INTEGRATED COGENERATION SYSTEMS

Efficiency, competitiveness, and flexibility for the energy transition

Public discussion document

September 2026

1. Introduction

The energy transition is profoundly altering the operational structure of the national energy system and market parameters—which, in turn, remain dependent on trends in energy commodity markets. Consumers—defined here as industrial and tertiary-sector end-users whose energy needs can be met by cogeneration plants located at or near their consumption sites—are being called upon to implement active decarbonization strategies for their production processes. This shift is driven by the need to operate in a market that increasingly demands goods and services compatible with environmental requirements. At the same time, these environmental imperatives can sometimes compromise the competitiveness of these companies (particularly those exposed to international competition, including from outside Europe).

Furthermore, consideration must be given to the growing need for energy independence, which drives the increased use of domestically produced, non-dispatchable renewable energy sources; this has an increasingly significant impact on the operational security of the interconnected national energy system.

Finally, there is the broader issue of ensuring that this entire process is managed as efficiently as possible to minimize overall costs for all end-consumers.

To contextualize the role that cogeneration can play in the aforementioned process, Italcogen has conducted a study analyzing specific business cases. The aim was to determine whether and how cogeneration can still be viewed as an enabling technology for the energy transition and the decarbonization of production processes, while maintaining competitive conditions for consumers who currently use—or might potentially use—cogeneration systems.

This document presents a summary of that study (with detailed results provided in Annex 1), alongside additional analyses, surveys, and considerations. These are intended to gather comments and further input from relevant stakeholders, enabling Italcogen to formulate a technical and institutional proposal regarding the future use of cogeneration. This proposal addresses both the national level—where European directives on energy efficiency must be transposed—and the international level (specifically the European Union), with the aim of developing targeted proposals that Italcogen will promote across Europe via Cogen Europe, the European association for cogeneration of which Italcogen is a member (for this reason, the consultation document is also published in English to facilitate discussion among stakeholders outside Italy).

Furthermore, this document serves as the analytical basis for an internal working group within ANIMA-Confindustria, where the final proposals to be developed will be discussed.

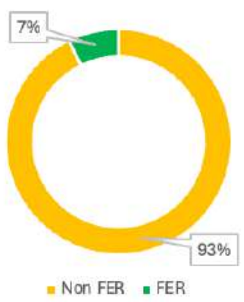
Stato di evoluzione della cogenerazione in Italia

Cogeneration accounts for the majority of national thermoelectric generation in Italy[1]. More specifically:

- in terms of capacity (in 2025):
  - 42.2% of total net installed thermoelectric capacity—amounting to approximately 25,600 MW—divided between power producers (approx. 20,000 MW, or 78.1% of cogeneration capacity) and self-producers (approx. 5,600 MW, or 21.9% of cogeneration capacity);
  - for self-production, the most significant technology is internal combustion engines (37.9%, approx. 2,100 MW), followed by combined-cycle systems (36.1%, approx. 2,000 MW) and turbines (12.7%, approx. 800 MW);
- in terms of generation (in 2024): 57.8% of total national thermoelectric generation, amounting to approximately 91 TWh out of a total of roughly 158 TWh.

In terms of application, cogeneration is primarily used for industrial purposes and for district heating and cooling. Natural gas is the predominant fuel, although the use of renewable gases is becoming increasingly significant.[2].

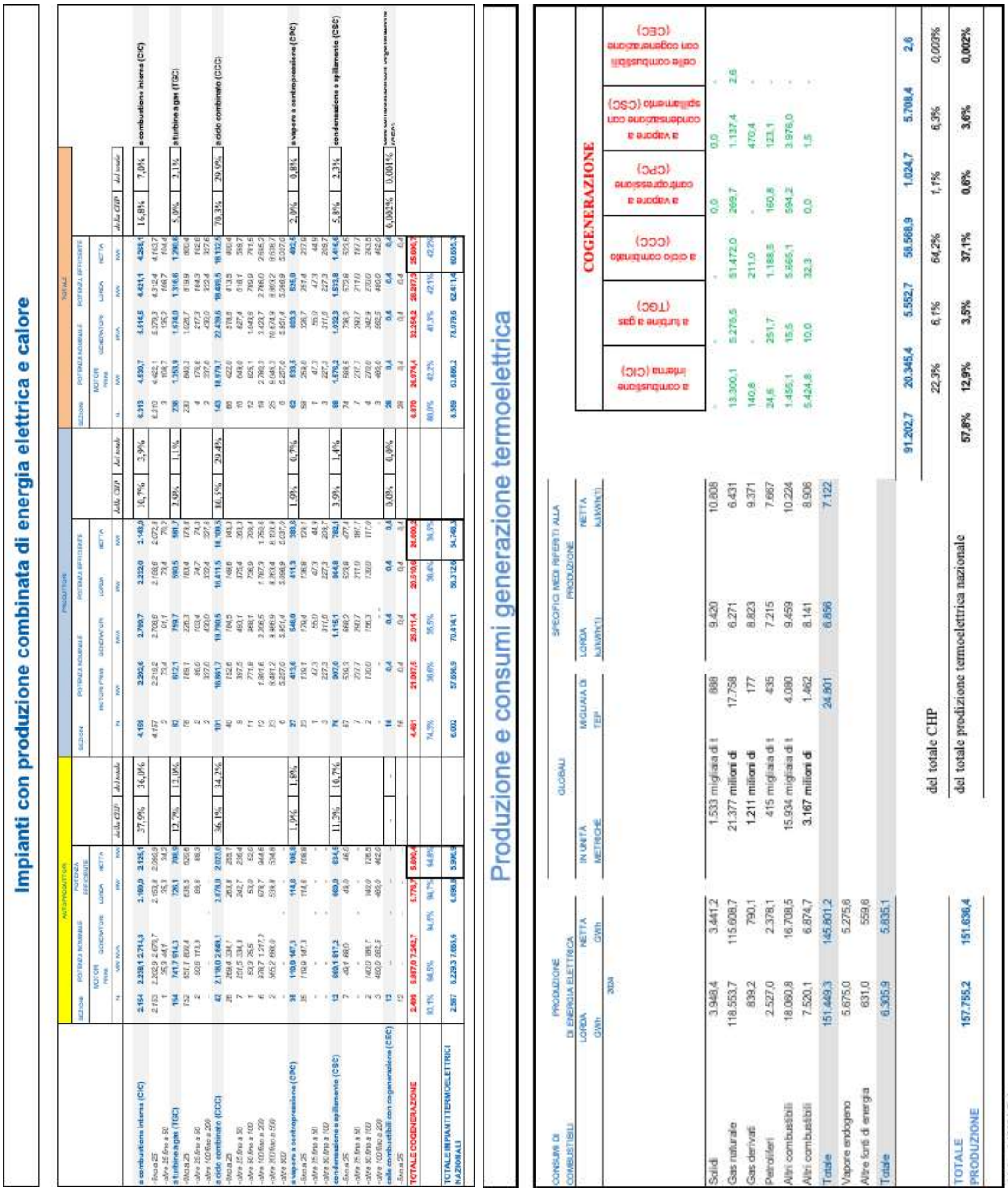
Potenza efficiente netta al 31/12/2023 (sezioni CHP) per combustibile prevalente [(1)]



- Di cui a gas: 86% del totale

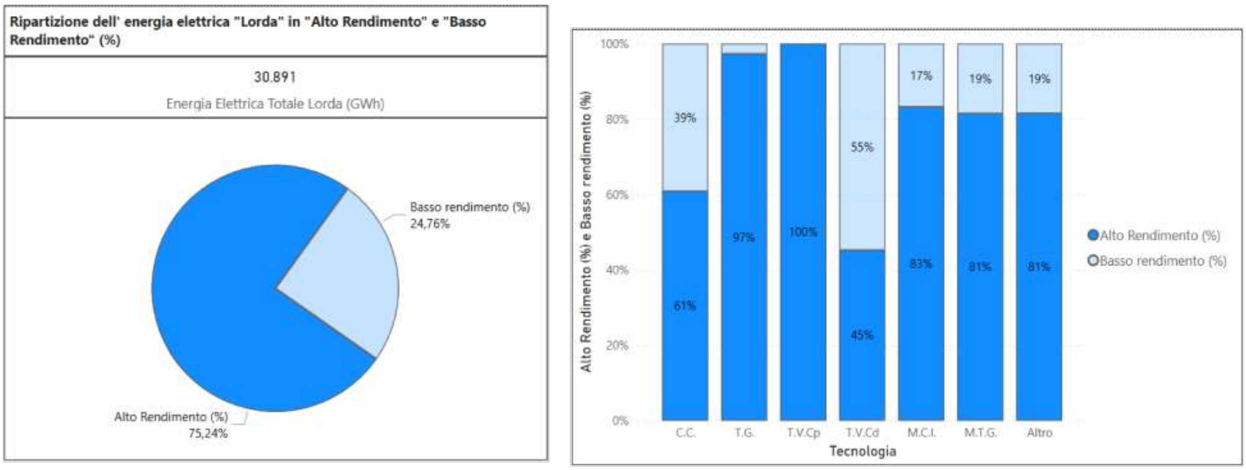
Potenza efficiente netta al 31/12/2023 (sezioni CHP) per uso finale prevalente		Numero sezioni
Teleriscaldamento/ teleraffreddamento	**5,5 GW**	**982**
Usi industriali	**13,9 GW**	**2.505**
Di cui: settore energetico	*3,9 GW*	*84*
Di cui: settore industriale	*9,2 GW*	*1.093*
Di cui: digestore	*0,6 GW*	*1.044*
Di cui: altri settori	*0,2 GW*	*284*
Senza produzione di calore/calore utile	**6,6 GW**	**3.170**
Totale	**26,1 GW**	**6.657**

[1] Cfr. https://www.terna.it/it/sistema-elettrico/statistiche/pubblicazioni-statistiche
[2] Dati Terna 2023.



