Integrated cogeneration systems (ICS)

Efficiency, competitiveness and flexibility for the energy transition

23 June 2026

Italcogen

Study aims

To analyse potential operational scenarios for CHP/HE (high efficiency)-CHP in the context of the energy transition, with increasing penetration of non-dispatchable renewable energy sources

Quantify the key parameters of individual operating configurations and compare them in order to identify optimal solutions for customers with CHP systems and for the national energy system

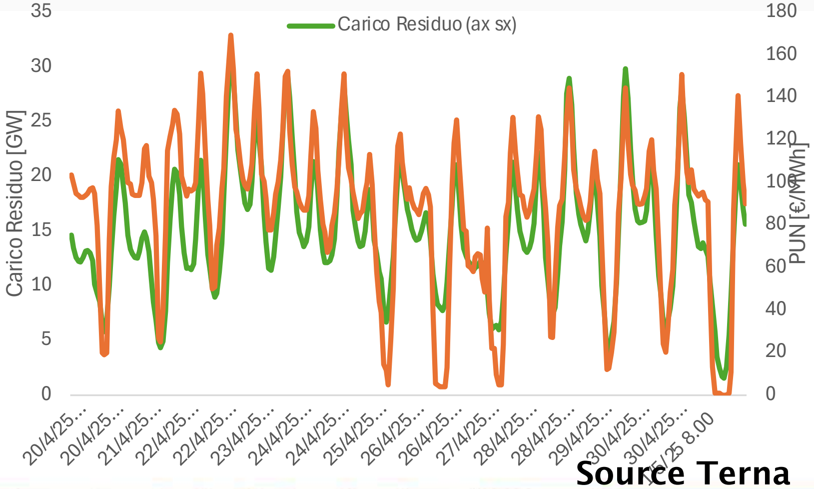
Propose a support scheme for HECHP that complements the traditional support mechanism; whilst not making modulation compulsory, it should encourage and incentivise it

A new concept of cogeneration is emerging, encompassing technologies, sources and systems that serve both the end-user and the energy system simultaneously

- It provides heat where and in ways that other sources or technologies cannot do so cost-effectively
- It supplies electricity to the end-user and the system in a flexible manner
- It helps to ensure the continuity of the electricity system's operation
- It guarantees efficiency and the lowest possible level of emissions

Market context

The period from 20 April to 1 May was characterised by public holidays with low Residual Load (RL)1, due to a reduction in electricity demand offset by high generation from renewable sources (particularly solar power during daylight hours). This phenomenon contributed to the PUN-index falling to very low levels, in some cases approaching zero during the middle of the day.
The expected gradual increase in the number of hours characterised by very low RC values (and therefore very low PUN values) will inevitably lead to growing problems regarding the economic viability of cogeneration plants, primarily affecting the least flexible ones.



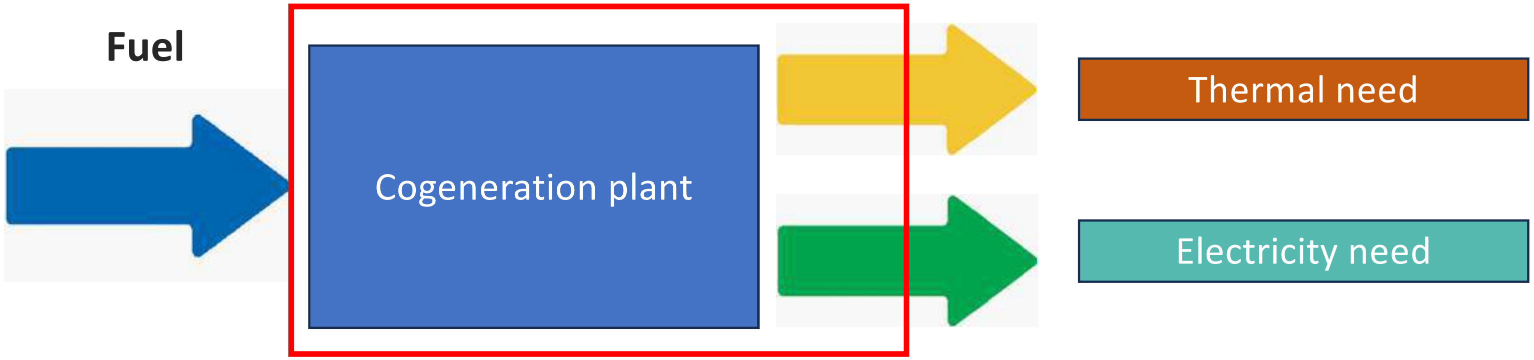
Source Terna

Assumptions

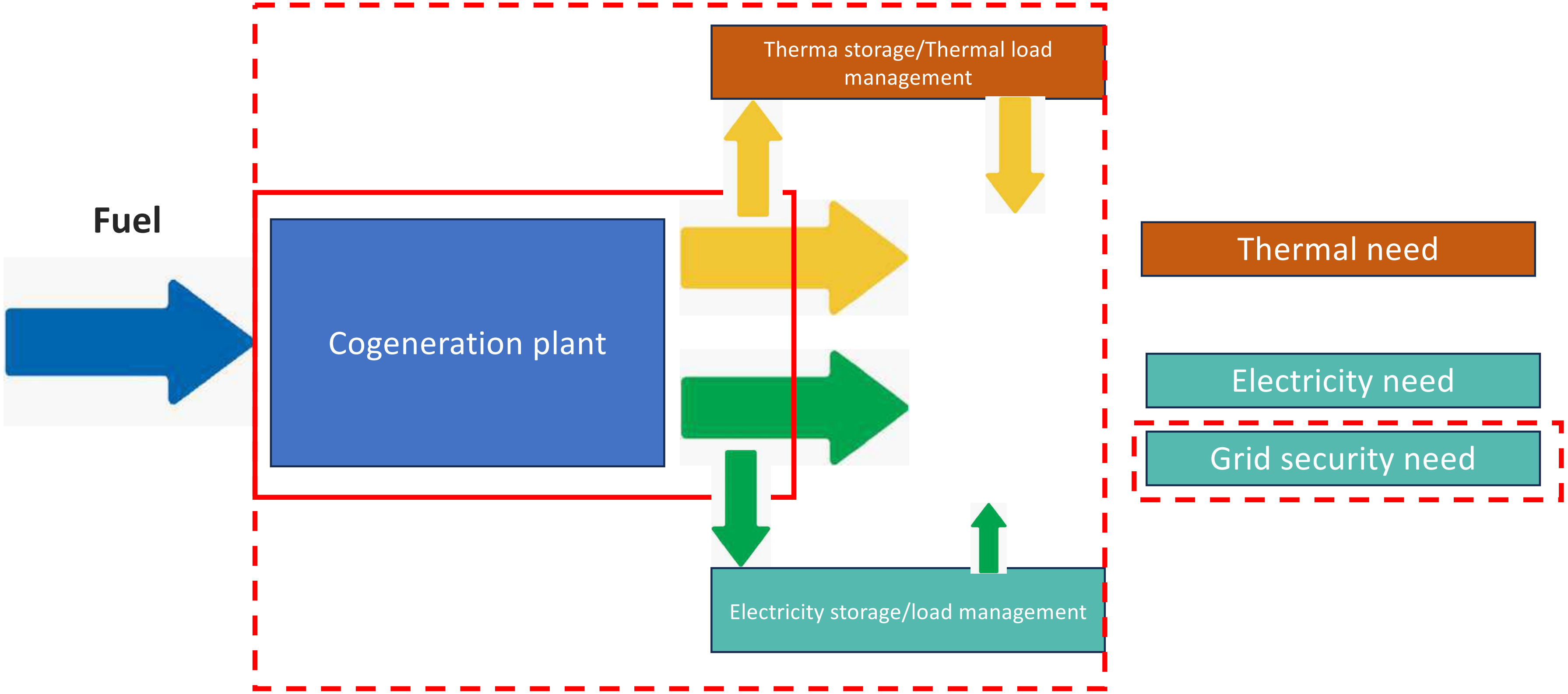
- The energy system is seeing a steady reduction in residual load and a continuous decline in average generation costs, which are leading to lower energy prices during periods of low residual load
- Cogeneration will become more widely accepted within the system if it is also able to manage its interaction with the grid, presenting itself to the system as a flexible and programmable resource
- Cogeneration can manage the baseline for electricity exchange with the grid in a flexible manner, based on market price trends (whilst continuing to supply thermal energy in the quantities and to the specifications required by the user)
- An additional option for providing modulation services by adjusting the reference baseline

Given that cogeneration is designed to meet users' needs, it is appropriate for flexibility to be determined by the user (the CHP operator) and for compliance with the general principle of flexibility – whereby the CHP plant does not meet the electricity demand during periods of low residual load – to be assessed retrospectively

Flexibility is a key requirement for the CHP sector: the current situation



Flexibility is a key requirement for the CHP sector: a changing landscape



New requirements for the HECHP – EU Directive 2023/1791 of 13 September 2023

Annex 3 "Methods for determining the efficiency of the cogeneration process" of Directive 2023/1791. The annex states that high-efficiency cogeneration meets the following requirements:

1. Production by cogeneration units yields primary energy savings, calculated in accordance with point (b), of at least 10% compared with the reference values for the separate production of electricity and heat. La produzione mediante unità di piccola cogenerazione e di miscrocogenerazione che forniscono risparmi di energia primaria può essere definita cogenerazione ad alto rendimento.

