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CORSO DI DOTTORATO IN METODI, MODELLI E TECNOLOGIE PER L'INGEGNERIA

DIPARTIMENTO DI INGEGNERIA CIVILE E MECCANICA



Development of small-medium scale territorial business models and assessment for the implementation of local hydrogen production and use chains

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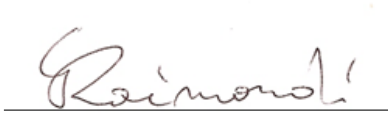
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Summary

In the energy transition away from fossil fuels, hydrogen is recognized to have a double face. On one side continuing to be a raw material in usual sectors (as refining and fertilizer production), but no longer produced by fossil methane. On the other side starting to be a substitute of fossil fuels in new sectors, not of current common use, such as high temperature heat production or transport.

To achieve these goals, different low-carbon supply chains will be considered in the coming years: international one very similar to what already happens for fossil fuels and local ones based on renewable sources present in the territory close to the final consumers. This thesis focuses on this second scenario, by analysing those enabling elements that can facilitate the introduction of local low-carbon hydrogen economy.

Among all the possible ones, two enabling elements have been focused on, that seem to be promising, but also the least investigated in literature: renewable energy communities (RECs) and climate finance according to the rules established in the European Union.

Both these enabling elements derive from a more than ten-years political action, born in particular within the European Union which has completed the implementation framework in recent years: the Italian scenario has been analysed and marginally the Spanish one.

In a REC based in Italy, it is possible to produce renewable hydrogen by selling it at a market price equivalent to the fossil one.

Using a hydrogen production, storage and consumption chain within multiple energy communities involved, it is possible in Italian scenario to better exploit renewable energy at a local level with a relevant increase in self-consumption at the same installed power level. It should be emphasized, however, that this scheme is not currently economically sustainable.

Considering a network of RECs in Spain using local residual lignocellulosic biomass, it is possible to simultaneously produce hydrogen, heat and electricity for local use, obtaining a cost per kilometre for a hydrogen vehicle that can be comparable to that obtained with diesel one.

Finally, considering the scenario of a high diffusion of RECs in the same territory with high penetration of renewable energy, the hydrogen produced using the excess of such renewables can be used for ancillary services for the regulation of the electric transmission grid. With the cost forecasts for fuel cells and electrolysers at 2035 this scenario will become economically sustainable.

In the field of introduction of low-carbon hydrogen in sectors where it has historically been used as a feedstock, climate finance is likely to be a driver with a sure impact in the coming years.

In the case of production of ammonia and synthetic methane from renewable electricity sources in Italy, climate finance fails nowadays to guarantee competitiveness with fossil fuel production. Despite the latter outcome, considering the expected evolution of electrolyser technology and a greater penetration

of renewable energy in Italy, clearly climate finance will enable a path towards energy transition for chemicals free from fossil feedstocks.

Abbreviations

AEM	Anion Exchange Membrane
ALK	Alkaline
ARERA	Italian Regulatory Authority of Energy, Networks and the Environment (in Italian language)
ASM	Ancillary Service Market
ASU	Air Separation Unit
ATR	Autothermal Reforming
BFD	Block Flow Diagram
BL	Battery Limit
BSP	Balancing Service Provider
CALA	Calabria region
CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CNOR	Central-Northern Italy
CSUD	Central-Southern Italy
CHP	Combined Heat and Power
CO_{2e}	CO_2 equivalent
COP26	Conference of the Parties 26th annual conference
COP27	Conference of the Parties 27th annual conference
CP	Concentration Polarization
CPC	Concentration Polarization Coefficient
DAM	Day-Ahead Market
DSO	Distribution System Operator
EF	Emission Factors
ENTSO-E	European Network of Transmission System Operators for Electricity
EOH	Equivalent Operating Hours
ETS	Emission Trading System
EU	European Union
EUA	European Union Allowance
FC	Fuel Cell
FFT	Fast Fourier Transform
GHG	Greenhouse Gas
GME	Italian Energy Services Operator (in Italian language)
GWP	Global Warming Potential
HRS	Hydrogen Refuelling Station
HB	Haber-Bosch process
HHV	Higher Heating Value
HV	High Voltage
ICE	Internal Combustion Engine
IF	Innovation Fund

IM	Intraday Market
IPCC	Intergovernmental Panel on Climate Change
JRC	Joint Research Centre
LCCA	Levelized Cost of Carbon Abatement
LCOA	Levelized Cost of Ammonia
LCOE	Levelized Cost Of Energy
LCOH	Levelized Cost Of Hydrogen
LCOP	Levelized Cost of Product
LCOU	Levelized Cost of Urea
LHV	Lower Heating Value
LV	Low voltage
MASE	Ministry of the Environment and Energy Security (in Italian language)
MB	Balancing Market (in Italian language)
MBR	Membrane Biological Reactor
MSD	Dispatching Services Market (in Italian language)
MV	Medium voltage
NF	Nano Filtration
NG	Natural Gas
NORD	Northern Italy
NPV	Net Present Value
OEM	Original Equipment Manufacturer
O&M	Operation and Maintenance
OPEX	Operational Expenditure
PCCC	Post Combustion Carbon Capture
Pd	Palladium
PEM	Proton Exchange Membrane
POD	Point of Delivery
PUN	Italian National Price (in Italian language)
PPA	Power Purchase Agreement
PSA	Pressure Swing Adsorption
PtG	Power-to-Gas
PtM	Power-to-Methane
PtP	Power-to-Power
PtX	Power-to-X
PV	Photovoltaic
PVPC	Voluntary Price for Small Consumers (as for the Spanish acronym)
RD	Real Decreto (Royal decree)
REC	Renewable Energy Community
RED	European Renewable Energy Directive
RED II	Renewable Energy Directive (second release)
RES	Renewable Energy Sources
RFNBO	Renewable Fuel of Non-Biological Origin
RO	Reverse Osmosis
SARD	Sardinia
SICI	Sicily
SME	Small and Medium Enterprise
SNG	Substitute Natural Gas
SO	Solid Oxide
SUD	Southern Italy
TDS	Total Dissolved Solids
TEU	Energy component of the access tariff (as for the Spanish acronym)
TRL	Technology Readiness Level
TSO	Transmission System Operator

UVAM	Virtually Aggregated Mixed Units (in Italian language)
WGS	Water Gas Shift
WWTP	Wastewater Treatment Plant

1 Introduction

1.1 Research background, motivation and scope

Federico Caffè was an Italian political economist working in Italy after the Second World War (1914-1987 presumed death). He was one of the first Italian economists of Keynesian inspiration. He spoke of the "failures" of the market, "jams" to the functioning of the market that stuck the progress towards a state of well-being (welfare state) [1].

Among these “failures” he listed unemployment, imbalances in wealth distribution, pollution.

In his vision of politics, Caffè attributed to the State the role of organizing society in order to remedy these “failures”, spontaneously reached by the market, by regulations and laws defining also incentives and taxation that could modify this spontaneous balance.

Nowadays many of the “failures” are not referred to only a sole State, and concern the whole World. Climate change is probably one of the biggest “failures” of the market, considering its own geographical and time scales. Consequently, as stated by Keynes' theory and elaborated by Caffè, only an intervention by a supranational state entity can lead to the solution of the problem. Since its signature in 1992, the United Nations Framework Convention on Climate Change (UNFCCC) defined the Conference of Parties (COP) that represents the entity that coordinates the economic and political activities to solve the climate change [2]: first in 1995.

In the path towards the transition from fossil sources towards those not emitting fossil carbon dioxide (renewables and nuclear), hydrogen produced with a small amount or without greenhouse gases emission (renewable or “green” hydrogen), is considered as a vector and a feedstock that will play an important role in the future energy and industrial landscape for climate change solution.

Hydrogen is considered renewable, low-emission or “green” in European Union if its production generates maximum 3.38 kg CO_2 per kg of hydrogen in lifecycle emissions [3].

Hydrogen is nowadays an important feedstock in global industries as oil refining and fertilizers. Global hydrogen use reached 95 Mton in 2022 with over 95% produced from fossil sources [4]. Hydrogen use could double if it will be used as energy carrier directly or to produce low-carbon fuels.

The announcements for new projects for the production of low-emissions hydrogen keep growing, but at the date only 5% of them have taken firm investment decisions due to uncertainties around the future

evolution of demand, the lack of clarity about certification and regulation and the lack of infrastructure available to deliver hydrogen to end users.

In this situation only public intervention by government entities can make the development path of the low-emission hydrogen market sustainable and therefore achieves the energy transition which otherwise would not develop spontaneously based on sole market evolution.

In recent years, many government actions in this direction have been established in various States (Cina, Japan) and supranational Entities (USA, EU) to solve the "failures" of the market that have generated the climate change (using Caffè words).

In particular in the European Union many regulatory frameworks are established to facilitate hydrogen economy as one of the paths toward solution of climate change. Those mechanism had an impact on all EU member States.

The present dissertation aims to contribute to explore the emerging opportunities from these EU regulatory frameworks to create a small-medium scale territorial green hydrogen market: new business models were defined and techno-economic analysis were carried out in different scenarios to assess economic feasibilities of local hydrogen production and use chains.

In the dissertation in particular, scenarios in Italy and Spain were discussed.

The international hydrogen supply chains in which hydrogen is produced in a Country and consumed in another Country, possibly even belonging to different continents, remain outside the scope of this dissertation. In fact, even if it is expected that this international hydrogen market at a global level will represent an important contribution to decarbonization in the coming years, only supply chains that can be developed completely at a regional level is considered in this work.

All parts are introduced in more detail and with literature background later in this booklet. In the next section, the outline of the dissertation is provided.

1.2 Dissertation outline

This doctoral thesis consists of two parts, each addressing a specific topic and composed of self-contained chapters. Below, a description of each part is given, linking it to the general context provided in the preceding section and guiding readers through the document. Concluding remarks and future perspective are provided in Chapter 8.

1.2.1 Hydrogen role in Renewable Energy Communities

The European Directive on Renewable Energy (RED II) [5] described Renewable Energy Communities (so called REC) as new entities enabling local production and consumption of renewables and energy carriers deriving from them.

RECs are aggregators of both distributed production of renewable energy and distributed consumption. Incentives in various forms are given to RECs by European States in order to facilitate their diffusion, contributing to increasing the renewables penetration in Europe.

The introduction of the concept of the REC at European level was an attempt by politics to define an original system of laws to introduce a new tool to act on the energy market by facilitating the solution to the "failure" of the climate crisis, using Caffè's words once again.

The present work aimed to give an original contribution to the understanding of the effects of the hydrogen use within the RECs in the European regulatory framework. In fact, the production and use of hydrogen in the RECs are a topic that, at the beginning of this doctoral work, appeared unaddressed in literature.

From Chapter 2 to Chapter 5 of present dissertation, different business models are defined ad assessed by a techno-economic point of view, both in Italy and Spain, for the production and use of hydrogen within the RECs considering various forms of renewable energy (wind, solar, biomass).

1.2.2 Impact of Climate Finance on hydrogen-based Power-to-X

The forms of financing, both public and private, aimed at supporting investments to address the climate change constitute the Climate Finance [6]: it represents an important tool to help solving globally the "failure" of climate change.

Climate finance and greenhouse gas emission reduction policies are becoming increasingly determining factors to take into consideration in feasibility studies, as several policies and programs are being put in place to accelerate the transition to a net-zero society [7].

Hydrogen is a building block for many feedstocks and its production in a "green" way based on electrical renewables is a key factor. Nowadays green production chains from renewables to chemical feedstocks or energy carriers, through hydrogen, (Power-to-X) appears not economically sustainable without supporting investments.

Climate Finance can introduce a mechanism in the market to reduce the economic gap between fossil and renewable pathway to production of energy carrier and chemicals.

In details in Chapters 7 and 8 are assessed Climate Finance impact on, respectively, feasibility of ammonia and substitute of natural gas (SNG) production in Italy, that appeared not assessed in literature combined with well-known techno-economic evaluations.

2 Economic assessment of hydrogen production in a Renewable Energy Community in Italy

This chapter is based on the following published article:

Spazzafumo G., Raimondi G. Economic assessment of hydrogen production in a Renewable Energy Community in Italy. E-Prime - Adv Electr Eng Electron Energy 2023; 4:100131. https://doi.org/10.1016/j.prime.2023.100131.

2.1 Introduction

Global issues regarding climate change are at the top of international priorities. With the Paris Agreement, 195 countries adopted the first universal and legally binding covenant on the global climate, defining a global action plan aimed at keeping global warming well below +2 °C compared to the pre-industrial era [8].

Europe has set carbon-neutrality goal by 2050 [9]. The Intergovernmental Panel on Climate Change clearly states that it is urgent to limit global warming to +1.5 °C rather than +2 °C [10]. The Glasgow COP26 confirmed the +1.5 °C threshold, and the final outlook states that commitments must be urgently transformed into tangible action [11].

Sharm el-Sheikh COP27 confirms COP26 previous conclusions, highlighting multi trillions needs per year to reach net zero emissions by 2050 [12].

Generation of renewable energy, both with large power plants and with small systems near the consumers, constitutes a crucial factor in curbing global warming.

2.1.1 Renewable energy community EU framework

The European Directive on Renewable Energy (RED II) [5] described Renewable Energy Communities (so called RECs) as a new legal entity for small scale decarbonisation both for residential end-users and SMEs [13][14][15][16]. In Italy the RED II Directive was adopted in November 2021 [17] and the full operative legislative framework should be completed by first quarter of 2023 with pronouncements of GSE (Gestore dei Servizi Energetici) and ARERA (Autorità di Regolazione per Energia, Reti e Ambiente). GSE is the Italian government-owned enterprise that promotes and incentives production of electricity from renewable sources and energy efficiency. ARERA is the Italian authority for regulation of markets based on a network.

A Renewable Energy Community is a legal entity as stated in article 2 paragraph (16) of RED II [5]. REC “in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity”. The primary purpose of REC is “to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits”.

Members of a REC are producers, consumers or prosumers (both producers and consumers) of renewable energy, and their role will be strategic in renewable evolution [18]. Article 8 of the reference Italian law [17] legally defined the concept of "shared energy", which is the energy produced by renewables and consumed in the same hour by users within a REC.

Furthermore in detail as defined in article 2, paragraph 1), letter q) of Dlgs 199/2021 [17], shared energy "is equal to the minimum, in each hourly period, between the electricity produced and fed into the grid by renewable source plants and the electricity withdrawn by all the associated end-customers located in the same market area". Shared energy receives economic subsidies by Italian Government.

2.1.2 Power-to-Gas for a local use of renewables

A REC produces, consumes, stores and sells renewable energy also via e-fuel (i.e., hydrogen). Hydrogen is currently used as a feedstock or energy carrier in different industrial sectors, and it will be used in many new applications during next year like logistics and transportation.

These new applications will start a different local market for renewables [19]. Production of green hydrogen is a key factor for decarbonization processes, as well as its sale price equal or lower to fossil hydrogen.

2.1.3 Literature review

The integration of a hydrogen Power-to-Gas (PtG) in a based on European Union (EU) framework REC appears not yet widely investigated. Pastore et al. [20] first introduced the concept to use REC incentives to support hydrogen production in decentralised energy systems. Bartolini et al. [21] investigated a REC with a high PV penetration and its management by different storage technologies including also a hydrogen PtG system.

Uyar et Besikci [22] assessed the integration of hydrogen to obtain a 100% renewable energy communities. Instead, maximization of renewable consumption inside the local installation area has widely investigated. Luthander et al. [23] made a review of strategies to increase residential PV self-consumption. Frieden et al. [24] described schemes in different EU States to stimulate renewable local consumption and minimise the local renewable excess.

Gallego-Castillo et al. [25] described different ways to increase renewable consumption in Spanish REC framework. Fischer and Madani [26] have revised role for heat pump for domestic heating to increase local renewable consumption. Todeschi et al. [27] described a methodology to plan REC in urban scenarios.

Alvaro-Hermana et al. [28] stated an optimisation model to increase local consumption in a REC. De Santi et al. [29] presented an optimization algorithm to size a REC.

Also hydrogen small-scale PtG system in decentralized energy systems is well described in the recent year. Ghenai et al. [30] have optimised a system for a community in a desert area.

Marino et al. [31] optimized a stand-alone PV system by hydrogen storage and fuel cell.

Fonseca et al. [32] reviewed state of the art of hydrogen implementation in distributed energy system. A PtG in an Italian incentivized REC with a local storage and tecno-economic assessment as described following appears not completely described in literature.

2.1.4 Scope of the work

Integration of a hydrogen Power-to-Gas in a Renewable Energy Community is dealed in this work. This study aims to assess economic competitiveness of hydrogen production in a REC by a PtG scheme, in the current Italian hydrogen market. More in detail the main objective of the study is to investigate the condition to produce renewable hydrogen inside a REC, obtaining a hydrogen selling price lower or equal to the minimum one found in current Italian market.

The purpose is achieved using economic subsidies to shared energy in a REC to decrease hydrogen selling price: REC subsidies are used as incentives to hydrogen production. Even if this idea is already presented in Pastore et al. [20], that appears as the only known work in the state of the art on hydrogen production in a REC under EU framework, novelty in this study is based on a different and explicit layout of the REC and of the PtG system. In fact, an electric interconnection scheme for the main components is defined in the study, such as a description of a hydrogen storage and delivering system.

An assessment of the mass of hydrogen that can be produced in each case is presented.

A calculation of the energy flows and of the impact of the components on Levelized cost of hydrogen (LCOH) and on Net present value (NPV) are presented. Lastly an optimal sizing of the technical components is investigated, within the possible renewable power range allowed for a single plant in a REC in Italy, to define economic sustainability limit of proposed scheme.

2.2 Material and methods

In this study, for electric residential users grouped in a REC, renewable generation is assured by a single centralized photovoltaic (PV) plant. An electrolyser is directly connected to the PV and uses exclusively energy from the PV (not from the grid). The energy converted into hydrogen is the excess one, not consumed in each hour of production by REC or by compression for hydrogen storage. The REC architecture is based solely on consumer members.

As a typical site, a village in a rural or remote area is considered, particularly in Central and the South of Italy: a study from ISTAT (the Italian Institute for Statistics) states that in those zones there are around 3,500 villages with a population under 2,000 inhabitants [33]. PV potential production in those areas is the best in Italy [34].

Handwerker et al. [35] stated that domestic production of hydrogen is not sustainable. To produce and sell renewable hydrogen by electrolysis in a PtG scheme, the best solution could be to install a centralised electrolyser connected directly to PV, with a storage.

A direct electrical connection of the electrolyser with the centralized PV plant avoids to buy electricity by the grid, preventing higher cost for hydrogen production.

The electrolyser market is pushing the Original Equipment Manufacturers (OEMs) in the sector towards bigger solution [36]: at least a 100 kW class for the electrolyser is suggested.

Based on CEI 0-16 Italian standard, when operating an electric machine with a higher power than 100 kW, it is mandatory to use medium voltage (MV) connection. In Italy the maximum incentivized power for renewables in a REC is 1 MW per each renewable plant [17].

This is the domain for the analysis in this paper. In this domain the analysed scenario is composed by a single centralised PV system, matched with a REC composed only by consumer members, with a local hydrogen storage system. Different cases are evaluated varying only the size of the components and not the layout of the system.

2.2.1 REC composition and characterization

It is a supposed community of 944 people, grouped in 450 electric users, each of them composed by one to maximum four people with a share like in Table 2.1.

Table 2.1: REC composition in the study

members in each electric user	*distribution of the classes in the REC [%]*	*users in the REC*	*people per class*
1	35%	158	158
2	30%	135	270
3	25%	112	336
4	10%	45	180
total	*100%*	*450*	*944*

The distribution of the classes is based on Italian demographic characterization carried out in 2020 [37]. Each user is a low voltage (LV) passive consumer: no power generation at the users' level is considered.

Energy consumed in the REC is estimated for each hour of the year.

To define the hourly energy consumption during a whole year (8,760 hours), each user is characterized by an energy hourly consumption, based on three independent factors: type of users (considering energy consumption behaviour in each hour of the day), numbers of members in the user (from 1 to 4), seasonal aspects (considering life style and building management).

Capozzoli et al. [38] defined three daily energy user Consumption Behaviour $CB(t)$ (in blue line in Figure 2.1) as percentages of daily electric total consumption estimated in each hour of the day. The sum of the percentages of energy consumption distribution over 24 hours is therefore equal to 100% of daily consumption.

For each hour is defined also a standard deviation to describe the stochastic daily variation of hourly consumption behaviour.

A fourth profile is defined for a single member user, that usually doesn't stay at home during the working-hours of a day.

The first three profiles (named type A, B, C), are suitable for all users (from 1 to 4 members), whereas profiles type D is used only for single member user.

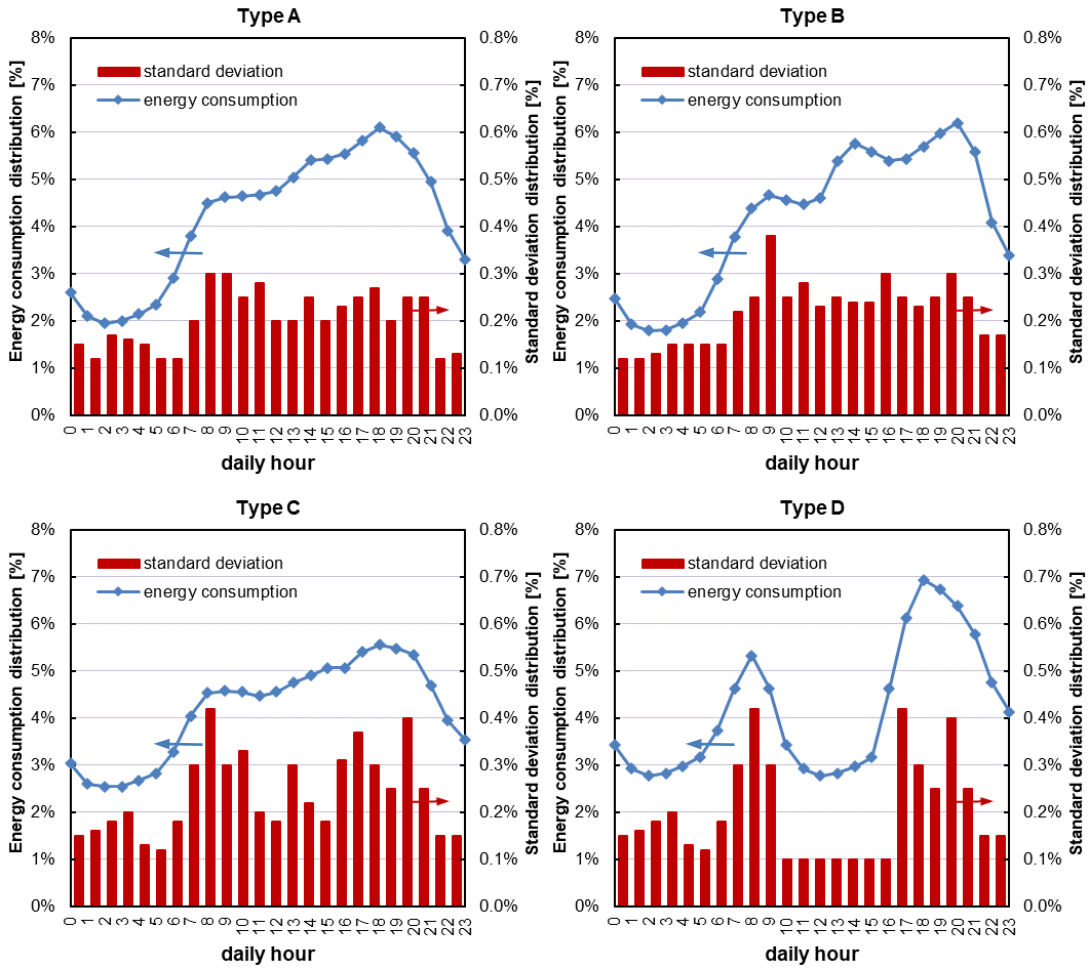


Figure 2.1. Energy consumption behaviours of different type of users with standard deviation

Capozzoli et al. [38] stated also the electric energy annual consumption for different users. Mean daily consumption with an associated standard deviation has been inferred for each user, as a function of number of members (shown in Table 2.2).

Table 2.2. Electric energy daily consumption for each user

members in each electric user	*Mean daily consumption [kWh/day]*	*standard deviation [kWh/day]*
1	3.84	0.46
2	7.26	0.87
3	7.95	0.95
4	10.82	1.30

Throughout the year the user electric consumption is affected by seasonal effects due to the variation in conditioning of buildings, illumination and lifestyle. Falabretti et al. [39] deduced the seasonal trend in power consumption by Italian national aggregate electrical demand from the national grid. Using open data for hourly national consumption [40] in Italy in 2017, with a Fast Fourier Transform analysis (FFT) a seasonal variation trend in electric consumption is inferred. A two harmonic signal reconstruction (red line in Figure 2.2) is able to describe the seasonal National fluctuation in

hourly power consumption $C^{Nat}(t)$ where t are the hours of the year (from 1 to 8,760) and C_m^{Nat} is the Italian average hourly consumption in 2017

$$C^{Nat}(t) = C_m^{Nat}[A_1 cos(\omega_1 t + \varphi_1) + A_2 cos(\omega_2 t + \varphi_2) + 1] \quad (2.1)$$

$$\begin{cases} C_m^{Nat} = 36579\ GWh \\ A_1 = 0.0472 \\ A_2 = 0.0910 \\ \omega_1 = 0.00077\ rad/h \\ \omega_1 = 0.00153\ rad/h \\ \varphi_1 = 1.780\ rad \\ \varphi_2 = -1.033\ rad \end{cases} \quad (2.2)$$

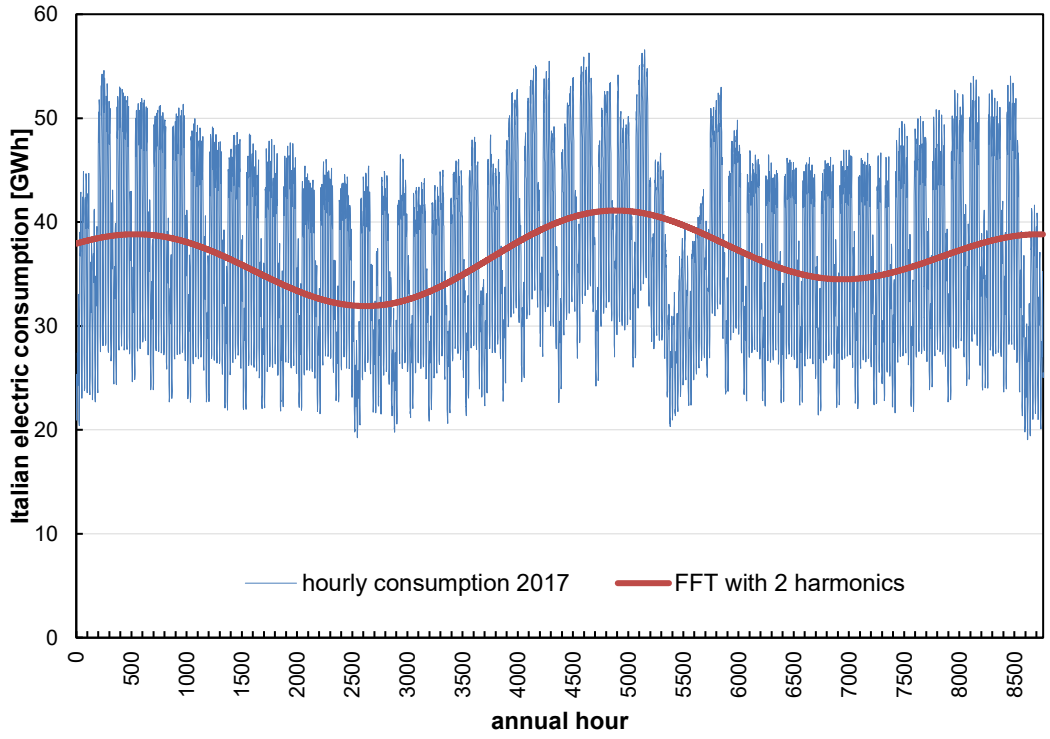


Figure 2.2. Seasonal electric consumption variation in Italy during 2017

Such a variation is normalized around its mean value to create an hourly Seasonal Factor $SF(t)$.

$$SF(t) = A_1 cos(\omega_1 t + \varphi_1) + A_2 cos(\omega_2 t + \varphi_2) + 1 \quad (2.3)$$

The parameters of Equation 2.3 have the same values indicated in Equations 2.2.

For each user, an hourly energy consumption trend $C^{user}(t)$ during the year is calculable by mentioned factors: a daily Consumption Behaviour attributing a type from A to D $(CB(t))$, an Average Daily Consumption based on members numbers (ADC), and a Season Factor $(SF(t))$.

The electric daily consumption behaviour $CB(t)$ of each user is calculated starting from data described in Figure 2.1 for four types of consumers (A, B, C and D). Each user maintains the same type during year. For each user of the REC, the percentage of consumption behaviour $CB(t)$ in each hour of a year is calculated as a random value in a Gaussian normal distribution that has mean value as

indicated in correspondent hour of Figure 2.1 (for the specific type) and correspondent standard deviation as indicated in the same Figure. Therefore, the hourly percentages of daily consumption behaviour are different for corresponding hours in the days during the year: $CB(t)$ has the same shape between days but a different value in each corresponding hour.

The average daily consumption (ADC) by each user is constant throughout the year, and it is calculated for each user as function of number of members (from 1 to 4) starting from value of mean value and standard deviation indicated in Table 2.2. For each user of the REC with a certain number of members, *ADC* is equal to a random value in the Gaussian normal distribution that has mean value as indicated in column 2 and standard deviation as indicated in column 3 of Table 2.2. The average daily consumption (ADC) of energy for each user is multiplied by that percentage of consumption behaviour $CB(t)$ defined above, to obtain the energy consumption value for each hour. Finally, the result is multiplied hourly by seasonal factor $SF(t)$, to create the ultimate trend of consumption for each user $C_{user}(t)$ in each hour during the year.

$$C_{user}(t) = CB(t) \cdot ADC \cdot SF(t) \tag{2.4}$$

An example of result of calculation of a user energy consumption $C^{user}(t)$ described above is shown in Figure 2.3 and Figure 2.4 for few hours and a whole year respectively. In the Figures a four members user is chosen with a power consumption daily distribution type A and an average daily consumption of *ADC*=11.66 kWh/day (annually 4,269 kWh/year). Figure 2.4 shows the seasonal trend.

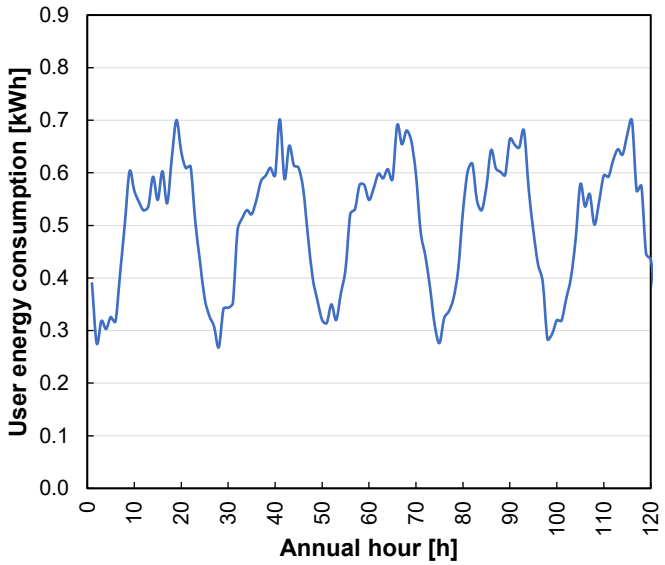


Figure 2.3. Four members type A user hourly consumption

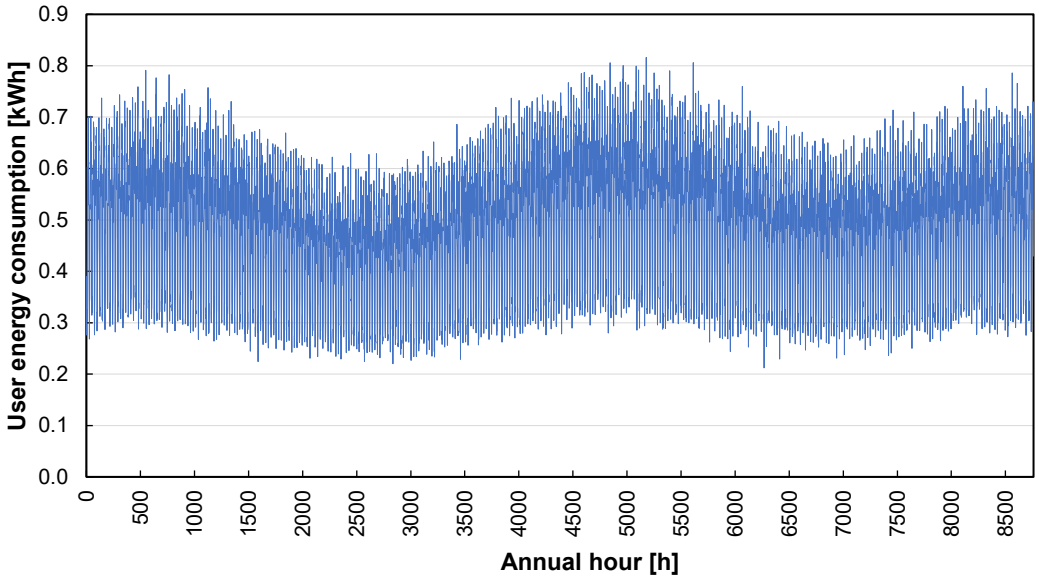


Figure 2.4. Four members type A user hourly consumption in a year

Lastly the annual consumption distribution of the whole members of a REC is defined adding each hour consumption deduced with the described methodology for the 450 users of the REC, hour by hour during the year.

$$C_{REC}(t) = \sum_{i=1}^{450} C_{user}(t) \tag{2.5}$$

In the assumed model there is no resolution thicker than the hour: within the hour all the quantities are considered constant. In particular, the powers exchanged by the members of the REC during the hour are constant, and therefore hourly power and hourly energy coincide from a numerical point of view. A maximum hourly consumption of 192 kWh, means that the maximum power consumed by REC is 192 kW.

2.2.2 Electric layout and flows

In this study the power generation is provided by a PV plant [41] that serves final users grouped in REC configuration through Distribution System Operator (DSO) grid. No distributed power generation (i.e. PV on the roof of the users) will be considered.

The layout of the electrical system is shown schematically in Figure 2.5.

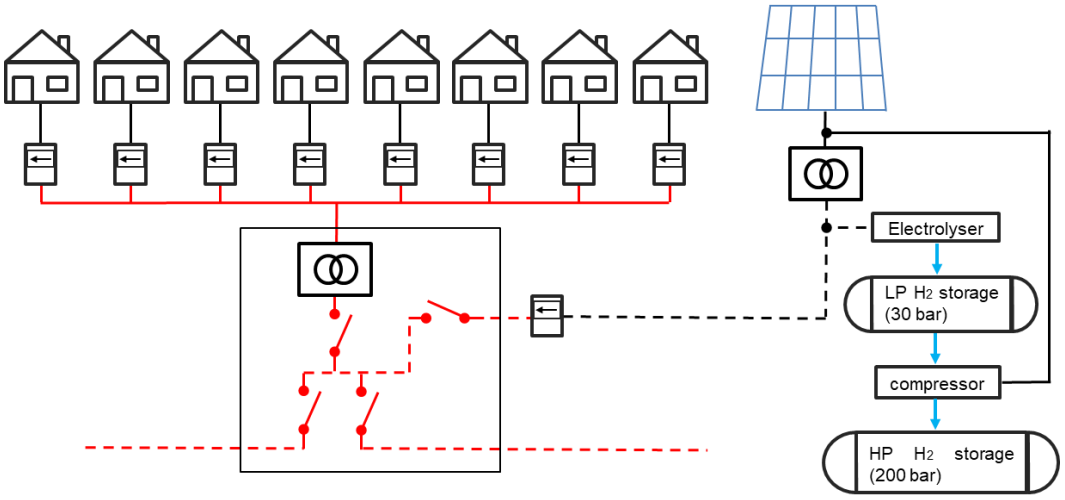


Figure 2.5. Electric layout

In solid line low voltage (LV) grid and in dashed line medium voltage (MV) grid are represented. The black line is the private (REC) grid, whereas the red line is the DSO grid. A symbol of electric meter defines the point of delivery (POD) of each producer or consumer who constitute the REC.

A POD for the power generation is considered with a private single MV line interconnected with electric DSO grid. Energy produced by PV ($E_{PV}(t)$) is drawn first by REC as shared energy ($E_{se}(t)$) and then by compressor ($E_{comp}(t)$)

$$E_{se}(t) = \min\left(C_{REC}(t);\ E_{PV}(t) - E_{comp}(t)\right) \tag{2.6}$$

Equation 2.6 is compliant with RED II and Italian reference law to define shared energy to estimate the subsidies to the REC. An electrolyser is connected to the FV line before POD to draw excess energy not used by compressor ($E_{Exc}(t)$) to produce hydrogen ($E_{Elect}(t)$) in the considered hour *t*. No energy from the grid is used to compress or produce hydrogen.

$$E_{Exc}(t) = \begin{cases} E_{PV}(t) - C_{REC}(t) & if \quad (E_{PV}(t) > C_{REC}(t)) \\ 0 \quad if \quad (E_{PV}(t) \leq C_{REC}(t)) \end{cases} \tag{2.7}$$

$$E_{Elect}(t) = \begin{cases} \min\left(\left\lfloor \frac{E_{Exc}(t) - E_{comp}(t)}{E_{core}} \right\rfloor; n_{core}\right) \cdot E_{core} & if\ E_{Exc}(t) \geq E_{comp}(t) \\ 0\ if\ E_{Exc}(t) < E_{comp}(t) \end{cases} \tag{2.8}$$

where n_{core} and E_{core} are number and power respectively of a single core in an electrolyser multicore as described below. A LV line from PV assures energy for compressor to store hydrogen at high pressure (200 bar) before selling.

If excess energy is not completely drawn by compressor or electrolyser, energy flows out of area ($E_{OOA}(t)$) where PV is installed and REC is connected throughout medium voltage DSO line (area described in Figure 2.5):

$$E_{OOA}(t) = E_{Exc}(t) - E_{Elect}(t) - E_{Comp}(t) \tag{2.9}$$

If REC has not enough energy from PV, energy from outside area ($E_{FOA}(t)$) is used:

$$E_{FOA}(t) = \begin{cases} C_{REC}(t) - E_{FV}(t) & if \quad (E_{FV}(t) < C_{REC}(t)) \\ 0 & if \quad (E_{FV}(t) \geq C_{REC}(t)) \end{cases} \tag{2.10}$$

2.2.3 Power generation by photovoltaic plant

Using data from JRC PVGIS initiative [34] a single kW peak PV system has been characterized in a Central Italy site ($E_{PV,1kWp}(t)$) during each hour of a reference year (2017 at Latitude in decimal degrees: 41.9230; Longitude in decimal degrees: 14.6470). The orientation for PV is South and slope is 34° that is optimal value as assumed by PVGIS software. The hourly production takes into account meteorological and season effects of a typical year. The annual production is 1,317 kWh/kWp.

The size of the PV power plant ($P_{p\ PV}$) in the study has been varied to define the more suitable solution. For each hypothesized size of the PV plant, an hourly distribution in a year of energy produced ($E_{PV}(t)$) by PV plant is evaluated based on same setting of JRC PVGIS (site, orientation, slope)

$$E_{PV}(t) = E_{PV,1kWp}(t) \cdot P_{p\ PV} \tag{2.11}$$

2.2.4 Electrolyser

The electrolyser is a modular AEM type EL 2.1 from Enapter [42]. The inferred data are summarized in Table 2.3.

Table 2.3. Single core characteristics of the electrolyser

power consumption with auxiliary [kW]	*3.05*
power consumption to produce hydrogen [kW]	*2.4*
volumetric hydrogen flow rate [Nl/hour]	*508*
mass flow rate [g/hour]	*45.7*
efficiency [% LHV]	*49.9%*

The electrolyser has a hydrogen output pressure up to 35 bar. A multicore electrolyser is assumed composed by independent cores (n_{core}), to better fit the power adsorbing of renewables not used in the REC or compressor hourly. Each core with auxiliary consumes an energy indicated by $E_{core} = 3.05\ kW$. Only on-off power mode is considered for each single core, with a simplified 0-100% duty cycle, without modulation of each core. The optimal number of cores is defined as output of the study, defining the total power input of electrolyser.

2.2.5 Storage of hydrogen

A low pressure (LP) 35 bar small hydrogen storage (cylinders) is put after the electrolyser that can be filled by a mass of hydrogen $Q_{Store\ LP}(t)$:

$$Q_{Store\ LP}(t) = Q_{Store\ LP}(t-1) + E_{Elet}(t) \cdot \eta_{Elect}/LHV_{H2} - Q_{H2\ trans}(t) \tag{2.12}$$

where η_{Elect} is efficiency indicated in Table 2.3 and LHV_{H2} is low heating value of hydrogen.

When a mass limit in LP storage ($Q_{H2\ LP\ lim}$) is reached, if there is enough excess of renewable, compressor draws energy ($E_{comp}(t)$) to transfer a mass of hydrogen ($Q_{H2\ trans}(t)$) to high pressure (HP) storage (200 bar).

$$E_{comp}(t) = \begin{cases} \min\left(P_{comp}; \frac{Q_{Store\ LP}(t-1)}{FROPR_{comp}}\right) & if\ Q_{H2\ Trans}(t) > 0 \\ 0 & if\ Q_{H2\ Trans}(t) = 0 \end{cases} \quad (2.13)$$

$$Q_{H2\ trans}(t) = \begin{cases} \min\left(Q_{H2\ Comp}; Q_{Store\ LP}(t-1)\right) \\ if\ Q_{Store\ LP}(t-1) \geq Q_{H2\ LP\ lim}\ AND\ E_{Exc}(t) \geq \min\left(P_{comp}; \frac{Q_{Store\ LP}(t-1)}{FROPR_{comp}}\right) \\ 0 \quad if\ Q_{Store\ LP}(t-1) < Q_{H2\ LP\ lim}\ OR\ E_{Exc}(t) < \min\left(P_{comp}; \frac{Q_{Store\ LP}(t-1)}{FROPR_{comp}}\right) \end{cases}$$

where $FROPR_{comp}$ is flow rate on power ratio of the compressor and it is inferred by [43]. Mass capacity of the LP storage $Q_{H2\ LP\ C}$ is defined as result of the simulation as maximum value in the year of mass of hydrogen stored in LP $Q_{Store\ LP}(t)$.

$Q_{H2\ comp}$ is the mass flow rate of the compressor depending of its nominal power P_{comp}

$$Q_{H2\ comp} = P_{comp} \cdot FROPR_{comp} \quad (2.14)$$

$$FROPR_{comp} = \frac{flow\ rate}{motor\ rating} = \frac{126\ kg/h}{335\ kW} = 0.376\ \frac{kg/h}{kW} \quad (2.15)$$

Hydrogen mass in HP storage is $Q_{Store\ HP}(t)$

$$Q_{Store\ HP}(t) = Q_{Store\ HP}(t-1) + Q_{H2\ trans}(t) - Q_{Del}(t) \quad (2.16)$$

When the mass of hydrogen in HP is higher than a limit ($Q_{H2\ CC}$), hydrogen is delivered to customer ($Q_{Del}(t)$) for selling.

$$Q_{Del}(t) = \begin{cases} Q_{H2\ CC} & if\ Q_{H2\ Store}(t-1) \geq Q_{H2\ CC} \\ 0 & if\ Q_{H2\ Store}(t-1) < Q_{H2\ CC} \end{cases} \quad (2.17)$$

Size of HP storage (200 bar) is defined so that delivery to customer happen no more frequently than once every 48 hours, to avoid a daily operation in the REC

$$Q_{Del}(t) \neq 0\ \ if\ \left(\bar{\bar{t}} - \bar{t}\right) \geq 48h \quad (2.18)$$

where $\bar{t}$ and $\bar{\bar{t}}$ are two consecutive hours of delivery of hydrogen.

Three-cylinder containers with a capacity of $Q_{Del}(t)$ composes the storage HP system (200 bar): one is at the customer, one at production site and one in travel or empty at the production site connected to the compressor, ready to be refill when the first one is full.

2.2.6 Economic facts

In a year simulation, cumulative values of shared energy, energy out of area, energy from outside area and hydrogen to the customer are calculated

$$E_{se\ ann} = \sum_{t=0}^{8760} E_{se}(t);\ \ E_{OOA\ ann} = \sum_{t=0}^{8760} E_{OOA}(t)\,; \tag{2.19}$$

$$E_{FOA\ ann} = \sum_{t=0}^{8760} E_{FOA}(t)\,;\ \ Q_{Del\ ann} = \sum_{t=0}^{8760} Q_{Del}(t) \tag{2.20}$$

Net present value (NPV) is considered as key factor for the economic analysis. Being that to have an economic benefit NPV has to be higher than zero, limit condition for feasibility can be considered as NPV equal to zero:

$$NPV = \sum_{a=0}^{n} \frac{E_{se\ ann}\cdot S_{\mathrm{se}} + (E_{se\ a} + E_{OOA\ a})\cdot PUN_a + Q_{Del\ a}\cdot P_{H2} - C_a - O\&M_a}{(1+d)^a} = 0 \tag{2.21}$$

where d is the interest rate, n lifetime of the investment, S_{se} is Italian economic subsidy for shared energy in a REC, PUN (Prezzo Unico Nazionale) is the wholesale electricity market price for Central Italy where the scenario is located, P_{H2} is minimum price of hydrogen in Italy [44]. Annual capital costs C_a and Operation and Maintenance costs $O\&M_a$ include PV, storages, compressor and electrolyser variable costs.

A Levelized Cost Of Hydrogen (LCOH) is evaluated for the various alternative cases, inspired by Levelized Cost Of Energy (LCOE) definition of Department for Business, Energy & Industrial Strategy [45].

$$LCOH = \sum_{a=0}^{n} \frac{C_a + O\&M_a - E_{se\ ann}\cdot S_{\mathrm{se}} - (E_{se\ ann} + E_{OOA\ ann})\cdot PUN_a}{(1+d)^a} \Big/ \sum_{t=0}^{n} \frac{Q_{Del\ ann,a}}{(1+d)^a} \tag{2.22}$$

Values considered in the simulation are shown in Table 2.4. Exchange ratio between euro and dollar is consider equal to 1.

