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The FitFor55 legislative package sets ambitious targets to make Europe the first climate-neutral continent by 2050. Within it, the EU Emission Trading Scheme is mandatory for energy operators with an installed capacity higher than 20 MW, calculated by considering units with a rated thermal input under 3 MW. The paper highlights the impact of the Emission Trading Scheme on the investment choices made by district heating systems operators, considering both current regulations and the potential extension of the Emission Trading Scheme to encompass lower energy capacities. The analysis concerns the simulation of four revamping scenarios (two fueled by natural gas and two partially by renewables) within an existing district heating system located in Italy. The economic analysis shows that an extension of the Emission Trading Scheme alone is not effective in hindering scenarios based on natural gas production. A reform of the power exchange market is necessary to drive decarbonization and encourage investment in renewable generation plants.

Keywords: EU Emission Trading Scheme; District Heating System; Energy Transition; Decarbonization; Energy Market; Renewable energy sources.

Nomenclature

ETS	Emission Trading System	
DHS	District Heating System	
DH	District Heating	
CO_2	Carbon Dioxide	
CHP	Combined Heat and Power	
TV	ETS inlet power threshold value (3MW)	(MW)
P_{th}	thermal power	(MW)
P_{el}	electric power	(MW)
F	fuel power	(MW)
LHV_{NG}	lower heating value	(GJ/m^3)
LHV_{bio}	lower heating value	(GJ/kg)
η_{th}	thermal efficiency	(%)
η_{el}	electrical efficiency	(%)
W	wood-biomass	
NG	natural gas	
EC	CO_2 allowances cost	(EUR/t)
IPEX	Power Exchange market price	(EUR/MWh)
IGEX	Natural Gas Exchange market price	(EUR/MWh)
OPM	Operating Profit Margin	(EUR/y)
NPM	Net Profit Margin	(%)
r	Annual revenues	(EUR/y)
e	Annual expenses	(EUR/y)
I	Initial Investment	(EUR)
GE	Internal combustion Gas Engine	
GEHP	Gas Engine with Heat Pump	
IBB	Integration and Back-up Boiler	
OBB	Thermal oil biomass boiler	
BB	Biomass boiler	
ORC	Organic Rankine Cycle	
IT	Italian electrical energy market	
IT MR	Italian electrical energy market revision	
ES	Spanish electrical energy market	
FF	Fossil fuel scenario (GE and IBB installation)	
FF_{HP}	Fossil fuel scenario (GEHP and IBB installation)	
R1	Partially renewable scenario (BB and IBB installation)	
R2	Partially renewable scenario (ORC, OBB, and IBB installation)	
CS	Generation plant: current state	

Introduction

The current economic, geopolitical, and environmental post-pandemic landscape underscores the urgent need to accelerate decarbonization. The unforeseen massive rise in gas prices and the ever-increasing costs of Emission Trading Scheme (ETS) allowances are driving the identification of feasible and commercially available renewable technologies to expedite the phase-out of fossil fuels. District Heating Systems (DHSs) are an established solution to decarbonize the thermal sector, leveraging a broad array of renewable heat sources flexibly. The “Fit For 55” legislative package, designed to align the EU's climate and energy policies with its ambition to become climate-neutral by 2050, highlights the importance of District Heating (DH) networks in decarbonizing the EU heating sector. It calls for swift action from the DH industry to shift away from fossil-fuel-based heat supply systems. The current proposal to amend Directive 2003/87/EC concerns phase 4 of ETS (2021 – 2030). This proposal establishes stricter limits on greenhouse gas emissions, revises regulations for the free allocation of allowances, includes provisions for extending the ETS to maritime transport (2024–2025), and introduces a new separate ETS for buildings and transportation. In particular, the Emission Trading Scheme II (ETS II) constitutes an extension of the established emission trading framework. Commencing in 2027, the ETS II encompasses both commercial and residential building sectors, alongside non-agricultural transportation segments (European Parliament and Council 2023). ETS II operates alongside the existing scheme, with its unique emission quotas and economic valuations. This evolution is strategically designed to comprehensively address emissions originating from the building and transportation domains while fostering a proactive drive toward emission mitigation within these sectors.

Participation in the EU ETS is still mandatory for small emitters with a total installed thermal capacity exceeding 20 MW, but units with a rated thermal input under 3 MW are not considered in this calculation. It would be more appropriate to include fossil fuel supplies to small Combined Heat and Power (CHP) and heat plants providing heat to the DH network, which are currently excluded from ETS regulation. Eurostat data indicates that DHS emissions under the current ETS represent about 6.5 Mt, less than 10 % of total estimated DHS emissions (European Commission 2021). The number of small and medium-sized district heating systems – not subject to the regulation – has grown over the decades and will continue to grow with the aim of limiting and managing the heating sector's emissions. The European Commission may extend the ETS to small emitters with a total installed capacity lower than 20 MW, however, the current proposal does not seem to adjust the power capacity threshold and the calculation mechanism.

Numerous studies (Casals 2006; European Climate Foundation 2020; Rootzén and Johnsson 2017; Bersani, Falbo, and Mastroeni 2022) have analyzed the potential effect of applying ETS to the building sector. According to one of the first analyses conducted, building energy demand can be reduced by applying both energy regulation and certification schemes (Rootzén and Johnsson 2017). However, a subsequent study by Cambridge Econometrics argued that extending regulations to the building and transport sector might not significantly cut emissions and could risk energy poverty for low-income households (European Climate Foundation 2020). Other works studied how carbon pricing under UE-ETS could drive the development of low-carbon technologies (Bersani, Falbo, and Mastroeni 2022). While carbon allowances encourage fuel switching between coal and gas plants, they may hinder the expansion of renewable technology capacity. All these studies focused on the ETS impact either on large power plants or on end users and although recent studies have focused on DHSs energy optimization in terms of an environmental and economic perspective (Lund, et al. 2014; Famiglietti, et al. 2021;

Sorknæs, et al. 2020) few works have delved into the effects of environmental policies on system operations.