2. Where cogeneration units are constructed or substantially upgraded after the transposition of this Annex, the direct carbon dioxide emissions from fossil fuel-fired cogeneration shall be less than 270 gCO_2 per 1 kWh of energy produced through combined generation (including heating/cooling, electricity and mechanical energy).

3. Cogeneration units in operation prior to the date of entry into force of this Directive may be exempted from this requirement until 1 January 2034, provided that they have a phased emission reduction plan to comply with the threshold of less than 270 gCO2 per 1 kWh by 1 January 2034 and that they have notified that plan to the relevant operators and competent authorities.

Remarks

In summary, compared with the provisions of the previous directive, the environmental requirement set out in point 3 above has been introduced, namely emissions of less than 270 g CO_2; this requirement is automatically met if the plant has an overall efficiency, calculated according to the first-principles method as set out in Annex 2 of the new directive, of 75% or 80%, depending on the type of plant.

Again, according to Annex 2 of the new directive (as in the previous one), in the case of cogeneration units with an overall efficiency of less than 75% or 80%, it is possible to use a 'virtual plant', excluding part of the electricity produced from the calculation until a small-scale 'virtual' cogeneration setup is achieved, capable of meeting the required overall efficiency values. Historically, the EED Directive allows for the possibility of classifying a virtual plant as high-efficiency, to take account of the fact that, in industrial contexts requiring high-temperature thermal energy, even when recovering as much thermal energy as possible, it is often not possible to meet the aforementioned overall efficiency targets, and this is why the option is provided to still recognise the cogeneration system, for the proportion of combined electricity and heat production capable of meeting the CAR conditions.

A combined reading of Annex 2 and Annex 3 of the new directive it therefore emerges that, by analogy, the same rule regarding the virtual plant may also be applied to the emission limit of 270 g CO2/kWh of total energy produced, as this parameter is inextricably linked to the overall efficiency value derived from first principles (270 g CO2/kWh corresponds, in terms of overall efficiency, to a value of 75%).

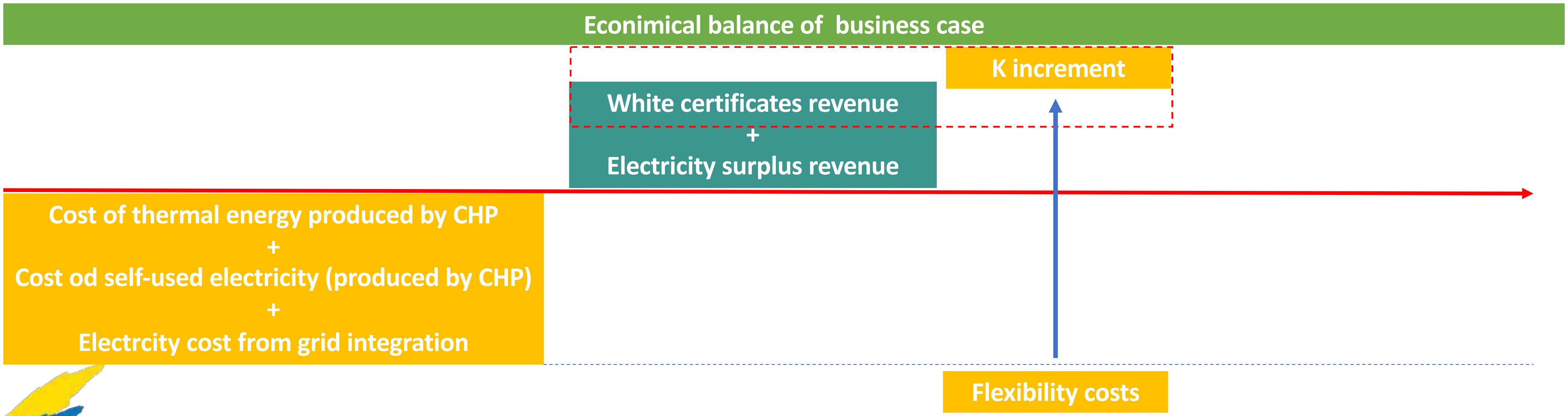
It is understood that the emissions limit for the definition of CAR is to be assessed solely in relation to high-efficiency cogeneration systems

Possible developments in the framework supporting the CAR

Directive 2023/1791 will be transposed by 2026, followed by a new decree redefining the CAR support scheme, which will amend/supplement the Ministerial Decree of 5 September 2011

- Cogeneration is required to become flexible in relation to the residual load
- The proposal to be put forward is to maintain the incentive scheme based on white certificates intact, whilst assessing the impact of increased flexibility and measuring the need to increase the K-factor to ensure the profitability of investments

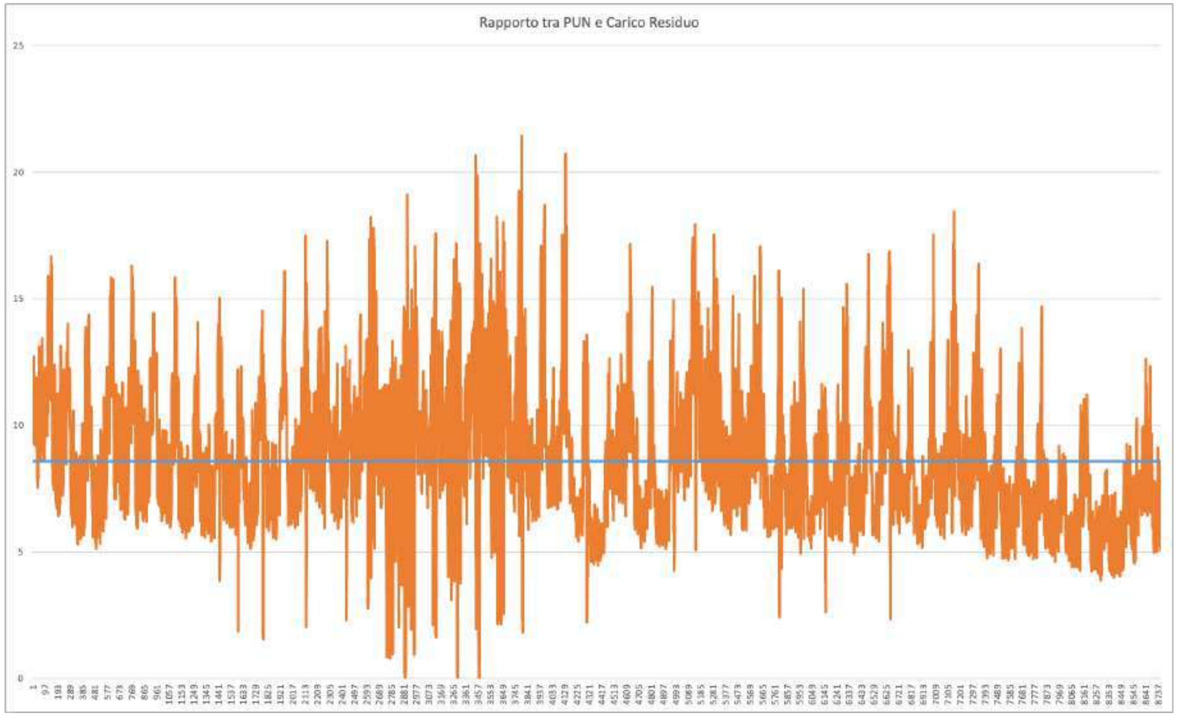
$$RISP = \frac{E_{CHP}}{\eta_{E\,RIF}} + \frac{H_{CHP}}{\eta_{T\,RIF}} - F_{CHP} \quad \Rightarrow \quad CB = (RISP*0{,}086)*K$$



The proposal is based on the principles of: simplicity, continuity, voluntary participation, and promoting flexibility

- Based on the 2025 price/volume scenario (PV 34,000 MWh)
- The relationship between RL (residual load and price trend) and RL/PUN was measured using Pearson's correlation coefficient (PC)

