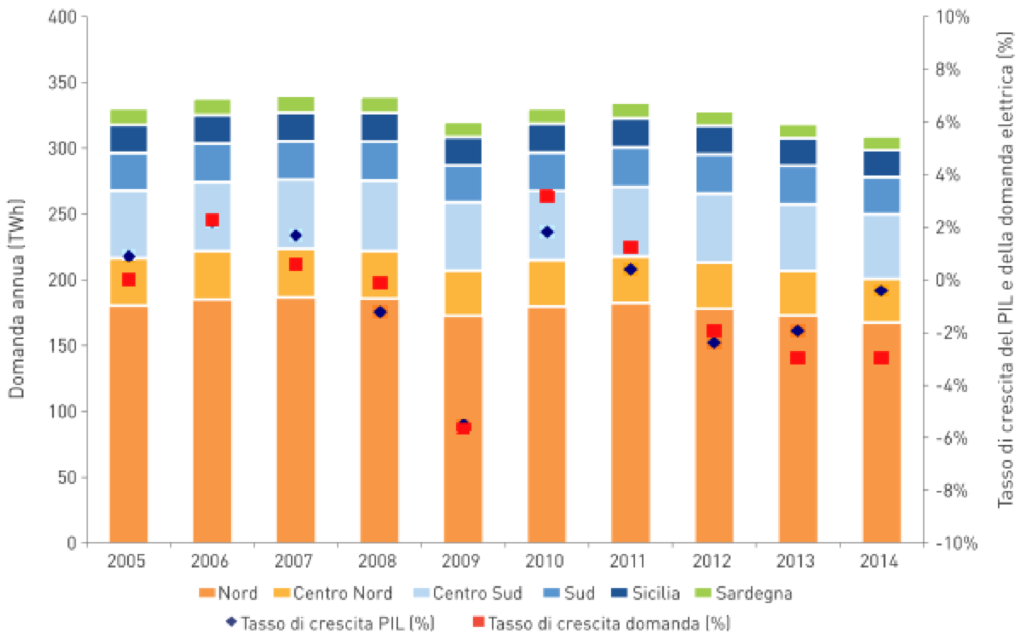


Figure 1.4: *Zonal demand and GDP grow rate.*

From the electricity production side, up to 2008 the conventional capacity installed has known a strong development, pushed by the expectation of growth in the electricity demand. In this period, investments have been addressed towards CCGT plants which rapidly became the marginal technology in the Italian market. After 2009 the focus for the investments in new capacity shifted towards renewable technologies, driven mainly by the decisions taken at a European level.

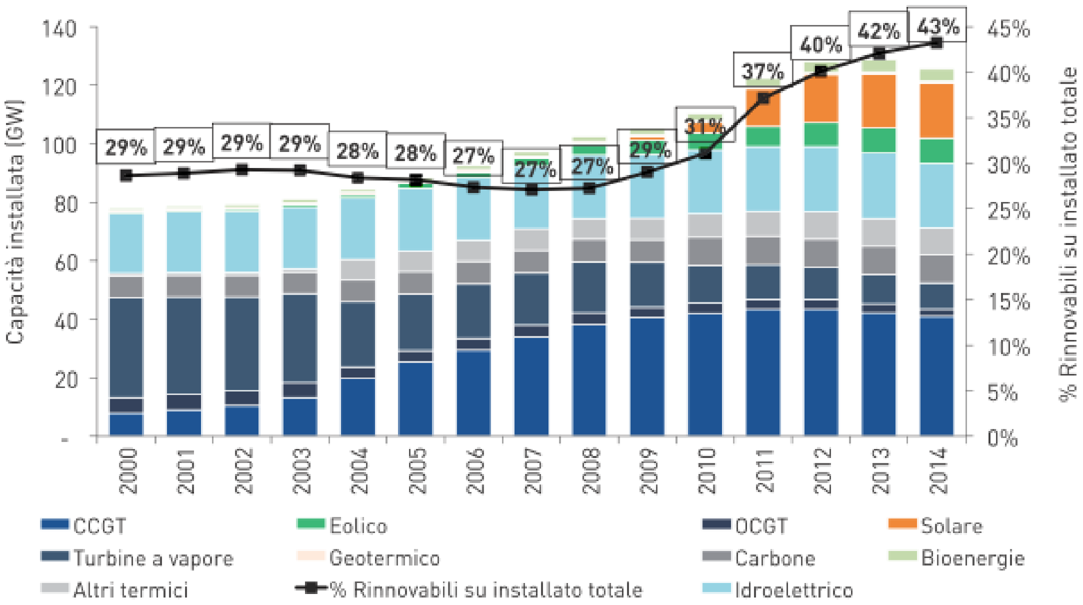


Figure 1.5: Evolution of installed capacity in Italy.

Linked to the GDP growth of 0,8%, in 2015 also the electricity demand registered a +1,5%, with 295 TWh. The national production covered the 86% of the overall national demand, with a strong increase of the gross import (50 TWh) which compensated the parallel increase of the exports (4,5 TWh). The largest increase involved the tertiary sector (+2,3%), followed by domestic (+1,2%) and industrial (+0,6%) ones.

In 2015 also the electricity production increased even if for a little percentage (+0,8%); this result is mainly linked to the growth of the thermoelectric production (+9%) with a share of 61% over the total production. The thermoelectric generation also faced the decrease in the renewable production (-9%, influenced by the lack of rain), which reached a share over the total production of 39%. Figure 1.6 shows the share in terms of installed capacity and electricity production among the most important generation groups in Italy.

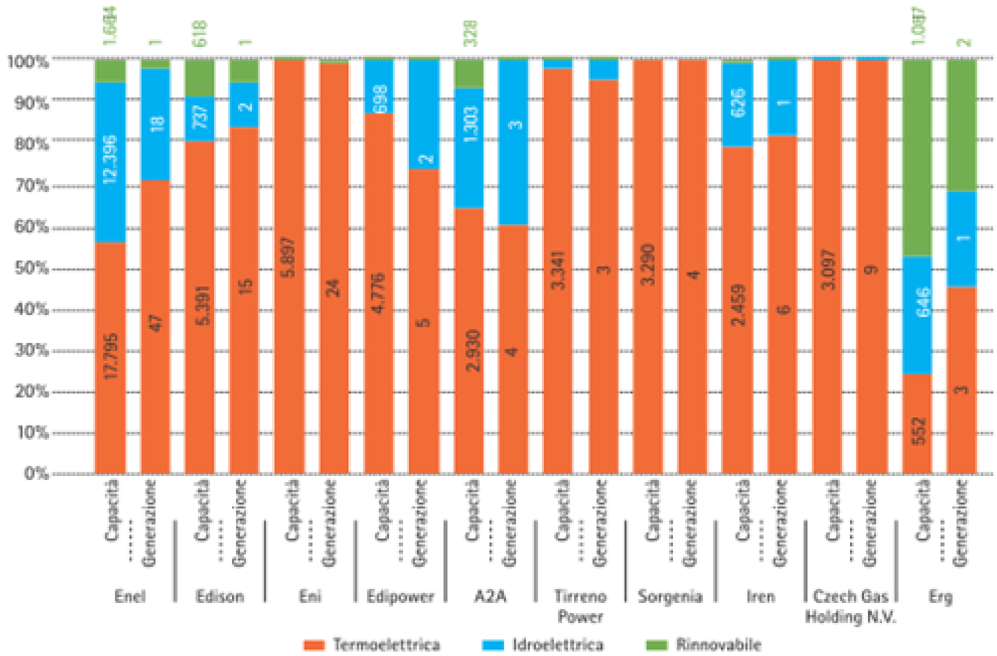


Figure 1.6: Gross capacity [MW] and generation [TWh].

In the decades after the liberalization, the increase in the installed capacity did not correspond to fully adequate investments in the grid development: as a result, nowadays Italy is interested by the presence of areas in the transmission grid that require an improvement, and this introduces congestion limits (see Figure 1.7 [5], red marked lines).

Figure 1.7: Transmission grid and critical borders (in red).

The different timetable that characterizes the investments and the development in the generation sector and in the electricity structure lead to a situation where the TSO (Terna) needs to keep in a secure situation a grid with a strong presence of non-programmable renewable sources connected at low and a medium voltage grids, operated by DSOs (almost 30 GW); moreover a large part of them is composed by PV plant which, because of their intrinsic technical characteristics, can contribute to worsen the already critical situations.
The limited interconnection at an internal level goes together with an overcapacity installed so that an installed capacity around 120 GW faces today a peak demand around 50 GW. The electricity demand between 2000-2008 increased by 14%, whereas in the same period the installed capacity increased by 45%; this led also to a strong increase in the marginal reserve share that went from 9% in 2005 to 46% in 2013 [4].
This situation, beyond its influence over the energy market and the revenues of the operators, can also potentially put in danger the capacity of the TSO to keep safe the electricity grid.
Hence, while the electricity management requires more and more flexibility and reserve capacity to face the fluctuations given by the non-programmable resources, the development of the latter causes a progressive erosion of available demand for the conventional capacity, reducing its profit and its possibility to survive.

1.2.2 Energy price and system costs

In the first decade after liberalization the effort in the direction of the CCGT technology determined an energy price on the DAM mainly influenced by the gas price, while the activity on the ASM was entirely linked to grid constraints and congestions. After the diffusion of RES, the different economic structure of the plants (with low variable costs and high fixed costs), has determined a strong reduction in the prices of electricity in terms of PUN (Prezzo Unico Nazionale), together with a change in the shape of the demand curve, where the residual load available for conventional plants has been shifted in the early morning and the evening [2].
The variation in the composition of the final tariff paid by the consumer in the last years (see Figure 1.8 [6] [7]), and likewise since 2008, is the result of mainly two aspects.

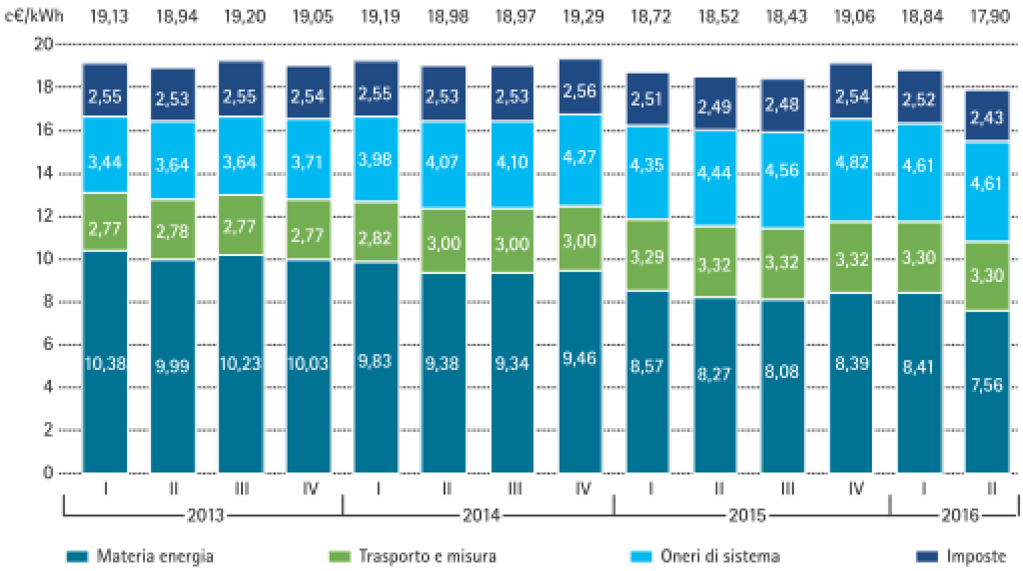


***Figure1.8**: Tariff for a residential consumer (2.700 kWh/y, 3 kW).*

On one side, the energy price component has decreased, but this occurred reflecting only in part the stronger reduction of the PUN, which has been partly compensated by the increase of the costs related to the dispatching activity performed by TERNA.
On the other side, the general charges related to the system management increased, mainly because of the support schemes put in place for the development of RES: the share of the A3 component among the general system charges is around 13,8 billions of euros, against a total value for the charges around 15,7 billions of euros. Despite the growth of these charges, the energy component remains the most relevant part of the final tariff paid by the consumers.

1.3 Future Trends and Resolutions

At the end of this introductive overview, it is possible to define the most important issues of the Italian market, which are linked to the future activities and resolutions of the regulator [7]. Among them, it is necessary to underline:

- the only partial integration of RES and DG in the market and at a grid level due to a limited possibility to participate to the energy markets and the absence of a legal framework that gives the possibility to create a generation portfolio and to manage properly the activities at a distribution level;
- the absence of a capacity remuneration mechanism able to send, through a market tool, price signals that have been lost in the last years and that can give instruments to stakeholders to evaluate their investments;
- the structure of the energy markets, which are called to be focused on real-time negotiation and to ensure an efficient and free allocation of the capacity;
- the necessity to define properly the roles and the intervention areas of the TSO and the DSOs.

These points will be the most important in the immediate future and have already been taken into consideration by the regulation authority. The resolutions must consider the evolution of the main market and system output and in particular should consider:

- the evolution of the electricity demand as a result of the trend of the GDP, the industrial demand, the energy efficiency increase which is expected in all the sectors and the shift of at least a part of the heating and the transport primary energy demand towards the electricity vector;
- the evolution of the electricity generation with the dismantling of old high-emission assets replaced by RES plants, the need of production systems able to guarantee the proper system flexibility and the development of storages systems.

By the year 2030 the expected situation could consider a recovery in terms of PUN and of the activity of CCGT in terms of equivalent hours per year; a consequent recovery of the revenues from conventional natural gas based technologies, limited by taxes and charges imposed on brown production.

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CHAPTER 2
The Combined Heat and Power Plant

This thesis work aims at building a tool that allows sizing a cogeneration plant to install and running it in an optimized way. Under this light, it is necessary to briefly present the technologies involved and the motivations that justify the work from the point of view of its usefulness in the next future.
In this chapter, the features regarding the CHP technology are presented; this involves a description from both a technical and a regulatory standpoint, to understand all the aspects that can influence further analysis.

2.1 The CHP Technology

2.1.1. Working principle

The evolution in the energy production and exploitation in the recent years, regarding the depletion of fossil fuel reserves and the climate changes with the global warming issue caused by the human activities, pushed the institutions all over the world towards the use of alternative resources (and power plants) more and more efficient and clean.
Even if CHP (Combined Heat and Power) plants are mostly fed by fossil fuels, hence they cannot be classified as renewable resources, they allow an important saving in terms of fuel consumption with benefits for the economics and for the environmental impact of the power plant; they are commonly judged to be fundamental for the energetic transition we are facing.
In Italy, such as in many countries of the world, electric energy comes from thermal power plants where heat is converted into mechanical energy through the exploitation of a thermodynamic cycle: usually the cycle used for the conversion is a Rankine-Hirn or a Brayton-Joule cycle. The mechanical energy produced is converted into electric energy through a generator. Independently from the cycle used, according to the second principle of thermodynamic, expressed in the Kelvin-Planck form, a part of the heat derived from the fuel combustion must be released in the environment and cannot be converted; the maximum theoretical limit is defined by the Carnot cycle efficiency.
For a common power plant, almost 35% of the introduced energy is released at the bottom of the cycle, while a typical share around 55% is converted into electricity.
Given these considerations, it seems reasonable to use this released heat, which is often characterized by a high temperature of the energy vector, for heating (and cooling) applications.
Formally the cogeneration definition according to the Legislative Decree 16 March 1999 n.79 is:

"Cogeneration is the combined production of electric energy and heat under the conditions defined by the Authority for the Electric Energy and the Gas, which guarantees an effective saving of energy with respect to the separated production"

Figure 2.1 presents the cogeneration working principle through the use of disgrams.

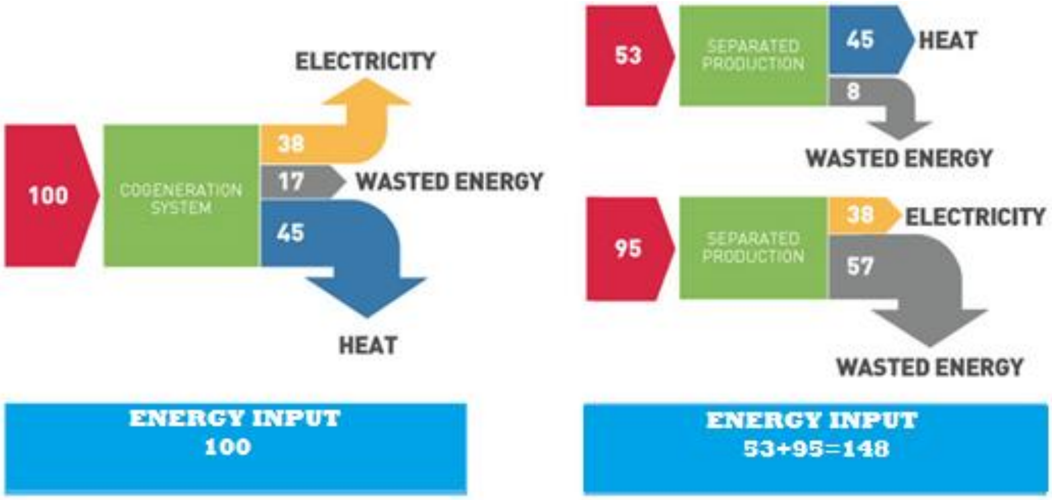

***Figure 2.1**: Working principle of a CHP plant.*

2.1.2. Advantages and limits of cogeneration

The main advantages of cogeneration are:

- a lower consumption of primary energy thanks to an increased system efficiency: the total efficiency (electric plus thermal) is usually higher than 80%.
- A reduced emission of pollutants and GHG in the atmosphere: the lower amount of fuel used allows reducing the emitted amount of flue gases.
- A reduction in terms of transmission losses in the electric grid, due to the fact that often CHP plants are placed near the final users or even at a distribution level.

Beyond the advantages, CHP plants are characterized also by mainly two limits:

- The presence of a thermal user near the plant: this is in contrast with the willingness to place traditional thermoelectric plants far from urban areas to reduce the impact of the emissions towards people (electricity transmission can be granted with an high efficiency); however the presence of an heat production requires short heat distribution grids due to its low transmission efficiency.
- The simultaneous presence of a thermal and an electric load in order to exploit the production of the CHP plant.

2.1.3. Main technologies for a CHP configuration

Cogeneration systems can be classified into two families: topping and bottoming systems [1]. Topping configuration is characterized by an exploitation of the energy vector for the heat production at the bottom of the line, while in bottoming system this occurs at the beginning when the heat can be exploited at very high temperature. Topping systems are the most diffused, because of the higher efficiency of turbines and engines at high temperature; also bottoming systems are used but only for particular application requiring huge amount of heat at high temperature such as steel factories or big industrial processes.

It is possible to define three different cogeneration technologies based respectively on a steam turbine (back-pressure and extraction-condensing turbine), a gas turbine (in simple or combined configuration) and an internal combustion engine. Actually only the last two technologies find a diffused application; in particular for CHP plant with a capacity below 10 MW the most used technology is the one based on internal combustion engines (ICEs) whose scheme is presented in Figure 2.2 [2].

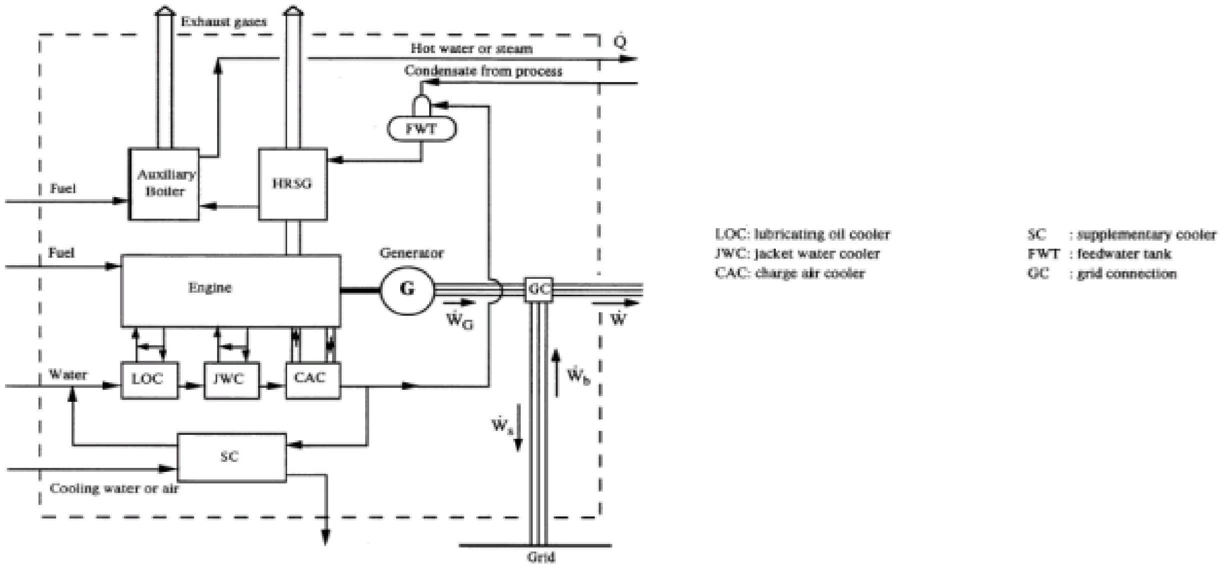

***Figure 2.2**: Scheme of an ICE based CHP plant.*

The use of big ICEs (from 1 to 10 MW) represents a mature technology able to grant also high electric efficiencies (up to 45%); small ICEs application is instead a more recent evolution.
It is possible to identify three main categories for the ICEs used in CHP plant:

- engines derived from automotive applications;
- engines derived from truck or ship traction;
- engines developed originally for stationary applications.

Usually for capacities above 1 MW the latter engines are used, while a choice between stationary and naval engines is made in the range from 150 kW up to 1 MW.
For what concerns the fuel used, it is possible to find natural gas fired engines based on Otto cycle, heavy oil fired engines based on Diesel cycle and dual fuel engines again based on spontaneous ignition. Moreover, especially for stationary application above 200 kW, the turbocharging technique is often used in order to increase the filling coefficient (or volumetric efficiency): the flue gases are used to run a turbine which drives a compressor elaborating the air going to the combustion chamber; this increases the air density, the mass of air pushed towards the combustion chamber and the useful power [3]. The temperature of the air at the compressor outlet is then decreased, thus increasing the air density by a further contribute, by the use of an intercooler.
For what concerns the cogeneration purposes, the energy vectors from which heat is recovered are mainly:

- the lubricant oil;
- the jacket cooling water;
- the air fed to the engine after the turbocharging through the intercooler;
- the flue gases.

While the latter energy vector is at high temperature, the others are characterized by medium to low temperature and hence can only be used to produce hot water and not to produce steam.

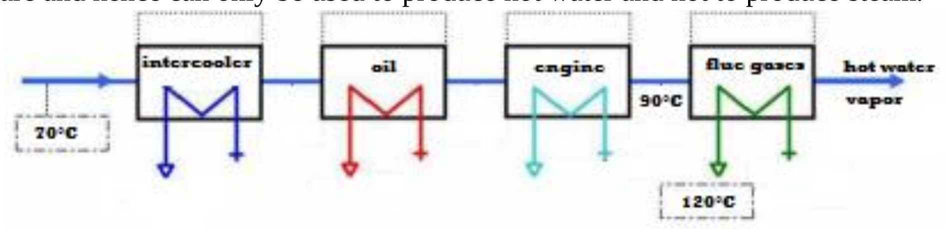

***Figure 2.3**: Heat recovery vectors in ICE CHP plants.*

The main advantage offered by the ICEs is the high flexibility during the working operations, since they can sustain different loads without any substantial risk of interruption in their services; moreover they can maintain even at 50% of load level a total efficiency equal to 85/90% of the nominal one: this characteristic makes them very suitable for the distributed generation (DG).

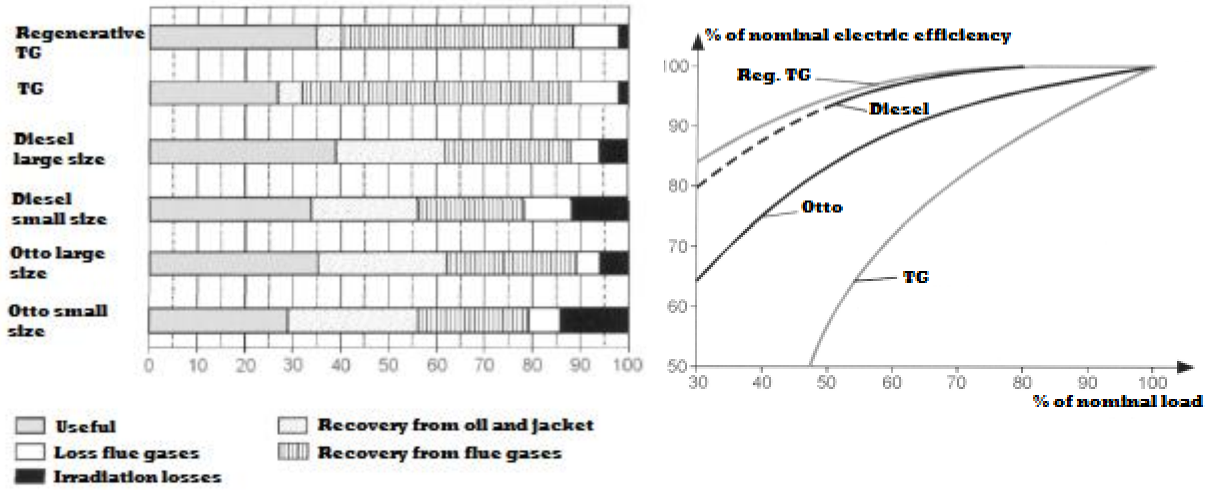

***Figure 2.4**: Efficiency of CHP plant and its variation with respect to load.*

As depicted in Figure 2.4, Otto cycle based ICEs are characterized by electric efficiencies going from 27% for small sizes to 38% for large sizes, while the thermal efficiency remains around 50%.
Diesel cycle based ICEs have instead higher electric efficiencies even for small sizes, whereas the thermal efficiency goes around a value of 40%.
For what concerns the value of the efficiencies with respect to the load, while the electric efficiency decreases with load, the thermal efficiency increases and this helps in keeping the total efficiency almost constant and high even at low loads.
ICEs CHP plant are often equipped with a by-pass valve that allows discharging through a radiator in a secondary circuit the heat that is eventually needed to be disposed.
The main drawbacks linked to the use of ICEs in CHP applications are concerning:

- The frequent need of maintenance of the engine.
- The high cost linked to the substitution of some damaged or worn out parts of the engine.
- The shorter working life (up to 100.000 hours for small size ICEs, typically between 15 and 20 years for big size ICEs).
- The need to use only high value fuels such as natural gas.

2.1.4. Fields of employment of the different technologies

The choice of the technology to be adopted is made on the basis of different considerations mainly linked to the energy demand from the consumer. In general, it is necessary to consider the peak and the average demand level and the ratio between the thermal and electric request.
The size of the CHP plant is the key parameter to be determined: typically all systems increase their electric efficiency together with their size. For all the applications requiring more than 10 MW of power, the combined cycle CHP plant are the most suitable; otherwise, for small loads, the best solution are ICEs CHP plants. In Figure 2.5 (left side) it is possible to see the different employment fields of the different technologies in terms of electric power and ratio between electric and thermal capacity; on the right side of the same figure the electric and the thermal efficiency are presented for each technology.

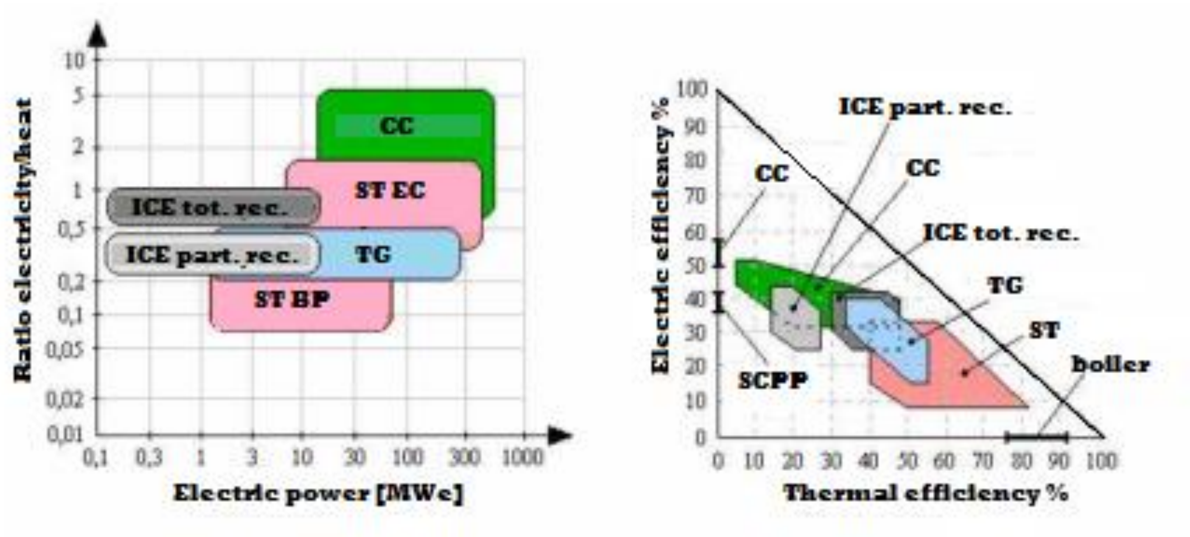

***Figure 2.5**: Application fields for different CHP plants.*

The values reported confirm that ICEs are the most suitable technology for small applications, while combined cycle becomes better for bigger load requirements.
Another important parameter is the temperature at which the fluid for the thermal users is required: while combined cycle are able to ensure heat at high temperatures, for temperatures below 300°C also ICEs can be used.
Other factors are linked to the reliability and the working life of the plant: the use of an ICE in general implies a more frequent maintenance due to the frictions at which mechanical parts are subjected.

2.1.5. Performance indexes for a CHP system

The performances of a CHP plant can be measured considering several parameters: energetic, environmental, noise emission and power quality indexes [1].
The most important parameters are the ones concerning the energy performances: these parameters are dealing with the production of electricity and heat and allow determining the amount of energy produced, the fuel consumption and the energy efficiencies. The LHV of the fuel used, the electric power and energy, and the thermal power and energy are the data used to derive the electric and the thermal efficiencies of the plant.

$$\eta_{el} = \frac{E_{el}[kWh]}{m_f[kg] * LHV_f[\frac{kWh}{kg}]} \qquad \eta_{th} = \frac{E_{th}[kWh]}{m_f[kg] * LHV_f[\frac{kWh}{kg}]}$$

According to the Legislative Decree 20/07, starting from 2011 the performance index that defines the HEC (High Efficiency Cogeneration) is the PES (Primary Energy Saving), defined as:

$$PES = \left(1 - \frac{1}{\frac{\eta_{th}}{\eta_{th,ref}} + \frac{\eta_{el}}{\eta_{el,ref}}}\right)$$

where:

- η_{th} and η_{el} are respectively the thermal and the electric efficiency of the CHP plant, defined as above.

- $\eta_{th,ref}$ and $\eta_{el,ref}$ are respectively the reference value of the thermal and electric efficiency defined according to a specific criterion. In particular, the most used criterion for what concerns a legislative evaluation is to consider the best available technology for the same fuel used in the CHP plant, in order to promote the technological evolution of the different systems [4].

Another important index is linked to the emission of GHG and pollutants in the atmosphere: in this case, the legislator has fixed the limit values and plants are subjected to periodical or continuous controls. Limits are concerning the emissions of CO, NO_x, CH_4, VOC and soot.

2.2 The Development of the CHP Technology

2.2.1. Regulatory framework

As stated above, cogeneration is one of the most efficient technologies for the rational use of energy, allowing an optimal employment of the primary energy of the fuel for the production of electric and thermal energy. Because of this, the EP (European Parliament) recognized the importance of cogeneration, to reach the targets of the Kyoto protocol, thus including among the priorities the definition of a normative framework that could promote the diffusion of combined electricity and heat production.

The Communication from EC (European Commission) to the EP in October 1997 [5] stated:

"Cogeneration is one of the technologies that can offer a major contribute to the energy efficiency problem in EU in the short and medium term, and can give a positive contribute to the environmental policies of EU"

However cogeneration had a different penetration level among the different European countries, even when there were no significant differences in terms of climate and economic structures: the reason for this should be individuated in the relative powers of the institutions in the single countries and in the role of the local governments.

The European Directive n. 2008/04/CE created a legal framework for the development of the HEC based on the useful heat demand and on the saving of primary energy. According to the Directive, the useful heat is the heat produced by the cogeneration process to fulfill a demand in an economically efficient way, meaning a demand not overcoming the actual need and which otherwise would be satisfied through other energy production processes [6].

In the Annex III of the Directive, it is possible to find an indication about the criteria that characterize the HEC: in case of small CHP plant (< $1MW_e$) and micro-CHP plant (< 50 kW_e) it is sufficient that the plant provides a saving of primary energy, whereas in other cases it is necessary to have a saving of primary energy equal or greater than 10% with respect to the separated production. The amount of primary energy saved is estimated and expressed through the PES coefficient.

As said, cogeneration is often correlated to distributed generation; the Annex A of the AEEGSI resolution n.160/06 defines [7]:

- the Distributed Generation (DG) as the set of generation plants with a nominal power below 10 MVA;
- the Microgeneration as the set of generation plants with a nominal electric power below 1 MW.

Moreover the AEEGSI resolution n. 42/02 defines the cogeneration as *"an integrated process of combined production of electric [...] and thermal energy, both intended to be useful energy vectors, [...] which, from whatever primary energy resources, satisfies both the conditions concerning the primary energy saving and the thermal limit"*

The Ministerial Decree of 4 August 2011 established the new criteria for the acknowledgment of the high efficiency condition for CHP plants: the condition defined entails a PES value at least equal to 10% for all types of CHP plant.
Beyond the indications of the European Directive, the Decree defines values for the reference electric efficiency classified on the basis of the type of fuel, and values for the reference thermal efficiency classified on the basis of the type of fuel and of the use of the heat. Moreover, correction factors for the different climatic zones of Italy are defined concerning the reference electric efficiency.

2.2.2. Support mechanism

The Ministerial Decree 20/07/04 [8] introduced the support mechanism known as White Certificates (technically named Titoli di Efficienca Energetica). This system foresees an obligation for distributors of electric energy and natural gas, combined with benefits for the subjects that realize interventions for the improvement in the final use of energy.
Briefly:

- Beneficiary Subjects receive a certain amount of WC in the measure of the amount of energy savings they reached through energy efficient interventions.
- Obliged Subjects are electric energy and natural gas distributors (with more than 50.000 customers) who are required to obtain a certain amount of WC through direct energy efficient intervention or buying them from other subjects.

Energy efficient interventions are evaluated based on the savings that they introduce, measured in terms of TOE (Tons of Oil Equivalent): one white certificate corresponds to one TOE.
Up to 2011 only distributors were involved in the WC system as obliged entities; from September 2011 HEC owners had access as beneficiary subjects. Starting from December 2012, new subjects have been admitted to the WC system: ESCO and other entities operating in the energy services sector, industries with an Energy Manager or a system for the management of energy according to ISO50001; moreover the obligation for WC has been restricted only to big distributors as stated above.
Since February 2013, the WC system is managed by the GSE.
The remuneration foreseen for the WC is updated every year and represents a support mechanism for the reduction in the consumption of primary energy recognized by the EC through the Directive 32/2006.
CHP plants benefit of other support mechanisms beyond the WC one. Among them, it is worth to cite:

- the dispatching priority, after the must run units and the renewable resources.
- the exemption from the purchase of the authorizations within the ETS (in Italy the Green Certificates system).
- other kind of facilitations such as simplified connection procedure, acknowledgement of the SEU condition, dedicated withdrawal or on spot trading systems.

2.2.3. CHP plants diffusion

The diffusion of the cogeneration technology is first influenced by the climatic conditions: a constant and high thermal load is a fundamental factor in order to obtain the maximum benefit from the installation of a CHP plant. This condition is particularly important when civil applications are considered, hence when the heat produced is exploited for space heating applications; on the other hand, industrial applications are characterized by more constant and flat heat demand.
Climatic conditions are well represented by the Degree Day indicator defined according to the 412/1993 Decree as the sum, extended to the whole heating period, of the positive differences between the internal ambient temperature, fixed at 20°C, and the mean external temperature.

This definition allows dividing Italy in climatic zones, with a certain level of load associated (see Figure 2.6).

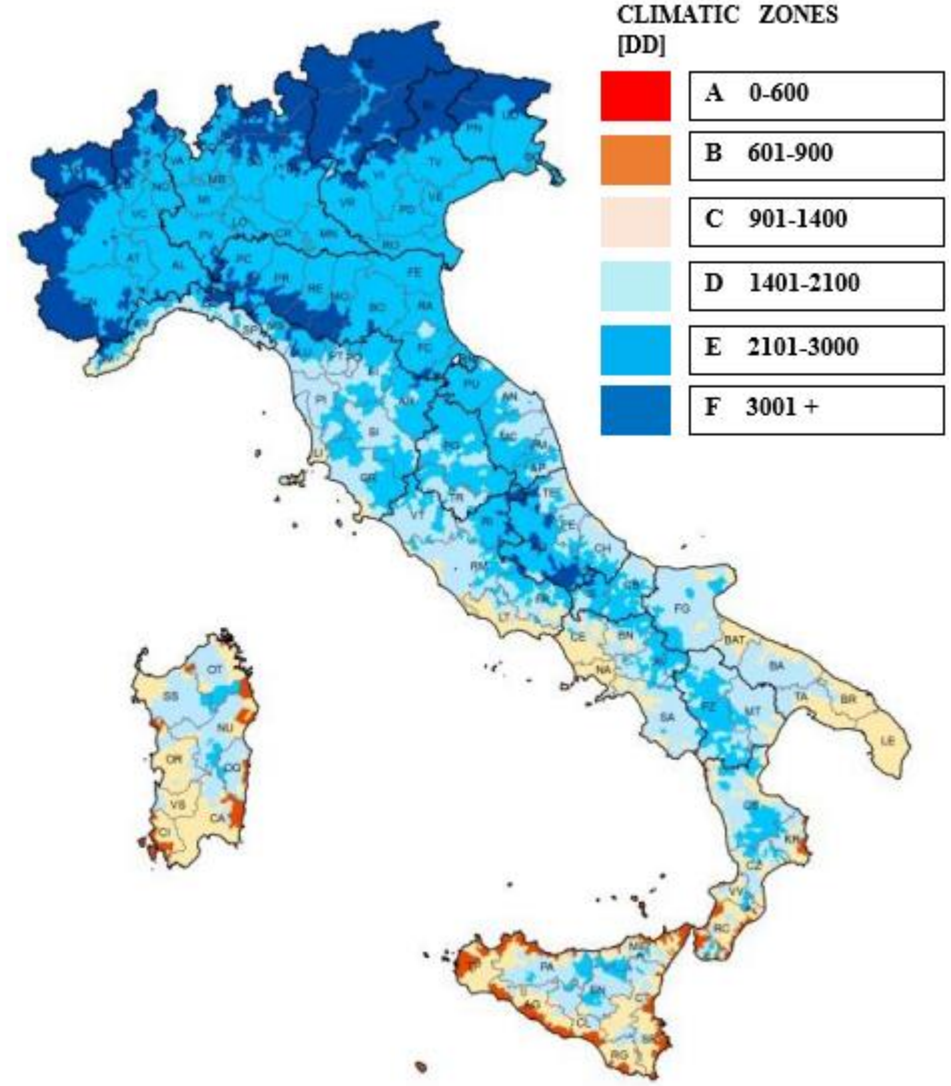

Figure 2.6*: National map of climatic zones.*

According to ISTAT (Italian national statistical institute) about 42% of people lives in regions belonging to zone E, 25% in zone D and 31% in zone C. In Figure 2.7 it is possible to see also an evaluation of the regional consumption of natural gas, related both the residential and to industrial activities: this confirms the fact that the thermal load is higher in the north of Italy, opening to a greater possibility of CHP plants diffusion.

Another factor to be considered is the seasonality in the thermal load that characterizes the larger part of the activities. As it is possible to see in Figure 2.8, while in the industrial sector the demand remains almost constant, in the tertiary sector we have a strong decrease between April and October linked to the end of the heating season [7].

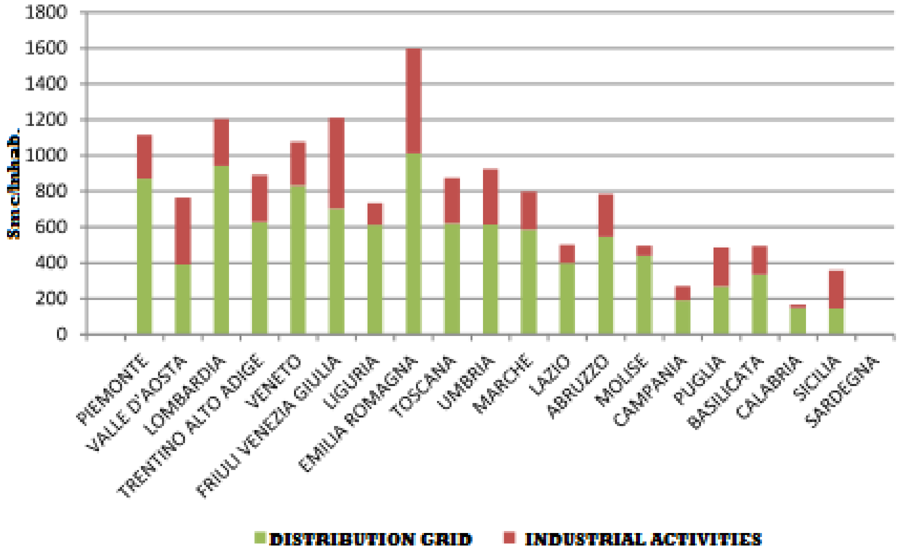

Figure 2.7*: Transported NG per inhabitant.*

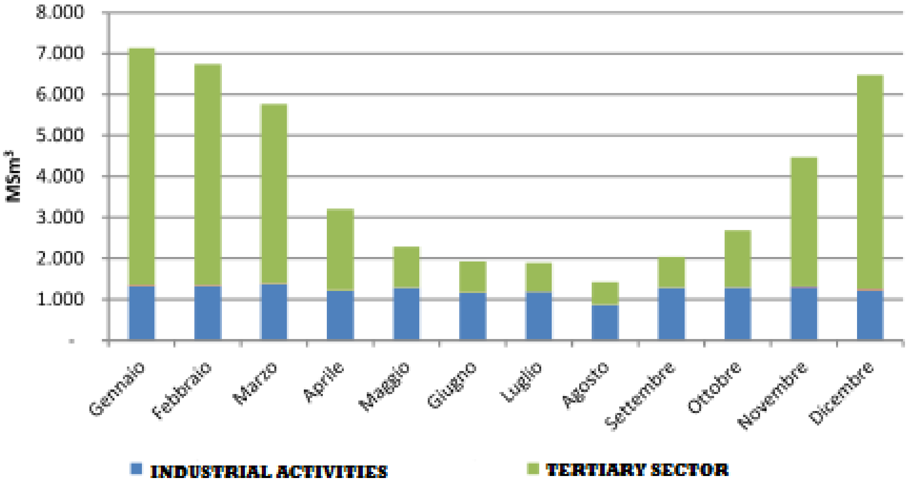

Figure 2.8*: Average NG consumption per month.*

It is useful to individuate, according to the above considerations, the location of the most important industrial activities and classify them on the basis of the magnitude of their energy consumption. Among them, it is possible to represent those plants which are characterized by a consumption of primary energy greater than 20 GWh per year.
From Figure 2.9 it is possible to see that the main part of industrial zones are concentrated in the northern part of Italy, even if large consumption plants are present also in the southern part. The plants characterized by the larger consumption are the steel factories, the chemical and the petro-chemical factories [9].

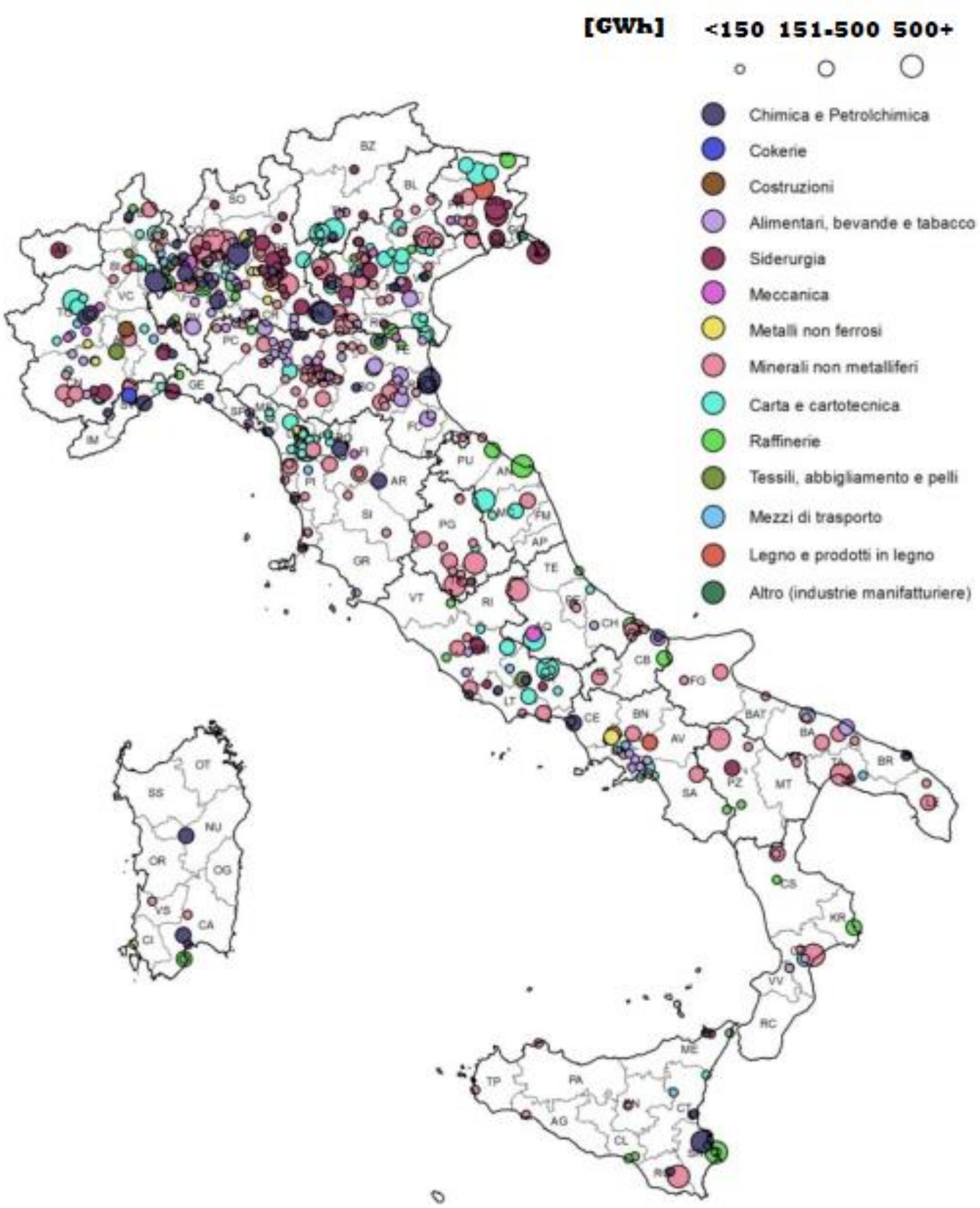

***Figure 2.9**: Industrial sites with a primary energy consumption higher than 20 GWh per year.*

According to Eurostat data, reported in Figure 2.10, the CHP technology in Italy knew a constant increase between 1990 and 2007; in the last years the maximum value was reached in 2010 and then it decreased to a value of produced electric energy equal to 95,7 TWh and of installed capacity equal to 21 GW in 2015, corresponding to the 18% of the overall generation capacity installed in Italy.
Around 75% of the electricity generated through CHP plants comes from the use of natural gas and only 8% derives from the exploitation of renewable resources [9].

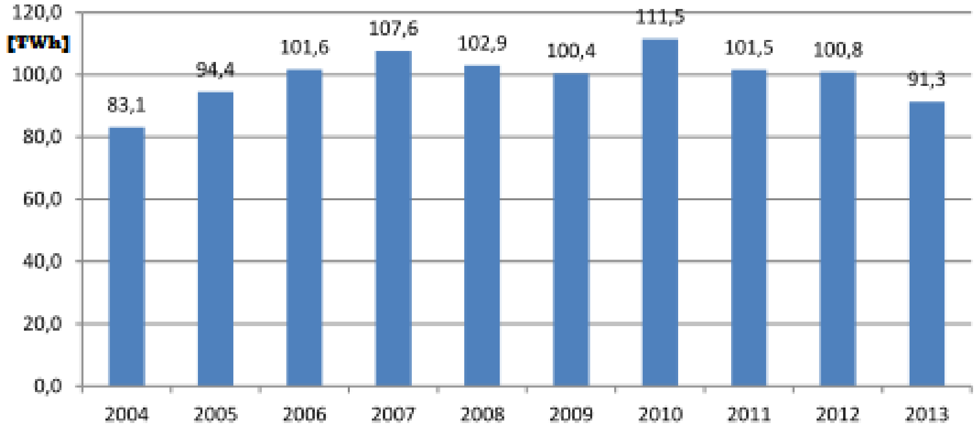

***Figure2.10**: Evolution of the electric energy from CHP plant.*

Among thermoelectric power plants, the HEC plants count for almost 16% (Figure 2.11).

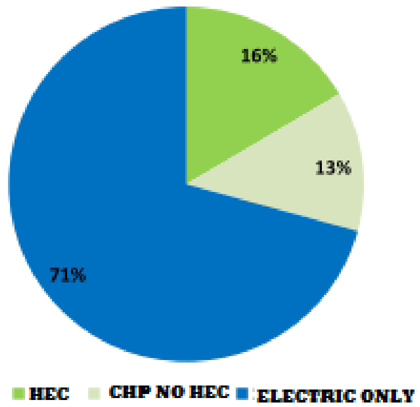

***Figure 2.11**: Thermoelectric capacity share.*

For what concerns the different technologies used, Figure 2.12 underlines the importance of the ICE solutions in terms of number of plants, while considering the installed capacity Combined Cycle share is the greatest: this indicates once more that ICE are widely used for small applications.

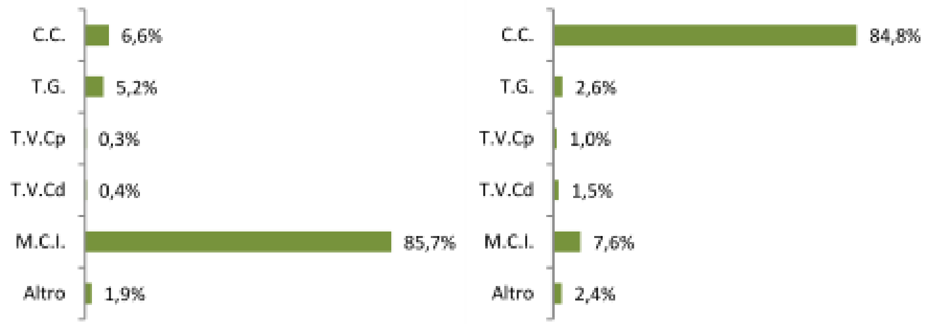

***Figure 2.12**: Number of HEC units (left) and generation capacity (right).*

Figure 2.13 reports the regional diffusion of HEC: almost 67% of the installed capacity is concentrated in the north of Italy, particularly in Lombardy and Piemonte.

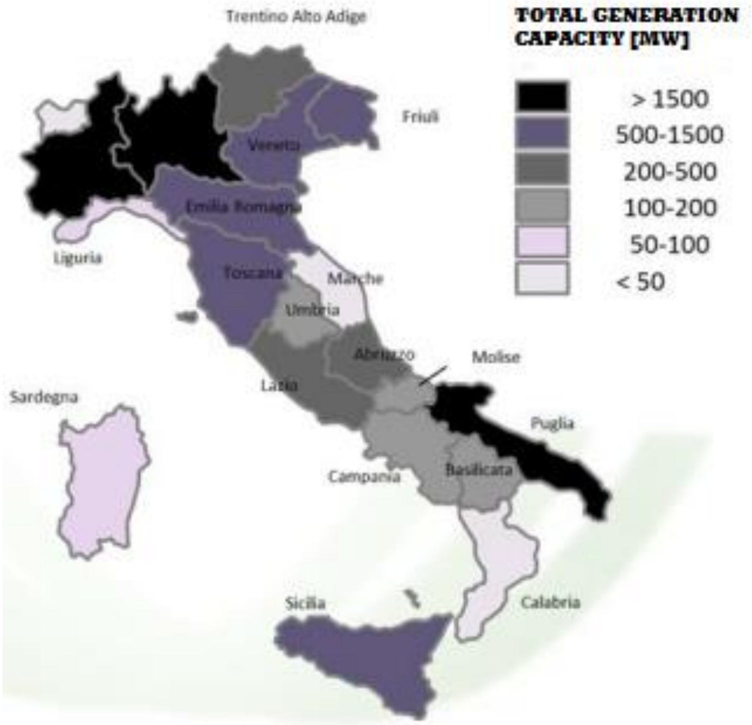

Figure 2.13: Geographic distribution of HEC.

Finally, for what concerns the different industrial sectors (Figure 2.14) in which CHP plants are exploited, it is possible to see that almost 76% of the heat produced by HEC is used by industrial plants, while the remaining 24% is used for the residential and tertiary sector through district heating infrastructures.

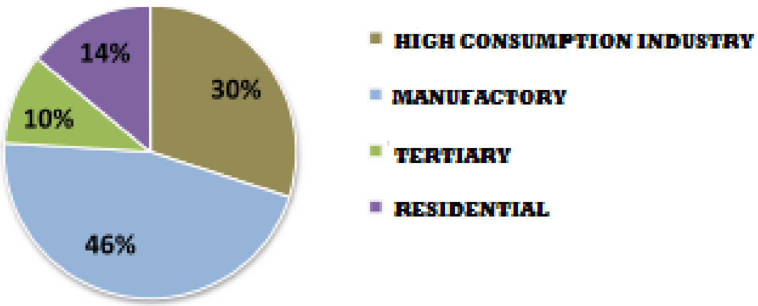

Figure 2.14:Use of the heat produced from HEC.

An evaluation of the potential for the future widespread of the cogeneration technology underlines a situation where the high energy consuming sectors have already overcome the technical potential of development; this situation can be easily explained considering the willingness to reduce the costs associated to energy consumption, especially for what concerns the costs related to electricity, and considering the economic crisis that has reduced the volumes of industries production managed by these plants [10].
Other sectors show instead important opportunities of development; among them it is possible to cite food and tobacco industries, textile and leather industries, wood and mineral industries.

2.3 The Combined Cooling, Heat and Power Solution

In order to face the problem related to the presence and to the variation of the thermal load, which affects in particular the residential and tertiary sectors but also the industrial demand, a solution is to add to the cogeneration system an absorption chiller in order to transform the CHP system in a CCHP (Combined Cooling Heat and Power) system.
This solution foresees the presence of a chiller to exploit the heat produced by the cogeneration system, typically the low temperature heat, in order to perform a refrigeration cycle.
An absorption chiller is a machine that exploits the affinity between two substances; one acts like a refrigerant and the other like an absorber, in order to perform a refrigeration cycle where the energy introduced is mainly under the form of heat. The key point, with respect to a traditional refrigeration cycle, is the compression of the refrigerant when it is in solution in the solvent, thus in the liquid phase: this allows using less valuable energy (electric energy) than in the case of a vapor compression.
As per Figure 2.15 [2], the absorption chiller works with three different thermal sources:

- the cold source which is found at the temperature of the ambient to be cooled and which goes through the evaporator;
- the hot sink where the heat is discharged through the condenser;
- the heat which is introduced at the stripping level and which corresponds to the highest temperature flow in the cycle.

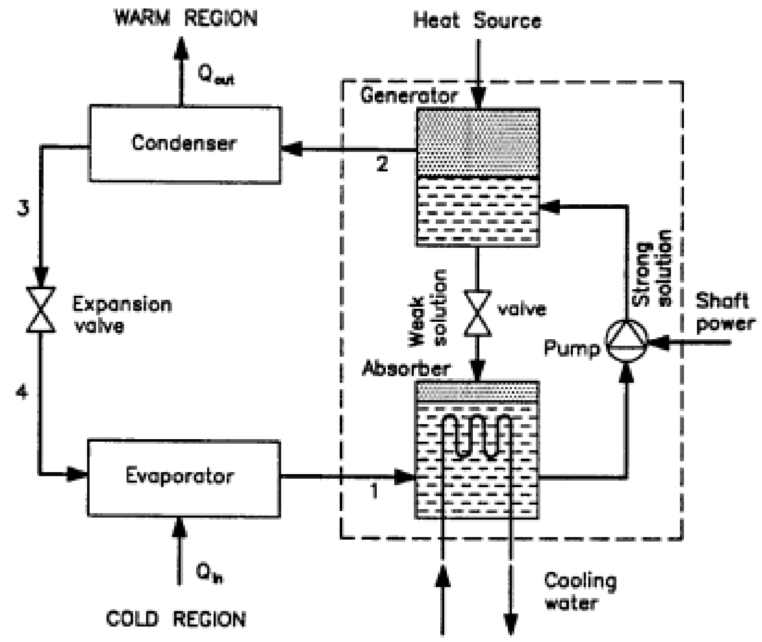

***Figure 2.15**: Absorption chiller scheme.*

In the evaporator, the refrigerant subtracts heat from the cold environment while evaporating and it is then sent to the absorber. In the absorber, the solvent absorbs it: this process generates a certain amount of heat that must be discharged through a dedicated circuit to keep the absorption process effective. The loaded solvent obtained is brought at a higher level of pressure through a pump: this is the only element of the scheme that requires electric energy (the amount of this energy is generally equal to a little percentage of the thermal energy required by the chiller).
At this point, the solution is sent to the stripper where the refrigerant is desorbed and the solvent is regenerated: being endothermic, this process requires heat which is supplied by a combustion process or by an energy vector from another process such as a turbine or an ICE.

The lean solvent is sent again to the absorber after performing a pressure reduction and an heat exchange with the incoming loaded solvent; on the other hand, the refrigerant at high temperature is sent to the condenser where it discharges heat towards the hot sink: this process should be performed at the lowest possible temperature to keep the efficiency of the cycle as high as possible.
The refrigeration cycle in an absorption chiller is hence realized through two fluids: the refrigerant and the solvent. The most used solutions are:

- Water (refrigerant) + Litium Bromide (solvent): they are widely used for applications where temperature of the cold side is above 0°C, in order to avoid water freezing.
- Ammonia (refrigerant) + Water (solvent): this solution requires a more complex plant scheme and introduces higher safety issues because of the toxicity of the ammonia; they are used mainly in applications where very low temperatures are required, up to -60°C.

The solution with water and litium bromide, and using hot water as the source of primary thermal energy, is the most diffused for civil and industrial application because of the usual presence of wasted flow of hot water which cannot be used in other processes but still own a certain amount of useful thermal energy, even if at low temperature.
In this configuration, water is brought in the evaporator at very low pressure to induce phase transition at lower temperatures. In the absorber, the litium bromide is distributed along some pipes uniformly in order to increase the volume to surface ratio and to push the absorption process. The use of the heat exchanger between the high temperature lean solvent and the low temperature loaded one allows the reduction of the amount of heat to be supplied to the stripper and reduces the temperature in the absorber, hence increasing the efficiency of the chiller.
The performance index used for chillers is the Coefficient Of Performance defined as the ratio between the useful energy obtained and the thermal energy introduced.

$$COP = \frac{Q_u}{Q_{th}}$$

Typical values for absorption chillers are between 0,6 and 0,75. It is worth to underline that absorption chiller keeps an efficiency at partial load that is stable and sometimes higher than the nominal one: this is linked to the absence of moving parts (except for the small contribute of the pump) whose performances decrease together with the load.

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CHAPTER 3
The Regulation Concerning HEC

In this chapter the regulatory framework involving the HEC plants is described. In particular, all the aspects correlated to the current classification of HEC plant from a legal and regulatory point of view are considered; then the issues concerning the future evolution of the economic treatment to which HEC will be subjected are also analyzed.

3.1 The Legislation about HEC and its Evolution

The will of reducing the physical distance between energy consumption and production has always been a central theme, especially since the diffusion of DG. Industrial users have been pushed to stock up on electric energy by themselves in order to reduce the energy costs and to increase the supply reliability. Nowadays, the reliability of the electric grid is very high, but the cost saving introduced by self-consumption is greater than before, thanks to a favorable legislation and to the improvement of technologies linked to DG such as RES and HEC.
These systems help in reducing the dependence of the user on the grid, improve the overall efficiency of the energy system and reduce the amount of pollutant emissions; hence it is considered necessary to recognize to them a special treatment for what concerns the electric energy costs.
Because of this, the development of HEC systems have been included in the EU targets: in the next sections, the legislation implemented at an Italian level is illustrated.

3.1.1 Relevant categories of SSPC: SEU, SEESEU and ASAP

Following the European Directive 2006/32/CE, the Legislative Decree (Dlgs) 115/08 has introduced the so called SEU (Sistemi Efficienti di Utenza).
In particular the category of SSPC (Sistemi Semplici di Produzione e Consumo) is defined as a set of loads and generators connected to the public grid; among them it is possible to find [1]:

- SEU;
- SEESEU (Sistemi Esistenti Equivalenti ai Sistemi Efficienti di Utenza);
- ASAP (Altri Sistemi di AutoProduzione);
- ASE (Altri Sistemi Esistenti).

The structure defined above is reported in Figure 3.1.

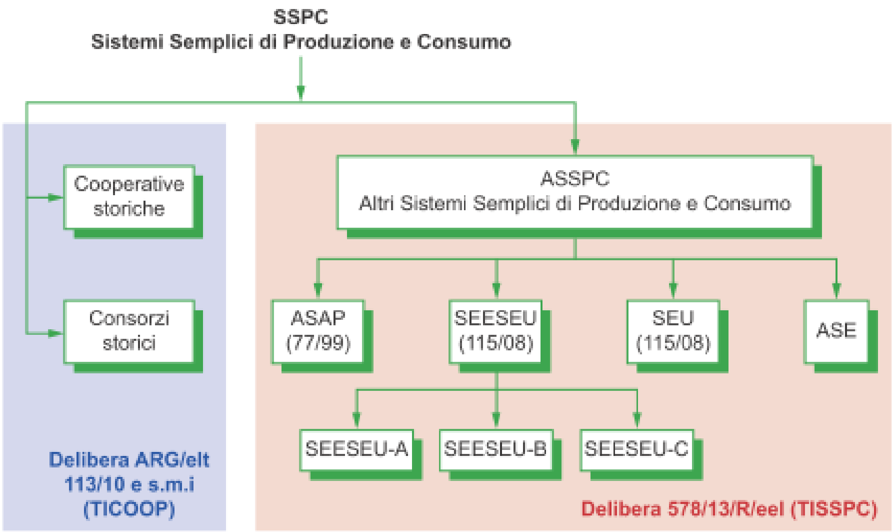

***Figure 3.1**: Classification of SSPC.*

The SEU are systems where the generators (RES or HEC) are managed by a single producer and are directly connected through a private link to a single final customer.
Moreover it is required that the energy use is characterized by a single unit of consumption, where the latter is intended to be the set of consuming systems connected to the electric grid whose energy withdrawn is exploited for a single activity or a single final aim. This consideration usually coincides with the requirement that a unique POD (Point Of Delivery) characterizes the consumption unit in its connection to the grid; an extra POD can be required for emergency situation or in order to supply LV users such as heat pumps or EV charging points.
The production plant has to consist in a RES or HEC power plant.
The SEESEU is a system where the bureaucratic procedure for the realization of all the main elements has been started before July 2008 the 4th; moreover these works have to be finished, started or at least fully authorized by January 2014 the 1st.
It is possible to define three different categories of SEESEU:

- SEESEU-A: when the unique producer coincides with the final customer, even with more than one consumption units;
- SEESEU-B: when the system respects fully the requirements of SEU definition;
- SEESEU-C: when the system does not fall in the above categories (e.g. when customer and producer are different or the plant is not a RES or HEC plant) and was already in operation before 2014. This last category has been introduced by AEEGSI in order to safeguard the investment made before July 2008 and not respecting the previously described conditions.

Since the 1st of January 2016 systems belonging to SEESEU-C could be considered as SEESEU-B if by July 2015 the 1st all the requirements described above concerning the SEU status are fulfilled.
The ASAP are systems where a producer generates electric energy and, through private connections, self-consumes at least 70% of the energy produced.
The ASE are all the energy systems that cannot be classified as belonging to the categories described above. As it is possible to see in Figure 3.1, SEU, SEESEU, ASAP and ASE belong to ASSPC (Altri Sistemi Semplici di Produzione e Consumo) in order to distinguish them from the other jurisdictional actors already defined before 2008 (Cooperative Storiche e Consorzi Storici).

***Table 3.1**: Requirements of SSPC.*

<table>
<tr><th>Type</th><th>RES/HEC obligation</th><th>Time limits</th><th>Structure limits</th></tr>
<tr><td>SEU</td><td>YES</td><td>new</td><td>Single costumer
Single producer
Single consumption unit
Single owned area</td></tr>
<tr><td>SEESEU-A</td><td>NOT NEEDED</td><td rowspan="2">existent</td><td>Single producer coincident with the costumer (even more than one consumption unit)</td></tr>
<tr><td>SEESEU-B</td><td>YES</td><td>Single costumer
Single producer
Single consumption unit
Single owned area</td></tr>
<tr><td>SEESEU-C</td><td>NOT NEEDED</td><td>operating by 1/1/14</td><td>NONE</td></tr>
<tr><td>ASAP</td><td>NOT NEEDED</td><td>NONE</td><td>At least 70% of energy produced self-consumed</td></tr>
<tr><td>ASE</td><td>NOT NEEDED</td><td>operating by 1/1/14</td><td>See art. 1.1 b) 578/13/R/eel</td></tr>
</table>

In order to be considered as a SEU or a SEESEU, a system shall receive a qualification released by the GSE. With the exception of plants benefitting of the on spot trading system, all the other systems must ask for a qualification to the GSE. From the temporal point of view, the request must by presented within 60 days since the beginning of the plant operations or, if the plant was already operating, within 60 days starting from the opening of the online system of the GSE. Beyond the temporal limits defined, the status, thus the special legislation, is not recognized until the day in which the request has been sent.
It is worth to underline that the SEESEU-A status recognizes the best advantages since the limits concerning the maximum capacity, the generation coming from RES or HEC plants and the single consumption unit are not present, hence it allows realizing a greater amount of energy self-consumed.

3.1.2 Tax reliefs and advantages for HEC plants

The electricity bill paid by a generic customer in Italy consists in three main parts: the selling services, the grid services and the taxes. As an example brought to explain the share among the three parts over-cited, for a standard domestic user (3 kW and 2.700 kWh/year) the selling services count for almost 50% of the energy cost, while grid services (37%) and taxes (13%) share the remaining part. This situation is represented in Figure 3.2.

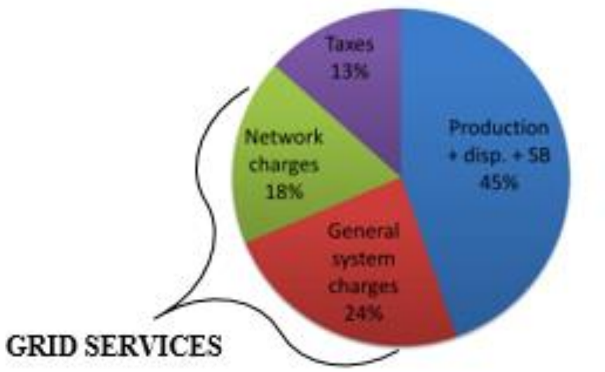

***Figure 3.2**: Composition of the Italian bill.*

The selling services comprehend all the activities that the retailer has to perform in order to buy and resell the energy to the costumers. They consist in:

- the energy price, as the proper price of electric energy, estimated considering the losses along the grid according to the voltage level of the supply;
- the retailing price, as the cost represented by the activities performed by the retailer to supply the energy to the costumer;
- the dispatching price, as the cost sustained by the TSO (Terna) to keep the system in safe and optimal condition and to guarantee a continuous supply of electricity across the whole network. Among the costs that must be covered by this item it is worth to cite the capacity remuneration, the interruptible load regulation, the must-run remuneration, the proper costs sustained by Terna on the ASM and all the cost correlated to the balancing activity performed by the TSO.

The taxes consist in an excise that is applied on the basis of the energy consumed monthly, and the VAT (Value Added Tax), equal to 10% or 22% depending on the costumer characteristics and applied to all the other voices summed up.
The third item is represented by the grid services comprehending the network charges and the general system charges.

The network charges comprehend all the activities of electric energy transmission, distribution and metering across the network; they include also the components UC3 for the transmission costs and UC6 for the service quality maintenance costs.
The general system charges cover the costs sustained for all those services that present a public usefulness. Even if, as part of the general taxation, only those tariffs established by a Dlgs can be considered as general system charges, also the charges introduced by the AEEGSI and characterized by the same aim and the same collection system are comprised in this voice of the bill. In particular the former are indicated with the letter A, whereas the latter with the mark UC. The whole set of system charges is presented below:

- A2: costs for the dismantling of nuclear plants;
- A3: costs for the generation plants development support (including RES support);
- A4: costs of special taxation regime (today only Ferrovie dello Stato);
- A5: costs of the research in the field of the electric network management;
- As: costs of the electric bonus for needy people;
- Ae: costs of very high consumption industries under a special regime;
- UC4: costs for the electric companies operating in minor islands;
- UC7: costs for the promotion of energy efficiency;
- MCT: costs for the remuneration of entities hosting nuclear plants.

The overall cost of the general system charges is around 15 billions of euros and, among all the items above, the A3 component contributes for 14,4 billions of euros (2016), with a weight much larger than all the other components.
In Figure 3.3, the evolution of the last decade in the electric energy cost is presented: as it has been stated in Chapter 1, against a fall in the energy price partly counterbalanced by the increase in the dispatching activity costs, the general system charges have increased with a constantly higher weight on the overall bill.

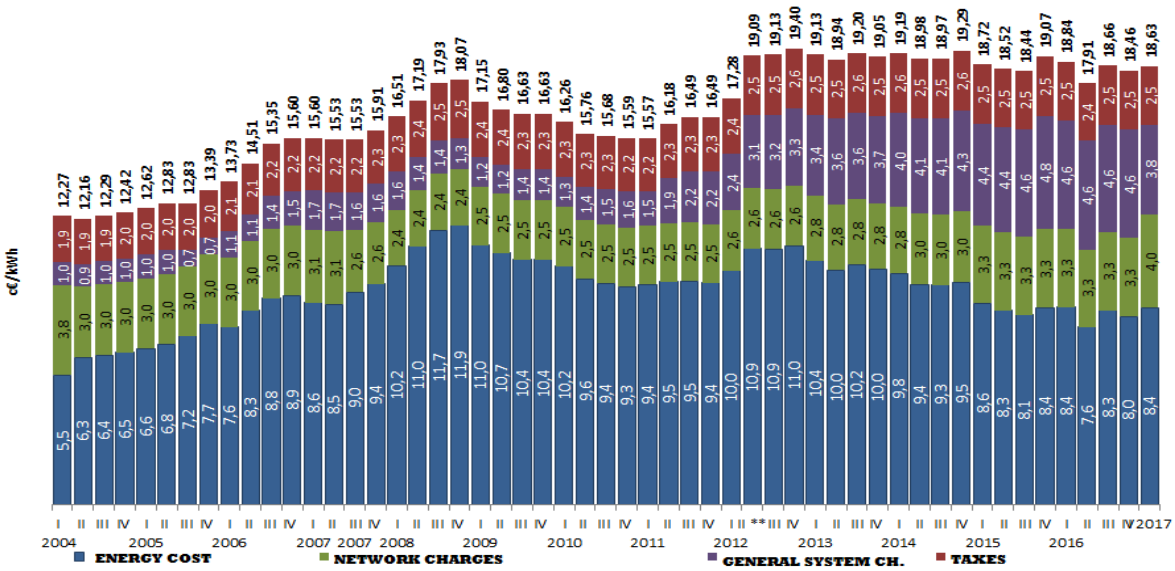

Figure 3.3: Evolution of the bill composition.

