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Investigating the Potential for Battery Energy Storage System in Distributed Photovoltaic Generation on Public Buildings in Brazil

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O presente trabalho em nível de Doutorado foi avaliado e aprovado, em 02 de julho de 2024, pela banca examinadora composta pelos seguintes membros:

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RESUMO EXPANDIDO

Introdução

A geração descentralizada de energia, que é a geração realizada por consumidores independentes, em várias usinas distribuídas geograficamente, como é o caso das microcentrais fotovoltaicas (FV), é uma abordagem eficiente para garantir acesso à energia elétrica em economias emergentes. Em sistemas FV de geração descentralizada integrados em edificações, a atratividade econômica é fortemente influenciada pelas tarifas de energia locais, pois o sistema FV irá atender à potência demandada pela edificação, resultando em um decréscimo da energia consumida da distribuidora de energia elétrica e consequentemente das despesas da unidade consumidora com energia elétrica adquirida diretamente da distribuidora. Com a acentuada queda dos preços dos equipamentos fotovoltaicos, as tarifas de consumo das distribuidoras usualmente são mais elevadas do que o custo da geração da energia fotovoltaica, pois incluem custos de operação e transmissão da rede, impostos e outros componentes, bem como a amortização de ativos de geração que tiveram seus custos de implantação mais altos do que os que a geração fotovoltaica apresenta no presente. A transição para a utilização de energia proveniente de fontes renováveis traz importantes benefícios econômicos, sociais e ao meio ambiente devido à menor poluição derivada da geração de energia, incentivando a pesquisa de soluções para integração destes sistemas à rede elétrica. Nos instantes em que a potência gerada pelo sistema FV é maior do que a demandada pela edificação há injeção da potência excedente na rede elétrica, com magnitude igual à diferença entre potência gerada e a demandada. O tipo de remuneração que o consumidor poderá receber nestas situações varia. Dependendo do país, poderá ocorrer pela forma de uma tarifa paga ao consumidor pela energia injetada na rede (feed-in tariff) ou por um sistema no qual seu saldo de energia positiva poderá ser utilizado para abater consumo em outro posto tarifário ou outro mês (net-metering). Nestas situações, a viabilidade econômica é influenciada pelo tipo de política pública utilizado sobre a remuneração dada à quantidade de energia injetada na rede. Uma alternativa para aumentar o percentual de autoconsumo e, assim, mitigar o eventual descasamento temporal entre consumo e geração, é a utilização de sistemas de armazenamento de energia. Assim, consumidores poderão armazenar a energia excedente gerada pelo sistema FV para uso posterior ou para compensar a intermitência da disponibilidade do recurso solar em qualquer instante. Isso poderá reduzir a circulação de grandes fluxos de potência nas redes elétricas, ou seja, potenciais situações que trariam problemas para o gerenciamento da rede elétrica. Sistemas de armazenamento de energia em baterias desempenharão um papel crucial na próxima fase de transição energética, podendo ajudar a transformar o setor elétrico do futuro. Devido à quantidade limitada de estudos no mundo analisando o funcionamento de sistemas de armazenamento aplicados em unidades consumidoras que dispõem de energia FV, é de grande importância a realização de estudos detalhados nesta área, a fim de que tais sistemas possam ser largamente incorporados pela sociedade.

Objetivos

O principal objetivo deste trabalho é apresentar um método para avaliar os impactos energéticos e econômicos associados à implementação de sistemas de armazenamento de energia em baterias de íons de lítio na geração distribuída em edifícios públicos com energia fotovoltaica no Brasil, no contexto atual e visando até 2030.

Metodologia

Os passos procedimentais da metodologia iniciaram-se com a análise abrangente que engloba a avaliação do recurso solar, do perfil de consumo da unidade prossumidora (PU em inglês) e do dimensionamento e definição da operação do sistema de armazenamento de energia em baterias. Posteriormente, os passos envolveram a otimização da demanda contratada, análise do sistema de compensação (*net metering*) da PU e avaliação dos impactos do Sistema de Armazenamento de Energia em Baterias (SAEB, ou BESS em inglês) nas despesas com energia elétrica da PU. Por fim, foram realizadas avaliações de atratividade do BESS levando em consideração a incidência ou não de tributação e regulamentações de sistemas de geração distribuída. Adicionalmente foi realizada a análise de sensibilidade que se estende até a perspectiva de 2030. A metodologia sugerida foi aplicada a um estudo de caso: a PU do Laboratório de Energia Solar Fotovoltaica da Universidade Federal de Santa Catarina (Fotovoltaica/UFSC www.fotovoltaica.ufsc.br), uma unidade de edifício público do Brasil.

Resultados e Discussão

Como resultado deste estudo, os benefícios anuais totais fornecidos pelo BESS sugerido neste trabalho representariam 126% das despesas anuais originais com energia da PU. Adicionalmente, o estudo demonstrou que a implementação do BESS é viável sob certas condições. As tarifas de energia analisadas para o caso base estão localizadas no primeiro quartil entre as concessionárias de energia brasileiras, sendo 59% abaixo da média nacional. Isso sugere que, apesar dos custos atuais no Brasil, sistemas de armazenamento de energia em baterias podem ter apelo financeiro em algumas regiões do país. Além disso, prédios públicos produtores de energia são candidatos ideais para a implementação destes sistemas, uma vez que frequentemente incluem uma ampla gama de unidades consumidoras nos níveis municipal, estadual ou federal, permitindo benefícios máximos da energia injetada na rede elétrica. É revelada a influência significativa que os custos associados a frete e impostos locais exercem sobre o custo final do BESS, dificultando sua viabilidade econômica. Atualmente no Brasil, a carga tributária sobre os sistemas de bateria importados pode chegar a até 80%. A viabilidade econômica da inserção de BESS em PUs está também dependente da localização geográfica do empreendimento (devido às variações nas taxações estaduais) e despesas com a demanda contratada não devem ser desconsideradas, pois se tornam mais proeminentes à medida que o tamanho do sistema aumenta. Políticas governamentais para isentar a tributação de BESS, mesmo que temporariamente, são extremamente interessantes para promover a adoção generalizada dessa tecnologia. Foi realizada uma análise abrangente englobando diversos cenários tarifários em escala nacional, incorporando considerações sobre as implicações fiscais nos custos de BESS ao longo dos anos prospectivos até 2030. Os resultados mostram que os pré-requisitos fundamentais para obtenção de um retorno de investimento favorável seria satisfeito para unidades prossumidoras públicas situadas em aproximadamente metade das concessionárias de distribuição em todo o Brasil. Isso é atribuído principalmente às disparidades, entre distribuidoras, observadas para as tarifas de energia de ponta e fora de ponta. Os resultados também demonstraram atratividade financeira positiva para todas as concessionárias examinadas, a partir de 2027. À medida que a utilização de fontes renováveis se expande, substituindo as fontes convencionais, há uma demanda crescente por soluções, especialmente por sistemas de armazenamento de energia, capazes de atender aos requisitos de flexibilidade e manter a resiliência da rede elétrica. Antecipando a progressão futura do setor, três necessidades principais surgem: (i) a necessidade de regulação aprimorada, (ii) o planejamento setorial integrado e adaptável e (iii) a competitividade econômica.

Considerações Finais

Os resultados demonstraram que a implementação de políticas temporárias de isenção de impostos federais e estaduais sobre os sistemas de armazenamento de energia em baterias seria altamente vantajosa para promover a integração dessa tecnologia. Objetivou-se com este trabalho contribuir para uma compreensão aprimorada da viabilidade financeira associada à incorporação de sistemas de armazenamento de energia em baterias em edifícios públicos e em campi universitários. A implementação de soluções de sistemas de armazenamento de energia em baterias para aplicações conectadas à rede elétrica tem sido escassa no Brasil até o presente, principalmente devido ao desconhecimento das vantagens que podem trazer e aos ainda altos custos (que estão caindo rapidamente) envolvidos. Os arcabouços regulatórios que regem a implantação de tais sistemas no país permanecem ausentes, tanto para consumidores no ambiente de contratação regulado quanto no ambiente de contratação livre, e o país carece de programas de incentivo para aplicações utilizando BESS. Com a queda dos custos das baterias juntamente com o aumento das tarifas de energia, espera-se aumento substancial na adoção de sistemas de armazenamento de energia em baterias em PUs no futuro próximo.

Palavras-chave: Energia solar fotovoltaica, Custo nivelado de armazenamento, armazenamento de energia.

ABSTRACT

In this work a method is developed, to assess the financial attractiveness provided by adding a Battery Energy Storage System (BESS) in distributed photovoltaic (PV) generation on public buildings in Brazil. The method is applicable to Prosumer Units (PU) connected to the medium voltage grid operating under time-based electricity tariffs and was based on techniques for measuring the electric energy demand and the surplus PV energy injected by the PU into the grid. Empirical data, including ambient temperature and solar irradiation, were employed to assess the solar radiation resource and the corresponding PV output. The BESS primary objective was aimed at the maximum use of the surplus PV energy and to achieve optimal reductions in electric energy expenses through effective energy arbitrage mechanisms. In BESS simulations, PU power flows were utilized. The procedural steps of the methodology began with an analysis encompassing assessment of solar resource, PU consumption profiles, and BESS sizing and operation. Subsequently, steps entailed contracted power optimization, PU net-metering analysis, and evaluation of BESS impacts on electric energy expenses. Lastly, a regulatory and economic analysis was carried out, incorporating considerations on BESS taxation, behind-the-meter regulations, and a sensitivity assessment extending to the 2030 outlook. The suggested methodology was applied to a case study of a public building PU in Brazil, the Solar Energy Research Laboratory Fotovoltaica/UFSC at Universidade Federal de Santa Catarina in Florianopolis. The findings indicated that during peak hours the adoption of the BESS would provide a 100% reduction in measured power demands and consumed energy, with a significant annual injection of power in the utility grid. During off-peak hours, the annual self-consumption of the PU would increase by nearly 30%. This outcome underscores the benefits associated with time-of-use billing structures for public PU+BESS. Approximately 85% of the total energy required to charge the BESS would be originated from the surplus of PV energy. The remaining 15% would be supplemented by the utility grid. The results suggest that the financial viability of incorporating BESS becomes favorable when the battery cost is below 365 US$/kWh. In approximately 50% of the Brazilian territory, prevailing economic conditions (mostly due to local distribution utility tariffs and local state taxes) support the adoption of BESS. Widespread, nationwide economic feasibility of integration is anticipated for the year 2027. It was observed that government policies to exempt BESS taxation, even if temporary, would be extremely interesting to promote the widespread adoption of this technology. The 2030 outlook of the transition to these benign renewable energy technologies is already in place, and will dominate the energy mix.

Keywords: Solar photovoltaics; Levelized storage cost; battery system, economic viability.

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LIST OF ABBREVIATIONS

ABBU	Brazilian Association of University Libraries
ACL	Free energy market
ACR	Regulated energy market
ATLAS	Brazilian Solar Energy Atlas
ANEEL	National Electrical Energy Agency
BESS	Battery Energy Storage System
BSRN	Baseline Surface Radiation Network
Cfa	Humid subtropical climate
CIF	Cost, Insurance and Freight
COFINS	Contribution to Finance Social Security
CONFAZ	National Council of Finance Policy
CU	Consumer Unit
DoD	Depth of Discharge
DOE	United States Department of Energy
EARPC	Environment America Research and Policy Center
e-Bus	Electric bus
EPBD	European Energy Performance in Buildings Directive
EV	Electric Vehicle
GHI	Global Horizontal Irradiation
ICMS	Tax on Circulation of Goods and Services
IPI	Tax on industrialized products
IRR	Internal Rate of Return
LCOS	Levelized Cost of Storage
LV	Low-Voltage
MRA	Minimum Rate of Attractiveness
MV	Medium-Voltage
NASA	National Aeronautics and Space Administration
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance Expenses
PIS	Tax on the Social Integration Program
PU	Prosumer unit
PV	Solar Photovoltaic
REN	Normative Resolution
ROI	Return On Investment
SoC	State of Charge
UFSC	Universidade Federal de Santa Catarina

SUMMARY

1 INTRODUCTION

Decentralized solar photovoltaic (PV) generation, i.e., generation carried out by independent consumers in several geographically distributed plants, is an elegant, benign and efficient approach to ensure access to electricity in emerging economies (KHAN *et al*., 2018). Studies show that, due to the socioeconomic growth trend in developing countries, the share of energy consumed in these countries will exceed that of developed countries in the coming decades (FERREIRA *et al*., 2018).

In the context of decentralized PV systems implemented or integrated within buildings, the economic appeal is significantly influenced by local energy tariffs, on top of the local solar radiation resource availability This influence stems from the fact that the PV system serves to meet the energy requirements of the building, resulting in a reduction in the energy sourced from the utility grid and, consequently, a decrease in electricity expenses for the PU.

Energy tariffs typically surpass the cost of PV generation, on one hand due to the inclusion of grid operation and transmission costs, taxes, and other associated components, and in the other hand due to the massive price reductions PV technologies have undergone in recent years. This dynamic becomes more complex with the inclusion of time-dependent pricing systems, as solar PV output might not match energy demands and related tariffs for a particular PU. The mismatch prompts the idea of using energy storage devices as buffers to lessen variations in supply and demand.

Luthander *et al.* (2015) defined energy self-consumption as the percentage of on-site energy generated that is consumed instantaneously by the building, not being fed into the utility grid. In instances where the power output from the PV system surpasses the electrical demand of the building, an excess of power is injected into the electrical grid, equal to the difference between the generated and demanded power. The manner in which the consumer is financially compensated in such scenarios varies, contingent upon the regulatory framework of the country. Compensation mechanisms may involve a tariff remitted to the consumer for the energy contributed to the grid (feed-in tariff) (DUMAN *et al*., 2020) or may adopt an energy compensation system where the positive surplus of injected energy into the utility grid serves to offset consumption within the same or subsequent billing periods, a practice known as net-metering (OSSENBRINK *et al*. 2017). The financial viability in these circumstances is intricately linked to the prevailing public policies governing the remuneration for the volume of energy integrated into the grid.

Energy storage systems appear as an alternative to increase the percentage of self-consumption and therefore mitigate the mismatch between consumption and generation. Thus, consumers can store the surplus energy generated by the PV system for later use or to compensate for the intermittent availability of the solar resource at any given moment. Furthermore, with decreasing feed-in tariffs and barriers to net metering programs all over the world, any kWh self-consumed will have an increasing value over any kWh fed to the public utility grid. Batteries, on the other hand, are still too expensive in many applications, but their cost learning curve is evolving fast, pretty much in the same way it did for the PV technology a few years back, and with the growing uptake of electric vehicles, it is expected that battery energy storage systems (BESS) costs will decline sharply before the end of the present decade. The cost-reduction learning curve of BESS has the same trend as that of the solar PV technology, and PV+battery installations will soon make economic sense.

The PV energy sector has witnessed significant advancements in the past decade, characterized by heightened financial appeal attributed to cost reductions. Integration with energy storage systems enhances the capabilities of photovoltaics, enabling services such as energy arbitrage, augmented self-consumption from PV generation, peak demand reduction, and backup services (REID *et al*., 2016). Research indicates that PV systems integrated with energy storage exhibit enhanced cost-effectiveness compared to standalone PV systems (KOSKELA *et al*., 2019). Numerous case studies within this domain extend to both residential (LI *et al*., 2018) and commercial settings (PARK *et al*., 2017). When the cost of energy derived from PV coupled with BESS attains values lower than prevailing utility energy tariffs, it becomes potentially feasible for consumers to self-generate the entire or a substantial portion of their energy needs. In these cases, tariff parity has been achieved. Notably, certain regions, such as Australia and the United States, have reported instances of commercial applications of PV systems with storage attaining tariff parity in specific states (GREEN and NEWMAN, 2017; RMI, 2014). The financial attractiveness of the combined PV+BESS configuration is contingent upon variables such as energy tariffs, mechanisms for compensating the surplus energy injected into the grid, and the initial costs associated with the storage system (HOPPMANN *et al.*, 2014).

In recent years, there has been a notable decline in the costs associated with BESS. A substantial reduction of approximately 84% has been recorded since 2010 (BNEF, 2019), with a comparatively moderate reduction of around 50% for large-scale systems, particularly power plants (IEA, 2019a). Focusing on lithium-ion battery technologies, the costs have witnessed a decrease of approximately 73%, reaching values ranging from 787 US$/kWh to 238 US$/kWh from 2010 to 2016 (BNEF, 2017). Projections indicate an anticipated further reduction in these costs by the year 2030, reaching values ranging from 480 US$/kWh to 145 US$/kWh, representing a potential reduction of up to 61% (IRENA, 2017). Furthermore, driven by heightened investments in research endeavors and the concurrent reduction in battery costs, it is anticipated that lithium-ion battery energy storage systems will exhibit a notable technical improvement. Projections for the year 2030 include a 50% increase in their operational lifespan and a 2% enhancement in overall efficiency (IRENA, 2017).

As far as investments in technical development BESS are concerned, it is expected that US$ 20 billion were be invested in 2022, which represents twice the value invested in the previous year (IEA, 2022). This represents the moment of greatest investment within the electricity sector, with 90% of deployments in the last two years using lithium-ion battery energy storage technology (highlighted by China and the US). In the period between 2010 and 2018, 60% of BESS were used for frequency control services; however, in recent years this fraction has decreased to 30%, with the increased use of BESS for energy arbitrage. Currently, BESS is mostly being used for energy arbitrage and peak demand reduction services. The integration of these systems with renewable energy has been showing competitive costs (IEA, 2022). By 2050, an estimated US$843 billion is expected to be invested in storage technologies (BNEF, 2019).

Storage systems can be used in residential, commercial, industrial, and power plant applications, as well as in small or large electric vehicle (EV) applications. Storage capacity of an estimated 10 GWh (in 2017), mostly composed of power plant applications, is expected to increase between 100 and 150 GWh in 2030 (IRENA, 2017). A total of 359 GWh in storage systems are expected to be added to the electric grid by 2050 (BNEF, 2019).

One of the main factors that affect the viability of storage systems is their lifetime, directly related to degradation, which is influenced by several factors such as the minimum state of charge (SoC), the operating temperature, the recharging rate, and the depth of discharge (DoD) (BISHOP *et al*. 2013). The minimum SoC values adopted for storage systems in stationary applications range from 20% (VAN DER KAM and VAN SARK, 2015; TULPULE *et al*., 2013) to 30% (AMIRIOUN *et al*., 2014; ZHANG *et al*., 2012).

An essential economic metric employed to assess the financial viability and return on investment of a BESS is the Levelized Cost of Storage (LCOS). This cost metric indicates the rate (US$/MWh) at which the stored energy should be discharged to neutralize system costs over its operational lifespan (BELDERBOS *et al*., 2017). Projections suggest that by the year 2040, the anticipated LCOS for Li-ion batteries is poised to undergo a reduction, reaching a value of 67 US$/MWh (BNEF, 2019).

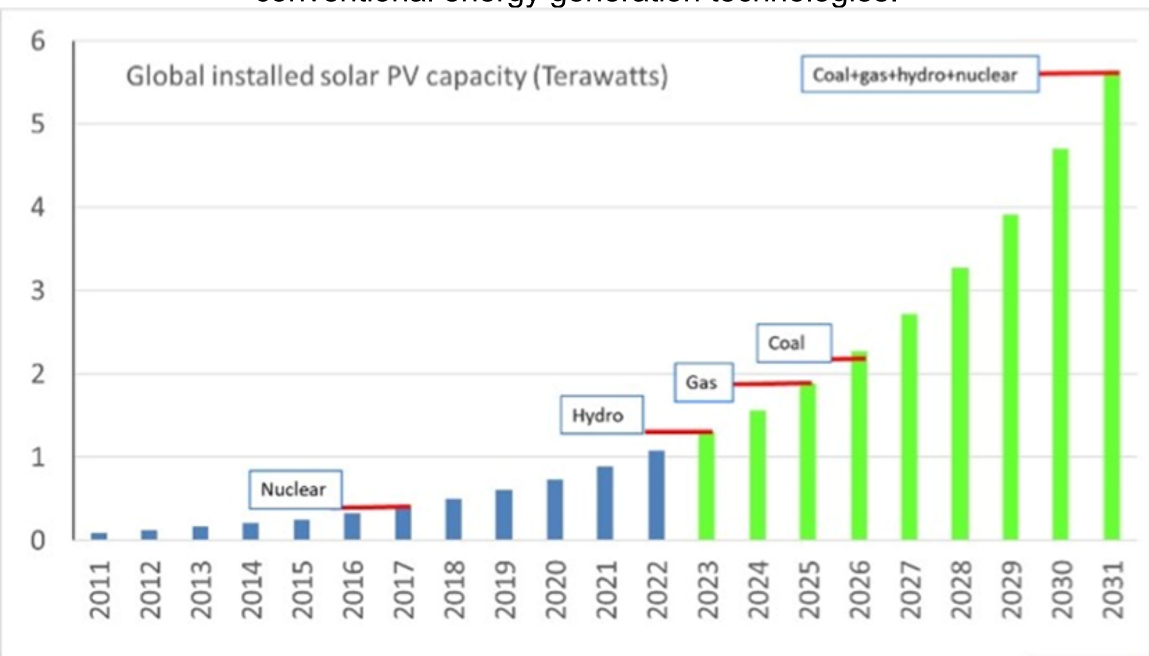
Most public Universities in Brazil own and operate a large number of buildings over a large area with a continuously rising need for electricity supply, in which grid-connected PV systems are increasingly being installed. Due to the large energy needs of university campuses, combined with the current social awareness of faculty and students, Universities should take a leadership role in the development and implementation of renewable energy projects, especially in public buildings, since these institutions play an important role in the innovation and training of future professionals, as well as in public opinion and dissemination of benign technologies for the society at large.

University campuses present conditions that make them attractive locations for the adoption of PV generators coupled with electrochemical storage systems. These environments have large areas available on building rooftops, parking lots, and land that is often ideal for the integration of PV technology. According to a report by EARPC (2017), a transition towards 100% of energy consumption from renewable energy sources is the best way forward for the hundreds of universities that have committed to neutralizing their carbon emissions by 2050.

The concept of a sustainable University can be defined as a higher education institution that involves and promotes the minimization of negative environmental, economic, and social effects generated by the use of its resources (VELAZQUEZ *et al*., 2006; SEDLACEK, 2013). Universities play a key role in sustainable development at the regional level. A greater concern with energy sustainability on university campuses has emerged since the release of the European Energy Performance in Buildings Directive (EPBD) (JANSSEN, 2004).

By 2050, it is anticipated that PV generation will surpass hydropower, becoming the predominant component of Brazil's energy mix. By the way, in late 2023, the total cumulative installed PV power capacity worldwide has surpassed the total cumulative installed hydropower capacity, as shown in Figure 1 below. In 2025 it will overcome the total installed capacity of Natural Gas; in 2026 it will surpass the total installed capacity of Coal, and by the beginning of next decade, the total cumulative installed PV power capacity worldwide is forecast to have overcome the total installed generation capacity of all of them (coal + natural gas + hydro + nuclear) put together. This shift is expected to create an increase need for solutions, notably storage systems, capable of meeting flexibility requirements and maintaining grid resilience.

Figure 1 - Global installed solar PV capacity (in TW) of solar photovoltaics and other conventional energy generation technologies.



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1.1 OBJECTIVES

1.1.1 Main objective

The main objective of this work is to present a method for evaluating the energy and economic impacts associated with the implementation of battery energy storage systems in distributed solar photovoltaic generation on public buildings in Brazil, in the current context and looking towards 2030.

1.1.2 Specific objectives

The specific objectives of this work are as follows:

a) Evaluate the consumption and generation profile of a commercial or industrial consumer unit (CU) (belonging to Group A – medium voltage supply and with electricity contracted under the green hourly tariff modality) with PV generation;

b) Define the operation of a stationary battery energy storage system, aiming at maximizing the use of the surplus PV energy and the highest reduction of electric energy expenses (energy arbitrage), to be integrated into a commercial or industrial consumer unit (belonging to Group A – medium voltage supply and with electricity contracted under the green hourly tariff modality) with PV generation;

c) Establish a methodology to assess the financial attractiveness of integrating battery energy storage systems into prosumer units within the Brazilian context;

d) Perform a sensitivity analysis of different technical and economic variables and their impacts on the financial attractiveness of these systems to assess whether, and when, these systems would achieve tariff parity in Brazil.

1.1.3 Contribution

The present work aimed to contribute with new knowledge regarding the uptake of BESS to ensure the dispatchability of PV generation systems in Brazil and fill the gaps that still exist in the National Electrical Energy Agency's Regulations (ANEEL) and the Brazilian Technical Standards. The knowledge acquired is indispensable in the evaluation of the impacts provided by the adoption of BESS on the electric energy expenses of PU’s, an integral part of the evaluation of the financial attractiveness of BESS in public buildings.

Although PV systems have been the focus of numerous studies in Brazil, the investigation of BESS remains relatively limited. There is a lack of studies in Brazil, based on measured data and considering degradation losses, that address the deployment of storage systems to facilitate energy arbitrage services and increase in PV self-consumption from public prosumer units with PV generation. This study aims to fill this gap.

The main contributions of this study are as follows:

- A method for the adoption of BESS in public buildings with integrated PV systems is presented. This method is based on techniques for measuring the electric energy demand and the surplus PV energy injected by the PU into the grid;
- A model that takes into account a methodology for optimizing the contracted power demand in public prosumers is proposed. By this means, the effect of BESS systems is investigated without neglecting power costs;
- A multi criteria sensitivity analysis is performed to investigate the impact of rising electricity tariff scenarios, falling battery prices and public incentives;
- A techno-economic analysis is made between BESS equipped public buildings under public regulations in Brazil. The discounted payback, net present value (NPV), internal rate of return (IRR), and LCOS of BESS in public prosumers are investigated;
- A model for BESS implementation in public prosumers applied to all geographical states in Brazil in order to identify the optimal locations for these systems currently and up to the 2030 outlook is finally proposed.

1.1.4 Structure

This work is structured into six parts: introduction, literature review, methodology, results, discussion and conclusion. The introduction provides a contextualization of the studied theme, along with the objectives of this work. Chapter 2 presents the literature review, encompassing the state of the art in the application of storage systems and the Brazilian scenario. Chapter 3 outlines the methodology used to achieve the study's objectives. Chapter 4 presents the results. Chapter 5 provides a discussion of the significance of the findings whereas Chapter 6 provides a summary of the key results obtained from the study. Finally, the literature references used are presented.

2 LITERATURE REVIEW

2.1 ENERGY STORAGE SYSTEMS

The photovoltaic energy sector has shown progress in the last decade, demonstrating an increase in its economic viability due to the reduction of acquisition and installation costs. When coupled with energy storage systems, they can offer energy arbitrage services, increase self-consumption of PV generation, reduce power demand peaks, and provide backup and off-grid capabilities in residential, commercial, and industrial consumer units connected to the electrical grid (REID *et al*., 2016).

The following are the main services offered by PV-storage systems:

- Energy arbitrage: Energy storage (from the grid or renewable energy sources) during lower energy tariff periods, are discharged during peak hours with higher energy tariffs. This service is beneficial for consumers subject to time-of-use energy tariffs, enabling them to reduce their electricity expenses;
- Increase in self-consumption of PV generation: PV-storage systems enable increased self-consumption of PV-generated energy, leading to reduced electricity expenses. This service is more advantageous in regions where there is low economic remuneration for the excess energy injected into the grid along with high energy tariffs;
- Peak demand reduction: The use of PV-storage systems can be aimed to decrease the power demanded from the electrical grid by the consumer during specific elevated power demand tariff periods. Such systems are ideal for consumers subject to high demand charges. Therefore, peak consumption reduction services provided by storage systems may lead to a decrease in contracted demand costs.
- Backup and Off-Grid: The use of PV-storage systems ensures electricity supply to the consumer during periods of grid instability or unavailability (Backup) and in systems not connected to the electrical grid (off-grid).

In the case of increased self-consumption of PV generation at another energy tariff period, both self-consumption and energy arbitrage services may occur.

Among the various electrochemical storage technologies, the lithium-ion technology presents greater technical and economic feasibility when compared to other technologies, such as lead-acid and nickel-sodium (DHUNDHARAA *et al*., 2018; ZHANG *et al*., 2016). Parra *et al.* (2015) showed that lithium-ion technology batteries are ideal for applications in PV power generation systems because of their longer life cycles, more flexibility in their state of charge, and lower losses when compared to other technologies. Additionally, lithium-ion technology exhibits higher efficiency than the other technologies. While Lead-acid and Nickel-sodium efficiencies range from 70 to 90%, Li-ion can achieve values up to 95% (BANGUERO *et al*., 2018).

Temperature regulation, on the other hand, plays a vital role in preserving the longevity of these systems. Manufacturers ensure a specific cycle count over their lifespan for operation at approximately 23°C. Smith *et al.* (2017) characterized the life cycle of commercially available lithium-ion batteries, especially developed for applications in which the energy generated by PV systems is used to charge the storage system, taking into account the factors described by Bishop *et al.* (2013). The authors showed the influence of operating temperature variation and the amount of energy discharged per cycle on the lifetime of these systems. Uddin *et al.* (2017) showed that battery energy storage systems with higher storage capacity can have reduced temperature losses.

Several theoretical models concerning degradation loss per cycle (charge/discharge) have been proposed (PLOEHN *et al.*, 2004; CHRISTENSEN and NEWMAN, 2006; AN *et al.*, 2014; DESHPANDE *et al.*, 2012), and investigations have also been conducted using simulations with different levels of accuracy (WANG *et al.*, 2011; PETERSON *et al.*, 2010; SCHMALSTIEG *et al.*, 2014; SANTHANAGOPALAN *et al.*, 2015).

2.1.1 Energy arbitrage services and increasing self-consumption of PV generation

This section presents an overview of recent research that uses BESS to improve the self-consumption of PV generation within building structures and to provide energy arbitrage services.

Luthander *et al.* (2015) demonstrated the potential to enhance self-consumption in residential setups through the deployment of PV-storage systems, reaching values of 13 to 24%, featuring capacities ranging from 0.5 to 1 kWh per kW of PV power installed. In this scenario, storage was employed for brief durations, typically under 24 hours.

Gupta *et al.* (2019) conducted a study involving 82 households. They demonstrated that the integration of PV systems with energy storage led to heightened levels of self-consumption and an average reduction of 8% in peak-time demand (maximum power consumed by the household from the utility grid during hours with higher utility electricity tariffs). Li *et al.* (2018) emphasized that the combination of PV and BESS could indeed enhance self-consumption and self-sufficiency, although the extent of improvement may not be directly proportional to the BESS capacity.

In Germany, Merei *et al*. (2016) performed a technical and economic evaluation of PV-storage systems in commercial consumers, determining that these systems lacked viability, primarily due to the constrained financial benefits derived from surplus energy integration into the grid. The authors proposed that the feasibility of these systems would be achieved when the cost of the storage system reached 200 EU$/kWh.

Beck *et al.* (2016) evaluated the impact of the temporal resolution of measured load and PV generation data on the self-consumption rate in residential systems with PV generation and energy storage. The BESS capacity was sized aiming to maximize self-consumption. Data with 60-minute resolution showed satisfactory results.

For applications within the United Kingdom, Hassan *et al.* (2017) conducted an evaluation of the operational dynamics of a PV-storage system, aiming to maximize economic benefits in a residential context. Their findings indicated that the economic viability of adopting storage systems materialized when the system cost reduced to 138 £/kWh. However, the assessment did not account for system losses. Uddin *et al.* (2017) similarly analyzed the economic feasibility of PV-storage systems but incorporated degradation losses. Their conclusion highlighted that when the cost of degradation losses is factored in, there is an absence of economic viability for the consumer. Dong *et al.* (2020) explored the potential of PV-storage systems within a community comprising 10 residences, concluding that storage systems cost emerged as the predominant variable influencing financial viability, with the system necessitating more than 10 years to achieve financial returns.

In Japan, Li *et al.* (2018) assessed of BESS feasibility in 200 residences. Their findings concluded that these systems would yield a financial return of 18 years in a scenario without incentives. Yoshida *et al*. (2016) examined an optimized operational approach for a PV-storage system, accounting for degradation in residential settings. Their findings indicated that within the Japanese context, PV-storage systems exhibit greater economic feasibility compared to standalone PV systems. Nevertheless, the authors did not encompass all household loads in their assessment.

Yu (2018) undertook an evaluation of the economic impacts associated with residential PV-storage systems in France. The study ascertained that residential PV-storage systems could potentially be economically viable before the year 2030. Furthermore, it demonstrated that operation aimed at maximizing self-consumption would exert a lesser impact on the electrical grid compared to operations involving total grid injection. In the United States, Heine *et al.* (2019) showed that storage systems sized 1.5 times larger than necessary to meet residential peak demands exhibited optimal economic attractiveness. In Portugal, Aelenei *et al.* (2019) examined the utilization of lithium-ion storage systems ranging from 13.5 to 54 kWh in a commercial building equipped with a 12 kWp PV system. Operating to maximize self-consumption, the 13.5 kWh system displayed superior economic viability, resulting in a 16% increase in self-consumption.

In a study by Barzegkar-Ntovom *et al.* (2020), the economic feasibility of residential PV-storage systems was evaluated across six Mediterranean countries, considering scenarios where policies do not provide financial compensation for surplus PV energy injected into the electrical grid. The study found that at a storage system cost of 500 €/kWh, these systems were considered economically unviable. The conclusion was drawn that they would only achieve tariff parity if the costs associated with storage systems were to decrease to 150 €/kWh, presenting economically viable in Italy, Cyprus, Spain, and Portugal. Notably, the authors did not furnish building consumption profiles, opting for equal monthly average values across all countries. Degradation losses were also not taken into consideration. Chaianong *et al.* (2020) conducted an investigation into the financial returns of PV-storage systems for residential consumers in Thailand, utilizing simulated consumption and PV generation data. Their findings indicated that these systems would attain economic viability when the cost of storage systems reached 100 US$/kWh.

However, it is noteworthy that the authors exclusively considered self-consumption services, neglecting the potential impact of energy arbitrage services, which could potentially enhance the economic viability of such systems.

In Australian research, Talent and Du *et al.* (2018) conducted an assessment focusing on optimizing the sizing of PV and storage systems in both residential and industrial contexts. Their findings underscored the viability of solutions that prioritize self-consumption, advocating for larger PV systems coupled with smaller storage systems. A study by Roberts *et al.* (2019) delved into the evaluation of PV-storage systems within residential apartment buildings. The outcomes revealed that implementing storage systems ranging from 2-3 kWh per apartment led to a notable increase in self-consumption, reaching up to 19%, with a corresponding reduction in peak demands of the building by as much as 30%. However, it is crucial to note that the analysis did not account for degradation losses. Li (2019) investigated the sizing of PV-storage systems for 2,057 residential consumers exhibiting diverse consumption profiles. The study's conclusion emphasized that higher household consumption correlates with greater final savings for the consumer. Nonetheless, it is important to highlight that degradation losses were not factored into this particular study.

In a simulation study conducted by Liu *et al.* (2020) in a commercial building in China, an operational mode was defined based on varying local energy tariff times. This approach resulted in a 15% increase in self-consumption of PV generation. In Portugal, Camilo *et al*. (2017) conducted an assessment of the economic viability of various configurations of residential PV-storage systems. Their findings indicated that a reduction in acquisition costs was necessary for these systems to be economically feasible, as they were deemed unviable at a cost of 393 EU$/kWh. Meanwhile, Vieira *et al*. (2017) examined the economic feasibility of residential PV-storage systems under different interest rates, determining that a storage system cost below 190 EU$/kWh would be required for viability at a 7% interest rate. Notably, both studies from Portugal omitted considerations of degradation losses and relied on estimated consumption and generation data.

Kaschub *et al.* (2016) conducted a technical and economic evaluation of residential photovoltaic (PV) storage systems incorporating electric vehicles in Germany. The study findings indicate that these integrated systems demonstrate financial viability, achieving levels of self-consumption as high as 70%. Even though the costs of PV and BESS technology are falling, the research of small-scale PV+BESS systems in Romania (CRISTEA *et al*., 2020) demonstrates the necessity of ongoing government subsidies for the viability of these integrated systems. These financial incentives are essential for promoting the use of decentralized, renewable energy systems.

In Brazil, the annual evolution of solar PV sources in distributed generation has been increasing exponentially, reaching 24 GW of installed power in October 2023 (ABENS, 2023). Therefore, the use of BESS tied to these systems has great potential to become an emerging market in Brazil. There has been some research dealing with the adoption of BESS in PV systems in Brazil. Nascimento and Rüther (2020) showed that the PV system is more economically viable than PV+BESS in residential applications. Lima and Feijão (2022) evaluated the economic feasibility of a large PV+BESS system using deterministic and stochastic linear programming approaches. The authors showed that the difference between peak and off-peak energy tariffs is a key determinant of the financial viability of these systems. Manito *et al.* (2022) evaluated the use of PV+BESS to reduce peak-hour demand on a distribution system feeder. Costa *et al.* (2022) modeled the regulated electricity market including smart grid, distributed generation (PV and wind), and BESS technologies. Rocha *et al.* (2022a; 2022b) evaluated the use of BESS in hybrid PV-wind projects at the distribution level and performed a review of Brazilian regulations targeting this implementation. Campos *et al.* (2020) evaluated the complementarity of PV and wind systems and the role of BESS in power plants in Brazil. Doile *et al.* (2022) evaluated the feasibility of hybrid PV and wind systems with BESS.

The majority of the aforementioned studies focused on residential consumers, with storage systems capacities ranging from 1 to 54 kWh. In cases where electric vehicles were integrated into the load, their capacities were relatively modest, not exceeding 32 kWh. It is noteworthy that a limited number of studies accounted for the degradation losses inherent to these systems. Furthermore, certain studies did not incorporate compensation mechanisms into their assessments, aiming to establish feasibility independent of local policy influences. Despite the attention given to the economic feasibility of these systems in numerous studies, existing methodologies tend to overlook the influence of expenses related to contracted power demand. This oversight could potentially result in an overestimation of the reported outcomes.

Table 1 presents an overview of the primary attributes of the PU (loads, PV system, and BESS) in the analyzed studies.

Table 1 - Overview of the primary attributes of the PU (loads, PV system, and BESS) in the analyzed studies.

Ref.	Loads			PV System		BESS		Contracted Power Optimization
	Non-Residencial	Measured data	Electric Vehicle	Measured data	Net-metering scheme	Measured data	Considers degradation losses	
Hassan *et al*. (2017)	-	-	-	-	-	-	-	-
Uddin *et al*. (2017)	-	✓	✓	✓	-	✓	-	-
Dong *et al*. (2020)	-	-	-	-	-	-	✓	-
Li *et al*. (2020)	-	✓	-	-	-	-	-	-
Yu (2018)	-	-	-	-	-	-	-	-
Heine *et al*. (2019)	-	-	-	-	✓	-	✓	-
Aelenei *et al*. (2019)	✓	✓	-	✓	✓	-	-	-
Barzegkar-Ntovom *et al*. (2020)	-	-	-	-	-	-	-	-
Chaianong *et al*. (2020)	-	-	-	-	-	-	-	-
Talent and Du *et al*. (2018)	✓	✓	-	-	-	-	-	-
Roberts *et al*. (2019)	-	✓	-	-	-	-	-	-
Li (2019)	-	✓	-	-	-	-	-	-
Liu *et al*. (2020)	✓	-	-	-	-	-	✓	-
Gupta *et al*. (2019)	-	✓	-	✓	-	✓	-	-
Merei *et al*. (2016)	✓	✓	-	-	-	-	✓	-
Beck *et al*. (2016)	-	✓	-	✓	-	-	-	-
Yoshida *et al*. (2016)	-	-	-	-	-	-	✓	-
Camilo *et al*. (2017)	-	-	-	-	✓	-	-	-
Vieira *et al*. (2017)	-	-	-	-	✓	-	-	-
Kaschub *et al*. (2016)	-	-	✓	-	-	-	✓	-
Cristea *et al*. (2020)	-	✓	-	-	-	-	-	-
Nascimento and Rüther (2020)	-	✓	-	-	✓	-	-	-
This work	✓	✓	✓	✓	✓	-	✓	✓

An absence was observed of methodologies for assessing the integration of BESS in PU's based on techniques for measuring the electric energy demand and photovoltaic generation data, obtained through energy meters installed at the frontier between the utility's grid and the PU. In Brazil, public entities (Federal, State, and Municipal) often occupy numerous buildings supplied with both low voltage (LV) and medium voltage (MV) grid, typically procuring their energy from the regulated market. Moreover, this research focused on the technical evaluation of BESS integration for energy arbitrage services and enhancing self-consumption in public buildings equipped with PV systems and electric vehicles, while examining their financial attractiveness until 2030, remains inadequately explored in the country.

2.2 BRAZILIAN SCENARIO

The feasibility of solar PV systems integrated with energy storage is significantly impacted by local policies. This section aims to examine the prevailing situation in Brazil, focusing on the electricity tariffing system and its regulatory framework. Furthermore, it delves into the dynamics of decentralized PV energy generation and the regulatory framework governing the compensation mechanisms for surplus energy fed back into the utility grid (net-metering).

2.2.1 Tariff structure

In Brazil, the oversight of the electricity sector falls under the scope of the National Electrical Energy Agency (ANEEL), which was established in December 1996. ANEEL's responsibilities include the standardization of guidelines and policies established by the Federal Government for the electricity sector, as well as the supervision of electricity supply to society.

Since the enactment of Law No. 8,631/1993 (BRASIL, 1993), there has been differentiation in energy tariffs across states, with rates established individually for each utility. This transition has led to a shift in the economic-financial framework of service concessions from being cost-oriented to being price-oriented.

In 2004, the Federal Government introduced a new model for the commercialization of electricity in the country (BRASIL, 2004a and 2004b). This new framework established that commercialization would be conducted in two distinct contracting environments: regulated and free market. In the regulated contracting environment (ACR), distribution utilities acquire electricity through auctions regulated by ANEEL and provide both contracts for the distribution system usage and the energy consumed by the customer. In the free market environment (ACL), utilities provide only the distribution system usage contract. In this case, electricity supply contracts are freely negotiated between generators and consumers.

ANEEL's Resolution N°. 1000/2021 (ANEEL, 2021a), issued on December 7th, 2021, delineates the general provisions governing the supply of electric energy within the regulated energy market. Within this framework, consumers are categorized into groups A and B, contingent upon the voltage level of their supply. Consumer units (CU) supplied with voltage equal to or exceeding 2.3 kV or sourced from underground systems (< 2.3 kV) are categorized under Group A, while consumer units supplied with voltage lower than 2.3 kV are classified under Group B.

Table 2 displays the classification of consumers within Group A based on the voltage supply of their respective consumer unit.

Table 2 – Voltage supply for subgroups of consumers within Group A.

Subgroup	Voltage supply
A1	> 230 kV
A2	88 a 138 kV
A3	69 kV
A3a	30 a 44 kV
A4	2,3 a 25 kV
AS	< 2,3 kV (underground)

Source: ANEEL (2021a).

Consumers categorized within Group A exhibit a characteristic binomial tariff structure, being charged based on both their power demand and their energy consumption.

ANEEL adopts the following definitions, through Resolution Nº. 1000/2021 (Art. 2) (ANEEL, 2021a), for active electric energy, reactive electric energy, power demand, and measured power demand.

> Active electric energy is defined as "That which can be converted into another form of energy, expressed in kilowatt-hours (kWh)" (ANEEL, 2021a).
>
> The power demand consists of the "Average of active electric powers requested to the grid by the portion of the installed load in operation at the consumer unit, during a specified time interval, expressed in kilowatts (kW)" (ANEEL, 2021a).
>
> The measured power demand consists of the "Highest demand for active power, verified by measurement, integrated at fifteen-minute intervals during the billing period" (ANEEL, 2021a).

For both groups, energy charges are calculated according to the actual consumption, whereas power demand charges are determined based on the referenced contracted power demand specified by the consumer.

Consumer units categorized in Group A are mandated to formalize power demand agreements with the energy utility, outlining the anticipated power demand for the upcoming months. Irrespective of whether the measured power demand exceeds or falls short of this agreed-upon value, consumers are obligated to remunerate the contracted demand. Inaccurate determinations regarding contracted power demand values can lead to considerable associated expenses, stemming from either an excessive contractual commitment or charges incurred for surpassing the stipulated power demand. It is incumbent upon the local utility to provide consumers with the contracted power demand figures. For monthly invoicing purposes, the highest value observed during the month, whether it be the measured power demand or the contracted power demand, is utilized.

Consumer units categorized within Group A are subject to the hourly tariff structure. This form of tariffing entails the application of distinct rates for electricity consumption ($/kWh) and power demand ($/kW), contingent upon the time of usage (peak (P) or off-peak (FP) hours). The adoption of this tariffing scheme is driven by the aim to rationalize electricity consumption. With varying rates throughout the day, consumers are encouraged to utilize periods with lower tariffs, thereby easing the burden on the electrical grid. Hourly tariffing comprises two modalities: Blue and Green.

Table 3 displays the tariffing attributes for both contracting modalities. Within the utilities concession area, peak hours (P) are delineated for all weekdays (Monday to Friday), usually spanning from 6:30 PM to 9:29 PM (ANEEL, 2021a).

Table 3 – Electric energy contracting for subgroups of Group A.

<table>
<tr><th></th><th>Energy</th><th>Power demand</th></tr>
<tr><td rowspan="2">Blue</td><td>Peak</td><td>Peak</td></tr>
<tr><td>Off-Peak</td><td>Off-peak</td></tr>
<tr><td rowspan="2">Green</td><td>Peak</td><td rowspan="2">Single value</td></tr>
<tr><td>Off-peak</td></tr>
</table>

Fonte: ANEEL (2021a).