  - CR/PUN = 8,58
  - IP = 0,74

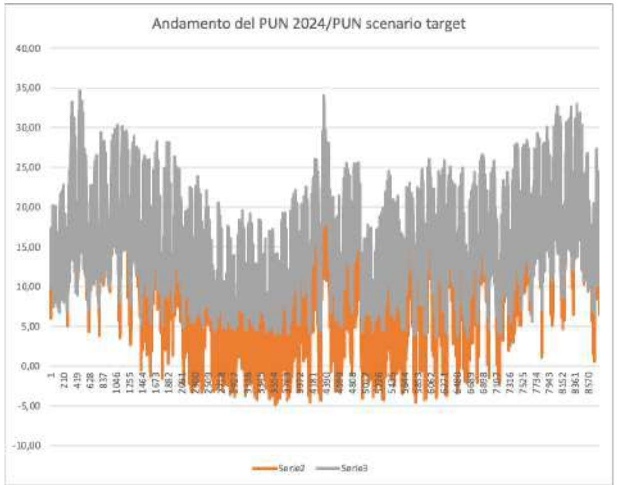


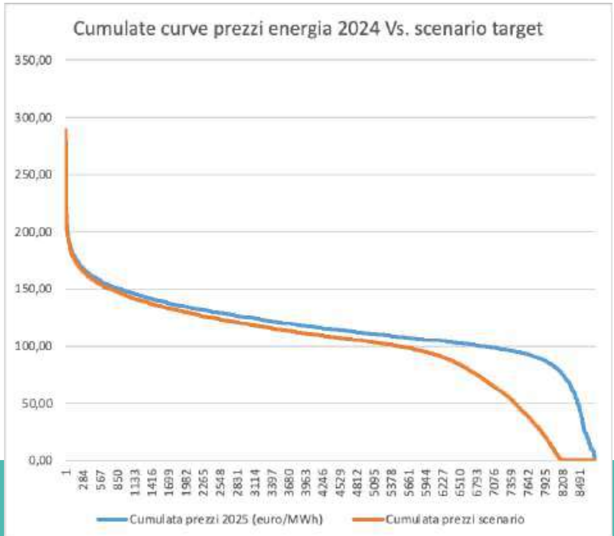
By adjusting the CR through changes in the share of renewable energy production, a new price profile is obtained

The new price profile also takes into account forecasts of changes in gas costs

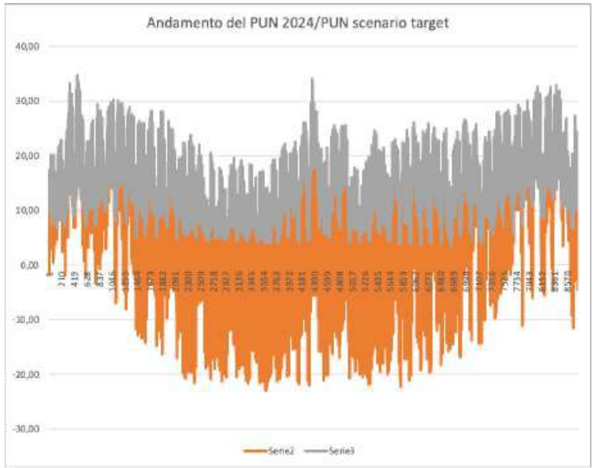
Analisi scenario (esempi)

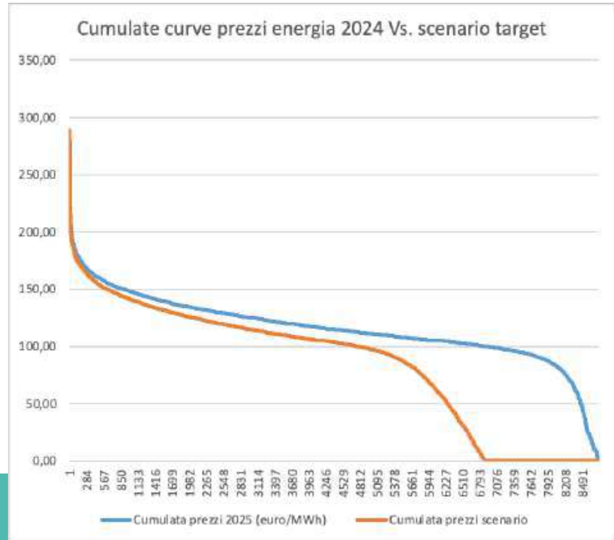
PV 2025 x 1,5 (50.000 MWh)





PV 2025 x 2,5 (85.000 MWh)

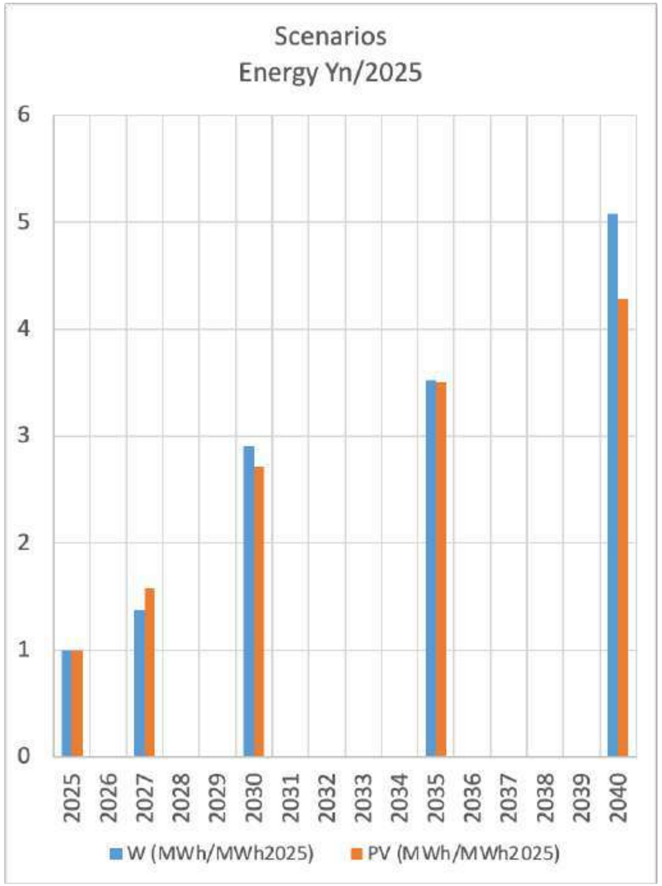




Reference scenarios

- **Scenarios derived from the PNIEC and from Terna/Snam's long-term scenarios**
- **The gas price has been incorporated on the basis of the latest average prices, which are affected by the ongoing geopolitical crisis (which primarily impacts the base case and Scenario 1)**

Scenarios		Wind		PV		Gas price	Wind		PV	
		(MW)	(MWh)	(MW)	(MWh)	(euro/MWh)	(MW/MW2025)	(MWh/MWh2025)	(MW/MW2025)	(MWh/MWh2025)
	2025	12.990	22.322	35.993	35.993	38,68	1,0	1,0	1,0	1,0
	2026					40,00				
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
	2031					25,35				
	2032									
	2033									
	2034									
3	2035		78.667		126.333	24,50		3,52		3,51
	2036									
	2037									
	2038									
	2039									
4	2040		113.475		154.333	23,00		5,08		4,29



Basic logic: defining management procedures

Simulate the base case: the heating scenario is as described. All heat is supplied by the CHP plant; the electricity generated covers internal demand, and any surplus is fed into the grid

(0) Base case

A reference scenario is established based on the production costs for heat (Prt) and electricity (Pre), and revenue assumptions for the WCs (white certificates)

The share of renewable energy is increased (residual load and market price – MP - decrease)

Conditions for activating flexibility

whnever MP < Pre two alternatives arise

- The CHP unit is switched off, the missing heat is supplied by a backup boiler
- The option of thermal storage is provided for

(1) CHP OFF + thermal integration

- The CHP plant remains operational and the electricity generated is stored so that it can be utilised (at least at Pre) during periods when MP > Pre
- In this case too, the option of thermal storage is available

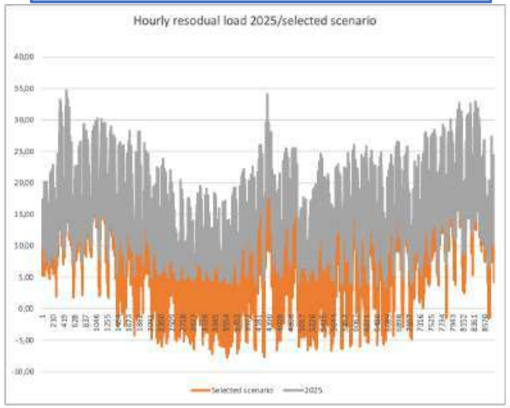
(2)CHP ON + storge

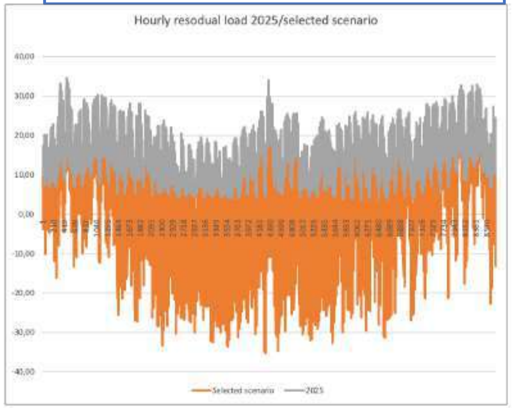
However, the cost of thermal energy is analysed in the various scenarios compared with the solution involving the generation of thermal energy using an electric resistance heater (Scenario 3), on the assumption that the PdC solution is not suitable given the requirement for heat at temperatures > 100/200 ° C