In Table 3.2 the different tariffs for the general system charges for a MV level costumer are reported. It is possible to compute that, if an electricity consumption below 8 GWh per month and an available capacity below 100 kW are considered, the network charges are equal to 7,76 €/MWh and the system charges are equal to 56,21 €/MWh, with a total tariff for the services costs equal to 63,97 €/MWh.

Table 3.2: *Grid service costs for a generic MV user.*

	GENERAL SYSTEM CHARGES									
	A2	**A3**	**A4**	**A5**	**Ae**	**As**	**UC4**	**UC7**	**MCT**	**TOT**
energy [c€/kWh]	0,09	4,828	0,21	0,008	0,007	0,38	0,02	0,045	0,018	5,621
power [€/kW]	-	-	-	-	-	-	-	-	-	0
fixed [€/year]	3,72	107,8	3,67	-	-	-	-	-	-	115,2
	NETWORK CHARGES									
	distribution		**transmission**		**metering**		**UC3**	**UC6**	**TOT**	
energy [c€/kWh]	0,048		0,591		-		0,122	-	0,7761	
power [€/kW]	28,183		-		-		-	-	28,183	
fixed [€/year]	397,861		-		261,756			115,1	774,717	

The Dlgs. 115/08 established that for SEU (and all the equivalent systems) all network charges and general system charges should by applied only to the withdrawn electric energy [1].
The resolution 578/13/R/eel by the AEEGSI clarified all the aspects linked to the connection, the qualification and the regime characterizing the SEU; after the resolution the TSO or the DSO is obliged to connect SEU and ASAP systems to the grid, whereas all the other request related to system not belonging to SSPC cannot be accepted. After the resolution the SEU have been fully recognized like a regulated entity.
The Decree 91/14 has established in particular that the exception recognized to the systems described is:

- for the SEU in operation by December 2014 the 31st, the variable component of the charges A and MCT are applied fully for the withdrawn energy and only for a share equal to 5% for the self-consumed part;
- for the SEU operating after 2014 December the 31st, as above with the difference that the share consisting in the 5% can be updated once every two years by the MiSE with a maximum increase equal to 2,5% of the previous value;
- for the SSP-A (SSPC system subjected to the on spot trading mechanism and consisting in RES plant with a nominal capacity below 20 kW), the variable part of the general charges is applied only to the withdrawn energy and no tariff is foreseen for the self-consumed one;
- for the SSPP-B (SSPC systems subjected to the on spot trading mechanism not belonging to SPP-A), the same regulation used for SEU an SEESEU is applied.

Table 3.3 presents the situation described above in a tabular form [1].

***Table 3.3**: Grid service costs for SSPC.*

<table>
<tr><th rowspan="2">TYPE</th><th colspan="2">network charges</th><th colspan="4">system charges</th></tr>
<tr><th>fixed</th><th>variable</th><th>A+UC fixed</th><th>UC variable</th><th>A variable</th><th>MCT</th></tr>
<tr><td>SSP-A</td><td rowspan="4">paid for each POD</td><td rowspan="4">paid according to the energy withdrawn</td><td rowspan="4">paid for each POD</td><td colspan="3">paid for the energy withdrawn</td></tr>
<tr><td>SSP-B
SEESEU-A
SEESEU-B
SEU</td><td rowspan="2">paid for the energy withdrawn</td><td colspan="2">paid for the energy withdrawn + 5% of the energy self-consumed</td></tr>
<tr><td>SEESEU-C</td><td></td><td></td></tr>
<tr><td>ASAP
ASE</td><td colspan="3">paid for all the energy</td></tr>
</table>

Up to now, as it is not possible to estimate directly the amount of self-consumed energy, the regulation authority with the resolution 609/2014/R/eel has decided to apply, for a transient period starting from January 2015 the 1st, a system of surcharge of the fix component of the general charges in a way that the overall effect is equivalent to that obtained applying the 5% charge on the self-consumed energy as described above. In particular, for the sake of simplicity this surcharge has been applied only to the $A3_{res}$ component.
The application of the surcharge, and the decree that established it, aims at covering the costs resulting from the reduction of the tariff of the MV level users with an available power above 16,5 kW and different from residential and public lighting users. In particular, these users have seen a reduction of the tariff A3 (variable and fix), A4 and UC3 (variable), which are the components directly involved in the decree 91/14.
In particular for the SEU and the SEESEU connected at LV level a surcharge equal to 36 €/year is applied, while for those systems connected at MV level is established by the formula:

$$SURCHARGE\ A3 = POWER\ [kW] * HOURS\ [h] * TAX\ RATE\ \left[\frac{€}{kWh}\right] * \alpha$$

where:

- POWER is the nominal capacity of the plant;
- HOURS is the conventional number of equivalent hours per year differentiated on the basis of the technology considered (for a CHP plant is equal to 7.000 h/y);
- TAX RATE is equal to 2,73 €/MWh;
- α is a conventional parameter estimating the self-consumption, generally equal to 0,5.

The systems classified as ASAP and ASE pay all the charges on the consumed energy.

In addition to the special regulatory system, the SEU and SEESEU systems allow having a complete saving of the selling cost and the variable costs in the bill relative to the energy self-consumed, allowing the installation of power plants in grid parity[1]. The amount of money saved will be higher the higher is the energy self-consumed; indeed the energy in excess will be sold at a price equal to the zonal price in the market, whereas the energy needed will be bought at a price equal to the electricity price in the bill.

[1] The grid parity is intended to be the economic feasibility of an investment relative to a power plant with reference to the cost of the energy paid by the costumer, hence it is associated with plants installed upstream the metering system and providing energy directly to the consumption unit. It is compared with the market parity, as the possibility to have an adequate return of the investment participating directly to the energy market, hence considering as reference price the energy (zonal) price.

Direct support mechanisms for HEC plants consisting in the White Certificates mechanism (described in Chapter 2) and of the benefit of the on spot trading mechanism are also present (only for plant with nominal power lower than 500 kW and only over a limited part of the general system charges). This mechanism consists in a compensation of the energy injected into the grid in order to offset the energy withdrawn from it. This is done recognizing a contribution, which is given back to the producer of energy and owner of the plant, equal to the monetary value of the minimum between the energy injected and withdrawn (valorized at the PUN) plus the monetary value of the services costs correlated to energy exchanged as the minimum between the energy sold and bought.
The resulting formula for the contribution recognized is then:

$$CONTRIBUTION = PUN * \min(E_i; E_w) + SERV.COSTS * E_{exch}$$

3.2 The General System Charges Reform

As described in the previous section, the general system charges, paid in the bill together with the network charges as a part of the grid services, constitute an important part of the electricity cost; hence their structure and application are fundamental factors influencing the worth of any investment in the electric energy generation and in the industrial sector.
Starting with the Dlgs 79/99, and then according to the Ministerial Decree of 26 of January 2000, the AEEGSI, with the deliberation 108/00, introduced a modulation of the general system charges applied to HV and EHV users with a consumption above 8 GWh/month: the modulation consisted in a tariff decreasing with the increase of the consumption.
With its deliberation 163/05, the AEEGSI started a consultation to extend the above graduation system to all the MV, HV and EHV users. This disposition found its application with the following deliberation 348/07, and up to December 2013 all the users cited paid a set of charges decreasing with the consumption increase and going to zero above 8 GWh/month for MV users and 12 GWh/month for HV and EHV users. After the redetermination of the general system charges by the Decree 83/12, a certain tariff, even if reduced, has been introduced also for a consumption above the upper limits.
Since January 2015, according to the Decree 91/14, as explained in the previous section, a reduction of the A3 and A4 components has been introduced for users at LV and MV level with available capacity above 16,5 kW.
In the same context, the measures adopted by Italy in order to protect high consumption industries, with the introduction of the Ae component, have been notified by the EC: because of this, and waiting for the decision by the EC, starting from January 2016 the tax relief for high consumption industries has been deleted and the Ae component has been put equal to zero.
Generally the components of the charges are updated by the AEEGSI every three months and, for what concerns the general system charges, they are applied with a monomial structure (i.e. with a single component expressed in €/kWh). Only the components A2, A3 and A5 have also a component expressed in terms of €/POD. Anyhow, the variable component nowadays covers almost the entire yield.
The recent evolution of the legislation, with the Decree 210/15, disposed a revision of the general system charges and, after the conversion into law (21/16), the final disposition towards the AEEGSI consisted in the requirement to *"adequate, from the 1st of January 2016, all over the national territory, the structure of the tariffs relative to the general system charges, applied to the users different from the residential ones, to the criteria ruling the network charges for the transmission, distribution and metering services, taking care in any case of the different level of voltage and of the connection parameters, beyond the different nature and peculiarities of the system charges with respect to the network charges"* [2].

Considering the amount of actors involved in the required reformation, the Authority started a process of consultation still in place in order to determine the best configuration to be adopted. Under this light, the actuation of the required reformation has been postponed in order to ensure a stable economic framework for all the investments already put in place and that still have to be made.
The consultation has been announced through the deliberation 138/16 and has started with the DCO 255/16. The document defines the limits of the reform and presents the perimeter of its application; in particular different hypothesis of reformation for the general system charges (thus comprehending the components A2, A3, A4, A5, As, MCT, UC4 and UC7 as defined previously) are reported and their consequences are analyzed. Even if the reform does not involve the regulation of high consumption industries, it seems to be useful and necessary that it is developed and put in place together with a general revision of the taxation of the electric energy concerning all the users and all the measures taken within this frame.

3.2.1 Hypothesis for the charges framework

In the context of the 255/16 DCO, the authority defined a set of possible hypothesis in order to reform the general system charges framework according to the requirements of the decree.
In relation to the reformation, the 210/15 establishes that the new framework should be consistent with the one characterizing the network services; at the same time, it is specified that the different peculiarities of the system charges must be taken into consideration.
In particular, the network charges are composed by four different items: TRAS (transmission), DIS (distribution), MIS (metering) and the components UC3 and UC6 as described. These charges are characterized by a trinomial structure resulting from the sum of three components: the energy quota (€/kWh), the power quota (€/kW) and the fixed quota (€/POD). In Figure 3.4 the shape of the network charges for a user at a MV level with an available capacity of 150 kW is reported [3]. Table 3.4 presents the tariffs for the first trimester of 2016: it is possible to see that, while the fixed quota increases with the voltage level, the power and the energy due decreases.

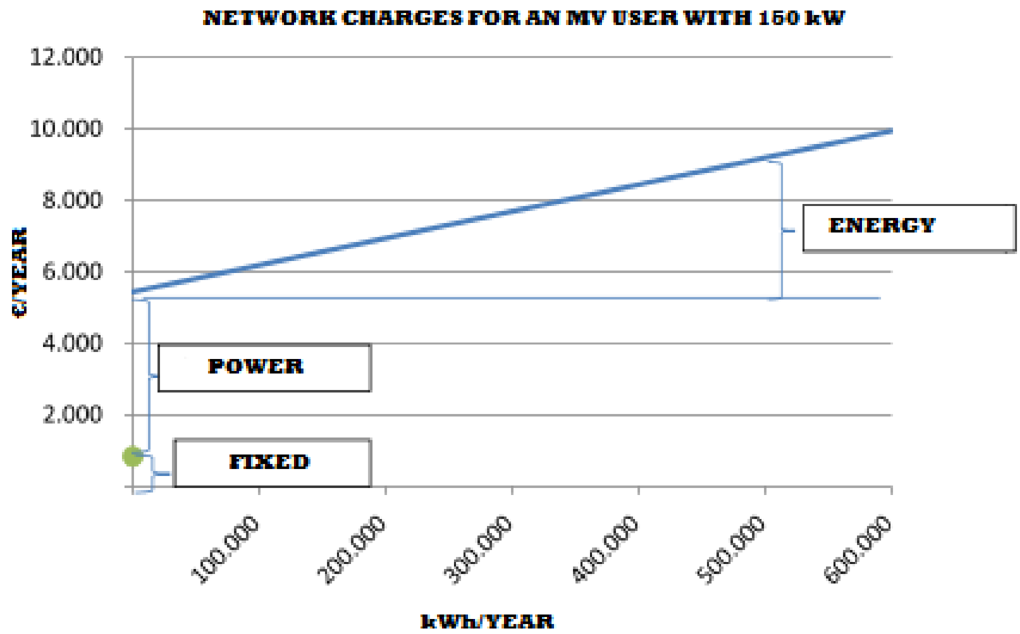

Figure 3.4: Trend of the network charges for a MV user 150 kW capacity.

Table 3.4: Tax rates of network charges.

	NETWORK CHARGES		
USER	c€/POD	c€/kW/YEAR	c€/kWh
BTIP	-	-	2,237
BTA1	2.748,48	3.017,11	0,941
BTA2	2.748,48	2.857,48	0,941
BTA3	2.748,48	3.176,75	0,941
BTA4	2.795,80	3.176,75	0,941
BTA5	2.795,80	3.176,75	0,941
BTA6	2.748,48	3.017,11	0,906
MTIP	-	-	1,465
MTA1	88.595,63	3.411,88	0,757
MTA2	84.106,96	3.063,73	0,751
MTA3	82.740,85	2.687,73	0,744
ALTA	2.099.709,72	1.835,13	0,120
AAT1	2.099.709,72	1.835,13	0,100
AAT2	2.099.709,72	1.835,13	0,100

It is clear that the reference to the structure implemented for the network charges cannot be interpreted as a reference to its adherence to the industrial costs: indeed the system charges represent a tax relief that covers some costs which in principle should be covered by the general taxation, while the network charges are correlated to a proper cost of a service performed by the network operations. Based on this, the reference to the network charges structure is translated in the adoption also for the system charges of a trinomial structure.
The AEEGSI has presented three different hypothesis of reformation which are analyzed below.

- Hyp. A:
  The new general system charges framework reflects in a complete manner the structure adopted for the network charges. This is done by the definition of a coefficient called K_{OG} that is applied to the total expense of a user for the network charges in order to determine the expected general system charges. The coefficient is determined as the ratio between the total yield from the system charges and the total yield from the network charges of the non-domestic users as a whole; this parameter is found to be equal to 2,91 on the basis of the volumes foreseen for the year 2016. In Table 3.5 the expected tariffs are presented.

Table 3.5: Hypothesis A tax rates.

	NEW TARIFFS		
USER	c€/POD	c€/kW/ YEAR	c€/kWh
BTIP	-	-	6,5192
BTA1	8.010,55	8.793,48	2,7426
BTA2	8.010,55	8.328,24	2,7426
BTA3	8.010,55	9.258,76	2,7426
BTA4	8.148,46	9.258,76	2,7426
BTA5	8.148,46	9.258,76	2,7426
BTA6	8.010,55	8.793,48	2,6406
MTIP	-	-	4,2698
MTA1	258.215,36	9.944,05	2,2063
MTA2	245.132,97	8.929,36	2,1888
MTA3	241.151,39	7.833,49	2,1684
ALTA	6.119.684,57	5.348,55	0,3498
AAT1	6.119.684,57	5.348,55	0,2914
AAT2	6.119.684,57	5.348,55	0,2914

- Hyp. B:
  In this case the new framework reflects the network charges structure only in part. In particular, it consists of a part based on a trinomial structure and a part based fully on the amount of energy withdrawn from the grid and uniform among all the users. The result is a set of three possible linear combination of the two framework joined, where each hypothesis is characterized by a different weight of the Hyp. A and the flat hypothesis:

$$B.1 = 0{,}75 * Hyp.A + 0{,}25 * Flat$$
$$B.2 = 0{,}5 * Hyp.A + 0{,}5 * Flat$$
$$B.3 = 0{,}25 * Hyp.A + 0{,}75 * Flat$$

In Table 3.6, 3.7 and 3.8 the expected tax rates for Hyp. B.1, B.2 and B.3 are reported: in this case the weight of the energy component is higher than before and so the structure foreseen reflects only in part the one characterizing the network charges.

***Table 3.6**: Hypothesis B.1.*

	NEW TARIFFS		
USER	c€/POD	c€/kW/YEAR	c€/kWh
BTIP	-	-	6,4235
BTA1	6.007,91	6.595,11	3,5910
BTA2	6.007,91	6.246,17	3,5910
BTA3	6.007,91	6.944,07	3,5910
BTA4	6.111,35	6.944,07	3,5910
BTA5	6.111,35	6.944,07	3,5910
BTA6	6.007,91	6.595,11	3,5145
MTIP	-	-	4,7365
MTA1	193.661,52	7.458,04	3,1888
MTA2	183.849,72	6.697,02	3,1757
MTA3	180.863,53	5.875,12	3,1604
ALTA	4.589.763,43	4.011,41	1,7964
AAT1	4.589.763,43	4.011,41	1,7527
AAT2	4.589.763,43	4.011,41	1,7527

***Table 3.7**: Hypothesis B.2.*

	NEW TARIFFS		
USER	c€/POD	c€/kW/YEAR	c€/kWh
BTIP	-	-	6,3279
BTA1	4.005,28	4.396,74	4,4396
BTA2	4.005,28	4.164,12	4,4396
BTA3	4.005,28	4.629,38	4,4396
BTA4	4.074,24	4.629,38	4,4396
BTA5	4.074,24	4.629,38	4,4396
BTA6	4.005,28	4.396,74	4,3886
MTIP	-	-	5,2032
MTA1	129.107,68	4.972,03	4,1714
MTA2	122.566,48	4.464,68	4,1627
MTA3	120.575,69	3.916,74	4,1526
ALTA	3.059.842,28	2.674,28	3,2432
AAT1	3.059.842,28	2.674,28	3,2140
AAT2	3.059.842,28	2.674,28	3,2140

Table 3.8: Hypothesis B.3.

	NEW TARIFFS		
USER	o€/POD	o€/kW/YEAR	o€/kWh
BTIP	-	-	6,2323
BTA1	2.002,63	2.198,37	5,2881
BTA2	2.002,63	2.082,05	5,2881
BTA3	2.002,63	2.314,69	5,2881
BTA4	2.037,12	2.314,69	5,2881
BTA5	2.037,12	2.314,69	5,2881
BTA6	2.002,63	2.198,37	5,2627
MTIP	-	-	5,6699
MTA1	64.553,84	2.486,01	5,1541
MTA2	61.283,24	2.232,34	5,1497
MTA3	60.287,84	1.958,38	5,1446
ALTA	1.529.921,14	1.337,14	4,6899
AAT1	1.529.921,14	1.337,14	4,6754
AAT2	1.529.921,14	1.337,14	4,6754

- Hyp. C:
  This last hypothesis, even if it is always based on a trinomial structure, is built differently for the charges associated to the component A3res (RES support) and for all the other components. This kind of consideration is suggested by the European discipline about the state help in the energy and environment sectors (2014/C 200/01) and it is considered to be relevant for all the high consumption industries and also for all those subjects that, mainly because of self-consumption such as SEU and SEESEU, don't pay entirely for the system charges on the basis of their consumption. The result of these considerations is a linear combination of the Hyp. B3 applied to the A3res component and of the Hyp. A applied to all the other components:

$$C = [Hyp.A]^{OTHERS} + [Hyp.B.3]^{A3res}$$

In Table 3.9 the expected tax rates are presented.

Table 3.9: Hypothesis C.

	NEW TARIFFS		
USER	o€/POD	o€/kW/YEAR	o€/kWh
BTIP	-	-	6,2910
BTA1	3.231,98	3.547,88	4,7672
BTA2	3.231,98	3.360,16	4,7672
BTA3	3.231,98	3.735,60	4,7672
BTA4	3.287,63	3.735,60	4,7672
BTA5	3.287,63	3.735,60	4,7672
BTA6	3.231,98	3.547,88	4,7261
MTIP	-	-	5,3834
MTA1	104.181,23	4.012,09	4,5509
MTA2	98.902,93	3.602,69	4,5438
MTA3	97.296,49	3.160,55	4,5356
ALTA	2.469.087,32	2.157,96	3,8018
AAT1	2.469.087,32	2.157,96	3,7783
AAT2	2.469.087,32	2.157,96	3,7783

It is worth to remind that, up to year 2016, the component A3res counts for the 96% of the A3 component and for the 86% of the whole system charges, with a trend in constant increase since 2011 because of the strong support policies adopted to promote the development of the RES[2].

As a first result, Table 3.10 reports the different share among all the users types of the system charges resulting from each hypothesis described previously. It is possible to see that Hyp. A shows a much greater redistribution with respect to the actual situation of the overall charges, because of its nature which is completely different from the actual structure and foresees a lower weight of the energy quota (€/kWh).

***Table 3.10**: Origin of the contributions for the system charges.*

	A	B.1	B.2	B.3	C	ACTUAL
PUBLIC LIGHTING	3,12%	3,09%	3,05%	3,02%	3,04%	3,36%
LV NON DOMESTIC USER	55,84%	50,22%	44,59%	38,96%	42,41%	44,92%
MV NON DOMESTIC USER	34,84%	37,63%	40,42%	43,21%	41,50%	42,60%
HV AND EHV USER	6,20%	9,07%	11,94%	14,81%	13,05%	9,12%
TOTALE	100%	100%	100%	100%	100%	100%
WEIGHT OF THE ENERGY DUE OVER THE TOTAL	*34,92%*	*51,19%*	*67,46%*	*83,73%*	*73,74%*	*92,89%*

With reference to the Hyp. A, users that are exploiting their connection power for a greater amount of equivalent hours per year feel less the increase of the charges foreseen by the reform. A further consideration is that the trade off point for the equivalent number of hours per year between an increase or a decrease of the expenses is lower for users connected at higher level of voltages.

According to the above considerations, the result at an aggregated level of the reformation will be: for the Hyp. A shifting of the weight of the charges towards the users connected at medium and low voltage level; the other hypothesis foresee a different share up to an increase of the contribution coming from HV users for the hypothesis B.2, B.3 and C.

3.2.2 Remarks about the reformation and its effects

In Table 3.11 the contribution coming from each component of the system charges and its evolution since 2011 are reported, confirming the statement made previously about the importance of the component A3 and in particular of the component A3res.

[2] In a document released on March 2017 the GSE estimated the expenses for the A3 component in 2017 to be equal to 12,6 G€ due to the conclusion of the Green Certificates iter. This expense is believed to decrease in the future years, after the peak reached in 2016, and to become zero before 2030 [5].

Table 3.11: Evolution of the contributions from the different components of the system charges [Billions of €].

YEAR	A2	A3	A4	A5	As	AE	MCT	UC4	UC7	TOT
2011	255	6.542	345	61	54	-	35	70	110	7.472
2012	151	10.281	295	41	18	-	33	69	236	11.124
2013	167	12.643	448	43	17	-	62	66	191	13.638
2014	323	12.903	435	51	17	799	47	64	114	14.754
2015	622	13.804	248	52	17	689	48	66	250	15.795
2016	587	14.446	247	52	17	-	48	66	600	16.063

As stated before, the nature of the system charges is different from the one of the network charges, and in principle the costs that they represent should be covered by the general taxation; this is not possible due to the macroeconomic context that characterizes Italy up to now.

The three key aspects to manage the system charges are the different parts that compose the trinomial structure described above. The reform shifts the contribution weight from the energy due towards the power and the fixed components. Even if this shift ensures a more secure yield, because it makes the contribution less dependent on the amount of the energy consumed (that is strictly linked to the contingent economic conditions), a too fast change in the way in which system charges are paid can influence negatively some users, which have a withdrawal characteristics different from the average, and some investments choices especially involving RES, HEC and energy efficiency. Moreover, given the large share of the A3res component over the whole charges, it seems reasonable that the major part of the corresponding contribution is related to the amount of energy withdrawn, and specifically to the energy coming from conventional resources.

The AEEGSI in its DCO expressed the will to apply the required reform on the basis of a structure not fully reflecting the network charges framework, such as the Hyp. B or C presented above. In the same document, the Authority defined the main consequences of the foreseen reform.

- The support to the development of RES and of the energy efficiency: it is preferable to choose a solution where the major part of the system charges are associated to the energy because this helps in reducing the payback time of the investments.
- The willingness of the different actors towards the reform: it is preferable to have a solution that increases the overall amount of paid charges for the lower number of users in order for the reform to be accepted.
- The difference with the actual situation: it is preferable to have the minimum variation with respect to the actual framework in order not to influence heavily the business plan of the different technologies involved.
- The importance of the high consumption plant regime: a structure with a high weight on the amount of energy withdrawn will introduce a higher need of compensation in order to reduce the tariff applied to high consumption plant.
- The spread of storage systems: it is necessary to consider that, as the power due increases, the spur for the users to install storage systems increases, with the aim of mitigating the peak withdrawals and so the amount of money to be paid (especially if the maximum capacity is exploited for a reduced number of equivalent hours as stated before).

All these remarks suggest that a good reform should take care of all the different aspects related to the energy policy at a national and European level, considering all the consequences that a possible change in the energy bill structure can have on the different actors involved in the electric energy sector.

3.3 Recent Regulatory Evolution

The Decree 244/16 (Milleproroghe 2016) [4], approved on 30 December 2016, has foreseen:

- to postpone the application of the new tariffs for not-domestic costumers, moving it from the 1st January 2016 to the 1st January 2018;
- to apply, starting from the 1st January 2017, all the variable components of the general system charges to the electric energy withdrawn from the public grid;
- to delete the application of 5% of the general system charges on the self-consumed energy for SEU and SEESEU (and the possibility to increase this percentage), starting from the 1st January 2017, and in a retroactive way since the 1st January 2015;
- to apply the system charges referred to the dismantling of the nuclear power plants to the electric energy withdrawn and not to the one consumed.

These decisions have been suggested by the verification by the EC about the compatibility of the Italian measures concerning the benefits for the high consumption industries; after the verification procedure, it was necessary to define a principle for the application of the system charges uniform for all the costumers connected to the electric network.

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CHAPTER 4

The Italian Energy Market and the Evolution of the Ancillary Services Provision

Because of the diffusion of RES and DG, in the last decade the role of dispatching resources has become more and more important. This occurs together with a general evolution of the energy markets in Italy and in Europe. In this chapter is reported a brief presentation of the actual framework and of its future evolution.

4.1 The Structure and the Working Principles of the Italian Electricity Markets

The Italian Electricity Market (IEM) is managed by the GME (Gestore dei Mercati Energetici) and aims at defining the scheduling for the consumption and production units connected to the electric network [1]. The IEM includes two different types of markets: the OTC (Over The Counter) market (also called Forward market) and the Spot market.

In the OTC market buyers and sellers define their economic and energetic transaction autonomously and independently from the GME; the contracts are subscribed days, months and years before the delivery of the electricity without a transparency mechanism with respect to the operators and without any obliged reference to standardized contracts. The energy transactions resulting from this market are communicated properly to the GME and to the TSO (Terna), and are taken into consideration in order to define the DAM closure [2].

The Spot market is organized in three sub-markets:

- The Day Ahead Market (DAM) where producers, wholesaler and customers that are eligible can buy or sell electric energy for the next day.
- The Intraday Market (IM) that allows to the producers, the wholesalers and the costumers to modify the injection/withdrawn programs.
- The Ancillary Service Market (ASM) where the TSO (Terna) purchases the dispatching resources needed to keep the network under a safe and secure condition. This market is articulated in a scheduling phase (ASM ex-ante) and in a balancing phase (Balancing Market).

The structure of the Italian Electricity Market is represented in Figure 4.1 [3].

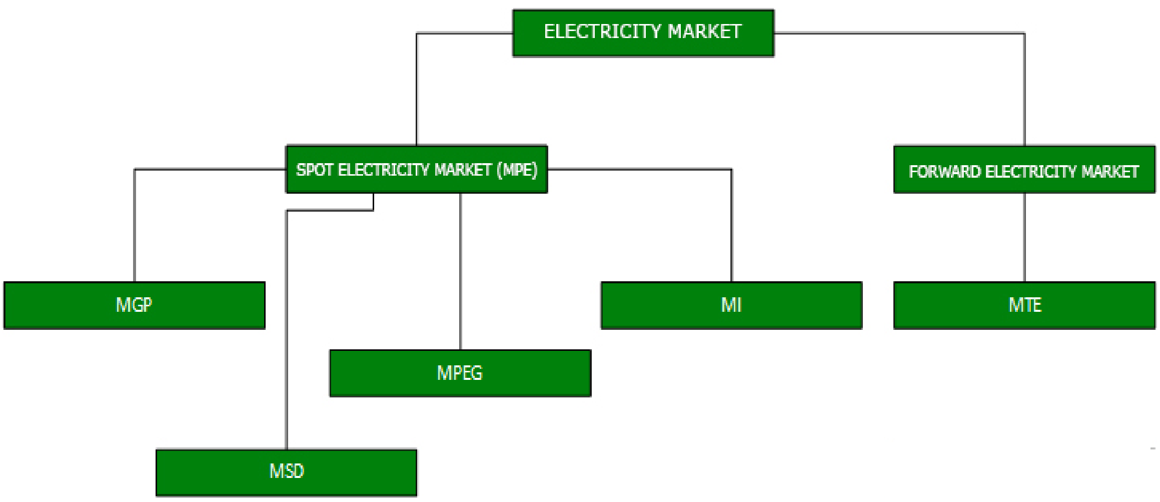

***Figure 4.1**: Structure of the Italian Electricity Market.*

According to the Grid Code, the energy markets are ruled within a zonal framework. The Italian territory is divided in zones and each zone has specific characteristics [4].
A grid zone is considered to be relevant if it is a portion of the transmission network for which a physical limit exists on the exchange of electricity with the adjacent zones, because of some security issues concerning the electric system. These limits are determined by calculation models based on the balance between the generation and the consumption of electricity within the zone.
Figure 4.2 represents the scheme of the relevant zones within the Italian transmission network; a relevant zone can hence correspond to a geographic zone, can be a virtual zone or can coincide with a limited production pole.

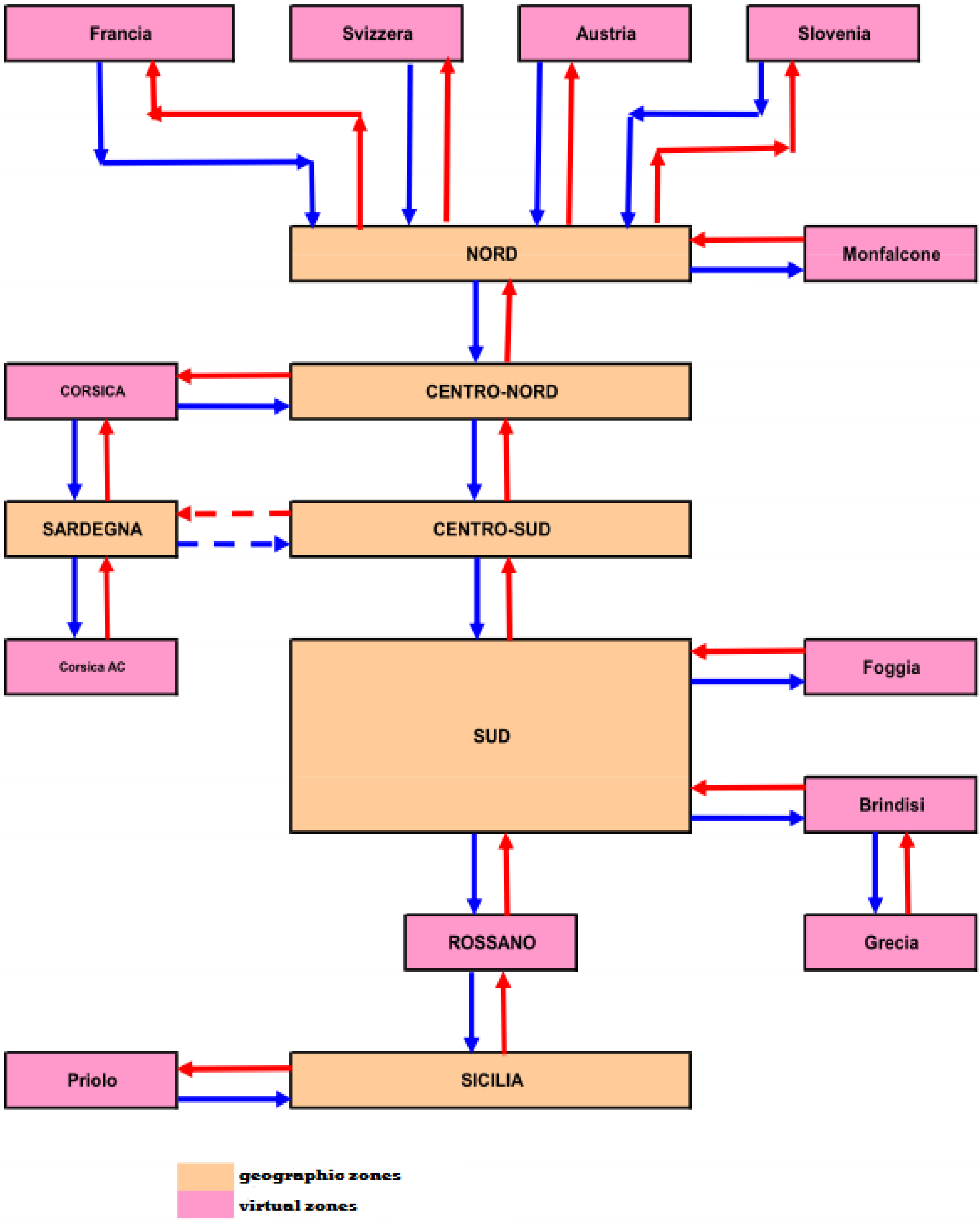

Figure 4.2: Relevant zones of the Italian transmission network.

In particular the individuation of a relevant zone considers the following criteria:

- the amount of electric energy exchanged among adjacent zones must be limited in the standard and more frequent working operations of the network, and must occur in the respect of all the security standards;
- the actuation of the binding programs of injection and the withdrawal of electricity does not cause any relevant congestion within the same zone, also considering the possible variations of these programs;
- the location of the different points where electricity is injected and withdrawn within the network does not influence in any way the capacity of energy exchange between different zones.

The structure of the TN presents a high degree of meshing in the northern zones, and then is characterized by two main corridors along the Adriatic and Thyrrhenic sides.
A section for the transmission of electricity is considered structurally critical if there are possible patterns for the production and consumption of energy within the reference zone that do not allow the free circulation of electricity without security issues, either with all the branches in service or after eventual problems that can put out of service any of them. If the capacity flowing along a given section is greater than the upper limit defined according the rules, the section is said to be operatively critic.

4.1.1 Day-Ahead Market and Intraday Market

It is usual to refer to the DAM and the IM as energy markets, given the final purpose that they have in common.
The DAM is a wholesale market where electric energy is sold and bought in hourly blocks for the next day; through the mechanism connected to this commercialization, the electricity prices, the amount of energy exchanged and the binding programs (injections and the withdrawals) are determined. The DAM is based on an implicit auction mechanism and hosts a large part of the electricity transactions characterizing the Italian market. All the actors with the proper qualification can participate to the DAM, and they deal with a central counterpart represented by the Market Operator, which is the GME.
After the evolution in the DAM structure that followed the market coupling requirements, the DAM nowadays opens at 8:00 of the ninth day before the delivery day, and closes at 12:00 of the day ahead the delivery day. The results of the market closure are presented to the market participants, to the dispatching units and to Terna before 12:55 under the form of the binding and cumulated programs.
The GME collects the offers it receives from buyers and sellers: each offer is characterized by a determined price for a given hour of the day and the corresponding amount of energy that the buyer/seller is ready to buy/sell at that price. The contracts presented in the DAM, differently from the ones of the OTC market, are transparent, meaning that anyone can know the price and the quantity of energy that has been exchanged in a given hour of a day.
The Market Operator collects the bids and builds the market curve as the sum of the single bids. It defines a market curve for the buyers and one for the sellers. Each market curve is built placing the bids characterized by the same price at the same level, and summing for every level all the bids on the basis of the quantity associated to them; this is done starting from the highest prices for the buyers and from the lowest prices for the sellers. The resulting graph represents all the bids presented to the GME with the energy price [€/MWh] on the ordinate and the quantity [MWh/h] on the abscissa.
The precedence system, on which the market closure is built, is based on a principle of economic efficiency: the application of this principle allows determining on the market graph a point, called point of market equilibrium, where the two market curve intersect. All the bids that, on the graph, are found on the left of this point are accepted, the ones that are on the right of this point are rejected. The mechanism described above is represented in Figure 4.3 [2].

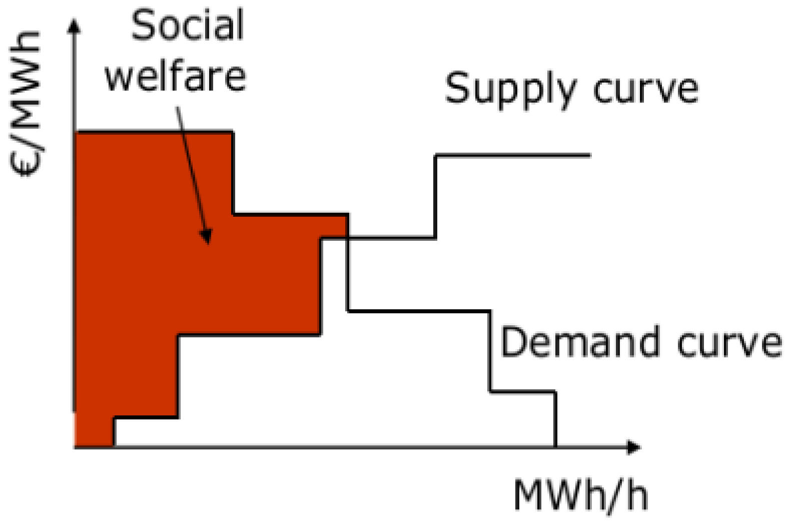

Figure 4.3: Market clearing mechanism for DAM and IM.

The economic efficiency principle applied in the reality meets the need to face possible congestions that are found along the grid. According to this consideration, a market curve is defined for each market zone, and thus an equilibrium price, called zonal price (P_z). All the bids from sellers that have been accepted are valorized at the zonal price, whereas all the bids from buyers are valorized at the PUN, computed as the weighted average of all the zonal prices based on the energy quantity associated to each price. The difference, resulting from this mechanism, between revenues and payments, is called congestion rent, and it is given to the TSO in order to make investments for the improvement of the transmission capacity of the network.

The IM allows to the market participants to make modifications to their binding programs resulting from the DAM through further bids for the selling or the buying of energy according to the information about the operations of the generation plants and the consumption of energy.

Nowadays the IM is organized in seven sessions, opening and closing at different hours and allowing a modification near to the real-time of the binding programs. The mechanism for the market closure of the IM is the same used for the DAM, however in this case all the bids, from both buyers and sellers, are valorized at the zonal price.

The complete scheme reporting the timetable of the opening and the closure of the different markets in the Spot market is presented in Table 4.1.

Table 4.1: *Timetable of the Italian Spot Market.*

	DAM	IM1	IM2	ASM1	BM1	IM3	ASM2	BM2	IM4	ASM3	BM3	IM5	ASM4	BM4	IM6	ASM5	BM5	IM7	ASM6	BM6
REFERENCE DAY	D-1				D															
PRELIMINARY INFORMATIONS	11.30	15.00	16.30	n.d.	n.d.	23.45*	n.d.	n.d.	3.45	n.d.	n.d.	7.45	n.d.	n.d.	11.15	n.d.	n.d.	15.45	n.d.	n.d.
OPENING OF THE SITTING	08.00**	12.55	12.55	12.55	°	17.30*	°	22.30*	17.30*	°	22.30*	17.30*	°	22.30*	17.15*	°	22.30*	17.30*	°	22.30*
CLOSING OF THE SITTING	12.00	15.00	16.30	17.30	°	23.45*	°	3.00	3.45	°	7.00	7.45	°	11.00	11.15	°	15.00	15.45	°	19.00
PROVISIONAL RESULTS	12.42	n.d	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
FINAL RESULTS	12.55	15.30	17.00	21.45	#	0.15	2.15	#	4.15	6.15	#	8.15	10.15	#	14.15	14.15	#	16.15	18.15	#
**:referred to D-9	*:referred to D-1		°:bids from ASM1		#:dispatching activity															

4.1.2 Ancillary Service Market

In order to guarantee a safe and reliable operation of the electric network, the TSO acquires in real time all the data of the conditions of the system and, based on the contingencies, operates on the available resources.

It is possible to distinguish three phases linked to the activity of the TSO:

1. The programming phase, where, according to the activity plan developed, regarding the demand prevision at a national level and the availability of the production, it determines the required level of generation, the grid working operations and the capacity reserve.
2. The real time phase, where it analyzes the electric system, in order to check and regulate the active and reactive power along the grid, and it restores malfunctions controlling the emergencies.
3. The operation analysis phase, where it elaborates the statistics of all the working operations data and collects all the indications for the network optimization analyzing the transmission system.

The TSO gets all the resources for step 1 and 2 in the Ancillary Service Market. In this market it defines all the contracts for the resolution of the congestions, for the creation of capacity reserve, for the real time balancing and all the other required negotiations. All the bids are remunerated on the ASM with the "pay as bid" mechanism.

Up to now the participants to the ASM are the relevant Unit of Production (UP), which are the UP with a capacity above 10 MVA (other requirements which must be fulfilled for each service are described below). Each relevant UP is connected to the grid through a point of delivery and it represents an UdD (Utente di Dispacciamento); similarly all the units not eligible for the ASM and of the same typology are aggregated under a unique UdD for each market zone. If a generic unit does not respect the binding program at which it is subjected, it generates an imbalance and it is called to pay an imbalance fee depending on the nature of the imbalance and on its characteristics. The relevant period on the ASM and for all the units that participate to this market is 15 minutes.

The ASM is divided in an ex-ante or scheduling phase, and in a balancing phase.

In the scheduling phase all the bids to buy or to sell are selected for the relevant periods of the next day; the TSO accepts the bids in order to provide the capacity for the reserve and to solve the congestions remaining along the network.

In the balancing phase the TSO selects the bids to buy and to sell for the secondary reserve and the real time balancing.

The time schedule of the Spot Market is reported graphically in Figure 4.4 [2].

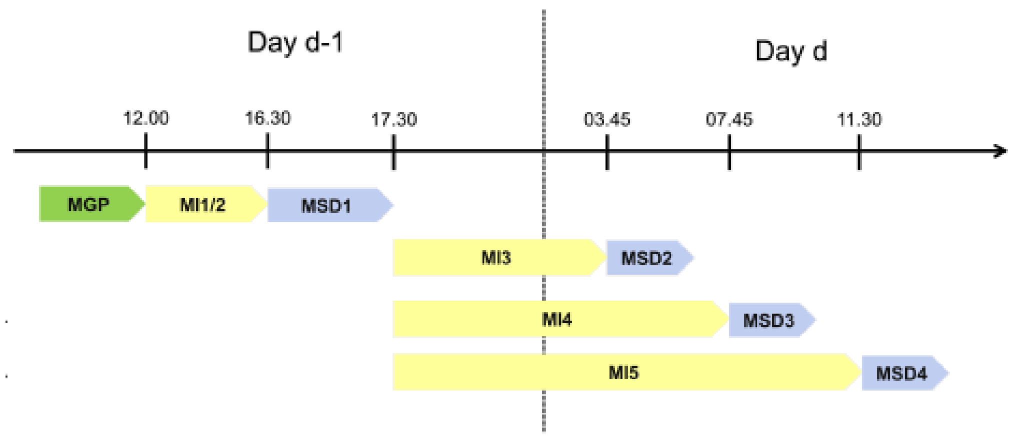

***Figure 4.4**: Schedule of the Spot Market.*

4.1.3 Resources for dispatching

The activity performed by the TSO is fundamental because it guarantees a high and constant level in the quality of the service provided. In its Grid Code Terna defines all the requirements and the characteristics that the plants admitted to the ASM, and providing an ancillary service, must fulfill [5]. Some services are mandatory and thus are provided in an automatic way without any remuneration; others are purchased by Terna on the ASM and are provided by the different units only after a dispatching order sent by the TSO [6]. The resources that Terna can exploit for its dispatching activity are presented below; in order to be available for the actual provision of these services, the production and consumption units must receive a qualification, guaranteeing that they fulfill all the requirements [7] (the UP are usually remunerated in €/MWh with the exception of some services specified next and remunerated with a token).

➢ Resources for solving congestion during the planning phase.

The TSO exploits the resources available during the planning phase in order to solve the congestions that are generated along the network by the cumulative programs of injection and withdrawn resulting from the DAM. The units are available to accept changes to their cumulative programs increasing or decreasing their production.
The relevant UP enabled for the service are:

- connected to the transmission grid,
- not belonging to the non-programmable category and not subjected to a trial phase or unavailable to modulate effectively their power;
- able to vary their production by at least 10 MW within 15 minutes from the beginning of the modulation;
- concerning hydropower plants, able to supply the maximum power for at least 4 hours during a day.

The UdD of the relevant UP must make completely available the residual margins with respect to the maximum and minimum power to the TSO, must communicate to the TSO any change in its working operations and must submit an offer to the ASM.

➢ Frequency containment reserve (FCR).

The FCR service (also called primary reserve) consists in guaranteeing continuously a capacity band, that can be activated by an automatic controller that gives the possibility to modulate the power injected by the production unit, increasing or decreasing it, when the grid shows a frequency variation. The FCR service involves the entire interconnected European network and it is performed by all the generators connected to the grid simultaneously. In order for this service to be effective, it is thus necessary that the primary reserve is continuously available and distributed along the grid as uniformly as possible.
The UP eligible for the primary control are all the units with a capacity above 10 MVA, with the exception of the non programmable units or those that cannot modulate their power.
The primary reserve aims at stabilizing the frequency but does not restore its set-point value.
In order to ensure the constant possibility to keep the system secure and to face frequency variations, the following capacity bands must be ensured:

- In Sardinia (and Sicily when not connected to the continental region), the UdD must make available a regulation band not lower than $\pm$ 10% of the efficient power (P_e) of each UP.
- In the other zones, the UdD must make available a regulation band not lower than $\pm$ 1,5% of the efficient power of each UP.

The UP providing a primary control service must be equipped with a speed regulator that guarantees the activation of the primary reserve when the frequency falls outside the range of ± 0,2 Hz with respect to the reference value of 50 Hz.
Each UP must supply at least 50% of the required power reserve within 15s, and within 30s all the primary reserve must be supplied. After 30s, if the frequency variation persists, all the UP must continue to provide power, increasing or decreasing their injection, unless they have reached their upper or lower limit. The power supplied by each UP must be guaranteed at a constant and stable level for at least 15 minutes from the beginning of the frequency variation.
The FCR is a mandatory service, automatic and not remunerated by the TSO through the ASM.

➢ Frequency restoration reserve (FRR)

In order to restore the power balance between the withdrawal and the injection of energy into the national grid it is necessary to activate the FRR, also called secondary reserve.
The FRR service consists in making available, during the scheduling phase and in real time, the secondary reserve band within the updated binding programs, and in making available, during the real time phase, the secondary reserve band for an automatic controller that can modulate the injection of power on the basis of a signal that it receives from the TSO.
The UP providing a FRR are equipped with a device able to receive signals from the TSO and to elaborate them; moreover these units must make available for the secondary control service a capacity band equal at least to ± 15% of the maximum power for hydroelectric units, and at least equal to ± 10MW/± 6% of the maximum power for thermoelectric units.
The secondary control is performed through a speed regulator placed onto the UP; this device receives and elaborates a signal, called Regulation Level, sent automatically at a central level, by the Grid Regulator. The GR defines a signal in order to compensate the frequency and power mismatches along the network.
Terna purchases the secondary reserve on the ASM selecting the bids related to the Secondary Reserve (RS) service. After the planning phase the TSO defines the reserved capacity according to the conditions of the network and to its needs; then, during the BM, it accepts in real time the bids needed and remunerates the UP providing the secondary control service. Hence, it is important to underline that the remunerated service is not the reservation of the capacity, but it is the actual use by the TSO of the secondary reserve in real time.

➢ Replacement reserve (RR)

The TSO in order to ensure the proper reserve margin defines a RR, also called tertiary reserve. This reserve is defined during the planning and the real time phases, and is activated both in ex-ante and during the balancing phase through some dispatching orders, and not through an automatic regulation such as in the case of the primary reserve (local regulator) and of the secondary reserve (grid regulator).
The RR service consists in the willingness to increase or reduce the amount of power injected from the network. In particular, it is possible to define two different type of tertiary reserve:

- Fast Reserve, if the modulation of power can be accomplished within 15 minutes from the request; this reserve aims at re-establishing the secondary reserve according to the ENTSO-E requirements and to face rapid variations of the frequency with a good speed and continuity.
- Substitution Reserve, if the modulation of power can occur within 120 minutes form the request, and can be sustained with no duration limits; this reserve aims at re-establishing the tertiary reserve when a change in the cumulative programs of some units occurs.

All the UP eligible for the tertiary reserve provision must be able to start the power modulation within 5 minutes from the receiving of the dispatching order, to provide a power variation of at least 10 MW within 15 minutes and, for the hydroelectric plants, to supply the maximum power for at least 4 hours during a day. Moreover, for the Fast Reserve service provision, it is required to have the possibility to modulate the power with a gradient equal to 50 MW/min and to have a required time, for the working conditions change, lower than 1 hour.

Such as the secondary band, the tertiary band is reserved during the planning and real time phases; if it is required, it is then accepted and mainly remunerated during the balancing phase (actually it is remunerated directly the reservation of power if there is no margin available with respect to P_{MAX} or P_{min}, and hence it must be created). The tertiary reserve bids are characterized by 'step bids', meaning that the UP offers its availability to change its injection through some steps 'up' or 'down' with respect to its programmed power.

In Figure 4.5 the timetable for the activation of the primary, secondary and tertiary reserve for the frequency containment is reported.

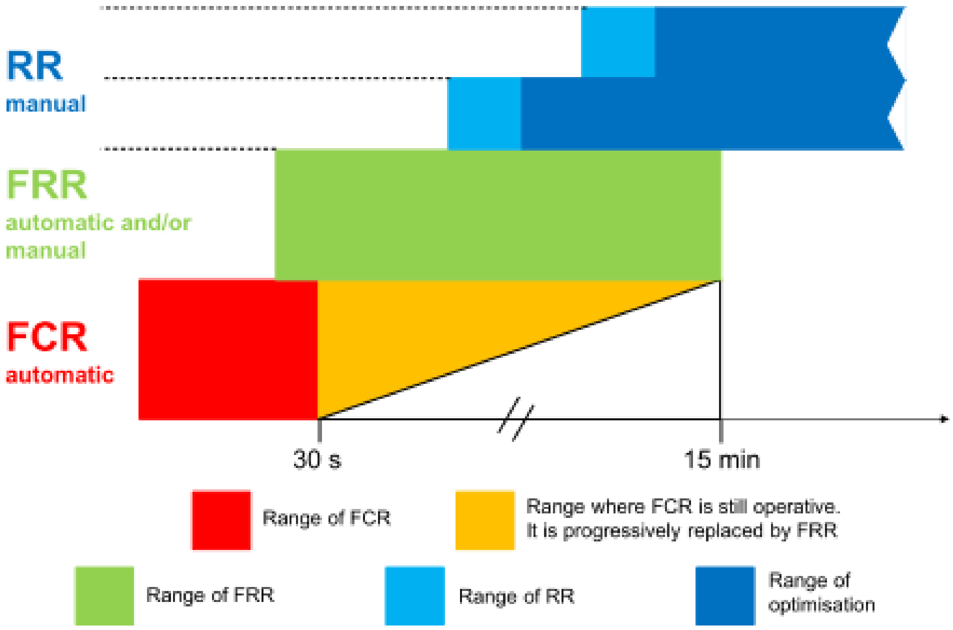

Figure 4.5*: Active power reserve activation scheme.*

➢ Resources for balancing.

In order to guarantee the balance between injection and withdrawal of electricity, to solve the congestions and to restore the FRR margin, the TSO uses real time balancing resources. They consist in the activation of the tertiary reserve and in the acceptance in real time of the bids presented on the ASM by units enabled for the balancing.

The UP has to install in its control point a hardware and software tool which can receive dispatching orders form the TSO.

With respect to the tertiary control, the UPs qualified as balancing resources are required to provide a variation of at least 3 MW of their power within 15 minutes: this is less restrictive than the requirements foreseen for the tertiary control, thus the balancing reserve entails a further amount of resources that can be exploited by the TSO with respect to the tertiary control.

The TSO purchases the balancing service on the ASM with the same mechanism used of the tertiary reserve.

- Interruptible load service.

The TSO uses the interruptible load service when the resources supplied on the ASM are not sufficient to maintain the security of the grid. This service concerns the passive users connected to the network and consists in the availability, from these users, to interrupt their withdrawal thanks to a Periferic Unit for the Load Shedding on the basis of a signal sent from the TSO in real time (<200 ms), in emergency (<5 s) or in postponed way (<15 min).

- Regulation of the reactive power.

The reactive power regulation service is used to control the voltage level along the network.
Such as the active power regulation, also the reactive power regulation is divided into a primary and a secondary reserve.
The primary reserve consists in the simple regulation of the voltage characterizing each generation group through an Automatic Voltage Regulator set up manually; usually two values are provided by the TSO: a value of the voltage during peak load hours, and a value during base load hours. The primary reserve is a mandatory service and it is not remunerated by the TSO.
The secondary reserve is supplied through the installation of an Autonomous System for the Reactive Power and Voltage Regulation and of a telecommunication system able to exchange signals with a Regional Voltage Regulator. The RVR acts on the different levels of the network in order to keep the voltage level at the value required and determined by the TSO through a national voltage level plan. Also the secondary reserve is a mandatory service and it is not remunerated on the ASM.

- Load rejection.

The load rejection service consists in the availability, for a generation unit, to remain in stable working conditions after the disconnection of the generation unit from the network. All the UdD, limited to the thermoelectric UPs with generation units characterized by a capacity higher than 100 MW, must be available to provide the service of load rejection.

- Recovery of the network.

The participation to the network recovery consists in the availability of a generation unit to participate to the actuation of a predefined operation plan of the electric network that is coordinated by the TSO. To do so, it is required for the generation unit to be able to perform a starting without any external supply of energy (black start capability) with a proper frequency and voltage regulation, and to perform a load rejection and remain in service, supplying only its auxiliaries, for a time of at least 12 hours.
This service is mandatory for the users participating to the ASM with reference to the Annex 10 of the Grid Code.

- Use of the intertripping system.

The availability to use the intertripping system (called telescatto) consists in the availability to be subjected to the control of a device that, according to some specific events and conditions verified onto the network or to some orders sent by the TSO, can disconnect the UP from the grid.

4.1.4 Provision of dispatching services

As described above, the provision of the dispatching services that are not mandatory is purchased by the TSO through the ASM within the two phases of scheduling and balancing. In particular, these resources consist in the resolution of the congestions, the secondary reserve, the tertiary reserve and the balancing capacity: they are purchased on the ASM thanks to some selected bids presented by the enable UP.

The offers presented can be:

- Offers to buy (or sell) energy for the Secondary Reserve (RS), relative to the decreasing (or increasing) of the power injected into the network.
- Offers to buy (or sell) energy for the Other Services (OS), relative to the decreasing (or increasing) of the power injected into the network.
- Minimum Offer (MO) in order to increase the injection, with respect to the cumulative program exiting from the IM, up to the minimum power.
- Shut-Down Offer (SDO) in order to decrease the injection, with respect to the minimum between the cumulative program result and the minimum power, down to zero.
- Start-Up Offer (SUO) in order to be remunerated for all the start-up operations referred to the ancillary service provision which are in excess with respect to the number of start up operations resulting from the other Spot Markets; the units that can present this type of offer are only thermoelectric.
- Configuration Change Offer (CCO) in order to be remunerated for all the configuration change operations referred to the ancillary service provision that are in excess with respect to the number of configuration change operations resulting from the other Spot Markets. The units that can present this type of offer are only the repowered or the combined cycle thermoelectric units.

In Table 4.2 all the foreseen bids are reported and their remuneration mechanism is specified.

***Table 4.2**: Bid type and its remuneration mechanism per technology.*

TECHNOLOGY	**BID**	
	Remunerated per MWh	**Remunerated through a token**
THERMOELECTRIC		
CCGT	RS and OS (up or down) MO and SDO	SUO and CCO
OCGT		SUO
Coal Plant		SUO
HYDROELECTRIC		
Production and PHES	RS and OS (up or down)	-
Others	RS and OS (up or down) MO and SDO	-

In order to perform all the activities foreseen in the ASM, Terna considers the data reported below.

- The forecast of the electricity demand, defined for each geographic zone and in the period of time before the given hour. The demand forecast is elaborated as the sum of a base forecast plus a correction: the base forecast is the result of the analysis of the demand of a certain number of days taken as models, corrected considering the demand of the days before the given day and that of the days before the model days, from which a correction factor is computed. Then the base forecast is corrected through a correction factor computed considering the meteorological conditions of the given day and the days before it, and comparing them to the meteorological conditions of the model days and of the days before them.
- The forecast of the production from renewable energy sources that are not programmable, particularly the wind production, defined for each zone and period. This is done considering the meteorological forecast regarding the wind and the temperature.
- The forecast of the production from the non-relevant UP not programmable, defined for each zone and period, taken in consideration the forecast elaborated by the GSE.

- The evaluation of the amount of secondary reserve needed. This is determined on the basis of the ENTSO-E policy, taking care of the interconnection among the continental zones, Sardinia and Sicily. It is defined for each zone and period.
- The evaluation of the amount of tertiary reserve needed, defined for each zone or at an aggregated level.
- The technical data of the UP in the UP register, in particular considering the variations and the communications that can cause the unavailability from the UdD, in the limits imposed by the Grid Code.
- The results of the energy markets.
- The valid bids in the scheduling phase.

The bids that every UP presents on the ASM must be composed as follows.

- A price for the Secondary Reserve in €/MWh, for what concerns an increase of the injected power (p^{+}_{RS}).
- A price for the Secondary Reserve in €/MWh, for what concerns a decrease of the injected power (p^{-}_{RS}).
- One up to three (four in the MB) couples of price, in €/MWh, and quantity, in MWh, for the Other Services provision, both in term of an increase and of a decrease of the injected power (Q^{+}_{1}, Q^{+}_{2}, Q^{+}_{3}; p^{+}_{1}, p^{+}_{2}, p^{+}_{3}) (Q^{-}_{1}, Q^{-}_{2}, Q^{-}_{3}; p^{-}_{1}, p^{-}_{2}, p^{-}_{3}).
- An offer for the Minimum service in €/MWh.
- An offer for the Shut-Down service in €/MWh.
- An offer for the Start-Up service in €/MWh.
- An offer for the Configuration Change service in €/MWh.

In the following Figure 4.6, Figure 4.7 and Figure 4.8 three different situations of bid structure are reported, according to the type of bid presented and to the situation resulting from the IM.

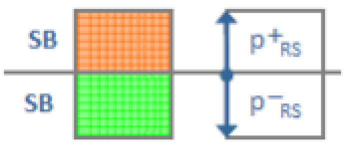

***Figure 4.6**: Structure of a single bid for RS service.*

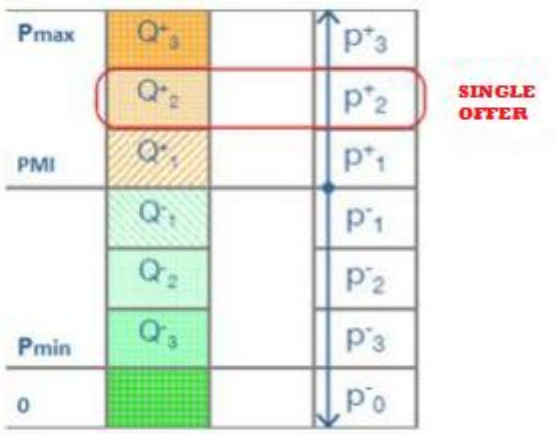

***Figure 4.7:** Structure of an OS offer.*

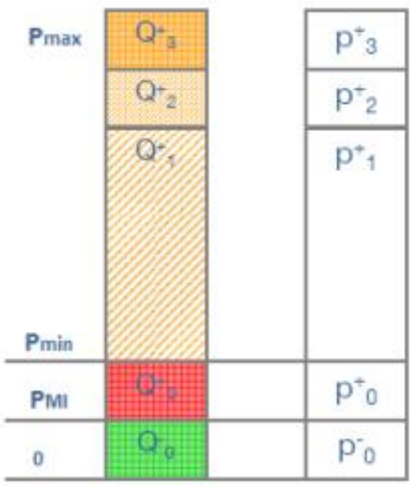

***Figure 4.8**: Structure of an offer from a plant not in service after IM.*

It is necessary to consider, for what concerns the bids presented onto the ASM, that the following requirements have to be fulfilled:

- the prices for the offers to sell must be higher than the prices for the offers to buy;
- the price of the Minimum offer must be lower than the price of each offer to buy;
- the price for the Start-Up must be lower than a cap value defined according to specific features related to the plant technology and the average prices found on the market;
- the price for the Configuration Change must be lower than a cap value defined according to specific features related to the plant technology and the average prices found on the market.

In Figure 4.9 the considerations relative to the limitations above are reported in a graphic form.

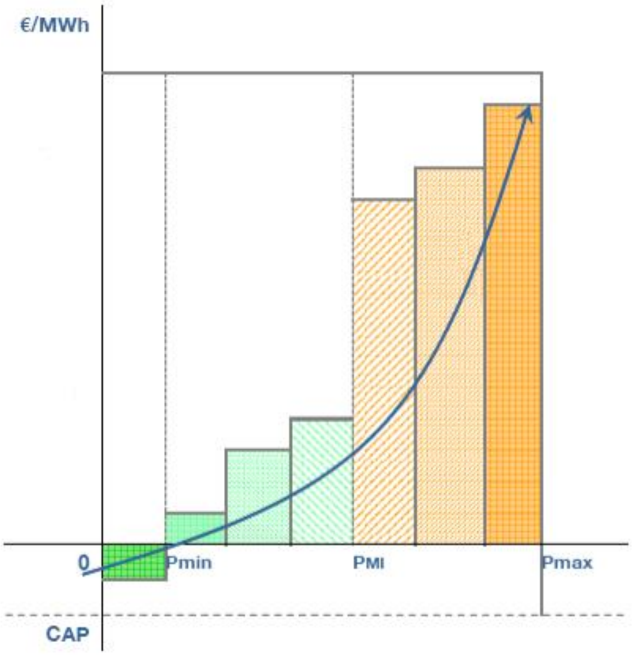

Figure 4.9*: Valid framework for the bid structure on the ASM.*

For each phase of the ASM, the TSO selects and accepts the valid bids according to a principle of economic efficiency, thus minimizing the costs of the dispatching activity. This consists in considering both the costs in the ex-ante and in the real-time phase, taking care of the working operations (and hence of the available services) of each units. Moreover, beyond the application of the principle of economic efficiency, the TSO can purchase the dispatching services from the different units according to the network security needs, which are linked to the grid congestions and to the units dislocation on the territory.

All the accepted bids are valued at the bid price, according to the pay as bid mechanism, with the exception of the revocation and netting procedures. All the bids reserved during the programming phase are remunerated only during the real time phase and only if they are activated. Moreover the reserved bids are called to present new bids that can be only ameliorative with respect to the reserved one.The results of each ASM phase are considered as definitive for the periods (thus the hours) that are no more involved in other ASM phases, whereas are considered preliminary if the above periods are involved in further ASM phases.

The overall procedure defining the ASM leads to the definition for each production unit of a program which is called “modified and corrected”; this program corresponds to the binding program (called PMI) resulting from the DAM and the IM, modified if necessary during the scheduling phase and then corrected if necessary during the real time phase.

All the UdD have the right and the duty to respect the program and accomplish all the operations required by the TSO, respecting the prescriptions of the Grid Code; if some energy in excess or in deficiency is exchanged, it constituteS an imbalance and is subjected to an imbalance fee through a mechanism that is not the object of this dissertation.
The sequence leading to the binding program modified and corrected is reported in Figure 4.10.

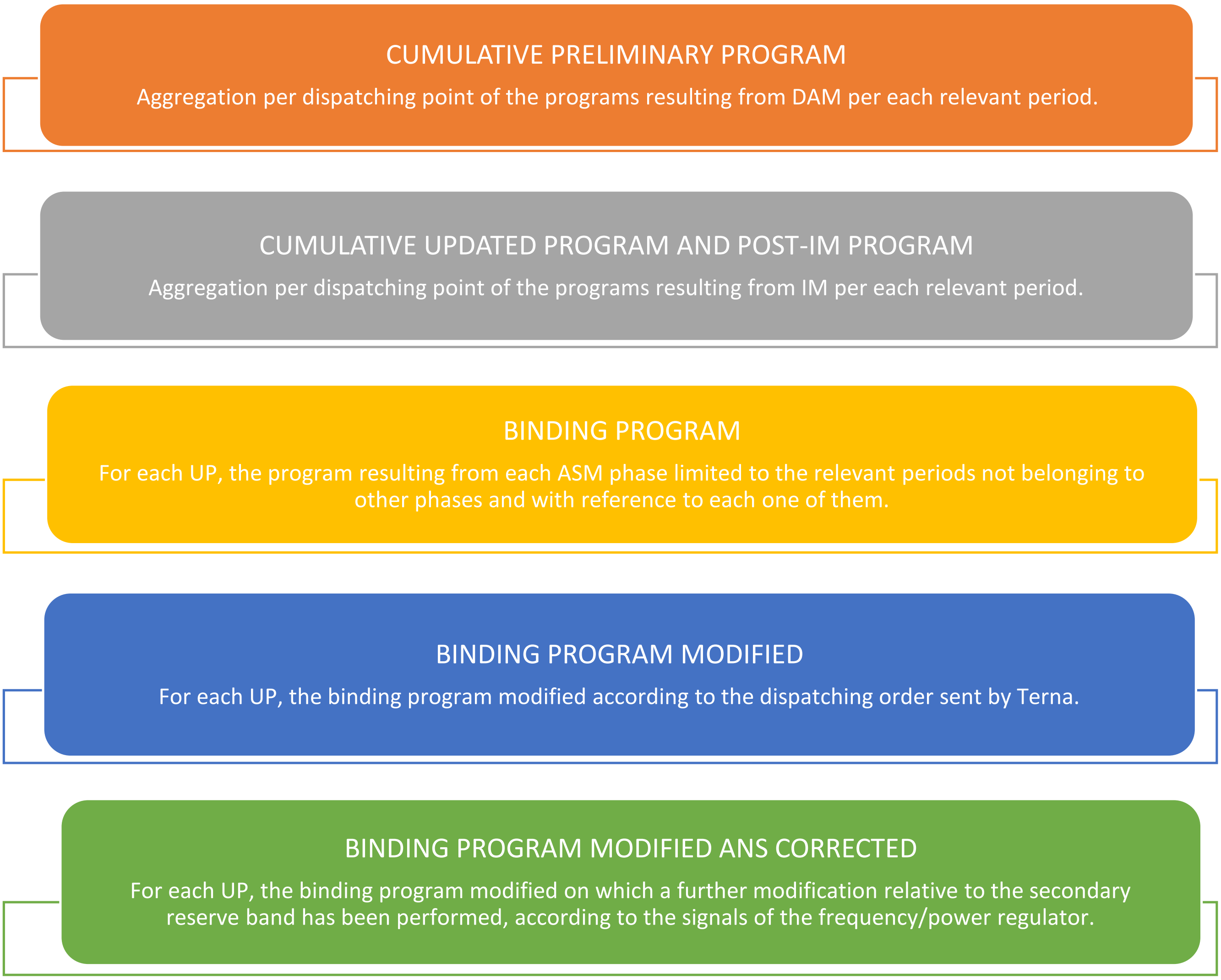

***Figure 4.10**: Development of the binding program relative to a UP.*

The recent widespread of not-programmable RES had some important consequences on the market activity; in particular, concerning the ancillary services provision:

- the volumes needed on ASM and BM were greater, due to the increased RES production (higher need of secondary and tertiary reserve), and to the necessity to operate a system with low demand and high renewable production during summer;
- the number of start-up orders was higher, because the reduction in the residual demand[3] makes the procurement of the reserve margins more complex and expensive;

[3] Portion of the load which is satisfied by thermoelectric UP.

- the use of the secondary and tertiary reserve was different and characterized by the requirements of fast time response and high modulation capacity for the called UP, because of the ramps introduced by the PV production.

4.2 The Reform of the Ancillary Services Provision

The rapid development of RES, especially non programmable ones such as PV and wind, imposes an evolution of the regulatory framework so that these plants can be hosted properly in the electric network. The eventual regulation must take care of the fact that a large part of the RES development is associated to systems connected at a medium and low voltage level (nowadays almost 30 GW [2]); moreover it is necessary to consider that ENTSO-E evaluates a fault involving the disconnection of a capacity greater than 3 GW as a relevant fault, that can have an important impact on the security of the grid.
Because of these considerations, there is a complex regulatory reform that the authority is carrying on; it aims at modifying the way the grid has been managed until today. Indeed, while the transmission grid, especially in Italy, is already developed and can be considered as a smart grid, it is necessary to implement technologies, also at a distribution level, that will allow managing the high level of generation hosted and ensuring the correct values of voltage and current, and in general a safe operation of the network.
The AEEGSI has promoted the use by DSOs of smart devices in the context of pilot projects in order to push the diffusion of these technologies at a distribution level also on a massive scale. However it is required that also the actors, thus loads and generators, connected to the grid contribute to the efficient and secure management of the system. Hence, the target is promoting the effective integration of DG into the electric system through: on one side the innovation in the management of the network and of the plants, meaning the reformation of the ancillary services provision; on the other side the promotion of the infrastructures development.

The regulatory evolution concerning the DG plants and the ASM, and aiming at increasing the quality of the service even in a situation with a high level of RES penetration, follows the European targets for what concerns the RES development and the reduction in the emissions level. Up to now the most important steps made in this direction by the authority are:

- The Deliberation 84/2012/R/eel, that defined the characteristics of the inverters and of the IPS (Interface Protection Systems) to be connected at medium and low voltage level.
- The Deliberation 243/2013/R/eel, that defined the timeline and the bureaucratic framework for the retrofit of plants connected at LV level with capacity above 6 kW and plants connected at MV level with capacity above 50 kW, according to the Grid Code Annex 70.
- The Deliberation 281/202/R/efr, that defined the imbalance fees for the not programmable RES plants in order to promote a better forecast of the energy injected into the grid.
- The Deliberation 344/202/R/eel, for the approval of the RIGEDI (RIduzione della GEnerazione DIstribuita in condizioni di emergenza del sistema elettrico nazionale) procedure.

The above activity followed the Deliberation ARG/elt 160/11 that aimed at performing a general revision of the ancillary services provision. In this context the authority has published the DCO 354/13 for the beginning of the discussion regarding a first introduction of the DG and the RES plants into the ASM. The DCO is based on a study carried out by the Department of Energy of Poltecnico di Milano and its specifications are presented in the next sections.

