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Benefits from power and heat cogeneration

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Abstract. A large fraction of heat production from power sources is wasted in the environment, despite its numerous potential energy uses, for example, district heating, seawater desalination, or hydrogen production. In this paper, we use the MIXOPTIM methodology to evaluate performance indicators of mixes of electric power sources with and without cogeneration of heat to assess the benefits it entails. It appears from the study that the cogeneration option is highly interesting for mixes with a large nuclear share. The case of France is analyzed in detail, with an evaluation of the overall potential of cogeneration in terms of economic competitiveness as well as in terms of greenhouse gas emission reduction.

1 Introduction

The purpose of this study is to quantify the benefits of heat cogeneration using electric power plants. Due to the very different characteristics of the various power sources (gas, wind, hydraulic, solar, nuclear,...) potentially present on a territory, to the fluctuating nature of the power demand and the production of these sources, the modeling of the behavior of such a mix of power sources is rather complicated and requests sophisticated tools.

In a previous paper published, we presented MIXOPTIM, a software toolbox dedicated to the overall analysis of an electric mix installed in a given territory [1]. The toolbox includes a Monte-Carlo simulation of the mix, and a frequency-domain spectrum analysis software, to assess the load-following capabilities of the mix. In order to evaluate the economic benefits of cogeneration, the descriptive capability of the software platform has been extended to include modeling of both power and heat production for each power source.

2 The hypotheses of the study

2.1 The whereabouts of MIXOPTIM

MIXOPTIM is a simulation software able to calculate the performance of a mix of energy sources on a territory. Many other simulation tools dedicated to the same objective do exist. Most of them are time-step models where

the behavior of the mix is followed for each time increment, according to a given scenario for the power demand [2]. The originality of the Mixoptim approach lies in the fact that it is a Monte-Carlo simulation tool that explores the entire phase space for the variables of the problem, *ie* the power demand on the territory, and the availability of the power sources at time t , whereas other simulation tools based on a time-step approach explore only one path (or scenario) in this multidimensional phase space. On the other hand, time-step models are able to take into account the history (or time-correlations) of the system along this path, with results depending on the details of the chosen scenario. Both approaches are thus complementary: MIXOPTIM gives a better description of rare situations (in the corners of the phase space) whereas time-step models simulate more easily time-dependent aspects as, for example, the (de)storage of energy.

Initially designed for the modeling of the sole electricity system, like most of the simulation tools listed above, the MIXOPTIM formalism has been extended to the modeling of heat-electricity cogeneration, along the following lines: in order to satisfy the energy demand, the modeled territory has a number of power plants producing electric energy from different sources (wind, solar, hydraulic, nuclear, coal, gas, etc...), hereafter labeled by the index i (Fig. 1). In the MIXOPTIM formalism, each production unit of the same nature (wind, solar, hydraulic, nuclear,...) refers to the same label i : the mix of power sources can be characterized by the (α_i) multiplet of the *total* installed power for each source of the same nature i and by the (Kd_i) multiplet of the availability coefficients of these

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sources. The values α_i and Kd_i is the main input data of the MIXOPTIM code.

Each source is characterized by a cogeneration coefficient γ_i , which is defined as the amount of usable heat power generated by the source i per MWe produced. The cogenerated heat is used to satisfy a fixed heat demand on the territory. Whenever the heat demand exceeds the cogenerated heat production, a complementary production from an external heat source is added. Conversely, if the heat demand is smaller than the cogenerated heat, the excess heat is dumped.

The dispatching order of the sources may be changed by the introduction of cogeneration. In the present paper, we assumed that the dispatching order of the *electric* sources prevails and that the complementary heat source is called for in the last position to provide the complementary thermal power when required.

No electricity storage or heat storage, nor heat-to-power capability is assumed in the mix. If necessary, those refinements could be added later on.

Of course, heat has a different value when it is produced at high or at low temperatures. For the sake of simplicity, in the present paper, we assign a unique economic value to one MWh of thermal heat, without any distinction in its final use: district heating or industrial heating.

Our modeling neglects all limitations induced by the transport either of electricity or heat within the territory. This “copper plate” approximation will provide valid results for small territories, or large ones showing similar distribution for power sources and power sinks.

In coherence with our copper plate approximation, the cost of transport and distribution of electricity and heat is assumed to be independent of the mix. It is also assumed to be the same in both cases with- and without cogeneration. This assumption releases us from taking into account transport and distribution costs in a *comparison* between these cases. We shall need to keep this in mind in our interpretation of the economic results of the model: the costs listed below are therefore exclusively *production* costs.

The territory is assumed to be thermally isolated, *ie* it cannot export or import heat from outside: all the produced heat is considered to be produced and consumed *locally* with no exports or imports. However, the territory is not electrically isolated and can export or import power $P_{ie}(t)$ (Fig. 1), within the limits of the interconnection capacity α_{ie} of the territory. The electric power exchanged with neighboring territories is taken into account in the model to assess the cost of energy supply (both electric and thermal) of the territory.

2.2 About the degradation of the electric conversion yield induced by cogeneration

Standard thermal sources dedicated to electric power production generally produce waste heat at a too-low temperature for most uses. Higher temperature heat could be generated in the same plants, but at the expense of their electric conversion efficiency [3]. For example, a typical pressurized water nuclear reactor (1.35 GWe) will dump

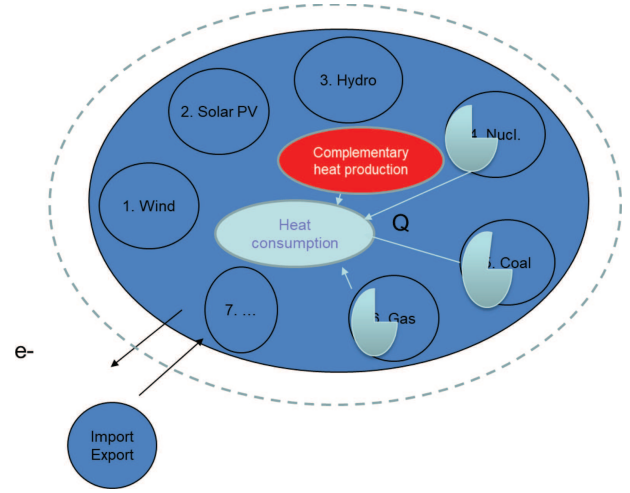


Fig. 1. A territory with its power and heat sources. The light blue crescents represent the heat cogeneration capability of some power sources. Only thermal power sources are offering power and heat cogeneration capability. The territory can exchange electric power with its neighbors. The dashed line represents the economic perimeter of the territory.