This paper aims to investigate how the Emission Trading Scheme influences investment decisions for district heating systems that rely on fossil fuel-based technologies. In Europe, thermal energy produced by district heating systems predominantly relies on fossil fuels. Notably, the proportion of renewable energy in these systems varies from a maximum of 80% in the Netherlands to a minimum of around 10% in Central and Eastern European countries, with Italy at approximately 25% (Corscadden, Möhring, and Krasatsenka 2021). Small to medium-sized district heating systems can potentially adopt revamping strategies to evade ETS inclusion by primarily using natural gas. As a result, this study examines different revamping scenarios applied to existing medium-sized District Heating Systems located in the northwest of Italy, assessing their economic, environmental, and energetic implications. To find a way out of the ETS system, the study considers both completely natural gas-fueled (FF and FF_{HP}) and partially renewable plants (R1 and R2). The revamping hypothesis exploits the current regulation that allows exclusion from the ETS system by installing several components characterized by a nominal power smaller than the Threshold Value TV (3 MW). The same scenarios are investigated supposing a possible ETS extension. Exclusion from the ETS system affects investment decisions, slowing down decarbonization only under specific energy market conditions, as discussed in greater detail in the article. To incentivize DH network operators to decarbonize their plants, payment for carbon dioxide (CO_2) allowances should be combined with a review of pricing in the national power market.

This analysis holds significance in highlighting a potential gap in the current regulatory framework, thereby facilitating an enhanced comprehension of potential amendments that could engender a more efficacious system congruence with European objectives.

1 Method

The sections that follow detail the specifics of constructing the simulation model. Section 1.1 elucidates the process of analyzing historical production data to formulate the thermal demand model. In section 1.2, the operational logic of the model and the components of the system that can be simulated are expounded upon. Subsequent to this, the following sections outline the energy and environmental assumptions, as well as the essential economic boundary conditions necessary for a comprehensive analysis.

1.1 Heat load profile

The paper analyses an existing DHS for which thermal energy production and consumption data are available. The heat demand model is developed by processing operational data collected over ten years of DHS operation. The developed simulation model (described in section 1.2) has a higher computational efficiency by working with hourly time-step data. This does not penalize the accuracy of the results. Since the data is acquired from the monitoring system at 6-minute intervals, values were averaged and aggregated on an hourly basis.

For each heating season, the hourly values are divided by the volume supplied. The average hourly heat thermal load of all years of operation is directly used as input in the simulation model developed on Matlab© software (MATLAB 2022).

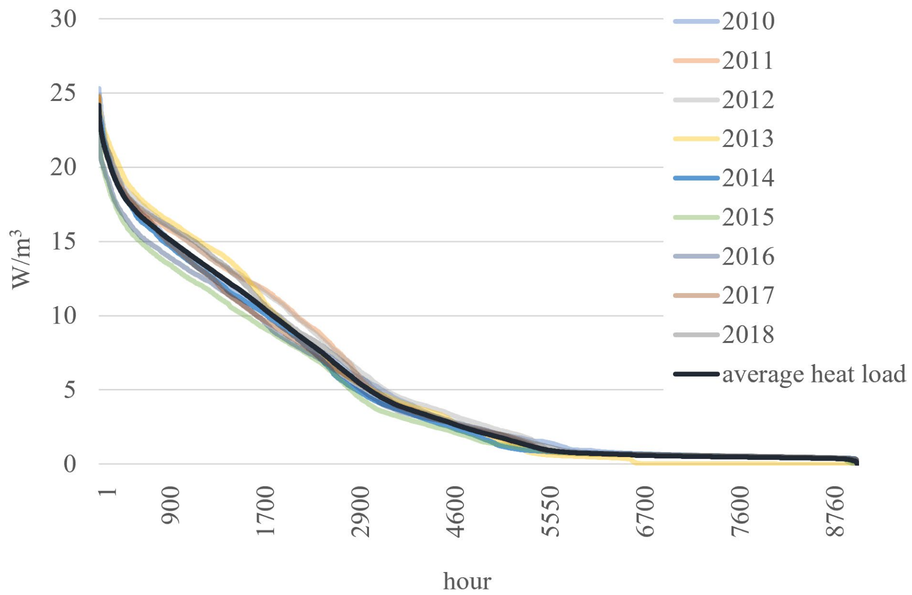

Figure 1. Specific heat load profiles [W/m^3]

1.2 Simulation model

By having information about the hourly heat supplied to the network, DH network temperatures, thermal plant configuration, and the nominal parameters and number of each component, the simulation model determines a range of factors. These include electrical power (P_{el}), fuel power (F), individual component work rates, thermal and electrical efficiency (η_{th} and η_{el}), as well as fuel consumption (e.g., wood biomass (W), natural gas (NG)).

The model enables the selection of all the generators installed in the DH plant and determines the priority order with which each component supplies the thermal demand. For each generator's technology, the number of units and the maximum rate modulation are entered. The minimum and the maximum power that can be achieved respectively by working with one unit at partial load and all units at full load are calculated. If the thermal demand is lower (or higher) than the minimum (or maximum) thermal output, the load is satisfied by alternative generators (e.g., natural gas boilers, biomass boilers). Priority in satisfying heat demand is given to renewable generators – when they are available – then to gas engines, and finally to integration and back-up gas boilers.

To correctly simulate the working performance and to obtain the model input correlation parameters, the variation of the components' performance is analyzed at partial load.

1.2.1 Gas Engine

Gas Engine (GE) is still the most satisfactory solution for cogeneration in civil and district heating applications. In recent years it has become increasingly common to install heat pumps to enhance heat recovery exploiting the waste heat from the second intercooler engine and from the exhausting gas at low temperature. It is assumed to cool exhausting gas until 50°C avoiding condensation. In the presented model, the combination of the Gas Engine and Heat Pump (GEHP) is considered as a single, unified unit.