Consumer units with a voltage supply exceeding 69 kV are mandatorily categorized under the Blue tariffing modality. In cases where the consumer unit receives a supply voltage below 69 kV, irrespective of its contracted power demand, the consumer selects their tariffing modality. Any change in tariffing modality is initiated upon the consumer's request, provided that the last change transpired within the previous 12 billing cycles or in the event of a supply voltage alteration.

Consumers classified in Group A within the regulated energy market (ACR) will be subject to a minimum contracted power demand threshold of 30 kW. The following are the stipulations outlined in REN 1000/21 (ANEEL, 2021a) concerning demand contracting:

- Request for increase: The utility has up to 30 days to provide the new power demand, provided that the request is made in writing;

- Request for reduction: It must be made in writing with a minimum advance notice of 90 days (Group A4) or 180 days (other groups), and the contracted power demand can only be reduced once every 12 months. If energy efficiency measures are implemented, the utility can reduce the demand at any time;
- Exceeding the contracted power demand: Occurs when the active power demand exceeds more than 5% of the contracted power demand. In this case, the local utility will charge double the tariff on the excess amount.

ANEEL adopts the following definition for the billing cycle, according to REN N°. 1000/21 (Art. 2) (ANEEL, 2021a).

> The billing cycle is defined as "The time interval corresponding to the billing of a specific consumer unit" (ANEEL, 2021a).

For the monthly billing of electricity consumer units belonging to Group A, two distinct types of tariffs are presented (ANEEL, 2021a):

> TE - Energy Tariff: "Monetary unit value determined by ANEEL, expressed in R$/MWh, used for monthly billing related to energy consumption" (ANEEL, 2021a).
>
> TUSD - Distribution System Usage Tariff: "Monetary unit value determined by ANEEL, expressed in R$/MWh or in R$/kW, used for monthly billing of users of the electric distribution system for system usage" (ANEEL, 2021a).

The determination of tariff values and their revisions are established within the concession agreements between utilities and the governing authority. These agreements incorporate provisions for annual, periodic (occurring every four years), and exceptional (if required) tariff modifications. Such adjustments are imperative to safeguard the financial stability of sector enterprises and thereby uphold the standards of electricity provision quality.

The monthly electricity billing for consumers categorized under Group A considers expenditures associated with the consumed electrical energy, expenses linked to the utilization of the distribution system, and charges and taxes. The electricity bill includes the following federal, state, and municipal taxes:

- Federal Taxes: Taxes levied by the Union to support federal government social programs, such as the Social Integration Program (PIS) and the Contribution to Finance Social Security (COFINS) (BRASIL, 2002; 2003; 2004c). Their maximum rates are 1.65% for PIS and 7.6% for COFINS, calculated on a non-cumulative basis, meaning the average rate varies with the volume of credits calculated monthly by the utility and with the taxes paid on costs and expenses during the same period;

- State Taxes: The Tax on Circulation of Goods and Services (ICMS) (BRASIL, 1988). In Santa Catarina, the rate is 17% for Group A (BRASIL, 2022c);
- Municipal Taxes: The utility collects the Contribution for the Cost of Public Lighting Service (COSIP).

To align the electricity cost with prevailing generation conditions, the tariff flag system has been incorporated into electricity billing since 2015. These flags, determined monthly by ANEEL based on hydroelectric generation, impact the electricity consumption subject to billing. The tariff flags consist of three distinct types: green, yellow, and red.

For consumers, under conditions of sufficient reservoir levels, there is no escalation in energy generation expenses (green flag). Conversely, as reservoirs deplete, the costs of generation escalate (yellow flag). In situations where reservoirs exhibit low water levels, necessitating the activation of thermal power plants, energy expenses undergo further increments (red flag). The purpose of the tariff flag system is to communicate to consumers the actual expenses of energy generation, promoting a more mindful utilization of electricity.

ANEEL releases electricity tariff baselines to each utility without taxes. These utilities incorporate taxes into their tariffs according to Equation (1).

$$Tariff\ (with\ taxes) = \frac{ANEEL\ homologated\ tariff}{(1-PIS-COFINS)*(1-ICMS)} \quad (1)$$

where:

PIS – Social Integration Program;
COFINS – Contribution to Finance Social Security;
ICMS – Tax on Circulation of Goods and Services.

In 2017, Brazil exhibited the third-highest residential electricity tariff among 27 countries. However, upon adjustment for purchasing power parity, which reflects the relative affordability or expense of electricity for consumers in each nation, Brazil's ranking shifted to sixth place (IEA, 2019b). Concerning commercial tariffs, although Brazil did not record the highest tariff values, its ranking remained above 75% of the global average (IEA, 2019b).

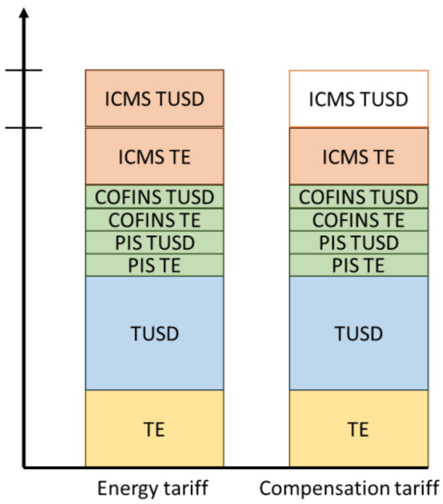
2.2.2 Distributed Generation

Consumers operating within the regulated energy market are permitted to deploy small-scale generators sourced from renewable energies, enabling them to self-generate electricity and feed surplus power into the utility grid. This process was facilitated by ANEEL through the establishment of the conditions for grid access for mini and microgeneration systems outlined in former Resolution Nº. 482 in 2012. Furthermore, to ensure compatibility with the stipulations of former REN 414/2010, ANEEL compatibilized their energy compensation framework via Resolution Nº. 687. Currently all former resolutions have been incorporated into REN 1000/21 (ANEEL, 2021a).

Resolution 1000/21 (ANEEL, 2021a) define PV microgeneration as power plants with installed capacity equal to or less than 75 kW, and minigeneration as power plants with installed capacity greater than 75 kW and equal to or less than 3 MW. An important aspect discussed in REN 1000/21 pertains to the constraint on the installed power capacity of the generating unit, ensuring it aligns with the available contracted power demand allocation for the consumer unit. Should the installed capacity exceed the contracted value, a request for increasing the contracted power demand must be made, covering at least the same magnitude as the intended capacity for the generating unit.

Figure 2 illustrates the components of the energy tariff billed to the consumed energy and the compensation tariff regarding the energy credits injected into the utility grid.

Figure 2 – Components of the billed tariff and the credit compensation tariff.



ANEEL establishes the following for consumer units of Group A:

- The surplus energy is the positive difference between the injected and consumed energy;
- The billing must consider the energy consumed by the Consumer Unit, subtracting the injected energy and any accumulated energy credits from previous billing cycles, per tariff post;
- The compensation must initially occur within the tariff post where the generation was registered and subsequently extend to other tariff posts, with an adjustment factor applied to the credits, equating to the division of energy tariffs (TE) across the tariff posts;
- The consumer unit has the opportunity to utilize energy credits within a period of up to 60 months.

ANEEL also allows consumers to use their respective energy credits in other units within the utility’s concession area, falling within the three categories described below:

- Shared Generation: refers to the assembly of consumers through a consortium or cooperative, comprising individuals or legal entities, possessing consumer units with microgeneration or minigeneration distributed in a location distinct from the consumer units where the surplus energy will be compensated;
- Remote Self-consumption pertains to consumer units owned by the same legal or natural entity, which have distributed generation located separately from the consumer unit where the energy will be compensated, all within the same concession area;
- Multiple Consumer Units (Condominiums): Characterized by the independent use of electricity, where each fraction with individualized use constitutes a consumer unit, and the installations serving common areas constitute a separate consumer unit, the responsibility of the condominium, administration, or property owner of the development, equipped with microgeneration or minigeneration.

illustrates the installed capacity per by consumption class and modality of consumer units with distributed PV generation for each year since 2016.

Table 4 illustrates the installed capacity per by consumption class and modality of consumer units with distributed PV generation for each year since 2016.

Table 4 – Consumer units with distributed PV generation in Brazil.

Installed power (kW) of consumer units with distributed PV generation									
Year	2016	2017	2018	2019	2020	2021	2022	2023	Current Tota l
Consumption Classes									
Commercial	20.371	53.331	171.859	637.495	1.151.550	1.357.758	1.883.196	2.376.467	8.068.002
Public lighting	30	0	24	418	508	556	869	721	8.046
Industrial	6.356	8.674	56.062	142.177	261.171	311.834	461.067	648.343	1.991.363
Public powers	1.816	4.57	8.756	16.191	34.955	40.3	69.911	107.324	299.513
Residential	19.502	48.726	141.214	598.49	1.061.678	2.284.913	4.646.874	3.845.922	13.534.643
Rural	670	7.956	42.08	191.789	438.215	697.693	1.198.283	1.263.609	4.009.230
Public Service	323	934	411	742	2.494	7.294	3.087	2.267	33.854
Modality									
Remote self-consumption	6.828	22.09	94.858	297.289	623.183	1.080.938	1.969.064	1.826.813	6.220.943
Shared Generation	184	2.635	4.186	54.808	156.217	184.897	189.35	194.167	820.583
On-site generation	42.037	99.388	320.738	1.234.373	2.167.430	3.433.610	6.103.004	6.231.528	20.888.859
Multiple CU	18	76	623	831	3.742	903	1.499	4.263	12.004
Total per year	49.067	124.192	420.406	1.587.302	2.950.572	4.700.348	8.263.286	8.258.653	27.944.650

Source: ANEEL (2024), up to March of 2024.

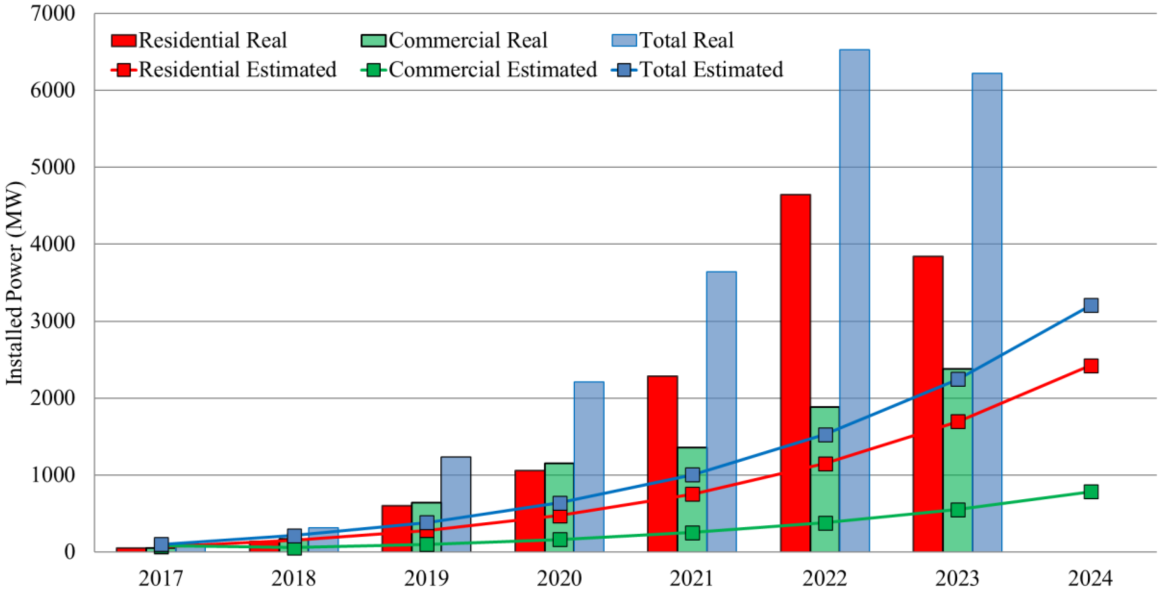
As outlined in the report, within Brazil, there has been a consistent annual growth in the number of consumer units equipped with distributed generation, culminating in an aggregate of roughly 19.68 GW in installed systems by the conclusion of 2022 (ANEEL, 2024). In 2023, for the first time, the total installed power was very similar to the year prior. Up to March 2024, an estimated 36% of the micro and minigeneration distributed systems utilizing photovoltaic solar energy originated from commercial and industrial contexts, while 48% were attributed to residential settings (ANEEL, 2024). On-site generation dominates the national landscape, representing 75% of all installed systems.

In 2017, ANEEL provided an overview of the yearly progression of the estimated installed capacity (MW) for residential and commercial photovoltaic systems up to 2024, as illustrated in Figure 3 (ANEEL, 2017).

It is evident that the initial forecasts underestimated the actual number of installed systems. Notably, in 2022, residential systems have surpassed commercial applications as the leading consumption class. Given the current rate of progress, it is anticipated that the initial forecast of surpassing a capacity of over 3000 MW by

2024 will be comfortably exceeded, signifying a notable escalation in the adoption of PV systems in Brazil.

Figure 3 – Estimate of the installed PV capacity and real installed capacity.

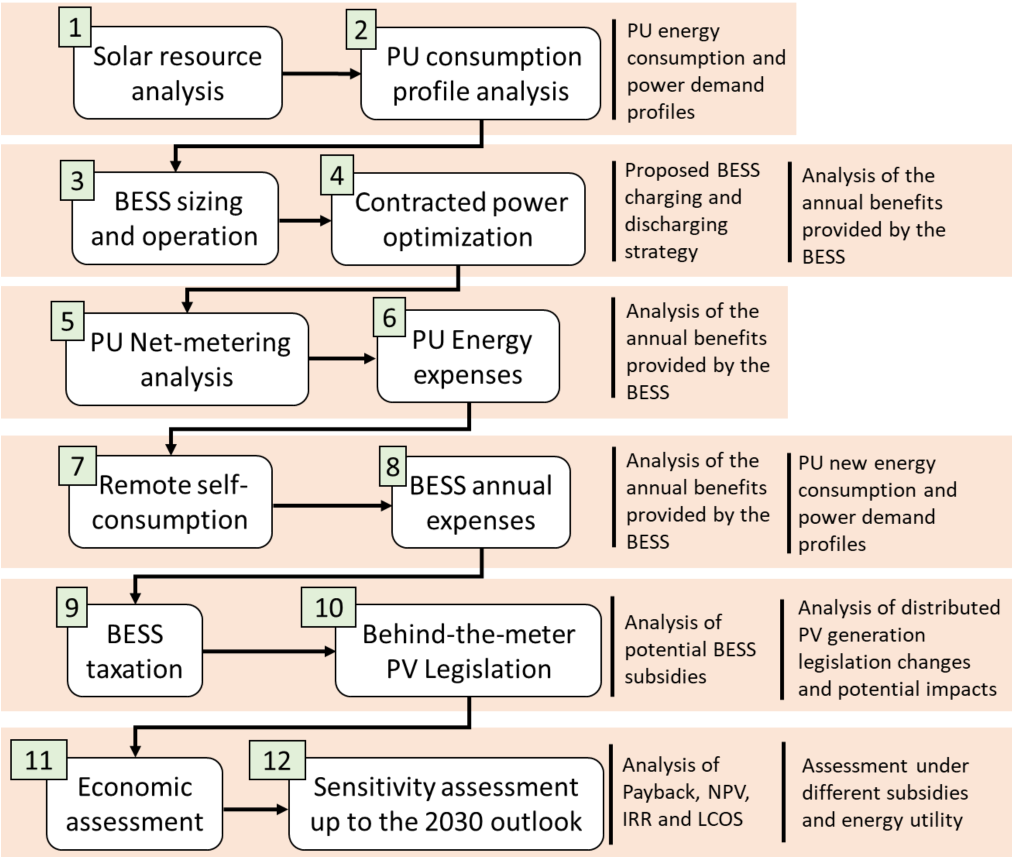


Source: ANEEL (2017; 2024), adapted.

3 PROPOSED METHOD

This thesis proposes a method for assessing the financial attractiveness provided by the adoption of BESS in PU in public buildings. The method is applicable to prosumer units connected on the medium voltage grid. It is based on techniques for measuring the electric energy demand and the surplus PV energy injected by the PU into the grid. The study was subdivided into distinct steps, as illustrated in Figure 4.

Figure 4 – Flowchart depicting the procedural steps of the methodology.



3.1 SOLAR RADIATION RESOURCE ANALYSIS

The evaluation of the solar radiation resource at the BESS integration site involves comparing measured daily average global horizontal irradiation (GHI) values with data obtained from NASA (ZHANG *et al*., 2007; NASA), NREL (MAXWELL *et al*., 1998; NREL), and the Brazilian Solar Energy ATLAS (PEREIRA *et al*., 2017) databases.

Measured GHI values, at one-minute interval, were obtained from Equation (2) while Equation (3) was used to calculate GHI values or a specified time interval

Δt. The GHI, in the specified time interval, is characterized as the sum of the GHI calculated at each one-minute interval obtained during the specified time interval. The gap-filling methodology for missing data described by Schwandt *et al.* (2013) was used when necessary.

$$G_{rr} = G.\frac{1}{60} \tag{2}$$

where:

G_{rr} = Global horizontal irradiation in one-minute interval [Wh/m²];
G= Global horizontal irradiance in one-minute interval [W/m²].

$$G_{rr}^{\Delta t} = \sum_{k=\mathrm{i}}^{k=j} G_{rr}^{k} \tag{3}$$

where:

$G_{rr}^{\Delta t}$ = Global horizontal irradiation in the specified time interval Δt [Wh/m²];
G_{rr}^{k}= Global horizontal irradiation in the specified time interval *k* [Wh/m²];
j= Sum upper limit;
i= Sum lower limit.

3.2 PROSSUMER UNIT CONSUMPTION PROFILE ANALYSIS

This work adopts the ANEEL definitions for power demand and measured power demand (ANEEL, 2021a), as follows: “power demand” is the average power required (or injected) by the PU to the utility grid, whereas “measured power demand” is the maximum power demand by the PU, in kW. The active electric energy injected/required to the utility grid by the PU in 15 minutes intervals was calculated using Equation (4). For a specified time interval Δt, the energy can be calculated as the sum of the active energies injected/required at each 15 minute intervals, obtained during a specified time interval, as shown in Equation (5).

$$E_P = P\ .\ \frac{15}{60} \tag{4}$$

where:

E_P = Active electric energy injected/required in 15 minutes intervals [kWh];
P = Active injected/required power demand in 15 minutes intervals [kW].

$$E_p^{\Delta t} = \sum_{k=\mathrm{i}}^{k=j} E_p^{k} \tag{5}$$

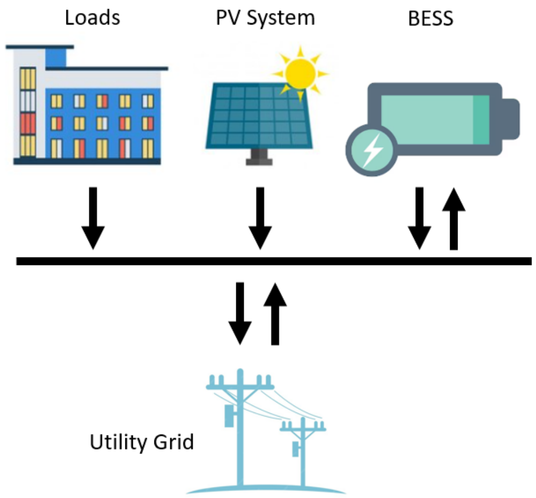
where:

$E_p^{\Delta t}$ = Active electric energy injected/required in the specified time interval Δt [kWh];
E_p^{k} = Active electric energy injected/required in the specified time interval *k* [kWh].

3.3 BESS SIZING AND OPERATION

Figure 5 illustrates the schematic diagram depicting the load, PV system, and BESS of the PU. The BESS operation aims to optimize the utilization of surplus PV energy, which would otherwise be fed into the utility's grid by the PU, and the final electricity expenses. By considering the disparity in electricity tariffs (with peak-hour kWh costs approximately 3.2 times higher than off-peak hours) (ANEEL, 2021b), the BESS stores surplus PV energy generated during off-peak hours and discharges it entirely to the utility's grid during peak hours.

Figure 5 – Schematic diagram depicting the load, PV system, and BESS of the PU.



Both the BESS and the electric utility can function to supply or absorb energy from the PU. The local utility acts as a backup to provide electricity in case the PV system and the BESS is unable to meet the PU's power demand.

The selected technology for the BESS was lithium-ion due to its extended lifespan, enhanced flexibility in charge state, and reduced losses. The instantaneous power of the BESS can reach any value within the limits specified by its rated power. The BESS was configured considering the PU requested/injected power demand profiles, adhering to the constraints of a 20% State of Charge (SoC), 80% Depth of Discharge (DoD), 88% efficiency[1], and 6,000 cycles durability at DoD. The method can also be applied to other BESS technologies, requiring only adjustments to the simulation parameters.

[1] The efficiency rate utilized in simulations for this study aligns with data sourced confidentially from commercially available companies for commercial use BESS.

Uddin *et al.* (2017) and Yoshida *et al.* (2016) highlighted the significance of considering degradation losses in BESS, as it significantly impacts the financial feasibility of these systems. The degradation per cycle model for Li-ion batteries employed in this study, was formulated by Smith *et al.* (2017) and serves as a reference in technical and economic assessments by the USA-DOE's National Renewable Energy Laboratory (NREL) (DIORIO *et al*., 2015).

The maximum BESS charging/discharging power was determined in order to accommodate the PU's peak demand. The storage capacity of the BESS is specified by Equation (6). An additional factor of 30% was considered, beyond the maximum monthly peak consumption, with the objective to optimize financial returns, considering the disparities between off-peak and peak tariffs.

$$E_{BESS} = \frac{C_{Peak} * 1.3}{BD * DoD} \tag{6}$$

where:

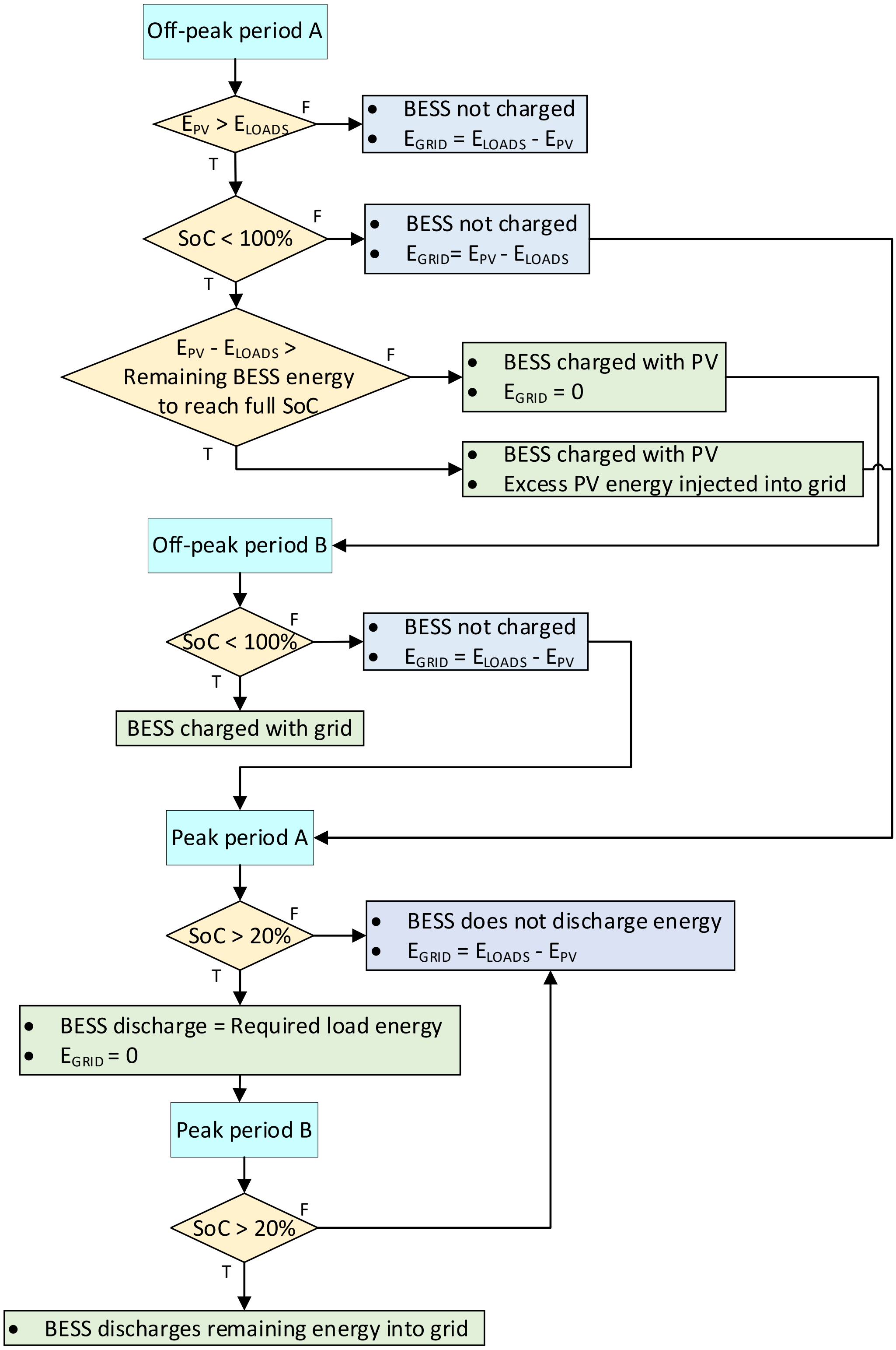
E_{BESS} = BESS storage capacity [kWh];
C_{PEAK} = Maximum monthly peak consumption [kWh];
BD = Number of business days;
DoD= Depth of Discharge [%].

The BESS operation was configured to maximize the utilization of surplus PV energy injected by the PU into the utility grid and to achieve the greatest reduction in the PU's electricity expenses through energy arbitrage. Its operation was elaborated for the following configurations:

a) Off-Peak A: Throughout a business day, the BESS would be charged by the surplus PV energy that would be fed into the utility's grid by the PU.
b) Off-Peak B: If it is not possible to fully charge the BESS with the surplus PV energy that would be fed into the utility's grid, supplementary charging will be carried out using electricity supplied from the utility's grid. Consequently, only the surplus PV energy that cannot be immediately consumed (self-consumed) or stored (BESS) will be directed into the grid.
c) Peak A: The BESS discharge process is carried out with the objective of achieving the maximum reduction in the PU's electricity expenses, primarily by offsetting the building's energy consumption.
d) Peak B: The BESS fully discharges its remaining energy at nominal power.

The adoption of the BESS in the PU implies new power demand profiles (injected/required from the utility grid), which can be derived from the original power demand profiles and BESS operation (charging/discharging process). Figure 6 summarizes the proposed BESS operation strategy.

Figure 6 – Proposed BESS operation strategy.



For each t instant, the amount of energy available in the BESS is shown in Equation (7), while the amount of energy needed to reach full SoC is given by Equation (8).

$$E_{BESS.A}(t) = (SoC(t) - SoC_{MIN}) \; . \; E_{BESS.R} \tag{7}$$

$$E_{BESS.NEC}(t) = (DoD_{BESS} \; . \; E_{BESS.R}) - \; E_{BESS.A}(t) \tag{8}$$

where:

$E_{BESS.A}(t)$ = BESS available energy, at *t* instant [kWh];
$SoC(t)$ = BESS state of charge, at *t* instant;
SoC_{MIN} = BESS minimum state of charge;
$E_{BESS.R}$ = BESS rated storage capacity [kWh];
$E_{BESS.NEC}(t)$ = Amount of energy necessary to reach full state of charge [kWh];
DoD_{BESS} = BESS depth of discharge.

3.3.1 Charging

The electrical energy that can flow between the PU (PV generators + loads), BESS, and the grid is a function of a series of situations and contingencies defined and described below, which determine how the charging process of the BESS takes place.

- Off-Peak period A:

a) $\boldsymbol{E_{LOADS}(t)} > \boldsymbol{E_{PV}(t)}$: The energy demanded by PU loads at *t* instant is greater than the PV generated energy, resulting in zero PV energy surplus. In this case, the BESS is not charged and the difference between the energy demanded by the loads and the generated energy is supplied by the grid. Equation (9) presents the amount of energy stored in the BESS. Equation (10) shows the energy supplied by the grid, at *t* instant.

$$E_{BESS.S}(t) = 0 \tag{9}$$

$$E_{GRID}(t) = E_{LOADS}(t) - \; E_{PV}(t) \tag{10}$$

where:

$E_{BESS.S}(t)$ = BESS stored energy, at *t* instant [kWh];
$E_{GRID}(t)$ = Energy supplied by the grid, at *t* instant [kWh];
$E_{LOADS}(t)$ = Energy demanded by loads at *t* instant [kWh];
$E_{PV}(t)$ = PV generated energy, at *t* instant [kWh].

b) $\boldsymbol{E_{LOADS}(t) < E_{PV}(t)} \;\; \boldsymbol{and} \;\; \boldsymbol{20\% \leq SoC < 100\%}$: The energy demanded by the loads is less than the PV generated energy, resulting in a surplus of PV energy. Since the BESS is below its maximum SoC, it is charged using the PV energy surplus. Equation (11) and Equation (12) show the amount of energy stored in the BESS and the energy flowing through the utility grid at *t* instant, respectively.

$$E_{BESS.S}(t) = E_{PV}(t) - E_{LOADS}(t) \tag{11}$$

$$E_{GRID}(t) = 0 \tag{12}$$

If the amount of surplus PV energy is greater than that required to charge the BESS, according to Equation (13), SoC(t) reaches 100% and the energy difference is injected into the grid. The amount of energy stored in the BESS and the surplus of PV energy injected into the grid at instant *t* are described by Equation (14) and Equation (15), respectively

$$E_{PV}(t) - E_{LOADS}(t) \geq E_{BESS.NEC}(t) \tag{13}$$

$$E_{BESS.S}(t) = E_{BESS.NEC}(t) \tag{14}$$

$$E_{GRID}(t) = E_{PV}(t) - E_{LOADS}(t) - E_{BESS.NEC}(t) \tag{15}$$

c) $\boldsymbol{E_{LOADS}(t) < E_{PV}(t)} \;\; \boldsymbol{and} \;\; \boldsymbol{SoC = 100\%}$: The energy demanded by the loads is less than the generated PV energy, resulting in a surplus of PV energy. In this case, the BESS is fully charged, and therefore the surplus of PV energy is injected into the grid. Equation (9) shows the BESS charged energy while, Equation (16) the surplus of PV energy injected into the grid, at t instant.

$$E_{GRID}(t) = E_{PV}(t) - E_{LOADS}(t) \tag{16}$$

- Off-Peak period B:

If the BESS is not fully charged after the period set for charging the BESS via the surplus of PV energy (SoC (t) < 100%), a new charging period is set using energy from the utility grid with fixed power value equal to the BESS nominal power. During this period two situations may occur, as follows:

a) $\boldsymbol{SoC(t) < 100\%}$: SoC is below its maximum capacity and it is charged through the energy provided by the electrical grid. Equation (17) and (18) show the amount of energy charged and the energy provided by the electric grid, at t instant, respectively.

$$E_{BESS.S}(t) = E_{BESS.NEC}(t) \tag{17}$$

$$E_{GRID}(t) = E_{LOADS}(t) - E_{PV}(t) + E_{BESS.NEC}(t) \tag{18}$$

b) $\boldsymbol{SoC(t)} = \mathbf{100}\%$: BESS SoC is at its maximum capacity, and thus, it does not require charging. Equation (9) and (10) show the amount of energy charged in the BESS and the energy supplied by the grid at *t* instant.

3.3.2 Discharging

- Peak period A:

The objective of the BESS operation during this period is to clear the PU's energy consumption. Thus, no energy is consumed from the grid. BESS discharges its stored energy in the power range between the minimum and maximum of the active power demanded by the load (respecting BESS nominal power). During this period, two situations may occur, as described below:

a) $\boldsymbol{SoC(t)} > \mathbf{20}\%$: The SoC is greater than the established minimum and the BESS will be discharged. Equation (19) shows the amount of energy discharged and Equation (12) the energy flowing through the utility grid at *t* instant.

$$E_{BESS.D}(t) = E_{LOADS}(t) - E_{PV}(t) \tag{19}$$

where:

$E_{BESS.D}(t)$ = BESS discharged energy, at *t* instant [kWh].

b) $\boldsymbol{SoC(t)} = \mathbf{20}\%$: SoC is equal to the minimum allowed, and therefore there is no BESS discharge. The utility grid will supply the PU loads. Equation (20) presents the amount of energy discharged by the BESS, while Equation (10) shows the energy supplied by the grid, at *t* instant.

$$E_{BESS.D}(t) = 0 \tag{20}$$

- Peak period B:

If the BESS has yet to be fully discharged, its operation is set to discharge all its remaining stored energy to the utility grid. It will discharge at a fixed power equal to its nominal power. During this period two situations may occur:

a) $\boldsymbol{SoC(t)} > \mathbf{20}\%$: SoC is greater than the minimum allowed and its discharge occurs. Equation (21) presents the amount of energy discharged by the BESS. Equation (22) displays the energy seen by the grid, at t instant. In this case, the BESS will discharge its energy into the grid.

$$E_{BESS.D}(t) = E_{BESS.A}(t) \tag{21}$$

$$E_{GRID}(t) = E_{LOADS}(t) - E_{PV}(t) - E_{BESS.A}(t) \tag{22}$$

b) $\boldsymbol{SoC(t)} = \mathbf{20}\%$: SoC is equal to the minimum allowed and the BESS is not discharged. The energy discharged and the energy supplied by the grid are shown in Equation (20) and (10), respectively.

3.4 ANNUAL BENEFITS PROVIDED BY THE BESS

The adoption of a BESS in the PU implies new power demand profiles, which can be obtained through the original power demand profiles and the BESS operation simulation (charge/discharge processes). The new energy profiles (injected or required from the grid) can be calculated using Equation (4) and Equation (5).

In order to evaluate the financial benefits, the PU power demand and energy expenses were calculated before and after the adoption of the BESS. Additionally, due to the possibility of compensation of surplus of electric energy (injected into the utility grid) into other consumer units (CU) as allowed by the Brazilian Regulation, the reduction in energy expenses of CU fed in low-voltage (LV) and medium-voltage (MV) was evaluated.

3.4.1 PU Contracted power

Power demand contracting in Brazil adheres to the guidelines of REN 1000/2021 (ANEEL, 2021a), such as allowing only one reduction/increase in contractual demand every 12 months and charging an overuse fee when the measured power demand is larger than 5% of the contracted demand. In the latter case, the utility will charge double the tariff on the surplus amount.

In the process of optimizing the contracted power, the adopted methodology considered that the set of possible power demand values to be contracted, in the analyzed period (1 year), can vary from a minimum value equal to the PV power installed at the PU (ANEEL, 2021a) to up to 120% of the original maximum measured power demand (injected or required from the utility), in intervals of 2% of the respective measured average power demand (injected or required), as shown in Equation (23). The objective is to optimize D_k^c. Equation (24) presents the new power demand value to be billed by the utility while Equation (25) indicates the utility charge for excess power demand.

$$D_k^c = [D_{LL}^c, \dots, D_{UL}^c] \quad \begin{cases} D_{LL}^c = P_{PV} \\ D_{UL}^c = (1.2) \,.\, D_{a,max}^m \\ \Delta D^c = (0.02) \,.\, D_{a,avg}^m \end{cases} \tag{23}$$

$$\text{Conditions:} \quad \begin{cases} D_{LL}^c \geq 30 \text{ kW} \\ D_{k+1}^c < D_k^c \ : only\ once \end{cases}$$

$$DF_k = \begin{cases} D_k^m \ ; \ if\ D_k^m > D_k^c \\ D_k^c \ ; \ if\ D_k^m < D_k^c \end{cases} \tag{24}$$

$$DU_k = \begin{cases} [2 \,.\, (D_k^m - D_k^c) \,.\, TD_k] \ ; \ if\ D_k^m > (1.05) D_k^c \\ 0 \ ; \ if\ D_k^m \leq (1.05) D_k^c \end{cases} \tag{25}$$

where:

D^c_{LL} = Contracted power lower limit [kW];
P_{PV} = PU PV installed power [kW];
D^c_{UL} = Contracted power upper limit [kW];
ΔD^c = Progression ratio for contracted power values;
$D_a{}^m{}_{max}$ = Annual maximum measured power demand [kW];
$D_a{}^m{}_{avg}$ = Annual average measured power demand [kW];
D^c_k = Possible contracted power demand values for the year [kW];
DF_k = Billed power demand [kW];
$D_k{}^m$ = Measured power demand values for billing period *k* [kW];
DU_k = Excess power demand [$];
TD_k = Power demand tariff (without taxes) for billing period *k* [$/kW].

In this method, four scenarios for monthly power demand contracting were analyzed, as following: a) Single level: Applies to PU with little or no variation in measured power demand over the analyzed period; b) Two levels: Normally applied to PU with seasonal variation of demand. Contracting of two demand values throughout the year, one for the period of higher demands and another for the period of lower demands; c) Three levels: Contracting option that more accurately models the load curve of the PU, resulting in three values of demand to be contracted throughout the year; d) Four levels: This contracting modality demands from the consumer an even greater dynamic in performing (with the utility) the contractual amendments for four demand values. This modality can be very advantageous to the consumer if the utility accepts the proposed changes in demand, throughout the analyzed period, without proposing additional costs of upgrading the public distribution system.

3.4.2 PU Net-metering

In Brazil, grid-connected PV installations up to 3 MW can operate under a net-metering system, in which the consumer receives an energy credit referring to the amount of energy injected into the utility grid. The compensation of the surplus of PV energy injected into the grid meets the regulatory prescriptions in place in the country (ANEEL, 2021a; BRASIL, 2022a), being first compensated in the tariff period (off-peak/peak) in which it was generated.

For the PU and the billing period (monthly), the surplus PV energy to be compensated (kWh) and the new energy credits can be calculated using Equation (26). If the injected surplus PV energy added to the remaining credits from the previous billing period is greater than the consumed energy, a non-zero value of new energy credits created in the respective billing period is obtained, as shown in Equation (27). Equation (28) presents the compensated energy cost for the billing period. The new energy credits generated (Equation (27)) can be used for compensation at another tariff period (q), provided that the conversion is performed, as indicated in Equation (29).

$$C_{(i)}{}^{j} = \begin{cases} Cons_{(i)} & if\colon Inj_{(i)}{}^{j} + Cred_{(i)}^{j-1} + \ Cred_{(q)}^{j} \geq Cons_{(i)} \\ Inj_{(i)}{}^{j} + Cred_{(q)}^{j} + \ Cred_{(i)}^{j-1} & if\colon Inj_{(i)}{}^{j} + Cred_{(i)}^{j-1} + \ Cred_{(q)}^{j} < Cons_{(i)} \end{cases} \quad (26)$$

$$Cred_{(i)}^{j} = \begin{cases} {Inj_{(i)}}^{j} + Cred_{(i)}^{j-1} + Cred_{(q)}^{j} - Cons_{(i)} & if: {Inj_{(i)}}^{j} + Cred_{(i)}^{j-1} + Cred_{(q)}^{j} > Cons_{(i)} \\ 0 & if: {Inj_{(i)}}^{j} + Cred_{(i)}^{j-1} + Cred_{(q)}^{j} \leq Cons_{(i)} \end{cases} \tag{27}$$

$${Cost_{(i)}}^{j} = C_{(i)} * {TC_{(i)}}^{j} \tag{28}$$

$$Cred_{(q)}^{j} = Cred_{(i)}^{j} * AF = Cred_{(i)}^{j} * \frac{TE_{(i)}}{TE_{(q)}} \tag{29}$$

where:

$C_{(i)}^{j}$ = Compensated energy in tariff station *i*, for billing period *j* [kWh];
$Cons_{(i)}$ = Consumed energy in tariff station *i*, for billing period *j* [kWh];
$Inj_{(i)}^{j}$ = Injected energy in tariff station *i*, for billing period *j* [kWh];
$Cred_{(i)}^{j-1}$ = Remaining energy credits from billing period before *j* in tariff station *i* [kWh];
$Cred_{(i)}^{j}$ = New energy credits in tariff station *i*, for billing period *j* [kWh];
$Cred_{(q)}^{j}$ = New energy credits in tariff station *q*, for billing period *j* [kWh];
j = Billing period;
i = Off-peak or peak;
q = Opposite of *i*;
$Cost_{(i)}^{j}$ = Compensated energy cost, in tariff station *i*, for billing period *j* [$];
$TC_{(i)}^{j}$ = Compensation tariff, in tariff station *i*, for billing period *j* [-$/kWh];
AF = Tariff adjustment factor;
$TE_{(i)}$ = Energy component, without taxes, in tariff station *i* [$/kWh];
$TE_{(q)}$ = Energy component, without taxes, in tariff station *q* [$/kWh].

The remaining credits for the following billing period are created by applying Equation (29) again with the inverse AF at the end of the compensation cycle and following the instructions of Equations (26), (27), and (28) for compensation in tariff period “q”. In the "remote self-consumption" mode, these credits can be consigned to other Consumer Units under the same ownership or used in the own PU.

3.4.3 PU Electric energy expenses

Equation (30) to (32) present the PU electricity expenses in the green hour tariff scheme modality.

$$X_D = \sum_{j=1}^{12} \left[(DF_k . TD_k) + (TU_k . DU_k) + (TN_k . DN_k) \right] \tag{30}$$

$$X_E = \sum_{j=1}^{12} (CE_k^{OP} . TE_k^{OP} - C_k^{OP} . TC_k^{OP}) + (CE_k^{P} . TE_k^{P} - C_k^{P} . TC_k^{P}) \tag{31}$$

$$VF^V = X_D + X_E \tag{32}$$

where:

X_D = Annual power demand expenses, [$];
DN_k = Non-utilized power demand for billing period *j* [kW];
TN_k = Non-utilized power demand tariff for billing period *j* [$/kW];
TU_k = Excess power demand tariff [$];
X_E = Annual energy expenses, [$];
CE_k^{OP} = Off peak energy consumption for billing period *j* [kWh];
CE_k^{P} = Peak energy consumption for billing period *j* [kWh];
TE_k^{OP} = Off peak energy tariff for billing period *j* [$/kWh];
TE_k^{P} = Peak energy tariff for billing period *j* [$/kWh];
C_k^{OP} = Off-peak compensated energy for billing period *j* [kWh];
C_k^{P} = Peak compensated energy for billing period *j* [kWh];
TC_k^{OP}= Off peak energy compensation tariff, for billing period *j* [$/kWh];
TC_k^{P} = Peak energy compensation tariff, for billing period *j* [$/kWh];
VF^V = Annual bill [$].

3.4.4 Remote self-consumption

The benefits provided by remote self-consumption of the remaining energy credits in other consumer units (fed in LV and MV) after each PU billing period are presented by Equations (33) and (34).

$$B_{MV} = CR_{(i)} * \ TC_{(i)} \tag{33}$$

$$B_{LV} = \left(CR_{(OP)} + \ (CR_{(P)} * AF)\right) * TC_{(OP)} \tag{34}$$

where:

B_{MV} = Financial benefits from remote self-consumption in MV fed CU [$];
B_{LV} = Financial benefits from remote self-consumption in LV fed CU [$];
$CR_{(i)}$ = Remaining energy credits after in tariff station *i* (off-peak or peak) [kWh].

3.5 BESS ANNUAL EXPENSES

The annual expenditures associated with the installation of the BESS in the PU include charges for its operation and upkeep throughout the course of its lifespan, reinvestments associated with inverter replacements after ten years, and potential annual increases in the PU power demand costs.

3.6 BESS TAXATION

Energy storage systems using Li-ion batteries are within the Mercosur common nomenclature NCM 8507.60.00, having the following federal taxes applied on the CIF value (Cost, Insurance and Freight) for their importation into Brazil: a)

Import tax (II): A federal tax, which, as of April 1, 2022, sets its rate at 9% (BRASIL, 2021a; BRASIL 2022b); b) Tax on industrialized products (IPI): Federal tax, for Li-ion electric accumulators at 11.25% (BRASIL, 2021b); c) Tax on the Social Integration Program (PIS) and on the Contribution to Finance Social Security (COFINS): In this case, the rates are 2.1% and 9.65%, respectively (BRASIL, 2015).

After applying the federal taxation on the CIF value, the state taxation referring to the Tax on Circulation of Goods and Services (ICMS) is applied on the resulting value. Li-ion battery energy storage systems are classified as “other” operations and services (general), with a tax rate of 17% (BRASIL, 2001).

3.7 NEW BRAZILIAN LEGISLATION FOR DISTRIBUTED PV GENERATION

Equations (35) and (36) show the composition of the current tariffs (without taxes) and Equation (37) shows the composition of the energy tariff applied to the consumer (with taxes).

$$TUSD_{(i)}{}^{j} = Wire\ A + Wire\ B + Charges + Losses \tag{35}$$

$$TE_{(i)}{}^{j} = Energy + Charges \tag{36}$$

$$T_{(i)}{}^{j} = \frac{TUSD_{(j)} + TE_{(j)}}{\left(1 - PIS(\%) - COFINS(\%)\right) * \left(1 - ICMS(\%)\right)} \tag{37}$$

where:

$TUSD_{(i)}{}^{j}$ = Distribution system usage tariff, without taxes, in tariff period *i*, for billing period *j* [$/kWh];
Wire A = Unit costs related to the maintenance and operation of the transmission lines [$/kWh];
Wire B = Unit costs of using the infrastructure of the utility's distribution network [$/kWh];
Charges = Unit costs to enable the implementation of public policies in the electricity sector [$/kWh];
Losses = Unit corresponding to technical and non-technical system losses [$/kWh];
$TE_{(j)}$ = Energy tariff, without taxes, in tariff period *i*, for billing period *j* [$/kWh];
Energy = Unit costs for energy acquisition [$/kWh];
$T_{(i)}{}^{j}$ = Tariff applied to the consumer, with taxes, in tariff station *i*, for billing period *j* [$/kWh].