4.2.1 Opportunities for the CHP plants in the actual market context

Even if, looking at the possible energy framework for the future, the presence of conventional thermoelectric plants seems to be less and less important, the CHP plants connected at the distribution level are judged a key technology because of all the reasons described in the previous chapters. In particular, all the CHP systems with a capacity below 10 MVA that nowadays cannot participate to the ASM would be able to provide the same ancillary services as the enabled units, thus helping the electric system. The combined introduction of RES connected at the transmission grid and of the DG into the ASM will increase a lot the amount of resources available to control the system. The Grid Code, the CEI 0-16 and CEI 0-21[4] already impose to these plants to vary their reactive power injection, according to their capability curves and to different modulation algorithms. However this does not entail any advantage for the generation units because these services are not remunerated; because of this, and considering that in the future the provision of mandatory services will remain not remunerated, it is not worth to consider all the services that do not carry any advantage from the economic point of view for the plant.
Instead, it is worth to understand the possibilities of the DG plants for the provision of power and frequency regulation services (such as secondary, tertiary and balancing reserve) that are remunerated [8].
The CHP plants are often characterized by a high level of flexibility in their working operations, even if it is necessary to consider that the partial load operations can increase the need of maintenance and reduce the useful life of the system. Moreover certain solutions are characterized by a huge reduction in terms of efficiency when working at partial load. A further consideration is that always these plants are installed in order to provide both electric and thermal energy to a user; being this user characterized by a specific demand of heat and electricity, the possibility to modulate the plant to participate to the ASM can be limited and can have important consequences on the operating plans made during the investment evaluation. Therefore, it is possible to say that CHP plants connected at the distribution level are concerned by some limits that are not regarding the usual thermoelectric plants. However, if it is justified from an economic point of view, there are several solutions that can overcome the problem linked to the local demand, such as the use of back-up boilers, which are nowadays already present for emergency situations.

4.2.2 New Market Models

As DG is not under the direct control of the TSO, but it is managed by the DSOs, it is necessary to define new models for the management of the ancillary services towards a more local framework. At least at the beginning, the participation to the ASM could be free, giving the possibility to perform an economic evaluation and to develop a better awareness of the new situation of all the actors involved. In particular, it is required that the market provides the proper price signals, giving a value to each service and avoiding tools that can cause a distortion of the free market: it is the market that chooses which plant is the most suitable, in a technology-neutral frame. Only certain externalities, that do not find a valorization on the market, could be remunerated, such as the environmental impact of each technology.
Given the above considerations, the three different market models that are proposed in the DCO 354/2013/R/eel are [9] [8]:

[4] CEI 0-16 and 0-21 are National Standard issued by the CEI under the approval of AEEGSI: they decline the prescriptions and the technical rules for the connection of power plants at MV and LV level.

➢ Extended Central Dispatching.

In this model, the market continues to be managed with the actual mechanism, enabling the new UdD to provide ancillary services according to the actual framework. In this case the TSO can purchase both during the planning phase and during the real time phase the resources it needs for what concerns the electric system as a whole; the contribution of the DG services for problems at a local level is not possible.

The DG and the RES plants can participate to the ASM thanks to an aggregator, which is a trader that acts as an UdD managing an adequate amount of generation capacity and that, on the basis of the data communicated by the generators, presents offers on the ASM.

This solution can be accompanied by two different ways to manage the distribution grid: the fit&forget logic, where the capacity of the distribution grid is increased so much that there is no way that new plants can cause any problem to the network; the smart logic, where the DSO can, when the security of the network is compromised, stop the injection of power and prevent a plant to participate to the ASM.

According to the fit&forget approach currently in place, the DG could provide ancillary services directly in the ASM and through an aggregator without any technical problem: the grid will be able to host all the capacity that has been offered in the ASM.

According instead to a smart approach, in order to guarantee a proper operation of the grid, the DSO should ensure some local services that will be needed. As these services are correlated with local problems, characterizing a specific point of the network, only the few units near this point can ensure their provision, whereas the TSO is managing a system equilibrium and thus can purchase services all over the network.

In this situation the DSO should verify the security of the grid during the planning phase and in real time, defining the compatibility of the participation of the DG to the ASM. This control by the DSO will be operated at the primary substations level, with the possibility for the DSO to directly use the DG in order to solve local issues.

The scheme for this first model is reported in Figure 4.11.

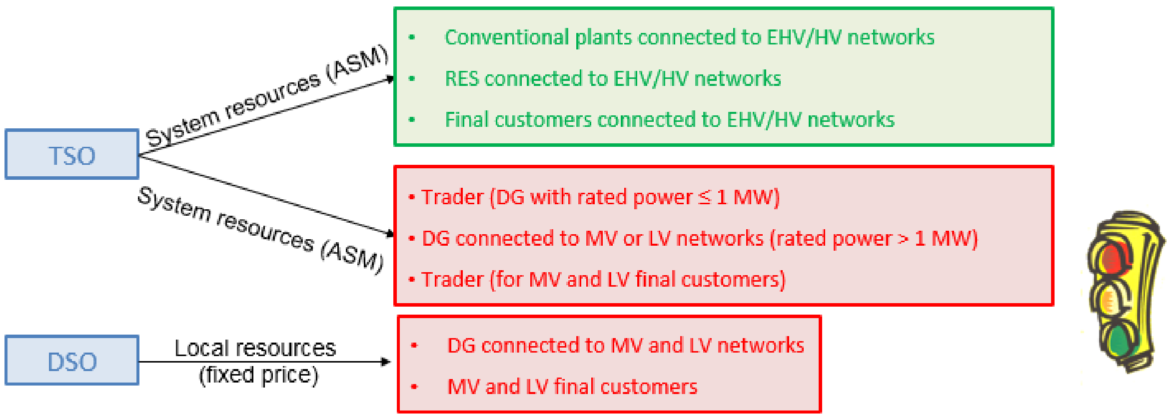

Figure 4.11: *Functional scheme for the Model 1.*

➢ Local Dispatch by the DSO.

In this model both local and system services can be offered on the ASM; moreover this solution can be implemented only with a smart approach towards the development of the distribution grid.

The TSO can purchase the ancillary services directly from the plants connected at the transmission grid or from the DSOs; the DSO becomes hence a UdD and can identify and select the proper plants at distribution level in order to provide the required services.

This can occur through a D-ASM (Distribution ASM) where it acts like Terna in the ASM. The plants can participate to this market as single units or in an aggregated form.
The DSO purchases on the D-ASM some resources and makes them available at the primary substations level; the TSO can hence purchase on the ASM the services from a single primary substation (nodal dispatching) or from a set of primary substations (zonal dispatching).
It is important to underline that, in this configuration, the DSO can buy on the D-ASM also those services which are needed at a local level, without presenting them to the TSO at the PS level. In this case the DSO could remunerate the local services on the market, but if they concern a specific point of the network (and can be solved only by certain units) it could remunerate these resources through an administrative price.
In Figure 4.12 the scheme for this second model is presented.

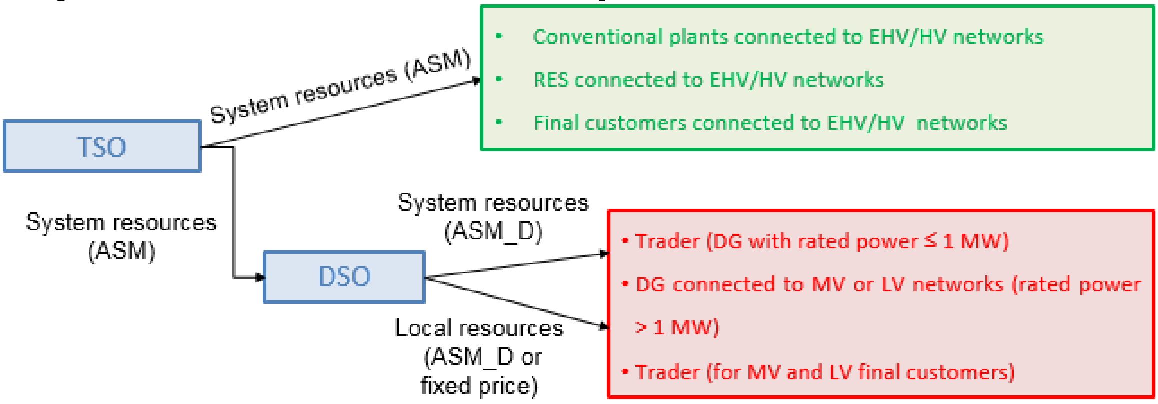

Figure 4.12: Functional scheme for the Model 2.

➢ Scheduled Program at HV/MV Interface.

In this last model the DSO is responsible towards the TSO for maintaining of a programmed profile for the energy exchanged at the PS level, both in the nodal and in the zonal form. The DSO, however, does not provide any service on the ASM which can be useful for the system management.
This kind of configuration leads to a lower impact of the variability introduced by the load and the generation connected at the distribution level, meaning that the amount of reserve and balancing capacity required to the TSO is reduced.
In order to fulfill the requirements at the PS interface, the DSO can select the proper resources on a D-ASM as for Model 2, and the plants can participate to the D-ASM market as single units or in an aggregated form. Figure 4.13 represents the scheme of this last model.

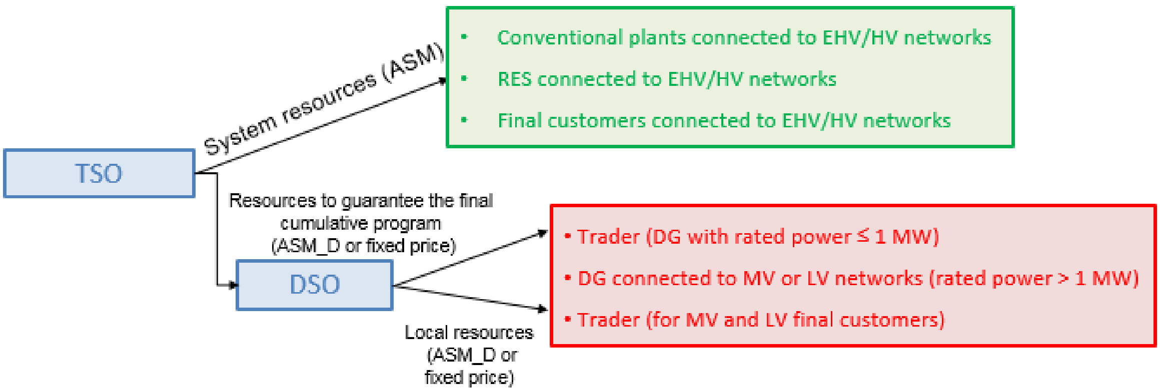

Figure 4.13: Functional scheme for the Model 3.

4.2.3 Dispatching resources provided by DG and RES

In this section all the possible ancillary services that the DG can provide are illustrated [8]. In particular, the services that are individuated can allow the DSO to become a central actor in the management of the ASM and can help the DG to provide resources for the ASM both at a system and at a local level. The services provided to face problems of the system will be purchased by the TSO (Model 1 and Model 2), whereas those services which can help at a local level will be purchased by the DSO (Model 2 and Model 3).
It is worth to underline that all the resources could be implemented only after the development of a proper telecommunication system "always-on", managing the forecasting, the monitoring and the remote control of the DG units. The real time data exchange between all the units and the TSO is a fundamental step to allow the required level of security in the grid management by Terna.

➢ Technical Requirements (off-market services).

These services refer to the obligation, in terms of resources provision, that the DG units should respect in order to be accepted within the ASM, in a way that their participation is reliable and secure. Among the technical requirements it is possible to find:

- Provision of primary reserve.
  In the case of a strong spread of RES and DG units there are two fundamental problems. The first is linked to the lack of inertia by the main part of these units with respect to the system frequency, such as full-converter wind generators or PV generators; this entails that the overall inertia of the system will decrease, and the effect of a frequency transient will be stronger. The second problem is linked to the impossibility for these plants, at least nowadays, to provide a primary reserve, in order to avoid the waste of part of the primary energy (renewable non-programmable energy) that will not be exploited because of security issues.
  It seems possible that in the future, to face this problems, new mechanisms for the primary reserve provision will be implemented, both from a technical and from a regulatory point of view; an example can be the mandate for all the RES units to include a device able to provide a synthetic inertia, and so to act towards frequency transients such as a rotating unit.
  In any case the provision of primary reserve could represent a mandatory service at least at a system level for all the units participating to the ASM; the TSO will require to all the generators and the loads this resource to guarantee a proper level of the service quality, also remunerating in some cases the service at a price higher than the zonal price.
- Voltage regulation.
  The presence of a DG unit at a MV level can cause a critical variation in the voltage profile. In particular, at the node in which the DG unit is connected, the voltage value can possibly overcome the upper voltage limit, with a value higher than the one at the main MV busbar. To prevent this, it could be necessary to implement a centralized logic for the voltage regulation, where the DSO could send signals to the generation units asking for a certain level of reactive power injection.
  The request to inject or absorb reactive power seems to represent in the future a technical obligation from both a system and a local point of view; if the regulation of the voltage through the use of the reactive power variation within the capability curve is not sufficient, it could be possible also to impose a reduction in the active power injection that could be remunerated.

- Availability for the use of the intertripping.
  The use of the intertripping could represent a mandatory service at both a system and a local level; this would allow to the TSO and the DSOs to manage the grid in a secure condition and with a high level of QoS. The intertripping will modify the actual discipline for the RES and DG curtailment (MPE and RIGEDI procedures).

➢ Market services.

These services refer to those resources needed to manage the congestions along the network, to provide an adequate amount of capacity reserve and to guarantee the equilibrium between injection and withdrawal in real time.

- Resources in the planning phase.
  The provision of resources during the planning phase is linked to the resolution of the congestions resulting from the cumulated programs after the DAM and IM. This service could be provided at both a system and a local level, and would be remunerated on the basis of the bids presented onto the ASM.
- Provision of secondary and tertiary reserve.
  The secondary and tertiary reserve service represents a resource at a system and at a local level. In particular, given the variability in the RES production and the reduced size of DG units, it seems difficult to purchase, at least initially, an upward reserve from these units, whereas the provision of downward reserve seems to be possible. When the electricity demand is low, hence when the downward reserve is required, the RES are the units usually responsible for the disequilibrium on the grid; the fact that these units could provide a downward reserve service would make the management of these situations much easier.
- Balancing resources.
  The balancing resources can be used to maintain the equilibrium along the network, to solve the congestions and to keep the needed reserve margins.
  Moreover, at a local level, the DSO could use the balancing service to keep the exchange of energy at the PS interface equal to the binding program established with the TSO. Hence also the balancing service will be useful at both a local and a system level.
- Demand response.
  The demand response is a service provided by the loads that is similar to the balancing service on the generation side. In real time the load receives a dispatching order and varies automatically its withdrawal. This service can be even more interesting from the user point of view if the user is a prosumer, hence it is characterized by the presence of both a generator and a load (it often occurs for DG units).
  Together with the demand response, also the load shedding could be an ancillary service provided by the demand side: this service corresponds to the intertripping use by the generation units. Both the demand response and the load rejection services are system and local resources remunerated through a market.

In Table 4.3 the considerations made regarding the possible ancillary services provided by DG are resumed in a tabular form.

***Table 4.3**: Ancillary services and their implementation framework.*

Dispatching resources	Type	System services	Local services
Resources for solving congestion during the planning phase	Market service	YES	YES
Resources for the primary power reserve	Technical requirement	YES	NO
Resources for the secondary and tertiary power reserve	Market Service	YES	NO
Resources for balancing	Market service	YES	YES
Reactive power reserve for voltage regulation	Technical requirement	YES	YES
Active power reserve for voltage regulation	Market service	NO	YES
Demand response and load shedding	Market service	YES	YES
Availability for use of the intertripping	Technical requirement	YES	YES

4.2.4 Stakeholders involved in the market evolution

In the new market context, according to the models described, an evolution of the main participants to the market management is required. In particular the stakeholders involved, and their prerogatives, are presented below.

➢ The Transmission System Operator.

The TSO will be in any case the central coordinator of the dispatching activity. The way in which it will act in the future is strictly linked to the market model chosen.

The TSO should implement new market mechanisms to guarantee an energy trading almost in real time both to face the unpredictability of non-programmable RES and to allow them to participate actively to the ASM. At the same time, the TSO should be able to build a proper framework for what concerns the upward and the downward reserve provision: in particular it will be necessary to consider, through a probabilistic algorithm, the possibility, due to the presence of unpredictable RES within the dispatching resources, that the service is not actually provided.

In any case the TSO will be responsible for the units connected to the transmission network. On the other hand the management of the DG units will be linked to the market model chosen. In particular, considering that the presence and the modulation of the DG units could bring to some problems along the distribution network, it is necessary to define some priorities between the activity of the TSO and the DSOs, beyond a communication system allowing the exchange of information in real time. This problem could be solved by the implementation of Model 2 or Model 3: in this models the DSO is responsible for the management of the resources at the distribution network level, hence it could control the network situation and at the same time (in Model 2) provide some dispatching resources to the TSO, but always checking first the security of its grid portion.

➢ The Distribution System Operator.

The DSO is the stakeholder that will be changed by the market evolution the most. Again, its role will be defined according to the market model chosen, but in any case its figure will be more and more important.

On one side, according to Model 1, the DSO could be responsible for the verification, during and after the planning and the real time phase, of the compatibility between the participation of the DG and of the loads to the ASM, and the security of the local grid. This means that for every PS the DSO will check the exact amount of energy that can be provided to the TSO and will reserve a margin in order to face some local issues.
On the other side, according to Model 2, the DSO keeps together two fundamental roles:

- As an UdD it gathers the right and the obligation towards the TSO to inject or withdrawn into the network the quantity of energy resulting from the binding program modified and corrected.
- As a responsible of the D-ASM it purchases the resources necessary at a local and at a system level, acting as a counterpart for the negotiations at the distribution level.

This last role would be covered by the DSO even for Model 3, where it would be responsible for the imbalance between the real and the binding program at the PS interface.
In general the DSO could be in the future the figure which the TSO refers to in order to manage the DG units and the loads; this approach would have a great advantage in terms of reliability and security of the services provision, exploiting the already existing communication channels between TSO and DSOs and ensuring the coordination among all the local and system services.

➢ The Aggregator.

In the new context a central role will be occupied by the aggregator, defined in the Grid Code draft presented by ENTSO-E as the Balancing Service Provider (BSP). Its presence arises from the necessity to have a simpler management of all the numerous small units connected to the distribution network, for what concerns the resources provision on the ASM, but also for what concerns the measurements and the verification of the services provided. This is crucial considering the importance that the reliability and the promptness in the service provision covers for the TSO.
The aggregator will have the advantage of creating a set of resources for the TSO and the DSO that will result substantial as a whole, making thus easier the purchasing of the resources themselves. Its presence will give also a better probabilistic estimation given the fact that it will gather a high number of units, and that this will reduce the uncertainty of their cumulative provision. Moreover, the presence of the aggregator will make easier the metering of the services provided and their checking in real time.
The type of units gathered by the aggregator could be homogeneous (only generators or only consumers) or not, according to the maturity level of the system. The presence under the same portfolio of both generators and loads will ensure a wider possibility for the aggregator to select the best configuration in order to offer upward and downward services on the ASM.
The aggregation of the units could be performed considering their size and/or their geographical position. In any case, the aggregator would have a complete view of all the resources under its control and of all the buses of the grid that they refer to; it would know the technical limits, the ongoing problems, the working plans and the unavailability of all the units, actually managing them in place of the DSO or of the TSO.
The presence of the aggregator is strictly linked to both a revision of several normative mechanisms (such as the imbalance fees) and to the implementation of communication systems between the different units aggregated and the central coordinator, in order to exchange the relevant data and to actuate the orders in real time.
Finally, it is possible to list the following advantages the aggregator will bring for the system:

- it allows the expansion of the communication channels and of the information exchanged across the network;
- it allows validating preventively the services provided by the DG units and the loads, and required by the TSO and the DSO at a system and at a local level;

- it facilitates the measurements and the gathering of all the technical parameters of the different units;
- it allows the installation of actuators on the units ensuring a high reliability of the services provision;
- it allows also improving the predictability of the different resources as a whole.

➢ The Final Users and the Prosumers.

The role of the final users will be very important in the future context. The prosumers could provide upward and downward resources thanks to the availability of both generators and loads. They will be able, having a high number of resources available, to provide a reserve margin by the modulation of the power injected or withdrawn from the grid, facing rapidly any frequency variation.
The services provided by the prosumer could be useful at both a system and a local level; final users could act in the ASM as single units or in aggregated form.
The possibility for these systems to represent useful resources for the dispatching activity will be more and more relevant in the future, especially when the economic opportunities given by the support scheme actually in place (described in the Chapter 3) will disappear.

The structure described and the links at each different network level in the new configuration are presented in Figure 4.12.

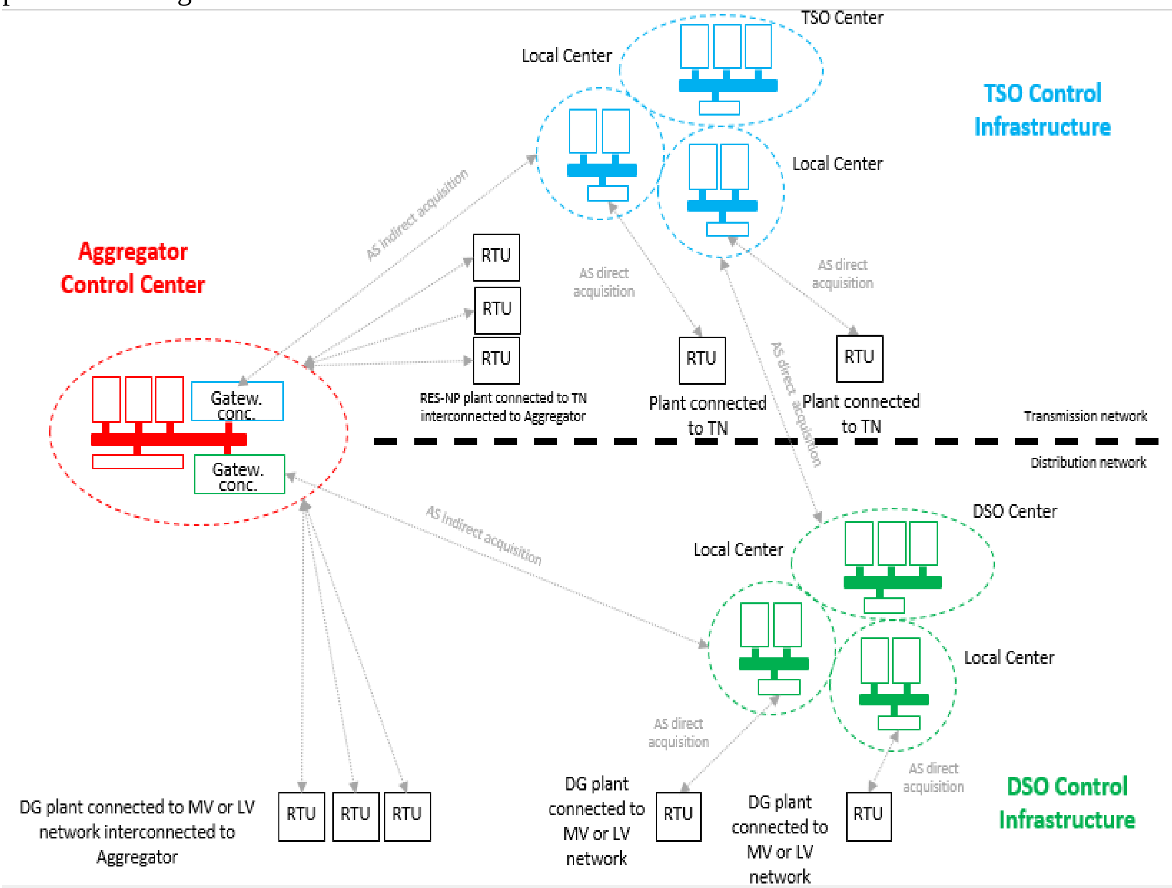

***Figure 4.12**: Communication framework in the new market configuration.*

4.2.5 DCO 298/2016 and RDE-1

The process of reform of the Ancillary Service Market has started with the Deliberation 393/2015/R/eel with the definition of RDE (Riforma Dispacciamento Elettrico) project [10]. The first phase of the RDEproject has been defined in the DCO 298/2016/R/eel and it has been called RDE-1.
The action of the authority is linked to the indications given by the European guidelines. Concerning the ASM reformation, the documents to consider are:

- the balancing guidelines, where it is specified the requirement for an harmonization and an integration of the balancing markets at a European level through an energy exchange based on an economic merit order that allows to the TSOs the sharing of the ancillary resources;
- the system operation guidelines that define the principles for the secure management of the electric system, and the rules for the coordination between TSO and DSOs during the phase of planning and in real time;
- the capacity market design that introduces, for the subscribed resources, the obligation to present offers on the energy and the ancillary markets.

Starting from the European principles regarding the above themes, the authority is moving in order to implement a first evolution for the ASM in a brief time.
In the RDE-1 the AEGGSI wants to enlarge the possibility to participate to the ASM to the RES plants, the DG and the loads in a voluntary form. Given the will to promote the application of the new rules in a short term, it is considered necessary to build this first phase on the actual ASM framework and hence implement the Model 1 described in the DCO 354/2013: this model is indeed the only one compatible with the actual regulation and the actual market architecture. Terna will remain the only subject with the complete view of the issues and the limits of the network in real time, and it will purchase the required resources on the ASM.
In the foreseen framework the UdD will remain the only counterpart of Terna, also in the case of the presence of an aggregator. This means that the BSP, which provides the ancillary services, and the BRP (Balancing Responsible Party), which is responsible for the imbalances, are the same subject and coincide in the UdD.
Nowadays the Grid Code foresees that the ancillary services can be provided by the units that are respecting two type of characteristics: an objective characteristic, linked to the exclusion of all the non-relevant units (with the RES), and a functional characteristic, linked to the requirement for a specific technical performance for each service. The RDE-1 foresees the possibility for the non-programmable RES to become relevant PU, given the technologic maturaty reached by these plants. Moreover it is required to allow the participation to the ASM also for the non-relevant units of production or consumption respecting certain geographical criteria: these units would be gathered in the UVA (Unità Virtuali Abilitate). The participation to the ASM will be mandatory for the units that are already enabled, whereas it will be voluntary for all the new stakeholders; this configuration is however considered as a temporary situation, while in the future a common rule should be defined for all the units.
The TSO will be able to control through a physical control point all the units, also the new ones, in order to ensure the transmission, the reception and the execution of orders.
For what concerns the rules for the definition of the UVA it is clear that on one side the wider is the geographical area on which the aggregation is allowed, the easier is the participation of the small and diffused units to the ASM. On the other hand, it is not possible to ignore grid limits in terms of transmission capacity.

Based on these reasons, the relevant unit of production cannot be aggregated and must participate to the ASM as single units; the non-relevant units can be aggregated and they can include different typologies of generation units. Moreover, the geographical perimeter of the aggregation cannot overcome the market zone one and it is not required to coincide with it.
The units that do not require to be enabled for the ASM are aggregated per zone, per typology and per UdD as of today. The same configuration is valid for the consumption units, with the specification that load and generators cannot be gathered under a single UdD.
The DCO foresees the possibility to require the enabling for the provision of also only one service and in an asymmetric way, it is possible to present bids only for the upward or the downward reserve.
The DSO must be informed about all the injection/withdrawal points relative to the UVA requiring the admission to the ASM; moreover they can report to Terna and to the UdD interested the presence of some problems at a local level with the possibility to state the unavailability of certain resources for the ancillary services provision.
It is required to define a lower limit for the capacity of the UVA participating to the ASM: the value indicated is 1 MW, in order not to limit the involvement of the DG and not to limit the dispatching capacity provided by the units on the market.
Furthermore it is defined a dispatching priority, when the economic merit order is not sufficient, for the RES units and for the HEC CHP units with respect to the conventional ones.

This first phase of the ASM reform, being based on the actual structure of the ASM, adopts solutions that in the future have to evolve.
In the framework presented in the DCO 298/16 and reported above, one of the main limits is that the IM is still too far from the delivery of the exchanged energy in temporal terms. The impossibility to operate in real time can constitute a barrier for the participation of certain units which are characterized by a high level of unpredictability and, being enabled for the ASM, should face the possibility of high cost linked to the imbalance fees. The traslation of the gate closure of the IM is hence considered a first step to implement new market solutions also for the ASM.
A further limit is the ‘stillness’ of the aggregation system for the UVA: in the future it is worth to understand for each ancillary service which is the optimal level of aggregation in order to guarantee a right fit of the UVA with the electric system. This consideration must be added to the necessity to gather in the future loads and generators under the same aggregator, as already stated.
Finally the RDE-1 does not consider the role of the DSOs as providers of ancillary services towards the TSO, given the better control that they can exert on the units connected at the distribution netwrok. This is linked to the necessity by the DSO to check the working conditions of the network at a local level before allowing any type of provision of ancillary service by the DG units.
Among the several aspects that the TSO should consider in order to be able to implement the required reformation for the ASM it is possible to cite:

- the purchasing of flexible resources;
- the definition of new products exchanged on the ASM;
- the necessity to open the market to all the actors with a technology-neutral approach;
- the possibility to have aggregation with a variable geometry according to the ancillary service which they refer to;
- the definition of the role of the DSOs;
- the definition of the new figure of the aggregator;
- the definition of the relationships among the TSO, the aggregator and the owner of the units of production and consumption;
- the revision of the imbalance fees;
- the definition of new market zones.

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CHAPTER 5

Analysis of the Opportunities for a CHP Plant within the ASM

Considering what has been stated in Chapter 4, especially for what concerns the future perspectives for the ancillary services provision from DG units, it is fundamental to evaluate quantitatively the opportunity that the opening of the ASM constitutes for the CHP plants.
This chapter describes the procedure that led to this evaluation and how the results obtained have been used to take into account the presence of the ASM in the optimization tool for the CHP plant.
The evolution that the energy market knew in the last decade is the precursor of a strong and deep reform that will handle the energy transition that Italy, such as the other countries in the world, is performing. In this context, the possibility for all the technologies to provide the services needed to maintain the network security is considered a key factor, even in the uncertainty that is characterizing the regulatory framework nowadays; the definition of the economic impact of this opportunity on the revenues of a typical DG, such as a CHP plant, is fundamental.
The procedure for the analysis of the ASM correlated to the CHP plants operations aimed at defining a set of reference prices to be used to evaluate the convenience for the participation of the plant to the ASM.
In particular the analysis has followed these steps:

- identification of the ancillary services of interest for the plant and for the logic implemented for its working operations (Section 5.1 and Section 5.2);
- deduction of the reference data for the analysis (sub-Section 5.2.1);
- elaboration of the data collected to produce a result through a specific statistical evaluation(sub-Section 5.2.2 and sub-Section 5.2.3).

5.1 The Reference Framework and the Data Collection

To perform e proper analysis of the market structure, it has been necessary to consider each market zone separately [1]; only the geographic relevant zones have been considered, since they define a wide area for the free flow of energy. The data used for the analysis are easily reachable on the GME web page, in the section of public offers and the market results [2].
It is possible to select the period of reference and the data to download. These data are downloaded under the form of an .xml file. The file reports each offer by every market participant with a recursive form based on the following fields:

- PURPOSE_CD: it identifies the typology of the offer; the statement BID defines the downward bids (availability to buy energy), and the statement OFF defines the upward bids (availability to sell energy).
- TYPE_CD: it indicates if the bid is predefined (STND) or if it is current (REG).
- STATUS_CD: it indicates the status of the bid after the closure of the market session. There are six possible outcomes: ACC for the accepted bids, REJ for the refused bids, REP for the replaced bids, REV for the revoked bids, INC for the inadequate bids and SUB for the submitted bids.
- MARKET_CD: it indicates the code of the market to which the offer is referred, among the markets presented in Chapter 4.
- UNIT_REFERENCE_NO: it defines the code of the production unit as it is defined in the RUP (Registro Unità di Produzione).

- MARKET_PARTICIPANT_XREF_NO: this code is the merging of the unit reference and the submitted code (see below); it is actually no more indicated in the public offer files.
- INTERVAL_NO: it indicates the hour for which the bid has been presented from 1 to 24.
- BID_OFFER_DATE_DT: it specifies the date of the bid in the format 'yyyymmdd'.
- TRANSACTION_REFERENCE_NO: number of the transaction.
- QUANTITY_NO: it defines the amount of energy (in MWh) presented by the unit.
- AWARDED_QUANTITY_NO: it defines the amount of energy (in MWh) recognized by the TSO.
- ENERGY_PRICE_NO: it defines the price (in €/MWh) presented by the unit.
- AWARDED_PRICE_NO: it defines the price (in €/MWh) recognized by the market.
- MERIT_ORDER_NO: it indicates the merit order for the bid.
- BALANCED_REFERENCE_NO: it defines the code for the balancing; it is present only for the IM.
- PARTIAL_QTY_ACCEPTED_IN: it indicates if the offer has been accepted partially ('Y') or not ('N').
- ADJ_QUANTITY_NO: it defines the quantity adjusted by Terna.
- ADJ_ENERGY_PRICE_NO: it defines the price adjusted by Terna.
- GRID_SUPPLY_POINT_NO: it refers to the relevant exchange point.
- ZONE_CD: it indicates the zone of reference among the Italian ones presented in Chapter 4.
- OPERATORE: it indicates the name of the operator.
- SUBMITTED_DT: it indicates the hour at which the offer has been presented in the format 'yyyymmddhhmmssmmm'.
- BILATERAL_IN: it indicates if the transaction occurred in the OTC market.
- SCOPE: it defines the scope of the bid. It is possible to find: RS for secondary reserve, ACC for the start-up, AS for the minimum upward and downward, CA for the configuration change and GR(1,2,3) for the upward and downward step bids.
- QUARTER_NO: it indicates the quarter hour of reference for the bid in the format '1,2,3,4'.
- BAType: it indicates if the bid is accepted within a mechanism of revoke, of netting or through a standard procedure.

An example of the .xml file used for the public offer analysis is presented in Figure 5.1.

PURPOSE _CD	TYPE_CD	STATUS_C D	MARKET_ CD	UNIT_REFER ENCE_NO	INTERV AL_NO	BID_OFFE R_DATE_	TRANSACTI ON_REFER	QUANTIT Y_NO	AWARDE D_QUAN	ENERGY_ PRICE_N	MERIT_O RDER_NO	PARTIAL_ QTY_ACCE	ADJ_QUA NTITY_N	ADJ_ENE RGY_PRIC	GRID_SU PPLY_POI	ZONE_C D	AWARDE D_PRICE_	OPERATO RE	SUBMITT ED_DT	BILATERA L_IN	SCOPE
BID	STND	REJ	MSD	UP_ACTV_1	1	20150927	373565476	0,01	0	0,01	0	N	0,01	0,01	PSR_193	NORD	0,01	ALPIQ EN	201509261	FALSO	AS
BID	STND	REJ	MSD	UP_ACTV_1	1	20150927	373565476	0	0	0,02	0	N	0	0,02	PSR_193	NORD	0,02	ALPIQ EN	201509261	FALSO	GR1
OFF	STND	REJ	MSD	UP_ACTV_1	1	20150927	373565476	0	0	2999	0	N	0	2999	PSR_193	NORD	2999	ALPIQ EN	201509261	FALSO	AS
OFF	STND	REJ	MSD	UP_ACTV_1	1	20150927	373565476	0,01	0	3000	0	N	0,1	3000	PSR_193	NORD	3000	ALPIQ EN	201509261	FALSO	GR1
OFF	STND	SUB	MSD	UP_ACTV_1	1	20150927	373565476	21	0	3000	0	N	21	3000	PSR_193	NORD	0	ALPIQ EN	201509261	FALSO	ACC
OFF	STND	SUB	MSD	UP_ACTV_1	1	20150927	373565476	10	0	3000	0	N	10	3000	PSR_193	NORD	0	ALPIQ EN	201509261	FALSO	CA
BID	STND	REJ	MSD	UP_ACTV_1	2	20150927	373565968	0,01	0	0,01	0	N	0,01	0,01	PSR_193	NORD	0,01	ALPIQ EN	201509261	FALSO	AS
BID	STND	REJ	MSD	UP_ACTV_1	2	20150927	373565968	0	0	0,02	0	N	0	0,02	PSR_193	NORD	0,02	ALPIQ EN	201509261	FALSO	GR1
OFF	STND	REJ	MSD	UP_ACTV_1	2	20150927	373565968	0	0	2999	0	N	0	2999	PSR_193	NORD	2999	ALPIQ EN	201509261	FALSO	AS
OFF	STND	REJ	MSD	UP_ACTV_1	2	20150927	373565968	0,01	0	3000	0	N	0,1	3000	PSR_193	NORD	3000	ALPIQ EN	201509261	FALSO	GR1
OFF	STND	SUB	MSD	UP_ACTV_1	2	20150927	373565968	21	0	3000	0	N	21	3000	PSR_193	NORD	0	ALPIQ EN	201509261	FALSO	ACC
OFF	STND	SUB	MSD	UP_ACTV_1	2	20150927	373565968	10	0	3000	0	N	10	3000	PSR_193	NORD	0	ALPIQ EN	201509261	FALSO	CA
BID	STND	REJ	MSD	UP_ACTV_1	3	20150927	373566460	0,01	0	0,01	0	N	0,01	0,01	PSR_193	NORD	0,01	ALPIQ EN	201509261	FALSO	AS
BID	STND	REJ	MSD	UP_ACTV_1	3	20150927	373566460	0	0	0,02	0	N	0	0,02	PSR_193	NORD	0,02	ALPIQ EN	201509261	FALSO	GR1
OFF	STND	REJ	MSD	UP_ACTV_1	3	20150927	373566460	0	0	2999	0	N	0	2999	PSR_193	NORD	2999	ALPIQ EN	201509261	FALSO	AS
OFF	STND	REJ	MSD	UP_ACTV_1	3	20150927	373566460	0,01	0	3000	0	N	0,1	3000	PSR_193	NORD	3000	ALPIQ EN	201509261	FALSO	GR1
OFF	STND	SUB	MSD	UP_ACTV_1	3	20150927	373566460	21	0	3000	0	N	21	3000	PSR_193	NORD	0	ALPIQ EN	201509261	FALSO	ACC
OFF	STND	SUB	MSD	UP_ACTV_1	3	20150927	373566460	10	0	3000	0	N	10	3000	PSR_193	NORD	0	ALPIQ EN	201509261	FALSO	CA
BID	STND	REJ	MSD	UP_ACTV_1	4	20150927	373566952	0,01	0	0,01	0	N	0,01	0,01	PSR_193	NORD	0,01	ALPIQ EN	201509261	FALSO	AS
BID	STND	REJ	MSD	UP_ACTV_1	4	20150927	373566952	0	0	0,02	0	N	0	0,02	PSR_193	NORD	0,02	ALPIQ EN	201509261	FALSO	GR1
OFF	STND	REJ	MSD	UP_ACTV_1	4	20150927	373566952	0	0	2999	0	N	0	2999	PSR_193	NORD	2999	ALPIQ EN	201509261	FALSO	AS

***Figure 5.1**: Example of the structure of a .xml file, reference to ASM - 27 of September 2015.*

5.2 The Analysis of the Data Collected

The analysis has been carried out on the data of the ASM of the year 2015.
The data, after being downloaded from the GME website, have been elaborated using the MATLAB® software [3]. The procedure for the analysis followed two ways: on one hand the relevant data referred to the ASM have been collected, divided and organized per month and then per reference week. After this, they have been subjected to a statistical analysis aiming at associating to a general price presented by a unit on the ASM a probability that its bid would be accepted; this is done for every hour of the year. On the other hand, the data referred to the DAM have been downloaded, divided and elaborated together with the ones collected for the ASM in order to associate to each province of the Italian territory a factor linked to the attractiveness of that area on the ASM[5]. This parameter has been used as a correction factor for the prices computed through the elaboration of the ASM data.
The overall procedure used for this analysis is represented in Figure 5.2.
The evaluation described has been performed both on the downward and on the upward bids (respectively BID and OFF purpose code), in order to evaluate the opportunity represented by the modulation of the power in both directions. However, in the context of this thesis work, only the results obtained for the upward services are presented, as they have been used in the optimization process presented for the CHP plants.

5.2.1 Organization of the data and generation of the reference files

The first step of the analysis consisted in the organization of the data collected from the GME website for the ASM. This was made through a typical *divide et impera* algorithm: thanks to a MATLAB® code, the .xml files, distinguished per month, have been imported in .mat files; then they have been divided into the six zones of interest, corresponding to the six geographical relevant zones specified in Chapter 4. The offers have been grouped according to the hour they belonged to, and among the different bids only those referring to upward offers (‘OFF’) with the scope of secondary reserve (‘RS’) or step reserve (‘GR’) have been considered.
Only the upward RS and GR bids have been taken into consideration as the provision of other types of services seems to be more difficult to be managed from the point of view of the operations of the plant. Moreover, at least in a first step, the CHP plant is judged to be able to provide upward reserve much easily, being the provision of downward reserve more complicated from an operative point of view. Moreover, this is too different than the current configuration where the production unit sells its energy, usually in excess, on the DAM. Because of this, and considering the possibility to present bids on the ASM in an asymmetric way, only the provision of upward reserve is presented.
Once the bids have been grouped for each month and hour, the relevant offers are extracted; for what concerns the upward reserve bids the relevant offers are considered all the bids that are associated to a price lower than the maximum price found among the accepted bids. All the relevant bids are collected and form the reference monthly structure for further calculations.

[5] This mechanism is linked to the fact that the TSO in certain hours, characterized by a specific electricity flow configuration along the grid, is actually obliged to purchase some ancillary services from specific units to guarantee the security of the network. In this sense, the attractiveness of a unit is related to its physical position with respect to the contingencies concerning the management of the overall grid security.

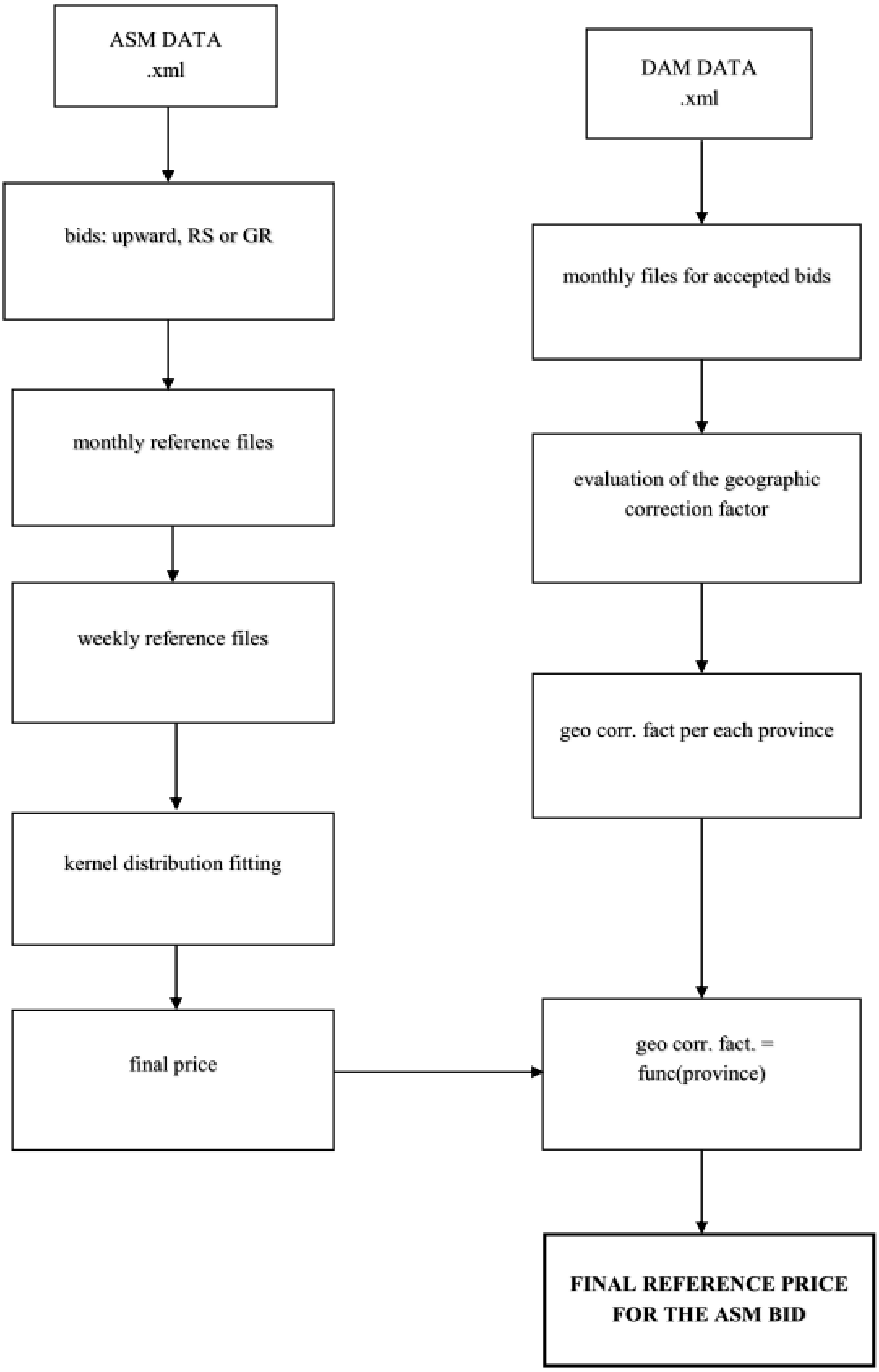

Figure 5.2*: General algorithm implemented for the ASM data analysis.*

A monthly structure has been created for each zone of the ASM; these structures are characterized by the parameters, taken from the public data, of the relevant bids.
Each structure contains a number of elements equal to the total number of hours of the month considered, and for each element, thus for every hour of the month, the following fields are defined:

- mrkt: it indicates the reference market, which is the ASM;
- purp: it defines the purpose of the bid;
- date: it indicates the reference date;
- hour: it indicates the reference hour of the day;
- zone: it indicates the reference zone;
- oper: it indicates the operator that presented the reference bid;
- unit: it indicates the name of the reference unit;
- scope: it indicates the scope of the bid;
- quant, adjquant, awquant: they indicate respectively the quantity bidded, the value adjusted by the TSO and the amount of energy accepted;
- price, adjprice, awprice: they indicate respectively the price bidded, the value adjusted by the TSO and the price awarded on the market;
- partial: it indicates if the bid has been partially accepted or not.
- status: it indicates the status of the bid.

These fields are defined for every relevant bid selected.
The structure of the obtained files is presented in Figure 5.3.

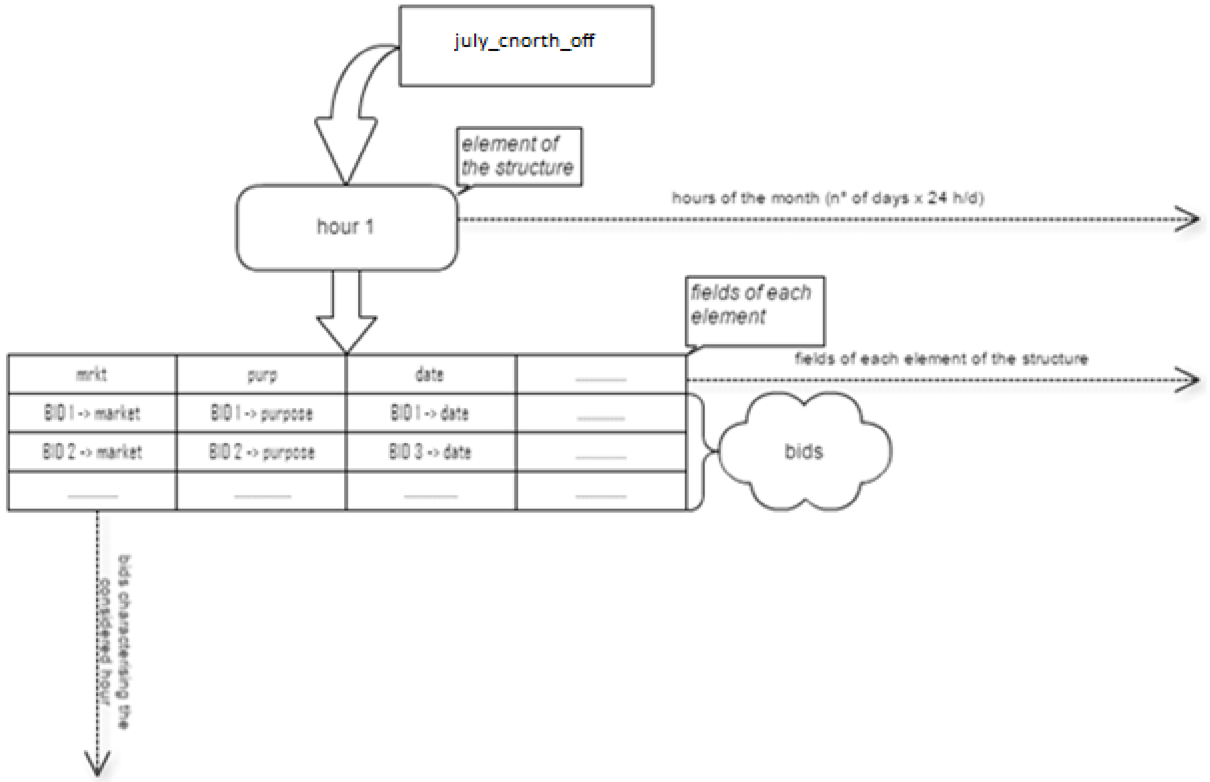

Figure 5.3: *Structure of the monthly reference file, example for July zone center-north.*

The monthly structures are elaborated through another MATLAB® code in order to generate the weekly reference structure.

For each month of the year considered (2015), the data collected and organized in the monthly structure are grouped according to the day of the week to which they refer: this allows the creation of a weekly structure composed by 24x7=168 elements, each one referring to a single hour of the week. The first 24 elements report all the relevant bids of the given month presented on Monday, divided according to their reference hour; the elements from 25 to 48 report the bids of Tuesday, and so on for all the days of the week.
The resulting structure used for the following calculations is presented in Figure 5.4.

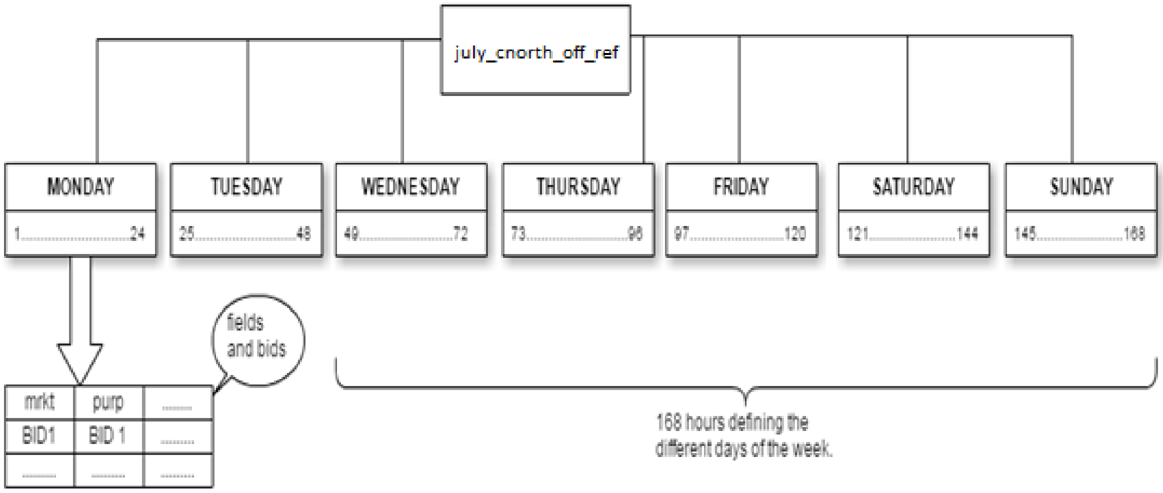

***Figure 5.4**: Structure of the weekly reference structure, example for July zone center-north.*

The creation of the weekly reference structures allows the improvement of the significance of the data from a statistical point of view: considering each month as owning specific features (that in general are expected to be the same every year), the creation of weekly reference structures deletes the exception that can be present in a given hour of the month, and makes the meaning of the data collected more general.
At this point, of the analysis all the relevant bids are grouped per month and per zone in a weekly reference structure; these files are used for the statistical evaluation of the offers.

5.2.2 Statistical evaluation of the files generated

The aim of the analysis is building, on the shape of the bids of the ASM collected from the GME website, a probability distribution that allows associating to every price, for a given hour of the year and for an upward reserve offer, the corresponding probability of acceptance.
However, before deepening this analysis, it is useful to present through some statistical parameters the main characteristics of the data obtained up to this point.
Thanks to the procedure described above, it has been possible to build a file as in Figure 5.4 for every month of the year and for every relevant zone of the ASM. The most important data for this step of the procedure are the prices and the quantities associated to each bid collected in the files.
As an example, it is possible to consider the file *mag_nord_off_ref.mat*, that is the reference weekly file for the month of May; according to the structure of Figure 5.4, in this file of 168 elements there are all the relevant bids divided per day of the week.
In Figure 5.5, it is possible to see the bids accepted among the relevant ones (on the left) and the distribution, under the form of an histogram, of all the relevant bids presented (on the right); the data reported refer to the hour 19:00 of the Wednesday within the reference week of May considered.

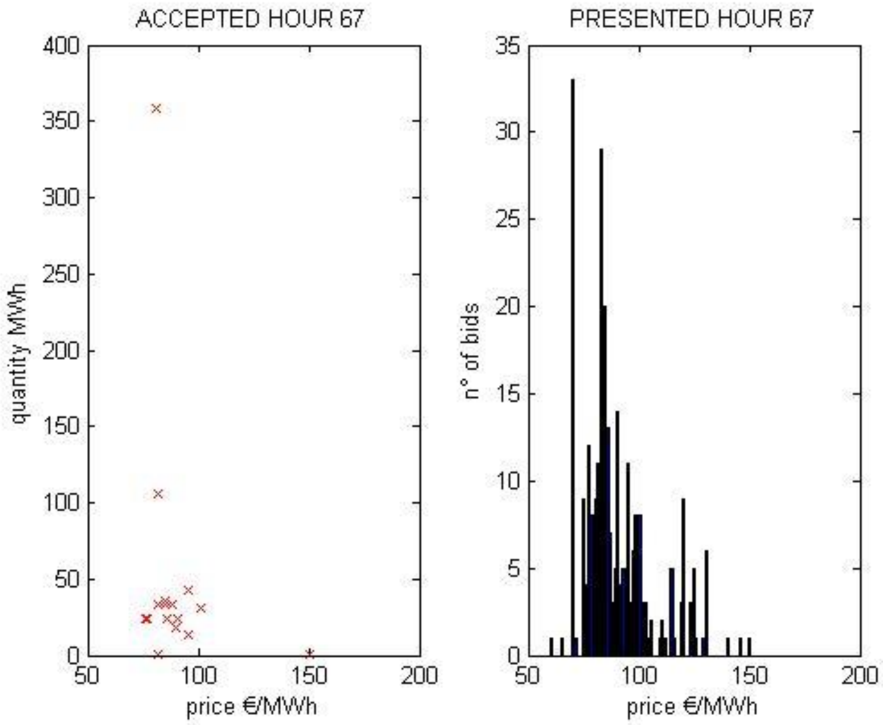

Figure 5.5: Hour 67, week of May: accepted (left) and presented (right) bids.

It is possible to notice that both the accepted and the presented bids are mainly comprised between 70 €/MWh and 95 €/MWh; however, there is an outlier among the accepted bids around 150 €/MWh and some outliers among the presented bids.

Figure 5.6 represents, through a boxplot, the behavior of the presented bids along the whole day of Wednesday of the reference week for May.

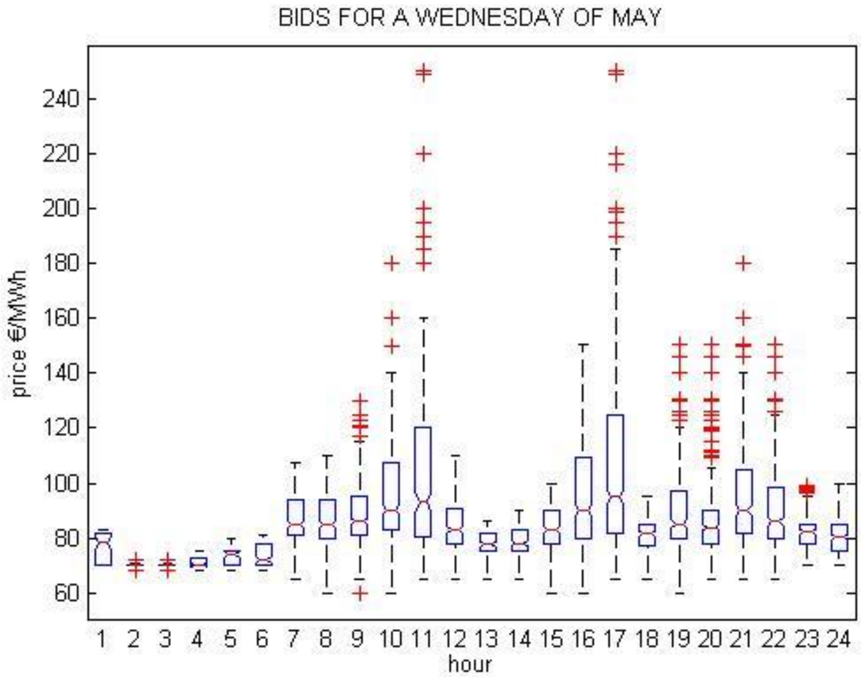

Figure 5.6: Boxplot representation for the Wednesday of the reference week for May.

The boxes represent the interquartile range (from the 25th to the 75th percentile) of the data for each hour of the day considered. The red line in the middle of the box defines the value of the median; outside the boxes a black line defines the extent of the sample and some red crosses, if present, report the outliers. The hour considered above (19:00) in Figure 5.5, compared to the other hours of the day of Wednesday, is characterized by an appreciable dispersion of the data. In general, from the diagram, the median is always comprised between 70 and 95 €/MWh, with degrees of dispersion that vary a lot, mainly according to the amount of data available.
Figure 5.7 represents the situation of the whole reference week of May for the North zone through the arithmetic mean of the price of the bids presented in each hour of the week.

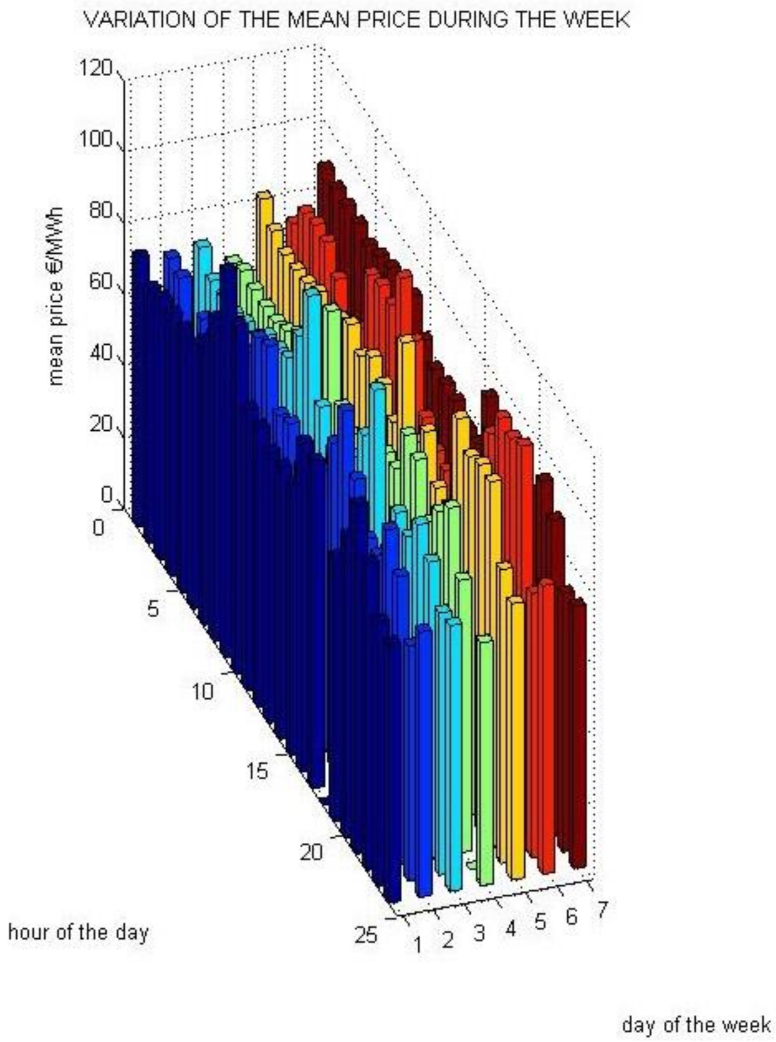

Figure 5.7: *Mean value of the prices along the reference week of May, north zone.*

In Figure 5.7 it is possible to see that a tendency to reach higher prices is present in the late morning and in the first evening for all the days of the reference week, and in this case higher prices are reached in the day of Saturday (6th day).
In order to understand the influence of the outliers and the degree of dispersion of the data collected, Figure 5.8 reports the variation of the trimmed mean for a percentage of trimming varying from 5% to 70%. The data represented are again referred to the hour 19:00 of Wednesday.

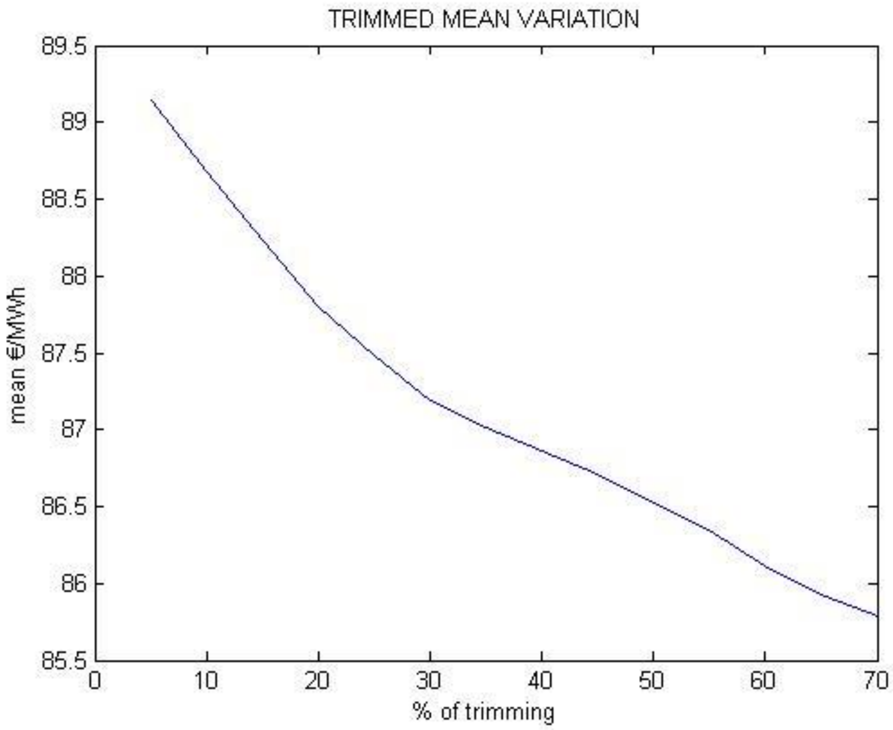

***Figure 5.8**: Trimmed mean variation with respect to the trimming degree.*

The fact that the trimmed mean decreases is linked to the presence of numerous upper outliers that disappear during the trimming. This tendency can be confirmed for all the other hours of Wednesday, as in Figure 5.6 it is common for almost every hour to have upper outliers. This must be considered during the further analysis because the presence of these outliers can influence the shape of the probability curve that will be built around the data collected.

Figure 5.9 represents the value of the mean price weighted on the amount of capacity associated to each accepted bid; the values are presented for each hour of every day of the week. The tendency to have peaks in the prices on the ASM in the morning and in the evening are confirmed; this is due to the ramps linked to the variation of the load and of the PV plants production present in the morning and in the evening.

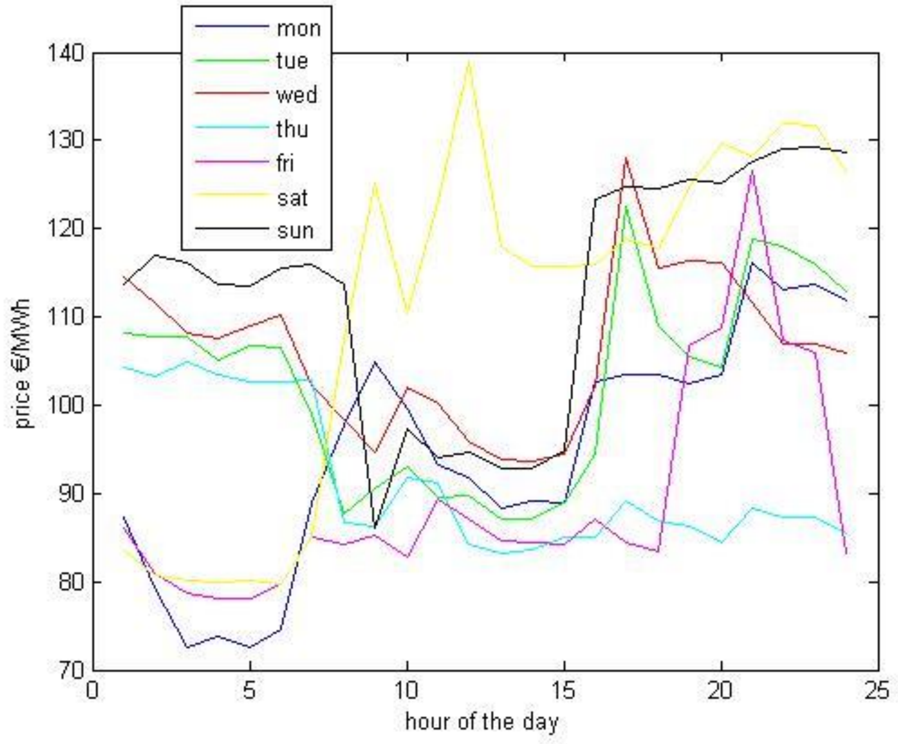

Figure 5.9*: Weighted mean along the reference week of May.*

Even if this work is not intended to perform a parametrical analysis of the ASM, it is important to understand the qualitative and quantitative nature of the data collected; the parameters presented above, and all the consequent considerations, can be analyzed for any hour of any month. This constitutes a powerful tool for the comprehension of the data collected.

At this point, the target is to build, on the shape of the collected bids for each month and zone represented by a reference week, a distribution function in order to evaluate the probability that an upward reserve offer is accepted based on the price of the bid. This problem consists in a non-parametric density estimation.

The simplest form to represent a set of data is the histogram: it divides the sample space into a number of bins and it defines the height of every bar according to the number of samples that fall into the considered bin. Always keeping into consideration the hour 19:00 of the reference Wednesday of May, the Figure 5.10 presents the histogram of the accepted bids: onto this data is required to have a distribution fitting.

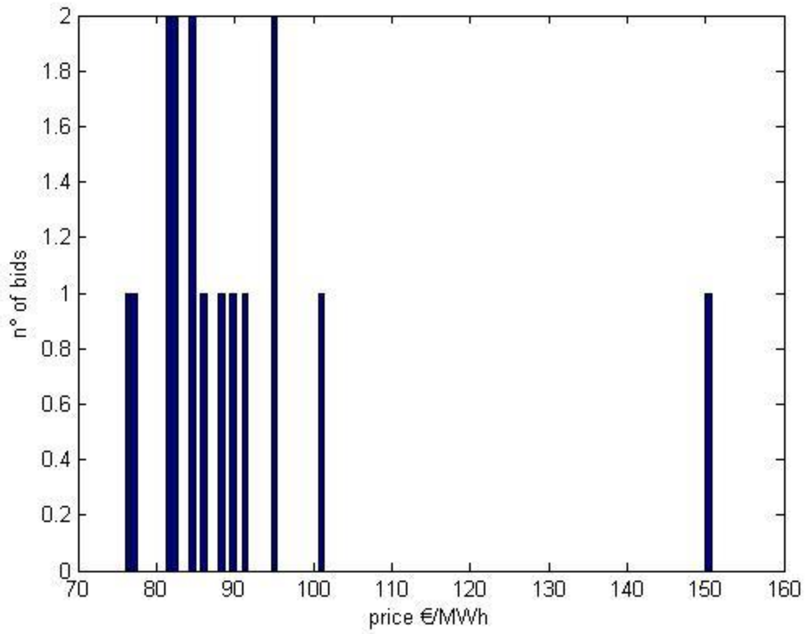

Figure 5.10: *Histogram for the accepted bids, May reference week, hour 67.*

In order to perform the requested fitting a Kernel Density Estimation (KDE) has been used.
In KDE the probability associated to a given value is proportional to the ratio between the number of samples falling in a given volume (but also area or interval), and the product between the volume (area or interval) and the total number of samples. In particular the KDE fixes the volume considered and determines the number of samples contained in it from the data. Therefore, the KDE allows modelling around each sample a volume that can be shaped according to the characteristics of the data.
In practice, using a defined probability density function, a distribution is built around each sample, and the sum of each density function gives the overall distribution fitting the data considered.
The result of this procedure performed on the data of Figure 5.10 is presented in Figure 5.11.

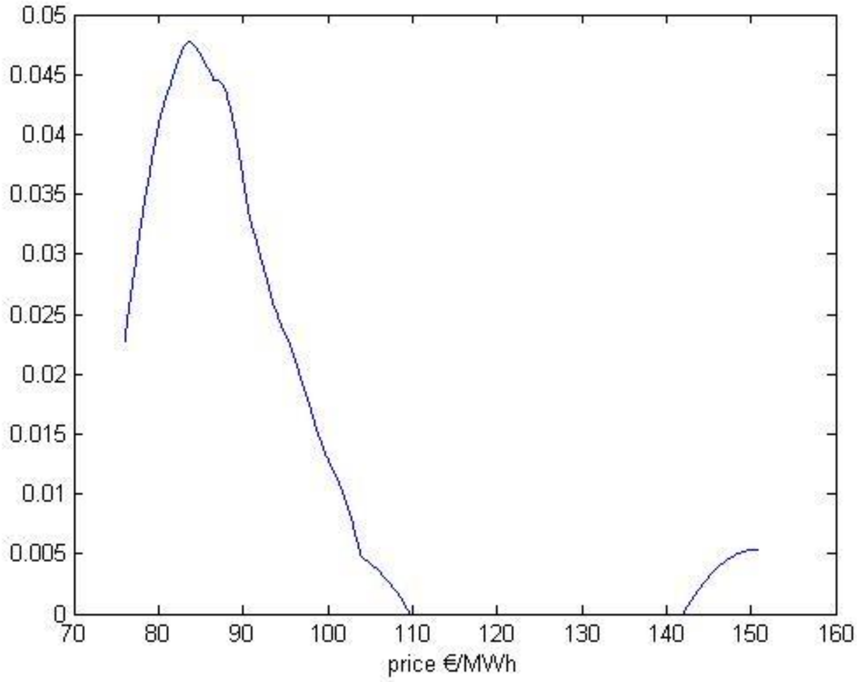

***Figure 5.11**: Kernel Distribution Estimation, May reference week, hour 67.*

Once the data have been fitted, it is necessary to consider that the possibility a given bid is accepted for the upward reserve service is higher the lower is the price associated to it. This consideration can be translated into a statistical evaluation through the use of the cumulative density resulting from the distribution of Figure 5.11.