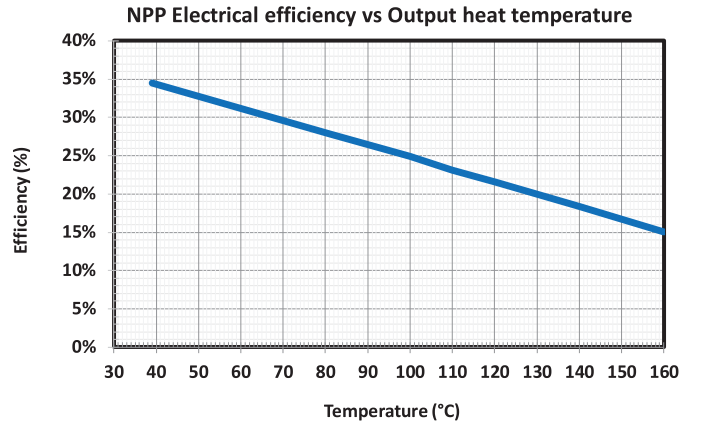


Fig. 2. Electric conversion efficiency of a nuclear power plant as a function of the output heat temperature at the condenser output.

2.6 GWth of waste heat at 40°C while keeping its nominal power conversion efficiency of 35%; alternatively, it could cogenerate 1.0 GWe and 3.0 GWth at 100°C if one accepts a reduction in the electric conversion efficiency from 35% to 25% (Fig. 2). In this latter case, the cogeneration coefficient of the nuclear source could be as high as $\gamma_i = 3$, and the overall energy yield summing up electric and heat production could raise up to 67% in terms of energy [4].

In the case of a gas source, the electric conversion efficiency drops from 58% to 43% when switching the gas plant from a Combined Cycle (CCGT) dedicated solely to electricity production, to a Combined Heat and Power (CHP) mode [5].

In our comparison between the two options with- and without cogeneration, the corresponding reduction in the electric conversion yield of thermal sources upon

Table 1. The fixed and variable costs of electricity production from different sources. The fixed cost is expressed in euros per MW installed and per hour of the facility lifetime, *ie* in €/MW/h, or €/MWh.

Costs	Source	Windonshore	Solar PV	Hydro	Nuclear Gen II	Nuclear new build	Coal	Other renewables	Gas CCGT	Peak power (gas turbines)
Variable costs M	(€/MWh)	15.5	10.2	8.4	16.8	18.4	53.6	79.8	55.1	81.5
Fixed costs F	(€/MW/h)	17.8	11.9	24.8	11.5	34.9	24.4	13.4	13.2	7.7

Table 2. Seasonal and diurnal modulation of the average heat demand.

	Summer	Winter
Day	0.66	2.0
Night	0.32	1.0

implementing cogeneration has been taken into account: down from 35% to 25% for a nuclear source, and from 58% to 43% for a gas source.

2.3 Cost of power sources

The fixed and variable costs of the electricity sources have been extracted from reference [6] (OECD/NEA 2020) (Tab. 1). Costs may have changed since then following the Ukraine invasion by Russia, especially for the gas source, but we nevertheless keep the old values because they reflect a long-term stable environment in a non-crisis situation. In any case, gas prices are deemed to be significantly higher.

2.4 Value assumed for the cogeneration coefficients

The cogeneration coefficients γ_i defined above have been assumed to be equal to zero for the non-thermal sources (wind, solar PV, and hydraulic) and to unity (1 MWth of usable heat power produced per MWe of electric power produced) for all thermal sources (nuclear, biomass, gas, oil and coal). Given the fact that the *maximum* cogeneration coefficient of a given thermal unit is often of the order of 2 to 3, the value $\gamma_i = 1$ chosen for this study comes down to assuming the cogeneration potential of the thermal sources is only partly utilized (between 33% and 50%).

2.5 Heat-electricity couplings

Heat and electricity demands are not completely decoupled. In the option *without* cogeneration, we have considered that 25% of the total thermal demand is covered by direct electric power; whereas in the case *with* cogeneration, we have assumed that 0% of the total thermal demand is covered by electric power. As an example, if we assume that the net electric demand is 40 GWe and the

heat demand is 60 GWth, the two cases with- and without cogeneration will have the same net electric demand of 40 GWe, (excluding the electric power used to produce heat), but a different total electric demand (40 GWe in the cogeneration option, and $40 + 0.25 \times 60 = 55$ GWe in the no-cogeneration option, including the electric power used to produce heat).

2.6 Heat demand profile

The heat demand is not the same throughout the year. We have assumed that the heat demand will vary from one period of the year to another, according to the following pattern (Tab. 2):

The heat demand is highest during winter days, and lowest during summer nights. This pattern, typical of district heating in Western countries, has been extracted from reference [7].

3 Economic indicators with- and without heat cogeneration

The performance indicators calculated by the MIXOPTIM code are average quantities extracted from the Monte-Carlo simulation of the mix. They are:

- the probability of a grid power outage (dimensionless, but can be expressed as the average duration in minutes or hours of power outage per year). This indicator characterizes the security of supply provided by the mix.
- The time-averaged power imported from and exported to the neighboring territories. This indicator characterizes the degree of energetic independence provided by the mix.
- The time-averaged hourly production cost of the electric power demanded on the territory.
- The time-averaged hourly production cost of the heat demand on the territory.
- The time-averaged hourly CO₂ production.
- The time-averaged heat cogenerated and produced by the complementary source to fulfill the heat demand.
- The time-averaged capacity factor for all sources.

As an example, we calculated these indicators for a ternary mix Wind-Nuclear-Gas that might represent very schematically a medium-sized European country, with an equal installed power of 40 GW for each of three sources,

Table 3. Comparison of the performance indicators of a ternary mix Wind-Nuclear-Gas with- and without cogeneration. Figures in black are input data for the MIXOPTIM software; figures in red are the result of the calculation.

	Without cogeneration	With cogeneration
Net average electric demand (net, <i>ie</i> excluding the electric power used to produce heat) (GWe)	40	40
Average heat demand (GWth)	60	60
Total average electric demand (total, <i>ie</i> including the electric power used to produce heat in the non-cogeneration case (GWe)	55	40
Hourly production cost of the electric power (M€/h)	3.0	2.50
Hourly CO ₂ production (kt/h)	29.5	19.4
Average imported electric power (GWe)	5.95	4.10
Average duration of a grid power outage (hours per year)	37	1.8
Average heat cogenerated (GWth)	0	30.6
Average heat produced by the complementary source to fulfill the heat demand (GWth)	45	29.4
Hourly production cost of the additional heat (M€/h)	3.41	2.23
Total production cost of power and heat (M€/h)	6.41	4.73

and a heat demand of 60 GWth, either with- ($\gamma_i = 1$ for nuclear and gas sources) or without cogeneration ($\gamma_i = 0$ for all sources).