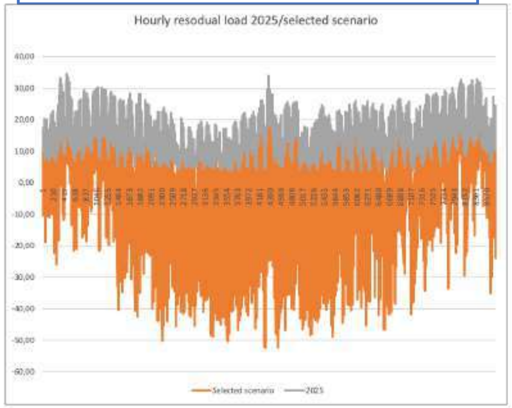
Simulations carried out on scenarios and hourly profiles using TERNA's quarter-hourly settlement data for 2025 (the reference year) and GME hourly prices

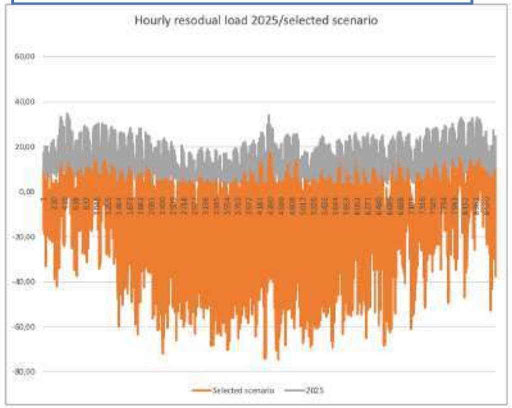
Scenarios – Residual load reduction

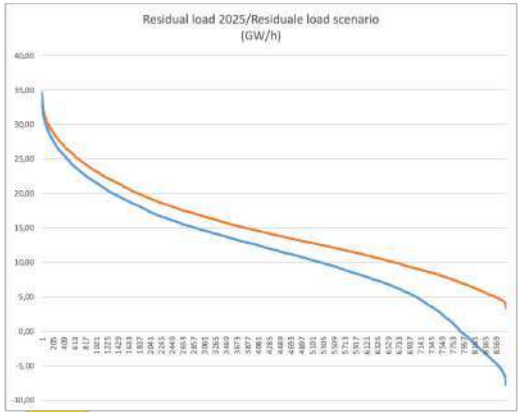
Scenario 1	Scenario 2	Scenario 3	Scenario 4

