Numerical Simulation of an on-Grid Natural Gas PEMFC - Solar Photovoltaic Micro CHP Unit: Analysis of the Energy, Economic and Environmental Impacts for Residential and Industrial Applications

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Abstract

As global natural resources depletion and concern on emission of greenhouse gases intensify, the interest for low emission technologies and the use of renewable energy increased in the world. In this context, this paper aims to present an hybrid energy system for on-grid micro residential and industrial applications. The system is composed of a micro combined heat and power (CHP) unit, including a natural gas (NG) reformer coupled with proton-exchange membrane fuel cell (PEMFC), solar photovoltaic modules (PV) and a bank of batteries (B), connected to the grid through a bidirectional inverter. Different system configurations (PEMFC + PV + B, PEMFC + B, PEMFC + PV), with or without cogeneration of the heat from the CHP system, were investigated to calculate the required NG and electricity flows and assess the economic cost during 10 years of operation in an 2020–2040 horizon. The impact of fuel cell sizing and two electricity tariffs was also assessed for both applications. Afterwards, the cash flow in terms of net present value of a 20 years operation period was simulated within the Brazilian context, yielding estimated paybacks between 7 and 19 years for the simulated cases. Finally, an environmental impact analysis was carried out to investigate the total GHG emissions for some cases of interest in this work. The proposed system could reduce total emissions up to 31% when compared to the complete power and thermal supply by the Brazilian Electricity grid and natural gas heater. The results showed that the proposed system were economically viable, relatively low-polluting and more efficient than traditional PV systems.

Keywords Combined heat and power (CHP) unit · Proton-exchange membrane fuel cell (PEMFC) · Solar photovoltaic (PV) modules · Batteries (B) · Natural gas (NG) · Simulation

Nomenclature

A_a	Active surface area (cm^2)
Alt	Alternative electricity tariff
B	Battery bank
C	Battery capacity (Ah)
CF	Cashflow (US\$)
CHP	Combined heat and power unit
$Conv$	Conventional electricity tariff
E_{CHP}	Total energy entering the CHP unit (Wh)

E_{el}	Electric energy generated by CHP unit (Wh)
E_{th}	Heat generated by CHP unit (Wh)
EM_{el}	Total CO_2 emission without the use of cogeneration ($\text{gCO}_2\text{eq/kWh}$)
EM_{CHP}	Total CO_2 emission considering cogeneration ($\text{gCO}_2\text{eq/kWh}$)
FC	Fuel cell
GHG	Greenhouse gases
I_{bat}	Battery current (A)
I_{cell}	Fuel cell current (A)
INV	Initial investment (US\$)
LHV_{gas}	Lower heating value of natural gas (kWh/kg)
m_{CH4}	Mass flow of methane gas (kg/min)
m_{CO2}	Mass flow of generated carbon dioxide (g/min)
N_{FC}	Number of single fuel cells
NG	Natural gas
n_{CH4}	Molar flow of methane (kmol/min)
n_{CO2}	Molar flow of carbon dioxide (mol/min)

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n_{H_2}	Molar flow of hydrogen (kmol/min)
NPV	Net present value (US\$)
MW_{CH_4}	Molecular weight of methane (kg/kmol)
MW_{CO_2}	Molecular weight of carbon dioxide (kg/kmol)
P_{el}	Electric power (W)
P_{th}	Thermal power (W)
PV	Photovoltaic panels
Q_e	Charge remaining in battery bank (Ah)
r	Interest rate (%)
S_{H_2}	Hydrogen stoichiometry
SOC	Battery state of charge (%)
V_{cell}	Single fuel cell voltage (V)
V_{gas}	Total natural gas consumption (m^3)
y	Time (years)

Greek Letters

η_{el}	Electric efficiency (%)
η_{th}	Thermal efficiency (%)
v_{gas}	Volumetric flow of methane gas (m^3/min)
ρ_{gas}	Density of natural gas (kg/m^3)

Introduction

Electric energy demand is expected to increase 1.3% per year up to 2050 in non-OECD countries, according to the U.S. Energy Information Administration [44]. All sectors will be affected by the change, especially the residential sector due to the urbanization process and increasing population's purchasing power in developing countries [24]. This phenomenon has led to greater environmental concern in most countries, which have intensified the search for cleaner and more efficient energy generation sources, leaded by photovoltaic and wind power. Alongside with this tendency, more reliable energy distribution / transmission processes have become increasingly necessary. In this context, the distributed electricity generation system emerges as an effective solution. Several advantages, such as higher reliability of electricity supply and greater voltage stability in the grid, can be achieved with the distributed generation system. In the economic context, attention is given to the lower operating costs in transmission and distribution. Moreover, from the environmental point of view, the lower emission of greenhouse gases and the conservation of natural resources are potential benefits with the use of renewable sources [16, 23].

More recently, developing countries, especially India, Brazil and China, have also started to show significant participation in the adoption of the distributed generation system, driven mainly by greenhouse emissions reduction policies and diversification of their energy matrices. Solar photovoltaic (PV) generation is still the most prevalent in the distributed micro-generation sector due to the ease of

installation, a large-scale world production and the rapid drop in the commercialization prices of photovoltaic modules (reduction of a factor of 100 between 1975 and 2015) [31]. In spite of its great advantages in both economic and environmental viewpoints, high area is required for modules installation which and its high dependence on the reverse metering factor (utilization factor of corresponding energy generation exported to the grid) may limit its applications in large cities.

Nowadays, the search for energy sources with lower pollutant emissions than traditional diesel and oil related technologies, such as natural gas, is being considered by many experts as the transition solution between more polluting energy sources (as oil and coal) and the purely renewable generation [24]. Thus, the combination of intermittent energy sources with storage devices and additional sources with the use of natural gas may become the ideal solution for the future of distributed generation, constituting hybrid energy systems.

