

On-site hydrogen refuelling station techno-economic model for a fleet of fuel cell buses

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ABSTRACT

Fuel cell electric buses (FCBs) have proven to be a technically viable solution for transportation, owing to various advantages, such as reliability, simplicity, better energy efficiency, and quietness of operation. However, large-scale adoption of FCBs is hindered by the lack of extensive and structured infrastructure and the high cost of clean hydrogen. Many studies agree that one of the significant contributors to the lack of competitiveness of green hydrogen is the cost of electricity for its production, followed by transportation costs. On the one hand, to reduce the investment cost of the electrolyzer, high operating hours should be achieved; on the other, as the number of operating hours decreases, the impact of the electricity costs declines. This paper presents an innovative algorithm for a scalable hydrogen refuelling station (HRS) capable of successfully matching and identifying the most cost-efficient levelized cost of hydrogen (LCOH) produced via electrolysis and connected to the grid, based on the HRS components' cost curves and the hourly average electricity price profile. The objective is to identify the least-cost range of LCOH by considering both the electric energy and the investment costs associated with a hydrogen demand given by different FCB sizes and electrolyzer rated powers. In addition, sensitivity analyses have been conducted to quantify the technology cost margins, and a cost comparison between the refuelling of an FCB fleet and the recharging infrastructure required for an equivalent fleet of Battery Electric Buses (BEB) has been performed. An LCOH of around 10.5 €/kg varying from 12 €/kg (2 FCB) to 10.2 €/kg (30 FCB) has been found for the best-optimized configurations. The final major conclusion of this paper is that FCB technology is currently not economically competitive. Still, a cost contraction of the electric energy price and the electrolyzer capital investment would lead to a 50% decrease in the LCOH. Furthermore, increasing renewable energies into the grid may shift the electricity cost curve, resulting in higher prices when the BEB recharging demand is more significant. This impact, in addition to the peak power load and longer recharging times, might contribute to bridging the gap with FCBs.

1. Introduction

1.1. Background and motivation

As declared by the European Commission, the transport sector is the main responsible among the anthropogenic activities of the air quality deterioration and the increase in air pollution levels in dense and populated areas in Europe [1–3]. This condition is even more exacerbated during the cold season and when stagnant wind conditions and atmospheric stability are frequently observed [4,5].

Indeed, transport CO₂ emissions correspond to at least 28% of European Union (EU) greenhouse gas emissions in 2020, of which 72% is

attributed to road transport [6]. In this context, heavy-duty transport vehicles, such as buses, trucks, and coaches, albeit representing up only 2% of the EU fleet, accounted for 28% of EU's road transport CO₂ emissions scenario [7]. Hence, they certainly have an impactful role in the climate-worsening. Consequently, this has promoted the implementation of numerous incentives to rapidly deploy valid alternative low-carbon solutions to replace the current fossil fuels-based transport vehicles [8]. The advantage of this policy has also been recognized as its potential to substantially improve the energy security [9,10]. It is also undoubted that the green transition, with a particular focus on sustainable mobility, circular economy, and climate change, holds significant potential for boosting economical and social factors alongside

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environmental benefits [11].

Fuel cell electric vehicles (FCEVs) that use a fuel cell to convert hydrogen (H_2) into electricity with water vapour as the only environment-friendly by-product are one of the technologies broadly under discussion in the present day that could help to meet the challenge towards sustainable mobility [12]. If hydrogen is produced via electrolysis powered by green energy, it presents a promising opportunity to significantly assist the decarbonization of the transportation sector, facilitate cross-sector integration, and potentially foster the growth of a unified market [13].

One of the possible solutions to refuelling hydrogen vehicles is the realization of distributed facilities with local H_2 generation to reduce the operational costs associated with fuel transport from the production to the utilization site [14]. In the context of on-site facilities, the number of running hours plays a crucial role in determining whether the cost of electricity for H_2 production and compression or the investment cost of individual components takes precedence [15]. Thus, it becomes imperative to design a hydrogen refuelling station (HRS) that is both cost-effective and functionally efficient, based on the actual demand.

1.2. State of research

The role of infrastructures for H_2 production, transport, storage, and dispensing is an active field of research and an important part of a pattern of technology acceptance and adoption. In a recent study, Gils et al. [16] demonstrated that H_2 is crucial for providing seasonal balancing, but large-scale infrastructures are needed to reduce supply costs. The advantages of utilizing H_2 as a carbon-free energy carrier and a flexible solution for short- and long-term storage due to its intrinsic ability to be converted into electricity, heat and transport fuel, thus connecting different sectors, have also been studied by Coppiters et al. [17] and Garcia et al. [18]. In addition, H_2 can be exploited as a stabilizer of electricity distribution systems, leveraging on the fast response dynamics of electrolyzers, as stated by Suarez et al. [19]. Cebulla et al. [20] observed a close correlation between wind power generation and the use of H_2 storage, while batteries appear to perform better in smoothing out power generation from photovoltaic systems. The practices in the Zhangjiakou fuel cell bus (FCB) project, as investigated by Zhang et al. [21], demonstrated the economic feasibility of commercializing H_2 vehicles in areas with abundant renewable resources. Finally, the review work conducted by Tashie-Lewis et al. [22] led to the conclusion that hydrogen technology has reached high maturity levels, but its uptake faces significant challenges due to cost barriers, especially the green H_2 production.

The H_2 generation cost from water electrolysis coupled with renewable generation has been investigated in several respects. Christensen compared the cost associated with hydrogen generation via electrolysis connected to the grid, directly connected to the renewable generator, and using curtailed electricity in the United States and Europe from the years 2020–2050 [23]. A global model that evaluates the most cost-effective location to purchase H_2 has been provided by Collis et al. [24]. They found a reduction in the costs when H_2 is transported in pipelines to industrial areas, while ammonia and liquid organic hydrogen carriers are preferred for long distances in the short term. Reuß et al. [25] elaborated a similar conclusion by affirming the distribution should be handled with gaseous compressed trailers for low fuel cell vehicle penetration rates and subsequently replaced by distribution. Dispenza et al. [26] studied the positive impact on savings by adding an energy storage system to the plant. Wang et al. [27] presented a mathematical model with the aim of designing an H_2 supply chain network that optimizes the HRS size and location in coastal areas. Uchman et al. [28] focused on analysing variable load distribution operating with an electrolyzer plant and a wind farm to determine the most efficient plant configuration that maximizes the system's flexibility. Gutiérrez-Martín et al. [29] carried out rigorous simulations of a hybrid renewable energy system, integrating the production from

photovoltaic with water electrolysis and batteries, proving that lower H_2 generation cost can be achieved by combining the technologies.

