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Thermal load estimation of apartment buildings for electrification analysis of energy communities

Relatore
Prof. Maurizio Repetto
Correlatore
Dr. Paolo Lazzeroni

Candidato
Adamo Porcelli

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Abstract

Nowadays, one of the biggest challenges to face in the energy sector is the transition to more sustainable methods of production and consumption of energy. In order to achieve this goal big changes, mainly focused on energy saving, are needed. Collective Self-Consumption and Energy Communities are going to play a key role in this transition, enhancing the efficiency of consumption and bringing benefits to both citizens and environment. Thanks to this new kind of organization, there is going to be a switch from the current electricity system, mainly centralized and based on fossil fuels, to a decentralized system, mostly powered by green and non-polluting energy. The aim of this master's thesis is to perform a techno-economic analysis of the energy consumption of an apartment building, in the form of a group of collective self-consumers. The work starts with the choice of a typical apartment building to be used for all the simulations. This step is followed by the creation of a simplified thermal model of the same construction, with the subsequent estimation of the thermal load of the building. At this point, the analysis of two different scenarios is carried out. In the first case all the thermal load is supplied by a traditional boiler, while electricity is in part produced by a photovoltaic system and in part bought from the grid. When the electricity production from PV fulfills the whole electric demand, the surplus is injected into the grid. In this scenario, the whole electric consumption is referred to the standard consumption of the private electric devices used inside the apartments, and this is the case of a virtual collective self-consumption. The second scenario presents an improvement: a heat pump is introduced in order to reduce the usage of the boiler (and to reduce the amount of burned fuel), switching part of the thermal load into electric. In this scenario, the utilization of the heat pump is preferred: the boiler only works as a backup when the whole thermal load cannot be fulfilled by the heat pump and in the rare cases in which COP becomes too low because of extreme temperatures, causing a less efficient performance of the pump. Moreover, during the moments in which the electric energy produced by the PV is higher than the users' demand, this surplus energy can be used by the heat pump to fulfill the thermal load. In this case, as opposed to the first scenario, the utilization of the heat pump implies a part of physical collective self-consumption, which is not incentivized as the virtual one.

The analysis of the two scenarios is made not only in terms of energy consumption, but also from an economic point of view. In this context, the benefits given by the introduction of the heat pump are shown, thanks to the reduction of fuel consumption, that generates a

positive effect both in terms of cost and energy savings, and environmental impact. Moreover, an investment analysis is performed, focusing the attention on various indicators, including payback time and internal rate of return. The PVGIS data set is used to download the temperature and irradiance data for all the points on the Italian map (with a distance of 2.5 km between each point). Thanks to these data, the simulation is performed on each point, but always using the same reference building. The results are then represented in spatial form, on a map, using the QGIS software.

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Introduction

The energy transition, based on the production and consumption of energy from renewable sources, is necessary and urgent. The introduction of new forms of collective cooperation, combined with the opportunities offered by new digital technologies, are going to play a key role in this transition and represent a big opportunity for the creation of new green economy models. The energy transition is especially necessary in terms of environmental sustainability, but it cannot be fully realized without a complex set of social, economic and technological changes. Being part of a community is the one of the first steps to take in order to fix the bond between men and the environment. The energy system is being transformed by the partnership between citizens and communities in energy projects and thanks to these initiatives, citizens have the opportunity to be always more involved in energy related affairs. The European Commission's Clean Energy for All Europeans Package underlines the important role that prosumers are going to play in the new energy system. In this context, the EU legislative framework defines Energy Communities as 'Renewable Energy Communities' and 'Citizen Energy Communities' [1] [2].

One of the factors that is helping energy community projects to increase is represented by renewable energy support schemes providing incentives for collective self-consumption users and members of energy communities. Another important point is the fact that the economic situation of the consumer is not a constraint, because decentralization brings benefits to everyone, including people who cannot be part of the project. The energy system can also take advantage from the introduction of energy communities because they provide flexibility and improve traditional network, that could be obsolete and therefore need upgrades. Moreover, energy prices are going to be lower, and this is a big advantage for customers. According to some estimates, Energy Communities are expected to own 17% of installed wind capacity and 21% of solar (European Commission, 2016) by 2030. While, by 2050, nearly half of EU households could be producing renewable energy (Kampman, Blommerde, and Afma, 2016) [2]. The majority of the Energy Communities is intended to stay connected to the energy system, while a small part will work as stand-alone systems (for example in remote areas and islands). As seen, energy communities can bring a lot of innovation and economic advantages, but their importance is not yet fully understood in each country of European Union. Some countries are already aware of their potential, while in other cases a lot of work needs to be done in order to remove the obstacles that prevent people from participating in this kind of projects.

In this context, this work aims at providing a tool for the energetic evaluation of a building (block of apartments) where electric energy is virtually shared between a group of households. The hourly thermal load of the entire building is calculated for a full year and the improvements given by the installation of a heat pump as a substitution to a traditional boiler (which will continue to work as a backup) are shown. The electric consumption of the building is also evaluated, starting from a previously calculated electric load of the households and with the support of a photovoltaic installation. In the first scenario, the PV helps fulfilling the electric load, while the thermal load is fully satisfied by the traditional boiler. In the second scenario, thanks to the introduction of the heat pump, the photovoltaic installation not only satisfies part of the electric load, but also can fulfill part of the thermal load feeding the pump. In both cases, an economic evaluation is performed, keeping into consideration the cost of the investment for the various installations and the yearly cost of electricity and natural gas. Moreover, an evaluation of the CO_2 emissions savings after the PV and heat pump installation is carried out. This whole simulation is performed for all the Italian regions, excluding the locations with an altitude higher than 850 m. The reason is that there are not big towns over this altitude and most of the villages are mountain locations, so the reference building used for the study would not be appropriate. The needed data are downloaded by PVGIS, a free online data set, while the calculation is implemented using MATLAB. All the results are later exported to QGIS in order to have them on a map, in which each cell corresponds to an actual point with a distance of 2.5 km from each other point. At the end, the attention is focused on three regions (one in Northern Italy, one in the Center and one in the South) and more particularly on three points, choosing three significant cities. The chosen regions are Piemonte, Lazio and Calabria with their most significative cities (Torino, Roma and Reggio Calabria).

Entering more into detail about the subdivisions in chapters:

- Chapter 1 presents an overview on Energy Communities and Collective Self-Consumption, showing the most important energy communities around the world and the economic contributions for energy communities and collective self-consumption users available in Italy.

- Chapter 2 shows how thermal load was evaluated, focusing the attention on the choice of the reference building and on the evaluation of degree days and climate zones.
- In Chapter 3, the energy community simulation is performed, from an energetic, economic and environmental point of view, with distinction between the two different scenarios.
- Chapter 4 shows the results of the simulation on a national scale, on a regional scale focusing on the three chosen regions and on a city scale.

1. Energy Communities

Energy Communities and Collective self-consumption are going to play a strong role in achieving the fixed objectives of decarbonization. The two tools are a way of organizing that can be used by citizens to respond to the urgent needs in the energy and environmental fields, that nowadays are in the public eye [3]. In this context, it is estimated that 264 million citizens of the European Union will join the energy market as prosumers, generating up to 45% of the overall renewable electricity of the system [1]. More specifically, a prosumer is a non-passive user who is not only a consumer, but also a producer, taking part in the production process. So, a prosumer owns his own energy production plant, producing his own energy. A part of this energy is consumed by himself and the rest can be used in different ways: it can be stored and used later when needed, it can be exchanged with other consumers situated close to the prosumer or, in case these two options are not available, it can be fed into the network. Obviously, the prosumer will benefit economically from this situation.

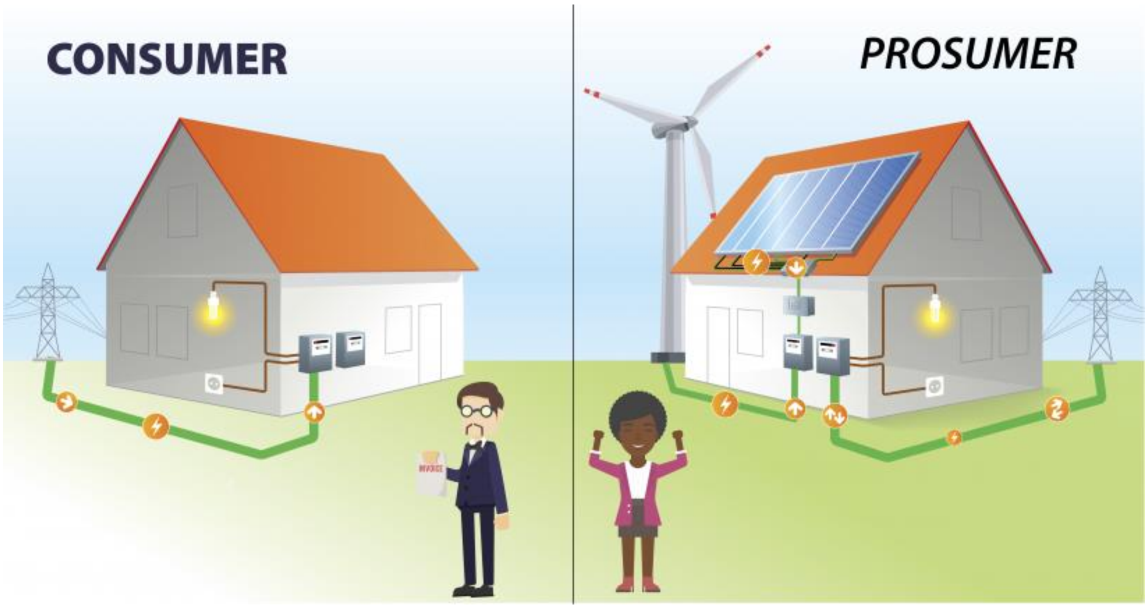

Figure 1.1 - Consumer vs Prosumer [4]

The most innovative forms of prosumption can be achieved through energy communities. All the energy communities share the same goal: providing affordable renewable energy to their members. Moreover, they rely on decentralization and localization of energy production.

Producing, storing and consuming electricity in the same site contributes to the energy transition, promoting energy efficiency and self-consumption. Today, self-consumption can be implemented not only individually but also collectively within condominiums or local energy communities [1].

1.1 Definitions and European Directives

With two directives promoted between 2018 and 2019 by the European Commission, the European Council and the European Parliament in the context of the Clean Energy for All Europeans Package, formally recognize Energy Communities at institutional level. They are the Renewable Energy Directive II (RED II) and the Electricity Market Directive (IEM), which aim is to put citizens at the center of a new model of production and consumption. Moreover, they push Member States to promote single self-consumption, Collective self-consumption (in which energy produced by the system built on the roof of a condominium can also be made available to individual condominiums and no longer just common services), and the Energy Community. Renewable Energy Directive II introduces the figures of “renewable energy self-consumers who act collectively” and “Renewable Energy Community - REC” [3].

With regard to Collective Self-Consumption schemes, the RED II Directive defines "the self-consumer of renewable energy" as a "final customer who, operating in its own sites located within defined borders or, if permitted by a Member State, in other sites, produces renewable electricity for its own consumption and can store or sell self-produced renewable electricity provided that, for a self-consuming renewable energy other than households, such activities do not constitute the main commercial or professional activity ". The directive therefore defines "renewable energy self-consumers acting collectively" as a "group of at least two renewable energy self-consumers acting collectively and located in the same building or condominium" [5].

Collective self-consumers can therefore:

I. produce renewable energy, also for its own consumption; store and sell the surplus production of renewable electricity, also through agreements of buying and selling of renewable electricity, electricity suppliers and peer agreements;

II. install and manage electricity storage systems combined with systems of generation of renewable electricity for self-consumption without being subject to any double charge, including network tariffs for stored electricity which remains in their availability;
III. maintain their rights and obligations as final consumers;
IV. receive remuneration, where appropriate also through support schemes, for the self-produced renewable electricity that they feed into the grid, which corresponds to the market value of this electricity and can take into account its long-term value term for the network, the environment and society [3], [5].

Moving on to Renewable Energy Communities, these are a "legal entity:

I. which, in accordance with the applicable national law, is based on open and voluntary participation, it is self-contained and is actually controlled by shareholders or members who are located in the vicinity of renewable energy production plants which they belong to and are developed by the legal entity in question;
II. whose shareholders or members are natural persons, SMEs or local authorities, including municipal administrations;
III. whose main objective is to provide environmental, economic or social benefits at the level of community to its shareholders or members or the local areas in which it operates, rather than financial profits " [3], [5].

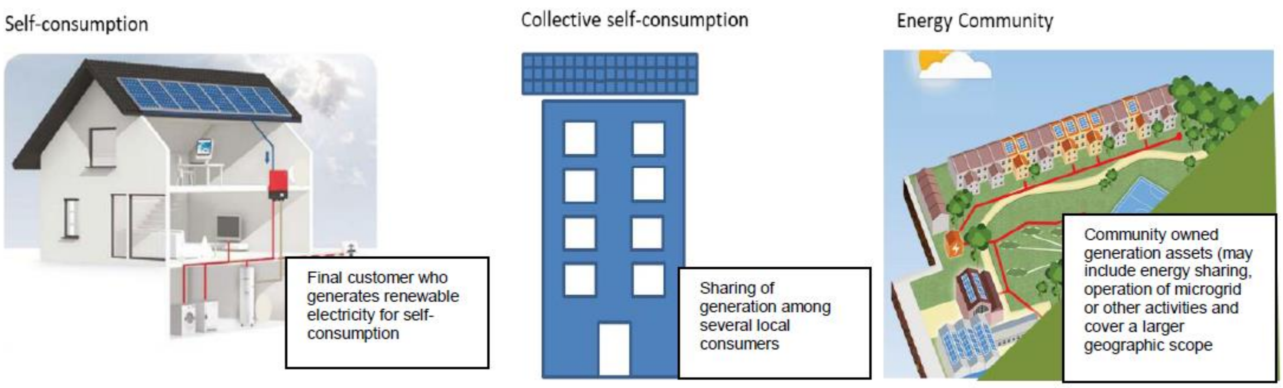

Figure 1.2 – Self-Consumption, Collective Self-Consumption and Energy Community [6]

Renewable Energy Communities are a big innovation, with features that are impossible to find within the current energy market. They are open to the voluntary participation of citizens, local authorities and businesses. In this context, all the choices are shared among the members of the community. One of the most important elements of the definition that the Parliament and the European Council give of RECs is the following: “communities operate in the energy market without having a prevalent profit-making purpose, with the aim of satisfying environmental, economic and, only ultimately, profit social needs. Another really important point to focus on concerns the possibility for Member States to grant the energy communities the right to manage the local distribution network. This means that the RECs can choose between a physical model, in which the community uses its own network to exchange energy between members, and a virtual model, which involves the use of the public network. The directive underlines that if a REC decides to manage the distribution network, it will have the same obligations as the other concessionaires and will have to respect the regulation of the reference sector [3], [5].

1.2 Physical and Virtual Self-Consumption

Nowadays in Italy it is possible to perform self-consumption following the "one to one" scheme, that provides for a Production Unit serving a Consumption Unit. Switching to collective self-consumption, two different configurations can be adopted: Physical and Virtual Self-Consumption.

1.2.1 Physical Self-Consumption

Physical self-consumption scheme presents a direct private connection between the generation plant and domestic/common users and a single access point to the public network called POD (Point of Delivery).

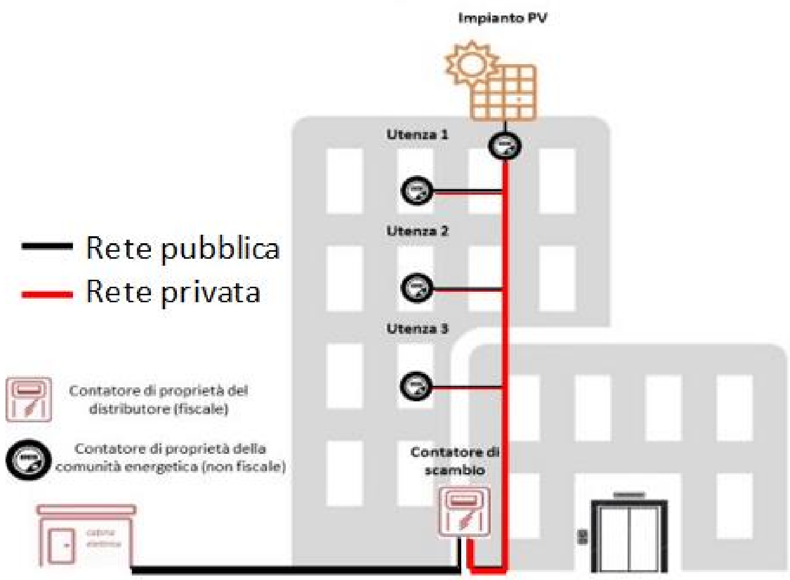

Figure 1.3 - Physical Self-Consumption scheme [3]

The physical self-consumption scheme only presents one POD of exchange with the grid and the energy produced and self-consumed remains within the perimeter of the private building network, therefore it is not subject to the application of the variable part of network and system charges. The main features of this configuration are:

- private condominium internal network with a single connection to the public network through a single fiscal meter;
- single contract for the supply of electricity for both common and domestic utilities of the condominium;

- non-fiscal measurement infrastructure for accounting of the utilities consumption.

According to the current regulation, all real estate units must be connected to their own tax meter and each user must be able to choose their own energy supplier. It must also be able to decide, at any time, not to be part of the self-consumption scheme: these rights would be compromised if users were not equipped with their own POD [3].

1.2.2 Virtual Self-Consumption

Unlike the previous case, in a Virtual Self-Consumption scheme the public network is used to exchange energy between generation and consumption units.

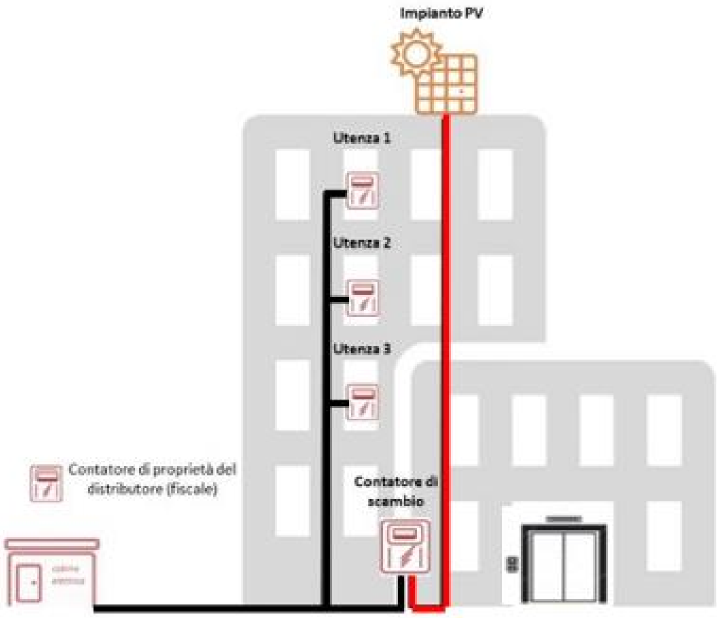

Figure 1.4 - Virtual Self-Consumption scheme [3]

In this case, every user is connected to the public network through his own POD and everyone is free to choose his own energy supplier or to exit the scheme. The main features of the virtual scheme are:

• unaltered network configuration: the public network ends at the POD of the individual end users, where a fiscal meter is installed;

• the metering service is carried out by the electricity distributor;

• each customer can choose his own energy supplier and exit the scheme at any time.

The condominiums appoint manager of the scheme who has the task to quantify the self-consumption quotas attributable to each participant on the basis of the fiscal measures of production of the plant and consumption of domestic and condominium utilities. The distribution of virtual self-consumption is calculated according to contractual agreements between the condominiums. It can depend on an energy criterion, for example in proportion to the withdrawals of each user in each time interval, or on a fixed criterion not related to the energy consumption of individual homes [3].

1.3 Examples of existing Energy Communities

Currently, various collective self-consumption and energy community projects are active in many countries around the world. These communities are mainly situated in Northern Europe, but the number of projects all over the world is growing in recent years.

Brooklyn Microgrid, New York (USA)

Brooklyn Microgrid (BMG) is a community-driven initiative that started in April 2016 in Park Slope. It is a small-scale network of New York City residents and business owners who support local solar energy production principally through residential photovoltaic systems. It was founded as a benefit corporation by its parent company, LO3 Energy, trying to create an energy grid where residential and commercial citizens can buy and sell locally generated renewable energy. Participants access the local energy market through the BMG mobile application. In the app, people can choose to buy local solar, renewable energy and/or grid energy. Thanks to the installation of a BMG smart meter system, which collects and records energy data, prosumers can choose whether to sell excess solar energy to the market or use it [7].

Figure 1.5 - A BMG prosumer [7]

Grupo Creluz, Rio Grande do Sul (Brazil)

Grupo Celuz is a small-scale community made of 6 small hydroelectric plants, for a total of 4 MW of supply. It was created in 1999 and today it ensures 27% of the electricity required by about 80.000 people in economic difficulties in the state of Rio Grand Do Sul. It is a local social enterprise made of 20.000 members. The members of the cooperative are pure prosumers, as they consume the energy they produce. Moreover, they provide free electricity to 600 poor families [1], [8].

Bioenergy Village Jühnde (Germany)

Jühnde is a small rural village in Saxony of around 750 inhabitants, famous for having become, in 2005, the first village to have a biomass plant entirely owned by its citizens. The project developed thanks to the University of Göttingen support.

It is a mixed plant: there is a 700 kW biogas cogeneration plant producing electricity which is supplied to the public grid and an additional 550 kW wood chip boiler used during winter to provide the heating that circulates around the local network. Overall, the plant produces double the electricity needs of the village and about 70% of its thermal needs, and it is owned by Jühnde’s inhabitants. Currently, nearly 75% of Jühnde's inhabitants are members of this company. Once they have bought the shares and become partners, they can buy heating and electricity from the company, this means that the energy consumers are also the producers of that energy [1], [9].

Figure 1.6 – Jühnde’s village [10], [11]

Tower Power, Edinburgh (Scotland)

Tower Power is a community that, by aggregating electricity use from a whole tower block, purchase their energy as an industrial load, therefore securing cheaper rates and passing on savings to residents. It was led by Community Energy Scotland working in partnership with Our Power, Energy Local, TMA, Glasgow City Council and City of Edinburgh Council. The project initially planned to install solar panels on the roofs of housing blocks, but this initiative was withdrawn because of several challenges such as the requirement to get permission from all owners and the high costs, implying that the returns were going to be small and too risky. The project started in 2015 and concluded in 2018 [12].

Middelgrunden wind farm, Øresund (Denmark)

This offshore wind farm, located 3 km outside the port of Copenhagen, was built in 2001 and consists of 20 wind turbines of 2 MW each, for a total of 40 MW of installed power.

The annual production (44 GWh) covers 4% of Copenhagen’s energy needs. Its fame is principally due to the structure of its property. In fact, 50% of the project is owned by the municipality of Copenhagen, while the remaining 50% is owned by a local partnership made up of more than 10,000 members ("Middelgrunden Wind Turbine Cooperative"). Middelgrunden is the largest wind project in the world to be in part owned by the community; it means that citizens can also lead big projects. Moreover, in this particular case the citizens ownership led to a wide public support, while similar parks owned by private companies were opposed [11] [13].