In the two cases with- and without cogeneration, we have assumed the same *net* electric demand of 40 GWe, (excluding the electric power used to produce heat), but a different *total* electric demand (40 GWe in the cogeneration option, and 55 GWe in the no-cogeneration option, including the electric power used to produce heat).

The comparison between the cogeneration and no-cogeneration options is summarized in Table 3.

In the studied case, the heat demand is only partly fulfilled using cogeneration. Cogeneration avoids the use of a dedicated (carbonated) heat source of 15.6 GWth, with subsequent savings in CO₂ (88 MtCO₂/y) and in costs (14.7 G€ saved per year). It appears that cogeneration improves all the performance indicators of the mix.

In order to bring more generality to these findings, we undertake in the following paragraphs a parametric study of a mix with- and without cogeneration. The parameters we varied in this study are the mix sizing, the magnitude of the heat demand, and the mix composition.

4 Influence of the mix size for a given heat demand

We applied a homothetic sizing factor to a ternary mix Wind-Nuclear-Gas having equally installed power capacity for each of the three sources and calculated the performance indicators of the mix as a function of this sizing factor. The scale of the sizing goes from 3 for a 30/30/30 GW mix (90 GW of total capacity) to 7 for a 70/70/70 GW mix (210 GW in total).

We assumed an average net electric demand of 40 GWe (net, *ie* excluding the electric power used to produce heat), and an average heat demand of 60 GWth, of the same order of magnitude as the cogeneration potential of the reference mix. In the option without cogeneration, we assumed as above that a quarter of the heat demand is covered by electrical heaters.

The results of the calculation using the MIXOPTIM software are summarized in Figures 3–6.

An undersized mix entails a large probability of power outage and requires more imported power, but this trend is attenuated in the cogeneration option. Cogeneration improves the security of supply of the mix, and the degree of independence of the territory, for all values of the mix sizing (Figs. 3 and 4).

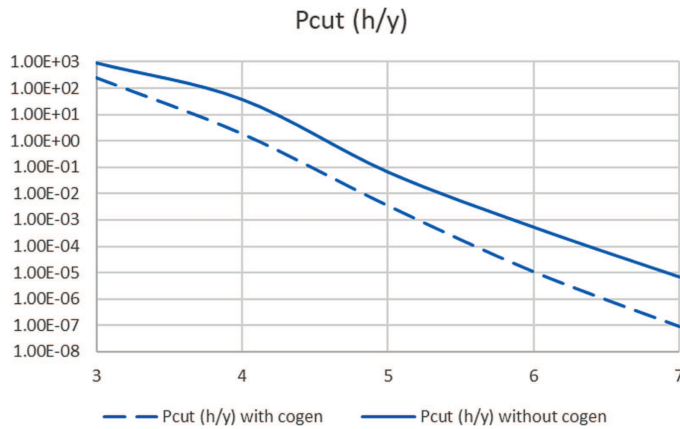


Fig. 3. Average duration of power outage (expressed in hours of outage per year) *ie* the “security of supply” criterion as a function of the mix sizing.

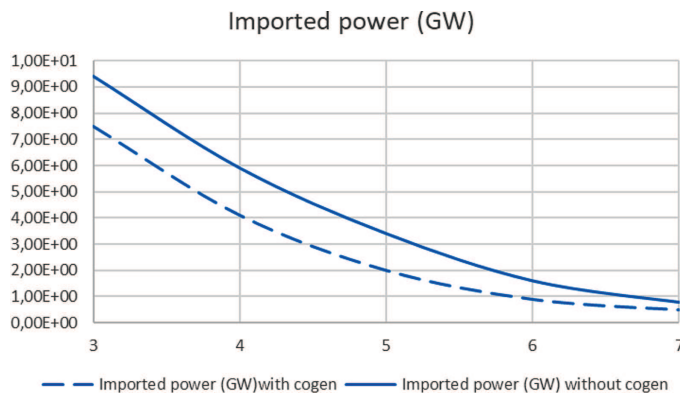


Fig. 4. The average imported power, *ie* the “independence” criterion as a function of the mix sizing.

In the option with cogeneration, the hourly cost of satisfaction of the electric demand increases when the mix sizing increases, whereas the cost of satisfaction of the heat demand follows the opposite trend. As a result, the global cost is largely independent of the mix sizing (Fig. 5).

The cogeneration option appears favorable from the economic point of view, whatever the mix sizing: as can be seen from Figure 5, the gain is of the order of 1.5 M€/h.

If the mix is undersized, the gas source is called for frequently, with detrimental effects on the CO₂ balance (Fig. 6). However, the CO₂ balance of the mix is always better with cogeneration, with a gain of the order of 10 ktCO₂/h in the present case study.

The complementary heat needed to fulfill the heat demand is only a fraction of the total heat demand: for the studied mix composition, cogeneration spares a significant amount of complementary heat, of the order of 15 GWth in the present case study.

The “optimum” mix sizing depends on the optimization criterion chosen: security of supply, independence, economy, or CO₂ production. In any case, the cogeneration option improves all performance indicators of the mix.

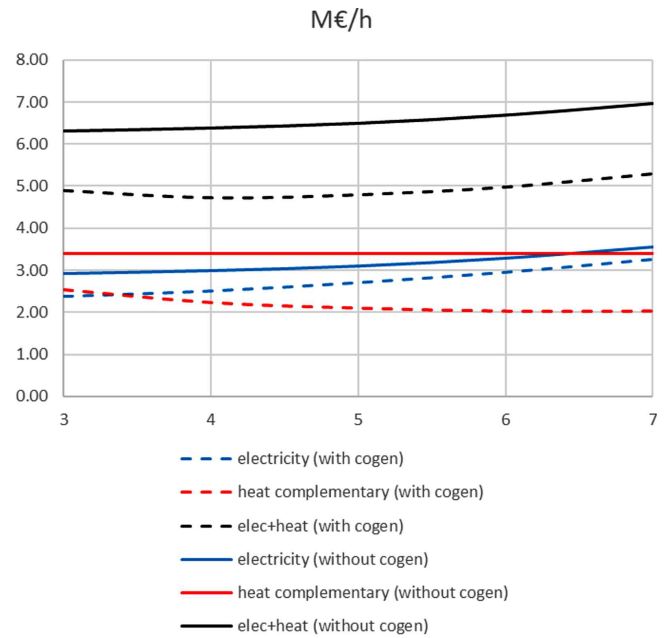


Fig. 5. Decomposition of the hourly production cost of the electric power and of the heat power demanded on the territory, as a function of the mix sizing (in the options with- and without cogeneration).