Among the energy conversion technologies, fuel cells have the desired potential for hybrid systems integration as they present high energy efficiency, relatively low pollutant emissions and allow for cogeneration as a consequence of high temperature stack operation [1, 12, 15]. Many studies have been developed in this area, aiming for hybrid systems optimization and economic evaluation. Rekioua et al. [37] presented a detailed review on hybrid systems configurations with proton-exchange membrane fuel cell (PEMFC) and demonstrated the feasibility of a PEMFC+PV system with hydrogen storage for small applications. Maclay et al. [32] studied a PV system coupled with reverse fuel cell, battery bank and ultra-capacitors as storage components. An economic assesment was performed to identify the best combination in terms of efficiency and cost. The work concluded that the integration of battery banks and fuel cells provided benefits in both energy and economic viewpoints in comparison with each technology separately and that ultracapacitors were unsuitable for the proposed application because of their low energy density. Later, Maclay et al. [33] carried out an experimental study to investigate the dynamic behavior of the same system under rapid changes of load demand. Their work focused on specifying design limitations for the fuel cells, battery bank and electrolyser for such systems, giving emphasis to components sizing and operating restrictions. Ozgirgin et al. [36] performed a simulation analysis on an integrated on-grid hybrid system with PV pannels, PEMFC and battery bank to supply a small residence in the proximities of Ankara (Turkey). They studied the impact of the seasons and the potential for cogeneration. The results showed that during the warmer seasons, the proposed system could successfully generate all thermal and electric power load demands, exporting extra energy to the grid. However, during winter time, much more area

for PV modules installation was needed. An energetic and exergetic study of a hybrid system with PEMFC and solid oxide fuel cell (SOFC) fed with natural gas (NG) was conducted by Barelli et al. [7] for small residential applications. Several parameters such as fuel cell temperature and pressure operating conditions were evaluated as to their impacts in each proposed configuration performance. Zuliani and Taccani [46] compared the differences in electric and thermal efficiencies of low and high temperature PEMFC systems for small applications (1 kW electrical output). It was found that the total system efficiency (26% to 34%) was higher than the general efficiencies of LTPEM type fuel cells systems found in the literature for this power specification. Di Marcoberardino and Manzolini [14] assessed the economic feasibility of a 5 kW PEMFC system fed with NG and compared the results with traditional CHP systems. The impact of NG composition and electric energy prices were evaluated in four countries of the European Union and always showed environmental benefit even if the system cannot be competitive even with subsidies from the governments. In the work of Inac et al. [25], the energy and exergy efficiencies of a system consisting of a SOFC unit fed by three different methods was studied. First, PV modules were used to provide electric energy to an electrolyser, which then produced hydrogen for the SOFC. Second, an anaerobic digester supplied biogas for use in the fuel cell and, finally, a local distribution network provided natural gas (methane) directly to the SOFC. Results proved that the third method showed better overall energy and exergy performance, followed by the second and first methods, respectively. Additionally, the highest exergy destruction occurred in the first method, followed by the second and third methods as well. Ahmadi et al. [4] investigated the influence of several operational parameters on the energy and exergy efficiencies of a system involving a SOFC with cogeneration. The system consisted of the combination of electrical output from the fuel cell with another heat and power combined cycle, composed of two turbines (high and low pressure) and a DHW (Domestic Hot Water) unit to supply a thermal demand. An improve in overall energy efficiency from 47.78% (only electric output from SOFC) to 60.05% (SOFC with a combined cycle) was observed. Moreover, the sensibility analysis showed that an increase in fuel utilization factor enhanced even more the energy and exergy efficiencies, while an increase in electric current density of SOFC produced the opposite effect. Finally, Azizi and Brouwer [6] investigated several methods for controlling a SOFC-GT (SOFC coupled with gas turbine) system in different configurations and compared multiple control strategies as for their impacts in energy efficiency and CO_2 sequestration by means of a sensibility analysis. The authors found that more robust control algorithms were requested in cases of variable turbine shaft speed over

stationary applications, requiring additional parameters to handle pressure fluctuations in the SOFC stack. Additionally, a literature review carried out by the authors showed that other variables as fast electrical and thermal transients, compressor stall / malfunctioning, cell degradation and fuel starvation remain as critical parameters for dynamic operation of physical SOFC-GT, requiring further research on this area. In addition to the reported studies, several other approaches for investigating hybrid system's operation can be found in literature with the use of HOMER [13, 38, 43], Aspen Plus® [7, 14, 46], LabVIEW, Matlab / Simulink routines [30, 32, 33, 37] and combination with AI (artificial intelligence) techniques [3, 35].

In this context, this paper presents a numerical simulation in Matlab (version R2019b) of an hybrid system consisting of a 5 kW PEMFC unit combined with solar PV (multiple 245 W modules) and battery bank (parallel combination of 48 V / 100 Ah batteries) for small on-grid residential and industrial applications in Brazil. Several system configurations with cogeneration possibility, two types of electricity tariffs (conventional (Conv.) and alternative (Alt.)) and two types of consumers (residential and industrial) were investigated to assess their impacts in system's operation, efficiency, economic analysis and GHG emission impact (in terms of gCO_2/kWh). The Brazilian natural gas market is currently under great transformation and development. The New Gas Market Program, announced in June 2019 by the Federal Government, has the main objective of creating a more dynamic and competitive market, ending the existing monopoly in the natural gas sector and implementing measures to increase competitiveness in all segments of the chain, from gas production, treatment, distribution and transportation. The national gas production is expected to more than double in a ten year's time, going from 124 million cubic meters in June 2019 to a total of 267 million cubic meters per day until 2032 and total cost reductions may reach 40% by the end of 2021 [10]. In that way, natural gas could effectively act as the transient solution between high pollutant energy generation systems and totally renewable systems (photovoltaic and wind) in Brazil and other countries, such as China and United States, that presently experience similar transformations in the NG market.

