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ENERGY AND ECONOMIC ANALYSIS OF AN HYBRID MICRO-CHP SYSTEM WITH FUEL CELL USING NATURAL GAS AND PHOTOVOLTAIC PANELS FOR RESIDENTIAL CONSUMERS IN 10 BRAZILIAN CITIES

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Abstract. *Hybrid systems composed of intermittent renewable sources, storage systems and fuel cells emerge as a possible solution for more efficient and less polluting energy generation, and should be investigated regarding their technical and economic applicability. In this context, the present work proposed a numerical simulation of a hybrid system for generating electricity and heat, connected to the electrical grid, consisting of a micro-CHP (PEMFC + auxiliary components), photovoltaic modules and batteries. The power flow control between the energy sources and the consumer demand was simulated using the MATLAB software (version 2019b). Its installation in the cities of São Paulo (SP), Rio de Janeiro (RJ), Salvador (BA), Fortaleza (CE), Belo Horizonte (MG), Manaus (AM), Curitiba (PR), Recife (PE), Porto Alegre (RS) and Campo Grande (MS) were investigated. Subsequently, cash flow analysis methods are introduced by calculating the net present value and total cumulative cost, under different scenarios of electricity and natural gas tariffs and with or without cogeneration. The system showed higher economic performance in the cities of Manaus due to high electricity tariff and São Paulo, as a result of low natural gas tariff. The results showed in the best case, a payback lower than 7 years. It was observed that, with the expected reduction in the equipment cost over the next 20 years, a decrease of more than 50% in the total cumulative cost could be achieved in 2043. In these projections, the greatest differences were observed in São Paulo (80%) where the OPEX of the system (electricity + natural gas) is the cheapest, while Porto Alegre presented the lowest reduction (51%).*

Keywords: *Proton Exchange Membrane Fuel Cell (PEMFC), Hydrogen, Battery storage, Payback, Net Present Value (NPV).*

1. INTRODUCTION

The search for renewable or cleaner sources of energy than those traditionally used for power generation in the last century is an irreversible and necessary process for the future development of large sustainable cities. Since the 1970s, when international research began pointing to the dangers related to the increasing concentration of greenhouse gases in the atmosphere and the imminent threat of global warming, many institutions have turned their attention to the problem, seeking ways to reduce carbon dioxide emissions (Gabriel, 2020).

Reports developed by the Energy Information Administration (EIA) indicated an increase in electricity consumption of over 100% in the residential sector between 2020 and 2050. Lower but still significantly high growth rates are expected for the industrial and commercial sectors, with projected increases of 45% and 82%, respectively, during the same time period (IEA, 2019). According to the EIA, it is expected that approximately 50% of this increase in electricity demand will be met by renewable energy sources, with solar panels and wind turbines playing a crucial role in the generation process. At the same time, there is an expectation that a significant portion of generation from sources such as coal and oil derivatives will be replaced by less polluting sources, with natural gas being highlighted (Gabriel, 2020).

One factor that can greatly contribute to the increased share of renewable generation, especially in metropolitan areas, is the decentralization of electricity generation through Distributed Generation. This process involves the participation of various lower-power energy sources distributed throughout the distribution network, as opposed to centralized generation where large power plants are responsible for meeting the entire electricity demand in their region. The inclusion of these smaller electricity sources, mostly represented by small consumers using photovoltaic panels and micro wind turbines, allows for a bidirectional flow of energy in the integrated grid. In addition to the reduction of the emissions, other technical issues such as improved voltage stability in the network and reduced transmission and distribution losses can be achieved by the new system (Ehsan, 2017).

Additionally, the new model also encourages the proliferation of energy storage systems, mostly composed of batteries. In Brazil, the legislation provides that energy generated by the user and exported to the power grid be "stored" in the form of energy credits, which can be used by the user later when their system is unable to meet their own demand. However, the current legislation foresees an increasing taxation on electricity exported to the grid, making self-owned energy storage systems increasingly attractive in the coming years (MME, 2022).

To reduce dependence on taxation of electricity exported to the grid (with limited space for component installation), a hybrid generation system composed of solar panels, fuel cells, and batteries allows residential or commercial consumers to generate their own energy from multiple sources, facilitating its adoption, particularly in competitive areas. Thus, Di Marcoberardino et al. (2017) conducted a numerical simulation of a system consisting of a 5 kW polymer electrolyte membrane fuel cell (PEMFC) using natural gas, residential heaters, and thermal storage system to meet the electrical and thermal demands of a residence in four different European Union countries: Spain, Italy, the United Kingdom, and the Netherlands, considering different electricity and natural gas prices and different compositions of natural gas, resulting in different energy and exergy efficiencies for each configuration. Gabriel (2020) developed a numerical simulation, using MATLAB, of a combined heat and power (CHP) hybrid system for electricity and heat generation connected to the power grid, consisting of a fuel cell operating on natural gas, photovoltaic panels, batteries, and a bidirectional hybrid inverter. Each device was modelled based on published literature, and a control routine was developed to manage the power flow between the mentioned sources, the consumer's demand, and the power grid, also considering the use of two different electricity tariffs (conventional and off-peak). Finally, a sensitivity analysis was conducted to evaluate the economic and environmental feasibility of the proposed system in the Brazilian context, by varying parameters such as different system configurations, different rates of increase in electricity and natural gas tariffs, utilization factor of credits in the grid (different scenarios proposed by the *Agência Nacional de Energia Elétrica* - ANEEL), number of powered consumers, and the possibility of cogeneration with the waste heat from CHP operation. Subsequently, Junior (2021) improved the simulator, paying special attention to the modelling of each subcomponent of the original system, especially photovoltaic generation and the micro CHP composed of the PEMFC fuel cell and natural gas reformer. In this work, real measurement data of global incident solar radiation, average ambient temperature, and average wind speed for the state of Rio de Janeiro in 2020 were used to compose the profile of electricity generation in the photovoltaic panels of the system.