As of Supplementary Law No. 194/2022 (BRASIL, 2022c), the maximum ICMS tax rate on electricity is limited to the rate charged on general transactions in each state (17 to 18%). Additionally, the law defines the non-incidence of ICMS tax on the maintenance and operation of the transmission lines and charges related to electricity transactions.

The National Council of Finance Policy (CONFAZ), through ICMS Agreement 16/2015 (CONFAZ, 2015), allowed for the exemption of ICMS levied on electricity supplied by the utility to the CU on credits generated from feeding energy into the grid. That is, the ICMS exemption falls on the amount corresponding to the sum of the electric energy fed into the grid with the energy credits originating in the CU itself. On January 6, 2022, the Legal Framework for Distributed PV generation was sanctioned in the country, through Law No. 14,300/2022 (BRASIL, 2022a). The law came into effect 12 months after its publication. Systems installed and registered before this date will remain under the regulatory regime of REN 482/2012 (ANEEL, 2012) until December 31, 2045, and after this date all systems will be under the regulation of the new legislation. The new law created a more solid legal and regulatory framework, providing the developing market with legal security, stability, and predictability. By protecting the consumer's right to produce their own energy and recognizing distributed generation as a strategy for the country's energy policy, it seeks to safeguard investments already made and offer more predictability of return on future investments.

Equation (38) shows the energy compensation tariff for the situation arising before Law 14,300/2022 takes effect, and Equation (39) shows its revised structure following the law's implementation. The main difference concerning the old legislation is that the compensation tariff no longer includes the “Wire B” portion of the ${TUSD_{(i)}}^{j}$, reducing the value of the compensated electric energy. Starting in 2023, as shown in Table 5, the Wire B portion of the compensation tariff gradually reduces on an annual basis until 2029.

$$ {TC_{(i)}}^{j} = {T_{(i)}}^{j} - ICMS_{(TUSD)} \tag{38} $$

$$ {TC_{(i)}}^{j} = {T_{(i)}}^{j} - ICMS_{(TUSD)} - \ Wire\ B \tag{39} $$

Table 5 - Wire B reduction from 2022 to 2030.

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030
TUSD Wire B reduction	0%	15%	30%	45%	65%	75%	90%	100%	100%

Source: (BRASIL, 2022a)

3.8 BESS ECONOMIC ASSESSMENT

Economic measures including Discounted Payback, Net Present Value (NPV), Internal Rate of Return (IRR), and Levelized Cost of Storage (LCOS) are used to assess the financial attractiveness of the return on investment of adopting BESS in a PV-powered PU.

The Discounted Payback is defined as the period to recover the initial investment using a discount rate before the cash flows are summed. This will usually be the Minimum Rate of Attractiveness (MRA). In this method, all future cash flows should be discounted by this rate over the period to which the flow is tied. The MRA is an interest rate that represents the minimum an investor stands to gain when investing, or the maximum an individual stands to pay when taking out a loan. Applying methods of comparison across time, such as the NPV, is important when utilizing the MRA to assess an investment's financial feasibility.

Future cash flows are added together to create present value, which is then discounted using a discount rate that reflects the required minimum return. The computation of the present value for year *k* is shown in Equation (40). According to Equation (41), the NPV is the present value at the conclusion of the period analyzed.

$$P(k) = -I + \sum_{k=0}^{N} \frac{(R_k - C_k)}{(1+MRA)^k} \tag{40}$$

$$NPV = P(N) \tag{41}$$

where:

P(k) = Present value of year k [$];
R_k = Revenue from year *k* (benefits) [$];
C_k = Costs from year *k* (expenses) [$];
N = BESS lifespan;
I = Initial investment.

The IRR is the hypothetical discount rate that, when applied to a cash flow, causes the investment returns brought to present value to equal the amount invested, i.e., NPV = 0. as shown in Equation (42).

$$0 = -I + \sum_{i=0}^{N} \frac{(R_k - C_k)}{(1+IRR)^k} \tag{42}$$

The LCOS (Equation 43) shows the average rate at which the energy stored in the BESS should be discharged in order to completely offset the lifetime expenditures of the system (JÜLCH *et al*., 2015).

$$LCOS = \frac{\sum_{t=1}^{t=n}\left[\frac{I+O\&M_n}{(1+MRA)^n}\right]}{\sum_{t=1}^{t=n}\left[\frac{BESSc\,(n)}{(1+MRA)^n}\right]} \tag{43}$$

where:

O&M (n) = BESS operation and maintenance cost per cycle [$];
BESSc (n) = BESS storage capacity per cycle (considering degradation) [kWh];
n = Number of cycles in its useful life;
t = Number of cycles used.

This method allows to perform sensitivity analyses of the financial attractiveness of the return on investment of the adoption of a BESS in the PV-powered PU regarding the following factors: a) Evolution of BESS costs; b) Evolution of the interest rate (MRA); c) Evolution of tariffs annual increase; d) Exemption of BESS federal and state taxes; e) Impacts of the new legislation, f) Different tariffs in place.

4 APPLICATION AND DISCUSSION OF THE PROPOSED METHOD

4.1 BASE CASE DESCRIPTION

While the methodology adopts a generalist approach that is applicable to any Public PU, practical illustration and validation were carried out using real data from a specific PU at the Universidade Federal de Santa Catarina (UFSC) in Florianópolis, Brazil (48° W, 27° S). This particular public building is the headquarters of the Solar Energy Research Laboratory Fotovoltaica/UFSC (www.fotovoltaica.ufsc.br), and is supplied by the utility grid at a medium voltage (MV) level of 13.8 kV. Global horizontal irradiation (GHI), power demand consumption, and power injected into the grid were measured onsite during the timeframe spanning from April 2017 to March 2018. This time period was chosen to reflect the data expected in a usual PU condition, not yet affected by the COVID pandemic period. All the acquired data were presented on a monthly basis. In order to illustrate daily and hourly variations, the data acquired on the week of March 4th to March 10th were presented. All tariff values were considered for the year 2021. A BESS was simulated for this public building.

4.1.1 Solar radiation resource analysis

To evaluate the solar radiation resource at the PU site (UFSC's main Campus) in the period between April and September 2017, measured GHI data from the Baseline Surface Radiation Network (BSRN) solarimetric station #3 (KÖNIG-LANGLO *et al*., 2013) at the UFSC Mechanical Engineering building were used obtained via the Data Publisher for Earth and Environmental Science PANGEA (BRSN). The data were collected with a time resolution of 1 minute. The measured data were previously approved by the BSRN quality control system (LONG *et al*., 2010). Additionally, mean ambient temperature data were used, obtained from measurements taken by BSRN station #3.

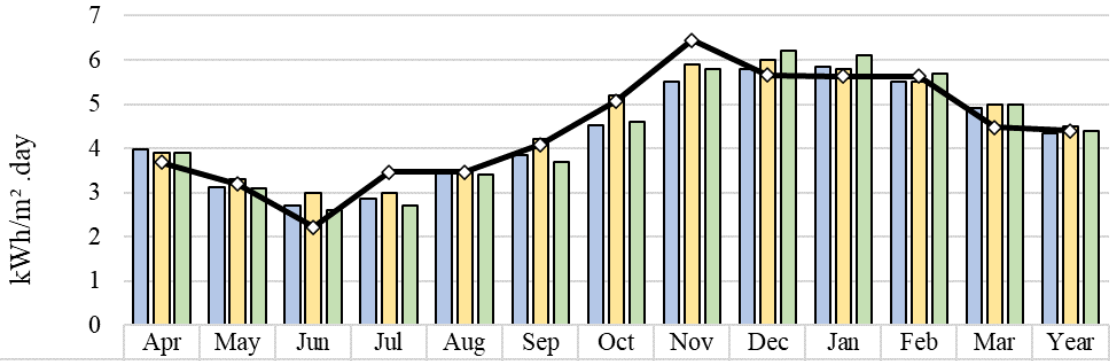
For the period between October 2017 and March 2018, GHI data with a temporal resolution of 1 minute, obtained from the Kipp & Zonen pyranometer (model SMP22) installed at FV-UFSC solarimetric station (Figure 7) were used. The solar radiation measurement station meets the best practices of installation and data acquisition systems. Its sensors have a high level of reliability and accuracy. To ensure best monitoring practices, the BSRN requirements (LONG *et al*., 2010) for installation and observation routines were followed. A more detailed description can be found in Mantelli *et al*. (2019).

Figure 7 – The UFSC Solar Energy Research Laboratory's solar radiation measurement station in Florianópolis-Brazil.

In accordance with the Köppen-Geiger climate classification (PEEL *et al*., 2007), the PU is situated within a humid subtropical climate (Cfa), characterized as oceanic, devoid of a dry season, featuring hot summers. Figure 8 illustrates the monthly progression of daily mean GHI measured on site for the analyzed period and GHI values derived from NASA, NREL and Brazilian Solar Atlas databases.

The solar energy resource in Florianópolis is abundant and well distributed throughout the year. The annual average daily measured GHI was 4.4 kWh/m², which coincides with values obtained through the different databases (4.3 kWh/m² (NASA), 4.5 kWh/m² (NREL) and 4.4 kWh/m² (Brazilian Solar Energy Atlas). Despite the city being located in the region with the lowest solar irradiation in Brazil, it presents great potential for the use of solar PV energy. In the analyzed period, little difference was observed between measured data and the main available databases. Considering that the interannual variability of the Brazilian average daily solar irradiation availability is approximately 6% (PEREIRA *et al*., 2017), the measured values of solar irradiation can be considered satisfactory.

Figure 8 – Daily GHI for Florianópolis-Brazil.



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Year
NASA	4.0	3.1	2.7	2.9	3.5	3.9	4.5	5.5	5.8	5.9	5.5	4.9	4.3
NREL	3.9	3.3	3.0	3.0	3.5	4.2	5.2	5.9	6.0	5.8	5.5	5.0	4.5
ATLAS	3.9	3.1	2.6	2.7	3.4	3.7	4.6	5.8	6.2	6.1	5.7	5.0	4.4
Measured	3.7	3.2	2.2	3.5	3.5	4.1	5.1	6.5	5.7	5.6	5.6	4.5	4.4

4.1.2 PU Power demand and energy consumption profile analysis

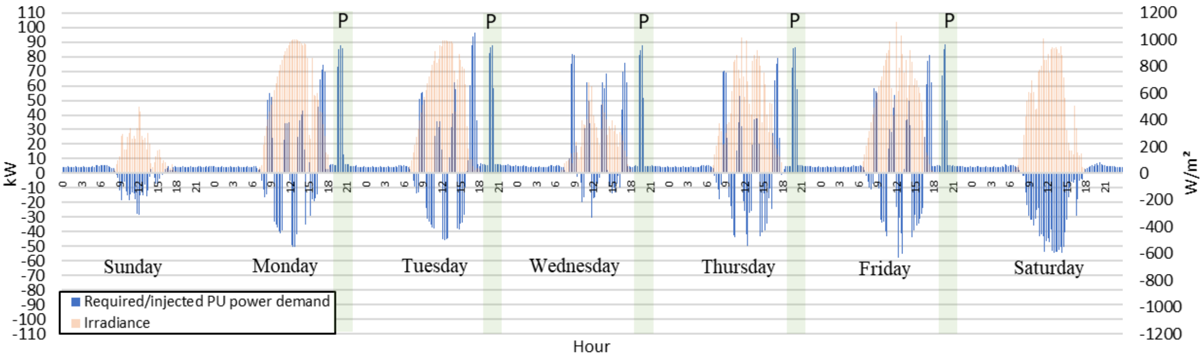
The UFSC Solar Energy Research Laboratory is fed by the local utility grid in medium voltage (MV) (13.8 kV). It acquires electrical energy under a green hourly scheme, featuring distinct energy tariffs for off-peak and peak hours (18:30 to 21:30), weekdays and weekends, with a unified tariff for power demand. The laboratory features various solar PV technologies, including 13.5 kW (CIGS) in the car parking lot, 66.2 kW (p-Si) and 13.5 kW (a-Si/μc-Si) on the roofs of the buildings, 2.4 kW (CdTe) at the e-Bus charging station, and 10 kW (a-Si/p-Si/μc-Si) on the ground, as illustrated in Figure 9. The total installed PV power at the PU is 105 kW.

Figure 9 – The UFSC Solar Energy Research Laboratory's existing solar PV generators in 2018.

The PU comprises primarily two buildings and an electric bus (e-Bus). Prominent electrical loads include transformers, air conditioning units, general-purpose outlets, LED lighting systems, numerous personal computers, a database and internet server, and the e-Bus charging station. On weekdays the e-Bus conducts five round trips, transporting students and staff between the main campus and the Laboratory along a 52 km route, initiating its charging at specific times: 08:00, 10:30, 13:00, 16:00, and approximately 18:45.

Figure 10 illustrates, for the PU without BESS, the progression of measured irradiance, required (positive values) and injected (negative values) measured PU power demand in 15-minute intervals during the week spanning from March 4th to March 10th.

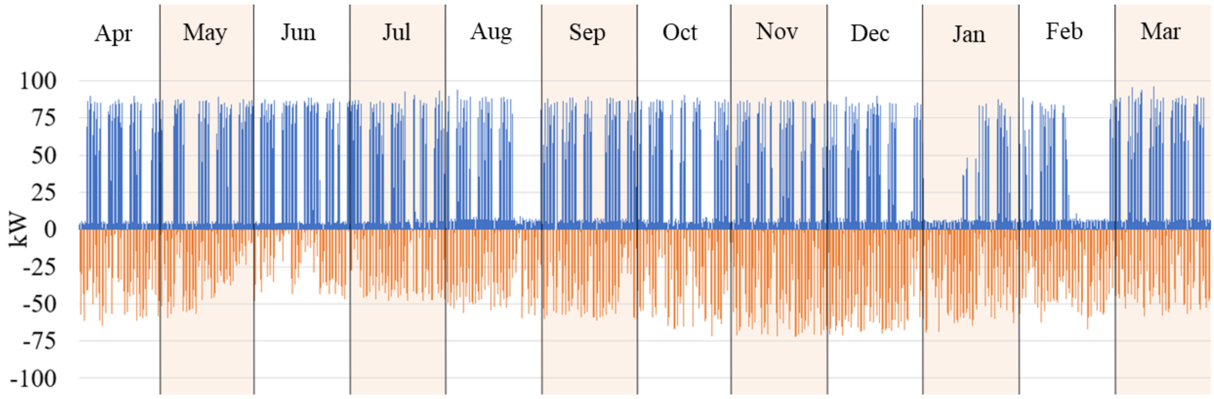
Figure 10 – Measured irradiance and required/injected PU power demand for the PU without BESS.



Notably, five discernible peaks in power demand align with the e-Bus charging periods, with the last peak coinciding with peak tariff hours. The findings reveal instances where PV generation fell short of power demand, resulting in power flow from the utility grid to the PU. Conversely, during periods of elevated PV generation, the PU contributed surplus power to the grid. It is worth noting that during weekends and public holidays, when activities at the Solar Energy Research Laboratory were minimal, nearly all the energy generated by the PV systems was fed into the grid.

The monthly evolution of the measured power demand fed (orange)/consumed (blue) from the PU, in 15-minute intervals can be observed in Figure 11.

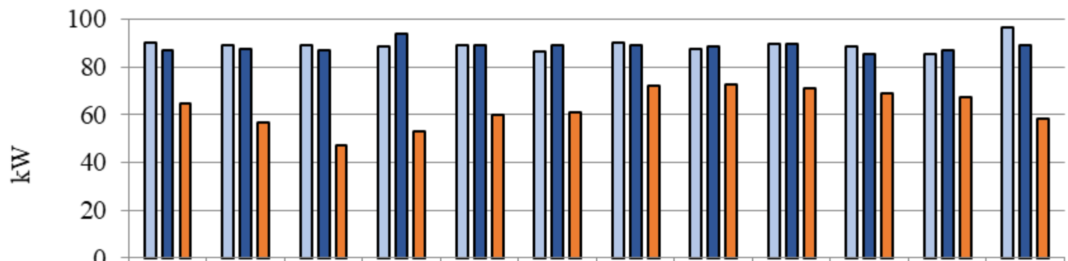
Figure 11 – Measured power demand injected (orange)/required (blue) from the PU, in 15-minute intervals.



During business days, the required power demand from grid exhibited elevated levels, attributed to the necessity of 75 kW power to charge the e-Bus. On non-business days, particularly when the e-Bus batteries remained uncharged, the PU required power demand was below 10 kW (sum of air conditioning appliances, computers, power electronics laboratory and LED lighting systems). Furthermore, the injected power into the utility grid displayed monthly variations, with its peak values occurring between the months of October and December.

Figure 12 illustrates the measured monthly progression of power demands, both injected and required, delineated between peak and off-peak hours. In Figure 13, the measured monthly energy consumption of the PU during peak and off-peak hours is depicted, alongside with the monthly injection of energy during off-peak periods.

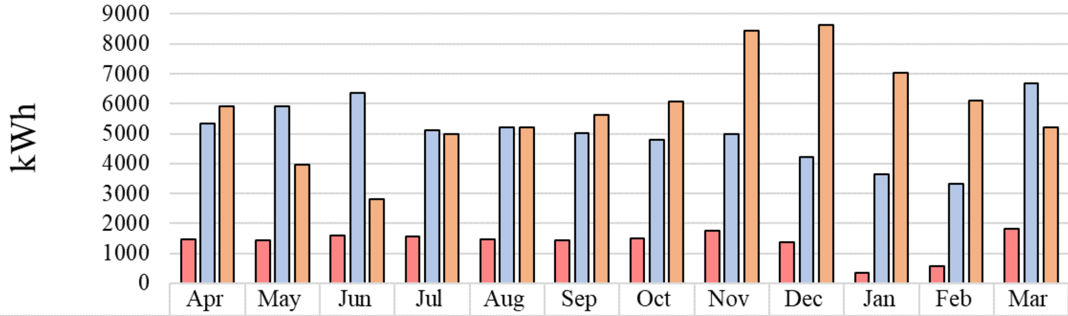
Figure 12 – Off-peak/peak required and off-peak injected measured power demands.



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Off-peak required	90.10	89.09	88.90	88.75	89.23	86.45	90.24	87.74	89.81	88.70	85.34	96.29
Peak required	87.17	87.60	87.17	93.65	89.18	89.18	88.85	88.75	89.42	85.30	86.83	88.90
Off-peak injected	64.90	56.69	46.90	53.14	60.14	61.10	71.86	72.53	71.14	69.07	67.10	58.22

Measured power demands required from the grid ranged between 85.34 kW to 96.29 kW, while the measured power demands injected into the grid varied between 46.90 kW to 72.53 kW. The annual energy consumed by the PU was approximately 77 MWh, of which 16.3 MWh (21.3%) was consumed in peak hours and 60.6 MWh (78.7%) during off-peak hours. The off-peak surplus of energy injected into the utility grid was approximately 70 MWh. The total PV excess energy corresponded to approximately 91% of all the PU energy consumption (peak + off-peak).

Figure 13 – Measured off-peak/peak energy consumption and off-peak injected energy into the grid.



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Peak consumption	1465	1435	1598	1563	1485	1425	1509	1753	1372	352	574	1834
Off-peak consumption	5347	5910	6348	5105	5209	5028	4791	4972	4219	3643	3338	6692
Off-peak injected	5910	3960	2810	4996	5216	5640	6062	8435	8627	7031	6096	5200

During five months within the studied timeframe, the quantity of surplus PV energy injected into the grid surpassed the energy consumption of the PU. In these particular months, under the framework of the Brazilian net-metering system, there existed the potential for reducing energy expenses at the Solar Energy Research Laboratory and other university owned consumer units.

4.2 BESS SIZING AND OPERATION

Table 6 displays the specified BESS technical information and The incorporation (via simulation) of the BESS in the PU was evaluated considering the previously described e-Bus operation (normal operation) and its last daily full charge during off-peak hours (09:31 p.m. to 10:30 p.m.).

Table 7 shows the summary of the proposed BESS and grid operation.

Table 6 - Proposed BESS technical data.

Variable	Value	Unit
Rated storage capacity	150	kWh
Rated charge/discharge power	100	kW
Roundtrip efficiency	88	%
Lifespan	6,000 cycles @ 80% *DoD*	
Minimum SoC	20	%

The incorporation (via simulation) of the BESS in the PU was evaluated considering the previously described e-Bus operation (normal operation) and its last daily full charge during off-peak hours (09:31 p.m. to 10:30 p.m.).

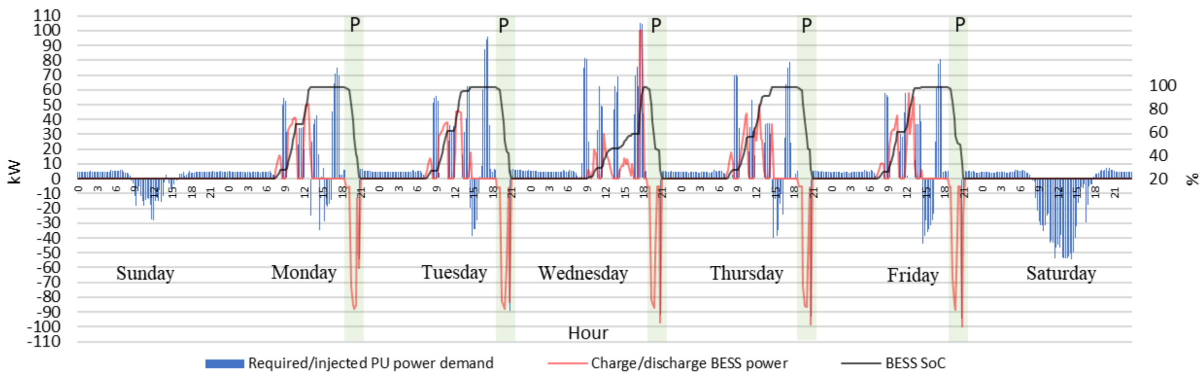
Table 7 - Summary of the proposed BESS and grid operation.

Time period	System point	Operation	Operational values
Off-peak period A: 05:01 to 17:15	Grid	Injected	Fixed power = 0 kW
	BESS	Charge	Power range (between min and max of surplus PV power <100 kW)
Off-peak period B: 17:16 to 18:30	BESS	Charge	Fixed power = 100 kW
Peak period A: 18:31 to 20:30.	Grid	Consumption	Fixed power = 0 kW
	BESS	Discharge	Power range (between min and max of PU required power)
Peak period B: 20:31 to 21:30	BESS	Discharge	Fixed power = 100 kW

4.2.1 Public Building PU with BESS

The simulated PU required/injected PU power (with BESS), in 15-minute intervals for the week between March 4th to March 10th, is presented in Figure 14, alongside the simulated BESS SoC and charge/discharge power.

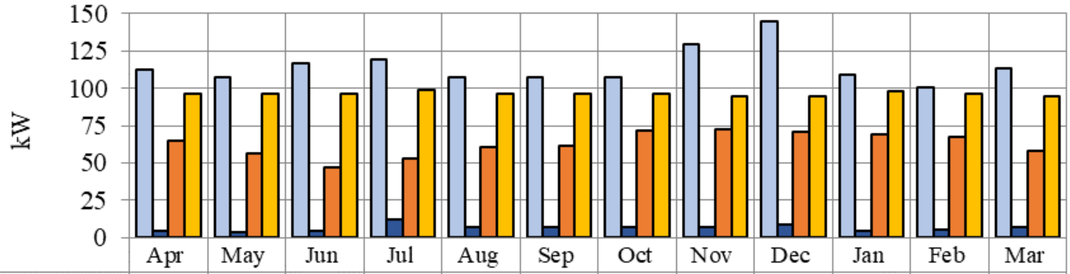
Figure 14 – Simulated PU required/injected power demand and BESS SoC and simulated charge/discharge power.



It can be observed that, on business days and during off-peak hours, the surplus PV energy that would be fed into the utility grid by the PU would be used to charge the BESS. In periods when PV generation was greater than PU demanded power and with full SoC, there would be a power flow from the PU to the utility grid (exporting surplus PV energy). The BESS supplements its charge from the grid, as demonstrated on Wednesday, to ensure a full SoC when entering peak hours. This necessity arises from lower irradiance levels, leading to a reduced surplus of the PU PV energy. During peak hours on business days, the BESS would supply the PU demanded power and subsequently would discharge to the utility grid all its remaining stored energy. On non-business days the charging/discharging process would be interrupted, and therefore all the surplus PV energy at the PU would be injected into the utility grid.

Figure 15 presents the monthly power demands (injected/required) during peak and off-peak hours considering the simulated BESS.

Figure 15 – Simulated off-peak/peak required and injected measured power demands considering the simulated BESS.



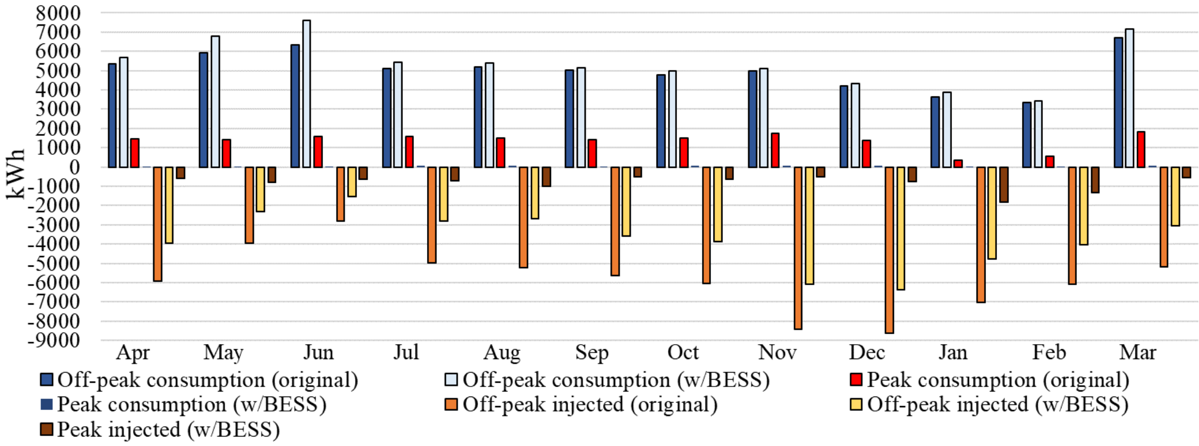
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Off-peak required	112.19	107.68	116.74	119.30	107.58	107.10	107.58	129.04	144.59	109.22	100.58	113.34
Peak required	4.75	3.79	4.56	12.53	6.82	6.72	6.86	6.86	8.74	4.32	5.42	6.62
Off-peak injected	64.90	56.69	46.90	53.14	60.14	61.10	71.86	72.53	71.14	69.07	67.10	58.22
Peak injected	96.45	96.64	96.54	98.85	96.40	96.16	96.35	94.53	94.96	97.74	95.87	94.91

Throughout peak hours, there would be an average reduction of 92.7% in required power demands, while during off-peak hours, an increase of up to 47% could be expected, occurring due to the need to complete BESS charging via energy from the utility grid. It can be noticed that during November and December these values exhibited an elevation, which can be attributed to e-Bus tests being carried out at unscheduled times. In the remaining months, the values consistently remained in the 100 to 120 kW range, representing an increase of, on average, 22%. The off-peak injected power exhibited variability within the range of 47 to 72 kW, with its peak value representing approximately 69% of the installed capacity of the PU PV system.

The simulated monthly energy consumption and injected energy into the utility grid during peak and off-peak hours is presented in Figure 16 in comparison with the original profiles.

The adoption of the BESS would result in an increased monthly off-peak energy consumption, around 7% (4.27 MWh), contingent upon the days throughout the year when BESS charging necessitated supplementation from the utility grid. In January and February consumption would be lower than in the other months due to vacation and Carnival periods, resulting in reduced e-Bus usage.

Figure 16 – Off-peak/peak energy consumption and injected energy into the grid considering the simulated BESS in comparison with the original profiles (measured data).



Furthermore, the integration of the BESS would lead to a reduction of the annual surplus of PV energy injected into the grid, primarily attributed to its utilization for BESS charging purposes. In this case, the surplus PV energy fed into the grid would be 45.1 MWh (36% reduction), and the energy consumed during peak hours would be reduced to 0.52 MWh (96.8% reduction), as compared to the values shown in Figure 13. Regarding the injection of stored energy into the grid during peak hours, the cumulative amount would be 9.8 MWh. The highest values would occur in January and February due to the vacation period when the e-Bus was not in use.

4.2.1.1 e-Bus time shiftable nature

The e-Bus represents the greatest load for the PU and an opportunity to shift peak consumption was also analyzed. Figure 17 presents, in 15-minute intervals for the week between March 4th to March 10th, the evolution of simulated PU required/injected power and BESS SoC and charge/discharge power. This case pertains to the scenario in which the final daily full charge of the e-Bus occurs during off-peak hours, specifically from 21:31 to 22:30. During peak hours, with the shift of the last e-Bus charging period, the BESS would provide energy to deduct the PU required power demand and then fully discharge its energy at its nominal power.

Figure 18 exhibits the monthly energy consumption and injected energy into the utility grid, considering the simulated BESS along with the simulated e-Bus peak shift. Shifting the last e-Bus charging period would not modify the amount of surplus PV energy fed into the grid by the PU during off-peak hours.

Figure 17 – Simulated PU required/injected power demand and BESS SoC and simulated charge/discharge power considering e-Bus peak shift.

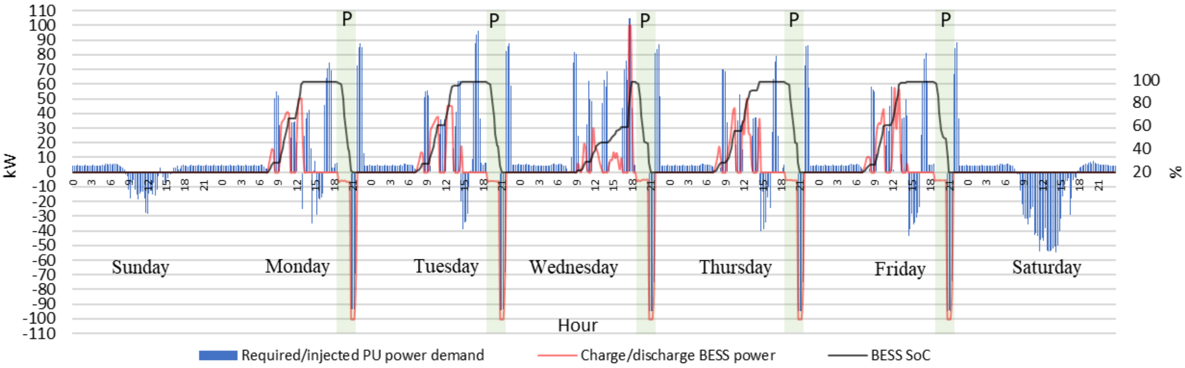
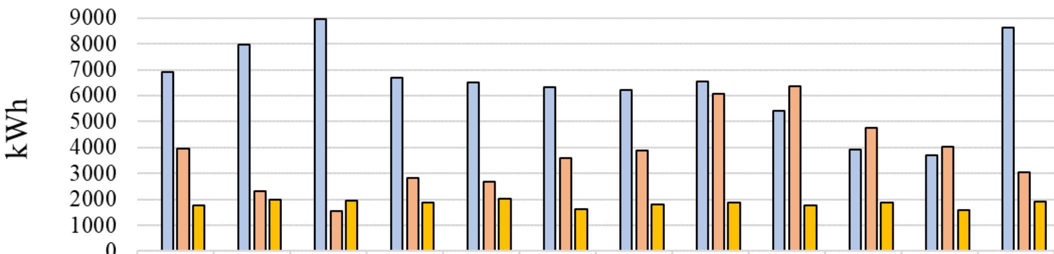


Figure 18 – Simulated off-peak/peak energy consumption and injected energy into the grid considering the simulated BESS and e-Bus peak shift.

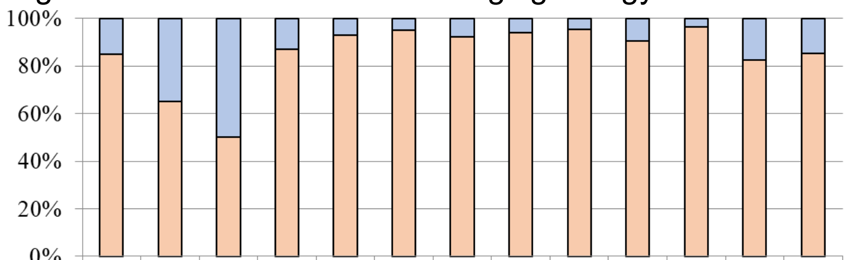


	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Peak consumption	0	0	0	0	0	0	0	0	0	0	0	0
Off-peak consumption	6921	7983	8955	6677	6498	6310	6203	6547	5397	3920	3709	8612
Off-peak injected	3971	2319	1552	2810	2663	3603	3865	6081	6356	4770	4035	3056
Peak injected	1760	1969	1955	1875	2021	1618	1801	1861	1772	1881	1597	1910

However, off-peak energy consumption would increase by approximately 28% (17.13 MWh) while the measured injected/required power demands would not change significantly. During peak hours, consumption would be nullified and the total energy injected into the grid would be 22.02 MWh (125% increase).

Figure 19 portrays the monthly evolution of the energy that would be used to charge the simulated BESS at the PU.

Figure 19 – Simulated BESS charging energy source.



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Year
Grid [kWh]	341	874	1254	322	189	106	181	145	104	231	71	454	4272
PV [kWh]	1937	1640	1258	2186	2553	2038	2197	2349	2268	2256	2057	2144	24883

Approximately 85% of the total energy required would be supplied from the surplus PV energy generated at the PU while the remaining 15% would be supplemented by the grid. Between August to February, 90% of the energy stored in the BESS would have been provided by the PU PV surplus. During April and March, this percentage would be between 80% and 85% whereas during May and June, it would be 65% and 50%. This observed decrease is caused by the least amount of monthly PV energy surplus, as shown in Figure 11. In June, approximately half of the PU surplus energy would be used to charge the BESS, resulting in a greater amount of grid supplied energy to complete the BESS SoC. Conversely, in August, the largest amount of surplus of PV energy injected into the grid could be observed due to the fact that the e-Bus was under maintenance (Figure 11).

4.3 BESS IMPACT ON ELECTRIC ENERGY EXPENSES

The variables used to analyze the financial attractiveness of the ROI (Return On Investment) of BESS adoption are shown in Table 8.

Table 8 - Variables assumed for economic assessment.

Variable	Value	Unit	Reference
BESS cost (I)	550	US$/kWh	GREENER, 2021
Annual O&M expenses	0.5	% of I	GREENER, 2021
BESS inverter reinvestment cost after 10 years	15	% of I	GREENER, 2021
MRA	6	%	GREENER, 2021
Tariff annual increase	5.2	%	Montenegro *et al.*, 2019
Off-peak energy tariff (MV)	0.0818	US$/kWh	ANEEL, 2021b
Peak energy tariff (MV)	0.2614	US$/kWh	ANEEL, 2021b
Power demand tariff (MV)	3.9175	US$/kW	ANEEL, 2021b
Non-utilized power demand tariff (MV)	3.0576	US$/kW	ANEEL, 2021b
Excess power demand tariff (MV)	7.8369	US$/kW	ANEEL, 2021b
Tariff adjustment factor (Off-peak to peak)	0.604		Equation (29)
Tariff adjustment factor (Peak to off-peak)	1.657		Equation (29)
Off-peak compensation tariff (MV)	0.0809	US$/kWh	Equation (38)
Peak compensation tariff (MV)	0.2606	US$/kWh	Equation (38)
Compensation tariff (LV)	0.1179	US$/kWh	Equation (38)
Off-peak compensation tariff post Law 14,300/2022 (MV)	0.0809	US$/kWh	Equation (39)
Peak compensation tariff post Law 14,300/2022 (MV)	0.1543	US$/kWh	Equation (39)
Compensation tariff post Law 14,300/2022 (LV)	0.0962	US$/kWh	Equation (39)
Annual PV energy injected into the grid degradation	0.5	%	Jordan *et al.*, 2016
ICMS (Energy tax)	17	%	BRASIL, 2022c
PIS (Energy tax)	1.0	%	Defined
COFINS (Energy tax)	5.0	%	Defined
II (BESS tax)	9.0	%	BRASIL, 2022b
IPI (BESS tax)	11.25	%	BRASIL, 2021b
PIS (BESS tax)	2.10	%	BRASIL, 2015
COFINS (BESS tax)	9.65	%	BRASIL, 2015
ICMS (BESS tax)	17	%	BRASIL, 2001

4.3.1 PU Contracted Power

The financial impact on power demand was assessed by comparing the power demand expenditures of the PU before and after the implementation of a BESS. Table 9 summarizes the simulated monthly evolution of the power demand to be contracted after BESS adoption. For each simulated profile, the computation of annual expenses revealed that contracting power demand in four tiers (January to May, June to October, November, and December) is the optimal solution leading to the lowest annual expenditure.

Table 9 – Simulated PU power demand (with BESS) measured and demand contracting suggestion (kW).

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Simulated Measured power demand after BESS insertion	109.22	100.58	113.34	112.19	107.68	116.74	119.30	107.58	107.10	107.58	129.04	144.59
1 level	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16
2 levels	111.87	111.87	111.87	111.87	111.87	111.87	111.87	111.87	111.87	111.87	139.35	139.35
3 levels	111.87	111.87	111.87	111.87	111.87	114.16	114.16	114.16	114.16	114.16	139.35	139.35
4 levels	111.87	111.87	111.87	111.87	111.87	114.16	114.16	114.16	114.16	114.16	123.32	141.64

The difference between expenses considering the lowest contracting cost (four levels) and the highest (one level) was 8%. The contracted power demand values would be 112 kW from January to May, 114 kW from June to October, 123 kW in November, and 142 kW in December. All subsequent analyses in this study will be conducted based on the proposed contracting of power demand in four levels.

During the analyzed timeframe, Figure 20 illustrates the progression of power demand expenses (without taxes) for the recommended power demand contracting in four levels. Table 10 displays the monthly evolution of power demand expenses before and after the adoption of BESS. Both the optimal power demand contracting (four-levels) and the contracting of a single level of 105 kW (scenario without BESS) were investigated. The annual power demand expenditure, before BESS analysis, was approximately US$4,770. After the BESS simulation, the PU annual power demand expenditure would be US$5,500, representing an increase of US$730 (13.3%).

Figure 20 – Power demand expenses (without taxes) considering the simulated BESS.

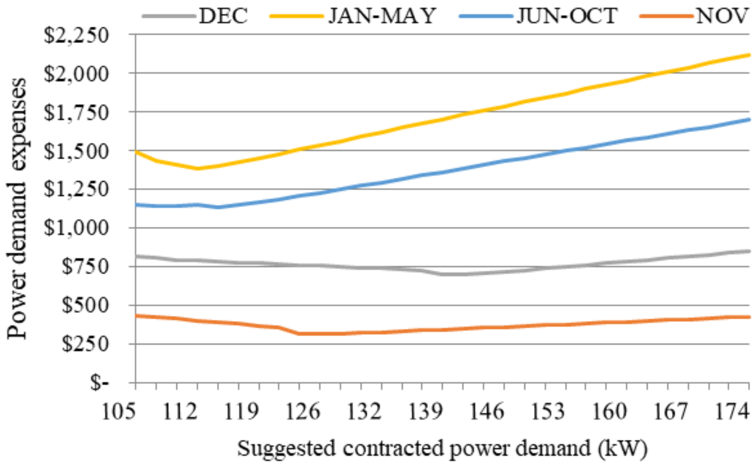


Table 10 - Power demand expenses (without taxes) considering the simulated BESS.

Month	Without BESS	With BESS	
	Base case (US$)	Base case (US$)	Suggested (US$)
Apr	398.53	454.71	439.51
May	397.66	421.84	435.05
Jun	397.50	508.18	457.33
Jul	397.37	538.27	467.36
Aug	397.78	421.45	441.08
Sep	395.39	419.57	440.67
Oct	398.65	421.45	441.08
Nov	396.50	652.74	505.52
Dec	398.28	835.50	566.44
Jan	397.33	427.87	436.37
Feb	394.44	407.54	428.94
Mar	403.85	468.23	444.02
Year	4,773.27	5,977.36	5,503.38

4.3.2 PU Electric energy expenses and Net-metering

The expenses incurred during both off-peak and peak hours, before and after the BESS adoption, were compared to evaluate the financial implications of the BESS on energy utilization. Furthermore, the annual costs and benefits entitled to the PU, both before and after the BESS adoption, were computed, considering the potential compensation for surplus energy injected into the grid. Table 11 presents, for the base scenario (without BESS and with normal e-Bus operation), the PU monthly evolution of energy consumption and electricity expenses. Additionally, it presents the option for the base scenario with the BESS (Option 1) and considering e-Bus shifted last charge taking place at off-peak hours (Option 2).

Table 11 - PU energy consumption and expenses with and without the simulated BESS.

Month	Base scenario: Without BESS and e-Bus normal operation				Option 1: With simulated BESS and e-Bus normal operation				Option 2: With simulated BESS and e-Bus shifted last charge			
	Off-peak		Peak		Off-peak		Peak		Off-peak		Peak	
	Cons. (kWh)	Exp. (US$)	Cons. (kWh)	Exp. (US$)	Cons. (kWh)	Exp. (US$)	Cons. (kWh)	Exp. (US$)	Cons. (kWh)	Exp. (US$)	Cons. (kWh)	Exp. (US$)
Apr	5,347	437.32	1,465	382.91	5,688	465.22	35	9.04	6,921	566.01	0	0
May	5,910	483.35	1,435	375.03	6,784	554.87	34	8.84	7,983	652.95	0	0
Jun	6,348	519.14	1,598	417.86	7,601	621.68	40	10.37	8,955	732.38	0	0
Jul	5,105	417.52	1,563	408.65	5,427	443.86	60	15.79	6,676	545.99	0	0
Aug	5,209	426.00	1,485	388.14	5,397	441.39	53	13.96	6,498	531.45	0	0
Sep	5,028	411.22	1,425	372.43	5,134	419.86	40	10.56	6,310	516.09	0	0
Oct	4,791	391.83	1,509	394.57	4,972	406.63	47	12.40	6,203	507.31	0	0
Nov	4,972	406.65	1,753	458.15	5,117	418.52	64	16.76	6,547	535.46	0	0
Dec	4,219	345.07	1,372	358.62	4,323	353.56	50	13.06	5,397	441.42	0	0
Jan	3,643	297.98	352	91.92	3,874	316.85	1	0.28	3,920	320.59	0	0
Feb	3,338	273.03	574	150.14	3,409	278.85	13	3.41	3,709	303.31	0	0
Mar	6,692	547.36	1,834	479.37	7,147	584.52	83	21.60	8,612	704.33	0	0
Year	**60,602**	**4,956.47**	**16,364**	**4,277.80**	**64,873**	**5,305.80**	**521**	**136.07**	**77,730**	**6,357.30**	**0**	**0**

In the absence of BESS, the PU exhibited an annual consumption of 60.6 MWh during off-peak hours, incurring expenses totaling US$4,956. Concurrently, during peak hours, the consumption was 16.36 MWh, leading to annual expenses amounting to US$4,277. When considering the adoption of the BESS, the annual PU consumption would undergo modifications, amounting to 64.87 MWh during off-peak hours and 0.5 MWh during peak hours. This translates to annual costs of US$5,305 and US$136, respectively. The annual cost would exhibit an increase of US$349 (7%) during off-peak hours and a decrease of US$4,141.73 (97%) during peak hours following the implementation of BESS.

Upon implementing BESS and accounting for the e-Bus shifted last charge, the PU would manifest an annual consumption of 77.73 MWh, corresponding to an annual expense of US$6,357 during off-peak hours. Notably, there would be no annual consumption or costs during peak hours. The outcomes indicate a surge in expenses by US$1,400 (28%) during off-peak hours, accompanied by a substantial reduction of US$4,277 (100%) during peak hours relative to the base scenario.

For the analyzed period, Table 12 illustrates the monthly evolution of energy credits (calculated via Equations (26) through (29)) and the corresponding financial benefits resulting from BESS adoption in the PU.

The PU would provide annual compensation of 53.5 MWh of energy credits during off-peak hours under the base scenario, generating an annual financial benefit of US$4,331. It would receive a yearly compensation of 5.5 MWh during peak hours, translating to a benefit of US$1,441 per year. With regard to “Option 1”, the PU would receive an annual benefit of US$3,925 (48.8 MWh in energy credits). The annual credits would be decreased to 0.5 MWh during peak hours, providing a benefit of US$135 per year. Considering “Option 2”, the PU would provide 67.5 MWh of compensated energy during off-peak hours, providing an annual benefit of US$5,460. There would not be any energy compensation during peak hours.

Table 12 - PU energy credits and benefits with and without the BESS.