Oldenbroek et al. [30] explored the technical and economic feasibility of achieving a 100% renewable energy system with FCEVs and H_2 as an energy carrier, ensuring a reliable and cost-effective energy supply. In a later work, the study is increased in spatial resolution, in which the system boundaries are expanded to the national level [31]. A cross-sector and cross-border energy model in the EU has been tackled by Brown et al. [32]. The critical role of FCEVs within an energy system and their contribution to decarbonization, as well as to the stability of the power network, has also been investigated by Alavi et al. [33]. Other works focus on hydrogen and smart grid integration, of which a comprehensive overview has been provided in a review article by Lin et al. [34]. Their investigation allowed the authors to affirm that although hydrogen has a great potential to be used in multiple smart grid applications, there are still many challenges to be faced, such as integration strategy, hydrogen energy monitoring and long-term storage. However, the widespread adoption of FCEVs cannot transpire without reliable, fast, and safe refuelling. The crucial parameters that affect the refuelling performance are evidenced in a recent research study by the Argonne National Laboratory [35]. In particular, their analysis revealed a strong correlation between pipe length and sizing and pressure drops. Furthermore, in order to favour the heat exchange, a large number of small tanks and greater precooling are required.

The optimal operational strategy of a multifuel station serving natural gas, hydrogen and electric vehicles is presented by Xu et al. in Ref. [36] and in a later work [37]. In the cited work, a hybrid stochastic/information gap decision theory optimization method is utilized to address the demand and renewable energy generation uncertainty to obtain the maximum expected profit from the system. The same approach is employed by Sriyakul et al. [38] to help investors on making the best capital outlay. Literature provides several studies on techno-economic models to find the best configuration of HRS components. Gunawan et al. [39] determined the optimal size of the system design to obtain the minimum levelized cost of hydrogen (LCOH) along the entire supply chain that is capable of meeting FCB demand for specific cities in Ireland. In contrast, Gröger et al. [40] studied the refuelling behaviour in free-floating carsharing from which determined the HRS size. Also in this case, the LCOH is used as a quality criterion. A hybrid system powered by wind, solar and battery established in Turkey is presented by Gökçek et al. [41]. In a recent study, Vincenti et al. [42] investigated an HRS design and operation applied to heavy-duty vehicles in the field of waste management.

Despite the wide range of available literature, there is a lack of clear and quantified information regarding the most cost-effective way to dimension an HRS facility that includes a grid-connected electrolyzer, compressor, compressed gas storage and dispensing, starting from the cost curves of these components and the hourly average electricity price profile. To fill this gap, the study introduces an innovative algorithm based on a series of step-by-step instructions in MATLAB environment designed to minimize the LCOH. Specifically, it endeavours to determine the most cost-optimal configuration for an HRS by evaluating both the electric energy costs and the investment costs associated with an H_2 demand given by various FCBs sizes and electrolyzer rated powers. This comprehensive approach aims to provide insight for stakeholders, ultimately facilitating the widespread adoption of H_2 technology in the transportation sector.

Furthermore, sensitivity analyses have been conducted to quantify the reduction cost margins for the technology, and a cost comparison between the refuelling of a fleet of FCB results and the recharging infrastructure required for an equivalent fleet of Battery Electric Buses (BEBs) has been performed.

1.3. Contribution of this paper

Although the cost-optimization of an HRS is not a novelty, the

influence of the national electric energy prices on selecting the electrolyzer size for maximizing HRS profitability in expectation of future expansion of the FCB fleets has not yet been widely investigated. The main characteristic of the algorithm is to determine the absolute minimum of the LCOH within predetermined demand ranges, as well as explore the entire distribution where LCOH variations are constrained. The added value of this algorithm is to provide a valuable tool to economic operators who need to address dimension evaluation challenges regarding optimal financing for HRSs also by considering the prospective advancement in demand. The hydrogen supply, production unit, compression storage, and dispensing are all components considered within the system boundaries of the techno-economic model. However, it's important to highlight that the minimization problem solved by this algorithm does not account for costs related to the acquisition, operation, maintenance, or disposal of the vehicles.

The paper is organized as follows. Section Methodology introduces the key factors that mainly influence the costs of an HRS facility, along with presenting the modeling principles and assumptions. Section Results and Discussion shows and comments on the results of the simulations and sensitivity analyses conducted to identify and quantify potential cost reduction margins. The last sub-section of Results and Discussion illustrates a cost comparison between a system for FCB refuelling and the one for BEB recharging. Finally, Section Conclusions evidences the paper's most important findings and proposes new directions for future research.

2. Methodology

The primary goal of most researchers studying the minimization of hydrogen supply, compression, storage and dispensing is to determine the lowest possible LCOH, which is associated with the assessment of the optimal system design. This includes the process of establishing the appropriate sizing and specifications for system components (such as the rated power of the electrolyzer or the energy consumption of compressors), determining the required number of units (e.g., the number of dispensers), and evaluating the preferred energy management strategy for example, directing energy flows to either the electrolyzer or battery).

The use of the LCOH as a quality criterion is, indeed, prevalent due to its versatility and effectiveness in providing a comprehensive view of the costs associated with H₂ technology [43]. It also enables long-term planning, making it a valuable tool for investment decision-making.

The cost-effectiveness of a hydrogen facility with on-site H₂ production is heavily dependent on its annual operating time, which refers

to the number of hours during which the plant has actually produced energy. This metric contrasts with the 8760 full load hours, representing the number of hours a plant operates at its maximum capacity output. On the one hand, as the number of operating hours increases, the H₂ production cost decreases as a consequence of the high investment cost depreciation over time, as shown in Fig. 1a. These results have been obtained by employing a cost curve function over different electrolyser sizes and common financial parameters used for evaluating the LCOH, for which a further elaboration is provided in the subsequent section. In particular, Fig. 1a evidences a cost-benefit achieved once 4000–6000 operating hours are reached, in line with findings from the International Energy Agency (IEA), whose observation evidenced an area of lowest cost of H₂ during mid-load operation, typically around 3000–6000, when the reduction of CAPEX due to higher utilization rates compensates the increase in electricity costs [44]. Similarly, Sayer et al. [15] draw parallel conclusions, identifying the lowest cost for large-scale electrolyzers at approximately 4500 full load hours per year. In addition, Fig. 1a illustrates that the economy of scale positively influences the LCOH, with large-scale electrolyzers being characterized by consistently more favourable costs.