By comparing the behavior of several engines at partial load (100%, 75%, 50%), a linear correlation between electrical power and thermal power is obtained. This correlation is subsequently used in the simulation model. Figure 2 shows the electrical/thermal power linear correlation at a partial load of a gas engine without a heat pump (GE) and one integrated with a heat pump (GEHP).

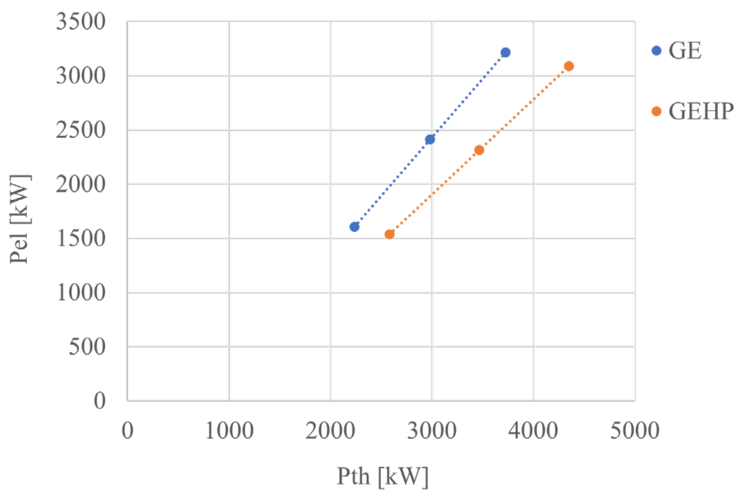

Figure 2. GE and GEHP electrical/thermal power linear correlations.

Compared to GE, GEHP is characterized by a slightly lower electrical energy and a higher thermal energy production, respectively due to the electrical absorption and the additional thermal output of the heat pump.

1.2.2 Organic Ranking Cycle (ORC)

To integrate renewable sources and to maintain cogeneration in DHS, Organic Rankine Cycle (ORC) cogeneration plant fueled by woody biomass can be envisaged. To study ORC performance at partial load, a commercial unit was chosen. In Table 1 ORC and thermal Oil Biomass Boiler (OBB) nominal data are shown.

Table 1. ORC and OBB nominal parameters (Turboden 2022)

ORC P_{th} (MW)	ORC P_{el} (MW)	OBB P_{th} (MW)	OBB η_{th} (%)	OBB F (MW)
4.1	1.1	5.3	85	6.2

Figure 3 shows efficiency trends described by two fourth-degree polynomial functions, which are used to simulate the operation of the ORC.

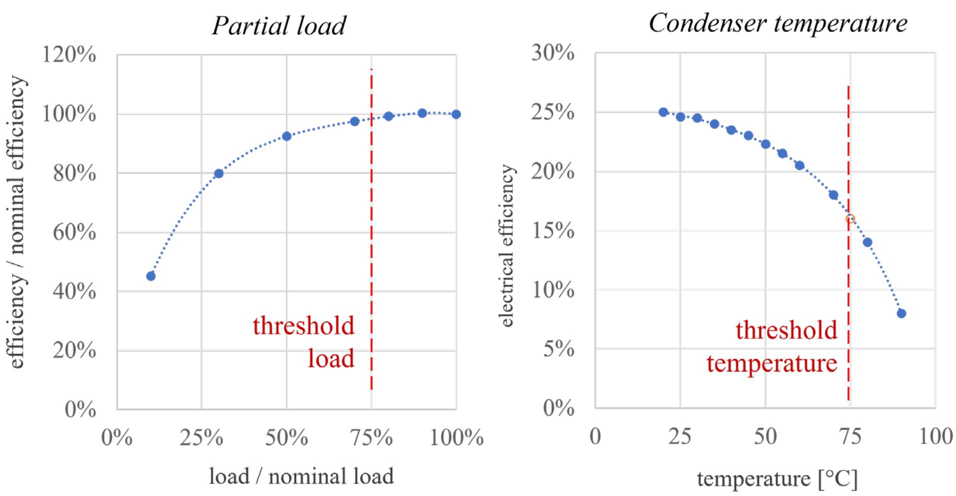

Figure 3. Efficiency trend at partial load and at different condenser temperatures.

Not to penalize the efficiency of the ORC unit and the thermal oil biomass boiler that can operate with constant efficiency up to 65% of its nominal power, it is supposed to modulate up to 75% of ORC nominal load and a temperature threshold equal to 75°C. The maximum flow rate circulating in the condenser of the ORC is 300 m^3/h. If the water flow rate exceeds the ORC threshold, the excess is directly heated by alternative generators (e.g., natural gas boilers, biomass boilers).

1.2.3 Biomass Boiler (BB)

Woody Biomass Boilers (BB) installed in district heating plants only allow the production of thermal energy. BB modulates the load by up to 65% with a constant thermal efficiency of 85%. Such limitation was set considering the need to maintain high values in terms of environmental aspects and pollutant emissions.

1.2.4 Integration and Back-up Boiler (IBB)

Typically, the peak thermal power must be covered by the Integration and Back-up Boilers (IBB) excluding one unit (N-1) in planned and/or unplanned shutdown. In addition, it is assumed that all other generating units (CHP, biomass, etc.) are unavailable. The thermal efficiency is considered constant and equal to 90%. IBB performance is not penalized at partial load. The simulation model assumes that integration components are employed only when the heat required by the network is higher than the maximum power that can be generated by principal power-generation modules.

1.2.5 Definition of fuel data

In the proposed analysis, biomass technologies exploit the supply chain of biomass products from neighboring forests using moist and low-calorific waste wood. The simulation model assumes a biomass Lower Heating Value (LHV_{bio}) equal to 2.35 kWh/kg considering a moisture content of 50% w.b. (wet basis). The Lower Heating Value of Natural Gas (LHVNG) is about 9.79 kWh/m^3.

Knowing the annual fuel consumption, CO_2 emissions have been evaluated through emission coefficients. The emission factor for natural gas assumed is 0.202 kg_{CO_2}/kWh (ISPRA 2021). Biomass is a carbon-neutral fuel, meaning that the carbon emitted by biomass burning won't contribute to climate change if it is grown in a sustainable way.