Therefore, the main contribution of this work is to provide a detailed analysis of such system considering the Brazilian scenario, assess its economic feasibility and compare total system's cost and cashflow analysis with conventional PV systems and direct electricity purchase from the grid. Additionally, the potential benefits evaluation in terms of equivalent CO_2 emissions reduction compared to the total energy supply from the Brazilian electricity grid and natural gas combustion (thermal demand) was also another original aspect of this study.

Fig. 1 Schematic representation of the modeled system

Methodology

Mass and Energy Balances

The proposed on-grid system consists of a 5 kW micro combined heat and power CHP unit (NG reformer + PEMFC), 245 W PV panels and a battery bank (B) (parallel connection of multiple 48 V / 100 Ah single batteries), connected to a bidirectional inverter to provide electric energy to a consumer in the AC terminal. On-grid distributed electricity generators are a complex system in which the relationship between the observed parameters. Then, the elaboration of a control action should be carried out on the basis of data on the current state of the object of control in order to guarantee that energy demand and future needs of power from the consumers will be provided and aim the lowest cost for electricity [2, 40, 45]. Then, the PV array works as the primary source of energy during the day, charging the battery and exporting extra energy production to the grid. When demand exceeds total generation within the system, PEMFC + NG reformer unit provides electrical output to sustain the deficit

just after a brief warming-up period of 30 min, during which it consumes 550 W from the grid. Once power demand is too high, the system starts to buy electricity directly from the grid. While running on alternative tariff, the logic is similar with one exception. The batteries were forced to charge to its maximum state of charge just before 5 PM and then fully discharge between 6 pm and 9 pm, exporting large amounts of energy to the grid and generating lots of energy credits.

Furthermore, cogeneration can be achieved for supplying an additional thermal demand. As allowed by Brazilian legislation, extra electric energy production within the system is sent to the grid, generating energy credits for future use when demand exceeds total generation. The reverse metering factor used in this work was 100%, according to Brazil's current scenario. Three climate options for photovoltaic power input has been considered, accounting for sunny, partially cloudy and cloudy days. Climate is randomly chosen in the simulation for each day. A schematic representation of the modeled system and the profile of consumers's electric demand are shown in Figs. 1 and 2, respectively.

Fig. 2 Consumers power demand for one day [19]

As seen in Fig. 2, residential energy consumption is relatively low in the early hours of the day, having a peak demand between 6 pm and 11 pm. On the other hand, the industrial load profile presents less fluctuation throughout the day.

Current in and out of the battery bank (I_{bat}), in A, is determined dividing electric power by the tension (48 V). State of charge (SOC) limits are fixed at 20% minimum and 90% maximum. Later, total charge remaining in the battery Q_e , in A.h., and battery's state of charge are updated according to Eqs. (1) and (2), where Δt , in h, is the interval time analysis (chosen equal to one minute) and C is the total battery capacity, in A.h [28].

$$Q_{e(t+1)} = Q_{e(t)} - I_{bat} \Delta t \quad (1)$$

$$SOC = 1 - \frac{Q_e}{C} \quad (2)$$

Next, Fig. 3 shows a schematic representation of the CHP unit, composed of natural gas reformer and PEMFC. The reformer consumes water and natural gas (assumed to be pure methane) and generates hydrogen for utilization in the PEMFC subsystem, which then produces electrical power output. As the reactions occur at high temperature, cogeneration with heat rejection from the PEMFC unit is achievable.

Molar flow of hydrogen going into the fuel cell (n_{H_2}) is given by Eq. (3) in kmol/min [25]. Number of single cells within fuel cell stack (N_{FC}) and active surface area (A_a), required to calculate the current into a single fuel cell I_{cell} , in A, were assumed as 75 and 200 cm^2 , respectively [11]. F is the Faraday constant (96.485 C/kmol) and S_{H_2} is the hydrogen stoichiometry (assumed equal to 1.00 in this study).

$$n_{H_2} = 60 \frac{S_{H_2} I_{cell} N_{FC}}{2F} \quad (3)$$

Then, molar flow of methane (CH_4) is defined as a quarter of the molar flow of hydrogen (H_2) (Inac 2019) and total gas consumption (v_{gas}), in m^3/min , within CHP unit is calculated in (4) by assuming 100% methane composition and standard ambient conditions. In (4), m_{CH_4} is the mass flow of methane (kg/min) and ρ_{gas} is the natural gas density (0.76 kg/m^3).

$$v_{gas} = \frac{m_{CH_4}}{\rho_{gas}} = \frac{0.016 n_{H_2}}{\rho_{gas}} \quad (4)$$

Finally, thermal power rejection (P_{th}), in W, caused by the exothermic reactions at high temperature operation of the fuel cell is given by (5) [11]. Electric (η_{el}) and thermal (η_{th}) efficiencies are calculated according to Eqs. (6) and (7) [11] and were found to be 51.2% and 48.8%, respectively. V_{cell} and I_{cell} are the stack total voltage (V) and current (A) through each single fuel cell.

$$P_{th} = N_{FC} (1.25 - V_{cell}) I_{cell} \quad (5)$$

$$\eta_{el} = \frac{1}{S_{H_2}} \frac{V_{cell}}{1.25} \quad (6)$$

$$\eta_{th} = \frac{1}{S_{H_2}} \left(1 - \frac{V_{cell}}{1.25} \right) \quad (7)$$

Figs. 4 and 5 present a four-day operation analysis of system's operation for two residential consumers with conventional tariff. Figure 4 shows the power flow through system's components while Fig. 5 shows the grid consumption and banked credits. Power flow through each system component was determined via a control algorithm introduced in Appendix Fig. 12 for conventional tariff. Load demand and PV generation are always positive, while for the battery bank, utility grid and PEMFC unit, power can be positive or negative. Negative power represents battery charging, PEMFC warming up power consumption and grid export. On the other hand, positive power means battery discharging, PEMFC power production and grid import.