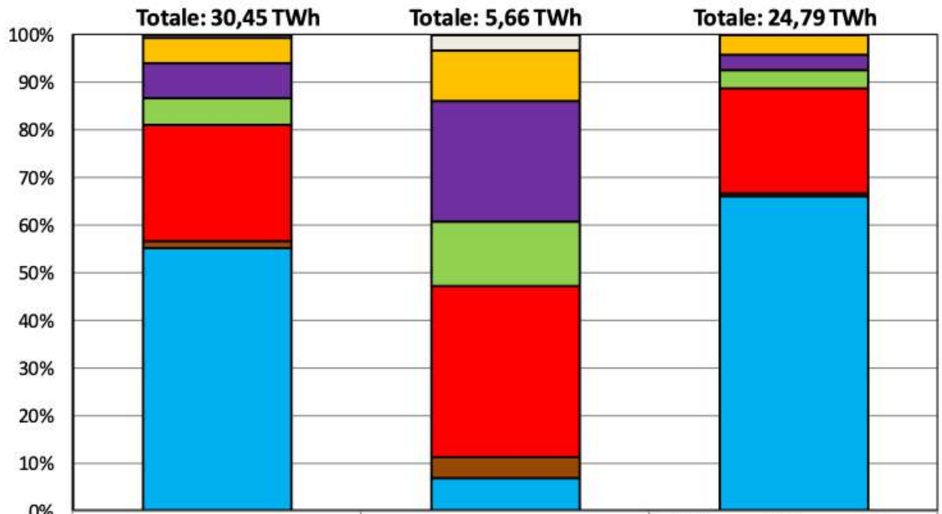
With regard to the portion of cogeneration that meets the high-efficiency criteria, the following general points apply; although the available data refer to 2023, they are nonetheless considered indicative of the current situation.[3]. **At least 75% of Italian cogeneration would therefore meet the high-efficiency criteria.**

[3] Cfr. https://www.gse.it/documenti_site/Documenti%20GSE/Cogenerazione/Rapporto%20Statistico%20sulla%20Cogenerazione%20ad%20Alto%20Rendimento%20-%202024.pdf



Low-efficiency and high-efficiency electrical energy

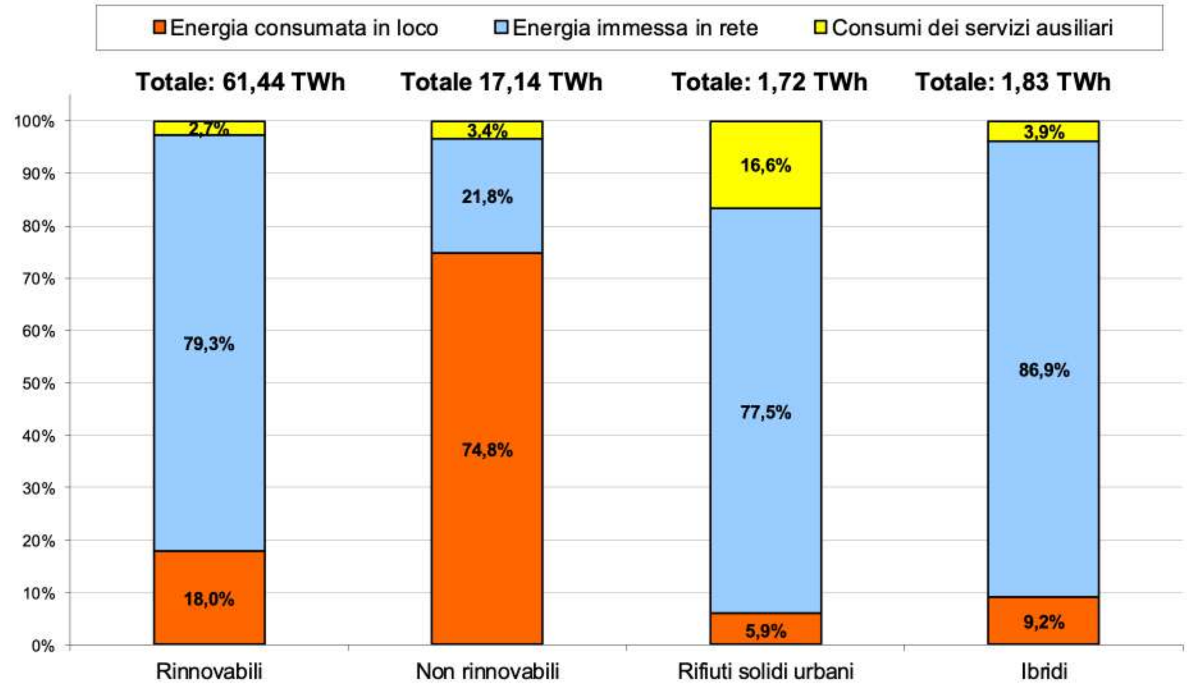
In practice, cogeneration accounts for the entirety of national distributed thermoelectric generation, and the vast majority of it directly meets user demand. More precisely, distributed thermoelectric generation[4] represents 33.4% of national thermoelectric generation; of this figure, 84.1% is cogeneration, 75% of which is consumed on-site..



	GD termoelettrica	GD termoelettrica solo produzione di energia elettrica	GD termoelettrica produzione combinata di energia elettrica e calore
Altre fonti di energia	0,6%	3,2%	0,0%
Rifiuti solidi urbani	5,2%	10,6%	4,0%
Bioliquidi	7,5%	25,3%	3,4%
Biomasse	5,6%	13,6%	3,8%
Biogas	24,6%	36,0%	22,0%
Altri combustibili fossili	1,3%	4,4%	0,6%
Gas naturale	55,2%	6,9%	66,2%

*Produzione di energia elettrica dalle diverse fonti utilizzate nell'ambito della **GD da termoelettrico***

[4] According to the definitions provided by ARERA, distributed generation refers to the set of generation plants connected to the distribution system.Cfr. https://www.arera.it/atti-e-provvedimenti/dettaglio/26/282-26



Breakdown of gross generation from distributed generation into electricity fed into the grid and electricity consumed on-site (for plants powered by renewable sources, non-renewable sources, and municipal solid waste, as well as for hybrid plants)

Within the bioenergy sector, power generation accounts for the largest share, representing 72% of the plants and 57% of production; biogas plants play the most significant role in this regard, particularly those based on agricultural activities (see the data highlighted in the following table)[5].

Bioenergie

	IMPIANTI		POTENZA EFFICIENTE LORDA		PRODUZIONE	
	N.		KW		GWh	
	2025		2025		2024	
Sola produzione di energia elettrica	880	28%	1.783.691	44%	7.395,2	43%
Solidi	**114**	**13%**	**773.426**	**43%**	**3.154,5**	**43%**
- rifiuti solidi urbani	29		386.003		956,0	30%
- biomasse solide	88		387.423		**2.198,6**	70%
Biogas	**645**	73%	456.251	26%	2.035,2	28%
- da rifiuti	180		215.177		491,7	
- da fanghi	15		4.966		16,4	
- da deiezioni animali	195		58.288		313,3	
- da attività agricole e forestali	278		177.820		1.213,9	
Bioliquidi	127	14%	554.014	31%	2.205,4	30%
- oli vegetali grezzi	108		474.535		2.037,7	
- altri bioliquidi	22		79.479		167,8	
Produzione combinata di energia elettrica e calore	2.243	72%	2.265.027	56%	9.841,5	57%
Solidi	314	14%	884.961	39%	3.234,4	33%
- rifiuti solidi urbani	27		517.286		1.292,7	
- biomasse solide	290		367.675		1.941,7	
Biogas	**1.678**	**75%**	**1.021.356**	**45%**	**5.460,6**	**55%**
- da rifiuti	194		149.504		414,8	
- da fanghi	72		46.772		109,5	
- da deiezioni animali	**592**		**206.017**		**892,4**	
- da attività agricole e forestali	**951**		**619.063**		**4.044,0**	
Bioliquidi	263	12%	358.710	16%	1.146,5	12%
- oli vegetali grezzi	199		300.055		979,0	
- altri bioliquidi	72		58.655		167,5	
TOTALE	3.123		4.048.718		17.237	

[5] From Terna statistical data

S.1 Do you agree with the approach adopted for analyzing cogeneration data in Italy? What issues or inaccuracies are noted in the presented data?

S.2 Italcogen is currently developing a periodic monitoring project to organize and interpret data regarding the cogeneration sector. What additional elements could or should be considered to provide an increasingly comprehensive picture of the sector? Where possible, please also provide references for sourcing the data and information deemed useful for this activity.

2. The contribution of cogeneration to the path of energy efficiency development

As detailed further below, the primary instrument supporting the development of cogeneration is the allocation of energy efficiency certificates (white certificates) in proportion to the primary energy savings achieved through the use of cogeneration. At the same time, the entities subject to the white certificate mechanism are all electricity and natural gas distributors serving more than 50,000 end-customers; they are required to meet specific annual energy-saving targets set by the State. Accordingly, the Ministerial Decree of 21 July 2025 entered into force on 12 September 2025, establishing the national quantitative targets and obligations for end-use energy savings for the 2025–2030 period to be achieved through the white certificate mechanism. The specifications for the energy-saving targets to be met during this period via the white certificate mechanism align with the provisions of the 2024 National Integrated Energy and Climate Plan (PNIEC). As is known, various measures work together to achieve these results, namely[6]:

- measures eligible for the issuance of white certificates;
- energy from high-efficiency cogeneration (HEC) associated with the issuance of white certificates;
- energy efficiency projects provided for by Ministerial Decree No. 106 of 2015;
- measures already incentivized under the white certificate scheme that continue to yield positive effects beyond their useful life.

Between January 1 and July 31, 2026[7]:

- 2,410 administrative proceedings were initiated by the GSE: specifically, 22 requests based on preliminary estimates and 2,388 based on final figures for High-Efficiency Cogeneration (CAR), 98% of which received a positive assessment;
- a total of 2,027,299 White Certificates were issued or withdrawn, of which 1,487,251 related to production from high-efficiency cogeneration units.

In practice, high-efficiency cogeneration has so far accounted for 73.4% of the white certificate supply in 2026, representing the dominant share of supply in the white certificate market.

S.3 Under current conditions, is the support mechanism for cogeneration based on the white certificate system considered to have been sufficiently effective from the perspective of the consumer or producer?