The economic revenues and the economic cost depend on the energy generated and distributed, the fuel consumed, and the resulting CO_2 emissions. The model finally calculates these economic flows.

1.3 Economic indicators

1.3.1 CO_2 allowances price

The study is extended to the historical trend cost of CO_2 allowances (Emission Cost - EC) (SendeCO2 2022). The analysis showed that until 2017 the maximum cost was about 7 EUR/t. In the following years, EC has increased rapidly. Market forecasts and various studies on the analysis of the evolution of the ETS assume that EC will settle at around 100 EUR/t (European Climate Foundation 2020; Bersani, Falbo, and Mastroeni 2022; EEX European Energy Exchange 2022a). The ETS is a closed market independent of energy market variations. However, it affects the electrical energy markets. Even assuming that the ETS is extended to the transport and building sectors, the new system should be devised to ensure a smooth start and to maintain market stability. To address this issue European Commission is planning to auction a higher number of allowances than the cap in the first year of the start of the system. This additional amount would be deducted from the auctioning volumes in later years to preserve environmental integrity (European Commission 2021a). Therefore, the economic analysis assumes a fixed EC of 100 EUR/t. The actual EUA price fluctuates based on market forces; however, a constant value allows an analysis under consideration without being confounded by the inherent volatility of the emissions market. Additionally, there is a lack of precise and comprehensive data available for accurate modeling of these variations.

1.3.2 Italian Power Exchange Market

The electricity cost is closely dependent on the natural gas price and EC. Therefore, changes in market price from 2015 to 2020 are analyzed (GME 2022). This period represents the most recent historical years preceding the onset of the pandemic and the ensuing energy crisis. By focusing on years that predate these extraordinary events, we aimed to minimize the influence of anomalous cost values and fluctuations that could arise from these unforeseen circumstances. Additionally, the choice of the 2015-2020 timeframe was informed by the absence of significant updates or policy alterations to the national market system. This specific period provides an opportunity to evaluate market dynamics and economic implications of the policy shift under investigation within a relatively stable and consistent regulatory context.

The analysis allowed us to obtain the correlation (1) between electricity price at national market (IPEX), natural gas cost at national market (IGEX) and Emission Cost (EC).

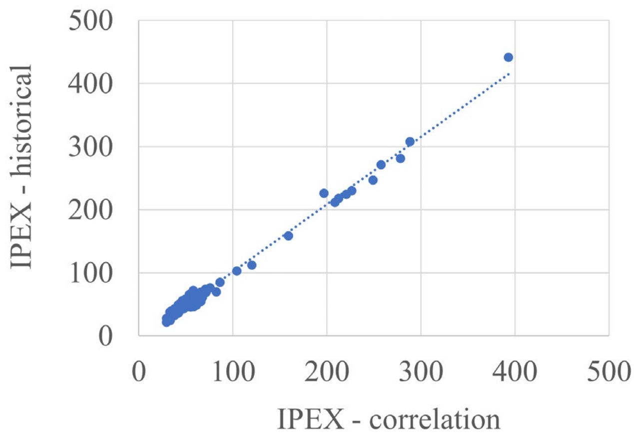

Figure 4. Comparison between historical IPEX and IPEX correlation calculated with correlation (1)

$$IPEX = f + m(IGEX + EC) \quad (1)$$

where $f = 8\,\frac{\mathrm{EUR}}{\mathrm{MWh}}$ and $m = 2$

IPEX depends on the costs incurred for gas-natural and emission allowances purchases multiplied by a factor m: m is inversely proportional to the average efficiency of the national thermoelectric power plant; f is a fixed profit set by the market. The wholesale price of electricity is set directly in the market based on purchases and sales between the various players involved, i.e., between producers and suppliers of energy. The energy produced from renewable sources has a dispatch priority. The remaining amount of energy demand is principally covered by gas-fired power plants that set the final selling price. Market dynamics and the correlation between IPEX, IGEX, and EC are not only characteristic of the Italian case but translatable to different European contexts (e.g., Austria, Germany, Belgium).

Figure 5 shows the electricity price at national market (IPEX) trend – shown in blue – compared to the trend obtained through the correlation (1) – shown in yellow. Power and natural gas future market data are respectively available until 2032 and 2024 (EEX European Energy Exchange 2022b; EEX European Energy Exchange 2022c). Forecast natural gas cost at national market (IGEX) up to 2032 are obtained by applying correlation (1). To obtain a wide economic analysis up to 2040, two additional scenarios are assumed in which the forecast IGEX value is increased and decreased by 20 EUR/MWh and $IPEX_{fut}$, $IPEX_{max}$, $IPEX_{min}$ are directly obtained by applying the correlation. The average IGEX value in 2040 is 40 EUR/MWh, which corresponds to IPEX equal to 128 EUR/MWh.

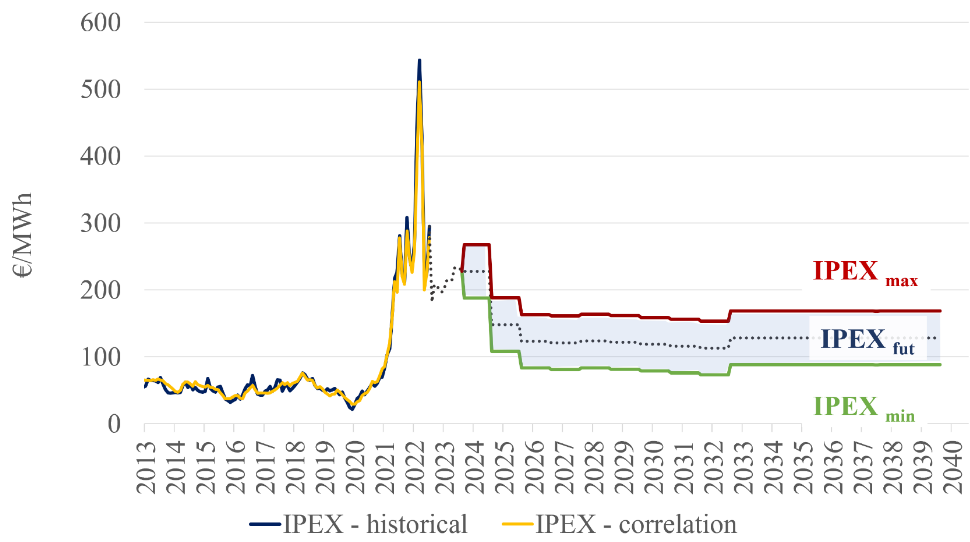

Figure 5. IPEX trend (from 2013 to 2040). Comparison between historical IPEX and IPEX correlation (from 2013 to 2022)