Table 2.4. Economic parameters

Parameter	***Value***	***Ref.***
Lifetime, n [year]	*20*	[46]
Interest rate, d	*5%*	[46]
PV capital cost [€/kW]	*1,250*	[47]
Electrolyser capital cost [€/kW]	*770*	[46],[48]
Storage (250 bar) capital cost [€/kWh]	*13.5*	[43]
Compressor capital cost [€/kW] (<10 kW)	*6,700*	[43]
PV O&M cost [of CAPEX]	*1.2%*	[47]
Electrolyser O&M cost [€/kW year]	*19*	[46]
Storage O&M cost [of CAPEX]	*0.5%*	[47]
Compressor O&M cost [of CAPEX]	*4%*	[43]
Shared energy subsidies [€/kWh]	*0.119*	[49], [50]
Electric price (South Italy 2022) [€/MWh]	*39*	[51]
Hydrogen selling price [€/kg]	*5*	[44]

Schnuelle et al. [46] stated that electrolyser capital cost is around 770 €/kW; Collins [48] assumed that in 2025 Enapter will able to produce electrolyser at 550 €/kW. With a precautionary approach higher cost is considered in the simulation. Parks et al. [43] stated capital cost for compressor over 100 kW: a specific value can be inferred around 770 €/kW. During simulation appears that a size for compressor useful for the purpose is under 10 kW: interviews at Italian hydrogen compressor manufacturers at the beginning of 2021 indicates a specific capital cost of around 6,700 €/kW with a compressor power under 10 kW. This cautionary value is considered in the simulation. Electric selling price is evaluated as average value in 2020 to not take into account high price volatility due to market instability of 2021 and 2022: the chosen value is lower than current value (over 100 €/MWh in many day in last 2 years). It is a precautionary approach because higher value of electric selling price makes the investment more profitable and described cases most feasible.

Nicita et al. [44], based on Viesi et al. [52], stated that in Italy hydrogen selling price is in the range between 5.0 €/kg and 11.3 €/kg where the lower price refers to hydrogen produced in centralized plants by large scale steam fossil methane reformer (SMR), the higher to hydrogen produced on-site by electrolysis with grid electricity. Lower value is considered in the simulation to investigate if a hydrogen production in a REC can be competitive with fossil large scale production in Italy (worst-case).

2.3 Results and discussion

The REC's electric consumption as composed is characterized by a maximum hourly value of 192 kWh, a minimum value of 53 kWh, and an average value of 122 kWh. During a whole year the calculated energy consumption of the REC is 1,068 MWh, that is 1,130 kWh per capita.

Italian law on REC states that the maximum power for a single power plant is 1 MW [17]: in the simulation is assumed this limit for the PV plant. Maximum power for the electrolyser is assumed around the same PV peak power: 300 cores is the maximum value assumed for the Enapter electrolyser.

Regarding the parameters used in the simulation, their limit values and calculation step are indicated in Table 2.5.

Table 2.5. Simulation parameters

	min	*max*	*step*
$P_{p\,FV}$ [kW]	125	1000	125
n_{core} [adm]	2	300	1
$Q_{H2\,LP\,lim}$ [kg]	1	10	1
P_{comp} [kW]	5	20	1
$Q_{H2\,CC}$ [kg]	5	40	1

For each power step of the PV plant, the combination of simulation parameters is investigated to obtain NPV positive, closest to zero and with maximum of hydrogen production in the reference year. In other words, for each of the eight cases defined by size of PV plant ($P_{p\,FV}$), a conditional optimization was carried out. The condition is that the NPV is positive, closest to zero; the optimization for each PV size allows to obtain the values for the parameters to maximise amount of renewable hydrogen produced. In fact, beyond the size of the photovoltaic system, the remaining four variables make it possible to size completely the PtG system, and then to obtain the optimal sizing of the whole plant. The variables define respectively the power of the electrolyser (P_{elect}) through the number of modules (n_{core}), the size of the low-pressure storage ($Q_{H2\,LP\,C}$) through the mass limit in LP storage ($Q_{H2\,LP\,lim}$), the compressor power (P_{comp}) and the size of hydrogen HP storage ($Q_{H2\,CC}$). It is important to note that NPV close to zero is the limit condition for economical sustainability. Starting from this limit conditions with a given PV size, decreasing the size of the PtG system by diminishing number of electrolyser modules and consequent storages, NPV becomes greater than zero, obtaining full economic feasibility. So, the existence of these limit conditions for each PV size, allows to orientate in the choice of the economically sustainable dimensioning of the system. Results of optimization are shown in Table 2.6 for each PV case, where main numerical results have been indicated: net present value of the cases (NPV), levelized cost of hydrogen ($LCOH$) and total amount of hydrogen delivered and sell in the market annually ($Q_{Del\,ann}$) have shown in Table 2.6 other than main recalled parameters.

Table 2.6. Results of simulation

Case number	***#1***	***#2***	***#3***	***#4***	***#5***	***#6***	***#7***	***#8***
$\boldsymbol{P_{p\,FV}}$ $[\boldsymbol{kW}]$	*125*	*250*	*375*	*500*	*625*	*750*	*875*	*1000*
$\boldsymbol{n_{core}}$ $[\boldsymbol{adm}]$	-	*31*	*56*	*46*	*18*	-	-	-
$\boldsymbol{Q_{H2\,LP\,lim}}$ $[\boldsymbol{kg}]$	-	*1*	*1*	*1*	*1*	-	-	-
$\boldsymbol{P_{comp}}$ $[\boldsymbol{kW}]$	-	*5*	*5*	*5*	*5*	-	-	-
$\boldsymbol{Q_{H2\,CC}}$ $[\boldsymbol{kg}]$	-	*13*	*32*	*36*	*18*	-	-	-
$\boldsymbol{Q_{H2\,LP\,C}}$ $[\boldsymbol{kg}]$	-	*2*	*5*	*4*	*2*	-	-	-
$\boldsymbol{P_{elect}}$ $[\boldsymbol{kW}]$	-	*95*	*171*	*140*	*55*	-	-	-
$\boldsymbol{NPV}$ $[\boldsymbol{k}€]$	*144.6*	*84.0*	*1.2*	*0.2*	*1.2*	*8.7*	*-72.6*	*-158.2*
$\boldsymbol{LCOH}$ $[€/\boldsymbol{kg}]$	-	*-8.33*	*4.96*	*4.99*	*4.94*	-	-	-
$\boldsymbol{Q_{Del\,ann}}$ $[\boldsymbol{kg}]$	-	*494*	*2,112*	*3,168*	*1,692*	-	-	-

Negative value of LCOH indicates that subsidies for shared energy have a higher impact on cash flow in comparison with capital cost and O&M cost.

Distribution of renewable energy in different cases is detailed in Figure 2.6.

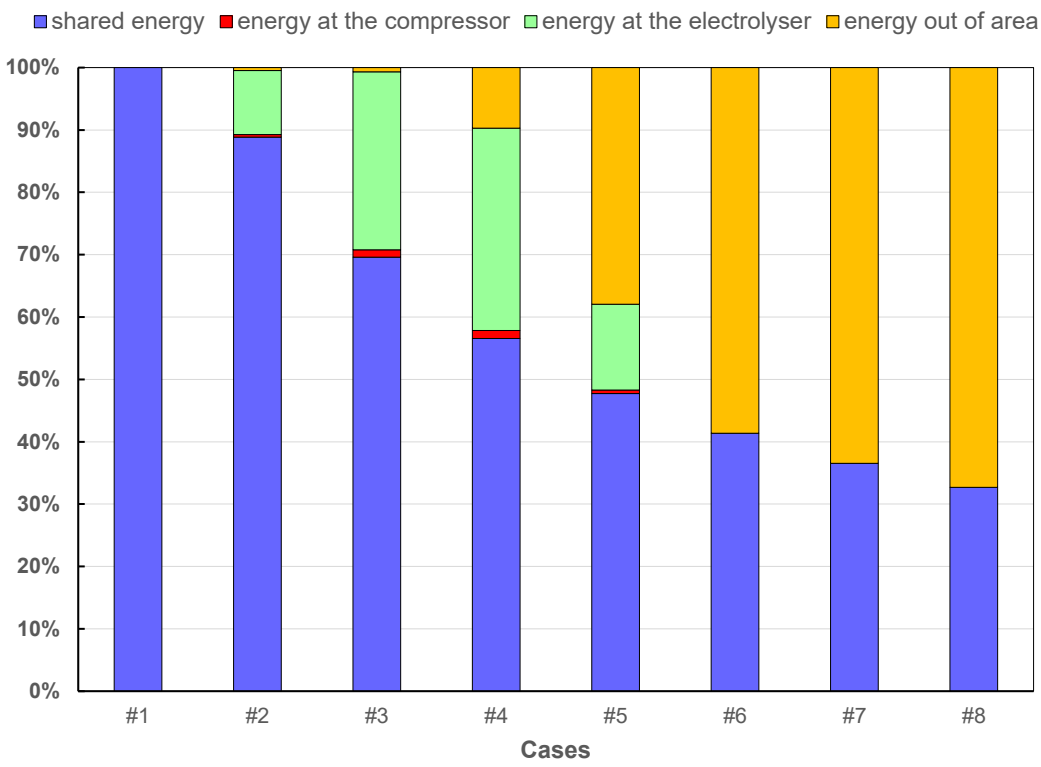


Figure 2.6. Renewable PV energy distribution in different cases

Case #1 has not enough renewables to produce hydrogen: the PV plant produces energy that is fully shared with REC and consumed by it. Without hydrogen supply chain, NPV is largely positive. Cases from #2 to #5 allow to produce hydrogen from renewables, selling it at the same price of fossil hydrogen (5 €/kg @200 bar), maintaining a NPV positive around zero. Case #2 have a much more than zero NPV because increasing electrolyser size to have NPV equal to zero, no extra hydrogen would be produced in the year: as shown in Figure 2.6 there is no relevant energy out of the area to convert in more hydrogen by more electrolyser core. In this condition have no sense obtain a NPV equal to zero buying a greater electrolyser that have no energy to produce hydrogen. For this reason, case # 2 has not NPV equal to zero.

An amount between hundreds or thousands of kilograms of hydrogen per year can be produced and sold at the same price and pressure value of fossil hydrogen from large SMR in cases from #2 to #5. Smaller electrolyser respectively for each cases (from #2 to #5) and consequently smaller storage systems, allows to sell hydrogen at the same price of hydrogen from SMR with a NPV greater than indicated in Table 2.6. In other words, there is the possibility to start a production of renewable hydrogen that makes the investment sustainable from an economic point of view (NPV greater than zero) by under sizing the PtG chain in comparison with that producing the maximum amount of hydrogen with a certain PV plant as indicated in Table 2.6.

In case from #2 to #5, enough shared energy allows to obtain economic subsidies that sustain the PtG supply chain more than the sale of hydrogen and electricity out of area (not shared in REC): in case #2 this situation is so impactful that LCOH is negative.

Increasing PV size, the shared energy perceptually decreases as indicated in Figure 2.6, and consequently the economic subsidies. In the case #6 with a PV plant of 750 kWp system is just

economically sustainable without hydrogen production (NPV equal to 8.7 k€): in case #6 PV size does not allow to increase significantly shared energy and the marginal energy produced in comparison with case #5 flows out of area away from REC.

Assumed price of energy is not enough for feasibility of the last three cases (from #6 to #8), and percentage of shared energy is too low. In them no production of hydrogen is allowed: in case #6 introducing the smallest PtG supply chain (only 1 core of electrolyser), NPV would be negative. In cases #7 and #8 NPV is negative without PtG supply chain. So, with electric price as assumed, a percentage of shared energy at least about 50% is necessary to obtain economic feasibility of a hydrogen PtG supply chain in a REC.

Case #4 and #5 are the best ones considering annual hydrogen sale (3,168 kg) and electrolyser capacity factor (24%) respectively. Capacity factor in case #5 is in line with Liponi et al. [53], but she stated a higher cost of hydrogen production.

These key performance indicators of presented analysis are shown in Figure 2.7.

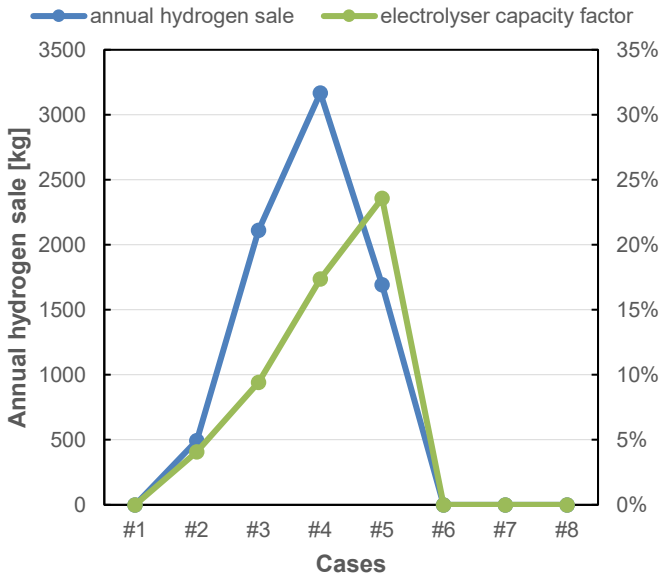


Figure 2.7. Annual hydrogen sale and electrolyser capacity factor

Three different conditions for PV size rise up from the study considering the same REC. A too small PV plant does not generate excess of renewable energy to convert into hydrogen: no PtG is achievable (case #1), even if, economically, the case is fully sustainable. A set of intermediate sizes of the PV plant generate both enough excess of electricity to be converted into hydrogen and a shared energy amount to obtain enough subsidies to economically sustain PtG chain (cases from #2 to #5). In this set optimal size can be define both to maximize amount of hydrogen annually produced and capacity factor of the electrolyser. A too big PV plant also if produces a lot of excess of renewable, generates perceptually too small amount of shared energy to sustain a PtG (case #6) or even the same PV additional power (case #7 and #8). In these last cases NPV is negative considering the only PV installation.

A general overview of total capital cost in different cases is indicated in Figure 2.8 for different cases investigated. It can be noted that capital cost of hydrogen supply chain is not the most relevant in

each case of the study in comparison with the capital cost of the PV plant that in any case is the predominant one.

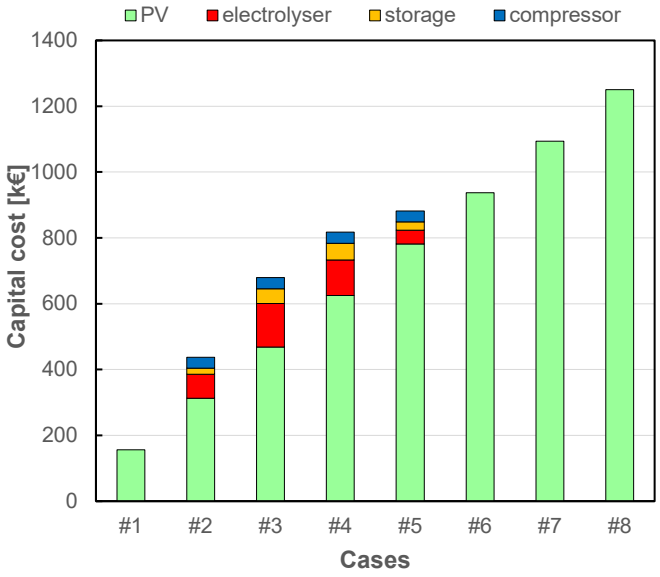


Figure 2.8. Total capital cost overview

2.4 Conclusions

This study explores production of hydrogen by electrolysis using excess of electricity in a Renewable Energy Community (REC) using a Power-to-Gas (PtG) scheme. Only residential electric users have been considered in the REC as case study, that are only consumers: no prosumers are assumed. Energy is generated by a single photovoltaic (PV) centralized plant. The study is defined for a small village in Central and the South of Italy, where thousands of villages are located with a good PV potential production. REC is composed by around 1 thousand people, grouped in 450 residential users. The proposed electrical layout describes a directly coupled electrolyser with the centralized PV plant. A storage system is defined, composed by low (35 bar) and high pressure (200 bar) cylinders, with a compressor that transfers hydrogen from first to second storage. No electricity is drawn by the grid by this electrolyser as well as by the compressor for storage purposes. The scheme presented is compliant with the European directives and the Italian legislation on REC. Italian incentive for shared energy in a REC is considered as well as revenue for selling electricity as well as hydrogen at the current lowest price in the Italian market (hydrogen from steam reforming fossil methane).

With assumed REC, eight different sizes for photovoltaic single plant in the power range allowed by Italian regulation have been explored (from 125 kWp to 1 MWp).

For each of them, in the study an optimal sizing of the PtG chain is presented at limit economic viable condition: power of both PV and electrolyser, capacities of the storages and power of the compressor has been defined to obtain a net present value (NPV) of the investment positive, closest to zero at the maximum of hydrogen production in a reference year. As general result, the study shows

that there are different sustainable sizes of the PtG in as defined REC to allow a local green hydrogen market at the same selling condition of fossil hydrogen from a large steam reforming plant.

More in detail, the main findings can be summarised as follows:

- The sizing of PV plant in view of the REC dimension and consumption characteristic is a critical aspect for the economic feasibility of the hydrogen PtG in a REC. A PV plant undersized or oversized nullifies the benefit of the proposed PtG scheme in a REC.
- Shared energy amount in REC is a useful key factor to define an optimal sizing of the renewable power generation. In the range between around 50% and 90% of shared energy in comparison with total renewable energy produced in a REC, the economic subsidies allow to produce green hydrogen at the same selling price of hydrogen from large steam reforming fossil methane plant.
- The amount of hydrogen generated in the case of maximum production quota is around 3 tons per year with a 140 kW electrolyser and a 500 kWp PV plant.
- There are sizes of the PtG based on a REC that allow to generate hydrogen at minimum Italian price and obtaining a NPV greater than zero.
- An electrolyser directly coupled at a single PV centralized plant enslaved at a residential REC has a capacity factor (up to 24% in case of 55 kW electrolyser and a 625 kWp PV plant) in line with one enslaved at a PV plant fully dedicated at hydrogen production by a PtG system. In the case addressed in the study the minimum selling price of hydrogen is lower than in PV plant full dedicated to PtG.

In conclusion, a PtG scheme in a residential REC can produce and sell in Italy green hydrogen (@200 bar) at the same price of fossil hydrogen from large scale steam methane reformer. Italian subsidies at shared energy in a REC is the key factor for this result, that can enable developing of a green hydrogen local market.

In future works a sensitivity analysis on many parameters involved in the study could better define the impact of foreseeable variations of the components of the systems (particularly electrolyser, compressor, storage systems) and of the value of electricity: within next few years, such sectors could appear to be highly volatile. Moreover, it appears to be of interest in a future study to compare economic feasibility of a centralized PV plant with a decentralized one with the same overall power peak but integrated at user's level. Effect of distribution of renewable energy between self-consumed energy and shared energy on economic behaviour of a hydrogen PtG in a REC could be of interest.

3 Exploring Renewable Energy Communities integration through a hydrogen Power-to-Power system in Italy

This chapter is based on the following published article:

Raimondi G., Spazzafumo G. Exploring Renewable Energy Communities integration through a hydrogen Power-to-Power system in Italy. Renew Energy 2023; 206:710–21. https://doi.org/10.1016/j.renene.2023.02.074.

3.1 Introduction

Global issues regarding climate change are on the top of international priorities. With the Paris Agreement, 195 countries adopted the first universal and legally binding covenant on the global climate, defining a global action plan aimed at keeping global warming well below +2 °C compared to the pre-industrial era [8]. Europe has set carbon-neutrality goal by 2050 [9]. The Intergovernmental Panel on Climate Change clearly states that it is urgent to limit global warming to +1.5 °C rather than +2 °C [10]. The Glasgow COP26 confirmed the +1.5 °C threshold, and the final outlook states that commitments must be urgently transformed into tangible action [11]. Sharm el-Sheikh COP27 confirms COP26 previous conclusions, highlighting multi trillions needs per year to reach net zero emissions by 2050 [12].

Generation of renewable energy, both with large power plants and with small systems near the consumers, constitutes a crucial factor in curbing global warming.

The European Directive on Renewable Energy (so called RED II) [5] describes Renewable Energy Communities (RECs) as a tool for small scale decarbonisation both for residential end-users and SMEs [13][14]. In Italy the RED II Directive was adopted in November 2021 [17] and the full operative legislative framework should be completed by the end of 2022 with pronouncements of GSE (namely Gestore dei Servizi Energetici) and ARERA (namely Autorità di Regolazione per Energia, Reti e Ambiente). GSE is Italian government-owned enterprise that promotes and incentives production of electricity from renewable sources and energy efficiency. ARERA is Italian authority for regulation of markets based on a network.

A Renewable Energy Community is a legal entity as stated in Article 2 number (16) of RED II [5]. REC "in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity". The primary purpose of REC is "to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits". A REC produces, consumes, stores and sells renewable energy also via e-fuel (i.e., hydrogen).

Members of a REC are producers, consumers or prosumers (both producers and consumers) of renewable power, and their role will be strategic in renewable evolution [18]. Article 8 of reference Italian law [17], has legally defined the concept of "shared energy", which is energy produced with renewables and consumed in the same hour by users within a REC. More in detail as defined in article 2, letter q) of 199/2021 [17], shared energy "is equal to the minimum, in each hourly period, between the electricity produced and fed into the grid by renewable source plants and the electricity withdrawn by all the associated end-customers located in the same market area". Shared energy receives economic subsidies by Italian Government. Shared energy is different by self-consumed energy, which is energy produced and consumed by the same user, at the same POD (point of delivery) of electric grid, at the same time.

Thanks to shared energy, RECs can prevent that relevant amount of electricity from renewables flow out from the local market area where both renewables and REC themselves are located. Different technologies and strategies can be used for this avoidance: storage devices, power-to-X (PtX) approach,

information sharing system and IoT to synchronize renewables production and consumption [15][39][54].

This study aims to define an original configuration to produce and use electricity from renewables within a defined area, to maximize electric autarchy (self-sufficiency) of users grouped in RECs in the same area, and to minimize the outflow of renewable energy from area of installation of renewables. As probable consequence on electric grid, the proposed configuration could create a minimum impact on electric parameters (i.e. frequency stability, power loss and voltage levels) out of the interested area [55] [56]. System configuration with two coordinated RECs linked by a hydrogen PtP system appears as novelty of this work, such as the sizing approach of the PtP subsystems.

3.2 Material and methods

For a group of electric users, in this study is proposed a configuration of a hydrogen Power-to-Power (PtP) system based on two RECs. Power generation is based on hybrid system (wind and photovoltaic). The purpose is to maximise autarchy of group of electric users installing renewables in their electric local market area and to minimize renewable energy outflow of the market area: this could avoid instability of the grid itself, that could disconnect renewables and generate curtailment [57]. This study presents a first scenario with a single REC that grouped the users, with a hybrid renewable system. A second alternative scenario introduces a PtP hydrogen system, in which the users are split in two RECs composed by the same users and using the same renewables power plant.

3.2.1 Technical features of the case studies

In this study the REC architecture is based on only consumers members with a centralized power generation, based on a hybrid configuration (both wind and photovoltaic) [58].

As typical site for the study is considered a village in rural or remote area particularly in Central and South of Italy: an ISTAT (the Italian Institute for Statistics) study states in those zones there are around 3,500 villages with a population under 2,000 inhabitants [33].

Handwerker et al. [35] states that domestic production of hydrogen is not sustainable. To store and share renewables among final users by hydrogen, the best solution could be to install a centralised electrolyser, with a single storage and a sole hydrogen fuel cell. On the same trend, the market of electrolyser is pushing the Original Equipment Manufacturers (OEMs) in the sector towards bigger solution [36]. Choosing hydrogen as technology to power a REC with a centralized solution at medium voltage (MV) seems to be suitable. Based on CEI 0-16 Italian standard, for more than 100 kW electric machine connected to the grid, is mandatory MV. In Italy the maximum incentivized power for renewables in a REC is 1 MW per each renewable plant [17]. This is the domain for the analysis in this paper.

3.2.2 REC composition and characterization

The scenario for this study is developed for private residential electric users. It is supposed a community of 420 people, grouped in 200 electric users, each of them composed by one to maximum four people with a share like in the Table 3.1.

Table 3.1. REC composition in the study

members in each electric user	*distribution of the classes in the REC [%]*	*users in the REC*	*people per class*
1	35%	70	70
2	30%	60	120
3	25%	50	150
4	10%	20	80
total	*100%*	*200*	*420*

Each user is a low voltage (LV) passive consumer: no power generation at the users' level is considered. The distribution of the classes is based on Italian demographic characterization carried out in 2020 [37].

Energy consumed in the REC is estimated each hour of the year. To define the hourly energy consumption during whole year (8,760 hours), each user is characterized by an energy hourly consumption based on three independent factors: type of users (considering energy consumption behaviour in each hour of the day); numbers of members in the users (from 1 to 4); seasonal aspects (considering life style and building management).

Capozzoli et al. [38] defines 3 daily energy user consumption behaviour $CB(t)$ (in blue line in Figure 3.1) as percentages of daily electric total consumption estimated in each hour of the day. The sum of the percentages of energy consumption distribution over 24 hours is therefore equal to 100% of daily consumption. For each hour is defined also a standard deviation, that describes the variation of the hourly electric consumption percentage. In fact, in each day at the same hour a stochastic variation of percentage of electric consumption occurs, due to lifestyle. This stochastic variation is quantified by standard deviation. A fourth profile is originally defined for a single member user, that usually doesn't stay at home during the working-hours of a day. First three profiles (named type A, B, C), are suitable for all users (from 1 to 4 members), whereas profiles type D is used only for single member user (Figure 3.1).

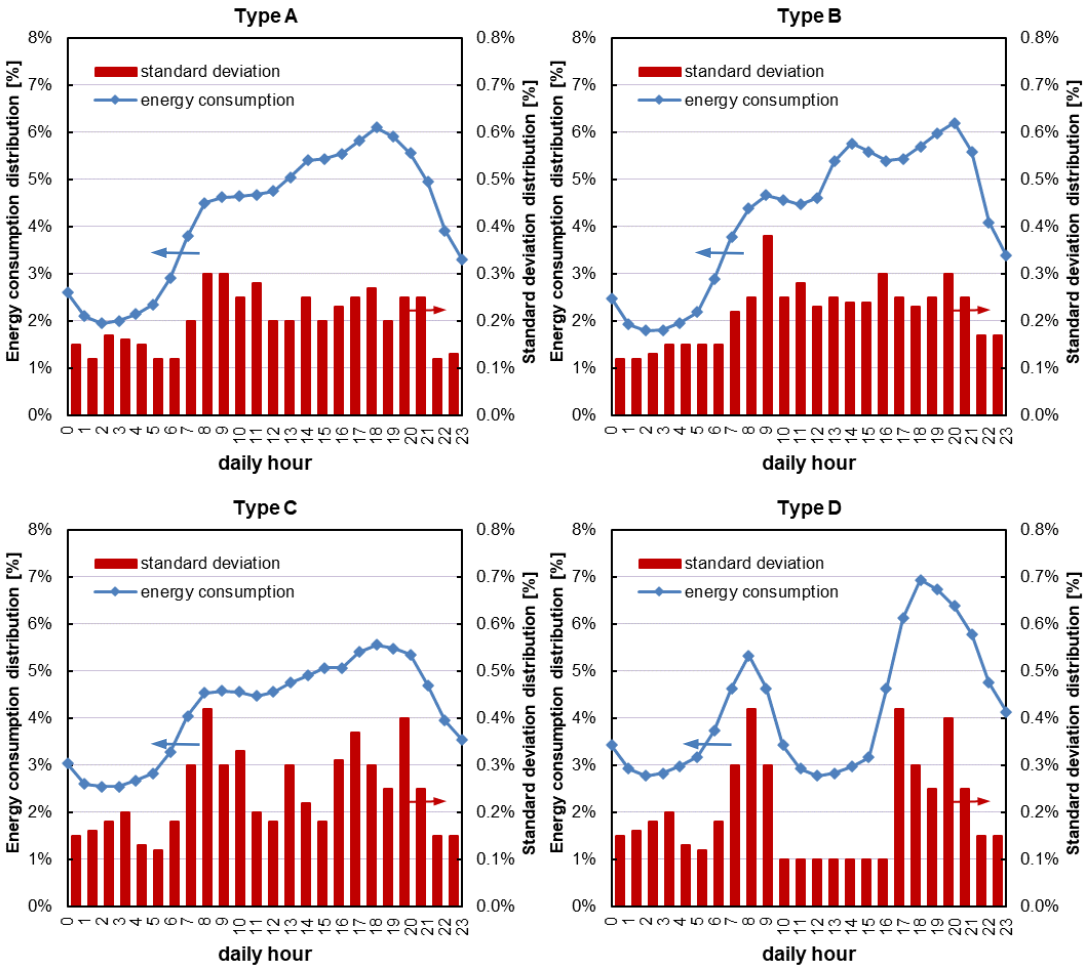


Figure 3.1. Energy consumption behaviours of different type of users with standard deviation

A standard deviation value associated to each hourly percentage of consumption makes it possible to define a consumption trend in a year for each user, which well reflects stochastic real behaviour, as will be better described below.

Capozzoli et al. [38] states also the electric energy annual consumption for different users. Starting from those data, an average daily consumption (ADC) with associated a standard deviation has been inferred for each user, as function of number of members (shown in Table 3.2).

Table 3.2. Electric energy daily consumption for each user

members in each electric user	*daily energy consumption [kWh/day]*	*standard deviation [kWh/day]*
1	3.84	0.46
2	7.26	0.87
3	7.95	0.95
4	10.82	1.30

Over a year the user electric consumption is affected by seasonal effects due to variation in conditioning of the buildings, illumination and lifestyle. Falabretti et al. [39] deduces the seasonal trend in power consumption by Italian national aggregate electrical demand from national grid. Using open

data for hourly national consumption [40] in Italy in 2017, with a Fast Fourier Transform analysis (FFT) a seasonal variation trend in electric consumption is inferred. A two harmonic signal reconstruction (red line in Figure 3.2) is able to describe the seasonal National fluctuation in hourly power consumption $C^{Nat}(t)$ where t is the hours of the year (from 0 to 8,760) and C_m^{Nat} is the Italian average hourly consumption in 2017

$$C^{Nat}(t) = C_m^{Nat}[A_1 cos(\omega_1 t + \varphi_1) + A_2 cos(\omega_2 t + \varphi_2) + 1] \quad (3.1)$$

$$\begin{cases} C_m^{Nat} = 36579\ GWh \\ A_1 = 0.0472 \\ A_2 = 0.0910 \\ \omega_1 = 0.00077\ rad/h \\ \omega_1 = 0.00153\ rad/h \\ \varphi_1 = 1.780\ rad \\ \varphi_2 = -1.033\ rad \end{cases} \quad (3.2)$$

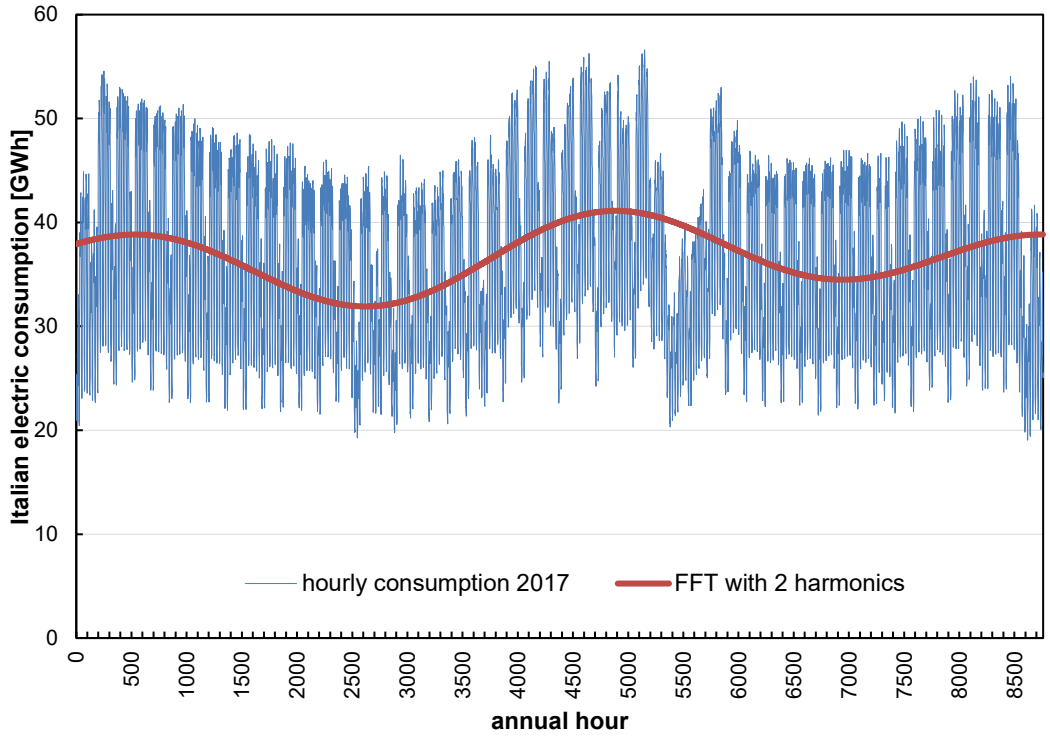


Figure 3.2. Seasonal electric consumption variation in Italy during 2017

Such a variation is normalized around its mean value to create an hourly seasonal factor $SF(t)$.

$$SF(t) = A_1 cos(\omega_1 t + \varphi_1) + A_2 cos(\omega_2 t + \varphi_2) + 1 \quad (3.3)$$

The values of parameters are the same indicated in (2).

For each user, an hourly energy consumption trend $C^{user}(t)$ during the year is calculable by mentioned factors: a daily consumption behaviour attributing a type from A to D $(CB(t))$, an average daily consumption based on numbers of members (ADC), and a season effect $(SF(t))$.

The electric daily consumption behaviour (shape of the daily curve) of each user is chosen among the four types (A, B, C and D as described in Figure 3.1): each user maintains the same type through each day of the year. A variation among the corresponding hours of the day is introduced by an hourly random value from Gaussian normal distribution, based on standard deviation of each hour as defined hourly for each type. So the hourly percentages of daily consumption behaviour are different for corresponding hours in the days during the year: $CB(t)$ have the same shape between days but different value in each corresponding hours.

The average daily consumption (ADC) by each user is constant throughout the year, and it is chosen for each user in a random mode in a Gaussian normal distribution of the consumption in the class of numbers of members, as described in Table 3.2. The average daily consumption (ADC) of energy for each user is multiplied by percentage of consumption behaviour $CB(t)$ defined above, to obtain the energy consumption value for each hour. Finally, the result is multiplied by hourly seasonal factor $SF(t)$, to create the ultimate trend of consumption for each user $C_{user}(t)$ in each hour over the year.

$$C_{user}(t) = CB(t) \cdot ADC \cdot SF(t) \tag{3.4}$$

An example of result of calculation of a user energy consumption $C^{user}(t)$ described above is shown in Figure 3.3 and Figure 3.4 for few hours and a whole year respectively. In the Figures a four members user is chosen with a power consumption daily distribution type A and an average daily consumption of *ADC*=11.66 kWh/day (annually 4,269 kWh/year). Figure 3.4 shows the seasonal trend.

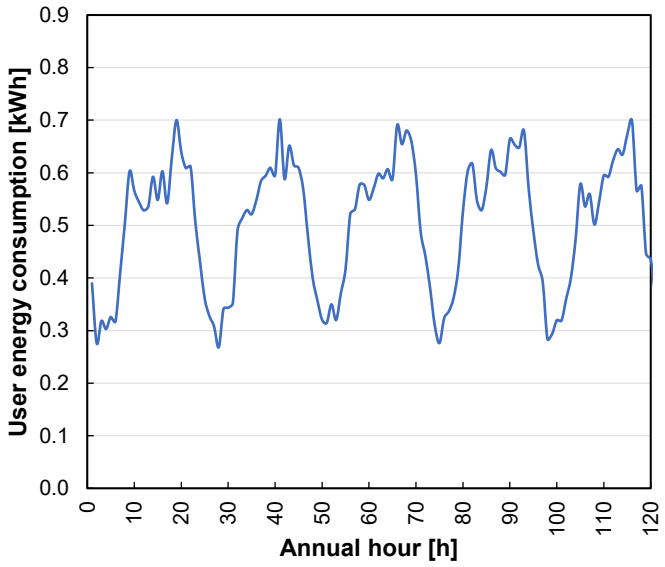


Figure 3.3. Four members type A user hourly consumption

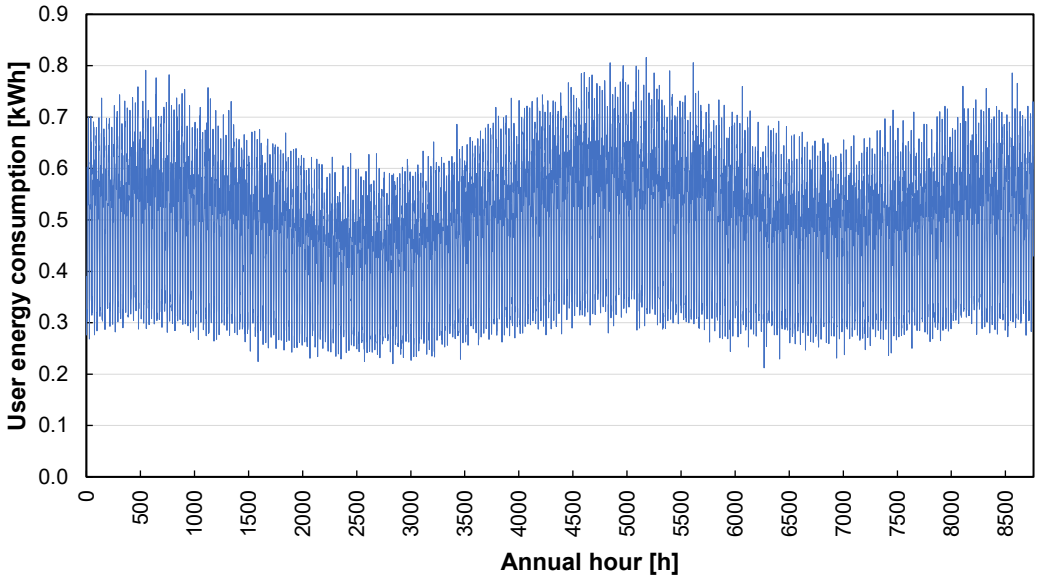


Figure 3.4. Four members type A user hourly consumption in a year

Lastly the annual consumption distribution of the whole members of a REC is defined adding each hour consumption deduced with the described methodology for the 200 users of the REC, hour by hour in the 8760 hours of the year.

$$C_{REC}(t) = \sum_{i=1}^{200} C_{user}(t) \quad (3.5)$$

The REC's electric consumption as composed is characterized by a maximum hourly value of 85 kWh, a minimum value of 24 kWh, an average value of 54 kWh. During the whole year the calculated energy consumption of the REC is 475 MWh, that is 1,130 kWh per capita.

In the model there is no resolution lower than the hour: within the hour all the quantities are considered constant. In particular, the powers exchanged by the elements of the REC during the hour are constant, and therefore hourly power and hourly energy from a numerical point of view coincide. A maximum hourly consumption of 85 kWh, means that the maximum power consumed by REC is 85 kW.

3.2.3 Electric configuration in basic and alternative scenario

In this study the power generation is provided by PV and wind ([41][59]) in a single site on which it is proposed to install both those forms of generation to serve final users grouped in REC configuration through Distribution System Operator (DSO) grid. No distributed power generation (i.e. PV on the roof of the users) will be considered. A unique point of delivery for the power generation is considered with a private single MV line interconnected with electric grid of the Distribution System Operator.

This configuration is considered as the basic scenario and is shown schematically in Figure 3.5.

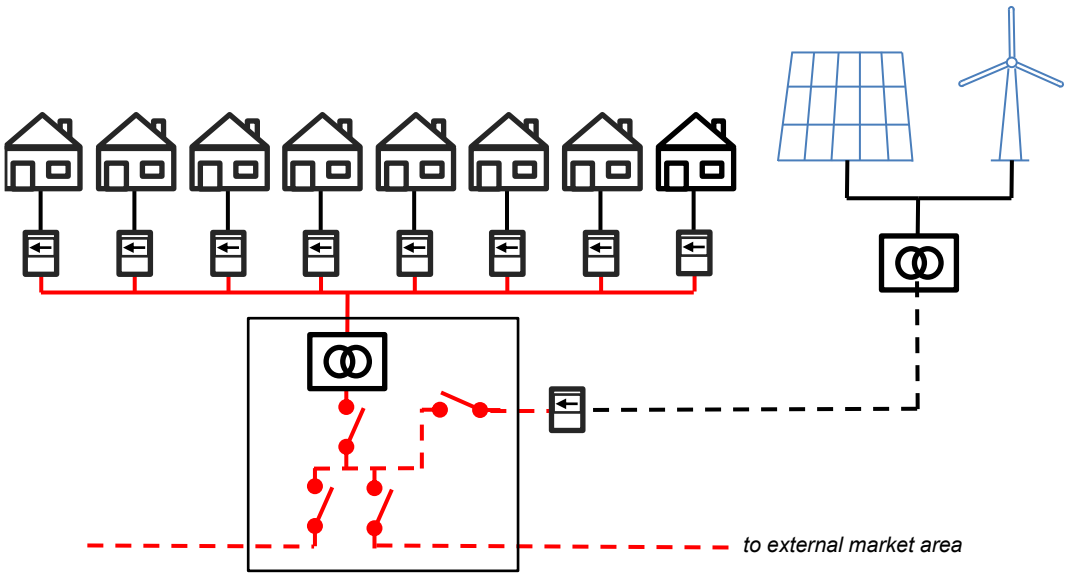


Figure 3.5. Electric configuration in basic scenario (electric local market area)

In solid line low voltage (LV) grid and in dashed line medium voltage (MV) grid; in black line the private grid, in red line the Distribution System Operator grid. A symbol of electric meter defines the point of delivery of each producer or consumer who constitute the REC.

An alternative scenario is proposed in this study based on a splitting of the same group of users in two different RECs. The first community (REC1) consumes directly power from hybrid power plant and produces hydrogen by an electrolyser using excess of renewables. No hydrogen is produced by electricity from the grid. The second energy community (REC2) consumes primarily electricity from a fuel cell, powered by hydrogen sold by REC1. Both the sub-communities can take energy from the grid for final use (production of hydrogen is not intended as a final use), and put into the grid electricity production. External electric market area (outside Figure 3.5 and 3.6 representations) will absorb peak of renewables power not fully converted in hydrogen, and supplying peak demand of energy not fully provided by renewables (REC1) or fuel cell (REC2).

The alternative scenario is showed in Figure 3.6.

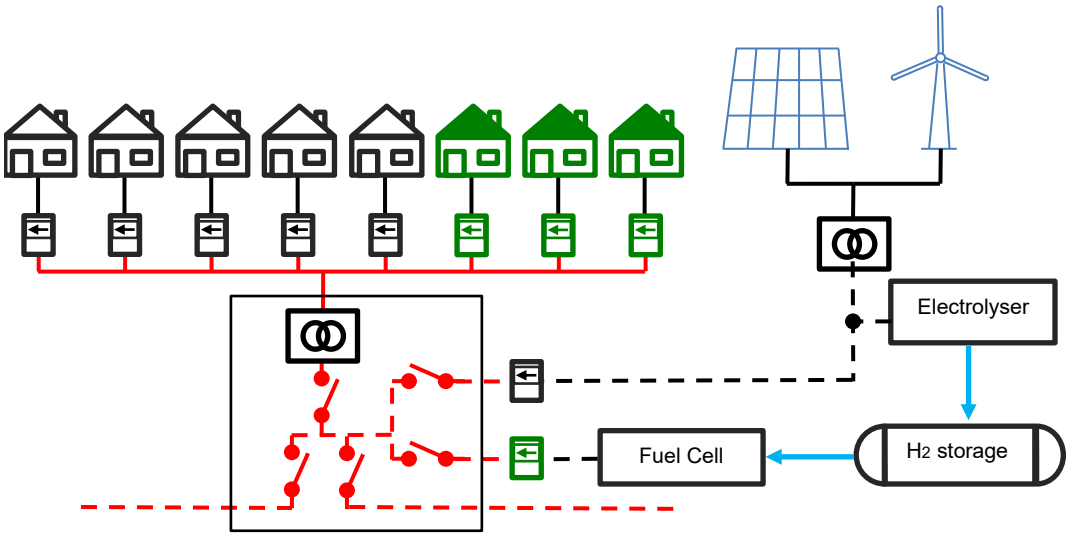


Figure 3.6. Electric configuration in alternative scenario (electric local market area)

In green line the symbols for users and point of delivery (meters) of REC2 members. The electrolyser is connected to the single electric line from renewables to produce hydrogen from the excess of electricity not directly used by the REC1. Hybrid power configuration (both PV and wind) expands the running hours of the electrolyser respect of a single source of renewables, obtaining a higher value of the capacity factor.

The REC2 composed by green point of deliveries is not compliant with Italian legal framework at the moment of writing (November 2022), because in a REC the production of electricity from renewable hydrogen is not provided by law [17] and consequently no subsidies is obtainable for shared energy in REC2.

3.2.4 Power generation by wind turbine

The basic wind turbine for this study is a Leitwind type LTW42 with an electric output of 250 kW at 9 m/s wind speed [60]. Starting from power curve of the turbine, based on studies of Pino et al. [61] a derated power curve is considered for the simulation, to obtain a more realistic electric output. A dimensionless power output versus wind speed on nominal speed ratio is defined by Pino analysis (Figure 3.7).