Economic Study

In order to evaluate system's feasibility and impact on each possible configuration (FC + PV + B, FC + PV and FC + B), an economic analysis was performed for both types of consumers in the Brazilian scenario. A total of ten PV panels and three batteries were used for each consumer. Energy input operation tariffs for electric energy and natural gas in 2020 are chosen equal to the current cost in the city of Rio de Janeiro, Brazil (as shown in Appendix Table 12). Electric

Fig. 3 Schematic representation of the CHP unit (PEMFC + NG reformer)

Fig. 4 Power flow through all system's components for a four days simulation

energy tariff was assumed to increase 2% above inflation per year against 0% increase in NG tariff after linear decay

Fig. 5 Grid parameters for a four days simulation

to 60% of its original cost during three consecutive years. The rapid decay in the predicted natural gas tariff was due to the decentralization program on the Brazilian NG market, initiated in 2018 [10].

For the economic assessment, first a net present value evaluation NPV of the system's operation is calculated according to Eq. (8).

$$NPV = -INV + \sum_{i=0}^N \frac{CF_{(i)}}{(1+r)^i} \quad (8)$$

The NPV represents all cash flows (US\$) of a project (incoming and outgoing) evaluated at present ($t=0$) [39]. In Eq. (8), INV correspond to the total investment on the project (US\$), representing a negative input cashflow at the beginning of system's operation. All equipment costs and each corresponding manufacturer are presented in Appendix Table 13. $CF_{(i)}$ is the cashflow (US\$) at year i , which can be a positive or negative value and r is the interest rate (taken as 2.5% a year) [39]. NPV must be positive for the system to be viable.

Secondly, the cumulative cost of each system configuration during ten years operation, for an installation of the system in the 2020 to 2040 horizon, is introduced as another parameter of economic analysis. In this to work, future acquisition costs of each power source in the system needed to be estimated for the next two decades. No reduction costs were considered in inverters acquisition. A linear decay function was used to interpolate IRENA's estimates on battery decaying prices up to 2040 [26], detailed in [29]. Eqs. (9) and (10) were used to estimate PV and CHP (PEMFC + NG reformer) decaying acquisition costs, according to data available in ([27, 42], where y corresponds to the year.

$$FC(y) = FC(y = 2020) \exp(0.3182 (y - 2020))^{-0.2367} \quad (9)$$

$$PV(y) = PV(y = 2020) [(1 + 0.09)^{(y-2020)}]^{-0.2875} \quad (10)$$

Figures 6, 7 and 8 show the decaying costs projections for each equipment in the horizon considered.

As seen in Fig. 7, PV modules prices will continue to decrease continuously within the next twenty years, but with a slower pace compared to the last decades, achieving almost 40% reduction by 2040. Following the projections, lead-acid batteries will experiment an even greater reduction on its purchase prices (approximately 65% in the same time interval). Finally, fuel cells are expected to have the major cost reductions as they are currently in the beginning of commercialization process, allowing for a 75% price decrease up to 2040. The resulting decay curve for the fuel cell / CHP investment was very similar to the predictions available in [41] study, thus serving as a partial validation of the economic model developed in this work.

Fig. 6 5 kW Fuel cell + NG reformer acquisition cost projection in the 2020 to 2040 horizon

Fig. 7 245 W PV modules acquisition cost projection in the 2020 to 2040 horizon

GHG Emission Impact Study

The GHG emission study included in this work aimed to evaluate the total impact (in terms of gCO_2/kWh) for a few cases of interest of the proposed system. Total contributions were divided in system components production and manufacturing process and operational CO_2 emissions from the power sources involved. In this study, all other greenhouse pollutants such as methane (CH_4) and nitrous oxide (NO_x) were accounted for their equivalent environmental impact in a gCO_2/kWh basis. PV panels contribution to CO_2 emission was considered to be fully of operational nature since major part of literature work on this area gather all modules

Fig. 8 100 Ah / 48 V battery acquisition cost projection in the 2020 to 2040 horizon

Table 1 Total equivalent CO₂ contribution from each system components production and manufacturing process

Components	CO ₂ emission (kg CO ₂ /kWe)	CO ₂ emission (kg CO ₂ /kWh)	CO ₂ emission (kg CO ₂ /un.)
CHP	36.20	–	182.00
Battery	–	37.63	180.60
Inverter	26.30	–	178.84

fabrication, operation and maintenance impact in a equivalent carbon dioxide per kilowatts-hour (gCO_2/kWh) basis.

Table 1 shows all equipment production impact contribution considered in this work. For the 5 kW PEMFC / CHP, the average value available in Evangelisti [18] work was considered, while, for the inverters, estimations on bidirectional inverters for solar systems with energy storage was used [5]. On the other hand, a mean value from data found in the literature [5, 8] was considered for the 4.8 kWh batteries.

Fuel cell operation, PV modules and conventional natural gas heaters (in cases when cogeneration with CHP was not accounted for) were the main contributors of the operational equivalent emission fraction. For PV modules, the mean value between [9], and [20] for polycrystalline Si panels was used.

As natural gas composition was assumed as 100% methane in this work and as each CH_4 molecule generates one CO_2 molecule during natural gas reforming process, the mass flow of CO_2 (in g/min) was obtained from Eq. (11). In Eq. 11, MW_{CO_2} and MW_{CH_4} are the molecular weight of carbon dioxide and methane (kg/kmol), n_{CO_2} and n_{CH_4} are the molar flows of CO_2 and CH_4 (kmol/min), v_{gas} is the natural gas flow (m^3/min) and ρ_{gas} is the density of natural gas under standard conditions ($0.76 kg/m^3$).

$$m_{CO_2} = MW_{CO_2} n_{CO_2} = MW_{CO_2} n_{CH_4} = MW_{CO_2} \frac{v_{gas} \rho_{gas}}{MW_{CH_4}} \quad (11)$$