Thus, this work aims to evaluate the economic feasibility of a combined on-grid hybrid system for electricity and heat generation (CHP) composed of photovoltaic panels, batteries, and a 5 kW microgenerator group (polymer electrolyte membrane fuel cell (PEMFC) + auxiliary components) for a specific residential demand, comparing its performance in different Brazilian cities. For this purpose, the simulator developed by Gabriel (2020) and Junior (2021) was used, where a detailed modelling of each subsystem involved was performed based on literature works, including an economic modelling with the electricity and natural gas costs of each city in question, allowing for a cash flow evaluation of the system for twenty years of operation (2023 to 2043). Finally, a second financial analysis will be presented to evaluate the reduction in the total cost of the proposed system over the next two decades. The ten cities studied regarding the financial impact of the proposed system in this work were: São Paulo (SP), Rio de Janeiro (RJ), Salvador (BA), Fortaleza (CE), Belo Horizonte (MG), Manaus (AM), Curitiba (PR), Recife (PE), Porto Alegre (RS), and Campo Grande (MS), totalling three cities in the Southeast region, three in the Northeast region, two in the South region, one in the North region, and one in the Midwest region of Brazil.

2. THEORETICAL MODEL

2.1 Thermodynamic Modeling of the Proposed Hybrid System

The objective of this work is the numerical simulation of a hybrid system for electricity and heat generation connected to the power grid. It consists of a 5 kW microgenerator group (PEMFC + auxiliary components), 415 W photovoltaic modules (each), and 48 V / 100 Ah batteries. Figure 1 illustrates the power flow schematic for the proposed system (left) as well as the typical power flow found in conventional energy generation systems for a residence (right) (Gabriel et al., 2022).

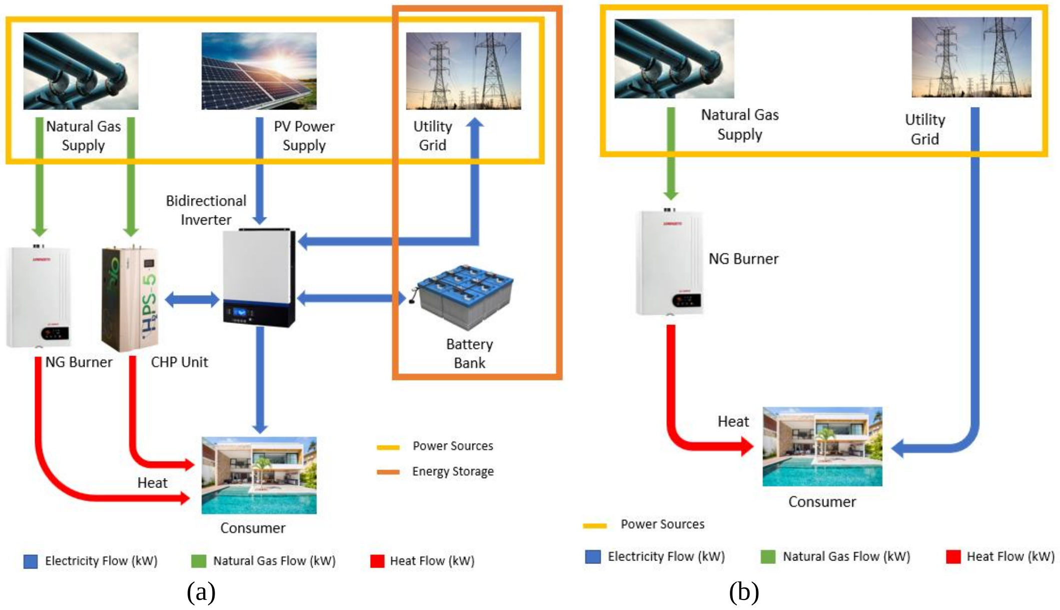

Figure 1: (a) Power flow schematic for the proposed system and (b) Power flow schematic for conventional systems (Gabriel et al., 2022).