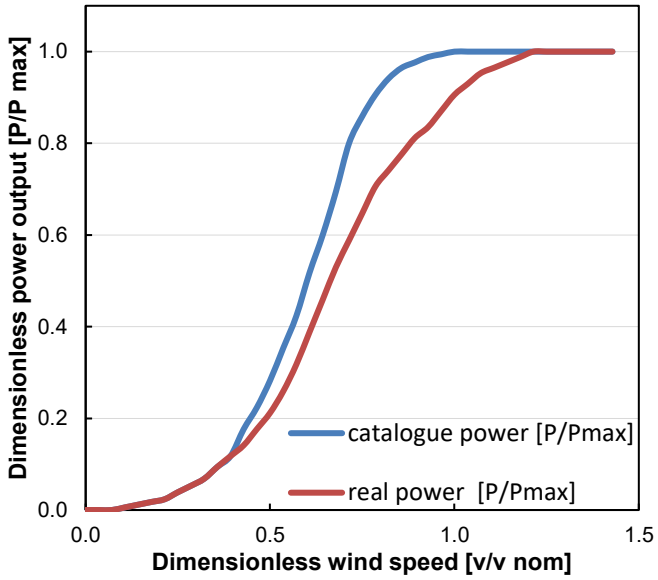


Figure 3.7. Derated dimensionless power curved for wind turbine

An average wind speed of 5.5 m/s at 50 m above ground level is assigned at the site for the plant, as stated by RSE Atlante eolico [62] characterization in many area of Central and Southern Italy. Using data from JRC PVGIS project [34] for a site in Central Italy (Latitude in decimal degrees: 41.9230; Longitude in decimal degrees: 14.6470; Elevation: 455 m above sea level), adapting the different ground level of the wind with a physical model as well-known [63], a hourly year distribution of the wind at 50 m is inferred with a 5.5 m/s average speed. The physical model to define the wind speed at different level [28] is described below, indicating with v the wind speed at a level h starting from a reference speed v_{ref} at a quota h_{ref}. The value for z_0 in that case is 0.1 m

$$\frac{v}{v_{ref}} = \frac{ln\left(\frac{h}{z_0}\right)}{ln\left(\frac{h_{ref}}{z_0}\right)} \tag{3.6}$$

Frequency analysis of wind distribution at 50 m above ground level is shown in Figure 3.8.

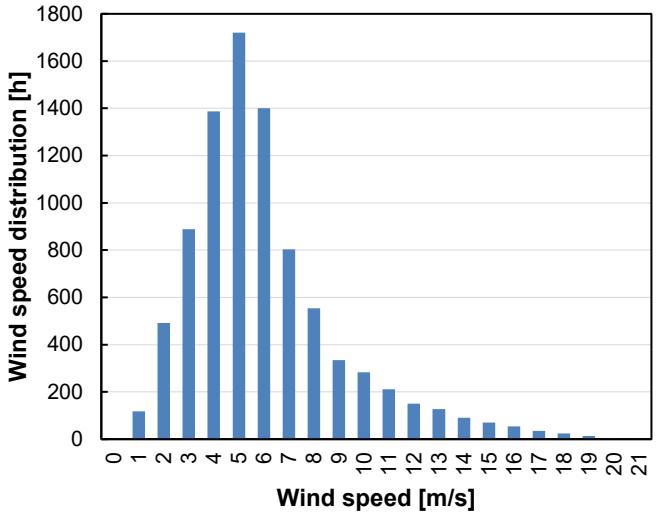


Figure 3.8. Wind speed distribution in supposed installation site for wind turbine

Using the Leitwind type LTW42 wind turbine with a hub at 50 m above ground level in mentioned conditions, an hourly power electric output is defined. For the supposed site a cumulated hour production of 1,954 hours per year is obtained.

The size of the wind turbine in the study has been varied, to define the more suitable solution: varying the nominal power output of the turbine, the shape of the derated power curve is maintained the same. With the same wind condition, different hourly energy distributions during the year are evaluated for different sizes of the wind turbine.

3.2.5 Power generation by photovoltaic

Using data from JRC PVGIS initiative [34] a single kW peak PV system has been characterized in the same Central Italy site of the wind analysis. The orientation for PV is South and slope is 34° that is optimal value as assumed by PVGIS software. The output from PVGIS is an hourly annual distribution of produced energy. The hourly production takes into account meteorological and season effects of a typical year. The annual production is 1,317 kWh/kWp.

Also the size of the PV power plant in the study has been varied to define the more suitable solution. For each hypothesized size of the PV plant, an hourly distribution of energy produced by PV plant is evaluated based on same setting of JRC PVGIS (site, orientation, slope).

3.2.6 Storage of hydrogen

A seasonal storage is considered for hydrogen. A metal hydrides system is assumed, including a very small gaseous quantity of hydrogen used for start-up of the fuel cell. The fuel cell supplies also the heat required for hydrogen extraction from metal hydrides. In this configuration the energy

consumption for the storage of the hydrogen is negligible and so not considered. The size of the storage is an output of the analysis. Compared to other technologies (battery or flywheel), hydrogen can store energy for seasons without relevant self-discharge [64].

3.2.7 Electrolyser and fuel cell stack

The electrolyser is a modular AEM type EL 2.1 from Enapter [42]. The inferred data are summarized in Table 3.3.

Table 3.3. Single core characteristics of the electrolyser

power consumption with auxiliary [kW]	*3.05*
power consumption to produce hydrogen [kW]	*2.4*
volumetric hydrogen flow rate [Nl/hour]	*508*
mass flow rate [g/hour]	*45.7*
efficiency [% LHV]	*49.9%*

A multicore electrolyser is assumed, to better fit the power adsorbing of renewables not used in the REC1 hourly. Only on-off power mode is considered for each single core, with a simplified 0-100% duty cycle, without modulation of each core. The optimal number of cores is defined as output of the study, defining the total power input of electrolyser.

A PEM fuel cell is considered. Its main characteristics are indicated in the Table 3.4.

Table 3.4. Fuel cell characteristics

nominal power [kW]	*85*
minimal load factor	*12%*
hydrogen consumption [kg/hour]	*5.4*
efficiency [% LHV]	*47.2%*

As for other technological elements, the fuel cell main dimensionless characteristics (minimal load factor and efficiency) are unchanged during the simulation. The round-trip efficiency (product of the electrolyser and fuel cell efficiencies) is 23.6%.

3.2.8 Economic analysis (LCOH and NPV)

A Levelized Cost Of Hydrogen (LCOH) was evaluated for the optimal alternative scenario, inspired by Levelized Cost Of Energy (LCOE) definition of Department for Business, Energy & Industrial Strategy [45].

$$LCOH = \sum_{t=1}^{n} \frac{C_{1,t} + O\&M_{1,t} - S_{1,t} - R_{\text{el }1,t}}{(1+d)^t} \Big/ \sum_{t=1}^{n} \frac{Q_{H2,t}}{(1+d)^t} \quad (3.7)$$

LCOH is based on REC1 that produces hydrogen, and specifically on capital costs $C_{1,t}$, subsidies $S_{1,t}$ for shared energy and electric revenues $R_{el\ 1,t}$ for both shared energy and energy outflow out

external area by grid, valued economically at wholesale electricity market price for South Italy [51]. Capital costs $C_{1,t}$ and Operation and Maintenance costs $O\&M_{1,t}$ include PV, wind, storage, electrolyser and fuel cell cost. Quantity of hydrogen produced $Q_{H2,t}$ is the same in each year, as energy production and sharing. Values considered in the simulation is indicated in Table 3.5. Exchange ratio between euro and dollar is consider equal to 1.

Table 3.5. Economic parameters

Parameter	*Value*	*Ref.*
Lifetime, n [year]	*20*	[46],[48]
Interest rate, d	*5%*	[46]
PV capital cost [€/kW]	*1250*	[47]
Wind capital cost [€/kW]	*1000*	[65]
Electrolyser capital cost [€/kW]	*770*	[46]
Storage capital cost [€/kWh]	*51*	[66]
Fuel cell capital cost [€/kW]	*2000*	[47]
PV O&M cost [of CAPEX]	*1.2%*	[47]
Wind O&M cost [€/kW year]	*12*	[65]
Electrolyser O&M cost [€/kW year]	*19*	[46]
Storage O&M cost [of CAPEX]	*0.5%*	[47]
Fuel cell O&M cost [€/kWh]	*0.02*	[47]
Shared energy subsidies [€/kWh]	*0.119*	[49], [50]
Electric price (South Italy 2021) [€/MWh]	*124*	[51]

An economic evaluation of the optimal alternative scenario is conducted using Net Present Value (NPV)

$$\begin{cases} NPV = NPV1 + NPV2 \\ NPV1 = \sum_{t=1}^{n} \frac{S_{1,t} + R_{\text{el }1,t} + LCOH \cdot Q_{H2,t} - C_{1,t} - O\&M_{1,t}}{(1+d)^t} \\ NPV2 = \sum_{t=1}^{n} \frac{S_{2,t} + R_{\text{el }2,t} - LCOH \cdot Q_{H2,t} - C_{2,t} - O\&M_{2,t}}{(1+d)^t} \end{cases} \quad (3.8)$$

where NPV1 And NPV2 are net present value for REC1 and REC2 respectively. Capital cost and Operation and Maintenance cost of PV, wind, electrolyser and storage are attributed at REC1, fuel cell cost at REC2.

3.3 Results and discussion

To define the common size of the hybrid power plant for both basic and alternative scenario, and the proportion between PV and wind generator, a consideration about the distribution of the energy produced in the site has been done. A 250 kW for each plant (both PV and wind) is analysed as a first hypothesis: an hourly distribution of energy annually produced at each level of power is shown in Figure 3.9. Red bars represent the hours of contemporaneous production by both wind and sun,

whereas blue bars represent only the production by wind and green bars represent only the production by sun. The distribution of cumulative power (red bar) is not the sum of each single distribution: it depends on stochastic contemporaneous overlapping between PV and wind production.

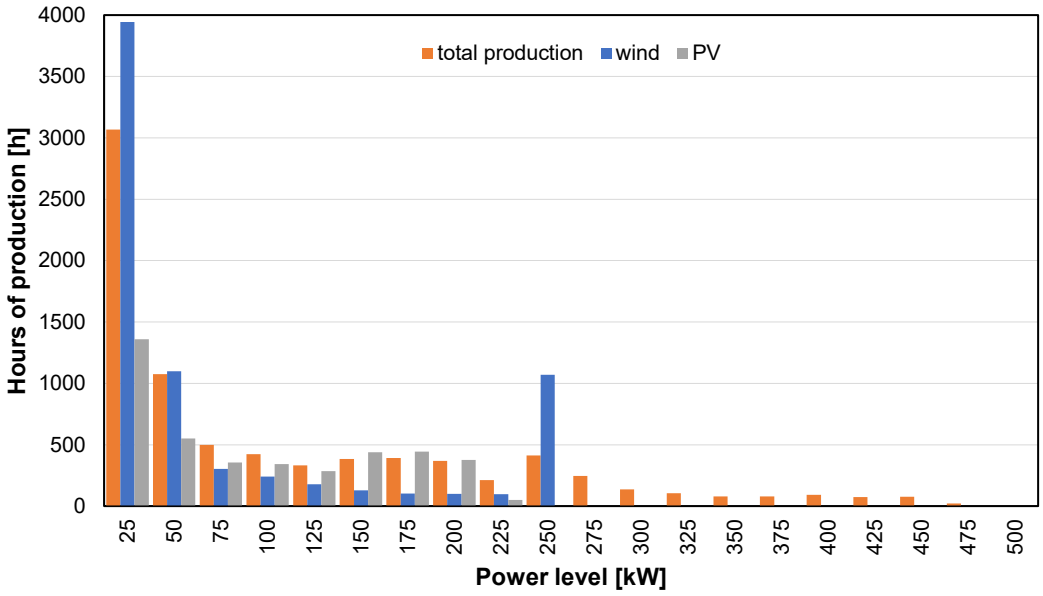


Figure 3.9. Distribution of power produced by wind and PV plants

With 25 kW step, in x-axis the power range is indicated in which the corresponding system (PV, wind or both) generate power for a number of hours in a typical year (y-axis). In the first step (25 kW in x-axis) are cumulated all the hours in a year in which the power output is between 0 and 25 kW. Obviously, in this group all the hours in which each system is turned off and does not produce energy are considered (i.e. PV in the night and wind during hours with wind speed under cut-in value). The trend shows that there are few conditions in which both PV and wind works at greater powers at the same time.

The wind plant has a relevant peak at the nominal power (250 kW for around 800 hours in a year), while the PV plant has a good performance up to 200 kW and disappear for higher powers. A so high peak of wind power exceeds by many times the maximum power need of the users, that is only 85 kW. In the alternative scenario this peak of wind power would be difficult to fully absorb by an electrolyser (net of REC1 consumption), because electrolyser sized to the renewable maximum power would have only a few hours of operation in a year, with a likely economic unsustainability (low capacity factor). On the other hand, it is not convenient to have an excessively small wind turbine, because it contributes with an important amount of energy of the users in conditions that would not be sufficiently covered by the PV. Therefore it was decided to set the PV and the wind power respectively to 55% and 45% of the total power installed. This sizing rule is considered for both basic and alternative scenario.

With reference to the basic scenario described in Figure 3.5, it is possible to define the matching between production of renewables and energy consumption by the REC for each hour of a year. Energy flows inside the REC are described by only three conditions: energy from renewables covers exactly the

REC needs, REC withdraws energy also outside from local market area (deficient renewables) or REC puts energy also into external local area by grid (excess renewables).

Consequently it is possible to define during a year the shared energy as defined in RED II (E_{se}), the energy taken from outside local market area by MV electric grid (energy from external grid E_{fg}) and the excess of energy fed into external market by MV grid (energy to external grid E_{tg}) and consumed outside local area.

Mathematically with each hour model (t) in the year

$$\begin{aligned} E_{se}(t) &= \min\left(C_{REC}(t);\ E_{Rw}(t)\right) \\ E_{fg}(t) &= \begin{cases} C_{REC}(t) - E_{Rw}(t) & if \quad (E_{Rw}(t) < C_{REC}(t)) \\ 0 & if \quad (E_{Rw}(t) \geq C_{REC}(t)) \end{cases} \\ E_{tg}(t) &= \begin{cases} E_{Rw}(t) - C_{REC}(t) & if \quad (E_{Rw}(t) > C_{REC}(t)) \\ 0 & if \quad (E_{Rw}(t) \leq C_{REC}(t)) \end{cases} \end{aligned} \tag{3.9}$$

where $E_{Rw}(t)$ is the total renewable energy produced in each hour of the year from sun $E_{PV}(t)$ and wind $E_{WP}(t)$

$$E_{Rw}(t) = E_{PV}(t) + E_{WP}(t) \tag{3.10}$$

The autarchy can be defined as ratio between annual shared energy (sum of shared energy in each hour of a year) and total amount of energy consumption during the period (sum of shared energy and energy from the grid in each hour of a year):

$$autarchy = \frac{\sum E_{se}}{\left(\sum E_{se} + \sum E_{fg}\right)} \tag{3.11}$$

Another parameter named market exchange ratio is defined between the total energy fed to the external grid (E_{tg}) and total energy drawn from the external grid (E_{fg}).

$$market\ exchange\ ratio = \frac{\sum E_{tg}}{\sum E_{fg}} \tag{3.12}$$

Both autarchy and market exchange ratio are evaluated as functions of the ratio between the production of renewable energy ($\sum E_{Rw}$) and the energy consumption of the REC ($\sum C_{REC}$).

The trend of autarchy and market exchange ratio are obtained by the simulation of the basic scenario with different total power size, maintaining the same proportion between solar and wind (55% and 45% respectively). The results of the simulation are shown in Figure 3.10.

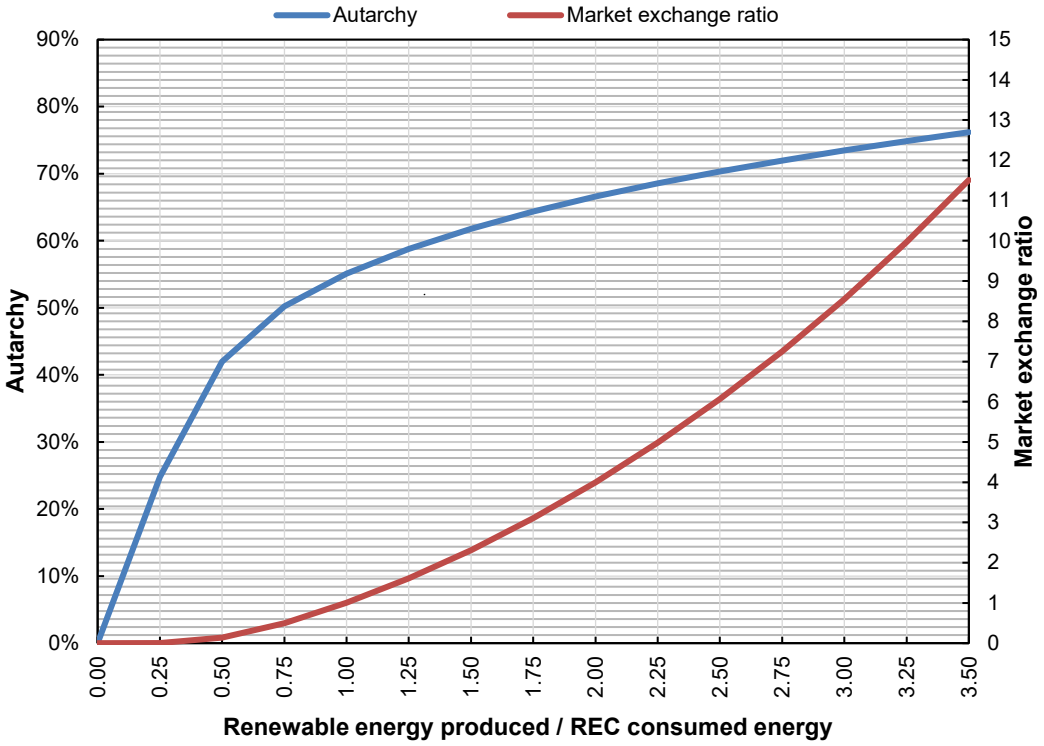


Figure 3.10. Distribution of autarchy and market exchange ratio in basic scenario

In Table 3.6 steps of simulation are shown with the detailed power installed used in each step.

Table 3.6. Simulation step in basic scenario

$\frac{\sum E_{Rw}}{\sum C_{REC}}$	*PV plant [kWp]*	*wind power [kW]*	*total renewables [kW]*	*autarchy [%]*	*market exchange ratio [adm]*
0.00	*0*	*0*	*0*	*0%*	*0.0*
0.25	*41*	*33*	*74*	*25%*	*0.0*
0.50	*81*	*67*	*148*	*42%*	*0.1*
0.75	*122*	*100*	*222*	*50%*	*0.5*
1.00	*163*	*133*	*296*	*55%*	*1.0*
1.25	*204*	*167*	*370*	*59%*	*1.6*
1.50	*244*	*200*	*444*	*62%*	*2.3*
1.75	*285*	*233*	*518*	*64%*	*3.1*
2.00	*326*	*267*	*592*	*67%*	*4.0*
2.25	*366*	*300*	*666*	*69%*	*5.0*
2.50	*407*	*333*	*740*	*70%*	*6.1*
2.75	*448*	*366*	*814*	*72%*	*7.3*
3.00	*489*	*400*	*888*	*73%*	*8.5*
3.25	*529*	*433*	*962*	*75%*	*10.0*
3.50	*570*	*466*	*1036*	*76%*	*11.5*

Annually REC consumed energy ($\sum C_{REC}$) is constant, therefore increasing the dimension of the hybrid power plant increases the ratio between renewable energy produced and REC consumed energy: autarchy has the same trend (blue curve in Figure 3.10). The market exchange ratio has a more than

linear growth (red curve in Figure 3.10). This is the effect of no dispatchability of renewables, that obviously are not synchronized with the consumption: to increase renewables means to increase even more the surplus to be fed into the external electric area by grid. The autarchy has no maximum point and have a continuous increasing trend with a decreasing slope. Marginal power installed tends to give progressively reduced contribution to autarchy and increased contribution to energy transfer outside local area considered.

A REC could improve the autarchy with data driven personal behaviours of the users that can synchronise consumption and renewables production, but they are difficult to realize and quantify.

To evaluate the effect of a hydrogen based PtP system on autarchy the alternative scenario (Figure 3.6) is introduced under the same boundary conditions: power size of the renewables, ratio between PV and wind, weather conditions and consequently distribution of power generation during the year, number of users and their own behaviour.

The proposed criterion to size the power generation for both basic and alternative scenario, considers the round-trip efficiency of the hydrogen PtP as a key factor. To obtain an excess of renewable energy able to substitute the energy drawn from the external area by a PtP hydrogen supply chain, the market exchange ratio has to be greater than the reciprocal of the round-trip efficiency. Due to round-trip efficiency slightly less than 25% as in this study, market exchange ratio greater than 4 is at least necessary. Due to techno-economic inadequacy to transform all the excess of renewables into hydrogen (e.g. in case of power renewables peaks) as stated by Liponi et al. study [53], a configuration is chosen that ensures market exchange ratio equal to 5. In this condition the excess of renewables can be made available as energy to the users by hydrogen based PtP. The proposed PtP system is asymmetric: electrolyser draws excess of energy from REC1 to feed only REC2 (not REC1) by a hydrogen fuel cell. REC2 has a fully dispatchable power from renewables.

Based on simulation described above, as derivable from Figure 3.10, a market exchange ratio equal to 5 corresponds to a renewable energy produced over REC consumed energy ratio equal to 2.25 and a hybrid power plant of 666 kW (as indicated in Table 3.6), composed by a 300 kW of wind power and 366 kWp of PV (45%-55% proportion as set before), with a total renewable production of 1,069 MWh and an energy request of users of 475 MWh. The total energy to external grid is 743 MWh that is 5 times the energy from external grid (149 MWh). In the basic scenario the renewables assure an autarchy of 68.6% (see Figure 3.10). This is the hybrid power plant size for both basic and alternative scenarios used in the comparative study.

Moreover in the basic scenario, the distribution per power class of the energy to the external area (produced by renewables and in excess respect the request of the users) is indicated in Figure 3.11.

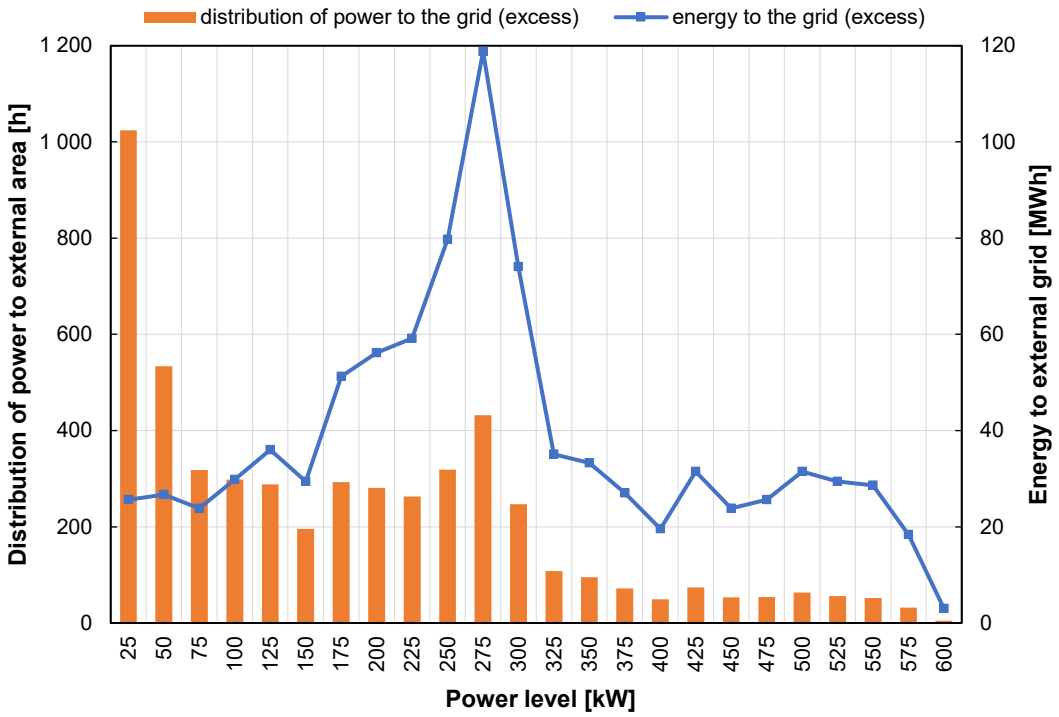


Figure 3.11. Distribution of renewable excess power to external area in basic scenario

The most of energy feeds the external area (around 75% of the total excess of energy) with a level of power up to 350 kW.

A first indication to define the size of the electrolyser can be inferred by Liponi et al. study [53]: it is not convenient by techno-economic matter have the same power between renewables and electrolyser. Liponi considers a PV plant without direct electric users, so the whole energy is used to produce hydrogen. In alternative scenario, only the excess of energy is useful to be transformed in hydrogen, so the optimal size of electrolyser will be less than in Liponi analysis (that is 70% of PV peak power).

In basic scenario the ratio between cumulated excess of energy not directly consumed by REC at each level of power normalized on total excess of energy is indicated with dashed line in Figure 3.12.

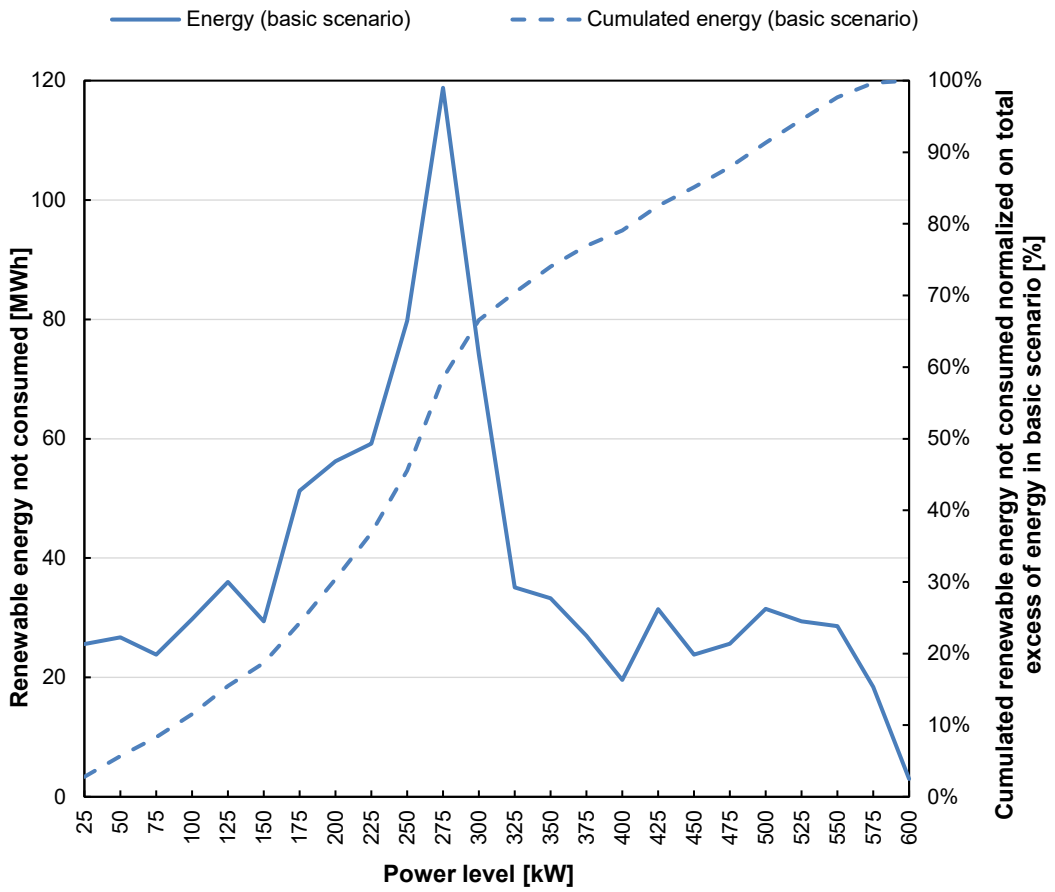


Figure 3.12. Energy to external grid in basic scenario

The ratio has a parabolic like trend until around 65% of its value and a linear like trend beyond: increasing the size of electrolyser until the point of change of trend means obtain the highest marginal benefit. Therefore the electrolyser size is set on this point.

The fuel cell sizing is defined at the maximum power need of the REC2. An ex-post evaluation of electrolyser and fuel cell capacity factor in comparison with literature was used to define the appropriateness of choices.

A new mathematical model is defined for energy flows in alternative scenario in each hour (t) of a year with the hydrogen PtP system

$$
\begin{gathered}
E_{se1}(t) = \min\left(C_{REC1}(t);\ E_{Rw}(t)\right) \\
E_{se2}(t) = \min\left(C_{REC2}(t);\ E_{FC}(t)\right) \\
E_{se}(t) = E_{se1}(t) + E_{se2}(t) \\
C_{REC}(t) = C_{REC1}(t) + C_{REC2}(t) \\
E_{Exc}(t) = \begin{cases} E_{Rw}(t) - C_{REC1}(t) & if \quad (E_{Rw}(t) > C_{REC1}(t)) \\ 0 & if \quad (E_{Rw}(t) \leq C_{REC1}(t)) \end{cases} \\
E_{Elect}(t) = \min\left(\left\lfloor \frac{E_{Exc}(t)}{E_{core}} \right\rfloor; n_{core}\right) \cdot E_{core} \\
E_{Store}(t) = E_{Store}(t-1) + E_{Elet}(t) \cdot \eta_{Elect} - \frac{E_{FC}(t)}{\eta_{FC}} \\
E_{FC}(t) = \begin{cases} P_{FC} & if\ \min(C_{REC2}(t); E_{Store}(t-1) \cdot \eta_{FC}) \geq P_{FC} \\ \min(C_{REC2}(t); E_{Store}(t-1) \cdot \eta_{FC}) & if\ \mathrm{LF}_{min}^{FC} \cdot P_{FC} < \min(C_{REC2}(t); E_{Store}(t-1) \cdot \eta_{FC}) < P_{FC} \\ 0 & if\ \min(C_{REC2}(t); E_{Store}(t-1) \cdot \eta_{FC}) \leq \mathrm{LF}_{min}^{FC} \cdot P_{FC} \end{cases} \\
E_{fg1}(t) = \begin{cases} C_{REC1}(t) - E_{Rw}(t) & if \quad (E_{Rw}(t) < C_{REC1}(t)) \\ 0 & if \quad (E_{Rw}(t) \geq C_{REC1}(t)) \end{cases} \\
E_{fg2}(t) = \begin{cases} C_{REC2}(t) - E_{FC}(t) & if \quad (E_{FC}(t) < C_{REC2}(t)) \\ 0 & if \quad (E_{FC}(t) \geq C_{REC2}(t)) \end{cases} \\
E_{fg}(t) = E_{fg1}(t) + E_{fg2}(t) \\
E_{tg}(t) = \begin{cases} E_{Rw}(t) - C_{REC1}(t) - E_{Elect}(t) & if \quad (E_{Rw}(t) - C_{REC1}(t) - E_{Elect}(t) > 0) \\ 0 & if \quad (E_{Rw}(t) - C_{REC1}(t) - E_{Elect}(t) \leq 0) \end{cases}
\end{gathered}
\tag{3.13}
$$

where $E_{se1}(t)$ and $E_{se2}(t)$ are the shared energy in the REC1 and in the REC2 respectively; $C_{REC1}(t)$ and $C_{REC2}(t)$ are the hourly energy consumption of REC1 and REC2 respectively; $E_{Exc}(t)$ is the excess of energy in REC1; $E_{Elect}(t)$ is the energy hourly used by electrolyser; n_{core} is the total number of cores which composes the electrolyser, E_{core} is the nominal power drawn by single electrolyser core; η_{FC} and η_{Elect} are the efficiencies of fuel cell and electrolyser respectively; $E_{Store}(t)$ is the energy stored in hydrogen; $E_{FC}(t)$ is the energy produced by fuel cell; P_{FC} is the nominal power of fuel cell and LF_{min}^{FC} is the minimal load factor of fuel cell as indicated in Table 3.4; $E_{fg1}(t)$ and $E_{fg2}(t)$ are the energy from the external grid drawn by REC1 and REC2 respectively.

Energy from renewables covers the REC1 needs and the excess renewable energy is converted into hydrogen in the power range of operability of the multi core electrolyser or put into the grid towards external market area for peak of power over the maximum capacity of the electrolyser. REC1 draws energy from external grid if there is an hourly deficient in renewables. If the stored hydrogen is enough, REC2 draws primarily energy from fuel cell in the range of its own modulation (from 12% to 100% of fuel cell nominal load); if necessary REC2 integrates fuel cell production with energy also from external market by grid. Inside the single hour a spike of energy could flow from REC2 to the external grid due to control system programming of the fuel cell, but this is not appreciable with the simulation tool that doesn't consider a variation of power levels inside the single hour. The split of users in two RECs in the alternative scenario is carried out on the energy request. For example, a 70%-30% splitting means that the REC1 has an energy request equal to 70% of the all users, and REC2 an energy request of 30%. Varying the level of splitting of the users, characteristics and performances of REC1 and REC2 are shown in Table 3.7. In bold the optimal splitting in two RECs with ratio 60%-40% to maximize the global autarchy.

Table 3.7. Autarchy using PtP hydrogen in different splitting level of the users

REC 1 size	*REC 2 size*	*electrolyser power [kW]*	*number of cores of electrolyser*	*fuel cell power [kW]*	*Autarchy*	*renewables energy to external grid*
100%	*0%*	*0*	*0*	*0*	*68.6%*	*69.5%*
90%	*10%*	*287*	*94*	*9*	*73.3%*	*8.0%*
80%	*20%*	*287*	*94*	*17*	*77.9%*	*8.4%*
70%	*30%*	*290*	*95*	*26*	*82.0%*	*8.7%*
60%	***40%***	***290***	***95***	***34***	***83.7%***	***9.1%***
50%	*50%*	*290*	*95*	*43*	*78.7%*	*9.6%*
40%	*60%*	*296*	*97*	*51*	*73.5%*	*9.7%*
30%	*70%*	*296*	*97*	*60*	*67.7%*	*10.3%*
20%	*80%*	*296*	*97*	*68*	*61.2%*	*10.9%*
10%	*90%*	*299*	*98*	*77*	*54.2%*	*11.2%*

In comparison with basic scenario with the same hybrid renewable power plant, autarchy of the group of users is 83.7%, with an increasing of 14.2%. The storage dimension to allow this result is 600 kg of hydrogen (around 20,000 kWh). The yearly trend of energy stored is showed in Figure 3.13. The storage dimension is lower than value requested for complying with Italian so called "Seveso III" law [67] that is of 5,000 kg of hydrogen.

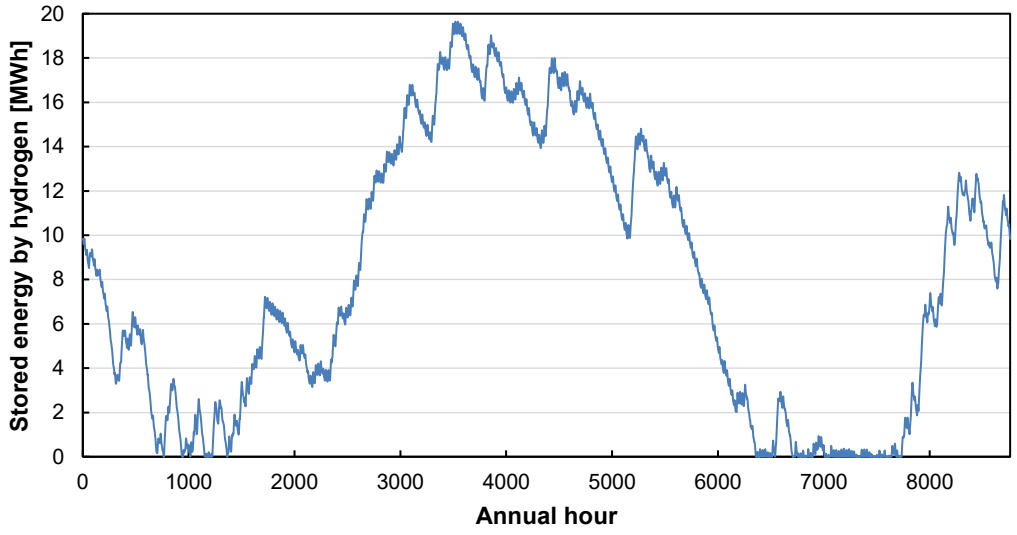


Figure 3.13. Level trend of energy stored as hydrogen in a year

In the optimal alternative scenario, renewable energy to external grid is globally only 9.1% of total renewable production versus 69.5% of basic scenario, and power to the external grid is distributed at a lower power level, as shown in Figure 3.14.

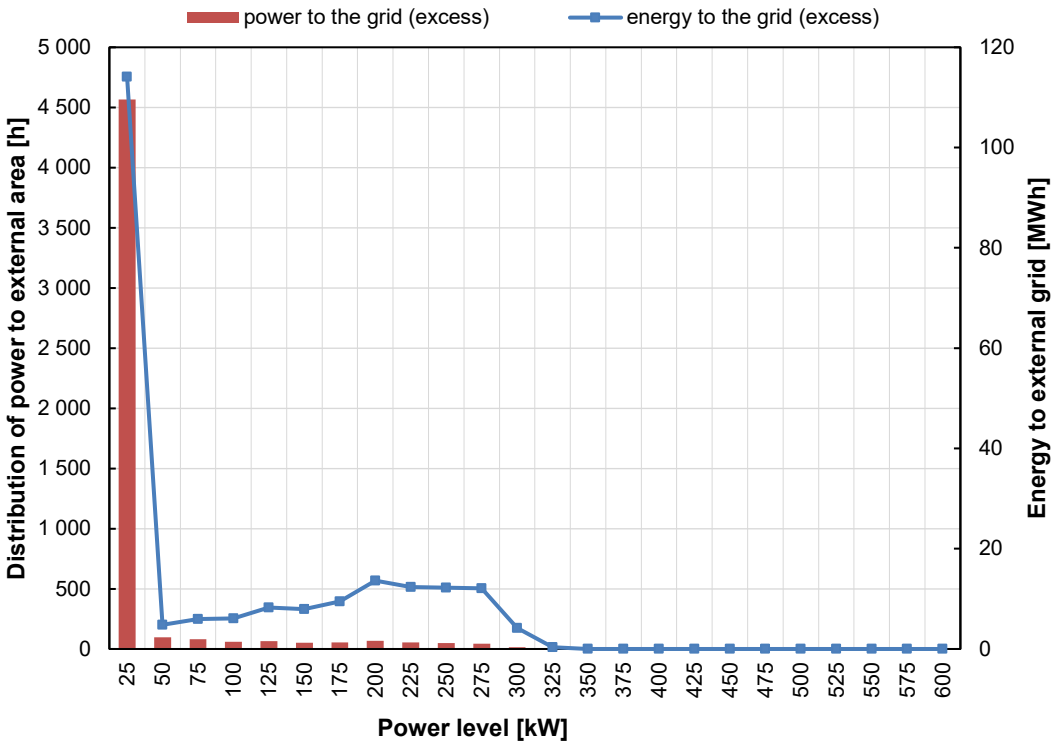


Figure 3.14. Distribution of renewable excess power to external area in alternative scenario

A comparison of energy to external grid per feeding power level between basic and optimal alternative scenario is shown with continuous line in Figure 3.15. In dashed line the cumulated energy to external grid normalized on total amount of energy fed in basic scenario: in the alternative optimal scenario a reduction of around 80% in feeding energy is reached, with prevalent power feeding at very lower power level (only 25 kW).

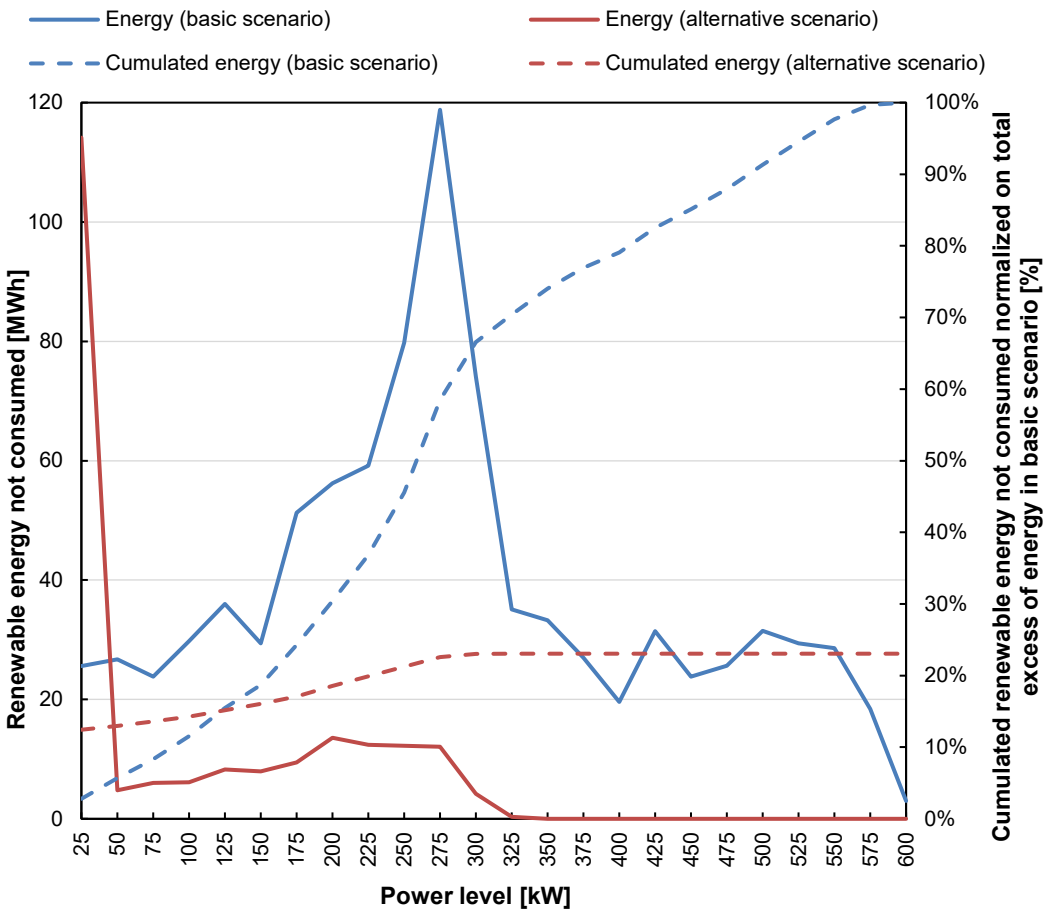


Figure 3.15. Energy not consumed comparison between basic and alternative scenario

Capacity factor for electrolyser is 30% in line with literature [53]. Capacity factor for fuel cell is 59%.

Despite Italian law does not give subsidies to shared energy produced with renewable hydrogen, in the study this revenue is considered, to understand the effect of this law amendment on the business case. With considered economic value (Table 3.5) LCOH is 9.51 €/kg and NPV is strongly negative (around -900,000 €). Storage has the biggest capital cost, more than double in comparison with PV one and three time the wind capital cost. Others subsystems have lower level of capital cost. An overview of the capital cost (in k€) in Figure 3.16.

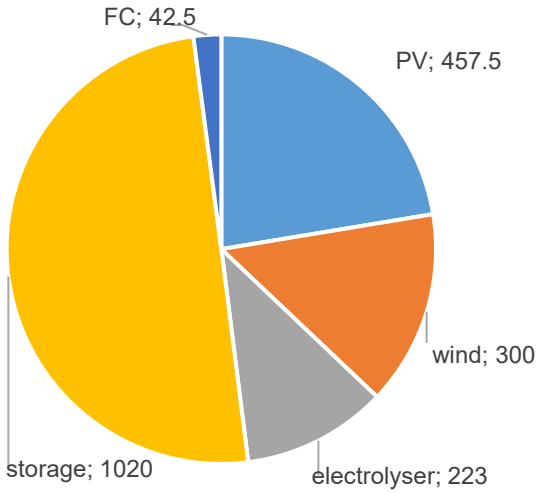


Figure 3.16. Capital cost of equipment [k€]

Without strong reduction of cost of storage, it will be difficult to obtain economic feasibility of the proposed scenario. Considering hybrid power plant as sized in the alternative scenario applicated to basic scenario (with all users grouped in a single REC and without hydrogen PtP system), the economic feasibility is reached: NPV is around 1.3 M€ and payback time is just under six years.

3.4 Conclusions

This study explores and compares performances of a residential Renewable Energy Community (REC), using hybrid renewable power generation (PV and wind) in two different scenarios. Members of the REC are only low voltage passive electrical users, with only centralized power generation (no prosumers are involved in the REC). A basic scenario presents electric autarchy (self-sufficiency) level of final users grouped in the REC, varying the total hybrid renewable power installed. An alternative scenario investigates electric autarchy (self-sufficiency) level of the same group of final users split in two different RECs using a hydrogen-based Power-to-Power (PtP) system. PtP system is composed by an electrolyser, a seasonal storage system composed by metal hydrides elements, a fuel cell. The first REC only produces hydrogen by excess of renewable energy not directly consumed for own electrical needs; the second REC draws electricity produced by a fuel cell by hydrogen bought from the first REC and stored by hydrides, without a direct coupling with renewables. The presented analysis shows that a PtP hydrogen-based system that integrates a couple of RECs is a way to improve substantially electric autarchy (self-sufficiency) of the final users: from 68.6% of correspondent basic scenario to 83.7% of optimal alternative scenario. Despite low round-trip efficiency using hydrogen as a carrier to storage renewables, thanks to seasonal storage capability of hydrogen, the presented configuration avoids that a relevant amount of energy flows out from the local area where users and renewables are installed: from 69.5% of total renewable energy produced of correspondent basic scenario to 9.1% of optimal alternative scenario. A sizing methodology of the components and subsystems is presented, allowing to create an optimal size hydrogen based PtP system for a group of users, split in two different RECs.

At the time of writing this paper, Italian laws do not provide and incentivise a renewable hydrogen fuel cell powering a REC, making the scheme presented in the study unpractical. Despite the same subsidies have been considered for the whole shared energy (both from renewables than from hydrogen fuel cell), the proposed configuration is economically not sustainable due to high capital cost of the components, in particular hydrides storage.

Cheaper technology for the hydrogen storage (i.e. pressurized cylinders) and amendments to incentive laws could make the proposed system viable.