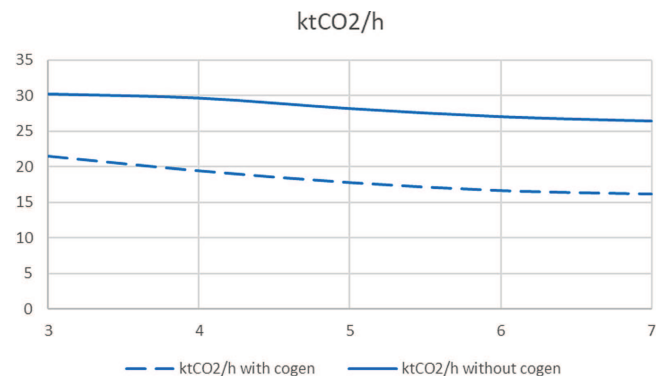


Fig. 6. Hourly CO₂ production as a function of the mix sizing.

5 Influence of the heat demand (cogeneration case)

We calculated the performance indicators of a ternary mix composed of wind turbines, gas, and nuclear sources, this time as a function of the magnitude of the heat demand. The installed power has been assumed to be 40/40/40 GW for each of these three sources (120 GW in total), and we let the heat demand vary between 20 and 70 GWth. The results are summarized in Figures 7–11.

Cogeneration improves the degree of security of supply and electric independence of the territory in the case of a high heat demand because it reduces the electric demand (remember we assumed that 25% of the heat demand was covered by electric power). However, the opposite is true

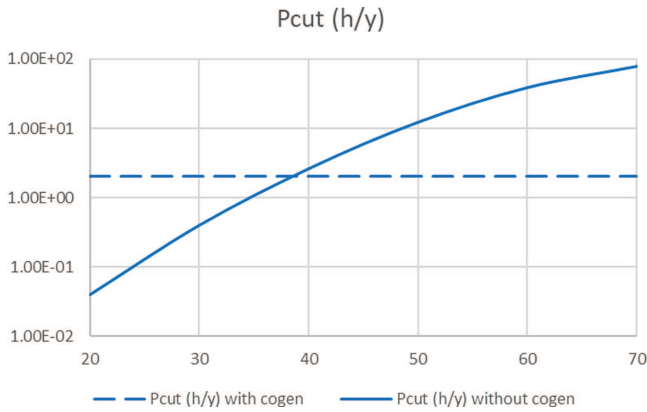


Fig. 7. The average duration of a power outage (in hours per year) as a function of the heat demand (in GWth).

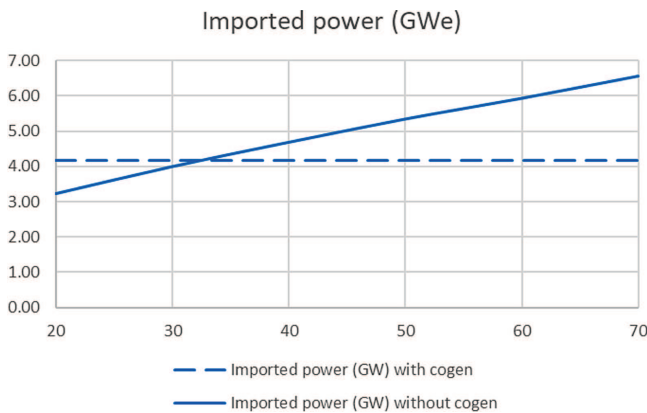


Fig. 8. The average amount of imported electric power, as a function of the heat demand (in GWth).

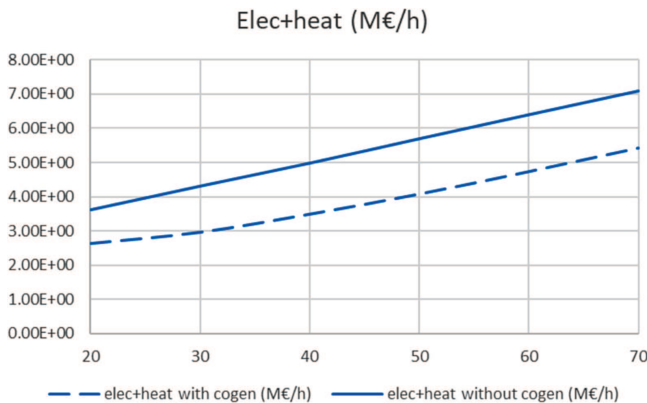


Fig. 9. The hourly production cost of the electric power and the heat power demanded on the territory (in M€/h), as a function of the magnitude of the heat demand (in GWth).

for low heat demand, because cogeneration entails a loss in conversion yield of the sources. In the present case study, the balance between these two antagonistic effects occurs when the heat demand equals roughly the electric demand (Figs. 7 and 8).

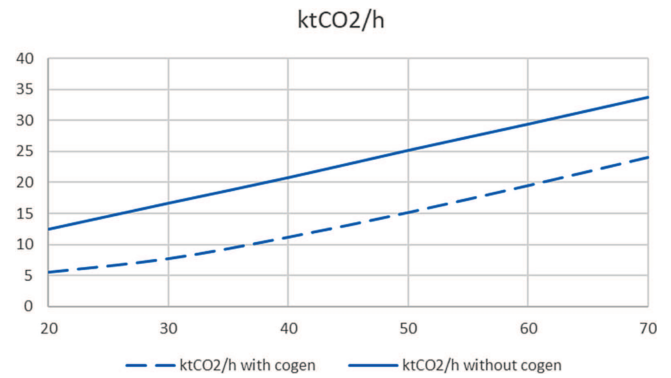


Fig. 10. The hourly amount of CO₂ (in thousands of metric tons) produced by the cogenerating mix, as a function of the magnitude of the heat demand (in GWth).

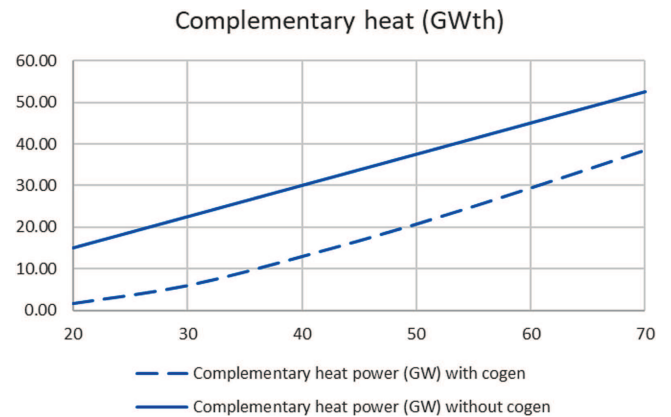


Fig. 11. The complementary heat needed in the options with and without cogeneration, as a function of the magnitude of the heat demand.