Starting from the distribution built, it is possible to define a cumulative distribution function (Figure 5.12 on the left); the complementary of this cumulative distribution function is the function that is able to associate to a given price the probability that the bid corresponding to that price is accepted, based on the data collected on the ASM .

This function is reported for the hour 19:00 of the reference Wednesday of May, with respect to the accepted bids, in Figure 5.12 (on the right).

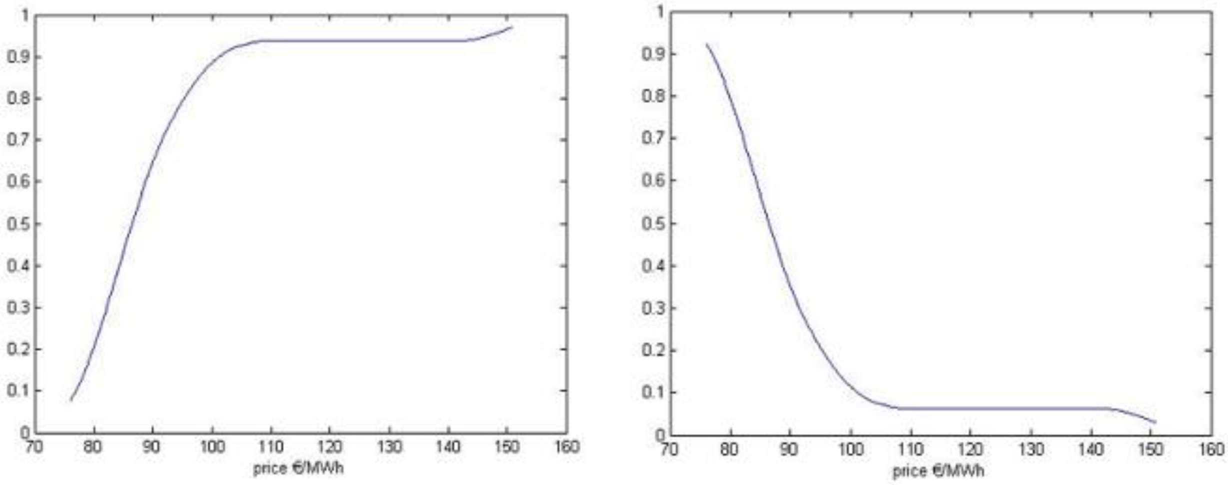

***Figure 5.12**: Cumulative distribution function (left) and derived probability (right).*

It is possible to see that in this case, because of the presence of an outlier among the accepted bids, up to 150 €/MWh, even if there is a great jump that brings the probability from 90% to 10% in a range of 20 €/MWh, the probability is still around 5% and does not tend to zero until this value.
The procedure described above is performed also on the presented bids (Figure 5.13), considering hence both the accepted and the rejected bids; it is obvious that the presence of a higher number of data increases the significance of the result. In this case, however, the resulting distribution is not dealing with a market indication, such as the accepted bids, but is dealing with the behavior of the participants to the ASM; this is in any case a useful consideration to perform a good evaluation of the data collected.

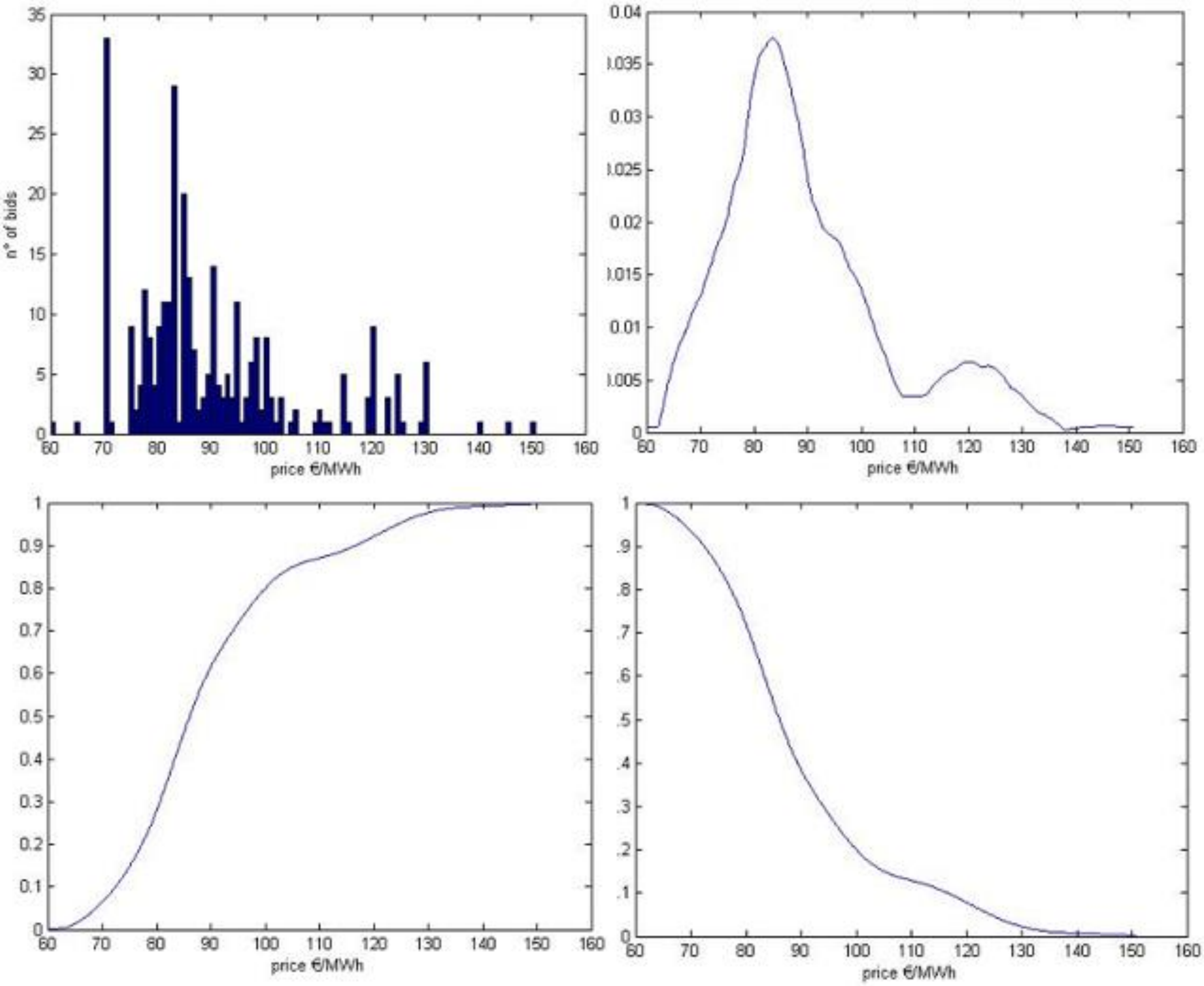

Figure 5.13: *Evaluation of the CDF on the presented bids, May reference week, hour 67.*

The next and final step is to elaborate the probabilities derived in order to define, for each hour of the reference week of each month and every zone, an opportunity price for the action of the CHP plant on the ASM. Figure 5.14 illustrates the procedure used.

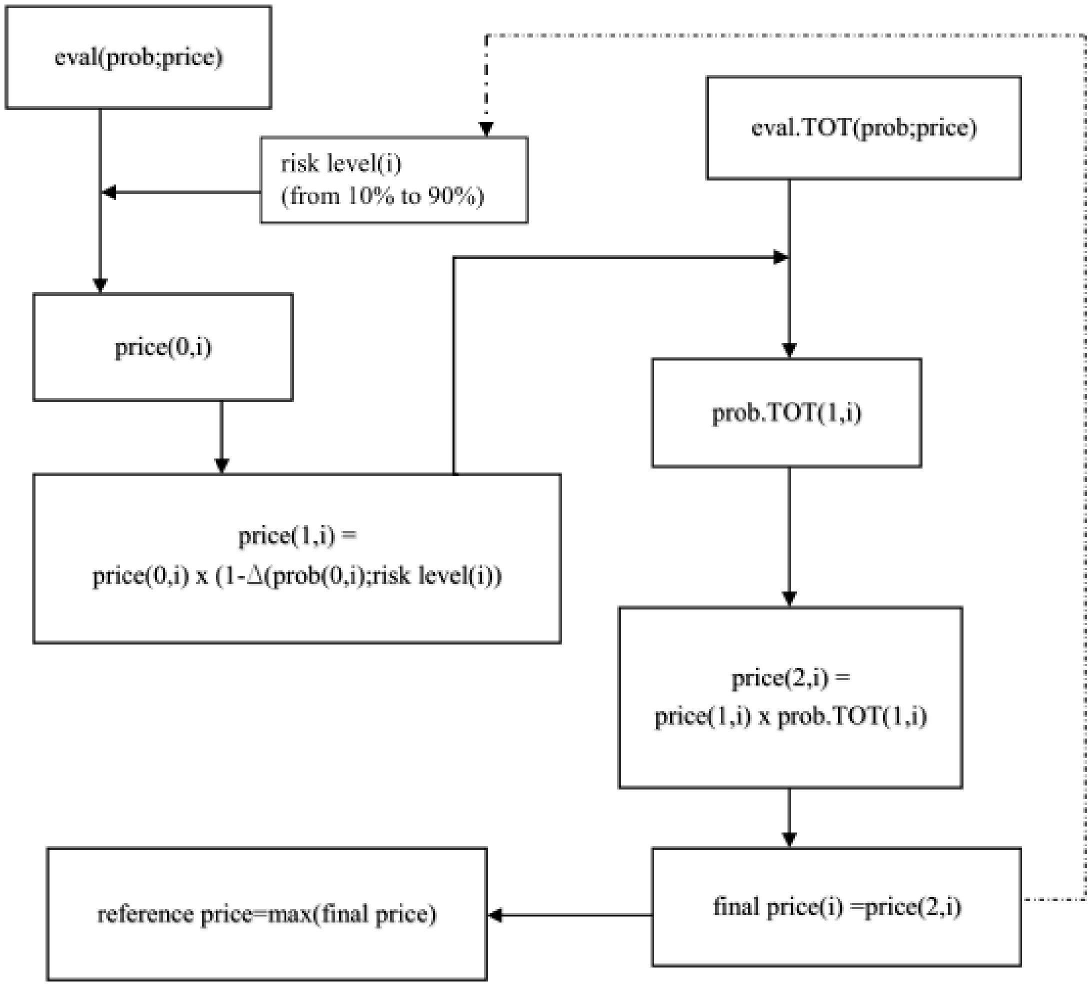

***Figure 5.14**: Algorithm implemented for the reference prices computation.*

The algorithm is based on the consideration of a risk level as an input: this parameter represents the level of risk that is associated to the acceptance of the bid presented on the market. The procedure foresees the consideration of different values of risk level, from 10% to 90%.

The parameter associated to the level of risk is the probability of acceptance, meaning that if 80% is indicated as an input for the risk level, it means that the level of risk implied is to have a probability of 80% that the bid presented at the price exiting from the algorithm will be accepted. This probability is directly linked to the revenues that the unit can obtain on the ASM.

The risk level is considered and, within the density distribution built on the accepted bids, the price corresponding to a probability equal (or the nearest possible) to the risk level is defined as P_0.

As the distribution fitting has been performed on real, discretized data, it is possible that, within the reference structures created for each month and characterized by a series of couples (probability, price), the value exactly equal to the risk level chosen is not present. Because of this, a variance is defined as the difference between the risk level and the nearest probability value found in the reference structure.

This variance is implicitly associated to the goodness of the evaluation that is performed: if the curve describing the distribution, in the contour of the point that is sought, is steep, the value of the variance is more likely to be high, or at least higher than in the case of a flat curve.

At the same time, a steeper curve in a given region means that the uncertainty linked to the bid acceptance, even with a small variation of the price bided, is high; therefore it is possible that a small number of euros of difference between two offers determines the acceptance of one offer and the refusal of the other.
According to this consideration, the value of the variance, as defined above, is used to weight and redefine the price derived from the risk level, which is the one corresponding to the probability value nearest to the risk level parameter in the (probability, price) reference structure previously determined. This allows defining the price P_1. This price is the one characterizing the bid that the plant owner is called to present on the ASM, thus the price at which the upward service will be remunerated if the offer is accepted. P_1 is not the reference price it is possible to use in the optimization tool, as it does not consider the probability for the bid acceptance; it is only a result of the risk level considered as input and of the distribution fitting performed on the ASM data.

$$P_1 = P_0 * \left(1 - \Delta(prob_0; risk\ level)\right)$$

Indeed, the higher the risk level, the lower will be the value of P_1 calculated, because a lower price is associated, for an upward reserve bid, to a higher probability to be accepted. Vice versa, if the risk level is lower, the price will be higher, with higher possible gains but also a higher risk that the bid will not be accepted.
At this point, a price for the bid to present on the ASM for the upward reserve has been computed for a given hour of the year. As said, the distribution fitting on the presented bids allows understanding the behavior of the participants to the market, beyond the behavior of the market itself. As occurred for the accepted bids, also for the presented bids the obtained distribution is a series of couples (probability, price).
The idea is to exploit this information by looking for the price that has been calculated up to now within the distribution built from the presented bids; once the price has been found, it is possible to consider the associated probability, always within the distribution derived from the presented bids, and to use this probability value to correct the price of the bids to define the reference price to be used in the optimization tool.
Through this last correction the actual price associated to the bid on the ASM for the upward reserve, according to the level of risk chosen, is defined.

$$P_2 = P_1 * prob_{TOT_1}$$

The values of P_1, P_2 and $prob_0$ are computed for every value of the risk level considered, and among the calculated values for P_2 the maximum is chosen. As the values of P_2 considers in an intrinsic way the probability associated to the acceptance of the bid presented on the market, they can be compared one each other and they can be compared also to the DAM prices. This price is finally the price that it is possible to use for a proper economic evaluation; the use of P_2 allows to take care of the fact that in certain hours the bids presented by the plant will be accepted and remunerated at a higher price than the one considered as a reference, whereas in other hours the bid will be refused, losing the potential gains. In this sense, the reference prices allow understanding the revenues and the opportunity represented by the ASM from an economic point of view, and to judge when it is better to participate to the ASM (i.e. when the market conditions are favorable).
The procedure described is performed on the distribution defined for each month and for each zone as described in this chapter, giving the possibility to evaluate all over the Italian territory the economic value provided to a plant by the participation to the ASM as a dispatching resource.

Before presenting some numeric results of this kind of procedure as examples, it is necessary to describe the parallel analysis performed to determine the geographic correction factor that allows further modifying and correcting the price computed as above.

5.2.3 Evaluation of the geographic correction factor

As stated in Section 5.1, the Italian network is divided into relevant zones, due to technical limits of the grid that can be in some cases even very localized. Taking care of this consideration, during the analysis carried out on the ASM bidding prices it seems necessary to consider the influence of the position of the plant on the grid. The localization of the plant must not be limited to the zone to which it belongs; it needs to refer to a more limited area: a good approximation of the plant position can be the definition of the province to which it belongs.

Figure 5.15 presents the algorithm used to define the geographic correction factor, that is the parameter used to modify the prices computed previously and which is linked to the position of the plant.

The localization of a plant, especially in the north zone, can influence a lot the possibility that a plant is called to provide a specific ancillary service, because of the presence of some internal transmission limits within the zone itself. This is actually the main reason for which, if the bids accepted on the ASM are analyzed, it is possible to notice that the economic efficiency principle, that would impose to accept the economic merit order offers for the upward reserve service, is not always respected.

Hence, an analysis of the geographical distribution of the bids helps to properly define the possibility for a plant to participate to the ASM, and also to understand which are the mechanisms behind the management of the transmission network.

Before implementing the algorithm elaborated and reported in Figure 5.15, it has been necessary to process the data collected for the DAM as it has been done for the data of the ASM (see section 5.2.1).

This is needed considering that the evaluation of the desirability of a bid for the upward reserve on the ASM is also linked to the activity of the plant on the DAM as a result of the market closure. Indeed, if a plant is not called to produce after the DAM closure, the cost that the TSO is called to sustain to accept the presented bid must take into consideration also the token to be paid for the start-up service of the plant; the economic value represented by the bid on the ASM for the upward reserve is not completely describing the actual cost of that service when provided by this plant. Because of this, the data for the year 2015 have been collected and elaborated, creating .mat files, exactly equal to the ones created for the ASM, containing the offers accepted on the DAM for each month and for each zone. The structure of these files is corresponding to the one in Figure 5.3, with the only difference of the type and nature of the bids contained.

Then, through a MATLAB® code, it has been possible to elaborate these data together with the monthly reference data created from the ASM bids. In particular, the procedure allowed the individuation, for each hour of the year, of all the plants that have presented a bid at a price lower than the maximum price accepted, and that were active on the DAM: these plants are considered to be completely eligible from the economic point of view. If the offer presented from these plants was refused, the reason for the refusal must be linked to their specific position in the context of the transmission network.

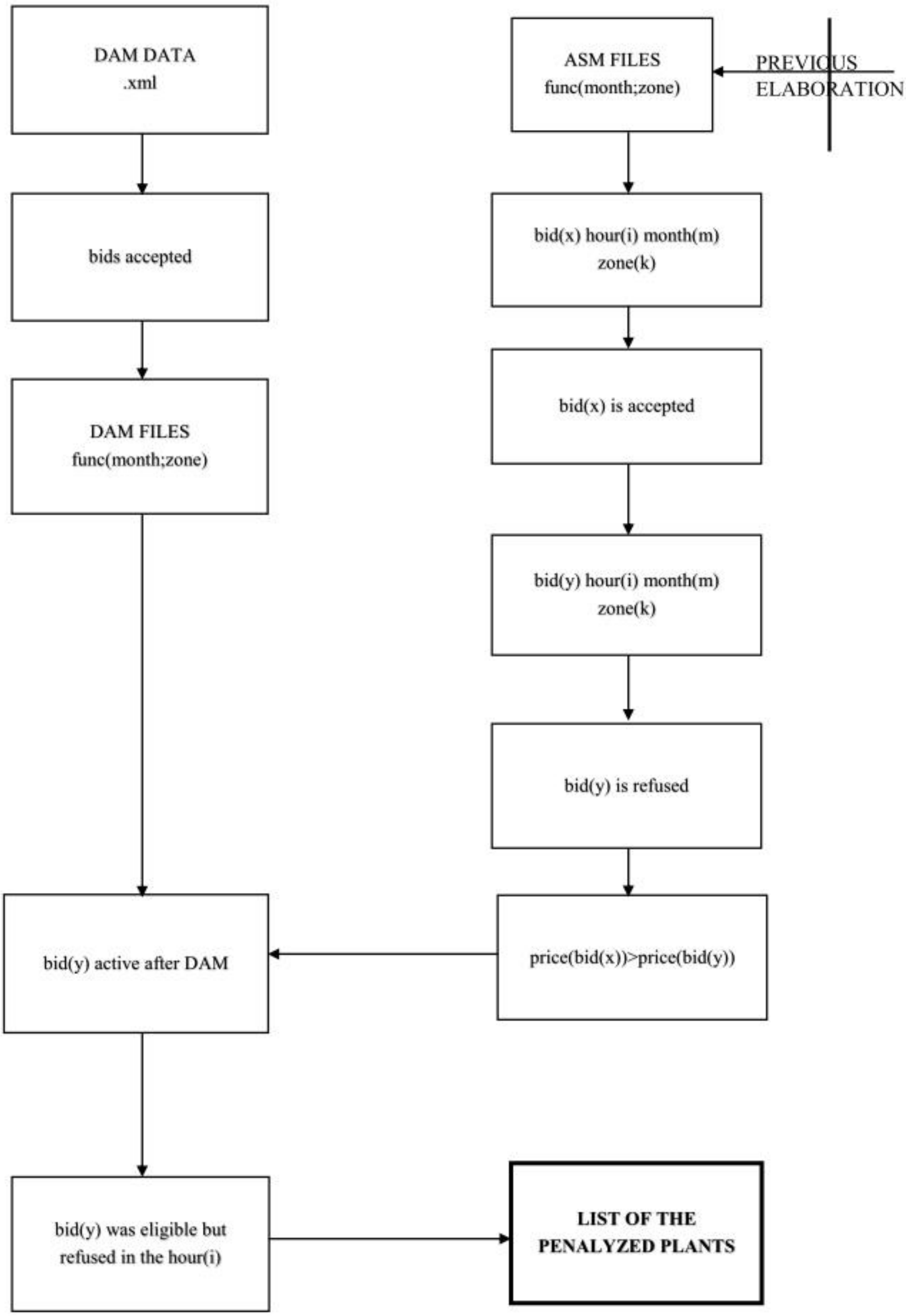

Figure 5.15: *Algorithm implemented for the evaluation of the geographic correction factor.*

The procedure required first of all the individuation of all the plants enabled for the service on the ASM and their localization on the territory; it is possible to find the data referred to this analysis, together with the correlated maps, in the Annex 8.
In Figure 5.16(a) it is represented the north zone together with the plants active in the month of May on the ASM.
On the map the plants accepted in the ASM are indicated with a green cross, whereas the plants eligible but refused are indicated with a red dot and a number: this number indicates the times (in terms of hours) in which the plant was eligible (bided price lower than accepted price and unit on after DAM) for the provision of upward reserve, but its bid was refused. The elaboration performed and resulting in this map allowed individuating within the north zone 4 sub-zones that seem to divide the transmission grid; these sub-zones are defined by the presence of similar characteristics in the ASM management. The procedure performed allowed also defining those plants that are essential for the proper management of the grid, which are those plants that are usually accepted on the ASM even if their bid was not optimal.
In a seminary organized in December 2016 by AEIT (the Italian association for electronics and communication) and titled “La trasformazione del Sistema elettrico, le nuove esigenze di gestione e gli strumenti per farvi fronte”, Luca Marchisio in behalf of Terna presented some topics related to the future evolution of the energy scenario particularly for what concerns the grid management. A specific focus has been dealing with the opening of the ASM to the DG units: Marchisio underlined the importance, with reference to the DCO 298/16 and to the definition of the UVA as explained in Chapter 4, to find the proper perimeter for the aggregation zones, expressing also the need to update periodically this geographic limits. The figure presented by Marchisio is reported in Figure 5.16(b); the similarity found with the intrazones individuated thanks to the analysis carried out and presented in Figure 5.16(a) is huge. This suggests that the introduction of the aggregator as a new actor on ASM must be handled taking care of the limits imposed by the grid management.

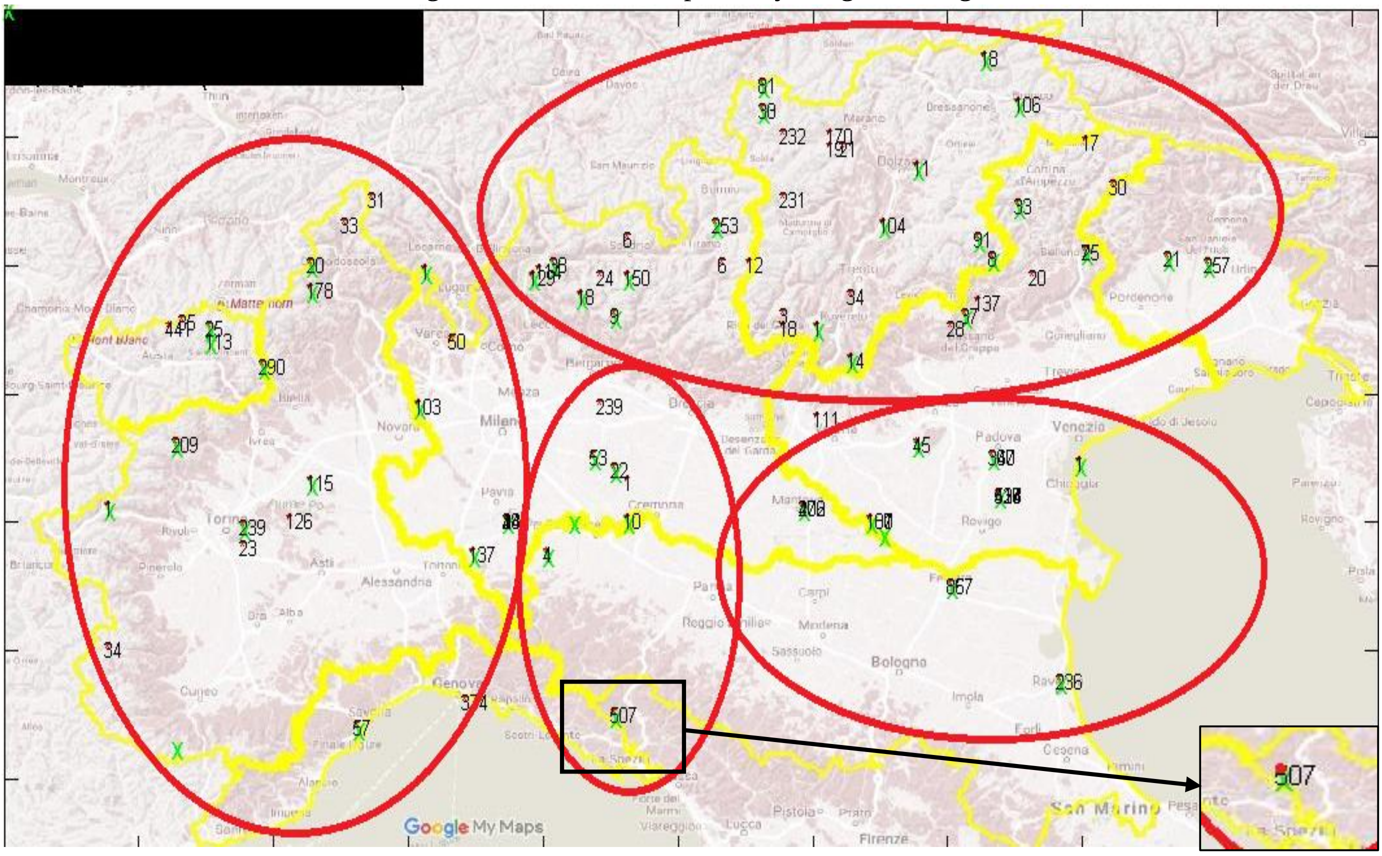

Figure 5.16(a)*: Elaboration of the data collected on a geographical base, month of May, north zone.*

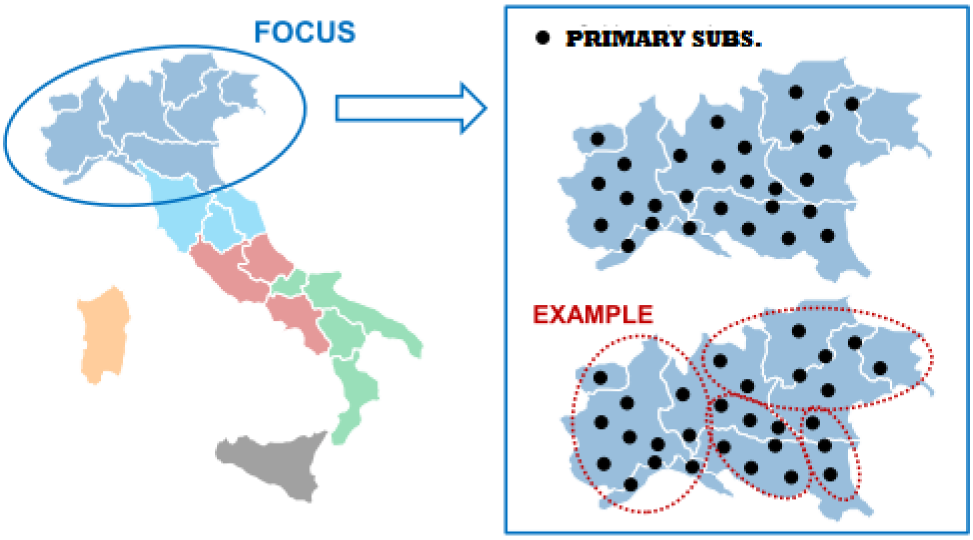

Figure 5.16(b): Subzones indication provided by Terna (December 2016).

Once each plant active on the ASM has been associated to a correction factor and to a province through an identification code (a number), it has been possible to associate to each province for every month a correction factor computed as follows:

$$corr\ fact_{plant} = 1 - \frac{elig\ bids_{refused}}{elig\ bids_{presented}}$$

$$corr\ fact_{province} = \sum_{n=1}^{n^\circ\ of\ plants} \left(corr\ fact_{plant}\right)_n$$

The province correction factors have been calculated for each month and then the reference correction factor has been computed as the mean of the calculated values. The results obtained for the correction factors of the provinces are reported in Table 5.1[6].

From Table 5.1 it is possible to see that the high number of power plants within the North zone, together with the concentration of high levels for the demand, the presence of intrazonal morphological limits and the direct link of the transmission grid with foreign countries, especially with France and Switzerland, result in small values for the zonal correction factors. These values are the mirror of the situation represented in Figure 5.16(a) through a map. The other zones, which are characterized by a much lower number of enabled power plants, present as an average higher values, even if there are still some exception where the correction factor still introduces a strong penalization.

It is necessary to specify that for those provinces belonging or representing a virtual pole of the transmission network, hence not belonging to the geographic relevant zones, and for those provinces that were not associated to a correction factor because of the lack of computational input data, the geographic correction factor has been defined as the one of the nearest province.

The correction factors resulting for each province are used to modify the reference prices of a given plant according to the province to which it belongs.

[6] According to the procedure described, a correction factor equal to 1 (or 100%) does not imply a modification of the reference prices linked to the geographical position, meaning that the unit is placed in a favorable area; vice versa a much lower correction factor implies a penalization in terms of probability of acceptance, which is considered reducing, by the factor calculated, the reference prices defined for the ASM.

This last step allows hence defining the final reference values of the prices for the upward reserve in the ASM; these prices can be considered in the economic evaluation exactly as DAM prices, meaning that the uncertainty linked to participation to the ASM is taken into consideration and used to modify the ASM prices according to the followed procedure.

***Table 5.1**: Geographic correction factors computed for the province of Italy.*

NORTH	
province	corr. fact.
ALESSANDRIA	10,86%
AOSTA	65,74%
ASTI	63,31%
BELLUNO	33,43%
BERGAMO	79,33%
BIELLA	47,59%
BOLOGNA	99,31%
BOLZANO	54,03%
BRESCIA	68,31%
COMO	52,69%
CREMONA	93,19%
CUNEO	63,31%
FERRARA	45,84%
FORLI-CESENA	98,04%
GENOVA	10,86%
GORIZIA	87,11%
IMPERIA	10,86%
LA SPEZIA	76,34%
LECCO	43,22%
LODI	64,00%
MANTOVA	53,51%
MILANO	43,22%
MODENA	99,31%
NOVARA	43,22%
PADOVA	65,25%
PARMA	93,19%
PAVIA	24,48%
PIACENZA	93,19%
RAVENNA	89,29%
REGGIO EMILIA	93,19%
RIMINI	89,29%
ROVIGO	100,00%
SAVONA	65,92%
SONDRIO	51,27%
TORINO	47,59%
TRENTO	64,60%
TREVISO	56,78%
TRIESTE	87,11%
UDINE	73,62%
VARESE	44,34%
VENEZIA	23,76%
VERBANO-CUSIO	33,61%
VERCELLI	46,95%
VERONA	65,25%
VICENZA	17,17%

CNORTH	
province	corr. fact.
AREZZO	98,04%
ASCOLI PICENO	74,19%
FIRENZE	95,75%
GROSSETO	100,00%
LIVORNO	73,24%
LUCCA	63,80%
MACERATA	74,19%
MASSA-CARRARA	63,80%
PERUGIA	96,56%
PESARO E URBINO	100,00%
PISA	95,75%
PISTOIA	95,75%
PORDENONE	59,03%
PRATO	95,75%
SIENA	100,00%
RIETI	78,83%
TERNI	78,01%

CSOUTH	
province	corr. fact.
AVELLINO	100,00%
BENEVENTO	100,00%
CASERTA	72,52%
CHIETI	68,20%
FERMO	82,21%
FROSINONE	49,89%
L'AQUILA	91,74%
LATINA	65,92%
NAPOLI	65,99%
PESCARA	99,59%
ROMA	49,89%
RIETI	78,83%
SALERNO	100,00%
TERAMO	33,41%
VITERBO	100,00%

SICILY	
province	corr. fact.
AGRIGENTO	98,66%
CALTANISSETTA	98,66%
CATANIA	74,45%
ENNA	74,45%
MESSINA	74,45%
PALERMO	93,52%
RAGUSA	35,47%
SIRACUSA	35,47%
TRAPANI	99,55%

SOUTH	
province	corr. fact.
BARI	35,00%
BRINDISI	35,00%
CAMPOBASSO	100,00%
CROTONE	100,00%
COSENZA	77,00%
ISERNIA	100,00%
LECCE	35,00%
MATERA	35,00%
POTENZA	35,00%
REGGIO CALABRIA	70,00%
TARANTO	35,00%
VIBO VALENTIA	70,00%

SARDINIA	
province	corr. fact.
CAGLIARI	53,33%
CARBONIA-IGLESIA	80,10%
MEDIO CAMPIDANO	53,33%
NUORO	94,76%
OGLIASTRA	53,33%
OLBIA-TEMPIO	80,00%
ORISTANO	94,76%
SASSARI	83,33%

5.3 Final Results of the Analysis

According to the procedure described, the main parameters that is necessary to consider are:

- the price P_2 that is the reference price to use in the optimization tool;
- the price P_1 and the probability $prob_0$ associated to the price P_2 as stated previously;
- the correction factor evaluated for each province of the Italian territory.

These parameters allow defining properly the activity of the CHP plant linked to the ASM market for the provision of upward reserve.

To illustrate the results obtained, in Table 5.2 are reported the prices for the reference week of July of the north zone. Each row refers to an hour of the day, indicated by the corresponding number; each column refers to a day of the reference week. For every day and every hour three parameters are presented: the price P_2 in the column "off ref", the price P_1 in the column "off pres", and the probability in the column "%".

Through a simple data formatting, the cells hosting the most favorable values are highlighted with a green shade, whereas the ones which are less favorable with a shade of red.

Price P_2 is the price of reference used for the ASM economic evaluation in the cash flow of the CHP plant, whilst price P_1 is the value of the bid that the plant owner has to present on the market according to the evaluation made: this price will be higher than P_2. Associated to P_1 and P_2 it is reported also a probability, which expresses the possibility in percentage points that the bid presented will be effectively accepted.

The data reported for July allow understanding that it is usual to find prices between 60 €/MWh and 70 €/MWh for the reference prices, often associated to probabilities above 80%. Despite this, it is possible to find hours when the optimal price is very high, and it is associated to low probabilities (as it occurs for the summer season of the South zone, see Figure 5.20). This suggests to the owner of the plant when it will be possible to exploit the possibilities given by the ASM in order to increase its revenues.

In Figure 5.17 it is possible to see the representation of the reference prices of Table 5.2. Even if prices are almost constant, it is possible to find outliers in the data linked probably to the activity of the PV plants, that in July is not negligible, and to the requirements of the loads, resulting in usual ramps in the morning and in the early evening.

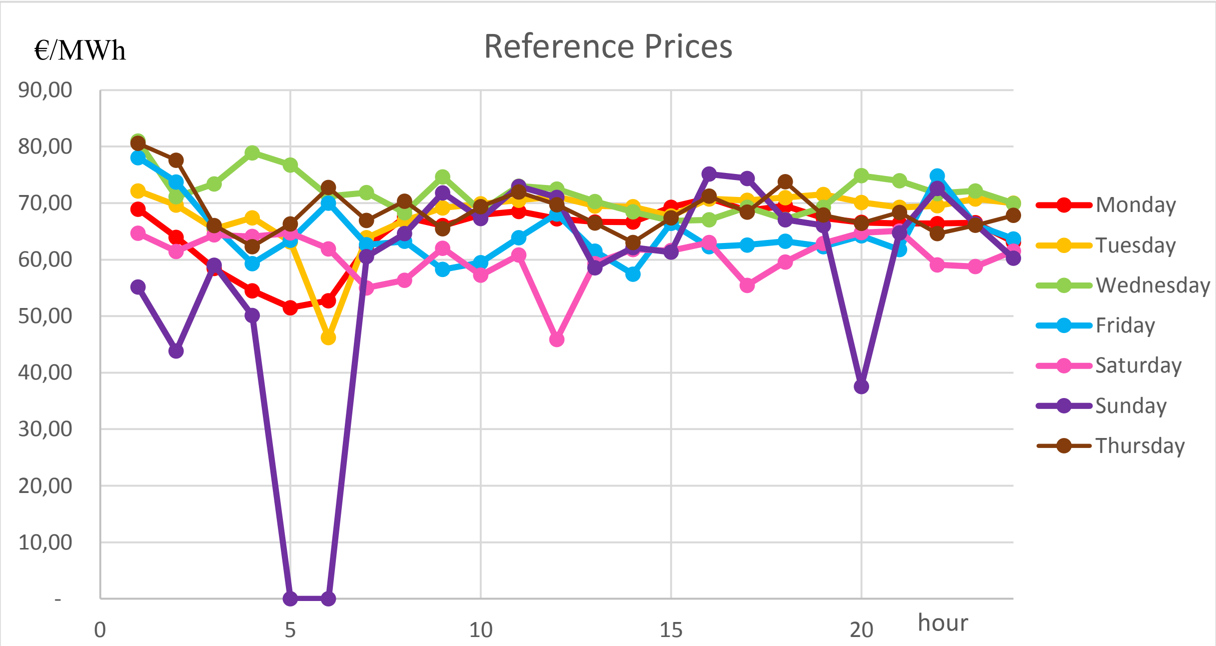

***Figure 5.17**: Reference prices for the reference week of the month of July, North zone.*

Table 5.2: Results of the analysis of the reference week of July, North zone. Prices in €/MWh.

July	Monday			Tuesday			Wednesday			Thursday			Friday			Saturday			Sunday		
	off ref	off pres	%	off ref	off pres	%	off ref	off pres	%	off ref	off pres	%	off ref	off pres	%	off ref	off pres	%	off ref	off pres	%
1	68,93	81,00	90,00%	72,16	80,69	89,98%	80,99	120,90	79,99%	80,56	104,29	89,99%	78,05	94,99	89,99%	64,65	86,39	89,99%	55,14	91,30	89,95%
2	63,96	74,18	89,98%	69,66	83,78	89,98%	71,11	84,22	90,00%	77,59	98,99	89,99%	73,75	95,88	79,98%	61,46	71,20	90,00%	43,83	93,32	89,93%
3	58,44	73,95	89,95%	65,43	84,40	89,89%	73,41	106,49	80,00%	66,03	86,18	89,98%	65,82	76,28	79,98%	64,38	77,48	79,97%	59,03	63,37	79,96%
4	54,48	75,38	89,99%	67,40	74,18	89,97%	78,90	102,48	89,99%	62,30	91,00	89,91%	59,31	72,68	79,98%	64,10	78,97	69,97%	50,10	63,00	36,00%
5	51,50	74,73	89,93%	63,15	70,59	89,99%	76,76	95,59	89,99%	66,34	85,39	89,99%	63,45	86,49	79,99%	64,71	80,20	70,00%	-	-	0,00%
6	52,74	73,66	89,95%	46,20	85,49	89,99%	71,22	105,69	79,99%	72,76	88,89	89,99%	70,00	81,08	79,98%	61,91	68,08	89,98%	-	-	0,00%
7	62,25	76,66	89,96%	63,86	71,76	89,95%	71,85	87,69	89,99%	66,92	78,68	89,98%	62,61	73,99	79,99%	55,00	69,65	89,95%	60,53	63,89	36,00%
8	67,54	79,37	89,97%	66,90	80,47	79,97%	68,29	91,50	80,00%	70,35	90,00	80,00%	63,25	72,19	89,99%	56,36	70,31	89,90%	64,60	75,19	70,00%
9	66,01	73,19	89,98%	69,17	75,80	90,00%	74,65	100,59	79,99%	65,44	93,00	80,00%	58,26	77,79	89,99%	62,03	66,84	89,93%	71,81	85,08	49,99%
10	67,95	72,98	89,98%	69,85	85,17	89,97%	68,64	82,29	89,99%	69,39	94,70	80,00%	59,48	74,39	89,99%	57,23	73,11	89,89%	67,26	79,93	39,97%
11	68,54	85,79	79,99%	70,51	85,47	89,97%	73,02	96,30	90,00%	71,95	88,28	89,98%	63,85	69,59	89,98%	60,80	73,37	89,96%	72,95	90,88	69,99%
12	67,25	84,28	79,99%	71,14	84,38	89,98%	72,50	90,29	90,00%	69,74	95,18	79,99%	68,07	97,40	80,00%	45,86	77,42	89,79%	71,04	82,25	67,67%
13	66,67	73,57	89,96%	69,49	82,87	89,97%	70,28	99,29	79,99%	66,47	81,78	89,98%	61,52	88,38	79,98%	59,30	69,37	89,97%	58,55	67,99	24,00%
14	66,64	75,27	89,96%	69,36	79,79	89,99%	68,45	90,09	79,99%	63,06	86,59	79,99%	57,43	74,49	79,99%	61,79	64,76	89,95%	62,15	65,58	89,99%
15	69,28	83,47	79,97%	67,72	85,39	89,99%	66,88	89,08	79,99%	67,38	80,89	89,99%	66,45	86,99	79,99%	61,60	65,48	89,98%	61,31	85,78	89,89%
16	70,88	89,58	79,98%	70,74	80,29	89,99%	67,03	93,19	79,99%	71,23	95,18	79,98%	62,28	85,00	80,00%	63,00	69,31	89,76%	75,14	90,22	59,82%
17	68,65	81,38	79,98%	70,50	80,80	90,00%	69,29	103,38	79,99%	68,41	82,09	89,99%	62,60	79,49	79,99%	55,47	76,18	89,99%	74,36	98,38	70,00%
18	69,53	80,38	79,98%	70,97	82,28	89,97%	67,11	91,20	80,00%	73,78	107,10	79,99%	63,24	80,20	80,00%	59,59	70,82	89,89%	67,05	79,74	69,94%
19	67,35	76,10	89,96%	71,54	80,48	89,98%	69,28	84,09	89,99%	67,88	97,39	79,99%	62,30	81,99	79,99%	62,89	69,48	89,97%	66,05	78,91	59,93%
20	66,58	80,90	80,00%	70,13	76,00	90,00%	74,85	113,78	79,98%	66,44	89,38	79,98%	64,21	78,78	79,98%	64,77	75,48	79,98%	37,58	156,35	24,00%
21	66,40	79,10	80,00%	69,25	76,09	89,99%	73,95	98,78	89,98%	68,36	99,19	70,00%	61,77	81,48	79,98%	65,07	94,27	69,97%	64,73	75,42	29,85%
22	66,37	79,29	79,99%	69,54	75,29	89,98%	71,70	89,08	89,99%	64,61	75,59	79,99%	74,82	115,57	89,98%	59,08	71,36	89,95%	72,58	88,49	89,99%
23	66,52	71,11	89,98%	70,76	79,49	89,99%	72,15	85,10	90,00%	66,08	88,20	80,00%	66,13	90,48	89,98%	58,76	78,30	90,00%	66,31	74,07	79,97%
24	63,11	77,48	89,97%	69,98	79,95	89,95%	69,95	90,89	79,99%	67,83	97,58	79,98%	63,68	84,38	79,98%	61,52	74,75	89,94%	60,23	79,80	60,00%

Figure 5.18 reports the behavior of the presented prices of Table 5.2. It is possible to see that they are obviously higher than the reference prices, as they represent a bid price and do not have to take into account the possibility that the bid is refused (as the reference prices do). In order to understand this mechanism, it is possible to look at the presented price for the hour 20:00 of Sunday, which is equal to 156 €/MWh; however the corresponding reference price is almost 40 €/MWh, meaning that the uncertainty linked to the acceptance of this bid is high. Because of this, the opportunity given by the ASM must be represented by the reference price that takes care in an intrinsic way of the acceptance risk, while it cannot be represented only by the presented price.

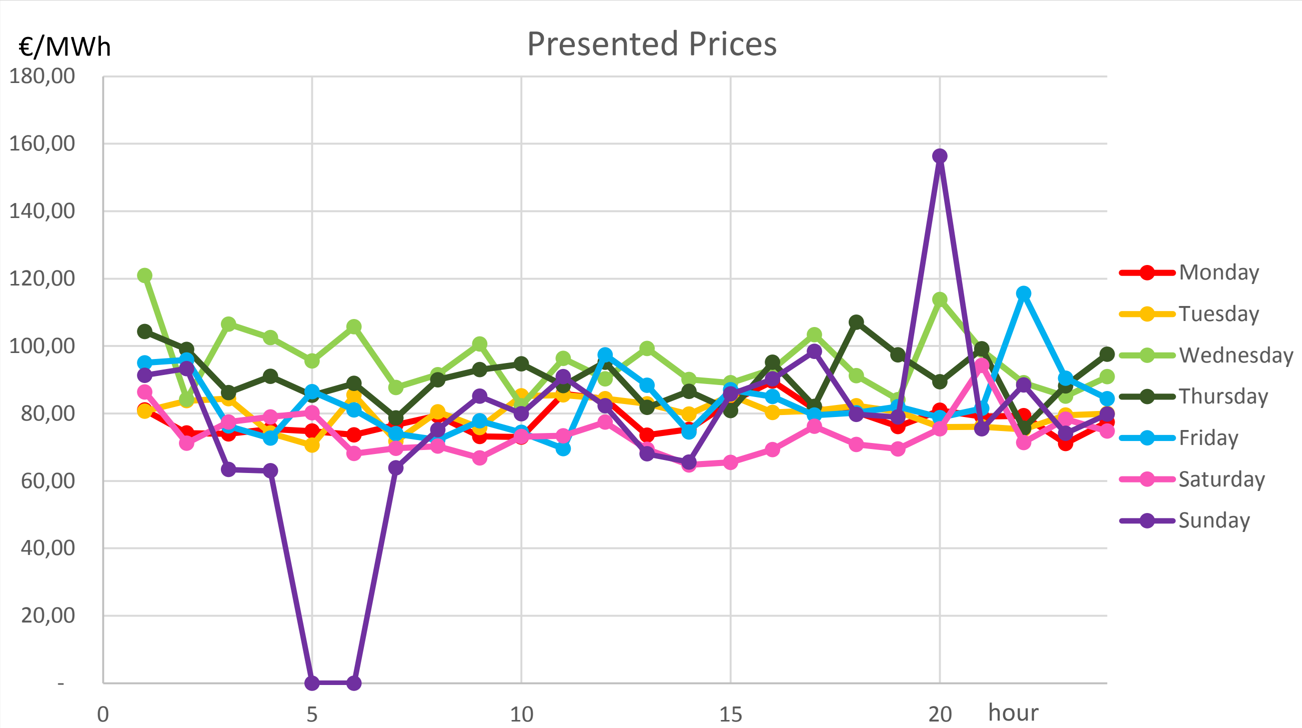

***Figure 5.18**: Presented prices for the reference week of the month of July, North zone.*

The data of Table 5.2 have been defined for every zone and every month. Given the amount of the data obtained, it is not possible to perform a complete analysis of them within this dissertation: only few significant examples will be reported and discussed below. The entire data are presented in Annex 6.

In Figure 5.19 the comparison between the reference prices of the North zone for the month of January and the month of July is reported. The prices for both months are almost constant and comprised within the reference band defined previously of 60 to 80 €/MWh. The reference prices of January are usually higher than the ones of July; however higher peaks always displaying in the early morning hours characterize July. Moreover, the month of July shows a proper amount of data always available in all the hours that allows defining always a reference price, whereas in January there are some "lacking" hours (in particular on Sunday). This lack of opportunity, already present in the few hours of Table 5.2, is correlated with a lack of data for the computational procedure; the absence of bids of interest in certain hours of the a day in the whole month is translated coherently in a lack of opportunity in those hours

A similar comparison is performed in Figure 5.20, where the reference prices of the South zone for the month of January and July are reported. The situation is completely different than the one found for the North zone. First of all the amount of significant data is for both months lower than before, mainly because of the reduced number of plants and the smaller volumes of electricity of the South zone.

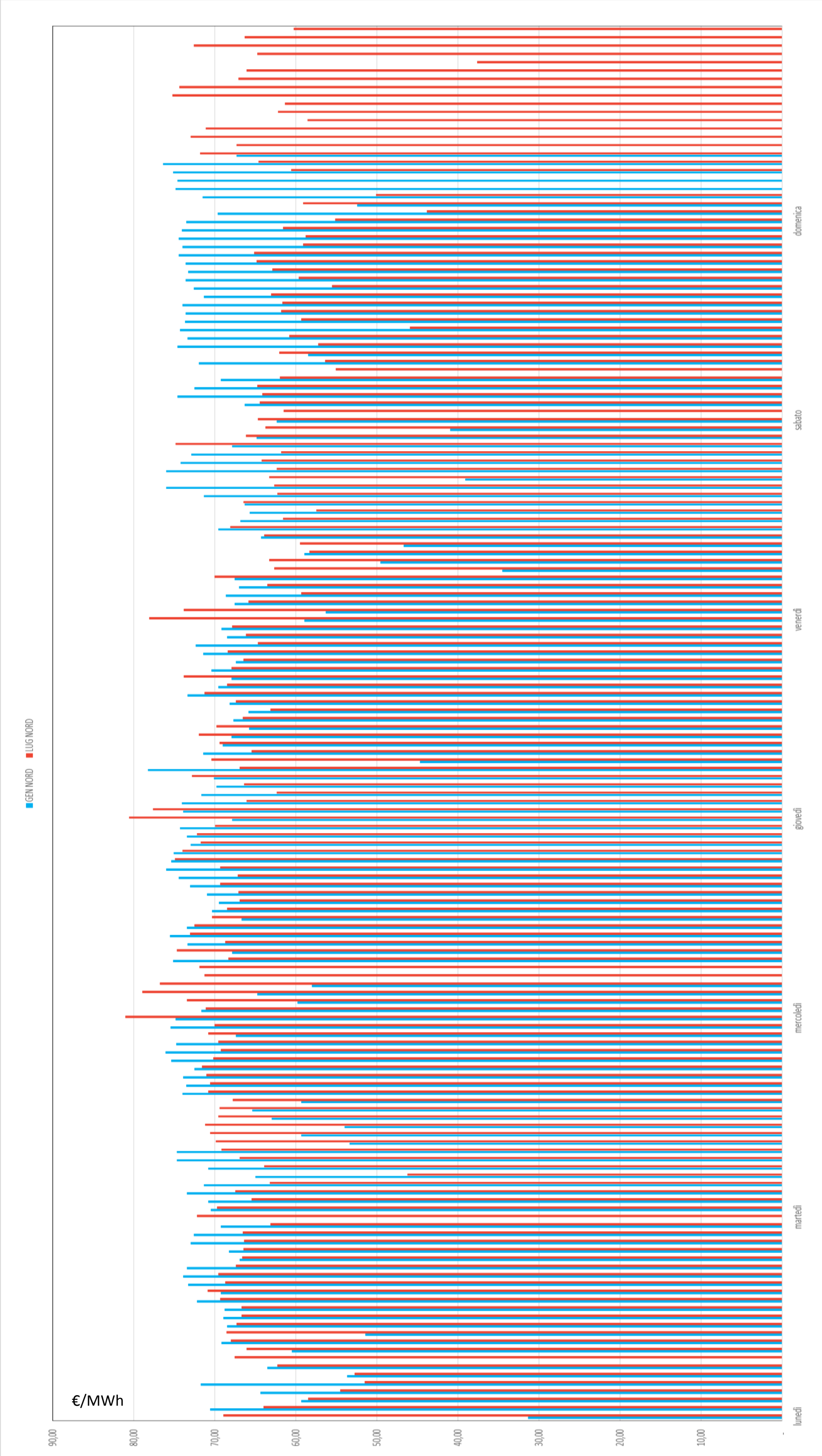

Figure 5.19: *Reference prices of the North zone, months of January and July.*

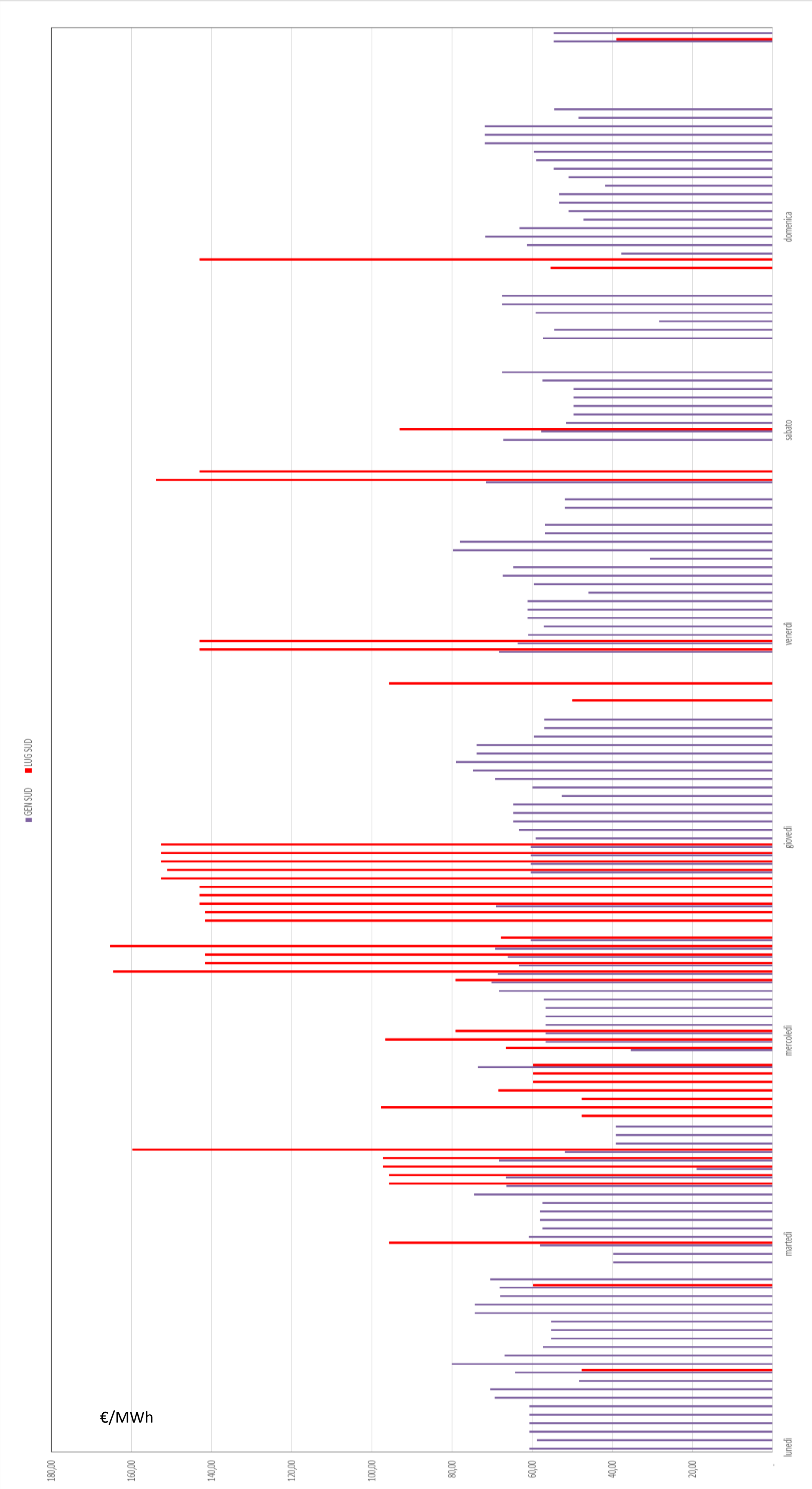

Figure 5.20: Reference prices of the South zone, months of January and July.

The most important aspect is the difference between the reference prices for the month of January, always comprised within the reference band (60 – 80 €/MWh) and the prices of July which are often above the upper limit of the reference band, reaching prices around 160 €/MWh: this situation suggests the possibility to operate selling the entire production on the ASM, given the opportunity represented by the price that it is possible to find in this market. The condition reported in Figure 5.20 for the South zone is strongly influenced by the presence of non-programmable renewable energy resources, in particular the presence of wind and photovoltaic plants. This is also suggested by the hours that present very high reference prices, which are always in the central part of day, in the early morning and in the late evening, when the influence of the unpredictability and of the variability of RES plants is greater.
Another fundamental aspect that is necessary to highlight is the repetitiveness of the characteristics of the data found. In Figure 5.21 the reference prices of the Center-North zone for the month of June are presented. It is possible to see that, beyond a group of data in the early morning of Monday, the opportunities of the ASM (meaning the possibility to participate to the market actively, expressed by the presence of a reference price) are always present in the evening for every day of the week. This suggests that the ASM is characterized by some elements that are influencing the market periodically. This periodical behavior is the sum of a set of variables (presence of RES plants, meteorological conditions, demand characteristics, grid contingencies) and displays within the single day such as within the same seasons in different years.
The considerations made above can be extended to the whole set of data collected, and allows highlighting some important factors underlying the management of the ASM and influencing the decisions of the TSO and the opportunity that this market represents for any new actor.

5.3.1 Considerations on the results obtained

As a conclusion of this section, it is worth to focus on the main results of the analysis carried out on the ASM. The study of the characteristics of the market and of the factors influencing it allowed understanding several aspects.

- The ASM is more and more important as the diffusion of non-programmable RES increases. The volumes exchanged on the ASM have increased in the last years, both in absolute terms and with respect to the volumes exchanged on the DAM. The exchange of energy is moving towards the real time, as the DAM has a reduced capacity to provide reliable and feasible results.
- The RES influence the dispatching activity. This is linked to the economic structure of the renewable plants which are characterized by the substantial absence of variable costs, making them non-competitive on the DAM (they can present bid at a variable price equal to 0 €/MWh); because of this Terna faces often a situation where a great amount of reserve or balancing capacity is needed, but the conventional power plants admitted to the ASM are turned off due to the reduced competitiveness of the DAM.
- There are some plants that can exert a market power. As they are essential for the management of the grid in secure conditions, they are always called to operate during the ASM; this places them in an advantaged position as they will intentionally offer their services at very high prices. This is translated in a mechanism according to which power plant purchase on the IM the energy sold in the DAM, modifying their position in order to be called to operate on the ASM. As they know that this will occur, they offer their services at very high prices, are remunerated and increase the costs that the TSO needs to sustain to keep the grid in a secure condition. This situation is well known to the operators of the energy markets, indeed, to face this risk, there are actually some units, identified as must run units, that are obliged to present their bids according to a specific framework in term of price [4].

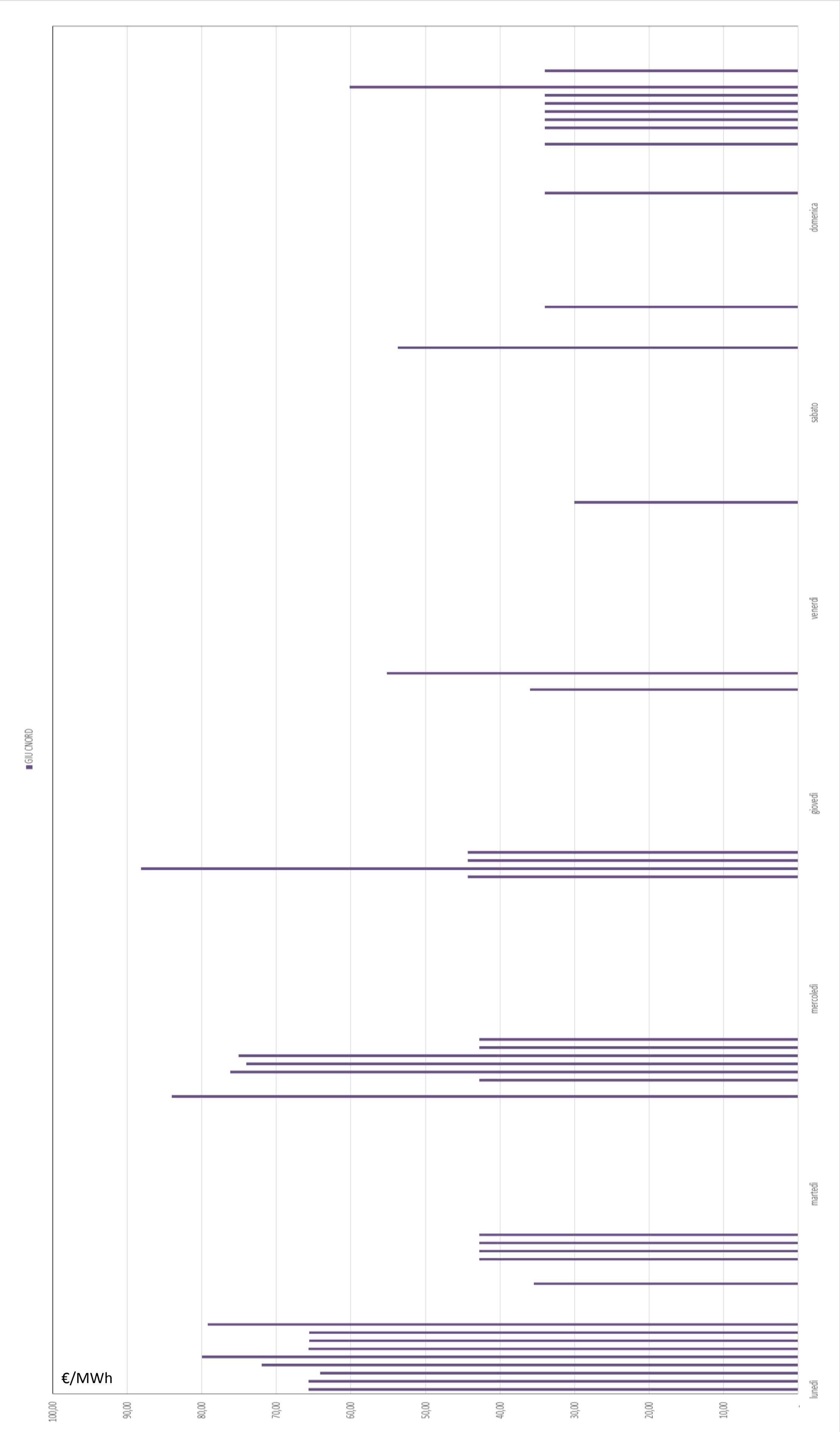

***Figure 5.21**: Reference prices of the Center-North zone, month of June.*

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CHAPTER 6
The Optimization Tool

In this chapter the tool elaborated for the optimization of a cogeneration and a trigeneration plant is presented. In particular, the analysis has been carried out through a MATLAB® code [1]; in the following sections the algorithm used is presented, in order to allow understanding the computational logic and the results that will be reported in the next chapters.

6.1 Sizing, Management and Economic Evaluation for a CHP Plant

The economic convenience in the installation of a cogeneration plant cannot be independent from a specific analysis of the electric, thermal and cooling loads required from the user; moreover, each user is characterized by very different load peculiarities, not only from the quantitative, but also from the qualitative point of view. Hence the technical and economic evaluation of a CHP plant is not straightforward and must consider the choice of the proper technology, the size and the management conditions of the plant, to be evaluated case by case.

The diagrams and the considerations presented in Chapter 2 usually help in the definition of the technology for the specific case.

The optimization tool developed in this thesis work is shaped on the characteristics of ICEs CHP plants, however its working principle can be applied also for other types of CHP plants.

Usually, once the profile of the thermal, cooling and electric demand is known, it is necessary to compare the different hypothesis concerning the size of the plant to be installed, and the way the plant is managed. Beyond the technical feasibility, the economic evaluation is the key factor around which any investment evaluation revolves. Within this evaluation, a number of parameters must be considered: the capital costs, the economic valorization for the different energy vectors, the presence of special economic treatment for the plant and all the operating costs.

Although the analysis cannot be generalized, few considerations can be made.

- The cogenerator is often under-dimensioned with respect to the peak demands of the user, in order to have the system working for the highest possible number of hours per year in working conditions near the nominal ones. This helps in obtaining higher values for the efficiencies. The peak loads can be easily covered by auxiliary boilers and by the national electric grid.
- The Payback Time (PT) is usually shorter if the plant is performing a high number of equivalent hours per year.
- The maximum value of revenues is not always coincident with the minimum value of the PT, this because the latter depends on the capital costs associated to the installation of the cogenerator. The CAPEX is depending on the technology chosen and on the factors relevant to each user situation, and it is typically affected by a considerable scale effect.
- The economic convenience is strongly influenced by the economic conditions of the electricity and gas provision. These conditions are often linked to ongoing situations and legislation that can be subjected during the years to reformation; because of this, it is always important to consider the context in which the investment is made, especially from a regulatory standpoint.

6.1.1 The sizing phase

The correct choice of the plant size is a necessary condition to have a proper economic return of the investment. The thermal and electric loads are variable along the day and along the year, and they follow different paths. This consideration is particularly relevant for civil users, while industrial users are generally characterized by more flat demand curves, at least within the same seasonal period.
A first approach could be based on the possibility to cover the peak loads from the thermal or the electric point of view; however this approach is generally wrong as the factors to be considered are multiple. In general, wasting heat is usually inconvenient especially for civil applications where the main saving is correlated with the natural gas price (as the VAT applied in the NG bill goes from 22% to 10%); the cost of the plant is proportional to its electric power, meaning that a plant with a greater nominal power will have a higher PT. Beyond this it is necessary to remember that, even if the global efficiency remains almost constant, at partial load the electric efficiency decreases.
Therefore, as a common rule, CHP plant are sized in order to have the highest number of equivalent hours per year of working operations, and in order to produce useful thermal energy and electric energy to be self-consumed or sold into the market.
In this chapter and in Chapter 7 and 8 it will be shown how these considerations are not always valid, and how the different parameters influence the correct operations of the plant.

6.1.2 Management of the plant

As already stated, when dealing with the working conditions of a CHP plant, considered the high variability of the loads both from a daily and from a seasonal point of view, it is usually necessary to establish a priority in the load tracking. In this context it is possible to define two different management conditions: heat or electricity tracking.
The heat tracking modality easily brings to have a surplus or a deficit regarding the electric production that can be sustained, thanks to the connection with the electric grid.
The electricity tracking modality implies a surplus or a deficit of heat, introducing the need to have auxiliary boilers and possibly a Thermal Energy Storage (TES).

6.1.3 Fundamental parameters for the economic evaluation

In the literature and in the practice there are a number of parameters used for an economic evaluation. Beyond the method used, it is always necessary to consider two aspects: the time extent of the analysis, linked to the cash flows, and the inflation rate for the actualization of the monetary flows.
Usually it is possible to distinguish between simple and precise methods.
For the purpose of the evaluation made in this work, two parameters have been considered: the Payback Time (PT) and the Net Present Value (NPV).
The PT is defined as the number of years that the investment takes in order to pay back, i.e. the year in which the cash flow becomes positive. The NPV is defined as the actualized cash flow value in the last useful year of the investment.

6.2 The Definition of the Optimal Plant Configuration

The evaluation of the optimal management of a CHP plant is a complex operation.
As explained, the regulation of the working conditions is strictly dependent on the kind of user that the plant is serving. In particular, a strong difference distinguishes the civil and the industrial applications. Civil applications are generally characterized by loads varying a lot along the day and the year; moreover the thermal load of civil user is entirely based on hot water (space heating) demand.

On the other hand, industrial applications are characterized by load curves which are more flat, because they are linked to a more constant activity. Beyond this, often the main part of the thermal load of an industrial user is composed by steam demand: this modifies the ability of the plant to cover the thermal load of the user.
Because of these differences, a specific algorithm has been implemented for the management of a CHP plant serving a civil or an industrial user; the main difference is laying on the need to produce a thermal energy vector with different characteristics. Indeed, as stated in Chapter 2, an ICE CHP plant is characterized by a production of heat that is only in part available at high temperature, thus useful to produce steam. The heat coming from the engine jackets, the intercooler and the lubricant oil is at low temperature, and can be exploited only for the production of hot water.

6.2.1 Structure of the optimization algorithm

The core of the optimization tool is the definition of the working conditions of the CHP plant in each hour of the year. The procedure is presented in Figure 6.1.
The algorithm starts considering a single hour. Each hour is associated to a specific thermal, electric and cooling load that has to be evaluated specifically for every user; moreover, each hour is characterized by a reference price on the DAM and on the ASM. The definition of these prices is described in Chapter 4; the involvement of the ASM in the operations of the plant allows evaluating the impact, from a cash flow point of view, of the opening of the market to the DG.
The first step in the procedure consists in the definition of the *de facto* situation, indicated as SDF from now on. The SDF refers to the situation where the CHP plant is shut off: the economic cost associated to this configuration is computed through a specific function.
Once the SDF cost has been defined, the cost of the best project situation (indicated as SDP from now on) is computed. This computation considers all the possible values of nominal gross power that can be erogated by the CHP plant, from 50% to 100% of the load power. For every value four different scenarios are defined: each scenario describes a way in which the plant can run, and calculates the values of every energy vector within it.
In particular scenario one (S1) considers as priorities the self-consumption of the electric energy produced and the exploitation of the thermal energy produced to cover the thermal load. Scenario two (S2) considers first the self-consumption of the electric energy and the coverage of the cooling load through the exploitation of the thermal energy produced. Scenario three and four (S3 and S4) are equal to S1 and S2 respectively for what concerns the exploitation of the thermal energy, but consider to firstly sell the electric energy on the energy market instead of self-consuming it.
The definition of every scenario is performed for each value of the gross power of the plant. For each value, among the four scenarios, it is possible to individuate the one associated to the minimum cost: this is defined as the best scenario for the gross power value considered. Once all the values of the nominal gross power of the plant have been considered, among all the best costs that have been computed for the specific hour, the optimal one is chosen: this cost will be associated with a specific power erogated by the plant and a specific scenario defining its working conditions.
At this point, the SDF and the resulting SDP costs are compared in order to determine if, in that specific hour, it is worth to turn on the plant. In the end of the computation, a modulation of the CHP plant power is performed according to economic considerations about the €/kW component in the bill.