1.3.3 Italian Power Exchange Market revision

In addition to establishing price trend scenarios, it is necessary to define power market exchange scenarios. Electricity market reform is likely to be implemented in the coming years. With the ever-increasing integration of renewable sources, the current pricing system, which is heavily influenced by fluctuations in fossil fuel prices, is not feasible. One of the possible assumptions is that IPEX will be set considering the prices defined by each energy producer averaged over the percentage of total consumption covered. Presently in Italy, 40% of electricity production is from renewable sources (ENEA 2021). It is cautiously assumed that by 2040 this percentage will be increased by 10%. Furthermore, this increase is projected to be supported by state feed-in-tariffs, unlike the already established capacity which will no longer receive subsidies. The price of renewable electricity produced by already installed plants is assumed to be 0 EUR/MWh. The economic support for new renewable installations is considered constant and equal to the average IPEX price. The electrical energy produced from fossil power plants and the electricity imported are priced equal to the IPEX trend (Figure 5).

1.3.4 Spanish Power Exchange Market

To obtain a comprehensive economic analysis, consideration of an additional market exchange scenario is necessary. Notably, the forecasted electricity cost trend in Spain diverges significantly, rendering it particularly intriguing for the analysis. Importantly, it stands as the sole instance among European countries where the projected price trajectories of electricity and natural gas show notable differences. Spain has set plans to increase renewable energy production, supplying 74% of its energy demand from renewable plants by 2030. Additionally, the divergence from other European countries might be attributed to Spain's decision to impose a price cap on natural gas. The electricity price follows a significantly lower trend than that in the rest of the European countries and is totally independent of the natural gas cost and the CO_2 allowances price variations. In 2040 the forecast natural gas cost at national market is like the Italian value, while the electricity price at national market is equal to 40 EUR/MWh. Scenarios are also analyzed in the "Spanish context", while maintaining the Italian regulatory framework, and applying Spanish energy prices.

1.3.5 Other costs

To achieve cost stability, wood chips price is considered constant (75 EUR/t) and independent of fluctuations in the natural gas market.

Finally, analyzing the evolution of the price of the heat supplied to the users connected to the DH network during the years of operation, a cost component related to the system charges has been identified, which is approximately constant and equal to 45 EUR/MWh. This component is added to the cost of natural gas (IGEX) to obtain the income related to the sale of the heat.

2 Results

In the following sections, a comprehensive analysis of an existing DHS case study located in northern Italy is provided. Section 2.1 presents the technical current state of the case study. This description encompasses various crucial attributes of the thermal plant and the network, providing essential context for the subsequent discussions. Moving forward, we assume and explore four distinct scenarios aimed at revamping the existing plant. In the sections that follow (sections 2.2 and 2.3), the results obtained from each scenario are discussed, evaluating their impact on energetic and environmental considerations, and economic viability.

2.1 Case study description and revamping scenarios

The third generation DHS (Lund, et al. 2014) under study is located in the north-west of Italy. The site is characterized by 2,617 degree days (climate zone E).

The DH network serves about 300 users (1 Mm^3). Supply and return temperatures are approximately 90°C and 60°C, respectively. Due to climatic and operational characteristics customary in northern Italy and in the central European area, this case study can easily be replicated and generalized.

The CHP plant was installed in 2010 and consists of 3 Gas Engines (GEs) with a total thermal output of 6 MWt and 4 Integration and Back-up Boilers (IBBs) of 8 MWt each. Each GE worked an average of 4,000 hours per year. Typically, gas engines need extraordinary maintenance (major overall) after about 60,000 hours of operation, requiring a components' revamping investment about 15 years after installation. It is assumed to address the necessary investment in 2025. Revamping scenarios are designed both by replacing all or part of GEs maintaining the type of component or by changing the heat generation technology.

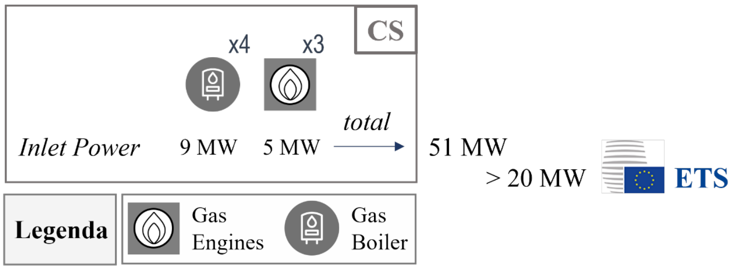

Figure 6. Generation plant: current state (CS).

With the intention of introducing a percentage of renewable energy, possible alternatives for heat generation have been analyzed. The choice of the source depends on the temperature levels to be maintained on the district heating network (90 – 60 °C) and the seasonality of the availability of the energy source. The DHS is in an area where it is possible to exploit a local and sustainable biomass-based products supply chain. Biomass technologies also allow reaching temperatures in line with those required by the network under analysis.