1.4 Incentives for energy communities and collective self-consumption users

The economic contributions for energy communities and collective self-consumption are recognized for a duration of 20 years starting from the commercial start date of the production plant. These incentives are calculated on the shared electricity (equal to the minimum, on an hourly basis, between the electricity input into the grid and the electricity drawn). For each kWh of shared electricity, the GSE recognizes, for a period of 20 years:

- a unit fee given by the sum of the transmission tariff for low voltage users ($7.61\ €/MWh$ for 2020), and the higher value of the variable distribution component for low voltage users ($0.61\ €/MWh$ for 2020). In the case of groups of renewable energy self-consumption users that act collectively, an additional contribution is added due to the avoided grid losses (variable according to the voltage level and the Zonal Hourly Price of electricity. Considering 2019's Single National Price it would have a value of $1.3\ €/MWh$ for low voltage and $0.6\ €/MWh$ for medium voltage);
- a premium rate (equal to $100\ €/MWh$ for groups of self-consumers and $110\ €/MWh$ for renewable energy communities).

At the end of the 20-year period, the unit fee can be extended on an annual basis [14].

2. Thermal Load

In this chapter, the method used to evaluate the thermal load of the building was presented.

2.1 Reference building

A typical building was chosen and the different simulations were performed always using the same building. The choice was made checking the period of construction of the majority of residential buildings in Italy. A typical apartment building of that period was therefore used.

The data found on ISTAT website [15] are summarized in the following table.

Construction period	Number of buildings
Until 1918	1832504
1919-1945	1327007
1946-1960	1700836
1961-1970	2050833
1971-1980	2117651
1981-1990	1462767
1991-2000	871017
2001-2005	465104
2006-2011	359979

Table 2.1 - Construction period of Italian residential buildings [15]

As it can be easily noticed that most of the buildings were constructed during the twenty years between 1961 and 1980.

In order to choose the correct type of building constructed in that period, the document “Building Typology Brochure – Italy” by Corrado V., Ballarini I. and Corgnati S. P. was consulted [16].

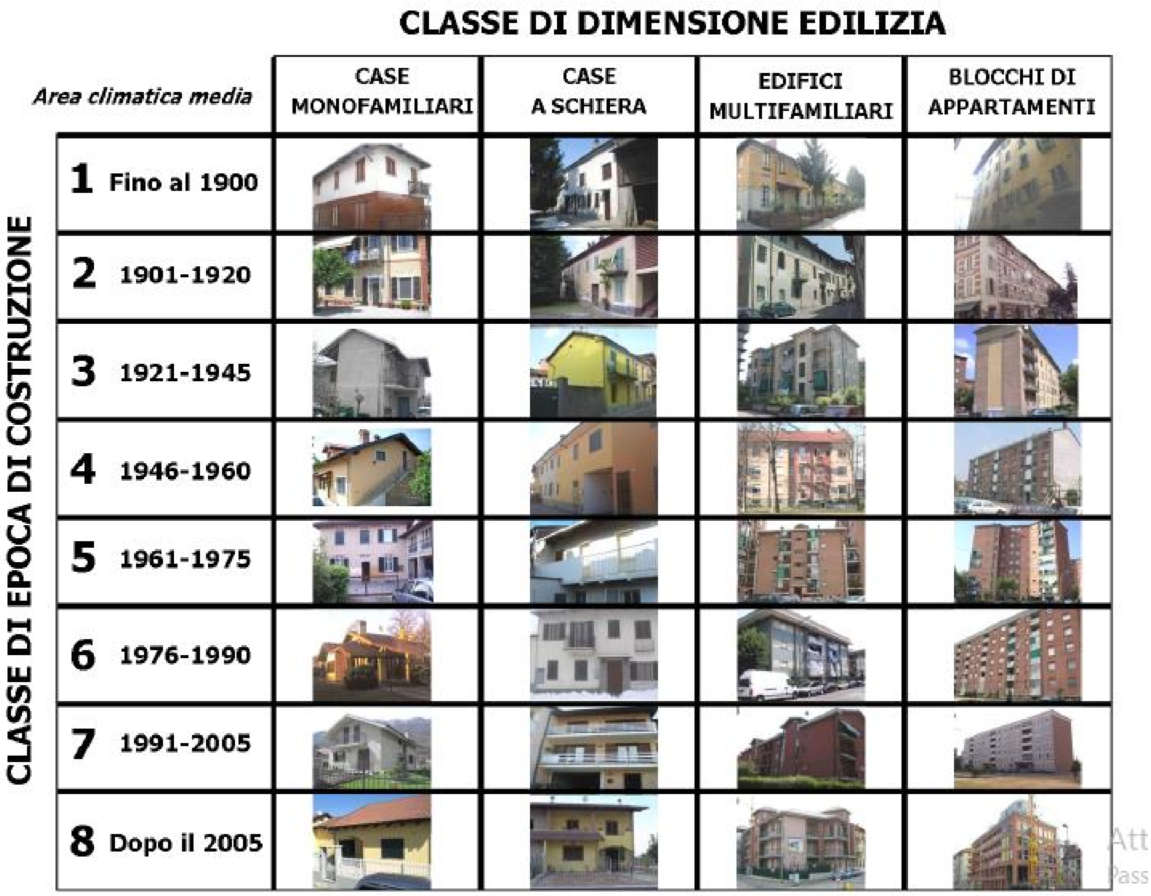

Figure 2.1 - Italian building size and period of construction class [16]

In this brochure, the construction periods are divided into different intervals if compared to the ones of ISTAT website. For this reason, an approximation was made, trying to redistribute the buildings created during the periods of Table 2.1 into the new periods of Table 2.2.

#	Construction period	Number of buildings
1	Until 1900	916252
2	1901-1920	916252
3	1921-1945	1327007
4	1946-1960	1700836
5	1961-1975	3109658
6	1976-1990	2521592
7	1991-2005	1336121
8	After 2005	359979

Table 2.2 - Construction period of Italian residential buildings (redistributed into new periods of interest) [15] [16]

As a result, time interval number 5 (1961-1975) was chosen as a reference and the building used for the simulation was a typical apartment building of that period. All the data and information regarding this building are reported in Table 2.3.

Symbol	Value	Parameter
$\boldsymbol{V}$	$9438\ m^3$	Air-conditioned gross volume
$\boldsymbol{\frac{S}{V}}$	$0.46\ m^{-1}$	Form factor
$\boldsymbol{A_{f,l}}$	$2869\ m^2$	Gross floor area
$\boldsymbol{N_a}$	40	Apartments number
$\boldsymbol{N_f}$	8	Floors number
$\boldsymbol{d_m}$	$0.4\ m$	External walls thickness
$\boldsymbol{U_t}$	$2.20 \frac{W}{m^2K}$	Roof heat transfer coefficient
$\boldsymbol{U_{p1}}$	$1.10 \frac{W}{m^2K}$	External walls heat transfer coefficient
$\boldsymbol{U_{p2}}$	$1.13 \frac{W}{m^2K}$	Internal walls heat transfer coefficient (towards unheated environment)
$\boldsymbol{U_{ss}}$	$1.65 \frac{W}{m^2K}$	Upper attic heat transfer coefficient
$\boldsymbol{U_{i1}}$	$1.56 \frac{W}{m^2K}$	Lower floor heat transfer coefficient (towards the outside)
$\boldsymbol{U_{i2}}$	$1.30 \frac{W}{m^2K}$	Lower floor heat transfer coefficient (towards unheated environment)
$\boldsymbol{U_s}$	$4.90 \frac{W}{m^2K}$	Windows heat transfer coefficient
$\boldsymbol{g_{gl,n}}$	0.85	Solar Factor
$\boldsymbol{\eta_{gn}}$	0.71	Generation yield
$\boldsymbol{\eta_d}$	0.86	Distribution yield
$\boldsymbol{b_{tr,u}}$	0.4	Correction factor for unheated indoor spaces (room with only one external wall)
$\boldsymbol{n}$	$0.6\ h^{-1}$	Air exchange rate (multi-family buildings, more than one exposed facade, average building air tightness, moderate shielding)
$\boldsymbol{\rho_{air}}$	$1.225 \frac{kg}{m^3}$	Air density
$\boldsymbol{c_{p,air}}$	$1005 \frac{J}{kg\ K}$	Air specific heat
$\boldsymbol{coeff}$	0.1037	Ratio between glazed and opaque surface

$\boldsymbol{H_1}$	$4\ m$	First floor height
$\boldsymbol{H_2}$	$3\ m$	Other floors height
$\boldsymbol{SS}$	$0.3\ m$	Slab between adjacent floors
$\boldsymbol{L_v}$	$3\ m$	Stairwell's smaller side
$\boldsymbol{H_v}$	$5.6\ m$	Stairwell's bigger side

Table 2.3 - Useful parameters [16] [17] [18] [19] [20]

The chosen building had eight floors and contained a total of 40 apartments, 5 for each floor. The height of each floor and the presence of two stairwells were assumed.

After the data collection, all the unknown parameters of the building useful to obtain the thermal load were calculated. The net floor area $A_{f,n}$ was obtained calculating the factor f_n [18] and multiplying it for the gross floor area.

$$f_n = 0.9761 - 0.3055 \cdot d_m \tag{2.1}$$

$$A_{f,n} = A_{f,l} \cdot f_n \tag{2.2}$$

At this point, the dispersing surface S_d (including both opaque and transparent surfaces) was calculated and, using the ratio between glazed and opaque surfaces (respectively S_t and S_{op}), the two contributes were evaluated.

$$S_{op} = \frac{S_d}{1 + coeff} \tag{2.3}$$

$$S_t = S_{op} \cdot coeff \tag{2.4}$$

The height of the stairwell HH, corresponding to the height of the building excluding the roof, and the net height of the air-conditioned spaces HH_n were given by:

$$HH = H1 + 7 * H2 + 7 \cdot SS \tag{2.5}$$

$$HH_n = HH - 7 \cdot SS \tag{2.6}$$

Thanks to this height and to the useful air-conditioned surface of a single floor $S_{clim,floor}$ also the net volume of air-conditioned spaces VV_n was obtained.

$$S_{clim,floor} = \frac{A_{f,n}}{8} - 2 \cdot L_v \cdot H_v \quad (2.7)$$

$$VV_n = S_{clim,floor} \cdot HH_n \quad (2.8)$$

At last, the internal, external, roof and ground floor dispersing surfaces $S_{d,int}$, $S_{d,ext}$, $S_{d,top}$ and $S_{d,bot}$ were calculated.

$$S_{d,int} = 2 \cdot \left(\left(L_v + (2 \cdot H_v)\right) \cdot HH\right) \quad (2.9)$$

$$S_{d,top} = \frac{A_{f,l}}{8} - 2 \cdot L_v \cdot H_v \quad (2.10)$$

$$S_{d,bot} = S_{d,top} \quad (2.11)$$

$$S_{d,ext} = S_{op} - S_{d,int} - S_{d,top} - S_{d,bot} \quad (2.12)$$

The internal dispersing surface $S_{d,int}$ (entirely opaque) includes 3 of the 4 sides of the two stairwells. The fourth side is part of the outer wall. The external dispersing surface $S_{d,ext}$ was evaluated excluding the roof and the ground floor, which have different transmittances compared to the external walls. The side of the stairwell that overlooks the external wall was also excluded, because the stairwell is a not an air-conditioned environment. Roof and ground floor dispersing surfaces ($S_{d,top}$ and $S_{d,bot}$) were assumed to be equal. For both, the base area of the two stairwells was subtracted from the floor surface.

2.2 Thermal Load Evaluation

Once all the parameters of interest of the building were obtained, the evaluation of the thermal load took place. It consisted in the calculation of the energy consumption of the reference building through a simplified model in which assumptions were made and some contributions were neglected. This simplification was implemented in part to make the model consistent with all the Italian cities, but also because of the lack of necessary data to further deepen the study. The thermal load profile should be evaluated considering:

- Transmission loads
- Solar radiation loads through windows
- Internal loads
- Ventilation loads

Nevertheless, solar and internal loads were neglected and not determined in this study. Being the subject of the study a typical reference building to be placed in all the geographical coordinates of whole Italy, a single orientation of the building was impossible to be established and for this reason the solar radiation loads were very difficult to be determined. Moreover, being the chosen building a fictitious one, there was not an exact location of windows and for this reason the radiation through windows was even harder to be calculated. In the case of internal loads, instead, there was no information about lights and other indoor equipment contributions. As a consequence of these difficulties and since both of these contributes (solar radiation and internal loads) have a "positive" effect, reducing the thermal load of the building, the decision was to neglect them. By doing so, the thermal load was slightly overestimated and a precautionary approach was adopted.

According to the chosen approach, the terms to calculate were transmission and ventilation loads. The first one is due to thermal conduction and is the result of the difference between the inside and the outside temperature ($T_{in} - T_{ext} = \Delta T$), multiplying the dispersing surface S_d and the heat transfer coefficient U. The latter is also related to the same temperature difference, but it is not a thermal conduction term. It is given by the product between ΔT, the net volume of air-conditioned spaces VV_n, the air exchange rate n and the density and specific heat of air. The procedure is summarized by the following equations.

$$Q_{t,ext} = U_{p1} \cdot S_{d,ext} \cdot \Delta T \tag{2.13}$$

$$Q_{t,top} = U_{ss} \cdot S_{d,top} \cdot \Delta T \tag{2.14}$$

$$Q_{t,bot} = U_{i1} \cdot S_{d,bot} \cdot \Delta T \tag{2.15}$$

$$Q_{t,int} = U_{p2} \cdot S_{d,int} \cdot \Delta T \cdot b_{tr,u} \tag{2.16}$$

$$Q_{t,t} = U_s \cdot S_t \cdot \Delta T \tag{2.17}$$

$$Q_v = \frac{\rho_{air} \cdot c_{p,air} \cdot n \cdot VV_n \cdot \Delta T}{3600} \tag{2.18}$$

The outside temperature T_{ext} was assumed to be equal to 20 °C.

The transmission loads were divided into five different contributes: the windows load $Q_{t,t}$, the external walls load $Q_{t,ext}$, the roof load $Q_{t,top}$, the ground floor load $Q_{t,bot}$ and the internal walls load $Q_{t,int}$, whose temperature difference was corrected by the correction factor for unheated indoor spaces $b_{tr,u}$. The ventilation load Q_v was divided by 3600 to standardize the unit of measurement.

The total thermal load was given by the sum of all the contributions divided by the distribution yield η_d, as shown in Equation 2.19.

$$Q_{th} = \frac{(Q_{t,ext} + Q_{t,top} + Q_{t,bot} + Q_{t,int} + Q_{t,t} + Q_v)}{\eta_d} \tag{2.19}$$

Using these formulas, Q_{th} was obtained as a power in W. This contribute was calculated hourly: multiplying it for the time step of 1 hour, the resulting thermal load was an hourly energy (Wh) estimated for a whole year. Summing all the hourly values, the total yearly thermal load was also obtained.

2.3 Degree days

The degree day of a locality is the sum extended to every day, in a conventional annual heating period, of the daily differences (only the positive ones) between the temperature, conventionally fixed for each country, and the average daily external temperature. The Decree of the President of the Republic of 26 August 1993, n. 412, hints at a conventional annual heating period and conventionally sets the room temperature at 20 °C [21].

$$GG = \sum_{e=1}^{n} (20 - T_e) \tag{2.20}$$

Where T_e is only considered when less than 20 °C. T_e indicates the average daily outdoor temperature of the conventional heating period of n days "which begins with the first three consecutive days characterized by an average daily temperature below 12 °C (in any case not after December 1st) and ends with the first three consecutive days characterized by an average daily temperature equal to or higher than 12 °C (in any case not before February 28th) [22]. So, degree days, express the thermal needs of a specific geographical area. A low degree day value indicates a short heating period and average daily temperatures close to the set room temperature. On the contrary, high degree day values indicate long heating periods and average daily temperatures significantly lower than the reference temperature [21].

In this study, the hourly outdoor temperature was known. T_e was calculated daily making an average of the 24 hourly temperature values. So, the first three consecutive days characterized by an average daily temperature below 12 °C and the first three consecutive ones characterized by an average daily temperature equal to or higher than 12 °C were determined. At this point, degree days GG could be obtained according to Equation 2.20.

2.4 Climate zones

The Italian climate zones (or climate regions) are areas characterized by similar average temperatures during the year. They are defined as a function of the degree days GG. Climate zones set a limit to the usage of the heating system, indicating the allowed annual period of operation and the maximum daily duration of activation. The Italian classification is shown in Table 2.4.

Zone	From [GG]	To [GG]	Daily hours	Start date	End date
A	0	600	6	December 1st	March 15th
B	601	900	8	December 1st	March 31st
C	901	1400	10	November 15th	March 31st
D	1401	2100	12	November 1st	April 15th
E	2101	3000	14	October 15th	April 15th
F	3001	+∞	No limitation (whole year)		

Table 2.4 - Climatic classification of Italian municipalities [21]

The indication of the daily hours of operation is general, with no details regarding the exact time. It is an information that varies from one municipality to another and for this reason some assumptions were made in order to have a standardized daily period of activation for each climate zone. The daily hours of operation used are summarized in Table 2.5.

Zone	Daily hours	Hours of operation
A	6	07:00-10:00 18:00-21:00
B	8	07:00-11:00 17:00-21:00
C	10	07:00-12:00 17:00-22:00
D	12	06:00-10:00 12:00-16:00 18:00-22:00
E	14	05:00-10:00 12:00-16:00 18:00-23:00
F	Whole day (no limitation)	

Table 2.5 - Daily hours of operation

After calculating thermal load and degree days, basing on the climate zone classification, the hourly thermal load of the various Italian cities was corrected, setting its value to zero during the not allowed periods of the year and respecting the daily hours limitation during the heating periods. At this point, the yearly total thermal load was evaluated again too. The results will be showed in the fourth chapter.

Obviously, the used method is a simplified approach, because actual climate zones are defined by law for each Italian Municipality, while in this study a climate zone is assigned to each analyzed point.

3. Energy community simulation

Once the thermal load estimation was over, the attention was focused on the two different energy community scenarios, involving the same reference building described in Paragraph 2.1. Both cases will be discussed in this chapter. The analysis of the two scenarios was made not only in terms of energy consumption, but also from an economic and environmental point of view. Moreover, an investment analysis was performed, focusing the attention on various indicators, including payback time and internal rate of return.

3.1 First Scenario: Photovoltaic installation

The first scenario consists in the installation of a photovoltaic system on the roof of the reference building. Doing so, instead of buying the whole consumed electricity from the grid, it will be in part produced by the PV system and in part bought from the grid. Moreover, when the electricity production from PV fulfills the whole electric demand, the surplus is injected into the grid. In this scenario, the whole electric consumption is referred to the standard consumption of the private electric devices used inside the apartments, and this is the case of a virtual collective self-consumption.

Firstly, the size of the PV system had to be chosen. It is strongly dependent on the location of installation, so an approach was identified to choose the size as a function of the local irradiance and loads. This choice had a limitation, given by the rooftop dimension. For this reason, before calculating the size of the PV system, the maximum installable capacity was estimated. After the choice of the size, an economic evaluation of the investment was performed.

3.1.1 Maximum PV capacity

The only available data was the gross floor area $A_{f,l}$, for this reason some assumptions were made. The rooftop surface was assumed to be the same of the gross surface of each floor and its slope equal to 30°. The chosen PV modules specifications are shown in Table 3.1, together with the data needed for the calculation.

Symbol	Value	Parameter
$\boldsymbol{A_{f,l}}$	2869 m^2	Gross floor area
$\boldsymbol{\alpha}$	30°	Roof slope
$\boldsymbol{S_m}$	1.6 m^2	Surface of a single PV module
$\boldsymbol{P_m}$	300 W_p	Power of a single PV module

Table 3.1 - Useful data for maximum installable PV size

As mentioned before, the rooftop surface was assumed to be the same of the gross surface of a single floor.

$$A_{roof} = \frac{A_{f,l}}{8} \tag{3.1}$$

This formula could be acceptable if the roof was horizontal, but in this case the roof slope had to be taken into account. Moreover, being the optimal orientation towards south, only half of the roof was considered (under the hypothesis of a gable roof, half facing north and half south). For this reason, the available surface for PV installation S_{PV} was estimated as shown in Equation 3.2.

$$S_{PV} = \frac{A_{roof}}{2 \cdot cos\alpha} \tag{3.2}$$

Moreover, only 90% of this surface was considered available for the installation, in order to save the necessary space for ordinary maintenance. This contribute was considered in the calculation of maximum PV size P_{max}.

$$P_{max} = \frac{0.9 \cdot S_{PV} \cdot P_m}{S_m} \approx 35\ kW \tag{3.3}$$

3.1.2 Design of PV size

At this point, the PV size could be calculated, considering the obtained P_{max} as upper bound. The idea was to create a function with irradiance and electric load as inputs and to perform a parametric analysis with different PV sizes (considering P_{max} as maximum value). The used electric load was a pre-calculated load which neglected the electricity consumption of common spaces, like the stairwell. Moreover, it was assumed not to vary during years; the considered yearly load was the same for the whole period of analysis. Going back to the parametric analysis, for each value of PV capacity, self-consumption SC and self-sufficiency SS were evaluated. At this point all the values were put in a SC-SS chart and the optimal point was chosen as the one nearer to the knee of the curve. The point on the knee of the curve identifies the PV size that simultaneously maximizes SC and SS, for this reason the closer point to this "optimal" one was chosen. The calculation is detailed as follows.

Starting from the photovoltaic nominal power $P_{n,PV}$, the yearly PV production profile P_{PV} was calculated.

$$P_{PV} = \frac{G(t)}{G_{ref}} \cdot P_{n,PV} \cdot PR \tag{3.4}$$

Where $G(t)$ is the hourly irradiance profile of an entire year in $\frac{W}{m^2}$ and G_{ref} is the reference irradiance, that is the value of irradiance used to define the nominal power of the photovoltaic module ($1000\frac{W}{m^2}$). $PR = 0.8$ is the performance ratio assumed for the PV plant.

At this point, the profile of hourly self-consumed energy P_{SC} was created, comparing hour by hour the PV production profile with the electric load profile Q_{el}. When PV production was higher than electric load, self-consumed energy was assumed to be equal to the electric load value; while when PV production was lower than the electric load, the self-consumed energy was the one produced by PV.

$$P_{SC,i} = \begin{cases} Q_{el,i} \ , & if\ P_{PV,i} > Q_{el,i} \\ P_{PV,i} \ , & if\ P_{PV,i} < Q_{el,i} \end{cases} \tag{3.5}$$

$$E_{SC} = \sum_{i=1}^{n} P_{SC,i} \tag{3.6}$$

The yearly energy self-consumption calculation is shown in Equation 3.6, where n is the number of yearly hours (8760). Once E_{SC} was known, self-consumption and self-sufficiency indexes SC and SS could be evaluated.

$$SC = \frac{E_{SC}}{P_{PV}} \tag{3.7}$$

$$SS = \frac{E_{SC}}{Q_{el}} \tag{3.8}$$

Where:

$$P_{PV} = \sum_{i=1}^{n=8760} P_{PV,i} \tag{3.9}$$

$$Q_{el} = \sum_{i=1}^{n=8760} Q_{el,i} \tag{3.10}$$

At this point, the distance of the SC-SS point from the point $Z: (SC = 1; SS = 1)$ was calculated.

$$dist = \sqrt{(1 - SC)^2 + (1 - SS)^2} \tag{3.11}$$

This procedure was repeated for all the different PV sizes chosen for the parametric analysis, changing every time the value of photovoltaic nominal power $P_{n,PV}$. So doing, a vector containing all the distances of the various SC-SS points from point Z was obtained. The minimum value of this vector corresponds to the minimum distance of a SC-SS point from the ideal point Z. This SC-SS point is the nearer one to the knee of the curve and it is the one corresponding to the best PV size (that maximizes both SC and SS) between the analyzed ones.

$$dist_{min} = \min\,(dist_1, dist_2, \dots, dist_k) \tag{3.12}$$

$$dist_{min} \rightarrow (SC_{opt}, SS_{opt}) \rightarrow P_{n,PV,opt} \tag{3.13}$$

k represents the number of evaluated PV sizes.