3.5 Appendix

A general overview of the facts and figures in the optimal splitting situation in two REC is defined in Table 3.8

Table 3.8. Facts in alternative scenario

Total users (domestic LV 3kW users)	*200*		*Sizing*			*PtP hydrogen based performances*			
Total people in the community	*420*		*PV peak power*	*366*	*kW*	*Total renewable generation*	*1068.8*	*MWh*	
			Wind nominal power	*300*	*kW*	*Energy to electrolyser*	*750.6*	*MWh*	
REC energy consumption			*Electrolyser nominal power*	*290*	*kW*	*Energy stored by hydrogen*	*374.7*	*MWh*	
Total electric consumption	*474.7*	*MWh*	*Fuel cell nominal power*	*34*	*kW*	*efficiency*	*47.2%*		
Electric consumption of REC1	*284.8*	*MWh*	*Hydrogen storage*	*600*	*kg*	*Energy produced by fuel cell*	*176.9*	*MWh*	
Electric consumption of REC2	*189.9*	*MWh*				*efficiency*	*23.6%*		
Shared Energy in REC			*Power flows*			*Running hours*			
Total shared energy	*397.4*	*MWh*	*Maximum REC1 demand*	*51*	*kW*	*Equivalent at nominal power*			
Shared energy inside of REC1	*220.5*	*MWh*	*Maximum REC2 demand*	*34*	*kW*	*Electrolyser*	*2591*	*h*	
Shared energy inside of REC2	*176.9*	*MWh*				*Fuel cell*	*5191*	*h*	
Renewable energy to external grid			*Maximum PV power output*	*324*	*kW*	*Capacity factor*			
Total energy to external grid	*97.7*	*MWh*	*Maximum wind power output*	*300*	*kW*	*Electrolyser*	*30%*		
REC1 energy to external grid	*97.7*	*MWh*	*Maximum hybrid power output*	*624*	*kW*	*Fuel cell*	*59%*		
REC2 energy to external grid	*0.0*	*MWh*				*At partialized power*			
Energy from the external grid			*Maximum REC1 to the grid*	*303*	*kW*	*Electrolyser*	*5009*	*h*	
Total energy from the external grid	*77.3*	*MWh*	*Maximum REC2 to the grid*	*0*	*kW*	*Fuel cell*	*8130*	*h*	
REC1 energy from the ext. grid	*64.4*	*MWh*				*Autarchy*	*83.7%*		
REC2 energy from the ext. grid	*12.9*	*MWh*	*Maximum excess by REC1*	*593*	*kW*				

4 Techno-economical assessment for combined production of hydrogen, heat and power from residual lignocellulosic agricultural biomass in Huesca province (Spain)

This chapter is based on the following published article:

Raimondi, G., Greco, G., Ongis, M., D'Antuono, G., Lanni, D., Spazzafumo, G. Techno-Economical Assessment for Combined Production of Hydrogen, Heat, and Power from Residual Lignocellulosic Agricultural Biomass in Huesca Province (Spain). Energies 2024, 17, 813. https://doi.org/10.3390/en17040813.

4.1 Introduction

To reach the goal of net zero carbon society in Europe, low carbon hydrogen has a key role. Production of hydrogen via electrolysis seems to be one of the most prominent generation pathways: up to 1,300 GW of electrolyser could be installed by 2050 in Europe [68].

The EU claims the principle of technology neutrality to reach its objective regarding low carbon hydrogen generation: Deutscher Verein des Gas und Wasserfaches and Hydrogen Europe [69] stated that if Europe want to be climate-neutral in few years, all options have to be used, and they described opportunities from pyrolysis of natural gas and biogas to produce hydrogen with low or even negative carbon emission if it is captured in a solid form. Vogel and Hickel [70] stated that high income countries are far from their Paris target and an enhancement of the decarbonization rate by a factor of ten by 2025 is required to comply with +1.5 °C global warming. Hydrogen production from biomass is an alternative pathway that could be considered in particular for small plants that could use residual biomass in particular from agricultural sector. In all European countries, lignocellulosic agricultural biomass is considered as a waste material, that is marginally used for energetic purpose with traditional and low efficient techniques [71].

Lignocellulosic agricultural biomass represents a completely different sector in comparison with intensive forestry cultivation in North-Central Europe: it has a marginal role in agricultural European economy due to low energy content, low density over the land, low potential added value [72]. A complete overview of different pathways to valorise lignocellulosic agricultural biomass was recently presented by Blasi et al. [73] showing potential production of biofuels, biochemicals, and biocomposites.

Lignocellulosic agricultural biomass appears well usable for a small-scale economy. The definition of Renewable Energy Community (REC) in the European Directive on Renewable Energy (so called RED II) [5] could be a new opportunity for energetic valorisation and exploitation of residual lignocellulosic waste material from agricultural sector, such as pruning. The main purpose of REC is "to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits" as stated in Article 2 number (16) of RED II [5]. A REC can produce, consume, store and sell renewable energy in different forms: for example, heat, power and hydrogen.

Wang et al. [74] described an optimized system to produce different energy vectors to better deploy renewables advantages at regional territorial level. Mustafa et al. [75] stated that it is feasible in a local community in Norway to produce biofuel for local mobility from gasification of local biomass from forest. The potential biofuel production from lignocellulosic local waste was huge (about three times) respect to the demand for public transport requirements. Payback period for the proposed plant was of 4 only years. No mention to combined production of heat and power.

Situmorang et al. [71] described the worldwide diffusion of small biomass gasification systems in particular for rural and local communities and their limit for implementation. Hydrogen direct production was mentioned as one of the alternatives, such as coupling with internal combustion engine (ICE).

Diaz et al. [76] overviewed the coupling of biomass as an energy source for use in ICE through a gasification process, emphasizing its advantages (mainly high flexibility in the use of different types of biomass and high reliability of ICE technology) and highlighting its limitations (mainly criticality in

designing the biomass supply chain in order to limit its supply costs and lack of knowledge of biomass gasification at local community level). No combined production of hydrogen, heat and power are mentioned.

Tomin et al. [77] described a renewable energy community in Japan based also on biomass local sources. The use of biomass, integrated with wind and solar, has enabled a high penetration of renewables in the energy community.

To the best knowledge of the authors, no paper describes a system based on residual lignocellulosic biomass to produce both hydrogen for mobility, and heat and power for residential sector. The main enabling technologies for the proposed system are biomass gasification, hydrogen membrane separation, production of heat and power by an ICE fed by a poor lower heating value syngas.

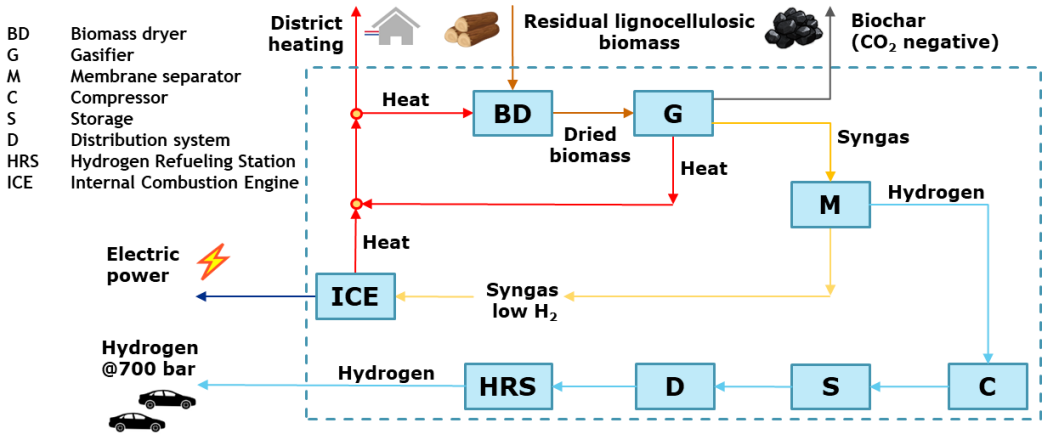


Figure 4.1. Simplified scheme of the proposed energy plant.

The main purpose of the present work is to describe, to size and to economically assess a set of coordinated energy plants producing combined hydrogen for mobility, heat and power for residential use (Figure 4.1). Each plant integrates a REC as defined in the European regulatory framework, placed in the province of Huesca in Aragón (Spain). Each plant uses local pruning from agricultural sector as feedstock. Hydrogen refueling stations (HRSs) enabling local mobility are included in the evaluations. To the best knowledge of the authors, this purpose represents a novel approach in the literature.

4.2 Materials and Methods

The presented study includes a technical-economic assessment of a system composed by different technologies linked together in an innovative way. All the technologies contribute to the creation of a local hydrogen production chain for mobility purpose, in an area that is completely lacking in it, despite having the potential for it. The province of Huesca in Aragón (Spain) is chosen as analysis area: it is a logistical hub between Zaragoza, the Pyrenees and Barcelona; it is an agricultural area with ample availability of biomass. All technologies in the study are at commercial stage or they will be within a few years.

This section will provide references to the scientific literature, corporate marketing documents and European and Spanish legislation that served as a premise for the study. In detail, the following will be addressed:

- Renewable Energy Communities in Spanish electric market
- Biomass resources in Aragón
- Harvesting and gasification of the residual lignocellulosic biomass
- Hydrogen separation in selective membranes and syngas treatment
- ICE fed by low heating value gases
- District heating in Spain
- Hydrogen refuelling stations and car fleet characterization
- REC modelling
- Economic analysis

4.2.1 Renewable Energy Communities in Spanish electric market

The European Directive on Renewable Energy (RED II) [5] described RECs as a new legal entities for small scale decarbonisation, designed for both residential end-users and small and medium enterprises (SMEs) [13–16]. Real Decreto (Royal Decree RD) 23/2020 on 23rd June 2020 [78] at Art. 4 introduced the term "renewable energy communities" into the Spanish legislation. As in many Countries in Europe, the REC concept is not easy to integrate in the pre-existing regulatory framework of decentralized and renewable power production [79].

Previously, as stated by Gallego-Castillo et al. [25], Real Decreto 244/2019 on 5th April 2019 [80] introduced for renewable plants two classes of power (up to 100 kW and over 100 kW), introducing a simplified regime for the first one and equating greater than 100 kW to renewable plant that sells energy to the wholesale domestic market. For renewable plants up to 100 kW, a simplified billing system is allowed, consisting in a direct discount on the customer electric bill for energy sold to the grid, with the limitation that the total economic value of the sold energy (exported energy out of the REC) cannot exceed the economic value of purchased energy (imported energy in the REC). Any excess of the value of sold energy (compared to purchased one) is in fact not paid to the producer. As Caballero et al. [81] stated, REC can use this form of incentives in Spain, because no direct payment of incentives is expected, together with the lower payment in the bill for self-produced energy in a shared plant (self-sufficiency of the REC). Self-sufficiency indicates the percentage of community consumption that has been satisfied by the generation in the community itself.

RD 244 introduced and allowed a common shared renewable plant for a REC, but REC's members as consumers have to be only at a maximum distance of 500 m from the generation plant. This constraint is a strong limitation for the development of the initiatives. As pointed out by Caballero et al. [81], the ulterior Real Decreto 29/2021 on 21st December 2021 [82] established that the electric connection of the renewable plant can be at both low and medium voltage level.

Caballero et al. [81] stated that REC in Spain can use multiple renewable sources and no limitation regarding type of renewables are imposed, as is the case, for example, in Italy (art. 2 comma 1 lett. *a* in [17]). Moreover, it is underlined that the aim of the REC in Spain is to increase the levels of self-

consumption and self-sufficiency by adopting also different energy carriers (e.g. hydrogen, heat, power).

Gallego-Castillo et al. [25] inferred that self-consumption installations shared by several consumers are allowed in a Spanish REC and also that nearby consumers can share energy from the same sole power plant. Final user and owner of generation plant have to be different entities: consequently, a cooperative (i.e.) is necessary to constitute to be the owner of the renewable power plant. In their work, the authors described the different components for electric price definition in Spain and explained difference between economic value of imported (purchased by REC v_{pur}) and exported electricity (sold by REC v_{sol}). They based on Voluntary Price for Small Consumers (PVPC as for the Spanish acronym) and Energy component of the access tariff (TEU as for the Spanish acronym)

$$\begin{cases} v_{pur} = PVPC + TEU \\ v_{sol} = v_{pur}/R_{imp/exp} \end{cases} \quad (4.1)$$

where $R_{imp/exp}$ is the ratio between v_{pur} and v_{sol}, and it is assumed equal to 1.39; TEU is considered constant over the last years equal to 44 €/MWh [25].

PVPC is considered as the medium value in the period between January 2023 and April 2023 equal to 153.97 €/MWh [83]. With the mentioned values, purchased and sold value of electricity by REC can be considered

$$\begin{cases} v_{pur} = 109.97\ €/MWh \\ v_{sol} = 79.32\ €/MWh \end{cases} \quad (4.2)$$

4.2.2 Biomass resources in Aragón

Considering only the first three most abundant cultivars in Aragón (almond tree, vineyard and olive tree), which covers around 80% of cultivated area [84], the total annual lignocellulosic biomass available in the region from annual pruning is around 269,000 ton/year with a moisture content around 15% produced on around 243,500 ha [85–87] in the region.

4.2.3 Harvesting and gasification of the residual lignocellulosic biomass

Different mechanized systems for pruning harvesting have been defined over the last years [88,89], such as for pruning transportation [90–92]. Technologies can be considered at commercial stage. From a literature review the total cost of the lignocellulosic biomass to be used for gasification purpose is defined, and it is described in Table 4.1.

Table 4.1. Lignocellulosic biomass harvesting and transformation costs

Working phase	cost	Ref.
Harvesting biomass dumped at roadside	40.0 €/ton	[89,93]
Transportation (50 km distance)	10.4 €/ton	[92]
Briquetting (without drying OPEX)	33.7 €/ton	[94]
Total cost	**84.1 €/ton**	

Using the residual heat produced by proposed system, during periods when there is no heat request from REC members (district heating), biomass is dried and processed into briquettes for subsequent gasification [94,95].

Briquettes of this kind of biomass can usefully feed a commercial air downdraft gasifier such as the one provided by RESET S.p.A., an Italian company manufacturing small CHP plants [96] up to 200 kW of electric power output. According to the company data, using common agricultural lignocellulosic waste material as pruning, the dry syngas composition contains averagely around 16% *vol*. of hydrogen, with no tar (detailed composition in Table 4.2).

The temperature of syngas at the outlet of the gasifier is 600 °C, as declared by RESET, and its lower heating value is assumed as 4.957 MJ/Nm^3 (4.405 MJ/kg). The data are well aligned with literature and indicate that the technology used by RESET is widespread and consolidated [97–99].

Table 4.2. Dried volume syngas composition from gasifier

CO	H_2	CH_4	CO_2	N_2
20%	16%	2%	10%	52%

4.2.4 Hydrogen separation in selective membranes and syngas treatment

Hydrogen can be extracted from a stream of syngas, partially or totally, using palladium-based membranes, also in a small scale hydrogen production with high purity [100–102]. TRL of this technology has increased over recent years and some companies are arising in the market to offer the design of membrane reactors and the supplying of systems [103,104].

The membrane technology works with a syngas at around 350-500 °C and at pressure between 3 to 25 bar with no poisoning elements for the membrane surface (like sulphur compounds) in the stream. Over the last few years, dense metallic membranes have been widely studied by Tecnalia research center and Eindhoven University of Technology [105] as a promising solution for hydrogen separation.

Cylindrical membranes have been realized depositing a thin (1-10 μm) Pd/Ag layer though electroless plating technique on a ceramic porous support with an external diameter of 14 mm and an internal diameter of 7 mm [106]. Recently, an additional ceramic porous protective layer have been developed, leading to the so-called double skin membranes, in order to improve their resistance to attrition in fluidized bed reactors and improve perm-selectivity, since the protective layer can close some defects of the membrane [107]. These membranes are able to reach a perm-selectivity of about 30,000 at 500 °C, and during long-term operations showed a decrease in perm-selectivity of about 0.33 per hour under fluidization exposure, consistently to what previously obtained by Nooijer et al. [108], where the decrease was 0.2 per hour in an empty tube (without fluidization exposure). A perm-selectivity of 30,000 means a hydrogen purity of 99.997%. Assuming a decrease of 0.33 per hour, the purity of 99.97% can be reached after approximately 9 years, or after 15 years using the value measured in the empty tube. This latter value of the purity is considered the limit of membrane operation, since this is the value required for hydrogen purity for fuel cell vehicle from the standards ISO 14687-2:2012 and ISO 14687:2019 [109].

Hydrogen permeation through Pd-based membranes can be described by the solution-diffusion mechanism: hydrogen molecules in the gas are adsorbed on the membrane surface and split into hydrogen atoms, which dissolve in the metallic layer [110]. Due to the presence of a driving force, related to the different hydrogen partial pressure at the two sides of the membrane, hydrogen atoms diffuse through the membrane, they recombine in a H_2 molecule and are then desorbed, ending up in the permeate stream. This mechanism is mathematically described by the solution-diffusion model, which is widely used to describe hydrogen permeation through Pd-based membranes [111]. The total flow rate of hydrogen separated, in a 1D representation, can be calculated as:

$$\dot{n}_{H_2\,sep} = \int \pi \cdot d_{ext} \cdot (1 - CPC) \cdot Per^0 \cdot \exp\left(-\frac{E_a}{R \cdot T}\right) \cdot \left[\left(p \cdot x_{H_2}\right)^n - p_{perm}^n\right] \cdot dz \quad (4.3)$$

where z is the axial coordinate, d_{ext} is the external diameter of the membrane (14 mm), Per^0 is the pre-exponential permeance, E_a is the activation energy, T is the temperature, p the retentate-side pressure, p_{perm} the permeate-side pressure and x_{H_2} the hydrogen molar fraction in the retentate stream. The syngas after the extraction of hydrogen is named retentate. The pressure exponent n is a parameter which depends on the rate-limiting step in the solution-diffusion mechanism, and is in general bounded between 0.5 and 1. In the Equation 4.3 all parameters can be considered constant along the membrane, except for the hydrogen molar fraction x_{H_2}, which depends on how much hydrogen is permeated in each axial position.

The coefficient (1-CPC) is introduced to account for concentration polarization (CP) losses, since the hydrogen fractions involved are quite low (14% molar at the inlet), and uses the concentration polarization coefficient (CPC), which is a parameter bounded between 0 (if no CP are present) and 1 (in case of infinite CP). Values for the membrane parameters and for CPC are reported in Table 4.3.

Table 4.3. Membrane parameters

Parameter	Value	Ref.
$Per^0\ [\frac{mol}{m^2 \cdot s \cdot bar^{0.749}}]$	1.3054	[101]
$E_a\ [J/mol]$	7,810	[101]
$n\ [-]$	0.749	[101]
$CPC\ [-]$	0.8	[111]

A gas conditioning system has to be designed to create the optimal working conditions for membrane in terms of temperature and pressure: heat exchangers and a compressor for syngas are required for this purpose.

An Atlas Copco HX&HN-15 oil-free intercooled reciprocating compressor [112] (a commercial model) is taken into account for the plant, operating within the range of flow rates and pressures required by the application under study.

In order to achieve an energy-efficient gas treatment system, a turbine expands the compressed and hot retentate coming out of the membranes. The turbine is coupled to an alternator to produce electricity, that is used for internal needs of the energy system proposed, lowering its own electric consumption. Expansion of a fuel gas at high pressure is well discussed in literature with potential commercial application: i.e. harvesting of energy from high pressure methane pipeline connecting to low pressure methane distribution grid [113–115]. D6100E class turbine from Deprag (German

company) is chosen for the study [116]. The turbine for retentate is modeled based on the information available from Deprag websites [113,116] and based on Weiss et al. [114]. In particular the isentropic efficiency is set equal to 0.69, obtained with an inlet pressure close to 14 bar. Electrical-mechanical efficiency of the turbine is set at 85% [99].

Pressure drops before compressor (4%) and before turbine (2%) are chosen in accordance with Rovense et al. [117].

Heat exchanger thermal efficiency is set at 90% and minimum temperature available for heat harvesting to be used in a district heating is set at 90 °C: heat of syngas or fluids (in ICE) at a lower temperature is dispersed into the atmosphere.

4.2.5 ICE fed by low heating value gases

It is important to highlight that the removal of hydrogen from the syngas stream inevitably reduces the heating value of the gas mixture. This lower heating value may lead to misfiring and poor functioning of the ICE system.

Therefore, to properly realize a combined heat and power (CHP) plant, the minimum lower heating value (LHV) for the gas feeding the ICE is set to 3.8 MJ/Nm^3 [118,119], and the power derating cannot overcome 70% of the power output when fed with methane [120]. The characteristics for power train in the CHP are from MAN E3262 E302-V12 engine originally fed by methane. The engine is used by RESET in its biggest solution. Engine efficiency using methane is 39.6% [121] and electrical efficiency of the connected alternator is supposed 95% [120].

4.2.6 District heating in Spain

In Spain usually the annual thermal demand in residential sector is around 3,350 hours in a year [122]: in a year with a continuous production of heat (i.e. from an ICE), only around a third of heat can be valorized in a district heating to space heating and domestic hot water. District heating efficiency is assumed to be 93% [123] and annual Spanish energy consumption for space heating and domestic hot water is 177 kWh/m^2 (considering buildings built by 2011) [124].

Cost of energy in a district heating in Spain is inferred starting from analysis of Soltero et al. [122] in Spanish market in 2014, Comodi et al. [125] in Italian market in 2016, and considering the cost of energy in Milan (Italy) heat district in 2023 [126]: same trend in cost is supposed in Spain and Italy. The obtained cost of energy in a district heating is 90.59 €/MWh. The value is aligned with data in gas Spanish market in the first half of 2023 [127].

4.2.7 Hydrogen refuelling stations and car fleet characterization

Caponi et al. [128] reviewed several hydrogen refuelling station (HRS) installations, summarizing cost and economic performances. An average CAPEX for HRS can be set as ratio with hydrogen daily dispensed at 5,300 €/(kg/day). Moreover Mayyas et al. [129] detailed the cost of each single element in the HRS (compressor, storage, dispenser, precooler, installation cost and general cost).

Both fuel cell and ICE hydrogen cars are considered in the study and in both cases passenger cars. Consumption is set equal to 1.1 kg of hydrogen each 100 km [130,131] for both power trains. The annual mileage of each car is set at 15,000 km/year [132].

4.2.8 REC modelling

The characterization and sizing of the REC is based on the previous works of Raimondi and Spazzafumo [133,134]. They allow to define the residential electricity consumption of a group of people who are part of a renewable energy community, foreseeing their electrical demand each hour in a year.

Although defined for the Italian panorama, the same electrical consumption is assumed for the Spanish scenario, due to similar latitude (similar day duration) and to socio-economic uniformity between the population in Aragón and Central Italy.

4.2.9 Economic analysis

General economic parameters used in the study are collected in Table 4.4. Exchange ratio between euro and dollar is considered equal to 1.

Table 4.4. Economic parameters

Parameter	Value	Ref.
Lifetime, *ny* [year]	20	[133]
Interest rate, *d*	5%	[46]
Biomass power generation capital cost [€/kWe]	5,200	[135]
Membrane capital cost [€/m^2]	5,700	[136]
Syngas compressor capital cost [€/kW]	690	[100]
Syngas turbine capital cost [€/kW]	1,000	[114,115]
Hydrogen stationary storage @200 bar capital cost [€/kWh]	13.5	[134]
Hydrogen mobile storage @200 bar capital cost [€/kWh]	17.6	[137]
Hydrogen stationary storage @900 bar capital cost [€/kWh]	24.3	[128]
Hydrogen compressor capital cost [€/kW]	6,700	[134]
Medium truck for hydrogen transportation capital cost [€]	41,100	[138]
Heat exchanger (gas-gas) capital cost [€/kW]	187.5	[139]
Heat exchanger (liquid-gas) capital cost [€/kW]	210	[140]
Gasifier O&M cost [% of CAPEX]	6.0%	[93]
Heat exchanger O&M cost [% of CAPEX]	3.8%	[140]
Reactor and membrane O&M cost [% of CAPEX]	4.5%	[102]
Hydrogen storage O&M cost [% of CAPEX]	0.5%	[134]
Hydrogen and syngas compressor O&M cost [% of CAPEX]	4.0%	[43]
Syngas turbine O&M cost [% of CAPEX]	4.0%	
Hydrogen refuelling station O&M cost [% of CAPEX]	3.0%	[128]
Human labour for H_2 production and logistic [€/year] (x2)	72,000	[141]
Truck O&M [€/km]	0.28	[142]

The duration of the initiative is set equal to the lifespan of the renewable energy communities, as assumed in Raimondi and Spazzafumo [133].

The capital cost of biomass power generation in literature has a wide range of variability, depending mainly by geographical place of installation. It includes gasifier, syngas purification (removing ashes) and dryer, and ICE-based electric generator.

Rentizelas et al. [93] declared a cost of 2500 €/kWe in Greece for 1 MWe; from IRENA 2021 outlook [135] an average value of 5200 €/kWe is inferred for 0-5 MWe in Europe, in a wide range of cases. The value is compliant with information from RESET website at FAQ section [96].

Capital cost of membranes production is taken from the work of Nordio et al. [136], which reports production costs specific per unit area of permeable surface. The membrane area required for the separation is estimated using a 1D model of the permeation process, as described in section 3.2.

Weiss et al. [114] and Galanti and Massardo [115] stated the same value for a microturbine capital cost in the power range of tens of kW. In this study the micro turbine is used as a power recovery in syngas treatment.

Hydrogen mobile storage is a cylinder storage on a chassis of a trailer: cost is inferred by a direct interview at Calvera Hydrogen S.A. (Spanish company) [137].

Regarding Operation and Maintenance (O&M) annual cost for the syngas turbine is assumed the same as the syngas compressor, because of belonging to the same technical sector.

Regarding the costs related to the working personnel, two employees are considered with a gross monthly cost of 3,000 €/month per person [141] who are responsible to maintain the gasifier and to refill HRSs.

A Levelized Cost Of Hydrogen (LCOH) is evaluated for the investigated scenario, taking as main reference the Levelized Cost Of Energy (LCOE) definition of Department for Business, Energy & Industrial Strategy [45]

$$LCOH = \sum_{t=1}^{ny} \frac{C_t + O\&M_t - S_t - R_t}{(1+d)^t} \Big/ \sum_{t=1}^{ny} \frac{Q_{H2,t}}{(1+d)^t} \quad (4.4)$$

considering all capital costs C_t, operation and maintenance costs $O\&M_t$, saving on the electric bills of REC members S_t and revenues from heat in district heating R_t. Quantity of hydrogen produced $Q_{H2,t}$ is the same in each year, as well as electricity production and sharing. Investment lifetime in number of years and interest rate are indicated with *ny* and *d* respectively.

Hydrogen as fuel in transport sector will be a real alternative if the kilometre cost of a hydrogen vehicle will be less or equal than fossil fuel kilometre cost.

In a simplified approach, only the cost of fuel and in particular the cost of diesel is considered to define the mileage cost of a car. For a diesel passenger car with a consumption of 20 km/liter and a cost of diesel at the refuelling station (VAT included) in Spain of 1.58 €/liter [143], hydrogen car has the same kilometre cost with hydrogen price of 6.87 €/kg (21% VAT included). Hydrogen consumption for a passenger car is considered equal to 1.1 kg/100 km, as declared.

4.3 Results and discussion

4.3.1 Overview of the proposed system

The study integrates different technologies, with the aim to create a hydrogen, heat and power combined production chain in the Aragónese province of Huesca in Spain, by a series of interdependent plants.

The modular basic plant is described in Figure 4.2.

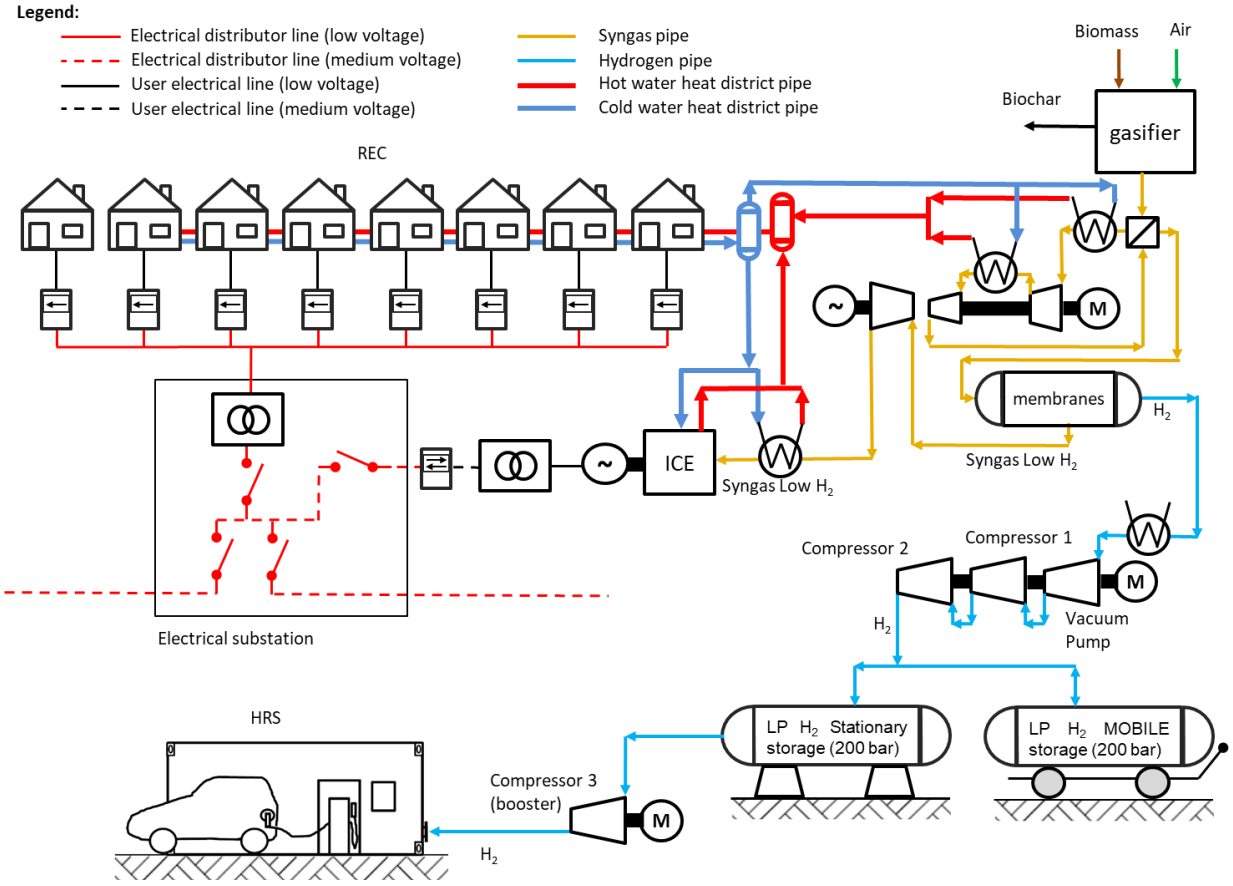


Figure 4.2. Balance of plant of the modular basic proposed plant.

The feedstock used is lignocellulosic biomass from annual pruning of local crops in Aragón. This biomass is gasified in a series of downdraft commercial reactors, that allow carbon capture by producing biochar. The hydrogen contained in the syngas is extracted with Pd-based membranes and made available to a network of local hydrogen refuelling stations.

The low hydrogen-content residual syngas (retentate) is used in an ICE for the production of electricity which supplies a REC, contributing to the economic sustainability of the initiative, thanks to the Spanish shared energy valorisation mechanism.

The waste heat from the process is valorised for heating some members of the REC and, in periods of the year with low residential heat request, to dry biomass for consequent gasification. A series of HRSs in the province of Huesca, served by stationary and mobile hydrogen storage system, allows to create a network in the province enabling hydrogen mobility.

REC, as legal entity, manages the whole system, selling electricity, heat and hydrogen to its members or, anyhow, in the territory where it is established.

Renewables electric power feeding the REC allows, in the simplified framework for Spanish regulation, a direct discount on electric bill of REC's members. The monthly savings on electric bills are supposed to fully devolved from members to REC entity, to sustain hydrogen production for local transportation, using lignocellulosic biomass from local pruning in Aragón farming. As direct consequences of the REC implementation, local jobs will be generated, pruning which is commonly a waste material, will be greatly valorised, and local pollution will be reduced by promoting the diffusion of zero-emission hydrogen vehicles and a sustainable local district heating.

All the activities are in line with REC general purposes: REC members under these hypotheses do not obtain any economic advantage.

4.3.2 Characterization of the subsystems

Starting from dried volume syngas composition of Table 4.2, a deeper characterization of gasifier and ICE is defined. It is considered in the pruning a content of carbon by weight of 50% and of hydrogen of 6% [144]. Water content in the biomass after drying is set at 12%. Moreover considering a biochar production according with RESET specification and an electrical efficiency of 95% for the MAN generator [120], the engine efficiency is defined using the composition of syngas from gasifier. The inferred value is 29.02%. It is aligned with statement of Gobbato et al. [120] considering the derating of efficiency in comparison with methane of a similar engine fed with syngas similar to this study.

With this assumption, wet weight composition of syngas is also inferred, as described in Table 4.5.

Table 4.5. Wet weight syngas composition from gasifier

CO	H_2	CH_4	CO_2	N_2	H_2O
18.5%	1.1%	1.1%	14.6%	48.1%	16.6%

This composition is used to define specific heats of syngas to characterize the first heat exchangers and, without water, the compressor behaviour (Table 4.6). In fact, a complete drying of the syngas is foreseen after the first heat exchangers.

Table 4.6. Specific heats and gas constant (at 700 K)

	c_p [kJ/kg k]	c_v [kJ/kg k]	k	R [J/kg k]
Syngas from gasifier (wet)	1.439	1.072	1.342	
Syngas from gasifier (dry)	1.311	0.965	1.358	329.69
Retentate from membrane (dry)	1.225	0.904	1.356	305.26

Atlas Copco HX&HN-15 is a double intercooled stage piston compressor. It is chosen for the compatibility with the syngas and for its oil-free functioning behavior. Moreover, it operates in the range of pressure and mass flow compliant with the size of the system. Technical datasheet is not sufficiently detailed for the simulation. According with general data from Atlas website [112], isentropic adiabatic efficiency is inferred equal to 85.9% for each of two stages of the compressor, using well known adiabatic isentropic mathematical model for the compressor.

A ratio between heat power removed in the interstage refrigeration and electrical power of the motor is also inferred equal to 0.6 to characterize the system energetic simulation.

Electro-mechanical efficiency of the compressor is set equal to 85% according to Di Marcoberardino et al. [145].

In the proposed scheme, the syngas is produced by an atmospheric downdraft gasifier, with a temperature at the exit of the gasifier of 600 °C, as declared by RESET.

It is cooled down by a regenerative heat exchanger and a water-syngas heat exchanger. This cooling allows to minimize energy consumption of syngas compression phase, required to bring the pressure from a value close to the atmosphere, up to the value for hydrogen separation with Pd-based membranes.

The membranes can work at different pressure values [145]. The value is chosen to optimize energy recovery by the downstream retentate expansion in turbine.

Hydrogen permeation through Pd-based membranes is evaluated by Equation 4.3 considering a syngas temperature (T) of 500 °C, a retentate-side pressure (p) of 14.58 bar and a permeate-side pressure (p_{perm}) of 0.2 bar.

With these values, from modelling evaluations it turns out a required membrane area of 5.16 m^2 to separate 50% of the hydrogen from the syngas: this percentage of removal is well explained and motivated as a consequence of engine constrain in the following Section 3.3.

Given the production cost of 5,700 €/m^2, as reported in Table 4.4, the cost of the membranes is estimated to be 29,469 €. Since hydrogen separated is 89.8 kg/day, the specific cost of the membranes per unit of kg_{H2} per day results in 328 €/(kg_{H2}/day).

Hydrogen is extracted by membranes that are connected to a vacuum pump (around 0.1 bar [100]), and with other two stages it is compressed up to 200 bar.

For purpose of this study, it is important to define the total power of the extraction and compression system, based on hydrogen mass flow rate. Spazzafumo and Raimondi [134] stated that for small flow rate can be assumed 0.376 (kg/h)/kW as ratio between hydrogen flow rate and power of a hydrogen compressor.

The hydrogen distribution system for automotive uses defined in this study concerns many hydrogen refuelling stations in a large territorial area: the entire province of Huesca in the Aragón region. In this scenario it is hypothesized to build not just a single gasification plant with an attached hydrogen refuelling station, but a series of plants like that described in Figure 4.2 to create a mobility network throughout the province.

The number of these plants is a result of the optimization of the storage and hydrogen logistic costs, as described below. To consider passenger car as intended use for the hydrogen represents a worst economic case respect heavy duty vehicle utilization: common level of hydrogen compression required for passenger car (700 bar) entails a higher cost of installations than for heavy duty vehicle (commonly 350 bar).

The major cities of the province of Huesca are taken into consideration as place for at least a plant and in particular those cities which represent a cumulative population of at least 50% of the inhabitants of the province. Table 4.7 shows the biggest cities of the province with number and percentage of inhabitant compared to the entire population of the province (224,264 inhabitants).

Table 4.7. Biggest cities of province of Huesca

	inhabitants	% of province population
Huesca	53,956	24%
Monzon	17,469	8%
Barbastro	17,174	8%
Fraga	15,353	7%
Jaca	13,129	6%
Total	117,081	53%

Considering that the gasification system is able to work for 7,200 hours a year [96] and that it requires four maintenance stops during the year, around two-weeks break every three months are inferred as required for each plant. HRSs obviously have to allow to refill hydrogen vehicles also when the own gasifier is shut down for maintenance. Each HRS dispenses hydrogen 261 day/year: Saturdays and Sundays are not considered as working days. A hydrogen storage is needed to manage maintenance period. Limit the storage is a way to decrease the capital cost: storage is always the most impactful cost in a hydrogen supply chain [133]. A territorial network of gasification plants and HRSs is a way to minimize the capital cost of storage: hydrogen to feed HRS with gasifier off can be transported via tube trailer from other gasifiers as long as there are enough active ones to supply both its own refuelling station and another one. With this approach it is not needed to have a stationary storage in each HRS to manage the two weeks of maintenance of the gasifier, but only a smaller one to manage the peak of hydrogen request in working day (*wd*) of HRS in a year, from Monday to Friday ($wd_{HRS} = 261$ days a year), compared to a continuous 24h/7days hydrogen production during the week ($wd_{gasif} = 7200h/24h = 300$ days a year). For these reasons each refueling station has both stationary and mobile hydrogen storage.

4.3.3 Constrains and optimization for the sizing

The described case study includes regulatory and technical constrains and a range of values for technical parameters in which to find the optimal solution to have a size of the territorial system that minimize the LCOH. LCOH is defined *from field to tank*, which means that it includes all the activities from harvesting of biomass in the field to refuelling of a hydrogen vehicle at 700 bar.

Figure 4.3 shows a flowchart summarizing the procedure for sizing and optimize the system.

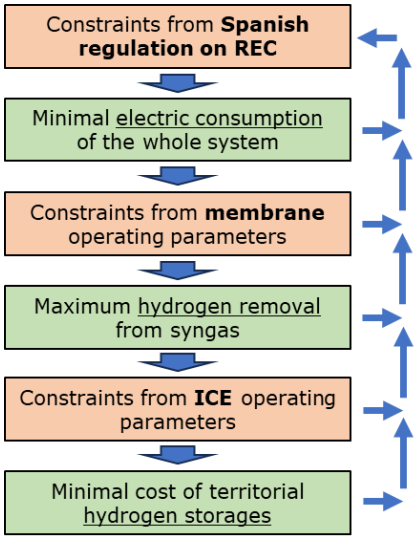


Figure 4.3. Flowchart for sizing and optimize the system

As mentioned, the Spanish regulation for REC allows a simplified payment rule for renewable power plant with a total energy output at most equal to 100 kW: a direct reduction of the bill due to contemporary produced and consumed energy in the REC and an economic compensation for energy exported and imported in the same month.

In the proposed plant, there are two systems that produce electricity: an ICE burning retentate and a turbine that expands retentate to partially recover compression energy. Their power output is indicated respectively as P_{ICE} and P_{tur}. Consumption of electricity for syngas compressor $P_{syn\ comp}$ and for vacuum pump and hydrogen compressors $P_{H2\ comp}$ to store hydrogen at 200 bar define the total electric output. All these facilities work simultaneously when the gasifier is running, without any variation on the load. Electricity requirements to boost hydrogen pressure at 900 bar for fast refueling phase is not considered as a continuous need, due to intermittency of that operation. A constrain in the optimal sizing of the basic plant is that the sum of all powers previously considered is equal to 100 kW.

$$P_{ICE} + P_{tur} - P_{syn\ comp} - P_{H2\ comp} = 100\ kW \tag{4.5}$$

Based on Spazzafumo and Raimondi [134], the minimal dimension of the REC is defined to assure that electricity produced in the REC E_{prod} by 100 kW net power output is completely valorized, or as simultaneously consumption E_{shared} (that is shared hourly inside the REC) or as economical balancing in each month of the year as exported E_{exp} and imported E_{imp}. In both cases there are a saving on the member's bill. Both conditions can be summarized in

$$\begin{cases} E_{shared} \rightarrow E_{prod} \\ E_{imp} v_{pur} - E_{exp} v_{sol} \rightarrow 0^{+} \ \ \forall\ month \end{cases} \tag{4.6}$$

considering values for v_{pur} and v_{sol} as in Equation 4.2.

This condition maximizes the saving on the bill of REC members, due to electric production in the REC. The size (number of members) of the REC is the unique independent variable: the shape of hourly consumption of the REC is based on life style and seasons, and it is not easily changeable, as well as the power output is constant for technical constrain when the gasifier is running and equal to zero when it

is in maintenance. Based on this consideration and on the assumptions described in Section 2.8, the minimal and optimal size is a REC composed by 777 persons grouped in 370 electric domestic passive users. These users have to be at a maximum distance of 500 m from generation plant to be considered in a single REC, according to the Spanish regulatory framework. Only a configuration inside a city can assure that condition: the Spanish countryside appears too sparsely populated. A monthly distribution of electricity with modular basic plant in the REC is shown in Figure 4.4.

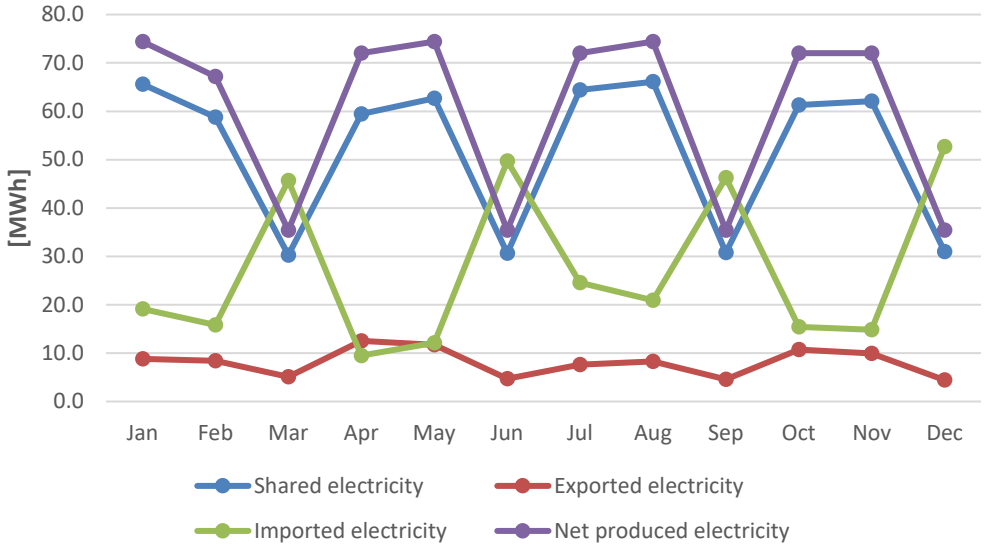


Figure 4.4. Monthly distribution of electricity in the REC.

March, June, September and December are the months with two weeks of shut off maintenance period of the gasifier.

To optimize the harvesting of energy from retentate a turbine is considered in the study. Its efficiency depends on inlet pressure [114] that depends on pressure needed by membranes and generated by syngas compressor. Given the order of magnitude of flow rates of this study, considering an oil free compression, the piston Atlas compressor is the best solution, so its outlet pressure defines the solution for the membrane and turbine performances and, consequently, turbine efficiency. The compressor ratio of the chosen Atlas compressor is 15 and, considering pressure drops, the pressure at the membrane is 14.58 bar and at the turbine is 14.3 bar. Temperature of the system is set by two constrains: the exit temperature from the gasifier (600 °C) and the maximum temperature endured by Pd-membrane (500 °C) to allow an acceptable long-life operation. Membrane lifetime chosen in this work is 10 years, since membranes are inside an empty tube and thus conditions are not extreme as in fluidized bed. As reported in Section 2.4 in fact, in fluidized bed membrane lifetime can be evaluated approximately 9 years. The value of 10 is chosen to be more conservative to the value of 15 years estimated for membranes in an empty tube from literature. With the lifetime of 10 years, only one membrane replacement occurs in the expected 20-year operating period.

These constraints on pressure and temperature in the system define the energy consumption for syngas treatment to allow the membranes to work, and also the capability of energy recovery by syngas turbine: with current chosen available technology for gasification, compression and Pd-membranes separation there is no room for optimization varying thermodynamic parameters.

Hydrogen removal percentage from syngas is a parameter to optimize: the higher the hydrogen removal rate, the greater the efficiency of the system. In the hypothesized scheme, the retentate powers

an internal combustion engine originally fed by natural gas. By depleting the syngas of the hydrogen removed from the membranes, the calorific value of retentate decreases: an excessive decrease in this value leads to engine malfunction. Two limits are defined: retentate LHV at least equal to 3.8 MJ/Nm³ [118,119], and ICE derating power output in comparison with methane fed at most equal to 70% [120]. Their variation based on different hydrogen removal percentage in syngas dried stream are plotted in Figure 4.5. Considering that the limit on LHV is never reached up for all percentage of hydrogen removal from 0% to 100%, 50% of hydrogen removal is the highest operable value, beyond which derating of the engine power does not allow reliable operation. This constrain means that the highest percentage of hydrogen removal is 50%.