S.4 What critical issues are still observed in relation to this mechanism?

S.5 What elements should be addressed in the context of a review or renewal of the use of white certificates to support the development of cogeneration?

[6] Cfr. https://www.gse.it/documenti_site/Documenti%20GSE/Rapporti%20Certificati%20Bianchi/Rapporto%20annuale%20Certificati%20Bianchi%202025.pdf

[7] Cfr. https://www.gse.it/servizi-per-te/news/efficienza-energetica-e-car-pubblicati-i-dati-sui-certificati-bianchi-dei-primi-sette-mesi-del-2026

3. Current support framework for HECHP (High efficiency CHP/CAR in Italian)

Support framework to high efficiency CHP (HECHP)[8] in Italy, the system relies primarily on the White Certificate mechanism (Energy Efficiency Certificates – TEE), operationally managed by the GSE. ARERA (the Regulatory Authority for Energy, Networks and Environment) defines the tariff rules, purchasing obligations, and cost allocation within utility bills regarding the recognition and valuation of these certificates. In summary, the support scheme for high-efficiency cogeneration (CAR) is based on the following points:

- recognition of efficiency: the GSE verifies that the plant achieves primary energy savings (PES) of at least 10% (or a positive value for small/micro-plants);
- issuance of White Certificates (CB CAR): CAR plants are entitled to the issuance of specific White Certificates based on the primary energy saved;
- role of ARERA: the Authority regulates the tariff components covering costs associated with CB CARs and continuously adjusts markets and dispatching rules to facilitate the integration of these efficient plants into the grid.

Current legislation (specifically Legislative Decree no. 20/07)—in addition to any regional or local initiatives and tax incentives—provides for:

- exemption from the obligation to purchase Green Certificates (for the period such an obligation was in force), which applied to electricity producers and importers with annual production and imports from non-renewable sources exceeding 100 GWh. However, this obligation no longer applies to production and imports from 2015 onwards;
- priority dispatching for electricity produced and fed into the grid by high-efficiency cogeneration plants over electricity produced from conventional sources; - energy efficiency certificates (or "white certificates") linked to primary energy savings, the application criteria for which—regarding high-efficiency cogeneration—are defined, most recently, by the Ministerial Decree of 5 September 2011;
- simplifications and specific provisions regarding grid connections, regulated by the Authority;
- offtake of electricity fed into the grid by plants with a capacity of less than 10 MVA—as an alternative to the free market—based on principles of procedural simplicity and applying market-based economic conditions as regulated by the Authority;
- procedural simplifications for the construction, connection, and operation of small high-efficiency micro-cogeneration plants.

S.6	On which aspects should efforts to support or simplify the development of cogeneration primarily focus?

[8] Cfr. https://www.arera.it/area-operatori/produzione-tup

4. Applicable authorization regimes for cogeneration

Legislative Decree No. 190 of November 25, 2024 (Consolidated Law on Renewable Energy) governs administrative regimes exclusively for renewable energy plants. Cogeneration (where high-efficiency but fueled by fossil sources) remains governed by Legislative Decree 20/2007 and Legislative Decree 115/2008, whereas it falls within the scope of the Consolidated Law on Renewable Energy only if it utilizes renewable sources (e.g., biomass, biogas, or renewable micro-cogeneration).

Renewable-source cogeneration

The Consolidated Act on Renewable Energy streamlines and reorganizes administrative procedures into three broad categories:

- Unrestricted activity (*attività libera*): for small renewable micro-cogeneration plants falling below specific power thresholds (e.g., biomass/biogas cogeneration plants up to 50 kW);
- Simplified Authorization Procedure (PAS): applicable to medium-capacity plants defined in the decree's technical annexes, managed electronically via a dedicated digital platform;
- Single Authorization (AU): mandatory for large renewable energy plants that exceed PAS power thresholds or require complex environmental assessments.

In practice, for renewable-source (FER) micro/small-scale cogeneration, if the plant is fueled by biomass or biogas and is of modest size, it may qualify as unrestricted activity or fall under the PAS.

Non-renewable-source cogeneration

The authorization regime for the construction and operation of a cogeneration plant in Italy varies according to the unit's nominal thermal and electrical capacity. Small-scale plants follow simplified procedures via the SUAP (One-Stop Shop for Productive Activities), while large plants require a regional or provincial Single Authorization. Specifically, the authorization regime for cogeneration can be divided into the following three categories:

- Micro-cogeneration (< 50 kWe): requires a simple notification or a declaration of commencement of works (*Edilizia Libera* or SCIA) submitted to the Municipality via the SUAP.
- Small-scale cogeneration (< 1 MWe and thermal capacity < 3 MW): subject to a certified notification or simplified procedure (such as the former DIA/SCIA or PAS) handled at the municipal level.
- Medium and large-scale plants (up to 300 MW): require the Single Authorization (AU) issued by the Region or the delegated Province, or the Single Environmental Authorization (AUA) covering environmental and emissions aspects.

Additional requirements and key constraints applicable to cogeneration include:

- Atmospheric emissions: the plant must comply with the limits set out in Legislative Decree 152/2006 (Environmental Code), often incorporated into the AUA.
- Fire safety: Mandatory opinion from the Fire Department, based on the installed thermal power threshold.

S.7 Is the authorization framework for cogeneration considered to be sufficiently represented? If not, please indicate any additional conditions affecting the authorization for the construction and operation of cogeneration plants.

S.8 Please indicate the most significant actions that Italcogen should undertake to improve the regulatory framework for the permitting of cogeneration plants.

5. Cogeneration and emissions

EU Directive 2023/1791 of 13 September 2023—which has yet to be transposed into national law—introduces additional criteria to the definition of high-efficiency cogeneration (HEC) by establishing a maximum emissions threshold linked to the energy produced.

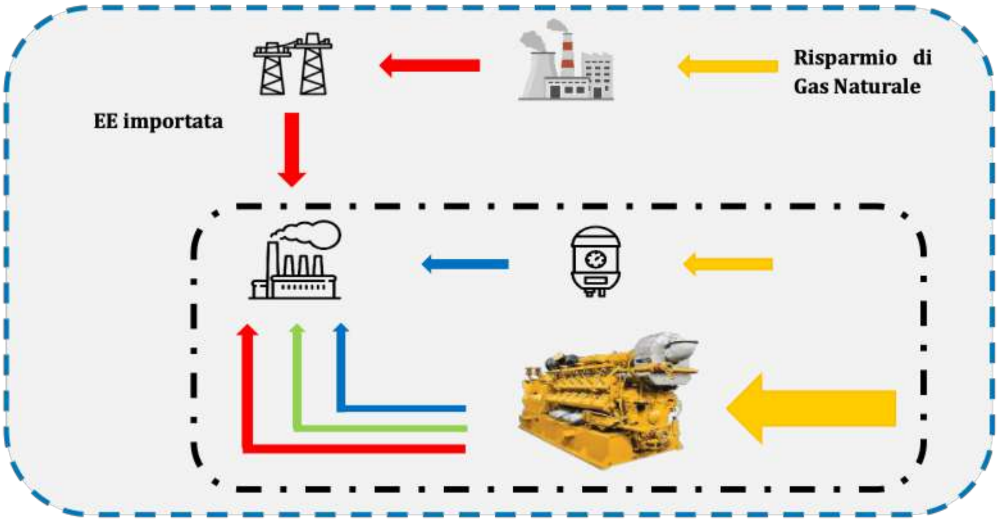
In practice, for cogeneration to be classified as high-efficiency—and thus qualify for the support schemes and special regulatory regimes established for it—two further conditions must be met in addition to the minimum primary energy savings (PES) threshold:

- for the construction or substantial refurbishment of cogeneration units following the transposition of this annex, direct carbon dioxide emissions from fossil-fuel-fired cogeneration must be lower than 270 gCO_2 per kWh of energy produced via combined generation (including heating/cooling, electricity, and mechanical energy);
- cogeneration units in operation prior to the Directive's entry into force may be exempted from this requirement until 1 January 2034, provided they have a progressive emissions reduction plan in place to meet the threshold of less than 270 gCO_2 per kWh by that date, and have notified said plan to the relevant operators and competent authorities.

In summary, compared to the previous directive, the environmental constraint described in point 3 above—namely, emissions of less than 270 gCO_2/kWh—has been introduced; this requirement is automatically met if the plant achieves an overall first-law efficiency (as specified in Annex 2 of the new directive) of 75% or 80%, depending on the plant type. Again according to Annex 2 of the new directive (as in the previous one), for cogeneration units with an overall efficiency below 75% or 80%, it is possible to use a "virtual plant" approach; this involves excluding a portion of the generated electricity from the High-Efficiency Cogeneration (HECHP) calculation to arrive at a reduced-scale "virtual" cogeneration configuration that meets the required overall efficiency thresholds. Historically, the EED allows a virtual plant to be classified as high-efficiency to account for situations—common in industrial settings requiring high-temperature thermal energy—where, despite recovering as much thermal energy as possible, the aforementioned overall efficiency targets cannot be met. This provision allows the cogeneration setup to still be recognized for the portion of combined electricity and thermal production that satisfies HECHP criteria.

A combined reading of Annex 2 and Annex 3 of the new directive suggests, by analogy, that the same rule applied to the "virtual plant" concept could also apply to the emission limit of 270 g CO_2/kWh of total energy produced; this is because that parameter is inextricably linked to the overall first-law efficiency value (in terms of overall efficiency, 270 g CO_2/kWh corresponds to a value of 75%).

In this regard, it is well known that cogeneration is a technology that increases fuel consumption at the specific facility while decreasing it within the national energy system—thanks to the efficient, combined generation of energy and the avoidance of grid losses. This is the principle underpinning the White Certificate system. However, this same reasoning is not extended to emission benefits. Indeed, when it comes to CO_2, the focus is placed on the facility boundary and the point of emission, leading to the view that cogeneration has a negative impact.