3.1.3 Economic evaluation

Once the capacity of the PV plant was established, the investment cost of the PV modules $I_{0,PV}$ had to be determined.

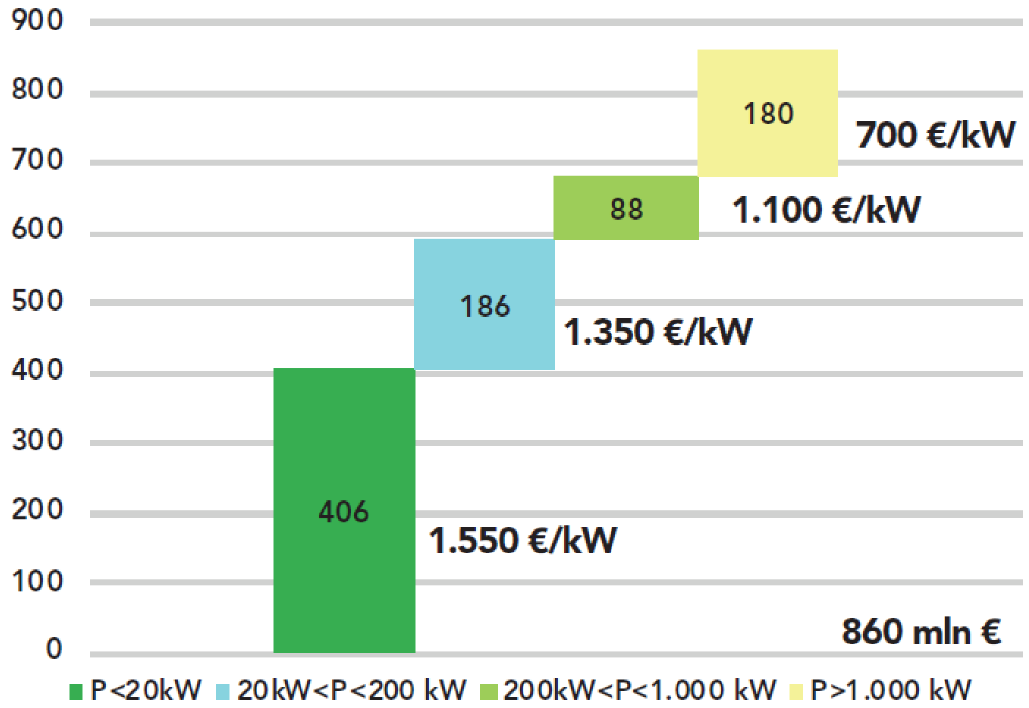

Figure 3.1 - Primary photovoltaic market in 2019 (mln €) [23]

Knowing the investment cost of different sizes of PV power plants, an estimation of the investment to made was done. The parametric analysis discussed in Paragraph 3.1.2 was performed on PV plants ranging from 20 to 35 kW. For this reason, in order to estimate the investment cost, a linear interpolation was carried out starting from the known costs shown in Figure 3.1. The chosen extreme values of the interpolation interval are shown in Table 3.2.

Symbol	Value	Parameter
$\boldsymbol{I_{0,PV1}}$	$1550\,\frac{€}{kWp}$	PV Power Plant 1 Investment Cost
$\boldsymbol{P_{n,PV1}}$	$20\ kW$	PV Power Plant 1 Nominal Power
$\boldsymbol{I_{0,PV2}}$	$1350\,\frac{€}{kWp}$	PV Power Plant 2 Investment Cost
$\boldsymbol{P_{n,PV2}}$	$200\ kW$	PV Power Plant 2 Nominal Power

Table 3.2 - Linear interpolation's extreme values

Performing the interpolation:

$$I_{0,PV} = I_{0,PV2} + \frac{\left(P_{n,PV} - P_{n,PV2}\right) \cdot \left(I_{0,PV1} - I_{0,PV2}\right)}{\left(P_{n,PV1} - P_{n,PV2}\right)} \tag{3.14}$$

$I_{0,PV}$ is the investment cost of the chosen PV plant, expressed in $\frac{€}{kWp}$. Multiplying it for the size of the plant, the value of the total investment $I_{0,PV,tot}$ in € is obtained.

$$I_{0,PV,tot} = I_{0,PV} \cdot P_{n,PV} \tag{3.15}$$

Before going on with the calculation, some data need to be introduced in order to fully understand the economic evaluation.

Symbol	Value	Parameter
$\boldsymbol{f_l}$	0.004	Yearly productivity loss factor
$\boldsymbol{d}$	0.05	Discount rate
$\boldsymbol{C_{O\&M}}$	$50\,\frac{€}{kWp}$	Operation and maintenance costs
$\boldsymbol{n_y}$	$200\ kW$	PV lifetime
$\boldsymbol{\eta_{PV}}$	0.15	PV efficiency

Table 3.3 - Useful PV data

As well as seen in Equation 3.15, the total operation and maintenance costs in € are obtained:

$$C_{O\&M,tot} = C_{O\&M} \cdot P_{n,PV} \tag{3.16}$$

At this point, the calculations shown in previous paragraph (from Equation 3.4 to Equation 3.10) were repeated, but this time for the entire PV lifetime n_y. The yearly worsening of PV production was taken into consideration adding to Equation 3.4 a loss term v_{loss} depending on the yearly productivity loss factor.

$$v_{loss} = 1 - f_l \cdot (y - 1), \qquad with\ y = 1, \dots, n_y \tag{3.17}$$

The term y represents the reference year. It means for the fist year $v_{loss} = 1$, for the second $v_{loss} = 1 - f_l$, for the third $v_{loss} = 1 - 2 \cdot f_l$, etc.

Using these factors, the yearly PV production profile P_{PV} was calculated year by year for the whole lifetime of the PV plant.

$$P_{PV} = \frac{G(t)}{G_{ref}} \cdot P_{n,PV} \cdot PR \cdot v_{loss} \tag{3.18}$$

As a consequence, all the values of parameters deriving from Equation 3.18 were also affected by v_{loss} and changed year by year. After evaluating P_{PV}, Equations from 3.4 to 3.10 were applied, obtaining P_{SC}, E_{SC}, SC and SS.

Reached this point, a clarification needs to be done. This scenario consists of a virtual collective self-consumption, and it means all the produced electricity is injected into the grid, while the consumed one is bought from the grid. The advantage is given by the energy communities incentives on the shared energy that are received.

Following these indications, the energy sold to the grid will equal the PV production, while the bought one will correspond to the whole electric load.

According to this reasoning, the economic value $C_{en,sold}$ of the energy sold to the grid was evaluated in Equation 3.19.

$$C_{en,sold} = P_{PV} \cdot C_s \tag{3.19}$$

$$C_{en,tot} = \sum_{i=1}^{n=8760} C_{en,sold,i} \tag{3.20}$$

$C_{en,tot}$ represents the yearly total revenue from the energy sale, while C_s is the hourly electricity zonal market price. The Italian subdivision consists of 6 different market zones: North, South, North-Center, South-Center, Sicily, Sardinia.

The total shared energy E_{shared} was evaluated summing, hour by hour, the minimum value between PV production and electric load Q_{el}.

$$E_{shared} = \sum_{i=1}^{n=8760} \min\,(P_{PV,i}; Q_{el,i}) \tag{3.21}$$

As seen in Paragraph 1.4, incentives on shared energy comprehend two different charges:

1. A unit price set by GSE, with a surplus for collective self-consumers.
2. A premium rate.

The first one is equal to $(7.61 + 0.61 + 1.3) = 9.52 \frac{€}{MWh}$ for low voltage utilities, while the second corresponds to $100 \frac{€}{MWh}$ for collective self-consumptioners. These incentives are guaranteed for 20 years [24].

$$Incentive1 = E_{shared} \cdot 9.52 \frac{€}{MWh} \tag{3.22}$$

$$Incentive2 = E_{shared} \cdot 100 \frac{€}{MWh} \tag{3.23}$$

With E_{shared} in MWh.

Thanks to these parameters, the yearly revenues R and the yearly costs C_y could be evaluated.

$$R = C_{en,tot} + Incentive1 + Incentive2 \tag{3.24}$$

$$C_y = c_{en} \cdot Q_{el} \tag{3.25}$$

The average price of electric energy bought from grid c_{en} was set to $0.22 \frac{€}{kWh}$.

This procedure is repeated for the whole lifetime n_y of the PV plant.

Another important evaluated parameter was $C_{y,ref}$, the reference yearly costs. They are the yearly costs incurred before the PV installation. In this particular case, it resulted to be the same as C_y, but only because the incentives were evaluated separately.

$$C_{y,ref} = c_{en} \cdot Q_{el} \tag{3.26}$$

At this point, the investment analysis could be completed calculating the values of Net Present Value (NPV), Internal Rate of Return (IRR), Payback Time (PBT) and Savings (C_{save}). "NPV is the difference between the present value of cash inflows and the present value of cash outflows over a period of time. It is used to find today's value of a future stream of payments" [25]. "IRR is a metric used in financial analysis to estimate the profitability of potential investments. It is a discount rate that makes the NPV of all cash flows equal to zero in a discounted cash flow analysis" [26] . "The term payback period refers to the amount of time it takes to recover the cost of an investment" [27].

$$CF = C_{y,ref} - C_y + R - C_{O\&M,tot} \tag{3.27}$$

$$NPV = -I_{0,PV,tot} + Inc_{PV} + \sum_{t=1}^{n_y} \frac{CF_t}{(1+d)^t} \tag{3.28}$$

$$C_{save} = [1 - \frac{mean(C_y - R + C_{O\&M,tot})}{C_{y,ref}}] \cdot 100 \tag{3.29}$$

Savings (C_{save}) represent the yearly saved money due to the installation of the PV system. The calculation was performed evaluating a yearly average of all the costs incurred during the 20 years of PV lifetime (subtracting incentives and earnings due to energy sold to the grid) and comparing this value with the reference yearly costs $C_{y,ref}$. A yearly average value of the costs needed to be calculated because the cash flows CF were evaluated yearly. Inc_{PV} is the incentive received for the installation of the PV plant. It covers 50% of the investment in the form of a tax deduction during the years or an immediate discount on the invoice. Obviously, in the case of discount on the invoice, a percentage of the incentive is held by the bank and for this reason the actual discount is lower, around 40% [28]. In this study, the discount on the invoice was chosen, as shown in equation 3.30.

$$Inc_{PV} = 0.4 \cdot I_{0,PV,tot} \tag{3.30}$$

The last two indicators to evaluate were IRR and PBT. For both evaluations, the procedure consisted in putting $NPV = 0$ and solving the equation as a function of the variable of interest. In the first case the variable of interest is the discount rate d, while in the second it is the time t, in years.

$$find\ \boldsymbol{d}\ \ s.t.\ NPV = 0 \tag{3.31}$$

$$find\ \boldsymbol{t}\ \ s.t.\ NPV = 0 \tag{3.32}$$

3.1.4 CO_2 emissions

The electric energy bought from the grid also generates CO_2 emissions. In fact, the emissions generated by the process of production of this energy must be taken into consideration. In this scenario, the positive impact of PV installation on environment was evaluated, trying to estimate the percentage of avoided CO_2 emissions with respect to the case with no photovoltaic production.

$$CO_{2_{save}}[\%] = (1 - \frac{e_{CO_2}}{e_{CO_2,rif}}) \cdot 100 \tag{3.33}$$

e_{CO_2} are the CO_2 emissions after the PV installation, while $e_{CO_2,rif}$ are the emissions of the reference case, without photovoltaic.

$$e_{CO_2} = EF_{grid} \cdot E_{net} \tag{3.34}$$

$$e_{CO_2,rif} = EF_{grid} \cdot Q_{el} \tag{3.35}$$

$EF_{grid} = 0.2763\ kgCO_2/kWh$ is the emission factor of electricity bought from the grid [29], while Q_{el} is the total yearly electric load, evaluated with Equation 3.10. E_{net} represents the net electric energy that generates emissions. It was calculated subtracting, hour by hour, the energy production from PV to the electricity consumption given by the electric load. So doing, it was possible to understand if, hour by hour, electricity was bought from grid or sold to it: in the first case CO_2 was being emitted, while in the second it was being saved.

$$E_{net} = \sum_{i=1}^{n=8760} Q_{el,i} - P_{PV,i} \tag{3.36}$$

Focusing on Equations 3.34 and 3.35, the emission factor of the grid is identical, and the same happens on both sides of the fraction of Equation 3.33. For this reason, the formulation could be simplified, and the percentage of avoided CO_2 emissions, in this particular case, resulted to be only dependent on the energy savings due to the photovoltaic installation.

$$CO_{2_{save}}[\%] = (1 - \frac{E_{net}}{Q_{el}}) \cdot 100 \tag{3.37}$$

3.2 Second Scenario: Heat pump installation

The second scenario presents an improvement: a heat pump is introduced in order to reduce the usage of the boiler (and to reduce the amount of burned fuel), switching part of the thermal load into electric. So doing, the decarbonization of consumptions is analyzed. In this scenario, the utilization of the heat pump is preferred: the boiler only works as a backup when the whole thermal load cannot be fulfilled by the heat pump and in the rare cases in which COP becomes too low because of extreme temperatures, causing a less efficient performance of the pump. Moreover, energy produced by PV can be used by the heat pump to fulfill the thermal load. In this case, as opposed to the first scenario, the utilization of the heat pump implies a part of physical collective self-consumption, which is not incentivized as the virtual one. The benefits given by the introduction of the heat pump are shown, thanks to the reduction of fuel consumption, that generates a positive effect in terms of energy savings, cost savings and environmental impact.

3.2.1 COP evaluation

The chosen heat pump was an ASHP (air source heat pump), more specifically an air to water heat pump. The decision was to follow a model able to evaluate the hourly variation of COP as a function of outside temperature. “Model-based flexibility assessment of a residential heat pump pool” by Fischer, Wolf, Wapler, Hollinger and Madani [30] and “Time series of heat demand and heat pump efficiency for energy system modeling” by Ruhnau, Hirth and Praktiknjo [31] were taken as reference. The first document was used to evaluate the value of maximum thermal capacity of the heat pump as a function of the source temperature, while from the second provided a model to evaluate the COP as a function of temperature. The variance of COP was showed using a quadratic regression [31]:

$$COP = \begin{cases} 6.08 - 0.09 \cdot \Delta T + 0.0005 \cdot \Delta T^2, & ASHP \\ 10.29 - 0.21 \cdot \Delta T + 0.0012 \cdot \Delta T^2, & GSHP \\ 9.97 - 0.20 \cdot \Delta T + 0.0012 \cdot \Delta T^2, & WSHP \end{cases} \tag{3.38}$$

$$\Delta T = T_{sink} - T_{source} \tag{3.39}$$

With ASHP=Air source heat pump, GSHP=Ground source heat pump, WSHP=Water source heat pump. The first equation (ASHP) was used for the study. Moreover, the heat sink temperatures were derived from ambient air temperature T_{source} [31]:

$$T_{sink} = \begin{cases} 40\ °C - 1.0 \cdot T_{source}, & radiator\ heating \\ 40\ °C - 0.5 \cdot T_{source}, & floor\ heating \end{cases} \tag{3.40}$$

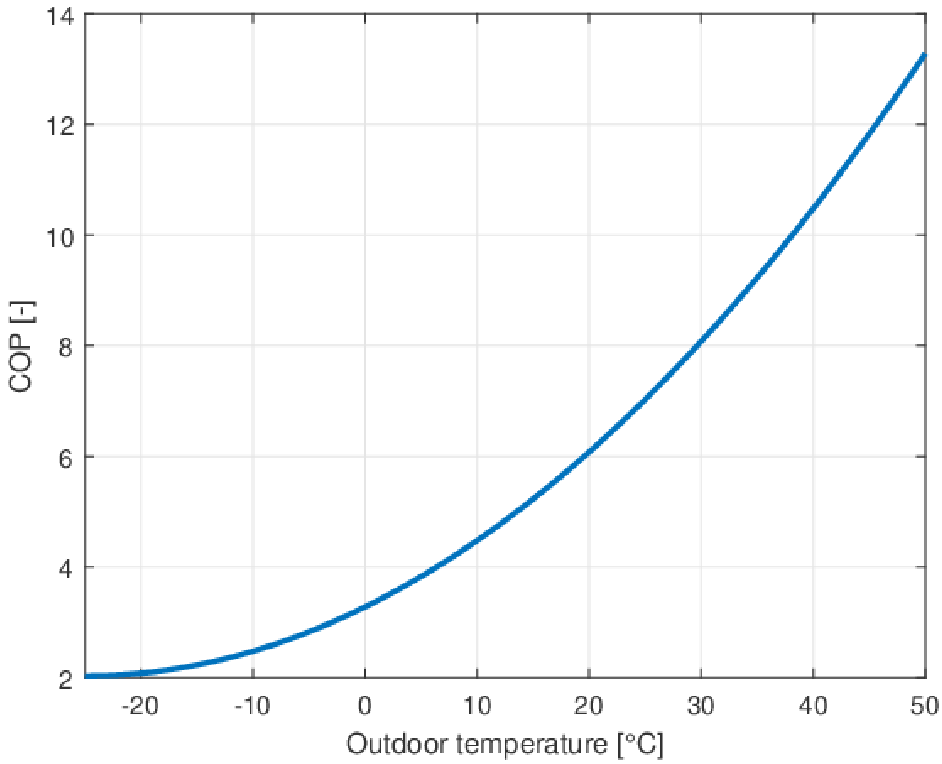

Figure 3.2 - COP variation with temperature

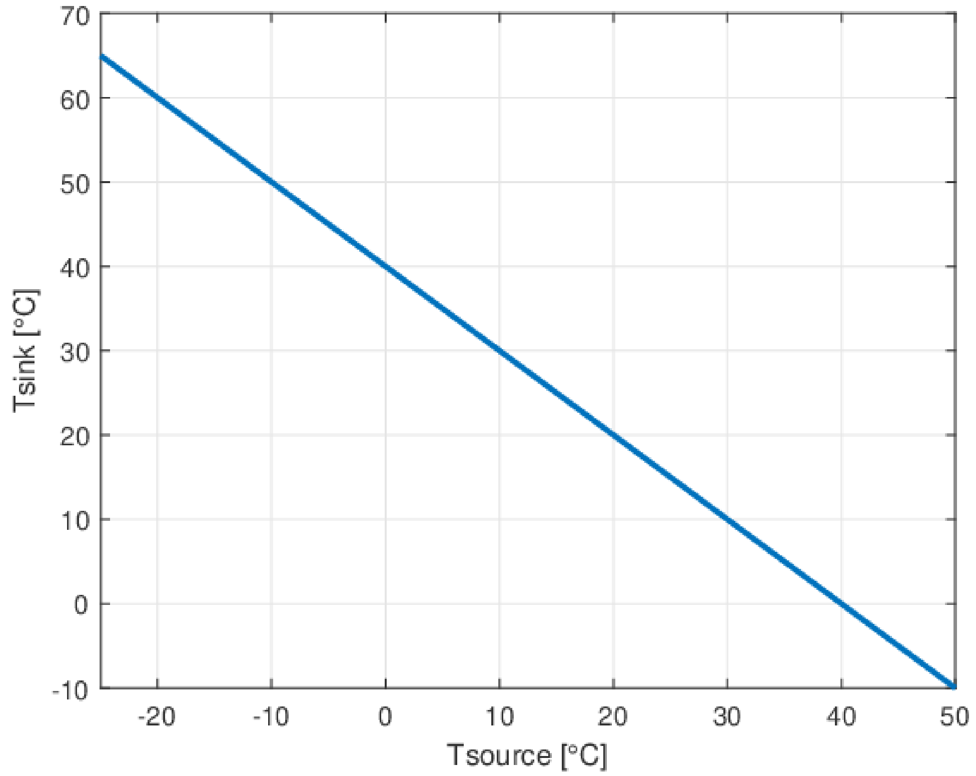

Figure 3.3 - Tsink dependance from outdoor temperature

So doing, starting from the outdoor temperature T_{source}, which hourly profile was a known data, the hourly COP profile for the whole year was evaluated.

3.2.2 Heat Pump maximal thermal capacity

The maximal thermal capacity of the heat pump $Q_{HP,max}$ was modelled linearly using the source temperature [30]:

$$Q_{HP,max} = a0 + a1 \cdot T_{source} \tag{3.41}$$

Coefficients a_0 and a_1 depend on the heat pump technology and were obtained using a least-square fit on HP data from manufacturers [30] [32].

Technology	a_0	a_1
ASHP	5.80	0.21
GSHP	9.37	0.30

Table 3.4 - Model coefficients used for the different heat pump technologies [30]

Starting from this information the model was applied to the study, correcting Equation 3.41 in order to scale the coefficients a_0 and a_1 for heat pumps with a higher thermal capacity. In fact, the study by Fischer et al. was intended for single residential houses, while in this thesis work it was adapted to a whole apartment building. The idea was to find the maximum needed thermal capacity of the building, based on the maximum thermal load during the colder period of the year. For this reason, the months of December and January were taken into consideration and the daily minimum temperature of the two months was evaluated. Starting from this temperature profile and repeating the procedure described in Chapter 2, the maximum needed thermal load was calculated. So doing, a thermal load profile containing the daily peak for each day of December and January was obtained. At this point, an average value of the minimum temperatures and maximum thermal load of the considered period was estimated.

$$T_{min,ave} = \sum_{i=1}^{n=62} T_{min,i} \tag{3.42}$$

$$Q_{max,ave} = \sum_{i=1}^{n=62} Q_{max,i} \tag{3.43}$$

$T_{min,i}$ is the daily minimum temperature, $Q_{max,i}$ indicates the daily thermal load peak and $n = 62$ is the total number of days of the chosen period (December and January).

Having calculated these values, maximum thermal capacity of the heat pump could be evaluated, using $T_{min,ave}$ as source temperature:

$$Q_{HP,max} = a0 + a1 \cdot T_{min,ave} \tag{3.44}$$

As mentioned before, this formulation with coefficients a_0 and a_1 refers to a relatively small heat pump and for this reason it was scaled considering the reference building actual thermal needs.

$$cost = \frac{Q_{max,ave}}{Q_{HP,max}} \tag{3.45}$$

$$Q_{HP,max,corr} = cost \cdot (a0 + a1 \cdot T_{source}) \tag{3.46}$$

So doing, the maximum thermal capacity of the heat pump as a function of the maximum thermal needs was evaluated.

3.2.3 COP limit

A lower limit on COP was set in order to understand when it is no more economically convenient to use the heat pump instead of the boiler. This limit value was evaluated comparing the production cost of 1 kWh of energy using respectively a heat pump and a boiler.

$$E_{HP} = \frac{c_{el}}{COP} \tag{3.47}$$

$$E_{boiler} = \frac{c_{methane}}{H_i \cdot \eta_b} \tag{3.48}$$

The heat pump is no more convenient when $C_{HP} > C_{boiler}$. Starting from this relation the limit value of COP was calculated.

$$E_{HP} > E_{boiler} \rightarrow \frac{c_{el}}{COP} > \frac{c_{methane}}{H_i \cdot \eta_b} \rightarrow COP < \frac{c_{el}}{c_{methane}} \cdot H_i \cdot \eta_b \tag{3.49}$$

$$COP_{lim} = \frac{c_{el}}{c_{methane}} \cdot H_i \cdot \eta_b \tag{3.50}$$

Symbol	Value	Parameter
$\boldsymbol{c_{el}}$	$20\,\frac{c€}{kWh}$	Average cost of electric energy bought from grid
$\boldsymbol{H_i}$	$9.94\,\frac{kWh}{m^3}$	Methane lower heating value
$\boldsymbol{\eta_b}$	0.9	Boiler efficiency
$\boldsymbol{Q_{th}}$		Annual thermal load
$\boldsymbol{c_{methane}}$		Methane selling price

Table 3.5 - Useful data

The value of methane selling price was estimated thanks to the data downloaded from ARERA website and will be discussed in next paragraph.