The power flow control routine between the energy sources and the consumers' demand was performed using MATLAB software (version 2019b). Basically, the priority for energy supply is given to the photovoltaic panels, which meet the demand and, in case of excess generation, charge the battery bank and export the surplus to the power grid when the battery bank is fully charged, generating energy credits. When the photovoltaic generation is insufficient to meet the demand, the secondary priority is given to the battery bank, which starts discharging until it reaches a minimum state of charge (pre-defined in the program). In the case of continued demand exceeding the photovoltaic generation and the battery bank being at its minimum state of charge, the fuel cell is activated to start operation after a brief heating period required for the operation of the system. Once in operation, the fuel cell supplies the users' demand, charges the battery bank with the excess generation, and, when the battery bank reaches its maximum state of charge (also pre-defined in the program), exports energy to the power grid to generate energy credits. This situation continues until a minimum credit reserve is reached (defined in the program), at which point the fuel cell is turned off. This control routine aims to prevent the fuel cell from operating multiple times a day, a process that could compromise the integrity of the system and require more maintenance. Finally, considering the minimum amount to be paid monthly to the power distribution companies for maintenance purposes, equivalent to the consumption of 100 kWh/month, the program was optimized to always have this contribution from the power grid. The electricity demand profile of the consumer was based on previous literature (Francisquini, 2006), which used data obtained from the ANEEL for residential consumers with a monthly demand exceeding 500 kWh.

Eq. (1) gives the power conservation constraint formula for the proposed hybrid system as a function of the electrical consumer demand. $P_{el(cons)}$, where positive $P_{el(CHP)}$, P_{pv}, P_{bat}, P_{grid} refers to electricity generation by the CHP unit or the PV panels, battery discharge and electricity importation from the grid. Negative $P_{el(CHP)}$ may occur for short periods during warm up and cooling processes in the CHP unit.

$$P_{el(CHP)} + P_{pv} + P_{bat} + P_{grid} = P_{el(cons)} \tag{1}$$

Finally, all the heat rejected by the CHP unit, $P_{th(CHP)}$, is used to provide the consumer's heat demand, $P_{th(cons)}$, when cogeneration is considered, which yields a proportional discount in natural gas (NG) bill cost. When no cogeneration in considered, all the heat demand is provided by a NG burner, P_{burner}, as seen in figure 1 and Eq. (2).

$$P_{th(CHP)} + P_{burner} = P_{th(cons)} \tag{2}$$

The PEM fuel cell, along with its auxiliary components (particularly the reformer), is the main energy source of the system, consuming natural gas from the local distribution network and separating the hydrogen molecules for subsequent conversion into electrical energy through the reforming process. The modelling of the CHP was carried out according to the formulation proposed by Junior (2021), and a schematic representation can be seen in Figure 7.

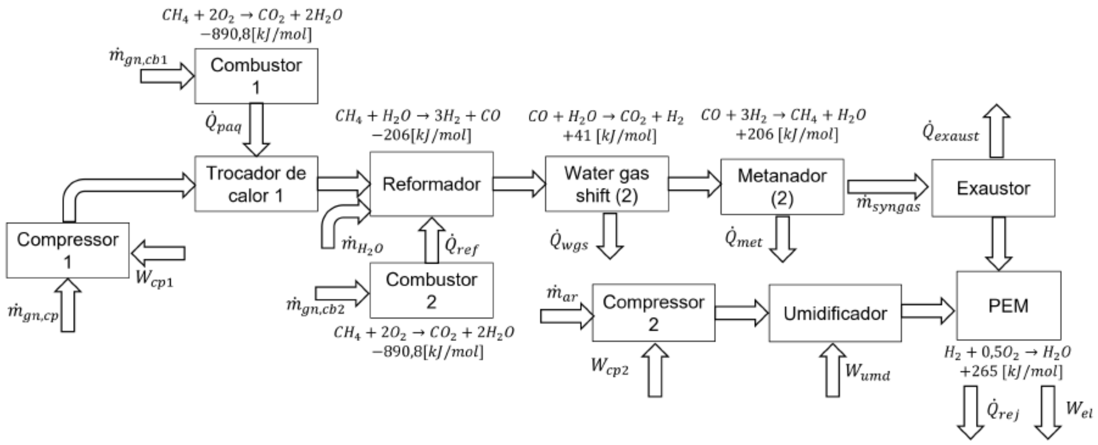

Figure 2: Basic operation diagram of the CHP (PEMFC + auxiliary components) (Junior, 2021)

In order to calculate the power supplied by the fuel cell, it is necessary to determine its net voltage E_{PEMFC}, ensuring that intrinsic operational losses are properly subtracted from the ideal and reversible voltage, E_{PEMFC}. These voltage losses are classified into three main occurrences: activation losses, E_{act}, ohmic losses, E_{ohm} and concentration losses, E_{con}. Thus, the actual voltage of the fuel cell can be estimated using Eq. (3):

$$E_{PEMFC} = E_{rev} - E_{act} - E_{ohm} - E_{con} \tag{3}$$

This work also considers the possibility of utilizing the heat generated in the process to additionally meet the thermal demand of residential users. Therefore, in cases without cogeneration, a residential natural gas heater is used to provide the required heat, while in cases with cogeneration, a heat exchanger is used to "capture" the waste heat from the CHP and meet the thermal demand without the need for a heater.

The battery bank modelling consists of assuming a constant voltage of 48 V for the bank, with the electric current being the result of the ratio. At the end of each cycle, the state of charge is updated based on the electric current supplied (or drained) to the batteries, taking into account the total storage capacity of the bank (100 Ah per battery unit) (Gabriel, 2020).