Total equivalent energy (in kWh) associated with the natural gas entering the CHP (E_{CHP}) was obtained from Eq. (12), where LHV_{gas} is the lower heating value of natural gas under standard conditions (14.37 kWh/kg) and V_{gas} is the total natural gas consumed at the end of system's operation (m^3).

$$E_{CHP} = V_{gas} \rho_{gas} LHV_{gas} \quad (12)$$

The total electric and thermal energy generated by the CHP (in Wh) were calculated by simple integration with electric and thermal power output from the CHP operation, as given by Eq. (13).

$$E_{i=el,th} = \int_0^t P_{i=el,th} dt \quad (13)$$

Table 2 Total equivalent CO₂ contribution from each system's power source

Power Source	CO ₂ emission (g CO ₂ /kWh)
CHP (wo/ cogeneration)	404.47
CHP (w/ cogeneration)	207.09
PV Panels	45.00
NG Heater	518.00
Electricity Grid	88.00

Finally, the equivalent GHG emissions (in gCO_2eq/kWh) of CHP's operation with and without cogeneration are given through Eqs. (14) and (15), respectively. The first portion of the right hand side corresponds to the emission generated by the gas reform process within the CHP, while the second portion of the right hand side corresponds to the equivalent emission produced during the natural gas extraction, production and refining process (CHP entry). The value $49.98 gCO_2eq/kWh$ is assumed for the equivalent emission per unit of energy of the processed natural gas [21].

$$EM_{el} = \frac{m_{CO_2}}{E_{el}} + \frac{49.98 E_{CHP}}{E_{el}} \quad (14)$$

$$EM_{CHP} = \frac{m_{CO_2}}{E_{el} + E_{th}} + \frac{49.98 E_{CHP}}{E_{el} + E_{th}} \quad (15)$$

Table 2 shows the contribution of CO_2 emissions through the operation of each power source of the proposed hybrid system. In cases where cogeneration was not accounted for, a typical residential heater using natural gas was used to supply the user's thermal demand, whose equivalent emission of CO_2 was considered similar to the equivalent emission obtained for natural gas burn in thermoelectric power plants in Brazil [34]. The value available in the National Energy Balance [17] was assumed for the average CO_2 emissions index generated in the Brazilian electricity energy matrix in 2018 ($88 gCO_2/kWh$).

Results and Discussions

Validation for Conventional PV Systems

In order to validate the NPV modelling of the developed Matlab program, the configuration of the system with pure PV was simulated using the electricity tariff prices for two different Brazilian states (Rio de Janeiro and Santa Catarina). These states have been chosen for the reason that they present the greater electricity prices disparity in Brazil (0.1678 US\$/kWh for Rio de Janeiro and 0.1185 US\$/kWh

for Santa Catarina, without taxes), thus providing a wider range for the proposed validation. The payback for the given system configuration was estimated and compared to those from Greener's predictions on the distributed generation from solar PV market in Brazil [22]. Table 3 presents all economic data acquired for a twenty-year simulation of the PV only configuration for two residential consumers in the two states, where both the estimated payback time from the program and the payback predictions by Greener are given.

It can be seen that the paybacks for residential cases were slightly below those presented in the report, the difference being attributed mainly to the outdated data contained in the Greener study, as it was carried out in the fourth quarter of 2019 (higher PV modules costs). The paybacks of industrial cases were slightly above those presented in the report, because, due to the absence of data related to low voltage industrial consumers in the report, the results calculated by the simulator were compared to the data estimated for low voltage commercial consumers. In this way, the differences

in the simultaneity and PR (performance ratio) expected for both types of consumers lead to a small disparity for the forecasts in this case. Finally, the estimated average paybacks were very close to the estimates made by Greener, with differences between 5% and 20% of the data obtained, proving the effectiveness of the control logic and the use of the cashflow analysis tool developed for the project.

Simulation for Two Consumers Cases

Figs. 9 (a) and 10 (a) show the cashflow in net present value (NPV) through a twenty-year operation starting in 2020 for two residential and industrial consumers, respectively. Results correspond to the use of conventional tariff. On the other hand, Figs. 9 (b) and 10 (b) estimate the total cumulative cost of a ten-year system operation in the 2020 to 2040 horizon. Tables 4, 5, 6, and 7 present detailed data collected from NPV analysis for each type of consumer.

Table 3 Economic parameters for a twenty-year system's operation on PV only configuration for two residential consumers in Rio de Janeiro and Santa Catarina states

Parameters	Residential		Industrial	
	Rio de Janeiro	Santa Catarina	Rio de Janeiro	Santa Catarina
Total Investment (US\$)	24,415	24,415	28,315	28,315
Electric Energy (US\$)	6064	4108	6064	4105
Maintenance (US\$)	7500	7500	9500	9500
Inverters substitutions (US\$)	9690	9690	9690	9690
Total System Cost (US\$)	47,669	45,713	53,569	51,610
Final profit in NPV (US\$)	115,358	64,644	152,897	88,152
Payback - Simulated (yr.)	3.3	5.0	2.9	4.5
Payback - Greener (yr.)	3.8	6.1	2.6	4.3

Fig. 9 **a** Cashflow in net present value (NPV) for twenty-year system's operation and **(b)** Total cost for ten-year system's operation in an 2020–2040 horizon for two residential consumers with conventional tariff

Fig. 10 **a** Cashflow in net present value (NPV) for twenty-year system's operation and **(b)** Total cost for ten-year system's operation in an 2020–2040 horizon for two industrial consumers with conventional tariff

Table 4 Technical data for 20-year system's operation for two residential consumers with conventional tariff

Parameters	With Cogeneration			Without Cogeneration		
	FC+PV+B	FC+PV	FC+B	FC+PV+B	FC+PV	FC+B
NG flow (m ³ /month)	286.14	285.58	398.33	286.29	285.41	398.33
Percentage of time PEMFC operation (%)	51.80	51.70	72.11	51.83	51.67	72.11
Bank substitutions	2	0	2	2	0	2
Required inverters	2	2	2	2	2	2