3.2.4 Methane consumption

For the calculation of COP_{lim}, $c_{methane}$ (which depends on the annual consumption $S_{methane}$ in m^3) had to be evaluated.

$$S_{methane} = \frac{Q_{th,boiler}}{H_i \cdot \eta_b} \tag{3.51}$$

$$c_{methane} = selling\ price + taxes \tag{3.52}$$

$$taxes = normal\ excise\ duty + regional\ additional + VAT \tag{3.53}$$

Annual consumption $[m^3]$	< 5000	$5000 - 50000$	$50000 - 200000$	$200000 - 2000000$	> 2000000
Selling price $[\frac{c€}{m^3}]$	57.1	52.4	48.9	40.8	39.1

Table 3.6 - Selling prices for methane condominiums for domestic use 2019 [33]

The values of taxes were downloaded from ARERA database, referring to a domestic use with a yearly consumption higher than $1560\ m^3$. The normal excise duty is equal to $18.6\ \frac{c€}{m^3}$ for domestic use with a yearly consumption higher than $1560\ m^3$. For the regional additional an average between all the values was chosen, with a result of $2.49577\ \frac{c€}{m^3}$. The value of VAT is set to 22% in Italy [34].

$$VAT = (selling\ price + normal\ excise\ duty + regional\ additional) \cdot 0.22 \tag{3.54}$$

At this point, the total expenses deriving from methane consumption could be calculated.

$$C_{methane} = S_{methane} \cdot c_{methane} \tag{3.55}$$

3.2.5 Heat pump and Boiler operation conditions

If, in particular conditions (e.g., when the external temperature becomes too low), the performance of the heat pump worsens a lot ($COP < COP_{lim}$), the switch from heat pump to boiler is made. But it is not the only occasion in which the boiler is put into operation. In fact, in the case in which $COP > COP_{lim}$, the heat pump works alone only if its maximal thermal capacity $Q_{HP,max,corr}$ is higher than the thermal load demand Q_{th}. If $Q_{HP,max,corr} < Q_{th}$ the heat pump covers its maximum thermal capacity, while the backup boiler is operated to satisfy the remaining thermal load. A general summary is presented as follows.

Operation conditions	Operating plant
$\boldsymbol{COP > COP_{lim}}$ $\boldsymbol{Q_{HP,max,corr} > Q_{th}}$	Heat pump only
$\boldsymbol{COP > COP_{lim}}$ $\boldsymbol{Q_{HP,max,corr} < Q_{th}}$	Heat pump + Boiler
$\boldsymbol{COP < COP_{lim}}$	Boiler only

Table 3.7 – Heat pump and boiler operation conditions

As shown in Table 3.7, priority was given to the heat pump. In this way, a big part of the thermal load was switched into electric, providing both economic and environmental benefits.

$$Q_{th,HP} = Q_{th,tot} - Q_{th,boiler} \tag{3.56}$$

$$Q_{el,HP} = \frac{Q_{th,HP}}{COP} \tag{3.57}$$

$$Q_{el,tot} = Q_{el} + Q_{el,HP} \tag{3.58}$$

Depending on the maximum values of hourly thermal loads $Q_{th,HP}$ and $Q_{th,boiler}$, the needed size of heat pump and boiler was chosen.

$$P_{HP} = \max\,(Q_{th,HP}) \tag{3.59}$$

$$P_{boiler} = \max\,(Q_{th,boiler}) \tag{3.60}$$

3.2.6 PV sizing

The sizing of the PV system followed the same procedure presented in Paragraph 3.1.1 and 3.1.2, using the same equations (from Equation 3.1 to Equation 3.13). The difference between the two cases consisted in the electric load, which was higher in second one because of the installation of the heat pump, that switched part of the thermal load into electric. For this reason, the PV sizes of the two different scenarios resulted to be different.

3.2.7 Economic evaluation

The economic evaluation of second scenario followed the one performed for the first case in Paragraph 3.1.3, but with some differences. The introduction of a heat pump shared by the inhabitants of the whole building led to a part of physical collective self-consumption, that is not incentivized. For this reason, some calculations differed from the ones seen in Paragraph 3.1.3. The differences consisted in the amount of energy sold to the grid $C_{en,sold}$ (Equation 3.19), the shared energy E_{shared} (Equation 3.21), the yearly costs C_y (Equation 3.25) and the reference yearly costs $C_{y,ref}$ (Equation 3.26). In this case, being the collective self-consumption physical, the energy produced from the photovoltaic plant was not necessarily sold to the grid, but it tried to meet the heat pump electric demand. If the PV production was higher than the heat pump electric load, the surplus energy was sold to the grid.

$$C_{en,sold} = \begin{cases} \left(P_{PV} - Q_{el,HP}\right) \cdot C_s \,, & if\ P_{PV} > Q_{el,HP} \\ 0 \,, & if\ P_{PV} < Q_{el,HP} \end{cases} \tag{3.61}$$

$$C_{en,tot} = \sum_{i=1}^{n=8760} C_{en,sold,i} \tag{3.62}$$

For this reason, also the value of shared energy E_{shared} changed:

$$E_{shared} = \begin{cases} \displaystyle\sum_{i=1}^{n=8760} \min\left(P_{PV,i} - Q_{el,HP,i}; Q_{el,i}\right) \,, & if\ P_{PV} > Q_{el,HP} \\ 0 \,, & if\ P_{PV} < Q_{el,HP} \end{cases} \tag{3.63}$$

The same happened for C_y and $C_{y,ref}$ with the adding of methane costs.

$$C_y = \begin{cases} C_{en} \cdot Q_{el} + S_{methane} \cdot c_{methane} & , if\ P_{PV} > Q_{el,HP} \\ C_{en} \cdot Q_{el} + C_{en} \cdot \left(Q_{el,HP} - P_{PV}\right) + S_{methane} \cdot c_{methane} & , if\ P_{PV} < Q_{el,HP} \end{cases} \quad (3.64)$$

$$C_{y,ref} = C_{en} \cdot Q_{el} + S_{methane,rif} \cdot c_{methane} \quad (3.65)$$

It is important to notice that $S_{methane}$ represents the m^3 of methane consumed after the installation of the heat pump, while $S_{methane,rif}$ indicates the consumption before the installation, with the whole thermal load satisfied using the boiler.

Passing to the investment analysis, the same approach as first scenario was followed too. The only difference consisted in the presence of an extra-investment, due to the installation of the heat pump and to the consequent plant upgrade. The unit investment cost for the heat pump was $I_{0,HP} = 700\ €/kWh_{th}$, the plant upgrade cost $c_{pu} = 30\ €\backslash m^2$, and the total floor heating area $S_{f,h} = 2181\ m^2$ (from calculations showed in Chapter 2). So, the total investment cost was calculated.

$$I_{0,HP,tot} = I_{0,HP} \cdot P_{HP} + c_{pu} \cdot S_{f,h} \quad (3.66)$$

As in the case of PV, an incentive for the heat pump installation was received. This time it was higher (65% of the investment in the form of a tax deduction during the years) and again with the possibility of an immediate discount on the invoice. In this case, the incentive passed from 65% to 52% [28]. The chosen one was the immediate discount.

$$Inc_{HP} = 0.52 \cdot I_{0,HP,tot} \quad (3.67)$$

Differently from the PV incentive, the heat pump one had some limitations. In fact, the heat pumps to be installed had guarantee a minimum value of COP, depending on the technology. The values are summarized in Table 3.8.

Heat pump type (External/Internal)	**External Environment [°C]**	**Internal Environment [°C]**	**COP**
Air/air	Inlet dry bulb: 7 Outlet wet bulb: 6	Inlet dry bulb: 20 Outlet wet bulb: 15	3.9
Air/water Useful thermal power for heating $\leq 35kW$	Inlet dry bulb: 7 Outlet wet bulb: 6	Inlet temperature: 30 Outlet temperature: 35	4.1
Air/water Useful thermal power for heating $> 35kW$	Inlet dry bulb: 7 Outlet wet bulb: 6	Inlet temperature: 30 Outlet temperature: 35	3.8
Brine/air	Inlet temperature: 0	Inlet dry bulb: 20 Outlet wet bulb: 15	4.3
Brine/water	Inlet temperature: 0	Inlet dry bulb: 30 Outlet wet bulb: 35	4.3
Water/air	Inlet temperature: 10 Outlet temperature: 7	Inlet dry bulb: 20 Outlet wet bulb: 15	4.7
Water/water	Inlet temperature: 10	Inlet dry bulb: 30 Outlet wet bulb: 35	5.1

Table 3.8 - Minimum COP for electric heat pumps [35]

The model of interest is the air/water one. As can be noticed in Figures 3.2 and 3.3, the minimum COP at the fixed internal and external temperatures was respected. For this reason, the incentive was applicable to the investment.

At this point, in the calculation of Net Present Value (NPV) the investment cost of heat pump and the influence of the incentive had to be added.

$$NPV = -I_{0,PV,tot} + Inc_{PV} - I_{0,HP,tot} + Inc_{HP} + \sum_{t=1}^{n_y} \frac{CF_t}{(1+d)^t} \tag{3.68}$$

The evaluation of Internal Rate of Return (IRR), Payback Time (PBT) and Savings (C_{save}) was identical, following Equations 3.27, 3.29, 3.31 and 3.32.

3.2.8 CO_2 emissions

The CO_2 emissions of second scenario were evaluated following the same reasoning seen in Paragraph 3.1.4, but with some differences due to the installation of the heat pump. In fact, in first scenario, the percentage of saved emissions was only calculated basing on the electric energy production. In this case, the thermal part contributed too, with the comparison between the reference situation with the whole thermal load satisfied by a methane boiler and the new one in which a big part of the thermal load was switched into electric by the heat pump. For this reason, the CO_2 emission savings included the positive effect given by both the PV and heat pump installation.

$$CO_{2_{save}}[\%] = (1 - \frac{e_{CO_2}}{e_{CO_2,rif}}) \cdot 100 \tag{3.69}$$

This formulation is the same used in Equation 3.33, but the terms e_{CO_2} and $e_{CO_2,rif}$ vary because of the addiction of the emission released to satisfy the thermal load.

$$e_{CO_2} = E_{net} \cdot EF_{grid} + S_{methane,new} \cdot H_i \cdot EF_{methane} \tag{3.70}$$

$$e_{CO_2,rif} = Q_{el} \cdot EF_{grid} + S_{methane,rif} \cdot H_i \cdot EF_{methane} \tag{3.71}$$

$EF_{methane} = 0.202\ kgCO_2\backslash kWh$ [36]. It is intended to be kWh of primary energy, for this reason the methane consumption $S_{methane}$ $[m^3]$ needed to be multiplied by methane's lower heating value H_i. $S_{methane,rif}$ represents the methane consumption of the reference scenario (only boiler, no heat pump), while $S_{methane,new}$ takes into account the presence of the heat pump, that reduces the methane consumption. In this case, differently from previous scenario, E_{net} also comprehends the electric consumption of the heat pump.

$$E_{net} = \sum_{i=1}^{n=8760} Q_{el,i} + Q_{el,HP,i} - P_{PV,i} \tag{3.72}$$

Q_{el} represents the electric load of the utilities of the private apartments, while $Q_{el,HP}$ is the electric load of the installed heat pump

4. Results

Following the procedure described in Chapters 2 and 3, all the results were obtained and they were shown in this chapter. The whole simulation was performed for all the points on the Italian map, with a distance of 2.5 km between each point. In order not to be repetitive, not all the results were showed in graphical form. The decision was to present thermal load, CO_2 savings and PBT in graphical form and the rest of the indicators in tabular form, stressing for each indicator the maximum, minimum, average value and standard deviation on a regional scale. For the graphical results, the attention was focused on whole Italy and on three specific regions. Later, the attention was focused on three different cities, showing what happened in those exact points. The decision was to choose a region in the North, a region in the Center and another one in Southern Italy (Piemonte, Lazio, Calabria). All the calculations were carried out for the thermal load part and for both the analyzed scenarios.

4.1 Thermal Load

As explained in detail in Chapter 2, total yearly thermal load, degree days and climate zone were evaluated. A summary of the results is shown in following paragraphs.

4.1.1 National scale

The results on national scale were presented. The values of degree days and climate zones of the Italian regions were shown in tabular form, while the thermal load was presented both in graphical and tabular form.

Thermal Load

Region	Yearly thermal load [MWh]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	250	851	104	118
Basilicata	219	796	61	68
Calabria	143	332	31	76
Campania	196	836	56	96
Emilia-Romagna	314	963	176	169
Friuli-Venezia Giulia	363	984	188	212
Lazio	185	892	61	92
Liguria	262	888	70	157
Lombardia	328	940	194	124
Marche	266	905	119	115
Molise	255	829	110	103
Piemonte	339	953	202	142
Puglia	161	798	61	69
Sardegna	153	863	29	81
Sicilia	131	336	29	61
Toscana	260	948	61	161
Trentino-Alto Adige	404	925	187	211
Umbria	288	866	132	103
Valle d'Aosta	527	883	294	248
Veneto	306	979	140	112

Table 4.1 - Yearly thermal load [MWh] of Italian regions

As it can be easily noticed, the average values varied a lot from region to region, most of all comparing Southern Italy regions with Northern ones. However, maximum values were quite similar. This happened because the peaks were reached in points with a high altitude, that were present almost in each region. All the points with an altitude higher than 850 meters were excluded from the study, reducing this effect, but the ones near this limit value still presented peaks. For this reason, the best indicator to follow is the regional average value.

The results were also showed on a national map, in Figure 4.3. All the points with an altitude higher than 850 meters were excluded from the simulation and highlighted in grey.

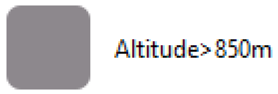

Figure 4.1 - Excluded points

For the rest of the points, a continuous color scale was chosen, by assigning to each color a value of thermal load. It means, not only the five showed colors were used, but also a middle ground between them for values that were different from the reference ones.

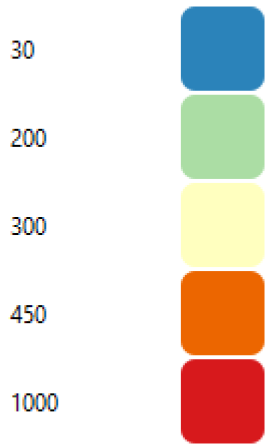

Figure 4.2 - Reference legend values/colors [MWh]

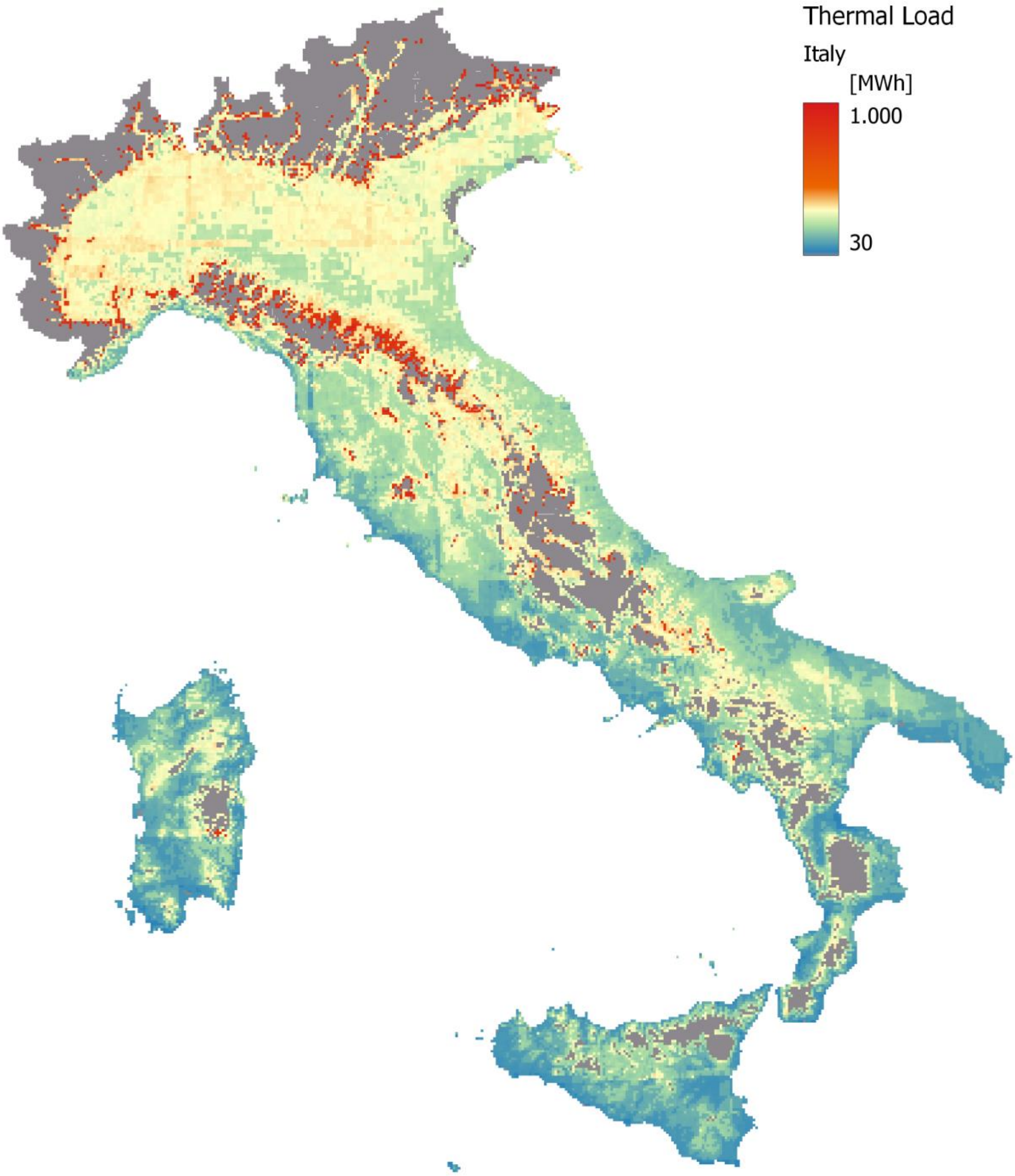

Figure 4.3 - Italian Thermal Load

As it can be clearly noticed from Figures 4.2 and 4.3, and from Table 4.1, the majority of regions presented an average thermal load around 200 or 300 MWh, also lower for the hottest regions. However, the legend had to reach the value of 1000 MWh because of the peaks, mostly reached in the points just above the fixed limit of 850 m.

Degree Days

Region	Degree days [gg]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	2061	3521	952	504
Basilicata	1934	3042	672	457
Calabria	1355	2928	448	588
Campania	1725	3292	623	614
Emilia-Romagna	2302	3971	1404	428
Friuli-Venezia Giulia	2441	4083	1548	477
Lazio	1657	3412	646	586
Liguria	2035	3668	811	658
Lombardia	2430	3943	1577	305
Marche	2141	3773	1172	421
Molise	2128	3222	996	490
Piemonte	2489	3880	1657	325
Puglia	1491	3136	625	489
Sardegna	1424	3292	416	605
Sicilia	1275	2788	470	482
Toscana	2032	3818	623	589
Trentino-Alto Adige	2634	3850	1511	412
Umbria	2319	3401	1256	346
Valle d'Aosta	2929	3546	2372	284
Veneto	2326	3970	1350	312

Table 4.2 - Degree days [gg] of Italian regions

Also in this case, a clear difference between Northern and Southern regions was highlighted. The similarity between maximum values was again related to the points with an altitude near to the set limit.

Climate zones

Region	Climate Zones			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	4	6	3	0.67
Basilicata	4	6	2	0.72
Calabria	3	5	1	1.1
Campania	4	6	2	1.01
Emilia-Romagna	5	6	4	0.63
Friuli-Venezia Giulia	5	6	4	0.61
Lazio	4	6	2	0.96
Liguria	4	6	2	0.92
Lombardia	5	6	4	0.4
Marche	5	6	3	0.58
Molise	4	6	3	0.61
Piemonte	5	6	4	0.4
Puglia	4	6	2	0.85
Sardegna	3	6	1	1.05
Sicilia	3	5	1	0.96
Toscana	4	6	2	0.86
Trentino-Alto Adige	5	6	4	0.52
Umbria	5	6	3	0.49
Valle d'Aosta	5	6	5	0.5
Veneto	5	6	3	0.45

Table 4.3 - Climate zones of Italian regions

The Italian convention indicates each climate zone with a letter. However, for the calculation it was necessary to use numbers. Each number corresponded to a letter, as showed in Table 4.4.

Number	Climate zone
1	**A**
2	**B**
3	**C**
4	**D**
5	**E**
6	**F**

Table 4.4 - Climate zones letters and numbers

Focusing on Table 4.3, the situation is similar to the one of previous indicators: the best indicator is the average value. Following the Italian model, a climate zone should be assigned to each Municipality, but in the studied case the situation is different. A climate zone has been assigned to each analyzed point on the Italian map and it means points with a distance of 2.5 km between each other. For this reason, almost in every region climate zone F is present: it is referred to mountain points with an altitude near to 850 meters and not to a whole municipality.

4.1.2 Piemonte

The regional results are summarized in Table 4.5.

Parameter	Average	Maximum	Minimum	Standard deviation
Thermal Load [MWh]	339	953	202	142
Degree Days	2489	3880	1657	325
Climate Zone	5	6	4	0.4

Table 4.5 - Piemonte's thermal part results

In this context, a graphical focus on the thermal load was done.

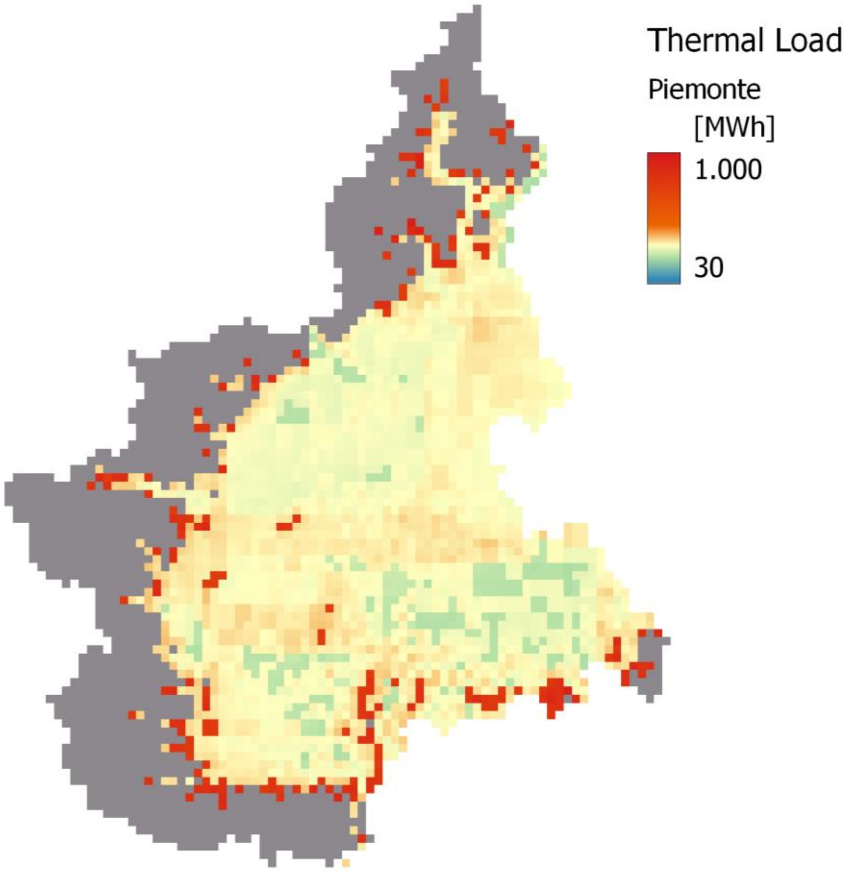

Figure 4.4 - Piemonte's Thermal Load

The decision was to keep the same legend reference values used in the national display also for the single regions, in order to better highlight the difference between them. As mentioned in previous paragraph, the peaks of thermal load are situated near the excluded points, at an altitude slightly lower than the chosen limit.