The modelling of the photovoltaic modules was based on the method proposed by Junior (2021), which uses various local meteorological factors to estimate the electric current, voltage, and consequently, the power of the panels at a given operating point. The performance of this device displays a non-linear current-voltage (I-V) curves, Eq. (3) (Duffie and Beckman, 2013):

$$I = I_L - I_0 \left[\exp\left(\frac{q(V+IR_S)}{\gamma k T_{cell}}\right) - 1\right] \tag{3}$$

The light current I_L depends on solar irradiance and temperature, Eq. (4)

$$I_L = \left(\frac{G}{G_{ref}}\right)[I_{L,ref} + k_t(T_{cell} - T_{ref})] \tag{4}$$

Where G is the solar insolation in W/m², G_{ref} the solar insolation at design condition W/m², $I_{L,ref}$ is the light current calculated based on the manufacturer data for short-circuit and maximum current point in A, k_t is the manufacturer-supplied temperature coefficient of short-circuit current in A/°C, *k* is the Boltzmann constant, and q is the electron charge in C.

The reverse saturation current, I_0, is described in function of the cell temperature and material band gap energy, and usually in the order of 10^{-5}A, described by Eq. (5):

$$I_0 = I_{L,ref} \exp\left(-\frac{qV_{oc}}{k\gamma T_{ref}}\right)\left(\frac{T_{cell}}{T_{ref}}\right)^3 \exp\left(\frac{q\varepsilon}{ka}\left(\frac{1}{T_{ref}} - \frac{1}{T_{cell}}\right)\right) \tag{5}$$

Where V_{oc} is the open-circuit voltage, a is the completion factor and ε is the diode diffusion factor.

Since this work aims to compare the performance of the presented system in different locations in Brazil, this information was obtained from data collected by the National Institute of Meteorology - INMET (INMET, 2023) in each considered city. Given the large amount of data for each city of interest in this work, it was decided to use the behaviour of irradiation, ambient temperature, and wind speed for three typical days per month as the basis, which are the first, eleventh, and twenty-first days of each month, with this behaviour being replicated for the following nine days.

Additionally, it should be noted that no modelling of the bidirectional hybrid inverter was performed, considering the high complexity of such equipment and its high operating efficiency (typically well above 90%, up to 98%) (Baumgartner, 2017), which would have a relatively small impact on the expected results of the simulations.

2.2 Economic Modeling

To simulate the cash flow and quantify the operational costs of the system, it was necessary to use the prices of electricity and natural gas import tariffs (R$/kWh and R$/m³, respectively) from the local distribution networks of each city: ComGas (São Paulo), CEG (Rio de Janeiro) [NATURGY, 2023], BahiaGas (Salvador), CeGas (Fortaleza), GasMig (Belo Horizonte), CiGas (Manaus), CompaGas (Curitiba), CoperGas (Recife), SulGas (Porto Alegre) e MsGas (Campo Grande). Regarding the cost of natural gas, the criterion adopted in this work was to use the tariffs related to the main gas distributors in each location, gathering the tariffs related to the "distributed generation/cogeneration" categories for the consumption in the CHP unit, as well as the "residential" category, used to estimate the relative discount on consumers' gas bills when cogeneration is used in the system. It should be noted that the tariffs presented in the references already include all taxes (ICMS, PIS/COFINS, etc.).

For the costs related to electricity import from the grid, the average tariffs from the main distributors in each city were used (ANEEL, 2023). The tariffs listed on the website do not include applicable taxes, so a survey of ICMS for each state, provided by (TAXGROUP, 2023), and an average estimate of PIS/COFINS for the months from January to December 2022 (EDP, 2023) were necessary, as these taxes vary from month to month. With the basic tariffs provided by ANEEL and the other taxes, the total import tariffs for electricity from the grid were calculated.

The first step in calculating the total initial investment of the system is the cost of acquiring the main equipment involved. To estimate this, values of real equipment with nominal operating values similar to those mentioned were researched, and these values are shown in Table 1, which also includes estimated installation and maintenance costs.

Table 1: Acquisition, installation, and maintenance costs of system components.

Equipment	**Capital Cost (per unit)**	**Installation Cost (per unit)**	**Maintenance Cost (unit/year)**
5 kW PEMFC-type Micro CHP (reference: model H2PS-5 – Helbio)	€ 56,000 (R$ 306,320)	€ 5.000 (R$ 27,350.00)	€ 140 (R$ 765.80)
6.8 kW bidirectional inverter (reference: CONEXT XW PRO - Intermepro)	US$ 3,230 (R$ 16,570)		-
48V/100 Ah VRLA battery (reference: automotive battery – Moura)	R$ 3,060	-	-
415 W monocrystalline PV panel (reference: CHSM72M-HC-415 – Chint Solar)	R$ 1,000	R$ 130	R$ 20

2.3 Financial Evaluation

The first financial evaluation tool used in this work is the analysis of the system users' cash flow in net present value (NPV). The method consists of evaluating all cash flows (positive or negative) in present value (SIMPSON, 2013). Equation (1) presents the calculation, where NPV_{sist} represents the net present value of the system, INV represents the total initial investment in the project, $CF(i)$ is the cash flow in year "i", r is the annual return on investment rate, and N is the total duration of the project/system operation in years.

$$NPV_{sist} = -INV + \sum_{i=0}^{N} \frac{CF(i)}{(1+r)^i} \tag{6}$$

Each cash flow is the total sum of revenue acquired by the user in year "i", composed of various costs, as shown in equation (2).

$$CF(i) = CT_{CD}(i) - OP_{tot}(i) - MAN_{tot}(i) - SBT_{tot}(i) \tag{7}$$

In equation (2), $CT_{CD}(i)$ represents the total cost of direct purchase of energy from the grid, $OP_{tot}(i)$ represents the total operation cost with electricity and natural gas in the system in year "i", $MAN_{tot}(i)$ is the maintenance cost in that year, and $SBT_{tot}(i)$ is the equipment replacement cost, when applicable.