Month	Base scenario: Without BESS and e-Bus normal operation				Option 1: With simulated BESS and e-Bus normal operation				Option 2: With simulated BESS and e-Bus shifted last charge			
	Off-peak		Peak		Off-peak		Peak		Off-peak		Peak	
	Cred. (kWh)	Ben. (US$)	Cred. (kWh)	Ben. (US$)	Cred. (kWh)	Ben. (US$)	Cred. (kWh)	Ben. (US$)	Cred. (kWh)	Ben. (US$)	Cred. (kWh)	Ben. (US$)
Apr	5,347	-432.80	340	-88.53	4,866	-393.86	35	-9.01	6,887	-557.45	0	0
May	3,960	-320.51	0	0.00	3,609	-292.12	34	-8.81	5,580	-451.66	0	0
Jun	2,810	-227.45	0	0.00	2,565	-207.62	40	-10.34	4,792	-387.87	0	0
Jul	4,996	-404.39	0	0.00	3,877	-313.81	60	-15.74	5,916	-478.85	0	0
Aug	5,209	-421.60	4	-1.16	4,199	-339.87	53	-13.91	6,011	-486.54	0	0
Sep	5,028	-406.97	370	-96.30	4,367	-353.47	40	-10.53	6,283	-508.56	0	0
Oct	4,791	-387.78	767	-199.97	4,827	-390.71	47	-12.36	6,203	-502.08	0	0
Nov	4,972	-402.45	1,753	-456.79	5,117	-414.18	64	-16.70	6,547	-529.93	0	0
Dec	4,219	-341.50	1,372	-357.51	4,323	-349.91	50	-13.01	5,397	-436.84	0	0
Jan	3,643	-294.90	352	-91.72	3,874	-313.57	1	-0.28	3,920	-317.29	0	0
Feb	3,338	-270.21	574	-149.57	3,409	-275.97	13	-3.40	3,709	-300.21	0	0
Mar	5,200	-420.91	0	0.00	3,802	-307.74	83	-21.54	6,220	-503.46	0	0
Year	**53,513**	**-4,331.47**	**5,531**	**-1,441.55**	**48,836**	**-3,952.84**	**521**	**-135.63**	**67,465**	**-5,460.74**	**0**	**0**

Based on the values presented in Table 11 and Table 12, the monthly progression of total energy expenses (off-peak + on-peak), as well as the financial benefit brought about by the compensation of excess energy at the PU were calculated, and are presented in Table 13.

Table 13 - PU energy credits and benefits with and without the BESS.

Month	Base scenario: Without BESS and e-Bus normal operation			Option 1: With simulated BESS and e-Bus normal operation			Option 2: With simulated BESS and e-Bus shifted last charge		
	Expenses (US$)	Benefits (US$)	Total (US$)	Expenses (US$)	Benefits (US$)	Total (US$)	Expenses (US$)	Benefits (US$)	Total (US$)
Apr	820.23	-521.33	298.90	474.26	-402.87	71.39	566.01	-557.45	8.57
May	858.38	-320.51	537.87	563.71	-300.93	262.78	652.95	-451.66	201.29
Jun	937.01	-227.45	709.56	632.05	-217.95	414.09	732.38	-387.87	344.51
Jul	826.17	-404.39	421.78	459.65	-329.55	130.10	545.99	-478.85	67.13
Aug	814.14	-422.76	391.38	455.35	-353.79	101.56	531.45	-486.54	44.91
Sep	783.65	-503.27	280.38	430.42	-364.00	66.42	516.09	-508.56	7.53
Oct	786.41	-587.76	198.65	419.03	-403.07	15.96	507.31	-502.08	5.22
Nov	864.80	-859.24	5.56	435.27	-430.88	4.39	535.46	-529.93	5.54
Dec	703.69	-699.01	4.68	366.62	-362.93	3.69	441.42	-436.84	4.58
Jan	389.90	-386.62	3.28	317.13	-313.85	3.28	320.59	-317.29	3.30
Feb	423.17	-419.78	3.39	282.26	-279.36	2.89	303.31	-300.21	3.10
Mar	1026.73	-420.91	605.82	606.13	-329.28	276.85	704.33	-503.46	200.87
Year	9,234.28	-5,773.03	3,461.25	5,441.87	-4,088.47	1,353.40	6,357.30	-5,460.74	896.55

According to the base scenario, the PU would incur yearly energy expenditures totaling US$9,234, concurrently qualifying for a benefit of US$5,773 attributable to produced energy credits. Consequently, the PU's net annual energy cost would amount to US$3,461. Assessing “Option 1”, the PU would present annual energy cost of roughly US$5,441, and would be eligible for the benefit of US$4,088 (due to its energy credits). The total net energy cost for the year would be US$1,353. Although the annual benefit via energy credits would be reduced by about US$2,107 (61%), the annual energy consumption expense of the PU would be decreased by $ 3,792 (41%). Given "Option 2", the PU would incur an approximate annual energy expenditure of US$6,357, coupled with eligibility for a benefit of US$5,460. This would result in a total net energy expense of US$896, reflecting a reduction of US$2,564 (74%) compared to the base scenario.

4.3.3 Remote self-consumption

Considering the potential for energy credit compensation in other CUs owned by UFSC (remote self-consumption), the evaluation encompassed the benefits arising from surplus energy compensation within UFSC's main campus (fed at MV) and in other LV CUs. During the time period under consideration, UFSC owned 83 CUs, of which 23 were fed at MV (13.8 kV) and the remaining (60) at LV (2.3 kV). The main campus (MV), the largest UFSC CU during the examined period, displayed annual consumption of 15.5 GWh (DPAE, 2019). All of the CU's feed in LV during that time were small and consumed a combined 0.74 GWh annually (DPAE, 2019).

Table 14 presents the quantity of energy credits remaining from the PU PV generators that would be compensated at other University CU's (MV or LV), and the equivalent financial benefits (calculated via Equations (33) and (34)).

For the base scenario, the PU presented 7.3 MWh of energy credits remaining, which if compensated at the University main campus would provide a benefit of US$591. On the other hand, if compensated in other UFSC CU's, fed at LV, a benefit of US$861 would be provided. In light of "Option 1", the remaining energy credits would amount to 4.5 MWh during off-peak hours and 7 MWh during peak hours. Compensating the remaining credits in the main campus (MV) would yield a total benefit of US$2,194. Alternatively, if compensated in other LV-fed CUs, the benefit would be US$1,902. For "Option 2", the PU would exhibit 2.1 MWh of outstanding energy credits during off-peak hours and 8.5 MWh during peak hours. The compensation of the remaining credits in the main campus (MV) would provide a total benefit of US$2,390. If compensated in University CU's supplied in LV, the benefit would total US$1,913.

Table 14 - Remaining energy credits and the respective financial benefit for a remote self-consumption scenario.

Month	Base scenario: Without BESS and e-Bus normal operation			Option 1: With simulated BESS and e-Bus normal operation					Option 2: With simulated BESS and e-Bus shifted last charge				
	Remaining energy credits	Remote self-consumption		Remaining energy credits		Remote self-consumption			Remaining energy credits		Remote self-consumption		
		Main campus (MV)	Other CU's (LV)			Main campus (MV)		Other CU's (LV)			Main campus (MV)		Other CU's (LV)
	Off-peak (kWh)	Off-peak (US$)	Off-peak (US$)	Off-peak (kWh)	Peak (kWh)	Off-peak (US$)	Peak (US$)	Off-peak (US$)	Off-peak (kWh)	Peak (kWh)	Off-peak (US$)	Peak (US$)	Off-peak (US$)
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	390	0.00	-101.61	-76.07
Nov	559	45.20	65.97	964	1,021	-78.09	-266.25	-313.11	0	1,580	0.00	-411.78	-308.52
Dec	2,135	172.73	251.74	2,033	1,940	-164.64	-505.68	-618.69	959	2,351	-77.73	-612.81	-572.38
Jan	2,805	226.93	327.08	896	2,378	-72.58	-619.61	-569.99	850	2,394	-68.91	-623.83	-567.79
Feb	1,806	146.27	212.97	625	1,676	-50.53	-436.77	-401.13	326	1,794	-26.46	-467.46	-388.82
Mar	0	0.00	0.00	0	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
Year	**7,305**	**-591.31**	**-861.24**	**4,519**	**7,016**	**-365.85**	**-1,828.50**	**-1,902.92**	**2,136**	**8,508**	**-172.91**	**-2,217.50**	**-1,913.57**

4.4 BESS ECONOMIC ASSESSMENT

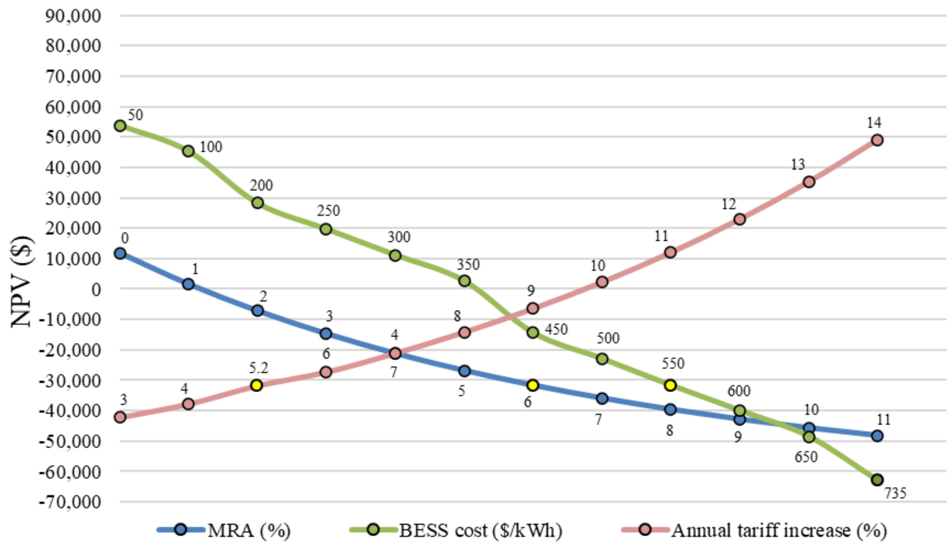
The economic indicators for the ROI (Return on Investment) of adding a BESS to the PU at the UFSC's Solar Energy Research Laboratory are shown in Table 15.

Table 15 - Economic indicators.

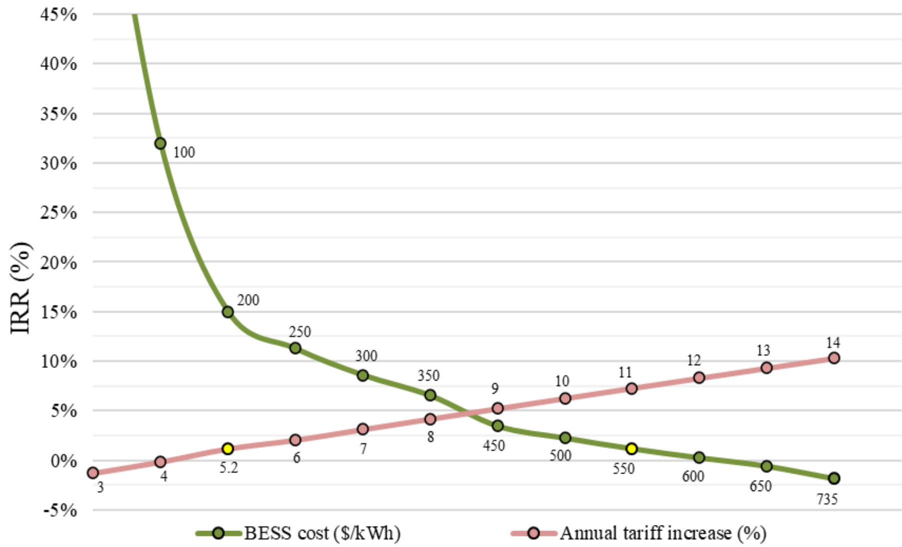
Economic indicators	Option 1: With simulated BESS and e-Bus normal operation		Option 2: With simulated BESS and e-Bus shifted last charge	
	Type of remote self-consumption:			
	Other CU's (LV)	Main campus (MV)	Other CU's (LV)	Main campus (MV)
NPV	-US$59,757.15	-US$52,178.94	-US$42,337.84	-US$31,723.15
IRR	-4.86%	-3.01%	-0.76%	1.17%
Payback	N/A			
LCOS	0.237 US$/kWh			

It can be observed that in all simulations carried out, the adoption of a BESS would not present financial attractiveness. All results indicate a negative NPV, and an IRR lower than the adopted MRA (6%). The LCOS would present a storage cost of approximately 0.24 US$/kWh. The best results would be provided by "Option 2" with the remote self-compensation in the University main campus (MV). In this scenario, a sensitivity analysis of financial indicators was conducted to assess the impact of variations in BESS cost, different MRA, and the annual increase in electric energy tariffs. The evolution of NPV, IRR, LCOS, and Payback Time taking into account the sensitivity analysis is shown in Figure 21(a) through (d).

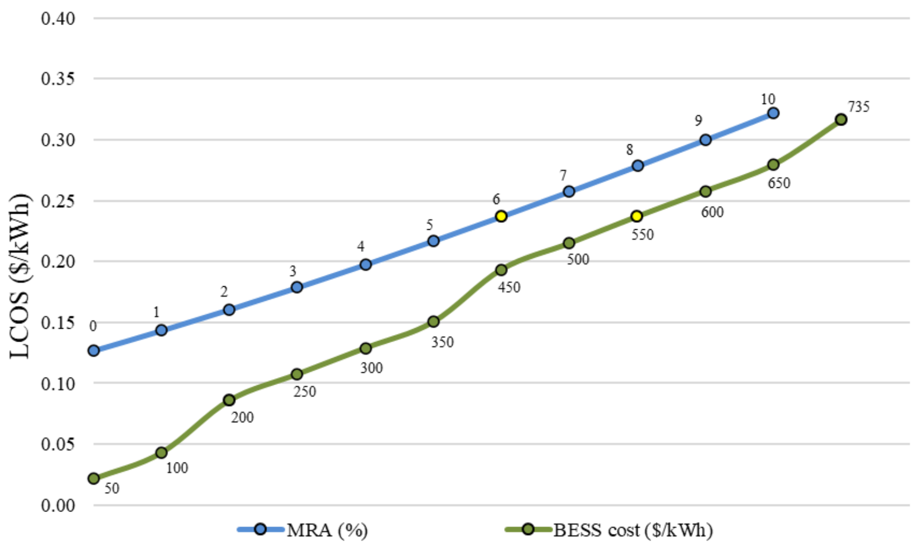
Figure 21 - Economic sensibility analysis for adoption of a BESS at PV-powered public buildings in Brazil.



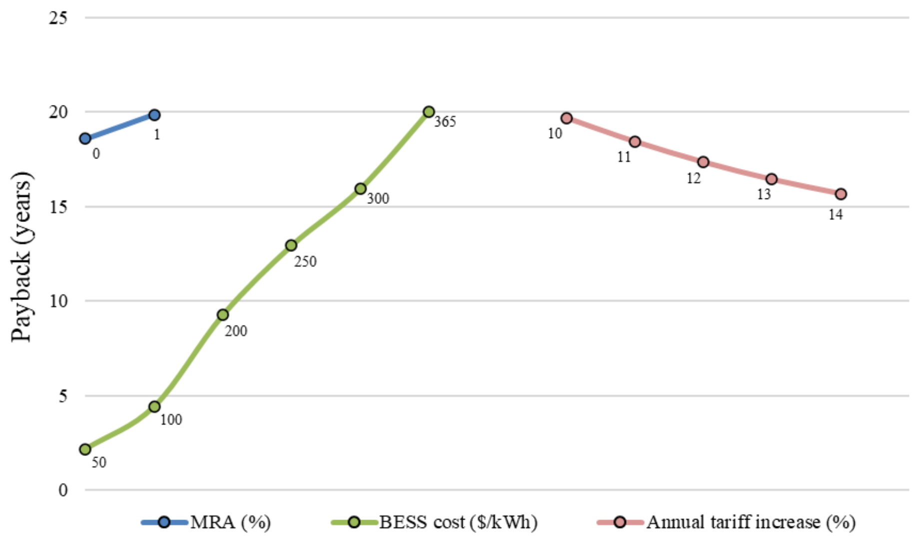
a) NPV sensitivity;



b) IRR sensitivity;



c) LCOS sensitivity;



d) Payback sensitivity;

The outcomes derived from the application of the proposed methodology reveal that, given annual tariff increments equal to or exceeding 10%, MRA less than 1%, and BESS cost below 365 US$/kWh (indicating a 34% cost reduction as presented in Table 7), the BESS demonstrates financial viability. This conclusion is substantiated by the positive NPV values depicted in Figure 21(a). Notably, the foremost influential factor affecting NPV is identified as the BESS cost. Moreover, the impact of reducing BESS cost is more pronounced on LCOS and IRR compared to the reductions in MRA (as illustrated in Figure 21(c)) and annual tariff increase (as depicted in Figure 21(b)), respectively.

In scenarios where the MRA equals to or is less than 1%, the annual tariff increase is equal to or greater than 10%, and the BESS cost is below 365 US$/kWh, the payback period would be less than the BESS lifetime, as illustrated in Figure 21(d). Specifically, for a BESS unit cost of 200 US$/kWh, the payback period would be less than ten years, aligning with the anticipated cost reductions before the end of the current decade.

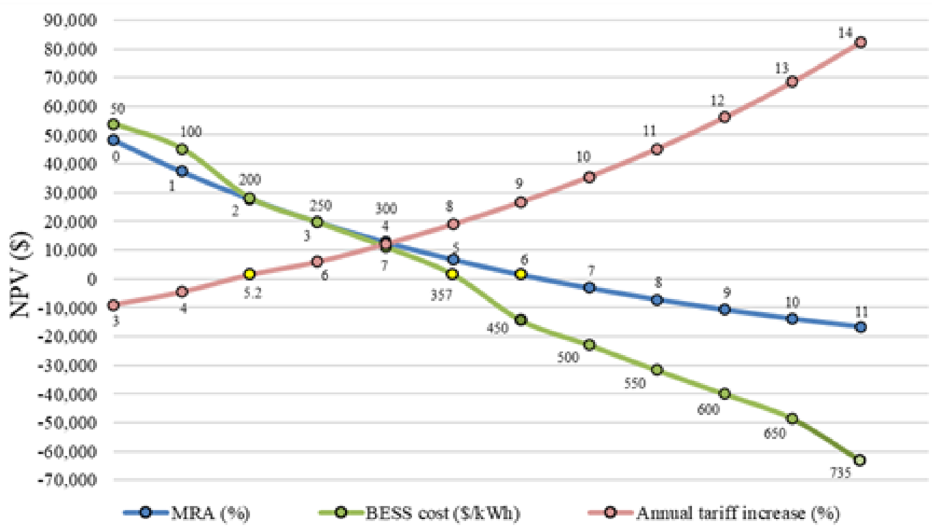
The findings indicate that the primary financial factor influencing the ROI is BESS cost. Notably, BESS in Brazil is currently subject to substantial taxation. The cost of BESS is presented in Table 16, including details on potential cost reductions if Federal and State taxes were excluded. BESS cost would experience a reduction from 550 to 418 US$/kWh (24.24%) in the absence of Federal taxes alone. Eliminating State taxes would result in a decrease from 550 to 471 US$/kWh (14.53%). Complete exemption from both Federal and State taxes would bring the eventual cost of BESS down to 357 US$/kWh (35% less).

Table 16 - Unit BESS cost and its reduction considering tax exemptions.

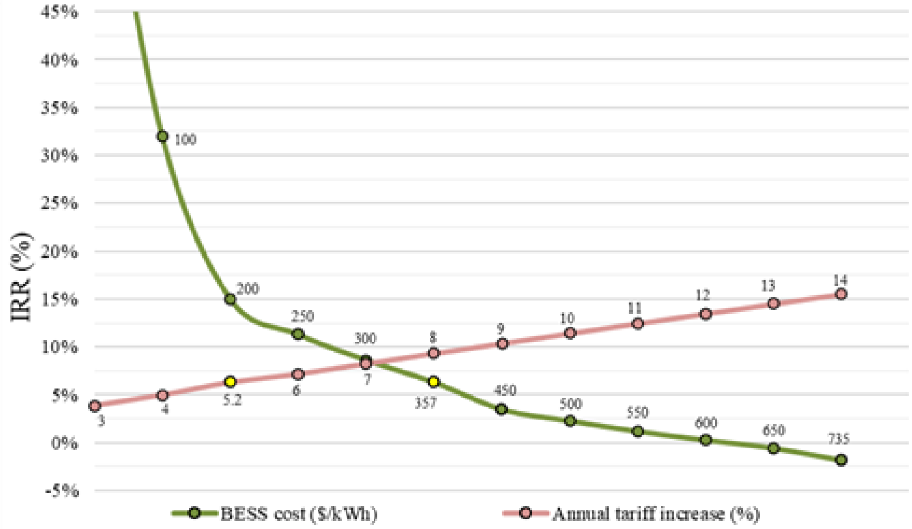
Unit cost	US$/kWh	Reduction %
Total tax incidence	550	-
Without II	514	6,82
Without IPI	504	8,52
Without PIS/COFINS	502	8,90
Free of Federal taxes	418	24,24
Free of State taxes (ICMS)	471	14,53
Free of Federal and State taxes	357	35,25

Taking into consideration the total tax exemption (Federal and State) on the cost of the BESS, which in this case would be 357 US$/kWh, Figure 22(a) to (d) present respectively, the evolution of NPV, IRR, LCOS and Payback Time taking into account the sensitivity analysis.

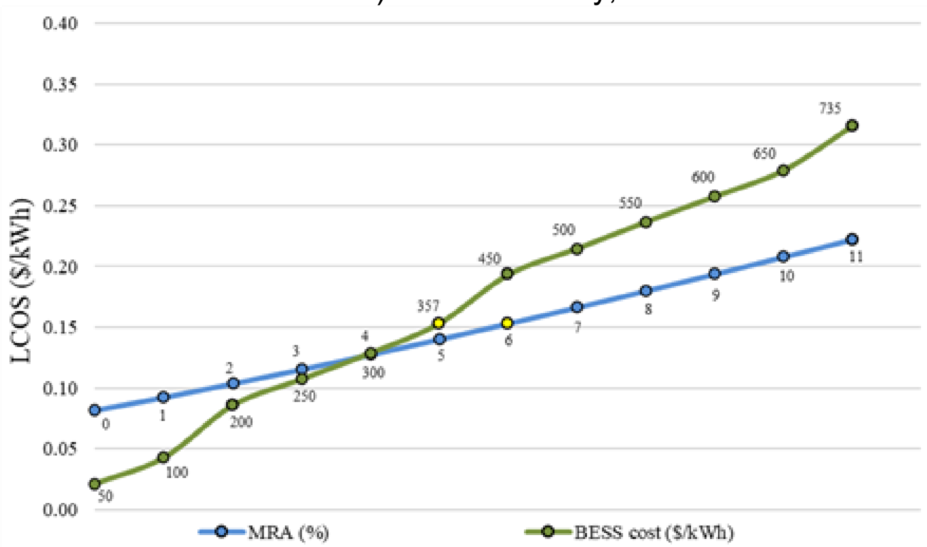
Figure 22 - Economic sensibility analysis for adoption of a BESS at PV-powered public buildings in Brazil (with total tax exemption).



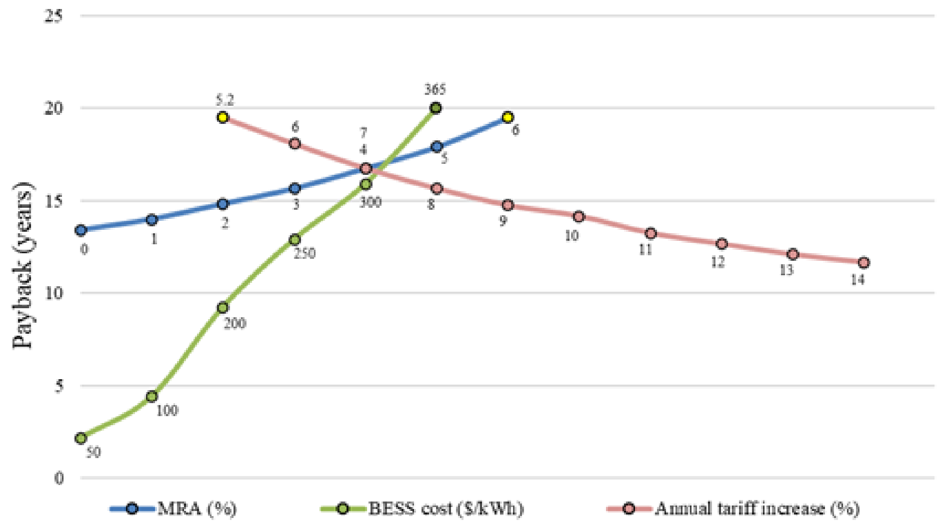
a) NPV sensitivity;



b) IRR sensitivity;



c) LCOS sensitivity;



d) Payback sensitivity;

Unit costs of 135 US$/kWh (BNEF, 2021) can be found in the international market for large BESS. It is apparent that the costs associated with insurance and freight of these systems in Brazil are the main cause of the current discrepancy between the international and domestic BESS costs.

Based on the calculations, the financial attractiveness of the BESS would manifest for annual tariff increases equal to or greater than 5.2%, MRA less than 6%, and a BESS cost (excluding taxes) below 357 US$/kWh, as illustrated in Figure 22(a). The influence of a reduced BESS cost on the LCOS remains more significant than the impact of a lower MRA. When considering MRA below 6.3% and an annual tariff increase of at least 5.2%, the payback period aligns with the system's lifespan under full tax exemption on BESS expenditures. These findings indicate that the BESS cost is still the major factor in the economics of adding batteries to PV-powered prosumer units in Brazil.

4.4.1 Effect of new Brazilian regulation for distributed PV generation

In light of the evolving legislative landscape in Brazil with the enactment of Law 14,300/2022, Table 17 provides economic indicators assessing the financial viability of adding BESS to the existing public PU. It can be observed that in all carried out simulations, the financial attractiveness of BESS remains elusive. The most favorable ROI outcomes continues to align with "Option 2", with remote self-compensation at the University's main campus (MV).

Table 17 - Economic indicators with Brazilian Law 14,300/2022 in effect.

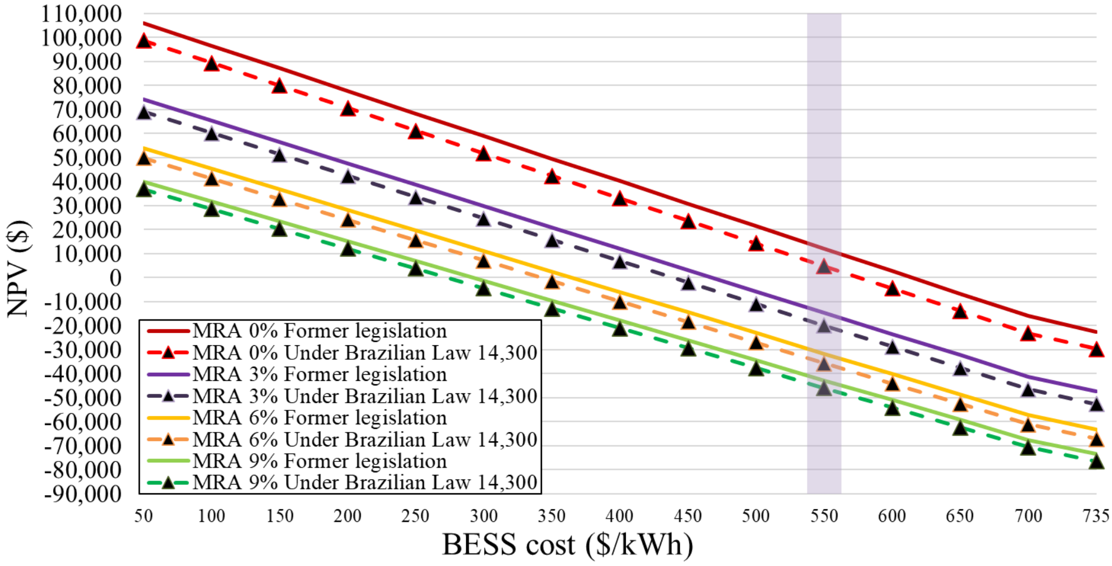
Economic indicators	**Option 1: With simulated BESS and e-Bus normal operation**		**Option 2: With simulated BESS and e-Bus shifted last charge**	
	Type of remote self-consumption:			
	Other CU's (LV)	Main campus (MV)	Other CU's (LV)	Main campus (MV)
NPV	-US$ 54,639.35	-US$ 54,799.76	-US$ 36,092.54	-US$ 35,711.45
IRR	-3.61%	-3.67%	0.41%	0.48%
Payback	N/A			
LCOS	0.237 US$/kWh			

Figure 23 illustrates the progression of NPV across different BESS unit costs and MRA values for PV systems, considering net-metering legislation without and with the enactment of Brazilian Law 14,300/2022.

In terms of NPV, Law 14,300/2022 presents an impact of US$7,148 for an MRA of 0% and exhibits a diminishing impact with increasing MRA (US$3,135 for an

MRA of 9%). These outcomes indicate that the alterations introduced by Law 14,300/2022 will not significantly affect the financial attractiveness of the BESS ROI.

Figure 23 - Evolution of NPV with respect to BESS cost and MRA variation, considering net-metering legislation without and with the enactment of Brazilian Law 14,300/2022.



4.4.2 Financial attractiveness: 2030 outlook

In accordance with market projections (GREENER, 2021), Figure 24 depicts the yearly progression of the anticipated BESS cost from 2022 to 2030, considering scenarios with and without the impact of Federal and State taxes (Table 16). In the year 2030, factoring in both Federal and State taxes, the projected cost of BESS could potentially amount to 331 US$/kWh. Excluding Federal taxes alone, the cost may decrease to 251 US$/kWh, and in the absence of both Federal and State taxes, the cost might be further reduced to 214 US$/kWh.

Figure 24 - BESS cost annual evolution.

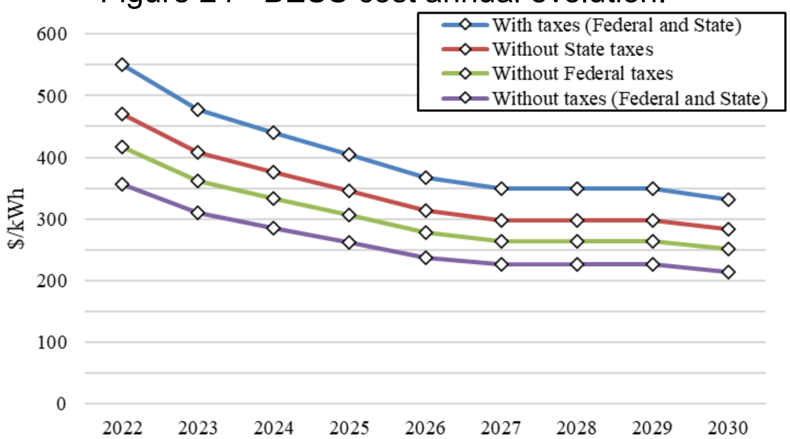


Table 18 presents the annual progression of NPV, IRR, Payback period, and LCOS from 2022 to 2030. The analysis encompasses various tax exemption scenarios, incorporating the assumptions outlined in Table 8 and the annual evolution of BESS costs (Figure 24). Cell colors are indicative, transitioning from various shades of red (indicating economic unattractiveness) to shades of green (indicating economic attractiveness).

Table 18 - NPV, IRR, Payback and LCOS annual evolution - 2022 to 2030.

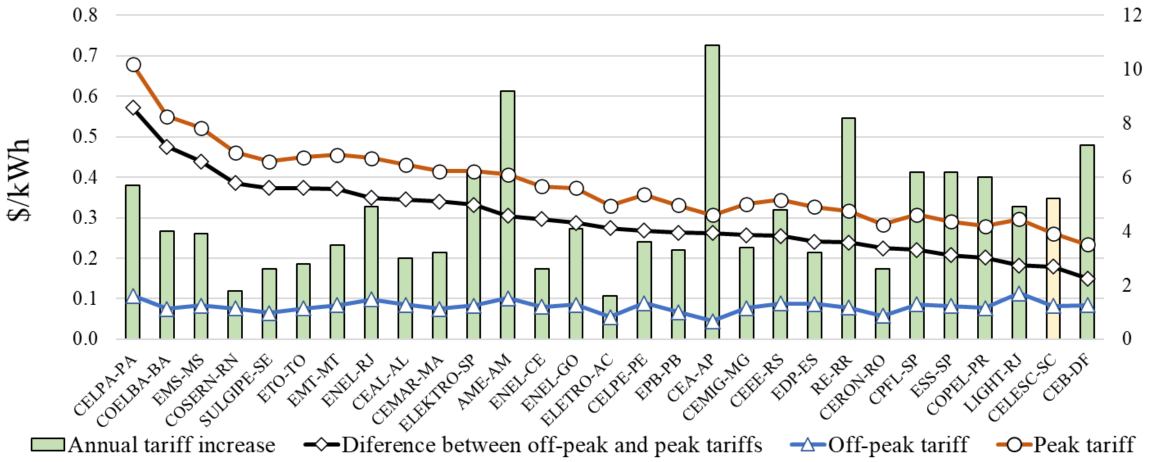
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPV ($)									
With taxes	-31,723.16	-20,137.79	-10,676.39	-1,049.04	8,752.89	15,603.47	19,512.24	23,624.27	31,085.14
Without State taxes	-18,054.50	-8,287.44	264.81	8,983.00	17,875.78	24,256.10	28,164.88	32,276.91	39,298.87
Without Federal taxes	-8,931.61	-387.21	7,569.39	15,660.58	23,957.70	30,055.88	33,964.65	38,076.68	44,753.80
Without taxes	1,445.28	8,578.93	15,845.82	23,247.31	30,854.73	36,608.06	40,516.83	44,628.86	50,961.12
IRR (%)									
With taxes	1.17%	2.61%	4.13%	5.81%	7.70%	9.11%	9.84%	10.59%	12.20%
Without State taxes	2.93%	4.44%	6.05%	7.85%	9.90%	11.43%	12.23%	13.05%	14.85%
Without Federal taxes	3.66%	5.92%	7.62%	9.53%	11.72%	13.38%	14.24%	15.13%	17.07%
Without taxes	6.30%	7.97%	9.81%	11.89%	14.31%	16.15%	17.11%	18.12%	20.32%
Payback (Years)									
With taxes	>20.0	>20.0	>20.0	>20.0	17.3	15.3	14.5	13.7	12.2
Without State taxes	>20.0	>20.0	20	17.0	14.4	12.8	12.2	11.5	10.3
Without Federal taxes	>20.0	>20.0	17.3	14.8	12.6	11.3	10.6	9.3	8.3
Without taxes	19.5	16.8	14.5	12.4	10.6	8.7	8.3	7.8	7.0
LCOS ($/kWh)									
With taxes	0.237	0.205	0.190	0.174	0.158	0.150	0.150	0.150	0.142
Without State taxes	0.202	0.175	0.162	0.148	0.135	0.128	0.128	0.128	0.121
Without Federal taxes	0.179	0.156	0.144	0.132	0.120	0.114	0.114	0.114	0.108
Without taxes	0.153	0.133	0.123	0.113	0.102	0.097	0.097	0.097	0.092

The data in Table 18 indicates that, commencing from 2026, the incorporation of BESS into distributed PV systems would exhibit financial viability, considering the impact of both Federal and State taxes on BESS. By 2030, the NPV would amount to US$31,085, the IRR would reach 12.2%, the payback period would span 12.2 years, and the LCOS would stand at 0.142 US$/kWh. In the absence of Federal and State taxes affecting BESS, the outcomes indicate that financial viability could be achieved since 2022. By 2030, the NPV would reach US$50,961, the IRR would stand at 20.32%, the payback period would be 7 years, and the LCOS would be 0.092 US$/kWh.

4.4.3 Sensitivity analysis considering different tariffs throughout Brazil

For various electric distribution utilities across the Brazilian territory and under the green hourly tariff modality, Figure 25 illustrates the progression of tariffs (with taxes) during off-peak and peak hours, as well as the differences between tariffs. Additionally, it showcases the annual increase in distribution utility tariffs over the past seven years (MONTENEGRO *et al*., 2019).

Figure 25 - Brazilian Distribution Utility tariff evolution (peak and off-peak) and annual tariff increase for most of the distribution utilities in the country.



In the analyzed timeframe, it is evident that, unlike off-peak tariffs, peak tariffs exhibit notable fluctuations across various distribution utilities in the country. The local utility (CELESC-SC), situated where the case-study prosumer unit is located, demonstrated the second smallest disparity between peak and off-peak tariffs. Additionally, it is apparent that the annual increase in tariffs ranged from 1.6% to 10.9% among different distribution utilities. These differences reflect infrastructure costs and asset upgrade, as well as increasing subsidies to low-income tariff consumers, which are diluted in the tariffs levied on the whole population served by that particular utility.

Table 19 and Table 20 portray the annual progression of NPV, IRR, and payback associated with the integration of a BESS in distributed PV systems. The values are derived from the assumptions outlined in Table 8, and the BESS cost evolution depicted in Figure 24 and tariff evolution presented in Figure 25. This analysis takes into account the impact of Federal and State taxes on the BESS cost. The color gradations in the cells serve as a visual aid, transitioning from shades of red (indicating economic unattractiveness) to shades of green (indicating economic attractiveness).

Table 19 - NPV annual evolution (BESS costs with taxes).

State	Utility	NPV ($) Considering the incidence of taxes (Federal and State) on the BESS — Year 2022	2023	2024	2025	2026	2027	2028	2029	2030
PA	CELPA	91,291.45	90,671.06	106,755.42	123,399.21	140,634.29	155,359.38	167,610.08	180,559.07	197,381.17
AM	AME	39,725.09	53,304.48	71,977.47	91,791.53	112,851.65	132,137.43	149,774.08	169,033.30	193,199.38
AP	CEA	37,270.72	49,925.03	70,521.51	92,679.57	116,569.43	139,244.84	160,915.14	184,947.50	214,734.40
BA	COELBA	33,659.29	37,137.21	48,153.14	59,358.90	70,762.09	79,235.60	84,787.63	90,561.75	99,701.84
MS	EMS	27,079.04	31,753.92	42,441.25	53,300.86	64,339.46	72,429.02	77,576.80	82,925.34	91,617.48
SP	ELEKTRO	19,237.31	28,334.46	41,414.86	54,917.51	68,868.58	80,160.86	88,823.87	98,024.00	110,929.55
RJ	ENEL	13,691.98	27,698.75	39,320.02	51,203.50	63,362.04	72,674.11	79,153.84	85,951.07	96,216.38
RR	RE	11,865.87	25,617.07	40,671.54	56,446.34	73,000.53	87,263.00	99,302.92	112,330.11	129,560.54
MT	EMT	5,734.08	11,555.78	21,083.12	30,724.47	40,483.81	47,230.27	50,968.11	54,836.78	61,975.86
SE	SULGIPE	-2,608.06	6,547.27	15,106.79	23,725.84	32,405.96	38,013.74	40,550.79	43,153.81	48,959.52
AL	CEAL	-2,672.61	4,375.85	13,222.46	22,148.37	31,149.90	37,100.41	40,000.38	42,987.35	49,198.94
MA	CEMAR	-3,899.87	3,964.09	12,969.30	22,062.03	31,245.09	37,386.35	40,488.80	43,690.53	50,129.73
RN	COSERN	-3,433.49	1,588.59	9,354.40	17,147.13	24,967.27	29,680.30	31,286.72	32,922.05	37,721.84
SP	CPFL	-10,834.62	1,854.37	13,293.01	25,052.10	37,151.51	46,477.33	53,051.97	60,034.24	70,584.42
GO	ENEL	-9,653.65	-904.97	8,669.88	18,380.22	28,231.62	35,094.84	38,975.90	43,016.09	50,356.94
TO	ETO	-6,498.98	-1,353.88	7,160.52	15,737.77	24,379.62	29,952.87	32,459.38	35,036.07	40,819.92
RS	CEEE	-14,989.81	-4,732.09	5,223.29	15,355.57	25,673.23	33,050.17	37,495.71	42,154.64	50,172.21
SP	ESS	-19,592.24	-6,939.60	3,953.81	15,133.88	26,618.36	35,291.13	41,172.22	47,417.94	57,185.92
PE	CELPE	-16,146.04	-7,446.55	1,489.77	10,522.08	19,653.83	25,753.59	28,825.07	32,007.12	38,438.74
CE	ENEL	-17,781.94	-10,561.15	-2,446.45	5,716.22	13,928.09	19,055.44	21,099.58	23,196.87	28,483.70
MG	CEMIG	-20,500.56	-10,654.94	-1,975.83	6,785.18	15,630.89	21,429.17	24,182.98	27,030.42	33,109.68
DF	CEB	-26,925.89	-12,966.22	-1,761.01	9,799.52	21,740.97	30,955.76	37,473.27	44,460.04	55,084.87
PR	COPEL	-22,562.30	-11,153.00	-661.54	10,083.21	21,096.45	29,259.26	34,588.73	40,237.97	49,361.18
RJ	LIGHT	-32,546.85	-17,744.31	-8,349.75	1,197.91	10,906.18	17,647.91	21,431.35	25,400.19	32,698.51
SC	CELESC	-31,723.16	-20,137.79	-10,676.39	-1,049.04	8,752.89	15,603.47	19,512.24	23,624.27	31,085.14
PB	EPB	-27,051.32	-19,182.92	-10,856.09	-2,461.39	6,003.43	11,405.67	13,747.71	16,167.04	21,801.21
ES	EDP	-33,816.03	-24,415.41	-16,318.34	-8,162.81	53.05	5,196.17	7,268.54	9,407.22	14,749.35
AC	ELETRO	-30,608.36	-23,585.00	-16,388.17	-9,176.51	-1,949.78	2,157.24	3,144.80	4,148.16	8,302.59
RO	CERON	-35,806.77	-27,130.67	-19,446.77	-11,726.11	-3,967.74	694.32	2,261.07	3,868.55	8,652.84

Table 20 - IRR and Payback annual evolution (BESS costs with taxes).