4.1.3 Lazio

The regional results are summarized in Table 4.6.

Parameter	Average	Maximum	Minimum	Standard deviation
Thermal Load [MWh]	185	892	61	92
Degree Days	1657	3412	646	586
Climate Zone	4	6	2	0.96

Table 4.6 – Lazio's thermal part results

As seen in Piemonte's case, a graphical focus on thermal load was done.

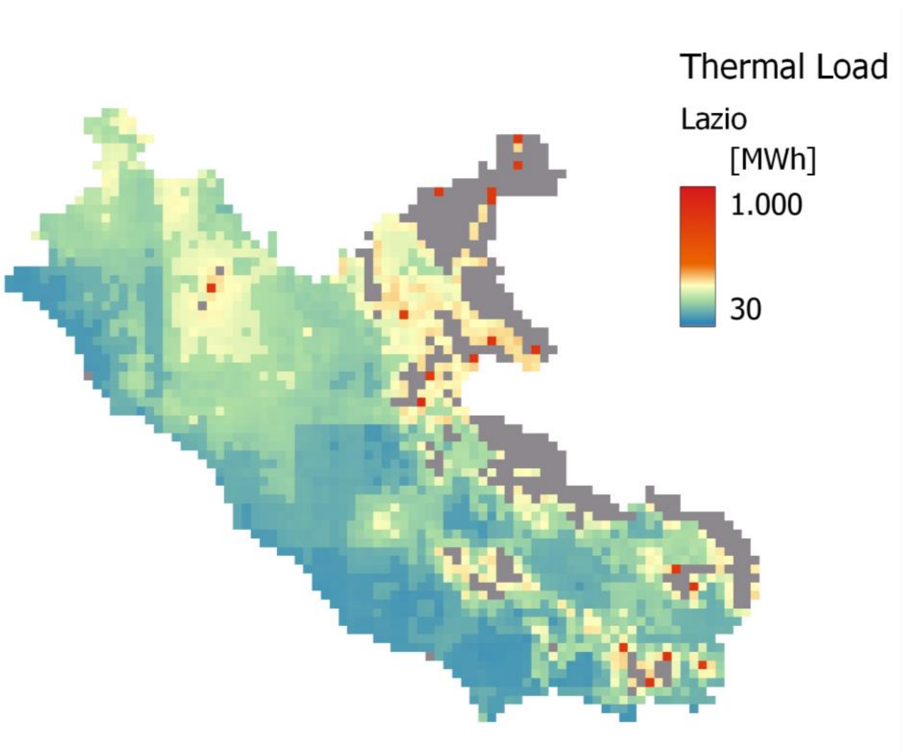

Figure 4.5 - Lazio's Thermal Load

Maintaining the same scale it is easy to understand how the average value of the thermal load is really lower than Piemonte's one. However, the maximum values of the two regions are comparable and this is not a surprise, In fact, for the reason explained before, these peak points are situated at an altitude near 850 m, and this is the same for each Italian region.

4.1.4 Calabria

The regional results are summarized in Table 4.7.

Parameter	Average	Maximum	Minimum	Standard deviation
Thermal Load [MWh]	143	332	31	76
Degree Days	1355	2928	448	588
Climate Zone	3	5	1	1.1

Table 4.7 – Calabria's thermal part results

The graphical focus on thermal load shows the big difference in terms of thermal needs between a region located in Southern Italy and a Northern one (always excluding the points over 850 meters of altitude).

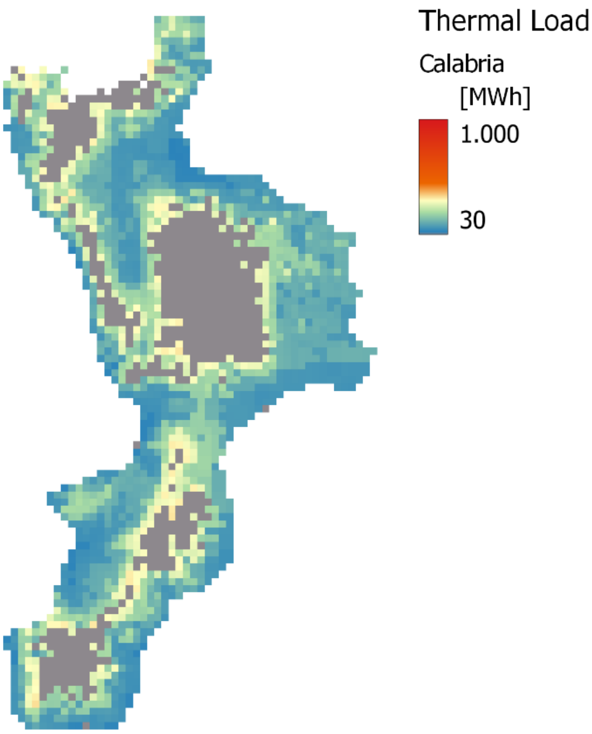

Figure 4.6 - Calabria's Thermal Load

In this case, using the same legend as before helps underlining the difference between the various regions. In Calabria, the orange value (450 MWh) is never reached, not even close. It means that not only the average thermal load is lower than Lazio's and most of all Piemonte's one, but there is a very big difference on the maximum load too. In fact, the red peaks, near to 1000 MWh, are never reached, not even in proximity of the excluded points.

4.2 First Scenario

As detailed in Chapter 3.1, first scenario presented the installation of a PV plant. The most significant results are shown as follows. Regarding the choice of the PV capacity, the values of PV size and corresponding SC and SS were shown. For the economic part, Cost savings, Internal Rate of Return, Net Present Value and Payback Time were presented. Finally, the CO_2 savings with respect to the reference case (without PV) were displayed. PBT and the amount of saved CO_2 were also showed in graphical form.

4.2.1 National scale

PV size

Region	PV size [kW]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	33	35	28	1.42
Basilicata	31	35	26	1.29
Calabria	30	35	26	1.91
Campania	31	35	26	1.79
Emilia-Romagna	34	35	31	0.66
Friuli-Venezia Giulia	35	35	32	0.56
Lazio	31	35	25	1.48
Liguria	33	35	27	1.86
Lombardia	34	35	29	0.75
Marche	34	35	30	1.16
Molise	32	35	28	1.27
Piemonte	35	35	31	0.46
Puglia	30	34	27	1.36
Sardegna	30	34	25	1.26
Sicilia	28	34	25	1.37
Toscana	33	35	27	1.53
Trentino-Alto Adige	34	35	28	1.35
Umbria	33	35	29	1.15

Valle d'Aosta	35	35	32	0.9
Veneto	34	35	31	0.86

Table 4.8 – PV size of Italian regions [kW] (First Scenario)

The maximum value of PV capacity was reached almost in every region. This happened because of the limitation given by the rooftop size, which prevented the plant from reaching a higher power. However, the regional average of 35 kW was only reached in the regions with the lowest annual irradiance values.

SC

Region	SC			
	Average	**Maximum**	**Minimum**	**Standard Deviation**
Abruzzo	0.81	0.88	0.79	0.01
Basilicata	0.81	0.84	0.79	0.01
Calabria	0.82	0.85	0.78	0.01
Campania	0.81	0.86	0.79	0.01
Emilia-Romagna	0.81	0.9	0.79	0.02
Friuli-Venezia Giulia	0.82	0.95	0.79	0.02
Lazio	0.81	0.86	0.79	0.01
Liguria	0.82	0.88	0.79	0.02
Lombardia	0.81	0.93	0.79	0.02
Marche	0.8	0.88	0.79	0.01
Molise	0.81	0.84	0.79	0.01
Piemonte	0.81	0.94	0.79	0.02
Puglia	0.81	0.84	0.79	0.01
Sardegna	0.82	0.86	0.79	0.01
Sicilia	0.82	0.86	0.78	0.01
Toscana	0.81	0.87	0.79	0.01
Trentino-Alto Adige	0.84	0.96	0.81	0.03
Umbria	0.81	0.84	0.79	0.01
Valle d'Aosta	0.85	0.93	0.81	0.02
Veneto	0.81	0.96	0.79	0.02

Table 4.9 – Self-Consumption index (SC) of Italian regions (First Scenario)

SS

Region	SS			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	0.33	0.35	0.26	0.01
Basilicata	0.34	0.35	0.28	0.01
Calabria	0.34	0.35	0.26	0.01
Campania	0.33	0.35	0.24	0.01
Emilia-Romagna	0.33	0.34	0.25	0.01
Friuli-Venezia Giulia	0.32	0.33	0.2	0.02
Lazio	0.34	0.35	0.24	0.01
Liguria	0.33	0.36	0.26	0.02
Lombardia	0.33	0.35	0.19	0.01
Marche	0.33	0.35	0.24	0.01
Molise	0.34	0.35	0.26	0.01
Piemonte	0.34	0.35	0.23	0.01
Puglia	0.34	0.35	0.28	0
Sardegna	0.35	0.37	0.26	0.01
Sicilia	0.35	0.36	0.26	0.01
Toscana	0.34	0.35	0.25	0.01
Trentino-Alto Adige	0.31	0.34	0.22	0.03
Umbria	0.33	0.35	0.26	0.01
Valle d'Aosta	0.31	0.34	0.28	0.02
Veneto	0.33	0.34	0.2	0.01

Table 4.10 – Self-Sufficiency index (SS) of Italian regions (First Scenario)

As explained in detail in Paragraph 3.1.2, the size of PV was chosen as a function of SS and SC. Table 4.9 and 4.10 show these values on a national scale.

Cost Savings

Region	Cost Savings [%]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	18.67	20.01	13.19	1.02
Basilicata	18.68	19.9	14.5	0.67
Calabria	18.85	20.36	12.9	1.05
Campania	19	20.74	11.24	1.05
Emilia-Romagna	17.97	19.22	12.05	0.78
Friuli-Venezia Giulia	17.04	18.66	7.77	1.74
Lazio	19.47	20.78	11.44	1
Liguria	17.95	20.93	13.05	1.37
Lombardia	17.8	19.59	7.13	1.1
Marche	18.35	19.96	11.66	1.09
Molise	18.49	19.54	13.02	0.79
Piemonte	18.59	19.94	9.08	1.16
Puglia	19.18	20.03	14.5	0.4
Sardegna	20.1	21.74	13.91	0.87
Sicilia	21.35	22.6	14.96	0.87
Toscana	18.96	20.95	12.57	1.16
Trentino-Alto Adige	16.33	19.39	8.57	2.18
Umbria	18.85	20.11	13.02	0.9
Valle d'Aosta	16.35	18.93	13.35	1.44
Veneto	17.83	19.06	7.13	1.09

Table 4.11 – Cost Savings [%] of Italian regions (First Scenario)

Table 4.11 show the average yearly cost savings of the 20 years after the installation with respect to the reference case without PV. The average value of the various regions resulted to be quite similar, but the regions with a higher irradiance (south and islands) benefited more from the installation.

PBT

Region	Payback time [years]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	8.2	13.4	6.7	0.9
Basilicata	7.6	11.4	6.3	0.6
Calabria	7.2	11.8	5.6	0.9
Campania	7.6	18.1	5.8	0.9
Emilia-Romagna	9.1	15.9	7.9	0.7
Friuli-Venezia Giulia	10.1	32.7	8	2.2
Lazio	7.3	13.9	6	0.7
Liguria	8.8	14.3	6.3	1.1
Lombardia	9.2	37.1	8.2	1.1
Marche	8.8	16.1	7	0.9
Molise	8.1	13.1	6.8	0.7
Piemonte	8.8	25.8	7.9	1
Puglia	7.2	10	6	0.5
Sardegna	6.7	9.9	5.4	0.5
Sicilia	5.9	9.5	4.8	0.5
Toscana	8.2	15.1	6.1	1
Trentino-Alto Adige	10.5	28.2	7.8	2.9
Umbria	8.1	13.8	6.9	0.7
Valle d'Aosta	10.4	13.7	7.7	1.3
Veneto	9.1	37.2	7.8	1.4

Table 4.12 – Payback time [years] for each Italian region (First Scenario)

Also in the case of payback time, regions with an higher value of yearly irradiance resulted to have advantages with respect to the others. There were some extreme points, in northern regions, in which PBT was too high. These points were shaded zones hidden behind mountainous elevations and for this reason the investment resulted to be not convenient.

Payback time was also showed in graphical form on the Italian map of Figure 4.7.

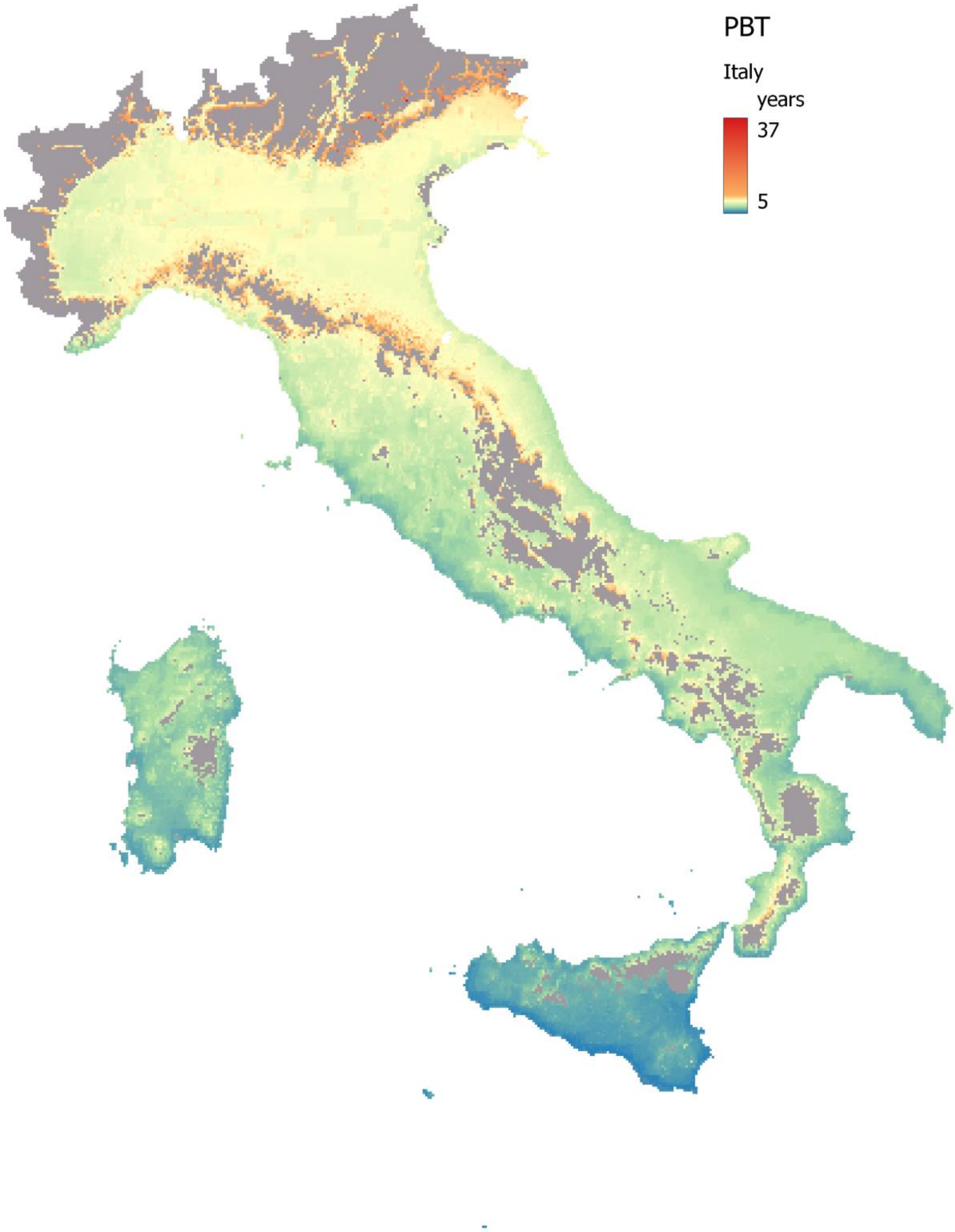

Figure 4.7 – Italian Payback Time (First Scenario)

The chosen legend is shown in Figure 4.8.

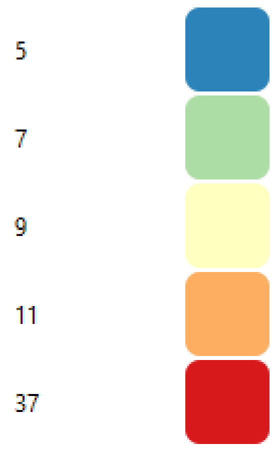

Figure 4.8 - Reference legend values/colors [years]

The values of the legend were not equally distributed for the reason explained before. There were few shaded points in which payback time increased a lot and these points were showed in red. Moreover, as already explained in Figure 4.1, the grey areas represent zones with an altitude higher than 850 meters.

IRR

Region	IRR [%]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	8.72	11.37	3.06	1.36
Basilicata	9.6	12.6	4.62	1.11
Calabria	10.46	14.41	4.27	1.75
Campania	9.74	13.83	0.68	1.59
Emilia-Romagna	7.23	8.99	1.6	0.79
Friuli-Venezia Giulia	6.26	8.79	-3.27	1.67
Lazio	10.28	13.31	2.75	1.4
Liguria	7.73	12.42	2.51	1.63
Lombardia	7.12	8.45	-4.11	0.97
Marche	7.77	10.78	1.53	1.23
Molise	8.77	11.29	3.29	1.08
Piemonte	7.63	8.96	-1.68	1.03
Puglia	10.5	13.43	6.04	1.07
Sardegna	11.58	15.07	6.13	1.26
Sicilia	13.74	17.46	6.71	1.5
Toscana	8.68	12.95	2.04	1.56
Trentino-Alto Adige	5.99	9.19	-2.28	2.14
Umbria	8.81	10.91	2.84	1.03
Valle d'Aosta	5.75	9.29	2.83	1.37
Veneto	7.26	9.24	-4.11	1.14

Table 4.13 - Internal rate of return for each Italian region (First Scenario)

IRR followed the same logic as PBT. The really low irradiance of shaded points caused IRR to be negative in that particular area. It means the sum of the post-investment cash flows was less than the initial investment and for this reason the investment was not worth in that point.

NPV

Region	NPV [k€]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	26.5	32.8	8.9	3.8
Basilicata	28	34.5	13.8	2.7
Calabria	29.6	37.2	12.4	4.2
Campania	28.7	37	2	3.9
Emilia-Romagna	22.8	27.1	4.7	2.5
Friuli-Venezia Giulia	19.7	26.3	-8.5	5.4
Lazio	30.3	36.6	7.1	3.6
Liguria	23.7	35.8	7.4	4.6
Lombardia	22.4	27.3	-10.5	3.2
Marche	24.3	32	4.5	3.7
Molise	26.4	31.6	9.9	2.9
Piemonte	24.4	28.5	-4.5	3.5
Puglia	30.2	35.7	16.3	2.2
Sardegna	33.3	40.6	16.6	3.1
Sicilia	38.4	44.5	19.1	3.3
Toscana	26.8	36.8	6	4.3
Trentino-Alto Adige	18.4	28.4	-6.1	6.7
Umbria	27	32.4	8.2	3
Valle d'Aosta	17.8	28	8.4	4.4
Veneto	22.7	26.9	-10.4	3.5

Table 4.14 - Net present value [k€] for each Italian region (First Scenario)

NPV presented the same problem seen for PBT and IRR in certain particular points. When NPV<0, the profit expected from the investment is negative, there will be a loss. However, to have a better idea of the general situation, average regional values should be considered. As already seen for the rest of indicators, regions with a higher irradiance received more benefits than the others.

CO2 savings

Region	CO_2 savings [%]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	41.22	43.45	30.87	1.7
Basilicata	41.5	43.08	33.97	1.1
Calabria	41.2	43.75	30.62	1.67
Campania	41.46	43.77	29.29	1.73
Emilia-Romagna	40.52	42.91	29.62	1.57
Friuli-Venezia Giulia	38.73	42	23.19	3.23
Lazio	41.96	43.91	28.36	1.68
Liguria	39.69	43.84	30.72	2.42
Lombardia	40.18	43.33	22.62	2.13
Marche	41.09	43.4	29.75	1.81
Molise	41.75	43.44	30.52	1.38
Piemonte	41.45	44.06	24.26	2.27
Puglia	42.04	43.52	34.11	0.68
Sardegna	42.74	45.1	30.66	1.46
Sicilia	42.2	44.34	31.01	1.3
Toscana	41.66	44.07	29.88	1.83
Trentino-Alto Adige	36.82	42.36	23.75	3.86
Umbria	41.37	43.78	31.68	1.58
Valle d'Aosta	36.85	41.98	30.37	2.61
Veneto	40.13	42.39	21.02	2.07

Table 4.15 – CO_2 savings [%] for each Italian region (First Scenario)

The percentage of CO_2 savings with respect to the reference case without PV resulted to be similar all over Italy and to be around 40%. In order to have an idea of the amount of saved CO_2, the value in tons for each region was also displayed.

Region	CO_2 savings [tons]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	12.54	13.21	9.39	0.52
Basilicata	12.62	13.1	10.33	0.33
Calabria	12.53	13.3	9.31	0.51
Campania	12.61	13.31	8.91	0.53
Emilia-Romagna	12.32	13.05	9.01	0.48
Friuli-Venezia Giulia	11.78	12.77	7.05	0.98
Lazio	12.76	13.35	8.62	0.51
Liguria	12.07	13.33	9.34	0.74
Lombardia	12.22	13.17	6.88	0.65
Marche	12.49	13.2	9.05	0.55
Molise	12.69	13.21	9.28	0.42
Piemonte	12.6	13.4	7.38	0.69
Puglia	12.79	13.23	10.37	0.21
Sardegna	13	13.72	9.32	0.44
Sicilia	12.83	13.48	9.43	0.4
Toscana	12.67	13.4	9.09	0.56
Trentino-Alto Adige	11.2	12.88	7.22	1.17
Umbria	12.58	13.31	9.63	0.48
Valle d'Aosta	11.2	12.77	9.24	0.79
Veneto	12.2	12.89	6.39	0.63

Table 4.16 – CO2 savings [tons] for each Italian region (First Scenario)

This indicator was also displayed in graphical form, in Figure 4.8.