For this reason, it might be appropriate to define a term analogous to PES, but referring to CO2 emissions avoided through cogeneration: the ESI (Environmental Saving Index). Just as PES indicates the primary energy saved thanks to the combined generation of electricity and heat, the ESI would translate that avoided primary energy into CO2 emissions. Less fossil-based primary energy means fewer emissions produced by that energy source.
The UNI 8887 standard calculates the ESI, but with reference to local pollutants; it would be appropriate to also have an indicator specifically addressing climate-altering gases, the dynamics of which must be considered on a global scale.

Regarding the CO2-based ESI, a "like-for-like technology" approach should be maintained, considering that cogeneration must be compared to the most similar separate generation technology. Industrial facilities housing a cogeneration unit require a continuous electricity supply, including during nighttime hours. The national grid can meet this demand only through thermoelectric generation, as most renewable sources cannot guarantee this type of supply. Furthermore, in Italy, dispatch priority is granted to both renewable sources and cogeneration. This means that when a cogeneration unit starts up, it is the thermoelectric power plant that is "switched off," not the renewable sources. Finally, one must consider that the energy produced by many photovoltaic plants is consumed on-site or secured through PPAs or other contractual arrangements. Given these considerations, it would be more accurate to use the emission factors of the thermoelectric generation fleet—rather than those of the national energy mix—when calculating emissions avoided through electricity generation.

The publication *ISPRA Emission Factors – Report on National Electricity Sector Emissions 2023* (published in 2025) lists the following parameters:

- thermoelectric generation emission factor: 414.9 gCO2/kWh
- national electricity grid emission factor: 256.3 gCO2/kWh

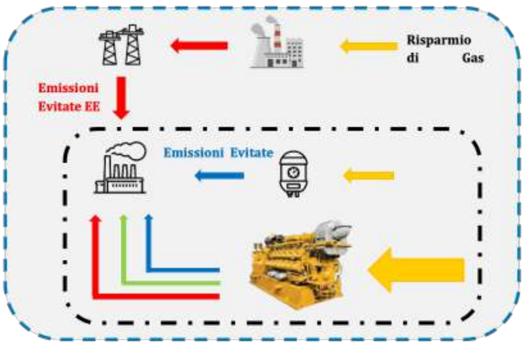
As noted above, the Energy Efficiency Directive—due to be transposed into Italian law—stipulates a CO2/kWh limit for cogeneration plants as a requirement for obtaining CAR qualification. To date, there are no standard methodologies for calculating the CO2 emissions of a cogeneration plant. Therefore, a simple, straightforward calculation method is proposed; this method can be updated annually using only an emission factor and other data already utilized in CAR calculations.

$$\text{Emissioni } CO_2 \text{ CHP} = (F_{\text{unità}} / \text{PCI}) * \text{fe GN}$$
$$\text{Energia Prodotta tot} = E_{\text{unità}} + H_{\text{unità}}$$
$$\text{Emissività Specifica} = \frac{\text{Emissioni } CO_2}{\text{Energia Prodotta tot}}$$

fe GN = fattore emissione gas naturale espresso – Database ISPRA - $kgCO_2/Sm^3$

To meet the emissions threshold of 270 gCO2/kWh, the efficiency of the cogeneration unit must be at least 78%. As previously mentioned, this threshold will also apply to the concept of a "virtual unit," representing the portion of the CHP unit that meets both the efficiency and emissions requirements. The effective power-to-heat ratio (Ceff), used to size the virtual unit, must be calculated by setting a threshold global efficiency ($\eta globale, soglia$) of 78%.

The proposal regarding avoided emissions and the ESI is presented in the two formulas and the graph below. The ESI calculation mirrors that of the PES exactly.



Emissioni Evitate

$$\text{Emissioni } CO_2 \text{ CHP} = (\text{Funità} / \text{PCI}) * \text{fe GN}$$
$$\text{Emiss. Evitate EE} = \text{E unità} * \text{fe EE}$$
$$\text{Emiss. Evitate ET} = \text{H unità} * \text{fe ET}$$
$$\text{Emissioni Evitate} = (\text{Emiss. Evitate EE} + \text{Emiss. Evitate ET}) - \text{Emiss. } CO_2 \text{ CHP}$$

ESI

$$\frac{(\textit{Emiss. Evitate EE} + \textit{Emiss. Evitate ET}) - \textit{Emiss.}CO_2 \textit{ CHP}}{\textit{Emiss. Evitate EE} + \textit{Emiss. Evitate ET}}$$

fe EE = fattore di emissione energia rete termoelettrica - Database ISPRA - gCO_2/kWh
fe ET = fattore di emissione energia termica - Database ISPRA - gCO_2/kWh

ESEMPIO DI CALCOLO

Grandezza	Valore	U.M.
$F_{unità}$	35.000	MWh_{in}
$E_{unità}$	15.050	MWh_e
$H_{unità}$	12.500	MWh_t
η_e	43,00%	
η_t	35,71%	
η_{tot}	78,71%	

EMISSIVITA' SPECIFICA

Emissioni CO_2	3.675.255	Sm^3
	7.424.014	$kgCO_2$
Energia Prodotta tot	27.550	MWh
Emissività Specifica	269,47	gCO_2/kWh

Da confrontare con i 270 gCO_2/kWh della EED

PROPOSTA - ESI

Emissioni CO_2	3.675.255	Sm^3
	7.424.014	$kgCO_2$
Emissioni Evitate EE	6.570.830	$kgCO_2$
Emissioni Evitate ET	2.800.000	$kgCO_2$
Emissioni Evitate	1.946.816	$kgCO_2$
ESI proposto 20,7753%		

Confrontabile con il PES

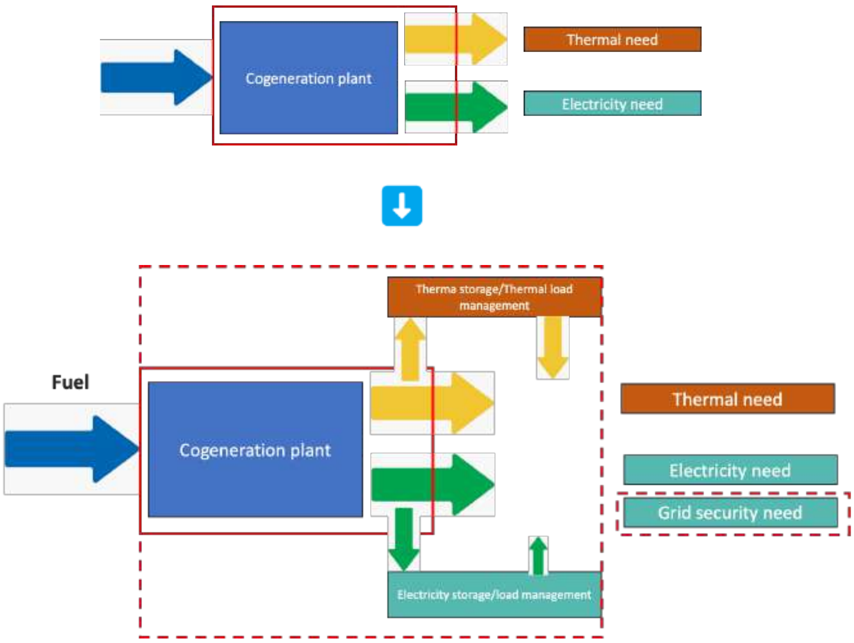
S.9 Are the observations regarding the relationship between cogeneration and emissions considered valid? Is the introduction of an index measuring emissions avoided through cogeneration (ESI) considered useful for the system??

S.10 Do you agree with the proposed implementation method for the new EU Directive 2023/1791 regarding the emission limit introduced in the new definition of HECHP?

S.11 What further considerations might be made regarding the relationship between cogeneration, emissions, and environmental sustainability from a consumer's perspective?

6. Cogeneration in the energy transition

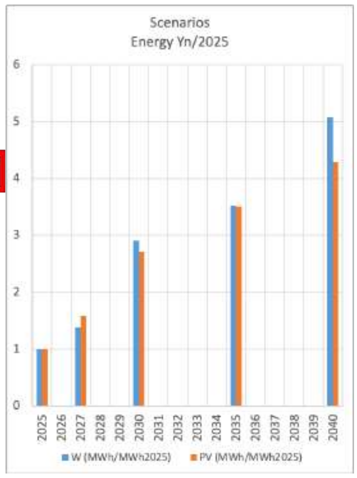
In light of the foregoing, Italcogen conducted a study to define the role of cogeneration within the energy transition process, starting from the current situation and envisioning a system evolution structured around a series of scenarios characterized by the increasing use of non-dispatchable renewable sources.
The perspective adopted is that of an end-user—utilizing a cogeneration system to meet their energy needs—who must interact with market signals for buying and selling energy, with the electricity system's security requirements, and with the broader needs of the national economic-energy system, which aims for a decarbonized and energy-independent future.
In this context, the energy system is experiencing a progressive reduction in residual load and a steady decline in average production costs, resulting in lower energy values during periods of low residual load. The study demonstrates that generation remains an economically viable solution for the end-user; however, cogeneration must be managed flexibly. This flexibility is achievable thanks to the inherent characteristics of the technologies typically used in cogeneration plants and through integration with other technologies to form Integrated Cogeneration Systems (ICS). From the electricity system's perspective, the acceptability of cogeneration increases if it can control its exchange profile with the grid—acting as a flexible, dispatchable resource by avoiding the supply of the local electrical load it serves during periods of low residual load. At the same time, given that cogeneration is tied to specific user needs, this flexibility must be managed in alignment with the requirements of the user (the cogeneration operator).