State	Utility	IRR (%) 2022	2023	2024	2025	2026	2027	2028	2029	2030	Payback (years) 2022	2023	2024	2025	2026	2027	2028	2029	2030
		Considering the incidence of taxes (Federal and State) on the BESS — Year																	
PA	CELPA	16.08%	17.27%	19.98%	23.19%	27.07%	30.20%	31.98%	33.87%	37.98%	8.8	8.3	7.3	6.3	5.3	4.8	4.5	4.3	3.8
AM	AME	10.15%	12.09%	14.46%	17.20%	20.41%	23.17%	25.08%	27.14%	30.86%	15.0	13.3	11.4	9.1	7.7	6.8	6.3	5.7	5.0
AP	CEA	9.69%	11.39%	13.76%	16.47%	19.63%	22.40%	24.43%	26.65%	30.42%	15.8	14.2	12.3	10.5	8.3	7.3	6.7	6.1	5.3
BA	COELBA	10.38%	11.43%	13.43%	15.73%	18.45%	20.45%	21.38%	22.33%	24.75%	13.7	12.6	11.0	8.7	7.4	6.8	6.4	6.3	5.6
MS	EMS	9.59%	10.73%	12.66%	14.89%	17.50%	19.42%	20.29%	21.19%	23.49%	14.5	13.3	11.5	9.2	7.8	7.1	6.8	6.5	5.9
SP	ELEKTRO	8.36%	9.87%	11.89%	14.21%	16.91%	19.05%	20.28%	21.58%	24.24%	16.4	14.7	12.7	11.0	8.6	7.6	7.2	6.8	6.0
RJ	ENEL	7.80%	9.98%	11.93%	14.16%	16.77%	18.75%	19.77%	20.82%	23.23%	17.1	14.3	12.4	10.7	8.3	7.5	7.2	6.8	6.1
RR	RE	7.39%	9.27%	11.36%	13.73%	16.48%	18.75%	20.24%	21.81%	24.72%	18.0	15.8	13.6	11.7	9.3	8.2	7.5	7.0	6.2
MT	EMT	6.81%	7.84%	9.53%	11.46%	13.69%	15.29%	15.96%	16.65%	18.51%	18.4	16.8	14.5	12.4	10.7	8.8	8.4	8.2	7.3
SE	SULGIPE	5.61%	7.10%	8.67%	10.46%	12.54%	13.95%	14.44%	14.94%	16.56%	>20	17.9	15.4	13.3	11.3	10.3	9.1	8.8	8.0
AL	CEAL	5.61%	6.73%	8.31%	10.12%	12.20%	13.65%	14.20%	14.76%	16.43%	>20	18.6	16.0	13.7	11.7	10.5	10.2	9.0	8.2
MA	CEMAR	5.43%	6.65%	8.25%	10.06%	12.15%	13.61%	14.19%	14.79%	16.48%	>20	18.7	16.2	13.8	11.8	10.6	10.3	9.0	8.2
RN	COSERN	5.47%	6.28%	7.74%	9.40%	11.33%	12.58%	12.91%	13.25%	14.66%	>20	19.4	16.6	14.3	12.2	11.1	10.8	10.6	8.7
SP	CPFL	4.54%	6.27%	8.05%	10.04%	12.33%	14.10%	15.11%	16.16%	18.29%	>20	19.6	16.9	14.5	12.3	11.0	10.3	9.0	8.0
GO	ENEL	4.60%	5.85%	7.47%	9.29%	11.39%	12.90%	13.60%	14.31%	16.08%	>20	>20	17.4	15.0	12.7	11.3	10.8	10.3	8.5
TO	ETO	5.02%	5.77%	7.28%	8.99%	10.95%	12.30%	12.79%	13.29%	14.82%	>20	>20	17.6	15.1	12.8	11.6	11.2	10.8	9.0
RS	CEEE	3.85%	5.24%	6.87%	8.70%	10.79%	12.33%	13.11%	13.91%	15.72%	>20	>20	18.5	15.8	13.4	12.0	11.3	10.8	8.8
SP	ESS	3.27%	4.94%	6.63%	8.52%	10.68%	12.34%	13.28%	14.26%	16.23%	>20	>20	19.0	16.3	13.8	12.3	11.5	10.8	8.9
PE	CELPE	3.57%	4.74%	6.26%	7.97%	9.93%	11.31%	11.90%	12.50%	14.09%	>20	>20	19.5	16.6	14.1	12.6	12.1	11.5	10.3
CE	ENEL	3.20%	4.13%	5.54%	7.13%	8.95%	10.18%	10.60%	11.03%	12.41%	>20	>20	>20	17.8	15.1	13.5	13.1	12.6	11.4
MG	CEMIG	2.84%	4.17%	5.64%	7.30%	9.19%	10.51%	11.05%	11.60%	13.11%	>20	>20	>20	17.6	14.9	13.3	12.8	12.3	11.1
DF	CEB	2.24%	4.02%	5.72%	7.61%	9.75%	11.42%	12.44%	13.50%	15.50%	>20	>20	>20	17.6	15.0	13.3	12.4	11.6	10.3
PR	COPEL	2.80%	4.25%	5.89%	7.72%	9.79%	11.38%	12.26%	13.18%	15.04%	>20	>20	>20	17.3	14.8	13.2	12.3	11.6	10.3
RJ	LIGHT	0.97%	3.01%	4.53%	6.22%	8.13%	9.54%	10.25%	10.98%	12.60%	>20	>20	>20	19.7	16.6	14.8	14.0	13.2	11.8
SC	CELESC	1.17%	2.61%	4.13%	5.81%	7.70%	9.11%	9.84%	10.59%	12.20%	>20	>20	>20	>20	17.3	15.3	14.5	13.7	12.2
PB	EPB	1.71%	2.58%	3.97%	5.51%	7.26%	8.48%	8.96%	9.46%	10.83%	>20	>20	>20	>20	17.7	15.8	15.2	14.5	13.1
ES	EDP	0.45%	1.52%	2.85%	4.34%	6.01%	7.16%	7.61%	8.07%	9.36%	>20	>20	>20	>20	20.0	17.9	17.1	16.4	14.7
AC	ELETRO	0.75%	1.43%	2.64%	4.00%	5.55%	6.52%	6.76%	6.99%	8.07%	>20	>20	>20	>20	>20	18.9	18.4	18.0	16.1
RO	CERON	-0.06%	0.84%	2.11%	3.52%	5.10%	6.16%	6.52%	6.89%	8.06%	>20	>20	>20	>20	>20	19.7	19.0	18.3	16.3

The findings indicate that the integration of a BESS with a rooftop PV generator in PU's could demonstrate favorable financial returns on investment. Specifically, PU's contracting energy with utilities such as CELPA, AME, CEA, COELBA, EMS, ELEKTRO, ENEL-RJ, RE, and EMT could have been experiencing financial attractiveness since 2022. Overall, for the utilities investigated, the combined use of BESS and PV is projected to achieve financial viability starting in 2027. Results show that CELPA, serving the Amazon state of Pará, exhibits the most favorable tariff conditions for achieving financial viability in the integration of a BESS to a grid-connected PV generator. This is attributed to substantial disparities between its peak and off-peak energy tariffs. Furthermore, utilities characterized by a substantial percentage of annual tariff increases, such as AME (Amazonas) and CEA (Amapá), would potentially yield significant ROI.

Table 21 and Table 22 display the yearly progression of NPV, IRR, and payback period, taking into account the exemption of Federal and State taxes on the cost of BESS.

Table 21 - NPV annual evolution (BESS costs without taxes).

NPV ($)										
Considering the exemption of taxes (Federal and State) on the BESS										
State	Utility	Year								
		2022	2023	2024	2025	2026	2027	2028	2029	2030
PA	CELPA	124,459.89	119,387.78	133,277.63	147,695.56	162,736.13	176,363.96	188,614.67	201,563.66	217,257.15
AM	AME	72,893.53	82,021.20	98,499.68	116,087.88	134,953.49	153,142.02	170,778.67	190,037.88	213,075.36
AP	CEA	70,439.15	78,641.74	97,043.71	116,975.92	138,671.27	160,249.42	181,919.72	205,952.09	234,610.38
BA	COELBA	66,827.73	65,853.93	74,675.35	83,655.25	92,863.93	100,240.19	105,792.22	111,566.34	119,577.82
MS	EMS	60,247.47	60,470.64	68,963.46	77,597.21	86,441.30	93,433.61	98,581.39	103,929.92	111,493.47
SP	ELEKTRO	52,405.75	57,051.18	67,937.07	79,213.86	90,970.42	101,165.44	109,828.46	119,028.59	130,805.53
RJ	ENEL	46,860.41	56,415.47	65,842.23	75,499.85	85,463.88	93,678.69	100,158.42	106,955.66	116,092.36
RR	RE	45,034.31	54,333.79	67,193.75	80,742.69	95,102.37	108,267.59	120,307.51	133,334.70	149,436.52
MT	EMT	38,902.51	40,272.50	47,605.33	55,020.82	62,585.65	68,234.85	71,972.70	75,841.36	81,851.84
SE	SULGIPE	30,560.37	35,263.98	41,629.00	48,022.19	54,507.81	59,018.33	61,555.38	64,158.40	68,835.50
AL	CEAL	30,495.83	33,092.57	39,744.67	46,442.72	53,251.74	58,105.00	61,004.97	63,991.94	69,074.93
MA	CEMAR	29,268.56	32,680.81	39,491.51	46,358.38	53,346.93	58,390.94	61,493.39	64,695.12	70,005.71
RN	COSERN	29,734.94	30,305.31	35,876.61	41,443.48	47,069.11	50,684.88	52,291.30	53,926.64	57,597.82
SP	CPFL	22,333.82	30,571.09	39,815.22	49,348.45	59,253.35	67,481.92	74,056.56	81,038.83	90,460.40
GO	ENEL	23,514.79	27,811.75	35,192.09	42,676.57	50,333.46	56,099.42	59,980.49	64,020.67	70,232.92
TO	ETO	26,669.45	27,362.83	33,996.23	40,034.12	46,481.46	50,957.46	53,463.97	56,040.65	60,695.90
RS	CEEE	18,178.63	23,984.62	31,745.50	39,651.92	47,775.07	54,054.76	58,500.30	63,159.22	70,048.19
SP	ESS	13,576.19	21,777.12	30,476.02	39,430.23	48,720.20	56,295.71	62,176.81	68,422.53	77,061.90
PE	CELPE	17,022.40	21,270.17	28,011.98	34,818.43	41,755.68	46,758.18	49,829.66	53,011.71	58,314.72
CE	ENEL	15,386.49	18,155.57	24,075.76	30,012.57	36,029.94	40,060.03	42,104.17	44,201.45	48,359.68
MG	CEMIG	12,667.87	18,061.77	24,546.37	31,081.53	37,732.74	42,433.75	45,187.56	48,035.00	52,985.66
DF	CEB	6,242.54	15,750.50	24,761.20	34,095.87	43,842.82	51,960.34	58,477.85	65,464.63	74,960.86
PR	COPEL	10,606.14	17,563.71	25,860.67	34,379.56	43,198.29	50,263.85	55,593.32	61,242.56	69,237.16
RJ	LIGHT	684.29	10,972.41	18,172.46	25,494.26	33,008.02	38,652.49	42,435.94	46,404.77	52,574.49
SC	CELESC	1,445.28	8,578.93	15,845.82	23,247.31	30,854.73	36,608.06	40,516.83	44,628.86	50,961.12
PB	EPB	6,117.12	9,533.80	15,666.12	21,834.96	28,105.28	32,410.26	34,752.30	37,171.62	41,677.20
ES	EDP	-647.60	4,301.31	10,203.87	16,133.54	22,154.89	26,200.76	28,273.12	30,411.80	34,625.33
AC	ELETRO	2,560.07	5,131.72	10,134.04	15,119.84	20,152.06	23,161.83	24,149.39	25,152.75	28,178.57
RO	CERON	-2,638.33	1,586.05	7,075.44	12,570.24	18,134.10	21,698.90	23,265.65	24,873.14	28,528.82

Table 22 - IRR and Payback annual evolution (BESS costs without taxes).

		IRR (%)									Payback (years)								
Considering the exemption of taxes (Federal and State) on the BESS																			
State	Utility	Year																	
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2022	2023	2024	2025	2026	2027	2028	2029	2030
PA	CELPA	25.56%	27.23%	31.30%	36.28%	42.60%	47.87%	50.92%	54.21%	61.50%	5.6	5.3	4.6	4.0	3.4	3.1	2.9	2.7	2.4
AM	AME	16.33%	18.75%	21.89%	25.62%	30.22%	34.33%	37.26%	40.50%	46.48%	10.2	8.3	7.2	6.1	5.2	4.4	4.2	3.8	3.3
AP	CEA	15.33%	17.39%	20.41%	23.97%	28.33%	32.30%	35.32%	38.68%	44.62%	11.2	9.4	8.1	6.8	5.7	5.0	4.5	4.1	3.5
BA	COELBA	18.26%	19.63%	22.45%	25.79%	29.89%	33.01%	34.47%	35.99%	39.91%	7.5	7.1	6.2	5.3	4.6	4.3	4.1	4.0	3.5
MS	EMS	17.23%	18.71%	21.42%	24.62%	28.52%	31.48%	32.83%	34.25%	37.92%	7.9	7.3	6.4	5.6	4.9	4.4	4.3	4.1	3.7
SP	ELEKTRO	14.86%	16.76%	19.46%	22.64%	26.50%	29.66%	31.52%	33.51%	37.67%	10.4	8.6	7.5	6.4	5.5	4.9	4.6	4.3	3.9
RJ	ENEL	14.53%	17.32%	19.98%	23.09%	26.89%	29.86%	31.41%	33.05%	36.83%	10.3	8.2	7.1	6.2	5.3	4.7	4.5	4.3	3.9
RR	RE	13.12%	15.43%	18.12%	21.25%	25.04%	28.29%	30.46%	32.81%	37.25%	12.1	10.5	8.4	7.2	6.1	5.3	5.0	4.6	4.1
MT	EMT	13.69%	14.96%	17.24%	19.89%	23.08%	25.42%	26.42%	27.46%	30.28%	10.6	9.0	7.9	6.9	6.0	5.4	5.2	5.0	4.5
SE	SULGIPE	12.41%	14.29%	16.42%	18.88%	21.83%	23.90%	24.62%	25.36%	27.79%	11.3	9.2	8.1	7.1	6.2	5.6	5.4	5.3	4.8
AL	CEAL	12.29%	13.69%	15.81%	18.26%	21.19%	23.28%	24.09%	24.92%	27.39%	11.5	10.5	8.4	7.3	6.3	5.8	5.6	5.4	5.0
MA	CEMAR	11.99%	13.52%	15.63%	18.08%	21.01%	23.12%	23.97%	24.84%	27.34%	11.8	10.7	8.5	7.4	6.4	5.9	5.7	5.5	5.0
RN	COSERN	12.51%	13.51%	15.48%	17.76%	20.48%	22.30%	22.79%	23.29%	25.37%	11.1	10.4	8.3	7.3	6.4	5.9	5.8	5.6	5.3
SP	CPFL	10.11%	12.20%	14.44%	17.02%	20.08%	22.53%	23.96%	25.46%	28.56%	14.3	12.4	10.7	8.5	7.3	6.4	6.1	5.7	5.1
GO	ENEL	10.70%	12.23%	14.32%	16.72%	19.59%	21.72%	22.71%	23.74%	26.32%	13.3	12.0	10.3	8.2	7.1	6.3	6.1	5.8	5.3
TO	ETO	11.59%	12.48%	14.58%	16.75%	19.47%	21.39%	22.10%	22.82%	25.06%	12.1	11.4	9.1	8.0	7.0	6.3	6.1	6.0	5.4
RS	CEEE	9.58%	11.27%	13.34%	15.70%	18.51%	20.64%	21.72%	22.85%	25.45%	14.8	13.0	11.2	8.8	7.6	6.8	6.4	6.2	5.5
SP	ESS	8.57%	10.55%	12.66%	15.05%	17.88%	20.12%	21.41%	22.78%	25.57%	16.2	14.0	12.1	10.3	8.1	7.3	6.8	6.3	5.7
PE	CELPE	9.55%	10.97%	12.92%	15.15%	17.79%	19.70%	20.53%	21.38%	23.64%	14.4	13.0	11.3	8.9	7.6	7.0	6.6	6.4	5.8
CE	ENEL	9.36%	10.47%	12.29%	14.36%	16.82%	18.52%	19.11%	19.71%	21.68%	14.4	13.3	11.5	9.1	7.9	7.2	7.0	6.8	6.2
MG	CEMIG	8.70%	10.30%	12.17%	14.31%	16.84%	18.66%	19.41%	20.18%	22.31%	15.5	13.6	11.8	10.2	8.0	7.3	7.0	6.7	6.1
DF	CEB	7.18%	9.26%	11.32%	13.65%	16.37%	18.58%	19.93%	21.37%	24.13%	18.3	15.5	13.4	11.4	9.0	8.0	7.4	7.0	6.2
PR	COPEL	8.05%	9.75%	11.77%	14.06%	16.75%	18.87%	20.07%	21.32%	23.93%	16.8	14.8	12.8	11.0	8.6	7.7	7.3	6.8	6.1
RJ	LIGHT	6.14%	8.53%	10.40%	12.51%	14.98%	16.85%	17.80%	18.79%	21.02%	19.8	16.0	13.8	11.8	9.3	8.3	7.8	7.4	6.7
SC	CELESC	6.30%	7.97%	9.81%	11.89%	14.31%	16.15%	17.11%	18.12%	20.32%	19.5	16.8	14.5	12.4	10.6	8.7	8.3	7.8	7.0
PB	EPB	7.34%	8.34%	10.06%	12.01%	14.29%	15.91%	16.56%	17.24%	19.11%	17.5	16.1	13.9	12.0	10.2	8.4	8.2	7.8	7.1
ES	EDP	5.85%	7.09%	8.72%	10.56%	12.71%	14.21%	14.81%	15.42%	17.15%	>20	18.0	15.5	13.3	11.3	10.3	9.0	8.6	7.8
AC	ELETRO	6.61%	7.38%	8.89%	10.61%	12.62%	13.92%	14.23%	14.55%	16.00%	18.8	17.3	14.9	12.8	11.0	9.2	9.0	8.8	8.1
RO	CERON	5.39%	6.42%	7.96%	9.70%	11.72%	13.09%	13.57%	14.05%	15.60%	>20	19.2	16.4	14.1	12.0	10.9	10.5	10.2	8.4

The analysis reveals that, for almost all surveyed distribution utilities, the incorporation of BESS in PV-powered PU’s could have yielded a financially advantageous ROI since 2022. However, starting from 2023, the deployment of BESS becomes economically viable for PU’s served by every distribution utility throughout the country.

Looking towards 2030, total tax exemptions would represent an increase of 64% in total NVP and 8.12% to the IRR. A decrease of 5.2 years of total payback time and 0.05 US$/kWh in the LCOS could also be observed.

Throughout Brazil, utilities characterized by a substantial percentage of annual tariff increases, such as AME (Amazonas) (9%) and CEA (Amapá) (10%), would potentially yield significant ROI. However, the majority of utilities present increases below 4%. The highest ROI was observed to be located in the Amazon state of Pará, due to substantial disparities between the local utility’s peak and off-peak energy tariffs (0.6 US$/kWh, almost double of the country’s average).

4.5 DISCUSSION AND FURTHER APPLICATIONS

4.5.1 Case study

The BESS application was considered and simulated for a public building with an electric bus as part of its loads. However, the proposed method is adaptable and can be applied in other scenarios with different load characteristics. The life span of a BESS and its configuration plays an important role when economic benefits of its implementation are accessed. Specifically, the proposed method incorporates BESS degradation losses, not usually considered in other studies, as shown in Table 1. For the UFSC case study, the BESS configuration and operation was defined in Table 6 and The incorporation (via simulation) of the BESS in the PU was evaluated considering the previously described e-Bus operation (normal operation) and its last daily full charge during off-peak hours (09:31 p.m. to 10:30 p.m.).

Table 7, based on Equation (6) and on the analysis of the prosumer unit power demand and energy consumption profiles.

Regarding the four scenarios for monthly power demand contracting analyzed, the result of the application of the proposed method in the case study indicated that there would be an increase of 13.3% on the PU annual power demand expenditure, considering the optimized four levels, as shown in Table 10. However, without any optimization to the PU power demand contracting, this annual power demand expenditure increase would rise to 25.2%. Such a considerable difference indicates the importance of optimizing the contracted power demand, since considerable reduction can be achieved, almost half of the new expenses was in the case study.

The e-Bus time shiftable nature was also taken into consideration, the analysis of the BESS adoption was carried out for normal load operation and the scenario in which the final daily full charge of the e-Bus occurs during off-peak hours. The analysis of the PU energy expenses, as shown in Table 13, indicates that although the shift change of the last e-Bus charging period would lead to increased energy costs, it would enable a greater amount of energy injection into the grid. Consequently, such a shift change would yield higher financial gains for the PU, rendering it as the preferable choice (Option 2) for minimizing annual energy expenditures.

As far as the utilization of energy credits is concerned, two scenarios were assessed, involving remote self-consumption in additional owned consumer units supplied via medium voltage, as well as via low voltage. The findings were outlined in Table 14. It is shown that the utilization of energy credits in other MV units is the preferable choice. The compensation tariff for LV consumer units is characterized as a monomial tariff, which is greater than the off-peak compensation tariff for medium voltage consumers (Table 8 and Equation (38)). The decisive factor is the higher compensation rate during peak hours, which favors MV units operating under a binomial tariff structure.

As a result of the application of the proposed method in the case study, the total annual benefits provided by the BESS would represent 126% of the annual PU original energy expenses.

As demonstrated in Table 15, BESS applications do not exhibit financial viability under the existing base case circumstances. Nonetheless, according to the sensitivity analysis illustrated in Figure 21, the BESS cost emerges as the most influential factor for achieving a greater return on investment, considering that annual tariff increases exceeding 10% are infrequent (Figure 25). Additionally, CIF costs associated with local taxes can hinder economic feasibility. It is shown in Table 18 that the base case would present a positive ROI in 2026.

Taking into account the new Brazilian regulation pertaining to distributed PV systems, implications on the base case scenario would result in a decrease of 0.69% of the IRR, not significantly altering its ROI.

To assess the sensitivity of the energy tariff, the proposed method was applied with actual energy tariff components by utility companies throughout Brazil (Figure 25). Moreover, the specific annual tariff increase for each utility was considered. The new tariff components impacted Equations (28) to (39) while maintaining the remaining assumptions outlined in Table 8.

For current BESS taxation and prices, every utility presented positive ROI in 2027. Utilities that presented a higher annual tariff increase or a greater difference between off-peak and peak tariffs were the most favorable ROI. The sensitivity analysis considered the photovoltaic generation profile of the case study, located in the southern part of Brazil, which is lower than in most of other regions of Brazil.

4.5.2 BESS utilization in different scenarios

Currently, viability of BESS incorporation in a PU consumer unit in Brazil is contingent upon the geographic location of the building (primarily due to variant state taxations) and expenses such as contracted power demand should not be disregarded as it becomes more prominent as the size of the system increases.

Electricity rates analyzed for the base case are located in the first quartile amongst Brazilian energy utilities, being 59% below national average (ANEEL, 2023). This suggests that, despite the current storage market costs, BESS may have financial appeal in some regions of Brazil. Additionally, public prosumer units are optimal candidates for implementation of BESS given that they frequently include a wide range of consumer units at the municipal, state, or federal levels, allowing for maximum energy benefits for net-metering regulations. Government policies to exempt BESS taxation, even if temporary, would be extremely interesting to promote the widespread adoption of this technology.

The market for this technology is experiencing substantial growth and the outlook for 2030 is extremely positive. Recent regulatory changes affecting PV distributed generation systems involve the imposition of charges associated with the utilization of the distribution network infrastructure. Specifically, these charges pertain to the remuneration of assets and the operational costs of the distribution service.

This research indicates that the imposition of these charges will not exert a substantial impact on the viability of BESS integration.

In the Brazilian context, commercial electricity tariffs during off-peak hours are, on average, notably lower than tariffs imposed on residential consumers (ANEEL, 2023). Conversely, average peak tariffs exhibit a slight increment for commercial consumers (ANEEL, 2023). This greater rate period discrepancy for commercial consumers renders this category particularly suitable for the integration of BESS in behind the grid applications. Such integration proves advantageous for storing energy during off-peak rates for subsequent utilization during peak periods.

For commercial prosumers, the cost for implementing BESS will have to decrease for it to become feasible. Currently in Brazil, the tax burden on battery systems can reach up to 80% (GREENER, 2021). Such a high figure harms the use of BESS, even though up to 40% BESS price reductions are anticipated by the end of the decade (GREENER, 2021). Further decrease in costs could come from government applied subsidies or other tax exemptions in order to enhance BESS. There are already some examples of these incentives being presently implemented on a global scale. The United States offers investment tax credits of 30% that can add up to reach 50% of BESS costs (PVMAGAZINE, 2022). Germany offers incentives that can cover up to 30% of BESS costs (IRENA, 2021) while Australia provides solar battery interest-free loans to reduce upfront BESS costs (AUSTRALIA, 2023).

As the utilization of renewable sources expands, supplanting non-renewable energy generation, there is a heightened demand for solutions, particularly storage systems, possessing the capability to fulfill flexibility requirements and uphold grid resilience. Anticipating the future progression of the sector, three principal needs come to the forefront: the necessity for heightened regulation, integrated and adaptable sectoral planning, and economic competitiveness. Furthermore, the forthcoming opportunities in energy auctions could pose a substantial impact on maintaining a steady supply of electricity during peak demand. It is also important to note that in Brazil, low-voltage consumers must buy electricity from their local distribution utility, and that only medium-voltage consumers that have a demand contract above 500 kW can choose to enter the free energy market and have bilateral contracts for energy supply with any utility in the country.

Government entities own a sizable number of public buildings, and alongside current regulations allow generated energy to be offset amongst consumer units owned by the same entity. This enables a notable reduction in their electricity expenses. Specifically, universities have a large number of students and faculty members, presenting extensive campus areas and consequently high electricity consumption due to the various activities carried out in their buildings. University campuses throughout the world can be considered ideal consumers for the integration of PV+BESS systems, while fostering sustainability initiatives, promoting scientific research, and training of qualified human resources in the area. Presently, the Ministry of Science, Technology, and Innovation in Brazil is actively supporting projects aimed at implementing renewable energy sources in public institutions dedicated to scientific research, technology, and innovation. Solar PV generation emerges as a prominent focus for large-scale deployment within this initiative (FINEP, 2022).

Implementation of battery solutions for on-grid applications have been scarce in Brazil. Regulatory frameworks governing the deployment of BESS in the country remain absent, either for consumers in the regulated energy market or the wholesale environment. The country lacks incentive programs for such applications. The implementation of public policies concerning the regulation of behind-the-meter BESS in Brazil is imperative to harmonize costs with market supply and demand. However, all the potential and stacked benefits of BESS have to be taken into account in order to justify the substantial financial investments required. With the declining costs of batteries alongside rising electricity tariffs, increased adoption of BESS is expected in the near future. A methodology to assess the potential benefits of BESS + PV generators on public buildings is the original contribution of this thesis to the further development of these technologies, and to the advancement of science in the field.

5 CONCLUSION

This study presented a novel methodology designed to assess the economic viability associated with the integration of battery energy storage systems in public prosumer units featuring distributed photovoltaic generation in public buildings. The proposed methodology is suitable for application to consumers not only in Brazil, but in any other scenarios where time-based electricity tariffs apply.

The main and specific objectives of this thesis were met and exemplified by a case study. The consumption and generation profiles of a public PU were evaluated at a selected case location is Florianópolis, Brazil. Simulations were carried out involving the BESS operation strategically planned to maximize the utilization of surplus PV energy fed into the utility grid by the PU. The primary objective was to achieve optimal reductions in electric energy expenses through effective energy arbitrage mechanisms.

Based on the required/injected power demand and energy profiles, a BESS was specified and sized. Its charging/discharging processes were defined, considering the maximum use of the surplus of PV energy and the highest reduction of the PU's electric energy expenses. Results showed that a BESS with a nominal power of 100 kW and a storage capacity of 150 kWh would be suitable to be inserted in the PU for this particular case. The simulation of a BESS yielded favorable energy results, with annual self-consumption of the PU increasing by nearly 30%.

A sensitivity analysis was performed considering different technical and economic variables such as MRA, annual tariff increases and BESS cost. It was shown that the parameter that exerts the most influence on financial viability was found to be BESS cost, highlighting the importance of subsidy programs for this technology in the country.

The method was also able to access the impact of the modifications introduced by Law 14,300/2022, showing that it would not exert a substantial impact on the financial appeal of the return on investment associated with BESS adoption in PV-powered public prosumer units.

Furthermore, a nationwide utility sensitivity was performed to access where and under which conditions these systems would achieve tariff parity in Brazil. Throughout the prospective years until 2030, a comprehensive investigation encompassing various tariff scenarios was conducted on a national scale, incorporating considerations of tax implications on BESS costs. The findings illustrate that the fundamental prerequisites for realizing a favorable financial return on investment would be satisfied for public prosumer units situated in approximately half of the predominant distribution utilities across Brazil. This is primarily attributed to the discernible disparities between peak and off-peak energy tariffs. The results also demonstrated positive financial attractiveness for all the examined utilities in 2027, possibly even earlier should real generation profiles (for each new location) were used.

The outcomes distinctly demonstrated that the implementation of temporary Federal and State tax exemption policies on BESS would be highly advantageous in fostering the integration of this technology. The findings suggested that, in the Brazilian context, initiatives combining BESS with PV generation projects could exhibit even more pronounced financial appeal in terms of return on investment when compared to projects solely focused on PV generation. The proposed methodology contributes to an enhanced understanding of the financial feasibility associated with the incorporation of BESS in public buildings and university campuses.

This study's scope is not exhaustive, subsequent research efforts may consider taking into account certain facets and potentialities within the system application, such as:

a) Uncertainties regarding energy consumption and the solar resource. In the future, better predictability techniques for these variables can be incorporated in to the method;

b) Other BESS functions, such as control of contracted power demand, outage protection, linearization of intermittent sources and supply quality support (voltage support, frequency support, and power factor correction);

c) Assessment of novel, more discretized energy tariff schedules and their potential benefits and drawbacks;

d) Evaluate the economic assessment of BESS in the free energy market (ACL).

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Assessing the economic viability of BESS in distributed PV generation on public buildings in Brazil: A 2030 outlook

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ABSTRACT

This paper proposes a method to assess the financial attractiveness provided by adding a Battery Energy Storage System (BESS) in distributed photovoltaic (PV) generation on public buildings in Brazil. The method is applicable to prosumer units (PU) connected on the medium voltage grid operating under time-based electricity tariffs. The BESS primary objective was to achieve optimal reductions in electric energy expenses through effective energy arbitrage mechanisms. The procedural steps of the methodology begin with an analysis encompassing assessment of solar resource, PU consumption profile, and BESS sizing and operation. Subsequently, steps entail contracted power optimization, PU net-metering analysis, and evaluation of BESS impacts on electric energy expenses. Lastly, a regulatory and economic analysis is conducted incorporation considerations on BESS taxation, behind-the-meter regulations, and a sensitivity assessment extending to the 2030 outlook. By 2050, it is anticipated that PV generation will surpass hydropower, becoming the predominant component of Brazil's energy mix. This shift is expected to create an increased need for solutions, notably storage systems, capable of meeting flexibility requirements and maintaining grid resilience. The results suggest that the financial viability of incorporating BESS becomes favourable when the battery cost is below 365 $/kWh. In approximately 50% of the Brazilian territory, prevailing economic conditions support the adoption of BESS. Nationwide feasibility of integration is anticipated for the year 2027. It was observed that government policies to exempt BESS taxation, even if temporary, would be extremely interesting to promote the widespread adoption of this technology. The 2030 outlook of the transition to these benign renewable energy technologies is already in place, and will dominate the energy mix.

1. Introduction

In the context of decentralized photovoltaic solar systems (PV) implemented or integrated within buildings, the economic appeal is significantly influenced by local energy tariffs. This influence stems from the fact that the PV system serves to meet the energy requirements of the building, resulting in a reduction in the energy sourced from the utility grid and, consequently, a decrease in electricity expenses for the prosumer unit (PU). Energy tariffs typically surpass the cost of PV generation due to the inclusion of grid operation and transmission costs, taxes, and other associated components. This dynamic becomes more complex with the inclusion of time-dependent pricing systems, as solar PV output might not match energy demands and related tariffs for a particular PU. The mismatch prompts the idea of using energy storage devices as buffers to lessen variations in supply and demand.

In instances where the power output from the PV system surpasses the electrical demand of the building, an excess of power is injected into the electrical grid, equal to the disparity between the generated and demanded power. The manner in which the consumer is financially compensated in such scenarios varies, contingent upon the regulatory framework of the country. Compensation mechanisms may involve a tariff remitted to the consumer for the energy contributed to the grid (feed-in tariff) [1], or may adopt an energy compensation system where the positive surplus of injected energy into the utility grid serves to offset consumption within the same or subsequent billing periods, a practice known as net-metering [2]. The financial viability in these circumstances is intricately linked to the prevailing public policies governing the remuneration for the volume of energy integrated into the grid.

The PV energy sector has witnessed significant advancements in the past decade, characterized by heightened financial appeal attributed to

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cost reductions. Integration with energy storage systems enhances the capabilities of photovoltaics, enabling services such as energy arbitrage, augmented self-consumption from PV generation, peak demand reduction, and backup services [3]. Research indicate that PV systems integrated with energy storage exhibit enhanced cost-effectiveness compared to standalone PV systems [4]. Numerous case studies within this domain extend to both residential [5] and commercial settings [6]. When the cost of energy derived from PV coupled with BESS attains values lower than prevailing utility energy tariffs, it becomes potentially feasible for consumers to self-generate the entire or a substantial portion of their energy needs. In these cases, tariff parity has been achieved. Notably, certain regions, such as Australia and the United States, have reported instances of commercial applications of PV systems with storage attaining tariff parity in specific states [7,8]. The financial attractiveness of the combined PV + BESS configuration is contingent upon variables such as energy tariffs, mechanisms for compensating the surplus energy injected into the grid, and the initial costs associated with the storage system [9].

In recent years, there has been a notable decline in the costs associated with BESS. A substantial reduction of approximately 84% has been recorded since 2010 [10], with a comparatively moderate reduction of around 50% for large-scale systems, particularly power plants [11]. Focusing on lithium-ion battery technologies, the costs have witnessed a decrease of approximately 73%, reaching values ranging from 238 $/kWh to 787 $/kWh from 2010 to 2016 [12]. Projections indicate an anticipated further reduction in these costs by the year 2030, reaching values ranging from 145 $/kWh to 480 $/kWh, representing a potential reduction of up to 61% [13]. Furthermore, driven by heightened investments in research endeavors and the concurrent reduction in battery costs, it is anticipated that lithium-ion battery energy storage systems will exhibit a notable improvement. Projections for the year 2030 include a 50% increase in their operational lifespan and a 2% enhancement in overall efficiency [13].

An essential economic metric employed to assess the financial viability and return on investment of BESS is the Levelized Cost of Storage (LCOS). This cost metric indicates the rate ($/MWh) at which the stored energy should be discharged to neutralize system costs over its operational lifespan [14]. Projections suggest that by the year 2040, the anticipated LCOS for Li-ion batteries is poised to undergo a reduction, reaching a value of 67 $/MWh [10].

1.1. Literature review

This section presents research that uses BESS to improve the self-consumption of PV generation within building structures and provide energy arbitrage services.

For applications within the United Kingdom, Hassan et al. [15] conducted an evaluation of the operational dynamics of a PV-storage system, aiming to maximize economic benefits in a residential context. Their findings indicated that the economic viability of adopting storage systems materialized when the system cost reduced to 138 £/kWh. However, the assessment did not account for system losses. Uddin et al. [16] similarly analyzed the economic feasibility of PV-storage systems but incorporated degradation losses. Their conclusion highlighted that when the cost of degradation losses is factored in, there is an absence of economic viability for the consumer. Dong et al. [17] explored the potential of PV-storage systems within a community comprising 10 residences, concluding that storage systems cost emerged as the predominant variable influencing financial viability, with the system necessitating more than 10 years to achieve financial returns.

In Japan, Li et al. [18] assessed of BESS feasibility in 200 residences. Their findings concluded that these systems would yield a financial return of 18 years in a scenario without incentives. Yu [19] undertook an evaluation of the economic impacts associated with residential PV-storage systems in France. The study ascertained that residential PV-storage systems could potentially be economically viable before the year 2030. Furthermore, it demonstrated that operation aimed at maximizing self-consumption would exert a lesser impact on the electrical grid compared to operations involving total grid injection. In the United States, Heine et al. [20] showed that storage systems sized 1.5 times larger than necessary to meet residential peak demands exhibited optimal economic attractiveness. In Portugal, Aelenei et al. [21] examined the utilization of lithium-ion storage systems ranging from 13.5 to 54 kWh in a commercial building equipped with a 12 kWp PV system. Operating to maximize self-consumption, the 13.5 kWh system displayed superior economic viability, resulting in a 16% increase in self-consumption.

In a study by Barzegkar-Ntovom et al. [22], the economic feasibility of residential PV-storage systems was evaluated across six Mediterranean countries, considering scenarios where policies do not provide financial compensation for surplus PV energy injected into the electrical grid. The study found that at a storage system cost of 500 €/kWh, these systems were considered economically unviable. The conclusion was drawn that they would only achieve tariff parity if the costs associated with storage systems were to decrease to 150 €/kWh, presenting economically viable in Italy, Cyprus, Spain, and Portugal. Notably, the authors did not furnish building consumption profiles, opting for equal monthly average values across all countries, and degradation losses were not taken into consideration. Chaianong et al. [23] conducted an investigation into the financial returns of PV-storage systems for residential consumers in Thailand, utilizing simulated consumption and PV generation data. Their findings indicated that these systems would attain economic viability when the cost of storage systems reached 100 $/kWh. However, it is noteworthy that the authors exclusively considered self-consumption services, neglecting the potential impact of energy arbitrage services, which could potentially enhance the economic viability of such systems.

In Australian research, Talent and Du et al. [24] conducted an assessment focusing on optimizing the sizing of PV and storage systems in both residential and industrial contexts. Their findings underscored the viability of solutions that prioritize self-consumption, advocating for larger PV systems coupled with smaller storage systems. A study by Roberts et al. [25] delved into the evaluation of PV-storage systems within residential apartment buildings. The outcomes revealed that implementing storage systems ranging from 2 to 3 kWh per apartment led to a notable increase in self-consumption, reaching up to 19%, and a corresponding reduction in peak demands of the building by as much as 30%. However, it is crucial to note that the analysis did not account for degradation losses in their assessments. Li [26] investigated the sizing of PV-storage systems for 2057 residential consumers exhibiting diverse consumption profiles. The study's conclusion emphasized that higher household consumption correlates with greater final savings for the consumer. Nonetheless, it is important to highlight that degradation losses were not factored into this particular study. In a simulation study conducted by Liu et al. [27] in a commercial building in China, an operational mode was defined based on varying local energy tariff times. This approach resulted in a 15% increase in self-consumption of PV generation.

In Brazil, the annual evolution of solar PV sources in distributed generation has been increasing exponentially, reaching 24 GW of installed power in October 2023 [28]. Therefore, the use of BESS tied to these systems has great potential to become an emerging market in Brazil. There has been some research dealing with the adoption of BESS in PV systems in Brazil. Nascimento and Rüther [29] showed that the PV system is more economically viable than PV + BESS in residential applications. Lima and Feijão [30] evaluated the economic feasibility of a large PV + BESS system using deterministic and stochastic linear programming approaches. The authors showed that the difference between peak and off-peak energy tariffs is a key determinant of the financial viability of these systems. Manito et al. [31] evaluated the use of PV + BESS systems to reduce peak-hour demand on a distribution system feeder. Costa et al. [32] modeled the regulated electricity market including smart grid, distributed generation (PV and wind), and BESS technologies. Rocha et al. [33,34] evaluated the use of BESS in hybrid PV-wind projects at the distribution level and performed a review of Brazilian regulations targeting this implementation. Campos et al. [35] evaluated the complementarity of PV and wind systems and the role of BESS in power plants in Brazil. Doile et al. [36] evaluated the feasibility of hybrid PV and wind systems with BESS.

Table 1 presents an overview of the primary attributes of the PU (loads, PV system, and BESS) in the analyzed studies. The analysis revealed that the predominant focus was on assessing the incorporation of BESS in residential consumers, involving storage systems with capacities ranging from 1 to 54 kWh. Instances where electric vehicles were integrated into the load exhibited relatively modest capacities, not surpassing 24 kWh.

Despite the attention given to the economic feasibility of these systems in numerous studies, existing methodologies tend to overlook the influence of expenses related to contracted power demand and commonly disregard battery degradation. This oversight could potentially result in an overestimation of the reported outcomes.

Furthermore, a limited number of studies utilized net-metering compensation schemes, and some studies omitted compensation mechanisms from their evaluations, intending to determine viability regardless of local policy influences.

An absence was observed of methodologies for assessing the integration of BESS in PU's based on techniques for measuring the electric energy demand and photovoltaic generation data, obtained through energy meters installed at the frontier between the utility's grid and the PU. In Brazil, public entities (Federal, State, and Municipal) often occupy numerous buildings supplied with both low voltage (LV) and medium voltage (MV) grid, typically procuring their energy from the regulated market. Moreover, research focused on the technical evaluation of BESS integration for energy arbitrage services and enhancing self-consumption in public buildings equipped with PV systems and electric vehicles, while examining their financial attractiveness until 2030, remains inadequately explored in the country.

Therefore, the main contributions of this study are as follows:

- Method for the adoption of BESS in public buildings with integrated PV systems based on techniques for measuring the electric energy demand and the surplus PV energy injected by the PU into the grid.
- The proposed model takes into account a methodology for optimizing the contracted power demand in public prosumers. By this means, the effect of BESS systems is investigated without neglecting power costs.
- A multi criteria sensitivity analysis is performed and the impact of rising electricity tariff scenarios, falling battery prices and public incentives is investigated.
- A techno-economic analyses is made between BESS equipped public buildings under public regulations in Brazil. By this means, the discounted payback, net present value (NPV), internal rate of return (IRR), and LCOS of BESS in public prosumers is investigated.
- Model for BESS implementation in public prosumers applied to all geographical states in Brazil in order to identify the optimal locations for these systems currently and up to the 2030 outlook.

2. Method

This paper proposes a method for assessing the financial attractiveness provided by the adoption of BESS in PU in public buildings. The method is applicable to prosumer units connected on the medium voltage grid. The study was subdivided into distinct steps, as illustrated in Fig. 1.

2.1. Solar radiation resource analysis

The evaluation of the solar radiation resource at the BESS integration site involves comparing measured daily average global horizontal irradiation (GHI) values with data obtained from NASA [37,38], NREL [39,40], and the Brazilian Solar Energy ATLAS [41] databases.

2.2. BESS sizing and operation

Fig. 2 illustrates the schematic diagram depicting the load, PV system, and BESS of the PU. The BESS operation aims to optimize the utilization of surplus PV energy, which would otherwise be fed into the utility's grid by the PU, and the final electricity expenses. Considering the disparity in electricity tariffs (with peak-hour kWh costs approximately 3.2 times higher than off-peak hours) [42], the BESS stores surplus PV energy generated during off-peak hours and discharges it entirely to the utility's grid during peak hours.

Both the BESS and the electric utility function to supply or absorb energy from the PU. The local utility acts as a backup to provide electricity in case the PV system and the BESS are unable to meet the PU's power demand. The selected technology for the BESS was lithium-ion (NMC) due to its extended lifespan, enhanced flexibility in charge state, and reduced losses. The BESS was configured considering the PU requested/injected power demand profiles, adhering to the constraints of a 20% State of Charge (SoC), 80% Depth of Discharge (DoD), 88% efficiency, and 6000 cycles durability at DoD.

Table 1
Overview of the primary attributes of the PU (loads, PV system, and BESS) in the analyzed studies.

Ref.	Loads			PV System		BESS		Contracted Power Optimization
	Non-Residencial	Measured data	Electric Vehicle	Measured data	Net-metering scheme	Measured data	Considers degradation losses	
[15]	–	–	–	–	–	–	–	–
[16]	–	✓	✓	✓	–	✓	–	–
[17]	–	–	–	–	–	–	✓	–
[18]	–	✓	–	–	–	–	–	–
[19]	–	–	–	–	–	–	–	–
[20]	–	–	–	–	✓	–	✓	–
[21]	✓	✓	–	✓	✓	–	–	–
[22]	–	–	–	–	–	–	–	–
[23]	–	–	–	–	–	–	–	–
[24]	✓	✓	–	–	–	–	–	–
[25]	–	✓	–	–	–	–	–	–
[26]	–	✓	–	–	–	–	–	–
[27]	✓	–	–	–	–	–	✓	–
[29]	–	✓	–	–	✓	–	–	–
This work	✓	✓	✓	✓	✓	–	✓	✓

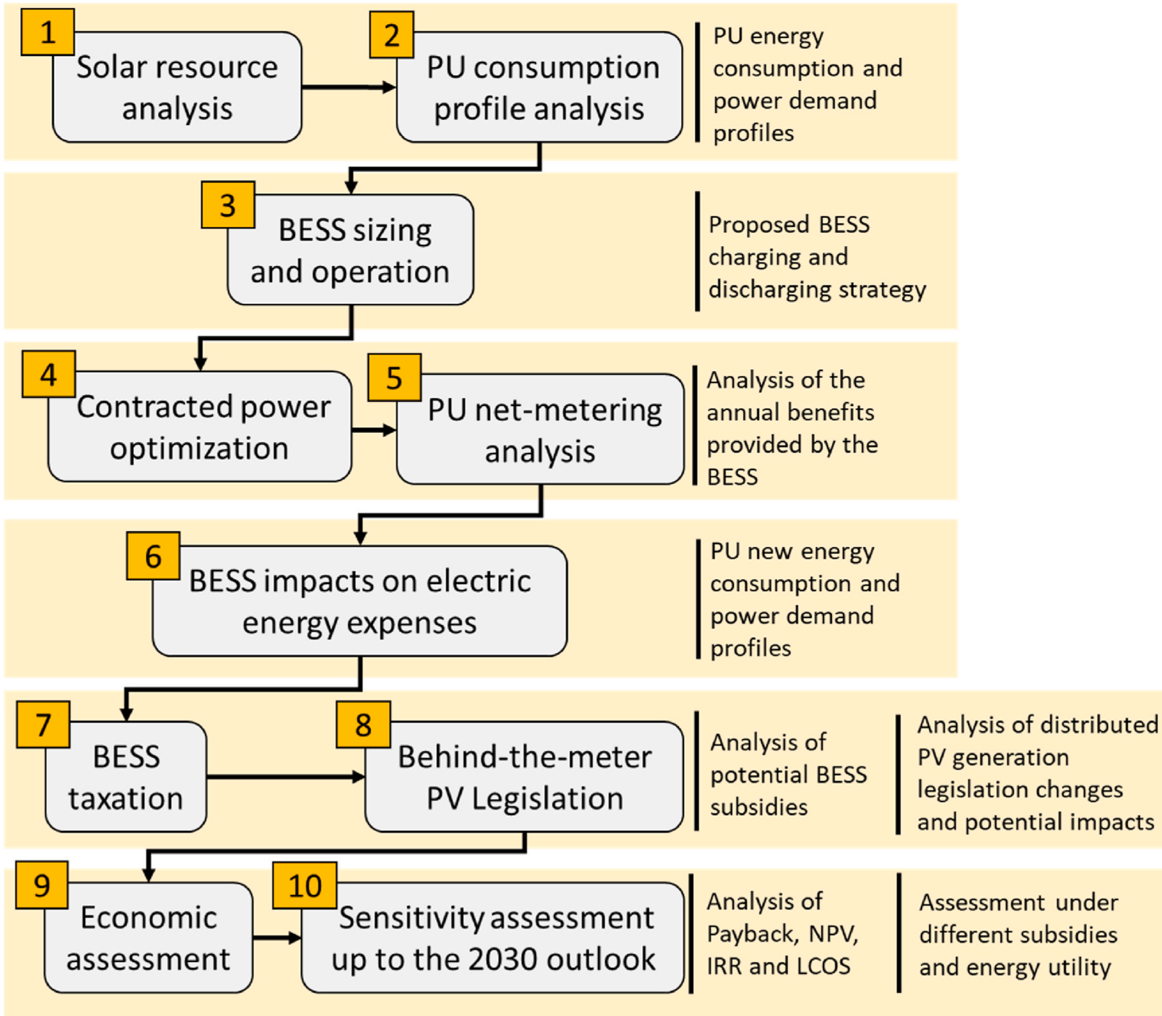

Fig. 1. Flowchart depicting the procedural steps of the methodology.