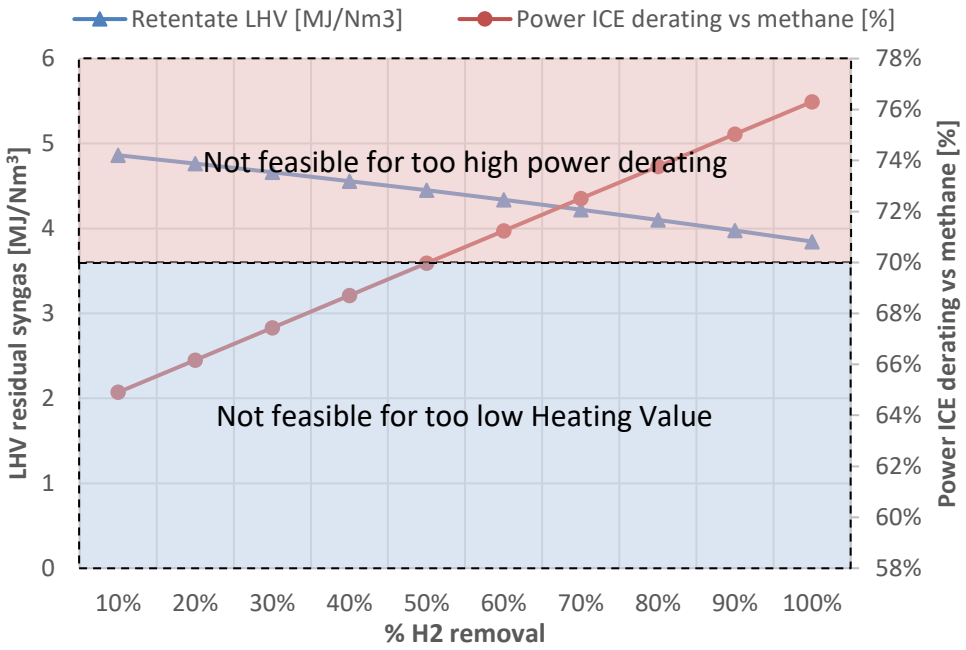


Figure 4.5. Retentate LHV and ICE derating based on hydrogen removal.

With 50% of hydrogen removal, weight composition of dry retentate is shown in Table 4.8 and its specific heats and gas constant are indicated in the last row of Table 4.3. Retentate LHV is equal to 4.45 MJ/Nm³.

Table 4.8. Dried weight syngas composition from membrane (retentate)

CO	H_2	CH_4	CO_2	N_2
22.4%	0.6%	1.3%	17.6%	58.1%

Previous constrains allow to define the size of the single gasifier and coupled HRS: proposed RESET gasification system PowerSkid 200+ is able to produce 520.3 Nm³/h (585.5 kg/h) of dried syngas with a composition as described in Table 4.6. It consumes 237 kg/h of pruning dried with a moisture composition of 10-15% (12% assumed) and compressed in briquettes. The system produces 16.6 kg/h of biochar. Pd-membranes extract a flow rate $\dot{m}_{H2}^{ext}$ equal to 89.9 kg/day of hydrogen (3.74 kg/h) over the 7,200 hours of annual activity. The optimal size of different machines is summarized in the Table 4.9 below

Table 4.9. Size of main components

ICE power output (P_{ICE})	163.1 kW
Syngas turbine power output (P_{tur})	44.9 kW
Syngas compressor power input ($P_{syn\ comp}$)	78.1 kW
Vacuum pump and hydrogen compressor power input ($P_{H2\ comp}$)	29.9 kW

Total electricity produced is 720 MWh/year with a shared electricity amount of 623.1 MWh/year. Exported electricity (out of REC) is 96.9 MWh/year and imported electricity 326.7 MWh/year: all exported electricity is compensated economically by value for imported one. Total economic revenues from electricity are equal to 92,600 €/year considering that all saving from REC members is devolved to the REC. A different policy could be actuated, but in the hypothesis of this study, all revenues are used to facilitate the hydrogen local supply and use chain for mobility.

Total thermal energy harvested from ICE, compressor and syngas treatment is equal to 3,197 MWh/year (at least at 90 °C): with a 3,350 hour/year of Spanish heating annual period, heat used in heating district is 1,005 MWh/year (31% of harvested energy). That energy avails 99 flats of around 70 m^2 each, producing an economical revenue of 91,000 €/year.

The single system consumes annually 1,706 ton of pruning with a total annual cost of 143,600 €/year.

Storage of hydrogen is a key factor to allow continuous refuelling of vehicle during maintenance stops of gasifiers: minimizing the number of hydrogen storage optimizing time management of maintenance stops of gasifier is a key factor to decrease capital cost of the territorial system proposed. To this purpose, considerations on hydrogen daily flow rates are needed in running or maintenance mode of the gasifier and in working or not working condition of the HRSs over the week (it is supposed that in the weekend HRSs are closed). Pd-membranes hydrogen flow rate $\dot{m}_{H2}^{ext}$ of 89.9 kg/day over the 7,200 running hours produces a total mass of hydrogen per year M_{H2}^{year} of 26.97 ton/year in each gasifier.

Hydrogen flow rate dispensed in the HRS during weekdays $\dot{m}_{H2}^{HRS}$ is bigger than the flow rate extracted from membrane $\dot{m}_{H2}^{ext}$, due to only 5 working days a week of the HRS. Hydrogen daily flow rate dispensed by a HRS during weekdays is

$$\dot{m}_{H2}^{HRS} = \frac{M_{H2}^{year}}{wd_{HRS}} = 103.27\ kg/day \tag{4.7}$$

where wd_{HRS} is the annual working day of the refueling station and M_{H2}^{year} the total mass of hydrogen produced per year by membranes of the single plant.

From a balancing of mass in a week with gasifier running

$$7\dot{m}_{H2}^{ext} = 5\dot{m}_{H2}^{HRS} + 7\dot{m}_{H2}^{maint} \tag{4.8}$$

where $\dot{m}_{H2}^{maint}$ is the daily flow rate of hydrogen to be stored for maintenance period, compared to $\dot{m}_{H2}^{ext}$ that is the hydrogen daily flow rate extracted by membrane. Consequently, daily flow rate of hydrogen to be stored for maintenance period $\dot{m}_{H2}^{maint}$ can be inferred

$$\dot{m}_{H2}^{maint} = \dot{m}_{H2}^{ext} - \frac{5}{7}\dot{m}_{H2}^{HRS} = 16.08\ kg/day \tag{4.9}$$

When the gasifier is shut down and HRS have to dispense hydrogen in daily refueling $\dot{m}_{H2}^{HRS}$, an amount of hydrogen has to be supplied by the running gasifiers, and the minimal number of required gasifiers n_{min}^{HRS} is

$$n_{min}^{HRS} = \frac{\dot{m}_{H2}^{HRS}}{\dot{m}_{H2}^{maint}} = 6.4 \quad (4.10)$$

Consequently, a group of seven gasifiers ($n_{opt}^{HRS} = 7$) constitutes the optimal territorial system of provincial hydrogen supply chain. As a result, each gasifier is equipped with a stationary storage M_{H2}^{stat} to manage the weekly operation and a mobile storage M_{H2}^{mob} to manage the maintenance of the gasifiers

$$\begin{cases} M_{H2}^{stat} = 7\dot{m}_{H2}^{ext} - 5\dot{m}_{H2}^{HRS} \cong 120\ kg \\ M_{H2}^{mob} = \left(\frac{365 - wd_{gasif}}{4} \cdot \frac{5}{7} \cdot \dot{m}_{H2}^{HRS} - M_{H2}^{stat}\right) / n_{opt}^{HRS} \cong 160\ kg \end{cases} \quad (4.11)$$

where wd_{gasif} is the annual working day of the gasifier.

Considering typical minimum inlet pressure for a booster hydrogen compressor [146] and consequently an usage rate of the hydrogen stored in a cylinder of 200 bar of around 88%, each basic plant have to be equipped with a hydrogen storage of 140 kg for stationary one and of 180 kg for mobile one (results of ratio from results indicated in Equation 4.11 and 88% of usage rate). One more mobile storage is necessary for managing logistic among the seven HRSs.

Considering the use of vehicles as stated, each HRS can serve 163 hydrogen passenger cars for a total of 1,141 hydrogen cars in the province. Territorial system is summarized as in Table 4.10 to have a uniform ratio over the cities between number of REC and total population of the cities, as well as for the number of hydrogen vehicle per 1,000 inhabitants.

Table 4.10. Characteristic of the provincial hydrogen system

	REC number	Ratio inhabitants on REC number	Hydrogen vehicles per 1,000 inhabitants
Huesca	3	17,985	9.1
Monzon	1	17,469	9.4
Barbastro	1	17,174	9.5
Fraga	1	15,353	10.6
Jaca	1	13,129	12.4

Total annual hydrogen production is 189 ton/year, consuming 11,900 ton/year of pruning, that is only around 4.5% of pruning annual production with the three most abundant cultivars in the region of Aragón.

4.3.4 LCOH from "field to tank"

In the province of Huesca, as in many areas in Europe, there is no infrastructure for a hydrogen chain (except experimental equipment of Fundación para el Desarrollo de las nuevas tecnologías del hidrógeno in Walqa near Huesca). For this reason, all infrastructures must be erected for production, storage, territorial transportation and refuelling of the vehicles. This entails a significant increase in expenditure and consequently an increase in the minimum selling price of hydrogen for the

sustainability of the initiative. For this reason, the concept of LCOH *from field to the tank* is introduced: all capital and operational costs from biomass harvesting to hydrogen dispensing at 900 bar are considered. This approach is certainly more unfavourable but it is the one most in line with those situations in which infrastructures do not exist.

Total cost for all territorial system (seven gasifiers and seven HRSs) is 14.34 million euro.

An overview of capital cost of a single plant is shown in Figure 4.6.

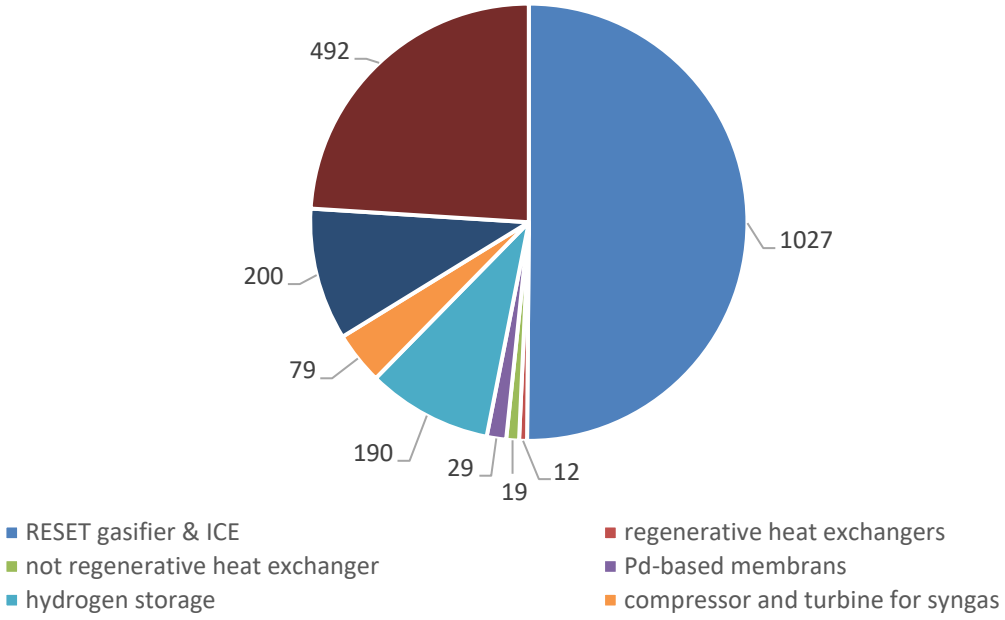


Figure 4.6. CAPEX overview of a single modular basic plant (values in thousand €)

Cost for gasifier and ICE is the most prominent one, followed by HRS and process hydrogen compressors to manage the extraction of hydrogen by membrane: these first three entries count for around 85% of total CAPEX. LCOH is equal to 8.90 €/kg that means a minimum cost of hydrogen at HRS (21% VAT included) of 10.77 €/kg. Last value is higher than hydrogen cost at HRS (VAT included) that allows same mileage with a diesel car (6.87 €/kg).

Table 4.11. Comparison of LCOH with literature data (adapted from [147])

H_2 production [kg/day]	H_2 source	H_2 Production Technology	Power Unit Technology	LCOH [€/kg]	Ref.
125	water	electrolysis	wind, PV, battery	7.94	[148]
125	water	electrolysis	wind, battery	9.86	[148]
25	water	electrolysis	PV, PEMFC	8.13	[149]
25	water	electrolysis	wind, PEMFC	5.97	[149]
125	water	electrolysis	wind, grid	5.64 to 7.98	[150]
60	water	electrolysis	hydro, grid	9.2 to 15.7	[151]
200	water	electrolysis	PV, grid	9.29	[152]
450	water	electrolysis	PV, grid	7.92	[147]
70	ammonia	cracking/PSA	-	8.06	[153]
200	ammonia	cracking/Pd-membrane	PEMFC	7.35	[154]
100	ammonia	cracking/Pd-membrane	SOFC	9.78	[155]
450	ammonia	cracking/Pd-membrane	PEMFC	6.28	[147]
450	ammonia	cracking/Pd-membrane	SOFC	6.89	[147]

100	biogas	ATR/WGS/Pd-membrane	SOFC	11.23	[156]
450	biogas	ATR/WGS/Pd-membrane	SOFC	7.25	[147]
630	lignocellulosic biomass	Gasification/Pd-membrane	ICE, turbine	8.90	this work

PSA - Pressure Swing Adsorption
ATR – Autothermal Reforming
WGS - Water Gas Shift

The LCOH emerging from the study has been compared with those available in scientific literature concerning solutions with both production and dispensing of hydrogen, using different feedstocks and technologies [147]. A summary is shown in the Table 4.11.

The territorial hydrogen distribution system proposed in this study seems to have an impact increasing the LCOH value.

4.3.5 Sensitivity and further development

The most prominent cost is gasifier and ICE cost, that represents the highest part in the overall CAPEX for the whole plant. It is also affected of high variation as stated in Figure 8.3 of the IRENA report [135] in Europe in the range of 0-5 MW. Minimum value of 2,800 €/kW can be considered as best realistic scenario.

Field pruning harvesting cost can be decreased: in normal cultivation operations, pruning on the ground must be treated with a passage of a mechanical means, that generates a cost for the farmer equivalent at the harvesting cost assumed in the scenario of this study (first row of Table 4.1). Consequently, that value is a fixed operational cost for the farmer, that cannot be attributed to the valorisation of the biomass like described in the study. In view of this consideration, a lignocellulosic biomass harvesting and transformation cost of 44.1 €/ton can be inferred.

Considering only these two variations on economical parameters, a LCOH of 3.90 €/kg is obtained, with a minimum cost of the hydrogen at HRS (VAT included) of 4.72 €/kg that is largely competitive with diesel. A total investment cost of 11.02 million euro is required in this case.

Another margin for improvement lies in the valorisation of harvested process heat. In fact, only around 30% of that heat is valorised in the district heating: if the gasifier would be installed near a SME operating with heating request during all year (i.e. laundry, dairy), this percentage could easily be raised to benefit the initiative.

Biochar valorisation is not contemplated in this study: future studies could consider it as a revenue stream. Biochar valorisation is a controversial matter due to its potential content of polycyclic aromatic hydrocarbons (PAHs). PAHs could be a risk for human health as well as the environment when biochar is used as soil amendment [157] that is one of the most common valorisation chain in an agriculture context. In industrial market opportunity for biochar could be reached, but a more detailed chemical analysis is necessary, which is out of scope of this work.

All aspects that lead to a LCOH lower than cost of diesel create the opportunity for a revenue for members of the REC, increasing the social acceptability of the initiative.

4.4 Conclusions

This study develops a techno-economic assessment for a network of modular energy plants fed by residual lignocellulosic waste biomass from farming in Huesca province of Aragón Region (Spain). The purpose is to generate at the same time different energy carriers to be used locally in a Renewable Energy Community (REC). Each plant is based on gasification of local pruning and contemporarily production of power, heat and hydrogen. Power and heat meet residential need of the REC's members, while hydrogen is used for mobility purpose. The considered gasification system is a carbon negative technology, due to its production of biochar, which traps carbon in its matrix. The plants supply heat and electricity exclusively for proximal RECs; hydrogen is used both for hydrogen refuelling station (HRS) adjacent at the plant and for others HRSs in the network during stop of gasifier in maintenance period, by mobile storage (tube trailer).

The main findings of the present study can be summarized as follows:

- technologies in the commercial or pre-commercial stage are available to allow the proposed scenario, alongside the whole chain;
- the production and integration of multiple energy carriers allows for better valorisation of the residual local lignocellulosic waste material;
- using local pruning as feedstock is a supply chain not in competition with food one, but in support of it;
- renewable energy community in Spain is a legal framework enabling new opportunity for local valorisation of territorial underutilized resources as pruning (residual agricultural waste material);
- incentives given to shared energy in renewable energy communities may trigger the creation of new mobility based on renewable hydrogen;
- the territorial approach, as an alternative at the single plant, allows a significant reduction in costs, especially due to the hydrogen storage needs;
- proposed system allows to obtain social and territorial advantages, not easily monetizable as job creation, abatement of local pollution by zero-emission hydrogen vehicles and local district heating, conversion of cost for agricultural waste management into positive economic value.

With a 100-kW electricity output plant, to be compliant with the simplified economic management system as in Spanish REC framework, a single modular basic plant is able to satisfy the electricity requirements of 777 persons grouped into 370 electric passive domestic users, thermal annual needs of 99 flats of around 70 m^2 each and 163 hydrogen cars (with a mileage for each vehicle of 15,000 km/year). Optimal territorial network is composed by seven plants in the five larger cities in the Huesca province: Huesca, Monzon, Barbastro, Fraga, Jaca. Seven HRSs cover around 50% of inhabitants of the Huesca province. Total biomass consumption is 11,900 ton/year of pruning, that is around 4.5% of pruning annual production with the three most abundant cultivars in the Region of Aragón. Levelized Cost Of Hydrogen (LCOH) is equal to 8.90 €/kg and consequently a minimum cost of hydrogen at HRS (21% VAT included) of 10.77 €/kg. The LCOH consider all the cost from pruning harvesting to hydrogen refuelled in a car at 700 bar (*from field to tank*) in a territory without hydrogen HRSs. Sensitivity analysis shows the actual possibility to obtain a LCOH at 3.90 €/kg.

In the study an economic valorisation of the biochar is not taken into account due to checks on the environmental compatibility of biochar produced by gasification technology considered: a future development could highlight a positive impact on LCOH.

Given the possibility by RED II European directive of creating REC throughout all Europe, the proposed study can be easily adapted to the different regulatory contexts of the States belonging to the European Union, obtaining similar results.

5 Integrating Renewable Energy Communities and Italian UVAM project through renewable hydrogen chain

This chapter is based on the following published articles:

Raimondi G., Spazzafumo G. Integrating Renewable Energy Communities and Italian UVAM project through renewable hydrogen chain. E-Prime - Adv Electr Eng Electron Energy 2024; https://doi.org/10.1016/j.prime.2024.100819

5.1 Introduction

Due to the increase in the diffusion of renewable energies in Italy, the state of the medium and low voltage (MV and LV) electric grid appears to be critical currently in many areas of the country. E-distibuzione (Enel group) is the biggest Italian electric distribution system operator (DSO) and it periodically publishes on line the state of the electric grid in a map with a qualitative graphical synthesis regarding the transport capability and quality of the service [158].

As declared on the web site, "through the map it is possible to obtain, in an interactive and immediate manner, qualitative indications regarding the availability of network capacity, through a classification of territorial areas by level of criticality". The criticality is linked to the average residual electricity transport capacity and stability of the electricity grid, measured through the most relevant parameters (frequency and voltage on the grid during days). In general, the greater the connections of renewable energy on the electricity grid, the higher the criticality encountered. Considering the electric grid in the 104 Italian provinces monitored in E-distibuzione on-line tool [158], during the last period available (from March to May 2023) 89 provinces are in medium-high critical level (around 90%), and the installation of additional renewable energy capacity will likely worsen this situation without investments empowering the grid or changing its topological structure. More in detail, the electric grid in the regions and provinces of Southern Italy appears to be in further difficulty due to the high renewable potential and the low electricity demand in those territories. Basilicata is the Italian region with the greatest difficulty in accepting new renewables, as both its two provinces present a medium-high criticality in the period considered. More in detail, carrying out an analysis at the high voltage (HV) level, it is estimated that counting the 71 HV/MV substations in the region, in 10 of them there is a usual inversion of the electrical flows from the DSO grid to the TSO (transmission system operator) one, with a transmission power level beyond the critical limit. In other 9 cases the substations are not always able to manage all the installed renewable power (the sections reach saturation of the transmission capacity). Globally in 27% of HV/MV substations in Basilicata there are medium-high criticalities on the grid to manage the renewables installed in the area.

In Italy, as well as in the rest of Europe, the push to install further renewable capacity is still strong, to be compliance with the climate transition objectives for 2030: "the revised Renewable Energy Directive, adopted in 2023, raises the EU's binding renewable energy target for 2030 to a minimum of 42.5%" (in 2022 the share of renewables in EU consumption was 22%) [159].

The European Directive on Renewable Energy (RED II) [5] described Renewable Energy Communities (so called RECs) as a new tool to increase renewable energy stock for residential end-users, associations or small and medium enterprises (SMEs). In Italy the RED II Directive was adopted in November 2021 [17] and the full operative legislative framework was defined by Directorial Decree number 22 adopted on 23 February 2024 [160]. RECs can be developed within the territory served by a single primary substation (HV/MV substation). Many different RECs could be developed independently into the same primary substation: no limits have been defined on the number of RECs by regulatory framework. Therefore, based on different needs from citizens, associations or SMEs, many RECs probably will be established under the same primary substation, without any coordination among them.

As highlighted in our previous study [133], without using dedicated storage, shared energy in a REC is only a small amount of the renewable electricity produced, due to the decoupling between

electric usual hourly consumption and renewable production (see Figure 10 in [133]). A great quantity of renewables produced in the REC will flow through the electric grid towards areas out from REC zone. Therefore, RECs that do not use electric storages will impact negatively on local electricity grid of DSO: more electricity than in the configuration without RECs will need to be managed by DSO electric grid flowing out from the HV/MV substation where the REC is installed. Therefore, electricity in excess produced by RECs could affect negatively on DSO grid, that often is currently already in crisis regarding transport capacity, as previously highlighted in Italian landscape.

Many studies in the literature consider the REC developing in Italy, as well as throughout Europe, and its potential effect on both DSO and TSO grids and on the stock of renewables. In our previously study [133] we shown that the amount of electricity flow out from the local market area of a residential REC based on both wind and solar without storage could be not negligible on the DSO grid. Introducing an electrolyser operating with a capacity factor around 30%, this excess of electricity can definitely be reduced both in peak of power and in energy amount. Weckesser et al. [161] described the RECs impact on DSO grid and the relevance of an optimal sizing of photovoltaics and battery storage on it. Moreover, depending on the REC's operating strategy the LV grid loading can be reduced by up to 58%. Mustika et al. [162] clearly expressed that RECs can have an important role in the stabilization of electricity TSO grid in particular with the provision of frequency reserve (manual frequency restoration of the tertiary reserve), anticipating some themes developed in the present work. The paper also described a case study in France based on battery storage and its positive effect on economics of the REC. García-Muñoz et al. [163] proposed a business model for a REC that offers reactive power as an ancillary service into the day-ahead and the intraday electric markets. Bartolini et al. [21] compared Power-to-Gas and battery storage in a REC with an high level of photovoltaic penetration and their effect on the local electric grid. Pastore et al. [164], considering an average electricity grid accommodation capacity up to 40% of renewable electricity [165], investigated effect of Power-to-X in RECs to mitigate the impact on the electric grid. Sănduleac et al. [166] described a methodology that increases the accuracy of the monitoring tools for distribution power grids with a REC to decrease the impact on the electric grid. Herenčić et al. [167] reported a case for Croatian city of Križevci with a REC and its techno-economic effect on the energy sharing in MV and LV distribution grids. As D'Adamo et al. [168] stated, REC investments have an attractive profitability with a low level of risk: so could be a wide spreading model during the next years. This could generate a good effect on the stock of renewables in Italy, supporting a nation's energy independence and resilience by mitigating risks related to geopolitical issues and financial speculation.

High penetration of renewable generation in Italy also affects the national electric transmission system, potentially increasing instability of the HV grid. Terna is the Italian TSO and it has already started several projects during last decades to mitigate the effects of renewable energy on its own HV transmission system. The Italian UVAM (in Italian language Unità Virtuali Abilitate Miste, i.e., virtually aggregated mixed unit) project is a key initiative by Terna to integrate intermittent renewable energy assuring stability in the grid from distributed energy resources [169].

Started in November 2018, the UVAM project was reviewed in different papers. Schwidtal et al. [170] underlined the main aspects of the UVAM project and reviewed it after 2 years of execution. Due to the inherently unprogrammable nature of most renewable energy sources, electricity markets face an increasing volatility and need for balancing from ancillary service markets (ASM) to stabilize the TSO grid. ASM was dominated until now from fossil fuel-based power plant, but this condition must

decrease during next years due to face out from fossil energy. Aggregation of multiple small units to one large unit through a so-called virtual power plant [171] is a solution to create more distributed resources for ancillary services on the grid, possibly using directly renewable energy and renewable energy storage (i.e. hydrogen). Through the aggregated dimension, they can potentially participate on electric market and more in detail at ASMs that each individual unit by itself would not be able to access (there's a minimum power dimension). Aggregation defining virtual bigger power plants is an essential building block for an effective energy transition and an increasing integration of renewables [172].

Also Gulotta et al. [173] in 2020 stated constitution of a relevant number of aggregators (entities that constituted UVAMs and that participated to ASM) that allowed to led to a more competitive auction market in Italy. in December 2021, Terna itself [169] stated that more than 220 UVAMs were qualified with a power of approximately 1280 MW and with 1072 PODs (Points of Delivery) involved. UVAMs were managed by 17 different Balancing Service Providers (BSPs). According to ENTSO-E [174], a BSP is an agent that can offer balancing services to the TSO.

Residential users too, if aggregated, can provide services on ASM, and consequently also a REC, through storages and electric measuring technology, is able to provide flexibility services to the grid [175].

Cancro et al. [176] described a similar scenario and proposed a new methodology to determine the optimal revenue of a UVAM based on residential users. They proposed as future work to consider REC as aggregator, but not developed it. Forouli et al. [177] reviewed the deployment of demand side flexibility in different European nations, to identify best practices and main barriers. In a comparative way they reviewed system developed in United Kingdom, Belgium, Italy and Greece. They underlined that RECs can be considered as enabling entities for participation to all electric markets (ASM in particular).

An UVAM based on renewable energy needs a storage that allows renewable energy to be dispatched in the electric market. Hydrogen can surely serve this purpose even if the round trip efficiency currently appears limited and lower than battery systems [133,178,179]. The low round trip efficiency implies that frequently the costs associated with a Power-to-Power (PtP) based on hydrogen is not sustainable from an economic point of view [133].

The aim of this work is to propose and investigate an original techno-business model that allows to produce renewable hydrogen from excess of renewables at a low cost by exploiting REC's incentives and using it to produce dispatchable renewable electricity for the richest electricity market existing in Italy (ASM) through UVAM project (Figure 1).

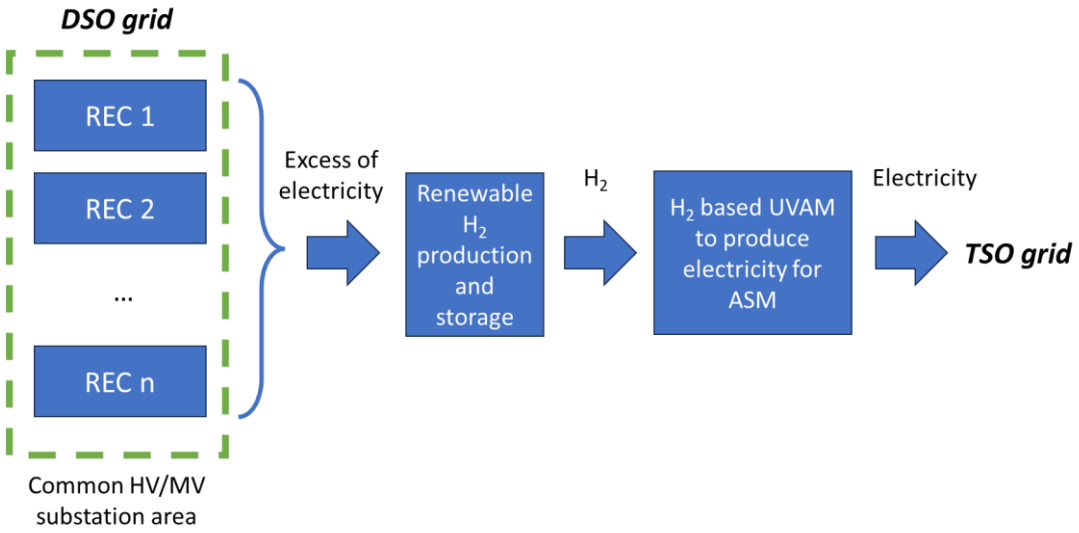


Figure 5.1: Simplified scheme of the proposed system

The production of hydrogen within a REC allows both to avoid the problem on the electricity DSO grids due to high level of renewables penetration, and to produce renewable hydrogen at a low cost due to incentives. The UVAM project allows in Italy to minimize the size of the power plant (only 1 MW as better described in the following Section) to access ASM, based on currently regulatory framework. To the best knowledge of the authors, no paper describes a such system that exploits an inherent problem of stability on DSO grid potentially created by RECs' deployment in a territory to solve a stability problem on TSO grid through UVAM fed by renewable excess from RECs. This represents the novelty of this work: in the current regulatory and legislative Italian context, we propose both a solution to the problems described above of management of the excess of renewable energy produced by RECs in a local grid and renewable balancing electricity TSO grid by ASM using UVAM based on renewable hydrogen. Taking into account REC's and UVAM's legal framework, this study offers a scenario that fully complies with the rules and regulations currently in effect in Italy, as well as considering technical economic state of the art.

Ferrucci et al. [180] concluded in their recent study that from a regulatory point of view, as RECs are already acknowledged by specific supporting schemes, they could not be acknowledged as UVAM too, to operate on the market offering ancillary services on the electric market. Our study proposes a techno-business model to overcome such an objection by proposing an original balance of plant of the equipment that allows RECs to participate in the ASM.

Brusco et al. [181] claimed a potential role of RECs in providing additional ancillary services on electric market, also using hydrogen as a storage system. They described a storage system in RECs (daily based on batteries and seasonal based on hydrogen) to increase autarchy of the RECs (self-consuming of electricity from local renewables) and to participate to ASM considering only 25% of energy stored is considered to be dedicated to the provision of ancillary services. Furthermore, Brusco's paper does not take into account the minimum limit of 1 MW for defining an UVAM in Italian regulatory framework (see following Section), appearing to be rather just a suggestion. In fact, all cases studies in Brusco et al. [181] considered 20 kW as maximum power adsorbed from or injected in the electric grid to assure ancillary services, which is a quantity incompatible with the UVAM project. Moreover, no detail on efficiency or cost of hydrogen supply chain were declared, so a comprehensive economic analysis was

not fully accomplished. In the opinion of the authors, a different sizing of the systems, an alternative use of renewables and a diverse business model can develop a feasible strategy to provide auxiliary services on the electric market, based on RECs.

Crespi et al. [182] described a technical scenario very similar to what is the purpose of this work, in fact the technological architecture presented corresponds to what is analysed in the present study, as well as the business model for participation in the electricity market. However, the fundamental regulatory element enabling the business model (i.e. regulatory Italian framework defining RECs) is lacking.

5.2 Material

5.2.1 Italian electric markets and UVAM project

Crespi et al. [182] showed an accurately description of the Italian electricity market and its functioning, partially taken up again below. In Italy there are various electricity submarkets to respond to different functions of the electricity distribution service. The Day-Ahead Market (DAM) is an auction market to provide base load generation, where participants (both producers and consumers) trade hourly electricity quantities for the next day by submitting bids indicating the quantity and the minimum and maximum sell/purchase prices. After each market session, the intersection of demand and supply prices defines the actual price (marginal clearing price) for each time slot and all the generation (consumption) units that bid a lower (higher) price are scheduled to generate (consume). The solution of the market balance takes into account also the transmission capacity limits between different zones of the electric grid (bidding zones), which are defined by Terna, generating different prices (zonal prices) if they are saturated. Zonal prices are applied for the remuneration of the generating units, whereas the accepted demand bids are conversely remunerated at the national single price (in Italian language Prezzo Unico Nazionale i.e. PUN), equal to the average of the zonal prices weighted on the quantities. In this study zonal prices and PUN of 2023 were used, inferred from GME (in Italian language Gestore dei Mercati Energetici, i.e., Energy Services Operator) website [183].

The Italian electricity market provides also the Intraday Market (IM) and the already mentioned ASM. As the DAM, the IM is an auction market where hourly energy blocks are traded to modify the preliminary schedules defined at DAM closure. Conversely, the ASM is the market where Terna procures resources for the management and control of the system, such as frequency regulation, control of congestions, voltage regulation, etc. The Italian ASM consists of a scheduling stage (in Italian named Mercato dei Servizi di Dispacciamento – MSD ex-ante) and the Balancing Market (Mercato del Bilanciamento - MB), each of them composed of multiple sessions. On the MSD ex-ante, Terna accepts purchase and sale offers to solve residual congestions on the network and establish adequate reserve margins. On the MB, which is open throughout the same day of operation, Terna accepts purchase and sale offers to perform the secondary regulation service and to maintain the balance between electricity injection and withdrawal in real time. In both MSD ex-ante and the MB, bids are remunerated with a pay-as-bid mechanism, i.e., at the offered price. They are normally most profitable electricity markets where the price of electricity can even be a time-and-a-half DAM hourly price [183,184].

Electric provider who wants to participate in electricity markets must be qualified according to the network code established by Terna [185].

The UVAM project represents the first integration in Italy of distributed energy resources to supply ancillary services to the power DSO grid such as balancing, tertiary reserve and congestion management in MSD ex-ante market [173].

With the aim of increasing the number of entities that could participate in the ASM beyond large electricity production power plants (equal or greater than 10 MVA), new rules were established in 2017 defining for the first time the UVAM as new aggregated entities [186]. New entities not obliged and too small to participate in the ASM were admitted to it, constituting a virtual bigger power plant through aggregation. As stated by Gulotta et al. [187] the admitted entities were small power plants, stationary energy storage systems or also electric vehicles.

As recalled by Gulotta et al. [173] in the early stage of UVAM project the minimum bid size to access the market qualification process was initially set at 10 and 5 MW, respectively for loads and generation plants. In 2020 [188] the minimum size threshold has been reduced to 1 MW for all type of UVAM [189].

The UVAM project has adopted a remuneration scheme based on both the energy dispatched in the ASM daily sessions (i.e. remunerated as pay-as-bid in €/MWh) and long-term capacity contracts, linked to the expected availability of the plant acting in regulation (i.e. remunerated for capacity as €/MW per year based on annual auction in capacity market) [173].

In this study the ASM sessions of 2023 were considered in all the seven Italian bidding zones: Table 5.1 summarizes the ASM in Italy in 2023 inferred from [184]. The considered market areas are CALA (Calabria region), CNOR (Central-Northern Italy), CSUD (Central-Southern Italy), NORD (Northern Italy), SARD (Sardinia), SICI (Sicily), SUD (Southern Italy) as described in Italian MSD [190].

Table 5.1: Electricity sale price on ASM (MSD ex-ante) in 2023 in Italian bidding zones

	CALA	*CNOR*	*CSUD*	*NORD*	*SARD*	*SICI*	*SUD*
mean value (all year sessions) [€/MWh]	*188*	*185*	*207*	*201*	*173*	*212*	*207*
ASM's active hours in 2023 [hours]	*722*	*1665*	*1869*	*5090*	*895*	*1545*	*937*
maximum price [€/MWh]	*305*	*320*	*331*	*351*	*265*	*303*	*335*
minimum price [€/MWh]	*120*	*130*	*122*	*120*	*145*	*122*	*123*

The market area with the greatest quantity of electricity exchanged (NORD) has a greater number of active market sessions (number of active hours) to prevent network imbalances. Bidding zones with lower electricity demand and greater predictability (CALA, SARD) showed ASM's active hours only around 10% of annual hours. An example of evolution of mean price in ASM during each hour of the year in CSUD bidding zone is indicated in Figure 5.2, such as an indication of the active market sessions of the ASM.

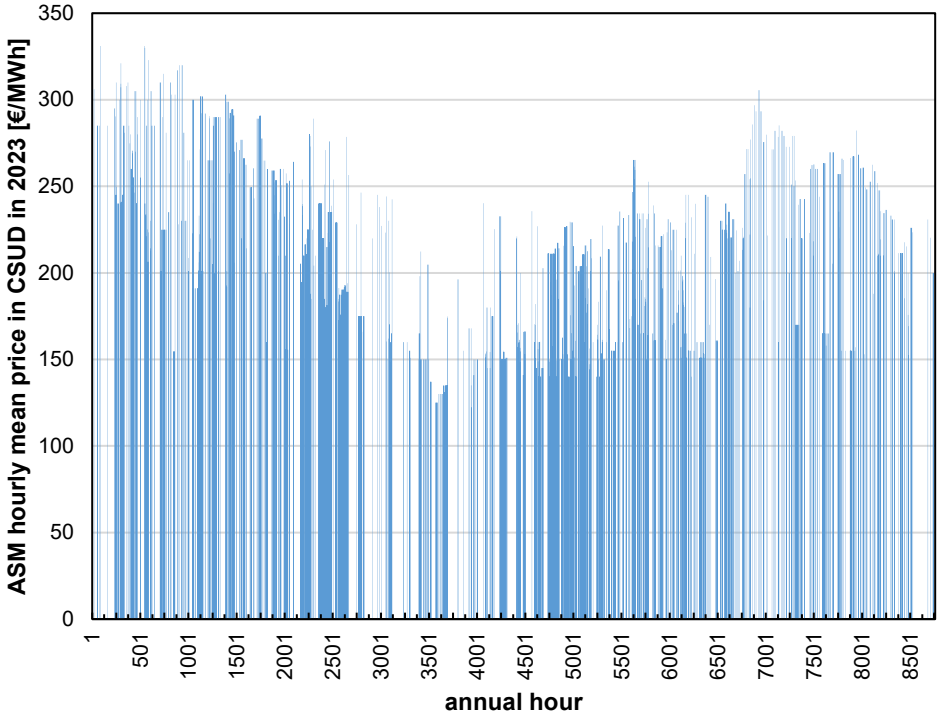


Figure 5.2: Mean price in ancillary service market in CSUD bidding zone in 2023

Based on available hydrogen between the seven different market areas in Italy (bidding zones), it is possible from any area to dispatch electricity to other areas, following successful auctions.

5.2.2 Renewable Energy Community in Italy

A Renewable Energy Community is a legal entity as stated in article 2 paragraph (16) of RED II [5]. REC "in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity".

Members of a REC are producers, consumers or prosumers (both producers and consumers) of renewable energy. In article 8 of the reference Italian law [17], "shared energy" is legally defined, as the energy produced by renewables and consumed in the same hour by users within a REC through the DSO grid. Furthermore in detail as defined in article 2, paragraph 1), letter q) of Dlgs 199/2021 [17], shared energy "is equal to the minimum, in each hourly period, between the electricity produced and fed into the grid by renewable source plants and the electricity withdrawn by all the associated end-customers located in the same market area". Shared energy receives economic subsidies by Italian Government. In February 2024 operative rules to constitution and managing for a REC in Italy was published in a specific decree [160] by the MASE (Ministry of the Environment and Energy Security), defining techno-economic rules for electric market area and subsidies representing the incentive mechanism. The geographical area to define a REC was established as the HV/MV substation feeding area in the DSO grid (primary substation).

As recently summarized by D'Adamo et al. [168], recipients of the measures include not only RECs, but also the so-called collective self-consumption of energy from renewable sources (composed

by groups of consumers operating within the same building or residential complex); and individual self-consumption of energy from remote renewable sources, in which a sole entity (company or private residential user) exchanges in the some hour energy from various production and consumption sites under its ownership and management. The incentive is assigned for 20 years and varies according to the size of the renewable source plants generating the shared energy and the zonal price:

- power plants with size less than or equal to 200 kW: tariff = 80 + max (0; 180 - zonal price) €/MWh with a maximum of 120 €/MWh;
- power plants with size greater than 200 kW and less than or equal to 600 kW: tariff = 70 + max (0; 180 - zonal price) €/MWh with a maximum of 110 €/MWh;
- power plants with size greater than 600 kW and less than or equal to 1 MW: tariff = 60 + max (0; 180 - zonal price) €/MWh with a maximum of 100 €/MWh.

In addition, for photovoltaic systems, there is an addition of 4 €/MWh or 10 €/MWh if located in central or northern Italian regions respectively, due to lower insolation in comparison with southern ones. Renewable plants installed in REC until 2026 in municipalities under 5000 inhabitants receive a 40% non-refundable loan for installations: in these cases, the incentive on shared energy is reduced by 50%. The new Italian regulation [160] also requires that a SME participating in the REC cannot have incentives corresponding to more than 55% of the shared energy. The excess quota over 55% must necessarily benefit directly citizens, to realize social and environmental improvements of the area where REC is established.

5.2.3 Power generation by photovoltaic plants in the RECs

In a REC, photovoltaic panels can be mounted in various ways, depending on their integration on roofs of pre-existent buildings or installation on the ground with or without solar tracking systems. The annual productivity and the daily production curve will depend on the carried-out installation and will have an impact on the definition of shared energy in view of REC incentives.

Using data from JRC PVGIS initiative [34] a single kW peak PV system can be characterized considering different mounting options, location of the plant, historical irradiation data. Hourly annual production of energy PV can be inferred and this time resolution is useful to define the shared energy based on hourly annual consumption of REC members.

A highly penetration PV condition in the area where the REC is based is a fundamental premise for this study, that is considering only PV as energy renewable source. In Italy REC can be realized with members and renewable plants connected to the same primary substation. The highest PV installed power per capita in Italy in 2023 is 0.9 kWp/capita with the mean Italian value of 0.5 kWp/capita [191]. Current PV Italian total amount is 30 GWp and in 2030 would be around 80 GWp [191]. A x2.6 increase is expected in very few years that will impact also the PV per capita, with a highest value at 2.3 kWp/capita and a mean value of 1.3 kWp/capita.

5.2.4 Hydrogen production, storage and use

Modular type electrolyser enables a better matching with renewables, due to partialization of the switching on of the individual modules. It is supposed a PEM technology that assures an efficiency

of 70% based on lower heating value (LHV) of the hydrogen [192]. The electrolyser architecture is assumed similar to a modular Enapter EL 2.1 type [42]. The inferred data of a single core electrolyser are summarized in Table 5.2.

Table 5.2: Single core characteristics of the electrolyser

power consumption with auxiliary [kW]	*3.05*
power consumption to produce hydrogen [kW]	*2.4*
mass flow rate [g/hour]	*64*
efficiency [% LHV]	*70%*

Pressure storage of the hydrogen is a common solution. A double pressure level (35 and 200 bar) is indicated in our previous study [134].

In a PtP approach internal combustion engine (ICE) and fuel cell (FC) are considered usual solutions in literature [193] to produce electricity using stored hydrogen produced by renewables. Due to different technological maturity, there are differences in particular regarding the efficiency and, above all, the cost of them. In fact, while for a hydrogen ICE the capital cost currently stands at around 800 €/kW [193], for fuel cell technology it stands at between 1600 and 2000 €/kW [193] with a peak at 3000 €/kW in Crespi et al. [192]. The efficiency values are also different: based on LHV the usual efficiency for an hydrogen ICE is 45% [193] while hydrogen fuel cell allows efficiency between 50% and 60% [192,193].

Considering that the electric generation in ASM is not continuous (typical active session also of only one hour) but which could involve multiple switching on and off even during the same day, it is important to consider warm up both consumption and time for the power generation system. Crespi et al. [194] characterized a 1 MW fuel cell system warm up stage: a hydrogen consumption of 20.9 kg in warm up was inferred with a net electric production of 250 kWh and a warm up time of 46 minutes.

5.2.5 Economic facts

A Levelized Cost Of Energy (LCOE) [45] and Net Present Value (NPV) can be used for the evaluation of different cases.

$$\begin{cases} LCOE = \frac{\sum_{a=0}^{N} \frac{C_a + O\&M_a - (CM_a + I_0)}{(1+d)^a}}{\sum_{t=0}^{N} \frac{E_a}{(1+d)^a}} \\ NPV = \sum_{a=0}^{N} \frac{C_a + O\&M_a - (CM_a + I_0)}{(1+d)^a} \end{cases} \quad (5.1)$$

Beyond the usual annual (a) expenditure items due to capital cost (C_a) and operation and maintenance cost ($O\&M_a$), two items are considered in decreasing the LCOE: the economical fee assigned in the capacity market by auctions for generation plants serving the ASM by UVAM (CM_a) and CAPEX incentive to REC constituted in Italy in municipalities with less than 5000 inhabitants (I_0). The 2023 capacity market auction is considered with an outcome for the new plants in Sicily of 75,000

€/MW per year [195]. Based on appendix 2 of Ministerial Decree number 414 adopted on 7 December 2023 [196], energy storage system in a REC constituted in municipality of less than 5000 inhabitants can receive a non-repayable loan of 40% of the capital cost.

In the Equation 5.1, d is the interest rate considered in the lifetime N for the investment. At the denominator, E_a represents the electricity sold in ASM in the considered year by UVAM.

In the operational cost the main relevant one is the electricity cost for the electrolysis to produce hydrogen: considering current commercial offers available for SMEs by electricity Italian suppliers, purchase price was defined as hourly PUN price in 2023 [183] with a surcharge commercial fee equal to 37 €/MWh. The mean purchase price in the typical year (assumed 2023) is 164 €/MWh.

To define the incentives for shared energy in the REC, the hourly zonal price in 2023 in Sicily is considered [183]: mean zonal price in the typical year (assumed 2023) is 125 €/MWh.

Economic values considered in the simulation are shown in Table 5.3.