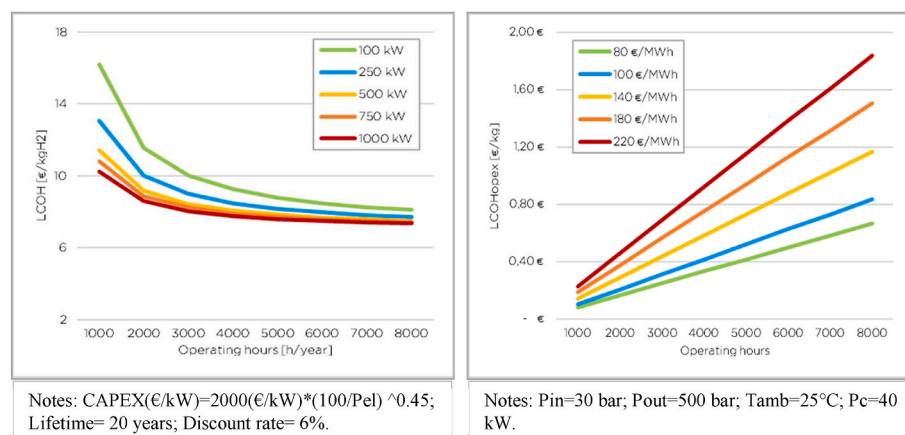
On the other hand, the impact of the electricity price on hydrogen compression, which is relatively energy-intensive in this kind of systems [45–47], grows even more significantly for greater electricity prices, as illustrated in Fig. 1b. The findings were derived from the assessment of the energy requirement for a 40 kW multi-stage hydrogen compression system across various electricity prices, ranging from 30 bar inlet pressure to 500 bar output pressure at an ambient temperature of 25 °C.

2.1. Techno-economic model description

In this study, an evolutionary algorithm has been developed with the aim of determining the optimum size of an HRS with on-site production via electrolysis to comply with the demand of.

A fleet of FCBs, from 2 to 30 vehicles, based on the lowest LCOH. In addition to analyzing different demand quantities, the algorithm also evaluates sizes ranging from 80 kW to 1 MW. It is assumed that the electrolyzer is directly connected to the grid.

To make this analysis worthwhile, it is important to understand the minimum hourly electricity price at which both the electrolyzer and compressor should operate for every proposed configuration. In this study, the Italian PUN (Prezzo Unico Nazionale), which serves as the benchmark price for electricity in the country's energy market, for the first three months of 2023 was taken as a reference [48] (Fig. 2). The



1a. LCOH of different size of electrolyzers in relation to the operating hours; **1b.** LCOH for hydrogen compression varying the electricity price in relation to the operating hours.

Fig. 1. a. LCOH of different size of electrolyzers in relation to the operating hours; Fig. 1b. LCOH for hydrogen compression varying the electricity price in relation to the operating hours.

Notes: Pin = 30 bar; Pout = 500 bar; Tamb = 25 °C; Pc = 40 kW. Notes: CAPEX (€/kW) = 2000 (€/kW)*(100/Pel)^{0.45}; Lifetime = 20 years; Discount rate = 6%.

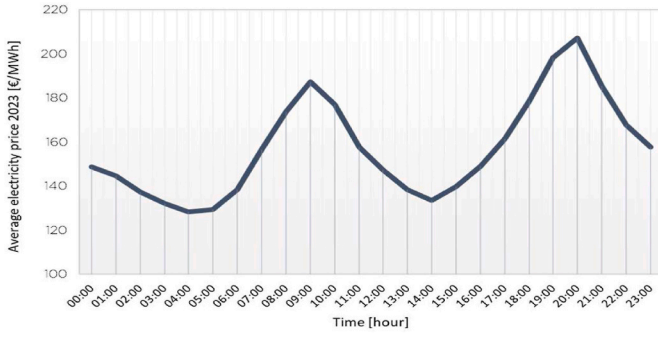


Fig. 2. Hourly average electricity price [€/MWh] trend for 2023 in Italy (current scenario).

PUN curve is characterized by two prominent peaks, one occurring from 7 a.m. to noon and the other between 5 p.m. and 10 p.m., coinciding with higher demand for electricity from the grid. Contrarily, there are two valleys in the early morning and middle of the day when most commercial and industrial activities are closed.

The lowest LCOH value in the algorithm is pinpointed by analyzing the average price during each continuous 1 to 24-h operation, selecting the minimum value for each time period. Consequently, a matrix is generated for every electrolyzer size under evaluation and FCB fleet configuration. Within this matrix, the minimum average electricity price is associated with the number of operational hours for both the electrolyzer and compressor necessary to fulfill the specified demand. This precise mapping enables to discern the most economically efficient system designs tailored to specific demand profiles, while mitigating the risk of over-dimensioning, which could lead to unnecessary capital expenditure. A representation of the modular structure of the algorithm showcasing the sequential flow of operations between different code segments is represented by the block diagram in Fig. 3.

The HRS included in this analysis comprises a PEM (Polymer Electrolyte Membrane) electrolyzer, a two-stage hydrogen compressor, a medium pressure 500 bar stationary storage and one or more hydrogen dispensers depending on the demand.