For a project to be viable, the net present value evaluated up to year N must be positive. It is observed that the initial investment represents a negative cash flow in year zero, and it should be offset by successive positive cash flows CF(i) (i.e., revenues) for this to be possible. Each cash flow is the total revenue acquired by the user in year "i". The factor r is the minimum percentage of profit that the user is willing to accept in their project (taken as 2.5% per year for this work).

The cumulative total cost analysis method consists of evaluating the total cost of the system, including the initial investment, operating costs for electricity and natural gas, maintenance costs, and equipment replacement throughout the entire operational life of the system, comparing it with the total cost of importing electricity that users would incur if they chose not to adopt the proposed system. However, the goal of this tool is to encompass the behaviour of the system over a 20-year horizon (2023 to 2043), resulting in 21 independent simulations, evaluating, for each year, the cumulative total cost for a 7-year system operation time, considered a reasonable time for consumers to achieve their investment payback.

To achieve this, it was necessary to estimate the expected reduction in the acquisition cost of the main equipment involved in the proposed system (PEM fuel cell, monocrystalline photovoltaic panels, and lead-acid batteries) until the year 2043. This process used graphs of "forecast of total installed capacity increase vs. time" and "percentage reduction in cost vs. total installed capacity increase" found in literature to estimate the cost reduction curves for each mentioned equipment (Gabriel, 2020). Table 2 displays the equations used for estimating the future cost $C(i)$ of each equipment in year i over a thirty-year horizon.

Table 2: Estimated cost of the equipments (Junior, 2021)

Equipment	Equation
PEMFC	$C(i) = C(2021) \cdot CAP^{-0.2367}$ (8)
Monocrystalline PV panel	$C(i) = C(2021) \cdot [(1 + 0.09)^{i} - 2021]^{-0.2875}$ (9)
Battery	$C(i) = C(2021) \cdot \left(1 - 0.0441(i - 2021)\right) \, for \; 2021 \leq i \leq 2026$ (10) $C(i) = C(2026) \cdot (1 - 0.0445(i - 2026)) \, for \; 2026 \leq i \leq 2032$ (11) $C(i) = C(2032) \cdot (1 - 0.0445(i - 2032)) \, for \; 2032 \leq i \leq 2037$ (12) $C(i) = C(2037) \cdot (1 - 0.0445(i - 2037)) \, for \; i > 2037$ (13)

The results showed a percentage reduction of 38% for photovoltaic panels, 76% for the fuel cell, and 61% for the batteries until the year 2043.

2.4 Assumptions

The following assumptions were made:

- A 5 kW CHP unit with three 48V/100 Ah lead-acid batteries was used for all cases, serving three consumers.
- The inverters were replaced after 15 years of operation, the battery bank after every 1,900 full cycles, and the fuel cell stack after 60,000 hours of operation.
- The natural gas consumption tariff had a 40% reduction in the first three years of operation (as expected in the "New Gas Market" program), and then remained constant relative to inflation after this initial period.
- The electricity tariff remained constant relative to inflation for the first scenario of the simulated cash flow, and in the second scenario, it increased at a rate of +2% relative to inflation for all cities.
- The rate of generating energy credits in the power grid resulting from the export of surplus electricity generated in the system was considered 100% for all cases.
- All heat rejected by the system was reused to meet the thermal demand of the users.
- The chemical composition of natural gas was considered pure methane for all considered cities.

3. METHODOLOGY

For each studied scenario, the cash flows of the users will be presented for twenty years of system operation, starting in 2023 and ending in 2043, considering the possibility of cogeneration or not. Subsequently, the simulations related to the cumulative total cost of the system will also be presented, considering a seven-year operation period, based on the initial year of adoption from 2023 to 2043 (21 simulations for each city). The simulations of the cumulative total cost aim to compare the total cost of the proposed system by considering the expected reduction in the acquisition costs of the involved equipment over the next two decades, contrasting it with the conventional system of direct purchase of electricity from the grid, allowing the prediction of the year in which adopting the system may prove advantageous for each tested city. The last section of results, regarding the cumulative total costs of the system, will only consider scenario 1, which includes the increase in electricity and natural gas tariffs.

4. RESULTS AND DISCUSSION

4.1 Cash Flow

Figure 3 shows the evolution of the cash flow in net present value (NPV) for twenty years of system operation in the scenario of +0% relative increment in electricity and natural gas tariffs for the selected cities, considering the start of operation in 2023. In the graphs, solid lines represent the system's performance considering cogeneration, while dashed lines represent the behaviour without the respective gas bill discount (without cogeneration). Tables 3 and 4 provide the percentage contribution of each energy source in the system to the total electricity demand of the users.