As can be seen in Figures 9 and 10, the benefits of cogeneration in terms of economy and in terms of CO₂ reduction are confirmed by the present parametric study, whatever the magnitude of the heat demand.

It appears that a balanced mix featuring thermal power sources can fulfill almost for free a substantial heat demand. In the present case study, the “free heat” is of the order of half the average power demand (Fig. 11). In the studied case, the production cost of the heat demand on the territory starts to increase more or less linearly when the heat demand exceeds 20 GWth. The value of this threshold depends on the composition of the mix. We study this aspect in the following section.

6 Influence of the mix composition

We calculated again the performance indicators of a ternary mix composed of wind turbines, gas, and nuclear sources, this time as a function of the proportions of these three components. The average *net* electric demand has been fixed at 40 GWe and the average heat demand at 60 GWth. Again in the non-cogeneration option, a quarter of the heat demand (15 GW) is assumed to be

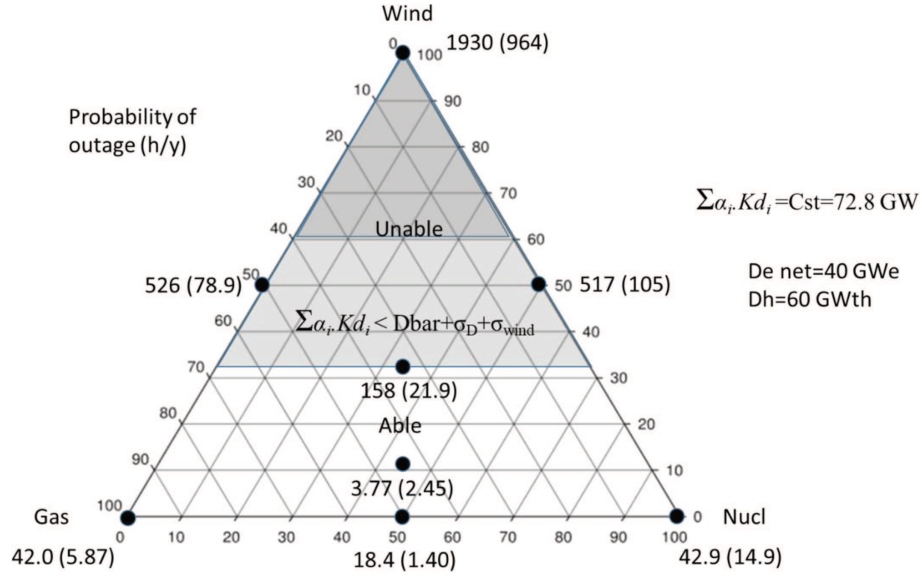


Fig. 12. The criterion “Electric security of supply” of the territory, expressed as the average duration per year of a power outage. The black dots in the ternary diagram are points where calculations have been made. Figures without brackets correspond to the option without cogeneration. Figures with brackets correspond to the option with cogeneration. The grey triangles delimit the zone of the diagram where the mix is unable to follow the fluctuations of the load.

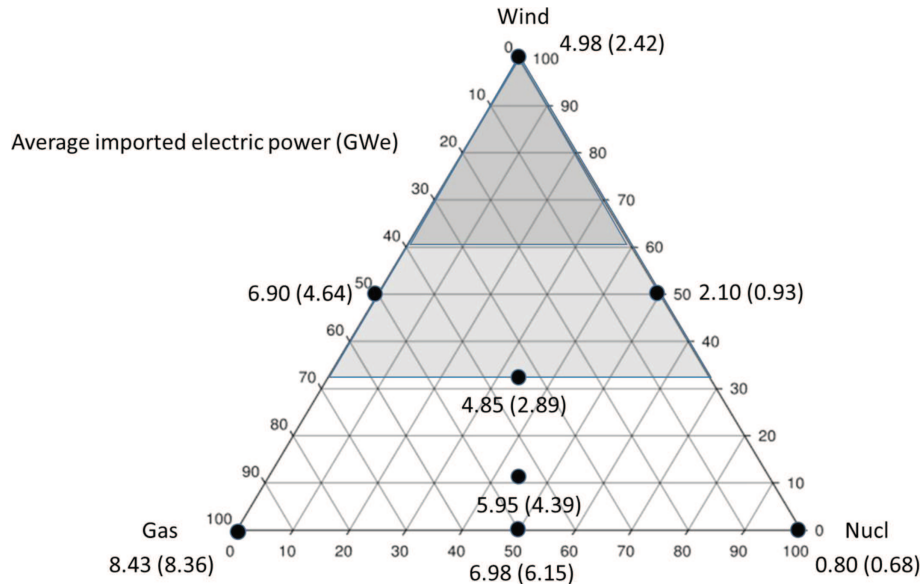


Fig. 13. The criterion “Electric independence” of the territory, expressed as the average amount of imported power.

fulfilled by electricity, the *total* average electric demand thus increasing to 55 GWe. The mix sizing $S = \Sigma \alpha_i K d_i$ has been kept constant, equal to 72.8 GW, a value that corresponds roughly to the actual French electric mix. A power import/export capability of 14 GWe (also typical of the French territory) has been included in the description. The results are shown in the form of ternary diagrams, where the triangular coordinates are the installed powers weighed by the availability coefficients $\alpha_i K d_i$. Each vertex of the triangle represents a pure mix of wind, gas, or nuclear. The results of the calculation are shown in Figures 12–17.

As can be seen in Figure 12, wind-rich mixes are prone to frequent outages because of the intermittence of production. In this study, cogeneration improves the security of supply because it reduces the total electric demand from 55 to 40 GWe.