Table 5.3: Economic parameters

Parameter	*Value*	*Ref.*
Lifetime, N [year]	*20*	[46]
Interest rate, d	*5%*	[46]
Electrolyser capital cost [€/kW]	*1185*	[192]
Storage (200 bar) capital cost [€/kWh]	*13.5*	[43]
Compressor capital cost [€/kW]	*1600*	[192]
Hydrogen ICE capital cost [€/kW]	*794*	[193]
Hydrogen Fuel cell capital cost [€/kW]	*3292*	[192]
Electrolyser O&M cost [€/kW/year]	*19*	[46]
Storage O&M cost [of CAPEX/year]	*0.5%*	[47]
Compressor O&M cost [of CAPEX/year]	*1%*	[192]
Hydrogen ICE O&M cost [of CAPEX/year]	*5%*	[193]
Hydrogen FC O&M cost [of CAPEX/year]	*2%*	[192]
ARERA shared energy fee [€/kWh]	*0.009*	[50]

Shared energy fee by ARERA (Italian Regulatory Authority of Energy, Networks and the Environment) is the incentive which is assigned due to the reduction of electricity losses on the grid due to the creation of a REC, in addition to whom based on Italian government incentives [160].

5.3 Case study

This study integrates different technologies to create the intended system (Figure 5.3).

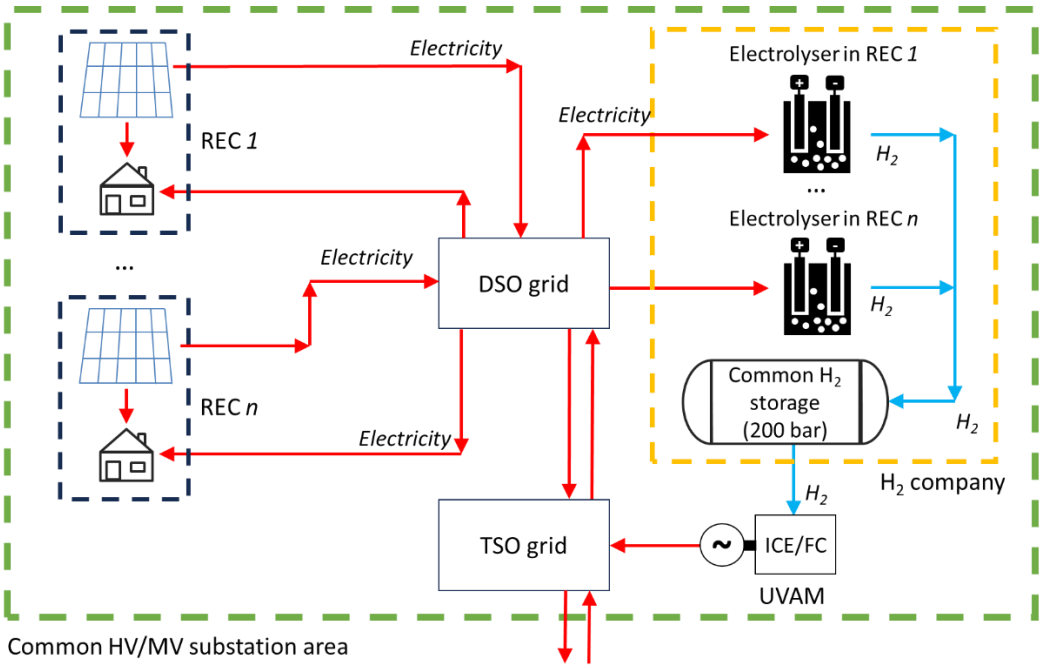


Figure 5.3: Scheme of the proposed system with the essential entities and flows

In a sole HV/MV substation area (indicated with a rectangle in green dotted line) where many RECs have been constituted (indicated with rectangles in black dotted line), a H_2 company (indicated with a rectangle in yellow dotted line) produces, stores and sells hydrogen from excess of renewables form each REC. The H_2 company is member of each REC, by connecting an electrolyser per each REC to DSO grid in the same HV/MV substation area. So, each REC is composed also by an electrolyser that drains excess of its renewables to produce hourly hydrogen, obtaining incentives for shared energy, otherwise flowing out of local DSO grid.

The H_2 Company is a SME and owns different electrolysers, each dedicated at a different REC using a different POD. The hydrogen produced by the H_2 Company from all the RECs in the HV/MV substation area is compressed and stored in a common storage system, transforming renewable energy into dispatchable energy ready for balancing the electricity grid.

The H_2 Company sells hydrogen to an electric company that manage a UVAM based on a 1 MW generating system (FC or ICE). The H_2 company cannot coincide with the electric company that manages the UVAM because under current Italian regulation [160] an electricity production and distribution company cannot be a member of a REC.

Based on available hydrogen in the storage of H_2 company, UVAM offers electricity auction shares in only upward-mode in daily ASM in all seven Italian different electric zones: it is supposed that there is enough interconnection capacity between the Italian zones to assure the transmission of electricity from one area to another. Electric connection of UVAM is directly at TSO grid inside the electric area where is based the RECs.

The proposed scheme is compliant with current Italian regulatory framework.

More in detail, each REC defined in this study has a layout as described in the Figure 5.4.

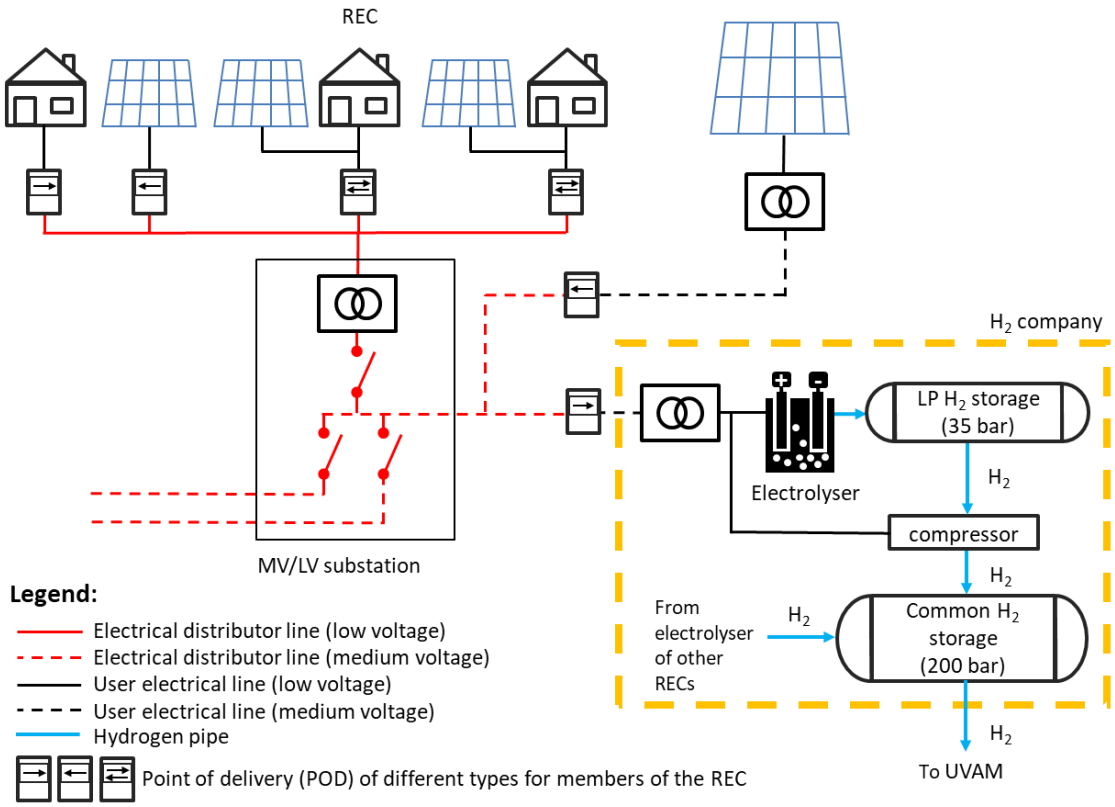


Figure 5.4: Electric layout of a typical REC integrating a member with hydrogen production chain

REC is supposed to be composed by residential members, stand-alone PV plants (integrated or not with the buildings) and H_2 company through one electrolyser dedicated the specific REC. The residential REC members are both passive members (electric consumers), or prosumers (both producer and consumer). Power generation is only by PV, that are connected both at LV or MV level.

PV can be both integrated in the grid of residential buildings (partially self-consumer) or not. No battery storage is considered at prosumer level. Consequently, each POD defining the member of the REC can be monodirectional in purchasing or in selling of electricity (only one arrow in the icon to the right or to the left respectively) or bidirectional (two arrows in the icon) for the prosumers as described in Figure 5.4.

5.4 Methods

The approach adopted in this study is discussed in this section.

5.4.1 Energy and hydrogen flows: mathematical model

In this study, the worst case for PV electricity production in the RECs is considered: all the PV panels is supposed integrated into the roof of the buildings without both solar tracking system and optimal slope (the same slope of the common roof in Italy is assumed). Therefore, a slope of 17 degrees with South orientation is considered. Supposed location for the plant and analysis is the area of Caltanissetta in Sicily (in decimal degrees latitude 37.498 and longitude 14.070) where is supposed

RECs' location and hydrogen production and use chain by UVAM. The typical solar year is 2020 that is the last one available on JRC PVGIS on line tool [34]. The annual PV specific production is 1,474 kWh/kWp considering constrains above defined.

The electrical consumption of the residential members of the REC is that presented in our previous study [134] and therefore can be directly correlated to the number of inhabitants taking part of the RECs.

Mathematical model for the characterization of consumption of REC, PV production, hydrogen production and storage is borrowed from our previous paper [134], so it is not here described. For common quantities the same nomenclature has been used here. To consider a set of RECs each one with a hydrogen producer member, mathematical model is reviewed in comparison to [134]. In each hour in the year (*t*) and for each REC (*i*) of the *n* composing the system, energy produced by PV ($E_{i,PV}(t)$) is drawn first for residential consumptions ($C_{i,REC}(t)$), than for hydrogen compression ($E_{i,Comp}(t)$) to move a quantity of hydrogen from low pressure storage to high pressure common storage ($Q_{i,H2\ trans}(t)$), than to produce hydrogen ($E_{i,Elect}(t)$) by the electrolyser belonging to each REC. Hydrogen production happens if the mass of hydrogen in the high-pressure hydrogen common storage ($Q_{Store\ HP}(t)$) is less than its limit ($Q_{Store\ HP}(t) < Q_{H2\ CC}$), and when there is an excess of renewables not used for residential uses or to compress hydrogen. No energy produced out of each REC is used to compress or produce hydrogen. So, electrolyser and compressor follow the PV excess after residential consumption. The shared energy in each REC ($E_{i,se}(t)$) in this configuration is describe in each hour of the year (*t*) and for each REC (*i*) by the following equation

$$E_{i,se}(t) = \min\left(C_{i,REC}(t) + E_{i,Comp}(t) + E_{i,Elect}(t);\ E_{PV}(t)\right) \tag{5.2}$$

Finally, if there is still availability of renewable electricity over power consumption from residential use, production and storage of hydrogen, this is fed into the grid and will be absorbed outside the area of influence of the RECs.

Total shared energy in the system is defined by

$$E_{se}(t) = \sum_{i=1}^{n} E_{i,se}(t) \tag{5.3}$$

where *n* is the number of RECs in the area involved in the system. Equations 5.2 and 5.3 are compliant with RED II and Italian reference law to define shared energy to estimate the incentives to electric flow in the RECs.

Each hour in the year, the electric company that manages UVAM evaluates the maximum purchase price in ASM auctions in all the seven Italian market zones ($PP_{auction}^{Max}(t)$). If this price is higher than expected selling price from UVAM ($SP_{UVAM}^{exp}(t)$), electric company activates the electricity generation at the considered time (*t*) if the hydrogen storage in the previous hour (*t-1*) is enough both for electric generation and eventually warm up. In fact, the state of the power plant at the (*t-1*) hour has to be evaluated: if the plant was running, it is sufficient that in the storage there is hydrogen for another hour of production, otherwise an extra quantity of hydrogen has to be considered for the warm up.

Hour by hour, the storage of hydrogen will be increased by the quantity produced by the electrolysers and decreased by the quantity absorbed for the operation of the UVAM

$$Q_{Store\ HP}(t) = Q_{Store\ HP}(t-1) + \sum_{i=1}^{n} E_{i,Elet}(t) \cdot \eta_{Elect}/LHV_{H_2} - Q_{UVAM}(t) \quad (5.4)$$

where $Q_{UVAM}(t)$ is the hydrogen for electric generation in UVAM with or without warm up, η_{Elect} is efficiency for FC or ICE (50% or 45% respectively) and LHV_{H_2} is lower heating value of hydrogen (Table 5.2).

The economic values of the energy input or output to the system are valued with the prices indicated previously. Out of caution and given the little weight it has in the simulations developed below, the electricity produced in warm-up was not economically valorised, while the quantity of hydrogen consumed is taken into consideration.

5.4.2 Constrains and Optimization for sizing

The peak power of all the PV plants is supposed to be less than 200 kWp and all the REC is supposed to be constituted in municipalities with less than 5000 inhabitants: based on current Italian regulation [196] these considerations define the 40% non-refundable loan for the CAPEX of hydrogen storage system and the incentives tariff (*IT*) as in the following equation:

$$IT = 0.5 \cdot min\begin{cases}[80 + \max(0; 180 - zonal\ price)]€/MWh \\ 120\ €/MWh\end{cases} \quad (5.5)$$

where 0.5 factor is the effect of non-refundable loan.

The whole system is supposed to be realized in internal area of Sicily, in Caltanissetta area: an annual production of 1,474 kWh/kWp is inferred as described in previous section.

PV per capita is set at 1.8 kWp/capita, in line with Italian evolution described in previous section for a highly penetration PV condition in the area where the REC is based. The 2023 capacity market auction for the new plants in Sicily of 75,000 €/MW per year [195] is considered as mentioned above, such as economical facts of Table 5.3.

In the simulation carried out for the twenty years of operation of the proposed system, the values of both electric zonal price and PUN are not modified based on future trends. The same consideration for the ASM, that is considered equal to 2023 each year of the simulation.

Several cases have been simulated by varying the total number of inhabitants involved in all the RECs: it is not relevant to discriminate whether those inhabitants are collected in one or more RECs and therefore whether there are one or more electrolysers within the H_2 company. Eight different simulations were carried out starting from 2500 inhabitants up to 20,000 inhabitants involved in the RECs. The number of inhabitants uniquely defines the installed photovoltaic power. In all cases, the UVAM is based on 1 MW power plant, analyzing both fuel cell and internal combustion engine solution to evaluate the impact of different efficiency and different CAPEX and OPEX. This size is the minimum one allowed by Italian electric market, minimizing the size of the inhabitant involved and allowing the probability to realize the presented study.

The sizes of the other systems (electrolyser, low pressure storage, compressor, high pressure storage) was established with an optimization process. Optimization objective function (*OOF*) is the difference between LCOE and annual mean selling price for electricity produced by UVAM assigned in hourly auctions over the year in the seven market areas of Italy (SP_{UVAM}^{mean})

$$OOF = LCOE - SP_{UVAM}^{mean} \tag{5.6}$$

Positive values of the optimization function indicate a not economically sustainable investment. The more negative the values, the more profitable the investment is. Optimization criteria is based on techno-economic requirement indicated in the flow chart below for each size of inhabitants considered in the RECs.

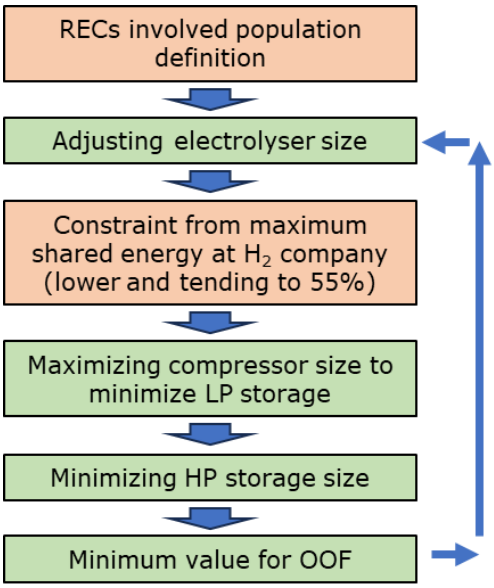


Figure 5.5: Flowchart for sizing and optimize the system

5.5 Results

Considering both an UVAM based on a fuel cell and on an internal combustion engine, the results of the optimizations are shown in the figure below considering the *OOF* as RECs size changes (number of people in all the RECs in the system).

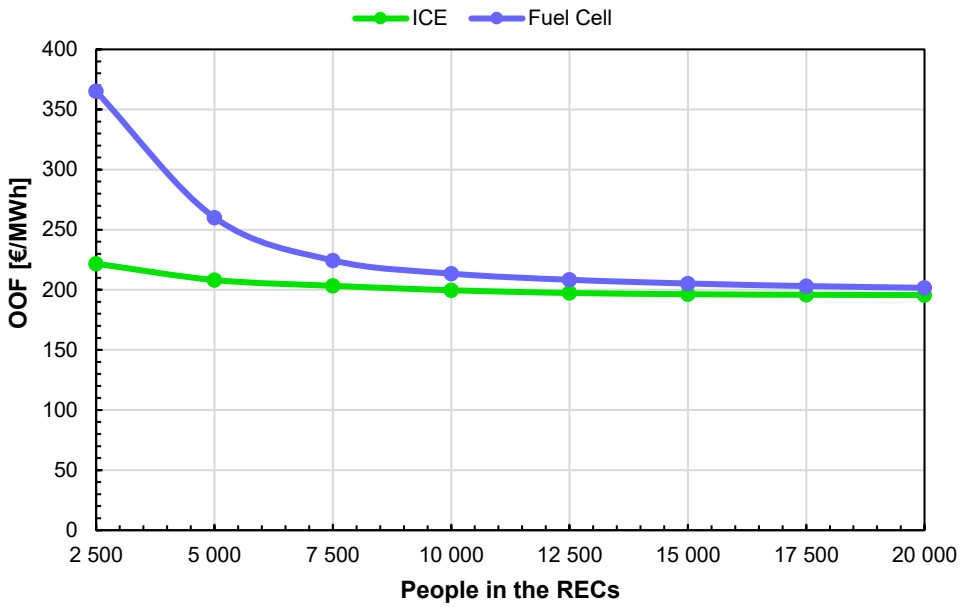


Figure 5.6: Optimization objective function (OOF) as a function of RECs' size

In both cases the proposed system does not reach the minimum values for economic sustainability as the objective function is always positive. By increasing the size of the population involved in the RECs, an asymptote value of the objective function is reached.

5.5.1 Effect of technology evolution (2035 forecast)

An evolution in efficiency and costs of fuel cell and hydrogen is expected in the coming years. Al-Hamed and Dincer [197] stated an efficiency of 60% for solid oxide fuel cell (SOFC) based on LHV. The same value is stated currently in datasheet from Convion, a SOFC manufacturer [198].

For a 250 kW SOFC (electric-only system), Whiston et al. [199] stated a median cost of 1909 $/kW (1775 €/kW with a dollar/euro exchange rate of 0.93) with a production volumes of 4000 system per year in 2035. In 2050 a reduction to 841 $/kW is expected with a production volume of 10,000 systems per year.

Krishnan et al. [200] argued a mean value cost for alkaline and PEM electrolyser at 2030 of 470 €/kW with an efficiency of 69%, substantially equal to what is assumed in this study (70%).

Considering the data as summarized in Table 5.4, not considering 40% non-refundable loan for the CAPEX of hydrogen storage system (the current incentives is provided until 2026 [196]) and consequently with incentives tariff (*IT*) as in the following equation

$$IT = min\begin{cases}[80 + \max(0; 180 - zonal\ price)]€/MWh \\ 120\ €/MWh\end{cases} \quad (5.7)$$

the results of the optimizations are shown in the Figure 5.7 below considering the trend of optimization objective function (*OOF*).

Table 5.4: Fuel cell and electrolyser data at 2035

Parameter	*Value*	*Ref.*
Fuel cell capital cost [€/kW]	*1775*	[199]
Electrolyser capital cost [€/kW]	*470*	[200]
Fuel cell efficiency (on LHV)	*60%*	[197,198]
Electrolyser efficiency (on LHV)	*70%*	[192,200]

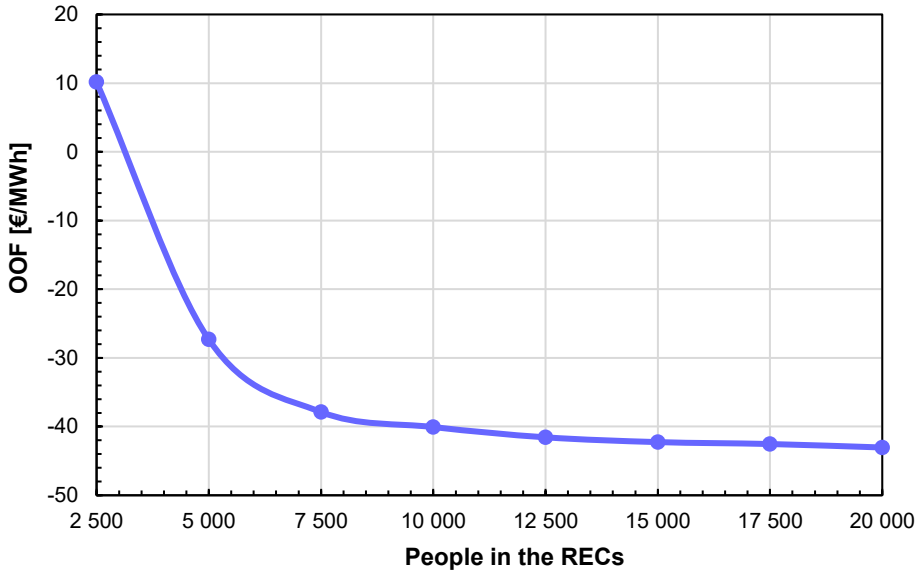


Figure 5.7: Optimization objective function (OOF) (2035 forecast)

The evolution of performances and costs of both fuel cell and electrolyser enables from 2035 the proposed model: starting from around 3000 people involved in the RECs the LCOE is smaller than annual mean selling price for electricity produced by UVAM in the seven market areas of Italy (211 €/MWh): optimization objective function (*OOF*) becomes negative.

In Figure 5.8 net present value (NPV) and investment return time better explain the trends of the economics and in Figure 5.9 the CAPEX breakdown of the main components of the system is shown.

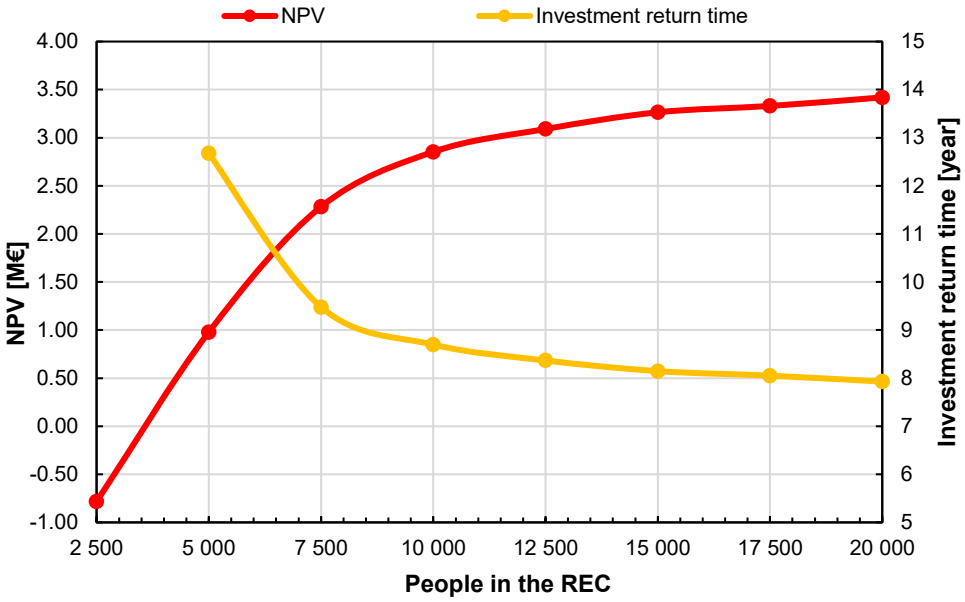


Figure 5.8: Net present value and Investment return time (2035 forecast)

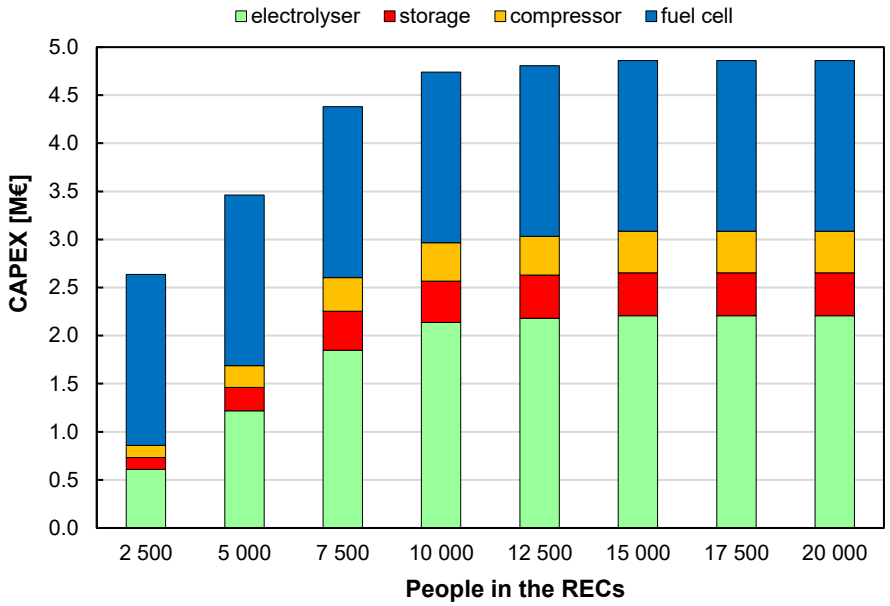


Figure 5.9: CAPEX distribution (2035 forecast)

A general overview of the facts and figures of the scenario with 10,000 people involved in the RECs is reported in Table 5.5. Beyond this size both the increase in capital expenditure and economic performance are marginal: consequently, this size could be considered the most suitable to manage the smallest UVAM allowed by Italian regulation (1 MW) based on photovoltaic installed in residential RECs. In this case LCOE is equal to 171 €/MWh with a total CAPEX of 4.75 million euro.

Table 5.5: Facts and figures with 10,000 people in the RECs

Total users (domestic LV 3kW users)	*4762*		*Electric flows in the RECs*		
Total people in the community	*10000*		*Renewable energy production*	*26532*	*MWh/year*
			Shared energy		
Sizing			*Shared energy for residential use*	*5422*	*MWh/year*
PV peak power	*18.0*	*MWp*	*Shared energy for electrolyzes*	*11987*	*MWh/year*
Electrolyzer nominal power	*4.54*	*MW*	*Shared energy in H2 compression*	*669*	*MWh/year*
Fuel cell nominal power (UVAM)	*1.00*	*MW*	*Total shared energy*	*18079*	*MWh/year*
Compressor nominal power	*250*	*kW*	*Renewable energy to the grid*	*8453*	*MWh/year*
Low pressure hydrogen storage	*116*	*kg*	*Energy from the grid (residential use)*	*5880*	*MWh/year*
High pressure hydrogen storage	*838*	*kg*	*Electric flows in the UVAM*		
Total hydrogen storage	*954*	*kg*	*Electricity to ASM*	*4714*	*MWh/year*
(based on LHV)	*31.8*	*MWh*	*Electricity produced in warm-up*	*320*	*MWh/year*
			Total hydrogen consumption	*251.7*	*ton/year*
ASM sessions and running hours			*Equivalent hours at nominal power*		
UVAM availability (due to H2 storage)	*6682*	*hh/year*	*Electrolyser*	*2638*	*hh/year*
Active market sessions (all 7 zones)	*6505*	*hh/year*	*Fuel cell*	*4861*	*hh/year*
UVAM active time (FC running)	*4714*	*hh/year*	*Load factor*		
Number of UVAM warm-up	*766*		*Electrolyser*	*30%*	
Annual warm-up time	*587*	*hh/year*	*Fuel cell*	*55%*	

5.6 Discussion

Based on the current costs of the hydrogen systems (electrolysers, FC and ICE), the proposed system appears to be economically unsustainable. Conversely, the projection of such economic values in 2035 makes the sustainability of the proposed scenario acceptable. In the latter case the proposed system, sized on 10,000 inhabitants participating to different RECs in the same primary HV/MV electrical substation, is the biggest one with a relevant marginal economic increasing. Photovoltaic generation in this system has an overall power of 18 MWp composed of many plants each one with a peak power less than 200 kWp; overall electrolyser power is 4.54 MW; a hydrogen compressor of 250 kW power assures the storage in a common high-pressure storage (200 bar) with a capacity of 838 kg of hydrogen starting from a 116 kg low-pressure storage (35 bar). Based on techno-economic evolution of electrolyser and fuel cell at 2035, LCOE of the latter case is 171 €/MWh for balancing service provider that manage the 1 MW UVAM. Considering an annual mean selling price for electricity in ancillary market of 211 €/MWh (2023 economic data) and a CAPEX of 4.75 million euro, net present value is 2.85 million euro and investment return time 8.7 years.

The proposed analysis is aimed at private entrepreneurs and managers of RECs, in particular in cases RECs have excess renewable production that is not consumed locally. The creation of a renewable hydrogen production and storage chain to serve the balancing of the national electricity grid could be a business of interest by 2035. In fact, the scenario will be technically feasible, compliant with regulatory Italian scenario and economically sustainable for create new companies in the field of decentralised electricity generation.

Batteries or more complex Power-to-X (PtX) plants [201,202] can be introduced to make the excess renewable energy produced in some RECs dispatchable in the TSO grid in ASM. However, these systems appear to present several intrinsic issues. Battery-based systems are unable to decouple power from stored energy and furthermore it is difficult to create configurations in which the energy input and output are on two different PODs (one for the DSO grid and one for the TSO one). More complex PtX systems producing (i.e.) ammonia or synthetic methane appear at present too expensive and not suitable to reach dimensions as small as those suitable for the plausible dimensions of RECs. Future studies may verify these considerations in more detail.

5.7 Conclusions

This study introduces an original business model based on a hydrogen producing company (H_2 company) and a balancing service provider in the Italian national electric grid that manage an UVAM (virtually aggregated mixed unit). In a high level of photovoltaic penetration area served by the same electrical primary substation (HV/MV substation) of the DSO grid, many renewable energy communities (RECs) integrate each one an electrolyser owned by H_2 company. The company produces hydrogen from excess of electricity generated in residential RECs powered by photovoltaic and stores hydrogen in a common high-pressure storage. Hydrogen stored is consequently sold to a balancing service provider that manage an UVAM of 1 MW based on hydrogen power plant that produce electricity in the ancillary service market feeding TSO grid, following awarding of daily auctions in the national electricity market.

The business model allows to aggregate and make dispatchable excess of renewables generated in a territory through REC and UVAM that represent innovative and flexible entities in the electric Italian market.

The purpose is to investigate by a techno-economic assessment the current and future economical sustainability of the business model in the Italian regulatory and market scenario, producing renewable hydrogen exploiting REC's incentives and using it to dispatch renewable electricity in the richest electricity market existing in Italy (ancillary service market) through UVAM project.

The main findings of the present study can be summarized as follows:

- the current regulatory framework in Italy allows the full realization from a legal perspective of the proposed scenario;
- the technological and cost maturity of the solutions currently available (electrolysers, fuel cells or internal combustion engines powered by hydrogen) does not allow present-day economic sustainability;
- currently Italian non-refundable loans for RECs established in municipality under 5000 inhabitants cannot compensate for the lack of economic maturity of the enabling technical solutions;
- the expected technical and cost evolutions for electrolyser and fuel cell in the coming years (by 2035) will allow economic sustainability to be achieved;

- in the assumed electrolyser and fuel cell evolution at 2035, considering a population greater than 3000 inhabitants aggregated in RECs in a high photovoltaic penetration condition (1.8 kWp/capita), the proposed business model is economically sustainable considering Italian electrical market at 2023.

In Italian regions with a likely wide development of RECs in the coming years, the proposed business model appears to be a valid alternative to reduce the impact of a high penetration of renewables on DSO grid, offering at the same time a solution for TSO grid balancing using renewable dispatchable energy.

6 Climate finance-driven feasibility study of a green ammonia and urea production plant in Italy

This chapter is based on the following published article:

Trotta L, Bernardini V, Ermini M V., Campana LG, Verna M, Raimondi G, Spazzafumo G. Climate finance-driven feasibility study of a green ammonia and urea production plant in Italy. Int J Hydrogen Energy 2024. https://doi.org/10.1016/j.ijhydene.2024.08.079.

6.1 Introduction

Global ammonia (NH_3) production reached 185 Million ton in 2020 [203], of which 70 % was employed in the manufacture of nitrogen fertilizers, primarily urea ($(NH_2)_2CO$), supporting food production for around half of the global population [204]. Besides the use as fertilizer, ammonia is utilised in a wide range of industrial applications ranging from refrigeration to the production of plastic and fibres, water treatment, mining, as neutralizer for nitrogen oxides emissions from fuel combustion [205], and in the pulp and paper industry.

Being connected to food industry, ammonia demand increased broadly in the last decade following the rise in the population. This trend is projected to continue in future years [206]. In addition, demand could further grow driven by new uses of ammonia as flexible long-term energy carrier and zero-carbon fuel [207].

Ammonia production is based on the century-old Haber-Bosch (HB) process which involves the catalytic reaction of nitrogen and hydrogen at elevated temperatures and pressures. As pointed out by Bicer et al. [208], the hydrogen feedstock is generated almost exclusively via steam reforming of fossil fuels: around 72 % of production is based on natural gas, 22 % on coal, naphtha and heavy fuel oil account for 5 %, with the remaining 1 % derived from other feedstocks. Therefore, current NH_3 production accounts for around 450 Million ton of CO_2 equivalent (CO_{2e}) emissions per year [203], more than 1.8 % of the total greenhouse gas (GHG) emissions globally, making NH_3 synthesis the largest carbon dioxide emitting chemical industry process [207].

Numerous efforts to tackle the climate crisis are being conducted globally. In 2015, with the Paris Agreement, 197 countries committed to keep the global average temperatures from rising well below 2 °C with the aim of working to limit it to 1.5 °C. Consequently, several countries have announced pledges to achieve net zero emissions over the coming decades [7].

Fasihi et al. [209] reviewed the various literature concerning sustainable ammonia production and identified three major groups of research. The first is focused on the production of the so-called blue ammonia, based on CO_2 capture from the traditional fossil fuel-based process; the second one on novel technologies, not commercially available yet, such as the electrochemical synthesis; the third one on the use of renewable energy sources (RES) and green hydrogen production via electrolysis. This last area is the object of the proposed study.

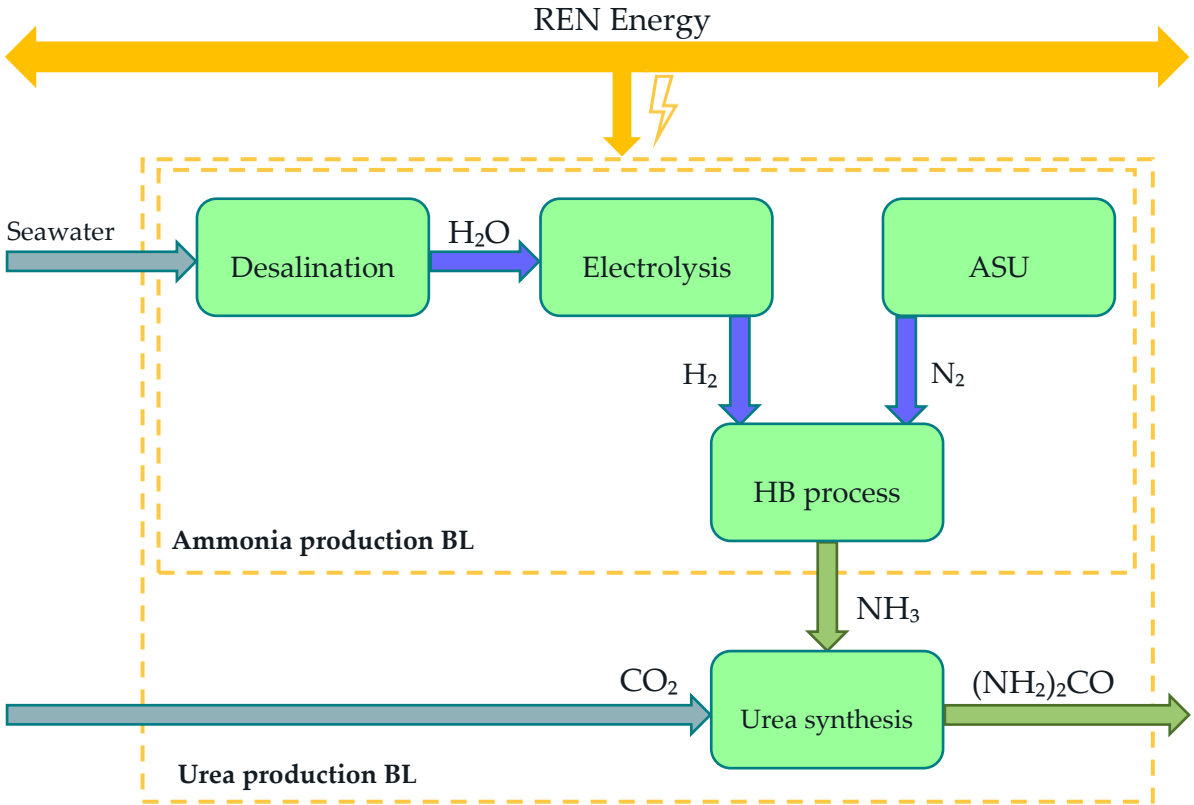
Large-scale urea production plants are based on the Basarov reaction, in which ammonia and carbon dioxide are reacted at 170 – 220 °C and 125 – 250 bar [210], in a mature chemical process operated using different techniques as stripping technologies [211]. CO_2 is usually made available during the traditional natural gas-based hydrogen production process. Therefore, integrated ammonia-urea plants are common worldwide. Almost 130 Million ton of CO_2 are utilized for urea production annually [210], with the bulk released downstream in the agriculture sector, sometimes only days later: the CO_2 embedded in the molecule is released to the soil and, as the urea decomposes, to the atmosphere when the fertilizer is applied [212]. When shifting to renewable production of hydrogen, external circular sources of CO_2 have to be considered [213]. This could be the case of carbon dioxide directly captured from the air or CO_2 emitted by other industrial sources and re-used for the fertilizer production.

There are few studies about green urea synthesis. Alfian et al. [214] analysed a series of different production processes, based on biomass gasification and electrolysis powered by a photovoltaic (PV) plant using a methodology aimed at minimizing production cost and environmental impacts. Milani et

al [211] discussed the production of green urea for the Australian market considering three different sources of CO_2 from a techno-economic point of view. Zhang et al. [210] evaluated the thermodynamic and economic performances of two green urea production processes (biomass-to-urea and power-to-urea). However, at the best knowledge of the authors, a technical-economic assessment combined with climate finance of an integrated green ammonia (from electrolytic hydrogen) and urea production plant is yet to be fully developed in literature. This is the scope of the proposed study. The simplified flowchart of the analysed plant is shown in Figure 6.1.

Integration of a well-known techno-economic assessment with climate finance represents a novelty in literature, in view of current trends of world finance. Climate finance is complementary to lifecycle assessments, as it integrates the GHG emissions analysis approach, with techno-economic aspects to sustain the decision making process and the associated policy implications [215].

Figure 6.1. Simplified flowchart of the proposed green ammonia and urea production plant



In recent years climate finance has introduced an increasingly weighty parameter into technical-economic evaluations compared to the past. For this reason, the proposed integration in the feasibility analysis of new production plants (particularly in the European Union) represents a truly relevant aspect to analyse.

6.2 Materials and methods

In view of combined techno-economic assessment with climate finance constraints, four topics were analysed as a premise for the study:

1. Hydrogen, ammonia and urea production technologies.

2. GHGs emissions calculation methodology.
3. Climate finance context analysis.
4. Methodology for economic assessment.

6.2.1 Hydrogen, ammonia and urea production technologies

A wide range of technologies are currently available for each phase of the production process. However, the scope of this study was limited to the most mature ones fit to produce green ammonia and urea using electrolytic hydrogen.

6.2.1.1 Alkaline electrolysis

Alkaline electrolysis is one of the most mature technologies for electrolytic hydrogen production [216]. Hydrogen and oxygen are formed at 10 bar [217] in pressurized stacks operating in a 25-30 % liquid solution of electrolyte, typically potassium hydroxide (KOH) or sodium hydroxide (NaOH) [218]. A system electrical consumption (including hydrogen purification and drying oxygen separation, water treatment, cooling system, control system etc.) of 50 to 78 kWh/kgH_2 was reported in 2020 [219], corresponding at a range of efficiency of 79% to 50% respectively based on higher heating value (HHV).

6.2.1.2 Water consumption and desalination

Hydrogen production consumes significant amounts of water. From a stoichiometric point of view, 9 kg of water are required for 1 kg of H_2 [220], however the actual consumption of the electrolysis unit can be far higher due to auxiliary systems, reaching 20 kg of water per kilogram of hydrogen at the system level [219].

Because of that, the water source should be explicitly accounted for medium and large-scale electrolytic hydrogen production. Simoes et al. [221] reviewed the various potential sources for water electrolysis in a comprehensive analysis. Despite the results of their study, for which public grid water was defined as the preferrable option, due to security of supply, water desalination was selected for the production plant proposed in this study.

Reverse Osmosis (RO) is the most widely used desalination process both for industrial applications and to produce drinking water [222], as it allows the removal of different types of dissolved and suspended chemical species, along with biological species (bacteria). Typically, 40 to 60 % of the feed salt water is recovered as fresh water [223]. The correspondent electric energy consumption can vary from 3 to 4 kWh/m^3 [222]. Brine, water rich in salt and chemicals, is obtained as a byproduct from the desalination process.

6.2.1.3 Nitrogen separation and electrified ammonia synthesis

The choice of the technology to be used for nitrogen (N_2) separation from air depends mainly on the required purity and on the scale of the plant. Based on the different boiling temperatures of air components, cryogenic distillation in an air separation unit (ASU) is the best suited technology for large volumes of production [224].

The on-site generated hydrogen and separated nitrogen can then be reacted in the HB process to obtain ammonia in presence of an iron-based catalyst [225]. The catalytic synthesis is carried out at 350 °C –

550 °C. The reaction is limited by thermodynamic equilibrium and nitrogen can only achieve partial conversion (25–35 %) by a single pass through the catalyst. Unreacted reactants need to be separated and recycled back in a synthesis loop for a reasonable conversion [226].
The energy consumption of the HB process is mostly related to recirculation, with values in the range of 500 to 861 kWh/ton NH_3 [227]. This range is also in line with the electricity demand of 738 kWh/ton NH_3 obtained by Fasihi et al. [209] for an all-electric ammonia plant with a 99 % overall conversion factor. This value includes the power consumption for nitrogen separation (approximately 90 kWh/ton), nitrogen and hydrogen compression at 150 bar and the consumption of the synthesis loop itself. Other literature sources report consumptions of 759 kWh/ton NH_3 [228], 640 kWh/ton NH_3 [229] and 778 kWh/ton NH_3 [230], respectively.

6.2.1.4 Carbon dioxide source

A detailed technical assessment of carbon capture technologies was given by Dziejarski et al. [231]. Their research highlighted that only post-combustion carbon capture (PCCC) and pre-combustion are characterized by commercial maturity. PCCC based on chemical absorption was broadly selected for CO_2 capture projects in recent years [232]. The carbon dioxide from cooled flue gas streams is sequestrated by an amine absorption and stripping process [14]. The amine-water solution reacts chemically with CO_2 to form carbamate which is then broken down by the application of heat. The majority of the energy consumption is related to amine regeneration [233].

6.2.1.5 Urea synthesis

Urea synthesis is conducted in a two-step reaction based on Basarov reaction [234]. Ammonium carbamate is firstly formed in a highly exothermic reaction in liquid phase from NH_3 and CO_2, then it is dehydrated to obtain urea and water [226]. The process is operated at 179-220 °C and 125-250 bar [210]. The unit is characterized by a large amount of output wastewater, coming from both the reaction stoichiometry and the evaporation and recirculation sections, in addition to the steam used in the wastewater treatment area itself [235]. The presence of a cleaning section allows for the removal of the residual ammonia and urea. In this way, a condensate clean enough to be discharged into the industrial sewerage network is obtained [236].

6.2.1.6 Renewable electricity

Green certified electric energy can be purchased by means of a Power Purchase Agreement (PPA). PPA is a financial tool, a medium- to long-term time scale agreement, that regulates the supply of power between a producer entity, who owns the renewable energy production plant, and a buyer entity, without the need of a physical connection among the two facilities [237]. The renewable energy can be accounted as actually consumed by the buyer who can cut its own emissions and avoid fluctuations in prices, while the off-taker, thanks to PPAs, already knows how long it will take to return on the investment and what the future revenues will be [238].
For onsite renewable energy installations, the theoretically achievable production with new wind and solar plants can be estimated using the European Database ENSPRESO [239] together with data from the Global Solar Atlas [240] and Global Wind Atlas [241]. While ENSPRESO considers the raw area

available for new installations with GIS-based estimates for the physical availability of locations [242], Global Atlases provide a first estimate of the power production in a selected area.

6.2.2 GHGs emissions calculation methodology

The greenhouse gas emissions analysis, aimed at identifying the products' carbon footprint, can be performed according to the Greenhouse Gas Protocol [243]. The carbon footprint is expressed in CO_2 equivalent (CO_{2e}), the standard unit to compare and account for emissions from various GHGs based on their Global Warming Potential (GWP). CO_2 equivalent emissions for each GHG are obtained by multiplying activity data with specific emission factors (EF), and with the GWP over a 100-year period. The base formula to calculate the GHG emissions is shown in Equation 6.1 [244]

$$kgCO_{2e} = Activity\ Data\ [unit] * EF\ \left[\frac{kgGHG}{unit}\right] * GWP\ \left[\frac{kgCO_{2e}}{kgGHG}\right] \quad (6.1)$$

The GHG Protocol uses GWP values established by the Intergovernmental Panel on Climate Change (IPCC) [245].

Calculating GHG emissions involves the following process [246]:

- Set the organizational boundaries (also referred to in this study as battery limit (BL)), after having identified the facilities included in the inventory.
- Identify the activity data, defined as the measure of the level of a certain activity or consumption that results in GHG emissions. Therefore, activity data include energy, raw materials, utilities, byproducts, products, and waste streams that cross the BL set.
- Identify the set of EF to be used for the calculation. EFs express the GHG emissions per unit of activity data (GHG emissions per unit of good).