In line with European ambitions to transition to a sustainable heating and cooling sector, there's an imperative to diminish thermal energy demand. European nations have progressively initiated policies enhancing the efficiency of buildings in the civil sector. Extensive refurbishment measures lead to an increase in efficiency on the consumer side, which, however, results in a reduced demand for district heat. Overall, this can cause techno-economic challenges due to reduced revenue and changing heat demand profiles. Therefore, to assess the techno-economic impact of the transformation of DHS, an analysis of the consumer side is conducted too through the developed simulation model that allows the simulation of users and generation plants simultaneously. It is assumed that by 2025 part of the connected users may already benefit from state subsidies. An average energy consumption reduction value of 15% has been hypothesized. The scenario assumes to insulate the roofs and the vertical opaque surfaces of buildings with centralized heating systems that can be characterized by cavity wall, according to the year of construction.

Since the GEs need a major overall or a whole substitution, it is necessary to define plant layout in relation to the available energy sources and the performance required. To reach the ETS exclusion all scenarios are designed with a gas-fired component inlet power lower than the Threshold Value TV (3 MW).

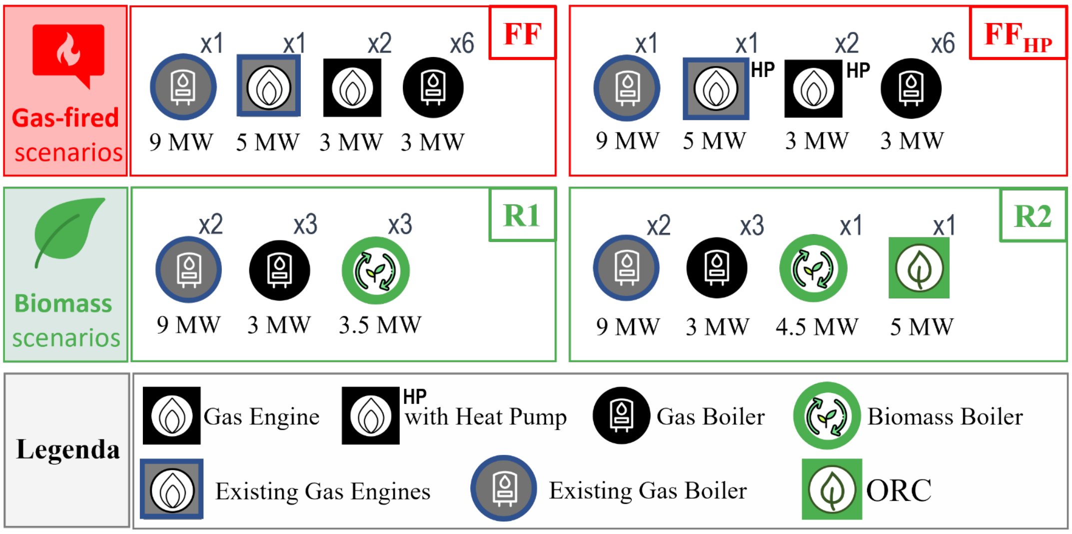

Figure 7. Revamping scenarios.

The Figure 7 shows four different scenarios analyzed (FF, FF_{HP}, R1 and R2). To determine which investment choice to make, two scenarios based on natural gas production and two alternatives in which the investment is oriented towards the integration of renewable sources are simulated. Components maintained from the initial configuration plant are represented in grey. The powers shown refer to the input power values considered in determining ETS exclusion.

FF and FF_{HP} configurations assume to perform the major overall on one of the three gas engines. FF scenario assumes the installation of two new Gas Engines (GEs), and FF_{HP} two new Gas Engines with Heat Pumps (GEHPs). In both fossil-fuel scenarios, the new components are not subject to ETS calculation. It is supposed to maintain one of the four initial Integration and Back-up Boilers (IBB) and to install six new IBBs with a thermal power input lower than the ETS Threshold Value TV (3 MW).

R1 is characterized by the installation of a Biomass Boiler (BB) whose thermal power covers the energy supplied by GEs in a gas-fired configuration. R1 plant layout does not allow the production of electrical energy. Therefore, in scenario R2 an ORC cogeneration plant fueled by wood chips is simulated.

In both cases, three new IBBs are installed and the other two are maintained from the generation plant's current configuration (Current State – CS) keeping power input subject to ETS regulation lower than 20 MW.

2.2 Energy and environmental performances

Using the developed simulation model, it is possible to obtain information about the thermal/electric energy generated, the efficiency of the single components and of the whole DHS, as well as the CO_2 emissions released. The thermal energy supplied to users is obtained considering a thermal loss factor on the network equal to 15%. This value was determined through analyzing production and sales from 2010 to 2020. The electrical energy delivered to the grid considers the amount of self-consumption of the generation plant. Scenario R1 is characterized by a plant configuration that does not allow power generation. As a result, the self-consumption amount must be taken from the electric grid (negative numbers shown in Table 2).

Given the same amount of heat produced (38 GWh/y), the FF_{HP} scenario emerges as the most efficient from an energy perspective. Heat pump installation allows it to reach a higher value of global efficiency, even with a slightly lower amount of electrical energy generation compared to the FF scenario. The CHP electrical energy produced in FF and FF_{HP} scenarios is sufficient to reach the required level for gas defiscalization. The

European Directive 2012/27 introduces the key definition of *efficient district heating and cooling* as a district heating or cooling system using at least 50% renewable energy or 75% of energy produced by cogeneration (European Parliament and Council 2012). The only scenarios that meet the definition are the partially renewable ones.

Table 2. Scenarios annual data.

	Primary energy (GWh/y)		Thermal energy (GWh/y)	Electrical energy (GWh/y)	Renewable (%)	Efficient DHS
	NG	W				
FF	61	-	38	16	-	no
FF_{HP}	57	-	38	15	-	no
R1	15	32	38	-1	66	yes
R2	34	19	38	2	60	yes

When evaluating only gas-fired generation scenarios (FF, FF_{HP}), FF_{HP} emerges as the most favorable in term of natural gas consumption. However, when evaluating across all scenarios, the lowest consumption value is observed in R1. Lower use of natural gas also results in a reduced environmental impact regarding CO_2 emissions. In the FF_{HP} scenario the emissions decrease by 7% compared to FF configurations; R1 represents the best solution emitting a quarter of the emissions compared to the most environmentally high-impact scenario FF (Figure 8). The subsequent section will determine whether potential emission allowance payments might alter the economic dynamics of the DHS and evaluate the influence of the ETS in guiding investment decisions.