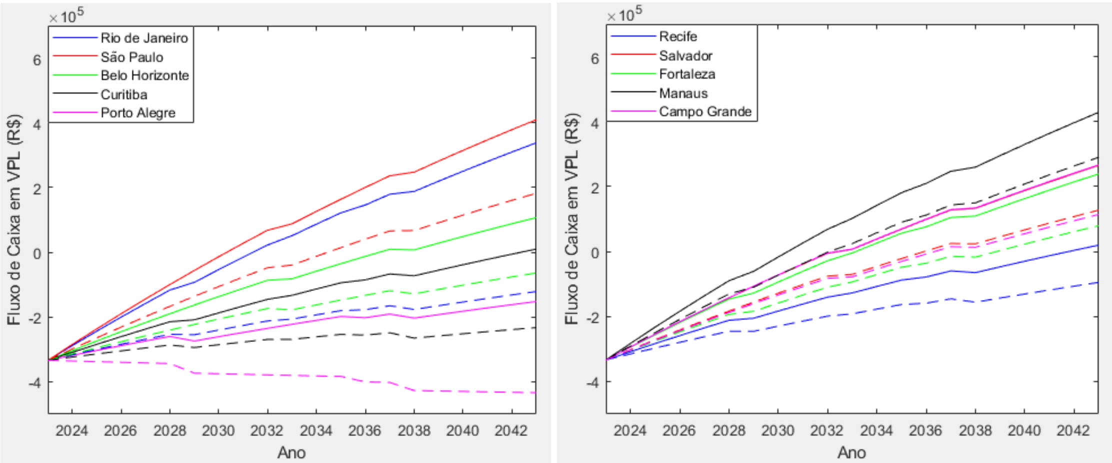

Figure 3: Cash flow in NPV for the studied cities in the scenario of +0% increment in electricity and natural gas tariffs.

Table 3: Share (%) of each energy source to the total electricity demand for cities in the South and Southeast regions.

Generation share	Rio de Janeiro	São Paulo	Belo Horizonte	Curitiba	Porto Alegre
Photovoltaic (%)	24.81	43.13	36.04	30.44	20.75
PEMFC (%)	73.06	54.74	61.61	67.31	77.17
Grid (%)	2.12	2.13	2.35	2.25	2.09

Table 4: Share (%) of each energy source to the total electricity demand for cities in the North, Northeast, and Midwest regions.

Generation share	Salvador	Recife	Fortaleza	Manaus	Campo Grande
Photovoltaic (%)	32.53	42.16	29.95	32.03	39.85
PEMFC (%)	65.09	55.60	67.84	65.60	57.84
Grid (%)	2.38	2.23	2.20	2.38	2.30

Firstly, it can be observed that the total initial investment (cash flow in the year 2023) for the system is the same (R$ 334,000) in all considered cities, as the same equipment was used in each location, without considering operation and maintenance costs. The various irregularities seen in the curves between the years 2023 and 2043 are due to equipment replacement, with the most significant being the replacement of inverters after fifteen years of system operation (2038). Regarding the contribution of each source to the total demand supply, it was observed that photovoltaic generation was higher for the cities of São Paulo (Southeast) and Recife (Northeast), resulting in a shorter operating time for the fuel cell in these cases. The opposite was observed for the city of Porto Alegre, where the incident global radiation is lower, resulting in a longer operating time for the fuel cell. The small 2% contribution of grid electricity is due to the mandatory minimum charge, equivalent to 100 kWh/month in the electricity bill. The system was optimized to utilize this energy to meet the electrical demand, avoiding unnecessary consumption of natural gas in the fuel cell + reformer group.

The intersection points of the cash flow curves with the abscissa axis (y=0) represent the year when the total initial investment was recouped through the adoption of the new system (payback), indicating the year when users would start profiting compared to the direct purchase of electricity and natural gas from the local distribution grid. The paybacks obtained for cogeneration cases ranged from eight years of system operation for the cities of São Paulo and Manaus to nineteen years of operation for the city of Curitiba, with Porto Alegre not even being able to recoup the investment over the twenty years of system operation. On the other hand, cases without cogeneration showed an even greater variation in the payback period, with Manaus again having the best performance (ten years) and Porto Alegre, Curitiba, Rio de Janeiro, Recife, and Belo Horizonte having the worst results, where it was not even possible to recoup the initial investment, resulting in a negative cash flow for the year 2043. This result is due to the high natural gas tariff for the "distributed generation/cogeneration" category in these cities, making the total cost of gas high when the cogeneration discount is not considered, rendering the adoption of the proposed system unfeasible for these cases. Furthermore, a difference in the final profit of R$ 430,000 for the best case and R$ -152,000 for the worst cogeneration scenario was observed. Manaus had the best overall performance, while Porto Alegre proved to be the worst scenario for system adoption. This difference can be easily explained by the high electricity tariff observed in Manaus (R$ 1.17/kWh), combined with the relatively low cost of gas consumption for the "distributed generation/cogeneration" category in that location. The opposite was observed for the state of Rio Grande do Sul. As the proposed system in this study involves replacing direct electricity consumption from the grid with natural gas consumption through the local distribution network, generating electricity from natural gas reforming and subsequent fuel cell generation, factors such as high electricity costs and low natural gas costs tend to favour system adoption. This behaviour remained consistent for cases where cogeneration was not considered, with Manaus again being the best location for system installation. However, the largest disparity between cogeneration and non-cogeneration cases was observed for the city of Rio de Janeiro, with a final profit of R$ 338,000 for cogeneration and R$ -120,000 for the non-cogeneration case. This difference is mainly due to the high natural gas tariff for the "residential" consumption category in Rio de Janeiro, where replacing consumption with "distributed generation" becomes the most advantageous scenario. Cities such as Belo Horizonte, Recife, Salvador, and Campo Grande, for example, have a smaller disparity between gas tariffs for the two consumption categories, resulting in a lower total savings when cogeneration is considered in the system.