At the beginning of the algorithm, the vehicle tank capacity, refilling time according to the specific characteristics of the dispensing system, and the compressor inlet and outlet conditions are settled. The bus filling time (t_{fill}) is calculated using Eq. (1):

$$t_{fill} = \frac{m_{tank}}{\dot{m}_{disp}} + t_{ling} \quad (1)$$

where the dispenser flow rate ($\dot{m}_{disp}$) is assumed to be equal to 1.68 kg/min according to the study by Caponi et al. [14] and in line with the indications by Reddi et al. [49]. It is noteworthy that this value falls below the limitations set by the SAE J2601/2 refuelling protocol for gaseous hydrogen powered heavy-duty vehicles. No subcooling is needed due to the slow filling rates.

t_{ling} defines 10 min lingering time between two consecutive fills [45]. Thus, with a single dispensing unit, it is possible to refill a maximum of 3 FCBs with the characteristics mentioned above in 1 h (N_{FCB1h}). Their number (N_{disp}) is obtained as expressed by Eq. (2), where m_{daily} refers to the average daily mass dispensed, certainly dependent on the number of FCBs to be refuelled:

$$N_{disp} = m_{daily} / (24 \cdot N_{FCB1h}) \quad (2)$$

Through the evaluation of the gas thermodynamic properties at each stage, it is possible to derive the compressor specific energy consumption (SEC_c) expressed in kJ/kg:

$$SEC_c = (h_{out} - h_{in}) / \eta_{el} \eta_{mech} \eta_{is} \quad (3)$$

where h_{in} is the specific enthalpy at the inlet, characterized by temper-

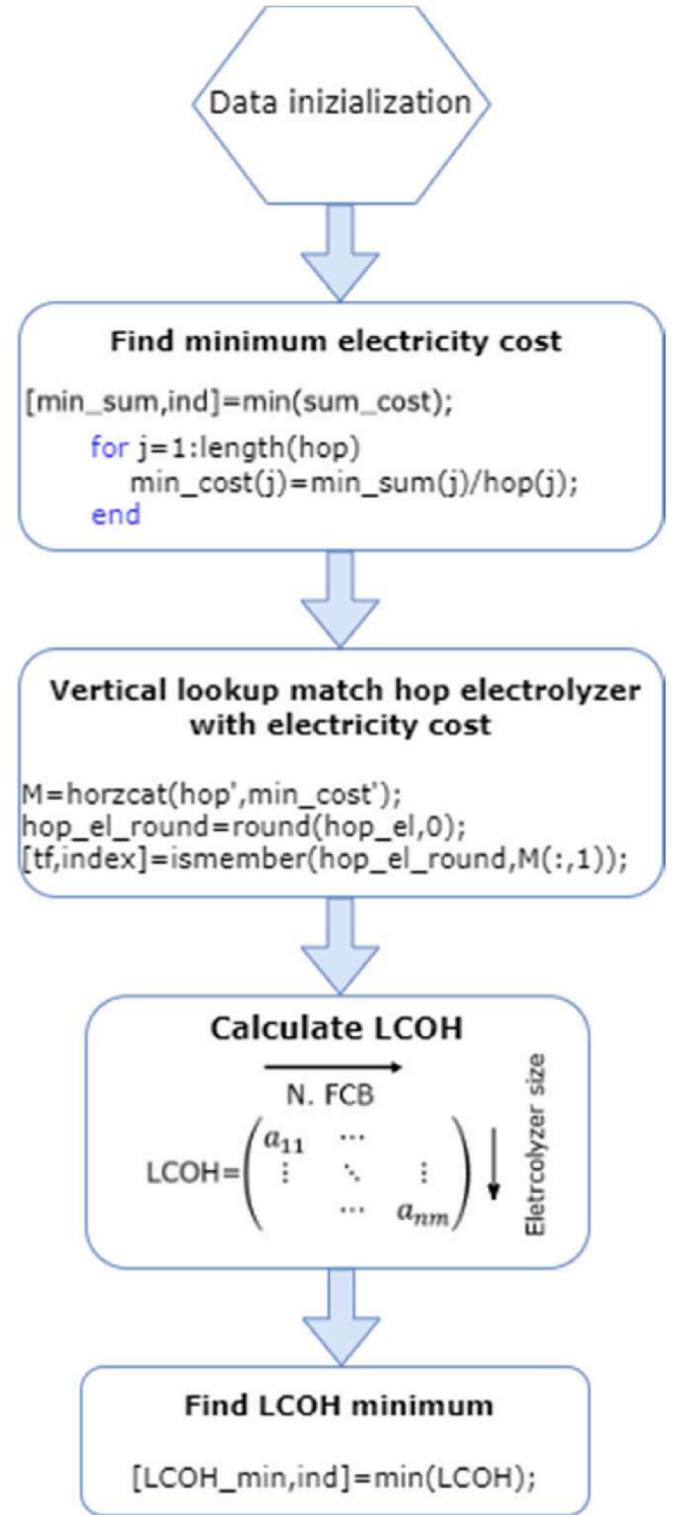


Fig. 3. Block diagram of the algorithm implemented in this study.

ature and pressure of $T_{in} = 298$ K and $p_{in} = 30$ bar, respectively; h_{out} is the specific enthalpy outlet of the last stage, to which corresponds $T_{out} = 376$ K and $p_{out} = 500$ bar conditions; η_{el} , η_{mech} , η_{is} represent electric (97%), mechanical efficiency (95%) and isentropic efficiency (85%). It is assumed the compressor can accommodate a 7% increment in the flow rate of the electrolyzer. The latter is scaled for the different rated power under investigation, taking as a reference a 1 MW PEM electrolyzer with a flow rate of 200 Nm³/h [50]. The compressed H₂ is stored in gas

cylinders at 500 bars, with a total maximum capacity equivalent to three days of production. Once the

Technical parameters are set, it is possible to calculate the LCOH (€/kg) for the production, compression and dispensing by dividing the sum of the annualized capital expenditure of each component (CAPEX_a), the fixed operational expenditures (OPEX_{fix}), i.e., regular operation and maintenance expenses (O&M), and the operational variable expenses (OPEX_{var}), that depends on the electricity price and the energy consumption, over the yearly hydrogen production (Eq. (4)). To derive the CAPEX_a, the total investment cost is multiplied by the CRF (Capital Recovery Factor), which takes into account 20 years of technology lifetime *t* and 6% discount rate *r* (Eq. (5)) [51].

$$LCOH = \frac{(CAPEX_a + OPEX_{fix} + OPEX_{var})}{H_2 \text{ annual production}} \quad (4)$$

$$CRF = \frac{r * (1 + r)^t}{(1 + r)^t - 1} \quad (5)$$

Specific cost curve relations presented in the reference literature by Caponi et al. [52] and Minutillo et al. [53] are employed to estimate the capital expenses of the electrolyzer and compressor. The capital cost of medium pressure storage is calculated using a price of 900 €/kg based on recent quotations, although prior literature suggests lower specific costs for similar operations [42,54]. OPEX_{fix} is evaluated on a yearly basis and calculated as a percentage of CAPEX for the different technologies, as reported by Crespi et al. [55] for the electrolyzer, Gunawan et al. [39] for the compressor, Li et al. [56] for the storage, and Gökçek et al. [41] for the dispenser. Additionally, OPEX_{var} is determined based on the specific energy consumption of the system components. A SEC of 55 kWh/kg is assumed for the PEM electrolyzer, falling within the technology's range [57], while for the compressor, it is derived considering an isentropic compression process with intercooling [58]. The economic data utilized for this analysis and their corresponding references in the literature are listed in Table 1, whereas the technical parameters and assumptions are illustrated in Table 2.