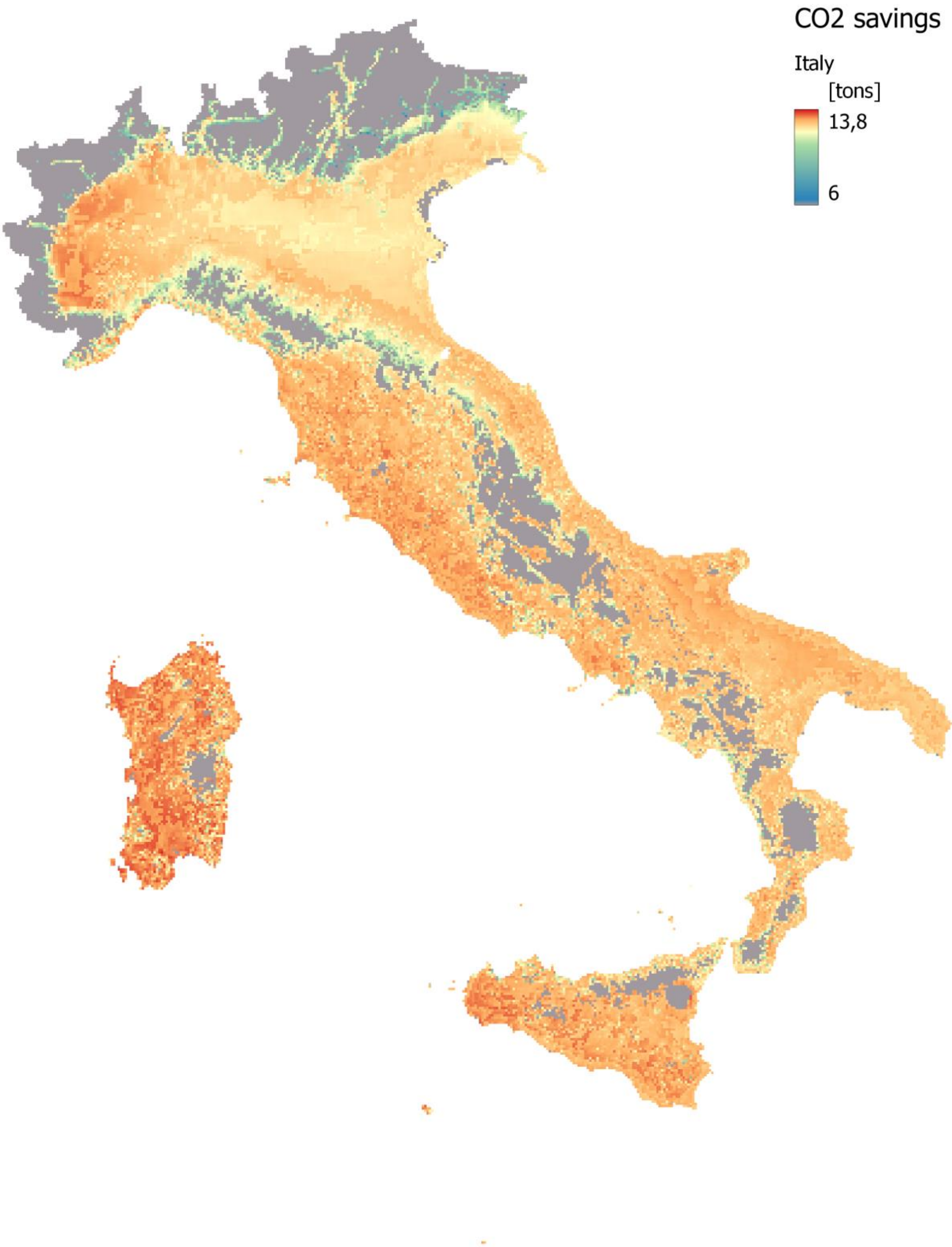

Figure 4.9 - Italian CO_2 savings [tons]

In the following paragraphs, the attention will be focused on singular regions.

4.2.2 Piemonte

Parameter	Average	Maximum	Minimum	Standard deviation
PV size [kW]	35	35	31	0.46
SC	0.81	0.94	0.79	0.02
SS	0.34	0.35	0.23	0.01
Cost Savings [%]	18.59	19.94	9.08	1.16
PBT [years]	8.8	25.8	7.9	1
IRR	7.63	8.96	-1.68	1.03
NPV [k€]	24.4	28.5	-4.5	3.5
CO_2 savings [%]	41.45	44.06	24.26	2.27
CO_2 savings [tons]	12.6	13.4	7.38	0.69

Table 4.17 - Piemonte's First Scenario results

A focus on the regional PBT map was displayed. Piemonte presented an average Payback time of 9 years, but with a peak of 25 years, corresponding to negative NPV and IRR. In the map this point is highlighted in red and, it is one of the shaded points mentioned before.

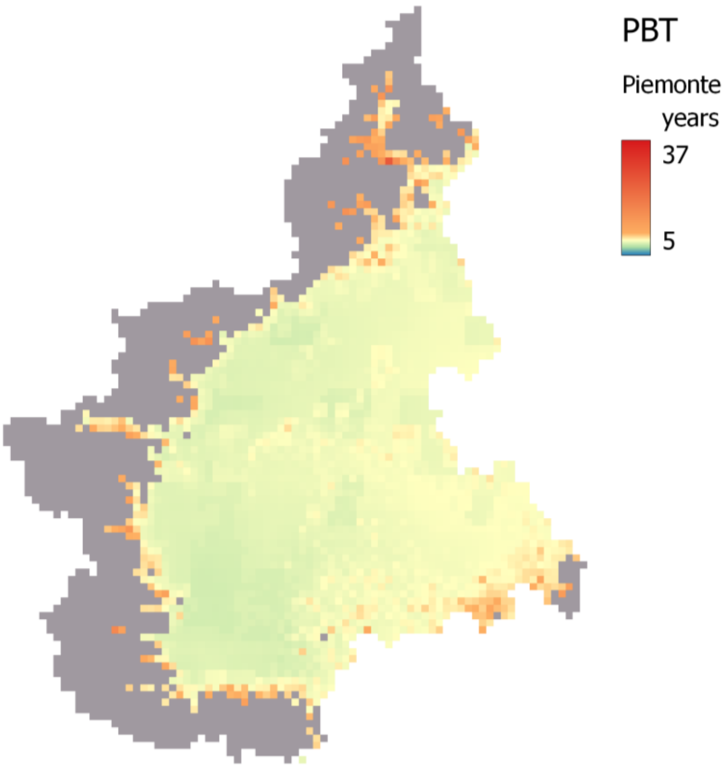

Figure 4.10 - Piemonte's Payback Time

4.2.3 Lazio

Parameter	Average	Maximum	Minimum	Standard deviation
PV size [kW]	31	35	25	1.48
SC	0.81	0.86	0.79	0.01
SS	0.34	0.35	0.24	0.01
Cost Savings [%]	19.47	20.78	11.44	1
PBT [years]	7.3	13.9	6	0.7
IRR	10.28	13.31	2.75	1.4
NPV [k€]	30.3	36.6	7.1	3.6
CO_2 savings [%]	41.96	43.91	28.36	1.68
CO_2 savings [tons]	12.53	13.3	9.31	0.51

Table 4.18 – Lazio's First Scenario results

Lazio's results show how, further south, the investment became more convenient. The needed PV size was lower because of the higher irradiance and, as a consequence, also the values of PBT, IRR and NPV were better. The rest of the indicators resulted to be similar to Piemonte's ones.

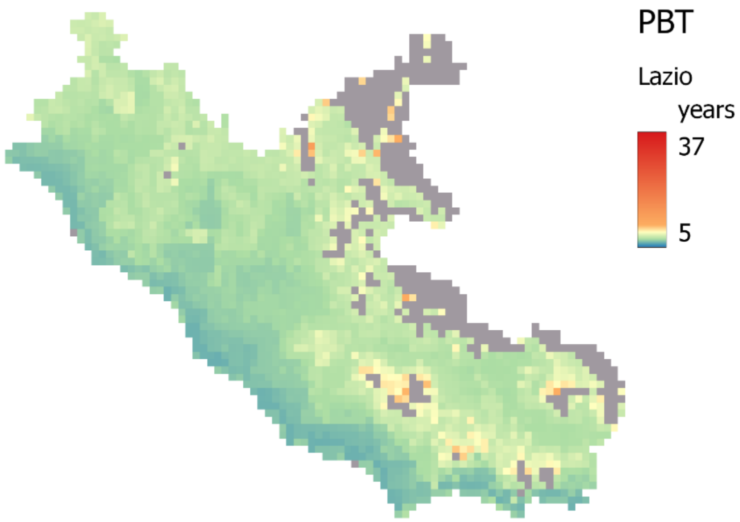

Figure 4.11 - Piemonte's Payback Time

4.2.4 Calabria

Parameter	Average	Maximum	Minimum	Standard deviation
PV size [kW]	30	35	26	1.91
SC	0.82	0.85	0.78	0.01
SS	0.34	0.35	0.26	0.01
Cost Savings [%]	18.85	20.36	12.9	1.05
PBT [years]	7.2	11.8	5.6	0.9
IRR	10.46	14.41	4.27	1.75
NPV [k€]	29.6	37.2	12.4	4.2
CO_2 savings [%]	41.2	43.75	30.62	1.67
CO_2 savings [tons]	12.6	13.4	7.38	0.69

Table 4.19 - Calabria's First Scenario results

Calabria's values resulted to be very similar to Lazio's one. For both regions, first scenario results were better than northern regions.

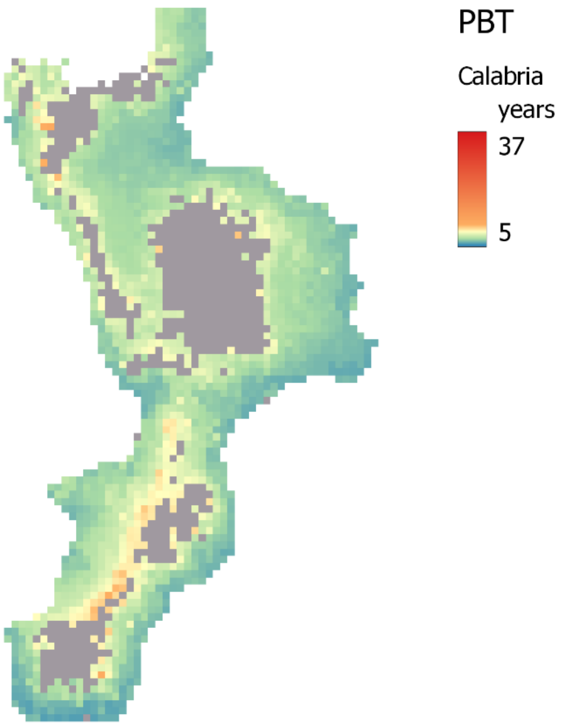

Figure 4.12 - Calabria's Payback Time

4.3 Second Scenario

Second scenario was described in Chapter 3.2. It presented the introduction of a heat pump for thermal heating, to reduce as far as possible the use of the preexisting methane boiler. Moreover, the installation of a PV plant was planned, using the same strategy of first scenario. The same indicators of the first scenario were calculated, with the addition of heat pump size. The most significant results are shown as follows.

4.3.1 National scale

PV size

Region	PV size [kW]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	35	35	27	0.87
Basilicata	34	35	28	1.41
Calabria	32	35	26	2.15
Campania	33	35	25	1.89
Emilia-Romagna	35	35	30	0.59
Friuli-Venezia Giulia	35	35	32	0.12
Lazio	33	35	26	1.73
Liguria	34	35	28	1.37
Lombardia	35	35	29	0.63
Marche	35	35	29	0.72
Molise	35	35	28	0.98
Piemonte	35	35	31	0.2
Puglia	33	35	28	1.7
Sardegna	32	35	25	1.97
Sicilia	31	35	25	2.08
Toscana	35	35	28	1.09
Trentino-Alto Adige	35	35	27	1.17
Umbria	34	35	29	0.95

Valle d'Aosta	35	35	35	0
Veneto	35	35	31	0.52

Table 4.20 - PV size of Italian regions [kW] (Second Scenario)

Comparing the values with the ones of first scenario it is easy to notice as the average PV size increased. This effect was due to the heat pump installation, which switched part of the thermal load into electric.

SC

Region	SC			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	0.81	0.92	0.78	0.02
Basilicata	0.8	0.84	0.77	0.01
Calabria	0.8	0.86	0.76	0.01
Campania	0.8	0.88	0.76	0.01
Emilia-Romagna	0.83	0.96	0.79	0.03
Friuli-Venezia Giulia	0.85	0.98	0.79	0.04
Lazio	0.8	0.88	0.77	0.01
Liguria	0.83	0.94	0.77	0.03
Lombardia	0.83	0.96	0.8	0.03
Marche	0.81	0.92	0.78	0.02
Molise	0.8	0.88	0.78	0.01
Piemonte	0.84	0.98	0.8	0.03
Puglia	0.8	0.86	0.77	0.01
Sardegna	0.8	0.87	0.76	0.01
Sicilia	0.8	0.86	0.76	0.02
Toscana	0.81	0.93	0.77	0.02
Trentino-Alto Adige	0.86	0.99	0.81	0.04
Umbria	0.81	0.88	0.78	0.01
Valle d'Aosta	0.88	0.94	0.84	0.03
Veneto	0.82	0.98	0.78	0.03

Table 4.21 - Self-Consumption index (SC) of Italian regions (Second Scenario)

SS

Region	SS			
	Average	**Maximum**	**Minimum**	**Standard Deviation**
Abruzzo	0.23	0.3	0.1	0.04
Basilicata	0.25	0.32	0.12	0.03
Calabria	0.28	0.34	0.16	0.04
Campania	0.25	0.32	0.12	0.04
Emilia-Romagna	0.2	0.25	0.09	0.03
Friuli-Venezia Giulia	0.19	0.25	0.07	0.04
Lazio	0.26	0.32	0.11	0.04
Liguria	0.22	0.31	0.1	0.04
Lombardia	0.19	0.24	0.08	0.02
Marche	0.22	0.28	0.1	0.03
Molise	0.23	0.3	0.11	0.03
Piemonte	0.2	0.25	0.09	0.03
Puglia	0.27	0.32	0.13	0.03
Sardegna	0.28	0.35	0.12	0.03
Sicilia	0.29	0.35	0.16	0.03
Toscana	0.23	0.32	0.09	0.04
Trentino-Alto Adige	0.17	0.24	0.07	0.04
Umbria	0.22	0.28	0.11	0.03
Valle d'Aosta	0.15	0.2	0.1	0.03
Veneto	0.2	0.26	0.08	0.02

Table 4.22 – Self-Sufficiency index (SS) of Italian regions (Second Scenario)

The values of SS decreased with respect to the previous scenario. This behavior was due to the increase of the electric load which is inversely proportional to the Self-Sufficiency index.

Cost Savings

Region	Cost Savings [%]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	32.68	36.72	28	1.15
Basilicata	32.75	35.97	25.26	1.36
Calabria	30.63	35.83	23.54	2.83
Campania	31.82	36.34	24.49	2.08
Emilia-Romagna	31.83	37.12	27.82	0.98
Friuli-Venezia Giulia	31.56	35.11	25.68	1.29
Lazio	32.03	36.21	25.88	1.92
Liguria	31.69	37.45	24.51	1.94
Lombardia	31.98	36.75	26.88	1.04
Marche	32.12	35.95	27.22	1.05
Molise	32.99	36.55	29.12	1
Piemonte	32.27	36.9	27.16	1.12
Puglia	31.49	35.77	26.55	1.91
Sardegna	31.53	37.11	22.83	2.59
Sicilia	32.1	37.4	23.44	2.5
Toscana	32.38	36.73	24.92	1.49
Trentino-Alto Adige	31.17	36.5	26.09	1.87
Umbria	32.59	35.48	28.42	0.94
Valle d'Aosta	31.92	34.59	29.06	1.66
Veneto	32.04	36.2	26.53	0.93

Table 4.23 - Cost Savings [%] of Italian regions (Second Scenario)

As expected, also Cost Savings increased with respect to the first scenario. In fact, while in the first case the savings were only a consequence of the PV installation, in the second one there was also a reduction of methane consumption thanks to the heat pump. It is true that the electric load increased, but this meant a bigger size of the PV plant. Moreover, electricity is much cheaper than methane.

PBT

Region	Payback time [years]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	9.6	14.5	3.7	1.8
Basilicata	9.8	15.9	4.7	1.8
Calabria	11.9	20.3	7.2	2.9
Campania	10.5	17.8	3.8	2.4
Emilia-Romagna	9.3	12.4	3.3	2
Friuli-Venezia Giulia	8.7	12.3	3.6	2
Lazio	10.6	16.5	3.8	2.1
Liguria	9.5	17.6	3.5	2.4
Lombardia	8.8	11.8	3.6	1.4
Marche	9.7	15.4	3.9	1.5
Molise	9	13.8	3.9	1.4
Piemonte	8.6	11.5	3.6	1.4
Puglia	11.3	17.7	4	2.1
Sardegna	11.1	22.1	4.1	2.5
Sicilia	11.2	18.2	6.9	2.1
Toscana	9.6	17.1	3.8	2.1
Trentino-Alto Adige	8.4	12.4	3.8	2.2
Umbria	8.9	13.1	4	1.2
Valle d'Aosta	7.2	9.8	4.1	2.4
Veneto	9	13	3.6	1.3

Table 4.24 – Payback time [years] for each Italian region (Second Scenario)

The Payback time variation depended on the geographical area of the region. Northern Italy regions benefited more than Southern ones from the heat pump introduction because they were the regions with the highest thermal load and the heat pump led to bigger savings and faster time to recover the investment. For this reason, the situation changed, and in this scenario colder regions had a shorter payback time.

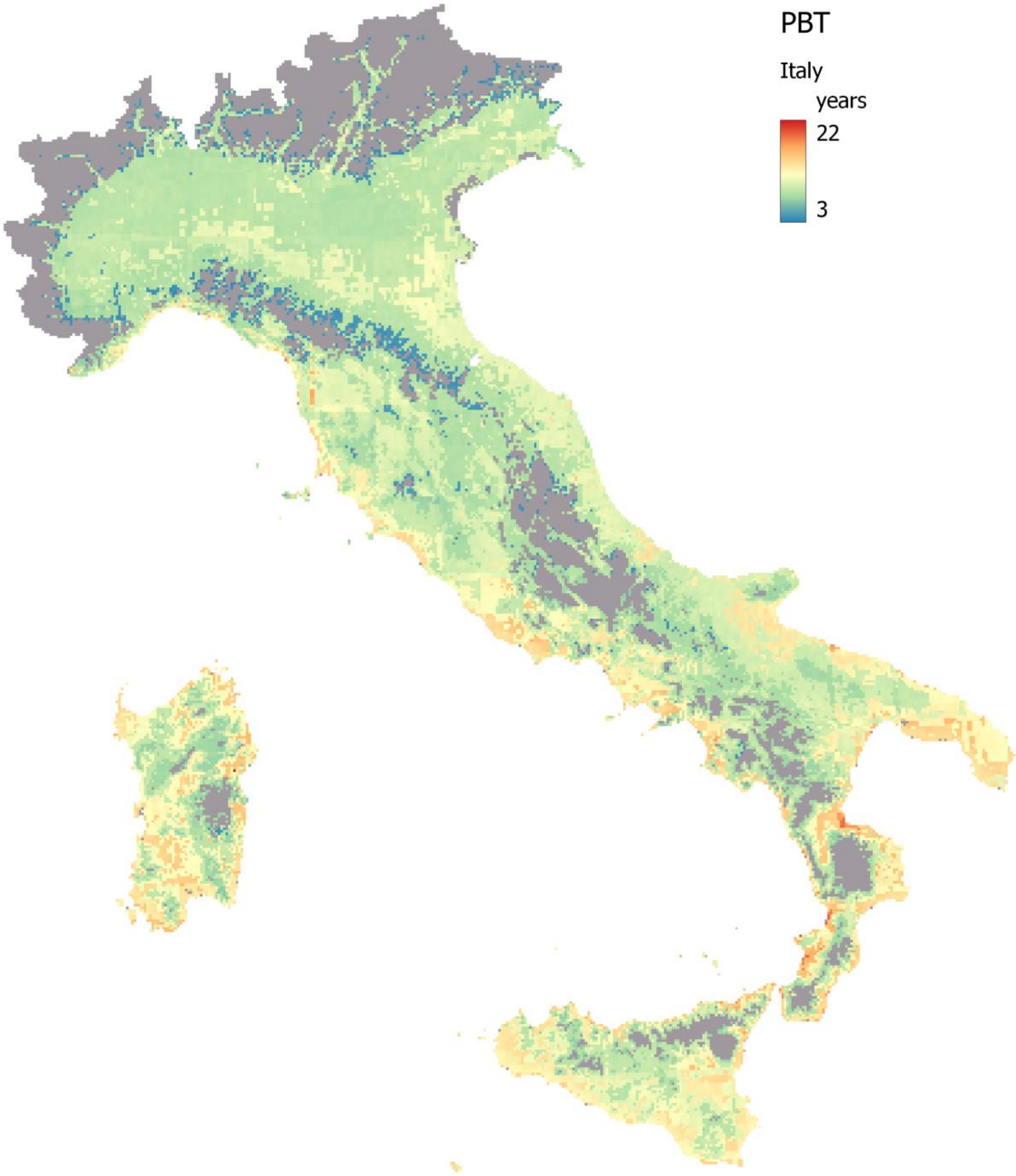

Figure 4.13 - Italian Payback Time (Second Scenario)

The figure shows even more clearly how colder zones managed to pay off the investment sooner.

IRR

Region	IRR [%]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	7.08	23.89	2.41	3.1
Basilicata	6.73	18.31	1.68	2
Calabria	4.84	10.45	-0.1	2.66
Campania	6.15	23.41	0.8	2.7
Emilia-Romagna	7.83	27.42	3.83	4.43
Friuli-Venezia Giulia	8.78	24.81	3.92	4.76
Lazio	5.93	23.35	1.37	2.5
Liguria	7.6	25.61	0.89	4.06
Lombardia	8.23	24.36	4.32	3.4
Marche	6.95	22.2	1.9	2.95
Molise	7.76	22.33	2.89	2.63
Piemonte	8.53	24.89	4.65	3.7
Puglia	5.13	21.89	0.86	2.14
Sardegna	5.45	21.5	-0.67	2.63
Sicilia	5.2	11.16	0.66	2.06
Toscana	7.31	23.26	1.08	3.86
Trentino-Alto Adige	9.65	23.22	3.86	5.56
Umbria	7.87	21.63	3.35	2.54
Valle d'Aosta	12.45	21.52	6.4	6.54
Veneto	7.83	24.39	3.41	2.91

Table 4.25 - Internal rate of return for each Italian region (Second Scenario)

Internal rate of return had a similar behavior to the one of payback time. In fact, the colder regions had a positive effect, while the hottest regions had a worsening with respect to the previous case. Some points of southern Italy reached negative values, but the average regional value was always acceptable.

NPV

Region	NPV [k€]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	84.7	331.3	24.7	46.8
Basilicata	76.9	275.6	13.3	26.7
Calabria	50	122.6	-0.8	32.8
Campania	68.4	336.3	7.4	37.5
Emilia-Romagna	99.4	362.3	45.2	67.9
Friuli-Venezia Giulia	114.4	368.7	47.7	76.9
Lazio	65.1	334	12.1	35.3
Liguria	89.7	353	7.2	61.9
Lombardia	104.6	353.1	50	52.5
Marche	84.7	322.5	20.7	45.5
Molise	91.4	316.1	29.4	40.3
Piemonte	109.9	351.1	53.9	58
Puglia	54.6	310.7	7.5	28.3
Sardegna	56.9	321.2	-5.5	34.7
Sicilia	52.3	125.8	5.1	26.3
Toscana	88.2	334.6	9.7	60.1
Trentino-Alto Adige	127.9	345.2	44.1	87.4
Umbria	96.3	319	34.2	39.6
Valle d'Aosta	175.9	321.2	81.9	104.9
Veneto	97.7	363.1	35.6	45.1

Table 4.26 - Net present value [k€] for each Italian region (Second Scenario)

NPV's behavior was related to PBT and IRR's one. Northern regions reached higher values than southern ones.