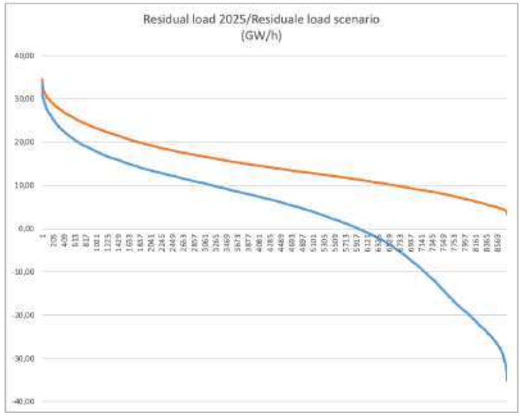


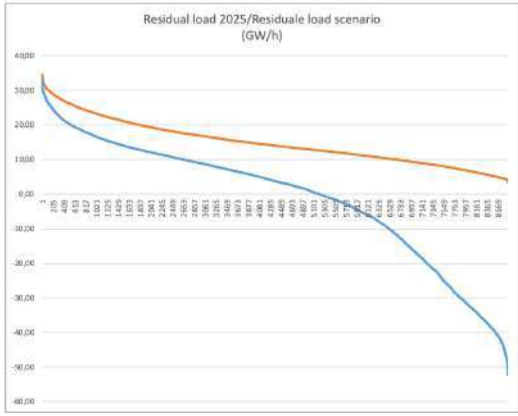


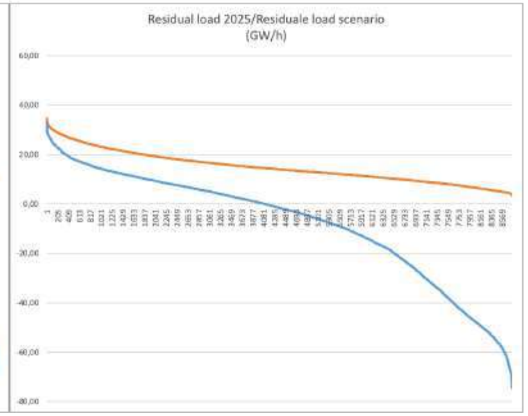






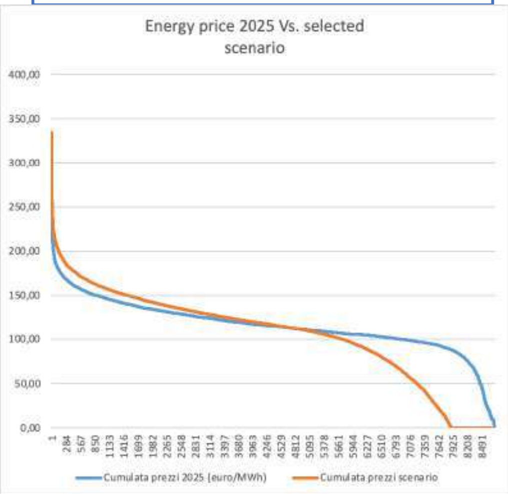


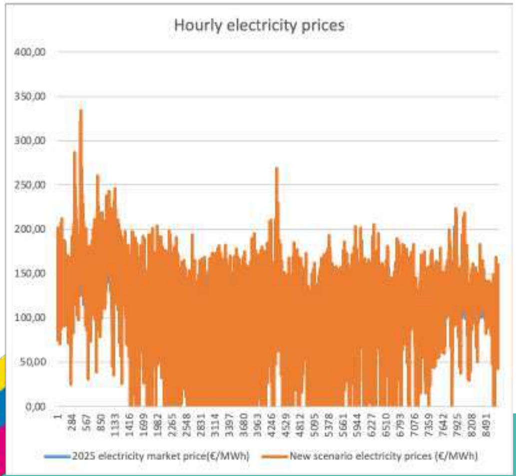




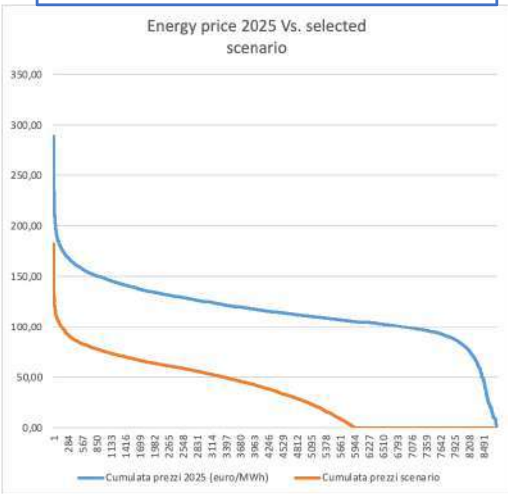
Scenarios – Market prices reduction

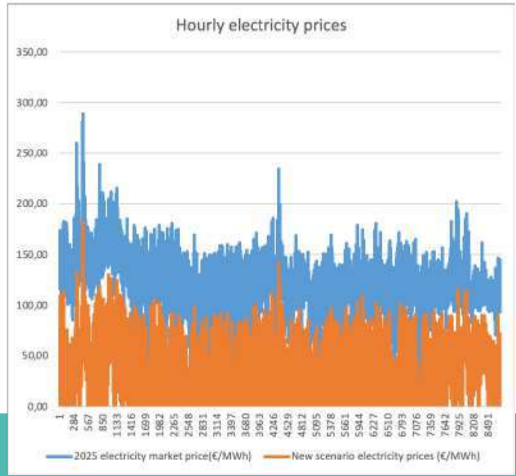
Scenario 1



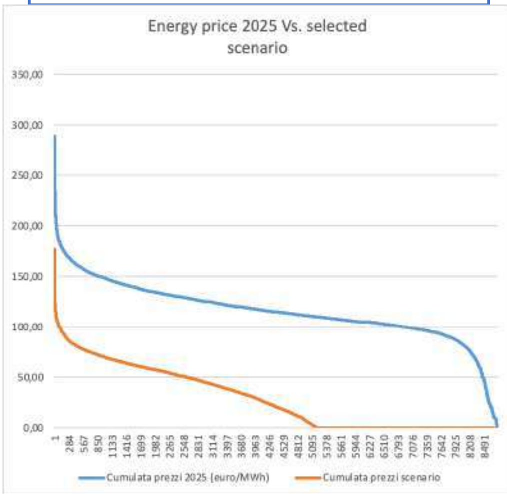


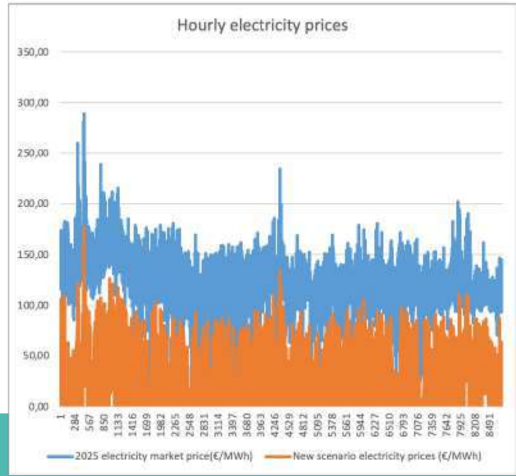
Scenario 2



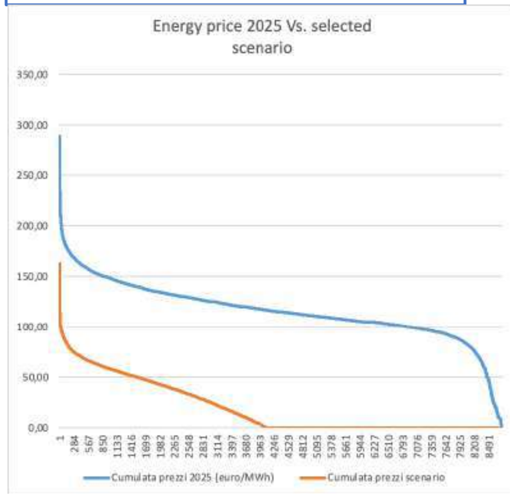


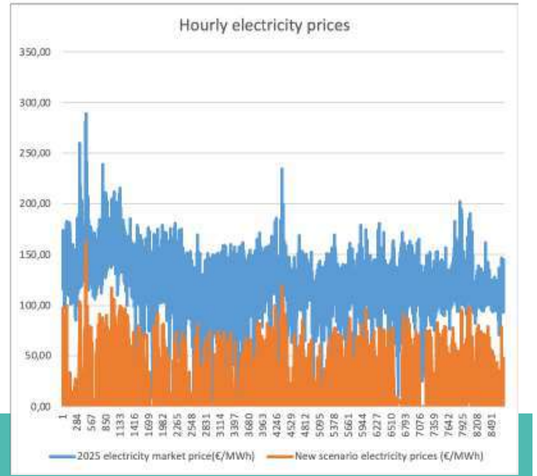
Scenario 3





Scenario 4





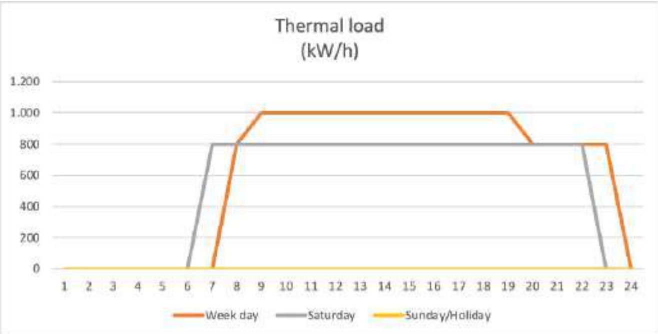
Business case

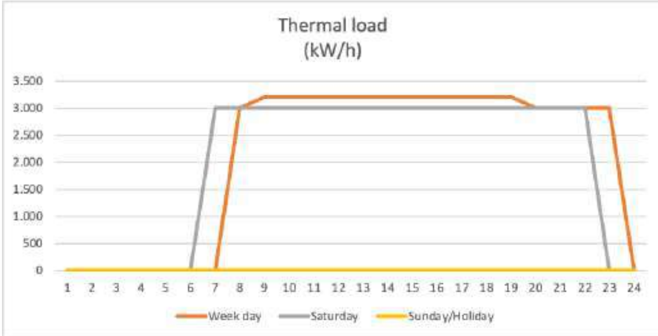
Three reference systems are simulated: micro, medium and large. For micro and medium systems, a daily/weekly operating mode is assumed; for large systems, continuous operation is assumed

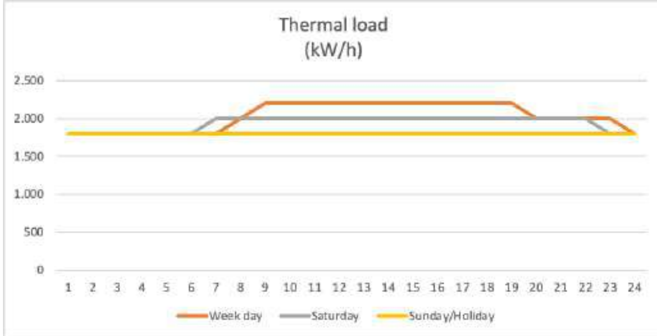
PLANT TYPE	MICRO		
Real load profile	F1	F2	F3
Thermal load (kWt)	1.000	800	0
Electrical load (kWe)	200	400	50
Pel CHP (kW)	500		

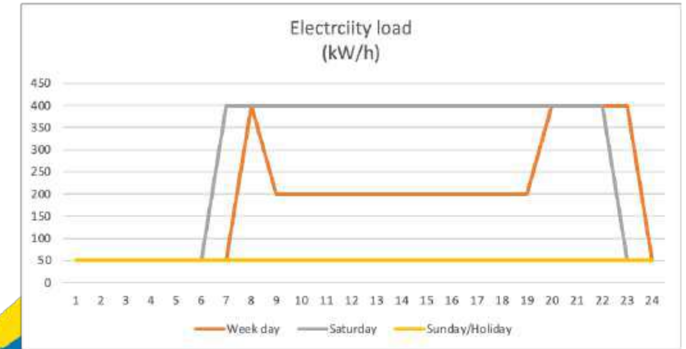
PLANT TYPE	MEDIUM		
Real load profile	F1	F2	F3
Thermal load (kWt)	3.200	3.000	0
Electrical load (kWe)	700	400	100
Pel CHP (kW)	1.500		

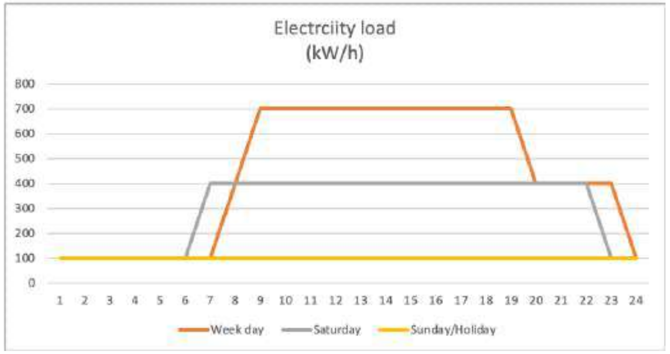
PLANT TYPE	LARGE		
Real load profile	F1	F2	F3
Thermal load (kWt)	2.200	2.000	1.800
Electrical load (kWe)	1.000	800	800
Pel CHP (kW)	5.000		

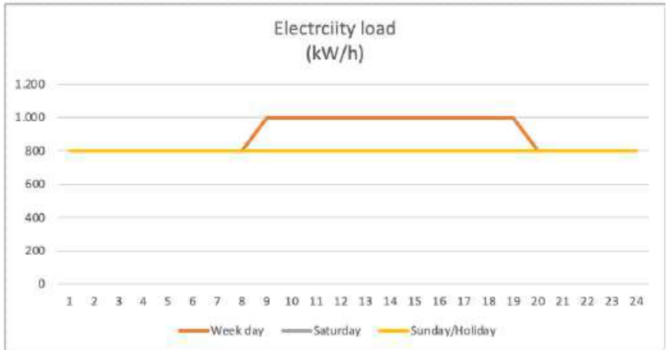












The same combined heat and power plant performs differently in terms of efficiency and the costs of electricity and heat production depending on how it is used in relation to the following two scenarios:

- Heat-only mode (with/without integration)
- Interruption of production (CHP ON/OFF) when flexibility conditions arise