In Figure 12, the upper part of the ternary diagram (in grey) represents mixes that are unable to follow the load and its fluctuations because the dispatchable power is insufficient. More precisely, in the upper part of the diagram, the average available electric power is smaller than the average demand $Dbar$ augmented by the standard deviation of the demand σ_D and of the mandatory

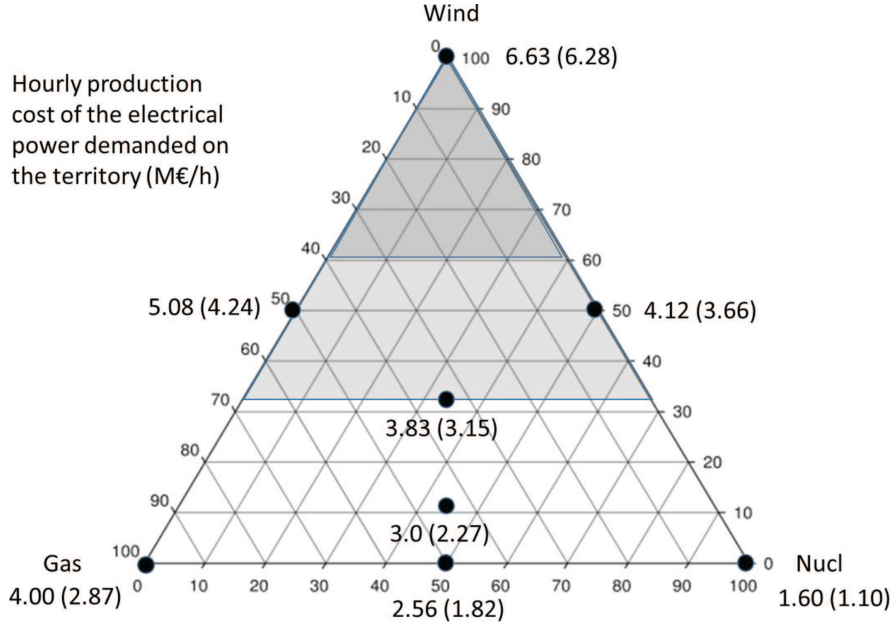


Fig. 14. The hourly production cost of the electric power demand on the territory (M€/h).

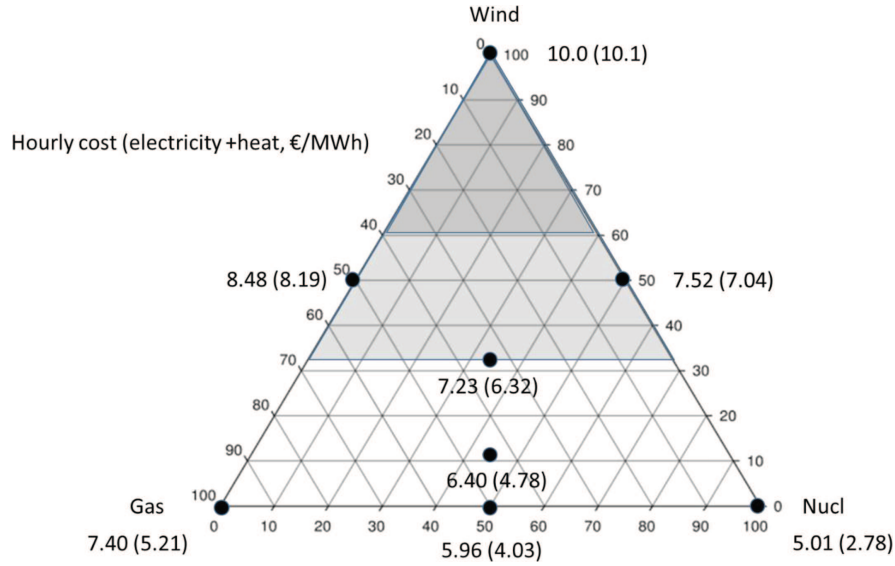


Fig. 15. The hourly production cost of the electric and heat power demanded on the territory (M€/h).

wind source σ_{win} :

$$\Sigma \alpha_i \cdot K d_i < \text{Dbar} + \sigma_D + \sigma_{\text{wind}}.$$

(this criterion for the aptitude of the mix to fulfill the demand and its fluctuations has been discussed in detail in a previous paper [8]). The smaller dark grey triangle corresponds to the “non-ability” zone in the option with cogeneration; the larger light grey triangle corresponds to the non-ability zone in the option without cogeneration. As can be seen in Figure 12, a mix with cogeneration tolerates a larger proportion of wind components, thanks to the reduction of the total electric demand, and despite

the reduction of the electric conversion efficiency of the thermal sources it entails. *This means that implementing cogeneration will allow the introduction of a larger amount of renewables in a given electric mix.*

The average amount of imported power is much larger for gas-rich mixes (Fig. 13) because the price of the imported MWh is frequently lower than the variable cost of the gas source: in this case, power import is then preferred to the mobilization of the local gas power sources.

The economic performance of cogeneration is improved for mixes that are rich in thermal sources (Figs. 14 and 15).

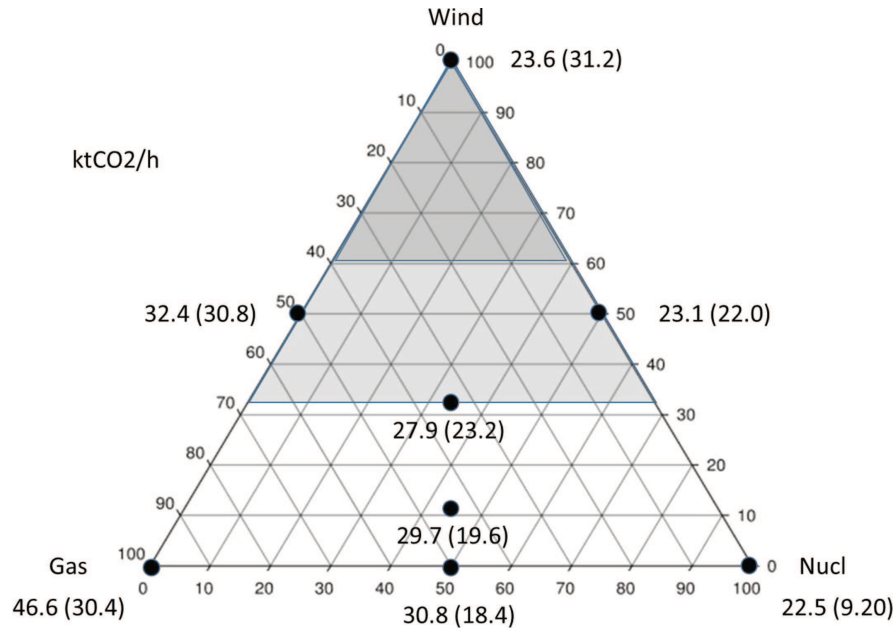


Fig. 16. The hourly amount of CO₂ produced by the mix.