Heat pump size

Region	NPV [k€]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	160	200	120	20
Basilicata	150	220	80	20
Calabria	120	180	60	30
Campania	140	210	70	30
Emilia-Romagna	170	230	100	10
Friuli-Venezia Giulia	180	230	120	20
Lazio	130	210	80	30
Liguria	140	230	80	30
Lombardia	180	220	140	10
Marche	170	210	130	10
Molise	150	190	100	20
Piemonte	180	240	140	10
Puglia	130	200	70	20
Sardegna	120	210	50	30
Sicilia	120	210	50	30
Toscana	150	250	70	30
Trentino-Alto Adige	180	220	140	10
Umbria	170	210	120	10
Valle d'Aosta	190	220	170	10
Veneto	170	230	110	10

Table 4.27 - Heat pump size [kW] for each Italian region

As expected, the size of the heat pump of the regions with a higher thermal load demand was bigger. The goal was to make the heat pump cover the thermal load as much as possible, but without oversizing it. For this reason, the boiler was not eliminated, but left to work as a backup to fulfill thermal load peaks not fully covered by the heat pump.

CO2 savings

Region	CO_2 savings [%]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	58.89	63.1	52.8	1.31
Basilicata	59.03	62.34	48.91	1.48
Calabria	56.32	62.36	45.49	3.49
Campania	57.76	63.93	46.74	2.56
Emilia-Romagna	58.27	63.09	52.13	1.31
Friuli-Venezia Giulia	57.92	62.59	50.99	1.75
Lazio	57.99	63.74	49.11	2.25
Liguria	57.44	63.75	47.44	2.39
Lombardia	58.48	63.76	52.52	1.24
Marche	58.37	63.42	52.99	1.24
Molise	59.35	63.76	54.78	1.18
Piemonte	58.68	63.81	52.52	1.44
Puglia	57.54	62.91	50.58	2.21
Sardegna	57.24	63.88	44.48	3.23
Sicilia	56.8	63.21	43.52	3.31
Toscana	58.56	63.46	48.43	1.81
Trentino-Alto Adige	57.45	63.43	51.77	2.41
Umbria	58.83	63.2	53.98	1.12
Valle d'Aosta	58.98	62.46	55.86	2.35
Veneto	58.43	63.08	51.82	1.14

Table 4.28 – CO_2 savings [%] for each Italian region (Second Scenario)

The impact on emissions was really good. In fact, the introduction of a heat pump led to a national average near 60% of savings with respect to the reference case. In first scenario (only photovoltaic) the savings were around 40%. Obviously, this increase was not only on a percentual scale, but also in absolute terms, as showed in next table.

Region	CO_2 savings [tons]			
	Average	Maximum	Minimum	Standard Deviation
Abruzzo	51.1	136.86	30.21	16.76
Basilicata	47.12	129.43	22.78	9.55
Calabria	35.66	62.06	17.31	11.47
Campania	43.39	137.1	21.47	13.89
Emilia-Romagna	59.18	148.74	40.23	24.09
Friuli-Venezia Giulia	65.27	150.63	41.43	29.52
Lazio	41.94	141.71	22.85	13.19
Liguria	51.8	144.45	22.65	22.62
Lombardia	61.07	148.57	42.55	18.05
Marche	52.76	143.81	32.08	16.35
Molise	52.21	133.62	30.13	14.75
Piemonte	62.74	150.97	42.82	20.47
Puglia	38.5	129.53	22.65	10.12
Sardegna	37.5	141.27	17.72	12.35
Sicilia	34.29	61.78	16.53	9.52
Toscana	52.28	147.26	22.77	22.76
Trentino-Alto Adige	70.38	146.87	39.39	30.62
Umbria	55.99	138.31	33.67	14.55
Valle d'Aosta	88.85	140.78	55.81	36.75
Veneto	58.05	151.66	34.13	15.96

Table 4.29 – CO_2 savings [tons] for each Italian region (Second Scenario)

This indicator was also displayed in graphical form, in Figure 4.14.

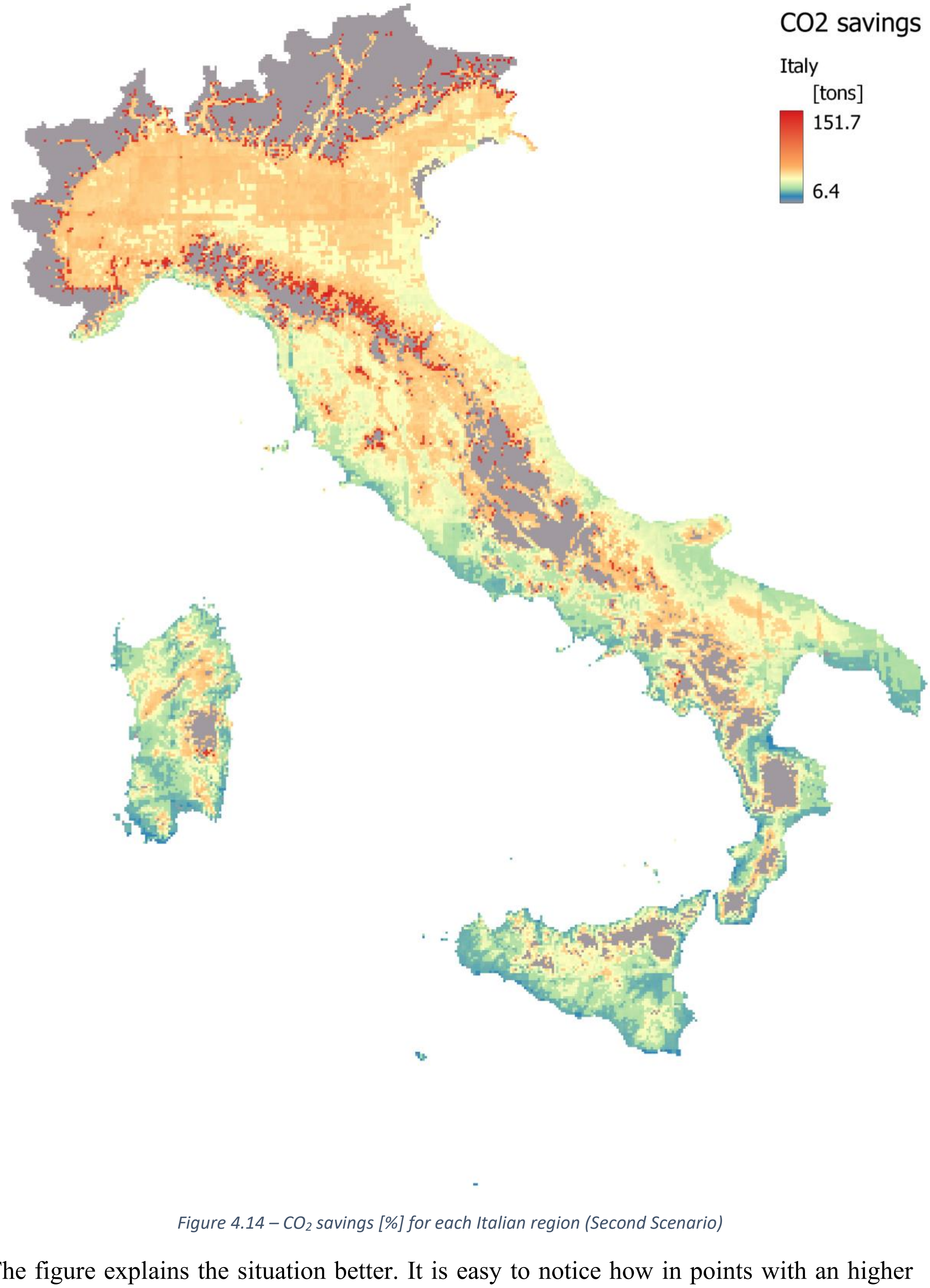

Figure 4.14 – CO_2 savings [%] for each Italian region (Second Scenario)

The figure explains the situation better. It is easy to notice how in points with an higher thermal load (northern italy, but most of all points with an altitude near to 850 meters) the savings were higher due to a bigger reduction in methane consumption thanks to the heat pump.

4.3.2 Piemonte

Parameter	Average	Maximum	Minimum	Standard deviation
PV size [kW]	35	35	31	0.2
SC	0.84	0.98	0.8	0.03
SS	0.2	0.25	0.09	0.03
Cost Savings [%]	32.27	36.9	27.16	1.12
PBT [years]	8.6	11.5	3.6	1.4
IRR	8.53	24.89	4.65	3.7
NPV [k€]	109.9	351.1	53.9	58
Heat Pump size [kW]	180	240	140	10
CO_2 savings [%]	58.68	63.81	52.52	1.44
CO_2 savings [tons]	62.74	150.97	42.82	20.47

Table 4.30 - Piemonte's Second Scenario results

A graphical evaluation of payback time and CO_2 savings was performed.

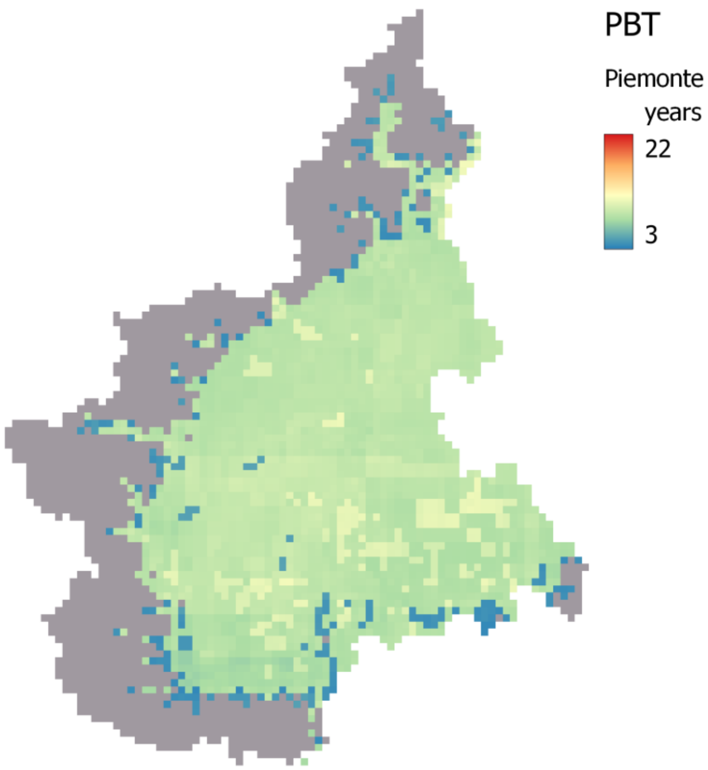

Figure 4.15 - Piemonte's Payback Time (Second Scenario)

It is evident how payback time decreased with the increase of thermal demand. As can be easily noticed from Figure 4.15, the "peaks" of low payback time were reached in the zones near the excluded points. It means the altitude was near to 850 meters and the thermal load was very high. The same happened for CO_2 savings: the points with a really low PBT also presented a really high value of emissions reduction.

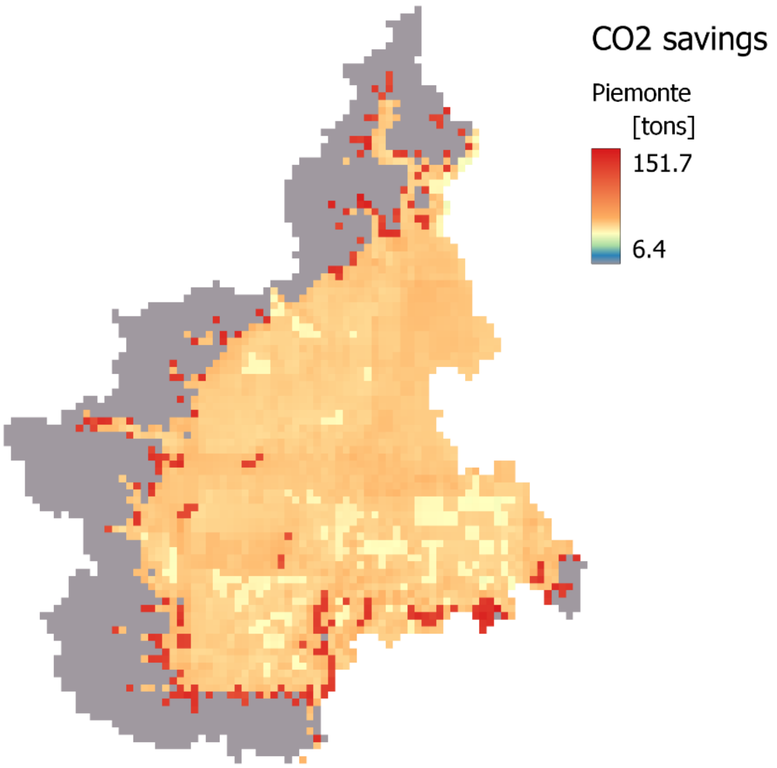

Figure 4.16 - Piemonte's CO_2 savings (Second Scenario)

4.3.3 Lazio

Parameter	Average	Maximum	Minimum	Standard deviation
PV size [kW]	33	35	26	1.73
SC	0.8	0.88	0.77	0.01
SS	0.26	0.32	0.11	0.04
Cost Savings [%]	32.03	36.21	25.88	1.92
PBT [years]	10.6	16.5	3.8	2.1
IRR	5.93	23.35	1.37	2.5
NPV [k€]	65.1	334	12.1	35.3
Heat Pump size [kW]	130	210	80	30
CO_2 savings [%]	57.99	63.74	49.11	2.25
CO_2 savings [tons]	41.94	141.71	22.85	13.19

Table 4.31 - Lazio's Second Scenario results

Comparing the values with Piemonte's ones, it is easy to notice a worsening in the economic parameters of the investment. Moreover, the size of PV and heat pump resulted to be smaller and, as a consequence, also the amount of avoided emissions

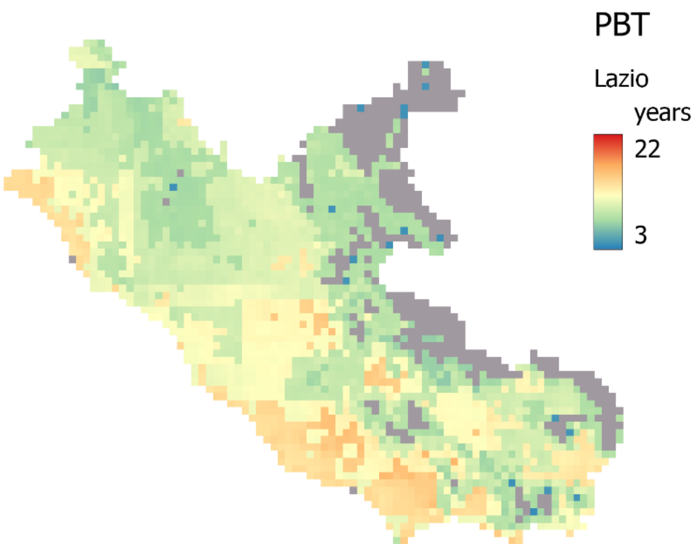

Figure 4.17 – Lazio's Payback Time (Second Scenario)

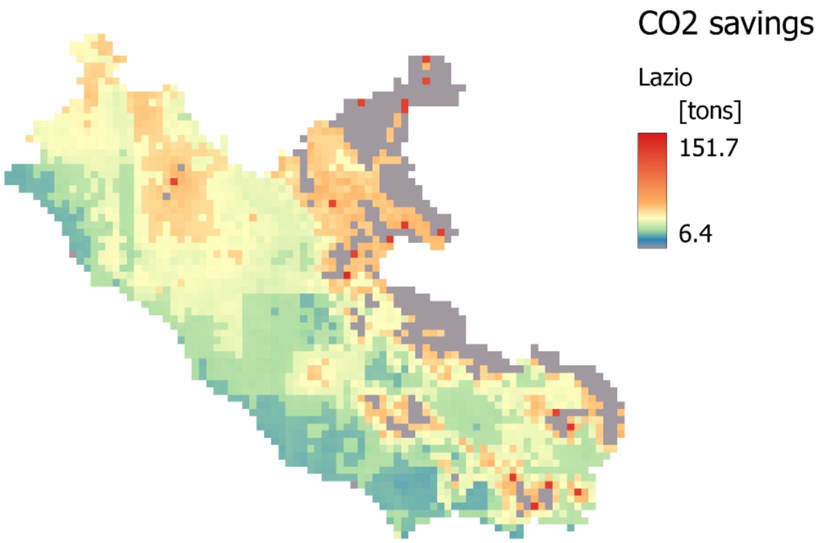

Figure 4.18 - Lazio's CO_2 savings (Second Scenario)

4.3.4 Calabria

Parameter	Average	Maximum	Minimum	Standard deviation
PV size [kW]	32	35	26	2.15
SC	0.8	0.86	0.76	0.01
SS	0.28	0.34	0.16	0.04
Cost Savings [%]	30.63	35.83	23.54	2.83
PBT [years]	11.9	20.3	7.2	2.9
IRR	4.84	10.45	-0.1	2.66
NPV [k€]	50	122.6	-0.8	32.8
Heat Pump size [kW]	120	180	60	30
CO_2 savings [%]	56.32	62.36	45.49	3.49
CO_2 savings [tons]	35.66	62.06	17.31	11.47

Table 4.32 - Calabria's Second Scenario results

Similarly to what already seen before, going further south PV and Heat pump size decreased together with the total amount of CO_2 savings. PBT increased, while IRR and NPV decreased too. A summary of PBT and emissions savings situation is showed in Figure 4.19 and 4.20.

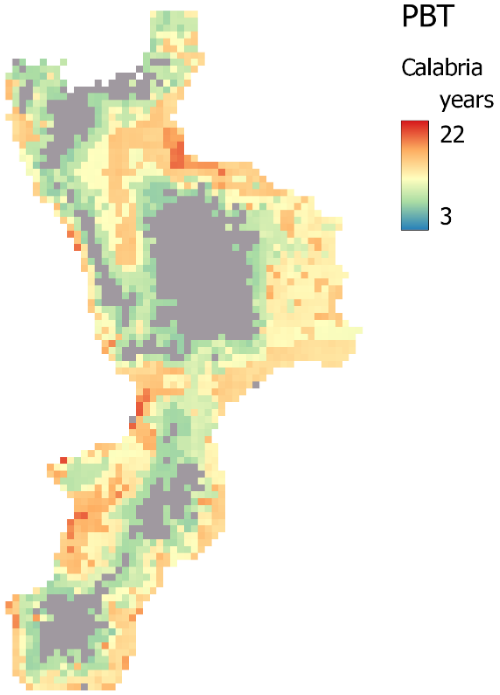

Figure 4.19 – Calabria's Payback Time (Second Scenario)

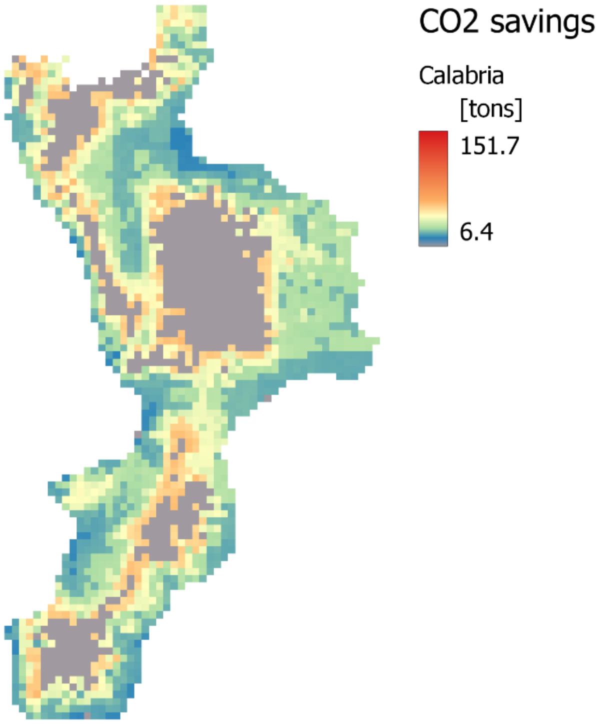

Figure 4.20 - Calabria's CO_2 savings (Second Scenario)

4.4 Focus on cities

The attention was at this point focused on the behavior of three cities, one for each of the analyzed regions. Second scenario, comprehending both PV and heat pump installation, was analyzed. The chosen cities were Torino, Roma and Reggio Calabria. For each of them, the most significative parameters were shown. Moreover, the daily profiles of thermal load, electric load and PV production were plotted, choosing as a reference a significative day during the first two weeks of March. The choice was dictated by the need of a day in which thermal load was not totally fulfilled by the heat pump and PV production had a quite significant value.

4.4.1 Torino

Parameter	Value
Yearly thermal load [MWh]	285.6
Heat pump yearly thermal load [MWh]	282.6
Boiler yearly thermal load [MWh]	3
Heat pump size [kW]	180
Boiler size [kW]	75
Seasonal COP	3.88
Degree days [gg]	2346
Climate zone	E
PV size [kW]	35
Self-Consumed energy [MWh]	38.9
Shared energy [MWh]	28.1
Cost savings [%]	33.16
Payback time [years]	9
NPV [k€]	95
IRR [%]	7.6
CO_2 savings [%]	59.43
CO_2 savings [tons]	56.16

Table 4.33 - Torino's results

From the results showed above it is easy to understand how many benefits the installations brought to the city of Torino. Nearly the whole thermal load was fulfilled by the heat pump, with the boiler only working as a backup when peaks occurred. This was also possible thanks to the choice of a very efficient heat pump, which maintained a seasoal COP of 3.88. The PV size resulted to be the maximum installable, because of the high needs of the heat pump. Moreover, the investment resulted to be really convenient, with a payback time of 9 years. As follows, the profiles of electric and thermal load of a significative day are displayed.