Table 5 Economic data for 20-year system's operation for two residential consumers with conventional tariff

Parameters	With Cogeneration			Without Cogeneration		
	FC+PV+B	FC+PV	FC+B	FC+PV+B	FC+PV	FC+B
Total Investment (US\$)	83,675	79,085	79,775	83,675	79,085	79,775
Electric Energy (US\$)	7136	7339	7101	7138	7335	7101
Natural Gas (US\$)	5134	5154	1190	44,602	44,500	57,566
Maint. & Replc. (US\$)	17,723	11,610	15,723	17,723	11,610	15,723
Total System Cost (US\$)	113,668	103,188	103,789	153,138	142,530	160,165
Final Profit in NPV (US\$)	42,892	52,354	51,615	10,903	20,467	5922
Payback (yr.)	2033	2032	2032	2038	2037	2039

All system configurations achieved payback before the year 2040 and required inverters substitution after fifteen years operation. Only two inverters and two battery bank substitutions were required in all residential cases. In cogeneration cases, a discount proportional to recovered heat from CHP and gas tariffs was made for each type of consumer, explaining the major gas bill cost reductions in these cases. Also, electric energy costs were very close to the minimum energy consumption of 100 kWh/month stated

for three-phase facilities connected to the grid, proving that the control system's algorithm worked well in delivering power through system's components. Percentage time operation of fuel cell varied between 52% in residential PEMFC+PV systems to 92% in industrial PEMFC+B cases and final profits up to US\$ 82,000 were achieved, accounting for system's feasibility in all scenarios. Very little difference was observed in the final profit between PEMFC+PV and PEMFC+B configurations with the use of

Table 6 Technical data for 20-year system's operation for two industrial consumers with conventional tariff

Parameters	With Cogeneration			Without Cogeneration		
	FC + PV + B	FC + PV	FC + B	FC + PV + B	FC + PV	FC + B
NG flow (m ³ /month)	396.63	396.10	512.05	396.30	396.34	512.05
Percentage of time PEMFC operation (%)	71.80	71.71	92.70	71.74	71.75	92.70
Bank substitutions	1	0	0	1	0	0
Required inverters	2	2	1	2	2	1

Table 7 Economic data for 20-year system's operation for two industrial consumers with conventional tariff

Parameters	With Cogeneration			Without Cogeneration		
	FC + PV + B	FC + PV	FC + B	FC + PV + B	FC + PV	FC + B
Total Investment (US\$)	83,675	79,085	76,545	83,675	79,085	76,545
Electric Energy (US\$)	7127	7144	7103	7140	7133	7103
Natural Gas (US\$)	22,308	22,294	25,461	57,331	57,336	70,725
Maint. & Replc. (US\$)	14,551	11,610	6380	14,551	11,610	6380
Total System Cost (US\$)	127,661	120,133	115,489	162,697	155,164	160,753
Final Profit in NPV (US\$)	71,658	78,602	82,491	43,262	50,209	45,805
Payback (yr.)	2031	2030	2030	2034	2033	2033

cogeneration, where the later presented slightly reduced costs in the industrial case. On the other hand, without cogeneration, PEMFC+PV configuration tended to show better cost effectiveness (especially on residential case) because of lower NG consumption. It should be noted, however, that the battery bank provides an effective means of energy storage, which could temporarily provide all electricity demand in the system in case of CHP's malfunctioning or if connection to the grid was lost at any moment. Therefore, FC + B or FC + PV + B configurations could be the ideal solution in case of critical applications, where security in energy supply is more important than the cost itself.

As evidenced by Figs. 9 (a) and 10 (a), the conventional PV systems were able to present a much larger profit at the end of 20 years operation because of extremely low initial investment. These results, however, could change considerably, according to Figs. 9 (b) and 10 (b). As fuel cells are currently in the beginning of commercialization process, major acquisition cost reductions expected for this technology within the next years may reshape system's cashflow and cumulative cost curves totally different. Even though some cost reduction is also expected for PV modules as well, other components / technologies of conventional PV systems are already fully mature in the market (for example the power inverters), explaining more flattened cost decay curves for such systems between 2020 and 2040.

Simulation for Five Consumers Cases

To investigate the impact of different electric energy tariffs and fuel cell sizing, a complete system (FC + PV + B)

was simulated under the same circumstances as before under conventional and alternative tariffs for five residential and industrial consumers. In these cases, however, only cogeneration scenarios were evaluated as to obtain the maximum profit as possible for the consumers. Again, a total of ten PV modules (245 W each) and three 100 Ah batteries were used per consumer.

Fig. 11 and Tables 8 and 9 show all data acquired along with the simulation for pure PV systems for the same power demand.

Both residential and industrial consumers required three inverters while running on conventional tariff and five inverters while on alternative tariff. Also, just one battery substitution was needed for industrial cases and three substitutions for residential cases with conventional tariff, while five substitutions were required for both of them on alternative tariffs's cases. Even though the fuel cell operated 100% of the time for all five consumers's cases (552 m³/month of NG), complementary electric energy from the grid was needed to supply total demand, except for the residential case with alternative tariff. In fact, the alternative tariff strategy has a positive effect, allowing major energy cost reductions by forcing the batteries to shift power generation within the system to around 6 pm and 9 pm. Thus, the system exports large amounts of energy to the grid when tariff is more expensive, generating more energy credits for use in other times of the day. That strategy comes with a price though, requiring the batteries to complete much more cycles than in the conventional tariff case, meaning more frequent bank substitutions and necessity for more inverters

Fig. 11 (a) Cashflow in net present value (NPV) for twenty-year system's operation and (b) Total cost for ten-year system's operation in an 2020–2040 horizon for five consumers with conventional and alternative tariffs

Table 8 Technical data for 20-year system's operation for five consumers with both tariffs