From standard cogeneration to flexible cogeneration

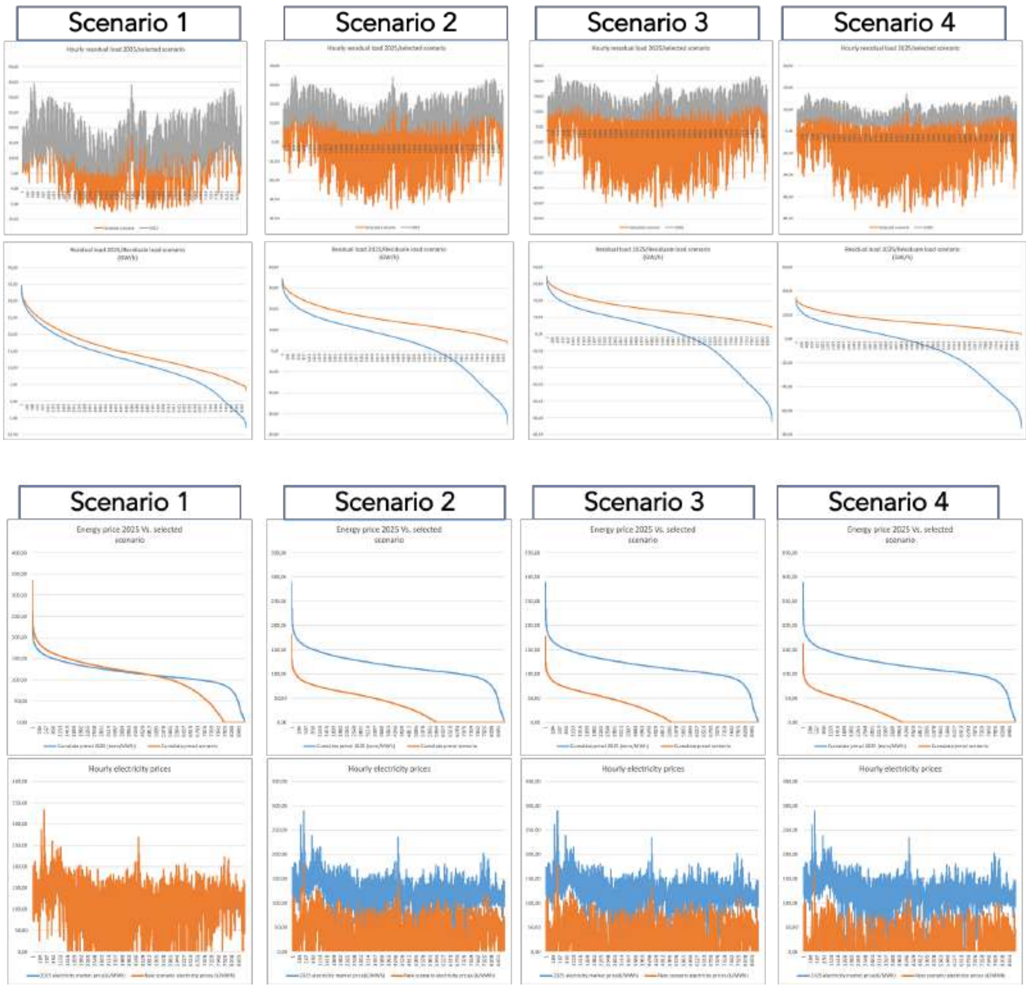
The study is based on the operating conditions of the national electricity system projected for 2025—assessed on an hourly basis—and adjusts them to reflect scenarios of increasing penetration of non-dispatchable renewable energy sources in line with PNIEC trajectories, while accounting for a plausible evolution in energy commodity prices.

Scenarios		Wind (MW)	Wind (MWh)	PV (MW)	PV (MWh)	Gas price (euro/MWh)	Wind (MW/MW2025)	Wind (MWh/MWh2025)	PV (MW/MW2025)	PV (MWh/MWh2025)
	2025	12.990	22.322	35.993	35.993	38,68	1,0	1,0	1,0	1,0
1	2027	15.823	30.800	44.173	57.000	45,00	1,2	1,38	1,2	1,58
	2028					30,00				
	2029					25,27				
2	2030	28.140	64.800	79.253	97.600	25,05	2,2	2,90	2,2	2,71
	2032									
	2033									
3	2035		78.667		126.333	24,50		3,52		3,51
	2037									
	2038									
4	2040		113.475		154.333	23,00		5,08		4,29



Considered scenarios

As the use of non-dispatchable renewable sources increases, and by leveraging the observed correlation between the reduction in residual load and the drop in zonal market prices (in the day-ahead market), it is possible to simulate market price trends for each hour across the various scenarios. These effects are clearly visible in every scenario, observed in terms of reduced residual load and lower hourly market prices—represented via annual cumulative curves (in the study, market prices were set to zero whenever they turned negative).



Annual cumulative curves of residual load and market price as the use of non-dispatchable renewable sources increases

Under such conditions, the electricity system:

- would continue to require adequate resources for security management (reserve margins, balancing, and grid congestion management in response to system contingencies)—a task facilitated by maintaining a residual load capable of supporting the operation of sufficient rotating resources;
- yet, at the same time, it would still be necessary to minimize the need to curtail renewable energy generation.

From the consumer's perspective, a cogeneration plant—which under normal operating conditions would supply electricity and thermal energy to the end-user at its own production cost (see table below)—faces a choice if the market price drops below that production cost: either continue supplying the load via the cogeneration plant or shut down the plant and purchase electricity from the grid, while bearing in mind that the production process still requires a thermal load to be met.

CHP production parameters (CHP ON - Thermal driven)			
Useful life of investment (years)	10		
Operation hours (h/year)	4.848		
	Electricity	Thermal	Total
Rated power (kW)	500		
Yield	0,28	0,42	
Energy production	2.215.300	4.430.600	6.645.900
Gas supllied form grid (kWh)	2.637.262	5.274.524	7.911.786
Gas supply expense (€/year)	160.873	321.746	482.619
Maintenance costs			
(€/kW)	300		
(€/anno)	50.000	100.000	150.000
Investment costs			
(€/kW)	1.000		
(euro)	166.667	333.333	500.000
Production cost (LOCE)			
(€/kWh)	0,09519	0,10271	
(€/MWh)	95,19	102,71	84%

(Example of electricity and thermal energy production costs via cogeneration for a 500 kW plant – costs and parameters based on Scenario 1)

The aforementioned transition also offers the end customer the possibility of managing their own production operations on a daily basis; however, experience suggests that adjusting production cycle schedules daily is not always straightforward or readily feasible. This is because such adjustments depend on numerous external variables—such as logistics, overall production planning, or simply personnel management. These factors introduce further considerations, as the temporal management of production—while complex—is a topic that could offer interesting avenues for future development.

The study was conducted based on three average plant sizes, designated as follows:

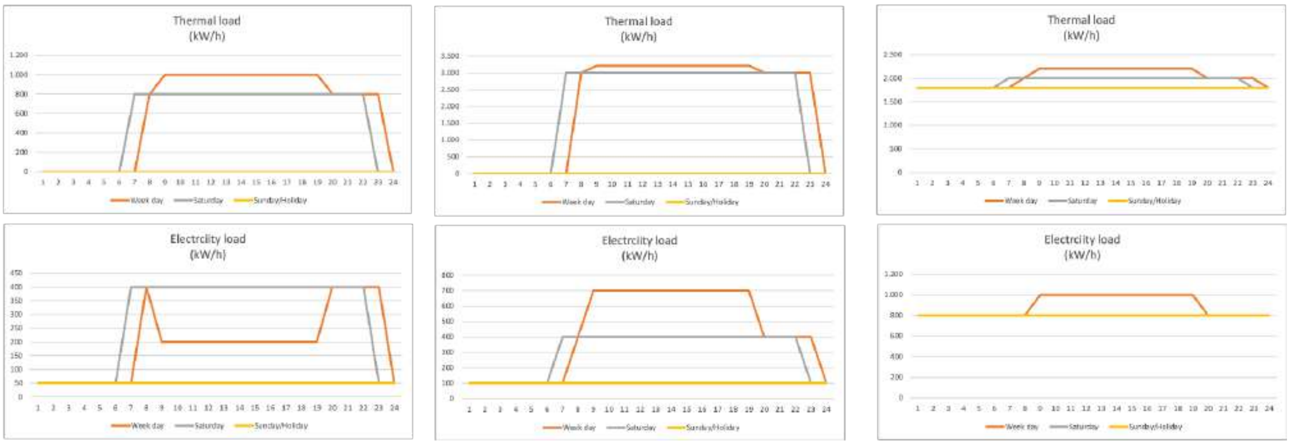
- “micro”: 500 kWe;
- “medium”: 1,500 kWe;
- “large”: 5,000 kWe.

Daily load profiles were similar for the first two cases, whereas for the “large” case, a more continuous thermal load—without overnight interruptions—was assumed.

PLANT TYPE	MICRO		
Real load profile	F1	F2	F3
Thermal load (kWt)	1.000	800	0
Electrical load (kWe)	200	400	50
Pel CHP (kW)	500		

PLANT TYPE	MEDIUM		
Real load profile	F1	F2	F3
Thermal load (kWt)	3.200	3.000	0
Electrical load (kWe)	700	400	100
Pel CHP (kW)	1.500		

PLANT TYPE	LARGE		
Real load profile	F1	F2	F3
Thermal load (kWt)	2.200	2.000	1.800
Electrical load (kWe)	1.000	800	800
Pel CHP (kW)	3.000		



In scenarios involving high-temperature thermal loads—for which no large-scale, commercially available alternative technology yet exists—the end user would essentially be forced to meet their thermal energy needs by generating high-temperature thermal energy via a supplementary boiler or an electric system.

The study demonstrates that shutting down cogeneration when the market price falls below the cost of generating electricity via cogeneration results in:

- an increase in the average annual cost of cogeneration-based production for the energy supplied under such conditions;
- a loss of local and systemic efficiency in electricity and thermal energy production, as the energy no longer produced via cogeneration would instead come from production cycles that are, overall, less efficient;
- a loss of avoided emissions associated with the energy not produced via cogeneration, given that there is no guarantee the replacement energy would yield an equivalent reduction in emissions.

As an alternative to shutting down cogeneration when the market price is lower than the internal production cost, the study considers the use of storage technologies—primarily electrical—to store the entire electricity output. This approach ensures that the cogeneration system not only avoids feeding surplus electricity into the grid during periods that would otherwise trigger a shutdown, but also allows the internal electrical load to be powered by the grid during those times; this contributes to increasing the residual load, thereby facilitating the integration of ever-growing amounts of electricity generated from non-dispatchable renewable sources. The stored electricity could then be used during hours when the market price rises above the internal production cost—a scenario typical of times when electricity generation from non-dispatchable renewable sources decreases. It should be noted that, in such a case, local cogeneration would continue to operate, thereby ensuring the maintenance of production efficiency levels, the volume of avoided emissions, the generation of white certificates for the energy efficiency market, and system inertia, while also enabling active participation in the dispatching services market.