2.2. Zero-emission buses case study

In this case study, H₂ demand arises from a fleet comprising small FCBs 8 m long, with a nominal capacity of 10.8 kg (*m_{tank}*) at 350 bars. The buses are equipped with a range extender in order to maximize the mileage by using either the hydrogen stored on board or the electricity from batteries. The combination of the two power-train systems guarantees an autonomy of more than 300 km. Driving tests conducted on a flat route encompassing urban and extra-urban areas, characterized by an average speed of 12.6 km/h, resulted in an average energy consumption of approximately 27 kWh/h, inclusive also of HVAC usage. This equates

To roughly 6 kgH₂/100 km of nominal hydrogen consumption. Therefore, the 8-m FCB exhibits lower energy consumption than larger vehicles in urban settings due to its enhanced manoeuvrability, faster acceleration, and reduced weight.

Additionally, it offers several other advantages, such as decreased

Table 1

Cost assumptions of the different HRS components utilized within the algorithm to assess the lowest LCOH, with literature references provided as indications.

Component	CAPEX	OPEX _{fix}	OPEX _{var}	Ref
Electrolyzer	2000 (€/kW) · (100/P _{el}) ^{0.45}	2%	55 (kWh/kg) · C _{el} (€/kWh)	[52,53, 55,57]
Compressor	43,872 · (P _c) ^{0.5861}	2%	SEC _c (kWh/kg) · <i>m_c</i> (kg/h) · <i>h_{op}</i> · C _{el} (€/kWh)	[39,53]
Storage 500 bar	900 (€/kg) · <i>m_{sto}</i>	0.5%	–	[56]
Dispenser	350 (€/kg) · <i>m_{daily}</i>	0.5%	–	[41,45]

Table 2

HRS and FCBs technical parameters.

Component	Value/Unit/Ref		
Compressor		Electrolyser	
Inlet pressure, <i>p_{in}</i>	30 [bar]	Discount rate, <i>r</i>	6 % [51]
Outlet pressure, <i>p_{out}</i>	500 [bar]	Lifetime, <i>t</i>	20 [years] [74]
Electrical efficiency, <i>η_{el}</i>	97 [%]	Storage	
Mechanical efficiency, <i>η_{mech}</i>	95 [%]	Nominal pressure, <i>P_{nom}</i>	500 [bar]
Isentropic efficiency, <i>η_{is}</i>	85 [%]	Stored mass, <i>m_{sto}</i>	3days*mass produced [kg]
FCB		Dispenser	
Tank capacity, <i>m_{tank}</i>	10.8 [kg]	Mass flow rate dispenser, <i>m_{disp}</i>	1.68 [kg/min]
Refilling time, <i>t_{fill}</i>	16.5 [min]	N. FCB filled in 1 h, <i>N_{FCB1h}</i>	3 [#]

passenger exchange time at stops, thereby allowing for greater flexibility and frequency. As anticipated in the Introduction, a cost comparison between the refuelling of a fleet of FCBs and the recharging of an equivalent fleet of BEBs is within the scope of this study. To facilitate a fair comparison, the BEB fleet is presumed, based on literature reference data, to comprise long-range vehicles equipped with a battery capacity of 260 kWh and an expected driving range of more than 300 km, therefore consuming, under nominal conditions and on flat routes, 0.86 kWh/km [59,60].

3. Results and discussion

The outcome of the algorithm is a tri-dimensional map that shows the LCOH for several combinations of daily demand and electrolyzer size (Fig. 4a). Two trends are evidenced:

- As the daily demand, and hence the fleet size, increases, the LCOH reduces from approximately 16 €/kg in the case of just 2 vehicles to 10 €/kg for a fleet of 30 FCB. Indeed, the system is over-dimensioned for small quantities in relation to the actual demand, leading to higher overall costs. In contrast, increasing fleet size can achieve a more suitable alignment between demand and production.
- As the rated power of the electrolyzer rises up, for the same quantity of hydrogen refuelled throughout the day, the LCOH initially decreases. However, after reaching a minimum value of around 10.2 €/kg, it begins to increase again. This is because for small electrolyzer sizes, the cost of electricity is prevailing due to the higher operational hours required to satisfy the demand. At the same time, the impact of the components' investment cost is less burdensome.

Fig. 4b shows that in addition to identifying an optimal combination of production and demand that minimizes the H₂ price that balances the previously described opposing trends, there is also a noticeable region of lower hydrogen specific costs.

The magnitude of this area widens with large-scale electrolyzer-rated power and FCB fleets, with a moderate variation of approximately 1% in the LCOH when the system size is increased by 5%–10%. This result implies that investing in a slightly over-dimensioned system with respect to the actual demand is viable without having a considerable impact on the costs. Furthermore, this approach provides more flexibility in case there is a need to expand the fleet size in the future.

A darker area of desirable LCOH values is also observed for larger electrolyze sizes, as they allow, at equal demand, a significant reduction in the operating hours and the associated costs, providing an advantage over other cost factors. Nevertheless, this result strongly depends on the electricity cost profile curve and the assumptions made in the model. For example, the model does not consider the cost increase resulting from