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	0	0
Yield	0	0	0
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
	0	0	0
Maintenance costs	0	0	0
(€/kW)	300	0	0
(€/anno)	50.000	100.000	150.000
Investment costs	0	0	0
(€/kW)	1.000	0	0
(euro)	166.667	333.333	500.000
Production cost (LOCE)	0	0	0
(€/kWh)	0	0	0
(€/MWh)	95	103	

CHP production parameters (market driven mode with CHP ON/OFF)			
Useful life of investment (years)	10		
Operation hours (h/year)	3.953		
	Electricity	Thermal	Total
Rated power (kW)	500	0	0
Yield	0	0	0
Energy production	1.791.100	3.582.200	5.373.300
Gas supllied form grid (kWh)	2.132.262	4.264.524	6.396.786
Gas supply expense (€/year)	130.068	260.136	390.204
	0	0	0
Maintenance costs	0	0	0
(€/kW)	300	0	0
(€/anno)	50.000	100.000	150.000
Investment costs	0	0	0
(€/kW)	1.000	0	0
(euro)	166.667	333.333	500.000
Production cost (LOCE)	0	0	0
(€/kWh)	0	0	0
(€/MWh)	101	110	

EXAMPLE

Integrating/Alternative technologies

For the purposes of the assessments, on-site integration technologies were taken into account

Electricity storage	
CAPEX (€/MW/h)	350.000
OPEX (€/MWh/year)	5.000

Steam boiler production	
CAPEX (€/Kg)	43
OPEX (€/MWh)	Gas cost

Thermal storage equipment (hot water)	
CAPEX (€/MWt)	22.000
OPEX	-

Full electrification option	
CAPEX (€)	100.000
OPEX (€/MWh)	Electricity cos

For each case and each scenario, the level of flexibility required to ensure compliance with the flexibility conditions is assessed

The cost of integration technologies is included in the net energy balance costs

EXAMPLE

Technology integration

Electricity storage	Storage capacity	MWh	4,90
	Energy stored	MWh	332
	CAPEX	€/MW/h	350.000
		€	1.715.000
	OPEX	€/MWh/year	5.000
		€/year	24.500
	Useful life of investment (years)	years	15
	Average unity storage cost	*€/MWh*	*419*
	Yearly storage cost	***€/year***	***138.833***
Steam boiler production	Production capacity need	Kg/hour	10.759
	Unit capex cost	€/Kg	43
	CAPEX	€	462.366
	Useful life of investment	years	20
	Yearly cost	**€/year**	**23.118**
Thermal storage equipment (hot water)	Storage capacity (MWt)	MWt	0,003
	CAPEX unit cost (€/MWt)	(€/MWt)	22.000
	CAPEX (€)	(€)	66
	Useful life of investment	years	10
	Yearly cost	**€/year**	**7**

Alternative technology

Full electrification option	Heat need	kWh/Kg	0,093
	Head capacity need	Kg/hours	10752,6882
	Electric boiler cost	€	100000
	Production efficiency	kWhel/kWht	1,05
	Duration	Years	10
	Yearly capital cost	€/year	10000
	Operational cost	€/year	902042,845
	Total production cost	**€/kWht**	**0,206**

MAIN RESULTS INTERPRETATION AND CONCLUSION

CONCLUSIONS

Flexibility comes at a cost to the user: the net economic balance deteriorates as the level of flexibility increases, driven by scenarios involving ever-higher penetration of non-dispatchable renewable sources (the base case is purely thermal operation, with no flexibility in electricity exchange with the grid)

The cost of flexibility depends on the costs of integration technologies

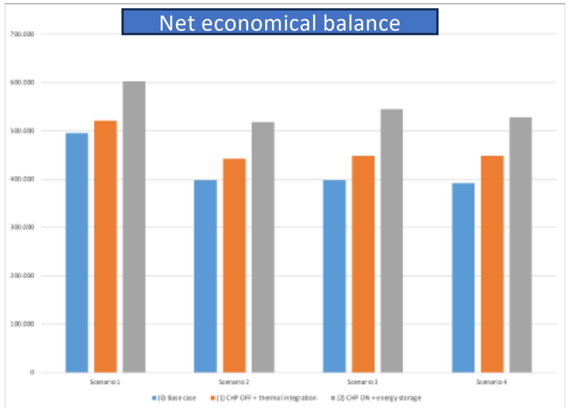
- Supplementary boilers
- Electric storage
- Thermal storage

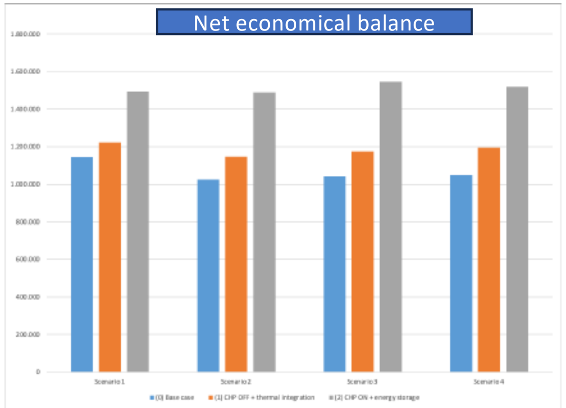
White certificates revenue
+
Electricity surplus revenue

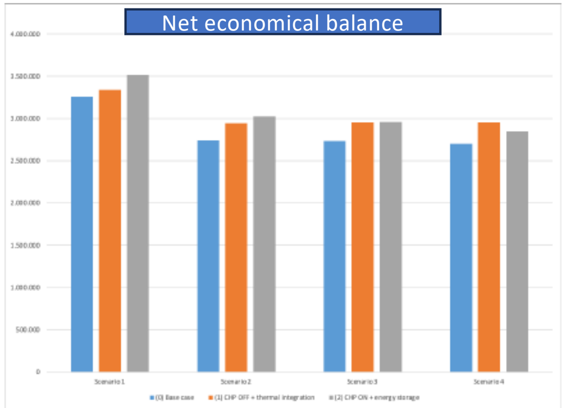
Cost of thermal energy produced by CHP
+
Cost od self-used electricity (produced by CHP)
+
Electrcity cost from grid integration

Type plant – CHP & Technology integration

Micro	Medium	Large







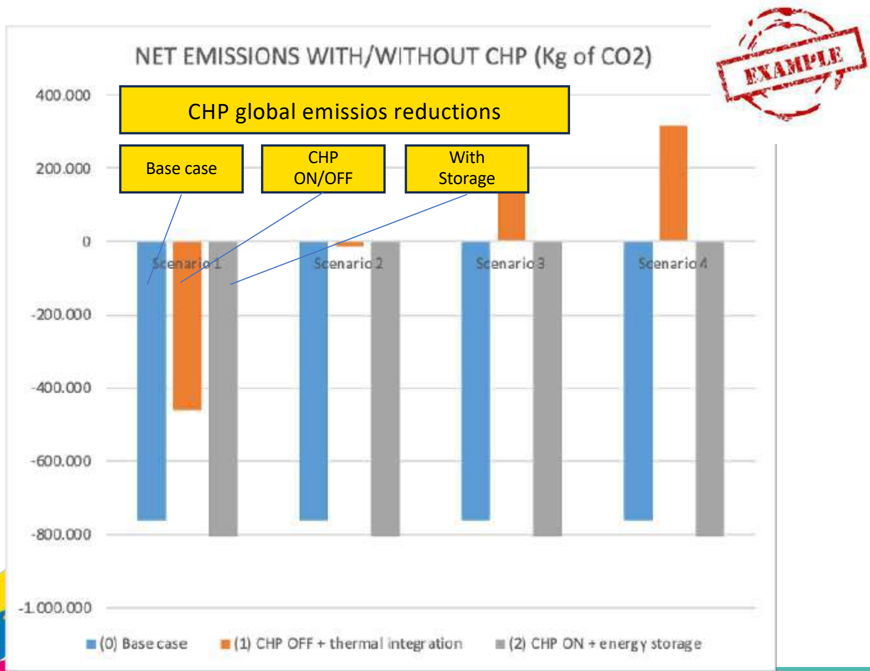
- Flexibility translates into a cost for the user: the net economical balance worsens as the amount of flexibility induced by scenarios with an ever-increasing penetration of non-programmable renewable sources increases (the base case is a purely thermal-continuous operation without any flexibility in the electricity exchange with the grid).
- The cost of flexibility depends on the costs of the integration technologies: Integration boilers / Electric storage / Thermal storage.
- Among the different scenarios, the evolution of gas prices plays a decisive role, even if the trend of cost differences between the various operating cases for each scenario is always respected.