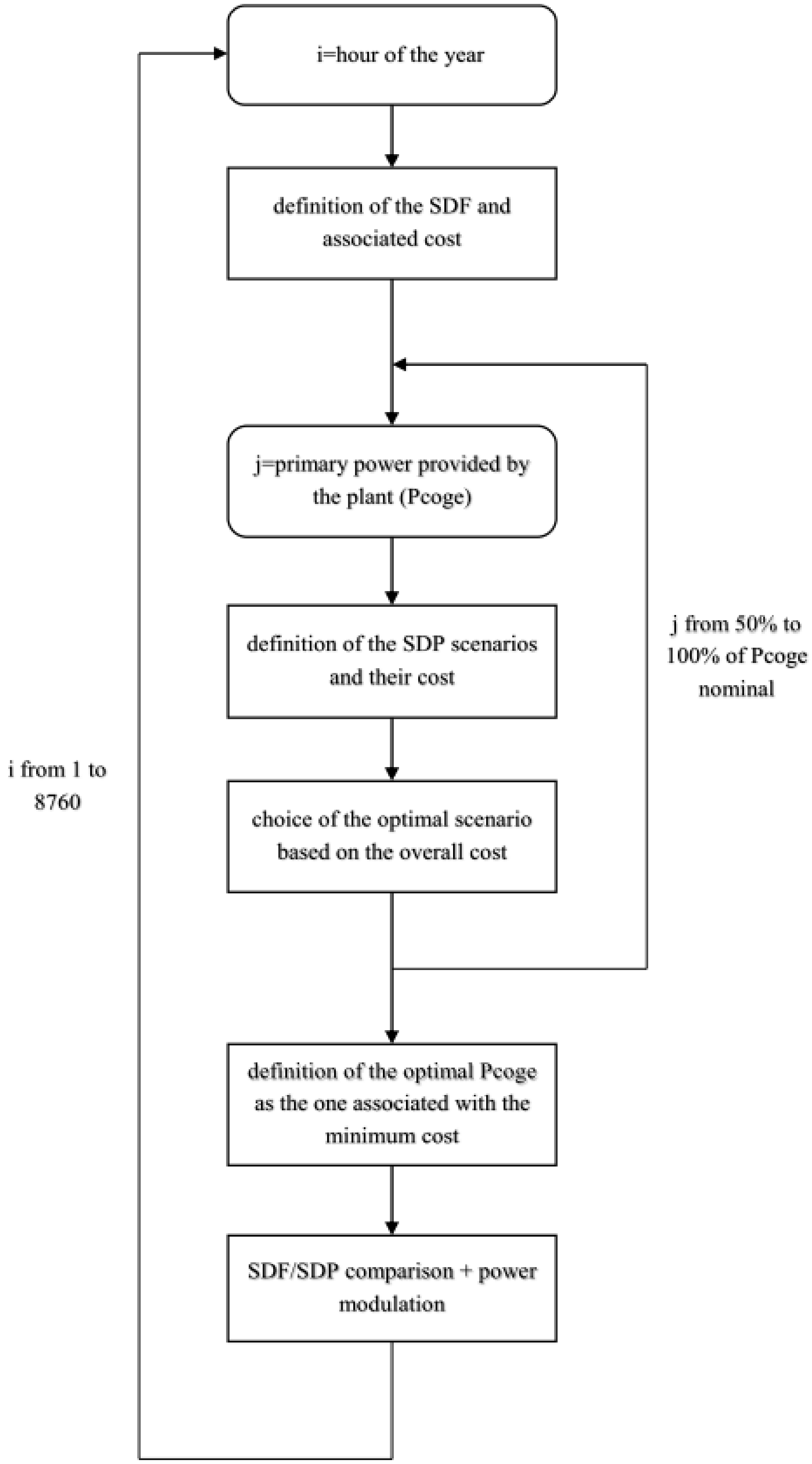

Figure 6.1: *Algorithm for the optimization routine.*

6.2.2 Scenarios management for civil users

Before starting the description of the definition of the energy vectors for the optimized behavior of the plant, it is worth to represent the plant scheme highlighting all the main vectors and assets. Figure 6.2 it shows the different energy flows and the different units that are participating to the optimization process.

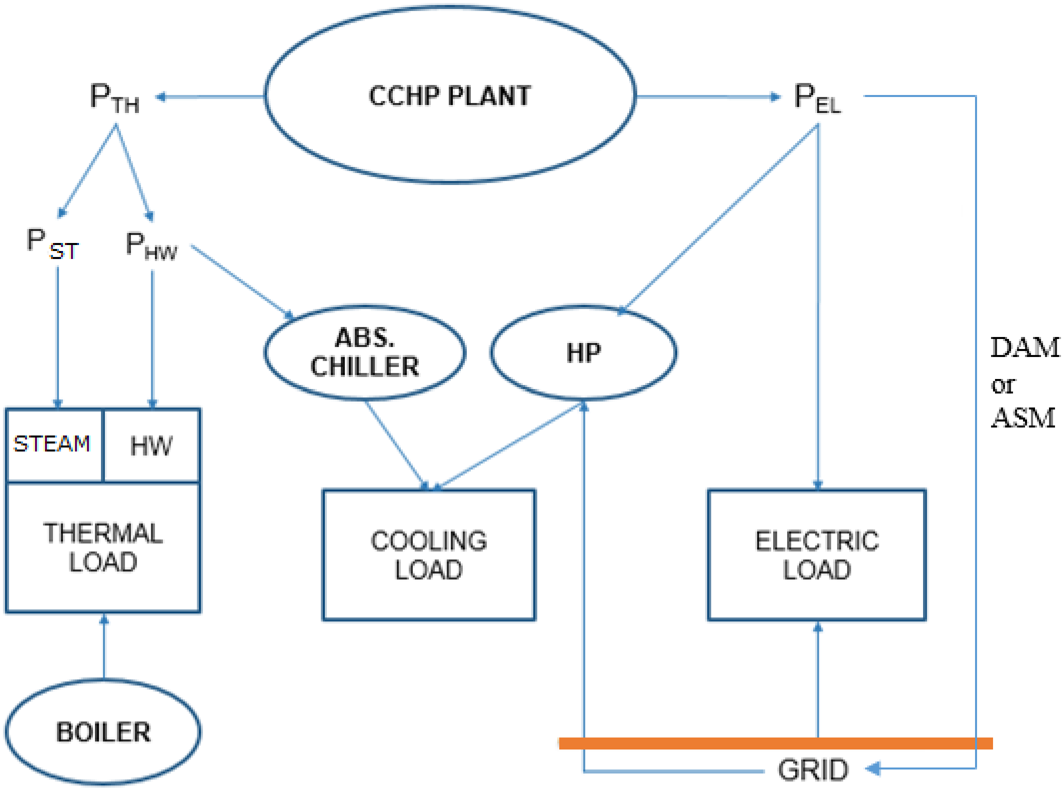

Figure 6.2: *Scheme for the CCHP plant.*

As stated above, for civil applications the thermal load is entirely exhausted by the production of hot water, hence there is no need to distinguish between the production of high temperature heat (P_{ST}) and low temperature heat (P_{AC}).

The first step of the scenarios management procedure consists in the computation of the SDF. In particular, in the SDF all the electric demand is covered withdrawing electricity from the grid; also the cooling load is covered only through the use of the heat pumps, running thanks to the electric energy from the grid. The thermal load is covered thanks to the exploitation of the boiler heat.

It is possible to compute the NG needed and the electricity withdrawn through the following equations:

$$kWh_{el} = load_{el} + \frac{load_{cool}}{COP_{HP}} \quad [kWh]$$

$$NG_{boil} = \frac{load_{th}}{LHV_{NG} * \eta_{boil}} \quad [Sm^3]$$

The monetary value associated to the SDF is computed with a specific function that will be illustrated next.

The next step is the cycle where the best scenario for each value of the nominal power provided by the CHP plant is determined. In particular, it is necessary to consider a determined hour of the year and a value of gross power from the CHP plant between 50% and 100% of its nominal power.
Given the values of the electric power (P_{EL}), the thermal power (P_{TH}) and the amount of NG needed at 100%, 75% and 50% of the load, it is possible, through a linear interpolation, to define for any value of the gross power the corresponding value of the three parameters above.
From them it is possible also to define the total, the electric and the thermal efficiency, according to:

$$\eta_{EL} = \frac{P_{EL}}{P_{gross}}$$

$$\eta_{TH} = \frac{P_{TH}}{P_{gross}}$$

$$\eta_{TOT} = \eta_{EL} + \eta_{TH}$$

These parameters are the basis for the scenarios definition, and now it is possible to proceed with the calculations for each scenario.

- SCENARIO 1: SELF-CONSUMPTION + HEATING FIRST.

S1 foresees the exploitation of the electric energy produced by the CHP plant for the self-consumption, and the use of the P_{TH} for the thermal load. The algorithm for the definition of the energy vector in this scenario is presented in Figure 6.3.
The P_{EL} is exploited to cover the electric demand; if it is not sufficient the remaining part is withdrawn from the grid. If the electric energy produced is higher than the electric load, the remaining part after the load coverage is used to produce refrigeration water through the heat pumps, if it is needed. If the heat pumps are not called to run, or if their load is not sufficient to run out the P_{EL}, the electricity produced in excess is sold in the DAM or in the ASM, according to the situation that is considered the most attractive. The elaboration of the ASM data explained in Chapter 4 allowed defining a set of hourly prices of reference for the upward reserve service that are fully compatible, through a simple side by side comparison, with the DAM prices: the prices computed contain, in an intrinsic way and thanks to the elaboration to which they have been subjected, the uncertainty linked to ASM framework and participation.
From a procedural point of view, this means that it is possible to compare them directly to the DAM, as it is done; from an economic point of view, this means that the reference prices that are used for the economic evaluation have been defined in order to take care of the possibility that in a single hour the bid of the plant is not accepted, whereas in another hour its bid is accepted at a price higher than the reference one, which is the price of the bid presented (in real life) by the unit on the ASM.
The elaboration concerning the ASM allowed also determining the hours along the year in which the participation to the ASM for the CHP plant, providing an upward reserve, can represent an opportunity: thanks to this analysis the plant will know how and when present a bid on the ASM, and the plant owner and/or the stakeholders will be able to understand the economic opportunity represented by the market participation from an investment point of view.
The P_{TH} is used to cover the thermal load. If it is not sufficient, the auxiliary boilers are activated.
If some heat remains unused, it is exploited to run the absorption chiller, and covers, through the chiller efficiency, the cooling load. In the case in which there is still some heat remaining, this heat is wasted; on the other hand if some cooling load is not covered, the heat pumps are activated and this load is exhausted.

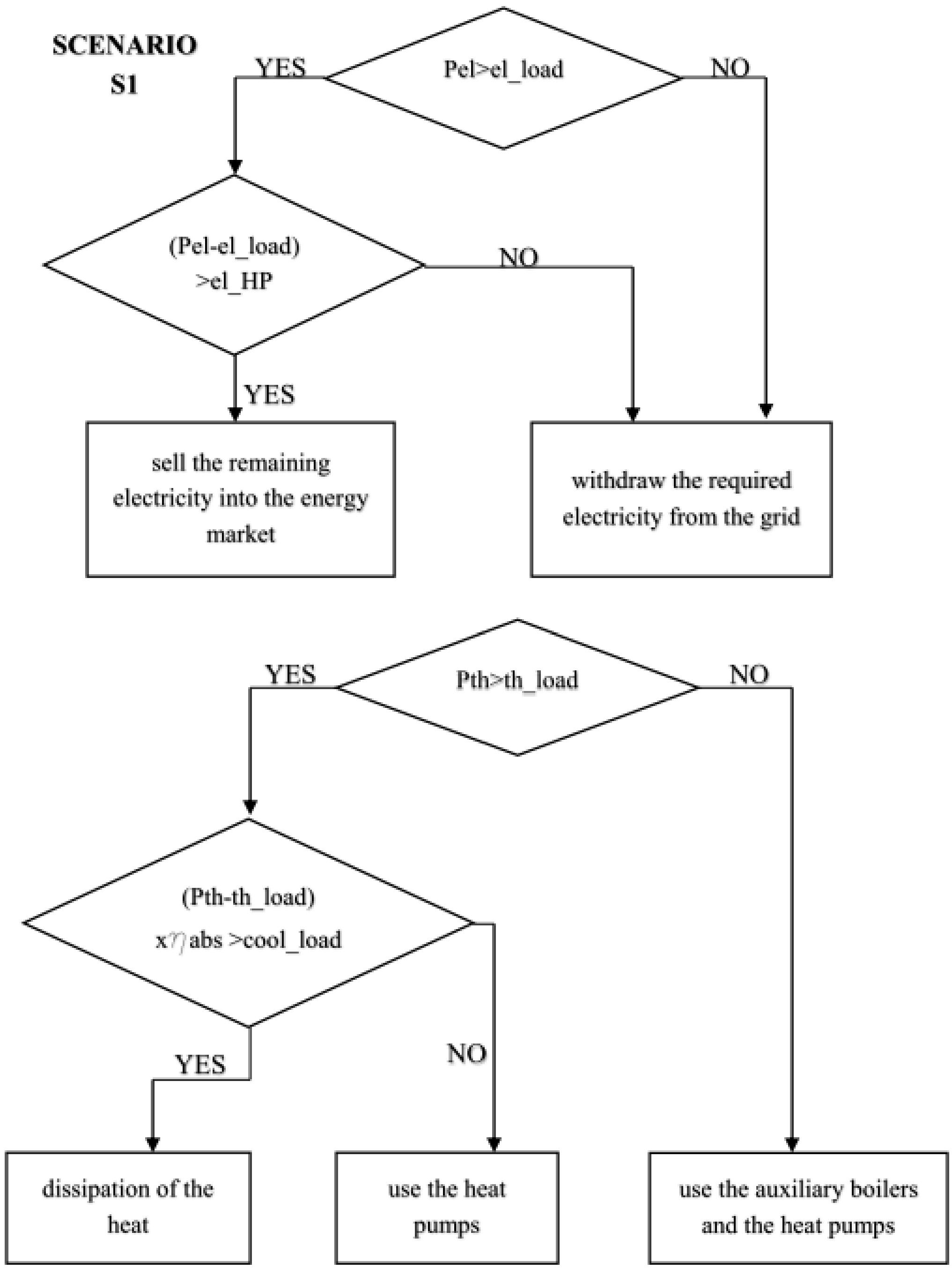

Figure 6.3: *Algorithm for the definition of Scenario 1.*

- SCENARIO 2: SELF-CONSUMPTION + COOLING FIRST.

Figure 6.4 reports the functional algorithm for S2.

The management of the electric energy produced by the plant is the same of S1.

In S2 the thermal energy produced by the CHP plant is firstly exploited to cover the cooling load through the use of the absorption chiller. If the cooling load is greater than the energy available, the heat pumps are used to cover the remaining cooling load, and the boilers are used for the thermal load.

If the heat available is higher than the one needed for the cooling load, it is used to cover the thermal load. In the case in which there is still an amount of heat not exploited, this is wasted; if instead there is still an amount of thermal load to be covered, the boilers are activated.

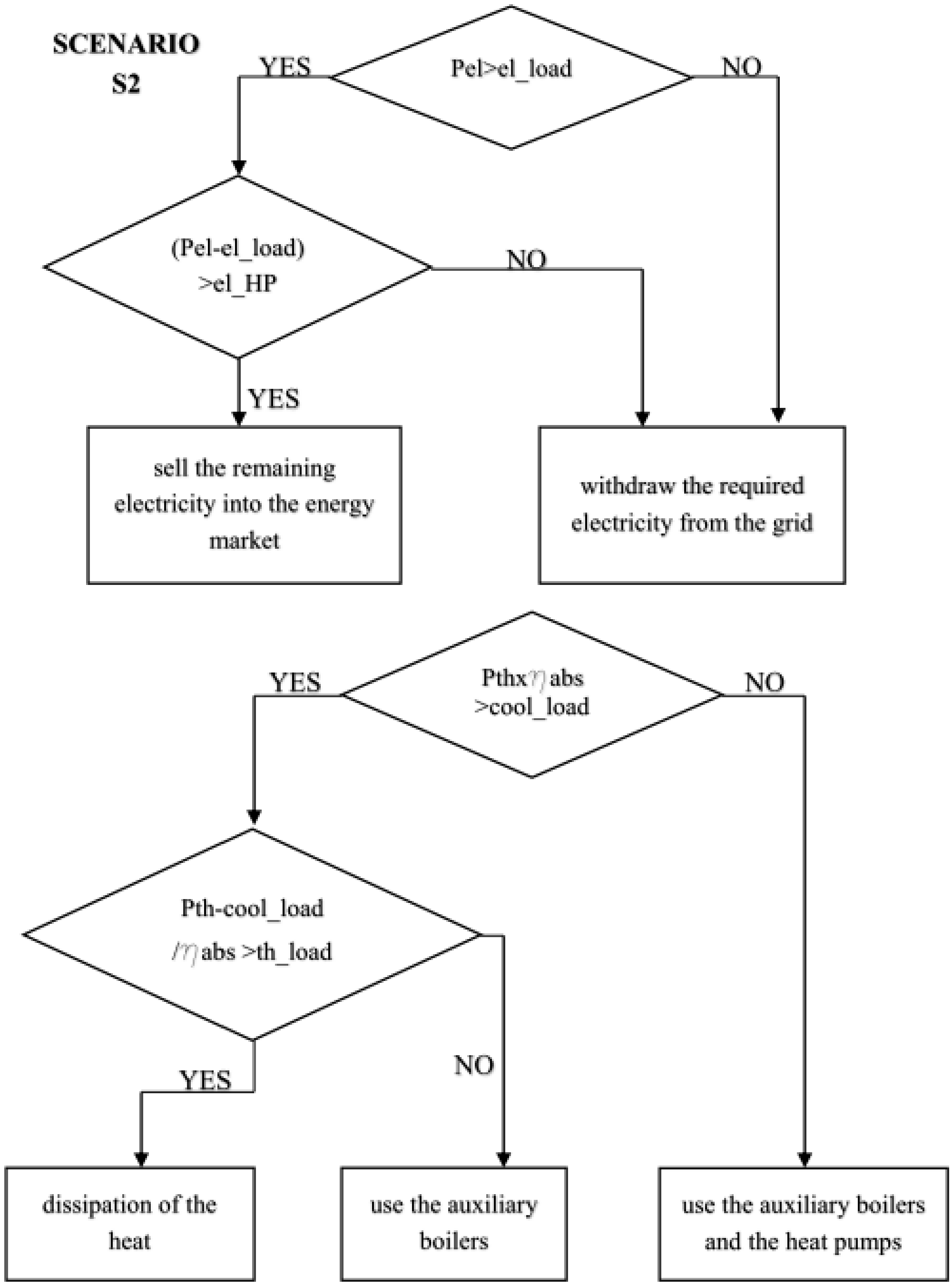

Figure 6.4*: Algorithm for the definition of Scenario 2.*

- SCENARIO 3: DAM/ASM + HEATING FIRST.

Figure 6.5 represents the algorithm for scenario 3.

In S3 the management of P_{EL} is simply based on the selling of electricity into the DAM or into the ASM.

This scenario is analyzed according to the consideration that the market price, particularly on the ASM, can be high enough to justify the complete selling of the electric energy produced without self-consumption. It is necessary to consider that in this configuration the UdD is called to purchase the amount of energy for its consumption on the DAM, then it will present an offer on the ASM for all its available electric power. In the delivery day, it will sell and buy energy according to the quantities defined in the DAM and in the ASM; however, in real time, only the amount of energy sold in the ASM exceeding the electric load (or vice versa the amount of electric load exceeding the energy sold in the ASM) will be registered at the POD level by the metering system. This means that when the opportunity given by the market price is better than the one represented by the self-consumption, it will be necessary to distinguish between the energy commercialized and the energy exchanged.

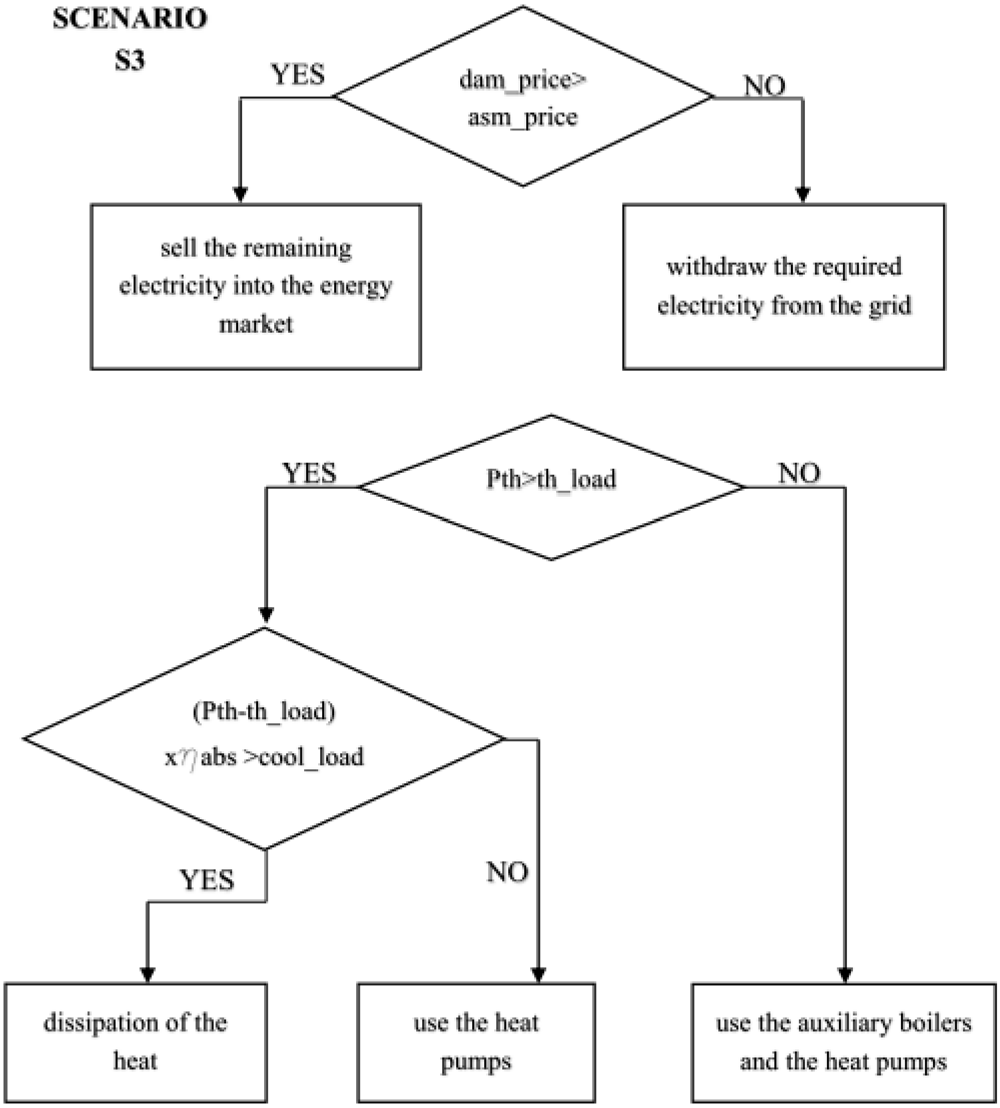

Figure 6.5*: Algorithm for the definition of scenario 3.*

The actual regulatory framework is not yet completely defined, and the situation described above could introduce a regulatory issue. Nowadays, in the DAM (on the commercialized energy) only the PUN is paid, which is a percentage of the total price paid in the bill. The grid services are paid only after the energy exchange. Once a plant owner (UdD) has bought a certain amount of energy on the

DAM and has sold another amount of energy on the ASM, it will pay the PUN on the DAM and it will be remunerated with a pay-as-bid mechanism on the ASM.
In this framework the added value for the UdD is not simply the opportunity represented by the ASM price, but also the possibility to purchase energy on the DAM at a price, and sell this energy on the ASM at an higher price. This practice, as it would introduce an evaluation that does not consider the costs associated to the electric energy in a right way, is considered unfair and in particular is judged to introduce in the market a possible arbitration mechanism.
Given the considerations above, the added value represented by the energy markets, particularly by the ASM, is computed associating to the energy commercialized in the DAM its whole cost, as if all the charges were paid in the moment of the energy purchasing. It is believed that in the future the new market regulation will take care of all these aspects.
For what concerns the management of the thermal energy, the situation is equal to S1.

- SCENARIO 4: DAM/ASM + COOLING FIRST.

Figure 6.6 presents the algorithm for S4.

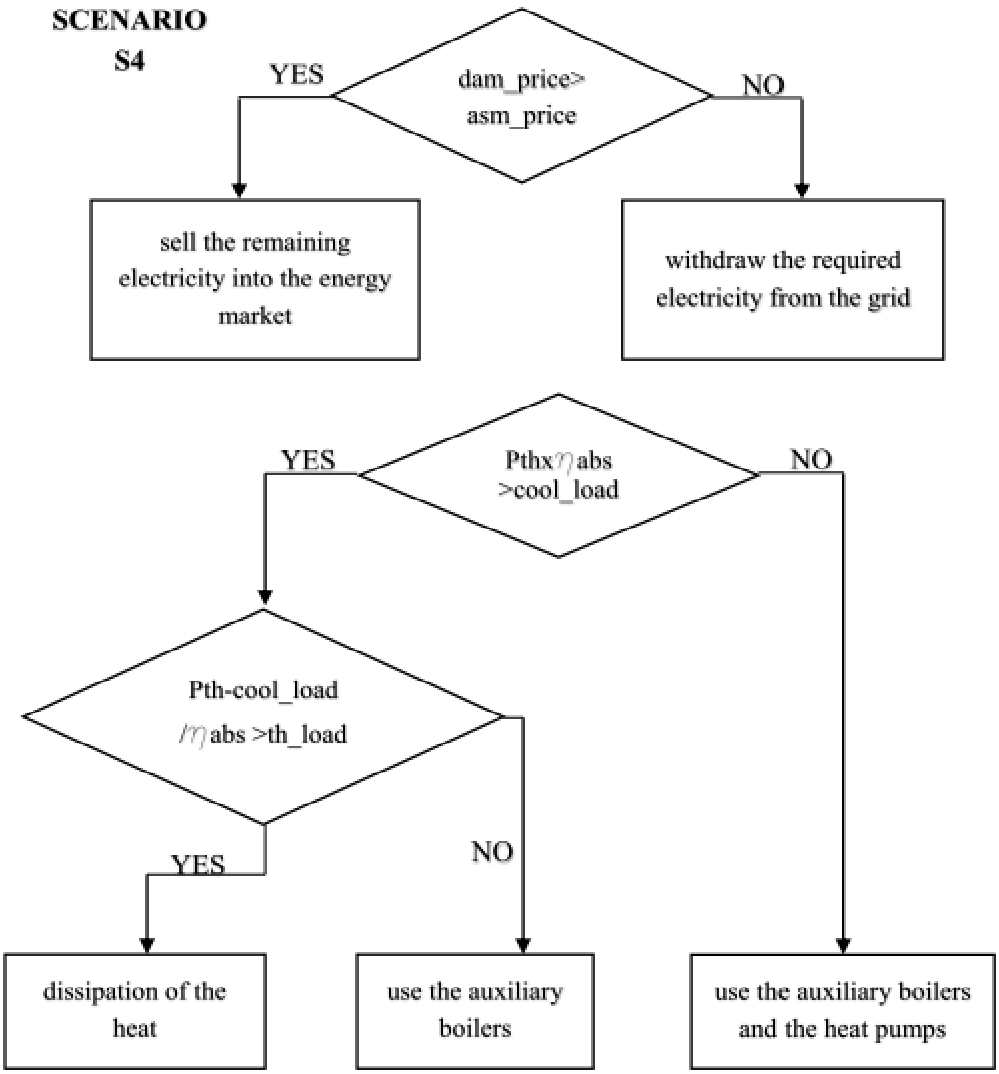

Figure 6.6: *Algorithm for the definition of scenario 4.*

In S4 the management of electricity is the same presented for S3, while the management of the thermal energy is the same presented for S2.
Once the calculations for all the four scenarios have been performed, the economic cost associated to each one is computed and the scenario characterized by the lowest cost is picked up in order to represent the best scenario for the current gross power value.
This procedure is performed for all the values of the nominal gross power from 50% to 100%.
When all the best scenarios have been defined, it is considered a curve where the power erogated by the plant goes from 50% to 100% of its nominal value, and for each value the best scenario's cost is reported. This allows choosing the optimal power value in the range considered; associated to this power value a specific scenario is already present, with a determined cost and a determined value for all the energy vectors and parameters, as they have been computed before.
The optimal cost, defined as the SDP cost, is compared with the SDF cost in order to establish if it is worth to turn on the plant in that hour. After this comparison, the pre-modulation optimal values of all the parameters are defined according to the previous calculations.

6.2.3 Scenarios management for industrial users

The computational procedure described above can be generalized also for what concerns the management of industrial users. However, as stated before, industrial users are concerned by the presence of a thermal load consisting in the production of steam, to be used in industrial processes, that requires a high temperature heat in order to be generated. This does not entail any issue if the CHP plant is based on a gas turbine, but introduces the need of a correction in the calculations if an ICE CHP plant is considered. Indeed a part of the thermal power available from an ICE CHP plant comes from low temperature energy vectors, such as the heat from the engine jackets, the lubricant oil and the intercooler. These flows are usually available at temperatures around 90°C, and they are useful to produce hot water, not to produce vapor.
Because of these considerations, a different algorithm for the thermal load management has been developed for what concerns the industrial users.
Following the distinction made before, Figure 6.7 presents the algorithm used for the thermal energy vectors in the case of a priority for the heating load.
In this first configuration, used for S1 and S3, the amount of high temperature thermal energy produced by the CHP plant (P_{ST}) is computed and it is compared with the high temperature thermal load, that is the one needed for the exclusive steam generation. If some of the heat produced is left after the coverage of the steam load, it is used for the production of hot water, together with the low temperature heat produced by the CHP plant (P_{HW}). The remaining heat, if present, it is used to cover the cooling load. On the other hand, when the thermal power produced by the plant is not sufficient, the boilers and the heat pumps are used. In the particular case of an industrial user, the high temperature and low temperature thermal loads must be considered as separated: this can lead to a situation where part of the low temperature heat produced by the cogeneration process is wasted, and at the same time the boilers are running in order to cover a part of the high temperature load (the P_{ST} production is not sufficient). Hence the unavailability of part of the heat for the generation of steam constitutes a penalization for the operations of the plant from an economic point of view.

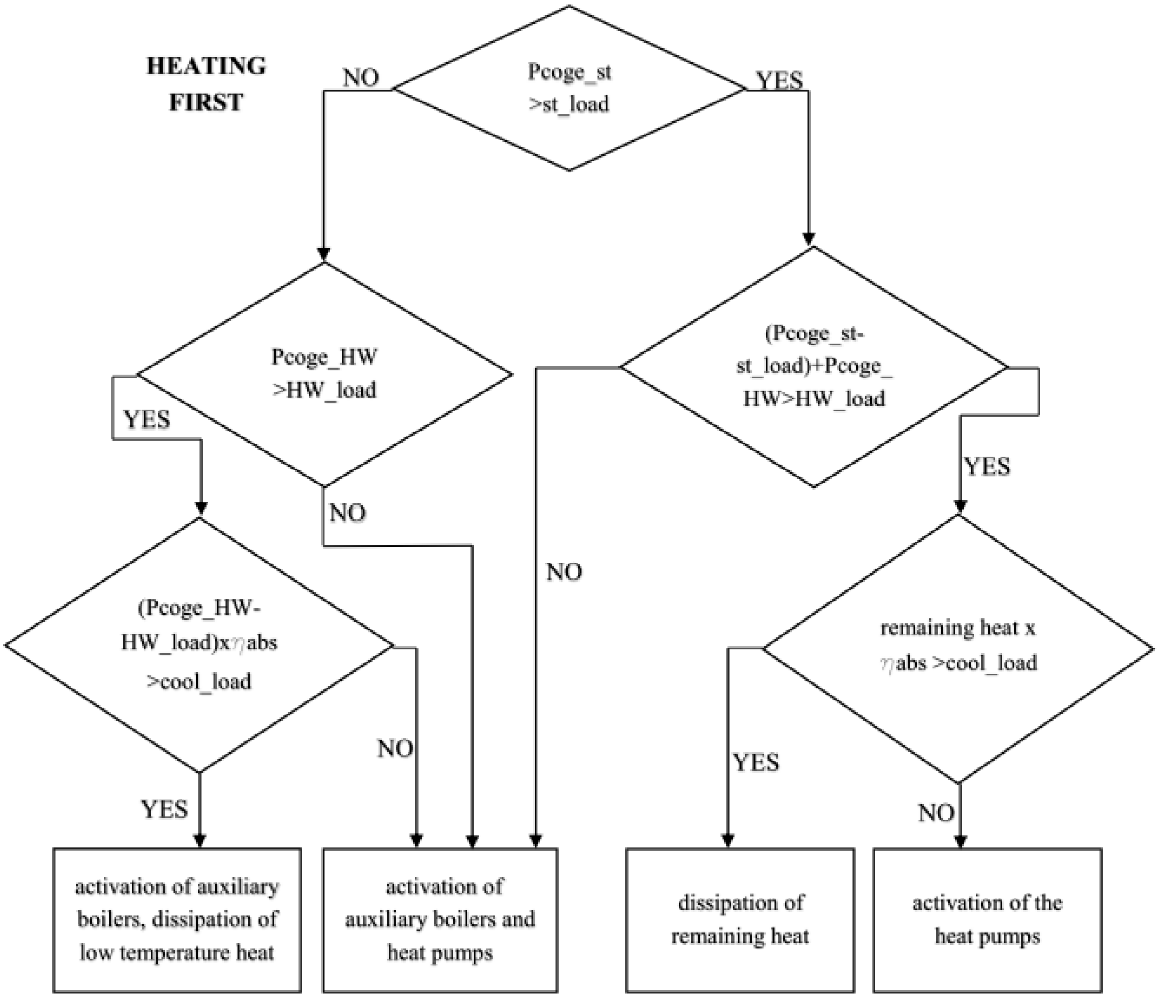

Figure 6.7*: Algorithm for the heat management for an industrial user, heating first scenario.*

The second configuration is the one giving the priority to the coverage of the cooling load, corresponding to the thermal load management of S2 and S4. Figure 6.8 presents the algorithm used in this case.

The low temperature heat P_{HW} is used first of all to cover the cooling load. If some of this heat is left, it is used to cover the low temperature thermal load, for the generation of hot water. The high temperature heat P_{ST} is used directly for the coverage of the high temperature thermal load; in the case a part of this heat is still available, it is used to cover the low temperature thermal load and the cooling load. As explained, also in the cooling first configuration the high temperature heat is not used for the cooling purpose, unless it is bigger than the steam and hot water thermal loads: this is justified by the higher quality that a high temperature attributes to this energy vector.

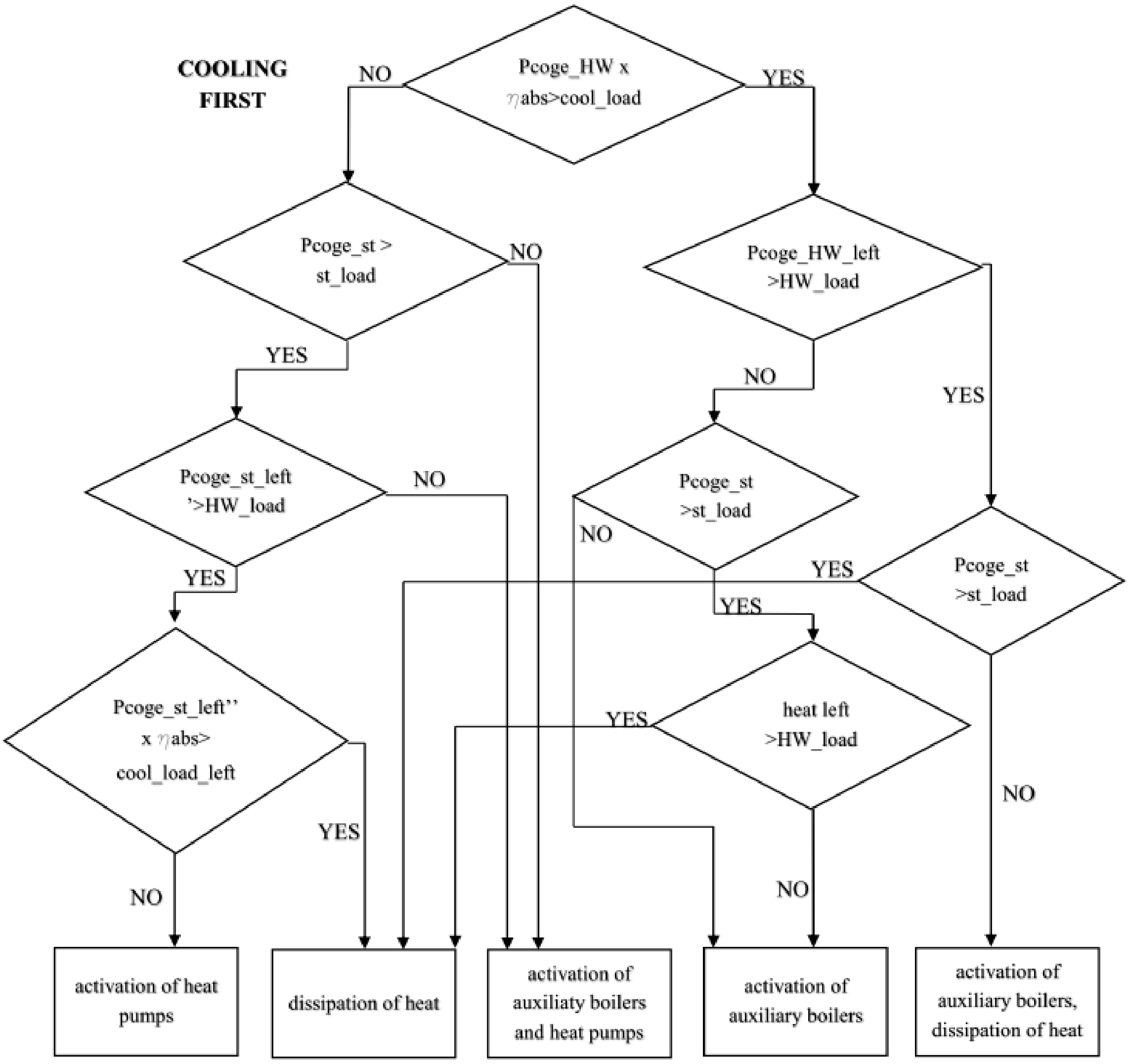

Figure 6.8: *Algorithm for the management of the heat for an industrial user, cooling first scenario.*

It can be observed that the share in the coverage of the cooling load between the heat pumps and the absorption chiller varies together with the energy (electrical and thermal) provided by the CHP plant; as a consequence, the electricity exchanged with the grid at every production level is influenced by both the variation of the electric energy provided by the plant and the variation in the way the cooling load is covered. To cope with this, the optimization procedure described is based on the assumption that the overall performances of the plant are measured at the point of connection of the external grid, equipped with a metering system for the exchanged energy (energy injected; energy withdrawn).

6.2.4 Qualitative evaluation of the optimization algorithm

Now that the logic for the definition of the different energy vectors in order to perform a proper optimization of the CHP plant working operations has been explained, it is worth to give a qualitative presentation of the possible behaviors of the algorithm, and hence of the results of the optimization procedure.

For a realistic example, the data reported in the following table can be considered.

***Table 1.1**: Reference data for the scenarios qualitative evaluation.*

DATA		
NG price (boiler)	0,313	€/Sm^3
NG price (CCHP)	0,301	€/Sm^3
η boiler	0,85	-
η CCHP (th)	0,44	-
η CCHP (el)	0,38	-
O&M	10	€/hour
COP HP	2	-
LHV NG	9,59	kWh/Sm^3
η CHILLER	0,7	-

For what concerns the costs correlated to electric energy, in Table 5.2 some reference prices are reported.

***Table 2.2**: Reference prices for electricity (only per kWh costs).*

ELECTRICITY		P_Z	DISPATC.	CHARGES	LOSSES	TAXES	TOT	
peak	F1	55,00	13,56	68,10	4%	10%	153,20	[€/MWh$_E$]
shoulder	F2	45,00	13,56	68,10	4%	10%	141,78	[€/MWh$_E$]
off peak	F3	45,00	13,56	68,10	4%	10%	141,78	[€/MWh$_E$]

With these data it is possible to compare the different economic values of the energy vectors whose computation has been described previously.

$$€_{BOILER} = €_{NG} * LHV_{NG} * \eta_{BOIL} = 38{,}36 \left[\frac{€}{MWh}\right]$$

$$€_{HP} = €_{EE,off-peak} * COP_{HP} = 70{,}89 \left[\frac{€}{MWh}\right]$$

Now it is necessary to define the cost of production for one MWh of primary energy from the CHP plant.

$$€_{COGE} = €_{NG,coge} * LHV_{NG} = 31{,}36 \left[\frac{€}{MWh}\right]$$

The type and the amount of energy that it is possible to produce with 1 MWh of primary energy through the plant depends on the working conditions. If the efficiency given above are considered as references, from 1 MWh$_{prim}$ of primary energy it is possible to derive 0,44 MWh$_{th}$ of thermal energy, 0,38 MWh$_{el}$ of electric energy and 0,308 MWh$_{fr}$ of cooling energy (with the absorption chiller).
Now, in order to compare the SDP and SDF scenarios, it is necessary to multiply the amount of energy of each type generated by the plant, by the economic cost per unit of the same type of energy in the SDF situation, thus generated by the boilers, the heat pumps or withdrawn from the grid.
The result is that the use of the CHP plant for the combined production of electricity and heat in a self-consumption configuration guarantees a wide revenue margin, equal to 39,4 [€/MWh$_{prim}$] if the heat is used for a thermal load and equal to 44,3 [€/MWh$_{prim}$] if it is used for the cooling purpose (with a COP equal to 2). This is correlated to the efficiencies of the CHP plant and to the economic value of the electricity vector when it is withdrawn from the grid.

For the same reason the running of the plant for the unique purpose of electricity self-consumption represents an economic advantage equal to 22,5 [€/MWh_{prim}]. The exploitation of the thermal production from the CHP plant exclusively depends instead on the valorization on the market of the electric energy; in particular a price on the market above 25 [€/MWh_{el}] justifies a heat production for the cooling purpose, whereas a price above 40 [€/MWh_{el}] justifies heat production for the heating purpose.
The electricity price influences strongly the choice of the optimal condition: it determines the amount of energy to be sold on the market and consequently the configuration of all the energy vectors within the plant scheme. A very high reference price will entail selling electricity entirely to the market; a good reference price will induce to prefer the selling to the usage of the electricity for the heat pumps, if the sum of the market revenues and the revenues guaranteed from the coverage of the cooling load by the absorption chiller is higher than the one from the electricity self-consumption. On the other hand, if the energy price on the markets is too low, once the electric load is exhausted, the plant is induced to leave the remaining thermal load to the boilers.
Given these considerations, it is possible to understand the importance of the analysis carried out regarding the ASM opportunities. A good understanding of the economic value of the market participation, together with a proper awareness of the modalities for this participation, is a key factor to evaluate the worth of the investment and the proper technical characteristics required for the CHP plant.
When an industrial user is taken into consideration, with the possibility to exploit only one of the two heat flows, while the other one is wasted, it is possible to derive that the revenues coming from a combined exploitation of electricity and heat are reduced to 31 [€/MWh_{prim}], and that the production for the exploitation of thermal production only is convenient if the electricity price on the market is above 60 [€/MWh_{el}]. Therefore the industrial condition can be penalized from the economic point of view, leading to reduced revenues and a reduced number of equivalent hours for the plant.
To provide a complete picture of the optimization procedure, Figure 6.9 presents a possible result of the elaboration described up to now.

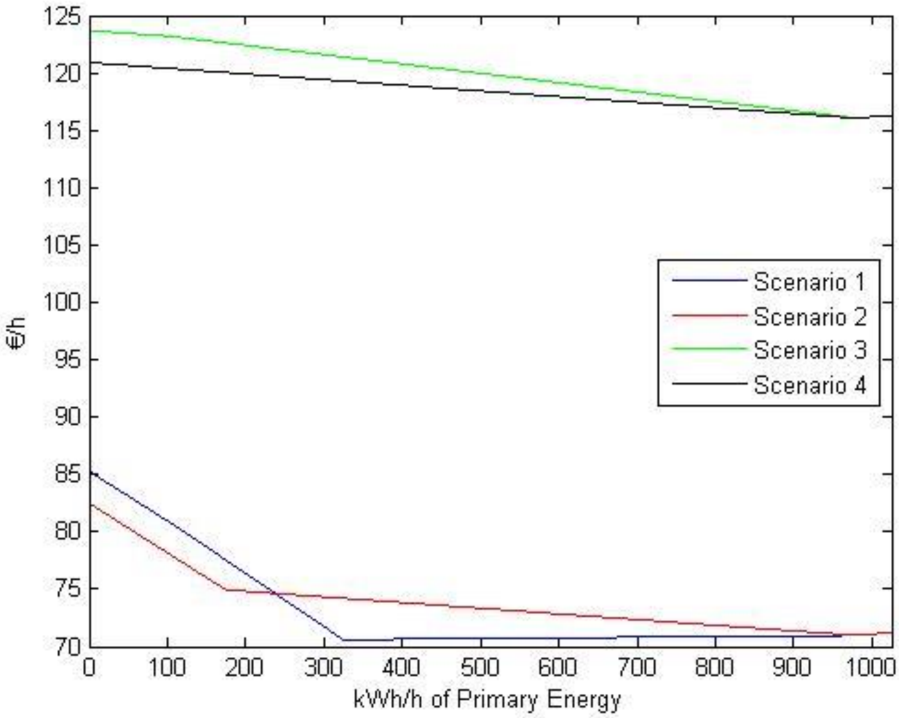

***Figure 6.9**: Example of a result from the optimization procedure for scenarios management.*

As specified, the diagram refers on the ordinate to the cost in €/h, and on the abscissa to the primary energy provided by the CHP plant in kWh_{prim}/h; this is linked to the optimization procedure that, as described above, is performed taking as reference parameter for the optimization cycle the nominal gross power. The description of the diagram aims at being qualitative, hence it is not worth to specify any numerical value or to refer to a specific load situation; it will be sufficient to say that, as on the abscissa the primary energy is reported, all the energy vectors and computation must be referred to it.

In the graph there are the cost curves (of a specific hour of the year) elaborated by the optimization procedure for all the four scenarios presented for a generic industrial user (hence with the high temperature/low temperature heat distinction). First of all it is possible to see that Scenario 3 and Scenario 4 are out of convenience, as the market price in the given hour is low; the difference between the upper and the lower curve represents the economic added value of the electricity self-consumption.

Scenario 1 and 2 present an intersection and a different behavior in the interval from 50% to 100% of the gross power value, which is the interval reported. In particular, it is possible to explain the discontinuity points on the curves as follows:

- In Scenario 2 (red curve) a low temperature heat consumption is present linked firstly to the cooling load coverage: this entails the complete coverage of the cooling load by the absorption chiller. Around 170 kWh_{prim}/h (corresponding in this case to 1 MWh_{prim}/h considering that the zero value corresponds to 50% of the nominal gross value of the plant considered) the electric load ends, and thus a discontinuity is present. A new slope is kept up to when, around 950 kWh_{prim}/h, the HW load ends: from this point on the slope is positive, meaning that the self-consumption for the steam load coverage, together with the selling of electricity on the energy market, is not convenient.
- In Scenario 1 (blue curve) there is only one discontinuity point and it is linked to the coverage of the cooling load. In this scenario the low temperature heat is first of all exploited to cover the HW demand; as the latter ends, it is used to cover the cooling load. In the first part of the curve the HW load has already been covered, and the cooling load is covered by the combined action of the absorption chiller, running with the low temperature heat from the CHP plant, and of the heat pumps, running with the electric energy from the CHP plant. This is the reason why the minimum of the blue curve is lower than the minimum of the red curve: in the red curve the low temperature heat for the HW demand was exploited while the electricity was sold on the market; in the blue curve the low temperature heat is exploited (to cover the cooling load through the absorption chiller) while the electricity is self-consumed to run the heat pumps. The cost difference between the two minimums values is exactly the difference between the economic revenue coming from the self-consumption (S1) and from the selling on the energy market (S2) of the amount of electricity that is used in Scenario 1 (in the configuration corresponding to its minimum value) to run the heat pumps. The impossibility, in Scenario 2, to self-consume the electricity produced, once the electric load ends, as the cooling load has already been covered, is the reason of the inconvenience of this scenario in absolute terms.

  It is worth to notice that, at 50% of the nominal gross power value, Scenario 2 presents a cost lower than Scenario 1; this is again linked to the reason explained above: as in Scenario 2 the cooling load has already been covered, the economic value associated to it (represented by the electric energy withdrawn to run the heat pumps) is gained. This however entails a penalization for Scenario 2 in absolute terms.

6.2.5 Economic evaluation of the energy vectors

The choice of the optimal working condition is based on the economic evaluation of the different scenarios. In particular, two different functions have been used for the evaluation of the SDF and the SDP situation.
The cost associated to each scenario is determined by the amount, in terms of kWh and Sm^3, of every energy vector. The total cost calculated through the SDF and SDP functions is the sum of the following contributions.

- Electric energy cost.

$$€_{EE} = \big((COMMERC. + DISPATC.) * (1 + \%_{loss}) + GRID\ SERV.\big) * EE_{comm} * (1 + VAT)$$

As specified before, the payment for the dispatching activities and the grid services is associated to the commercialization of the energy, and not to its withdrawal as it actually occurs, in order to prevent any kind of irregular action with respect to the purchasing and the selling of energy from DAM to ASM.
In the evaluation of the electricity cost performed at this point of the optimization process, the excise and the per kW costs are not considered; the former are not varying, thus can be evaluated ex-post, the latter must be computed at the end of every month considering the maximum value of the engaged power. This calculation will be the object of a specific section.

- Natural gas cost.

$$€_{NG} = (COMMERC + GRID\ SERV. + EXCISE) * NG_{comm} * (1 + VAT)$$

Similarly to the electricity cost, the natural gas cost is based on a commercialized cost for the selling service, on a grid service costs and on an excise. The excise and the grid services costs are regressive: their specific value decreases as the amount of natural gas consumed during the year increases. This is taken into account for the analysis, considering that the installation of a CHP plant shifts the burden of the energy costs on the gas bill.
The natural gas used for the production of electric energy is subjected to a tax exemption that is performed as a reduction of the excise foreseen for the natural gas.
The cost for the electric energy and for the natural gas are enough to describe completely all the costs sustained in the SDF configuration; other voices are instead necessary for the SDP configuration.

- Electricity selling gains.

$$€_{DAM/ASM} = EE_{SOLD} * €_{EE} * (1 + \%_{loss})$$

The amount of money gained from the selling of electric energy onto the markets depends on the amount of energy sold, on the price granted on the market, and it is increased, for what concerns the DAM, of a share equal to the losses avoided on the basis of the voltage level for the injection.

The cost of the electric energy, the cost of the natural gas for the boilers and the power plant, the gains from the DAM and the ASM, together with the operation and maintenance costs foreseen for the CHP plant, compose the total cost sustained for every scenario. This cost allows determining the optimal value for the power provided by the plant in any hour, and it allows choosing among the possible energy management configurations the best one in order to reduce as much as possible the costs, thus increasing the SDP revenues.

6.2.6 Power modulation

The optimization procedure is based on the definition of the cost for every configuration and the choice of the optimal management of the plant. As explained in section 6.2.5, the cost associated to the electric energy is not comprising the cost sustained for the monthly peak power engaged. This is linked to the impossibility to determine before the last hour of each month the exact amount of money to be paid, and consequently to determine the optimal plant management linked to this cost component. Moreover, as illustrated in Chapter 3, the future system charges payment will foresee a higher burden on the per kW component, changing the structure of the electricity cost in the direction of a reduction of the engaged power.

These considerations suggested the need to have a proper modulation of the power in order to optimize the plant operations in function of the per kW cost.

Figure 6.9 presents the algorithm used for the modulation of the power.

The procedure starts from the consideration that, as illustrated in Section 6.2.2, the operation of the CHP plant only for the self-consumption of electric energy justifies by itself the turning on and the increasing of the power provided by the plant: when there is a load, it is always more convenient to produce electricity through the CHP plant than to withdraw it from the grid.

It is necessary to consider also that, when scenarios S3 or S4 are judged to be the best, the power cost is paid on the power engaged, resulting from the amount of energy withdrawn in an hour, and not on the amount of energy commercialized. The energy withdrawn is the difference between the energy purchased on the DAM and the one sold on the ASM, and obviously cannot go below zero.

Therefore, from the qualitative analysis performed, it is possible to state that the power engaged will be positive if the electric load is higher than the maximum power that can be provided by the plant, or if the plant is shut off. In particular, the first situation cannot be modulated, while the second can be modified in order to reduce the overall cost by taking into consideration the per kW tariff.

The plant will be shut off when the electric load is very low with respect to the minimum value of power that the plant can provide, hence when the plant is oversized. The aim of the modulation is to find the configuration that guarantees the total minimum cost if also the per kW cost is considered.

The first step consists in the division between the hours in which the plant is turned on and in which the plant is turned off. Then the maximum power value among the turn-on hours is selected and all the turn-off hours with a power value below that one are discharged.

With the remaining hours, that are the ones that can possibly be subjected to the modulation, it is possible to calculate the total cost (€/kWh + €/kW) deriving from the turning on of each hour, starting from the one with the higher withdrawal. The total cost is computed simulating every useful combination, and the combination resulting in the lowest overall cost is chosen. At this point, the new maximum engaged power value is used to determine the new monthly cost per kW, and all the hours that need to be modulated, are modified according to the best combination defined above.

This procedure is performed at the end of each month and it is the last step in the definition of the optimal configuration for the plant management. After the power modulation, the optimization tool proceeds with the economic computation, since the operation framework is already determined.

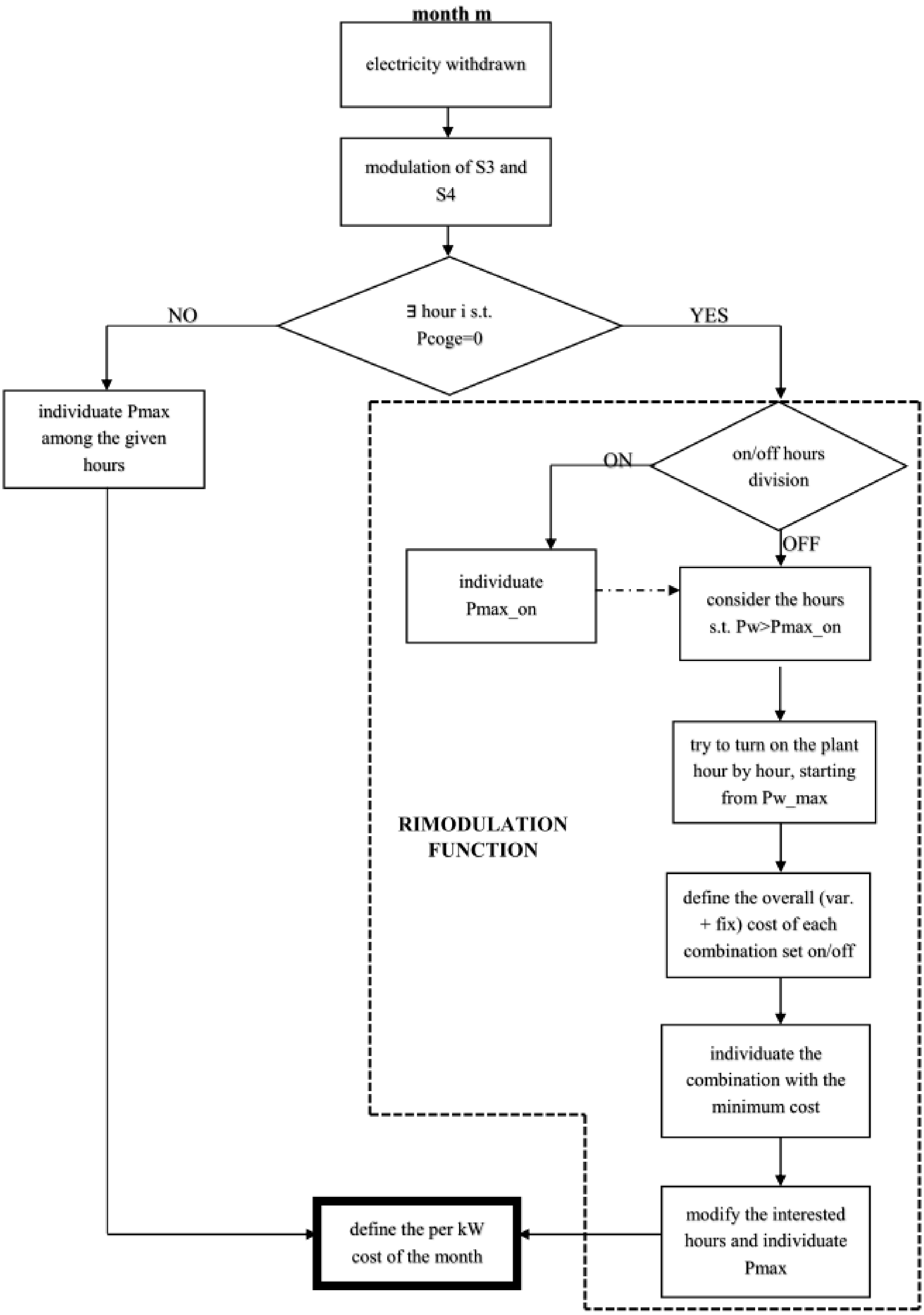

***Figure 6.9**: Algorithm for the power modulation.*

6.3 The Definition of the Technical and Economic Parameters

The core of the optimization tool deals with the analysis of the different possible configurations for the plant, and with the definition in every hour of the year of the one that guarantees the minimum costs, thus the maximum revenues. After the definition of the energy vectors value, of the costs associated to them and of the optimal working conditions of the plant, it is necessary to determine the technical and economic parameters requested.
These parameters consist in the PES, as defined in Chapter 2, together with the revenues coming from the White Certificates system, and in the cash flow computation.

6.3.1 Computation of PES and of WC

The computation of the PES is fundamental for the evaluation of the proper operation of the plant. Indeed, the high efficiency condition for the CHP plant gives access to support mechanisms such as the SEU condition and the WC. The HEC is recognized if the PES of the plant is higher than 10%.
Within the optimization tool the HEC condition is imposed by the exploitation of an algorithm, reported in Figure 6.10.
The procedure is based on the calculation of the hourly value of the PES, according to the indications given together with the Ministerial Decree 05/2011. Once the PES value of every hour is determined, considering the optimal working condition defined for each hour by the tool, the ratio between the variation of the PES and the corresponding variation of the cost associated to the plant operations is calculated for a modulation of the power provided by the plant upward and downward.
In particular, when possible, it is simulated a variation of the plant power in the hour considered, that can be an increase or a decrease, and the *upward ratio* and the *downward ratio* are defined as:

$$ratio_{up} = \frac{PES\left(kW_{opt} + 10\right) - PES\left(kW_{opt}\right)}{€\left(kW_{opt} + 10\right) - €\left(kW_{opt}\right)} = \frac{\Delta PES_{up}}{\Delta €_{up}}$$

$$ratio_{down} = \frac{PES\left(kW_{opt} - 10\right) - PES\left(kW_{opt}\right)}{€\left(kW_{opt} - 10\right) - €\left(kW_{opt}\right)} = \frac{\Delta PES_{down}}{\Delta €_{down}}$$

Since the optimal situation defined by the tool guarantees the minimum cost, both for an increase and for a decrease of power the cost will increase, meaning that the denominator of the two ratios will always be positive. Given this, it is possible to state that if a ratio is positive then the PES value will increase with the power modulation; otherwise if it is negative, the PES value will decrease with the power modulation.
Once the optimization of every hour has been performed, and the $ratio_{up}$ and $ratio_{down}$ have been defined in every hour, the annual value of the PES is computed as:

$$PES_{annual} = \frac{\sum_{i=1}^{8760} PES_i * Pcoge_{opt_i}}{\sum_{i=1}^{8760} Pcoge_{opt_i}}$$

where $Pcoge_{opt}$ is the gross power of the plant and its summation defines the primary energy provided by the CHP plant.

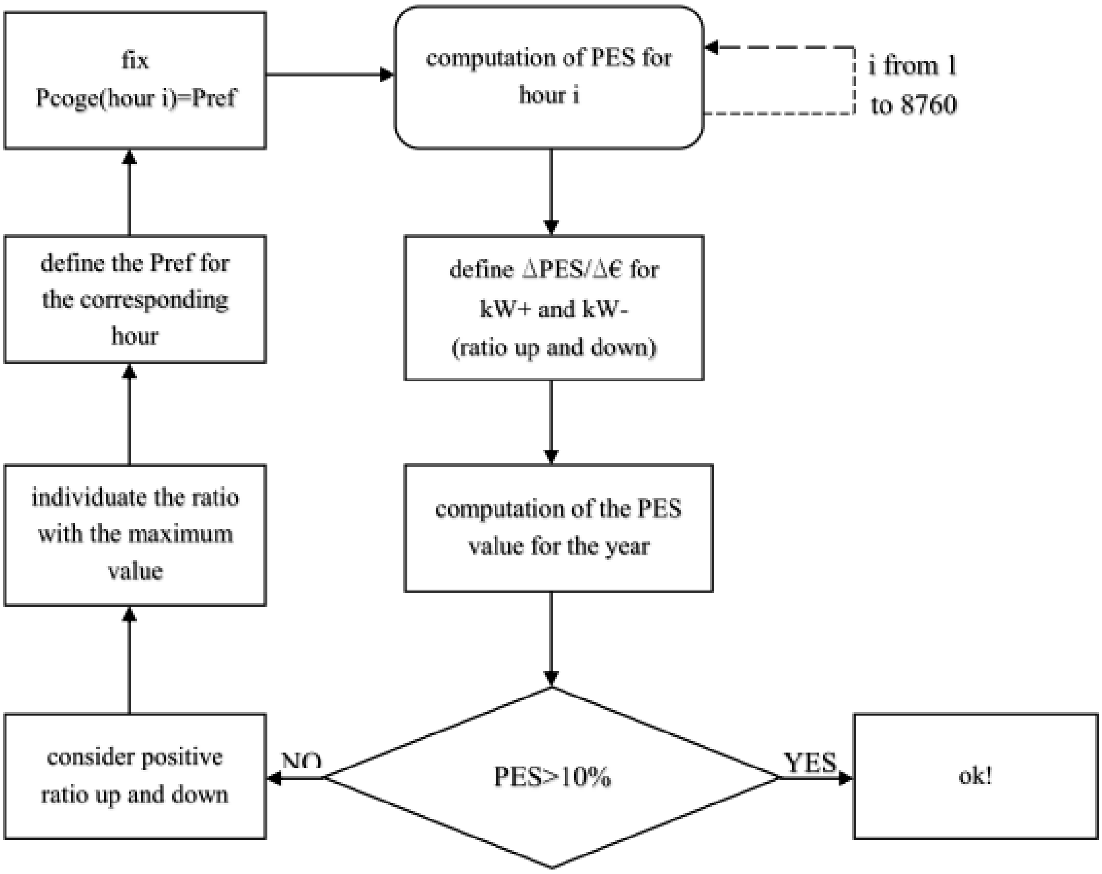

Figure 6.10: *Algorithm for the PES value checking.*

The annual PES value is the value that is needed for the HEC definition: it is not required to have a PES value above the minimum limit in every hour of the year, but it is required to have an annual overall value above the minimum one. This gives the possibility to give up on the PES value for a certain number of hours per year in order to obtain higher revenues, if the overall value of the PES is still higher than the minimum required.

Once the annual PES has been computed, it is necessary to individuate the optimal hour that needs to be modified if the calculated value is below the minimum acceptable. For this purpose, it is necessary to consider only the positive values of the ratios computed as above, the ones for which the variation of the PES with the power modulation is positive. In this hours it is known that when the power is varied, the PES value increases, and so does the annual PES value.

However it is easy to understand that the weight of each hour onto the annual PES value is not constant, but it is linked to the primary energy provided by the plant in that specific hour, and each hour is characterized by different ratio values, in terms of PES variation per unit of cost increase.

Among all the hours that are characterized by a positive ratio (up or down), the one that is linked to the maximum value of this ratio is chosen as the one which guarantees, for the purpose to increase the annual PES value, the optimal modification capacity.

The chosen hour will be hence characterized by a positive ratio and by the maximum ratio value, meaning that it will entail the maximum PES variation per unit of cost increase. In this sense the tool results to be an optimization tool also for what concerns the PES definition, under the light of the current legislation.

Once the chosen hour has been identified, it is possible to associate to it a chosen power, as the one guaranteeing the PES variation as defined in the ratio up or down. If the annual PES value is still below the minimum required, the computation for the optimization tool is repeated but the PES value for the chosen hour is kept fixed at the reference value, so that it is possible to impose the optimal situation for the annual PES value over the optimal configuration for the current hourly cost computed in the tool.
This procedure allows determining the optimal configuration of the CHP plant considering the necessity to respect the legislative limits imposed for the PES, condition that is necessary to exploit the special treatments and the support mechanism foreseen for the HEC systems.

As explained, the algorithm is based on the PES values computation for every hour of the year. This calculation is performed according to the indications given in the Ministerial Decree 05/2011.
The procedure described is based on the consideration that the HEC concept is referred to the useful thermal energy, and under this light the electric energy generated is considered as a by-product.
The HEC definition is linked to a minimum global efficiency value, as the sum of electric and thermal efficiency, that for ICE CHP plant is equal to 75%. In the computation of the PES according to the legislation, the cogeneration is referred only to the part of the process that, taking as reference the thermal useful power produced, is performed in a high efficiency condition, thus in this case with a global efficiency above 75%.
Given this, the first step consists in the definition of the useful electric energy and of the useful thermal energy, without the wasted one. Then a coefficient, indicated as C_{eff}, is defined as:

$$C_{eff} = \frac{\eta_{el}}{\max(\eta_{glob}; 0{,}75) - \eta_{el}}$$

From the reported formula it can be seen that, if the global efficiency of the cogeneration process is below the reference value, the plant is split into a CHP plant with the reference efficiency (75%), and a plant not producing through a cogenerative process. This configuration is called virtual machine.
The C_{eff} value allows deriving the quota of electric and primary energy that can be attributed to the virtual machine, and from them the electric and thermal efficiencies of the virtual machine.

$$Pcoge_{el_{CHP}} = C_{eff} * Pcoge_{th}$$

$$P_{coge_{el_{noCHP}}} = Pcoge_{el} - Pcoge_{el_{CHP}}$$

$$Pcoge_{prim_{noCHP}} = Pcoge_{prim} - Pcoge_{prim_{CHP}}$$

$$\eta_{el_{CHP}} = \frac{Pcoge_{el_{CHP}}}{Pcoge_{prim_{CHP}}}$$

$$\eta_{th_{CHP}} = \frac{Pcoge_{th_{CHP}}}{Pcoge_{prim_{CHP}}}$$

Once the virtual machine parameters have been defined, it is possible to calculate the value of the PES and of the energy saving. To do this, it is necessary to calculate a reference electric efficiency value for the calculation of the PES and for the calculation of the savings.

The reference efficiency for the PES is defined as:

$$\eta_{el_{ref-PES}} = \left(\eta_{ref_{NG}} + fact_{clim}\right) * \left(coeff_{el_{grid}} * \left(\frac{el_{grid}}{el_{tot}}\right) + coeff_{el_{auto}} * \left(\frac{el_{self}}{el_{tot}}\right)\right)$$

The reference efficiency for the NG is equal to 52,5%, and it is added to a correction factor linked to the climatic zone. The electric energy produced is then weighted on the basis of two different coefficients, one for the energy sold to the grid, another for the energy self-consumed.
The PES value is hence calculated as:

$$PES = 1 - \frac{1}{\frac{\eta_{el_{CHP}}}{\eta_{el_{ref-PES}}} + \frac{\eta_{th_{CHP}}}{\eta_{ref_{th}}}}$$

The reference value for the thermal efficiency is equal to 90%.
The reference electric efficiency for the saved energy is equal to the one used for the PES, with the difference that the starting value of the electric efficiency considered equal to the reference one for the national electricity production system (46%).
The energy saving is then calculated as:

$$RISP = \frac{Pcoge_{el_{CHP}}}{\eta_{el_{ref-RISP}}} + \frac{Pcoge_{th}}{\eta_{ref_{th}}} - Pcoge_{prim_{CHP}} \quad [kWh]$$

The energy saving is used to compute the amount of WC for which a plant at the end of the year is eligible. This number is defined as:

$$WC = RISP * 0{,}086 * K$$

where K is a correction factor defined according to the equivalent power provided by the plant during the year, considering the total amount of electric energy produced under the HEC condition ($Pcoge_{elCHP}$) and the number of physical hours of operation for the plant during the year. Dividing the former with the latter, the equivalent power of the plant across the year in the HEC configuration is obtained. A different value of the K factor is associated to a specific interval of this power, and the overall factor K is calculated as the weighted average of the different values indicated for each interval of power, based on the plant power as computed before.
Once the K parameter is determined, the White Certificates number is calculated, and the revenues coming from them are computed according to the value of a single WC as defined every year by the AEEGSI[7] [2].

6.3.2 Cash Flow definition

The last step in the optimization procedure consists in the computation of the main economic parameters.
The total cost sustained in the SDF is computed as the sum of the cost from the NG consumption and from the electricity consumption, considering the per kW component, the excises and the annual due.

[7] The Ministerial Decree of 28 December 2012 has transferred (operatively since February 2013) to the GSE the management of the WC mechanism; the competent Ministers should care about the update of the guide lines and the operative rules for the projects evaluation. The AEEGSI is still in charge only for what concern the definition of the WC contribution.

With the total cost of the SDF and SDP it is possible to define the revenues as:

$$annual\ revenues = €_{SDF} - €_{SDP}$$

The cash flow is calculated over a lifetime of 20 years, where year one is the year in which the operations start, whereas year zero is the year in which the investment is done.

$$cash\ flow_{YEAR_0} = -CAPEX$$

Starting from year one, and considering a determined inflation rate, the cumulated cash flow can be defined as:

$$cash\ flow_{YEAR_i} = cash\ flow_{YEAR_{i-1}} + \frac{revenues_{YEAR_i}}{(1 + inflation\ rate)^i}$$

The inflation rate allows actualizing the flows of money foreseen for the future in the current monetary value.
The cash flow leads to the definition of the NPV (Net Present Value):

$$NPV = cumulated\ cash\ flow_{YEAR_{20}}$$

Beside the NPV, also a simple economic parameter is defined: the Payback Time.

$$PT = \frac{CAPEX}{revenues} * \frac{1}{(1 + inflation\ rate)^1}$$

The NPV and the PT, together with the revenues, allow determining the worth of the investment and the optimal size in the proper way.

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CHAPTER 7

A Study Case: Sizing a CCHP Plant for the Formec Biffi S.p.A. Industrial Site.

This chapter presents the results obtained from the exploitation of the optimization tool for the sizing of a CCHP plant for an industrial user. The evaluation carried out entailed a first phase in which the input parameters (especially for what concerns the thermal, electric and cooling load profiles) have been elaborated. Then the tool presented in Chapter 6 has been used in order to evaluate the optimal size for the CHP plant to be installed from an economic point of view, considering both the actual situation, without the possibility for the plant to participate to the ASM, and the future situation, considering the possibility to participate to the ASM, and the relevant opportunities, described in Chapter 5.

Hence this chapter represents a summary of all the aspects regarding the use of the optimization tool and allows showing quantitatively all the considerations that have been made in the previous chapters.

7.1 Definition of the Input Data for the Optimization Tool

Formec Biffi S.p.A. (from now on named Formec) is a leader company in the food industry and since 1966 operates in its headquarter of San Rocco al Porto (LO); in the last decades the company has known a strong technological evolution and has acquired an increasing expertise. As many other industrial production sites, also Formec has the willingness to increase the control on the energy flows of its production plant, by improving the energy efficiency of the different processes and by the installation of a CHP plant. Formec represents a good industrial case study on which it is possible to perform the optimization procedure developed theoretically in the previous chapters.

The production plant of San Rocco al Porto is located in climatic zone E, with 2.701 DD; it is characterized by different buildings: two designated for the production processes, one for the laboratories, the offices and a warehouse. Moreover a restaurant, an internal market point and a huge green area are at the service of the personnel. Figure 7.1 and 7.2 present a view of the industrial site.

There are two points of connection with the national electric network, one at medium voltage and the other at low voltage. For the thermal demand coverage, there are three boilers: a Nova Sigma type with 1.047 kW_{th} of nominal power entered in service in 2014, and two Nova Sigma type from 1980 with 930 kW_{th} of nominal power. The plant is equipped with a system for the generation of cooling water, for both production and AC purposes. A first refrigeration group has a cooling power of 163 kW_f and a nominal absorption of 55 kW_{el} from which it is possible to derive a COP of 2,96; however the machine is proved by wear, is installed in an unsuitable area and has been subjected to a retrofit entailing the substitution of the refrigerant used (R22) with a new one (R422). A second refrigeration group has a cooling power of 383 kW_f. Because of the bad conditions characterizing the refrigeration systems, their COP is considered to be around 2.