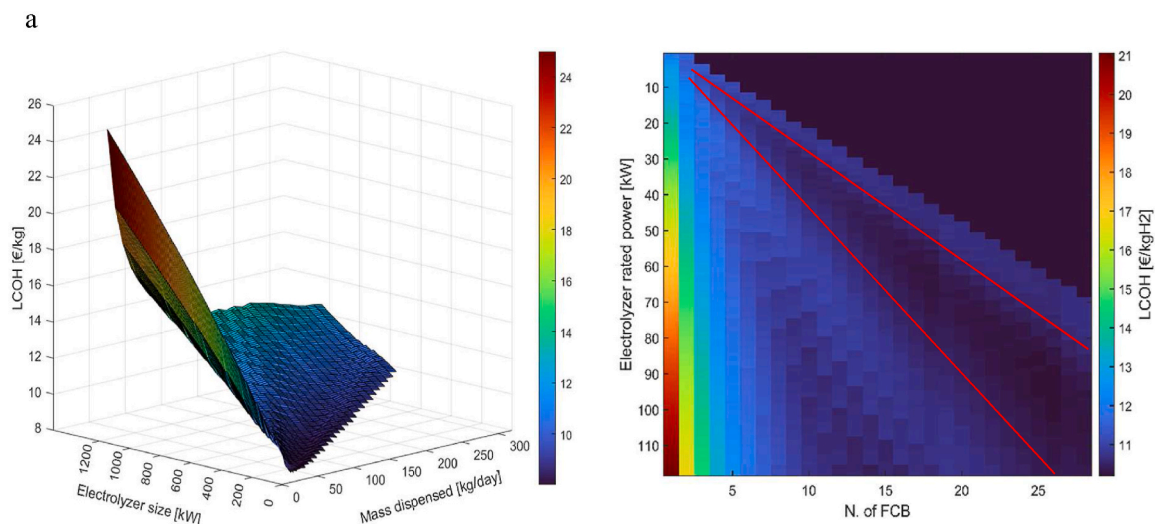


Fig. 4. a. LCOH tri-dimensional results with changing electrolyser size (kW) and daily demand (kg/day). Fig. 4b. LCOH two-dimensional results in which it is evidenced the region with lower prices.

greater system complexity in large-scale plants. Ultimately, Fig. 5 reveals the minimum LCOH for the sample FCB fleets and the corresponding optimal electrolyzer size among the range investigated. The objective of the algorithm is to select the smaller equipment while simultaneously reducing the operational costs, resulting in a declining curve obtained as the number of deployed FCBs increments. The best configuration is found when the system operates continuously for an average of 16 h per day. It is important to highlight that these findings strictly rely on the electricity cost profile given as an input, which, in this specific case, has a pronounced depreciation during the early.

Hours of the day. Additionally, it has to be noted that the study is based on the PUN, which represents the wholesale electric energy price purchased in the Italian power exchange, which includes electricity generated from renewables and a majority derived from fossil-fuel sources.

To be considered green, the hydrogen produced should be certified through certificates of origin, incurring an additional cost of approximately 6 €/MWh [61] that must be added to the electricity purchase price. However, since this cost constitutes a small fraction of the total price, its impact on the LCOH is not so relevant.

The situation differs when green hydrogen certification is achieved via purchasing power agreements (PPAs) between a renewable energy seller and a long-term committed off-taker. In this case, the price is established by a mutual agreement between the parties and is influenced by many factors. For instance, the average price for energy supplied from a photovoltaic power plant via PPAs is around 70 €/MWh [62], which is significantly more competitive compared to purchasing from

the national grid. Considering this cost for the hours of national medium radiation, a new scenario is envisioned where the input energy cost vector is altered. As a result, the minimum LCOH is approximately 7 €/kg, which is 30% lower than the one determined based on the PUN, and it allows for larger electrolyzer optimal sizes at equal demand.

3.1. Sensitivity analysis

Upon further investigating into the contribution of CAPEX and OPEX of each HRS component on the LCOH, it is observed that the variable operational cost of the electrolyzer - which is directly related to its energy consumption - represents about 70% of the total costs. If this value is expressed by reference to the energy content of hydrogen (lower heating value LHV), which is equal to 33.33 kWh/kg, the cost comes out to be around 240 €/MWh. Secondly, the investment of the electrolyzer itself accounts for 8% of the overall costs, equivalent to 25.2 €/MWh. Fig. 6 illustrates the CAPEX and OPEX contribution to the LCOH for each HRS component in the best-optimized configuration. Therefore, a sensitivity analysis has been conducted to identify and quantify potential cost reduction margins for the operational and capital costs of the electrolyzer.

It is widely recognized that the operational costs are closely interwind with the energy consumption for hydrogen production, thereby, the electricity prices. In particular, a new scenario has been investigated in this study, wherein the optimal sizing of the electrolyzer and other components has been determined to achieve the minimum H₂ production cost. This scenario assumes a cut down electric energy cost profile based explicitly on Italy's average hourly price for 2019 (Fig. 7), which is around 67% lower than the estimated price for 2023.

By comparing the results, it emerges, as expected, that there is about 20% cost contraction in the LCOH attributed to the operational cost of the electrolyzer at the expense of the incidence of capital cost shares that experience a rise (Fig. 8). These results suggest that, on equal demand, a lower electricity price enables the selection of smaller equipment with the aim of downsizing the system cost. Therefore, when approaching the investment decision, it becomes crucial not only to conduct a predictive study on the current and future load demand but also to appraise the price evolution of the energy prices to render a chance of profitability for HRSs.

With respect to the CAPEX, a cost scaling function has been employed to determine the investment required for the electrolyzer at various sizes, as explained in the methodology section. Specifically, a baseline scenario is assumed, which involves a 100 kW electrolyzer with

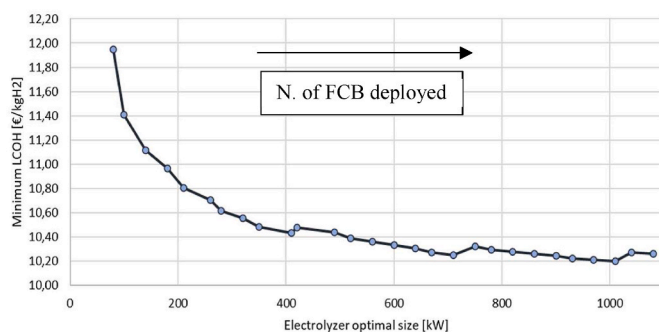


Fig. 5. Algorithm result in terms of minimum LCOH [€/kgH₂] and corresponding electrolyzer size at increasing number of FCBs, i.e., from 2 to 30.

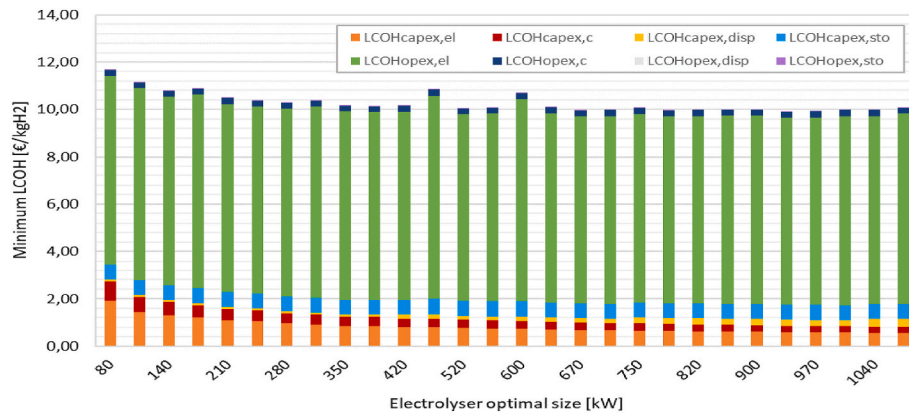


Fig. 6. Best optimized configurations LCOH breakdown.