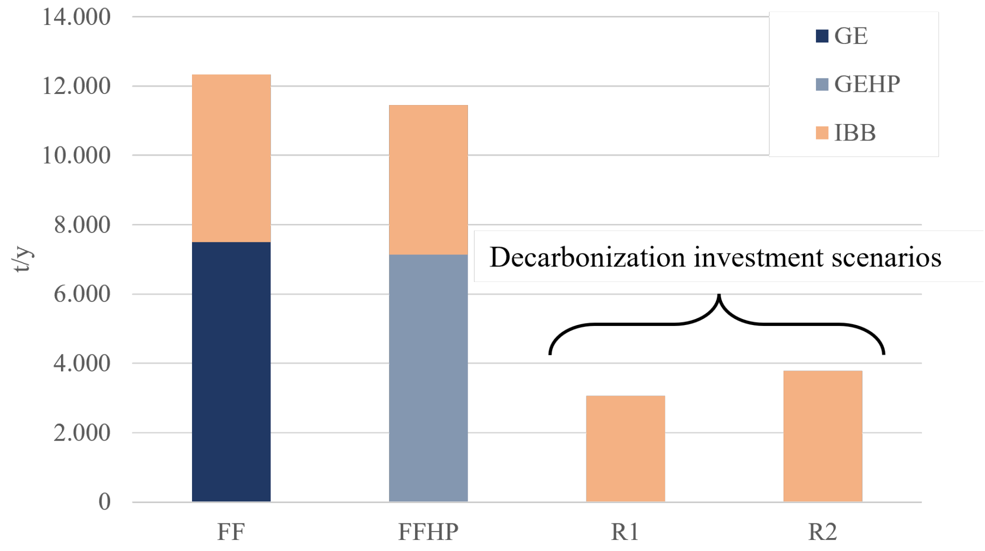

Figure 8. CO_2 annual emissions [t/y].

2.3 Economic performance

Operating Profit Margins (OPMs) are calculated for each plant configuration from 2025 to 2040 considering the economic indicators and trends cost defined in the previous section. At year zero the investment (I) – shown in Table 3 – is made all at once. FF and FF_{HP} are characterized by the lowest initial investment expense. Scenarios involving the use of biomass also include the construction of a wood chip storage facility.

Table 3. Scenarios' investment.

	FF (kEUR)	FF_{HP} (kEUR)	R1 (kEUR)	R2 (kEUR)
GE	2,500			
GEHP		2,800		
BB			4,500	2,000
ORC				1,700
OBB				2,600
IBB	780	780	390	390
Wood storage			250	250
Total investment	**3,280**	**3,580**	**5,140**	**6,940**

The economic revenues concerning electricity and heat sold to customers and the economic costs related to the market prices of combustion fuel, O&M cost and staff cost are calculated for each year from 2025 to 2040. Each scenario is evaluated considering the current ETS regulation and its potential extension. The regulation's impact is examined across 3 power exchange market scenarios. First, generation plants are analyzed in the current Italian electricity market (IT), then on the assumption of its revision (IT MR), and finally in the "Spanish context" (ES). Figure 9 shows the Net Profit Margin (NPM) in 2040 for each case knowing annual revenues (r) and expenses (e) and considering the IGEX variations. As previously detailed, the variation affects the IPEX in the IT case (Figure 5), partially affects it in IT MR and it is totally independent in the ES case.

$$NPM = \frac{\left(\sum_{y=2025}^{2040} r - e\right) - I}{\sum_{y=2025}^{2040} r} * 100\% \qquad (2)$$

Considering the current ETS regulation, none of the analyzed configurations are subject to the emissions allowance. FF and FF_{HP} configurations plant achieve the highest total OPM, with a simple payback time of less than 4 years. Gas engines are economically advantageous both because of the lower investment required and because during operation they allow additional income from the electrical energy sale. Although R2 allows the production and sale of electrical energy, it is generated in a smaller amount that does not compensate the initial investment equivalent to twice the FF (or FF_{HP}) investment.

To determine whether the extension of the ETS would tip the economic outcome in favor of scenarios with the integration of renewables, EC is attributed to the emissions generated. Again, the investment in fossil fuel components emerges as the most profitable. This is because of the price of electrical energy is closely related to the natural gas cost, which also influence the heat tariffs applied to users. Conversely, the ETS market operates as a distinct, insulated market unaffected by fossil fuel price fluctuations.

Envisioning a reform of the Italian energy market, the extension of the ETS would facilitate scenarios with heat production from renewable sources.

Finally, the extension of the ETS is most pronounced when electricity pricing is wholly decoupled from natural gas cost variations, as seen in the "Spanish context" where fossil fuel technology investments become significantly riskier.

	ETS									ETS II								
	IT			IT RM			ES			IT			IT RM			ES		
	min	IGEX	max	min	IGEX	max	min	IGEX	max	min	IGEX	max	min	IGEX	max	min	IGEX	max
FF	41%	31%	25%	30%	17%	10%	30%	9%	-6%	6%	5%	5%	-10%	-13%	-15%	-11%	-25%	-34%
FF_{HP}	42%	32%	27%	32%	20%	13%	32%	12%	-1%	9%	8%	7%	-6%	-9%	-10%	-7%	-19%	-28%
R1	19%	14%	10%	19%	15%	11%	19%	15%	12%	8%	4%	1%	8%	4%	1%	8%	4%	2%
R2	18%	14%	11%	16%	12%	7%	16%	10%	5%	4%	2%	-1%	2%	-1%	-4%	2%	-3%	-7%

Figure 9. Net profit margin.

Figure 10 shows how much each expenditure item affects the total revenues. While in the IT case the increase in expenditure does not cause a significant difference between the biomass and natural gas scenarios, in the IT MR and ES case ETS extension (boxed in red) reverses the economic balance of the system by favoring the partially renewable scenarios (R1 and R2) with lower CO_2 emissions.