Parameters	Residential			Industrial		
	Conv.	Alt.	PV only	Conv.	Alt.	PV only
NG flow (m ³ /month)	552.34	552.36	0	552.38	552.38	0
Percentage of time PEMFC operation (%)	99.99	99.99	0	100	100	0
Bank substitutions	3	5	0	1	5	0
Required inverters	3	5	6	3	5	8

Table 9 Economic data for 20-year system's operation for five consumers with both tariffs

Parameters	Residential			Industrial		
	Conv.	Alt.	PV only	Conv.	Alt.	PV only
Total Investment (US\$)	99,640	106,100	56,530	99,640	106,100	72,740
Electric Energy (US\$)	92,080	7505	7109	219,324	169,748	7113
Natural Gas (US\$)	0	0	0	26,636	26,636	0
Maint. & Replc. (US\$)	40,366	62,813	38,380	25,193	62,813	49,840
Total System Cost (US\$)	232,086	176,418	102,019	370,793	365,297	129,693
Final Profit in NPV (US\$)	171,289	213,036	284,166	162,253	163,877	359,351
Payback (yr.)	2028	2027	2024	2028	2028	2024

to perform great power flow during peak hours. Because the most part of consumer demand is concentrated during peak hours for the residential case, the alternative tariff strategy provided higher reduction on energy cost than the industrial case, allowing total profit of US\$ 213,000 at the end of system's operation.

Again, it can be seen that, in the year 2020, conventional PV systems (without batteries) are still much cheaper to generate the same amount of energy than the proposed system,

achieving paybacks before four years operation time. On the other hand, as shown in Fig. 11 (b), major cost reductions in total system operation costs can be obtained when considered beginning of system's operation several years ahead, mainly due to cheaper investment on system components (specially the PEMFC unit). For the residential case, the FC + PV + B system would become economically competitive with PV only systems by the year 2040, when alternative tariff strategy is considered.

Simulation with alternative tariff for two consumers's cases were performed but no advantage was observed due to low energy consumption from the grid. In other words, the alternative tariff strategy could not reduce energy bill costs while the system was oversized, thus presenting worse results than the conventional tariff due to more battery bank substitutions and additional inverters required.

CO₂ Equivalent Emissions for Two Consumers Cases

Tables 10 and 11 present the GHG impact study for two residential and industrial consumers in terms of gCO_2eq/kWh considered in this work. Total consumers' power and thermal demands and electric power generated / consumed by each power source in the system are shown. Also, each power source percentage contribution to the supply of total demand and equivalent CO₂ emissions of component's manufacturing

Table 10 CO₂ equivalent emissions for two residential consumers with conventional tariff

Parameters	With Cogeneration			Without Cogeneration		
	FC + PV + B	FC + PV	FC + B	FC + PV + B	FC + PV	FC + B
Electric demand (kWh)	645,269	645,269	645,269	645,269	645,269	645,269
PV generation (kWh)	175,042	175,430	0	175,037	174,751	0
CHP elec. Generation (kWh)	447,422	445,959	623,028	447,554	446,654	623,028
Grid consumption (kWh)	22,805	23,879	22,241	22,677	23,863	22,241
Thermal demand (kWh)	426,449	425,055	593,823	426,575	425,717	593,823
Operational Contributions (energy supply per source)						
CHP (%)	81.54	81.38	98.21	41.76	41.70	50.28
PV (%)	16.33	16.39	0.00	16.33	16.32	0.00
Grid (%)	2.13	2.23	1.79	2.12	2.23	1.79
NG burner (%)	0.00	0.00	0.00	39.80	39.75	47.92
eq. emissions (g CO ₂ /kWh)	178.08	177.87	204.95	384.25	383.89	453.20
Components' Manufacturing & Replacement Contribution						
CHP (g CO ₂ /kWh)	0.17	0.17	0.15	0.17	0.17	0.15
Batteries (g CO ₂ /kWh)	3.03	0.00	2.62	3.03	0.00	2.62
Inverters (g CO ₂ /kWh)	0.67	0.67	0.58	0.67	0.67	0.58
TOTAL						
Total (g CO ₂ /kWh)	181.95	178.70	208.30	388.12	384.73	456.55

Table 11 CO₂ equivalent emissions for two industrial consumers with conventional tariff

Parameters	With Cogeneration			Without Cogeneration		
	FC + PV + B	FC + PV	FC + B	FC + PV + B	FC + PV	FC + B
Electric demand (kWh)	817,198	817,198	817,198	817,198	817,198	817,198
PV generation (kWh)	174,753	174,812	0	175,108	174,747	0
CHP elec. Generation (kWh)	620,226	619,820	800,889	619,694	619,867	800,889
Grid consumption (kWh)	22,219	22,566	16,310	22,396	22,584	16,310
Thermal demand (kWh)	591,153	590,766	763,347	590,646	590,811	763,347
Operational Contributions (energy supply p. source)						
CHP (%)	86.01	85.98	98.97	44.02	44.02	50.67
PV (%)	12.41	12.42	0.00	12.44	12.41	0.00
Grid (%)	1.58	1.60	1.03	1.59	1.60	1.03
NG burner (%)	0.00	0.00	0.00	41.95	41.96	48.30
eq. emissions (g CO ₂ /kWh)	185.10	185.06	205.86	402.35	402.42	456.04
Components' Manufacturing & Replacement Contribution						
CHP (g CO ₂ /kWh)	0.13	0.13	0.12	0.13	0.13	0.12
Batteries (g CO ₂ /kWh)	1.54	0.00	0.69	1.54	0.00	0.69
Inverters (g CO ₂ /kWh)	0.51	0.51	0.23	0.51	0.51	0.23
TOTAL						
Total (g CO ₂ /kWh)	187.27	185.69	206.89	404.53	403.06	457.06

process (including battery bank and inverters replacement) are also informed. No variation in GHG emissions was observed between the conventional and alternative strategies for the electricity impact study and, thus, the results for five consumers cases were not shown in the current analysis.