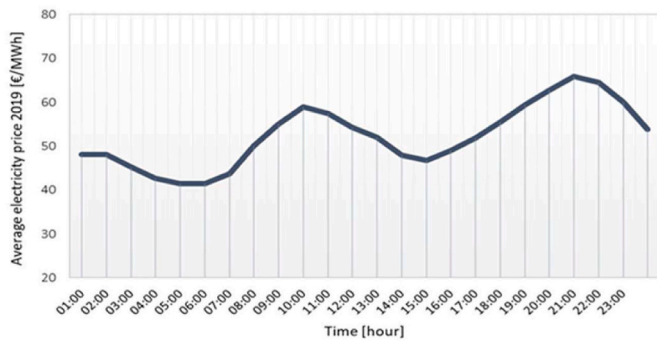


Fig. 7. Hourly average electricity price [€/MWh] trend for 2019 in Italy (new scenario).

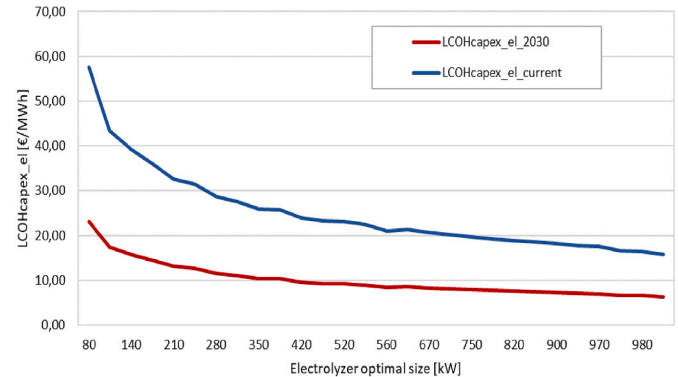


Fig. 9. LCOH electrolyser CAPEX [€/MWh] in the current scenario and for the scenario considering a cost reduction of the component by the end of 2030.

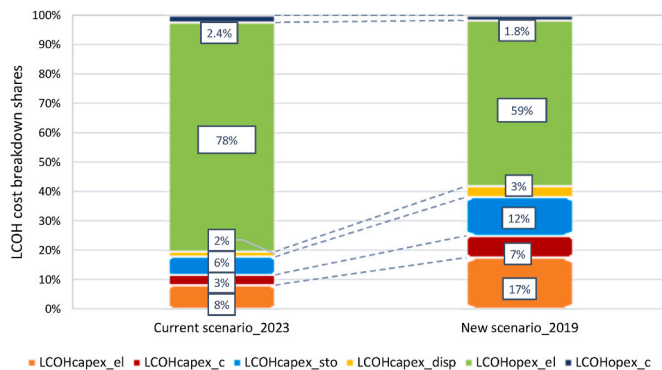


Fig. 8. Comparison in terms of percentage share of LCOH between the current scenario based on 2023 electric energy prices and the new scenario based on 2019.

a reference price of 2000 €/kW. However, according to authoritative sources, it is expected that by the end of 2030, a cost reduction of approximately 40–60% will be achieved [51,63,64]. This will happen thanks to a combination of several factors, including large-scale industrial production, long-standing technology learning rate and an overall improvement in materials, durability, and efficiency. Fig. 9 illustrates the LCOH CAPEX relative to the electrolyzer in the best-optimized configurations for both the current scenario and the scenario for which a 60% reduction in the specific capital cost is applied.

3.2. Comparison with battery electric buses

Based on the findings in the previous section, it emerges that even

selecting the lowest H_2 cost to the pump as a benchmark among the investigated cases, which aims to minimize capital costs and at the same time maximize operational working hours, an LCOH equal to 10.2 €/kg corresponding to around 300 €/MWh would be obtained. This is the case for a fleet of 27 FCBs and an electrolyzer size of 1.01 MW. If the same fleet consisted of battery electric buses (BEBs), a cost reduction of 20% would be achieved. This value was determined by assuming the cost for a fast charging station, which can accommodate up to 8 buses of 495,636.00 €, a charger O&M cost equal to 1500 €/month, and an average electricity price of 166 €/MWh [65]. The time horizon and discount rate of this technology are the same as those used in calculating the LCOH.

Although the BEBs technology is more cost-competitive in the current scenario, benefiting -among other factors- from the alignment between the charging hours with higher BEBs convergence and the lower electricity prices (Fig. 10), this might not hold true in the future.

Indeed, the planned expansion of renewable energy production in Italy, outlined in strategic plans such as the PNIEC (Integrated National Energy And Climate Plan) [66] and the 2023 Development Plan [67], to reach decarbonization goals set by the EU, might contribute to the flattening of the price peaks in the central daylight hours. Vice versa, it might also result in a rise in the prices during the night when energy availability is lower, thereby shortening the price gap with green hydrogen technology [68–70].