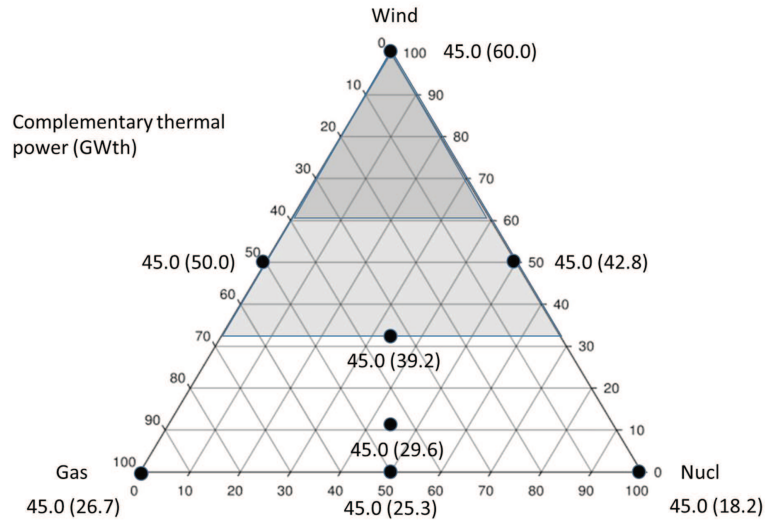


Fig. 17. The amount of complementary thermal power needed to supplement the cogenerated thermal power to satisfy the demand.

Mixes that are rich in Gen II nuclear sources achieve the lowest production cost. This conclusion does not hold true if the nuclear component of the mix is made of Gen III power plants, characterized by higher investment costs.

Heat cannot be cogenerated by wind turbines. In wind-rich mixes, heat must be produced additionally, with detrimental effects on the CO₂ balance since the complementary heat source has been assumed to be gas-fired (Fig. 16).

Cogeneration works only if a sufficient amount of thermal power sources is available in the mix. The gas-nuclear asymmetry shown in the ternary diagram is due to the calling order of the electric sources (nuclear source is called

for before any gas source) and from the fact that the high variable cost of gas favors the import of electric power (Fig. 17).

7 Final energy needs in form of heat

In order to evaluate the final energy needs in the form of heat, we have to compile detailed energy data through all sectors (residential, commercial, industry, transport, agriculture, and non-energy). A thorough examination of each usage is required not only by considering the primary energy sources as is usually done in energy statistics but by allocating the corresponding final energy

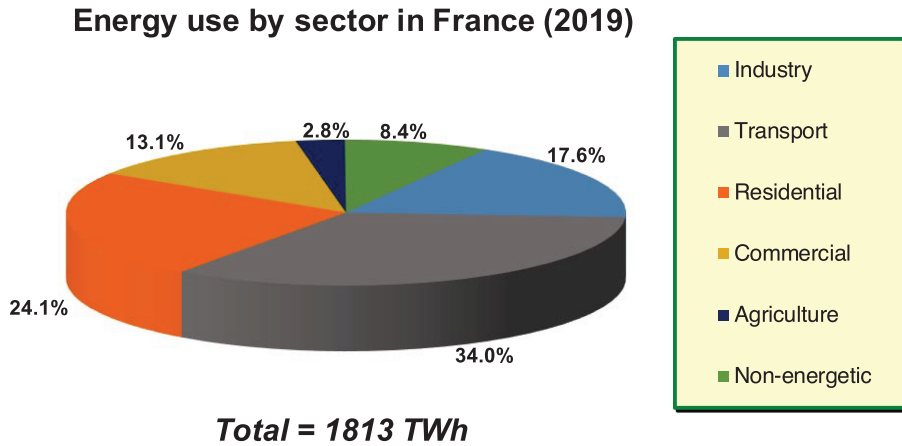


Fig. 18. Final energy use in 2019 by sector in France.

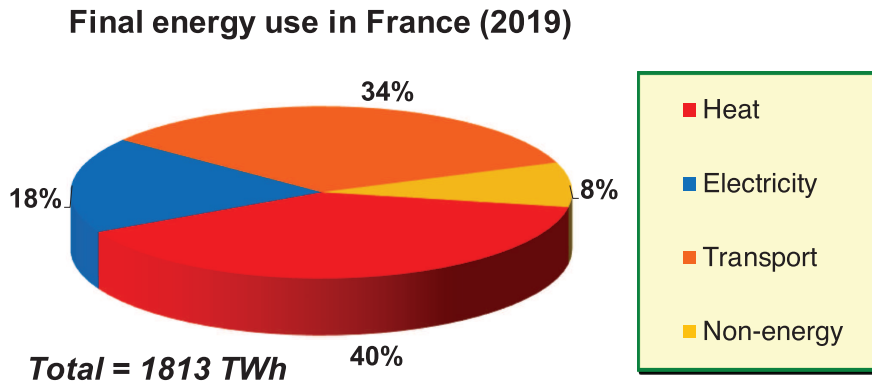


Fig. 19. Around 40% of the final energy is consumed to generate heat.

whenever the needs are in the form of heat. As an example, we shall focus our work on the territory of a single country, metropolitan France, although the exact same methodology may equally apply to analyze any other territory and ultimately extend it at the world scale.

The annual amount of energy use in France is of the order of 1813 TWh (Fig. 18). Energy use in transport (616 TWh) is primarily based on liquid fuels from oil products to power cars, trucks, planes, and ships. Similarly, non-energy manufacturing (152 TWh) also relies on petroleum for chemicals (ethylene, methanol, and ammonia), lubricants, elastomers, paraffin, waxes, cosmetic products, etc... Other sectors (residential, commercial, and agriculture) are consuming their energy in the form of heat, at least partially.

In the residential and commercial sectors, a large part of energy use is dedicated to space heating and water heating. Both requirements are at low temperatures (around 70°C for individual houses, 90°C for collective buildings). The detailed breakdown of energy use, given by the French Ministry of energy transition [9,10] is summarized in the following Table 4. Heat represents 83% of final energy needs in the residential sector and 57% in the commercial sector.

The total energy consumption in industry amounts annually to 320 TWh, using primarily natural gas (122 TWh) and electricity (115.5 TWh). In the industrial sector, heat is required in specific processes (thermal and thermochemical treatments, drying, sterilization) and space and water heating for buildings and offices. From reference [11], 40% of final energy use is heating furnaces, 21% for drying, 6% for space heating, 12% for raw material, and 21% for other electric uses (motors and pumps). Heat Roadmap Europe [12] details the temperature range required in different industrial processes. Both results are reported in Table 5. Heat accounts for 66% of energy use in the industry among which 41% – or 87 TWh – are at low temperatures either for space and water heating or for heating processes below 200°C, found mainly in the paper and pulp industry, food industry, and part of chemical industries.

Finally, in the agriculture sector, about 15% of the total energy consumption is spent on heating for space, gardening in hot greenhouses, or flower growing.

Summing up all sectors, the total energy needs in the form of heat is 718 TWh, representing 40% of the final energy consumption (Fig. 19), out of which 556 TWh (32.5% of final energy) are at low temperatures.