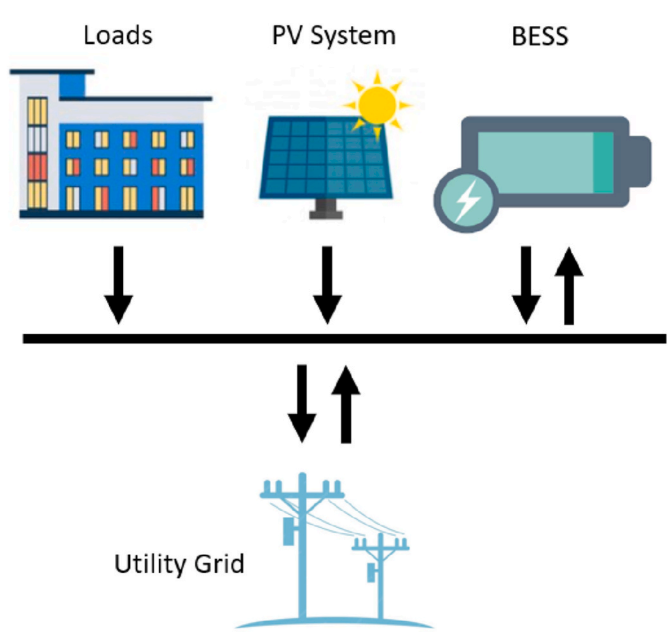

Fig. 2. Schematic diagram depicting the load, PV system, and BESS of the PU.

Uddin et al. [16] and Yoshida et al. [43] highlighted the significance of considering degradation losses in BESS, as it significantly impacts the financial feasibility of these systems. The degradation per cycle model for NMC batteries, employed in this study, was formulated by Smith et al. [44] and serves as a reference in technical and economic assessments by the USA-DOE's National Renewable Energy Laboratory (NREL) [45].

The maximum BESS charging/discharging power is determined in order to accommodate the PU's peak demand. The storage capacity of the BESS is specified by Eq. (1). An adjustment factor is introduced to optimize financial returns, considering the disparities between off-peak and peak tariffs.

$$E_{BESS} = \frac{C_{Peak} * 1.3}{BD * DoD} \tag{1}$$

where:

E_{BESS} = BESS storage capacity [kWh];
C_{PEAK} = Máximum monthly peak consumption [kWh];
BD = Number of business days;
DoD = Depth of Discharge [%];

The BESS operation was configured to maximize the utilization of surplus PV energy injected by the PU into the utility grid and to achieve the greatest reduction in the PU's electricity expenses through energy arbitrage. Its operation is elaborated for the following configurations:

- Off-Peak A: Throughout the business day, the BESS would be charged by the surplus PV energy that would be injected into the utility's grid by the PU.
- Off-Peak B: If it is not possible to fully charge the BESS with the surplus PV energy that would be injected into the utility's grid, supplementary charging will be carried out using electricity supplied from the utility's grid. Consequently, only the surplus PV energy that cannot be immediately consumed (self-consumed) or stored (BESS) will be directed into the grid.
- Peak A: The BESS discharge process is carried out with the objective of achieving the maximum reduction in the PU's electricity expenses, primarily by offsetting the building's energy consumption.
- Peak B: The BESS fully discharges its remaining energy at nominal power.

The insertion of the BESS into the PU implies new power demand profiles (injected/required from the utility grid), which can be derived from the original power demand profiles and BESS operation (charging/discharging process). Fig. 3 summarizes the proposed BESS operation strategy.

2.3. Annual benefits provided by the BESS

In order to evaluate the financial benefits, the PU power demand and energy expenses were calculated before and after the adoption of the

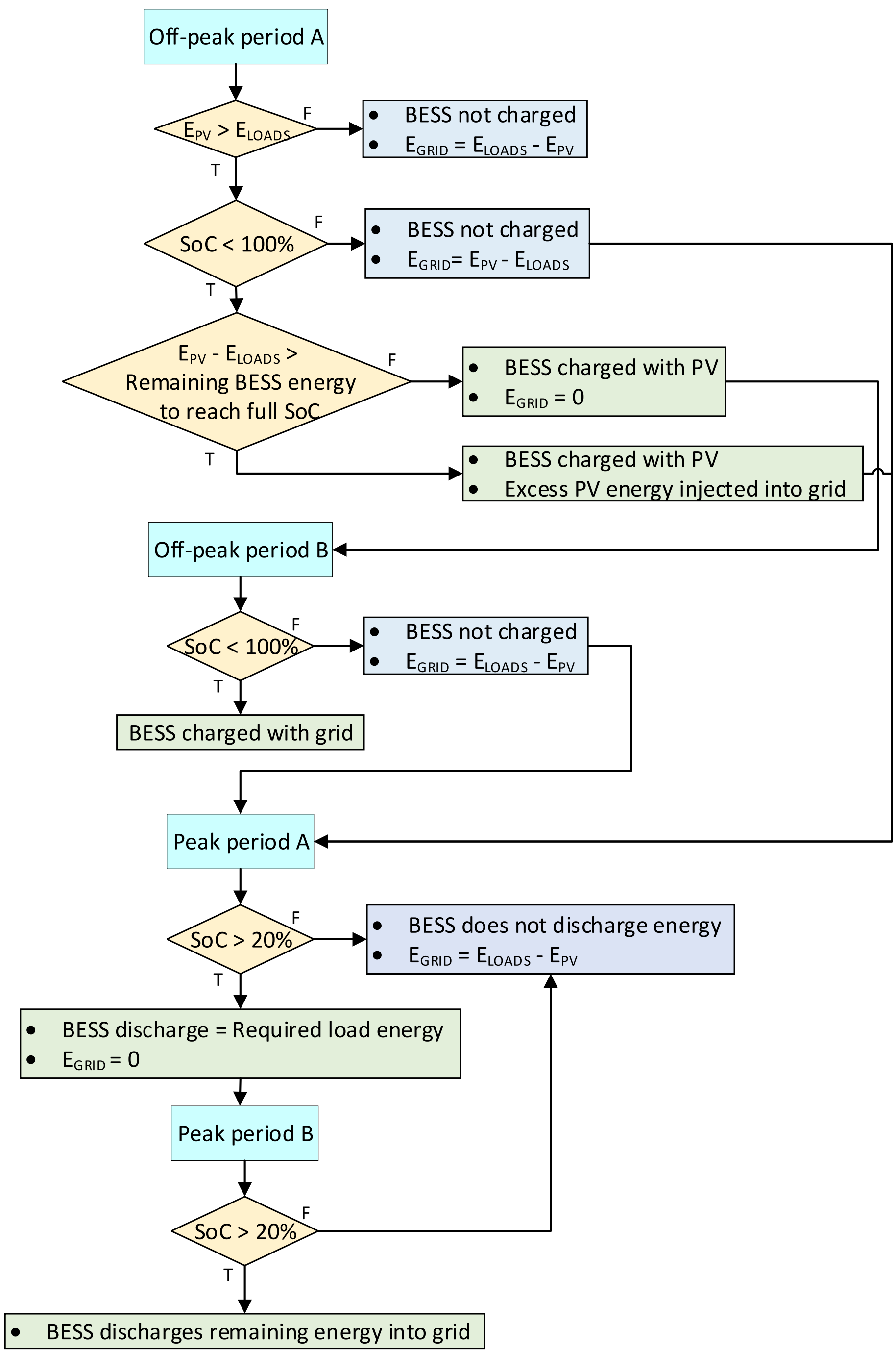

Fig. 3. Proposed BESS operation strategy.

BESS. Additionally, due to the possibility of compensation of surplus of electric energy (injected into the utility grid) into other University consumer units (CU) as allowed by the Brazilian Regulation, the reduction in energy expenses of CU fed in low-voltage (LV) and MV were evaluated.

2.3.1. PU contracted power

Power demand contracting in Brazil adheres to the guidelines of REN 1000/2021 [46], such as allowing only one reduction/increase in contractual demand every 12 months and charging an overuse fee when the measured power demand is larger than 5% of the contracted demand. In the latter case, the utility will charge double the tariff on the surplus amount.

In the process of optimizing the contracted power, the adopted methodology considered that the set of possible power demand values to be contracted, in the analyzed period (1 year), can vary from a minimum value equal to the PV power installed at the PU [46] to up to 120% of the original maximum measured power demand (injected or required from the utility), in intervals of 2% of the respective measured average power demand (injected or required), as shown in Eq. (2). The objective is to optimize D_k^c. Eq. (3) presents the new power demand value to be billed by the utility while Eq. (4) presents the utility charge for excess power demand.

$$D_k^c = \left[D_{LL}^c, \ldots, D_{UL}^c\right] \begin{cases} D_{LL}^c = P_{PV} \\ D_{UL}^c = (1.2)\,.D_{a,max}^m \\ \Delta D^c = (0.02)\,.D_{a,avg}^m \end{cases} \tag{2}$$

$$\text{Conditions}: \begin{cases} D_{LL}^c \geq 30\ \text{kW} \\ D_{k+1}^c < D_k^c\ \text{:only once} \end{cases}$$

$$DF_k = \begin{cases} D_k^m\ ;\ if\ D_k^m > D_k^c \\ D_k^c\ \ ;\ if\ D_k^m < D_k^c \end{cases} \tag{3}$$

$$Cred_{(i)}^j = \begin{cases} Inj_{(i)} + Cred_{(i)}^{j-1} + Cred_{(q)}^j - Cons_{(i)} & if\ : Inj_{(i)}{}^j + Cred_{(i)}^{j-1} + Cred_{(q)}^j > Cons_{(i)} \\ 0 & if\ : Inj_{(i)}{}^j + Cred_{(i)}^{j-1} + Cred_{(q)}^j \leq Cons_{(i)} \end{cases} \tag{6}$$

$$DU_k = \begin{cases} \left[2\,.\left(D_k^m - D_k^c\right)\,.TD_k\right]\ ;\ if\ D_k^m > (1.05)D_k^c \\ 0\ \ ;\ if\ D_k^m \leq (1.05)D_k^c \end{cases} \tag{4}$$

where:

D_{LL}^c = Contracted power lower limit [kW];
P_{PV}=PU PV installed power [kW];
D_{UL}^c = Contracted power upper limit [kW];
ΔD^c = Progression ratio for contracted power values;
D_{max}^m = Annual maximum measured power demand [kW];
D_{avg}^m = Annual average measured power demand [kW];
D_k^c = Possible contracted power demand values for the year [kW];
DF_k = Billed power demand [kW];
D_k^m = Measured power demand values for billing period k [kW];
DU_k = Excess power demand [\$];
TD_k = Power demand tariff (without taxes) for billing period k [\$/kW].

In this work, four scenarios for monthly power demand contracting were analyzed, as following: a) Single level: Applies to PU with little or no variation in measured power demand over the analyzed period; b) Two levels: Normally applied to PU with seasonal variation of demand. Contracting of two demand values throughout the year, one for the period of higher demands and another for the period of lower demands; c) Three levels: Contracting option that more accurately models the load curve of the PU, resulting in three values of demand to be contracted throughout the year; d) Four levels: This contracting modality demands from the consumer an even greater dynamic in performing (with the utility) the contractual amendments for four demand values. This modality can be very advantageous to the consumer if the utility accepts the proposed changes in demand, throughout the analyzed period, without proposing additional costs of upgrading the public distribution system.

2.3.2. PU net-metering

In Brazil, grid-connected PV installations up to 3 MW can operate under a net-metering system, in which the consumer receives an energy credit referring to the amount of energy injected into the utility grid. The compensation of the surplus of PV energy injected into the grid meets the regulatory prescriptions in place in the country [46,47], being first compensated in the tariff period (off-peak/peak) in which it was generated.

For the PU and the billing period (monthly), the surplus PV energy to be compensated (kWh) and the new energy credits can be calculated using Eq. (5). If the injected surplus PV energy added to the remaining credits from the previous billing period is greater than the consumed energy, a non-zero value of new energy credits created in the respective billing period is obtained, as shown in Eq. (6). Eq. (7) presents the compensated energy cost for the billing period. The new energy credits generated (Eq. (6)) can be used for compensation at another tariff period (q), provided that the conversion is performed, as indicated in Eq. (8).

$$C_{(i)}{}^j = \begin{cases} Cons_{(i)} & if\ : Inj_{(i)}{}^j + Cred_{(i)}^{j-1} + Cred_{(q)}^j \geq Cons_{(i)} \\ Inj_{(i)} + Créd_{(q)}^j + Cred_{(i)}^{j-1} & if\ : Inj_{(i)}{}^j + Cred_{(i)}^{j-1} + Cred_{(q)}^j < Cons_{(i)} \end{cases} \tag{5}$$

$$Cost_{(i)}{}^j = C_{(i)} * TC_{(i)}{}^j \tag{7}$$

$$Cred_{(q)}^j = Cred_{(i)}^j * AF = Cred_{(i)}^j * \frac{TE_{(i)}}{TE_{(q)}} \tag{8}$$

where:

$C_{(i)}^j$ = Compensated energy in tariff station i, for billing period j [kWh];
$Cons_{(i)}$ = Consumed energy in tariff station i, for billing period j [kWh];
$Inj_{(i)}^j$ = Injected energy in tariff station i, for billing period j [kWh];
$Cred_{(i)}^{j-1}$ = Remaining energy credits from billing period before j in tariff station i [kWh];
$Cred_{(i)}^j$ = New energy credits in tariff station i, for billing period j [kWh];
$Cred_{(q)}^j$ = New energy credits in tariff station q, for billing period j [kWh];
j = Billing period;

i = Off-peak or peak;
q = Opposite of i;
$Cost_{(i)}{}^{j}$ = Compensated energy cost, in tariff station i, for billing period j [$];
$TC_{(i)}{}^{j}$ = Compensation tariff, in tariff station i, for billing period j [-$/kWh];
AF = Tariff adjustment factor;
$TE_{(i)}$ = Energy component, without taxes, in tariff station i [$/kWh];
$TE_{(q)}$ = Energy component, without taxes, in tariff station q [$/kWh]

The remaining credits for the following billing period are created by applying Eq. (8) again with the inverse AF at the end of the compensation cycle and following the instructions of Eqs. (5)–(7) for compensation in tariff period "q". In the "remote self-consumption" mode, these credits can be consigned to other Consumer Units under the same ownership or used in the own PU.

Two instances of utilization of the remaining credits at the end of each billing period are examined. Remaining credits are compensated in one of two ways: either at the UFSC main campus (fed in MV) or at other CU (owned by UFSC), fed in LV. During the time period under consideration, UFSC owned 83 CUs, of which 23 were fed at MV (13.8 kV) and the remaining (60) at LV (2.3 kV). The main campus (MV), the largest UFSC CU during the examined period, displayed annual consumption of 15.5 GWh [48]. All of the CU's feed in LV during that time were small and consumed a combined 0.74 GWh annually [48].

2.3.3. PU electric energy expenses

Eqs. (9)–(11) present the PU electricity expenses in the green hour tariff scheme modality.

$$X_D = \sum_{j=1}^{12} \left[(DF_k . TD_k) + (TU_k \ . DU_k) + (TN_k \ . DN_k) \right] \tag{9}$$

$$X_E = \sum_{j=1}^{12} \left(CE_k^{OP} . TE_k^{OP} - C_k^{OP} . TC_k^{OP} \right) + \left(CE_k^{P} . TE_k^{P} - C_k^{P} . TC_k^{P} \right) \tag{10}$$

$$VF^V = X_D + X_E \tag{11}$$

where:

X_D = Annual power demand expenses, [$];
DN_k = Non-utilized power demand for billing period j [kW];
TN_k = Non-utilized power demand tariff for billing period j [$/kW];
TU_k = Excess power demand tariff [$];
X_E = Annual energy expenses, [$];
CE_k^{OP} = Off peak energy consumption for billing period j [kWh];
CE_k^{P} = Peak energy consumption for billing period j [kWh];
TE_k^{OP} = Off peak energy tariff for billing period j [$/kWh];
TE_k^{P} = Peak energy tariff for billing period j [$/kWh];
C_k^{OP} = Off-peak compensated energy for billing period j [kWh];
C_k^{P} = Peak compensated energy for billing period j [kWh];
TC_k^{OP}= Off peak energy compensation tariff, for billing period j [$/kWh];
TC_k^{P} = Peak energy compensation tariff, for billing period j [$/kWh];
VF^V = Annual bill [$]

2.3.4. Remote self-consumption

The benefits provided by remote self-consumption of the remaining energy credits in other UFSC CU (fed in LV and MV) after each PU billing period are presented by Eqs. (12) and (13).

$$B_{MV} = CR_{(i)} * \ TC_{(i)} \tag{12}$$

$$B_{LV} = \left(CR_{(OP)} + \left(CR_{(P)} * AF \right) \right) * \ TC_{(OP)} \tag{13}$$

where:

B_{MV} = Financial benefits from remote self-consumption in MV fed CU [$];
B_{LV} = Financial benefits from remote self-consumption in LV fed CU [$];
$CR_{(i)}$ = Remaining energy credits after in tariff station i (off-peak or peak) [kWh].

2.4. BESS annual expenses

The annual expenditures associated with the installation of the BESS in the PU include charges for its operation and upkeep throughout the course of its lifespan, reinvestments associated with inverter replacements after ten years, and potential annual increases in the PU power demand costs.

2.5. BESS taxation

Energy storage systems using Li-ion batteries are within the Mercosur common nomenclature NCM 8507.60.00, having the following federal taxes applied on the CIF value (Cost, Insurance and Freight) for their importation into Brazil: a) Import tax (II): A federal tax, which, as of April 1, 2022, sets its rate at 9% [49,50]; b) Tax on industrialized products (IPI): Federal tax, for Li-ion electric accumulators at 11.25% [51]; c) Tax on the Social Integration Program (PIS) and on the Contribution to Finance Social Security (COFINS): In this case, the rates are 2.1% and 9.65%, respectively [52].

After applying the federal taxation on the CIF value, the state taxation referring to the Tax on Circulation of Goods and Services (ICMS) is applied on the resulting value. Li-ion battery energy storage systems are classified as "other" operations and services (general), with a tax rate of 17% [53].

2.6. New brazilian legislation for distributed PV generation

Eqs. (14) and (15) show the composition of the current tariffs (without taxes) and Eq. (16) shows the composition of the energy tariff applied to the consumer (with taxes).

$$TUSD_{(i)}{}^{j} = Wire\ A + Wire\ B + Charges + Losses \tag{14}$$

$$TE_{(i)}{}^{j} = Energy + Charges \tag{15}$$

$$T_{(i)}{}^{j} = \frac{TUSD_{(j)} + TE_{(j)}}{(1 - PIS(\%) - COFINS(\%)) * (1 - ICMS(\%))} \tag{16}$$

where:

$TUSD_{(i)}{}^{j}$ = Distribution system usage tariff, without taxes, in tariff period i, for billing period j [$/kWh];
$Wire\ A$ = Unit costs related to the maintenance and operation of the transmission lines [$/kWh];
$Wire\ B$ = Unit costs of using the infrastructure of the utility's distribution network [$/kWh];
$Charges$ = Unit costs to enable the implementation of public policies in the electricity sector [$/kWh];
$Losses$ = Unit corresponding to technical and non-technical system losses [$/kWh];
$TE_{(j)}$ = Energy tariff, without taxes, in tariff period i, for billing period j [$/kWh];
$Energy$ = Unit costs for energy acquisition [$/kWh];
$T_{(i)}{}^{j}$ = Tariff applied to the consumer, with taxes, in tariff station i, for billing period j [$/kWh];

As of Supplementary Law No. 194/2022 [54], the maximum ICMS tax rate on electricity is limited to the rate charged on general transactions in each state (17–18%). Additionally, the law defines the non-incidence of ICMS tax on the maintenance and operation of the transmission lines and charges related to electricity transactions.

The National Council of Finance Policy (CONFAZ), through ICMS Agreement 16/2015 [55], allowed for the exemption of ICMS levied on electricity supplied by the utility to the CU on credits generated from feeding energy into the grid. That is, the ICMS exemption falls on the amount corresponding to the sum of the electric energy fed into the grid with the energy credits originating in the CU itself. On January 6, 2022, the Legal Framework for Distributed PV generation was sanctioned in the country, through Law No. 14,300 [47]. The law will come into effect 12 months after its publication. Systems installed and registered before this date will remain under the regulatory regime of REN 482/2012 [56] until December 31, 2045, and after this date all systems will be under the regulation of the new legislation. The new law created a more solid legal and regulatory framework, providing the developing market with legal security, stability, and predictability. By protecting the consumer's right to produce their own energy and recognizing distributed generation as a strategy for the country's energy policy, it seeks to safeguard investments already made and offer more predictability of return on future investments.

Eq. (17) shows the energy compensation tariff for the situation arising before Law 14,300 takes effect, and Eq. (18) shows its revised structure following the law's implementation. The main difference concerning the old legislation will be that the compensation tariff will no longer include the "Wire B" portion of the $TUSD^j_{(i)}$, reducing the value of the compensated electric energy. Starting in 2023, as shown in Table 2, the Wire B portion of the compensation tariff will be reduced gradually on an annual basis until 2029.

$$TC_{(i)}{}^{j} = T_{(i)}{}^{j} - ICMS_{(TUSD)} \tag{17}$$

$$TC_{(i)}{}^{j} = T_{(i)}{}^{j} - ICMS_{(TUSD)} - \ Wire\ B \tag{18}$$

2.7. BESS economic assessment

Economic measures including Discounted Payback, Net Present Value (NPV), Internal Rate of Return (IRR), and Levelized Cost of Storage (LCOS) will be used to assess the financial attractiveness of the return on investment of adopting BESS in a PV-powered PU.

The Discounted Payback is defined as the period to recover the initial investment using a discount rate before the cash flows are summed. This will usually be the Minimum Rate of Attractiveness (MRA). In this method, all future cash flows should be discounted by this rate over the period to which the flow is tied. The MRA is an interest rate that represents the minimum an investor stands to gain when investing, or the maximum an individual stands to pay when taking out a loan. Applying methods of comparison across time, such as the NPV, is important when utilizing the MRA to assess an investment's financial feasibility.

Future cash flows are added together to create present value, which is then discounted using a discount rate that reflects the required minimum return. The computation of the present value for year k is shown in Eq. (19). According to Eq. (20), the NPV is the present value at the conclusion of the period analyzed.

$$P(k) = -I + \sum_{k=0}^{N} \frac{(R_k - C_k)}{(1 + MRA)^k} \tag{19}$$

$$NPV = P(N) \tag{20}$$

where:

$P(k)$ = Present value of year k [$];
R_k = Revenue from year k (benefits) [$];
C_k = Costs from year k (expenses) [$];
N = BESS lifespan;
I = Initial investment.

The IRR is the hypothetical discount rate that, when applied to a cash flow, causes the investment returns brought to present value to equal the amount invested, i.e., NPV = 0. as shown in Eq. (21).

$$0 = -I + \sum_{i=0}^{N} \frac{(R_k - C_k)}{(1 + IRR)^k} \tag{21}$$

The LCOS (Eq. (22)) shows the average rate at which the energy stored in the BESS should be discharged in order to completely offset the lifetime expenditures of the system [57].

$$LCOS = \frac{\sum_{t=1}^{t=n} \left[\frac{I + O\&M_n}{(1+MRA)^n} \right]}{\sum_{t=1}^{t=n} \left[\frac{BESSc\ (n)}{(1+MRA)^n} \right]} \tag{22}$$

where:

$O\&M\ (n)$ = BESS operation and maintenance cost per cycle [$];
$BESSc\ (n)$ = BESS storage capacity per cycle (considering degradation) [kWh];
n = Number of cycles in its useful life;
t = Number of cycles used.

In this work, sensitivity analyses of the financial attractiveness of the return on investment of the adoption of a BESS in the PV-powered PU were carried out regarding the following factors: a) Evolution of BESS costs; b) Evolution of the interest rate (MRA); c) Evolution of tariffs annual increase; d) Exemption of BESS federal and state taxes; e) Impacts of the new legislation, f) Different tariffs in place.

3. Results

3.1. Base case description

While the methodology adopts a generalist approach that is applicable to any Public PU, practical illustration and validation were conducted using real data from a specific PU at the Universidade Federal de Santa Catarina (UFSC) in Florianópolis, Brazil (48° W, 27° S). This particular public building is supplied by the utility grid at a medium voltage (MV) level of 13.8 kV. Global horizontal irradiation (GHI), power demand consumption, and power injected into the grid were measured onsite during the timeframe spanning April 2017 to March 2018.

3.1.1. Solar radiation resource

In accordance with the Köppen-Geiger climate classification [58], the PU is situated within a humid subtropical climate (Cfa), characterized as oceanic, devoid of a dry season, featuring hot summers. Table 3 illustrates the monthly progression of daily mean GHI measured on site for the analyzed period and GHI values derived from NASA, NREL and Brazilian Solar Atlas databases.

Despite being in the region with the lowest solar irradiation levels in Brazil, solar energy resource is abundant and well distributed throughout the year, indicating substantial potential for the utilization

Table 2
Wire B reduction from 2022 to 2030.

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030
TUSD Wire B reduction	0%	15%	30%	45%	65%	75%	90%	100%	100%

Table 3
Daily GHI for Florianópolis-Brazil (kWh/m^2).

Month	Apr	May	Jun	Jul	Aug	Set	Oct	Nov	Dec	Jan	Feb	Mar	Year
NASA	4.0	3.1	2.7	2.9	3.5	3.9	4.5	5.5	5.8	5.9	5.5	4.9	4.3
NREL	3.9	3.3	3.0	3.0	3.5	4.2	5.2	5.9	6.0	5.8	5.5	5.0	4.5
ATLAS	3.9	3.1	2.6	2.7	3.4	3.7	4.6	5.8	6.2	6.1	5.7	5.0	4.4
Measured	3.7	3.2	2.2	3.5	3.5	4.1	5.1	6.5	5.7	5.6	5.6	4.5	4.4

of solar PV energy. Measured values are observed to vary from 2.2 to 4.1 kWh/m^2/day (April to September) and from 4.5 to 6.5 kWh/m^2/day (October to March) throughout the year. The yearly measured GHI was 4.4 kWh/m^2, which is very similar to values found in multiple databases. Brazil's daily average solar irradiation availability exhibits interannual fluctuation of about 6% [41], indicating that the measured values are adequate.

3.1.2. PU power demand and energy consumption profiles

The UFSC Solar Energy Research Laboratory is fed by the local utility grid in medium voltage (MV) (13.8 kV). It acquires electrical energy under a green hourly scheme, featuring distinct energy tariffs for off-peak and peak hours (18:30 to 21:30), weekdays and weekends, with a unified tariff for power demand. The laboratory features various solar PV technologies, including 13.5 kW (CIGS) in the car parking lot, 66.2 kW (p-Si) and 13.5 kW (a-Si/μc-Si) on the roofs of the buildings, 2.4 kW (CdTe) at the e-Bus charging station, and 10 kW (a-Si/p-Si/μc-Si) on the ground, as illustrated in Fig. 4. The total installed PV power at the PU is 105 kW.

The PU comprises primarily two buildings and an electric bus (e-Bus). Prominent electrical loads include transformers, air conditioning units, general-purpose outlets, LED lighting systems, numerous personal computers, a database and internet server, and the e-Bus charging station. On weekdays the e-Bus conducts five round trips, transporting students and staff between the main campus and the Laboratory along a 52 km route, initiating its charging at specific times: 08:00, 10:30, 13:00, 16:00, and approximately 18:45.

Table 4 presents, for the PU and for peak and off-peak hours, the monthly evolution of requested energy and maximum injected/requested power from the grid.

The results indicate that the maximum power demand ranged between 85 kW (February) and 93 kW (July). The annual energy consumed was approximately 77 MWh, of which 78.7% (60.6 MWh) was consumed during off-peak hours and 21.3% (16.3 MWh) during peak hours.

3.1.3. BESS configuration and operation

Table 5 displays the specified BESS technical information and Table 6 shows the summary of the proposed BESS and grid operation.

The incorporation of the BESS in the PU was evaluated considering

Fig. 4. The UFSC Solar Energy Research Laboratory's existing solar PV generators.

the previously described e-Bus operation (normal operation) and its last daily full charge during off-peak hours (09:31 p.m. to 10:30 p.m.).

3.2. BESS impacts on electric energy expenses

The variables used to analyze the financial attractiveness of the ROI (Return On Investment) of BESS adoption are shown in Table 7.

3.2.1. PU power demand

The financial impact on power demand was assessed by comparing the power demand expenditures of the PU before and after the implementation of a BESS. Table 8 summarizes the monthly evolution of the power demand to be contracted after BESS adoption. For each simulated profile, the computation of annual expenses revealed that contracting power demand in four tiers (January to May, June to October, November, and December) is the optimal solution leading to the lowest annual expenditure.

The difference between expenses considering the lowest contracting cost (four levels) and the highest (one level) was 8%. The contracted power demand values would be 112 kW from January to May, 114 kW from June to October, 123 kW in November, and 142 kW in December. All subsequent analyses in this study will be conducted based on the proposed contracting of power demand in four levels.

During the analyzed timeframe, Fig. 5 illustrates the progression of power demand expenses (without taxes) for the recommended power demand contracting in four levels. Table 9 displays the monthly evolution of power demand expenses before and after the adoption of BESS. Both the optimal power demand contracting (four-levels) and the contracting of a single level of 105 kW (scenario without BESS) were investigated. The annual power demand expenditure, before BESS analysis, was approximately $4773.00. After the BESS simulation the PU annual power demand expenditure would be $5503.00, representing an increase of $730.00 (13.3%).

3.2.2. PU electricity expenses and energy credit benefits

The expenses incurred during both off-peak and peak hours, before and after the BESS adoption, were compared to evaluate the financial implications of the BESS on energy utilization. Furthermore, the annual costs and benefits entitled to the PU, both before and after the BESS adoption, were computed, considering the potential compensation for surplus energy injected into the grid. Table 10 presents, for the base scenario (without BESS and with normal e-Bus operation), the PU monthly evolution of energy consumption and electricity expenses without and with the adoption of the BESS. Additionally, it presents the option for the base scenario with the BESS (Option 1) and considering e-Bus shifted last charge taking place at off-peak hours (Option 2).

In the absence of BESS, the PU exhibited an annual consumption of 60.6 MWh during off-peak hours, incurring expenses totalling $4956.47. Concurrently, during peak hours, the consumption was 16.36 MWh, leading to annual expenses amounting to $4277.80. When considering the adoption of the BESS, the annual PU consumption would undergo modifications, amounting to 64.87 MWh during off-peak hours and 0.5 MWh during peak hours. This translates to annual costs of $5305.80 and $136.07, respectively. The annual cost would exhibit an increase of $349.32 (7%) during off-peak hours and a decrease of $4141.73 (97%) during peak hours following the implementation of BESS.

Upon implementing BESS and accounting for the e-Bus shifted last

Table 4
Monthly evolution of requested energy and maximum injected/requested power from the grid.

Month	Apr	May	Jun	Jul	Aug	Set	Oct	Nov	Dec	Jan	Feb	Mar
Peak consumption	1465	1435	1598	1563	1485	1425	1509	1753	1372	352	574	1834
Off-peak consumption	5347	5910	6348	5105	5209	5028	4791	4972	4219	3643	3338	6692
Peak demand	87.17	87.60	87.17	93.65	89.18	89.18	88.85	88.75	89.42	85.30	86.83	88.90
Off-Peak demand	90.10	89.09	88.90	88.75	89.23	86.45	90.24	87.74	89.81	88.70	85.34	96.29
Off-Peak injected	64.90	56.69	46.90	53.14	60.14	61.10	71.86	72.53	71.14	69.07	67.10	58.22

Table 5
Proposed BESS technical data.

Variable	Value	Unit
Rated storage capacity	150	kWh
Rated charge/discharge power	100	kW
Roundtrip efficiency	88	%
Lifespan	6000 cycles @ 80% *DoD*	
Minimum SoC	20 %	

Table 6
Summary of the proposed BESS and grid operation.

Time period	System point	Operation	Operational values
Off-peak period A: 05:01 to 17:15	Grid BESS	Injected Charge	Fixed power = 0 kW Power range (between min and max of surplus PV power <100 kW)
Off-peak period B: 17:16 to 18:30	BESS	Charge	Fixed power = 100 kW
Peak period A: 18:31 to 20:30.	Grid BESS	Consumption Discharge	Fixed power = 0 kW Power range (between min and max of PU required power)
Peak period B: 20:31 to 21:30	BESS	Discharge	Fixed power = 100 kW

Table 7
Variables assumed for economic assessment.

Variable	Value	Unit	Reference
BESS cost (I)	550	$/kWh	[59]
Annual O&M expenses	0.5	% of I	[59]
BESS inverter reinvestment cost after 10 years	15	% of I	[59]
MRA	6	%	[59]
Tariff annual increase	5.2	%	[60]
Off-peak energy tariff (MV)	0.0818	$/kWh	[42]
Peak energy tariff (MV)	0.2614	$/kWh	[42]
Power demand tariff (MV)	3.9175	$/kW	[42]
Non-utilized power demand tariff (MV)	3.0576	$/kW	[42]
Excess power demand tariff (MV)	7.8369	$/kW	[42]
Tariff adjustment factor (Off-peak to peak)	0.604		Calculated
Tariff adjustment factor (Peak to off-peak)	1.657		Calculated
Off-peak compensation tariff (MV)	0.0809	$/kWh	Calculated
Peak compensation tariff (MV)	0.2606	$/kWh	Calculated
Compensation tariff (LV)	0.1179	$/kWh	Calculated
Off-peak compensation tariff post Law 14,300 (MV)	0.0809	$/kWh	Calculated
Peak compensation tariff post Law 14,300 (MV)	0.1543	$/kWh	Calculated
Compensation tariff post Law 14,300 (LV)	0.0962	$/kWh	Calculated
Annual PV energy injected into the grid degradation	0.5	%	[61]
ICMS (Energy tax)	17	%	[54]
PIS (Energy tax)	1.0	%	Defined
COFINS (Energy tax)	5.0	%	Defined
II (BESS tax)	9.0	%	[50]
IPI (BESS tax)	11.25	%	[51]
PIS (BESS tax)	2.10	%	[52]
COFINS (BESS tax)	9.65	%	[52]
ICMS (BESS tax)	17	%	[53]

charge, the PU would manifest an annual consumption of 77.73 MWh, corresponding to an annual expense of $6357.30 during off-peak hours. Notably, there would be no annual consumption or costs during peak hours. The outcomes indicate a surge in expenses by $1400.82 (28%) during off-peak hours, accompanied by a substantial reduction of $4277.80 (100%) during peak hours relative to the base scenario.

For the analyzed period, Table 11 illustrates the monthly evolution of energy credits (calculated via Eq. 5 through 8) and the corresponding financial benefits resulting from BESS adoption in the PU.

The PU would provide annual compensation of 53.5 MWh of energy credits during off-peak hours under the base scenario, generating an annual financial benefit of $4331.47. It would receive a yearly compensation of 5.5 MWh during peak hours, translating to a benefit of $1441.55 per year. With regard to “Option 1”, the PU would receive an annual benefit of $3925.84 (48.8 MWh in energy credits). The annual credits would be decreased to 0.5 MWh during peak hours, providing a benefit of $135.63 per year. Considering “Option 2”, the PU would provide 67.5 MWh of compensated energy during off-peak hours, providing an annual benefit of $5460.74. There would not be any energy compensation during peak hours.

Based on the values presented in Tables 10 and 11, the monthly progression of total energy expenses (off-peak + on-peak), as well as the financial benefit brought about by the compensation of excess energy at the PU were calculated, and are presented in Table 12.

According to the base scenario, the PU would incur yearly energy expenditures totalling $9234.28, concurrently qualifying for a benefit of $5773.03 attributable to produced energy credits. Consequently, the PU’s net annual energy cost would amount to $3461.25. Assessing “Option 1”, the PU would present annual energy cost of roughly $5441.87, and would be eligible for the benefit of $4088.47 (due to its energy credits). The total net energy cost for the year would be $1353.40. Although the annual benefit via energy credits would be reduced by about $2107.85 (61%), the annual energy consumption expense of the PU would be decreased by $ 3792.41 (41%). Given “Option 2”, the PU would incur an approximate annual energy expenditure of $6357.30, coupled with eligibility for a benefit of $5460.74. This would result in a total net energy expense of $896.55, reflecting a reduction of $2564.70 (74%) compared to the base scenario.

3.2.3. *Remote self-consumption in other CU’s*

Considering the potential for energy credit compensation in other CUs owned by UFSC (remote self-consumption), the evaluation encompassed the benefits arising from surplus energy compensation within UFSC’s main campus (fed at MV) and in other LV CUs. Table 13 presents the quantity of energy credits remaining from the PU PV generators that would be compensated at other University CU’s (MV or LV), and the equivalent financial benefits (calculated via Eqs. (12) and (13)).

For the base scenario, the PU presented 7.3 MWh of energy credits remaining, which if compensated at the University main campus would provide a benefit of $591.31. On the other hand, if compensated in other UFSC CU’s, fed at LV, a benefit of $861.24 would be provided. In light of “Option 1”, the remaining energy credits would amount to 4.5 MWh during off-peak hours and 7 MWh during peak hours. Compensating the remaining credits in the main campus (MV) would yield a total benefit of $2194.35. Alternatively, if compensated in other LV-fed CUs, the benefit

Table 8
PU power demand (with BESS) measured and demand contracting suggestion.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Measured power demand after BESS insertion	109.22	100.58	113.34	112.19	107.68	116.74	119.30	107.58	107.10	107.58	129.04	144.59
1 level	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16	114.16
2 levels	111.87	111.87	111.87	111.87	111.87	111.87	111.87	111.87	111.87	111.87	139.35	139.35
3 levels	111.87	111.87	111.87	111.87	111.87	114.16	114.16	114.16	114.16	114.16	139.35	139.35
4 levels (suggested)	111.87	111.87	111.87	111.87	111.87	114.16	114.16	114.16	114.16	114.16	123.32	141.64

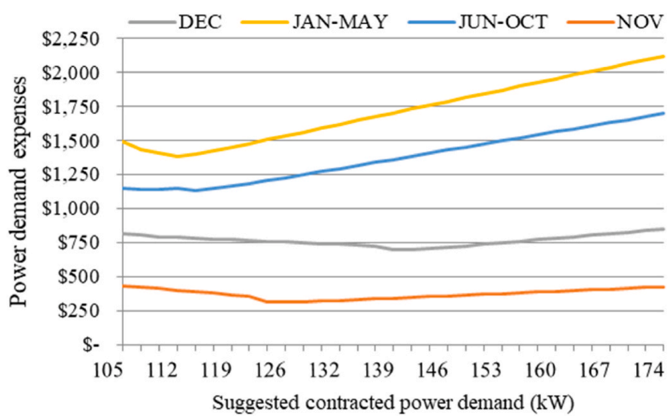

Fig. 5. Power demand expenses (without taxes) considering the simulated BESS.

Table 9
Power demand expenses.

Month	Without BESS	With BESS	
	Base case ($)	Base case ($)	Suggested ($)
Apr	398.53	454.71	439.51
May	397.66	421.84	435.05
Jun	397.50	508.18	457.33
Jul	397.37	538.27	467.36
Aug	397.78	421.45	441.08
Sep	395.39	419.57	440.67
Oct	398.65	421.45	441.08
Nov	396.50	652.74	505.52
Dec	398.28	835.50	566.44
Jan	397.33	427.87	436.37
Feb	394.44	407.54	428.94
Mar	403.85	468.23	444.02
Year	4773.27	5977.36	5503.38

would be $1902.92. For "Option 2", the PU would exhibit 2.1 MWh of outstanding energy credits during off-peak hours and 8.5 MWh during peak hours. The compensation of the remaining credits in the main campus (MV) would provide a total benefit of $2390.41. If compensated in University CU's supplied in LV, the benefit would total $1913.57.

3.3. BESS economic assessment

3.3.1. Remote self-consumption in other CU's

The economic indicators for the ROI (Return on Investment) of adding a BESS to the PU at the UFSC's Solar Energy Research Laboratory are shown in Table 14. It can be observed that in all carried out simulations, the adoption of a BESS would not present financial attractiveness. All results indicate a negative NPV, and an IRR lower than the adopted MRA (6%). The LCOS would present a storage cost of approximately 0.24 $/kWh. The best results would be provided by "Option 2" with the remote self-compensation in the University main campus (MV). In this scenario, a sensitivity analysis of financial indicators was conducted to assess the impact of variations in BESS cost, different MRA, and the annual increase in electric energy tariffs. The evolution of NPV, IRR, LCOS, and Payback Time taking into account the sensitivity analysis is shown in Fig. 6(a) through (d).

The outcomes derived from the application of the proposed methodology reveal that, given annual tariff increments equal to or exceeding 10%, MRA less than 1%, and BESS cost below 365 $/kWh (indicating a 34% cost reduction as presented in Table 7), the BESS demonstrates financial viability. This conclusion is substantiated by the positive NPV values depicted in Fig. 6(a). Notably, the foremost influential factor affecting NPV is identified as the BESS cost. Moreover, the impact of reducing BESS cost is more pronounced on LCOS and IRR compared to the reductions in MRA (as illustrated in Fig. 6(c)) and annual tariff increase (as depicted in Fig. 6(b)), respectively.

In scenarios where the MRA equals or is less than 1%, the annual tariff increase is equal to or greater than 10%, and the BESS cost is below 365 $/kWh, the payback period would be less than the BESS lifetime, as illustrated in Fig. 6(d). Specifically, for a BESS unit cost of 200 $/kWh, the payback period would be less than ten years, aligning with the anticipated cost reductions before the conclusion of the current decade.

The findings indicate that the primary financial determinant influencing the ROI is BESS cost. Notably, BESS in Brazil is currently subject to substantial taxation. The cost of BESS is presented in Table 15, including details on potential cost reductions if Federal and State taxes were excluded. BESS cost would experience a reduction from 550 to 418 $/kWh (24.24%) in the absence of Federal taxes alone. Eliminating State taxes would result in a decrease from 550 to 471 $/kWh (14.53%). Complete exemption from both Federal and State taxes would bring the eventual cost of BESS down to 357 $/kWh (35% less).

Unit costs of 135 $/kWh [62] can be found in the international market for large BESS. It is apparent that the costs associated with insurance and freight of these systems in Brazil are the main cause of the current discrepancy between the international and domestic BESS costs. Taking into consideration the total tax exemption (Federal and State) on the cost of the BESS, which in this case would be 357 $/kWh, Fig. 7(a)–(d) present respectively, the evolution of NPV, IRR, LCOS and Payback Time taking into account the sensitivity analysis.

Based on the calculations, the financial attractiveness of the BESS would manifest for annual tariff increases equal to or greater than 5.2%, MRA less than 6%, and a BESS cost (excluding taxes) below 357 R $/kWh, as illustrated in Fig. 7(a). The influence of a reduced BESS cost on the LCOS remains more significant than the impact of a lower MRA. When considering MRA below 6.3% and an annual tariff increase of at least 5.2%, the payback period aligns with the system's lifespan under full tax exemption on BESS expenditures. These findings indicate that the BESS cost is still the major factor in the economics of adding batteries to PV-powered prosumer units in Brazil.

3.3.2. Effect of new Brazilian regulation for distributed PV systems

In light of the evolving legislative landscape in Brazil with the enactment of Law 14,300, Table 16 provides economic indicators assessing the financial viability of adding BESS to the existing public PU. It can be observed that in all carried out simulations, the financial attractiveness of BESS remains elusive. The most favourable ROI outcomes continues to align with "Option 2", with remote self-compensation at the University's main campus (MV).

Fig. 8 illustrates the progression of NPV across different BESS unit

Table 10
PU energy consumption and expenses with and without the BESS.

Month	Base scenario: Without BESS and e-Bus normal operation				Option 1: With BESS and e-Bus normal operation				Option 2: With BESS and e-Bus shifted last charge			
	Off-peak		Peak		Off-peak		Peak		Off-peak		Peak	
	Consumption (kWh)	Expenses ($)	Consumption (kWh)	Expenses ($)	Consumption (kWh)	Expenses ($)	Consumption (kWh)	Expenses ($)	Consumption (kWh)	Expenses ($)	Consumption (kWh)	Expenses ($)
Apr	5347	437.32	1465	382.91	5688	465.22	35	9.04	6921	566.01	0	0
May	5910	483.35	1435	375.03	6784	554.87	34	8.84	7983	652.95	0	0
Jun	6348	519.14	1598	417.86	7601	621.68	40	10.37	8955	732.38	0	0
Jul	5105	417.52	1563	408.65	5427	443.86	60	15.79	6676	545.99	0	0
Aug	5209	426.00	1485	388.14	5397	441.39	53	13.96	6498	531.45	0	0
Sep	5028	411.22	1425	372.43	5134	419.86	40	10.56	6310	516.09	0	0
Oct	4791	391.83	1509	394.57	4972	406.63	47	12.40	6203	507.31	0	0
Nov	4972	406.65	1753	458.15	5117	418.52	64	16.76	6547	535.46	0	0
Dec	4219	345.07	1372	358.62	4323	353.56	50	13.06	5397	441.42	0	0
Jan	3643	297.98	352	91.92	3874	316.85	1	0.28	3920	320.59	0	0
Feb	3338	273.03	574	150.14	3409	278.85	13	3.41	3709	303.31	0	0
Mar	6692	547.36	1834	479.37	7147	584.52	83	21.60	8612	704.33	0	0
Year	**60,602**	**4956.47**	**16,364**	**4277.80**	**64,873**	**5305.80**	**521**	**136.07**	**77,730**	**6357.30**	**0**	**0**

costs and MRA values for PV systems, considering net-metering legislation without and with the enactment of Brazilian Law 14,300. In terms of NPV, 14,300 presents an impact of $7148.87 for an MRA of 0% and exhibits a diminishing impact with increasing MRA ($3135.99 for an MRA of 9%). These outcomes indicate that the alterations introduced by Law 14,300 will not significantly affect the financial attractiveness of the BESS ROI.