It can be observed, from the obtained results, that the use of cogeneration with the CHP heat rejection has a great impact over total CO_2 produced by unit of energy. This highlights the benefits of cogeneration in both economic and environmental performance for the proposed hybrid system, where total CO_2 emissions could be reduced from approximately 388 to 182 gCO_2eq/kWh for the complete system (FC+PV+B) for the residential case. Additionally, the inclusion of the PV modules seemed to significantly improve the system's performance in an environmental point of view. As a meaningful part of the electric demand is provided by the solar power source, the fuel cell needs to operate less time in the FC+PV+B and FC+PV cases, reducing the total gCO_2eq/kWh generated. Also, it can be seen that the total contribution of each equipment production / manufacturing process has minor effects over total operational contributions of the power sources (PV and CHP), mainly due to the high energy generated during the 20 year's operation, which dilutes the components manufacturing process GHG impact.

Finally, if all the electric and thermal demands were provided solely by the Brazilian electricity grid and natural gas heater, the total CO_2 emission would be 259.14 gCO_2eq/kWh and 268.39 gCO_2eq/kWh , respectively for the residential and industrial cases. Furthermore, even though conventional PV systems usually present equivalent emissions of 40 gCO_2eq/kWh to 80 gCO_2eq/kWh [9, 20], if a natural gas heater is also used to supply the corresponding thermal demand for the residential consumer, total emission could rise up to 233.25 gCO_2eq/kWh for such systems. Therefore, the proposed on-grid hybrid system proved to be an interesting alternative solution to other green energy systems by presenting relatively low pollutant emission to the environment when cogeneration is considered.

Conclusions and Perspectives

An hybrid system was presented and simulated under different system configurations and two type of tariffs, allowing for cogeneration from high temperature operation of the CHP unit. Energy and economic assessments were made and proved for the system's viability in all discussed scenarios, where great economic advantages were achieved as compared to direct electric energy consumption from the grid. Paybacks between 7 and 19 years of system's operation were achieved for different combinations of the studied parameters considering beginning of operation in 2020. Additionally, more than 50% reductions in total system cumulative cost were obtained considering the predicted decrease in system's components

acquisition costs for the next two decades. For two consumers cases, the best scenario was achieved with the FC+PV configuration for the residential load profile and the FC+B configuration for the industrial load profile, mainly due to different power demand fluctuation throughout the day. Additionally, for five consumers cases, it was found that the alternative tariff strategy could provide significantly cost reductions only when system was undersized because of relatively high battery bank substitutions costs. From the GHG impact study, it could be seen that the proposed system presented relatively low CO_2 emissions when cogeneration with CHP heat rejection was included in the analysis. The best scenario was obtained with the FC+PV configuration, where operational emissions were approximately equal to the FC+PV+B configuration, but components production and manufacturing had a minor contribution due to the absence of the battery bank. Considering cogeneration, total calculated emissions were 178.7 gCO_2eq/kWh (residential case) and 185.69 gCO_2eq/kWh (industrial case) for this configuration. Thus, the proposed system could reduce total emissions up to 31% when compared to the complete power and thermal supply by the Brazilian Electricity grid and natural gas heater (estimated as 259.14 gCO_2eq/kWh and 268.39 gCO_2eq/kWh , respectively, for the consumers). The results show that, beyond requiring much less space for equipment installation, the analysed system has the advantage of power shifting control throughout the day over conventional PV systems. As consequence, less dependence on reverse metering factor variation is expected from the former. Finally, the battery bank could sustain energy supply even if connection to the grid was lost at any moment, providing an efficient back-up for consumer's power demand, opening up several potential applications for the proposed system.

In future works, an experimental validation of the developed simulation tool is considered of great interest for this work. Additionally, several modules can be added to the proposed simulation tools. For instance, a control algorithm with the use of neural networks or fuzzy-logic based techniques should be elaborated in order to maximise system's performance in both efficiency and economic viewpoints. Also, a more realistic value for hydrogen stoichiometry in FC reactions and different NG compositions should also be examined as to obtain a more accurate result for system's efficiency and to extend the system's applicability on different regions of the planet. A sensitivity analysis for various fuel purchasing and power selling price would lead to more realistic pay back times. Moreover, an exergy analysis should be carried out in order to identify possible improvements on system arrangement and process. Also, PEMFC stack substitutions should be considered after stack lifespan is reached. A model of battery degradation can also be added. Finally, a comparison with other types of load profiles (as commercial consumers) for small and medium power applications should also be evaluated.

Appendix

Fig. 12 Control algorithm for power flow through the system for each PEMFC operation condition (turned off, warming up, power production and cooling down). a) Turned off, b) Warming up, c) Power production, d) Cooling down

Fig. 12 (continued)

Table 12 Grid electricity and natural gas costs used in this study

Electric energy		Natural gas		
Type of tariff	Cost (US\$/kWh)	Type of consumer	Consume range (m ³ /month)	Cost (US\$/m ³)
Conventional	0.244	Distributed	0–200	1.127
Alternative (low) before 17:00 and after 22:00	0.215	Generation	201–5000	0.753
		Residential	0–7	1.543
			8–23	2.012
			24–83	2.437
Alternative (inter.) 17:00 to 18:00 and 21:00 to 22:00	0.297	Industrial	above 84	2.572
			0–200	1.507
			201–500	1.463
Alternative (high) 18:00 to 21:00	0.445		above 500	1.420

Table 13 Equipment costs considered in this study

Equipment	Acquisition Cost (US\$/unit)	Installation Cost (US\$/unit)	Maintenance Cost (US\$/unit/year)	Manufacturer
Micro CHP w/ 5 kW PEMFC Unit	63,000	5625	157.5	Helbio
6.8 kW Bidirectional Inverter	3230		–	Intermepro
48 V / 100 Ah VRLA Battery	765	–	–	Moura
245 W PV pannel	162	32.5	5.0	Yingli

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Declarations

Conflict of Interests The authors declare that there is no conflict of interests.

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