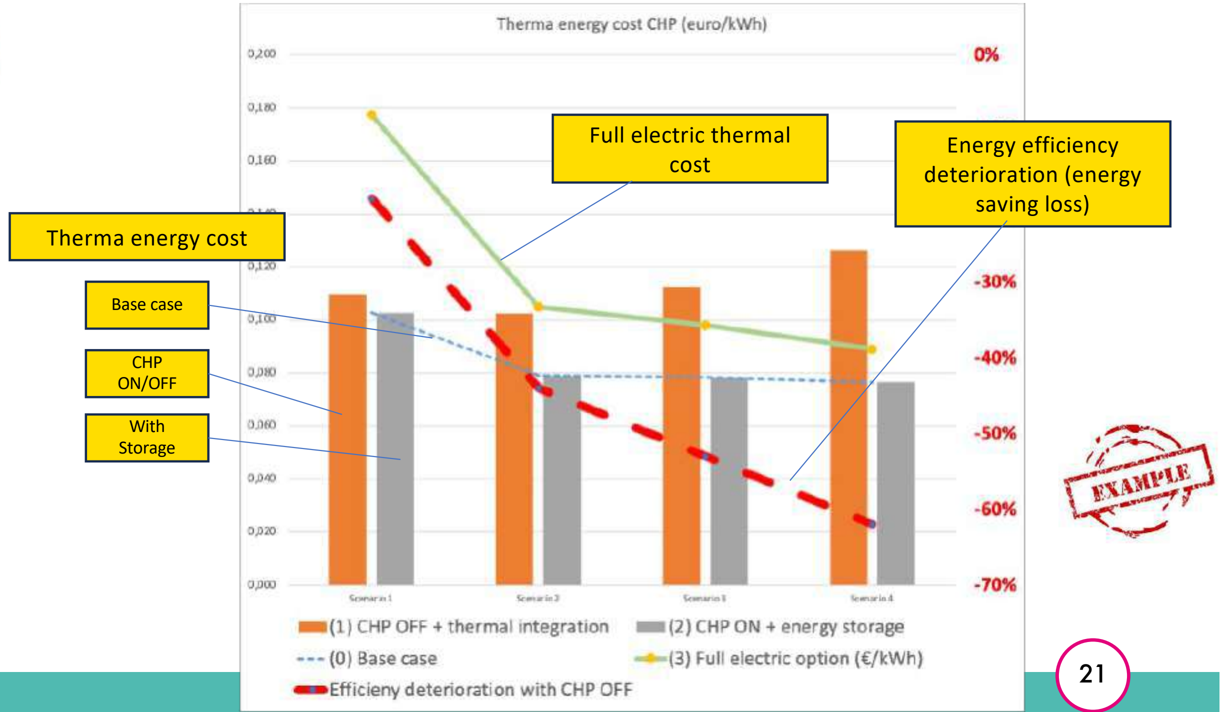
What is considered ?

Reduction of CO_2 emissions in different operating modes – CHP, for the same energy supplied to the user, allows for CO_2 emissions savings linked to primary energy savings.

The cost of thermal energy for the end user in different operating modes, also in relation to the thermal/full-electric alternative.

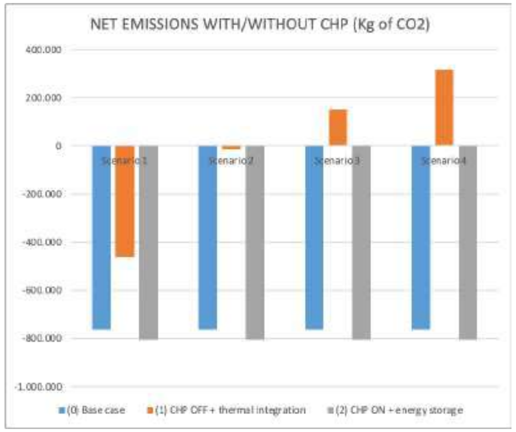
The loss of conversion efficiency (difference between PES) in the CHP on/off mode compared to the CHP-on mode (basic/flexible).

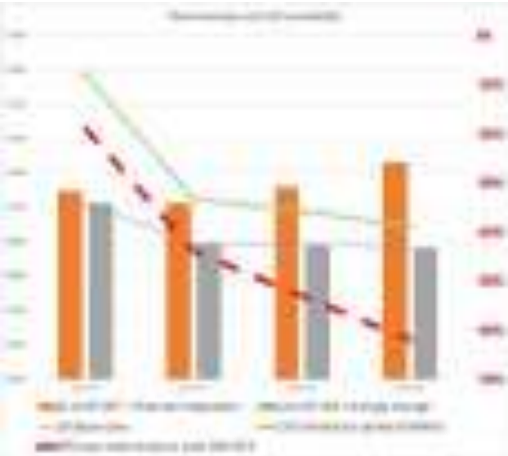




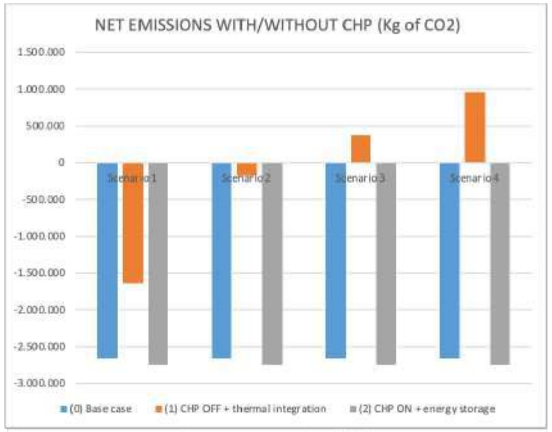
Type plant – CHP & Technology integration

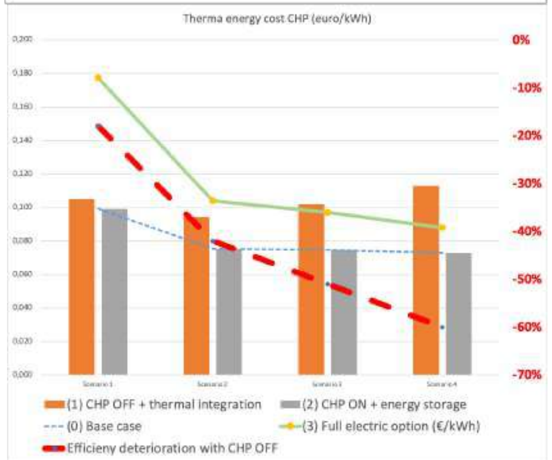
Micro



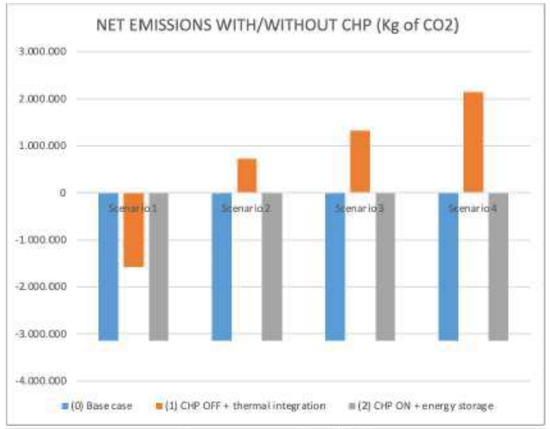


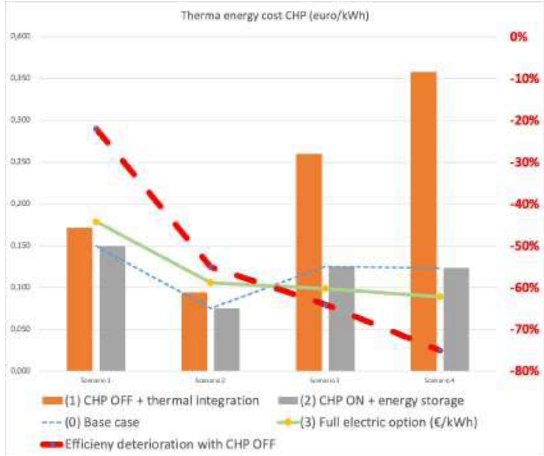
Medium





Large





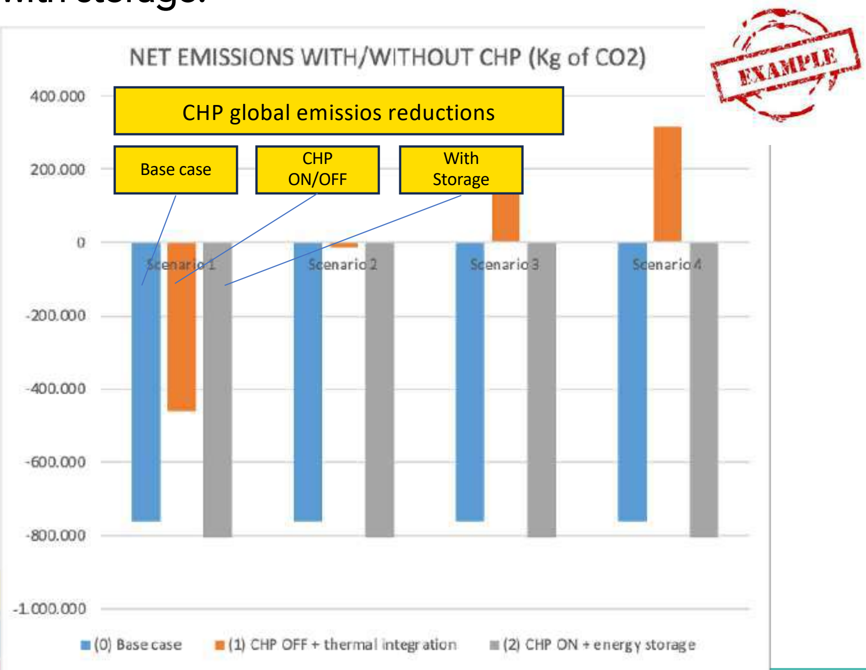
WHAT CAN WE PRELIMINARILY CONCLUDE?