The primary energy vectors exploited within the plant are: the electric energy withdrawn from the grid, the natural gas used to run the boilers and the LPG used, in much lower volumes, to serve the thermal load of the “bicarbonate” department.

In the elaboration of the data available to generate the input data needed for the optimization tool, the thermal load of the “bicarbonate” department, covered nowadays using LPG, has not been considered, because the actual absence of connection for the transport of hot water entails some important construction works whose costs cannot be evaluated easily.

Figure 7.1: *Top view of the industrial site (Google®).*

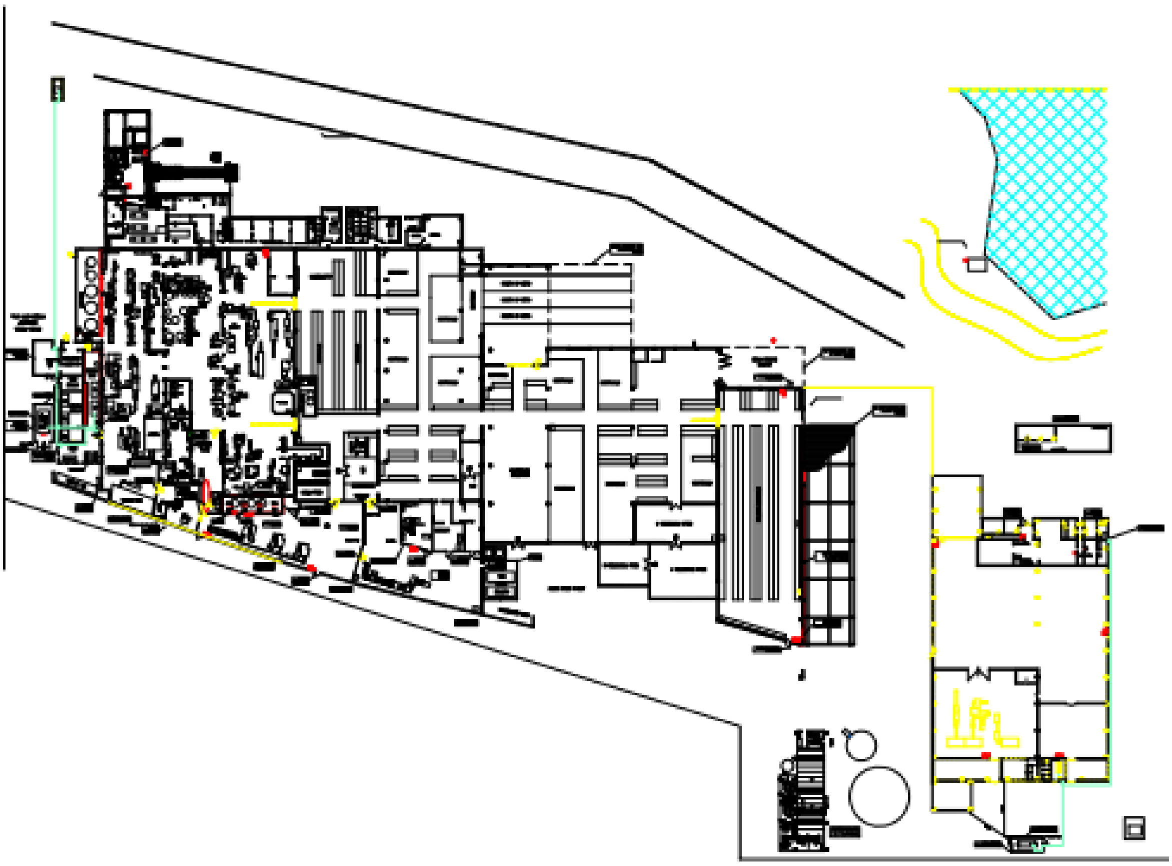

Figure 7.2: *Industrial site layout.*

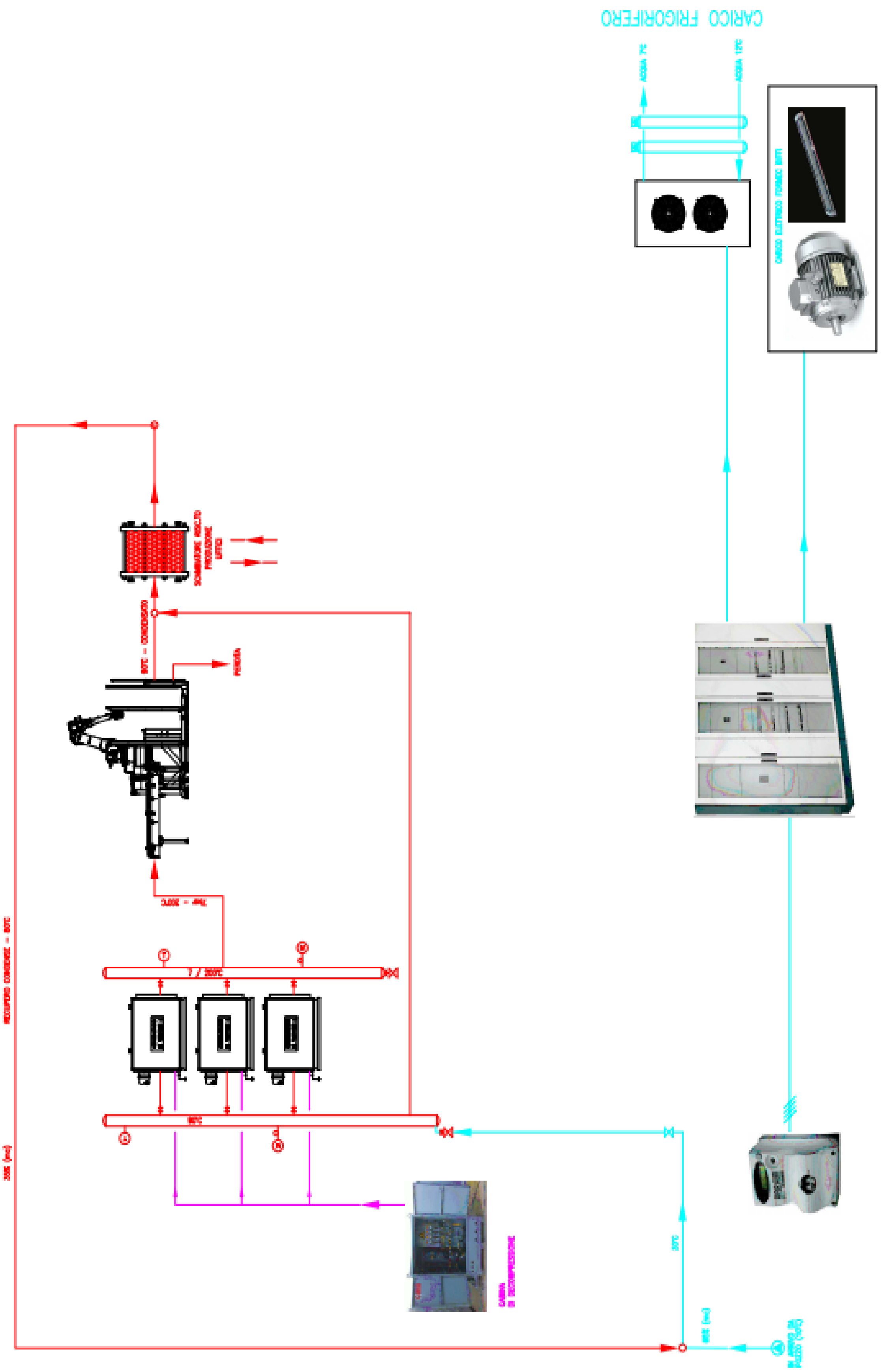

***Figure 7.3**: Actual layout of energy assets within the production plant.*

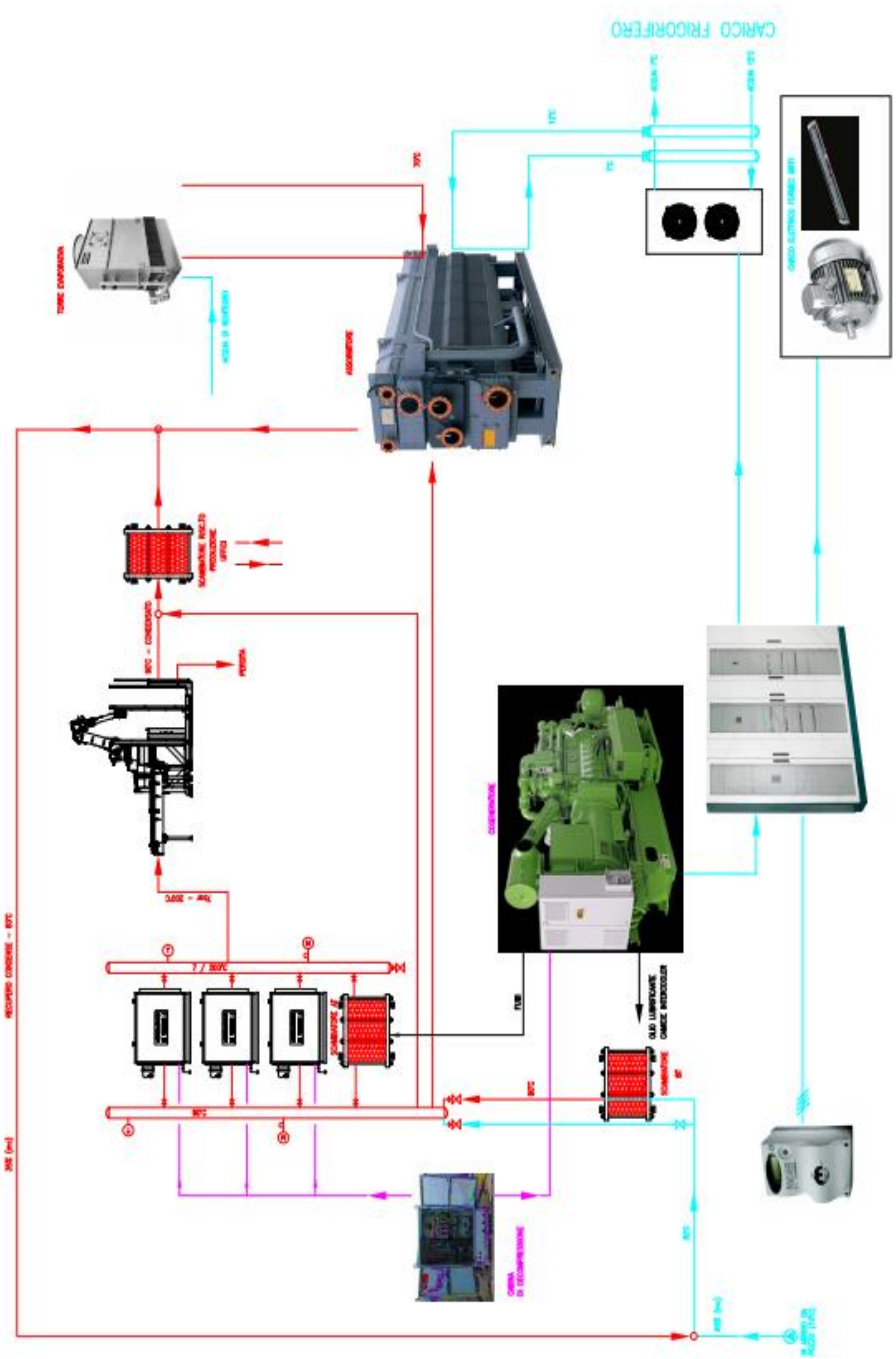

***Figure 7.4**: Future layout of energy assets within the production plant..*

The input data provided comprehend the electric load of both the MV and LV users, the thermal load served by the boilers and the cooling load served by the refrigeration groups, that is the one characterized by a temperature between 7°C and 12°C; the cooling load of the refrigeration rooms, requiring a temperature around 0°C, has not been considered (the use, in the absorption chiller, of ammonia requires very high security standards).
In Figure 7.3 the layout of the energy assets of the production plant is presented in the actual situation as described above, whereas Figure 7.4 presents the layout in the future configuration, meaning with the presence of the CHP plant. The introduction of the power plant, together with the absorption chiller, entails limited modifications of the actual layout, and the power plant can easily be connected to the actual frame as an addition.

7.1.1 Analysis of the loads and elaboration of the consumption profiles

The data on which the optimization has been performed refer to the year 2015.
For what concerns the electric load, thanks to the presence of suitable metering systems, it has been possible to use the annual hourly consumption profile for the MV and the LV connection point. This allowed having very precise and specific data, requiring substantially no further elaboration; however, as the electric energy is used to run the heat pumps that generate cold water to cover the cooling load, it has been necessary to perform a splitting procedure in order to separate the amount of electricity used for the actual electric load: this allowed generating the reference cooling load. The procedure followed is illustrated next. Figure 7.5 reports the actual (net) reference electric load, comprehending both the MV and LV withdrawal. The annual electric demand is evaluated as equal to 5,211 GWh_{el}.

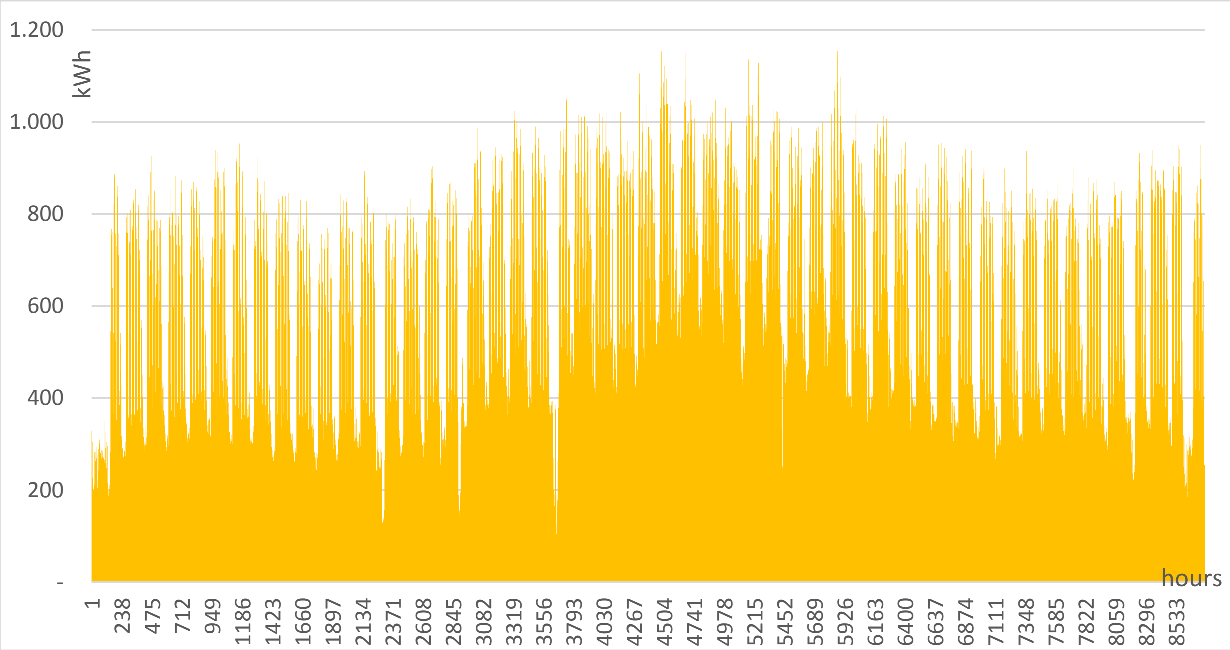

***Figure 7.5**: Annual reference electric load of Formec.*

For what concerns the thermal load, the absence of suitable metering systems introduced the need of a proper elaboration performed on the NG bill data.
The procedure consisted in two main steps:

- The derivation of the hourly consumption of natural gas.
- The computation of the amount of thermal energy required for the generation of steam and for the generation of hot water.

The analysis started from the data derivable from the bills.
In Table 7.1 the consumption of NG in terms of standard cubic meters is reported: the data have been derived from the bill, hence they represent the actual consumption, month by month, of Formec. The first step consisted in the translation of these data into an hourly profile; this has been made through a construction of a reference weekly profile defining the proportion in terms of thermal load among the different hours of the day, and the different days of the week.

Table 7.1*: NG consumption data derived from the bills.*

MONTH	Smc
JANUARY	71.647
FEBRUARY	65.463
MARCH	62.156
APRIL	59.291
MAY	55.771
JUNE	57.537
JULY	56.383
AUGUST	51.417
SEPTEMBER	52.515
OCTOBER	56.748
NOVEMBER	56.702
DECEMBER	65.314
TOTAL	**710.944**

Figure 7.6 presents the elaboration performed for the month of January, that qualitatively describes also the other months. In particular, the thermal load is supposed to be maximum from Monday to Friday from 6 A.M. to 12 P.M., while it is reduced of a factor of two during the night and from 2 P.M. of Saturday, and of a factor of four during Sunday. This logic is based on the real working operations of Formec; the resulting data, even if derived through a qualitative and computational procedure, represent the actual consumption on a monthly base, and respect the actual behavior of the thermal load on an hourly base.
Following the logic explained above and hence generating a profile qualitatively similar to the one presented in Figure 7.6, it was possible to derive a consumption profile for the NG on as hourly base for the whole year.

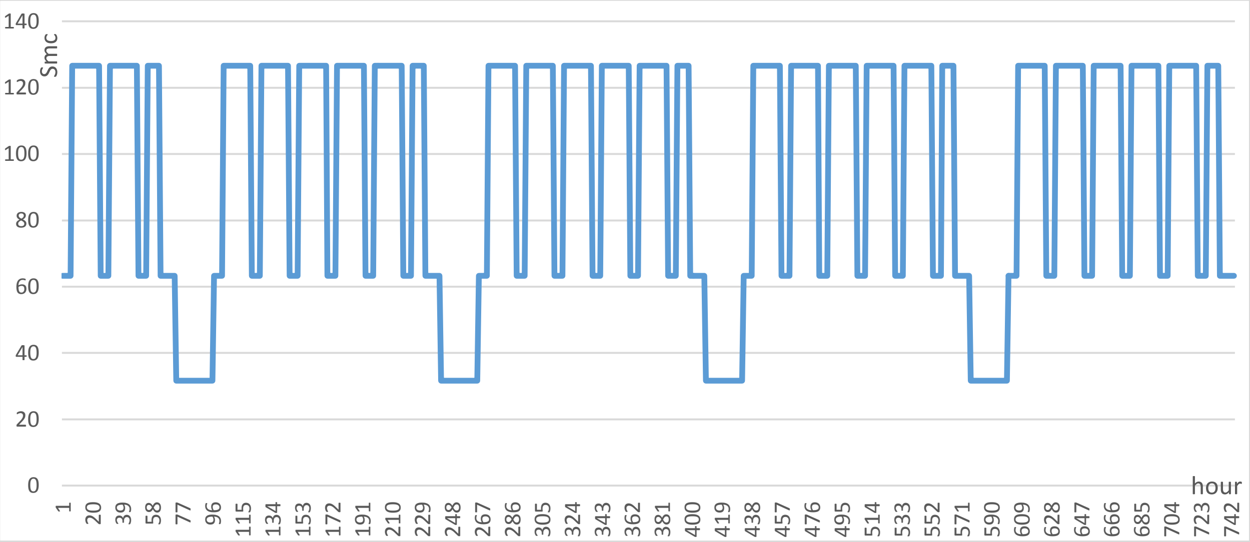

Figure 7.6*: Reference NG consumption derived on an hourly base for the month of January.*

The second step consisted in the definition of the thermal load required, in terms both of steam and hot water generation. Starting from the NG consumption profile, the overall thermal load has been computed always on an hourly base and for the whole year as:

$$th_{load}[kWh_{th}] = NG[Sm^3] * \ LHV_{NG}\left[\frac{kWh}{Sm^3}\right] * \eta_{boil}$$

where the boiler efficiency has been taken equal to 85% and the LHV of NG equal to 9,6 kWh/Sm^3.

At this point the distinction between hot water and steam generation has been performed. As stated in Chapter 6, when dealing with an industrial user, this distinction is fundamental because it can heavily influence the capacity of the heat produced by the CHP plant to actually cover the thermal demand. The procedure followed to calculate the exact hourly volume for the hot water and the steam load is described below.

- First the estimation performed by MetaEnergia ESCo srl about the amount of NG used for the ambient heating has been considered. In particular, according to the analysis by MetaEnergia, almost 40.000 Sm^3 of NG are used per year to heat the environments of the plant. Considering the formula used before, it is possible to estimate a heating load around 330.000 kWh_{th}/year. In order to spread this load on the entire heating season the data of the external temperature, available on the ARPAlombardy website, have been collected; these data are given hour by hour and, taking as a reference internal temperature 20°C, allowed defining a "degree hour" measure, as the difference between the reference internal required temperature and the outer temperature, during the heating season. From this procedure, it has been possible to define the weight of each hour with respect to the overall ambient heating load as the ratio between the value of the "degree hour" measured for that hour and the sum of all the "degree hour" computed for the whole season; the resulting percentage has been multiplied by the total ambient heating load to find the expression of the ambient heating load in that hour. This procedure allowed building the yearly profile for the ambient heating load hour by hour.
- The second step consisted in the evaluation of the amount of heat needed to heat the water up to its boiling temperature before entering the high temperature heat exchanger. In this phase the water is heated up to 90°C and hence also the low temperature heat coming from the CHP plant can be used. In order to compute quantitatively the amount of heat needed, it is necessary to consider that the production plant is equipped with a condensate recovery, thanks to which a part of the condensed steam is recovered together with the hot water at a temperature around 70°C. This water is mixed with some water coming from a well at 10°C, with a ratio of 35/65% for condensate and well water respectively; hence the final temperature of the water incoming to the boilers is around 30°C. According to the CHP plant sheet data reported next, the power plant is able to provide 302 kW_{th} at nominal power from the flue gases, elaborating across the economizer and the boiler 453 kg/h; this means that at nominal condition the power plant can provide about 30 kW_{th} to increase the temperature of the water from 30°C to 90°C (about 10% of the nominal available power for the steam generation). It possible to consider that for a given thermal load associated to steam generation, a low temperature load for the heating of water in the economizer section equal to 10% of the steam generation load is present.
- Given the considerations above, from the total thermal load it is possible to subtract the ambient heating load; the remaining load represents a volume equal to 110%, where 100% is the steam generation load and 10% is economizer load. Therefore the thermal load can be divided into a steam generation load and an hot water generation load (sum of the ambient heating load and of the economizer load). In this way it is possible to generate the specific thermal load profile on an yearly basis distinguishing the steam and the hot water load.

The result obtained are presented in Figure 7.7 and 7.8.

The annual thermal demand resulting from the elaboration is equal to 5,795 GWh_{th}, with 4,968 GWh_{th} for the steam generation and 0,826 GWh_{th} for the hot water demand coverage.

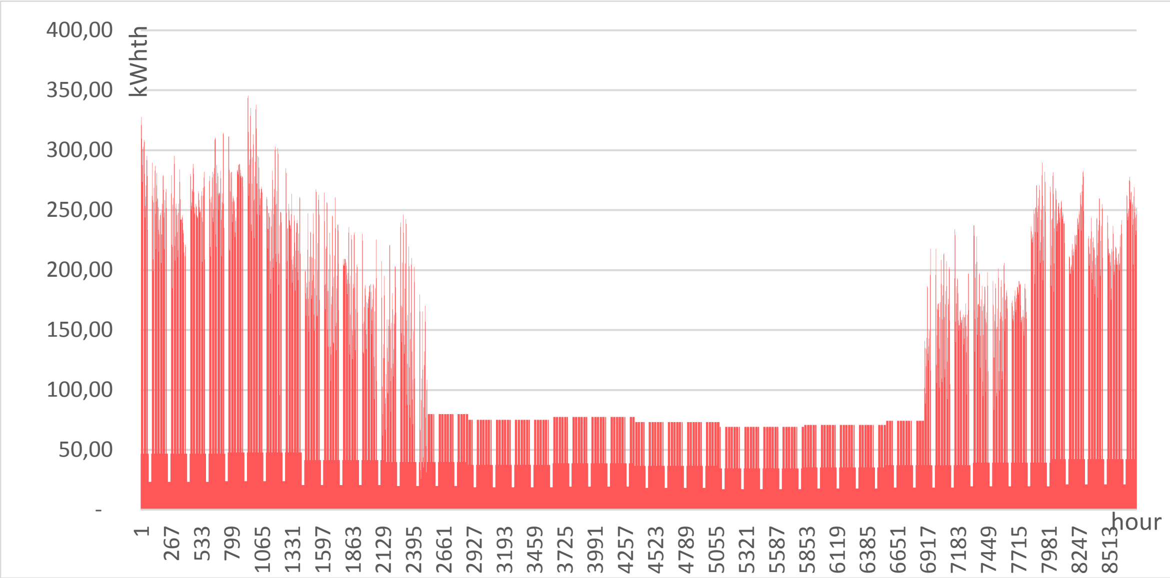

***Figure 7.7**: Reference thermal load for the hot water generation.*

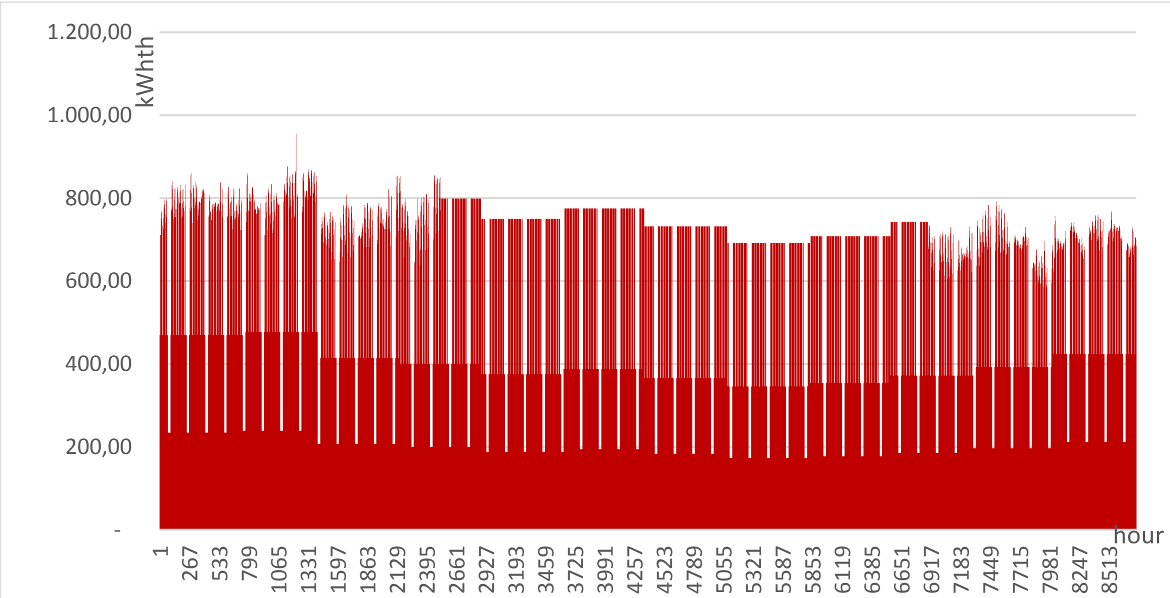

***Figure 7.8**: Reference thermal load for the steam generation.*

The last step in the load profiles elaboration consisted in the definition of the cooling load.
In order to define an hourly consumption profile, the total (gross) electric load of the month of July, equal to 548.000 kWh_{el} was considered; during the month of July, because of the combined presence of very high external temperatures and high production volumes, the cooling load required by the production plant is considered to be maximum, needing the maximum power provided by the heat pumps. Under this light, considering a maximum value for the electric capacity engaged by the heat pumps equal to 280 kW_{el}, and considering twelve working hours per day, it was possible to define a total electric consumption in the month of July equal to 105 MWh_{el}. Of this amount, about 33 MWh_{el} can be associated to the AC. Thanks to this evaluation, the production cooling load was defined as the 14% of the total electric consumption of July, whereas the AC cooling load was defined as the 6% of the same amount. Taking into consideration the variation of the external ambient conditions, a reference percentage was defined for every month, with respect both to the cooling load associated to the production processes and to the one associated to the AC.

The production cooling load was calculated every month according to the percentage established (from 8% in January to 14% in July) with reference to the corresponding month; the AC cooling load was computed only for the cooling season months, always with reference to the corresponding month (percentage from 3% to 6%). Then, having defined the monthly values for both the cooling loads, the hourly consumption profile was obtained simulating a consumption for the production processes going in parallel with the operations of the production site, and a consumption for the AC consistent with the activity of the site and with the standard ambient conditioning operations. Once the hourly profiles were defined, the total cooling load hour by hour was calculated as the sum of the two values defined.

The cooling load obtained is reported in Figure 7.9. The annual cooling load resulting is equal to 1,368 GWh_f. The obtained profile is coherent with the rated power of the cooling units from which its elaboration started, as described above.

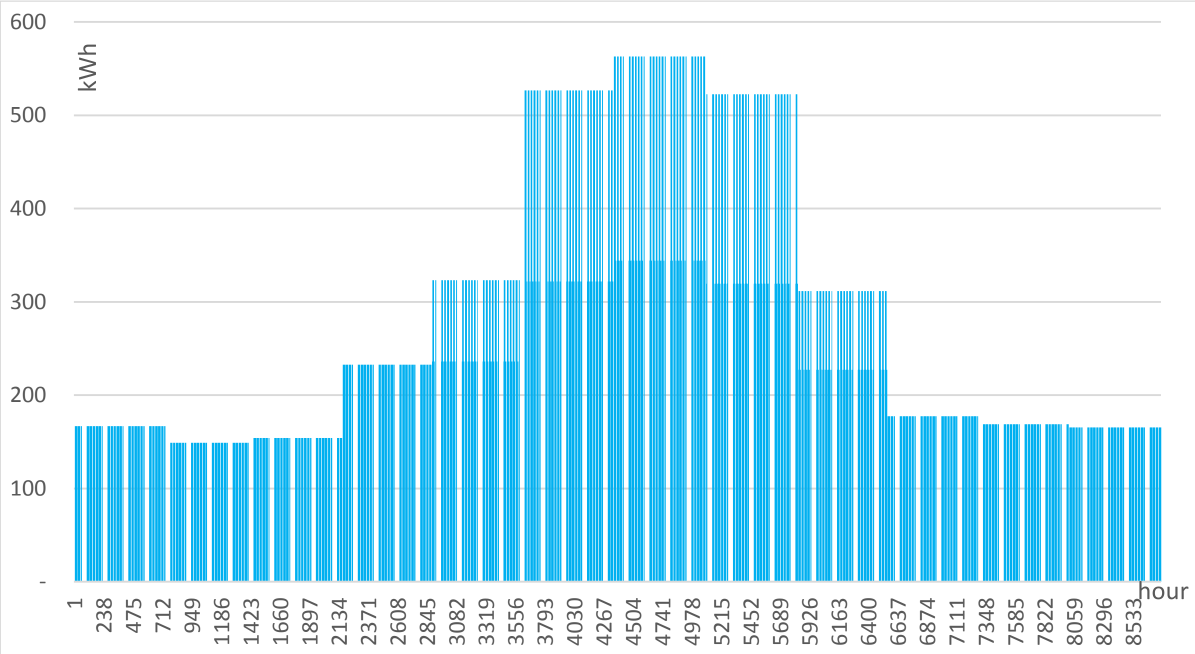

Figure 7.9: *Reference consumption profile for the cooling load.*

7.1.2 Reference tariffs for the NG and electricity bills

In order to run the optimization tool, it is required to set the proper values for the electric energy and the natural gas tariffs paid in the bill; these values are fundamental for the computations performed in the *economic* and *economic_sdf* functions described in Chapter 6.

The computation of the economics flows for the optimization of the CHP plant operations in the case of Formec has been referred to the latest available values for all the tariffs present in the electricity and NG bills.

In Table 7.2 the tariffs for the electric energy are presented with all the necessary specifications. In particular, the grid services are divided into network services and system charges; for the general system charges, and thus for the grid services, the tariff foreseen for every hypothesis of reform is also specified (as presented in Chapter 3). The dispatching tariff refers to January 2017, and it is updated every three months. The selling services are defined independently by every user with a retailing company; finally the excises are characterized by the presence of two different values in a regressive scheme. Table 7.3 reports the tariffs for the grid services and for the excises paid in the natural gas bill. In this case the grid services tariff is regressive, so an increase in the natural gas consumption, as it occurs with the implementation of a CHP plant, will decrease the per unit cost of the primary energy vector.

Moreover the NG used for the electricity production is subjected to a tax exemption through an excise decreased down to 0,000135 €/Sm^3; the amount of NG used in the CHP plant that can benefit of the excise reduction is computed multiplying the produced electric energy (kWh$_{el}$) by 0,22, obtaining directly the NG volume in Sm^3.
All the values reported are taken from the updated tariffs present on the website of the AEEGSI in the section relative to the prices and the tariffs applied to electric energy and natural gas. The values reported in the tables are hence equal if another user of the same type of Formec is considered; the only value that changes is the one relative to the selling services, which are negotiated by each costumer with its retailer.
To complete the framework of the different costs considered, it is necessary to specify that the VAT for an industrial user is equal to 10%, that the O&M costs for the CHP plant are fixed equal to 10 €/h (hence about 90.000 €/y for an always on power plant) and that the grid losses for a user connected at MV level are equal to 3,8%.

Table 7.2: *Reference tariffs for the electricity bill used in the calculation of the optimization tool, study case Formec.*

NETWORK CHARGES (TRAS DIS MIS UC3 UC6)						
€/kWh						0,007630
€/kW/y						26,69
€/POD/y						695,95
GENERAL SYSTEM CHARGES						
	ONGOING	*A*	*B1*	*B2*	*B3*	*C*
€/kWh	0,053372	0,021684	0,031604	0,041526	0,051556	0,045356
€/kW/y	-	78,33	58,75	39,17	19,58	31,61
€/POD/y	110,60	2.411,51	1.808,64	1.205,76	602,88	972,96
GRID SERVICES (NETWORK SERVICES + SYSTEM CHARGES)						
	ONGOING	*A*	*B1*	*B2*	*B3*	*C*
€/kWh	0,061002	0,029314	0,039234	0,049156	0,059186	0,052986
€/kW/m	2,2238	8,7518	7,1198	5,4878	3,8558	4,8576
€/POD/m	67,21	258,96	208,72	158,48	108,24	139,08
€/POD/y	806,55	3.107,46	2.504,58	1.901,70	1.298,83	1.668,91
DISPATCHING SERVICES						
€/kWh						0,0135623
SELLING SERVICES						
F1	**€/kWh**					0,05318
F2						0,04318
F3						0,04318
EXCISE						
0 - 200.000 kWh/y	**€/kWh**					0,0125
+ 200.000 kWh/y	**€/kWh**					0,0075

***Table 7.3**: Reference tariffs for the NG bill used in the calculations of the optimization tool, study case Formec.*

EXCISE			
	BOILER	**CHPp**	
<1.2M	0,012498	0,001619	€/Smc
>1.2M	0,007499		
GRID SERVICES			
1 - 120	0,0265540	€/Smc	
121 - 480	0,1265140		
481 - 1.560	0,1053310		
1.561 - 5.000	0,1011020		
5.001 - 80.000	0,0813290		
80.001 - 200.000	0,0514131		
200.001 - 1M	0,0260300		
+ 1M	0,0074710		
SELLING SERVICES	0,2457300	€/Smc	

7.1.3 CHP plant economic and technical data

The choice of the size for the CHP plant to be installed is linked also to the characteristics, both technical and economic, of the power plants considered. The machines that have been considered for this analysis are by AB Energy SpA, and in particular consist in the line ECOMAX® NG; AB Energy SpA owns a great expertise in the field of energy machines and cogeneration, and its power plants can be considered as a good reference.

In the case of Formec, the possible sizes subjected to an optimization process are four: 600 kW_{el}, 800 kW_{el}, 1.000 kW_{el} and 1.200 kW_{el}.

The technical data relative to the working operation at nominal and at partial load, down to 50% of the nominal load, have been taken from AB Energy SpA website and are reported in Table 7.5.

During the calculations, the partial load values of the different energy flows are computed through a linear interpolation of the available data at 100%, 75% and 50% of the load.

For what concerns the economic data, they have been derived from real estimations presented by AB Energy SpA; in particular the cost of the CHP plant includes:

- A capital expenditure at year 0 for the construction and the installation of the power plant, consisting in the engine and in the absorption chiller with all the systems linked to them and necessary for the correct operations of the power plant.
- A capital expenditure at year 5 and 10 for the necessary maintenance of the plant, and in particular linked to the possible substitution of those parts of the engine which are submitted to high temperatures and/or great stresses, that are more likely to be subjected to wear and erosion, such as the pistons and the valves.

It is worth to highlight that the capital costs indicated do not comprehend the O&M costs that, as stated previously, are computed every time the CHP plant is on (resulting to be proportional to the number of physical hours in which the power plant is on), and that are equal to 10 €/h.

Table 7.4 reports the economic reference data for the engines presented above.

***Table 7.4**: Economic reference data for the CHP plants according to the size.*

SIZE	600	800	1000	1200	kWel
year 0	804.000	1.056.000	1.300.000	1.536.000	€
year 5	20.092	26.389	32.486	38.383	€
year 10	70.362	92.424	113.790	134.460	€

Table 7.5: *Data sheet of the power plants used for the optimization process, study case Formec.*

ECOMAX 6	100	75	50	% of Pn	ECOMAX 8	100	75	50	% of Pn
P primary	1.601	1.234	832	kW	P primary	2.140	1.650	1.112	kW
P electric	637	477	315	kW	P electric	851	637	421	kW
P thermal	706	560	400	kW	P thermal	956	763	550	kW
for HW gen.	404	292	184	kW	for HW gen.	515	373	235	kW
for steam gen.	302	267	215	kW	for steam gen.	441	390	315	kW
P cooling	522	416	299	kW	P cooling	704	564	409	kW
etta electric	39,79%	38,66%	37,90%	-	etta electric	39,77%	38,64%	37,88%	-
etta thermal	44,10%	45,34%	48,05%	-	etta thermal	44,67%	46,24%	49,42%	-
etta total	83,89%	84,00%	85,94%	-	etta total	84,44%	84,88%	87,30%	-
NG	167	129	85	Smc/h	NG	223	172	114	Smc/h
COP abs. chil.	70%	70%	70%	-	COP abs. chil.	70%	70%	70%	-
ECOMAX 10	**100**	**75**	**50**	**% of Pn**	**ECOMAX 12**	**100**	**75**	**50**	**% of Pn**
P primary	2.657	2.048	1.440	kW	P primary	2.855	2.201	1.547	kW
P electric	1.067	799	528	kW	P electric	1.189	891	589	kW
P thermal	1.204	954	682	kW	P thermal	1.209	946	665	kW
for HW gen.	689	499	314	kW	for HW gen.	767	555	350	kW
for steam gen.	515	456	367	kW	for steam gen.	442	391	315	kW
P cooling	888	708	509	kW	P cooling	906	715	508	kW
etta electric	40,16%	39,02%	36,68%	-	etta electric	41,65%	40,47%	38,04%	-
etta thermal	45,31%	46,59%	47,34%	-	etta thermal	42,35%	42,99%	43,00%	-
etta total	85,47%	85,61%	84,02%	-	etta total	83,99%	83,45%	81,04%	-
NG	277	214	150	Smc/h	NG	298	229	161	Smc/h
COP abs. chil.	70%	70%	70%	-	COP abs. chil.	70%	70%	70%	-

7.1.4 Reference values for the market prices

The last set of input data to consider before performing the optimization procedure concerns the reference prices to use for the DAM and the ASM. The reference prices for the DAM are well known and have been considered equal to the zonal prices of year 2015. For what concerns the reference prices for the ASM, the elaboration performed and described in Chapter 5 was used; in particular, for the study case regarding Formec, it is necessary to consider the reference prices of the North zone, and the geographic correction factor of the province of Piacenza. It is well known that the production plant is placed in the province of Lodi, but its location, near Piacenza and the Po river, makes it electrically connected to the EHV bus of Piacenza, hence it is more efficient to consider as geographic correction factor the one of the Piacenza province. The correction factor calculated for the province of Piacenza is equal to 93,19 %.

As an example Figure 7.10 and 7.11 report graphically the reference prices for the month of January and July both for the ASM and for the DAM. It is possible to see that the reference values for the ASM do not present particular outliers and are consistent with the considerations made in Chapter 5 with respect to the ASM prices and opportunities.

In the next sections the results obtained from the optimization analysis will be presented and it will be possible to see the difference, in economic and revenues terms, between the situation with and without the ASM participation opportunity; this will allow to evaluate the weight of the ASM on the revenues of a CHP plant in the actual regulatory framework.

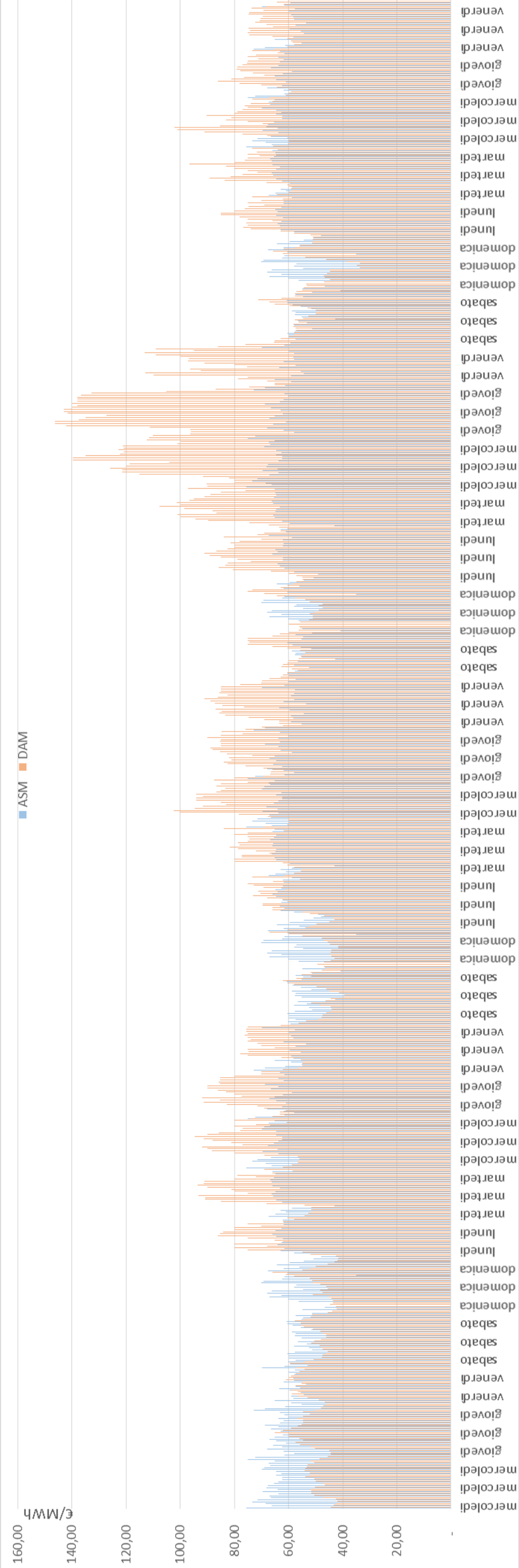

Figure 7.11: *Reference prices for the month of July.*

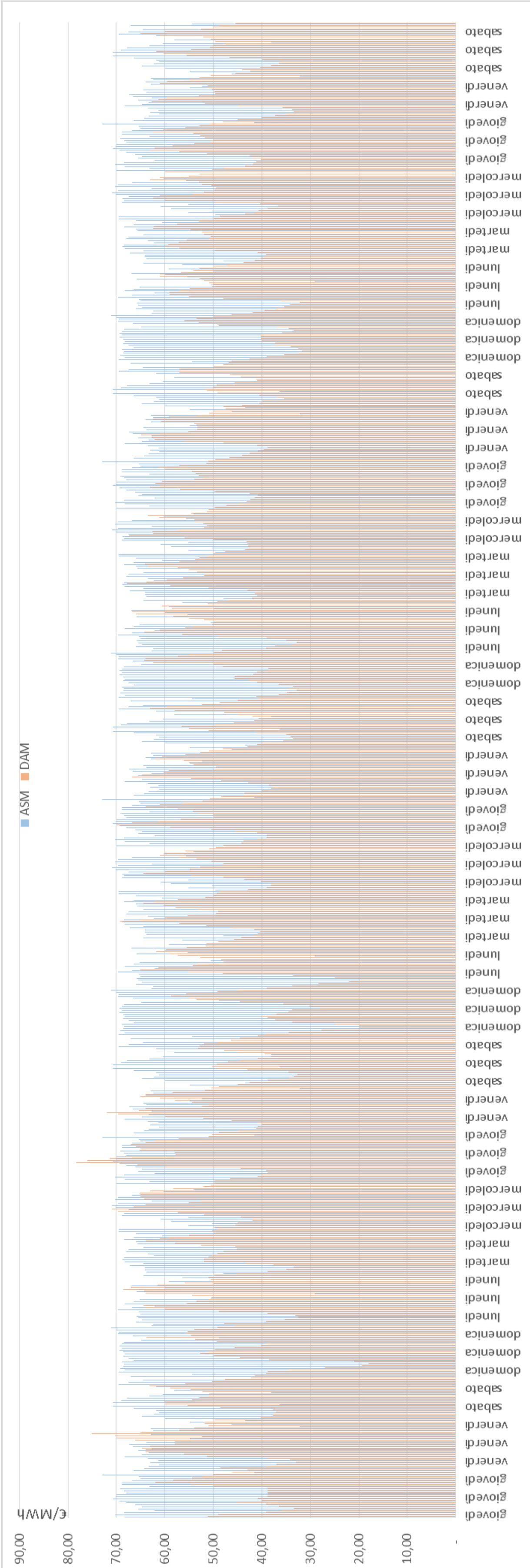

Figure 7.10: *Reference prices for the month of January.*

7.2 Results of the Optimization Procedure for the Size of 600 kW_{el}

In this and in the following sections the results obtained for the different sizes of the CHP plant presented above will be reported. The procedure, as widely described in Chapter 6, entails the definition of all the energy vectors in every hour of the year, according to an optimization algorithm referred to the economic flows that each energy vector represents. The results obtained cannot be entirely reported in the following dissertation, because of space limitation; considering this, for every size considered, the most important and representative parameters are presented in order to allow understanding quantitatively the key factors for each size.

The first size elaborated by the optimization tool is 600 kW_{el}. The reference to this size is consistent with the characteristics of the load presented previously, and ensures a proper coverage of the electric, thermal and cooling demand with a very high number of equivalent hours for the working operations of the power plant. The results obtained can be presented considering first of all the operations of the power plant resulting from the optimization, together with the main technical parameters linked to them; then it is necessary to specify the main results from the economic point of view, thus to consider the resulting cash flows. Connected to both the economic and technical aspects, the analysis performed allowed also elaborating a specific framework for the NG and electricity bills in the future: from these data, it is possible also to evaluate the impact of the general system reform on the actual and on the future situation. For every size presented, first of all the results obtained from an optimization process with reference to the actual market framework are reported; then the perspectives after the ASM opening and the market reform as described in Chapter 4 and 5 are presented.
In the context of the thesis work other aspects have been considered (the choice of the proper period of the year in which it possible to perform the plant maintenance, the requirements introduced by the optimization tool in terms of power modulation , etc.); however, given the space limitation imposed by the present dissertation, they will not be presented.

7.2.1 Management of the electric, thermal and cooling load

As stated above, even if the different energy flows have been defined for the whole year, only some significant examples are reported here.
The first aspect to focus is the management of the thermal load; the thermal load comprehends the demand of steam and of hot water, involving both the ambient heating and the production processes; moreover it is indirectly linked, after the introduction of an absorption chiller, to the cooling load. Figure 7.12 presents the management of the different thermal energy fluxes for the 28 of January, a reference day for the winter season.
From the graph it is possible to see that during a typical winter day the CHP plant is not able to cover all the thermal load, and this introduces the need to activate the auxiliary boilers. The diagram distinguishes between the steam and the hot water demand; when the low temperature heat available from the CHP plant is higher than the hot water demand, there is the simultaneous activation of the boilers and dispersion of part of the heat produced by the power plant. In fact, the remaining load, covered by the boilers, requires high temperature heat as it is linked to the steam generation: this makes the low temperature heat available useless.
Figure 7.13 reports an example for the thermal load management of the 6 of July, a reference day for the summer season. The differences with respect to the winter situation are visible: first of all the hot water demand is very low and it is merely linked to the preheating of the water entering the evaporator and the boilers. Despite this, the low temperature heat is, beyond the night-time, entirely used and there is no heat dissipation; this is correlated with the presence of cooling load that, thanks to the absorption chiller, can be covered using the low temperature heat that otherwise would be wasted.

The low temperature heat used in the absorption chiller is not reported in this diagram, but it is presented in a specific graph relative to the cooling load. The presence of a huge steam demand still introduces the need the activate the auxiliary boilers in all the hours.

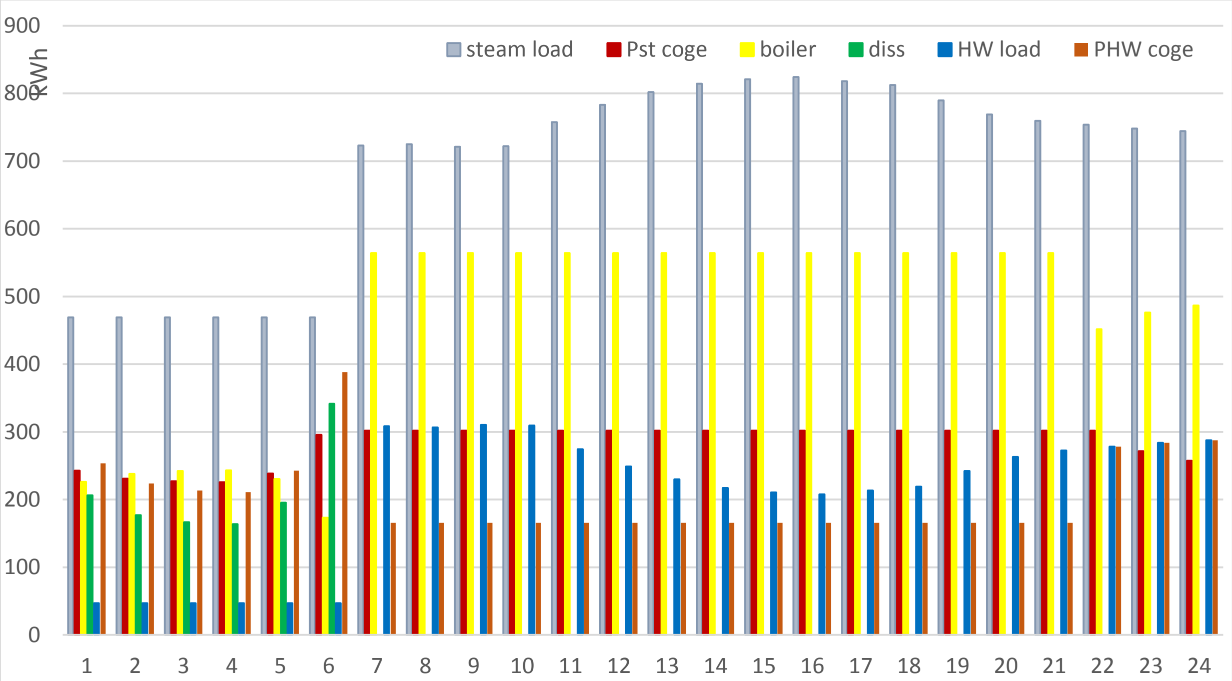

Figure 7.12*: Thermal load management in a typical winter day.*

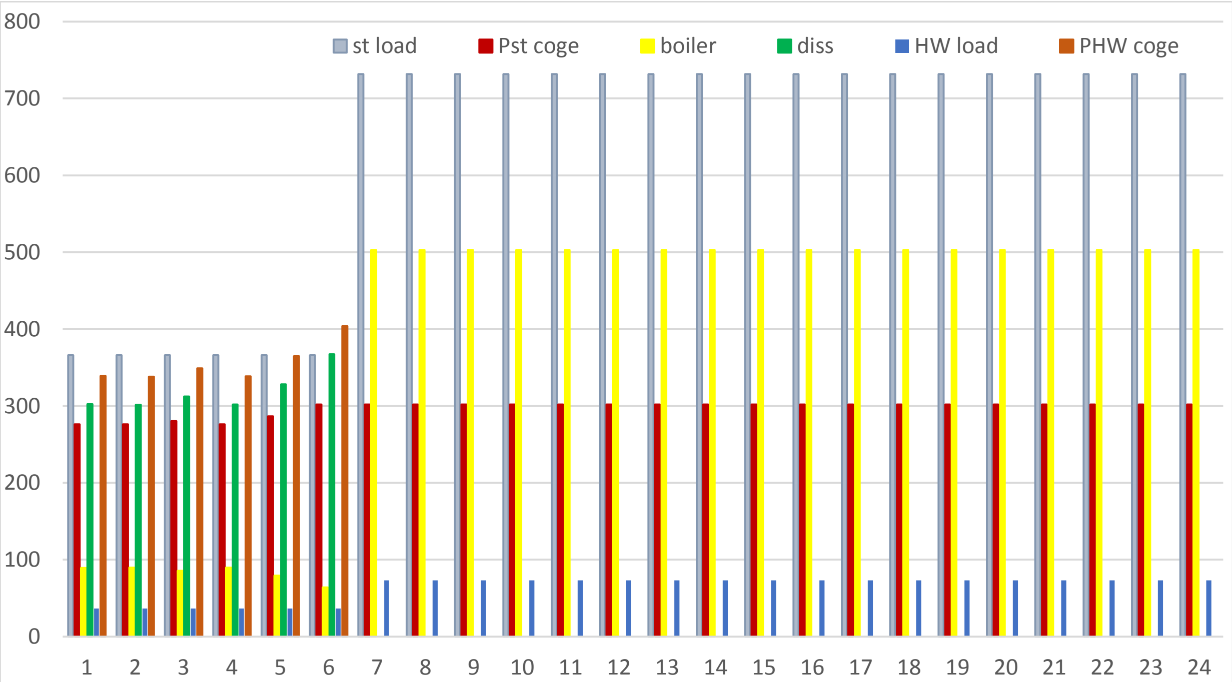

Figure 7.13*: Thermal load management for a typical summer day.*

Figure 7.14 presents the situation concerning the management of the electric load; in this graph, the demand from the heat pumps is not considered; it is instead considered under the form of cooling load. The graph is referred to the 4 of May; in this case there is no need to operate a distinction between the different seasons of the year as they have almost the same characteristics.

On the other hand the electric load management is influenced by local contingencies, linked to the market and to the electricity demand hour by hour. The diagram highlights an aspect already cited: the CHP plant is undersized for the peak load characteristics, but this allows having a very high number of operative hours, decreasing the payback time.

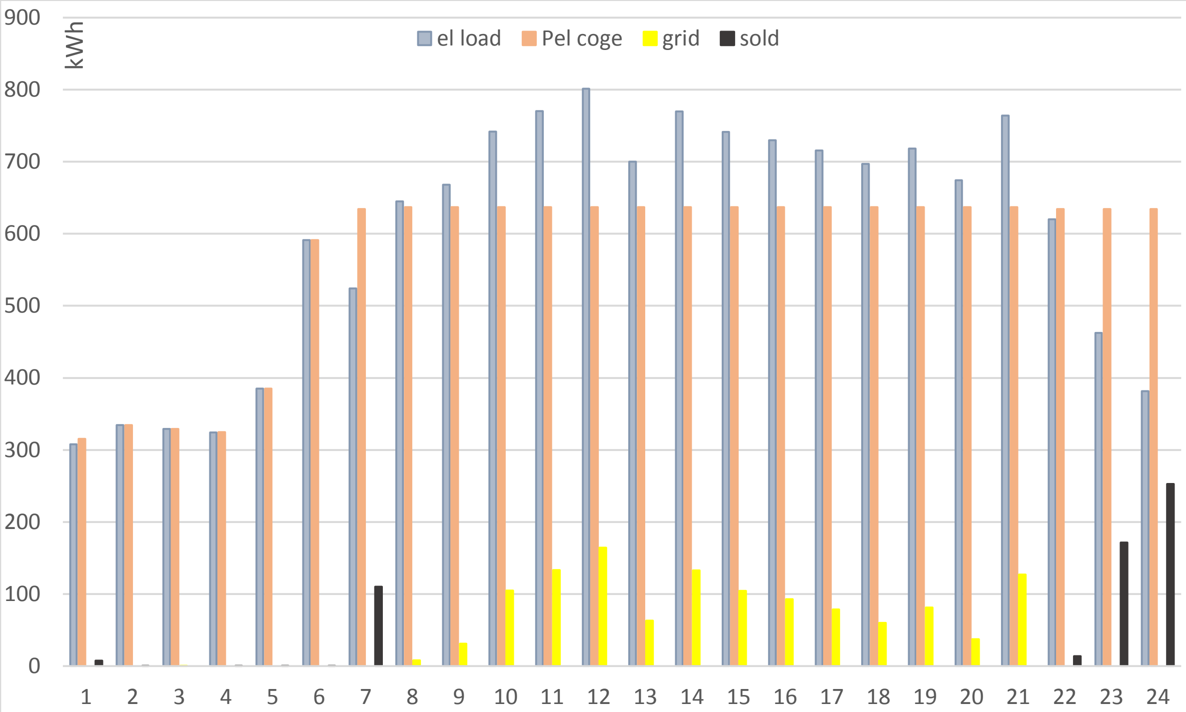

***Figure 7.14**: Electric load management.*

Figure 7.15 presents the management of the cooling load for the 28 of January, a reference day of the winter season. It is possible to see that, being the cooling load low, it can be covered by the exploitation of the absorption chiller for a large amount of hours per day. In the same way Figure 7.16 presents the management of the cooling load for the 6 of July: here the cooling load is much higher, and to cover it the heat pumps are used. The heat pumps are fed by electric energy that can come from the grid or can be produced and self-consumed in place by the power plant.

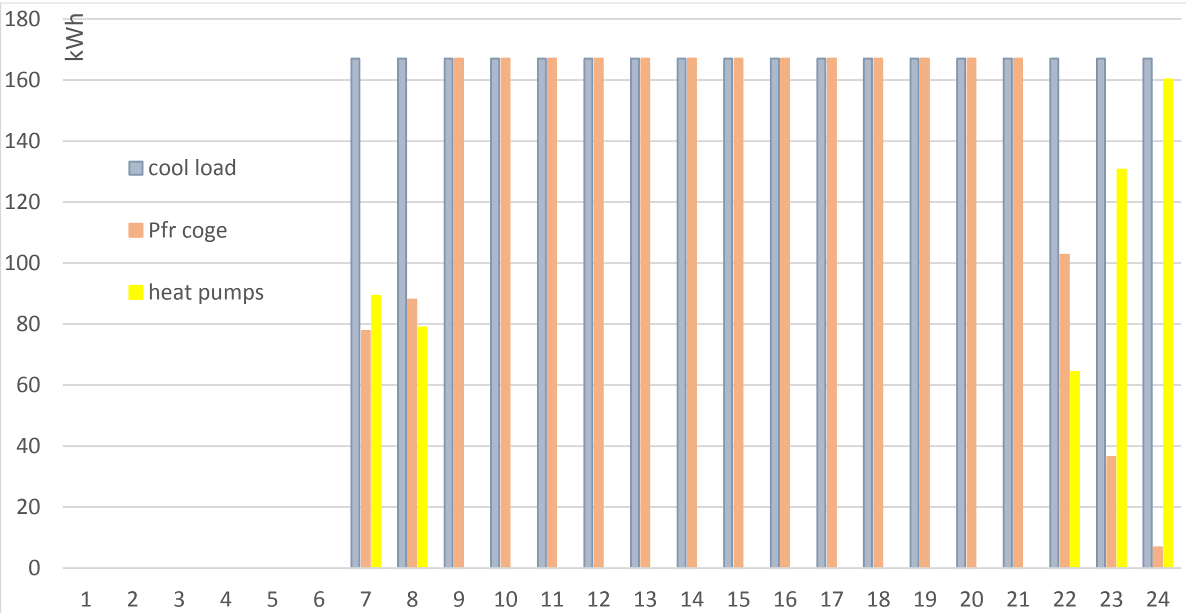

***Figure 7.15**: Cooling load management in a typical day of the winter season.*

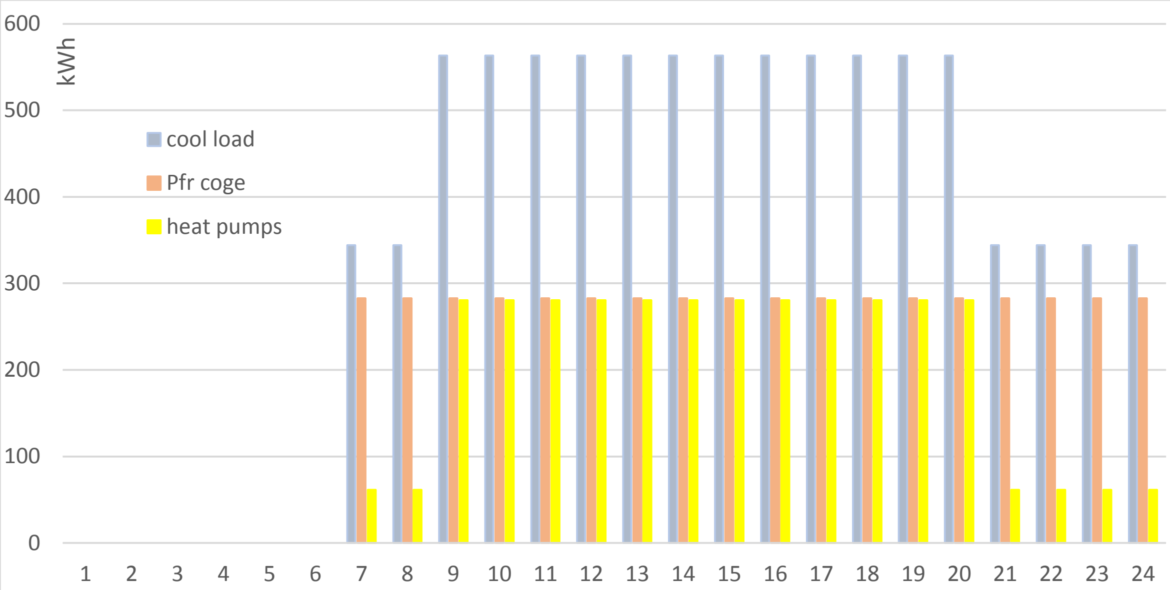

Figure 7.16: *Cooling load management for a typical day of the summer season.*

7.2.2 Working operations characteristics resulting from the optimization process

This section presents the results obtained after the optimization procedure in terms of CHP plant working operations.

Figure 7.17 reports the management of the electric energy produced by the CHP plant on an annual basis: on a total equal to 4,715 GWh of electric energy generated by the CHP plant over a year, 4,518 GWh (corresponding to 96%) have been self-consumed in place, 0,059 GWh (corresponding to 1%) have been used to run the heat pumps and produce cold, and 0,137 GWh (3%) have been sold on the DAM. This indicates that the self-consumption is by far the most advantageous use that can be done of the electricity produced, given the economics associated to the electricity as an energy vector. It is worth to underline that even the heat pump activation is actually a form of self-consumption, however it has a different aim and because of this it is distinguished from the pure electric load; the distinction allows understanding that in the overall balance of the electric energy from the CHP plant, the self-consumption associated to the heat pumps is a minor part.

Figure 7.18 reports the management of the thermal energy produced by the CHP plant, always on an annual basis. The total thermal energy produced by the CHP plant is equal to 5,361 GWh; of this volume, 2,994 GWh (56%) are self-consumed directly for steam or hot water generation, 1,440 (27%) are used to run the absorption chiller and produce cold water, and 0,926 GWh (17%) are dissipated and wasted. In this case, the amount of energy used for the refrigeration is not negligible and there is a good amount of heat wasted. This is linked to two aspects: the refrigeration performed by the absorption chiller through the use of low temperature heat substitutes a high quality energy vector such as the electric energy otherwise used in the heat pumps (both produced by the cogenerator and withdrawn from the grid); moreover the volume of wasted heat is associated to the presence of a high amount of high temperature heat needed, in front of a major production of low temperature heat by the CHP plant.

The data about the CHP plant working operations allow highlighting a very high number of equivalent hours per year, around 7.400 h/y, linked to the size chosen (under-estimated with respect to the loads).

This huge number of equivalent hours is also linked to the almost constant demand that characterizes Formec all over the year.

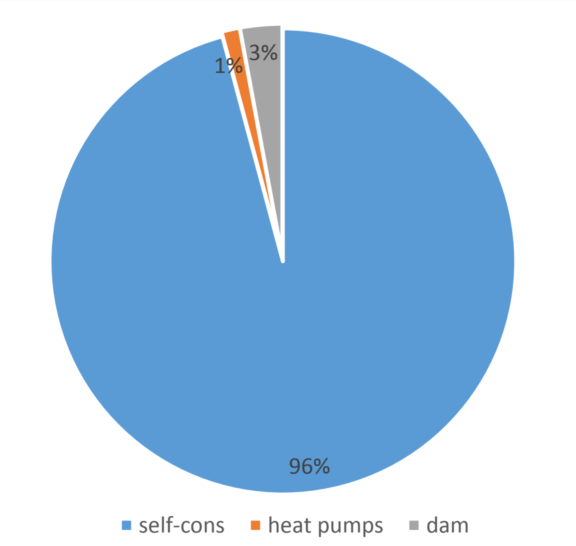

Figure 7.17: Management of the Pel by the CHP plant, 600 kWel size.

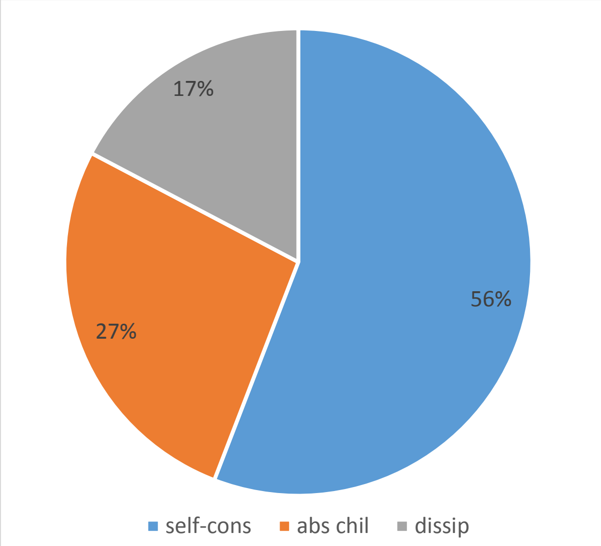

Figure 7.18: Management of the Pth by the CHP plant, 600 kWel size.

Figure 7.19 reports the share among the different energy assets in the coverage of the electric load. On a total electric load of 5,210 GWh over a year, 4,518 GWh (87%) have been provided by the CHP plant, whereas only 0,692 GWh (13%) have been withdrawn from the grid. This underlines again the importance of the self-consumption of electricity for an optimal behavior of the power plant.
Figure 7.20 presents the management of the thermal load. The annual thermal load of 5,795 GWh has been covered by 2,994 (52%) GWh generated by the CHP plant and 2,801 (48%) GWh from the boilers. As already said, the contribution of the boilers to the thermal laod coverage is still high due to the high steam generation demand that cannot be covered by the CHP plant.

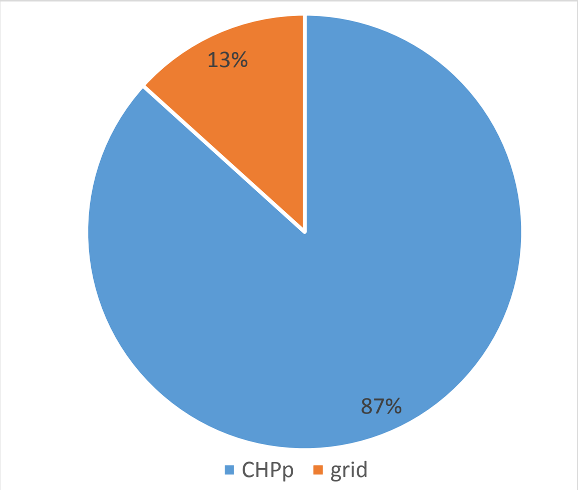

Figure 7.19: Electric demand coverage, 600 kWel size.

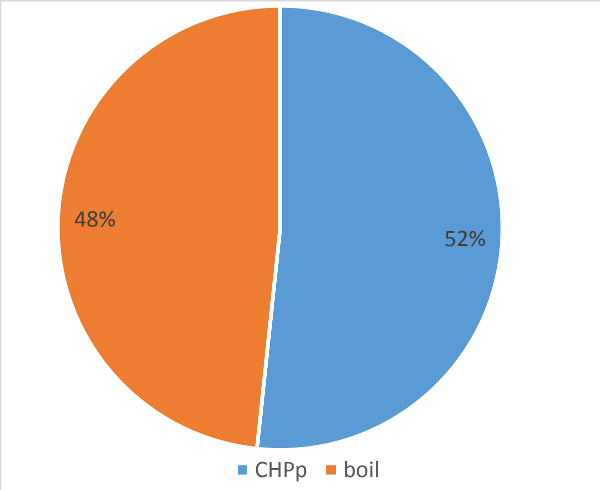

Figure 7.20: Thermal demand coverage, 600 kWel size.

Figure 7.21 reports the management of the cooling load. It is possible to see that the annual cooling load equal to 1,368 GWh has been covered by mainly the absorption chiller (1,008 GWh, 74%) and in part by the heat pumps (0,360 GWh, 26%).

In particular, the diagram presents a detail of the amount of electricity used to run the heat pumps coming from the grid and coming from the CHP plant: it is possible to see that about 35% of the energy for the heat pumps came from the CHP plant, while the remaining 65% came from the grid. Hence it is possible to conclude that the amount of cooling load covered by the CHP plant as a whole is equal to 74% plus 9%, equal to 83%.