Simulating local electricity storage during periods of low residual load is an approach that could be replaced by directing internally generated electricity toward other locally installed decarbonization technologies—such as hydrogen production (to serve as an input for the cogeneration process itself, thereby reducing emissions[9]) or heat generation via power-to-heat technologies that complement the thermal output of the cogeneration system. As is well known, local integration—facilitated by the development of "Simple Production and Consumption Systems" (SSPC) under current, fully established regulations[10]—allows for the cost-effective use of internally generated electricity compared to purchasing power from the grid[11].

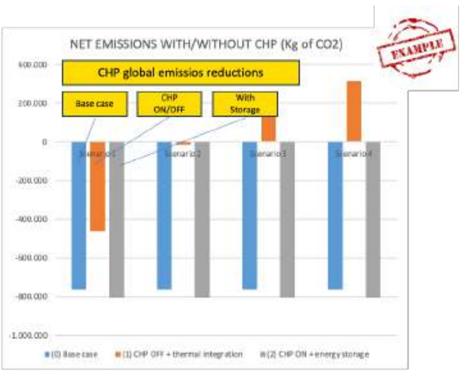
All of the above leads to the conclusion that the future of cogeneration must be viewed in the context of integrated systems, requiring new approaches to sizing, design, and management.

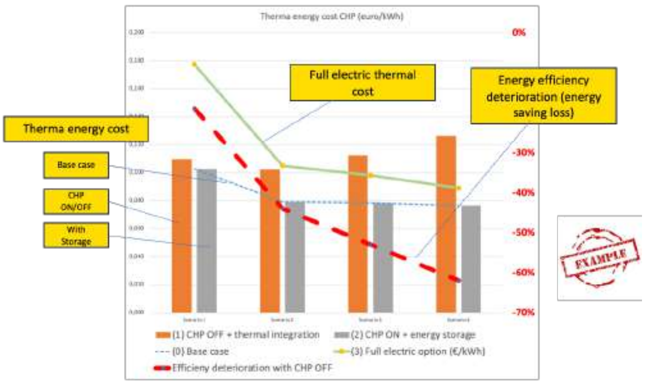
The study measures, for each scenario and case study:

- the cost of procuring energy carriers for the consumer to meet their energy needs;
- the reduction in CO2 emissions across the various operating scenarios (noting that, for a given amount of energy supplied to the user, cogeneration enables CO2 emission savings linked to primary energy savings) [12];
- the cost of thermal energy for the end-user across the various operating scenarios, including a comparison with a full-electric thermal alternative;
- the loss in conversion efficiency, calculated as the difference in primary energy savings (PES) between intermittent cogeneration use and continuous cogeneration use (achieved through the integration of storage technologies or local electricity utilization).

Leading to the conclusion that:

- the optimal condition for managing flexibility is one that utilizes thermal storage, thereby allowing the cogeneration system to continue providing thermal service to the user;
- this consistently represents the superior option in terms of:
  - maintaining system efficiency;
  - reducing emissions;
  - for the scenarios of greatest interest (2 and 3), the all-electric alternative would prove (almost) never to be competitive compared to flexible cogeneration with storage (or other local applications yielding overall effects similar to storage).

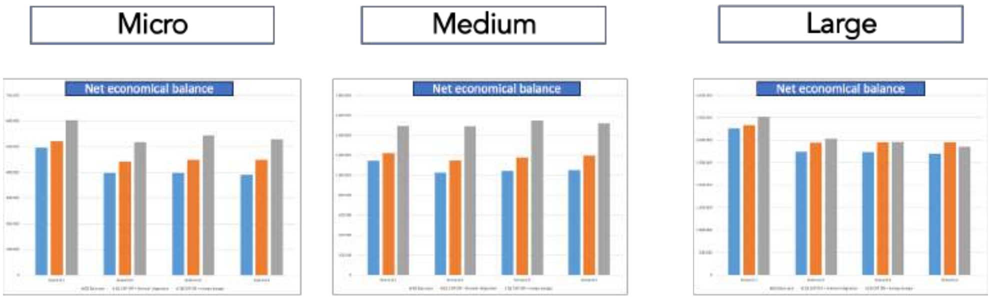




---

[9] It should be noted that currently available cogeneration technologies allow for the direct use of significant quantities of hydrogen—mixed with methane gas (which itself can be either natural or biological)—without requiring technological modifications.
[10] Decreto Legislativo 8 novembre 2021, n. 210
[11] https://www.arera.it/atti-e-provvedimenti/dettaglio/13/578-13
[12] Regarding the supply component from the electricity grid and the natural gas system, the economic terms of the current tariff structure have been applied.

360
However, flexibility comes at a cost to the user: the net economic balance deteriorates as the magnitude of flexibility increases—driven by scenarios with ever-higher penetration of non-dispatchable renewable sources (the base case represents pure thermal operation, simply following load without any flexibility in electricity exchange with the grid).



Naturally, the cost of flexibility depends on the costs of integration technologies (supplementary boilers, electrical storage, thermal storage, or other technologies for local use of internal generation via conversion into other energy carriers). Gas price trends also play a decisive role across the various scenarios, although the relative cost differences between operating modes within each specific scenario generally remain consistent.

In summary, the study indicates that—excluding the option of using heat pumps or other technologies not yet widely available commercially as alternatives to cogeneration—an all-electric approach to heat production would be less cost-effective than cogeneration (except in extreme cases).

At the same time, the study demonstrates that—in order to introduce flexibility into cogeneration—choosing to neither supply the internal electrical load nor feed power into the grid when the market electricity price falls below the internal generation cost, or opting to shut down the cogeneration unit and use supplementary combustion sources rather than maintaining cogeneration operations integrated with storage (electrical or thermal):

- is invariably uneconomical for the customer;
- consistently worsens overall system performance in terms of primary energy savings and avoided emissions.

S.12 The analyses highlight the value of energy efficiency achieved through system-oriented flexibility, which, however, introduces new cost elements for the installed "integrated" cogeneration system. This raises the question of how to cover these additional costs in light of the flexibility value provided by the solutions under study. One possible approach would be to grant a premium on the White Certificates issued upon verification that flexibility conditions have been met. In this regard—and considering that cogeneration must primarily meet production-related energy needs—the exercise of flexibility should remain voluntary for the user, supported by a measurement system capable of determining the actual level of flexibility provided to the grid. Is this solution considered appropriate?

S.13 As an alternative to the approach outlined above—specifically in cases where flexibility entails shutting down the cogeneration plant under certain market conditions (while acknowledging the resulting inefficiencies)—support for cogeneration would need to be linked to the need to cover fixed production costs through the inclusion of a capacity premium component. Is the current capacity market considered an adequate mechanism to address this requirement?

S.14 Alternatively, what mechanism could be introduced to reward flexible cogeneration capacity? What further modifications or additions to current support mechanisms could be adopted?

The assessments in question refer to a cogeneration solution based on an internal combustion engine. Similar considerations could be applied to other cogeneration technologies. You are invited to provide information and suggestions for potentially extending the study to include other cogeneration technologies.

Considerations regarding operational mechanics in relation to market price

The cogeneration management logic adopted in this study warrants further examination to realistically assess the options available to consumers for meeting their energy needs in a manner that ensures cost-effectiveness and long-term stability.

In this regard, it should be noted that, for a consumer, the cost of electricity must account for the entire supply chain and the services required for the actual delivery of electricity for end-use. This means that the market price determined by the exchange is, in principle, only one component of the final price paid by the customer; all other elements contributing to the final cost must be added to it. Consequently, one must consider the user's cost for full access to electricity, which includes expenses related to grids, balancing, and adequacy (as well as system costs).

Furthermore, while a consumer’s production scheduling can take into account the hourly fluctuations of the commodity component (i.e., the day-ahead market energy price), this option is often limited. It cannot be adopted as a long-term procurement strategy, given that such price trends cannot be predicted with certainty over the long term. Therefore, end customers tend to procure energy by fixing the price through medium- and long-term contractual instruments (such as long-term contracts or Power Purchase Agreements).

Currently, commodity pricing structures involving negative prices still exist; however, the only way to capitalize on such conditions is by accessing additional market segments (such as ancillary service markets). This approach does not constitute a primary business activity for a typical customer, and the methods for managing energy needs—and deriving value from that management—require significant further development at the system level. It is therefore necessary to compare, based on realistic criteria, the option of self-supplying electricity via cogeneration against the option of meeting both electricity and thermal needs solely through electricity drawn from the grid. Given that the electrification process demands an ever-increasing supply of electricity—specifically, renewable electricity—the first step in ensuring consistency is to consider:

- for the electrified solution, the user's total cost chain for actually usable renewable electricity;
- for the cogeneration solution, in addition to the factor mentioned above, the fact that—much like renewable electricity—self-generated energy (both electrical and thermal) must also be derived from renewable sources (decarbonized cogeneration) [13].

S.15 Do you agree with the views expressed regarding the relationship between wholesale market price dynamics and the actual impact on consumers? What other factors should be taken into account when assessing the costs consumers will face in connection with the energy transition (e.g., costs for system adequacy mechanisms such as capacity payment schemes or storage management, and dispatching/balancing costs)?

S.16 What further assessments could be carried out regarding dispatch costs and their impact on consumers?

To this end, a general business case was analyzed to compare the cost of carbon-free electricity production via cogeneration, assessing whether such self-generated energy is competitive with sourcing renewable electricity from the grid.
To evaluate the cost of carbon-free electricity production via cogeneration, the following factors based on the current situation were taken into account:

- current gas prices;
- gas grid and system charges;
- the CO2 compensation cost for gas usage, calculated using the cost of a Guarantee of Origin linked to the average value of CO2 emission allowances;
- the average value of system charges for the first two quarters of 2026[14].