3.3.3. Financial attractiveness: 2030 outlook

In accordance with market projections [59], Fig. 9 depicts the yearly progression of the anticipated BESS cost from 2022 to 2030, considering scenarios with and without the impact of Federal and State taxes (Table 7). In the year 2030, factoring in both Federal and State taxes, the projected cost of BESS could potentially amount to 331 $/kWh. Excluding Federal taxes alone, the cost may decrease to 251 $/kWh, and in the absence of both Federal and State taxes, the cost might be further reduced to 214 $/kWh.

Table 17 presents the annual progression of NPV, IRR, Payback period, and LCOS from 2022 to 2030. The analysis encompasses various tax exemption scenarios, incorporating the assumptions outlined in Table 7 and the annual evolution of BESS costs (Fig. 9). Cell colors are indicative, transitioning from various shades of red (indicating economic unattractiveness) to shades of green (indicating economic attractiveness).

The data in Table 17 indicates that, commencing from 2026, the incorporation of BESS into distributed PV systems would exhibit financial viability, considering the impact of both Federal and State taxes on BESS. By 2030, the NPV would amount to $31,085.14, the IRR would reach 12.2%, the payback period would span 12.2 years, and the LCOS would stand at 0.142 $/kWh. In the absence of Federal and State taxes affecting BESS, the outcomes indicate that financial viability could be achieved since 2022. By 2030, the NPV would reach $50,961.12, the IRR would stand at 20.32%, the payback period would be 7 years, and the LCOS would be 0.092 $/kWh.

3.3.4. Sensitivity analysis considering different tariffs throughout Brazil

For various electric distribution utilities across the Brazilian territory and under the green hourly tariff modality, Fig. 10 illustrates the progression of tariffs (with taxes) during off-peak and peak hours, as well as the differences between tariffs. Additionally, it showcases the annual increase in distribution utility tariffs over the past seven years [54].

In the analyzed timeframe, it is evident that, unlike off-peak tariffs, peak tariffs exhibit notable fluctuations across various distribution utilities in the country. The local utility (CELESC-SC), situated where the case-study prosumer unit is located, demonstrated the second smallest disparity between peak and off-peak tariffs. Additionally, it is apparent that the annual increase in tariffs ranged from 1.6% to 10.9% among different distribution utilities. These differences reflect infrastructure costs and asset upgrade, as well as increasing subsidies to low-income tariff consumers, which are diluted in the tariffs levied on the whole population served by that particular utility.

Tables 18 and 19 portray the annual progression of NPV, IRR, and payback associated with the integration of a BESS in distributed PV systems. The values are derived from the assumptions outlined in Table 7, and the BESS cost evolution depicted in Figs. 9 and 10. This analysis takes into account the impact of Federal and State taxes on the BESS cost. The color gradations in the cells serve as a visual aid, transitioning from shades of red (indicating economic unattractiveness) to shades of green (indicating economic attractiveness).

The findings indicate that the integration of a BESS with a rooftop PV generator in PUs could demonstrate favourable financial returns on investment. Specifically, PUs contracting energy with utilities such as CELPA, AME, CEA, COELBA, EMS, ELEKTRO, ENEL-RJ, RE, and EMT could have experienced financial attractiveness since 2022. Overall, for the utilities investigated, the combined use of BESS and PV is projected to achieve financial viability starting in 2027. Results show that CELPA,

Table 11
PU energy credits and benefits with and without the BESS.

Month	Base scenario: Without BESS and e-Bus normal operation				Option 1: With BESS and e-Bus normal operation				Option 2: With BESS and e-Bus shifted last charge			
	Off-peak		Peak		Off-peak		Peak		Off-peak		Peak	
	Credits (kWh)	Benefits ($)	Credits (kWh)	Benefits ($)	Credits (kWh)	Benefits ($)	Credits (kWh)	Benefits ($)	Credits (kWh)	Benefits ($)	Credits (kWh)	Benefits ($)
Apr	5347	−432.80	340	−88.53	4866	−393.86	35	−9.01	6887	−557.45	0	0
May	3960	−320.51	0	0.00	3609	−292.12	34	−8.81	5580	−451.66	0	0
Jun	2810	−227.45	0	0.00	2565	−207.62	40	−10.34	4792	−387.87	0	0
Jul	4996	−404.39	0	0.00	3877	−313.81	60	−15.74	5916	−478.85	0	0
Aug	5209	−421.60	4	−1.16	4199	−339.87	53	−13.91	6011	−486.54	0	0
Sep	5028	−406.97	370	−96.30	4367	−353.47	40	−10.53	6283	−508.56	0	0
Oct	4791	−387.78	767	−199.97	4827	−390.71	47	−12.36	6203	−502.08	0	0
Nov	4972	−402.45	1753	−456.79	5117	−414.18	64	−16.70	6547	−529.93	0	0
Dec	4219	−341.50	1372	−357.51	4323	−349.91	50	−13.01	5397	−436.84	0	0
Jan	3643	−294.90	352	−91.72	3874	−313.57	1	−0.28	3920	−317.29	0	0
Feb	3338	−270.21	574	−149.57	3409	−275.97	13	−3.40	3709	−300.21	0	0
Mar	5200	−420.91	0	0.00	3802	−307.74	83	−21.54	6220	−503.46	0	0
Year	**53,513**	**−4331.47**	**5531**	**−1441.55**	**48,836**	**−3952.84**	**521**	**−135.63**	**67,465**	**−5460.74**	**0**	**0**

Table 12
PV-powered PU at the UFSC Solar Energy Research Laboratory: Energy expenses and benefits.

Month	Base scenario: Without BESS and e-bus normal operation			Option 1: With BESS and e-bus normal operation			Option 2: With BESS and e-bus shifted last charge		
	Expenses ($)	Benefits ($)	Total ($)	Expenses ($)	Benefits ($)	Total ($)	Expenses ($)	Benefits ($)	Total ($)
Apr	820.23	−521.33	298.90	474.26	−402.87	71.39	566.01	−557.45	8.57
May	858.38	−320.51	537.87	563.71	−300.93	262.78	652.95	−451.66	201.29
Jun	937.01	−227.45	709.56	632.05	−217.95	414.09	732.38	−387.87	344.51
Jul	826.17	−404.39	421.78	459.65	−329.55	130.10	545.99	−478.85	67.13
Aug	814.14	−422.76	391.38	455.35	−353.79	101.56	531.45	−486.54	44.91
Sep	783.65	−503.27	280.38	430.42	−364.00	66.42	516.09	−508.56	7.53
Oct	786.41	−587.76	198.65	419.03	−403.07	15.96	507.31	−502.08	5.22
Nov	864.80	−859.24	5.56	435.27	−430.88	4.39	535.46	−529.93	5.54
Dec	703.69	−699.01	4.68	366.62	−362.93	3.69	441.42	−436.84	4.58
Jan	389.90	−386.62	3.28	317.13	−313.85	3.28	320.59	−317.29	3.30
Feb	423.17	−419.78	3.39	282.26	−279.36	2.89	303.31	−300.21	3.10
Mar	1026.73	−420.91	605.82	606.13	−329.28	276.85	704.33	−503.46	200.87
Year	9234.28	−5773.03	3461.25	5441.87	−4088.47	1353.40	6357.30	−5460.74	896.55

Table 13
Remaining energy credits and the respective financial benefit for a remote self-consumption scenario.

Month	Base scenario: Without BESS and e-Bus normal operation			Option 1: With BESS and e-Bus normal operation					Option 2: With BESS and e-Bus shifted last charge				
	Remaining energy credits	Remote self-consumption		Remaining energy credits		Remote self-consumption			Remaining energy credits		Remote self-consumption		
		Main campus (MV)	Other CU's (LV)			Main campus (MV)		Other CU's (LV)			Main campus (MV)		Other CU's (LV)
	Off-peak (kWh)	Off-peak ($)	Off-peak ($)	Off-peak (kWh)	Peak (kWh)	Off-peak ($)	Peak ($)	Off-peak ($)	Off-peak (kWh)	Peak (kWh)	Off-peak ($)	Peak ($)	Off-peak ($)
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	390	0.00	−101.61	−76.07
Nov	559	45.20	65.97	964	1021	−78.09	−266.25	−313.11	0	1580	0.00	−411.78	−308.52
Dec	2135	172.73	251.74	2033	1940	−164.64	−505.68	−618.69	959	2351	−77.73	−612.81	−572.38
Jan	2805	226.93	327.08	896	2378	−72.58	−619.61	−569.99	850	2394	−68.91	−623.83	−567.79
Feb	1806	146.27	212.97	625	1676	−50.53	−436.77	−401.13	326	1794	−26.46	−467.46	−388.82
Mar	0	0.00	0.00	0	0	0.00	0.00	0.00	0	0	0.00	0.00	0.00
Year	**7305**	**−591.31**	**−861.24**	**4519**	**7016**	**−365.85**	**−1828.50**	**−1902.92**	**2136**	**8508**	**−172.91**	**−2217.50**	**−1913.57**

Table 14
Economic indicators.

Economic indicators	Option 1: With BESS and e-Bus normal operation		Option 2: With BESS and e-Bus shifted last charge	
	Type of remote self-consumption:			
	Other CU's (LV)	Main campus (MV)	Other CU's (LV)	Main campus (MV)
NPV	-$59,757.15	-$52,178.94	-$42,337.84	-$31,723.15
IRR	−4.86%	−3.01%	−0.76%	1.17%
Payback	N/A			
LCOS	0.237 $/kWh			

serving the Amazon state of Pará, exhibits the most favourable tariff conditions for achieving financial viability in the integration of a BESS to a grid-connected PV generator. This is attributed to substantial disparities between its peak and off-peak energy tariffs. Furthermore, utilities characterized by a substantial percentage of annual tariff increases, such as AME (Amazonas) and CEA (Amapá), would potentially yield significant ROI.

Tables 20 and 21 display the yearly progression of NPV, IRR, and payback period, taking into account the exemption of Federal and State taxes on the cost of BESS. The analysis reveals that, for almost all surveyed distribution utilities, the incorporation of BESS in PV-powered PUs could have yielded a financially advantageous ROI since 2022. However, starting from 2023, the deployment of BESS becomes economically viable for PUs served by every distribution utility throughout the country.

3.3.5. Summary of main results

- Conditions for economic viability in the current scenario would be of an annual tariff increase exceeding 10%, MRA less than 1%, and BESS cost below 365$/kWh.
- Considering total BESS tax exemptions (new cost = 357$/kWh), the conditions would be of an annual tariff increase exceeding 5.2% and MRA less than 6%.
- Regulatory changes introduced by Law 14,300 will not significantly affect the financial attractiveness of the BESS ROI.
- Looking towards 2030, total tax exemptions would represent an increase of 64% in total NVP and 8.12% to the IRR. A decrease of 5.2 years of total payback time and 0.05 $/kWh in the LCOS could also be observed.

Table 15
Unit BESS cost and its reduction considering tax exemptions.

Unit cost	$/kWh	Reduction %
Total tax incidence	550	–
Without II	514	6,82
Without IPI	504	8,52
Without PIS/COFINS	502	8,90
Free of Federal taxes	418	24,24
Free of State taxes (ICMS)	471	14,53
Free of Federal and State taxes	357	35,25

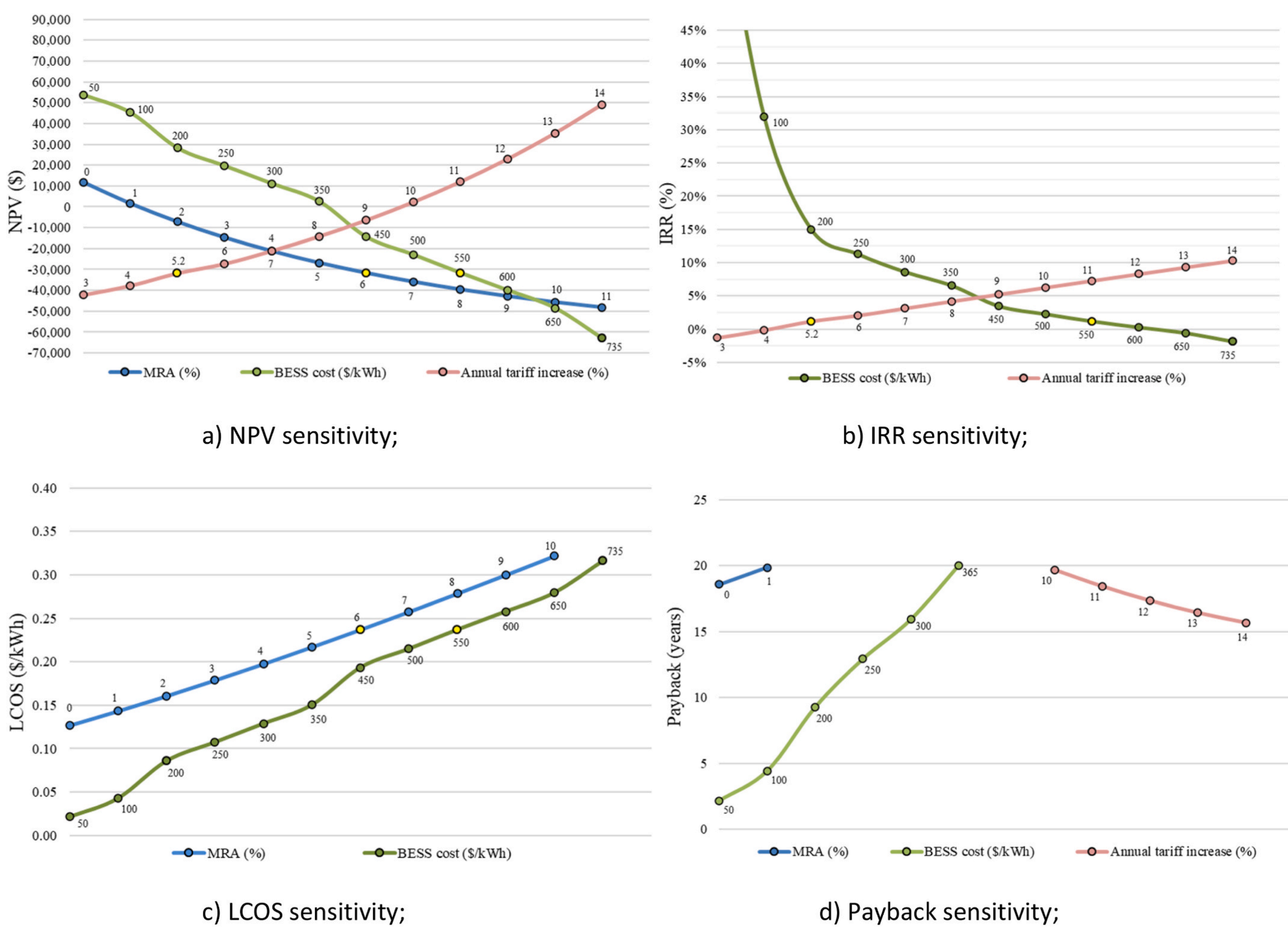

Fig. 6. Economic sensibility analysis for adoption of a BESS at PV-powered public buildings in Brazil.

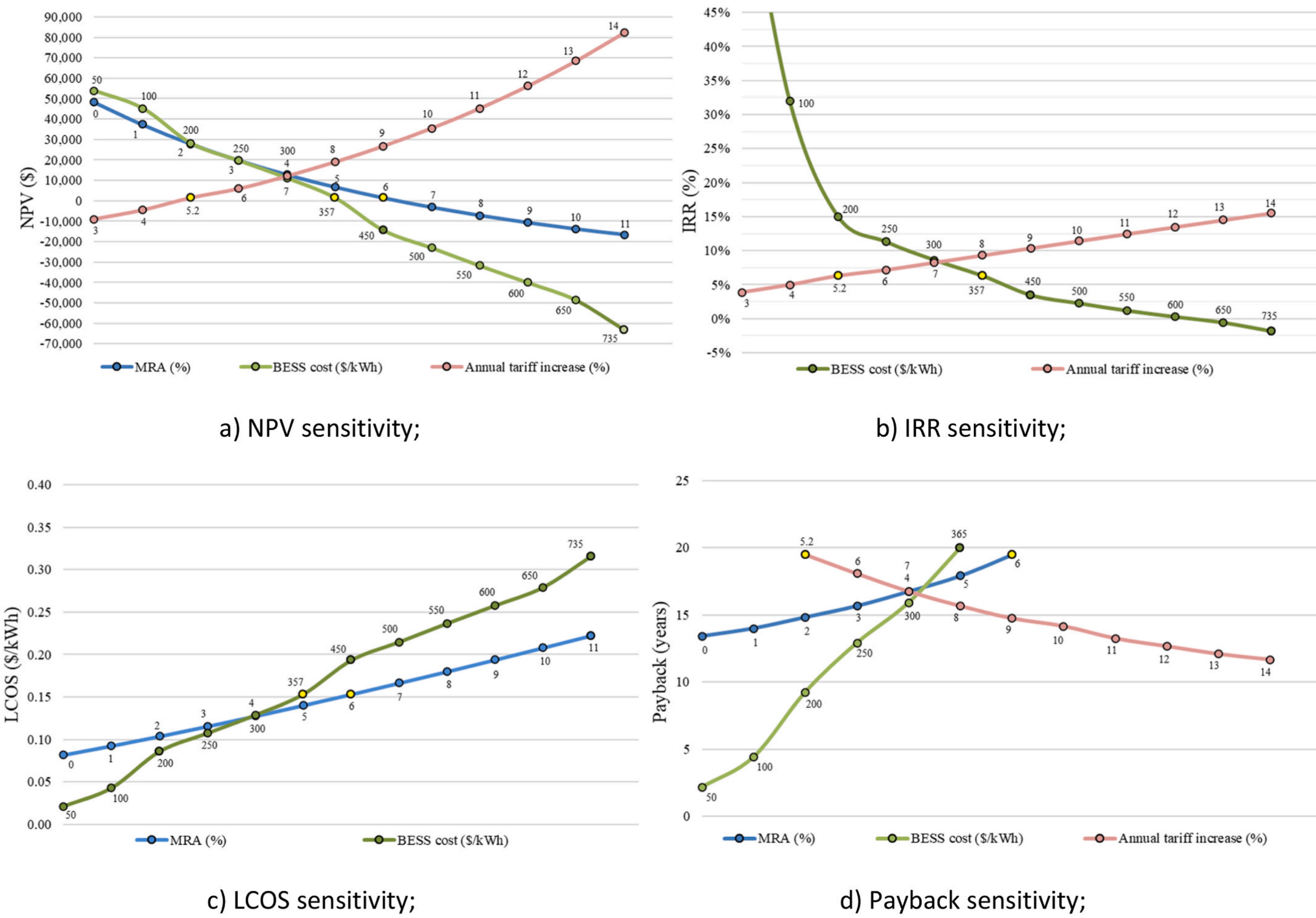

Fig. 7. Economic sensibility analysis for adoption of a BESS at PV-powered public buildings in Brazil (with total tax exemption).

Table 16
Economic indicators with Brazilian Law 14,300 in effect.

Economic indicators	Option 1: With BESS and e-Bus normal operation		Option 2: With BESS and e-Bus shifted last charge	
	Type of remote self-consumption:			
	Other CU's (LV)	Main campus (MV)	Other CU's (LV)	Main campus (MV)
NPV	-$ 54,639.35	-$ 54,799.76	-$ 36,092.54	-$ 35,711.45
IRR	−3.61%	−3.67%	0.41%	0.48%
Payback	N/A			
LCOS	0.237 R$/kWh			

- Throughout Brazil, utilities characterized by a substantial percentage of annual tariff increases, such as AME (Amazonas) (9%) and CEA (Amapá) (10%), would potentially yield significant ROI. However, the majority of utilities present increases below 4%.
- The highest ROI was observed to be located in the Amazon state of Pará, due to substantial disparities between the local utility's peak and off-peak energy tariffs (0.6 $/kWh, almost double of the country's average).
- Overall, for the utilities investigated, the combined use of BESS and PV is projected to achieve financial viability starting in 2027. With tax exemptions, this could be pushed back to 2023.

4. Discussion

The results of this study reveal a significant influence of BESS costs on economic competitiveness, where CIF costs associated with local taxes can hinder economic feasibility. Currently, viability is contingent upon the geographic location of the enterprise (due to variant state taxations) and expenses such as contracted power demand should not be disregarded as it becomes more prominent as the size of the system increases. Government policies to exempt BESS taxation, even if temporary, would be extremely interesting to promote the widespread adoption of this technology.

The market for this technology is experiencing substantial growth and the outlook for 2030 is extremely positive. Recent regulatory changes affecting PV distributed generation systems involve the imposition of charges associated with the utilization of the distribution network infrastructure. Specifically, these charges pertain to the remuneration of assets and the operational costs of the distribution service. This research indicates that the imposition of these charges will not exert a substantial impact on the viability of BESS integration.

As the utilization of renewable sources expands, supplanting non-renewable counterparts, there is a heightened demand for solutions, particularly storage systems, possessing the capability to fulfill flexibility requirements and uphold grid resilience. Anticipating the future progression of the sector, three principal needs come to the forefront: the necessity for heightened regulation, integrated and adaptable sectoral planning, and economic competitiveness. Furthermore, the forthcoming opportunities in energy auctions could pose a substantial impact on maintaining a steady supply of electricity during peak demand. It is also

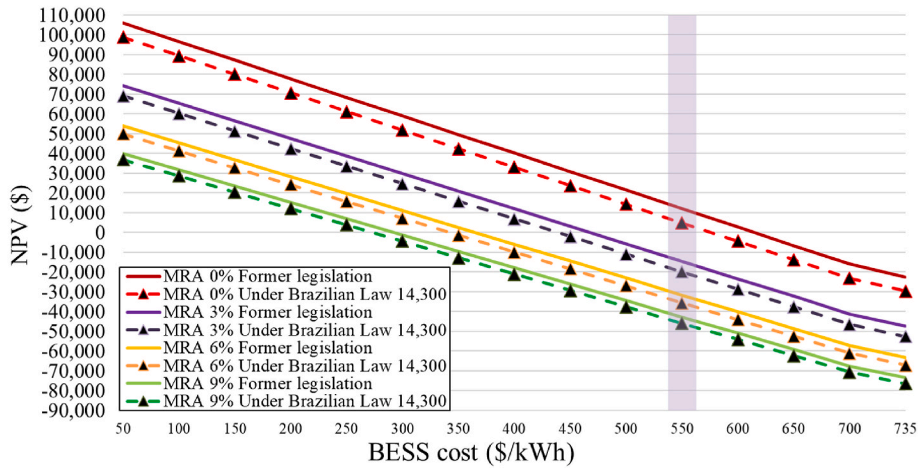

Fig. 8. Evolution of NPV with respect to BESS cost and MRA variation, considering net-metering legislation without and with the enactment of Brazilian Law 14,300.

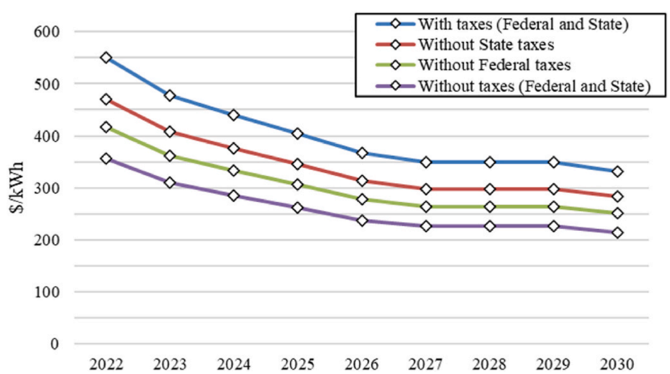

Fig. 9. BESS cost annual evolution.

important to note that in Brazil, low-voltage consumers must buy electricity from their local distribution utility, and that only medium-voltage consumers that have a demand contract above 500 kW can choose to enter the free energy market and have bilateral contracts for energy supply with any utility in the country.

Government entities own a sizable number of public buildings, and alongside current regulations allow generated energy to be offset amongst consumer units owned by the same entity. This enables a notable reduction in their electricity expenses. Specifically, universities have a large number of students and faculty members, presenting extensive campus areas and consequently high electricity consumption due to the various activities carried out in their buildings. University campuses throughout the world can be considered ideal consumers for the integration of PV + BESS systems, while fostering sustainability initiatives, promoting scientific research, and training of qualified human resources in the area. Presently, the Ministry of Science, Technology, and Innovation in Brazil is actively supporting projects aimed at implementing renewable energy sources in public institutions dedicated to scientific research, technology, and innovation. Solar PV generation emerges as a prominent focus for large-scale deployment within this initiative [63].

Table 17
NPV, IRR, Payback and LCOS annual evolution - 2022 to 2030.

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPV ($)									
With taxes	-31,723.16	-20,137.79	-10,676.39	-1,049.04	8,752.89	15,603.47	19,512.24	23,624.27	31,085.14
Without State taxes	-18,054.50	-8,287.44	264.81	8,983.00	17,875.78	24,256.10	28,164.88	32,276.91	39,298.87
Without Federal taxes	-8,931.61	-387.21	7,569.39	15,660.58	23,957.70	30,055.88	33,964.65	38,076.68	44,753.80
Without taxes	1,445.28	8,578.93	15,845.82	23,247.31	30,854.73	36,608.06	40,516.83	44,628.86	50,961.12
IRR (%)									
With taxes	1.17%	2.61%	4.13%	5.81%	7.70%	9.11%	9.84%	10.59%	12.20%
Without State taxes	2.93%	4.44%	6.05%	7.85%	9.90%	11.43%	12.23%	13.05%	14.85%
Without Federal taxes	3.66%	5.92%	7.62%	9.53%	11.72%	13.38%	14.24%	15.13%	17.07%
Without taxes	6.30%	7.97%	9.81%	11.89%	14.31%	16.15%	17.11%	18.12%	20.32%
Payback (Years)									
With taxes	>20.0	>20.0	>20.0	>20.0	17.3	15.3	14.5	13.7	12.2
Without State taxes	>20.0	>20.0	20	17.0	14.4	12.8	12.2	11.5	10.3
Without Federal taxes	>20.0	>20.0	17.3	14.8	12.6	11.3	10.6	9.3	8.3
Without taxes	19.5	16.8	14.5	12.4	10.6	8.7	8.3	7.8	7.0
LCOS ($/kWh)									
With taxes	0.237	0.205	0.190	0.174	0.158	0.150	0.150	0.150	0.142
Without State taxes	0.202	0.175	0.162	0.148	0.135	0.128	0.128	0.128	0.121
Without Federal taxes	0.179	0.156	0.144	0.132	0.120	0.114	0.114	0.114	0.108
Without taxes	0.153	0.133	0.123	0.113	0.102	0.097	0.097	0.097	0.092

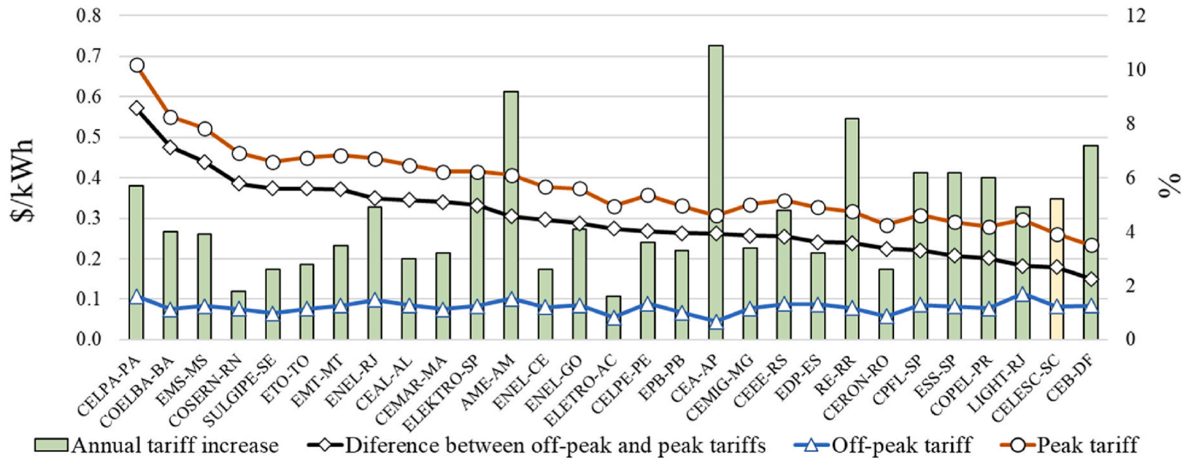

Fig. 10. Brazilian Distribution Utility tariff evolution (peak and off-peak) and annual tariff increase.

Table 18
NPV annual evolution (BESS costs with taxes).

NPV ($)										
Considering the incidence of taxes (Federal and State) on the BESS										
State	Utility	Year								
		2022	2023	2024	2025	2026	2027	2028	2029	2030
PA	CELPA	91,291.45	90,671.06	106,755.42	123,399.21	140,634.29	155,359.38	167,610.08	180,559.07	197,381.17
AM	AME	39,725.09	53,304.48	71,977.47	91,791.53	112,851.65	132,137.43	149,774.08	169,033.30	193,199.38
AP	CEA	37,270.72	49,925.03	70,521.51	92,679.57	116,569.43	139,244.84	160,915.14	184,947.50	214,734.40
BA	COELBA	33,659.29	37,137.21	48,153.14	59,358.90	70,762.09	79,235.60	84,787.63	90,561.75	99,701.84
MS	EMS	27,079.04	31,753.92	42,441.25	53,300.86	64,339.46	72,429.02	77,576.80	82,925.34	91,617.48
SP	ELEKTRO	19,237.31	28,334.46	41,414.86	54,917.51	68,868.58	80,160.86	88,823.87	98,024.00	110,929.55
RJ	ENEL	13,691.98	27,698.75	39,320.02	51,203.50	63,362.04	72,674.11	79,153.84	85,951.07	96,216.38
RR	RE	11,865.87	25,617.07	40,671.54	56,446.34	73,000.53	87,263.00	99,302.92	112,330.11	129,560.54
MT	EMT	5,734.08	11,555.78	21,083.12	30,724.47	40,483.81	47,230.27	50,968.11	54,836.78	61,975.86
SE	SULGIPE	-2,608.06	6,547.27	15,106.79	23,725.84	32,405.96	38,013.74	40,550.79	43,153.81	48,959.52
AL	CEAL	-2,672.61	4,375.85	13,222.46	22,146.37	31,149.90	37,100.41	40,000.38	42,987.35	49,198.94
MA	CEMAR	-3,899.87	3,964.09	12,969.30	22,062.03	31,245.09	37,386.35	40,488.80	43,690.53	50,129.73
RN	COSERN	-3,433.49	1,588.59	9,354.40	17,147.13	24,967.27	29,680.30	31,286.72	32,922.05	37,721.84
SP	CPFL	-10,834.62	1,854.37	13,293.01	25,052.10	37,151.51	46,477.33	53,051.97	60,034.24	70,584.42
GO	ENEL	-9,653.65	-904.97	8,669.88	18,380.22	28,231.62	35,094.84	38,975.90	43,016.09	50,356.94
TO	ETO	-6,498.98	-1,353.88	7,160.52	15,737.77	24,379.62	29,952.87	32,459.38	35,036.07	40,819.92
RS	CEEE	-14,989.81	-4,732.09	5,223.29	15,355.57	25,673.23	33,050.17	37,495.71	42,154.64	50,172.21
SP	ESS	-19,592.24	-6,939.60	3,953.81	15,133.88	26,618.36	35,291.13	41,172.22	47,417.94	57,185.92
PE	CELPE	-16,146.04	-7,446.55	1,489.77	10,522.08	19,653.83	25,753.59	28,825.07	32,007.12	38,438.74
CE	ENEL	-17,781.94	-10,561.15	-2,446.45	5,716.22	13,928.09	19,055.44	21,099.58	23,196.87	28,483.70
MG	CEMIG	-20,500.56	-10,654.94	-1,975.83	6,785.18	15,630.89	21,429.17	24,182.98	27,030.42	33,109.68
DF	CEB	-26,925.89	-12,966.22	-1,761.01	9,799.52	21,740.97	30,955.76	37,473.27	44,460.04	55,084.87
PR	COPEL	-22,562.30	-11,153.00	-661.54	10,083.21	21,096.45	29,259.26	34,588.73	40,237.97	49,361.18
RJ	LIGHT	-32,546.85	-17,744.31	-8,349.75	1,197.91	10,906.18	17,647.91	21,431.35	25,400.19	32,698.51
SC	CELESC	-31,723.16	-20,137.79	-10,676.39	-1,049.04	8,752.89	15,603.47	19,512.24	23,624.27	31,085.14
PB	EPB	-27,051.32	-19,182.92	-10,856.09	-2,461.39	6,003.43	11,405.67	13,747.71	16,167.04	21,801.21
ES	EDP	-33,816.03	-24,415.41	-16,318.34	-8,162.81	53.05	5,196.17	7,268.54	9,407.22	14,749.35
AC	ELETRO	-30,608.36	-23,585.00	-16,388.17	-9,176.51	-1,949.78	2,157.24	3,144.80	4,148.16	8,302.59
RO	CERON	-35,806.77	-27,130.67	-19,446.77	-11,726.11	-3,967.74	694.32	2,261.07	3,868.55	8,652.84

Table 19
IRR and Payback annual evolution (BESS costs with taxes).

State	Utility	IRR (%)									Payback (years)								
		Considering the incidence of taxes (Federal and State) on the BESS																	
		Year																	
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2022	2023	2024	2025	2026	2027	2028	2029	2030
PA	CELPA	16.08%	17.27%	19.98%	23.19%	27.07%	30.20%	31.98%	33.87%	37.98%	8.8	8.3	7.3	6.3	5.3	4.8	4.5	4.3	3.8
AM	AME	10.15%	12.09%	14.46%	17.20%	20.41%	23.17%	25.08%	27.14%	30.86%	15.0	13.3	11.4	9.1	7.7	6.8	6.3	5.7	5.0
AP	CEA	9.69%	11.39%	13.76%	16.47%	19.63%	22.40%	24.43%	26.65%	30.42%	15.8	14.2	12.3	10.5	8.3	7.3	6.7	6.1	5.3
BA	COELBA	10.38%	11.43%	13.43%	15.73%	18.45%	20.45%	21.38%	22.33%	24.75%	13.7	12.6	11.0	8.7	7.4	6.8	6.4	6.3	5.6
MS	EMS	9.59%	10.73%	12.66%	14.89%	17.50%	19.42%	20.29%	21.19%	23.49%	14.5	13.3	11.5	9.2	7.8	7.1	6.8	6.5	5.9
SP	ELEKTRO	8.36%	9.87%	11.89%	14.21%	16.91%	19.05%	20.28%	21.58%	24.24%	16.4	14.7	12.7	11.0	8.6	7.6	7.2	6.8	6.0
RJ	ENEL	7.80%	9.98%	11.93%	14.16%	16.77%	18.75%	19.77%	20.82%	23.23%	17.1	14.3	12.4	10.7	8.3	7.5	7.2	6.8	6.1
RR	RE	7.39%	9.27%	11.36%	13.73%	16.48%	18.75%	20.24%	21.81%	24.72%	18.0	15.8	13.6	11.7	9.3	8.2	7.5	7.0	6.2
MT	EMT	6.81%	7.84%	9.53%	11.46%	13.69%	15.29%	15.96%	16.65%	18.51%	18.4	16.8	14.5	12.4	10.7	8.8	8.4	8.2	7.3
SE	SULGIPE	5.61%	7.10%	8.67%	10.46%	12.54%	13.95%	14.44%	14.94%	16.56%	>20	17.9	15.4	13.3	11.3	10.3	9.1	8.8	8.0
AL	CEAL	5.61%	6.73%	8.31%	10.12%	12.20%	13.65%	14.20%	14.76%	16.43%	>20	18.6	16.0	13.7	11.7	10.5	10.2	9.0	8.2
MA	CEMAR	5.43%	6.65%	8.25%	10.06%	12.15%	13.61%	14.19%	14.79%	16.48%	>20	18.7	16.2	13.8	11.8	10.6	10.3	9.0	8.2
RN	COSERN	5.47%	6.28%	7.74%	9.40%	11.33%	12.58%	12.91%	13.25%	14.66%	>20	19.4	16.6	14.3	12.2	11.1	10.8	10.6	8.7
SP	CPFL	4.54%	6.27%	8.05%	10.04%	12.33%	14.10%	15.11%	16.16%	18.29%	>20	19.6	16.9	14.5	12.3	11.0	10.3	9.0	8.0
GO	ENEL	4.60%	5.85%	7.47%	9.29%	11.39%	12.90%	13.60%	14.31%	16.08%	>20	>20	17.4	15.0	12.7	11.3	10.8	10.3	8.5
TO	ETO	5.02%	5.77%	7.28%	8.99%	10.95%	12.30%	12.79%	13.29%	14.82%	>20	>20	17.6	15.1	12.8	11.6	11.2	10.8	9.0
RS	CEEE	3.85%	5.24%	6.87%	8.70%	10.79%	12.33%	13.11%	13.91%	15.72%	>20	>20	18.5	15.8	13.4	12.0	11.3	10.8	8.8
SP	ESS	3.27%	4.94%	6.63%	8.52%	10.68%	12.34%	13.28%	14.26%	16.23%	>20	>20	19.0	16.3	13.8	12.3	11.5	10.8	8.9
PE	CELPE	3.57%	4.74%	6.26%	7.97%	9.93%	11.31%	11.90%	12.50%	14.09%	>20	>20	19.5	16.6	14.1	12.6	12.1	11.5	10.3
CE	ENEL	3.20%	4.13%	5.54%	7.13%	8.95%	10.18%	10.60%	11.03%	12.41%	>20	>20	>20	17.8	15.1	13.5	13.1	12.6	11.4
MG	CEMIG	2.84%	4.17%	5.64%	7.30%	9.19%	10.51%	11.05%	11.60%	13.11%	>20	>20	>20	17.6	14.9	13.3	12.8	12.3	11.1
DF	CEB	2.24%	4.02%	5.72%	7.61%	9.75%	11.42%	12.44%	13.50%	15.50%	>20	>20	>20	17.6	15.0	13.3	12.4	11.6	10.3
PR	COPEL	2.80%	4.25%	5.89%	7.72%	9.79%	11.38%	12.26%	13.18%	15.04%	>20	>20	>20	17.3	14.8	13.2	12.3	11.6	10.3
RJ	LIGHT	0.97%	3.01%	4.53%	6.22%	8.13%	9.54%	10.25%	10.98%	12.60%	>20	>20	>20	19.7	16.6	14.8	14.0	13.2	11.8
SC	CELESC	1.17%	2.61%	4.13%	5.81%	7.70%	9.11%	9.84%	10.59%	12.20%	>20	>20	>20	>20	17.3	15.3	14.5	13.7	12.2
PB	EPB	1.71%	2.58%	3.97%	5.51%	7.26%	8.48%	8.96%	9.46%	10.83%	>20	>20	>20	>20	17.7	15.8	15.2	14.5	13.1
ES	EDP	0.45%	1.52%	2.85%	4.34%	6.01%	7.16%	7.61%	8.07%	9.36%	>20	>20	>20	>20	20.0	17.9	17.1	16.4	14.7
AC	ELETRO	0.75%	1.43%	2.64%	4.00%	5.55%	6.52%	6.76%	6.99%	8.07%	>20	>20	>20	>20	>20	18.9	18.4	18.0	16.1
RO	CERON	-0.06%	0.84%	2.11%	3.52%	5.10%	6.16%	6.52%	6.89%	8.06%	>20	>20	>20	>20	>20	19.7	19.0	18.3	16.3

Table 20
NPV annual evolution (BESS costs without taxes).

State	Utility	NPV ($)								
		Considering the exemption of taxes (Federal and State) on the BESS								
		Year								
		2022	2023	2024	2025	2026	2027	2028	2029	2030
PA	CELPA	124,459.89	119,387.78	133,277.63	147,695.56	162,736.13	176,363.96	188,614.67	201,563.66	217,257.15
AM	AME	72,893.53	82,021.20	98,499.68	116,087.88	134,953.49	153,142.02	170,778.67	190,037.88	213,075.36
AP	CEA	70,439.15	78,641.74	97,043.71	116,975.92	138,671.27	160,249.42	181,919.72	205,952.09	234,610.38
BA	COELBA	66,827.73	65,853.93	74,675.35	83,655.25	92,863.93	100,240.19	105,792.22	111,566.34	119,577.82
MS	EMS	60,247.47	60,470.64	68,963.46	77,597.21	86,441.30	93,433.61	98,581.39	103,929.92	111,493.47
SP	ELEKTRO	52,405.75	57,051.18	67,937.07	79,213.86	90,970.42	101,165.44	109,828.46	119,028.59	130,805.53
RJ	ENEL	46,860.41	56,415.47	65,842.23	75,499.85	85,463.88	93,678.69	100,158.42	106,955.66	116,092.36
RR	RE	45,034.31	54,333.79	67,193.75	80,742.69	95,102.37	108,267.59	120,307.51	133,334.70	149,436.52
MT	EMT	38,902.51	40,272.50	47,605.33	55,020.82	62,585.65	68,234.85	71,972.70	75,841.36	81,851.84
SE	SULGIPE	30,560.37	35,263.98	41,629.00	48,022.19	54,507.81	59,018.33	61,555.38	64,158.40	68,835.50
AL	CEAL	30,495.83	33,092.57	39,744.67	46,442.72	53,251.74	58,105.00	61,004.97	63,991.94	69,074.93
MA	CEMAR	29,268.56	32,680.81	39,491.51	46,358.38	53,346.93	58,390.94	61,493.39	64,695.12	70,005.71
RN	COSERN	29,734.94	30,305.31	35,876.61	41,443.48	47,069.11	50,684.88	52,291.30	53,926.64	57,597.82
SP	CPFL	22,333.82	30,571.09	39,815.22	49,348.45	59,253.35	67,481.92	74,056.56	81,038.83	90,460.40
GO	ENEL	23,514.79	27,811.75	35,192.09	42,676.57	50,333.46	56,099.42	59,980.49	64,020.67	70,232.92
TO	ETO	26,669.45	27,362.83	33,996.23	40,034.12	46,481.46	50,957.46	53,463.97	56,040.65	60,695.90
RS	CEEE	18,178.63	23,984.62	31,745.50	39,651.92	47,775.07	54,054.76	58,500.30	63,159.22	70,048.19
SP	ESS	13,576.19	21,777.12	30,476.02	39,430.23	48,720.20	56,295.71	62,176.81	68,422.53	77,061.90
PE	CELPE	17,022.40	21,270.17	28,011.98	34,818.43	41,755.68	46,758.18	49,829.66	53,011.71	58,314.72
CE	ENEL	15,386.49	18,155.57	24,075.76	30,012.57	36,029.94	40,060.03	42,104.17	44,201.45	48,359.68
MG	CEMIG	12,667.87	18,061.77	24,546.37	31,081.53	37,732.74	42,433.75	45,187.56	48,035.00	52,985.66
DF	CEB	6,242.54	15,750.50	24,761.20	34,095.87	43,842.82	51,960.34	58,477.85	65,464.63	74,960.86
PR	COPEL	10,606.14	17,563.71	25,860.67	34,379.56	43,198.29	50,263.85	55,593.32	61,242.56	69,237.16
RJ	LIGHT	684.29	10,972.41	18,172.46	25,494.26	33,008.02	38,652.49	42,435.94	46,404.77	52,574.49
SC	CELESC	1,445.28	8,578.93	15,845.82	23,247.31	30,854.73	36,608.06	40,516.83	44,628.86	50,961.12
PB	EPB	6,117.12	9,533.80	15,666.12	21,834.96	28,105.28	32,410.26	34,752.30	37,171.62	41,677.20
ES	EDP	-647.60	4,301.31	10,203.87	16,133.54	22,154.89	26,200.76	28,273.12	30,411.80	34,625.33
AC	ELETRO	2,560.07	5,131.72	10,134.04	15,119.84	20,152.06	23,161.83	24,149.39	25,152.75	28,178.57
RO	CERON	-2,638.33	1,586.05	7,075.44	12,570.24	18,134.10	21,698.90	23,265.65	24,873.14	28,528.82

Table 21
IRR and Payback annual evolution (BESS costs without taxes).