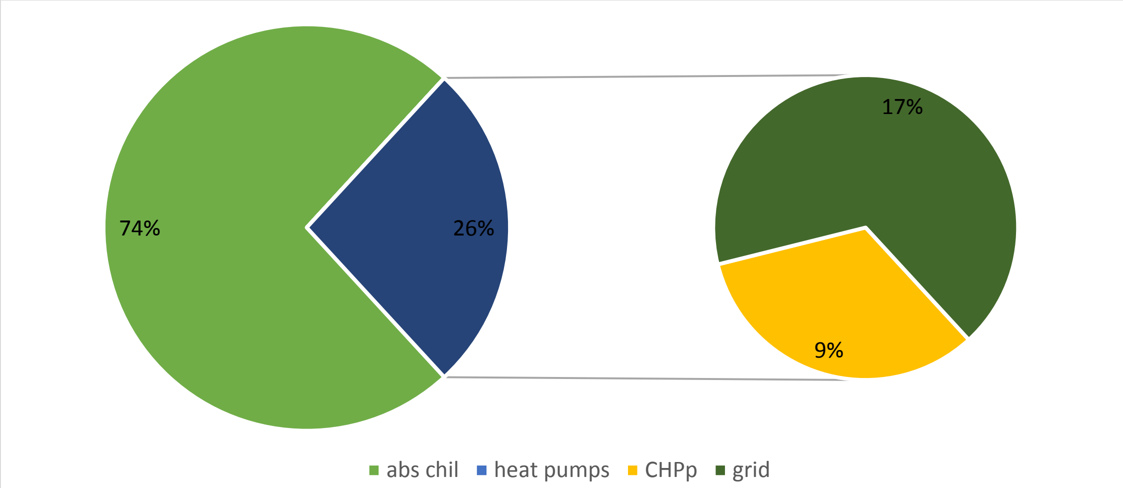

***Figure 7.21**: Cooling load management, 600 kWel size.*

7.2.3 Economic results and cash flow

The optimization procedure allowed obtaining for the size equal to 600 kW_{el}, a PES value of 27,8%, linked to the very high equivalent number of hours per year in which the CHP plant is active. Correlated to the PES value there was a saving in terms of primary energy with respect to a separated production of energy of 5,681 GWh, corresponding to about 500 White Certificates and to an annual incoming linked to the WC mechanism of 40.658 €/y.
The total SDF cost is estimated equal to 1,11 M€/y, while the SDP cost is around 685 k€/y, meaning that the total annual revenue is equal to 425 k€/y. In particular the "operation revenues" (linked to the activity defined hour by hour by the optimization tool) is equal to 364 k€/y; the cost related to the €/kW item in the electricity bill went from 30,6 k€/y down to 10 k€/y. The excises for the electric energy remained the same, as they are linked to the energy consumption. The overall cost for the NG increased due to the increase of the NG consumption, however the per unit cost paid decreased, due to the regressive behavior of the tariffs applied in the NG bill.

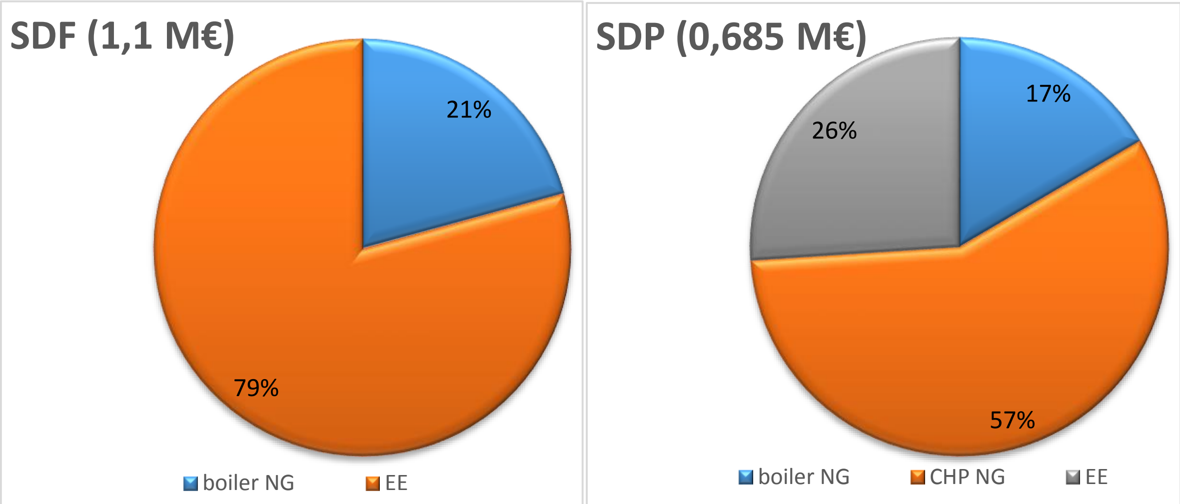

***Figure 7.22**: Share of the production plant costs among the different items, 600 kWel size.*

Figure 7.22 presents the share of the SDF and SDP situation from the costs point of view.
It is possible to see that from the SDF to the SDP configuration there has been a translation of the monetary expenses from the electricity vector to the NG vector; the weight of the NG on the costs passed from 21% to 74%, whereas the weight of the electric energy went from 79% down to 26%. This reflects a complete change in the economic framework of the production site, due to the presence of the CHP plant.
The electricity sold in the DAM was equal to 0,137 GWh, corresponding to about 8,5 k€/y meaning that the average price received by the power plant for the electric energy was around 60 €/MWh.
The cash flow resulting is presented in Table 7.6.

Table 7.6*: Cash flow, 600 kWhel size.*

Inflation Rate	0	1	2	3	4	5		
year	*cash flow [€]*						CAPEX	Revenues
0	- 804.000	- 804.000	- 804.000	- 804.000	- 804.000	- 804.000	804.000	€
1	- 378.315	- 382.530	- 386.662	- 390.714	- 394.688	- 398.586	-	425.685
2	47.369	34.767	22.493	10.535	- 1.118	- 12.478	-	425.685
3	473.054	447.932	423.625	400.096	377.314	355.245	-	425.685
4	898.739	857.007	816.892	778.312	741.191	705.457	-	425.685
5	1.304.332	1.242.915	1.184.250	1.128.180	1.074.559	1.023.249	20.092	405.593
6	1.730.016	1.643.929	1.562.246	1.484.684	1.410.983	1.340.902	-	425.685
7	2.155.701	2.040.973	1.932.830	1.830.805	1.734.469	1.643.428	-	425.685
8	2.581.386	2.434.085	2.296.147	2.166.844	2.045.512	1.931.548	-	425.685
9	3.007.070	2.823.306	2.652.341	2.493.096	2.344.593	2.205.948	-	425.685
10	3.362.393	3.144.975	2.943.830	2.757.489	2.584.636	2.424.086	70.362	355.323
11	3.788.078	3.526.526	3.286.192	3.065.013	2.861.153	2.672.975	-	425.685
12	4.213.762	3.904.300	3.621.842	3.363.580	3.127.034	2.910.012	-	425.685
13	4.639.447	4.278.333	3.950.910	3.653.450	3.382.689	3.135.761	-	425.685
14	5.065.132	4.648.663	4.273.525	3.934.878	3.628.511	3.350.761	-	425.685
15	5.490.816	5.015.326	4.589.815	4.208.109	3.864.879	3.555.523	-	425.685
16	5.916.501	5.378.359	4.899.904	4.473.381	4.092.156	3.750.534	-	425.685
17	6.342.186	5.737.797	5.203.912	4.730.927	4.310.691	3.936.259	-	425.685
18	6.767.870	6.093.677	5.501.959	4.980.972	4.520.821	4.113.139	-	425.685
19	7.193.555	6.446.033	5.794.162	5.223.734	4.722.869	4.281.597	-	425.685
20	7.619.240	6.794.901	6.080.635	5.459.426	4.917.146	4.442.033	-	425.685
Payback Time	1,89	1,91	1,93	1,95	1,96	1,98	y	
Net Present Value	7.619.240	6.794.901	6.080.635	5.459.426	4.917.146	4.442.033	€	

The cash flow is reported for different inflation rates; among them the reference value is considered equal to 2%. For this value the PT is equal to 2 years and the NPV , to the 20th year, is equal to 6 M€. This suggests that the investment is very attractive and effective from an economic point of view: it guarantees a very short return time and very high revenues in the long term.

7.2.4 Analysis of the NG and electricity bills in the SDP

This section presents a detailed analysis of the main energy costs of the production site before and after the installation of the CHP plant. All the computations have been performed by the optimization tool: the SDF data are linked to input data and to the consumption profile defined and described previously; the SDP data are linked to the optimization procedure carried out hour by hour by the tool. The specific data of the foreseen consumption, allowing to build the expected NG and electricity bills, are very important tools for the evaluation during the plant operations of the management of the power plant.

This can help to understand if there is something wrong with the plant working conditions, to individuate the issues and to modify promptly the operations framework, thus reducing the losses associated to possible problems.
The first energy vector presented is the NG consumed by the production plant. Table 7.7 reports the reference NG bill in the SDF; the total expense for the NG was around 230 k€/y, with a per unit cost of 32,44 c€/Sm^3 as an average.

***Table 7.7**: SDF reference bill.*

SDF			
MONTH	**Smc**	**TOTAL [€]**	**€/Smc**
JANUARY	71.624	26.869	0,3751
FEBRUARY	65.442	22.567	0,3448
MARCH	62.136	21.165	0,3406
APRIL	59.272	18.555	0,3130
MAY	55.753	17.433	0,3127
JUNE	57.519	17.985	0,3127
JULY	56.365	17.624	0,3127
AUGUST	51.401	16.072	0,3127
SEPTEMBER	52.498	16.415	0,3127
OCTOBER	56.730	17.739	0,3127
NOVEMBER	56.684	17.724	0,3127
DECEMBER	65.293	20.416	0,3127
TOTAL	710.720	230.565	0,3244

The SDP bill is presented in Table 7.8. In particular the specific data for the boilers and the CHP plant consumption are reported.
It is possible to see that the NG consumed by the boilers is less than 50% of that consumed in SDF; on the other hand the volume of NG consumed by the CHP plant is big (78% of the total consumption), but its per unit cost is low: this is correlated to the regressive tariff applied for the network services paid in the NG bill, and to the tax exemption which CHP plants are granted.
The result of this variation is an amount of NG consumed as a whole that increased by a factor equal to 2,23, but a cost of this energy vector that increased by a factor of 2. The average cost of the NG was in the SDP equal to 30,07 c€/Sm^3.

***Table 7.8**: SDP reference NG bill, 600 kWel size.*

SDP BOILERS				SDP CHPp				SDP TOTAL			
MONTH	**Smc**	**TOTAL**	**€/Smc**	**MONTH**	**Smc**	**TOTAL**	**€/Smc**	**MONTH**	**Smc**	**TOTAL**	**€/Smc**
JANUARY	35.587	12.884	0,3620	JANUARY	95.818	33.473	0,3493	JANUARY	131.406	46.357	0,3528
FEBRUARY	31.777	10.413	0,3277	FEBRUARY	92.014	29.110	0,3164	FEBRUARY	123.791	39.524	0,3193
MARCH	28.093	8.784	0,3127	MARCH	97.732	29.390	0,3007	MARCH	125.826	38.174	0,3034
APRIL	30.085	9.407	0,3127	APRIL	96.619	29.055	0,3007	APRIL	126.704	38.462	0,3036
MAY	28.738	8.986	0,3127	MAY	104.554	31.441	0,3007	MAY	133.293	40.427	0,3033
JUNE	31.177	9.749	0,3127	JUNE	108.580	32.652	0,3007	JUNE	139.757	42.400	0,3034
JULY	29.135	9.110	0,3127	JULY	121.300	36.477	0,3007	JULY	150.436	45.587	0,3030
AUGUST	24.524	7.413	0,3023	AUGUST	116.310	33.761	0,2903	AUGUST	140.833	41.174	0,2924
SEPTEMBER	25.869	7.555	0,2921	SEPTEMBER	105.946	29.697	0,2803	SEPTEMBER	131.815	37.252	0,2826
OCTOBER	25.526	7.320	0,2868	OCTOBER	100.322	28.120	0,2803	OCTOBER	125.848	35.441	0,2816
NOVEMBER	23.713	6.800	0,2868	NOVEMBER	100.414	28.146	0,2803	NOVEMBER	124.127	34.946	0,2815
DECEMBER	29.278	8.396	0,2868	DECEMBER	103.148	28.913	0,2803	DECEMBER	132.427	37.309	0,2817
TOTAL	343.503	106.818	0,3110	**TOTAL**	1.242.759	370.236	0,2979	**TOTAL**	1.586.262	477.054	0,3007

Table 7.9 reports the electricity bill generated as a reference for the SDF situation. It is possible to see that the monthly peak value of the power withdrawn form the grid is always higher than 600 kW_{el}, meaning that the CHP plant won't never ensure a complete independence form the network. The major cost is linked to the € per kWh item, with a low weight of the per kW expenses. This is correlated to the equivalent number of hours of power engagement, which measures yearly the capacity of the plant to exploit the peak power paid month by month; this parameter is equal to 5.104 h/y, suggesting a high and almost constant level of electricity consumption.

***Table 7.9**: SDF reference electricity bill.*

SDF							
MONTH	**kW max**	**kWh with**	**€ per kWh**	**€ per kW**	**€ excise**	**TOTAL**	€/kWh
JANUARY	1.010	403.753	55.014	2.245	3.340	61.158	0,1515
FEBRUARY	1.040	399.347	54.307	2.314	3.340	60.526	0,1516
MARCH	970	406.320	55.136	2.158	3.340	61.184	0,1506
APRIL	1.035	424.011	57.678	2.301	3.340	63.883	0,1507
MAY	1.186	513.354	69.937	2.637	3.340	76.512	0,1490
JUNE	1.368	580.758	79.062	3.043	3.340	86.083	0,1482
JULY	1.388	686.763	93.605	3.088	3.340	100.676	0,1466
AUGUST	1.397	613.794	83.413	3.106	3.340	90.504	0,1474
SEPTEMBER	1.310	530.773	72.155	2.912	3.340	79.033	0,1489
OCTOBER	1.043	454.137	61.832	2.319	3.340	68.057	0,1499
NOVEMBER	1.021	437.063	59.386	2.270	3.340	65.558	0,1500
DECEMBER	1.032	445.320	60.570	2.296	3.340	66.770	0,1499
TOTAL		5.895.392	802.094	30.690	40.082	879.943	0,1493

Table 7.10 presents the SDP reference electricity bill. It is possible to see a reduction of the electricity withdrawn equal to 86%, that corresponded to an equal reduction of the per kWh expenses, whereas the per kW cost decreased by a factor of 60%. As said, the excises paid remained unvaried. This situation contributed to an increase of the per unit cost of the electricity, that went from 149 €/MWh to 206 €/MWh. The equivalent number of hours per year for the peak power engagement decreased down to 1.845 h/y, and the weight of the per kW expenses over the total increased of almost 100%, passing from 3,5% in the SDF, to 6,5% in the SDP.

***Table 7.10**: SDP reference electricity bill, 600 kWel size[8].*

SDP								
MONTH	**kW max**	**kWh with**	**kWh DAM**	**€ per kWh**	**€ per kW**	**€ excise**	**TOTAL**	€/kWh
JANUARY	289	32.953	16.592	4.554	643	3.340	8.936	0,2712
FEBRUARY	329	36.694	11.374	5.029	732	3.340	9.508	0,2591
MARCH	256	25.951	18.715	3.550	570	3.340	7.851	0,3025
APRIL	282	32.340	17.859	4.469	626	3.340	8.832	0,2731
MAY	407	67.801	2.952	9.363	906	3.340	14.033	0,2070
JUNE	590	116.088	4.490	15.989	1.312	3.340	21.106	0,1818
JULY	610	161.955	9.329	23.502	1.357	3.340	28.669	0,1678
AUGUST	618	115.904	1.748	15.925	1.375	3.340	21.112	0,1822
SEPTEMBER	531	78.249	4.186	10.751	1.181	3.340	15.724	0,2010
OCTOBER	317	45.127	6.464	6.210	705	3.340	10.660	0,2362
NOVEMBER	299	39.233	14.982	5.399	666	3.340	9.805	0,2499
DECEMBER	313	52.204	28.896	7.196	695	3.340	11.636	0,2229
TOTAL		804.501	137.588	111.936	10.768	40.082	167.872	0,2064

A further step in the costs analysis of the different energy vectors consisted in the forecast of the evolution of the electricity bill under the light of the future general system charges reform presented in Chapter 3. In particular, knowing the future possible tariffs relative to every reform hypothesis, and having built step by step the electricity bill, it is possible to define the expected electricity bill in every reform scenario, and to study the effect of the different hypothesis on the electricity cost, thus on the plant revenues.

[8] The indication about the energy (kWh_{el}) sold on the DAM is not involved in the computation of the economic flows reported in the presented bill, which refer only to the expenses and do not include the market revenues.

Table 7.11 presents in a summarized form the results obtained for each reform scenario for both the SDF and the SDP; it is indicated also the share of the new expense among the energy, power and taxes items.

***Table 7.11**: Effect of the general system charges hypothesis of reform on the electric energy expense.*

	A	B1	B2	B3	C
SDF TOTAL	-11,68%	-7,18%	-2,69%	1,89%	-0,95%
€ per kW	15,54%	12,03%	8,84%	5,94%	7,69%
€ per kWh	77,23%	81,37%	85,12%	88,55%	86,48%
€ excise	7,23%	6,60%	6,03%	5,51%	5,83%
SDP TOTAL	4,12%	4,23%	4,34%	4,51%	4,38%
€ per kW	24,25%	19,70%	15,17%	10,64%	13,42%
€ per kWh	48,11%	53,13%	58,14%	63,16%	60,07%
€ excise	27,65%	27,17%	26,69%	26,20%	26,50%

In the rows relative to the SDF and SDP the variation of the total cost of electricity is indicated with respect to the current situation. It is possible to see that, according to the content of DCO 255/16 (Section 2, Paragraph 2.13), due to the high number of equivalent hours for the power engagement in the SDF, an increase of the power tariff is translated into a decrease of the total expense: this is true especially in the case of hypothesis A and B1, the ones entailing the greater shift of the electric energy costs from the per kWh to the per kW item. In all the reform hypothesis the share of the per kW cost over the total increases from the 3,5% of the ongoing situation.

A totally different evolution concerns the SDP. In this case every hypothesis of reform entails an increase of the expense, always around 4%. As the total expense decreases, the weight of the excise component over the total increases, because it remains constant while the other cost items decrease.

7.2.5 Role of the electricity market and opportunities from the ASM

The role of the electricity markets in the operations of a CHP plant connected at the distribution level is minor; this aspect is also resulting from the optimization analysis: the contribute of the DAM revenues is around the 2% of the total revenues, and only 3% of the total electric energy generated is sold on the electricity market.

The elaboration carried out on the ASM data, described in Chapter 5, allowed defining a framework to evaluate the impact of the ASM presence on the operations of the power plant. From a qualitative point of view, the opportunity to participate to the ASM could increase the revenues coming from the electricity selling, and could justify the installation of a power plant with a bigger size to better exploit this opportunity.

The optimization procedure allowed defining properly the influence of the electricity markets in the SDP with and without the possibility to participate to the ASM. The framework described in the previous sections refers to a configuration without the possibility to participate to the ASM, hence it has been developed with reference to the current framework.

The data regarding the DAM in this situation are reported in Table 7.12; clearly the ASM is excluded from the analysis. The average selling price is about 62 €/MWh, which is a typical value for the DAM price.

The situation with the possibility for the CHP plant to participate to the ASM changes significantly. The data referred to this new configuration are reported in Table 7.13.

***Table 7.12**: Market data, without-ASM configuration, 600 kWel size.*

	DAM			ASM		
	kWh	**€**	**€/kWh**	**kWh**	**€**	**€/kWh**
JANUARY	16.592	887	0,0534	-	-	-
FEBRUARY	11.374	651	0,0573	-	-	-
MARCH	18.715	1.031	0,0551	-	-	-
APRIL	17.859	979	0,0548	-	-	-
MAY	2.952	147	0,0499	-	-	-
JUNE	4.490	269	0,0600	-	-	-
JULY	9.329	1.280	0,1372	-	-	-
AUGUST	1.748	110	0,0628	-	-	-
SEPTEMBER	4.186	221	0,0527	-	-	-
OCTOBER	6.464	335	0,0518	-	-	-
NOVEMBER	14.982	909	0,0606	-	-	-
DECEMBER	28.896	1.727	0,0598	-	-	-
TOTAL	137.588	8.545	0,0621	-	-	-

***Table 7.13**: Market data, with-ASM configuration, 600 kWel size.*

	DAM			ASM		
	kWh	**€**	**€/kWh**	**kWh**	**€**	**€/kWh**
JANUARY	3.073	196	0,0639	41.048	2.925	0,0713
FEBRUARY	4.123	251	0,0609	20.937	1.435	0,0686
MARCH	3.453	231	0,0669	38.519	2.502	0,0650
APRIL	4.972	319	0,0643	44.124	2.892	0,0656
MAY	448	30	0,0680	24.978	1.578	0,0632
JUNE	3.218	201	0,0624	9.869	601	0,0609
JULY	9.168	1.271	0,1386	1.661	120	0,0724
AUGUST	814	57	0,0705	9.432	617	0,0654
SEPTEMBER	977	52	0,0527	35.599	2.383	0,0669
OCTOBER	1.145	67	0,0587	42.599	2.766	0,0649
NOVEMBER	6.973	484	0,0693	30.900	1.974	0,0639
DECEMBER	8.589	605	0,0704	60.515	4.051	0,0669
TOTAL	46.952	3.764	0,0802	360.180	23.846	0,0662

From the data presented it is possible to see that the amount of energy sold on the electricity markets is increased a lot, passing from 137 MWh/y to 407 MWh/y; the main part of the electricity has been sold on the ASM, meaning that the average price found on the ASM was, even after the leveling based on the probability of acceptance, higher than the one found on the DAM. As a result the amount of electric energy sold on the DAM is about 11% of the total; on the other hand the average price at which this energy was sold has been higher than before and equal to 80,2 €/MWh. Moreover this selling price has been even higher than the average selling price on the ASM, which has been equal to 66,2 €/MWh.

On the DAM the price has been influenced by the performances of the month of July[9], and clearly by the fact that the amount of energy sold has been lower than in the SDF and was required to be above the reference price of the ASM.

The revenues resulting in this new configuration are about 4 k€/y from the DAM and about 24 k€/y from the ASM, for a total of 27,6 k€/y; this number is much greater than the 8,5 k€/y computed for the SDF situation. It is possible to conclude that, for the size of 600 kW_{el}, the participation to the ASM in the North zone, with reference to the province of Piacenza and to the study case of Formec, means an increase in the market revenues of more than 200%. However it is necessary to consider how this opportunity has influenced the working operations of the power plant.

The new operational framework is presented in Table 7.13 together with a comparison between the SDF and the SDP situations.

Table 7.13*: Comparison between the DAM+ASM and the only DAM situations, 600 kWel size.*

Pel COGE				Pth COGE			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
self-cons	4.518.477	4.518.445	0,00%	self-cons	3.060.834	2.994.311	2,22%
heat pumps	35.269	59.378	-40,60%	abs chil	1.509.376	1.440.428	4,79%
market	407.133	137.588	195,91%	dissip	1.024.811	926.591	10,60%
TOTAL	4.960.878	4.715.411	5,21%	TOTAL	5.595.022	5.361.330	4,36%

COOLING LOAD				ELECTRIC LOAD			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
abs chill	1.056.563	1.008.299	4,79%	CHPp	4.518.477	4.518.445	0,00%
heat pumps	312.237	360.501	-13,39%	grid	692.515	692.547	0,00%
CHPp	70.537	118.756	-40,60%				
grid	241.699	241.744	-0,02%				
TOTAL	1.368.800	1.368.800		**TOTAL**	5.210.992	5.210.992	

THERMAL LOAD			
kWh	**DAM+ASM**	**DAM**	%
CHPp	3.060.834	2.994.311	2,22%
boil	2.734.426	2.800.949	-2,38%
TOTAL	5.795.260	5.795.260	

As already stated, the opportunity to cover the electricity demand, because of the high electric energy price paid in the bill, is always caught by the CHP plant, indeed the self-consumed electric energy is the same with and without the ASM participation. With the possibility to participate to the ASM, the amount of electricity used for the heat pumps decreases; this is linked to two aspects: the opportunity represented by the valorization of the electricity on the ASM and the fact that it is possible to generate cold exploiting the heat produced by the CHP plant at the same time in which the electricity is sold on the ASM. The electricity produced by the plant increased by a factor around 5%.

For what concerns the management of the thermal energy from the CHP plant, the overall thermal energy produced increased by 4,3%; consequently both the heat used to cover the thermal load and the heat used to run the absorption chiller increased. At the same time the dissipated heat increased by 10%, meaning that in certain hours the price of electricity on the market was high enough to justify the turning on of the plant, even when no heat demand was present.

The lower part of the table refers to the load management.

According to the considerations just made, the electric load performed no variations, whereas the cooling load was covered more by the use of the absorption chiller than by the heat pumps.

[9] The reference price of the month of July is influenced by the presence of high production from non-programmable RES plants, in particular PV plants. This aspect is highlighted also in Chapter 5.

In particular it is possible to see that all the heat pumps load reduction was in charge to the CHP plant, not regarding the grid withdrawal. Finally the increase of the thermal self-consumption allowed a decrease of the boilers load.
It is possible to conclude that the participation to the ASM influenced coherently the management of the plant from the working operations point of view.
Table 7.14 presents the variation from the economic point of view.
From the data reported it is possible to see that the participation to the ASM increased the equivalent number of hours for the operations of the CHP plant, producing an increase of the WC revenues of about 1,5 k€/y. As stated, there has been an increase of the market revenues. The higher number of working hours for the CHP plant has caused an increase of the NG linked expenses of almost 15 k€/y that partly compensated the major revenues coming from the market. The result of this combination has been a total yearly revenue passing from 425 k€/y to 430 k€/y, with an increase of 1,24%.
The economic parameters, thanks to the revenue increase, have been better for the DAM+ASM situation, even if the variation has been limited. The PT and the NPV have been calculated with an inflation rate of 2% and with an investment lifetime of 20 years.

***Table 7.14**: Economic parameters variation with and without the ASM opportunity, 600 kWel size.*

	DAM+ASM	DAM	%	
PES	27,71	27,80	-0,32%	%
Eq hours	7.788	7.403	5,20%	h/y
mrkt reven.	27.610	8.545	223,11%	€/y
WC	42.124	40.658	3,61%	€/y
Revenues	430.958	425.685	1,24%	€/y
€ per NG	492.138	477.054	3,16%	€/y
€ per EE	167.865	167.872	0,00%	€/y
PT	1,90	1,93	-1,40%	y
NPV	6.166.868	6.080.635	1,42%	$€_{act}$

At the end of this section it is possible to say that the opportunity represented by the ASM has been fully exploited by the CHP plant after the optimization procedure; this resulted in a huge increase of the electricity sold and of the corresponding revenues. However, this increase has been translated in a limited net revenue, due to the costs correlated with the CHP plant operations.

7.3 Results of the Optimization Procedure for the Size of 800 kW_{el}

The second size of the CHP plant tested for the study case of Formec has been the 800 kW_{el}. Also for the 800 kW_{el} size was possible to define all the parameters presented previously; because of the limited space available, for this and for the next (bigger) sizes, only the main aspects are presented. These aspects include: details about the produced energy and the loads management, the cash flow and a detailed comparison between the configuration with and without the ASM participation.

7.3.1 Working operations characteristics resulting from the optimization process

Figure 7.23 and 7.24 present the management of the thermal and electric energy generated by the CHP plant. As expected, with respect to the 600 kW_{el} size, the percentage of electric energy sold on the DAM increased (from 3% to 9%), and consequently the percentage of electricity self-consumed, for either the pure electric load or the heat pumps, decreased. For what concerns the management of the thermal energy produced, there was an increase of the heat wasted (from 17% to 18%); this increase was reflected, in percentage terms, on the amount of heat exploited in the absorption chiller over the total (from 27% to 23%), whereas the share of the heat self-consumed for the thermal load coverage increased.

The number of equivalent working hours was around 6.700 h/y.

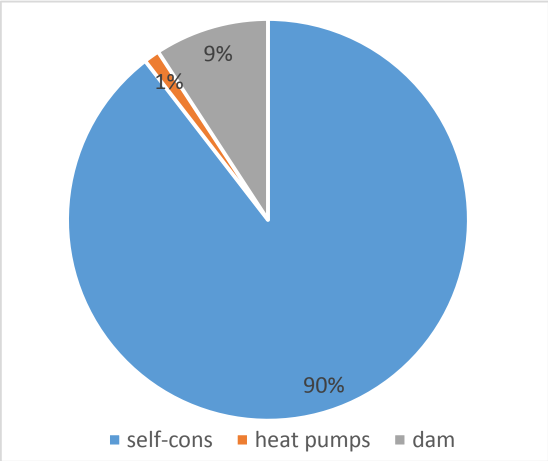

Figure 7.23: *Management of the Pel from the CHP plant, 800 kWel size.*

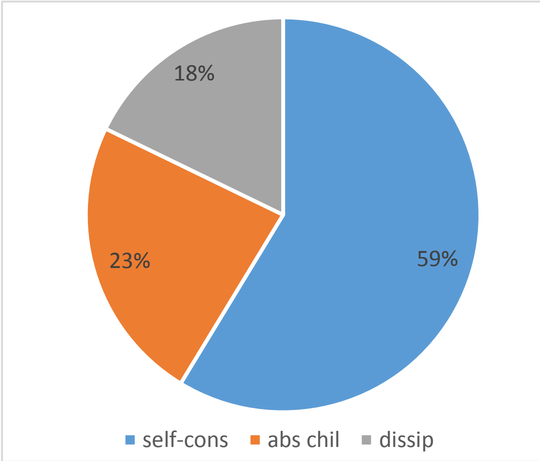

Figure 7.24: *Management of the Pth from the CHP plant, 800 kWel size.*

Figure 7.25, 7.26 and 7.27 report the management of respectively the electric, the thermal and the cooling load.

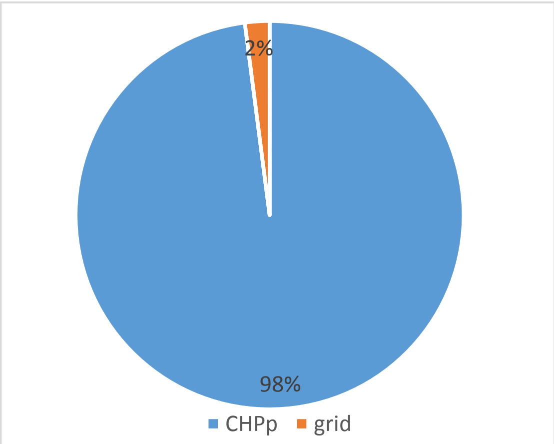

Figure 7.25: *Electric demand coverage, 800 kWel size.*

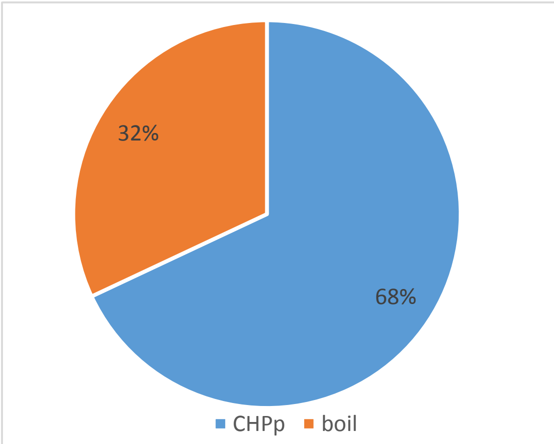

Figure 7.26: *Thermal demand coverage, 800 kWel size.*

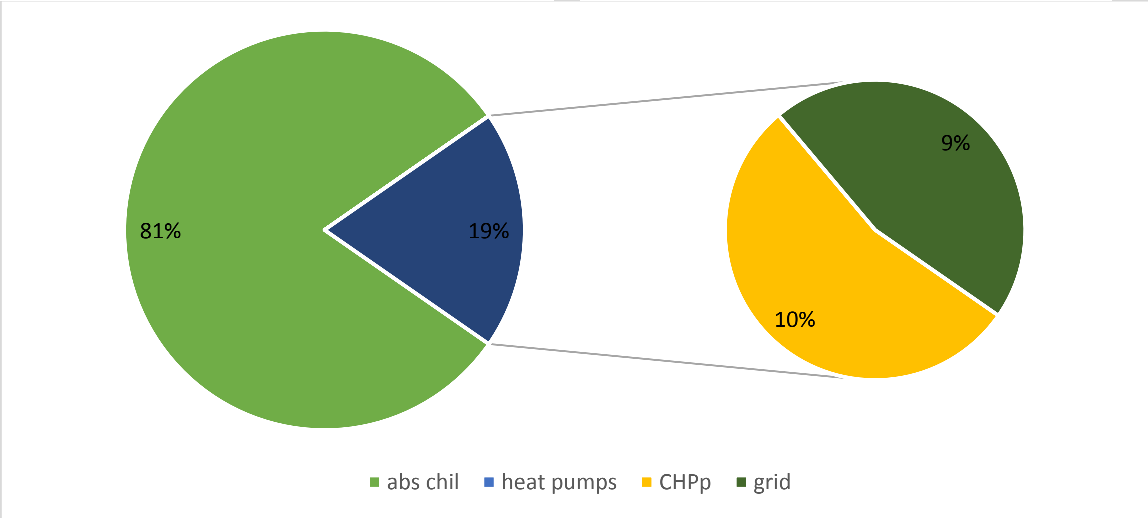

Figure 7.27: *Cooling demand coverage, 800 kWel size.*

In a comparison with the 600 kW_{el} size, for both the electric and the thermal load, the weight of the CHP plant energy exploitation is greater; this is linked to the possibility to provide a higher of nominal power. The coverage of the cooling load from the absorption chiller increases (from 74% to 81%),and the remaining part covered by the heat pumps is provided mainly by the CHP plant electricity production: for the 800 kW_{el} size the percentage of the total cooling load covered by the CHP plant is 91%.

7.3.2 Economic results and cash flow

Table 7.15 reports the cash flow obtained for the 800 kW_{el} size.

Table 7.15: *Cash flow, 800 kWel size.*

Inflation Rate	0	1	2	3	4	5		
year	*cash flow [€]*						**CAPEX**	**Revenues**
0	- 1.056.000	- 1.056.000	- 1.056.000	- 1.056.000	- 1.056.000	- 1.056.000	1.056.000	€
1	- 546.022	- 551.071	- 556.022	- 560.876	- 565.637	- 570.307	-	509.978
2	- 36.044	- 51.142	- 65.847	- 80.173	- 94.134	- 107.742	-	509.978
3	473.934	443.837	414.717	386.529	359.235	332.796	-	509.978
4	983.911	933.916	885.857	839.638	795.166	752.356	-	509.978
5	1.467.500	1.394.034	1.323.859	1.256.786	1.192.641	1.131.261	26.388,80	483.589
6	1.977.478	1.874.457	1.776.704	1.683.884	1.595.684	1.511.814	-	509.978
7	2.487.456	2.350.122	2.220.671	2.098.543	1.983.225	1.874.246	-	509.978
8	2.997.434	2.821.078	2.655.932	2.501.124	2.355.861	2.219.419	-	509.978
9	3.507.412	3.287.371	3.082.659	2.891.980	2.714.165	2.548.155	-	509.978
10	3.924.966	3.665.377	3.425.198	3.202.679	2.996.249	2.804.497	92.424,00	417.554
11	4.434.943	4.122.482	3.835.355	3.571.098	3.327.521	3.102.671	-	509.978
12	4.944.921	4.575.062	4.237.469	3.928.786	3.646.052	3.386.645	-	509.978
13	5.454.899	5.023.160	4.631.698	4.276.056	3.952.331	3.657.097	-	509.978
14	5.964.877	5.466.822	5.018.198	4.613.212	4.246.831	3.914.671	-	509.978
15	6.474.855	5.906.091	5.397.119	4.940.547	4.530.003	4.159.979	-	509.978
16	6.984.833	6.341.011	5.768.610	5.258.348	4.802.285	4.393.606	-	509.978
17	7.494.811	6.771.625	6.132.817	5.566.893	5.064.094	4.616.107	-	509.978
18	8.004.788	7.197.975	6.489.883	5.866.452	5.315.833	4.828.014	-	509.978
19	8.514.766	7.620.104	6.839.947	6.157.285	5.557.890	5.029.829	-	509.978
20	9.024.744	8.038.054	7.183.148	6.439.647	5.790.637	5.222.034	-	509.978
Payback Time	2,07	2,09	2,11	2,13	2,15	2,17	y	
Net Present Value	9.024.744	8.038.054	7.183.148	6.439.647	5.790.637	5.222.034	€	

It is possible to see that the annual revenue had an increase of about 84 k€/y (from 426 k€/y to 510 k€/y); the PT passed from less than 2 years to slightly more than 2 years, suggesting that the revenue increase does not compensate entirely the increase of the CAPEX in terms of return time. However the revenue increase corresponded to an increase of the NPV_{20} of more than 1 M€.

7.3.3 Role of the electricity market and opportunities from the ASM

Table 7.16 and 7.17 present the data referred to the activity on the electricity markets for the configuration without and with the ASM participation opportunity.

From the qualitative point of view, the variation of the conditions from the ”only DAM” to the “DAM+ASM” configuration is the same presented for the 600 kW_{el} size.

***Table 7.16**: Market data, whithout ASM configuration, 800 kWel size.*

	DAM			ASM		
	kWh	**€**	€/kWh	**kWh**	**€**	€/kWh
JANUARY	52.134	2.575	0,0494	-	-	-
FEBRUARY	58.030	3.267	0,0563	-	-	-
MARCH	67.979	3.666	0,0539	-	-	-
APRIL	60.462	3.205	0,0530	-	-	-
MAY	20.273	1.036	0,0511	-	-	-
JUNE	15.632	861	0,0551	-	-	-
JULY	26.785	2.761	0,1031	-	-	-
AUGUST	17.522	1.012	0,0578	-	-	-
SEPTEMBER	18.554	975	0,0526	-	-	-
OCTOBER	36.569	1.783	0,0488	-	-	-
NOVEMBER	66.705	4.031	0,0604	-	-	-
DECEMBER	84.614	4.919	0,0581	-	-	-
TOTAL	525.259	30.093	0,0573	-	-	-

***Table 7.17**: Market data, with ASM configuration, 800 kWel size.*

	DAM			ASM		
	kWh	**€**	€/kWh	**kWh**	**€**	€/kWh
JANUARY	6.331	389	0,0614	107.931	7.669	0,0711
FEBRUARY	16.880	1.052	0,0623	75.987	5.208	0,0685
MARCH	13.705	945	0,0690	101.256	6.609	0,0653
APRIL	13.149	868	0,0660	101.729	6.667	0,0655
MAY	5.382	365	0,0678	53.518	3.385	0,0632
JUNE	7.497	453	0,0605	31.178	1.900	0,0609
JULY	22.329	2.500	0,1120	12.815	917	0,0716
AUGUST	4.878	318	0,0652	32.570	2.140	0,0657
SEPTEMBER	2.687	146	0,0543	57.121	3.896	0,0682
OCTOBER	7.112	448	0,0630	88.475	5.720	0,0647
NOVEMBER	27.866	2.129	0,0764	78.245	5.026	0,0642
DECEMBER	26.915	1.880	0,0699	127.805	8.486	0,0664
TOTAL	154.732	11.494	0,0743	868.631	57.624	0,0663

In the configuration without the ASM opportunity, the electric energy sold was around 525 MWh/y, with an average selling price of 57,3 €/MWh. In the configuration with the ASM opportunity, the electricity sold was around 1.023 MWh/y, with an average price of 66,3 €/MWh on the ASM and of 74,3 €/MWh on the DAM; as before, the main part of the electric energy was sold on the ASM.
This framework is translated from the economic point of view in an increase in terms of market revenues from 30 k€/y to 69 k€/y, equal to more than 100%.
Table 7.18 presents the variation in terms of the plant management from one configuration to the other. It is possible to see that, as for the 600 kW_{el} size, the amount of electric energy self-consumed did not change, while the electricity used for the heat pumps decreased, compensated by the increase of the amount of cooling load covered by the absorption chiller. The production and the dissipation of heat increased, but the amount of heat provided by the auxiliary boilers decreased
In the same way, Table 7.19 reports the variation of the main parameters of the study case analysis passing from one configuration to the other.

The number of equivalent working hours increased, together with the revenues from the WC. While the expenses for the electricity remained unvaried, the ones for the NG increased of almost 28 k€/y, compensating in part the higher revenues coming from the market and from the WC support mechanism. This resulted in an annual revenue increase of 2,5%, from 509 k€/y to 522 k€/y.
As for the 600 kW_{el} size, it is possible to say that the opportunity to participate to the ASM represents for the plant a benefit, that reduces the PT and increases the NPV_{20}; however the added value provided by the ASM participation constitutes few percentage points of the total revenues.

Table 7.18*: only DAM and DAM+ASM configurations comparison, 800 kWel size.*

Pel COGE				Pth COGE			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
self-cons	5.104.373	5.104.359	0,00%	self-cons	4.071.772	3.941.993	3,29%
heat pumps	31.257	71.668	-56,39%	abs chil	1.693.131	1.577.629	7,32%
market	1.023.363	525.259	94,83%	dissip	1.384.161	1.196.557	15,68%
TOTAL	6.158.993	5.701.286	8,03%	TOTAL	7.149.064	6.716.179	6,45%
COOLING LOAD				**ELECTRIC LOAD**			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
abs chil	1.185.191	1.104.340	7,32%	CHPp	5.104.373	5.104.359	0,00%
heat pumps	183.609	264.460	-30,57%	grid	106.619	106.633	-0,01%
CHPp	62.515	143.336	-56,39%				
grid	121.094	121.124	-0,02%				
TOTAL	1.368.800	1.368.800		**TOTAL**	5.210.992	5.210.992	

THERMAL LOAD			
kWh	**DAM+ASM**	**DAM**	%
CHPp	4.071.772	3.941.993	3,29%
boil	1.723.488	1.853.267	-7,00%
TOTAL	5.795.260	5.795.260	

Table 7.19*: Economic parameter variations with and without the ASM, 800 kWel size.*

	DAM+ASM	**DAM**	%	
PES	26,76	27,06	-1,12%	%
Eq hours	7.237	6.700	8,02%	h/y
mrkt reven.	69.118	30.093	129,68%	€/y
WC	50.476	47.965	5,23%	€/y
Revenues	522.881	509.978	2,53%	€/y
€ per NG	545.800	517.871	5,39%	€/y
€ per EE	72.433	72.437	-0,01%	€/y
PT	2,06	2,11	-2,37%	y
NPV	7.394.134	7.183.148	2,94%	$€_{act}$

7.4 Results of the Optimization Procedure for the Size of 1000 kW_{el}

The third optimization procedure has been performed on the 1.000 kW_{el} size. This size, according to the input data referred to the Formec consumption, and in particular to the peak thermal and electric loads, is already near the nominal power value of the CHP plant which is expected to guarantee an almost complete independence from the auxiliary energy assets beside the cogenerator.

7.4.1 Working operations characteristics resulting from the optimization process

Figure 7.28 and 7.29 present the evolution for the 1.000 kW_{el} size in the management of the electric and thermal energy produced by the power plant.

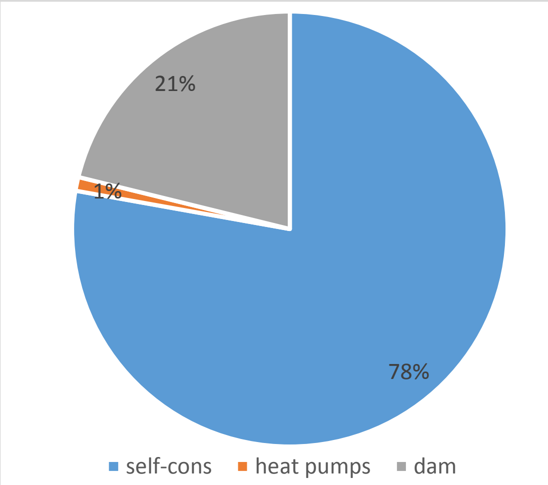

Figure 7.28: Management of the Pel from the CHP plant, 1.000 kWel size.

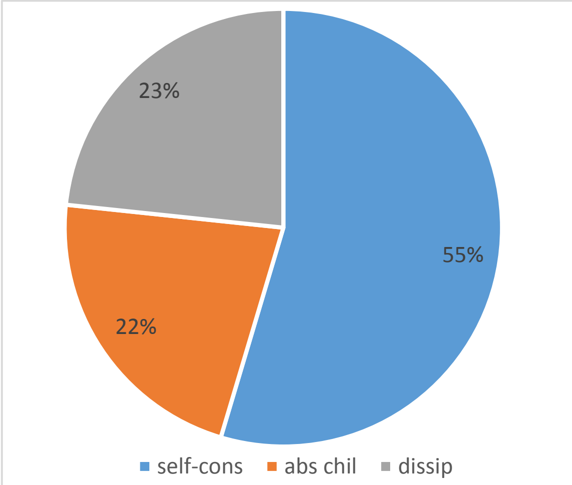

Figure 7.29: Management of the Pth from the CHP plant, 1.000 kWel size.

As the size of the power plant increases, the percentage of electric energy produced which is sold on the DAM increases. In the same way, the amount of heat which is wasted and not exploited increases. Figure 7.30, 7.31 and 7.32 represents the situation concerning the management of the electric, thermal and cooling load.

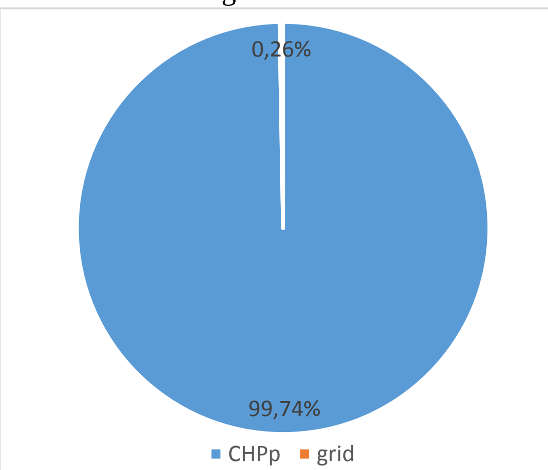

Figure 7.30: Electric demand coverage, 1.000 kWel size.

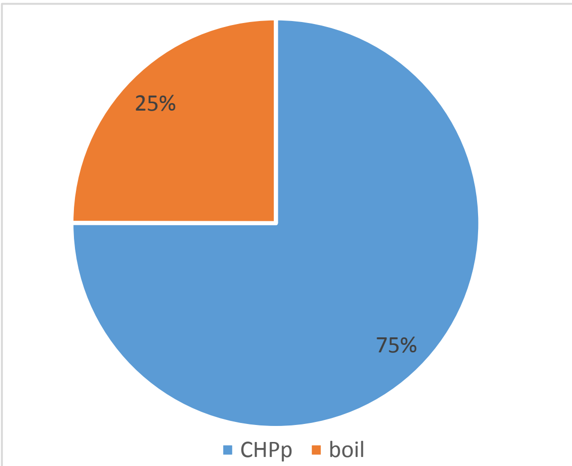

Figure 7.31: Thermal load coverage, 1.000 kWel size.

It is possible to see that the electric load and the cooling load are substantially covered entirely by the energy production of the CHP plant. On the other hand the thermal load still needs 25% of the energy to be produced by the auxiliary boilers: this is linked to the necessity to produce steam, that often cannot be completely fulfilled by the CHP plant alone.

As expected, the 1.000 kW_{el} size is able to provide almost the entire amount of energy needed by the production site. The operational data confirm however that: the steam demand introduces the need to always activate the auxiliary boilers, while at the same time a large part of the heat produced (23%) is wasted. Moreover, the consumption profiles, also for the electric and the cooling load, entail some peaks that still require withdrawing electricity from the grid: this can be evaluated looking at the electricity bills and in particular to the maximum power withdrawn values.

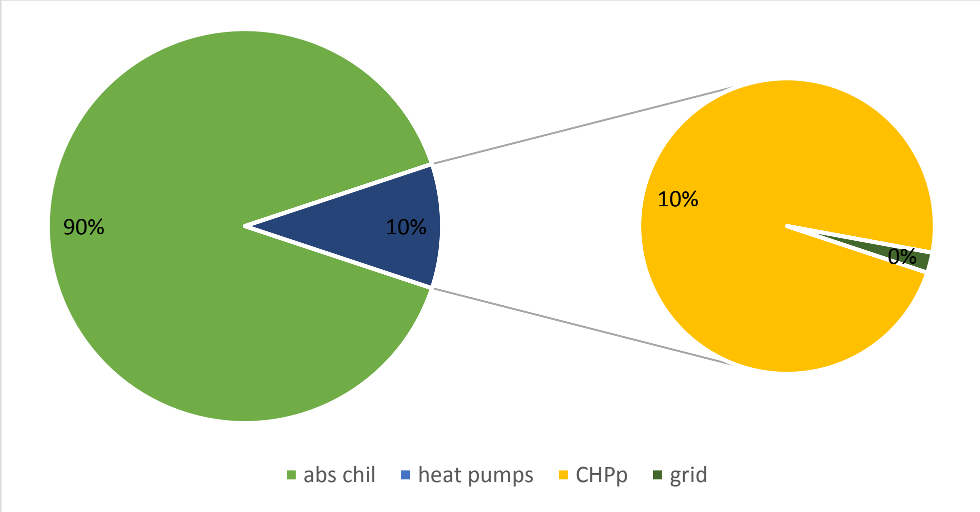

***Figure 7.32**: Cooling demand coverage, 1.000 kWel size.*

7.4.2 Economic results and cash flow

Table 7.20 reports the cash flow obtained for the 1.000 kW_{el} size.

***Table 7.20**: Cash flow, 1.000 kWel size.*

Inflation Rate	0	1	2	3	4	5		
year	cash flow [€]						CAPEX	Revenues
0	- 1.300.000	- 1.300.000	- 1.300.000	- 1.300.000	- 1.300.000	- 1.300.000	1.300.000	€
1	- 775.621	- 780.813	- 785.903	- 790.894	- 795.789	- 800.591	-	524.379
2	- 251.242	- 266.766	- 281.886	- 296.616	- 310.971	- 324.964	-	524.379
3	273.137	242.191	212.248	183.265	155.200	128.014	-	524.379
4	797.516	746.109	696.693	649.169	603.441	559.422	-	524.379
5	1.289.410	1.214.129	1.142.216	1.073.480	1.007.741	944.833	32.486	491.893
6	1.813.789	1.708.117	1.607.850	1.512.639	1.422.166	1.336.133	-	524.379
7	2.338.168	2.197.215	2.064.353	1.939.008	1.820.651	1.708.800	-	524.379
8	2.862.547	2.681.471	2.511.906	2.352.957	2.203.810	2.063.720	-	524.379
9	3.386.926	3.160.931	2.950.683	2.754.850	2.572.231	2.401.740	-	524.379
10	3.797.515	3.532.632	3.287.509	3.060.367	2.849.611	2.653.806	113.790	410.589
11	4.321.894	4.002.646	3.709.248	3.439.190	3.190.237	2.960.399	-	524.379
12	4.846.273	4.468.006	4.122.717	3.806.979	3.517.763	3.252.393	-	524.379
13	5.370.652	4.928.758	4.528.079	4.164.055	3.832.692	3.530.483	-	524.379
14	5.895.032	5.384.948	4.925.493	4.510.732	4.135.507	3.795.330	-	524.379
15	6.419.411	5.836.622	5.315.114	4.847.311	4.426.677	4.047.565	-	524.379
16	6.943.790	6.283.824	5.697.096	5.174.086	4.706.647	4.287.789	-	524.379
17	7.468.169	6.726.598	6.071.588	5.491.344	4.975.849	4.516.574	-	524.379
18	7.992.548	7.164.988	6.438.737	5.799.362	5.234.697	4.734.464	-	524.379
19	8.516.927	7.599.037	6.798.687	6.098.408	5.483.590	4.941.979	-	524.379
20	9.041.306	8.028.789	7.151.579	6.388.744	5.722.910	5.139.612	-	524.379
Payback Time	2,48	2,50	2,53	2,55	2,58	2,60	y	
Net Present Value	9.041.306	8.028.789	7.151.579	6.388.744	5.722.910	5.139.612	€	

With respect to the 800 kW_{el} size, the annual revenue increased again, passing from 509 k€/y to 524 k€/y. The increase was modest compared to the one registered from 600 kW_{el} to 800 kW_{el} (+84 k€/y), meaning that the load that is available for the the CHP plant is close to the end. This is suggested also by the evolution of the PT and of the NPV_{20}: the PT increases for a value equal to almost half a year (from 2,11 to 2,53), whereas the NPV_{20} slightly decreased. These values indicate that the 1.000 kW_{el} size is worse than the 800 kW_{el} size from the economic point of view.

7.4.3 Role of the electricity market and opportunities from the ASM

Table 7.21 and 7.22 present the market data framework for the configuration with and without the ASM participation opportunity.

Table 7.21*: Market data, without ASM configuration, 1.000 kWel size.*

	DAM			ASM		
	kWh	**€**	€/kWh	**kWh**	**€**	€/kWh
JANUARY	102.933	4.967	0,0483	-	-	-
FEBRUARY	144.915	8.321	0,0574	-	-	-
MARCH	146.871	8.008	0,0545	-	-	-
APRIL	120.090	6.270	0,0522	-	-	-
MAY	77.367	3.943	0,0510	-	-	-
JUNE	80.503	4.144	0,0515	-	-	-
JULY	99.778	8.325	0,0834	-	-	-
AUGUST	80.398	4.458	0,0554	-	-	-
SEPTEMBER	82.116	4.320	0,0526	-	-	-
OCTOBER	118.775	5.956	0,0501	-	-	-
NOVEMBER	163.031	10.222	0,0627	-	-	-
DECEMBER	196.286	11.740	0,0598	-	-	-
TOTAL	1.413.062	80.673	0,0571	-	-	-

Table 7.22*: Market data, with ASM configuration, 1.000 kWel size.*

	DAM			ASM		
	kWh	**€**	€/kWh	**kWh**	**€**	€/kWh
JANUARY	12.060	716	0,0594	216.435	15.316	0,0708
FEBRUARY	44.589	2.805	0,0629	189.656	12.962	0,0683
MARCH	31.934	2.205	0,0691	223.993	14.608	0,0652
APRIL	22.506	1.515	0,0673	195.654	12.787	0,0654
MAY	20.951	1.404	0,0670	126.773	8.020	0,0633
JUNE	27.422	1.564	0,0570	90.736	5.479	0,0604
JULY	73.604	6.763	0,0919	70.066	4.887	0,0698
AUGUST	21.117	1.316	0,0623	133.550	8.803	0,0659
SEPTEMBER	10.222	568	0,0556	199.892	13.629	0,0682
OCTOBER	23.577	1.491	0,0632	206.096	13.275	0,0644
NOVEMBER	73.235	5.839	0,0797	192.485	12.538	0,0651
DECEMBER	72.537	5.235	0,0722	228.798	15.216	0,0665
TOTAL	433.754	31.419	0,0724	2.074.134	137.521	0,0663

As the size of the CHP plant is increased again, the amount of electricity sold on the energy market continues to increase. The mean selling price for the “only DAM” configuration is around 57 €/MWh, with an amount of electricity sold that is three times the volume calculated for the 800 kW_{el} size. The volume almost doubles when the opportunity represented by the ASM is introduced, up to 2 GWh/y sold on the ASM (average selling price of 66,3 €/MWh) and 433 MWh/y sold on the DAM (average selling price of 72,4 €/MWh).
The total revenue in the first configuration is around 80 k€/y; it becomes almost 169 k€/y in the configuration “DAM+ASM”.
Table 7.23 presents the data referred to the management in the configuration without and with the ASM participation, and their relative variation.

***Table 7.23**: Only DAM and DAM+ASM configurations comparison, 1.000 kWel size.*

Pel COGE				Pth COGE			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
self-cons	5.197.492	5.197.204	0,01%	self-cons	4.560.033	4.347.764	4,88%
heat pumps	44.852	68.312	-34,34%	abs chil	1.822.993	1.755.832	3,83%
market	2.507.889	1.413.062	77,48%	dissip	2.616.361	1.856.876	40,90%
TOTAL	7.750.232	6.678.578	16,05%	TOTAL	8.999.387	7.960.472	13,05%
COOLING LOAD				**ELECTRIC LOAD**			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
abs chil	1.276.095	1.229.083	3,82%	CHPp	5.197.492	5.197.204	0,01%
heat pumps	92.705	139.717	-33,65%	grid	13.501	13.788	-2,08%
CHPp	89.704	136.624	-34,34%				
grid	3.001	3.094	-3,01%				
TOTAL	1.368.800	1.368.800		**TOTAL**	5.210.992	5.210.992	

THERMAL LOAD			
kWh	**DAM+ASM**	**DAM**	%
CHPp	4.560.033	4.347.764	4,88%
boil	1.235.227	1.447.496	-14,66%
TOTAL	5.795.260	5.795.260	

As explained, from the first to the second configuration, the energy sold on the electricity markets increases, and thanks to the higher amount of heat available the coverage of the cooling demand is performed through the absorption chiller for a bigger share. The thermal energy produced, and dissipated, increases, and the heat required from the boilers consequently decreases.
Table 7.24 presents how the passage to the “DAM+ASM” configuration influences the main parameters.

***Table 7.24**: Economic parameter variations with and without the ASM, 1.000 kWel size.*

	DAM+ASM	**DAM**	%	
PES	24,23	25,35	-4,41%	%
Eq hours	7.264	6.259	16,05%	h/y
mrkt reven.	168.940	80.763	109,18%	€/y
WC	54.569	51.653	5,64%	€/y
Revenues	551.254	524.379	5,13%	€/y
€ per NG	647.573	585.101	10,68%	€/y
€ per EE	46.960	47.006	-0,10%	€/y
PT	2,41	2,53	-4,92%	y
NPV	7.591.018	7.151.579	6,14%	$€_{act}$

The market and WC revenues increase is in part compensated by the higher expense linked to the NG consumption.
Looking at the data previously presented, it is possible to see that the effect of the ASM participation increases as the size of the CHP plant increases; this is clearly linked to the higher volumes that a bigger size is able to move towards the ASM market opportunities.

7.5 Results of the Optimization Procedure for the Size of 1200 kW_{el}

The last elaboration presented is relative to the 1.200 kW_{el} size. This size fully covers, in terms of nominal power, the consumption peaks presented by the Formec input data; hence it is a good mirror to evaluate the effectiveness of sizing a plant in order to try to make the production site independent from any other energy assets beyond the CHP plant.

7.5.1 Working operations characteristics resulting from the optimization process

Figure 7,33 and 7.34 reports the management of the electric and thermal energy produced by the CHP plant for the 1.200 kW_{el} size.

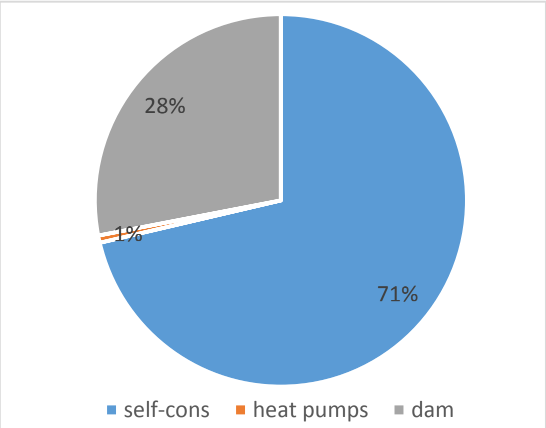

Figure 7.33: *Management of the Pel from the CHP plant, 1.2000 kWel size.*

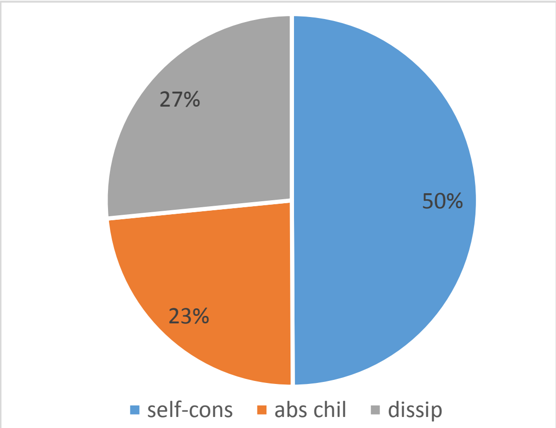

Figure 7.34: *Management of the Pth from the CHP plant, 1.200 kWel size.*

Again, as the size increases, the amount of electricity sold to the energy market and the amount of heat wasted increase.
Figure 7.36, 7.37 and 7.38 present the evolution in the loads management.

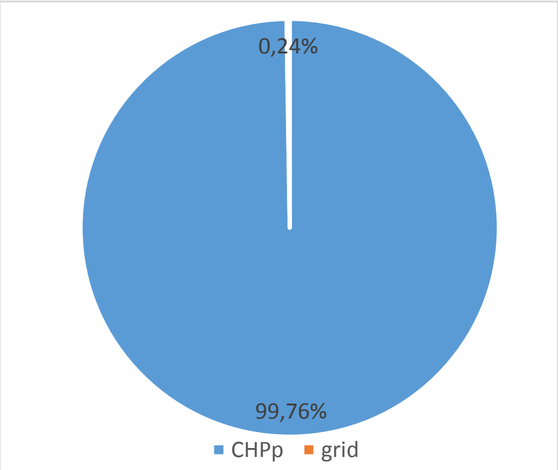

Figure 7.36: *Electric demand coverage, 1.200 kWel size.*

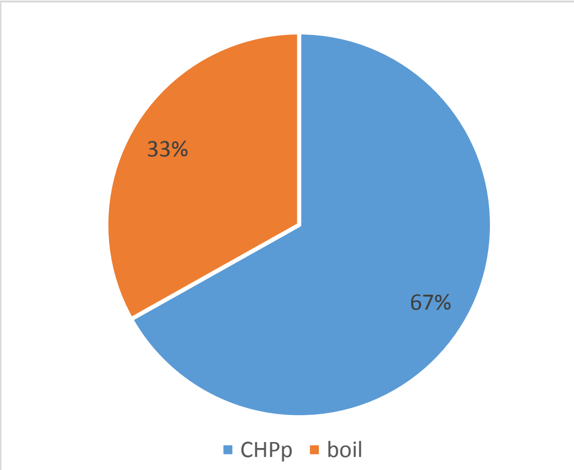

Figure 7.37: *Thermal load management, 1.200 kWel size.*

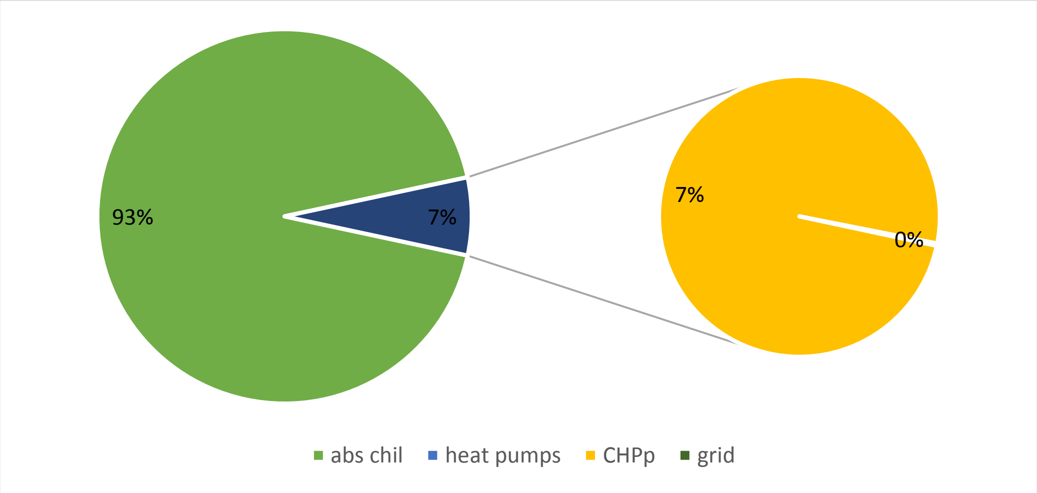

***Figure 7.38**: Cooling load management, 1.200 kWel size.*

It is possible to see that, while the erosion of the electric and cooling loads by the CHP plant is complete, the thermal load coverage performs an inversion and the heat covered by the auxiliary boilers increases with respect to the 1.000 kW_{el} size. This is linked to the fact that the amount of heat available from the flue gases decreases passing from 1.000 kW_{el} to 1.200 kW_{el} size, due to the ICE operation characteristics.

7.5.2 Economic results and cash flow

Table 7.25 reports the cash flow obtained for the 1.200 kW_{el} size.

***Table 7.25**: Cash flow, 1.200 kWel size.*

Inflation Rate	0	1	2	3	4	5		
year	*cash flow [€]*						CAPEX	Revenues
0	- 1.536.000	- 1.536.000	- 1.536.000	- 1.536.000	- 1.536.000	- 1.536.000	1.536.000	€
1	- 1.017.336	- 1.022.472	- 1.027.506	- 1.032.443	- 1.037.285	- 1.042.035	-	518.664
2	- 498.672	- 514.027	- 528.983	- 543.553	- 557.751	- 571.591	-	518.664
3	19.991	- 10.618	- 40.234	- 68.902	- 96.661	- 123.550	-	518.664
4	538.655	487.808	438.931	391.924	346.695	303.156	-	518.664
5	1.018.936	944.779	873.936	806.218	741.451	679.468	38.383	480.281
6	1.537.599	1.433.383	1.334.494	1.240.591	1.151.358	1.066.503	-	518.664
7	2.056.263	1.917.150	1.786.022	1.662.312	1.545.500	1.435.108	-	518.664
8	2.574.927	2.396.128	2.228.697	2.071.750	1.924.483	1.786.160	-	518.664
9	3.093.591	2.870.363	2.662.692	2.469.263	2.288.889	2.120.495	-	518.664
10	3.477.794	3.218.177	2.977.872	2.755.147	2.548.443	2.356.363	134.460	384.204
11	3.996.458	3.683.068	3.395.015	3.129.840	2.885.357	2.659.615	-	518.664
12	4.515.122	4.143.356	3.803.977	3.493.621	3.209.313	2.948.426	-	518.664
13	5.033.786	4.599.086	4.204.921	3.846.805	3.520.809	3.223.485	-	518.664
14	5.552.449	5.050.304	4.598.004	4.189.703	3.820.324	3.485.445	-	518.664
15	6.071.113	5.497.055	4.983.378	4.522.614	4.108.320	3.734.931	-	518.664
16	6.589.777	5.939.383	5.361.197	4.845.828	4.385.239	3.972.537	-	518.664
17	7.108.441	6.377.331	5.731.607	5.159.628	4.651.507	4.198.829	-	518.664
18	7.627.104	6.810.942	6.094.754	5.464.288	4.907.534	4.414.344	-	518.664
19	8.145.768	7.240.261	6.450.781	5.760.075	5.153.714	4.619.597	-	518.664
20	8.664.432	7.665.329	6.799.827	6.047.246	5.390.425	4.815.076	-	518.664
Payback Time	2,96	2,99	3,02	3,05	3,08	3,11	y	
Net Present Value	8.664.432	7.665.329	6.799.827	6.047.246	5.390.425	4.815.076	€	

With respect to the last size analyzed, there is a decrease in terms of annual revenues of almost 5 k€/y, and a corresponding deterioration of either the economic parameters. This indicates that the consumption erosion is ended, and that it is not worth to increase the size of the power plant, even from the NPV point of view.

7.5.3 Role of the electricity market and opportunities from the ASM

Table 7.26 and 7.27 present the market framework in the configuration with and without the ASM participation opportunity. Table 7.28 and 7.29 report the variation induced, in terms of plant operations and evaluation parameters, by the introduction of the ASM participation opportunity.

Table 7.26*: Market data, without ASM configuration, 1.200 kWel size.*

	DAM			ASM		
	kWh	**€**	**€/kWh**	**kWh**	**€**	**€/kWh**
JANUARY	134.025	6.447	0,0481	-	-	-
FEBRUARY	191.383	11.046	0,0577	-	-	-
MARCH	192.065	10.554	0,0549	-	-	-
APRIL	155.066	8.119	0,0524	-	-	-
MAY	112.576	5.732	0,0509	-	-	-
JUNE	135.829	6.971	0,0513	-	-	-
JULY	193.490	15.130	0,0782	-	-	-
AUGUST	144.432	7.966	0,0552	-	-	-
SEPTEMBER	128.610	6.783	0,0527	-	-	-
OCTOBER	165.746	8.335	0,0503	-	-	-
NOVEMBER	223.352	14.046	0,0629	-	-	-
DECEMBER	265.575	16.001	0,0603	-	-	-
TOTAL	2.042.147	117.130	0,0574	-	-	-

Table 7.27*: Market data, with ASM configuration, 1.200 kWel size.*

	DAM			ASM		
	kWh	**€**	**€/kWh**	**kWh**	**€**	**€/kWh**
JANUARY	16.097	948	0,0589	290.289	20.552	0,0708
FEBRUARY	59.243	3.753	0,0633	280.830	19.173	0,0683
MARCH	44.089	3.040	0,0689	314.868	20.555	0,0653
APRIL	27.493	1.859	0,0676	310.095	20.339	0,0656
MAY	31.781	2.114	0,0665	206.892	13.139	0,0635
JUNE	49.902	2.810	0,0563	207.981	12.613	0,0606
JULY	128.992	11.338	0,0879	128.704	8.767	0,0681
AUGUST	36.775	2.255	0,0613	223.889	14.625	0,0653
SEPTEMBER	15.226	870	0,0571	319.067	21.523	0,0675
OCTOBER	33.374	2.107	0,0631	325.698	20.825	0,0639
NOVEMBER	102.617	8.171	0,0796	285.426	18.421	0,0645
DECEMBER	101.998	7.359	0,0721	307.108	20.320	0,0662
TOTAL	647.588	46.622	0,0720	3.200.849	210.852	0,0659

***Table 7.28**: Only Dam and DAM+ASM configurations comparison, 1.200 kWel size.*

kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
self-cons	5.198.588	5.198.304	0,01%	self-cons	4.152.207	3.872.299	7,23%
heat pumps	23.498	45.815	-48,71%	abs chil	1.887.952	1.824.189	3,50%
market	3.848.437	2.042.147	88,45%	dissip	3.332.466	2.060.079	61,76%
TOTAL	9.070.523	7.286.266	24,49%	TOTAL	9.372.625	7.756.567	20,83%
COOLING LOAD				**ELECTRIC LOAD**			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
abs chil	1.321.566	1.276.932	3,50%	CHPp	5.198.588	5.198.394	0,00%
heat pumps	47.234	91.868	-48,59%	grid	12.405	12.688	-2,23%
CHPp	46.997	91.630	-48,71%				
grid	237	237	0,01%				
TOTAL	1.368.800	1.368.800		**TOTAL**	5.210.992	5.211.082	

THERMAL LOAD			
kWh	**DAM+ASM**	**DAM**	%
CHPp	4.152.207	3.872.299	7,23%
boil	1.643.053	1.922.961	-14,56%
TOTAL	5.795.260	5.795.260	

***Table 7.29**: Economic parameters variation with and without the ASM, 1200 kWel size.*

	DAM+ASM	**DAM**	%	
PES	23,30	24,75	-5,88%	%
Eq hours	7.629	6.128	24,49%	h/y
mrkt reven.	257.474	117.130	119,82%	€/y
WC	56.147	51.976	8,02%	€/y
Revenues	558.134	518.664	7,61%	€/y
€ per NG	732.513	630.116	16,25%	€/y
€ per EE	45.829	45.871	-0,09%	€/y
PT	2,81	3,02	-7,05%	y
NPV	7.445.229	6.799.827	9,49%	$€_{act}$

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CHAPTER 8

A Study Case: Sizing a CCHP Plant for the Bovisa La Masa Campus.

This chapter presents the results obtained from the exploitation of the optimization tool for the sizing of a CCHP for the Bovisa La Masa campus of Politecnico di Milano. The elaboration reported allows on one side to highlight the differences between an industrial study case, such as the Formec Biffi S.p.A., and a civil study case, such as this one; on the other side it allows understanding the different results that can be obtained in terms of energy markets influence on the economics of the power plant when the typology and the location of the latter varies.
The chapter structure consists in a presentation of the main input data, followed by the results of the optimization process for two different sizes of the CHP plant that have been selected according to the characteristics of the consumption profiles.