Next, Figure 4 shows the evolution of the cash flow in net present value (NPV) for twenty years of system operation in the scenario of +2% and +0% relative increment in electricity and natural gas tariffs, respectively, for the selected cities, considering the start of operation in 2023.

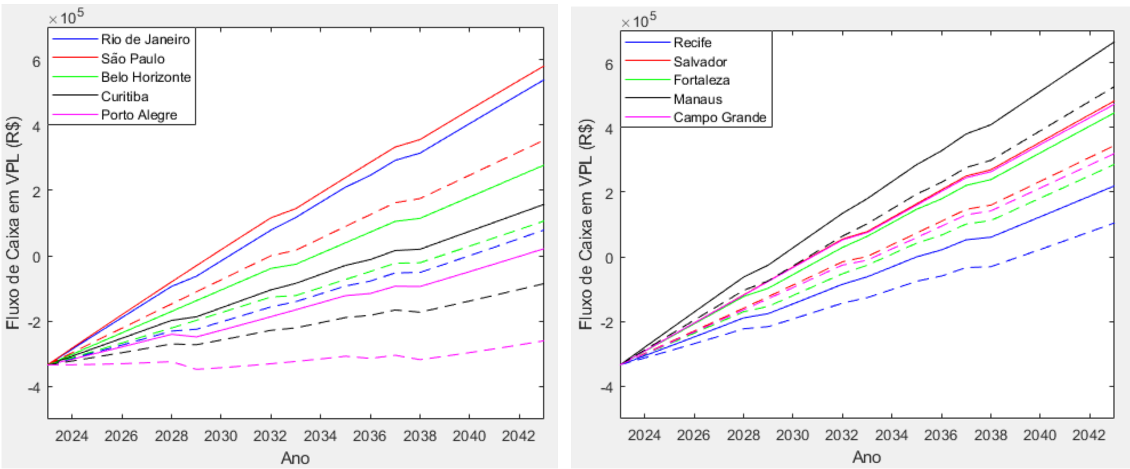

Figure 4: Cash flow in NPV for the studied cities in the scenario of +2% and +0% increment in electricity and natural gas tariffs, respectively.

It is evident that a slight increase in electricity tariffs, relative to inflation, is sufficient to significantly alter the expected results. In the new scenario, cogeneration cases achieved final profits of up to R$ 665,000 (Manaus), with the worst result again for the city of Porto Alegre (R$ 22,000). However, unlike the last simulated scenario, Porto Alegre achieved a positive cash flow for the year 2043, indicating a recoupment of the investment in the new system after twenty years of operation. In the non-cogeneration cases, the best results, in sequence, were: Manaus (R$ 526,000), São Paulo (R$ 354,000), Salvador (R$ 344,000), Campo Grande (R$ 319,000), Fortaleza (R$ 285,000), Belo Horizonte (R$107,000), Recife (R$ 105,000), Rio de Janeiro (R$ 79,000), Curitiba (R$ -85,000), and Porto Alegre (R$ -260,000). The expected average paybacks ranged from seven years of operation for Manaus and São Paulo to nineteen years of operation for Porto Alegre in the cogeneration cases. It is worth noting that the largest differences in the final profit for the two simulated scenarios (+0% and +2% annual increase in electricity tariffs) were observed in cities where the cost of grid electricity consumption is higher. In this context, Manaus, Salvador, and Fortaleza achieved a profit more than R$ 200,000 higher when tested in the new scenario, where the cost of electricity increases over time, as expected.

In general, it can be noted that cities with lower electricity costs (Curitiba and Porto Alegre) showed the worst results, indicating a strong correlation between the final profit and this factor. On the other hand, the natural gas tariff had a relatively smaller impact on both paybacks and final profits for the tested cases. For example, São Paulo has by far the lowest natural gas tariff for the "distributed generation/cogeneration" category, at only R$ 0.9/m³, yet it achieved inferior performance compared to Manaus (higher electricity tariff). Finally, photovoltaic generation had a relatively small influence on the tested cases, partly due to its limited contribution to the total user demand, which varied between 20% and 43% among the tested cities.

4.2 Cumulative Total Cost

Figure 5 shows the evolution of the cumulative total cost for seven years of system operation, considering cogeneration, in the scenario of +0% relative increment in electricity and natural gas tariffs for the selected cities over the next twenty years. In the graphs, solid lines represent the cumulative total cost considering the adoption of the system in each city, while dashed lines indicate the total cost of grid electricity that would be paid for the same demand in the case of non-adoption of the system with the respective electricity tariffs for the same cities.