Furthermore, it is important also to consider the prevalent issue of high peak power demand concentrated within a short timeframe during the day. This situation can lead to potential local grid disturbances and pose challenges in terms of equipment sizing at the depot [71,72]. In addition, the deployment of BEBs is hindered by the undoubted drawback of time-consuming recharging, whose optimization and scheduling

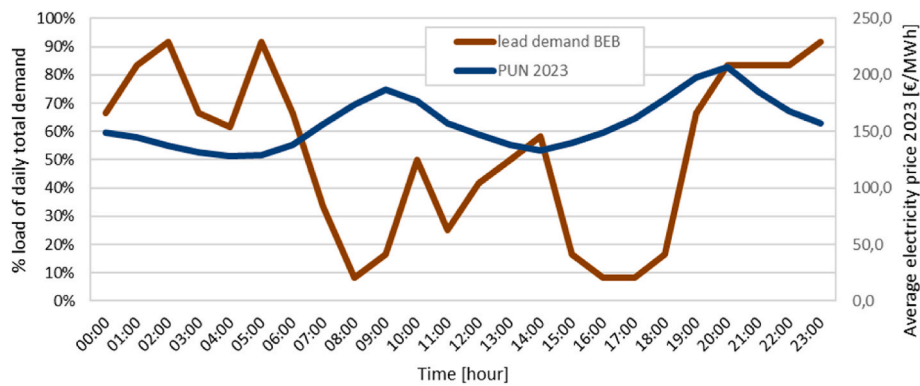


Fig. 10. Temporal distribution of BEBs charging during the day and electric energy price profile for 2023.

result in significantly more challenging than FCBs. Finally, a recent study [73] demonstrated that BEBs are a suitable option on urban routes characterized by low average speed and high frequency. Nevertheless, battery electric technology encounters strong economic and technical barriers when employed in suburban areas. These findings support the thesis that BEB and FCB represent a complementary solution for decarbonizing the public transport sector rather than a competitive one.

4. Conclusions

The successful establishment and diffusion of the H₂ technology in the mobility sector, particularly in the heavy-duty vehicles segment, is a subject of significant interest because of the demand for sustainable and efficient low-carbon solutions to replace the current fossil fuel-based transportation. The technology's reliability is decisive, but its cost-effectiveness is equally crucial. Consequently, it is imperative to promote tools and models that establish the costs associated with the purchase and operation of the vehicle and those associated with the consequential refuelling infrastructure. Without the study of a cost-effective and functionally efficient HRS design, the future of H₂ vehicles will be uncertain. Thereby, it is fundamental to prioritize the definition of the appropriate sizing and specifications for the HRS components, determine the required number of units and evaluate the preferred energy management strategy in order to determine the lowest possible H₂ cost for production, compression, storage, and dispensing. In this context, the number of operating hours and the electricity price play a crucial role in the optimization process.

However, until now, the combined effect on the LCOH of opposing dynamics, such as the investment cost associated with increasing component sizes and the variable operational cost due to the energy consumption at increasing operating hours, has been unclearly illustrated and quantified. This paper provides an innovative algorithm capable of successfully matching and identifying the most cost-efficient HRS facility dimension, which includes a grid-connected electrolyzer, compressor, compressed gas storage, and dispensing based on the components' cost curves and the hourly average electricity price profile. The main algorithm characteristic is to investigate a dimensional range for the electrolyzer and connected systems for a given demand while evidencing the corresponding LCOH for each possible solution. Thus, the algorithm defines the absolute minimum value and, in addition, shows the entire LCOH distribution, identifying intervals with cost deviations limited to within 1%.

As a result, the best optimal configurations coincided with an LCOH from 12 €/kg for small fleet sizes (e.g., 2 FCB) to 10.2 €/kg for a fleet of 30 FCB and obtained by operating the electrolyzers continuously for 16 h, mostly during night-time or the first half of the day. In fact, the gas market tensions that occurred in the recent past have generated significant price variations in electricity prices with phenomena of pronounced fluctuations.

Furthermore, due to the prevalence of the electrolyzer LCOH OPEX and CAPEX on the overall cost, sensitivity analyses have been performed to quantify the potential margins for cost reduction in the technology. In particular, an average electricity price below 67% (according to 2019 data) with respect to the base case results in a 20% cost contraction in the LCOH attributable to the electrolyzer OPEX, while the electrolyzer CAPEX rises by 10%. Therefore, when demand remains constant, a lower electricity price leads to an optimal LCOH for smaller equipment sizes, further reducing system costs. It is also fundamental for the technology competitiveness to reduce the production costs of components, especially electrolyzers, thanks to which an average LCOH decrease of around 19% could be achieved. The combined effect of these two factors on the LCOH would lead to a cost reduction of more than 50%.

Finally, until now, the results for the specific system investigated show that deploying an equivalent BEB fleet would be 20% less expensive. However, the stringent requirements of public service impose significant limitations on the temporal distribution of the recharges, which are heavily concentrated during night-time. This concentration results in challenging load peaks that are hard to manage for the grid and recharging times. Additionally, a strategy that aims to improve the introduction of renewable energies into the grid might cause a variation of the current electricity cost curve profile towards higher prices during the hours when there is greater affluence of BEBs.

Future research could focus on improving the design model of the HRS by dimensioning the optimal volume of the hydrogen stored on an hourly basis in alignment with the demand. Furthermore, the integration of renewable energy generation with the electricity curve profile, the relative evaluation of specific agreements between the parties involved and the study of future market scenarios would add further value to this analysis. In the end, there is significant research interest in exploring the integration of HRS and H₂ vehicles as engaged elements within the grid, which would require a comprehensive and detailed study.

CRedit authorship contribution statement

R. Caponi: Conceptualization, Data curation, Investigation, Methodology, Writing – original draft. **E. Bocci:** Conceptualization, Data curation, Funding acquisition, Resources, Writing – review & editing. **L. Del Zotto:** Methodology, Supervision, Validation, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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NOMENCLATURE

h	Specific enthalpy of hydrogen, kJ/kg
m	Hydrogen mass, kg
$\dot{m}$	Hydrogen mass flow rate, kg/s
N	Number
p	Pressure of hydrogen, bar
P	Power, kW
r	Discount rate, %
t	Time, min/years
T	Temperature of hydrogen, K

Acronyms

APRR	Average Pressure Ramp Rate
BEB	Battery Electric Bus
CAPEX	Capital Expenditure
CRF	Capital Recovery factor
EU	European Union
FCB	Fuel Cell Bus
FCEV	Fuel Cell Electric Vehicle
H ₂	Hydrogen
HRS	Hydrogen Refuelling Station
IEA	International Energy Agency
LCOH	Levelized Cost of Hydrogen
LHV	Lower Heating Value
O&M	Operation and Maintenance
OPEX	Operational Expenditure
PEM	Polymer Electrolyte Membrane
PNIEC	Integrated National Energy And Climate Plan
PPA	Purchasing Power Agreement
PUN	Prezzo Unico Nazionale
SAE	Society of Automotive Engineers
SEC	Specific Energy Consumption

Subscripts

a	Annualized
c	Compressor
disp	Dispenser
el	Electrical
fill	Filling
fix	Fixed
in	Inlet
is	Isentropic
ling	Lingering
mech	Mechanical
out	Outlet
var	Variable

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