Table 4. Energy consumption in the residential and commercial sectors for year 2019 in France. Specific power uses include home appliances (TV sets, refrigerators, freezers, washing machines, dishwashers...) and all electric and electronic devices (computers, internet, lighting, etc.).

Energy needs in France in 2019 (in TWh)		
	Residential	Commercial
Space heating	289.1	101.4
Water heating	48.6	22.6
Cooking	24.0	11.1
Cooling	1.2	21.7
Specific power	73.1	70.3
Other uses	0.0	10.4
Total	436.0	237.5

It is worth noting that the production of heat transported and distributed in heat networks amounts to 25.6 TWh for end-users, representing less than 5% of the overall heat consumption at low temperatures.

It appears from these figures that the needs for energy in the form of heat are very large and about the same order of magnitude as the cogeneration potential of the mix of power sources present in the French metropolitan territory. It would thus be possible in principle to fulfill a large fraction of these heat needs by cogeneration. In the following section, we shall quantify the benefits of heat-electricity cogeneration in one application of special interest: district heating.

8 Electricity and heat cogeneration for district heating in France

District heating using a centralized network of hot water is developing in many cities due to its economic and ecological advantages. As seen from Table 4, the annual consumption for space heating in France amounts to 390 TWh and 462 TWh when adding water heating. The peak power called for in wintertime is close to 100 GWth. This is the same order of magnitude as the amount of heat dumped by the nuclear reactor fleet of this country. It is thus very appealing to recover at least part of the wasted nuclear heat and use it through heat networks to replace individual heating installations, not only because the latter is more expensive but also to slash down CO₂ emissions due to gas heating.

8.1 Economic comparison: with- and without cogeneration of power and heat for district heating

The 2019 French power mix is assumed; the average electric power demand has been assumed to be 39.7 GWe

Table 5. Energy needs in the French industry: two-thirds of the energy is in the form of heat.

Energy uses in industry in 2019 (in TWh)	
Space heating	34
Process heat	177
<100°C	12
100°C–200°C	41
200°C–500°C	22
>500°C	102
Total heat	211
Refrigeration and cooling	12
Other uses of energy	97
Total	320

(pure, *ie* excluding the electric power used to produce heat); The average low-temperature heat demand for the 2019 French metropolitan territory has been assumed to be 60 GWth.

It is also assumed that the heat demand remains the same with- and without cogeneration, and that it is fulfilled 75% by natural gas and 25% by electric heaters in the no-cogeneration option¹. Therefore, in the cogeneration option, the electric consumption of the territory decreases because the electric heating of homes shall be partially replaced by district heating.

It is assumed that the cogenerated heat is produced at 100°C, with a subsequent loss in electric conversion yield for the nuclear source (from 35% to 25%).

Under these assumptions, the following results have been obtained using the MIXOPTIM software in the options with- and without cogeneration (Tab. 6).

The above results compare only *production costs* and consider neither the transport nor the distribution costs of heat and electricity. Within these limitations, it can be seen that the cogeneration option is largely preferable to the non-cogeneration option, both from the economic and environmental points of view. This is because the French power mix has a low carbon content, with a large nuclear share (above 70%). Cogeneration appears to be less interesting when the electric mix is composed mainly of fossil fuel sources and would be thoroughly impossible with a mix composed exclusively of renewables, non-thermal sources.

¹ The actual distribution of energy sources for heat use in France stands as follows: 40% natural gas, 22% electricity, 13% biomass, 13% domestic oil, 5% district heating, 3% heat pumps, 1% LPG, 1% coal and the rest (2%) is miscellaneous renewables or waste. Our simplification considering only two sources (gas and electricity) is close enough to reality in terms of CO₂ emissions, taking into consideration the present trend of progressively switching from domestic oil to gas.

Table 6. Comparison of the performance indicators of the French mix with and without cogeneration. Data in black are input data for the MIXOPTIM software; Data in red are the result of the calculation.

	Without cogeneration	With cogeneration
Net average electric demand (net, <i>ie</i> excluding the electric power used to generate heat) (GWe)	39.7	39.7
Average heat demand (GWth)	60.0	60.0
Total average electric demand (including the electric demand devoted to heat production) (GWe)	54.7	39.7
Cost of satisfaction of the electric demand (€/MWe)	45.4	50.2
Hourly cost of satisfaction of the electric demand (M€/h)	2.48	1.99
CO ₂ production (t/h)	23520	16600
Average heat cogenerated (GWth)	0	28.6
Average heat produced by the complementary source to fulfill the heat demand (GWth)	45.0	31.4
Additional cost of satisfaction of the heat demand (M€/h)	3.42	2.38
Total hourly cost of satisfaction of electric power and heat demand (M€/h)	5.90	4.47

9 Conclusion

Electricity and heat are complementary energy vectors, as the former is difficult to store and easy to transport, whereas it is the opposite for the latter. This complementarity has not been fully explored in the present study, since we focused on average values, with simplified assumptions on time and space fluctuations of production and consumption of power on a territory. Notwithstanding, heat and electricity are natural partners, and this study confirms the benefits of their cogeneration. Cogeneration brings improvement on all the performance indicators of the mix: the security of supply provided by the mix is improved despite the inevitable reduction in the electric conversion yield because the total demand for electricity is reduced; the average power imported from neighboring territories can be reduced for the same reason; the hourly production cost of the electric plus heat power demanded on the territory is reduced, as well as the total amount of CO₂ produced because there is less need for additional, carbon-intensive heat sources. However, the interest in cogeneration depends on the composition of the power mix: cogeneration is thoroughly impossible with non-thermal sources like wind, solar PV, or hydraulic; it is moderately interesting when using carbonated fossil sources, and highly interesting with the nuclear source, an energy source basically decarbonated. The benefits on all the performance indicators of the mix are especially large for countries like France, equipped with a mix of

power sources having a large nuclear share. These benefits decrease with the progressive introduction of non-thermal renewable power sources in the mix. However, because power generation from wind and solar sources is intermittent, it requires to be backed up by a substantial amount of controlled, dispatchable power sources, with a plausible choice between nuclear and gas. Both are thermal sources, and their presence in the mix guarantees the preservation of a large heat cogeneration capability. In the case of France, the overall cogeneration potential has the same order of magnitude as the heat demand: a large fraction of this demand could be fulfilled by this means. Cogeneration is especially interesting for the production of heat at *low* temperatures, readily available for district heating.

In view of its obvious benefits, we hope that policy-makers will provide incentives to promote electricity-heat cogeneration.

Conflict of interests

The authors declare that they have no competing interest to report.

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The two authors have shared equally the tasks and responsibilities of this study, the first named providing the calculations with the software Mixoptim, and the second the input data.

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