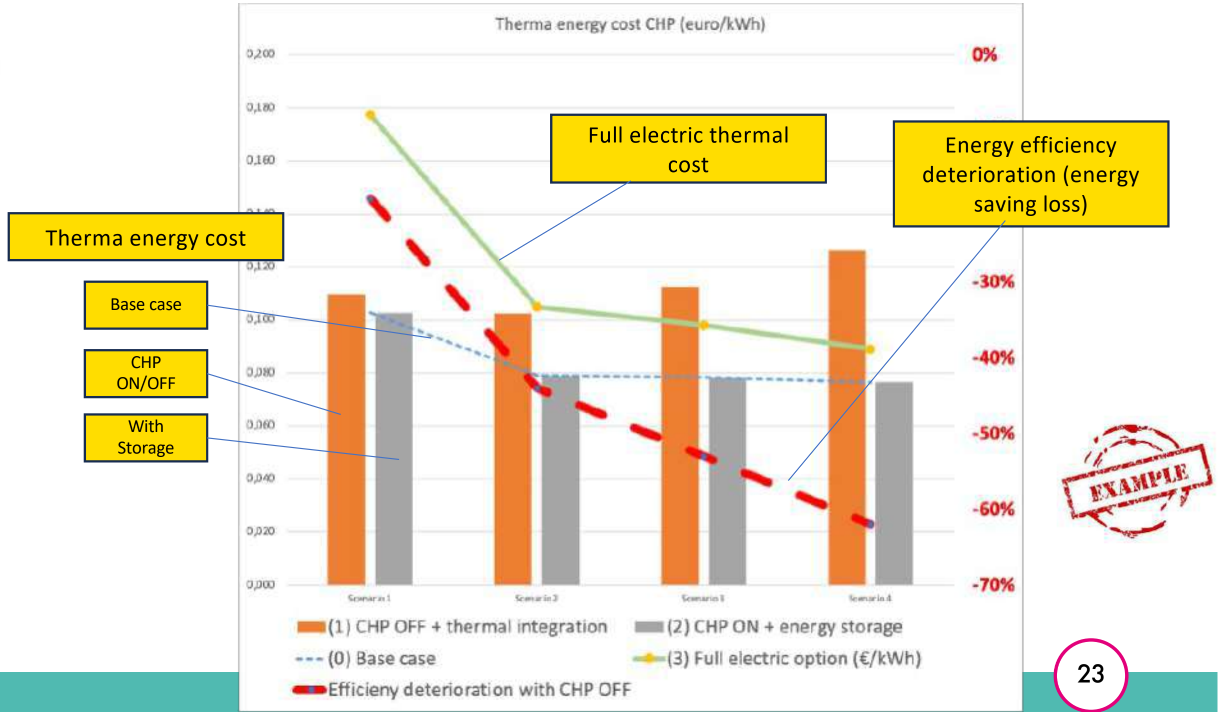
The optimal flexibility management scenario involves the use of storage, allowing cogeneration to continue providing thermal services to the user.

It has been shown that this is always the best scenario in terms of:

- Maintaining system efficiency
- Reducing emissions

For the most interesting scenarios (2 and 3), the full-electric alternative would (almost) never be competitive with flexible CHP with storage.





Excluding the possibility of using a power plant, the alternative of generating heat using electricity is always uneconomical compared to cogeneration (except in extreme cases)

In order to make cogeneration more flexible (i.e. not to supply the internal electrical load and not to feed into the grid when the market price of electricity is lower than the internal cost of electricity production), switching off the cogeneration system and use supplementary combustion sources instead of keeping the cogeneration system running in conjunction with a storage service (electrical/thermal)

- it is, however, always uneconomical for the customer
- it always reduces the system's overall performance in terms of primary energy savings and emissions avoided

Local use of CHP electricity

Value of the raw material (electricity)

Zero-price energy on the market occurs unpredictably in the medium term.
Price risk management is mitigated with long-term trading instruments (indexed/non-indexed).

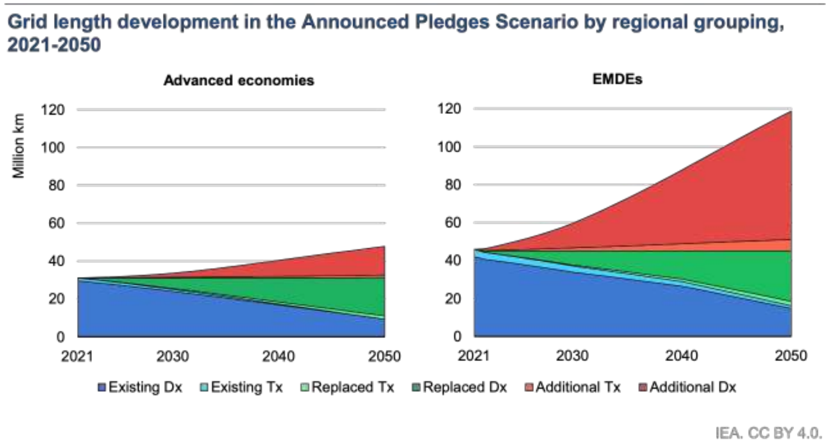
A PPA mechanism would set the transaction price as the market price changes (in this case, the price never goes to zero).

When the quarterly price also goes to zero, the CFD support mechanism shifts the production cost to the bill items (raw material/charges). One way or another, the user pays the production cost of the electricity drawn from the grid.

(e.g.) RES-X (Italian incentive scheme), PV, long-time value €54/MWh
40% discount on the reference rate of €90/MWh

It is important to refer to the cost to the user for full electricity availability, which includes the cost of networks/balancing/adequacy (and system costs).

Increasing electrification is a source of increased electricity grid/system costs.



https://iea.blob.core.windows.net/assets/ea2ff609-8180-4312-8de9-494bcf21696d/ElectricityGridsandSecureEnergyTransitions.pdf

What conclusion do we reach?

Useful energy at zero cost DOES NOT EXIST

The electrification process requires

- **Increasing availability of electricity**
- **Electricity that must be renewable**

Economics CHP on-site – Condizioni attuali

For CHP, we assume:
- current gas price
- gas network and system charges
- CO2 compensation charge for gas use
- current 2026 average system charges

The carbon-free production cost of electricity from CHP is calculated and the aim is to evaluate whether this self-supplied energy is competitive or not compared to a grid supply.

Carbon-free electricity from on-site and self-supplied CHP is proven to be competitive compared to grid supply

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%

On-site, carbon-free cogeneration would remain a viable and competitive option compared to green electricity supply from the grid well into the future.

The need for system flexibility (see the first part of the study), combined with the above, suggests that during periods of low residual load and low prices, "local retention of CHP electricity generation" is the option that avoids losses in efficiency and avoided emissions.

Users are willing to seize low-price opportunities, but they need to manage risks and not adopt purely opportunistic behavior.

The above suggests that CHP can make (carbon-free) electricity available to integrated processes such as CHP
Heat pumps
Power-to-heat technologies
Local green hydrogen production

Finally: the heat produced would also be carbon-free

Final considerations

Guidelines for Support Policies

Cogeneration must enhance efficient flexibility and guide the use of renewable fuels in cogeneration.

The overall objective of the energy transition must be the "efficient reduction of emissions," not just the increase in specific forms of production.

Cogeneration does not consume land or disturb the landscape because it is integrated into consumer sites, and the energy intensity of CHP (energy/installed capacity) is among the highest at the system level among production technologies that reduce global CO_2 emissions.

Cogeneration is a potential that should be placed at the center of the energy transition process, especially for consumption that cannot otherwise be decarbonized, as it is an efficient solution for the use of renewable fuels (a scarce resource).

Cogeneration is not a bridging solution, but a solution.

CHP integrates with other technologies to flexibly and efficiently connect to the energy system ginvig INTEGRATED COGENERATIVE SYSTEMS (ICS)

Thank you for your attention

ITALCOGEN

Via Scarsellini 11/13 - 20161 Milano
italcogen@anima.it | Tel. 02 45418399