Under these conditions, the economic parameters for the on-site cogeneration of electricity and thermal energy are presented in the table below.

[13] Si faccia riferimento anche al successivo paragrafo 8 del presente documento.
[14] Ipotesi a favore dell'elettrificazione dal momento in cui gli effetto del recente decreto bollette del 2026 hanno comportato un abbassamento degli oneri di sistema specialmente nel secondo trimestre 2026.

Prezzo gas (€/MWh)	50
Oneri rete e sistema gas (€/MWh)	16
Compensazione emissioni (€/MWh)	15
Prezzo gas prelevato da rete (€/MWh)	**81**

CHP production parameters (CHP ON - Thermal driven)			
Useful life of investment (years)	10		
Operation hours (h/year)	OFF		
	Electricity	Thermal	Total
Rated power (kW)	500		
Yield	0,30	0,40	
Energy production	2.215.300	4.430.600	6.645.900
Gas supllied form grid (kWh)	2.461.444	4.922.889	7.384.333
Gas supply expense (€/year)	199.377	398.754	598.131
Maintenance costs			
(€/kW)	300		
(€/anno)	50.000	100.000	150.000
Investment costs			
(€/kW)	1.000		
(euro)	166.667	333.333	500.000
Production cost (LOCE)			
(€/kWh)	0,11257	0,12009	eta tot
(€/MWh)	112,57	120,09	90%

Consequently, the electricity procurement cost for the end customer would be as indicated below.

Autoconsumo	SI
Potenza (kW)	1.000
Prelievo annuo (kWh)	1.000.000
Perdite	5,0%
Costo acquisto EE da rete (€/kWh)	0,054
Costo produzione on-site (€/kWh)	0,113
Costo compesansione emissioni (€/kWh)	0,02

			TOTALE ONERI E RETE			Dispacciamento	Mercato Capacità	Energia
			Quota fissa	Quota potenza	Quota energia	Quota energia	Quota energia	Quota energia
			euro/punto di prelievo/anno	euro/kW per anno	euro/kWh	euro/kWh	euro/kWh	euro/kWh
Tipologia di utenza	MTA2	Altre utenze in media tensione con pote	1270,888	51,4745	0,047845	0,01	0,005	0,1126

Corrispettivi unitari energia elettrica da rete			Quota risparmio autoconsmo (SCSi)
Quota fissa	Quota potenza	Quota energia	Quota energia
euro/punto di prelievo/anno	euro/kW per anno	euro/kWh	euro/kWh
1270,888	51,4745	0,175415307	0,062945

Quota fissa	Quota potenza	Quota energia
€/anno	€/anno	€/anno
1.270,89	51.474,50	112.570,31

Costo finale energia elettrica	**165.315,69**
Autoapprovigionamento	

If the same energy requirement were met using electricity from the grid, the final cost to the customer would be as follows.

Autoconsumo	NO
Potenza (kW)	1.000
Prelievo annuo (kWh)	1.000.000
Perdite	5,0%
Costo acquisto EE da rete (€/kWh)	0,054
Costo produzione on-site (€/kWh)	0,113
Costo compesansione emissioni (€/kWh)	0,02

			TOTALE ONERI E RETE			Dispacciamento	Mercato Capacità	Energia
			Quota fissa	Quota potenza	Quota energia	Quota energia	Quota energia	Quota energia
			euro/punto di prelievo/anno	euro/kW per anno	euro/kWh	euro/kWh	euro/kWh	euro/kWh
Tipologia di utenza	MTA2	Altre utenze in media tensione con pote	1270,888	51,4745	0,047845	0,01	0,005	0,0540

Corrispettivi unitari energia elettrica da rete			Quota risparmio autoconsmo (SCSi)
Quota fissa	Quota potenza	Quota energia	Quota energia
euro/punto di prelievo/anno	euro/kW per anno	euro/kWh	euro/kWh
1270,888	51,4745	0,116845	0,062845

Quota fissa	Quota potenza	Quota energia
€/anno	€/anno	€/anno
1.270,89	51.474,50	122.687,25

Costo finale energia elettrica Approvvigionata da rete	175.432,64

While all previously stated considerations regarding thermal energy remain unchanged, the simulation demonstrates that supply via decarbonized on-site cogeneration would be even more cost-effective than sourcing renewable electricity from the grid (see the table below).

Da rete (cost from grid €/year)	175.433	
Autoconsumo (cost from self-consumption €/year)	165.316	-5,8%

It should be noted that this balance refers solely to the procurement of electricity from the grid, without accounting for the potential capital and operating costs of alternative high-temperature heat generation systems—other than concentrating systems—that would need to be installed locally at the point of consumption[15]. That said, to project such an assessment into the future while maintaining the same conclusions, the following considerations must be taken into account.

-
- Grid costs and general electricity charges are likely to rise to accommodate power system developments driven by increasing decarbonization and the costs associated with expanding renewable electricity sources.
- Dispatching and balancing costs—even if optimized—will remain significant, given that the growth of renewable electricity relies primarily on non-dispatchable sources; these require substantial management costs to control the profile of generation fed into the grid.
- Long-term natural gas prices are still projected to fall, despite the current geopolitical situation; however, this reduction must be weighed against rising gas system charges linked to sector decarbonization plans (incentives for biomethane and renewable hydrogen) and the increased costs of securing decarbonized gas supplies—driven by the expected rise in emission allowance prices, which are reflected in the value of Guarantees of Origin.

In light of the above, it is evident that—contrary to the prevailing narrative—cogeneration is not merely a "bridge technology." Under specific conditions, it can serve as a stable solution for efficiently meeting an end-user's energy needs (particularly where there is a specific demand for thermal energy) while ensuring high efficiency and full decarbonization.

[15] This means that, at present, extraordinary support measures would still be required for the use of such technologies. Breakdown of gross distributed generation (DG) output into electricity fed into the grid and electricity consumed on-site (for plants powered by renewable sources, non-renewable sources, and municipal solid waste, as well as for hybrid plants).

S.17 The current analysis proceeds from the assumption that the electrification process is being carried out while maintaining the existing tariff structure for electricity grid transport services and the current methods of recovering system charges—specifically through tariff components applied as surcharges and via electricity transport service charges. It is evident that any future scenarios regarding the application of such charges to support electrification—scenarios currently unknown—could significantly alter the overall picture and the resulting conclusions. Any legislative or regulatory intervention in this area should, however, adhere to the general principles of efficiency and cost minimization for consumers. It must also address how the various grid and system costs—which would persist and, in all likelihood, could even rise in absolute terms compared to current levels—are distributed among different categories of users. In light of the foregoing, what further considerations might be made?

S.18 The analyses performed do not take into account the potential for participating in markets for dispatching services under the new arrangements introduced by recent European regulations—implemented in Italy via the Integrated Text on Electricity Dispatching (TIDE). The study demonstrates that cogeneration allows for flexible management of the electricity exchange baseline with the grid based on market price fluctuations (while continuing to supply thermal energy to the user in the required quantities and according to necessary specifications). Cogeneration would thus offer an additional opportunity to provide modulation services by varying the reference baseline. From the consumer's perspective, is this approach to managing cogeneration considered attractive? What challenges are identified? What further elements need to be developed to effectively utilize cogeneration for the provision of services to the electricity system?

7. Cogeneraiton and guarantees of origin

The issuance of Guarantees of Origin (GOs) for (high-efficiency) cogeneration plants is currently governed by the conditions set out in Article 16 of the Decree of the Minister of the Environment and Energy Security No. 224/2023 of 14 July 2023.

In general, for a cogeneration plant fueled by renewable sources[16] [17], the producer may request, alternatively:
a) the issuance of GOs for energy production from renewable sources;

Where GOs are issued for energy production from renewable sources, GOs may be issued for both thermal energy production and electricity production, each separately identified with the high-efficiency cogeneration attribute. In the event that biomethane drawn from the grid is used to produce cogenerated electricity and thermal energy, High-Efficiency Cogeneration (CAR) plants may be qualified for the purpose of GO recognition; consequently, the use of biomethane must be certified through the cancellation of an equivalent number of GOs issued for biomethane production.

b) the issuance of GOs for electricity produced via high-efficiency cogeneration (it is noted that electricity from high-efficiency cogeneration—including that from non-renewable sources—is eligible for the issuance, upon the operator's request, of a Guarantee of Origin for electricity from high-efficiency cogeneration).

The Guarantee of Origin for electricity from high-efficiency cogeneration, issued by the GSE, corresponds to a standard quantity of 1 MWh and relates to net energy production measured at the plant boundaries and transferred to the grid; it may be issued only if the annual electricity from high-efficiency cogeneration is no less than 50 MWh, rounded according to commercial practice; b) it may be used by the producers to whom it is issued to demonstrate that the electricity they sell is produced via high-efficiency cogeneration;
c) it is issued subject to verification of the reliability of the data provided by the applicant and their compliance with regulatory provisions;
d) if issued in other European Union Member States, it is also recognized in Italy, provided that the guarantee of origin in question includes all the elements set out in Annex 5 and originates from countries that adopt instruments for promoting and incentivizing high-efficiency cogeneration similar to those in force in Italy and that grant the same possibility to plants located in Italy, based on agreements concluded between Italian authorities and the competent authorities of the foreign country from which the high-efficiency cogeneration electricity is imported.

It should be noted that Guarantees of Origin (GOs) are also issued in relation to production from renewable sources by plants included in projects that qualify for white certificates.

---

[16] Obviously, in the case of cogeneration from new renewable sources, the information set out in letter (b) applies.
[17] For high-efficiency cogeneration plants fueled by renewable sources and connected to district heating and/or district cooling networks, Guarantees of Origin (GOs) may be issued for both energy carriers produced (Art. 16, paragraph 3 of the GO Decree). Consequently, there is an entitlement to the issuance of GOs for both thermal energy production and electricity production. This option is not available to producers requesting the issuance of GOs for electricity produced via high-efficiency cogeneration as referred to in Article 10, paragraph 1, of Legislative Decree no. 102 of 2014 (Art. 16, paragraph 2). In this regard, it should be noted that for high-efficiency cogeneration (CAR) plants, it is possible to certify electricity production from high-efficiency cogeneration; where the CAR plant is fueled by renewable sources (typically biomass), it is possible to:
- request the issuance of a certificate for electricity production from high-efficiency cogeneration; or
- request the issuance of GOs for electricity production from renewable sources with a high-efficiency cogeneration (CAR) attribute and/or for thermal energy production from renewable sources.