8.1 Definition of the Input Data for the Optimization Tool

The Bovisa La Masa campus is situated in the north-west zone of the city of Milan. It consists in a set buildings that are used as classrooms, laboratories and offices. It is possible to individuate three different areas within the whole campus: a central zone (1) comprehending the buildings B14, B15, B16, B22, B12, B13, B18, B19, B20, and B24; a northern zone (2) composed by the buildings BL25, BL26, BL27 and BL28. A third zone (3) is placed in the southern part of the campus and comprehends the building B23. Currently these three areas are served by different PODs, in the future all the electricity will be exchanged through only one. For the purpose of the analysis presented hereby, the whole set of buildings has been considered, hence the consumption profiles evaluation involved the three different zones together.
Figure 8.1 presents the top view of the campus.

Figure 8.1: *Top view of the Bovisa La Masa campus.*

The campus is provided by a series of boilers, which in the future will serve as auxiliary and/or back up boilers, with an efficiency that is considered equal to 85%. The heat pumps equipped in the campus are judged to have a COP equal to 4.

8.1.1 Definition of the consumption profiles

The construction of the consumption profiles, concerning, as required by the tool, the thermal, the electric and the cooling load, has been based on the data provided by CPL CONCORDIA® group, which is the firm in charge for the management of the energy assets and the metering systems of the campus. In particular, the NG consumption evaluation involved seven PDR (Punto Di Riconsegna): two for the central zone, four for the northern zone and one for the southern zone. The electric energy consumption evaluation involved four different POD (Point Of Delivery): two for the central zone, one for the northern and one for the southern zone. Thanks to the metering data provided hour by hour, all the consumption profiles have been built for the 8760 hours of the year.
Figure 8.2, Figure 8.3 and Figure 8.4 reports the electric load and the thermal load reference profiles.

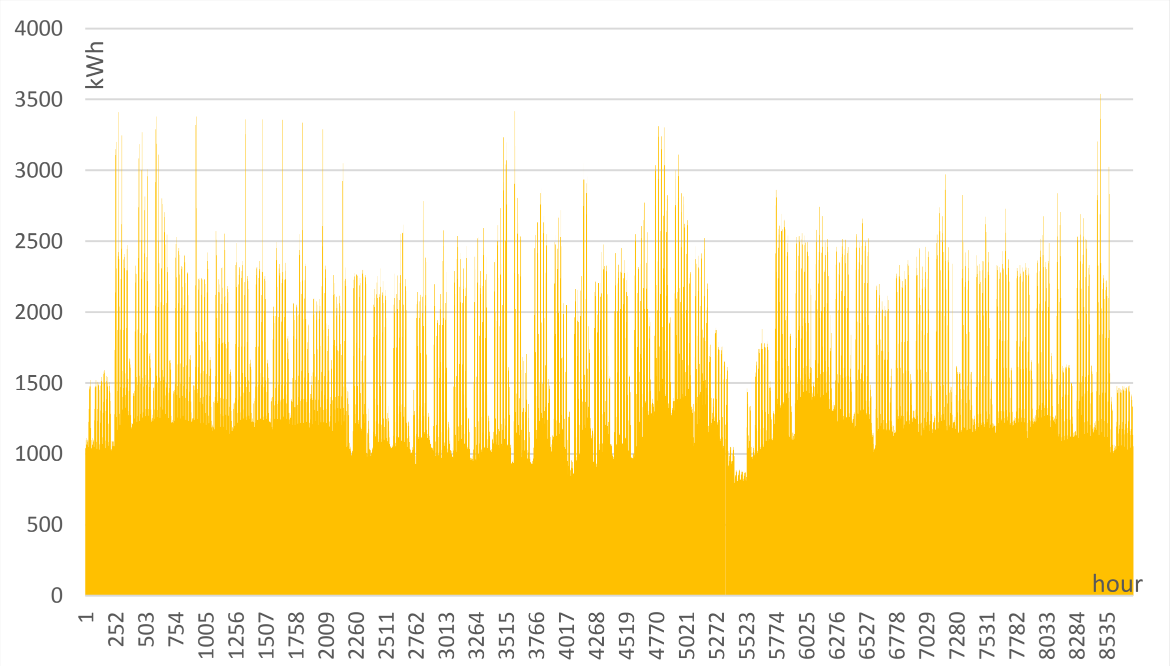

***Figure 8.2**: Annual reference electric load of Bovisa La Masa.*

From the hourly consumption profiles of the electric energy, through a straightforward estimation based on the volumes of the different buildings, it has been possible to derive the cooling load profiles. The electric energy demand of the shoulder seasons have been taken as reference base load and, taking care of all the issues concerning the activities in every period of the year, the cooling load has been estimated for all the different buildings; this allowed defining an annual consumption profile also for the cooling demand.

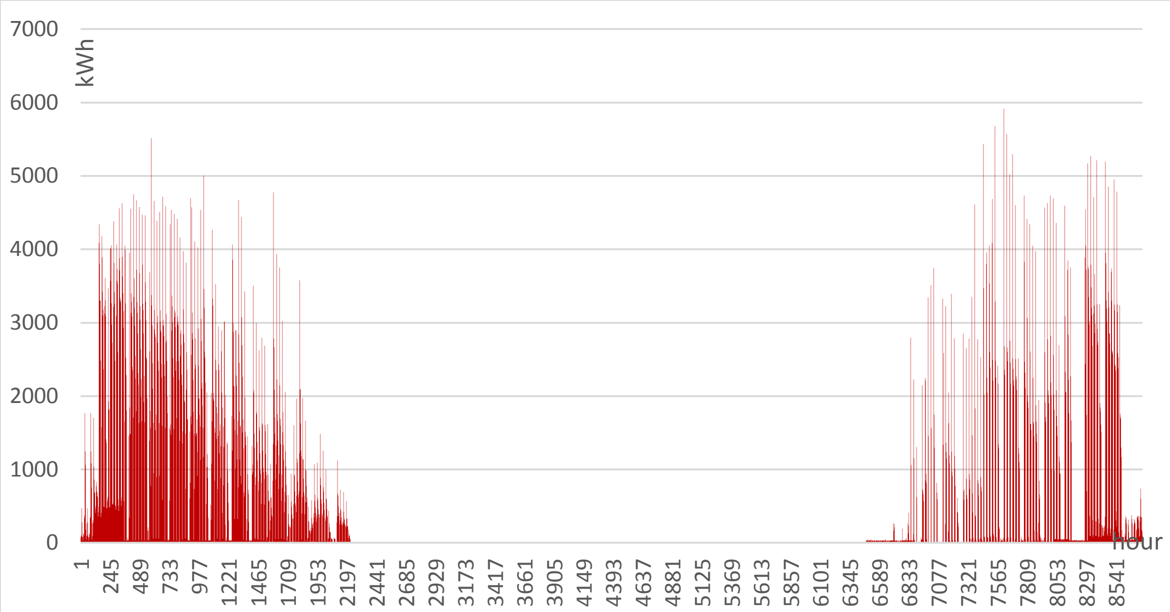

Figure 8.3*: Annual reference thermal load of Bovisa La Masa*

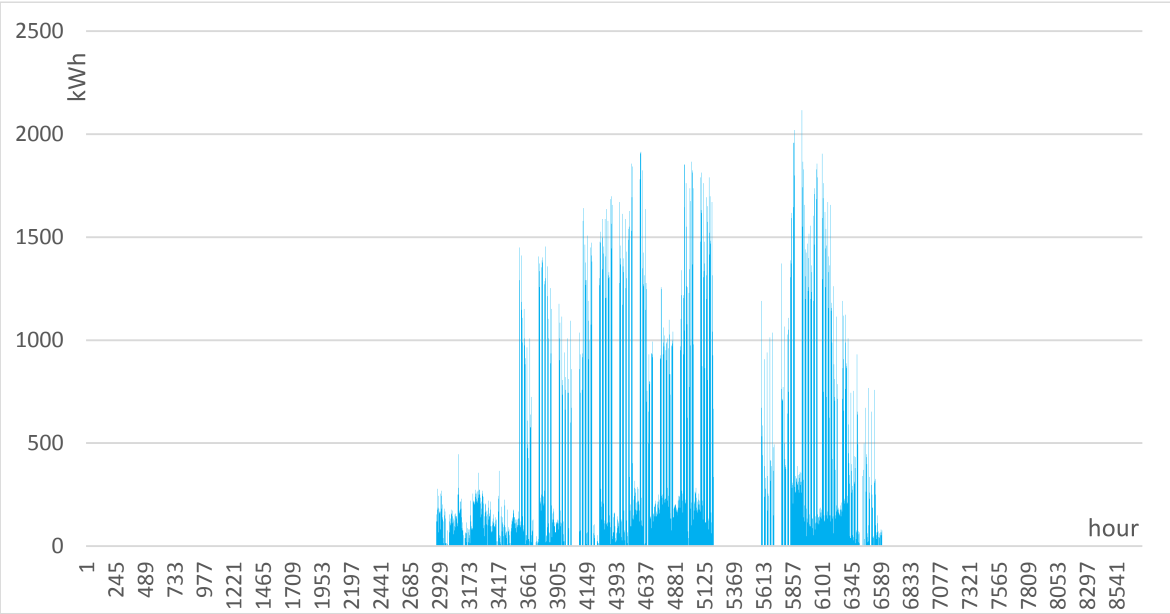

Figure 8.4*: Annual reference cooling load of Bovisa La Masa.*

Comparing the consumption profiles reported with the ones presented in Chapter 7 for Formec, it is possible to see the differences between a typical industrial and civil user. The differences are particularly concerning the thermal and cooling load profiles: in the study case of Bovisa La Masa the heat demand is entirely concentrated in the heating season, as it is linked only to ambient heating purposes; the same is valid for the cooling demand, which vice versa is concentrated in the cooling season. Moreover the consumption profiles are shaped according to the campus academic activity, and it is possible to see that the demand in the Christmas period and in the central weeks of August is strongly reduced.

Another important aspect that must be highlighted, and that distinguishes the civil study case of Bovisa La Masa from the industrial one of Formec, is the nature of the thermal load.

Differently from the Formec case, where there was the need to differentiate between steam and hot water demand, in the Bovisa La Masa case all the heat demand is characterized by low temperature requirements, as it involves the production of hot water for the ambient heating. This is coherent with the distinction highlighted in Chapter 6, and performed in the optimization tool, between the management of an industrial and a civil user thermal load, considering the different nature, from the thermodynamic point of view, of the heat flows available from the ICE based CHP plant.

8.1.2 Reference tariffs for the NG and electricity bills

The tariffs considered for the payment of the NG and of the electric energy are exactly the same presented for Formec in Chapter 7; the only difference consist in the selling services that clearly are negotiated by every consumer differently.

Table 8.1 and Table 8.2 report the values used in the optimization procedure; the same considerations done in Chapter 6 are valid also in this study case.

From the economic flows point of view, it is worth to underline that the VAT considered in this case is 22%, with the exception of the NG used to run the CHP plant that is subjected to the industrial VAT, equal to 10%. The O&M costs sustained, considering the size of the CHP plants considered (see Section 8.1.3) are fixed to 20 €/h, for an overall annual cost around 200 k€/y. Finally the grid losses considered in the calculation of the electricity bill and of the DAM revenues are equal to 3,8%, being the POD connection at MV level.

Table 8.1: *Reference tariffs for the NG bill, study case Bovisa La Masa.*

EXCISE			
	BOILER	**CHPp**	
<1.2M	0,012498	0,001619	€/Smc
>1.2M	0,007499		
GRID SERVICES			
1 - 120	0,0265540	€/Smc	
121 - 480	0,1265140		
481 - 1.560	0,1053310		
1.561 - 5.000	0,1011020		
5.001 - 80.000	0,0813290		
80.001 - 200.000	0,0514131		
200.001 - 1M	0,0260300		
+ 1M	0,0074710		
SELLING SERVICES	0,2612000	€/Smc	

***Table 8.2**: Reference tariffs for the electricity bill, study case Bovisa La Masa.*

NETWORK CHARGES (TRAS DIS MIS UC3 UC6)						
€/kWh						0,007630
€/kW/y						26,69
€/POD/y						695,95
GENERAL SYSTEM CHARGES						
	ONGOING	*A*	*B1*	*B2*	*B3*	*C*
€/kWh	0,053372	0,021684	0,031604	0,041526	0,051556	0,045356
€/kW/y	-	78,33	58,75	39,17	19,58	31,61
€/POD/y	110,60	2.411,51	1.808,64	1.205,76	602,88	972,96
GRID SERVICES (NETWORK SERVICES + SYSTEM CHARGES)						
	ONGOING	*A*	*B1*	*B2*	*B3*	*C*
€/kWh	0,061002	0,029314	0,039234	0,049156	0,059186	0,052986
€/kW/m	2,2238	8,7518	7,1198	5,4878	3,8558	4,8576
€/POD/m	67,21	258,96	208,72	158,48	108,24	139,08
€/POD/y	806,55	3.107,46	2.504,58	1.901,70	1.298,83	1.668,91
DISPATCHING SERVICES						
€/kWh						0,0135623
SELLING SERVICES						
F1	€/kWh					0,04538
F2	€/kWh					0,46790
F3	€/kWh					0,03125
EXCISE						
0 - 200.000 kWh/y		€/kWh				0,0125
+ 200.000 kWh/y		€/kWh				0,0075

8.1.3 CHP plant economic and technical data

The choice of the size of the machine to be tested for the optimization procedure is fundamental. As for the study case of Formec, the machines by AB Energy S.p.A., and in particular the line ECOMAX®NG, have been used.

For the Bovisa La Masa study case the sizes considered have been two: 2 MW_{el} and 2,7 MW_{el}.

Table 8.3 reports the capital expenditure data, from the year zero, five and ten. Table 8.4 presents the main technical data concerning the working operations at 50%, 75% and 100% of the engine load; as explained in Chapter 7, the partial load parameters needed for the calculations have been computed through a linear interpolation between these values.

***Table 8.3**: Economic reference data for the CHP plants according to the size.*

SIZE	2.000	2.700	kWel
year 0	2.400.000	3.051.000	€
year 5	59.972	76.237	€
year 10	210.180	267.300	€

***Table 8.4**: Data sheet of the power plants used for the optimization process, study case Bovisa La Masa.*

ECOMAX 20	**100**	**75**	**50**	% of Pn
P primary	4.544	3.503	2.462	kW
P electric	2.004	1.501	992	kW
P thermal	1.805	1.431	1.022	kW
for HW gen.	923	816	659	kW
for steam gen.	774	685	552	kW
P cooling	1.368	1.094	790	kW
etta electric	44,10%	42,85%	40,29%	-
etta thermal	39,72%	40,85%	41,53%	-
etta total	83,82%	83,70%	81,82%	-
NG	474	365	257	Smc/h
COP abs. chill.	70%	70%	70%	-
ECOMAX 27	**100**	**75**	**50**	% of Pn
P primary	6.059	4.671	3.283	kW
P electric	2.679	2.007	1.326	kW
P thermal	2.398	1.901	1.359	kW
for HW gen.	1.231	1.089	878	kW
for steam gen.	1.032	913	736	kW
P cooling	1.818	1.454	1.051	kW
etta electric	44,22%	42,96%	40,39%	-
etta thermal	39,58%	40,71%	41,41%	-
etta total	83,79%	83,67%	81,80%	-
NG	632	487	342	Smc/h
COP abs. chill.	70%	70%	70%	-

8.1.4 Reference values for the market prices

In order to evaluate the impact of the energy markets participation, it is required to provide as input data also the reference prices for the DAM and the ASM. As for the Formec study case, the reference DAM market prices are the ones available from the GME website [1]. For what concerns the ASM reference prices, they have been evaluated according to the elaboration presented in Chapter 5. In particular it has been necessary to consider in this case the geographic correction factor of the province of Milan, which resulted very low and equal to 43,22%. This value entails, in the evaluation of the reference prices to be use for the ASM within the optimization procedure, a strong penalization; a value of the correction factor so low caused a reduction of the reference prices, and hence will induce a much smaller benefit from the ASM participation for the CHP plant.

Figure 8.5 presents the obtained reference prices for the DAM and for the ASM for the month of January; Figure 8.6 reports the same data for the month of July.

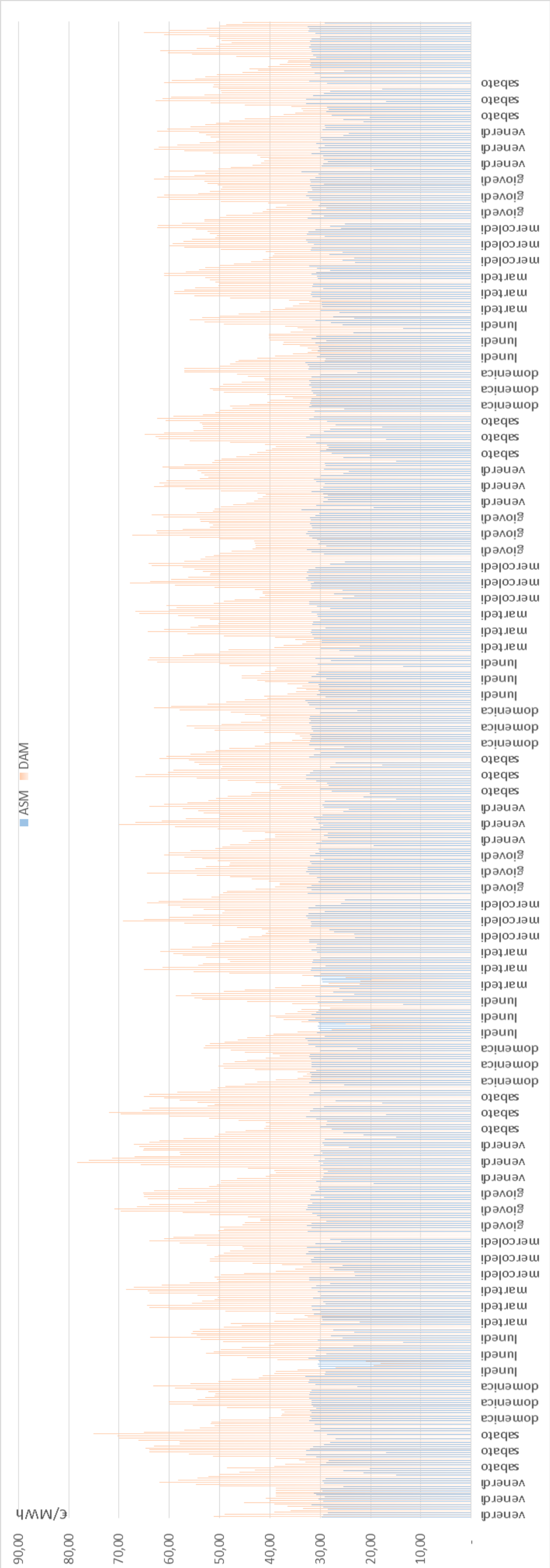

Figure 8.5: *Reference market prices for the month of January.*

Figure 8.6: *Reference market prices for the month of July.*

8.2 Results of the Optimization Procedure for the size of 2.000 kW_{el}

The main results obtained from the optimization procedure are presented following the same path of Chapter 7. First of all the management of the different loads is analyzed, together with some graphical support; then the main working operations characteristics and economic results are presented. The last sub-section reports a description of the role of the market in the SDP with the possibility to participate to the ASM.

The first size analyzed is 2.000 kW_{el}. This size seems consistent with the demand data presented previously.

8.1.1 Management of the electric, thermal and cooling load.

The analysis of the loads coverage starts with the thermal load management. The examples reported in Figure 8.7 and 8.9 describes the thermal load management of a typical winter season day (26 of January) and a typical summer season day (6 of July).

There are some differences with respect to the diagrams presented for the industrial case of Formec; in this case there is no distinction between high temperature and low temperature heat demand, hence only one thermal load is presented. The consumption profile is affected by a high variability not only from a seasonal point of view (as stated previously), but also within a single day; the heat demand is concentrated mainly in the central part of the day: this is typical of a civil user and of a tertiary sector application.

It is possible to see a huge difference between the management of the winter and the summer season. Beyond the difference between the heat and the cooling demand that characterizes the two seasons, in the reference winter day the amount of heat dissipated is negligible, whereas in the reference summer day it is very high with respect to the CHP plant production; this phenomenon is even greater during the shoulder seasons when there is neither heating nor cooling demand.

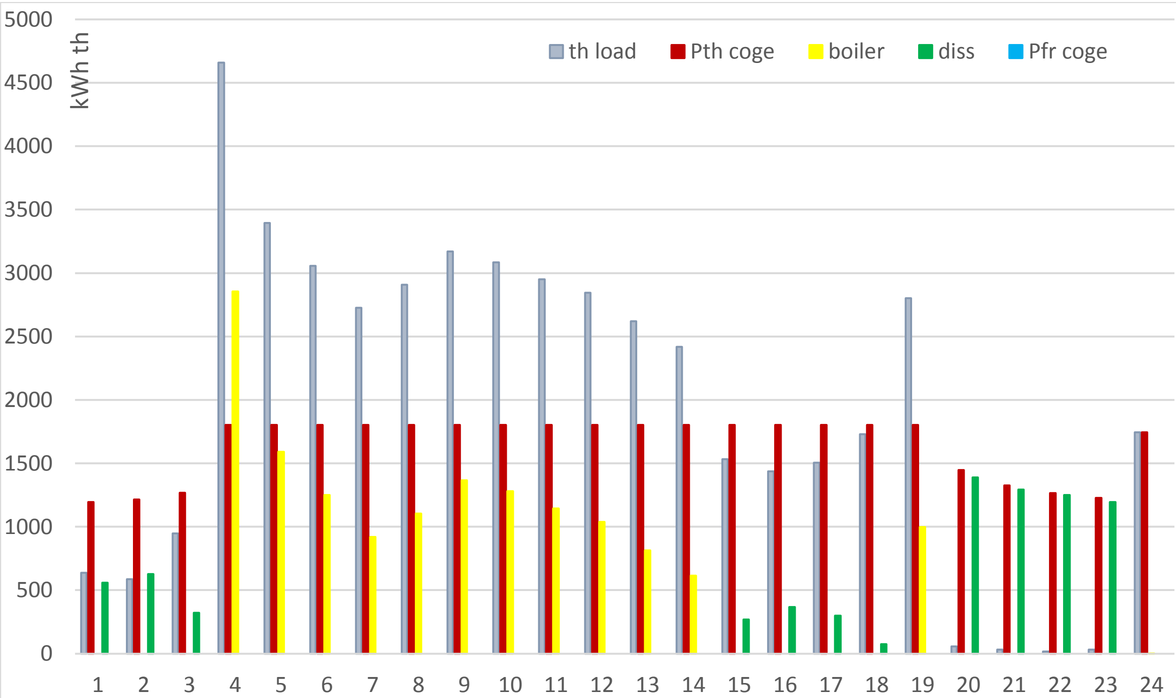

Figure 8.7: *Thermal load management for a typical winter season day, 26 of January.*

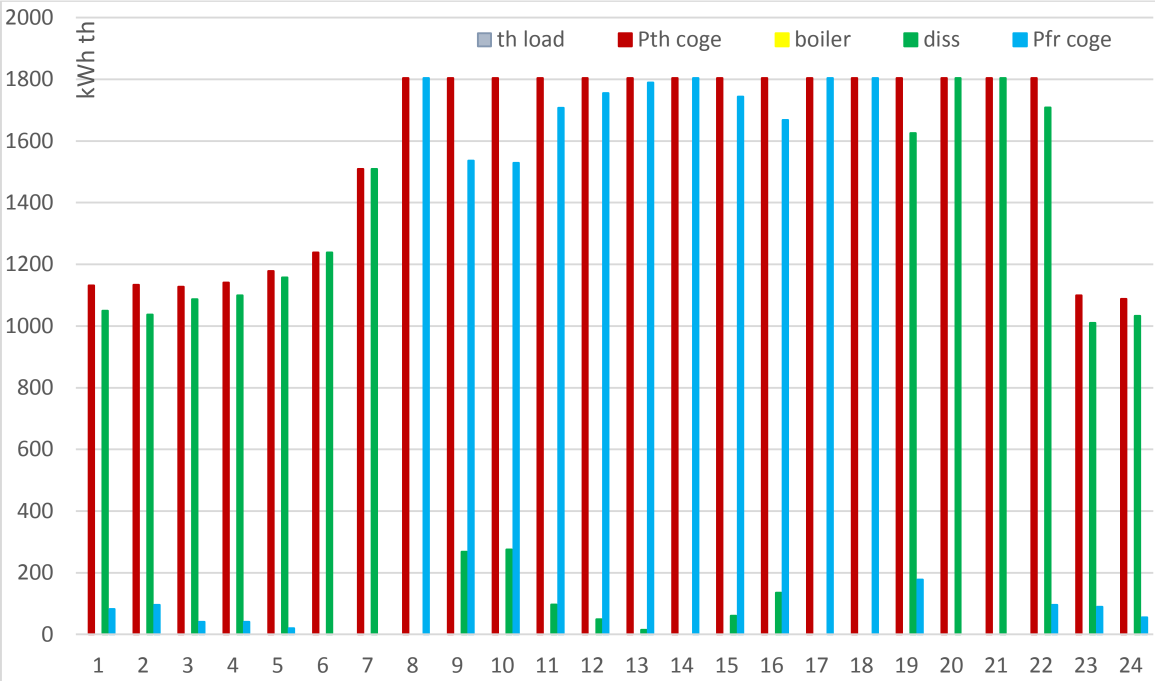

Figure 8.8*: Thermal load management of a typical summer day, 6 of July.*

As the electric demand coverage justifies the turning on of the CHP plant, when there is no thermal load the heat is entirely (or in large part) dissipated. The effect of this on the PES value is however minor, because of the characteristics of the CHP plant: thanks to the ICE high flexibility, and to the electric efficiency that characterizes the 2.000 kW_{el} size, the penalization on the PES is very low, and it is possible to obtain high values even dissipating a large quantity of heat. However, the exploitation of only a minor part of the heat produced reduces a lot the revenues that the energy saving induces thanks to the WC mechanisms, because all the electric energy produced in a non-cogenerative asset is not recognized in the WC calculation.
Figure 8.9 reports the electric load management on the 4 of May.

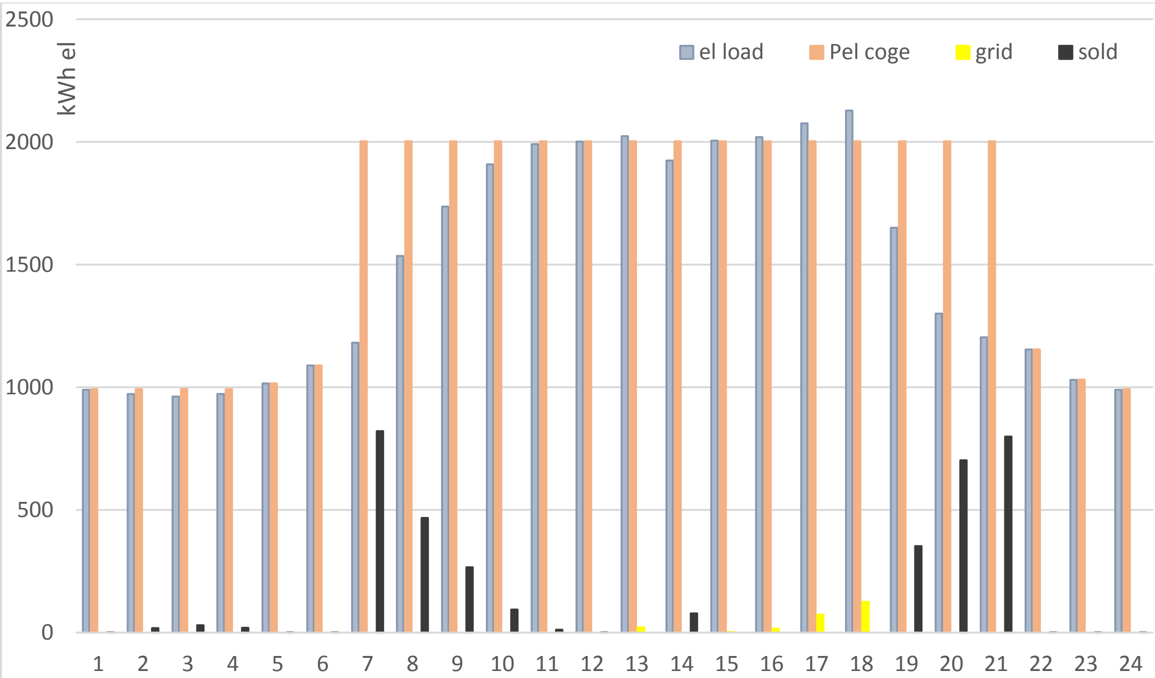

Figure 8.9*: Electric load management.*

The electric load management is characterised by a more constant behavior, with the presence of a high base load in the evening and night hours, and a peak load in the central part of the day starting from the early morning. Analyzing the input data presented in Section 8.1, and looking at Figure 8.9, it is possible to say that the electric demand is the one leading the CHP plant activities, with a low amount of electricity withdrawn from the grid, and the presence of a certain amount of energy sold on the market when the latter represents an opportunity, or when there is the presence of a thermal or cooling load.

The cooling load management, already recalled in Figure 8.8, is presented for a typical summer day (6 of July) in Figure 8.10. The main part of the cooling load is covered through the exploitation of the absorption chiller, thanks to the availability of a huge amount of heat from the power plant that otherwise would be wasted. As stated above, the cooling load, like the thermal load, is characterized by a variable profile, where the demand is concentrated in the central hours of the day.

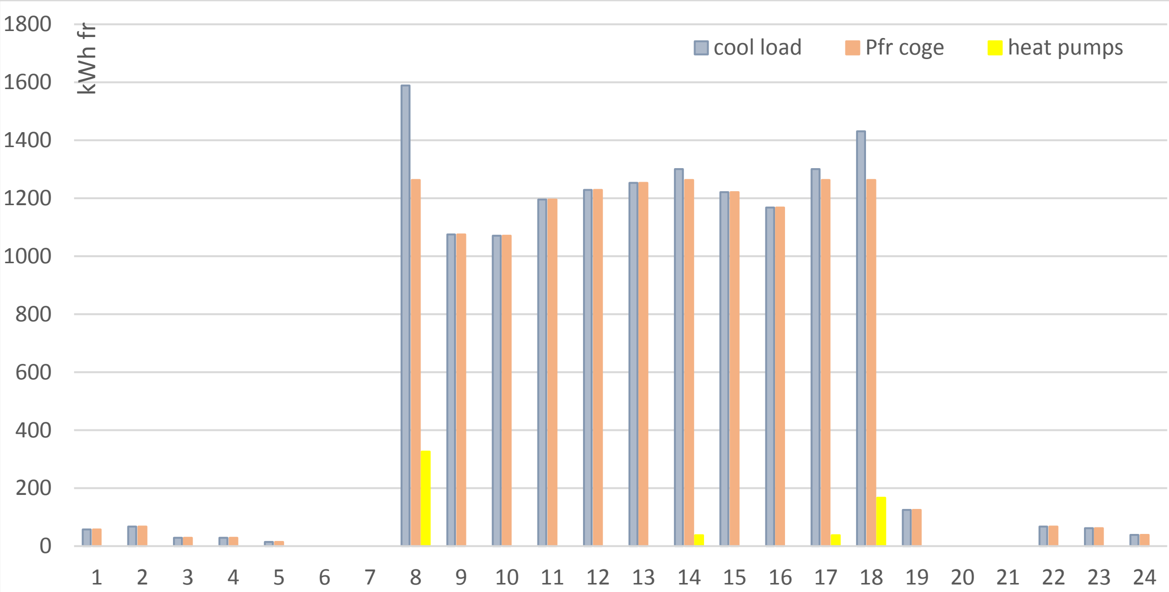

***Figure 8.10**: Cooling load management, 6 of July.*

8.2.1 Working operations characteristics resulting from the optimization process

This section reports an analysis of the results of the optimization process from the point of view of the CHP plant operations.

Concerning the management of the electric power generated, almost the entire volume of electricity produced is used to cover the electric demand; only 6% of the power production (corresponding to 795 MWh_{el}) is sold on the DAM.

On the thermal power management side, confirming the considerations made in the previous sub-section, the large part of the heat is dissipated (65% corresponding to 8,446 GWh_{th}), while the self-consumed heat is used for the heating and the cooling purposes in a way proportional to the heating and cooling demand, because of the fact that the two loads do not overlap.

Figure 8.11 and 8.12 present the management of the electric and thermal power produced by the CHP plant.

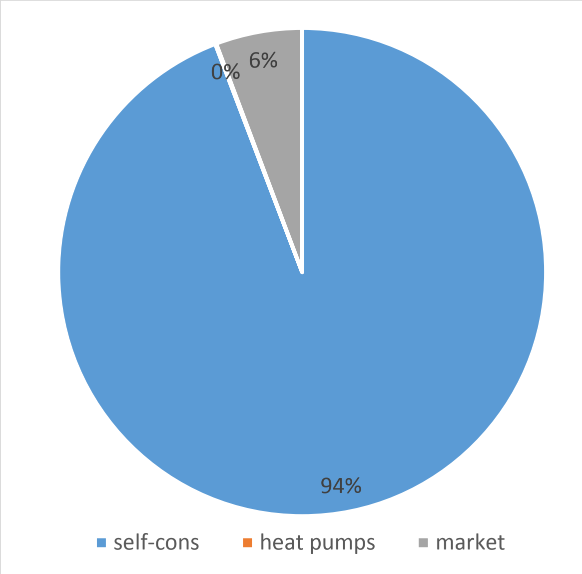

Figure 8.11: *Electric power management, 2.000 kWel size.*

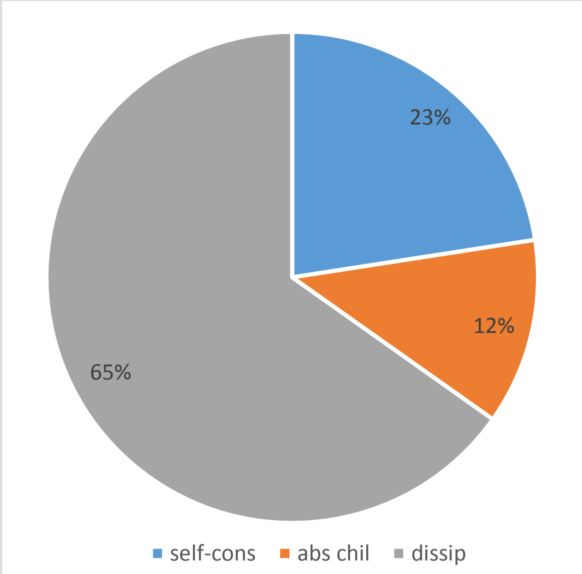

Figure 8.12: *Thermal power management, 2.000 kWel size.*

The operations of the power plant are ruled by the electricity consumption profile, mainly because of the high ratio between the electric and the thermal load. Because of this, as reported in Figure 8.13, the main part of the electric load is covered by the CHP plant production. On the other hand, even if a large part of the heat produced is wasted, 26% of the thermal demand is still covered by the boilers: this is linked to the fact that the thermal load is concentrated in a reduced number of hours per year, with very high peaks; thus it can be covered by the CHP plant production only in part, while in the remaining hours, which are the majority, the heat is wasted. This consideration suggests the worth to introduce a thermal storage and to exploit it to shift the peak loads: this could decrease the amount of heat needed from the boilers and, at the same time, reduce the volume of heat wasted, increasing the performances of the power plant. The thermal load management is reported in Figure 8.14.

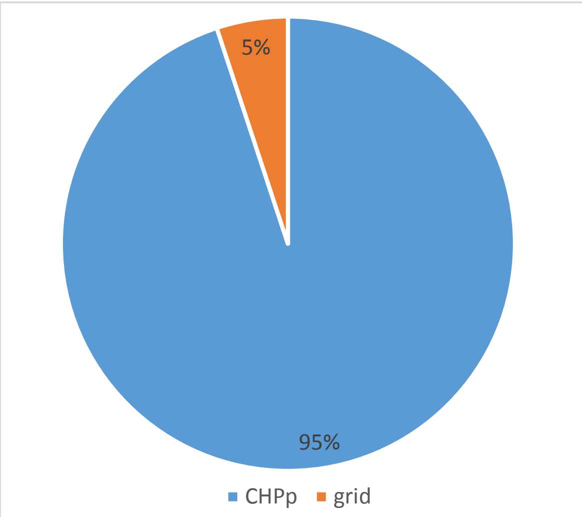

Figure 8.13: *Electric load management 2.000 kWel size.*

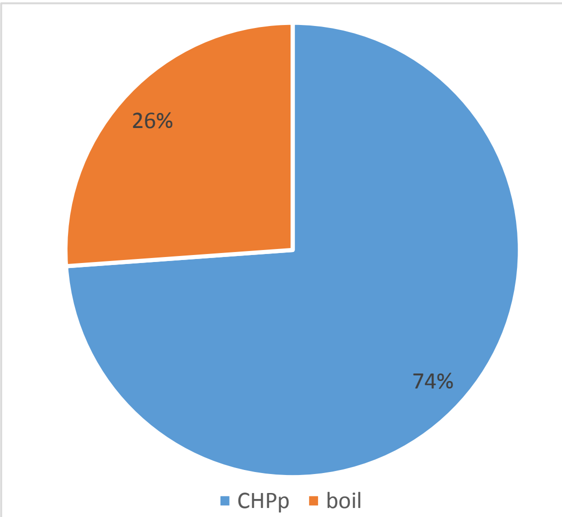

Figure 8.14: *Thermal load management, 2.000 kWel size.*

Figure 8.15 reports the cooling load management. It is possible to see that the 98% of the cooling load is covered by the CHP plant, and this is performed almost entirely through the absorption chiller, whereas the heat pumps run also thanks to electric energy withdrawn from the grid (18 MWh_{fr} over a total amount of 54 MWh_{fr} generated by the heat pumps).

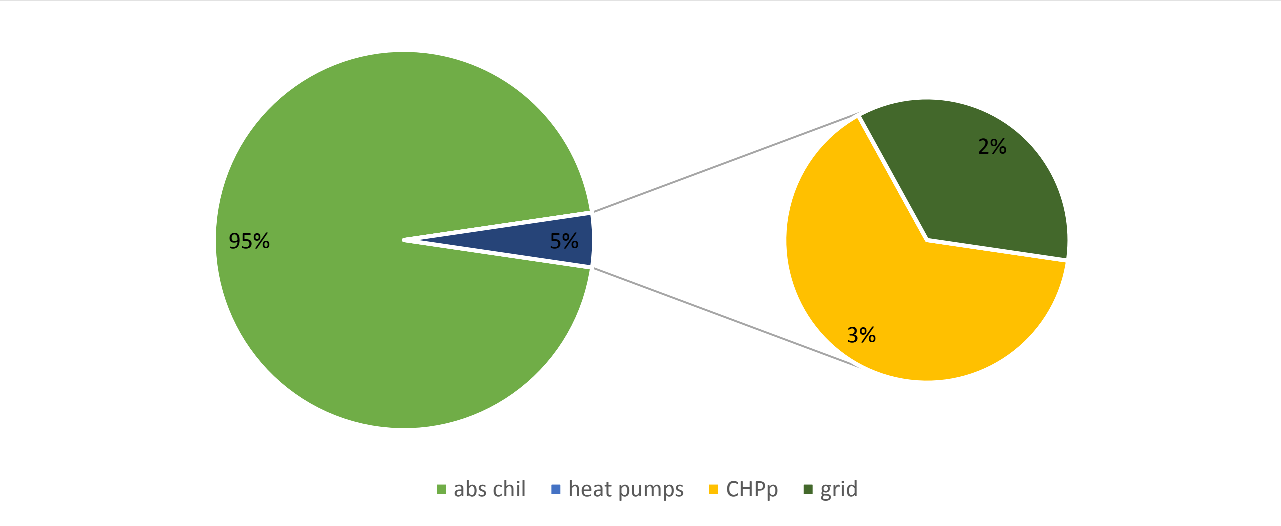

***Figure 8.15**: Cooling load management, 2.000 kWel size.*

8.2.2 Economic results and cash flow

Table 8.5 presents the cash flow.

***Table 8.5**: Cash flow, 2.000 kWel size.*

inflation rate	0	1	2	3	4	5		
year	cash flow[€]						CAPEX	REVENUES
0	- 2.400.000	- 2.400.000	- 2.400.000	- 2.400.000	- 2.400.000	- 2.400.000	2.400.000	
1	- 1.313.674	- 1.324.429	- 1.334.974	- 1.345.314	- 1.355.455	- 1.365.403	-	1.086.326
2	- 227.347	- 259.508	- 290.831	- 321.347	- 351.086	- 380.073	-	1.086.326
3	858.979	794.870	732.838	672.795	614.655	558.336	-	1.086.326
4	1.945.305	1.838.808	1.736.436	1.637.982	1.543.251	1.452.060	-	1.086.326
5	2.971.660	2.815.349	2.666.037	2.523.324	2.386.839	2.256.235	59.972,00	1.026.354
6	4.057.986	3.838.718	3.630.664	3.433.106	3.245.379	3.066.868	-	1.086.326
7	5.144.313	4.851.954	4.576.376	4.316.388	4.070.898	3.838.900	-	1.086.326
8	6.230.639	5.855.158	5.503.545	5.173.944	4.864.666	4.574.169	-	1.086.326
9	7.316.965	6.848.429	6.412.534	6.006.523	5.627.904	5.274.424	-	1.086.326
10	8.193.112	7.641.593	7.131.280	6.658.458	6.219.797	5.812.302	210.180,00	876.146
11	9.279.438	8.615.293	8.004.972	7.443.243	6.925.454	6.447.455	-	1.086.326
12	10.365.764	9.579.353	8.861.533	8.205.171	7.603.970	7.052.362	-	1.086.326
13	11.452.091	10.533.867	9.701.298	8.944.906	8.256.390	7.628.464	-	1.086.326
14	12.538.417	11.478.931	10.524.598	9.663.096	8.883.716	8.177.133	-	1.086.326
15	13.624.743	12.414.638	11.331.754	10.360.368	9.486.915	8.699.674	-	1.086.326
16	14.711.070	13.341.080	12.123.084	11.037.330	10.066.913	9.197.333	-	1.086.326
17	15.797.396	14.258.349	12.898.898	11.694.576	10.624.604	9.671.293	-	1.086.326
18	16.883.723	15.166.537	13.659.500	12.332.678	11.160.845	10.122.685	-	1.086.326
19	17.970.049	16.065.733	14.405.187	12.952.195	11.676.462	10.552.581	-	1.086.326
20	19.056.375	16.956.025	15.136.254	13.553.667	12.172.247	10.962.006	-	1.086.326
Payback Time	2,21	2,23	2,25	2,28	2,30	2,32	y	
Net Present Value	19.056.375	16.956.025	15.136.254	13.553.667	12.172.247	10.962.006	€	

The PES value obtained for the size of 2.000 kW_{el} is equal to 18%, much lower than the values obtained for the study case of Formec. The amount of energy saved has been only of 6,8 GWh/y, with a ratio energy saved over nominal electric power of the plant equal to 3.400; the same value computed for the Formec study case with the 600 kW_{el} was equal to 9.500, almost three times higher. This is correlated with the amount of heat wasted in the study case Bovisa La Masa, which did not allow to valorize the CHP plant production from the WC point of view. Correlated to this consideration, the revenues for the WC mechanism are equal to 58 k€/y, very low considering the size of the plant.

The total annual revenue was equal to 1,086 M€/y, corresponding to a PT of 2,25 years and an NPV_{20} of more than 15 M€ (considering an inflation rate of 2% and an investment lifetime of 20 years).

The number of equivalent working hours was equal to 6.919 h/y; the market revenues accounted for 52 k€/y, corresponding to a volume of electric energy sold on the DAM equal to 0,795 GWh_{el}.

8.2.3 Role of the electricity market and opportunities from the ASM

This section presents the results of the optimization procedure on the market revenues with and without the opportunity for the power plant to participate to the ASM. As stated in Section 6.1, the opportunity represented by the ASM does not seem to be huge in the Bovisa La Masa study case, because of the penalization introduced by the geographic correction factor. Hence it is not expected to have results, in terms of economical benefit, such as the ones obtained for the Formec case, especially for the bigger sizes considered.

Table 8.6 reports the economic flows associated to the energy markets in the configuration without the ASM opportunity.

Table 8.6*: Market data, without ASM configuration, 2.000 kWel size.*

	DAM			ASM		
	kWh	**€**	**€/kWh**	**kWh**	**€**	**€/kWh**
JANUARY	101.257	4.954	0,0489	-	-	-
FEBRUARY	63.915	3.525	0,0551	-	-	-
MARCH	34.579	2.314	0,0669	-	-	-
APRIL	23.292	1.584	0,0680	-	-	-
MAY	41.265	2.761	0,0669	-	-	-
JUNE	27.900	1.699	0,0609	-	-	-
JULY	154.807	12.463	0,0805	-	-	-
AUGUST	54.668	3.247	0,0594	-	-	-
SEPTEMBER	21.940	1.416	0,0645	-	-	-
OCTOBER	30.902	1.951	0,0631	-	-	-
NOVEMBER	95.858	6.999	0,0730	-	-	-
DECEMBER	144.138	9.419	0,0653	-	-	-
TOTAL	794.522	52.332	0,0659	-	-	-

It is possible to see that the revenues coming from the electricity selling do not constitute a relevant share of the total revenues, meaning that in this study case the market has a marginal role. This is consistent with the consideration made previously, according to which the electric load was always the one leading the CHP plant operations; this aspect entails the absence of a remarkable amount of electricity available for the energy market.

Because of the low reference prices resulting from the ASM, the situation does not change even when the opportunity to provide ancillary services is considered. Table 8.7 reports the data from the configuration with the ASM participation.

***Table 8.7**: Market data, with ASM configuration, 2.000 kWel size.*

	DAM			ASM		
	kWh	**€**	€/kWh	**kWh**	**€**	€/kWh
JANUARY	98.581	4.892	0,0496	2.676	81	-
FEBRUARY	63.915	3.525	0,0551	-	-	-
MARCH	34.571	2.314	0,0669	8	0	-
APRIL	23.286	1.584	0,0680	7	0	-
MAY	41.256	2.760	0,0669	9	0	-
JUNE	27.900	1.699	0,0609	-	-	-
JULY	154.807	12.463	0,0805	-	-	-
AUGUST	54.668	3.247	0,0594	-	-	-
SEPTEMBER	21.934	1.415	0,0645	6	0	-
OCTOBER	30.899	1.951	0,0631	3	0	-
NOVEMBER	94.456	6.963	0,0737	1.402	40	-
DECEMBER	144.135	9.419	0,0653	3	0	-
TOTAL	790.408	52.234	0,0661	4.114	122	-

The amount of electricity sold on the ASM is almost equal to the electric energy that the CHP plant could produce in two hours; the revenues from the ancillary services provision are irrelevant.
The result in terms of CHP plant working operations and economic flows is that nothing changes if the participation to the ASM is allowed. Table 8.8 presents the relevant data variations.

***Table 8.8**: Comparison between DAM+ASM and only DAM situations, 2.000 kWel size.*

Pel COGE				**Pth COGE**			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
self-cons	13.045.877	13.045.877	0%	self-cons	2.814.515	2.814.515	0%
heat pumps	17.776	17.776	0%	abs chil	1.620.465	1.620.465	0%
market	794.522	794.522	0%	dissip	8.518.378	8.518.378	0%
TOTAL	13.858.175	13.858.175	0%	TOTAL	12.953.358	12.953.358	0%
COOLING LOAD				**ELECTRIC LOAD**			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
abs chil	1.134.326	1.134.326	0%	CHPp	13.045.877	13.045.877	0%
heat pumps	54.970	54.970	0%	grid	698.205	698.205	0%
CHPp	35.552	35.552	0%				
grid	19.418	19.418	0%				
TOTAL	1.189.296	1.189.296		**TOTAL**	13.744.083	13.744.083	

THERMAL LOAD			
kWh	**DAM+ASM**	**DAM**	%
CHPp	2.814.515	2.814.515	0%
boil	996.017	996.017	0%
TOTAL	3.810.532	3.810.532	

8.3 Results of the Optimization Procedure for the size of 2.700 kW_{el}

The second size tested for the optimization procedure in the Bovisa La Masa study case has been the 2.700 kW_{el} size. From the results presented for the 2.000 kW_{el} size in Section 8.2, it is possible to see that the CHP plant results to be optimally sized to cover the loads. Increasing the size will hence bring to have an almost complete coverage of the electric demand, an increased volume of the thermal and cooling load covered by the CHP plant, and an increased amount of heat dissipated.
The results are reported presenting the main operations characteristics resulting from the elaboration, the cash flow and the analysis of the economic flows associated to the energy markets, considering also the possibility to participate to the ASM.

8.3.1 Working operations characteristics resulting from the optimization process

Figure 8.16 presents the management of the electric energy generated by the CHP plant. It is possible to see that, being the electric demand almost completely covered already with the 2.000 kW_{el} size, the electricity production increase was mainly sold on the DAM.
Figure 8.17 reports the management of the thermal energy by the CHP plant. The share of heat wasted is equal to 68%, while the amount of heat useful to cover the thermal and cooling load is only a minor part. As expected, the increase in the engine size caused an increase of the heat dissipated.

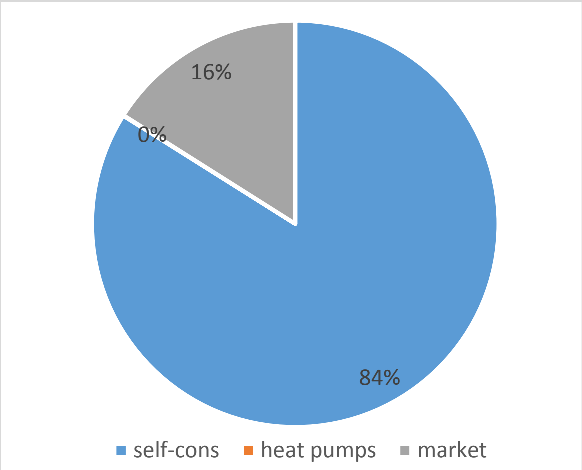

***Figure 8.16**: Electric power management, 2.700 kWel size.*

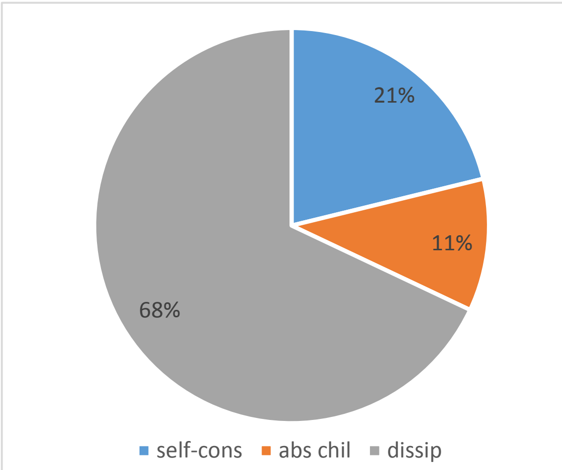

***Figure 8.17**: Thermal power management, 2.700 kWel size.*

Figure 8.18, 8.19 and 8.20 present the management of the electric , thermal and cooling load.
It is possible to see that the electric and cooling load are entirely covered by the CHP plant, while 14% of the thermal load is still covered using the boilers; this linked to the presence of peak load that cannot be covered by the CHP plant.

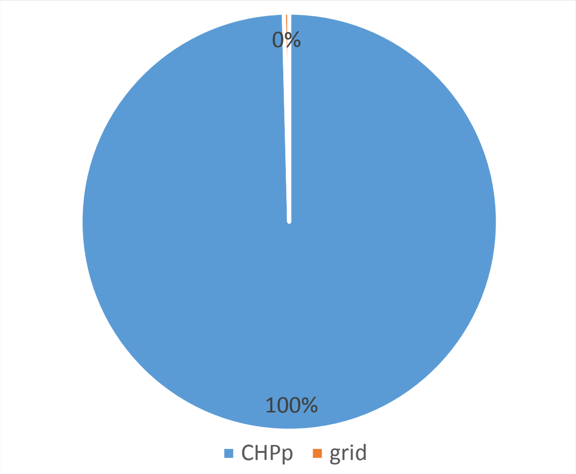

Figure 8.18: Electric load management, 2.700 kWel size.

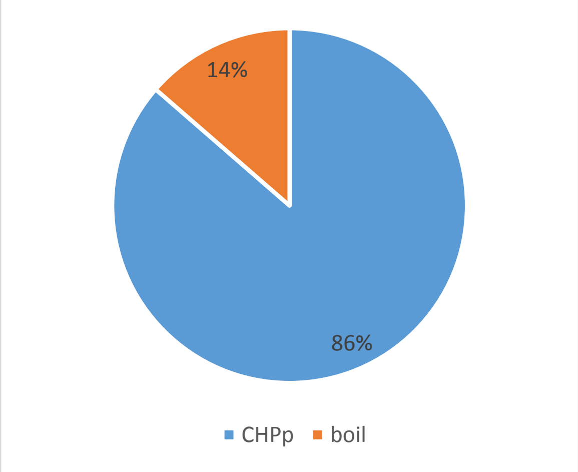

Figure 8.19: Thermal load management, 2.700 size.

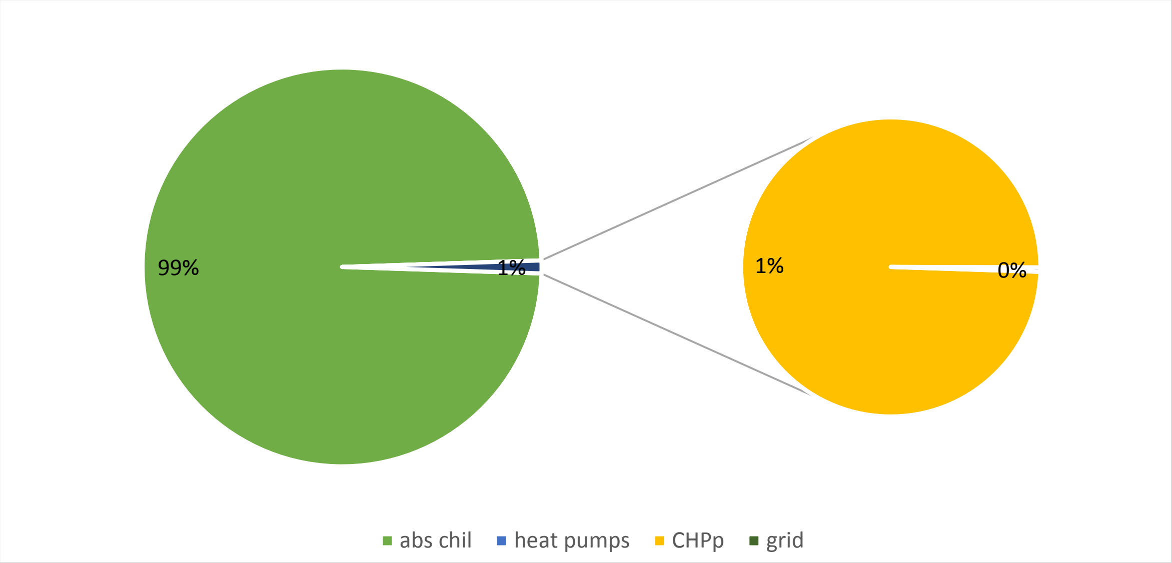

Figure 8.20: Cooling load management, 2.700 kWel size.

8.3.2 Economic results and cash flow

Table 8.9 presents the cash flow for the 2.700 kW_{el} size.
The annual revenues were equal to 1,160 M€/y. This value corresponded, with a capital expenditure of 3 M€, to a PT of 2,7 year (inflation rate equal to 2%) and a NPV_{20} of 15,6 M€.
The revenues linked to the WC were equal to 52 k€/y, and the ones coming from the electricity selling to 162 k€/y. The number of equivalent working hours was equal to 6.099 h/y and the PES value was equal to 17,49.

***Table 8.9**: Cash flow, 2.700 kWel size.*

inflation rate	0	1	2	3	4	5		
year	cash flow[€]						CAPEX	REVENUES
0	-3.051.000	-3.051.000	-3.051.000	-3.051.000	-3.051.000	-3.051.000	-3.051.000	
1	-1.890.002	-1.901.497	-1.912.767	-1.923.818	-1.934.656	-1.945.288	-	1.160.998
2	-729.005	-763.376	-796.852	-829.466	-861.248	-892.229	-	1.160.998
3	431.993	363.477	297.182	233.011	170.874	110.685	-	1.160.998
4	1.516.753	1.405.910	1.299.333	1.196.807	1.098.132	1.003.120	76.237	1.084.760
5	2.677.751	2.510.560	2.350.884	2.198.294	2.052.387	1.912.792	-	1.160.998
6	3.838.749	3.604.272	3.381.817	3.170.611	2.969.941	2.779.146	-	1.160.998
7	4.999.746	4.687.156	4.392.535	4.114.608	3.852.204	3.604.245	-	1.160.998
8	6.160.744	5.759.318	5.383.435	5.031.110	4.700.533	4.390.054	-	1.160.998
9	7.054.442	6.576.461	6.131.242	5.716.055	5.328.433	4.966.140	267.300	893.698
10	8.215.439	7.627.497	7.083.664	6.579.947	6.112.762	5.678.892	-	1.160.998
11	9.376.437	8.668.127	8.017.412	7.418.676	6.866.924	6.357.703	-	1.160.998
12	10.537.435	9.698.453	8.932.850	8.232.976	7.592.079	7.004.190	-	1.160.998
13	11.698.432	10.718.578	9.830.339	9.023.559	8.289.344	7.619.892	-	1.160.998
14	12.859.430	11.728.603	10.710.230	9.791.116	8.959.792	8.206.274	-	1.160.998
15	14.020.428	12.728.628	11.572.869	10.536.316	9.604.452	8.764.734	-	1.160.998
16	15.181.425	13.718.752	12.418.593	11.259.811	10.224.319	9.296.601	-	1.160.998
17	16.342.423	14.699.072	13.247.734	11.962.234	10.820.344	9.803.140	-	1.160.998
18	17.503.421	15.669.686	14.060.617	12.644.198	11.393.445	10.285.559	-	1.160.998
19	18.664.418	16.630.690	14.857.562	13.306.298	11.944.504	10.745.005	-	1.160.998
20	19.825.416	17.582.179	15.638.880	13.949.115	12.474.368	11.182.573	-	1.160.998
Payback Time	2,63	2,65	2,68047	2,71	2,73	2,76	y	
Net Present Value	19.825.416	17.582.179	15.638.880	13.949.115	12.474.368	11.182.573	€	

8.3.3 Role of the electricity market and opportunities from the ASM

Table 8.10 presents the economic flows linked to the activity on the energy markets in the configuration without the possibility to participate to the ASM. As expected, the amount of electric energy sold on the DAM, and the correspondent revenues, increased; the volume of money gained on the market was not negligible with respect to the total revenues and the electric energy sold was equal to 2,6 GWh_{el}.

The possibility to participate to the ASM did not change the economic flows associated to the electricity selling; the amount of electric energy sold on the ASM was again negligible, due to the loss of opportunity expressed through low values for the ASM reference prices. The penalization correlated to the lack of opportunity on the ASM increases as the size of the plant analyzed increases: this is linked to the fact that the gains expected from a bigger volume of electricity sold on the markets are absent. The better economic results that the ASM participation was able to introduce in the study case of Formec for the biggest size are not present: this consideration can help in the definition of the proper size to be installed, also taking into account the fact that the energy markets won't be possibly able to ensure the (expected) revenues.

Table 8.11 reports the data relative to the market economic flows in the configuration with the ASM participation opportunity.

***Table 8.10**: Market data, without ASM configuration, 2.700 kWel size.*

	DAM			ASM		
	kWh	**€**	€/kWh	**kWh**	**€**	€/kWh
JANUARY	283.314	14.150	0,0499	-	-	-
FEBRUARY	208.765	12.027	0,0576	-	-	-
MARCH	116.068	7.396	0,0637	-	-	-
APRIL	150.838	8.468	0,0561	-	-	-
MAY	191.772	10.661	0,0556	-	-	-
JUNE	130.180	6.841	0,0526	-	-	-
JULY	416.492	32.925	0,0791	-	-	-
AUGUST	209.972	11.639	0,0554	-	-	-
SEPTEMBER	80.064	4.938	0,0617	-	-	-
OCTOBER	127.088	7.145	0,0562	-	-	-
NOVEMBER	310.444	21.543	0,0694	-	-	-
DECEMBER	391.085	25.015	0,0640	-	-	-
TOTAL	2.616.082	162.747	0,0622	-	-	-

***Table 8.11**: Market data, with ASM configuration, 2.700 kWel size.*

	DAM			ASM		
	kWh	**€**	€/kWh	**kWh**	**€**	€/kWh
JANUARY	278.332	14.039	0,0504	4.982	151	-
FEBRUARY	208.765	12.027	0,0576	-	-	-
MARCH	115.448	7.384	0,0640	621	14	-
APRIL	149.232	8.425	0,0565	1.609	45	-
MAY	189.228	10.606	0,0560	2.547	70	-
JUNE	130.106	6.839	0,0526	75	2	-
JULY	416.492	32.925	0,0791	-	-	-
AUGUST	209.972	11.639	0,0554	-	-	-
SEPTEMBER	79.785	4.931	0,0618	279	8	-
OCTOBER	126.602	7.133	0,0563	486	13	-
NOVEMBER	306.869	21.451	0,0699	3.575	102	-
DECEMBER	390.489	24.998	0,0640	596	17	-
TOTAL	2.601.319	162.397	0,0624	14.769	424	-

Table 8.12 presents the changes in terms of working operations and economic flows induced by the ASM participation. The data confirm that the ASM did not represent an opportunity, and that the possibility to sell services on this market did not introduce any advantage from the cash flow point of view.

***Table 8.12**: Comparison between DAM+ASM and only DAM situations, 2.700 kWel size.*

Pel COGE				Pth COGE			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
self-cons	13.698.127	13.698.124	0%	self-cons	3.288.028	3.288.028	0%
heat pumps	6.153	6.153	0%	abs chil	1.681.333	1.681.333	0%
market	2.616.088	2.616.358	0%	dissip	10.549.832	10.549.825	0%
TOTAL	16.320.368	16.320.635	0%	TOTAL	15.519.194	15.519.186	0%
COOLING LOAD				**ELECTRIC LOAD**			
kWh	**DAM+ASM**	**DAM**	%	kWh	**DAM+ASM**	**DAM**	%
abs chil	1.176.933	1.176.933	0%	CHPp	13.698.127	13.698.124	0%
heat pumps	12.363	12.363	0%	grid	56.607	56.611	0%
CHPp	12.305	12.305	0%				
grid	57	57	0%				
TOTAL	1.189.296	1.189.296		**TOTAL**	13.754.734	13.754.734	

THERMAL LOAD			
kWh	**DAM+ASM**	**DAM**	%
CHPp	3.288.028	3.288.028	0%
boil	518.445	518.445	0%
TOTAL	3.806.474	3.806.474	

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CONLUSIONS

The results obtained in this thesis work allowed to define a reference economic framework for the opportunity to participate to the ASM for a CCHP plant installed on the distribution grid, and to evaluate the influence that the ASM opening can have on its revenues.
The analysis carried out on the ASM highlighted the complex nature and the multiple aspects that influence the activity of the TSO and of the dispatching units operating in the market. The reference prices obtained indicate that the possibility to sell ancillary services on the market represents for a DG plant a relevant opportunity from the economic point of view; however, the many volatile factors influencing the management of the market can make this opportunity much greater or can reduce it to zero. The analysis presented in Chapter 4 highlighted first of all the structure of the prices found on the ASM; in particular, the prices reflect the effects of the presence of PV and wind production plants, so that the higher need of capacity reserve and of real-time balancing increases the possibility to obtain high revenues from the market participation for programmable power plants.
The statistical analysis performed on the gathered prices produced an estimation of the relation between the price of the bids presented on the ASM and the probability of acceptance for these bids; the results presented, concerning the upward reserve service, highlighted the differences between the different zones of the Italian grid. The North zone is characterized by a huge number of units participating to the market (linked to a higher demand); the main consequence is that the market provides signal prices for almost all the hours, thanks to the amount of data available, and that the economic parameters calculated are generally less attractive than those of the other zones, given the high level of competition of the market. The North zone resulted to be affected by some internal transmission limits, allowing the division of the zone into four sub-zones, influencing the activity of the TSO and the probability of acceptance for the bids of the different plants. The point has been taken into account introducing a geographic correction factor: this factor expresses the tendency by the TSO to accept bids presented in certain areas with respect to the others.
The other relevant zones of the ASM resulted to host a lower amount of data, because of the lower demand and to the reduced number of power plants present with respect to the North zone. The reference prices obtained have been particularly higher for the South zone in the summer period, reflecting how PV and wind production plants influence directly the prices found on the market and hence the economic opportunity linked to it.
The reference economic framework built for the upward reserve suggested that the opportunity represented by the ASM opening to DG is linked to the location of the plant, to the contingencies of the market and to characteristics of the network.
The analysis focused also on the regulatory framework concerning CHP plants, and in particular on the SEU qualification and the general system charges reform. The modification of the legislation correlated with the support mechanisms for CHP plants, and with the parameters influencing their economic flows, can put in danger the security of the long-term investment made, thus it must be taken into due account. In particular, the shifting of the economic burden for the general system charges towards the power component (€/kW) can be either advantageous or not, mainly depending on the withdrawal profile of the user, but in any case changes heavily the features of the not-domestic users electricity bill. In this configuration, the possibility to produce, and self-consume, electric energy can become a great advantage, especially for the peak loads levelling. At the same time, the malfunctioning and the shut-off of the power plant, even for a reduced number of hours, can put in danger the economic saving ensured by self-consumption, particularly if it occurs during peak load hours, when the power engaged with the network is maximum. A good maintenance of the power plant, together with a proper awareness concerning the electric demand management, is hence fundamental to obtain the expected revenues from this type of investments in the next future.

The use of the economic parameters derived was made possible by the development of an optimization tool for the sizing and the operations of a CCHP plant. The results obtained for the Formec Biffi S.p.A. study case highlighted the possibility to obtain higher revenues thanks to the ASM participation with respect to the current situation; this condition is linked to the characteristics of the consumption profiles of the user and to the opportunities defined on the market and correlated to the plant localization. The economic flows linked to the ASM market participation increase with the size of the plant considered: this suggests that, when the opportunity represented by the market is significant, it is worth to oversize the power plant, with respect to the demand requirements, as this guarantees higher revenues due to the electricity selling. However, this consideration increases the power plant cash flow dependence on the contingencies of the market and on the regulatory issues that can influence the stability of the economic returns.

The Bovisa La Masa study case highlighted the differences between a civil and an industrial user. The different demand profiles influenced the power plant revenues. Moreover, the location of the CCHP plant penalized the economic returns obtainable from the ASM participation: the reduction of the reference prices introduced by the geographic correction factor reduced the economic flows correlated to the market. Due to these issues, the ASM opening did not entail, for the Bovisa La Masa study case, an increase in terms of revenues, meaning that the oversizing of the power plant in this case is not worthy.

Finally, it is possible to conclude that the opportunity to participate to the ASM represents for the DG plant, and in particular for those plants that can easily modulate their power such as CCHP plants, a possibility to increase the revenues and to size the plant according to a different logic; however, this evaluation is strictly correlated with the many aspects that influence the market and the regulatory framework that rules the activities of the power plants. The heterogeneity that results from different study cases highlights the need to evaluate each situation taking into account all the aspects involved in the optimization of the power plant operations and in the activity of the specific plant on the ASM.

A further development of the work done could consist in the implementation of the downward reserve service in the optimization tool; this will allow to evaluate the opportunity that the ASM opening represents considering the possibility to modulate the CHP plant both increasing and decreasing the power, according to the service that the plant is called to provide. This is consistent with the future possibility, also for the DG, to provide services on the ASM in a symmetric way.

The provision of the upward reserve service is easier to be implemented in an optimization procedure regarding the operations of a power plant, as the mechanism to supply this service is conceptually similar to the simple selling of energy on the DAM (already performed nowadays by the DG units). The provision of the downward reserve service is more complex, because it entails a decrease of the power generated by the plant that involves not only the electricity production management, but influences also the management of the local demand. The implementation of the downward reserve service provision in the optimization tool should take into account the possibility that, once the power plant is called to decrease its production, the new configuration required could entail the activation of the boilers or of the heat pumps to cover the thermal and/or cooling load, because of the reduction, together with the electric energy, also of the heat produced by the plant.

Due to this, the procedure to be designed to allow the provision of a downward reserve service within the optimization tool, could consist in the steps described below.

- The first step is the elaboration of some reference prices for the downward reserve service, as it has been done for the upward reserve service. This reference prices will be associated to a probability of acceptance able to modify the associated revenues, taking into account the possibility to have the bid presented actually accepted (or not).
- The reference prices for the downward reserve service, as calculated above, will be used to evaluate the revenues coming from the service provision, together with the zonal price

granted by the DAM. Beside the evaluation of this monetary flow, it is necessary to consider the influence of the plant modulation on the coverage of the local loads; this can be done considering the optimization curve built independently from the downward service provision, hence according to the simple selling of the energy on the DAM, adding the economic flows deriving from the downward reserve service. This procedure allows to consider the opportunity represented by the downward reserve provision, taking care at the same time of the configuration of the power plant required for the provision of the service itself, hence of all the energy vectors possibly needed to cover local loads which could remain uncovered, after the power modulation.

- Beyond the evaluation of both the revenues coming from the downward reserve service provision and the eventual costs correlated with the new power plant configuration, linked to the local loads coverage, it is necessary to consider also the penalization represented by the possibility that, if the bid presented on the ASM by the power plant is not accepted, the plant will sell electricity on the DAM in a working point different from the optimal one. This consideration can be incorporated in the analysis adding it to the economic flow, by means of a factor linked to the probability of acceptance, which could be the same evaluated before in the definition of the reference prices.

Another possible improvement, consistent with the actual structure of the optimization tool, could foresee the implementation of the use of electric and thermal storage systems.

LIST OF ACRONYMS

AEEGSI	Autorità per l'Energia Elettrica, il Gas e il Sistema Idrico
ASAP	Altri Sistemi di AutoProduzione
ASE	Altri Sistemi Esistenti
ASM	Ancillary Service Market
ASSPC	Altri Sistemi Semplici di Produzione e Consumo
BM	Balancing Market
CCHP	Combined Cooling, Heat and Power
CHP	Combined Heat and Power
CoP	Coefficient of Performance
DAM	Day Ahead Market
DD	Degree Day
DG	Distributed Generation
DSO	Distribution System Operator
EC	European Commision
EP	European Parliament
ESCo	Energy Service Company
EU	European Union
GME	Gestore dei Mercati Energetici
GSE	Gestore dei Servizi Energetici
HEC	High Efficiency Cogeneration
ICE	Internal Combustion Engine
IEM	Italian Energy Market
IM	Intraday Market
MiSE	Ministero per lo Sviluppo Economico
NPV	Net Present Value
OECD	Organisation for Economic Co-operation and Development
PES	Primary Energy Saving
PdR	Punto di Riconsegna
PoD	Point of Delivery
PS	Primary Substation
PT	Payback Time
PUN	Prezzo Unico Nazionale
RUP	Registro delle Unità di Produzione
SEESEU	Sistemi Esistenti Equivalenti ai Sistemi Efficienti di Utenza
SEU	Sistemi Efficienti di Utenza
SSPC	Sistemi Semplici di Produzione e Consumo
TOE	Tons of Equivalent Oil
TSO	Transmission System Operator
UdD	Utente del Dispacciamento
UP	Unità di Produzione
UVA	Unità Virtuale Abilitata
VAT	Value Added Tax
WC	White Certificate

ANNEXES

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