According to the GHG Protocol [247], emission sources of all seven major GHGs (CO_2, CH_4, N_2O, SF_6, NF_3, HFCs, PFCs) have to be accounted for. Sources must be organized in the following Scopes:

- Scope 1, direct and owned emissions, from sources owned or controlled by the reporting entity.
- Scope 2, indirect and owned emissions, meaning emissions that are a consequence of the operations of the entity but occur at sources not owned or controlled by it. This is typically the case of purchased electricity, heat and steam.
- Scope 3, indirect not owned emissions, meaning other emission not included in the above Scopes on which the entity cannot intervene directly to limit them. It is the case of activities linked to the production of raw materials, their transportation, but also waste management.

6.2.3 Climate finance context analysis

The forms of financing, both public and private, aimed at supporting investments to address the climate change constitute the climate finance [6]. Climate finance and GHG emission reduction policies are becoming increasingly determining factors to take into consideration in feasibility studies, as several policies and programs are being put in place to accelerate the transition to a net-zero society [7].

The European Emission Trading System (EU ETS) is one of the first examples of carbon taxation mechanism, covering large industrial emitters, including ammonia and urea production. Under the EU ETS, emitters must compensate their emissions with the corresponding number of European Union Allowances (EUAs), each covering the emission of 1 ton of CO_{2e}. The performance of the products in terms of GHG emissions is compared with the reference benchmark values to determine the number of

EUAs to be granted for free. The rest of the allowances has to be purchased on the carbon market, with a carbon price that reached a peak of about 100 EUR/ton CO_{2e} in August 2022 [248]. The EU ETS benchmark for ammonia is equal to 1.57 ton CO_{2e}/ton NH_3 from 2021 to 2025 [249].
An equivalent price to that of the EU ETS will be applied on goods imported in Europe (including fertilizers) from 2026 via the recently approved Carbon Border Adjustment Mechanism (CBAM) [250]. CBAM is aimed at contrasting the carbon leakage, the delocalization of the production and, consequently, of the carbon emissions outside of Europe due to the cost of carbon.
In case of the use as fuel, ammonia emission intensity, and consequently urea emission intensity, is also the concern of the Renewable Energy Directive II (RED II) [5], which introduced the definition of renewable fuel of non-biological origin (RFNBO). RFNBOs, to be classified as such, must achieve an emission saving of at least 70 % compared to the fossil fuel comparator - the average fossil fuel- with an emission intensity of 94 gCO_{2e}/MJ. This means for ammonia, considering a lower heating value of 18.8 MJ/kg [251], a limit of 0.53 ton CO_{2e}/ton NH_3.
In this complex landscape, climate finance has emerged as a viable solution for combating climate change and its environmental consequences while also funding adaptation actions [252]. Several initiatives are available to support the development and the deployment of zero or low-carbon technologies. The Innovation Fund (IF) [253] is one of the largest funding programs, with around 38 billion EUR from 2020 to 2030 for projects in the sectors covered by the EU ETS. The IF supports up to 60% of the relevant costs, defined as the additional cost due to the application of the innovative technology/process of the selected projects. Another financial tool of relevance is the EU Taxonomy [254], a classification aimed at directing investments towards projects and activities that are environmentally sustainable. Activities that respect the technical screening criteria of the Taxonomy, being sustainable, are more likely to be financed. For ammonia a maximum level of emissions of 1.948 ton CO_{2e}/ton NH_3 is set.
In the described landscape it is clear why GHG products emissions assessment is becoming one of the determining factors when evaluating the feasibility of a project. Main references for ammonia and urea carbon footprint are shown in Table 6.1.

Table 6.1. Product carbon footprint, international references

Type	Standard	Value [tonCO_{2e}/ton$_{product}$]	Ref.
Grey ammonia	International average	2-5	[255]
Blue ammonia	EU ETS Benchmark	1.57	[249]
Blue ammonia	European Taxonomy	1.95	[256]
Green ammonia	-	-	-
Ammonia as RFNBO	RED II	0.525	[257]
Grey Urea	European average	0.89	[258]

6.2.4 Methodology for economic assessment

The economic evaluation of the green ammonia and urea production plant was carried out by assessing the Levelized Cost of Ammonia (LCOA) and the Levelized Cost of Urea (LCOU) over the entire lifetime of the plant. Such parameters were calculated by adapting the general formula for the calculation of the

Levelized Cost of Product (LCOP), shown in Equation 6.2, from the methodology set by the European Commission [259].

$$LCOP = \frac{CAPEX + \sum_{n}^{N} \frac{OPEX}{(1+r)^n} - \sum_{n}^{N} \frac{Operational\ benefits}{(1+r)^n}}{\sum_{n}^{N} \frac{Units_{produced}}{(1+r)^n}} \quad (6.2)$$

where r represents the discount rate, n the year and N the lifetime of the plant. The total capital costs (CAPEX) were calculated as the sum of the capital expenditures for each system component (renewable power production plant, water desalination unit, electrolyser, ammonia synthesis and ASU, urea synthesis unit). The CAPEX estimate was based on international literature (Table 6.2) with an expected accuracy range of ±50 %, in accordance to Class V estimate of the AACE methodology [260].

Table 6.2. Literature reference values for CAPEX estimate

Cost Item	Value	Unit	Ref.
Onshore wind farm	1200	USD/kW	[261]
PV plant	740	USD/kW	[229]
Water Desalination Unit	2.5	USD/(l/day)	[222]
Electrolyser	1000	USD/kW	[219]
Ammonia synthesis unit (including ASU)	175000	USD/tpd[1]	[262]
Urea synthesis Unit	56000	USD/tpd	[263]

[1] ton per day

The annual Operational Expenditures (OPEX), containing both the Operation and Maintenance (O&M) costs and the variable operational costs (i.e. electricity cost, water cost etc.) [32], were estimated based on the energy and mass balance of the plant. Operational benefits are detailed in the following section. The main economic parameters used for the current study are presented in Table 6.3.

Table 6.3. Economic parameters

Economic data	Value	Unit	Ref.
Plant lifetime (N)	20	years	[264]
Discount rate	10	% year	[265]
Grid electricity price[1]	110	EUR/MWh	[266]
Electricity price (PPA)[1]	54.9	EUR/MWh	[267]
Oxygen selling price	150	EUR/ton	[217]
Domestic water price	1.17	EUR/m^3	[268]
Carbon tax[1]	66.4	EUR/ton	[248]
Industrial insurance	1	% of CAPEX	[269]
Maintenance	2	% of CAPEX	[270]
Euro-dollar conversion factor	1.1	-	[271]

[1]Average price for 2021

6.2.4.1 Operational benefits

Following the international methodology set by the European Commission [272], operational benefits were considered in the LCOP calculation. These include any revenues from the sale of EU ETS allowances, preferential tariffs, or other market regulatory support programs. The potential revenues

from EUAs sale can be calculated basing on the methodology detailed in [273], after having estimated the expected product emission intensity.

Oxygen, by-product of the electrolysis process and air separation process, was accounted for among the operational benefits. Guilera et al. [217] explored the influence of oxygen selling on the competitiveness of Synthetic Natural Gas (SNG) produced via methanation using electrolytic hydrogen and captured CO_2. The results showed that SNG price can be consistently reduced, close to the current price of conventional natural gas. Squadrito et al. [274] investigated the use of the byproduct oxygen for medical applications, finding it economically feasible. Despite these, as pointed out by Campion et al. [275], only a few studies have explored the influence of the sale of oxygen and heat on ammonia, and therefore urea, cost assessments.

Operational benefits represent the integration of climate finance with techno-economic aspects: economic flows, defined by climate regulations, influence the analysis of lower environmental impact technologies by helping them to gain competitiveness in comparison with the cheaper fossil-based technologies. In fact, mathematically in Equation 6.2, the operational benefits have a negative sign as addend of the numerator and, therefore, can reduce the LCOP.

6.2.4.2 Levelized cost of carbon abatement

LCOP does not provide any information regarding possible CO_2 reduction connected to the green product substitution. In their papers, Hassler et al. [276], as well as Gillingham and Stock [277], have highlighted how common approaches lack an understanding of the carbon abatement associated with a measure or an investment, leading to unclear climate cost-benefit. To do so, the Levelized Cost of Carbon Abatement (LCCA) can be assessed for both green ammonia and green urea.

LCCA defines how much CO_2 can be reduced by a specific investment or policy, taking into account factors related to geography and specific asset [278]. The Center on Global Energy Policy at Columbia University SIPA [278] suggested a methodology that is also consistent with levelized metrics in previous literature on abatement costs in other sectors [45,46].

$$LCCA\left[\frac{EUR}{tonCO_{2e,abated}}\right] = \frac{C_1 - C_0}{E_0 - E_1} \quad (6.3)$$

Equation 6.3 calculates the LCCA in EUR per ton of CO_2 abated by dividing the difference in annualized costs of technology change, from the conventional one to the decarbonized/innovative one, by the carbon abatement achieved by switching the grey product with the green one. Accordingly, C_1 and C_0 represent the capital and operational costs of the plant and of the reference fossil-based one respectively; E_1 and E_0 the associated emissions.

In the following evaluations, the reference plant considered for the production of both ammonia and urea is a methane-based plant. To face the issue of data availability regarding the costs associated to a similar plant, in the proposed study C_0 was calculated multiplying the reference fossil-based average product cost (263 USD/ton NH_3 and 294 USD/ton of urea in 2021 [281]) by the number of units (ton) produced.

For what concerns the denominator of the ratio, the difference of emission intensity between the green products, output of the new plant, and the reference ones is proposed to be estimated considering an

emission level for the grey products equal to the EU ETS benchmark for ammonia and the international European average for urea. Both values can be found in Table 6.1.

6.2.5 Workflow

The workflow diagram adopted for the proposed study is shown in Figure 6.2.

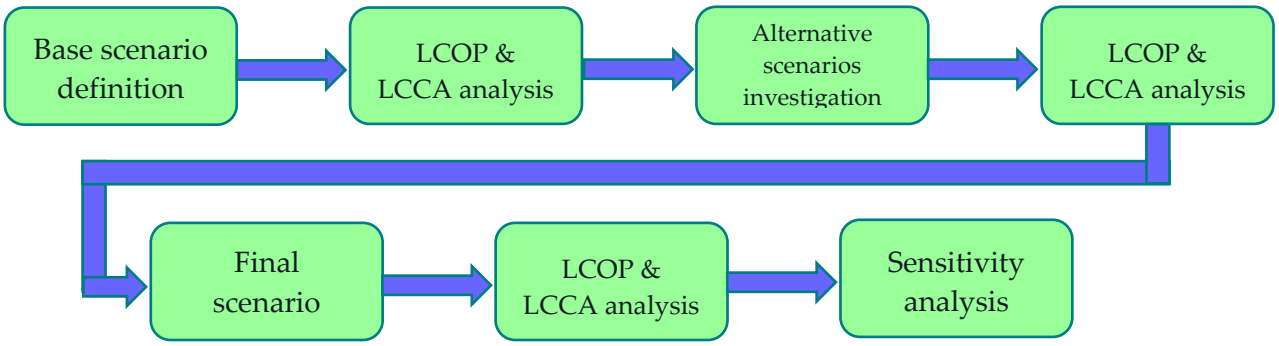


Figure 6.2. Workflow diagram adopted for the definition and analysis of the case study scenarios

A first scenario, also referred to as "base scenario", was defined basing on the concept shown in Figure 6.1., the technologies detailed in the "Hydrogen, ammonia and urea production technologies" section and the assumptions presented above. The economic and climate finance parameters were estimated for both green NH_3 and green urea considering the two different battery limits as indicated in Figure 6.1. due to:

- The relative lack of international regulation on green urea production and of literature references for LCOU calculation; therefore, a results comparison was mainly possible when considering ammonia production.
- International and climate finance regulations are mostly referred to NH_3.

A set of alternative scenarios, which differentiate from the base case for the variation of only one parameter (i.e. the source of electric energy), was then defined to investigate the effect of such variations on the output parameters. The objective was to find the best scenario in terms of product competitiveness, provided that European limitations in terms of ammonia footprint were respected. This meant looking for those elements that have a positive effect on the LCOP, and consequently on LCCA. Building on the results of such analysis, a final enhanced scenario was defined and analysed.
Sensitivity analyses to key economic parameters, such as electricity price and CO_2 taxation, were carried out to determine the relative influence of these variables. To facilitate the interpretation of the results, the methodology adopted by Arnaiz del Pozo et al. [269] was followed, therefore only one parameter was varied at a time, keeping all the others at their reference value.

6.3 Results and discussion

6.3.1 Assumptions

As possible location for the new plant, an industrialized area close to the coast in the Southern part of the Italian peninsula was considered. Railway lines, roads, water supply, and high-voltage electricity transmission lines were assumed to be available at the BL of the plant. The design of the process scheme was built around a 100 MW alkaline electrolyser working for 8700 hours per year. This size, which can be found in other literature studies concerning green hydrogen and green ammonia, allows to build a fertilizer production plant of medium scale. An efficiency of 75 % based on HHV was assumed for the electrolyser. Electricity, steam and cooling water consumption for urea production were based on the description provided in the "Urea synthesis" section and according to online available data [236]. The overall mass and energy balance of the plant was estimated consequently, resulting in a production of about 88,000 ton/year of ammonia and 150,000 ton/year of urea.

The revenues from the sale of by-product oxygen both from the electrolyser and the ASU were considered as sold to industrial users. The revenues from the sale of excess EUAs were also taken into account among the operational benefits.

Regarding CO_2 source, it had to be considered that placing the PCCC unit within the BL of the green ammonia and urea plant would have involved the availability of a stream of flue gas. Such stream might come from an external emitting production plant that sells (or yields) it to the green plant. At the best knowledge of the authors, this circumstance is not regulated yet in Italy.

An alternative is to directly acquire a stream of captured CO_2 from an external entity. In this case, a regulatory framework might be developed in the upcoming years, considering the deployment expected for capture systems [232]. This latter option brings economic benefits to both the emitting entity and the owner of the new plant: the former cuts its own emissions and does not have to bear the costs of transporting and storing the captured CO_2; the latter obtains a feedstock without having to bear the costs associated with the construction and operation of the PCCC unit.

6.3.2 Base scenario

Base scenario (indicated as scenario 1) is characterized by the use renewable electric energy purchased via PPA. No renewable power plant is considered inside the BL of the plant. Wastewaters from hydrogen and urea production units are discharged. The PCCC is not included in the BL of the plant, therefore a pure stream of CO_2 is acquired for free from an external emitter. A simplified process scheme of the scenario is shown in Figure 6.3.

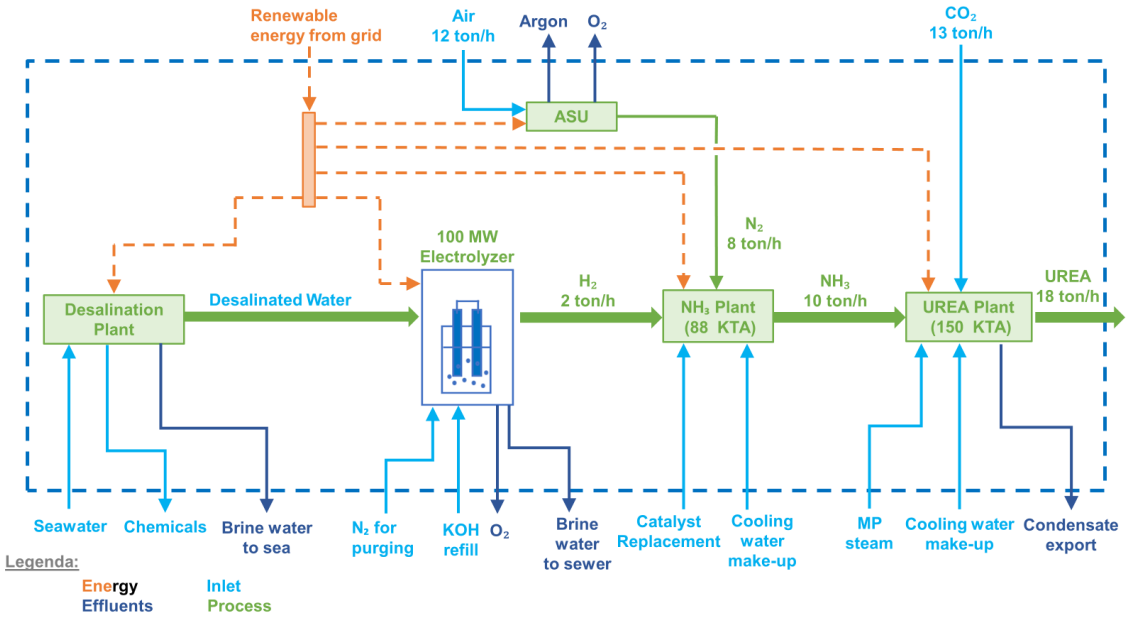


Figure 6.3. Scenario 1 - process schematic of urea production from green H_2 using renewable energy from the grid and external CO_2 stream.

Ammonia emissions were estimated at 3.2 $kgCO_{2e}$/ton NH_3, well below all the international standards (Table 6.1). Consequently, urea emissions were 2.4 $kgCO_{2e}$/ton of urea. The split of emissions by scope and by unit is shown in Figure 6.4. It has to be noted that 0 ton of Scope 1 CO_{2e} emissions is coherent with the use of renewable energy sources only; whereas Scope 2 emissions are not related to electricity but to steam consumption. Therefore, most emissions are Scope 3 emissions, due to imported feedstocks (i.e. KOH for the electrolysis unit; ammonia synthesis catalyst etc.) and disposed wastes.

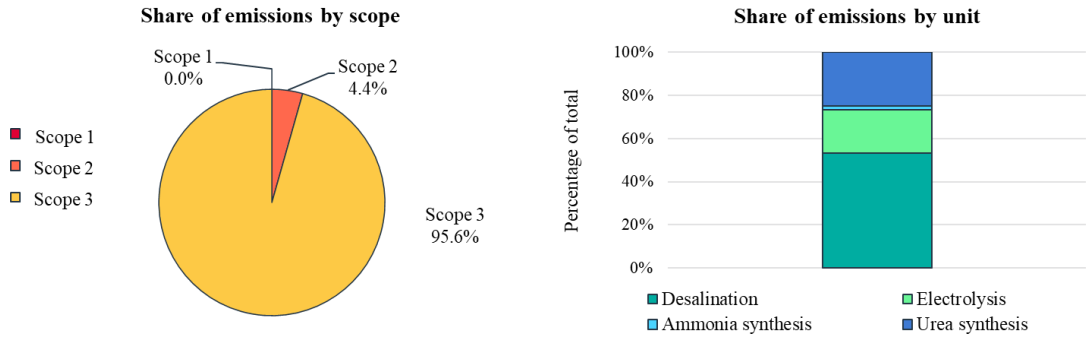


Figure 6.4. On the left urea production emission breakdown by scope; on the right, urea production emission breakdown by unit.

An average PPA price in 2021 in the European region was considered (55 EUR/MWh). The projected capital expenditures and operational expenditures were 214 million euro and 67 million euro per year. The cost for utilities and offsites was included in the capital investment cost and estimated at 25 % of the CAPEX of the process units. The expected revenues were 27 million EUR/year, considering oxygen selling, at a sale price of industrial oxygen, and EUAs trading. Excess EUAs were estimated considering the reference benchmark value (as detailed in the "Climate finance context analysis." section), the level of production of the plant and the expected emission level of the products. Each allowance was

supposed to be sold at 66.4 EUR/ton CO_2, the average value for each EUA on the carbon market in 2021 [248].

The estimated levelized cost of products of ammonia and urea were respectively 651.9 EUR/ton and 423.4 EUR/ton. Such LCOA value is in line with the references that can be found in literature. To cite a few, Armijo et al. estimated a levelized cost of 500 to 700 EUR/ton NH_3 for the flexible production of renewable ammonia [229]; Osman et al. assessed ammonia production in an industrial-scale facility in the UAE powered by RES solely, obtaining a LCOA of 718 USD/ton [270]; Alcantara et al. calculated a LCOP of 655 EUR/ton for a wind-powered green ammonia production [282]. Further references can be found in the study proposed by Salmon et al. [283], in which a comprehensive review of the literature concerning green ammonia production cost is performed.

The LCCA for ammonia and urea in the base scenario resulted in 278.0 EUR/ton $CO_{2e,abated}$ and 204.6 EUR/ton $CO_{2e,abated}$ calculated by comparing the plant with the reference case described in the previous chapter. Provided that an emission reduction is achieved, a positive value of LCCA indicates a higher cost of the production of renewable products compared to that of fossil-based ones.

6.3.3 Alternative scenarios

6.3.3.1 Scenario 2

Scenario 2 includes in the BL of the study a PCCC unit. The additional consumptions necessary for the functioning of such unit (mainly power, cooling water and steam) were taken into consideration. The flue gas sent to the CC unit was assumed to be acquired for free from an external emitting entity. A simplified process scheme of scenario 2 is shown in Figure 6.5.

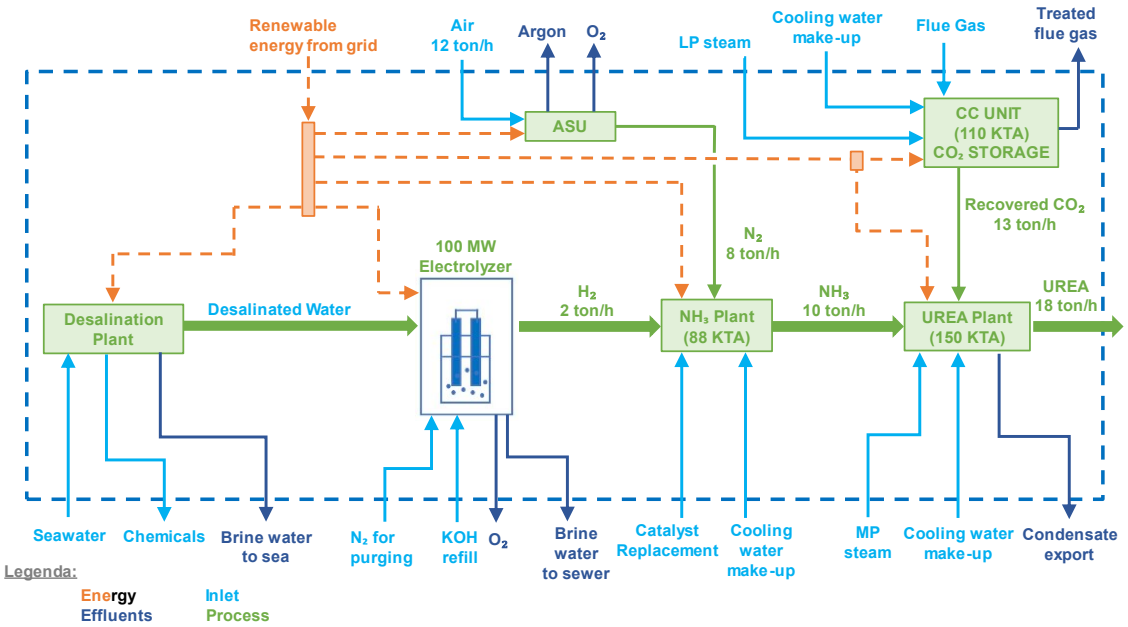


Figure 6.5. Scenario 2 - process schematic of production from green H_2 using renewable energy from the grid and CO_2 from internal carbon capture unit.

6.3.3.2 *Scenario 3*

Scenario 3 investigates the economic and environmental impact of using conventional electric energy from the Italian grid to power all the plant units but the electrolyser. Green electricity from PPA is considered for the electrolyser as the use of energy from RES is a key requirement for H_2-derived products to be considered green [284]. A simplified process scheme of scenario 3 is shown in Figure 6.6.

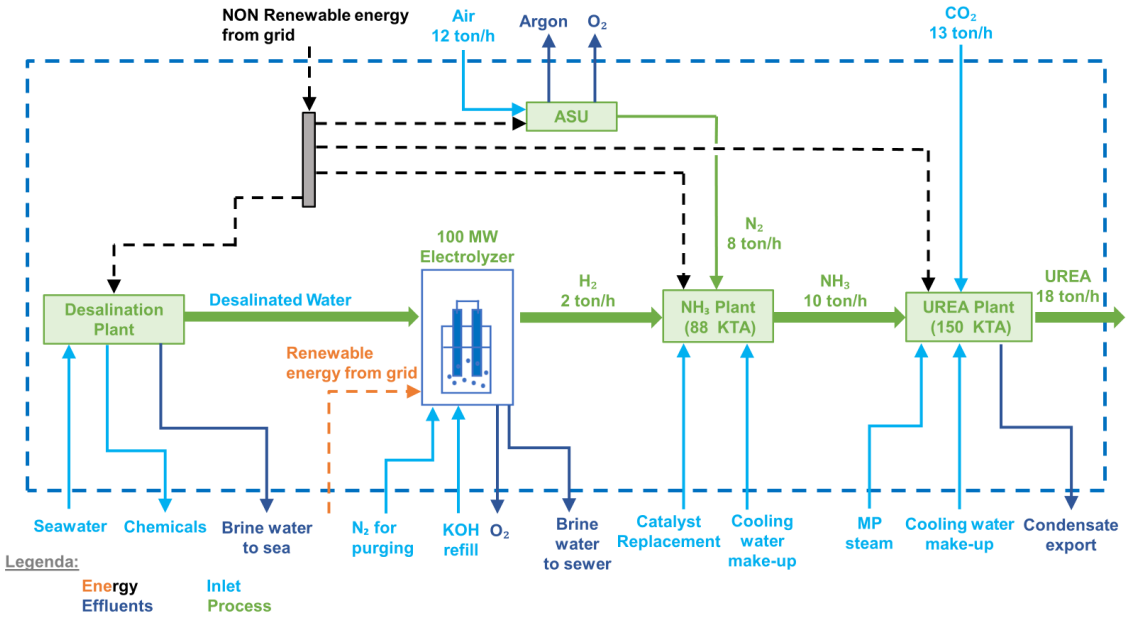


Figure 6.6. Scenario 3 - process schematic of urea production from green H_2 using non-renewable energy from the grid and external CO_2 stream.

6.3.3.3 *Scenario 4*

Scenario 4 is characterized by the presence of a renewable plant with a rated output equal to the total power required by the plant (110 MW). The size of the renewable plant was defined so that when the most favourable environmental conditions exist, all the generated renewable electricity is drawn by the plant. Therefore, no electrical energy storage systems were considered. In cases of electricity production lower than the rated output, the remaining necessary energy shall be drawn by the grid. In detail, the purchasing of certified green electric energy via PPA was considered to cope with the fluctuations of the RES. Considering the location of the plant, applying the methodology presented in the "Renewable electricity" section, the estimated energy production for a PV plant and a wind farm is shown in Table 6.4. Building on such values, the wind farm was chosen over the PV plant due to lower specific cost of energy.

Table 6.4. Renewable energy production

Wind farm		
Specific production	3500-4000	kWh/kW
Energy produced	385-440	GWh/year
Specific cost of power	1200	USD/kW
Specific cost of energy	0.30-0.34	USD/kWh
PV Plant		
Specific production	1200-1400	kWh/kW

Energy produced	145-165	GWh/year
Specific cost of power	740	USD/kW
Specific cost of energy	0.53-0.62	USD/kWh

A simplified process scheme of scenario 4 is shown in Figure 6.7.

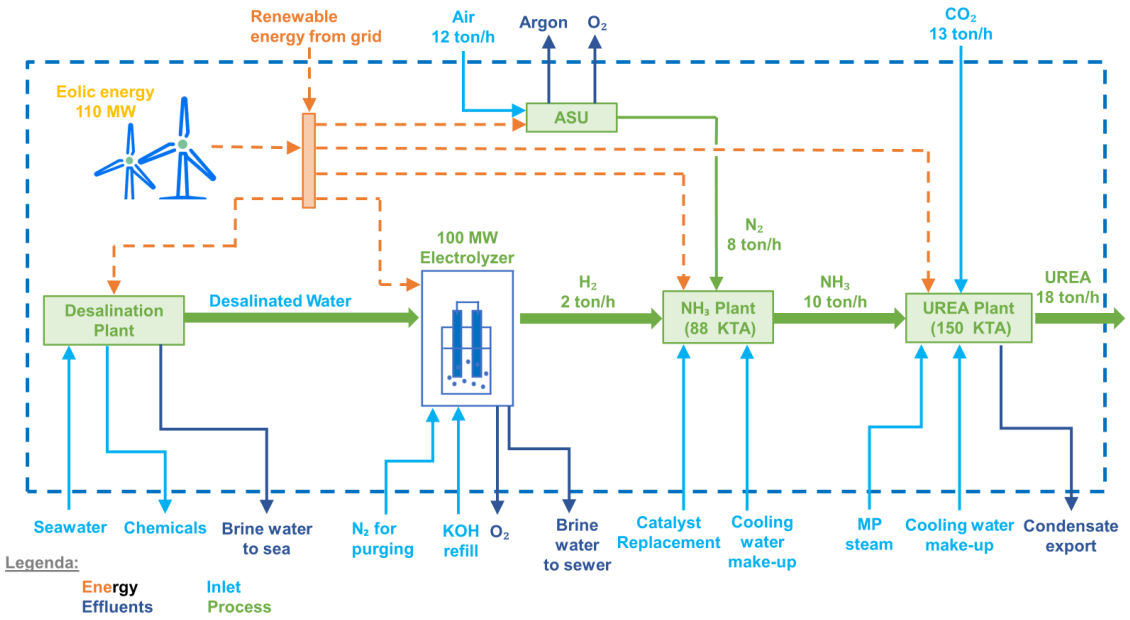


Figure 6.7. Scenario 4 - process schematic of urea production from green H_2 using renewable energy both from the grid and from dedicated wind farm and external CO_2 stream.

6.3.3.4 Scenario 5

Scenario 5 differs from Scenario 1 only for the use of brine water, from electrolysis, and wastewater, from urea synthesis, as cooling water make-up. This allows to reduce the water consumption of the plant and to increase its circularity. A simplified process scheme of scenario 5 is shown in Figure 6.8.

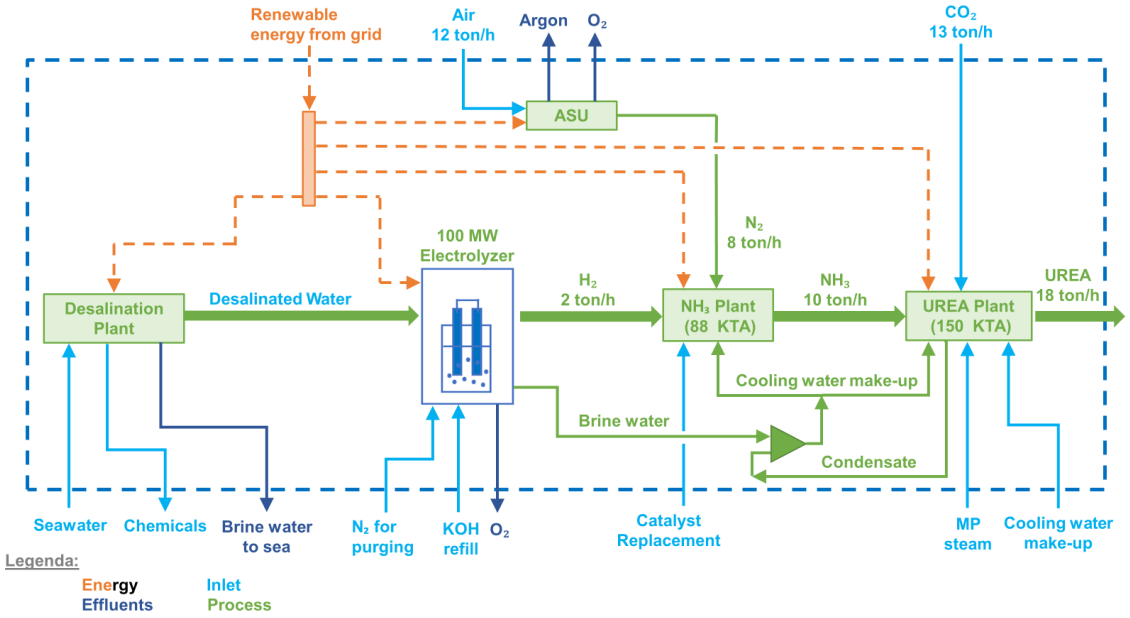


Figure 6.8. Scenario 5 - process schematic of urea production from green H_2 using renewable energy from the grid, external CO_2 stream and brine water reuse.

6.3.4 Scenarios results comparison

The results of the analysis are shown in Table 6.5

Table 6.5. Scenario comparison results

LCOP		LCCA	
Ammonia [EUR/ton]	**Urea** [EUR/ton]	**Ammonia** [ton$CO_{2e,abated}$/ton]	**Urea** [ton$CO_{2e,abated}$/ton]
651.9	521.3	278.0	348.2
705.3	460.6	349.4	285.9
741.6	417.5	271.4	197.9
651.9	421.0	278.0	201.9

All the scenarios respect the limitations in terms of products emissions. Scenarios 2 and 3 are characterized by worse economic and climate performances. The higher CAPEX and OPEX of scenario 2, due to the construction and operation of the PCCC unit, leads to higher LCOPs. In addition to that, the emission reduction is lower due to the PCCC consumption, causing an even higher LCCA and an emission level of almost 90 kgCO_{2e}/ton of urea. Scenario 3 is negatively impacted by the higher price of conventional grid energy, compared to electricity purchased via PPA, and higher electricity carbon footprint. In detail, emissions reached 170 kgCO_{2e}/ton NH_3 and 130 kgCO_{2e}/ton of urea. Therefore, both the economic and environmental parameters are affected in a negative way.

Scenario 4 has a significantly higher CAPEX, due to the presence of the wind power plant; however, internally produced energy provides large savings in operating costs, and, overall, LCOP decreases. Although the carbon footprint of products does not change, as the EF associated with the energy is zero in both cases, the LCCA decreases since the costs incurred to abate the same number of emissions is lower. The reuse of electrolysis brine mixed with process condensate, analysed in scenario 5, has a modest percentage impact on LCOP, given the low weight of water supply on the overall costs. Water reuse also allows for an improvement from a carbon footprint perspective, by avoiding the contribution associated with grid water purchased for cooling purposes.

The breakdown of the emissions by scope for the alternative scenarios analysed is shown in Figure 6.9. It has to be noted that Scenario 3 not only is characterized by the highest GHG emissions in absolute terms, as described above, but is also the only one with the strongest contribution from scope 2 GHG emissions.

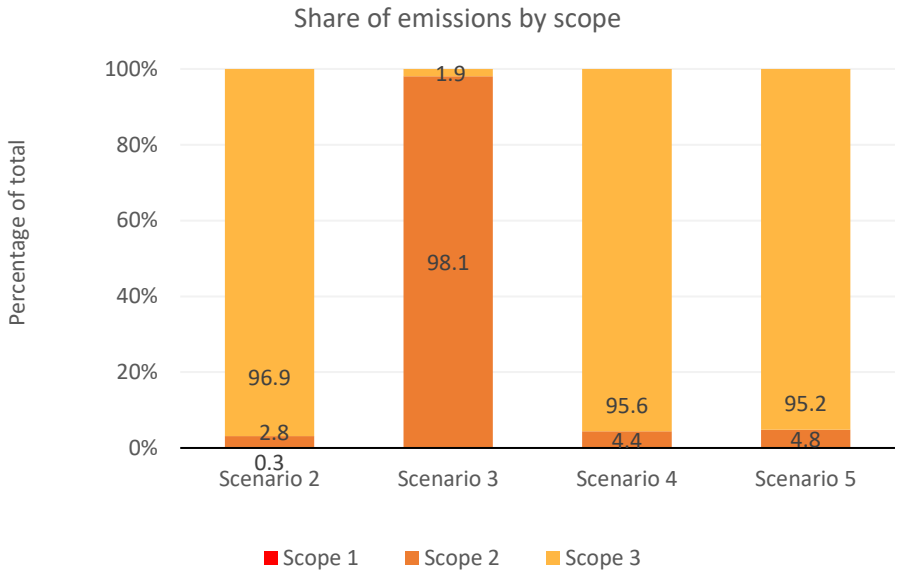


Figure 6.9. Scenarios total emissions breakdown by scope

6.3.5 Final scenario

The final scenario was built by implementing in the base case scenario the wind farm from scenario 4 and the water reuse from scenario 5. The process scheme obtained is shown in Figure 6.10.

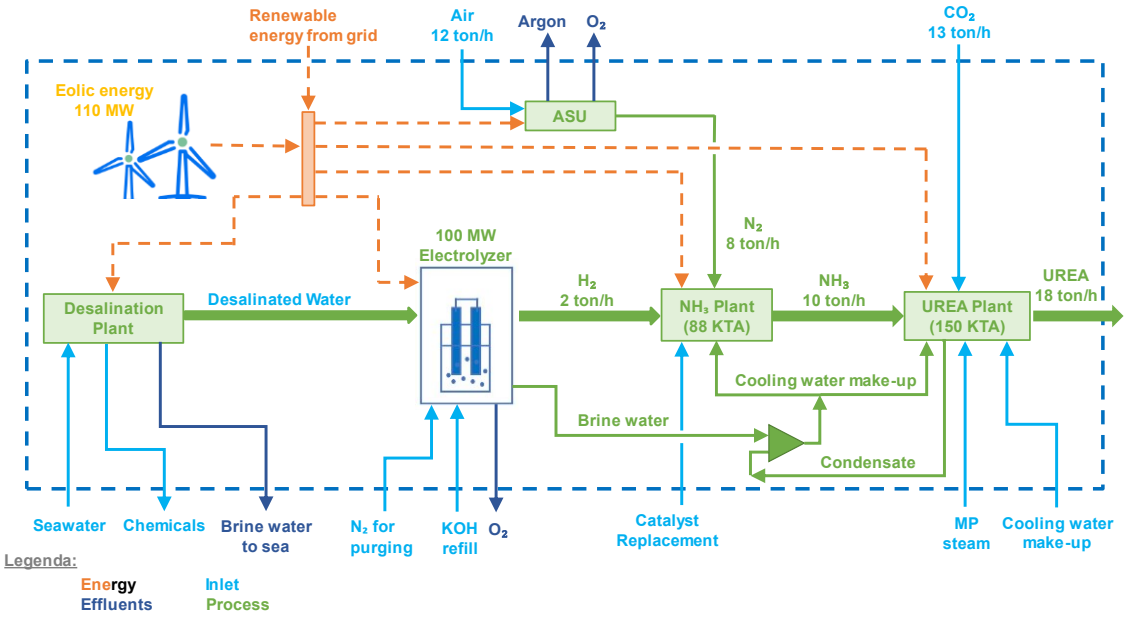


Figure 6.10. Final Scenario - process schematic of urea production from green H_2 using renewable energy both from the grid and from dedicated wind farm, external CO_2 stream and brine water reuse.

The results are reported in a straightforward way in Table 6.6. The carbon footprint of both ammonia and urea is extremely low, standing at almost zero tonCO_{2e}/ton of product. This allows the products to be certified as green, and to avoid the payment of carbon taxes. Moreover, it allows the access to one of the international funding mechanisms. Regarding LCOP, it can be noted that the obtained LCOA is quite low, compared to other references in literature for green production. This highlights the positive

effect of oxygen and EAUs selling on the competitiveness of the final product. However, green NH_3 is still not able to compete, from a purely market price point of view, with fossil based NH_3. In fact, a price in the range of 200-300 EUR/ton NH_3 was recorded in recent years, even though natural gas shortages of 2022 led to ammonia prices exceeding 1000 EUR/ton [204]. Similarly, fossil-based urea registered a price of 150 up to 300 EUR/ton in the 10-years period preceding 2021 but reached peaks of 820 EUR/ton in 2022 [285].

Table 6.6. Final scenario results

LCOP				**LCCA**	
Ammonia [EUR/ton]		**Urea** [EUR/ton]		**Ammonia** [EUR/tonCO_2]	**Urea** [EUR/tonCO_2]
Green	Fossil	Green	Fossil		
641.6	200-300	415.1	150-300	348	273

6.3.6 Sensitivity analysis

A sensitivity analysis was carried out to analyse the effect of different parameters on LCOA:

- Oxygen selling price; between 0 EUR/ton, meaning the byproduct oxygen is vented, and 200 EUR/ton.
- Renewable electric energy price; between 41 EUR/MWh and 79 EUR/MWh, respectively the minimum and maximum PPA price in 2022 [267].
- Carbon price; between 0 EUR/ton, meaning no taxation mechanism considered, therefore the operational benefits from EUAs selling are equal to 0 EUR, and 100 EUR/ton, maximum carbon price at the date.
- CAPEX; a variation of ± 50 % for the final scenario CAPEX was considered, as in line with the accuracy range of the AACE methodology.
- Electrolyser efficiency; between 50 and 79%, corresponding to the minimum and maximum electrolyser system electrical efficiency detailed in the paragraph "Alkaline electrolysis".

Figure 6.11. shows the results of the analysis. CAPEX sensitivity resulted in ±40 % LCOA variation. It also has to be noted that oxygen venting led to a +43 % higher cost. A decrease in the electrolysis system efficiency resulted in a strong increase of LCOA, touching 913 EUR/ton. On the other hand, the expected improvements in the upcoming years have the potential to further reduce the cost of the green hydrogen-derived products. The electricity price had a remarkable effect on LCOA, although only a part of the energy is purchased from the grid and not generated by the wind farm within the BL of the plant. Lastly, carbon tax value variations were found to have a relatively smaller influence on the LCOA.

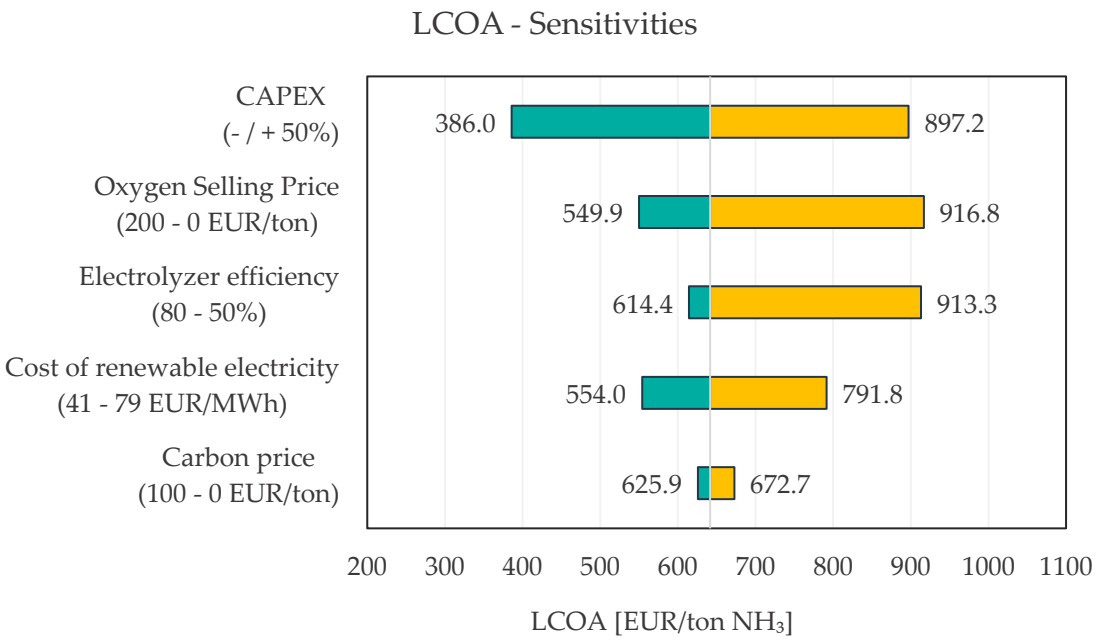


Figure 6.11. Results of the sensitivity analysis on LCOA from the final scenario

LCOA changes result in LCOU variations. Moreover, LCOU depends on the cost of the stream of CO_2 required for green urea synthesis. Therefore, a last analysis was conducted to highlight the influence of such CO_2 price on LCOU. Carbon dioxide stream price was varied between 0 EUR/ton CO_2, the reference value in the proposed study, and 100 EUR/ton CO_2, the maximum value attributed to CO_2 in the carbon market. The creation of a decarbonized circular economy, in fact, could result in CO_2 beginning to be considered as a valuable, not so abundant, commodity. A maximum LCOU of 490 EUR/ton was obtained (Figure 6.12).

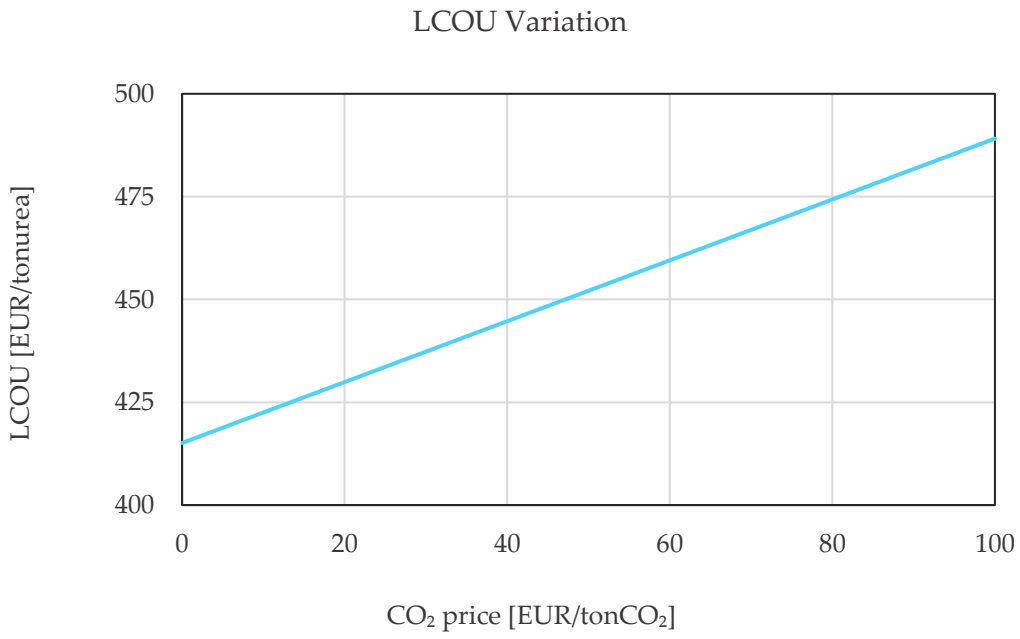


Figure 6.12. CO_2 stream price effect on LCOU.