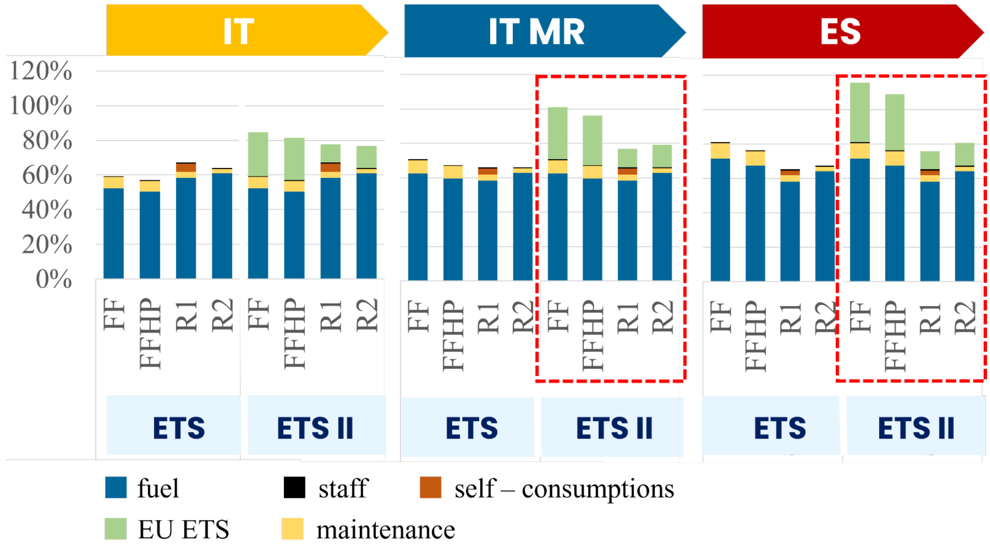

Figure 10. Expenses over total revenues in IT, IT MR, and ES power market context.

3 Discussion

The study assesses the effectiveness of the ETS system in driving investment in medium-sized DHSs towards renewable technologies by promoting thermal sector decarbonization.

A detailed analysis was conducted of generalizable existing DHS with a heated total volume supplied and a climate zone which are common in the north of Italy and in Central Europe. The analysis provides valuable insights for the district heating system in the specific case study, which, in terms of generation plant typology and network extension, is generalizable compared to European District Heating Systems. Moreover, it provides an intriguing methodology and calculation logic that can be applied to other DHSs with varying heat production and revamping scenarios. Four different scenarios are assumed and simulated with the aim of identifying the best plant layout that would maximize the net profit margin in 2040. In recent years, the rising cost of CO_2 allowances has significantly lowered the plant operating profit constituting a relevant economic problem. Leveraging the prevailing ETS directive, which permits system exclusion installing components with input power below 3 MW, every scenario is tailored to fulfill these specific plant configuration prerequisites. The revamping scenarios which supply part of the heat demand through renewable sources exploiting wood biomass have a lower environmental impact in terms of CO_2 emissions. Yet, these are not economically viable either within the existing ETS framework or its potential successor. This is partly because the initial investment cost is higher. However, the principal constraint is tied to the electricity price determination in the Italian power exchange market (IPEX). IPEX is closely linked to the price of natural gas on which heat cost applied to district users also depends. This correlation favors scenarios characterized by gas engine installation, which have proportionally higher revenues for higher expenses.

In order to make EU ETS extension effective, reform of the system of the energy market is necessary. The same scenarios are analyzed in the "Spanish context" where the electricity price is totally independent of natural gas due to the high percentage of electricity produced from renewable sources. In parallel, a revision of the Italian energy market is assumed in which the electricity price is defined as a weighted average of the prices of the different energy producers with respect to the percentage of demand covered. To provide a cautious estimate, the percentage of renewable electricity production in 2040 was assumed to be 50%. This value is lower than the European (European Commission 2021b) and national scenarios (MASE 2019) but allows for an assumption of a higher electricity price that is not completely independent of natural gas, thus providing an intermediate perspective between the Spanish scenario and the current Italian energy market system. The extension of the ETS in both cases changes the economic results. Scenarios that minimize CO_2 emissions are also cost-effective. Considering current the ETS regulation and assuming its extension from 2026, the most advantageous revamping investment appears to be one based on the use of natural gas (FF_{HP}). This would be economically unfavorable only in a market system where IPEX and IGEX are unrelated.

Environmental policy alone is not sufficient in influencing renewable integration investment decisions. To ensure that energy regulations can effectively drive decarbonization, there must be a concomitant change in the electricity market.

The paper spotlights two pressing challenges associated with the Emission Trading Scheme (ETS): firstly, a technical loophole that allows District Heating Systems (DHSs) with thermal installed capacities higher than 20 MW to circumvent CO_2 allowances payments. Furthermore, it accentuates the urgency of extending the system to encompass all energy systems, even those with installed capacity below 20 MW, while simultaneously reforming the actual Italian power exchange market. This revision should lead to an electricity price determination that is not reliant on natural gas prices, making investments in renewable technologies economically more attractive and ultimately enabling the achievement of European decarbonization goals.

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Figures

Figure 1. Specific heat load profiles [W/m^3]

Figure 2. GE and GEHP electrical/thermal power linear correlations.

Figure 3. Efficiency trend at partial load and at different condenser temperatures.

Figure 4. Comparison between historical IPEX and IPEX correlation calculated with correlation (1)

Figure 5. IPEX trend (from 2013 to 2040). Comparison between historical IPEX and IPEX correlation (from 2013 to 2022)

Figure 6. Generation plant: current state (CS).

Figure 7. Revamping scenarios.

Figure 8. CO_2 annual emissions [t/y].

Figure 9. Net profit margin.

Figure 10. Expenses over total revenues in IT, IT MR, and ES power market context.

The authors report there are no competing interests to declare.