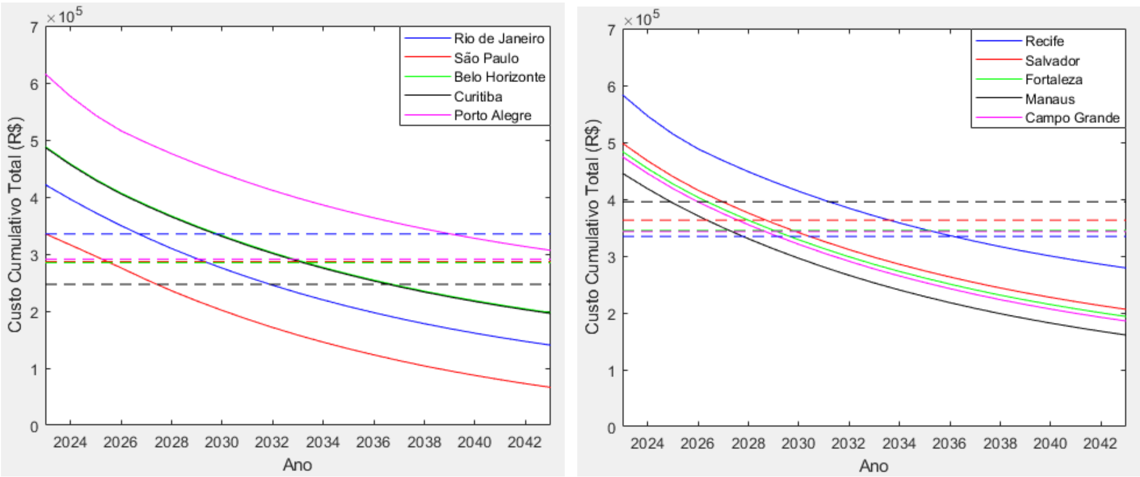

Figure 5: Evolution of cumulative total cost for the studied cities in the scenario of +0% increment in electricity and natural gas tariffs.

The simulations show that reductions of more than 50% in the cumulative total cost can be achieved for the system in the tested cases, considering the adoption of the system over the next 20 years. The intersection points of the cumulative total cost lines with the respective dashed lines indicate the expected year when the proposed system becomes more advantageous than the traditional direct purchase of electricity from the grid, starting from the seventh year of system operation. Among all the tested cities, it was observed that the only city where the cumulative total cost and the total cost of grid electricity lines did not intersect was Porto Alegre. This result shows that the adoption of the proposed system does not become advantageous even with operation between the years 2043 and 2050, considering all the anticipated reductions in the acquisition cost of the microgenerator fuel cell + natural gas reformer group, photovoltaic panels, and batteries in the envisioned horizon. On the other hand, Manaus achieved a more advantageous cumulative total cost for seven years of operation than the traditional direct grid purchase system as early as 2025, followed by São Paulo in 2026. The subsequent years of recoupment, in order, were Rio de Janeiro (2027), Salvador and Campo Grande (2029), Fortaleza (2030), Belo Horizonte (2033), Recife (2036), and Curitiba (2037).

The results of this section indicate that the majority of the total cost of the proposed system, when cogeneration is considered, comes from the acquisition cost of the considered equipment (especially the fuel cell and natural gas reformer), with a smaller portion attributed to operational costs. Even without a decrease in electricity and natural gas tariffs relative to inflation, reductions of up to 60% in the cumulative total cost were achieved for most of the tested cases in the long-term horizon of interest, confirming that the initial investment in the system will be much lower and more easily offset by operational costs.

5. CONCLUSION

The cash flow analysis results demonstrated the feasibility of the system for implementation in almost all simulated cities when considering the discount provided by cogeneration in the natural gas bill. The best performance was observed in the cities of Manaus and São Paulo, primarily due to the high electricity tariff in the former case and the low natural gas tariff for the "distributed generation/cogeneration" category in the latter. When cogeneration was not considered, a delay of the payback period of 3 to 10 years was observed, along with a variation in the final profit ranging from R$ 140,000 to R$ 450,000 for all tested cases, highlighting the high impact of the natural gas tariff. Furthermore, the impact of a +2% annual increase in electricity tariffs was observed, resulting in higher variability of results in cities where the cost of grid electricity import is higher, advancing the payback period by 1 to 6 years and increasing the final profit by R$ 150,000 to R$ 235,000 compared to the respective cases without an annual tariff increase.

Lastly, a final simulation was performed using the cumulative total cost analysis tool, where the system was tested for a seven-year duration to determine the optimal year for users to adopt the proposed solution in order to achieve a payback period of less than seven years. It was observed that, with the anticipated reduction in equipment acquisition costs over the next 20 years, a decrease of more than 50% in the cumulative total cost could be achieved by varying the start of system operation between 2023 and 2043. In this scenario, the largest differences were observed in cities with lower system operation costs, with São Paulo experiencing the highest percentage reduction (80%) and Porto Alegre the lowest (51%).

Areas for improvement in this study include experimental validation of the proposed system, the use of time-varying electrical and thermal demand profiles, evaluation of the impact of natural gas composition, variation of the system configuration including solid oxide fuel cells (SOFC) and/or lithium-ion batteries, and the use of more complex financial tools such as the Monte Carlo method for risk analysis of the project.

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8. RESPONSIBILITY NOTICE

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