6.4 Conclusions

This study presents an application of an innovative approach integrating well-known techno-economic methodologies and climate finance requirements based on GHG emissions estimate, new in literature. Climate finance introduces an increasingly weighty parameter into technical-economic evaluations that can be quantified through operational benefits, according to new climate regulations. Operational benefits impact on LCOP decreasing its value and, consequently, improving the competitiveness of the greener technologies in comparison with fossil based ones. For this reason, comprehensive assessments in the planning of new production plants (particularly in the European Union) represent a very relevant aspect to analyse.

The approach was applied to assess the feasibility of a new green ammonia and urea production plant to be located in Southern Italy. Five different scenarios were analysed and compared in terms of emissions, LCOP and LCCA. A final enhanced scenario was obtained building on the results of such analysis.

The key findings of the study can be summarized as follows:

- An integrated techno-economic and climate approach is needed to assess the feasibility of a production plant in view of political regulations of climate finance.
- Climate finance is an essential tool to increase green ammonia and green urea competitiveness.
- Considering climate finance current values, green products are still not able to compete with the fossil-based ones produced in Italy.
- A LCOA of 640 EUR/ton NH_3 was obtained for the proposed production plant (reference ammonia market price in recent years is 200-300 EUR/ton NH_3 excluding 2022).
- A LCOU of 415 EUR/ton was obtained the proposed production plant (reference urea market price in recent years is 150-300 EUR/ton of urea excluding 2022).
- The possibility to substantially lower the carbon footprint of ammonia and, consequently, urea was found.
- Free-of charge CO_2 stream is a key factor for competitive green urea production.
- Absence of a specific regulation regarding captured CO_2 streams management could have a negative effect on the point above.
- The revenues from by-product oxygen selling can substantially increase the competitiveness of the products.
- LCCA evaluation for new plants leads to a comprehensive assessment of the green product substitution impact, as required by the market.
- A LCCA for green ammonia and green urea substitution to conventional fossil-based product of 348 and 273 EUR/ton $CO_{2e,abated}$ respectively was found.
- LCOP is strongly affected by CAPEX and byproduct oxygen selling price variations.
- Electric energy price has a remarkable effect on LCOP.
- Carbon tax variations have a minor effect on LCOP, compared to the other parameters analysed.

From a technological point of view, the challenge of producing green urea requires not only a clean energy source, but also a carbon-neutral CO_2: fossil ammonia cannot simply be replaced with the

renewable NH_3 produced by electrolysis, and circular sources of carbon are also needed. Therefore, the use of CO_2 streams from other industrial processes proved to be an attractive solution, although the need of a legal framework to regulate the trading of CO_2 streams was emphasized.

The role of climate finance is closely related to the international attention on climate change and GHG emission reduction. Therefore, should the outlined trends in terms of legislation, carbon taxation mechanism and green products incentives continue and strengthen, not considering climate finance when assessing the feasibility of a new plant means building a probably "out-of-market" new plant.

7 Techno-economic and climate finance assessment of a methanation plant with green hydrogen production and CO_2 recycling in Italy

This chapter is based on the following published articles:

De Paolis R, Bernardini V, Campana LG, Ermini M V., Verna M, Raimondi G, Spazzafumo G. Techno-economic and climate finance assessment of a methanation plant with green hydrogen production and CO2 recycling in Italy. Int J Hydrogen Energy 2024. https://doi.org/10.1016/j.ijhydene.2024.07.137.

7.1 Introduction

The fossil natural gas price in Europe appeared stable for many years, but it started to increase since October 2021 and reached a peak in February 2022, after the Russian invasion of Ukraine. The sanctions on Russian gas imports and the new Asian demand have generated a wider recourse to European storages and a rise in the prices of natural gas in all Europe and in particular in Italy [286]. Currently, due to new diversified supply chains, coordinated European actions and energy saving measures, the price of natural gas appears stable again and comparable to the value at the end of 2021. Despite this, the geopolitical contest does not give certainties on the persistence of the current situation.

Among the technologies that have seen renewed interest in the context of the current global geopolitical situation there is the Power to Methane (PtM now on) process, aimed at the production of green natural gas through renewable energy sources. This technology, which has already been known for years [287] could potentially increase national and European self-production of natural gas, using additional renewables and CO_2 recycling, through the means of a carbon capture plant. However, European stock of renewables is not enough for the deployment of PtM. Slosarski [288] stated that EU energy policies are effective however not sufficient to call it a transition towards renewables. Moreover, Bersalli et al. [289] stated that only tax incentives on their own are insufficient to assure deployment of renewable energies. Along with other studies [290,291], it is possible to say that still not enough renewable deployment has been reached throughout Europe to fully enable a transition towards PtM.

Gorre et Al. [292] and Guilera et al. [217] stated in a review of PtM that, with the current technological solutions available nowadays, e-methane (electrical methane produced by a PtM process) production is not economically feasible. Another techno-economic review about the STORE & GO project [293] regarding Falkenaghen, Solothurn and Troia plants shows that technologies are sufficiently mature but the cost of the SNG produced is still too high.

To facilitate the energy transition in different parts of the world, and in particular in Europe, various financial tools have been adopted to support the implementation of technologies with a lower environmental impact but a higher cost.

Climate finance is the application of project financing to public or private initiatives which support adaption or mitigation towards climate change. Several specific EU fundings are based on climate targets [294]. The adoption of climate finance tools allows to overcome market conditions and constraints, making (such as PtM) feasible initiatives that would not be viable considering only technical-economic analysis.

Many studies approach climate finance from an economic, social and financial point of view underlining its potential evolution connected to classical economic parameters [295–297]. Some papers directly link financial aspects with technical ones for example in spreading renewables [298] and carbon capture systems [299] in developing countries. However, the effect of climate finance on a techno-economic feasibility study of a single plant regarding renewables or renewable derivative products (Power-to-X) appears to be a path that is not sufficiently detailed.

This paper introduces and discusses a new methodology to assess the feasibility of a PtM plant using both techno-economic analysis and climate finance existing tools in EU at the date. The case study considers an application in northern Italy.

At the best knowledge of the authors, there are no integrated techno-economic-climate studies in literature about PtM: this represents the novelty of the study.

Matschoss et al. [300] described the potential of biomethane and e-methane (methane from renewable energies) in Germany, but they did not consider the impact of climate finance on the economic sustainability of the proposed scenario.
Similarly, Fonder et al. [301] analysed the production of methane from renewables in a supply chain located in different Countries (Morocco and Belgium), but they also did not provide guidance on the impact of climate finance on the cost of synthetic methane produced. Same approach has been demonstrated in the review paper on green hydrogen-based e-fuels of Nemmour et al. [302]. They reviewed the role of power to fuel technologies for the decarbonization of energy sector, without analysing the impact of climate finance on the cost of fuels.
The present study shows a methodology that can help stakeholders implementing the production of SNG or e-methane considering not only the classical techno-economic assessment, but also climate parameters, targets and opportunity related with climate finance to help the spread of innovative and green technologies.

7.2 Material and methods

To define and apply a new methodology to assess economical sustainability of a SNG production plant in Italy using both techno-economic and climate finance criteria, different topics have been considered and evaluated from literature, such as technologies, climate finance and carbon assessments and economics.

7.2.1 Technologies

This section provides references to the scientific literature on key technologies that served as a premise for the study.

7.2.1.1 Wastewater Treatment Plant (WWTP)

EU hydrogen politics assumed that 6 GW of electrolysers will be installed in 2024, and 40 GW by 2030 [303]. Water sources must be guaranteed for hydrogen electrolysis production not in competition with food sector and human use in general. Water reuse from industrial wastewater is a preferential choice based on economic, environmental and social criteria.
Wastewater must be treated to reach at least the quality of grid water to be compliant with use in an electrolyser. Grid water quality requirements are commonly available (i.e. on ARPA database [304] that is Agenzia Regionale per la Protezione Ambientale in Italian language).
Many technologies are available for industrial wastewater treatment and the most suitable one can be chosen based on the specific characteristics of the wastewater. Main technologies are Membrane Biological Reactor (MBR) [305], Nano Filtration (NF) [306], Reverse Osmosis (RO) [307], also combined among them.
MBR technology is a combination of biological-activated sludge process and membrane filtration. Still, water coming out from MBR can't be used as industrial process water [305].
NF technology removes small molecules, inorganic salts, and monovalent ions as Na and Cl. Good efficiencies were noted for conductibility, salinity, and TDS (Total Dissolved Solids) [307,308].

RO is a technology that allows to have better performances than NF [309], especially for salinity, conductivity, TDS, Na and Cl.
Lately, literature works underlined the importance of the combination of different technologies, such as MBR and RO, as a valuable method for wastewater reclamation [309]. The combination of the two allows to reach water quality requirements for the use as process water [306].
S. G. Simoes et al. [221] stated that water coming from WWTPs can be used for electrolysis; different waste sources were compared, and industrial wastewater was declared to obtain better economic performances than the use of grid water.
WWTP can improve water quality and make it compliant with the requirement of the demineralization unit commonly matched at the electrolyser to supply water to electrochemical process. The best option to reach water quality requirements compliant for electrolysis demineralization unit is the combination of MBR and RO [306,309].

7.2.1.2 Renewable Energy Source (RES)

Given the geographic location assumed for the methanation plant in the study (northern Italy), a literature recognition was carried out on different RES available in that region.
Data analysed are coming from ENSPRESO [242], and EMHIRES [310,311], at NUTS-2 level (regional). In northern Italy there is very little wind potential, confirmed by installed power in northern regions of less than 3% of whole Italian wind power [302]. Different the situation for photovoltaic power (PV): despite PV Equivalent Operating Hours (EOH) are lower compared to the values in the southern regions, PV is a viable option in norther Italy. About 50% of the total Italian installed power is in the northern regions [312]. EOH can vary between 1000 hour/year and 1400 hour/year, depending on the site chosen, according also to EU PVGIS software [34].

7.2.1.3 Electrolysis

Electrolysis is one of the first steps in the PtM chain. Main technologies, excluding R&D level, are available: Alkaline (ALK), Proton Exchange Membrane (PEM), Anion Exchange Membrane (AEM) and Solid Oxide (SO). Cavaliere [313] published a recent and exhaustive review on the topic.
The first industrial scale technology is the ALK, which is the most widely used and reliable [314], with a lower CAPEX due to no noble metals, which works between 40 and 90 °C [315,316] with a consumption between 4.2 and 4.7 kWh/m^3 of hydrogen [317]. Disadvantages are represented by corrosion due to the KOH liquid electrolyte and efficiency.
PEM overcomes ALK efficiency, improves footprint but requires higher CAPEX due to noble metals and a Nafion membrane, which acts as a polymeric solid electrolyte [318], working between 20 and 100 °C. Moreover, lifetime is halved in comparison to ALK (40,000 h vs 80,000 h) [314].
AEM appears in literature with lowest TRL [314], despite its high potential as it combines the advantages of ALK and PEM not having noble metals and with a solid electrolyte.
SO electrolysis operates at higher temperatures between 700 and 1000 °C [318], which improves kinetics and allows to have lower consumption, about 3.3-3.7 kWh/m^3, way lower than low temperature electrolysis [319]. Up to now, it leads to a higher CAPEX due to utilization of materials which can withstand high temperatures. Considering that up to 80% of the costs over the lifetime are based on electrical consumption, SO could lead to lower hydrogen costs [320]. Heat must be provided to the electrolyser, but it can be coupled with the exothermic reaction of methanation, lowering the operating

costs [320]. Despite that, some tests were carried out for the thermal coupling of methanation through Sabatier reaction and SO, e.g. by the HELMETH project, which show that still some problems have to be overcome, as continuous process has to be reached, but efficiency can exceed 80% LHV based, according to partial results of the study [319,321].

7.2.1.4 Carbon Capture

CO_2 usage as a feedstock is a very attractive option as it can contribute to the formation of innovative products, such as e-methane. Carbon Capture can be performed in pre-combustion, oxy-combustion or post combustion.

Regarding post combustion carbon capture, absorption, adsorption, and membranes are different techniques that can be utilized to capture CO_2. The last one envisages a membrane in which CO_2 permeates and gets captured, there is no regeneration of substances, CAPEX is lower but up to now there is not high enough TRL (stated equal to 7) [315].

In the adsorption process, CO_2 is compressed, and it bonds on the surface of a solid adsorber and gets discharged through depressurization and heating, with a discontinuous process. The latter and the low efficiency are the main limits [315,322].

In the chemical absorption process with amines, CO_2 is bonded with amines and then heated for about 1 kWh/kgCO_2 [322] to release CO_2. Monoethanolamine in an aqueous solution is the main solvent, the flue gas passes through a washing section with water and then into a stripper, in which heat is transferred to regenerate the solvent and capture the CO_2 [323]. This technology is used, for example, in a power plant in Saskatchewan, Canada [324] and in a Waste to Energy plant in Oslo [325].

7.2.1.5 Methanation

In the methanation process, H_2 and CO_2 are converted into CH_4 and H_2O. The process can be carried out both biologically and chemically. Only chemical methanation will be addressed, due to the slow kinetics and low flexibility of the biological one [326,327].

The equation for the chemical methanation is the Sabatier reaction (7.1):

$$CO_2 + 4H_2 \rightarrow CH_4 + H_20 \quad (7.3)$$

The reaction is exothermic with a mole decrease, so is favoured by low temperature and high pressure [45] being reversible. However, kinetic would be slow so it is fundamental to use the right catalyst to lower reaction activation energy. Nickel is the most used for CO_2 methanation, thanks to its selectivity to CH_4 and its lower cost. Reaction occurs at 300-400 °C and at 10-30 bar [326,328]. CO_2 conversion is about 95%, depending on pressure and temperature [329]. Fixed bed reactors are the most used for this kind of reaction, with partial product recycling [326,327].

7.2.2 Climate Finance and Carbon Assessment

Climate finance is the application of project finance to initiatives that support mitigation or adaptation actions towards the climate change, thus referring to local or international fundings from private or public sources.

EU pushes the transition towards a low carbon economy, more efficient and sustainable [330], providing fundings up to 23 billion euros in 2021 [331]. Other than that, also private fundings must be moved toward green investments.
Targets are provided by Paris Agreement (2015), EU Green Deal and Climate Law (2020 onwards), to reach net zero in 2050 [332]. Politics that can allow to reach these targets are provided by EU with Directives and Regulations.

7.2.2.1 EU ETS & CBAM

European Union Emission Trading System (EU ETS) was revised in the Fit for 55 [333] package, with an extension of the sectors involved. EU ETS is a scheme that covers more than 11 thousand plants, covering CO_2, N_2O and PFCs, and allowing a 43% reduction in GHG in the sectors covered (in 2020 compared to 1990), covering Scope 1 (direct combustion) and Scope 2 (imported electricity and steam).
The system is defined as "cap and trade", where a maximum threshold is set for CO_2 equivalent (CO_{2e}), the standard unit to compare and account emissions from various GHGs emissions; based on that, a precise number of EU Allowances (EUAs) is envisaged, each one accounting for one tonne of CO_{2e}. This number decreases every year, and companies receive part of EUAs for free, and they must surrender a number of EUAs to balance their emissions. These allowances must be purchased on the market, and their price can fluctuate from few euros in late 2000s, until 70 to 100 €/EUA in 2022 [334].
Of course, the more the company is able to lower its carbon emissions, the lower will be the carbon tax that has to be paid for the EU ETS. If the feedstock is low carbon (e-methane), then the amount of tax to be paid is very low or even allowances can be sold on to the market, depending on the carbon footprint [335].
The same amount of tax has to be paid by foreign industries which want to export products into EU territory, thanks to the Carbon Border Adjustment Mechanism (CBAM) [336].

7.2.2.2 Renewable Fuels of Non-Biological Origin (RFNBO)

EU RFNBO Delegated Act is a part of the wider Renewable Energy Directive (RED), which was implemented to improve the development of RES, reaching 22% of share in 2020 (against the 20% target).
A RFNBO is a transport fuel, liquid or gaseous, of non-biological origin in which the hydrogen component is produced through an electrolyser which uses renewable electricity [5]. To be defined so, there is a fossil fuel comparator: the RFNBO must produce at least a 70% GHG reduction in comparison to the latter. The threshold is 28.2 gCO_{2e}/MJ for the RFNBO certification [337]. For these reasons, the aim of the e-methane is to be used as a transport fuel.

7.2.2.3 EU Innovation Fund

The Innovation Fund (IF) is one of the most extended programmes for public fundings [338], which gives funds to low-carbon technologies, carbon capture utilization and storage, renewable electricity, or innovative energy storage.
The IF provides, for large scale projects such the one in this study, up to 60% of the relevant costs, defined as the difference between the conventional production and the innovative project [339]. The

calculation of the relevant costs follows the levelized cost methodology, which will be addressed in the economics section.

7.2.2.4 Carbon Assessment

Regarding the carbon assessment, GHG Protocol Corporate Accounting and Reporting Standard was used, in order to reach a standard reporting system internationally valid [340]. GHG Protocol covers seven Greenhouse Gases (GHGs): carbon dioxide (CO_2), methane (CH_4), nitrogen oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbon (PFCs), hexafluoride (SF_6), nitrogen trifluoride (NF_3). Three different scopes are accounted for the evaluation of the GHG emissions:

- Scope 1: direct emissions, emitted from sources controlled or possessed by company, derived e.g. from combustion.
- Scope 2: indirect emissions derived from electricity and steam imports, which physically occur outside the company.
- Scope 3: indirect emissions, which considers emissions derived from company activities but are not direct responsibility of the latter, e.g. transportation, extraction, utilization, wastes, etc.

Following considered standard, Scope 1 and 2 are mandatory for the accounting of GHG emissions, instead Scope 3 is optional. Of course, if also Scope 3 is considered the analysis becomes more complex but at the same time more precise in evaluating the effect of an industrial activity.
Regarding the emissions accounting, data must be converted to CO_2 equivalent (CO_{2e}) to estimate the impact of different GHGs. To understand how much CO_{2e} is associated to a specific GHG, it is possible to use the 100 years Global Warming Potential (GWP, [341]) as per IPCC methodology [342].
To calculate the emissions, the activity data (data from the process units e.g. fuel or electricity consumed) are multiplied by an emission factor (how much CO_{2e} is linked to a specific stream): the result is the quantity of emissions produced by the plant, measured in CO_{2e}. The specific emission factor of the product (measured in $ton_{CO2e}/ton_{product}$) was compared to the threshold set by the RFNBO.
Moreover, levelized cost of carbon abatement (LCCA) methodology from Columbia University was used to calculate the climate-economic feasibility of the different scenarios. Measured in €/$tonCO_{2e}$, this parameter allows to calculate the cost of every ton of CO_{2e} abated, and in this way to compare different scenarios both in an economic and climate perspective. Following, LCCA formula from Columbia University methodology [343]

$$LCCA = \frac{C_1 - C_0}{E_0 - E_1} \tag{7.4}$$

where C is the cost difference and E the GHG emission saving thanks to the implementation of the innovative technology. In particular, the subscript *1* refers to the innovative plant, the subscript *0* to the base scenario for NG purchasing.

7.2.3 Economics

The economic analysis has the aim of having an estimation of the costs involved in building and running the plant.

Capital expenditure (CAPEX) and operational expenditure (OPEX) are taken into account, using both literature and Technip Energies in-house data. Moreover, also the operational benefits of the plant were considered: within that, electrolytic oxygen selling (after compression and storage) for both industrial and medical purposes, and carbon tax saved thanks to the carbon capture installation (refer to EU ETS).

The output of the economic analysis is the levelized cost of energy (LCOE), which is defined as the ratio between the Net Present Value (NPV) and the actualized energy produced [344], as described in the following equation:

$$\text{LCOE}\left(\frac{€}{\text{MWh}}\right) = \frac{CAPEX + \sum_1^n \frac{OPEX}{(1+d)^n} - \sum_1^n \frac{Operational\ Benefits}{(1+d)^n}}{\sum_1^n \frac{Volume\ produced}{(1+d)^n}} \quad (7.3)$$

where *d* is the interest rate, *n* is the lifetime of the plant, *volume produced* is the quantity of product measured in MWh/y, and the *Operational Benefits* include, per IF methodology [345], eventual secondary earnings from the projects (e.g. electrolytic oxygen selling or EU ETS allowances sold). It has to be noted that the LCOE represents the cost of production of natural gas, including all the units inside the battery limit for the production of e-methane (energy, electrolyzer, methanation, carbon capture, WWTP).

LCOE represents the minimum selling cost of the product in the market to reach the breakeven point for the project. LCOE is the output which will be compared to the current NG selling price, to understand if it is economically feasible to produce e-methane as a transport fuel.

Following, the values used in the analysis:

Table 7.1 - Economic parameters values

Parameter	***Value***	***Ref.***
Lifetime, n [year]	*20*	internal dataset
d (interest rate)	*4%*	internal dataset
PV capital cost [€/kW]	*650*	[346]
Electrolyser capital cost [€/kW]	*950*	[347]
Carbon Capture capital cost [€]	*Not disclosed*	internal dataset
Methanation reactors capital cost [€]	*Not disclosed*	internal dataset
WWTP MBR CAPEX [€/m³/h]	*4000*	[305]
WWTP RO CAPEX [€/m³/h]	*11000*	[348]
Electrolyser O&M cost [€/kW]	*19*	[349]
PPA price [€/kWh]	*55*	[350]
Electric energy price) [€/MWh]	*65*	[351]
Fossil natural gas cost [€/MWh]	*40*	[352]
EU ETS price [€/EUA]	*66*	[334]
Oxygen selling price [€/kg]	*0,17*	[353,354]
Oxygen compression OPEX [€/kg]	*0,01*	internal dataset

7.2.4 Assumptions and technology choices for case study: a basic scenario

Assumptions for the study are:

- Electrolyser size is 100 MW. This size was set in order to reach a substantial amount of e-methane produced in the current Italian market, specifically about 5% of national CNG consumption in 2021 [355].
- Alkaline technology is considered for the electrolyser due to its higher maturity, reliability, lifetime, and lower CAPEX.
- Electrolytic oxygen selling produced by electrolysis is considered (at 200 bar).
- WWTP is composed by MBR and RO units for the wastewater reclamation.
- Chemical absorption technology is considered for carbon capture, due to its maturity, with a common flue gas coming from an industrial plant near the methanation plant.
- Methanation plant is geographically located in Northern Italy.
- Methanation technology is based on fixed bed reactors.
- Energy and NG prices are set as average of 2020-2022 period.
- Operating hours of the plant is 8700 hour/year.

Considering those assumptions defining the general context, a basic scenario (scenario 1) for the e-methane production plant is defined. Basic scenario represents a backbone to evaluate the effect of technological alternatives for the methanation plant, in view of defining a more economic and environmentally sustainable plant (final scenario).

Renewable energy source for the basic scenario is provided by a Power Purchase Agreement (PPA), which allows to buy a certain amount of green electric energy, and virtually use it in another area of the grid, without physical connection to the renewable energy plant. A PPA value for the energy is set at 55 €/MWh [350].

A block flow diagram (BFD) of the basic scenario is indicated in the following figure:

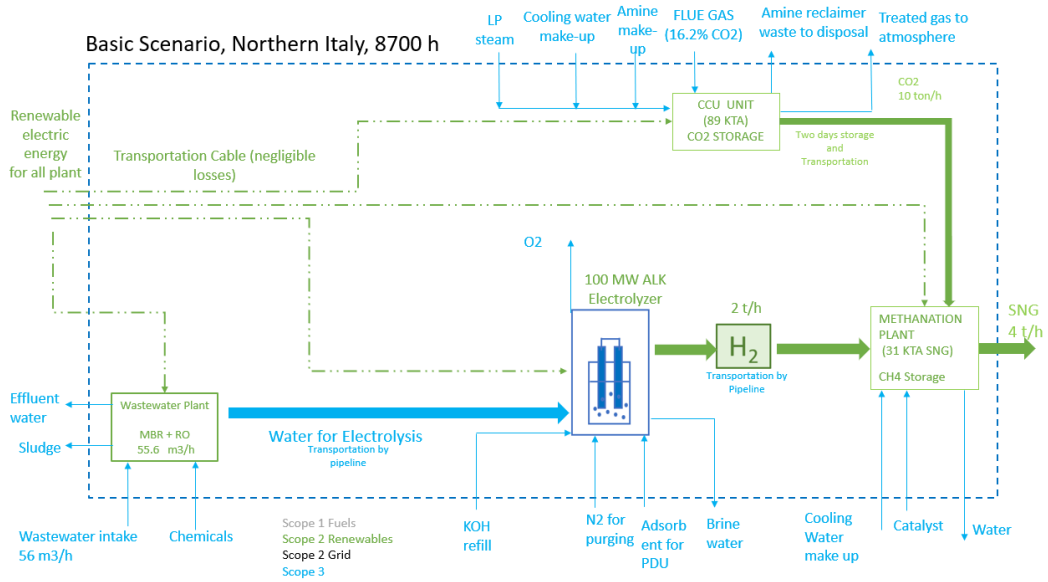


Figure 7.1. – Block Flow Diagram of Basic Scenario

Following, a description of the mass balances for the different units, based on literature and industrial data as explained in the technology overview:

- WWTP: 37.5 m^3/h are exiting the unit. Considering the losses in MBR and RO, about 35%, the wastewater intake is of 56 m^3/h.
- Electrolyzer: 37.5 m^3/h of water are needed to produce 2 ton/h of hydrogen to feed the methanation, considering that a relevant amount of water is wasted as brine; moreover, slightly less than 15 ton/h of oxygen are produced.
- Carbon capture: Considering the concentration of CO_2 assumed as 16.2% vol, more than 410 kta of flue gas are needed to capture about 89 kta of CO_2 to feed the methanation.
- Methanation: in this reaction, for every kg of H_2 about 5.5 kg of CO_2 are needed, in order to produce slightly less than 2 kg of SNG considering a CO_2 conversion of 94%. H_2O is a by-product of the reaction (4.5 kg every kg of H_2).

For the scope of this study, it was not important to design every block in detail (as operating conditions, temperatures etc.), but only overall mass balances.

In Table 7.2**Errore. L'origine riferimento non è stata trovata.**, the share of energy required by every unit which is part of the battery limit of the system (referring to the Basic Scenario) is shown.

Table **Errore. Per applicare 0 al testo da visualizzare in questo punto, utilizzare la scheda Home.**7.2 – Share of energy consumption

Unit	***Share of energy consumption [%]***
Electrolyzer	*93*
Carbon Capture	*5,5*
Methanation	*1*
WWTP	*0,5*

In Table 7.3 a summary of the values for the calculation of LCOE and LCCA (referring to the basic scenario) is indicated.

Table 7.3 - Values for basic scenario

Total CAPEX [M€]	*155*
Total OPEX [M€/y]	*60*
Operational Benefits [M€/y]	*30*
Total produced e-methane [MWh/y]	*425,000*
C1-C0 [M€]	*400*
E0-E1 [ktonCO2e]	*1900*

7.2.5 Methodology to investigate different scenarios

To evaluate different plant configurations based on common assumptions of basic scenario, an analysis of alternative sources for main feedstocks for methanation process is considered. Only electricity and water source alternatives are evaluated, considering that is difficult to define alternative for the source of carbon: it is generally supposed extracted from a flue gas of a generic industrial plant in proximity of the methanation plant.

Three electricity sources are considered for feeding the whole methanation plant (both electrolyser and chemical reactors): electricity from the electrical grid, renewable electricity from PPA and renewable electricity both by PPA and by direct PV connection.

A water source comparison is considered between grid water and wastewater treated with a WWTP.

To evaluate different scenarios, two main parameters are considered: LCOE and LCCA. These two parameters previously described can give an economic and climate evaluation that can help to improve the performance of the plant regarding these two aspects.

Starting from the basic scenario, different parameters were changed (once at a time), to understand if both economic and carbon parameters were enhanced. If an alternative scenario showed an improvement both for the LCOE and LCCA, then the modification would be implemented in what is defined as final scenario.

To summarise, a methodological framework is displayed in Figure 7.2.

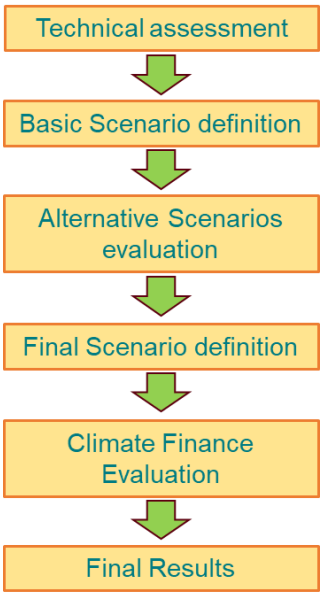


Figure 7.2 - Methodological Framework

7.3 Results and discussion

7.3.1 Alternative scenarios evaluation

The different scenarios considered are:

- Scenario 2: use of grid electricity for the entire plant.
- Scenario 3: WWTP deletion and use of grid water.
- Scenario 4: PV Plant implementation, partial self-production of renewable energy.
- Scenario 5: reuse of treated brine water out of the electrolyser as make-up water.

Scenario 2 showed that the use of grid electricity is not convenient both from an economic and climate point of view. The carbon footprint associated with energy mix from grid is referring to Italian energy mix 2020 [356]. Scenario 3 improved slightly the carbon footprint, as WWTP is associated with fugitive emissions, but overall LCOE increases, showing that water circularity is beneficial for the economics.
Regarding Scenario 4, a 100 MW PV Plant is envisaged. Considered EOH is 1300 hour/year. Carbon footprint is the same as the Basic Scenario (same amount of renewable energy), but economics improved, showing that the PV plant is more economically viable than the electricity both from PPA and from grid, despite having a higher CAPEX; in fact, the OPEX are then only related to the maintenance of the plant and not to the purchase of electric energy. The remaining electric energy, not provided by the solar plant, is assumed to be provided by PPA.
Scenario 5 improves in both ways as less water is used in the overall balance of the plant.
Only Scenario 4 and 5 improved both LCOE and LCCA. For these reasons, both the PV plant and the brine water recycling were added to the basic scenario, obtaining the final scenario.
Following in Table 7.4, the value of LCOE and LCCA for the different scenarios:

Table 7.4 – LCOE and LCCA values

	LCOE	LCCA
Scenarios	[EUR/MWh]	[€/ton$CO_{2e,abated}$]
Base Scenario	110	225
Scenario 2	140	ND
Scenario 3	115	275
Scenario 4	105	210
Scenario 5	108	220
Final Scenario	100	200

Following, the overall block flow diagram (BFD) of the final scenario:

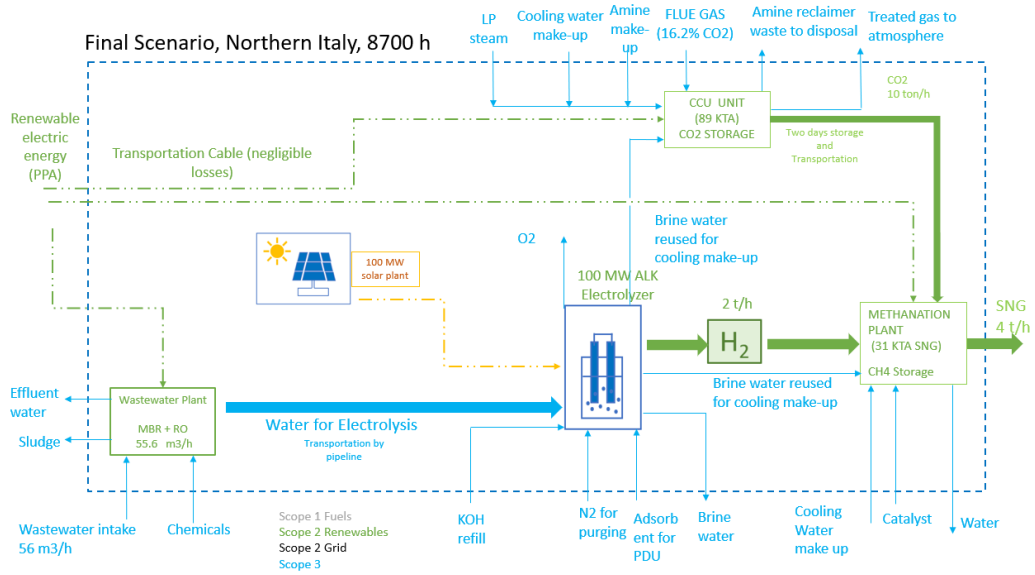


Figure 7.3**Errore. Per applicare 0 al testo da visualizzare in questo punto, utilizzare la scheda Home.** - Block Flow Diagram of the Final Scenario

Regarding the carbon footprint part, the emission factor reached is about 4.5 gCO_{2e}/MJ, equivalent to 0.2 $tonCO_{2e}/ton$, against the RFNBO threshold of 28.2 gCO_{2e}/MJ (1.4 $tonCO_{2e}/ton$). The reduction is more than 70% compared to the fossil fuel comparator, reaching more than 95% of carbon footprint saving: for this reason, it is possible to certify the e-methane produced as a RFNBO.

For the economics, instead, results are slightly different. CAPEX and OPEX are very high, especially due to the electrolysis unit. Given that, also considering operational benefits previously described, LCOE is about 100 €/MWh. Comparing it to the NG cost for the reference period (40 €/MWh, from November 2020 to November 2022 [352]), the cost increase of e-methane is about 60 €/MWh, 2.5 times the price of fossil NG.

Regarding LCCA, which allows to estimate the amount of money to be invested to abate one ton of CO_{2e}, the value is about 200 €/$tonCO_{2e}$, with a saving of more than 90,000 tons per year of CO_{2e}.

7.3.2 Climate Finance Evaluation

As it was described before, and considering the results obtained, it is possible to certify e-methane produced with methodology presented in this study as a RFNBO. It means that it has a "green label" given by EU and can be sold at a higher price in comparison to the fossil alternative, as it is associated with far less GHG emissions that can allow whoever buys it to reduce their carbon footprint, as it happens for other e-fuels or for Sustainable Aviation Fuels.
Moreover, being the plant an innovative project regarding carbon capture utilization, it can be funded by the EU IF. This means that up to 60% of the relevant costs (defined as the increase in costs given by the implementation of the innovative plant [339]) could be given by public fundings, with the possibility to greatly reduce LCOE and make it comparable to the fossil alternative. In particular, if the plant gets EU IF fundings, they can be inserted into the Operational Benefits, and LCOE would go down to about 70 €/MWh, starting to be more comparable to fossil NG and showing that climate finance is able to boost the energy transition.

7.3.3 Future developments and Policy Implications

If SO reaches a high enough TRL, LCOE can significantly decrease thanks to the higher efficiency and the waste heat reuse of the exothermic methanation reaction [319–321]. Electricity cost, which accounts for more than 90% of the plant overall annual OPEX, would decrease by 20-25% for the same amount of hydrogen produced.
Moreover, improvements can also be made on the Renewable Energy side, installing a tracking PV system (which can be both 1D or 2D) to increase the EOH, despite a slightly higher initial CAPEX.
Not only technological improvements, but also policy developments are needed to make it feasible to produce e-methane or other related green fuels through PtX. The EU IF is a way to fund innovative plants, as explained in previous paragraphs. Other schemes or fundings are needed, for example contracts for difference can be implemented to fund the difference in price between green (i.e. RFNBO) and fossil alternative (the difference has been highlighted in previous paragraphs).
Governments are supportive of climate funds to new technologies as in EU it is in force the principle "polluters have to pay for their greenhouse gas emissions" via the Emissions Trading System (ETS). The money raised via the EU ETS is reinvested into the Green Climate Finance Instruments like the EU IF, not impacting the countries with excessive taxation policies, but creating new market opportunities.
E-methane production is one of the accepted new technologies suitable for funding. In addition, at the COP28 Global Methane Pledge Summit in December 2023, EU presented the first ever EU methane regulation for the energy sector and announced €175 million in funding to methane actions, focusing among the others to substitute fossil methane with e-methane [357], following the target to slash methane emissions by 30% by 2030.
Improvements can be made, and the current geopolitical situation in which NG price can increase and decrease within the space of a few months, with problems affecting the reservoirs too, are for sure the reasons that can help PtM to establish in the following years.

7.4 Conclusions

A techno-economic and climate assessment was carried out to understand if PtM is nowadays a viable alternative to fossil natural gas, due to the problems regarding the current geopolitical situation and to reduce carbon footprint. The analysis was made regarding technical, economic and climate feasibility. The novelty of this article consists in considering, along with the technical and economic feasibility, also the climate one, assessing the carbon footprint and the possible certification schemes of e-methane as an RFNBO and evaluating a possible funding by EU IF.

Economic parameters as CAPEX, OPEX, Operational Benefits (such as electrolytic oxygen selling and EU ETS carbon tax avoided) were considered, calculating both LCOE and LCCA.

A scenario analysis was performed to reach the final scenario within the boundaries of the study, composed of:

- A WWTP, with MBR and RO technologies combined.
- A 100 MW PV Plant and PPA to cover the rest of the electric energy needed.
- 100 MW ALK Electrolyser, with electrolytic oxygen selling after compression and storage, and brine water reuse.
- Chemical absorption technology for carbon capture, based on amines.
- Methanation with fixed bed reactors.

The results for the climate part were positive: it is possible to certify e-methane as an RFNBO thanks to the 95% of GHG saving (compared to the required 70%). This results in a saving of more than 90,000 tons of CO_{2e} per year.

The Climate Finance could cover the difference in price between innovative investments and fossil alternatives. It is possible in this case, as the product is low carbon and certifiable as a RFNBO, and the plant is innovative, to fund the plant by public fundings such as EU IF. Considering also EU IF, the LCOE is 70 €/MWh.

The LCOE is still far from the natural gas price for the reference period, but this study shows that if similar mechanisms for funding are deployed, they could help the spread of innovative and green technologies making them economically viable and comparable to the fossil alternatives.

8 Conclusions and outlooks

8.1 Conclusions

General purpose of this thesis is to identify new business models that enable the development of hydrogen local economy, using different incentive schemes set up at national level in particular in Italy but also in other Countries (Spain in detail). In particular, two main systems within the European Union have been investigated: Renewable Energy Communities (RECs) and Climate Finance frameworks.
A wide general conclusion is that with both REC scheme or Climate Finance as a source of financing, the hydrogen production, storage and use systems, as described in this thesis, highlight an increase in economic sustainability without, however, generates profits. A break-even point can be reached in some cases and in next years.

In the first four Chapters (from Chapter 2 to Chapter 5) of this thesis the role of hydrogen within RECs is explored. Several renewable sources are considered to feed the REC: solar, wind and biomass. Hydrogen is supposed to achieve different uses: regulation of the electric grid, seasonal storage of renewable energy for local electrical generation, energy vector in the transport sector, general use for manufacturing industry or small and medium enterprises.
In all described scenarios, the use of incentives assigned to energy communities to make local hydrogen supply chains more economically sustainable is the common element. In fact, with the state of evolution of the hydrogen-based technologies, the cost of the various components does not allow diffusion without incentives. One of the purposes of the RECs is to provide economic and environmental advantages at a local community around shared renewable power plants: therefore, the creation of new, more environmentally sustainable energy supply chains is absolutely compatible.
Hydrogen in the REC is strategical for different aspects

1. REC incentives are one of the few ways at the moment to have economic support (in particular for OPEX) for small-scale hydrogen production and use chains (first initiatives, pilot plants, small needs)
2. it is an alternative way to batteries to manage the excess energy produced by renewables, increasing the matching between renewable production and consumption, particularly at a seasonal level (increasing seasonal dispatchability of renewables)
3. it decouples easily power from energy in a storage system (strongly coupled in battery case)
4. it allows to easily bring together various economic sectors (energy, building, transport, SMEs) and different supply chains (sun, wind, biomass)

In detail, the studies presented demonstrate that RECs can be a local suitable way for financing local renewable hydrogen production, bringing the sales price to values similar to fossil hydrogen one (Chapter 2). The enabling condition for this result and its limit is having a cohesive community with the

common intention of wanting to support the creation of such a local supply chain. In fact, to obtain that result all incentives must be allocated to hydrogen without a redistribution among members of the energy community. The benefit for the community is indirect starting local renewable hydrogen economy. This hypothesis has always been considered in all subsequent studies except that of Chapter 5, in which the incentives are proportional to the electricity consumed by the electrolyser for hydrogen production.

In the Chapter 3, hydrogen is used as a seasonal energy storage of local renewables in a double REC configuration. From an energy point of view, the proposed configuration allows an increase in local self-consumption of renewable energy around 15% (using the same dimension of wind and solar plants). The seasonal storage of hydrogen is the key for this result despite the low round trip efficiency of the system. Two main limits appear: one is the cost of the proposed configuration, that makes the operation completely unsustainable from an economic point of view; the second one is the Italian regulation for REC that not allows feeding from hydrogen (the use of citizen energy community is a solution).

Regarding cost, more in detail the highest cost is represented by hydrogen storage. It proves to be the technology that will have to reduce more its costs, in order to guarantee the advantages presented in the study.

A system of co-production of different energy carriers is presented in Chapter 4, where the members of the REC represent users for both electricity and residual heat from the system. Hydrogen in this case is intended for mobility.

In this case, the source for producing hydrogen is not electricity but local residual lignocellulosic biomass which is gasified and in which the hydrogen flow is separated and purified via Palladium membranes.

This case, considering that the investigated scenario does not include a single plant but a network of plants distributed in a territory (province of Huesca in Spain), solves some critical elements that emerged in previous studies. In particular, hydrogen storage has been reduced, thanks to the combination of fixed and mobile hydrogen pressure tanks which have made it possible to significantly reduce the cost of storage.

The production system in this case is based on Palladium membranes which represent the third cost item, after the gasification and electricity production system and the hydrogen vehicle refuelling network.

Precisely a market evolution of these last two systems represents the key to obtaining a cost of hydrogen aligned with or cheaper than traditional fuels in transport application (diesel).

Already today, if the cost of these technologies reached in some Asian market is applied in Europe, the economic sustainability of the system presented would be achieved.

Finally, a scheme of multiple coordinated RECs for the production of hydrogen to be used for electricity production in support of the national electric transmission grid has been investigated in Chapter 5. Involving the Italian UVAM project scheme, a supply chain of production and use of hydrogen at territorial scale is assessed to provide ancillary service for the electrical power grid (TSO level).

In a high level of photovoltaic penetration area served by the same electrical primary substation (HV/MV substation) of the DSO grid, many renewable energy communities (RECs) integrate each one an electrolyser. Hydrogen produced and stored is consequently used to balancing service through an UVAM of 1 MW based on hydrogen power plant that produce electricity in the ancillary service market feeding TSO grid.

The business model allows to aggregate and make dispatchable excess of renewables generated in a territory through REC and UVAM that represent innovative and flexible entities in the electric Italian market.
The technological and cost maturity of the solutions currently available (electrolysers, fuel cells or internal combustion engines powered by hydrogen) does not allow present-day economic sustainability. Moreover, currently Italian non-refundable loans for RECs established in municipality under 5,000 inhabitants cannot compensate for the lack of economic maturity of the enabling technical solutions.
The expected technical and cost evolutions for electrolyser and fuel cell in the coming years (by 2035) will allow economic sustainability to be achieved.
In Italian regions with a likely wide development of RECs in the coming years, the proposed business model appears to be a valid alternative to reduce the impact of a high penetration of renewables on DSO grid, offering at the same time a solution for TSO grid balancing using renewable dispatchable energy.

In the last two Chapters (Chapter 6 and Chapter 7), the effect of Climate Finance to increase the sustainability of green hydrogen supply production and utilization chains is assessed, considering plant in Italy and with local energy supply chain. Ammonia production (Chapter 6) and methane synthesis (Chapter 7) are considered as products from a Power to Chemical approach using hydrogen as a feedstock.
Climate finance introduces an increasingly weighty parameter into classical technical-economic evaluations that can be quantified through operational benefits, according to new climate regulations. Operational benefits (key elements in the evaluation of the production cost) impact on levelized cost of chemical products decreasing its value and, consequently, improving the competitiveness of the greener technologies in comparison with fossil-based ones. For this reason, comprehensive assessments in the planning of new production plants (particularly in the European Union) represent a relevant aspect to analyse, now and in the coming years.
The Climate Fnance framework set up in Europe and assessed in Italian conditions has a positive and significant impact both on the production of low-carbon ammonia and methane, but not enough to be competitive with fossil products at current price.
A LCOA of 640 €/ton NH_3 is obtained for the proposed production plant (reference ammonia market price in recent years is 200-300 €/ton NH_3 excluding 2022).
A LCOE of 70 €/MWh of methane is obtained for the investigated synthesis plant for substitute of natural gas (in the period from January 2023 to nowadays, Dutch TTF Natural Gas Futures Price was always under 75 €/MWh with a mean value of 40 €/MWh [358]).
Italian scenario does not appear to be the most advantageous due to the high costs of electricity in the internal market [359] due to low penetration of renewables in comparison with the electricity internal demand.

8.2 Outlooks

To enable the development of local hydrogen supply chains within renewable energy communities, a cost reduction of hydrogen storage is essential, both for compression storage and other types such as

those based on metal hydrides. Reduction in storage cost appears more impactful than reduction in most debated topics, as fuel cell and electrolyser costs.

In fact, it is clear that the advantage of hydrogen in comparison with batteries, is in the creation of seasonal shift in energy production, for which storage is a fundamental element.

In those business models in which hydrogen storage can be limited and, consequently, its economic impact is not so crucial, the price of electrolysers and fuel cells will have to undergo a decrease of at least one order of magnitude to have an economic sustainability for small-scale applications and therefore also for RECs. Many studies assure that within a decade the conditions should be reached.

Furthermore, as regards the production chains of hydrogen from biomass, attention will have to be paid to reducing the costs of gasification plants which currently have a cost in Europe much higher than in the rest of the world.

The cost of the gasification plant has a greater impact than much more complex technologies based on particular materials such as Palladium membranes.

When the above conditions will be met, the business models integrating hydrogen into RECs as presented in this thesis will be absolutely sustainable. RECs prove to be a good incentive to the growth of hydrogen in end-use markets, helping to improve local consumption of renewable, energy local valorisation of resources, stability of electric grid.

Climate finance proves to be a very useful tool in contributing to the implementation of low carbon chemical production chains.

A parallel evolution of climate finance tools and hydrogen production technologies from electrolysis and carbon capture, together with a necessary greater penetration of renewable energy in the Italian market are the three paths that can lead to the Italian viability of production of non-fossil chemicals.

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[A] Article
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