S.19 Is it considered that cogeneration guarantees of origin can have real value for consumers?

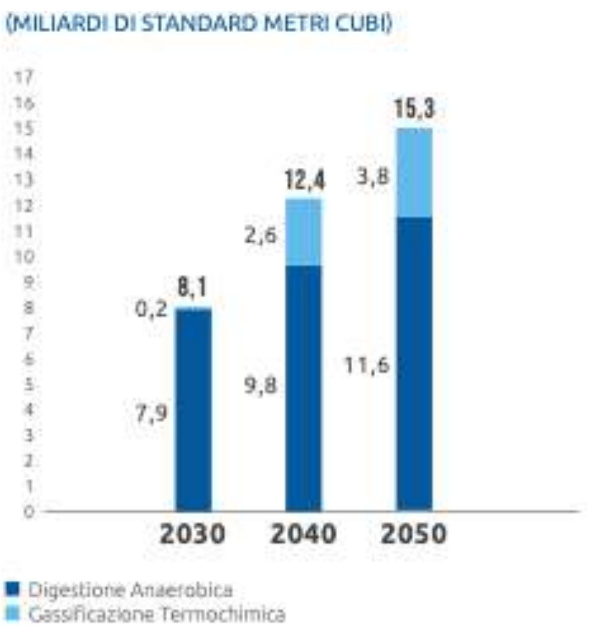
S.20 What further considerations should be addressed regarding guarantees of origin for high-efficiency cogeneration?

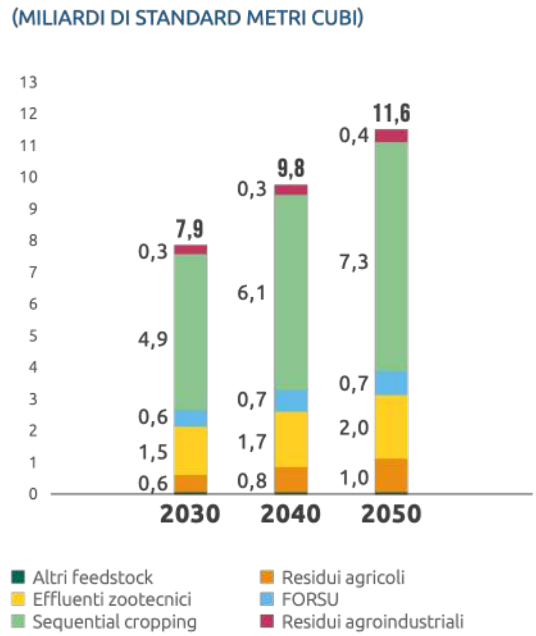
8. Cogeneration and renewable sources

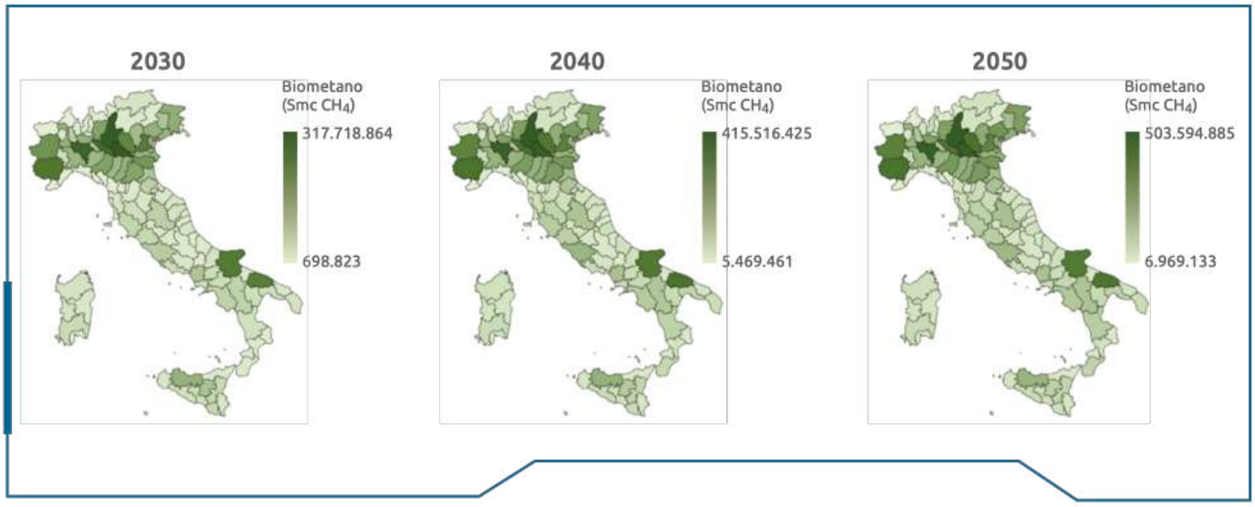
Based on assessments conducted by Italcogen, natural gas consumption for cogeneration appears to be approximately 7 billion standard cubic meters (Smc) per year. As previously noted, current cogeneration systems are already capable of fully utilizing biomass, biogas, and biomethane, as well as hydrogen—albeit within certain limits—when blended. Consequently, there is a need to promote the use of renewable sources, given that their application in cogeneration represents the most efficient way to utilize these resources, which are scarce within the system.

Regarding renewable gas (biomethane) in particular, a recent joint study by the Italian Biogas Consortium (CIB) and Snam S.p.A. [18] has identified Italy's biomethane production potential, breaking the data down by province.

[18] Cfr. https://consorziobiogas.it/wp-content/uploads/2026/05/SnamCIB-Il-potenziale-del-biometano-nelle-province-italiane-1.pdf







Key findings of the joint CIB-SNAM study

S.21 In light of the foregoing, prioritizing the use of biomethane and other renewable sources for cogeneration is considered fundamentally important. Is this proposal supported?

S.22 What further considerations should be made regarding the relationship between cogeneration and renewable sources?

9. Summary of proposals for the development and decarbonization of distributed electricity and heat generation

The analyses conducted above demonstrate that cogeneration can still represent a viable method for managing locally distributed primary energy, supporting cost-effective supply for end-users with specific needs (particularly high-temperature thermal energy) and efficient use of primary sources—especially when those sources are renewable (with particular reference to biomethane and renewable hydrogen). At the same time:

- new and projected operating conditions for the national electricity system mean that cogeneration must fulfill its role while integrating with these new conditions; this entails the emergence of cogeneration systems integrated with active energy management technologies, ensuring that distributed, on-site production methods remain sufficiently flexible throughout the day. Beyond the baseline flexibility dictated by market conditions, these integrated cogeneration systems can provide additional flexibility resources within dispatching service markets;
- under recent European directives, the definition of high-efficiency cogeneration includes an environmental/emissions component that must be managed alongside the calculations required to determine high-efficiency status within a flexible cogeneration management regime;
- users—who must maintain cost-effective supplies—are increasingly required to demonstrate the sustainability of their goods and services production, leading to a growing demand for renewable heat and electricity.

Developing cogeneration solutions—which, in principle, represent a highly beneficial option for both consumers and the system—requires a new perspective on the tools available to the market. For this reason, the following solutions are proposed:

a. Judiciously apply the principles of the new Energy Efficiency Directive regarding the linking of high-efficiency status to emission limits. For this reason, Italcogen has actively promoted an initiative within the CTI (Comitato Termotecnico Italiano, member of UNI) to define shared rules for calculating emissions—rules that could be utilized during the process of recognizing High-Efficiency Cogeneration (CAR) status. In this context, Italcogen also proposes introducing a new coefficient to characterize the emissions avoided by cogeneration systems.

b. Flexibility is a key feature of modern cogeneration systems, requiring them to integrate with new technologies; this entails new costs and management methods that must be duly considered within support schemes and the criteria for recognizing CAR status, respectively.

c. Maintain and develop the White Certificate system to avoid undermining the market's supply side, while acknowledging that energy efficiency is taking on an added dimension of flexibility, leading to the concept of "flexible energy efficiency."

d. Alongside—or as an alternative to—potential flexibility premiums, consideration could be given to an incentive system based on installed capacity made available to meet user needs while simultaneously offering the flexibility required for the increasing integration of non-dispatchable renewable sources into the system.

e. Encourage the development of dispatchable resource offerings from users who integrate cogeneration into their production of goods and services.

f. Foster a genuine market for Guarantees of Origin regarding electricity and heat produced by high-efficiency (renewable) cogeneration systems.

g. Given the efficiency with which cogeneration systems utilize primary energy sources, it is advisable to provide support mechanisms and usage priority for renewable sources (biomethane and renewable hydrogen) in high-efficiency cogeneration—whether at decentralized locations or at the production site of the renewable energy carriers (e.g., efficient local use of biogas).

S.23 Is the list of topics identified to foster the efficient use of primary resources through cogeneration considered exhaustive? What additional elements could be identified, and what further proposals could be put forward?

In addition to the foregoing—which forms the framework for a broad-scope, medium- to long-term initiative—it is considered essential not to miss the opportunity to promote the efficient use of primary resources through cogeneration, leveraging the budgetary flexibility granted for energy investments during the 2026–2028 period. To this end, a measure should be introduced to provide capital-account recognition of costs incurred for installing new cogeneration systems and/or refurbishing existing high-efficiency cogeneration systems designed for self-consumption, provided these systems are required to offer any available capacity to the dispatching services market in accordance with current TIDE regulations[19].

S.24 Is the latest proposal considered correct? What critical issues are identified, or what additional characteristics should the systems generated through such incentives possess?

[19] https://www.arera.it/area-operatori/produzione-tide

Appendix 1

For more information about cogeneration, see
https://energy.ec.europa.eu/topics/energy-efficiency/cogeneration-heat-and-power_en