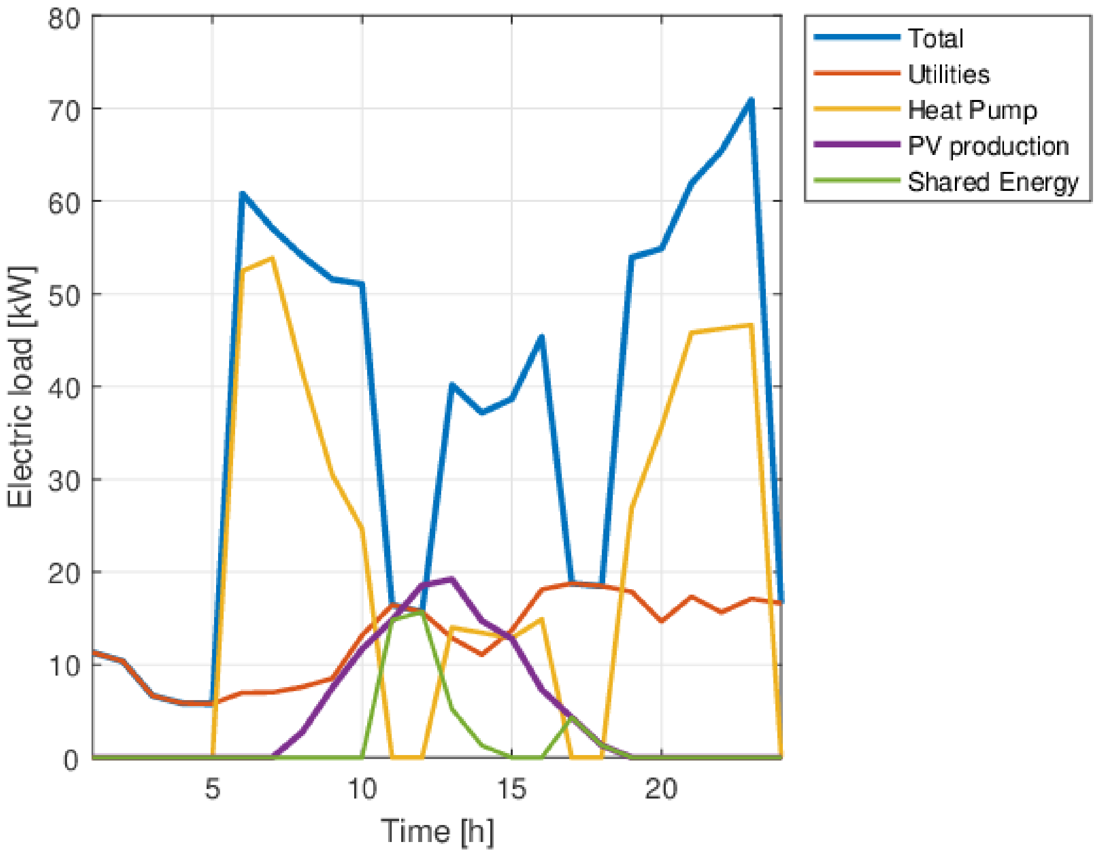

Figure 4.21 - Torino's daily Electric Load, PV production and Shared Energy (first weeks of March)

As it can be noticed, most of the electric load was due to the high usage of the heat pump, especially during the colder hours. PV production was only able to fulfill the utilities thermal load duing his peak (around noon), the rest of electricity needed to be bought from grid. This happened because of the high thermal load and the limited size of the rooftop. A small part of produced energy was sold to grid, around midday. The hourly shared energy was also displayed. Its value is equal to zero when the heat pump electric load is higher than the PV production, while when the opposite happens it is equal to the minimum value between the surplus energy (PV production – Heat pump electric load) and the utilities electric load.

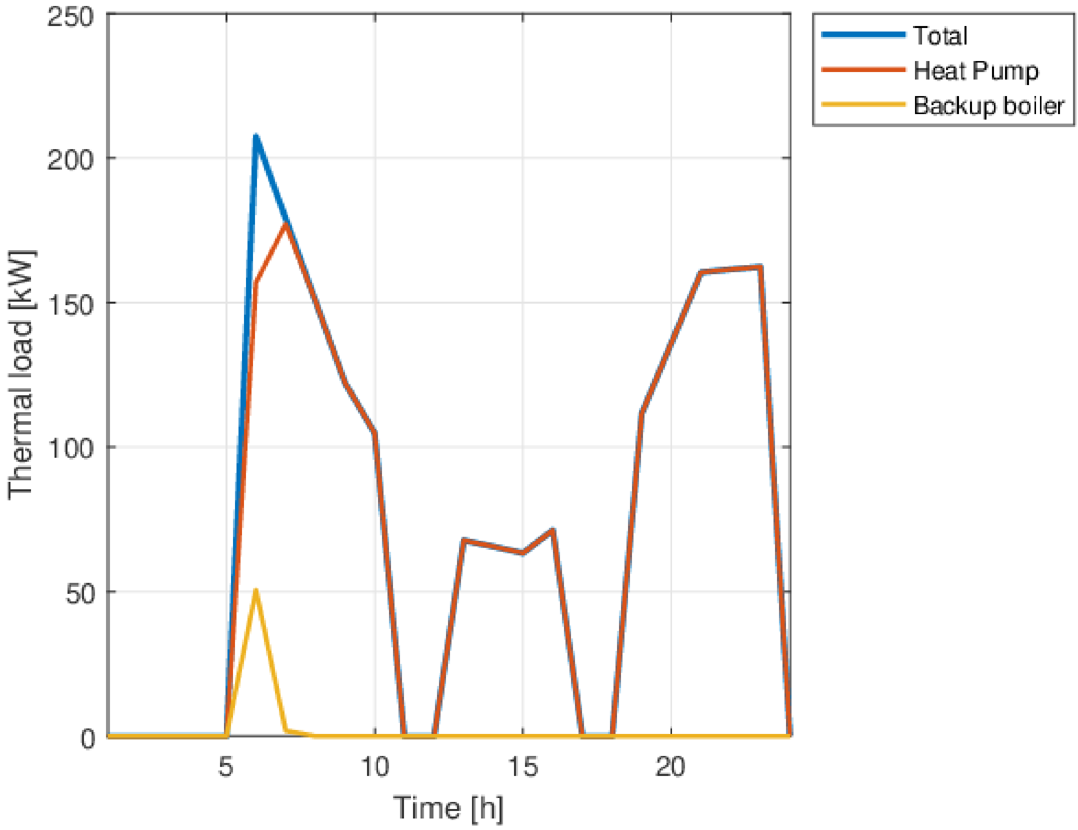

Figure 4.22 - Torino's daily Thermal Load (first weeks of March)

For what concerns thermal load, as expected from the results in Table 4.33, most of the needs were satisfied by the heat pump. The boiler only worked when a peak occurred, during a particularly cold hour: the heat pump did not manage to fulfill the whole load and the backup boiler came into operation.

4.4.2 Roma

Parameter	Value
Yearly thermal load [MWh]	120.5
Heat pump yearly thermal load [MWh]	118.8
Boiler yearly thermal load [MWh]	1.6
Heat pump size [kW]	125
Boiler size [kW]	50
Seasonal COP	4.39
Degree days [gg]	1431
Climate zone	D
PV size [kW]	33
Self-Consumed energy [MWh]	40.2
Shared energy [MWh]	34
Cost savings [%]	31.34
Payback time [years]	12
NPV [k€]	38.4
IRR [%]	3.89
CO_2 savings [%]	57.8
CO_2 savings [tons]	33.2

Table 4.34 - Roma's results

Comparing Roma's results with Torino's ones it was easy to understand how the amount of thermal load affected all the other parameters. In fact, being the thermal load less than half of Torino's one, the size of the heat pump decreased too. However, a reduction of nearly 60% in the thermal load led to a reduction of 30% on heat pump size. Being the two reductions not proportioned, Roma benefited less from this investment than Torino. For this reason, the time to recover the investment raised to 12 years and the values of NPV and IRR decreased. On the other hand, being the size of the heat pump smaller, the electric load requests were lower too. This led to a PV size lower than Torino's one.

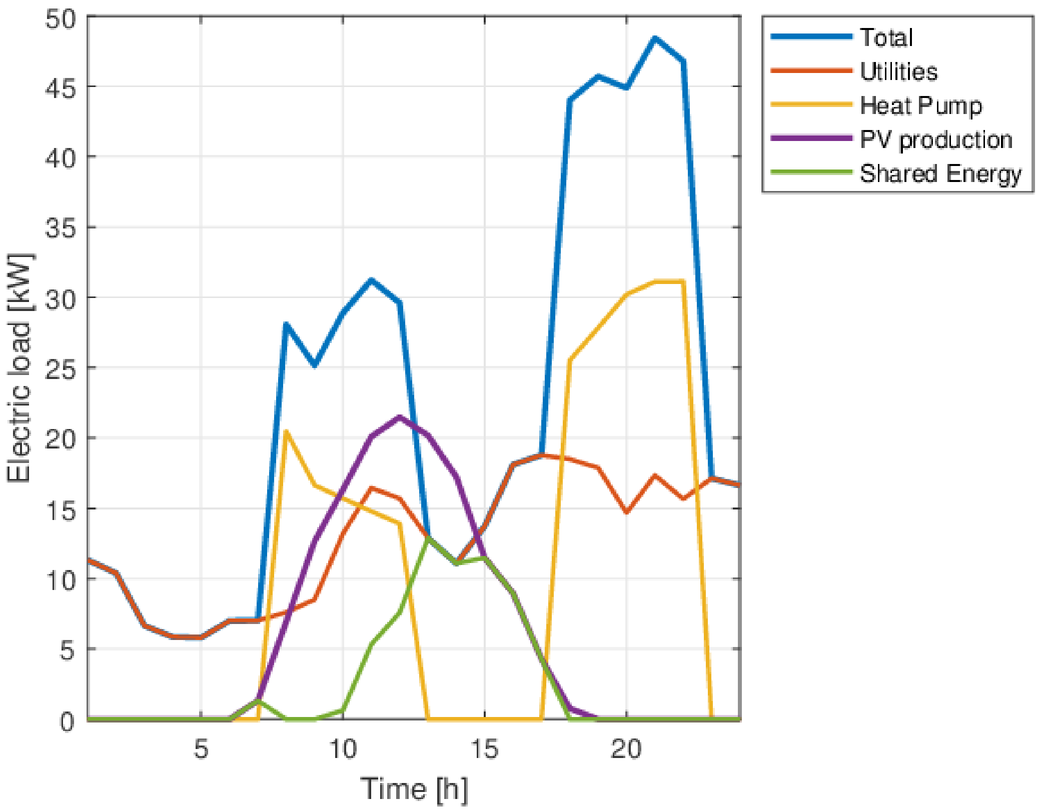

Figure 4.23- Roma's daily Electric Load, PV production and Shared Energy (first weeks of March)

As expected, the values of total electric load resulted to be lower than Torino's ones. This result was due to the lower size of the heat pump, since the chosen utilities electric load was the same. Despite the lower size of the PV plant, the value of PV production was higher than Torino's one, because of the presence of a higher irradiance. This production could fulfill the utilities' and part of the heat pump load during peak hours, but the rest of electric energy had to be bought from grid. Moreover, part of produced energy, between noon and 15:00 had to be sold to the grid.

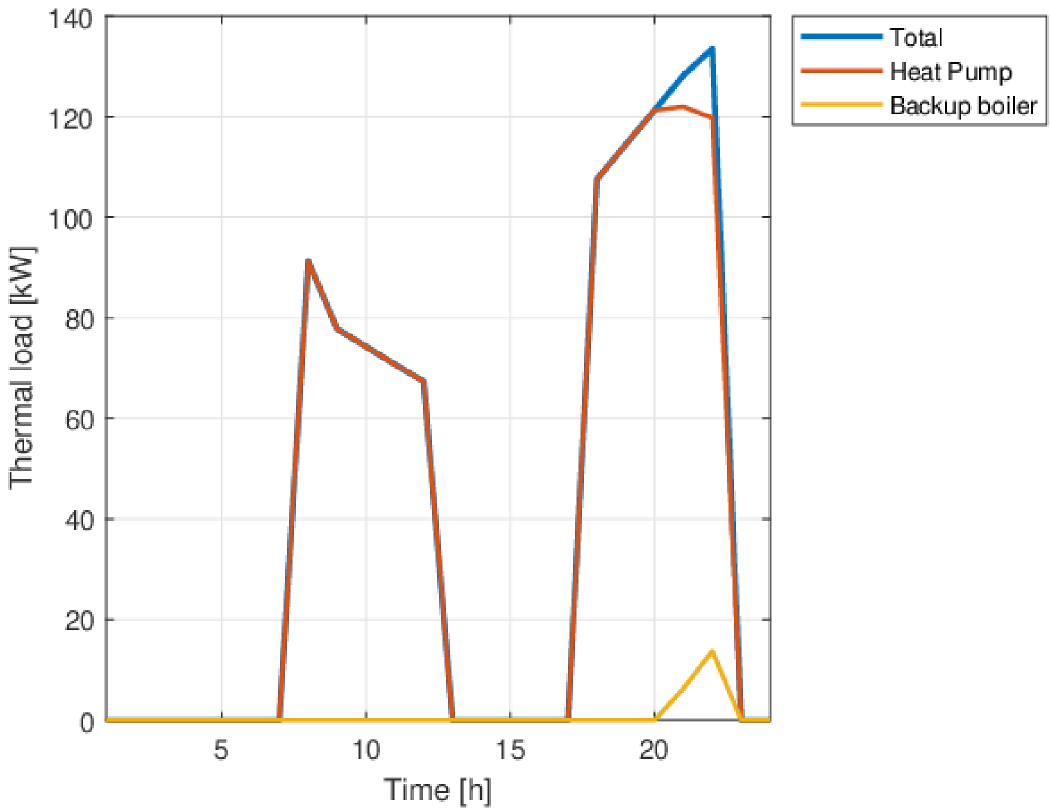

Figure 4.24 - Roma's daily Thermal load (first weeks of March)

It is easy to notice how total thermal load was really lower than Torino's one. Nearly the total load could be fulfilled by the heat pump, except a peak during the evening, when the backup boiler started to work.

4.4.3 Reggio Calabria

Parameter	Value
Yearly thermal load [MWh]	63.3
Heat pump yearly thermal load [MWh]	57.4
Boiler yearly thermal load [MWh]	5.9
Heat pump size [kW]	85
Boiler size [kW]	60
Seasonal COP	4.75
Degree days [gg]	696
Climate zone	B
PV size [kW]	29
Self-Consumed energy [MWh]	39.5
Shared energy [MWh]	35.5
Cost savings [%]	27.17
Payback time [years]	15
NPV [k€]	18.3
IRR [%]	2.31
CO_2 savings [%]	51.58
CO_2 savings [tons]	23

Table 4.35 - Reggio Calabria's results

As in Roma's case, but more clearly, a lower thermal load led to an increase of payback time (to 15 years) and to less economic advantages in terms of NPV and IRR. Yearly cost savings resulted to be 27%, not bad if compared to the ones of the other two cities (31% and 33%). It means that also in this case, the investment gave a big advantage in terms of emissions and cost savings, but with a longer period to recover the investment with respect to the previous cases. However, higher temperatures led to a higher seasonal COP, while the lower thermal load combined with the higher irradiance brought to a lower needed PV capacity, saving on the PV investment.

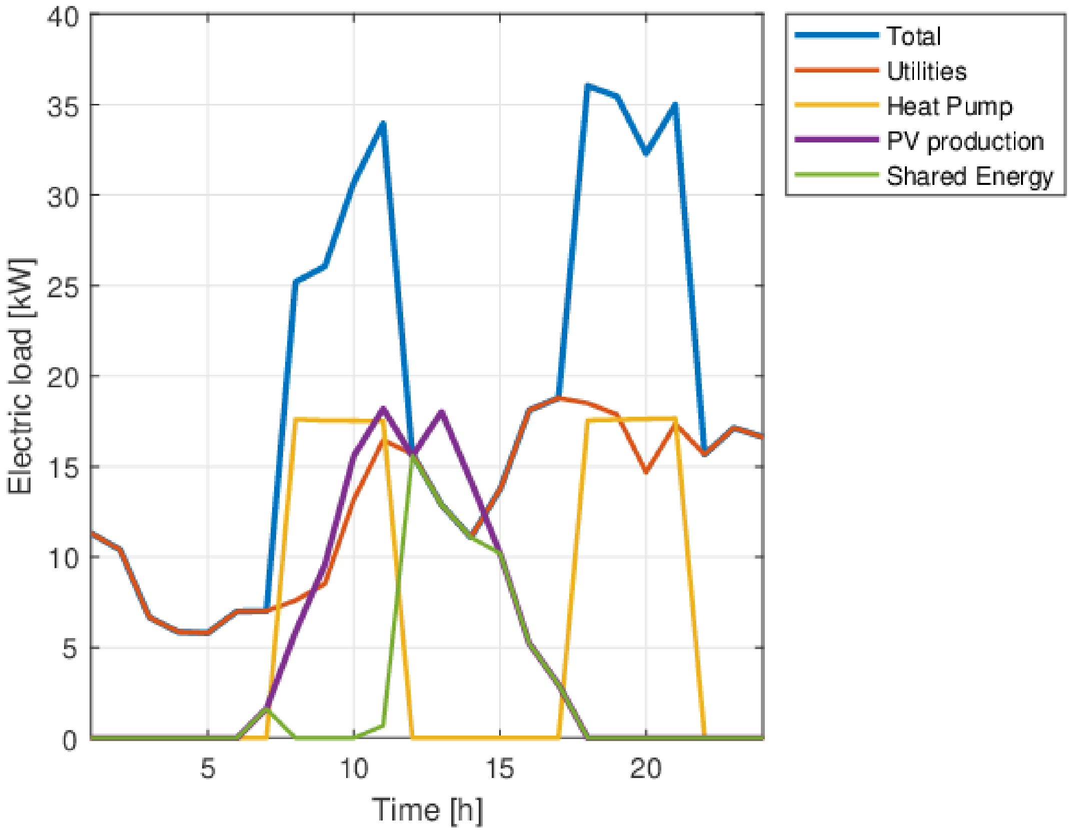

Figure 4.25 – Reggio Calabria's daily Electric Load, PV production and Shared Energy (first weeks of March)

Despite the much lower PV size, the PV production was similar to Torino's one because of the higher irradiance. Moreover, the total electric load resulted to be significantly lower than both previous cities as a result of a lower heat pump electric load, in turn due to the low thermal needs. As already seen in previous cases, during the hours of production peak, a part of produced energy was sold to grid.

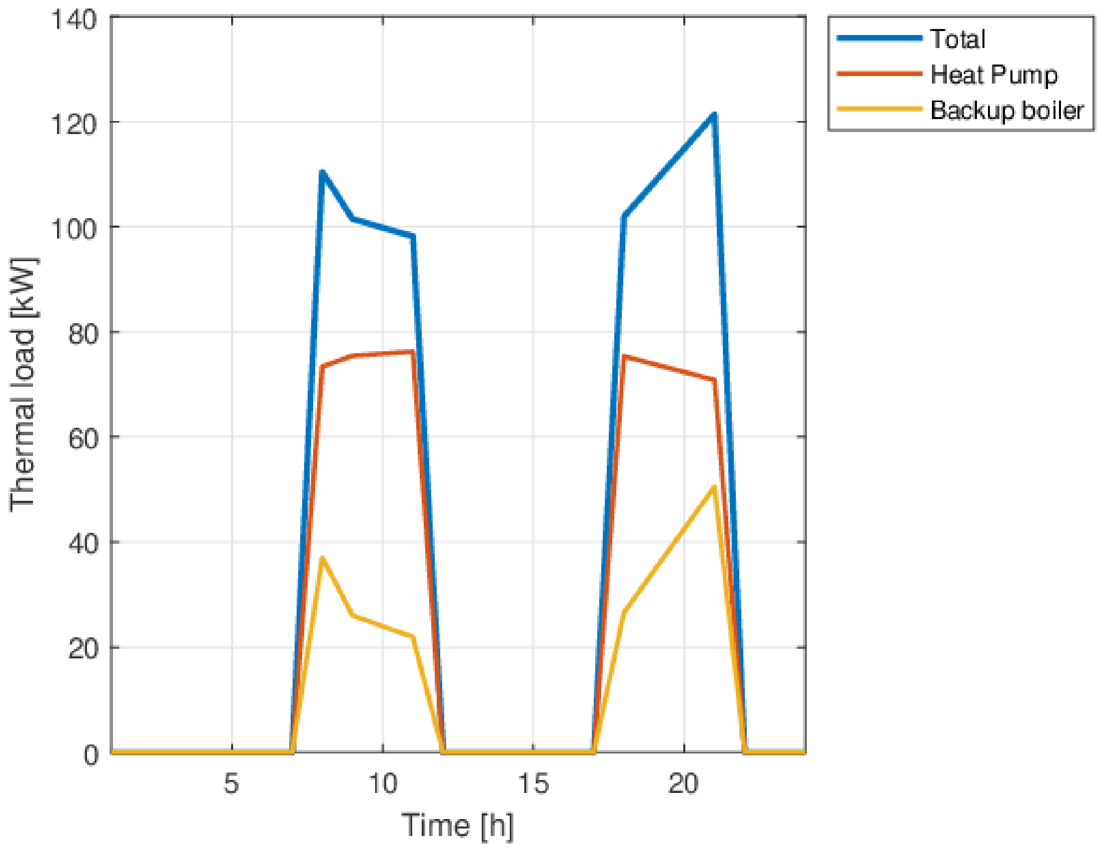

Figure 4.26 – Reggio Calabria's daily Thermal Load (first weeks of March)

Analyzing the yearly heat pump and boiler's thermal load from Table 4.35, it can be noticed that the backup boiler share was much higher than Roma and Torino's cases, however maintaining optimal values, under 10%. This higher use of boiler was due to peaks of thermal needs during February and March. In fact, the heat pump was sized with reference to the coldest months (December and January) and for this reason did not cover these peaks. Nonetheless, this was a good idea because a higher size of the heat pump would have led to an oversizing of the plant and, as a consequence, to higher investment costs. Figure 4.26 highlights this phenomenon if compared to Figures 4.22 and 4.24.

Conclusions

The aim of this thesis work was to perform a techno-economic analysis of the energy consumption of an apartment building, in the form of a group of collective self-consumption users. Two different scenarios were analyzed: the first consisted of a photovoltaic installation, while the second included both the introduction of a PV system and a heat pump. For both scenarios the simulation was performed on the whole Italian territory, showing the results for all the Italian regions and focusing the attention on three of them. The choice of the regions was made dividing Italy into three macro-regions: North, Center and South. A region from each of these areas was chosen. Moreover, a focus on the most significant cities of these regions was done. In addition to this techno-economic analysis, an environmental analysis was performed, measuring the amount of avoided CO_2 emissions in both the analyzed cases. The whole simulation was performed using MATLAB and the results showed in graphical form on the Italian map were obtained from QGIS software. The needed irradiance and temperature data, instead, were downloaded from PVGIS data set.

The results of both scenarios highlighted a very good environmental impact, with an evident amount of CO_2 savings for all the Italian regions. Moreover, all the regions presented important yearly cost savings, also thanks to the energy communities incentives that helped to reduce the payback time of the initial investment. However, each region benefited differently from the two scenarios, both from an energetic and an economic point of view. More into detail, first scenario, which consisted in a photovoltaic installation, favored regions with a higher yearly irradiance, in particular Southern Italy regions. The higher irradiance value allowed smaller PV sizes, which led to a lower investment and, as a consequence a lower payback period. Moreover, the higher PV production at equal PV size led to higher yearly cost savings. The second scenario, instead, presented a totally opposite situation. In this case, the improvement was not only about the electric energy consumption, but also regarding the thermal load satisfaction. In fact, both a photovoltaic system and a heat pump were installed. The heat pump worked to fulfill as much as possible the thermal load, switching the methane consumption into electricity consumption. Photovoltaic system produced energy to satisfy part of the electric load, given by the sum of the utilizes electric load and the heat pump electric load. However, a backup methane boiler was used in particular cases to help the heat pump fulfilling thermal load peaks. Differently from the first scenario, in this case the regions that benefited more from the installations were the colder regions, in particular Northern Italy ones. These regions presented a higher thermal load, that meant a bigger heat pump size and a higher investment. Nevertheless, this investment was quickly paid back thanks to the really low new yearly costs if compared to the reference ones when only the boiler was present. Southern Italy regions exploited heat pump less than northern ones and for this reason spent more time to amortize the initial expenditure. In fact, it was evident from the studied cases that the heat pump of a northern region with a thermal load four time higher than a southern region was only twice the size of the southern region's one. This meant colder regions managed to exploit the heat pump investment better. For this reason, they presented lower payback periods, higher values of IRR and NPV, and higher CO_2 savings.

To summarize, some regions benefited more from PV installation and others from the introduction of the heat pump, but overall, all the regions took a big advantage from both scenarios. The new installations led to good economic results, both in terms of yearly savings and payback time, but most of all gave a huge contribution to the reduction of CO_2 emissions.

In conclusion, the work showed how collective self-consumption can contribute both to the production of green energy, reducing emissions, and to cost savings, thanks to the share of produced energy and with the help of incentives given to energy communities and groups of collective self-consumers.

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