State	Utility	IRR (%)									Payback (years)								
		Considering the exemption of taxes (Federal and State) on the BESS																	
		Year																	
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2022	2023	2024	2025	2026	2027	2028	2029	2030
PA	CELPA	25.56%	27.23%	31.30%	36.28%	42.60%	47.87%	50.92%	54.21%	61.50%	5.6	5.3	4.6	4.0	3.4	3.1	2.9	2.7	2.4
AM	AME	16.33%	18.75%	21.89%	25.62%	30.22%	34.33%	37.26%	40.50%	46.48%	10.2	8.3	7.2	6.1	5.2	4.4	4.2	3.8	3.3
AP	CEA	15.33%	17.39%	20.41%	23.97%	28.33%	32.30%	35.32%	38.68%	44.62%	11.2	9.4	8.1	6.8	5.7	5.0	4.5	4.1	3.5
BA	COELBA	18.26%	19.63%	22.45%	25.79%	29.89%	33.01%	34.47%	35.99%	39.91%	7.5	7.1	6.2	5.3	4.6	4.3	4.1	4.0	3.5
MS	EMS	17.23%	18.71%	21.42%	24.62%	28.52%	31.48%	32.83%	34.25%	37.92%	7.9	7.3	6.4	5.6	4.9	4.4	4.3	4.1	3.7
SP	ELEKTRO	14.86%	16.76%	19.46%	22.64%	26.50%	29.66%	31.52%	33.51%	37.67%	10.4	8.6	7.5	6.4	5.5	4.9	4.6	4.3	3.9
RJ	ENEL	14.53%	17.32%	19.98%	23.09%	26.89%	29.86%	31.41%	33.05%	36.83%	10.3	8.2	7.1	6.2	5.3	4.7	4.5	4.3	3.9
RR	RE	13.12%	15.43%	18.12%	21.25%	25.04%	28.29%	30.46%	32.81%	37.25%	12.1	10.5	8.4	7.2	6.1	5.3	5.0	4.6	4.1
MT	EMT	13.69%	14.96%	17.24%	19.89%	23.08%	25.42%	26.42%	27.46%	30.28%	10.6	9.0	7.9	6.9	6.0	5.4	5.2	5.0	4.5
SE	SULGIPE	12.41%	14.29%	16.42%	18.88%	21.83%	23.90%	24.62%	25.36%	27.79%	11.3	9.2	8.1	7.1	6.2	5.6	5.4	5.3	4.8
AL	CEAL	12.29%	13.69%	15.81%	18.26%	21.19%	23.28%	24.09%	24.92%	27.39%	11.5	10.5	8.4	7.3	6.3	5.8	5.6	5.4	5.0
MA	CEMAR	11.99%	13.52%	15.63%	18.08%	21.01%	23.12%	23.97%	24.84%	27.34%	11.8	10.7	8.5	7.4	6.4	5.9	5.7	5.5	5.0
RN	COSERN	12.51%	13.51%	15.48%	17.76%	20.48%	22.30%	22.79%	23.29%	25.37%	11.1	10.4	8.3	7.3	6.4	5.9	5.8	5.6	5.3
SP	CPFL	10.11%	12.20%	14.44%	17.02%	20.08%	22.53%	23.96%	25.46%	28.56%	14.3	12.4	10.7	8.5	7.3	6.4	6.1	5.7	5.1
GO	ENEL	10.70%	12.23%	14.32%	16.72%	19.59%	21.72%	22.71%	23.74%	26.32%	13.3	12.0	10.3	8.2	7.1	6.3	6.1	5.8	5.3
TO	ETO	11.59%	12.48%	14.58%	16.75%	19.47%	21.39%	22.10%	22.82%	25.06%	12.1	11.4	9.1	8.0	7.0	6.3	6.1	6.0	5.4
RS	CEEE	9.58%	11.27%	13.34%	15.70%	18.51%	20.64%	21.72%	22.85%	25.45%	14.8	13.0	11.2	8.8	7.6	6.8	6.4	6.2	5.5
SP	ESS	8.57%	10.55%	12.66%	15.05%	17.88%	20.12%	21.41%	22.78%	25.57%	16.2	14.0	12.1	10.3	8.1	7.3	6.8	6.3	5.7
PE	CELPE	9.55%	10.97%	12.92%	15.15%	17.79%	19.70%	20.53%	21.38%	23.64%	14.4	13.0	11.3	8.9	7.6	7.0	6.6	6.4	5.8
CE	ENEL	9.36%	10.47%	12.29%	14.36%	16.82%	18.52%	19.11%	19.71%	21.68%	14.4	13.3	11.5	9.1	7.9	7.2	7.0	6.8	6.2
MG	CEMIG	8.70%	10.30%	12.17%	14.31%	16.84%	18.66%	19.41%	20.18%	22.31%	15.5	13.6	11.8	10.2	8.0	7.3	7.0	6.7	6.1
DF	CEB	7.18%	9.26%	11.32%	13.65%	16.37%	18.58%	19.93%	21.37%	24.13%	18.3	15.5	13.4	11.4	9.0	8.0	7.4	7.0	6.2
PR	COPEL	8.05%	9.75%	11.77%	14.06%	16.75%	18.87%	20.07%	21.32%	23.93%	16.8	14.8	12.8	11.0	8.6	7.7	7.3	6.8	6.1
RJ	LIGHT	6.14%	8.53%	10.40%	12.51%	14.98%	16.85%	17.80%	18.79%	21.02%	19.8	16.0	13.8	11.8	9.3	8.3	7.8	7.4	6.7
SC	CELESC	6.30%	7.97%	9.81%	11.89%	14.31%	16.15%	17.11%	18.12%	20.32%	19.5	16.8	14.5	12.4	10.6	8.7	8.3	7.8	7.0
PB	EPB	7.34%	8.34%	10.06%	12.01%	14.29%	15.91%	16.56%	17.24%	19.11%	17.5	16.1	13.9	12.0	10.2	8.4	8.2	7.8	7.1
ES	EDP	5.85%	7.09%	8.72%	10.56%	12.71%	14.21%	14.81%	15.42%	17.15%	>20	18.0	15.5	13.3	11.3	10.3	9.0	8.6	7.8
AC	ELETRO	6.61%	7.38%	8.89%	10.61%	12.62%	13.92%	14.23%	14.55%	16.00%	18.8	17.3	14.9	12.8	11.0	9.2	9.0	8.8	8.1
RO	CERON	5.39%	6.42%	7.96%	9.70%	11.72%	13.09%	13.57%	14.05%	15.60%	>20	19.2	16.4	14.1	12.0	10.9	10.5	10.2	8.4

5. Conclusions

This study introduces a methodology designed to assess the economic viability associated with the integration of battery energy storage systems in public prosumer units featuring distributed photovoltaic generation within public buildings. The proposed methodology is suitable for application to medium voltage consumers in Brazil and other contexts operating under time-based electricity tariffs. The selected case location is Florianópolis, Brazil, and the simulations conducted involved the BESS operation strategically planned to maximize the utilization of surplus PV energy injected into the utility grid by the PU. The primary objective was to achieve optimal reductions in electric energy expenses through effective energy arbitrage mechanisms.

The main findings are presented below.

- For the analyzed period, the PU had a consumption of approximately 77 MWh, of which 16.3 MWh (21.3%) were consumed during peak hours and 60.6 MWh (78.7%) during off-peak hours.
- Based on the power demand profiles injected/requested from the utility's grid by the PU, the BESS was specified (150 kWh/100 kW).
- If the BESS were to be installed in the PU, power costs would increase by 25%. However, through contracted power optimization, costs would increase by 13%.
- Due to the BESS operation strategy, energy expenses during off-peak hours would increase (7% for "Option 1″ and 28% for "Option 2″). Conversely, during peak hours, expenses would decrease (97% for "Option 1″ and 100% for "Option 2″).
- The best economic results would be provided by "Option 2" with the remote self-compensation (10.6 MWh total energy credits) in other medium voltage consumer units.
- In the current scenario, the system does not demonstrate financial feasibility. Financial viability would be attained given annual tariff increments equal to or exceeding 10%, MRA less than 1%, and BESS cost below 365 $/kWh.
- The parameter that exerts the most influence on financial viability was found to be BESS cost.
- With an exemption from all taxes, BESS cost would diminish to 357 $/kWh, representing an approximate reduction of 35%, thereby rendering it economically viable in the current context. This highlights the importance of subsidy programs for this technology in the country.
- The outcomes further indicate that the anticipated modifications introduced by Law 14,300 would not exert a substantial impact on the financial appeal of the return on investment associated with BESS adoption in PV-powered public prosumer units.
- In the evaluation of the financial landscape through the year 2030 for the base case, the project would commence exhibiting financial attractiveness from the year 2026 onward.

Throughout the prospective years until 2030, a comprehensive investigation encompassing various tariff scenarios was conducted on a national scale, incorporating considerations of tax implications on BESS costs. The findings illustrate that the fundamental prerequisites for realizing a favourable financial return on investment would be satisfied for public prosumer units situated in approximately half of the predominant distribution utilities across Brazil. This is primarily attributed to the discernible disparities between peak and off-peak energy tariffs. The results also demonstrated positive financial attractiveness for all the examined utilities in 2027.

The outcomes distinctly demonstrated that the implementation of temporary Federal and State tax exemption policies on BESS would be highly advantageous in fostering the integration of this technology. The findings suggested that, in the Brazilian context, initiatives combining BESS with PV generation projects could exhibit even more pronounced financial appeal in terms of return on investment when compared to projects solely focused on PV generation. It is expected, that this work will contribute to an enhanced understanding of the financial feasibility associated with the incorporation of BESS in public buildings and university campuses.

CRediT authorship contribution statement

G.X.A. Pinto: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Validation, Visualization, Writing – original draft, Writing – review & editing. **H.F. Naspolini:** Conceptualization, Formal analysis, Investigation, Methodology, Visualization, Writing – original draft, Project administration. **R. Rüther:** Conceptualization, Formal analysis, Funding acquisition, Investigation, Methodology, Resources, Supervision, 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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The role and benefits of storage systems in distributed solar PV generation on public buildings in Brazil

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ABSTRACT

This paper proposes a method for assessing the energy and economic impacts provided by the adoption of battery energy storage (BESS) in public buildings with integrated photovoltaic (PV) systems under current legislation. The method is applicable to prosumer units (PU) connected on the medium voltage grid and is based on techniques for measuring the electric energy demand and the surplus PV energy injected by the PU into the grid. Empirical data, including ambient temperature and solar irradiation, were employed to assess the solar radiation resource. In BESS simulations, PU power flows were utilized. The BESS defined operation (charging/discharging schedules) was aimed at the maximum use of the surplus PV energy and the largest reduction in electricity expenses (energy arbitrage). The suggested methodology was applied to a case study of a public building PU in Brazil. The results showed that, during peak hours, the adoption of the BESS would provide a 100 % reduction in measured power demands and consumed energy with a significant annual injection of power in the utility grid. During off-peak hours, the annual self-consumption of the PU would increase by nearly 30 %. This outcome underscores the benefits associated with time-of-use billing structure for public PU + BESS. Approximately 85 % of the total energy required to charge the BESS would be originated from the surplus of PV energy. The remaining 15 % would be supplemented by the utility grid. The findings show that currently, the insertion of BESS would not present financial attractiveness. However, it is anticipated that BESS costs will drop during the next few years. A sensitivity analysis was carried out which concluded that for a cost of US$408 (expected value for 2025) the BESS would present financial attractiveness.

Introduction

Decentralized PV generation, i.e., generation carried out by independent consumers in several geographically distributed plants is an efficient approach to ensure access to electricity in emerging economies (Khan et al., 2018). Studies show that, due to the socioeconomic growth trend in developing countries, the share of energy consumed in these countries will exceed that of developed countries in the coming decades (Ferreira et al., 2018).

Luthander et al. (Luthander et al., 2015) define energy self-consumption as the percentage of energy generated that is consumed instantaneously by the building, not being injected into the utility grid. Energy storage systems appear as an alternative to increase the percentage of self-consumption and therefore mitigate the mismatch between consumption and generation. Thus, consumers can store the surplus energy generated by the PV system for later use or to compensate for the intermittent availability of the solar resource at any given moment. Furthermore, with decreasing feed-in tariffs and barriers to net metering programs all over the world, any kWh self-consumed will have an increasing value over any kWh fed to the public utility grid. Batteries, on the other hand, are still too expensive in many applications, but their cost learning curve is evolving fast, and with the growing uptake of electric vehicles, it is expected that BESS costs will decline sharply before the end of the present decade. The cost-reduction learning curve of BESS has the same trend as that of the solar PV technology, and PV + battery installations will soon make economic sense.

As far as investments in BESS are concerned, it is expected that US$ 20 billion will be invested in 2022, which represents twice the value invested in the previous year. This represents the moment of greatest investment within the electricity sector, with 90 % of deployments in the last two years using lithium-ion battery energy storage technology (highlighted by China and the US). In the period between 2010 and 2018, 60 % of BESS was used for frequency control services; however, in

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Nomenclature

ANEEL	Brazilian National Electrical Energy Agency
ATLAS	Brazilian Solar Energy Atlas
BESS	Battery Energy Storage System
BSRN	Baseline Surface Radiation Network
CU	Consumer Unit
DoD	Depth of Discharge
DOE	USA Department of Energy
EARPC	Environment America Research and Policy Center
e-Bus	Electric Bus
EPBD	European Energy Performance in Buildings Directive
EV	Electric Vehicle
GHI	Global Horizontal Irradiation
INMET	Brazilian National Institute of Meteorology
IRR	Internal Rate of Return
LCOE	Levelized Cost of Energy
LCOS	Levelized Cost of Storage
MRA	Minimum Rate of Attractiveness
MV	Medium Voltage
NASA	The National Aeronautics and Space Administration
NREL	National Renewable Energy Laboratory
NPV	Net Present Value
O&M	Operation and Maintenance Expenses
P	Peak Time
PU	Prosumer Unit
PV	Photovoltaic
ROI	Return On Investment
SoC	State of Charge
UFSC	Universidade Federal de Santa Catarina

recent years this fraction has decreased to 30 %, with the increased use of BESS for energy arbitrage. Currently, BESS is mostly being used for energy arbitrage and peak demand reduction services. The integration of these systems with renewable energy has been showing competitive costs (International Energy Agency - IEA, 2022). By 2050, an estimated US$843 billion is expected to be invested in storage technologies (Bloomberg New Energy Finance-BNEF, 2019).

Storage systems can be used in residential, commercial, industrial, and power plant applications, as well as in small or large electric vehicle (EV) applications. Storage capacity of an estimated 10 GWh (in 2017), mostly composed of power plant applications, is expected to increase between 100 and 150 GWh in 2030 (International Renewable Energy Agency - IRENA, 2017), while power dispatch is expected to reach 225 MW in 2025, out of which approximately 10 MW would be used in residential, commercial and industrial systems (International Finance Corporation-IFC, 2017). A total of 359 GWh in storage systems are expected to be added to the electric grid by 2050 (Bloomberg New Energy Finance-BNEF, 2019).

Among the various electrochemical storage technologies, the lithium-ion technology presents greater technical and economic feasibility when compared to other technologies, such as lead-acid and nickel-sodium (Dhundharaa et al., 2018; Zhang et al., 2016). Parra et al. (Parra et al., 2015) showed that lithium-ion technology batteries are ideal for applications in PV power generation systems because of their longer life cycles, more flexibility in their state of charge, and lower losses when compared to other technologies. Additionally, lithium-ion technology exhibits a higher efficiency when compared to other technologies. While Lead-acid and Nickel-sodium efficiencies range from 70 to 90 %, Li-ion can achieve values up to 95 % (Banguero et al., 2018).

One of the main factors that affect the viability of storage systems is their lifetime, directly related to degradation, which is influenced by several factors such as the minimum state of charge (SoC), the operating temperature, the recharging rate, and the depth of discharge (DoD) (Bishop et al., 2013). The minimum SoC values adopted for storage systems in stationary applications range from 20 % (Tulpule et al., 2013; Van Der Kam & Van Sark, 2015) to 30 % (Amirioun & Kazemi, 2014; Zhang et al., 2012).

Smith et al. (Smith et al., 2017) characterized the life cycle of commercially available lithium-ion batteries, especially developed for applications in which the energy generated by PV systems is used to charge the storage system, taking into account the factors described by Bishop et al. (Bishop et al., 2013). The authors showed the influence of operating temperature variation and the amount of energy discharged per cycle on the lifetime of these systems. Uddin et al. (Uddin et al., 2017) showed that battery energy storage systems with higher storage capacity can have reduced temperature losses. In Germany, Beck et al. (Beck et al., 2016) evaluated the impact of the temporal resolution of measured load and PV generation data on the self-consumption rate in residential systems with PV generation and energy storage. The BESS capacity was sized aiming to maximize self-consumption. Data with 60-minute resolution showed satisfactory results.

Some public University buildings own and operate a large number of buildings over a large area with a continuously increasing need for electricity supply, in which grid-connected PV systems are increasingly being installed. Due to the large energy needs of University campuses, combined with the current social awareness of faculty and students, Universities should take a leadership role in the development and implementation of renewable energy projects, especially in public buildings, since these institutions play an important role in the innovation and training of future professionals.

University campuses present conditions that make them attractive locations for the adoption of PV generators coupled with electrochemical storage systems. These environments have large areas available on building rooftops, parking lots, and land that is often ideal for the integration of PV technology. According to a report by EARPC (EARPC, 2017), a transition towards 100 % of energy consumption from renewable energy sources is the best way forward for the hundreds of universities that have committed to neutralizing their carbon emissions by 2050.

The concept of a sustainable University can be defined as a higher education institution that involves and promotes the minimization of environmental, economic, and social effects generated by the use of its resources (Sedlacek, 2013; Velazquez et al., 2006). Universities play a key role in sustainable development at the regional level. A greater concern with energy sustainability on university campuses has emerged since the release of the European Energy Performance in Buildings Directive (EPBD) (Janssen, 2004).

Kolokotsa et al. (Kolokotsa et al., 2016) state that, concerning physical space, population, and the various types of activities performed on campuses, universities can be considered mini-cities. Alshuwaikhat and Abubakar (Alshuwaikhat & Abubakar, 2008) show that energy and environmental impacts caused by universities can be considerably reduced by using efficient choices of organizational and managerial measures. Park and Kwon (Park & Kwon, 2016) explored renewable energy generation systems on the campus of Kyung-Hee University in South Korea and have shown that grid-connected PV systems are more efficient than stand-alone systems. Alyahya and Irfan (Alyahya & Irfan, 2016) evaluated the role that University institutions play in achieving the goal of 41 GW of installed renewable power in Saudi Arabia by 2030.

Literature review

Presented below are studies that implement BESS to facilitate energy arbitrage services and enhance self-consumption of PV generation within building structures.

Gupta et al. (Gupta et al., 2019) conducted a study involving 82 households and demonstrated that the integration of PV systems with energy storage led to heightened levels of self-consumption and an average reduction of 8 % in peak-time demand (maximum power consumed by the household from the utility grid during hours with higher utility electricity tariffs). Chaianong et al. (Chaianong et al., 2020) examined the financial viability of PV-storage systems for residential consumers in Thailand, utilizing simulated consumption and PV generation data. They established that these systems would become economically feasible when the cost of storage systems reached 100 US $/kWh. Other aspects such as a 10 % increase in energy tariffs, adjustment of peak time hours and subsidies for battery investment are shown to enhance the feasibility of these systems. However, it's important to note that the authors focused solely on self-consumption services, without considering the potential advantages of energy arbitrage services, which could potentially enhance system viability. Roberts et al. (Roberts et al., 2019) assessed PV-storage systems in residential apartment buildings and revealed that the inclusion of storage systems with a capacity of 2–3 kWh per apartment could increase self-consumption by up to 19 % and reduce the building's peak demand by as much as 30 %. Li (Li, 2019) conducted an analysis on the sizing of PV-storage systems for 2057 residential consumers with varying consumption profiles. The study concluded that higher household consumption was associated with greater overall savings. According to Li et al. (Li et al., 2018) emphasized that the combination of PV and BESS could indeed enhance self-consumption and self-sufficiency, although the extent of improvement was not directly proportional to the BESS capacity.

Talent and Du et al. (Talent & Du, 2018) evaluated the optimization of PV-storage system sizing, both in residential and industrial contexts. They underscored that the most economically favorable solutions involved maximizing self-consumption, typically achieved through larger PV systems and smaller storage systems. Aelenei et al. (Aelenei et al., 2019) evaluated the application of lithium-ion storage technology across a range of capacities (from 13.5 to 54 kWh) in a commercial building equipped with a 12 kWp PV system. In pursuit of maximizing self-consumption, the 13.5 kWh storage system emerged as the most economically viable option, resulting in a 16 % increase in self-consumption. Furthermore, Liu et al. (Liu et al., 2020) conducted simulations on a PV system with storage within a commercial building setting in China. They devised an operational mode based on varying local energy tariffs throughout the day, achieving a 15 % increase in self-consumption of PV-generated electricity and a reduction in CO_2 emissions of up to 39 %. Kaschub et al. (Kaschub et al., 2016) conducted a technical and economic evaluation of residential photovoltaic (PV) storage systems incorporating electric vehicles in Germany. The study findings indicate that these integrated systems demonstrate financial viability, achieving levels of self-consumption as high as 70 %. Even though the costs of PV and BESS technology are falling, the research of small-scale PV + BESS systems in Romania (Cristea et al., 2020) demonstrates the necessity of ongoing government subsidies for the viability of these integrated systems. These financial incentives are essential for promoting the use of decentralized, renewable energy systems.

It is evident from the analysis that a substantial proportion of the examined studies predominantly focused on residential consumers, utilizing storage systems with capacities ranging from 2 to 21 kWh. In cases where electric vehicles were integrated into the load, their capacities were relatively modest, not exceeding 32 kWh. It is noteworthy that a limited number of studies accounted for the degradation losses inherent to these systems, potentially leading to an overestimation of the reported outcomes. Furthermore, certain studies did not incorporate compensation mechanisms into their assessments, aiming to establish feasibility independent of local policy influences.

Although PV systems have been the focus of numerous studies in Brazil, the investigation of BESS remains relatively limited. It was found that there is a lack of methodologies or studies in Brazil, based on measured data and considering degradation losses, that address the deployment of storage systems to facilitate energy arbitrage services and increase in PV self-consumption from public prosumer units with PV generation and large-scale electric vehicles. This study aims to fill this gap.

Method

This paper proposes a method for assessing the energy and economic impacts provided by the adoption of BESS in public buildings with integrated PV systems. The method is applicable to prosumer units connected on the medium voltage grid and is based on techniques for measuring the electric energy demand and the surplus PV energy injected by the PU into the grid. Fig. 1 presents the flowchart detailing the steps of the applied method.

Base case description

Although the methodology presents a generalist approach applicable to any PU, real data from a PU of the Universidade Federal de Santa Catarina (UFSC), in Florianópolis-Brazil (48° W, 27° S), was analyzed to exemplify a tangible and practical case study. This public building is fed by the utility grid in medium voltage (MV) (13.8 kV).

Fig. 2 shows an aerial view of the PU, which presents PV generation of different technologies, totaling 105 kWp. In accordance with the Köppen-Geiger climate classification (Peel et al., 2007), the PU is situated within a humid subtropical climate (Cfa), oceanic, without a dry season, with hot summer. Table 1 presents the identification, location and power of the PV systems connected to the PU shown in Fig. 2. The connection of each solar PV generator to the building's electrical installations is done utilizing circuit breakers integrated into the buildings' low voltage distribution boards with decentralized inverters. The variation in PV technologies leads to differences in electrical parameters (current and voltage) and efficiency. Nevertheless, the aim is to assess the aggregate energy generation of the five systems rather than comparing each individual system.

Besides the electrical loads consisting mostly of air conditioning appliances, general purpose outlets (used mainly to power computers), power electronics laboratory and lighting systems using LED lamps, the PU is equipped with a 90 kW electric vehicle charger, which is consistently employed for the purpose of charging the laboratory's electric bus (e-Bus), representing the PU most substantial load demand.

On weekdays, the e-Bus commutes students, staff and academics five times a day between the UFSC's main campus, located in the central region of Florianópolis, and the Solar Energy Research Laboratory, located 26 km North of the main Campus. The route taken by the e-Bus is shown in Fig. 3. The energy storage system uses Mitsubishi Heavy Industries Li-ion batteries (128 kWh capacity), which leads to a 74 km range for a minimum SoC of 20 %. The distance traveled for each roundtrip is approximately 52 km and takes about 1 h. The e-Bus is charged five times a day, for a period of approximately 1 h, at the following times: 08:00 am; 10:30 am; 1:00 pm; 4:00 pm, and approximately 6:45 pm. Four charges are performed during off-peak hours and one during peak hours. The peak time (P) adopted in this work is characterized by the period between 6:31 pm and 9:30 pm on weekdays, as defined by the local utility company.

The PU electric energy demand (consumption) and injected surplus PV energy data were recorded at 15-minute intervals by the bidirectional electric energy meter located at the border between the PU and the utility, between April 2017 and March 2018. The data period of choice is justified because of the time period (before the COVID/19 pandemic) and the experimental e-Bus being fully operational. During the considered period, UFSC had 83 consumer units (CU), of which 23 were fed at MV. All the CU's owned by UFSC had electricity supply contracts with the local utility company (CELESC) in the green tariff mode (peak and off-peak energy tariffs and a single demand tariff)

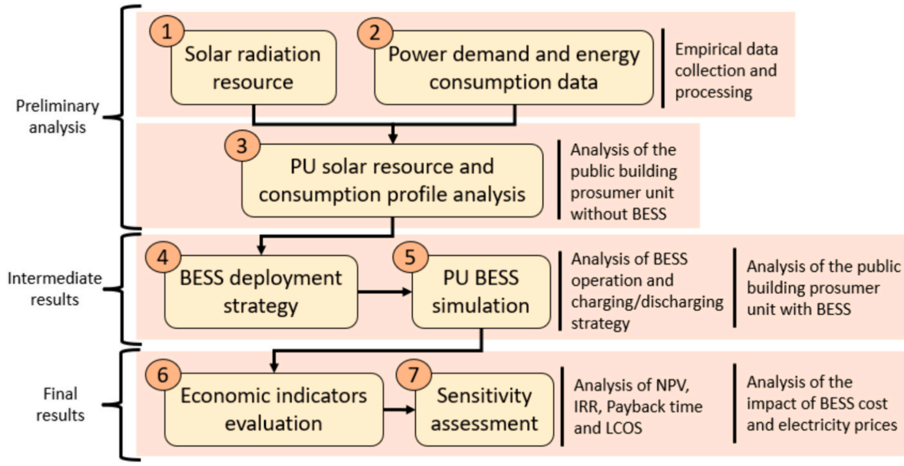


Fig. 1. Flowchart of the preliminary analysis and evaluation of results.

Fig. 2. Aerial view of the Solar Energy Research Laboratory at Universidade Federal de Santa Catarina in Florianópolis-Brazil with the e-Bus, which represents the largest single load during battery charging for 1-hour periods five times/day shown at the bottom right.

Table 1
The Solar Energy Research Laboratory's PV systems.

Identification	Localization	PV technology	Power (kW)
1	Parking lot	CIGS	13.44
2	A building	p-Si	66.15
3	B building	a-Si/μc-Si	13.50
4	e-Bus stop	CdTe	2.44
5	PV ground systems	a-Si/ p-Si/ μc-Si	10.00
		Total	105.53

presenting a total annual electricity consumption of approximately 26.9 GWh and annual electricity bill expenses of approximately US$ 3.3 million (DPAE, 2019).

Empirical data collection and processing

Solar radiation resource

To evaluate the solar radiation resource at the PU site (UFSC's main Campus) in the period between April and September 2017, measured GHI data from the Baseline Surface Radiation Network (BSRN) solarimetric station #3 (König-Langlo et al., 2013) at the UFSC Mechanical Engineering building were used obtained via the Data Publisher for Earth and Environmental Science PANGEA (Baseline Surface Radiation Network – BSRN, n.d.). The data were collected with a temporal resolution of 1 min. The measured data were previously approved by the BSRN quality control system (Long & Dutton, 2010). Additionally, mean ambient temperature data were used, obtained from measurements taken by BSRN station #3.

For the period between October 2017 and March 2018, GHI data with a temporal resolution of 1 min, obtained from the Kipp & Zonen pyranometer (model SMP22) installed at FV-UFSC solarimetric station (Fig. 4) were used. The solarimetric station meets the best practices of installation and data acquisition systems. Its sensors have a high level of reliability and accuracy. To ensure best monitoring practices, the BSRN requirements (Long & Dutton, 2010) for installation and observation routines are followed. A more detailed description can be found in Mantelli et al. (Mantelli et al., 2019).

The GHI values, at 1-minute interval, were obtained from Eq. (1) while Eq. (2) was used to calculate GHI values or a specified time interval Δt. The GHI, in the specified time interval, is characterized as the sum of the GHI calculated at each one-minute interval obtained during the specified time interval.

$$I_{rr} = I.\frac{1}{60} \tag{1}$$

where:

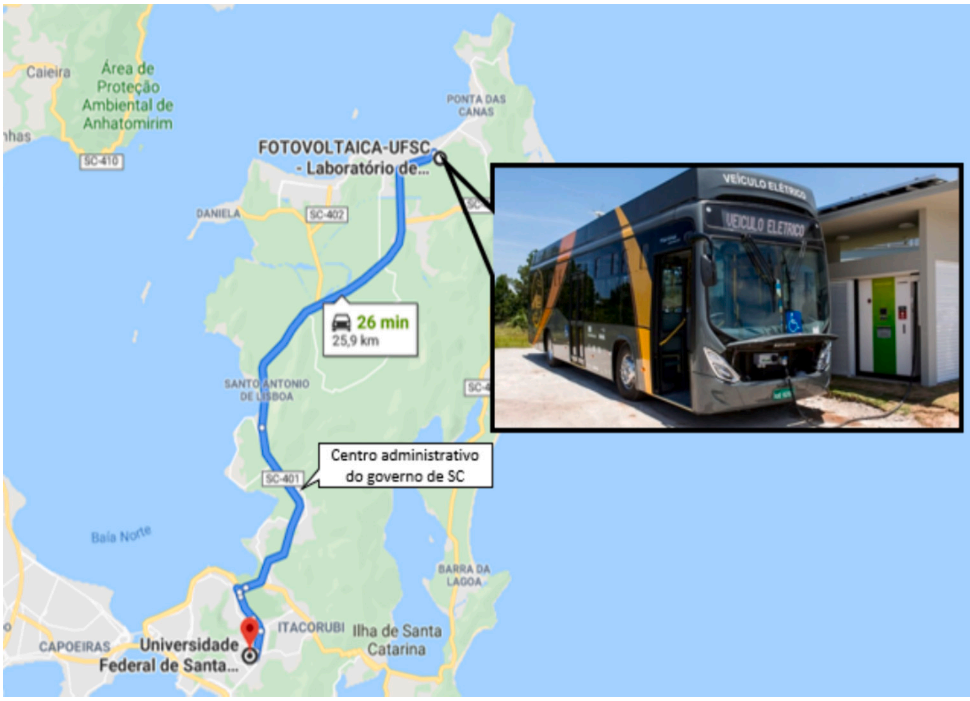


Fig. 3. The Solar Energy Research Laboratory's e-Bus 52 km round trip route.

Fig. 4. The UFSC Solar Energy Research Laboratory's solar radiation measurement station in Florianópolis-Brazil.

I_{rr}= Global horizontal irradiation in one-minute interval [Wh/m^2];
I= Global horizontal irradiance obtained via BSRN in one-minute interval [W/m^2].

$$I_{rr}^{\Delta t} = \sum_{k=i}^{k=j} I_{rr}^{k} \quad (2)$$

where:

$I_{rr}^{\Delta t}$= Global horizontal irradiation in the specified time interval Δt [Wh/m^2];
I_{rr}^{k}= Global horizontal irradiation in the specified time interval k [Wh/m^2];
j= Sum upper limit;
i= Sum lower limit.

The values of the daily average GHI obtained for the analyzed period were compared with those for a typical meteorological year from NASA (NASA - National Aeronautics and Space Administration, n.d.; Zhang et al., 2007), NREL (NREL – Nacional Renewable Energy Laboratory, n.d.; Maxwell et al., 1998) and the Brazilian Solar Energy ATLAS (Pereira et al., 2017) databases. The average daily temperature values obtained for the analyzed period were compared with average daily values of ambient temperature from NASA (NASA - National Aeronautics and Space Administration, n.d.) and the Brazilian National Institute of Meteorology (INMET) databases (INMET – Instituto Naconal de Meteorologia, n.d.). The gap-filling methodology for missing data described by Schwandt et al. (Schwandt et al., 2013) was used when necessary.

PU Power demand and energy profiles

This work adopts the ANEEL definitions for power demand and measured power demand (Agência Nacional De Energia Elétrica, ANEEL, 2021a), as follows: "power demand" is the average power required (or injected) by the PU to the utility grid, whereas "measured power demand" is the maximum power demand by the PU, in kW. The active electric energy injected/required to the utility grid by the PU in 15 min intervals was calculated using Eq. (3). For a specified time interval Δt, the energy can be calculated as the sum of the active energies injected/required at each 15 min intervals, obtained during a specified time interval, as shown in Eq. (4).

$$E_P = P.\frac{15}{60} \quad (3)$$

where:

E_P = Active electric energy injected/required in 15 min intervals [kWh];
P = Active injected/required power demand in 15 min intervals [kW].

$$E_p^{\Delta t} = \sum_{k=i}^{k=j} E_p^{k} \quad (4)$$

where:

$E_p^{\Delta t}$ = Active electric energy injected/required in the specified time interval Δt [kWh];
E_p^{k} = Active electric energy injected/required in the specified time interval k [kWh].

BESS deployment strategy

BESS operation

Fig. 5 shows a schematic of the operation of the grid connected PU (with PV generation and simulated BESS). It is observed that both the BESS and the utility operate by supplying or absorbing energy from the PU. The local utility serves as a backup power supply whenever the PV system and the BESS do not meet the PU demand. Due to the differences in electricity tariffs (during peak hours, one kWh costs on average approximately 3.2 times more than during off-peak hours) (Agência Nacional De Energia Elétrica, ANEEL, 2021b), the BESS stores the surplus PV energy that would have been fed into the grid during off-peak hours and fully discharges its energy into the grid during peak hours. where:

P_{BESS} = BESS charging/discharging power [kW];
P_{PV} = PV generated power [kW];
P_L = Power demanded by the PU's loads [kW].

The lithium-ion (NMC chemistry) technology was chosen for the BESS since this technology displays a considerable life cycle, more SoC flexibility, and lower losses than most of the other Li-ion battery technologies. The instantaneous power of the BESS can reach any value within the limits specified by its rated power. In order not to overestimate the results, the applied methodology takes into account the degradation losses per operation cycle of the BESS. Uddin et al. (Uddin et al., 2017) and Yoshida et al. (Yoshida et al., 2016) showed that BESS degradation losses is a crucial issue to be taken into account as it influences the financial viability of these systems. The adopted degradation per cycle model for NMC batteries was developed by Smith et al. (Smith et al., 2017), used as a reference by the USA-DOE's National Renewable Energy Laboratory (NREL) in technical and economic evaluations (Diorio et al., 2015).

Charging and discharging strategy

The BESS charging and discharging process takes into account the following assumptions: a) the operating hours of the e-Bus and, consequently, the charging hours of its batteries; b) the BESS being charged during off-peak hours in order to maximize the use of the surplus PV energy injected into the grid; c) the BESS being discharged at peak hours in order to obtain the highest reduction of electric energy expenses (energy arbitrage); d) the BESS does not operate on holidays and weekends, since the PU is permanently connected to the utility grid and the e-Bus does not operate on weekends and public holidays. This assumption increases the BESS life cycle due to a reduction on its annual charging/discharging frequency; e) A SoC of 20 %, DoD of 80 %, roundtrip efficiency of 88 % (ratio of the energy output during discharge to the energy input during charging), and durability of 6000 cycles in DoD; f) complementary charging from the utility grid when it is not possible to complete the full BESS SoC with the surplus PV energy. Therefore, only the PV energy generated that cannot be consumed (immediate self-consumption) or stored (BESS) will be injected into the grid.

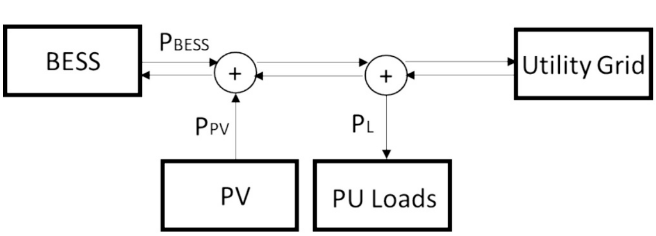


Fig. 5. Grid-connected PV and BESS systems schematic diagram.

The proper operation of the BESS is defined by time periods. The BESS control system may or may not allow the injection of excess PV energy into the grid. Likewise, it may or may not allow the consumption of energy from the grid, both at a fixed power or in an acceptable power range, with a certain power factor (appropriate to the load and respecting the established limits). The response time of the BESS can be assumed to be instantaneous (ms), justified by the response time of Li-ion batteries.

For each t instant, the amount of energy available in the BESS is shown in Eq. (5), while the amount of energy needed to reach full SoC is given by Eq. (6).

$$E_{BESS.A}(t) = (SoC(t) - SoC_{MIN}).E_{BESS.R} \tag{5}$$

$$E_{BESS.NEC}(t) = (DoD_{BESS}.E_{BESS.R}) - E_{BESS.A}(t) \tag{6}$$

where:

$E_{BESS.A}(t)$ = BESS available energy, at t instant [kWh];
$SoC(t)$ = BESS state of charge, at t instant;
SoC_{MIN} = BESS minimum state of charge;
$E_{BESS.R}(t)$ = BESS rated storage capacity [kWh];
$E_{BESS.NEC}(t)$ = Amount of energy necessary to reach full state of charge [kWh];
DoD_{BESS} = BESS depth of discharge.

Charging. The electrical energy that can flow between the PU (PV generators + loads), BESS, and the grid is a function of a series of situations and contingencies defined and described below, which determine how the charging process of the BESS takes place.

To take maximum advantage of the surplus PV energy, in the period between 05:00 a.m. and 05:15 p.m., the BESS is charged with instantaneous power equal to the instantaneous surplus PV power. In the charging process, three situations can occur, as follows:

a) $\boldsymbol{E_{LOADS}(t) > E_{PV}(t)}$: The energy demanded by PU loads at t instant is greater than the PV generated energy, resulting in zero PV energy surplus. In this case, the BESS is not charged and the difference between the energy demanded by the loads and the generated energy is supplied by the grid. Eq. (7) presents the amount of energy stored in the BESS. Eq. (8) shows the energy supplied by the grid, at t instant.

$$E_{BESS.S}(t) = 0 \tag{7}$$

$$E_{GRID}(t) = E_{LOADS}(t) - E_{PV}(t) \tag{8}$$

where:

$E_{BESS.S}(t)$ = BESS stored energy, at t instant [kWh];
$E_{GRID}(t)$ = Energy supplied by the grid, at t instant [kWh];
$E_{LOADS}(t)$ = Energy demanded by loads at t instant [kWh];
$E_{PV}(t)$ = PV generated energy, at t instant [kWh];

b) $\boldsymbol{E_{LOADS}(t) < E_{PV}(t)}$ ***e*** $\boldsymbol{20\% \leq SoC < 100\%}$: The energy demanded by the loads is less than the PV generated energy, resulting in a surplus of PV energy. Since the BESS is below its maximum SoC, it is charged using the PV energy surplus. Eqs. (9) and (10) show the amount of energy stored in the BESS and the energy flowing through the utility grid at t instant, respectively.

$$E_{BESS.S}(t) = E_{PV}(t) - E_{LOADS}(t) \tag{9}$$

$$E_{GRID}(t) = 0 \tag{10}$$

If the amount of surplus PV energy is greater than that required to charge the BESS, according to Eq. (11), $SoC(t)$ reaches 100 % and the energy difference is injected into the grid. The amount of energy stored in the BESS and the surplus of PV energy injected into the grid at t instant are described by Eqs. (12) and (13), respectively

$$E_{PV}(t) - E_{LOADS}(t) \geq E_{BESS.NEC}(t) \tag{11}$$

$$E_{BESS.S}(t) = E_{BESS.NEC}(t) \tag{12}$$

$$E_{GRID}(t) = E_{PV}(t) - E_{LOADS}(t) - E_{BESS.NEC}(t) \tag{13}$$

c) $\boldsymbol{E_{LOADS}(t) < E_{PV}(t)}$ ***e SoC*** $=$ **100%**: The energy demanded by the loads is less than the generated PV energy, resulting in a surplus of PV energy. In this case, the BESS is fully charged, and therefore the surplus of PV energy is injected into the grid. Eq. (7) shows the BESS charged energy while Eq. (14), the surplus of PV energy injected into the grid, at t instant.

$$E_{GRID}(t) = E_{PV}(t) - E_{LOADS}(t) \tag{14}$$

If the BESS is not fully charged after the period set for charging the BESS via the surplus of PV energy ($SoC\ (t) < 100$ %), a new charging period is set using energy from the utility grid with fixed power value equal to the BESS nominal power. The period was defined between 5:16 PM and 6:30 PM (75 min) since it is immediately before peak hours, and has enough duration to complement BESS charging. During this period two situations may occur, as follows:

a) $\boldsymbol{SoC(t) < 100}$**%**: SoC is below its maximum capacity and it is charged through the energy provided by the electrical grid. Eqs. (15) and (16) show the amount of energy charged and the energy provided by the electric grid, at t instant, respectively.

$$E_{BESS.S}(t) = E_{BESS.NEC}(t) \tag{15}$$

$$E_{GRID}(t) = E_{LOADS}(t) - E_{PV}(t) + E_{BESS.NEC}(t) \tag{16}$$

b) $\boldsymbol{SoC(t)} = $ **100%**: BESS SoC is at its maximum capacity, and thus, it does not require charging. Eqs. (7) and (8) show the amount of energy charged in the BESS and the energy supplied by the grid at t instant.

Fig. 6 shows the simplified schematic diagram of the BESS charging strategy.

Discharging. The first 2 h (06:31 p.m. to 08:30 p.m.) of the BESS operation during peak hours aim to clear the PU's energy consumption. Thus, during this period, no energy is consumed from the grid. BESS discharges its stored energy in the power range between the minimum and maximum of the active power demanded by the load (respecting BESS nominal power). During this period, two situations can occur, as described below:

a) $\boldsymbol{SoC(t) > 20}$**%**: The SoC is greater than the established minimum and the BESS will be discharged. Eq. (17) shows the amount of energy discharged and Eq. (10) the energy flowing through the utility grid at t instant.

$$E_{BESS.D}(t) = E_{LOADS}(t) - E_{PV}(t) \tag{17}$$

where:

$E_{BESS\text{-}D}(t) =$ BESS discharged energy, at t instant [kWh].

b) $\boldsymbol{SoC(t)} = $ **20%**: SoC is equal to the minimum allowed, and therefore there is no BESS discharge. The utility grid will supply the PU loads. Eq. (18) presents the amount of energy discharged by the BESS, while Eq. (8) shows the energy supplied by the grid, at t instant.

$$E_{BESS.D}(t) = 0 \tag{18}$$

If after 08:30 p.m., the BESS has yet to be fully discharged, its operation is set to discharge all its remaining stored energy to the utility grid in the period between 08:31 p.m. and 09:30 p.m. It will discharge at a fixed power equal to its nominal power. During this period two situations may occur:

c) $\boldsymbol{SoC(t) > 20}$**%**: SoC is greater than the minimum allowed and its discharge occurs. Eq. (19) presents the amount of energy discharged

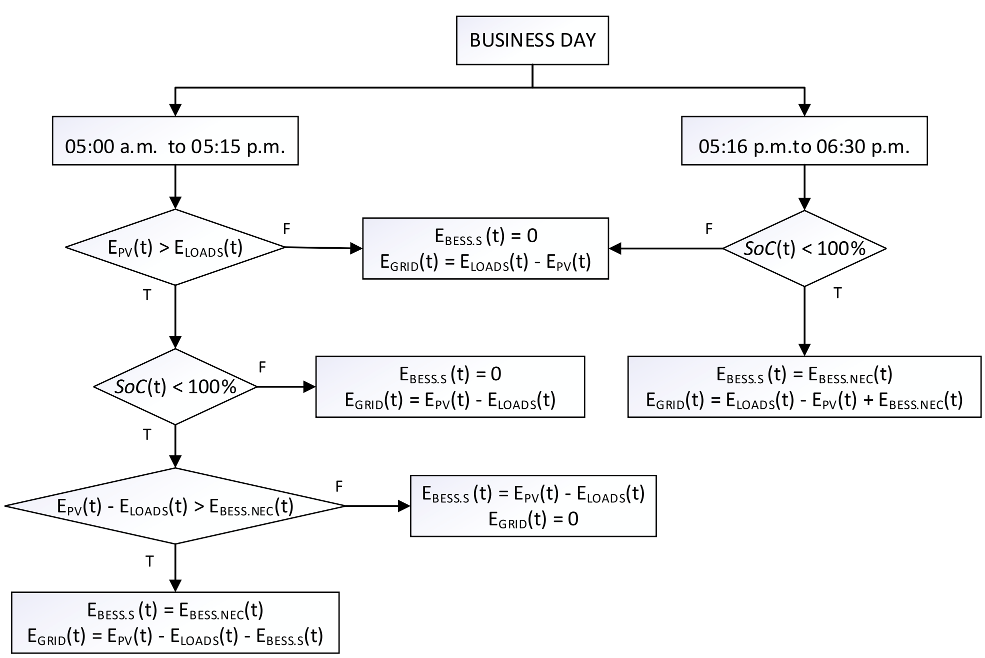


Fig. 6. Simplified schematic diagram of the proposed BESS charging strategy.

by the BESS. Eq. (20) displays the energy seen by the grid, at t instant. In this case, the BESS will discharge its energy into the grid.

$$E_{BESS.D}(t) = E_{BESS.A}(t) \tag{19}$$

$$E_{GRID}(t) = E_{LOADS}(t) - E_{PV}(t) - E_{BESS.A}(t) \tag{20}$$

d) $\boldsymbol{SoC(t)} = \mathbf{20\%}$: SoC is equal to the minimum allowed and the BESS is not discharged. The energy discharged and the energy supplied by the grid are shown in Eqs. (18) and (8), respectively.

Fig. 7 shows the simplified schematic diagram of the BESS discharging strategy.

Analysis of the public building PU with BESS

The adoption of a BESS in the PU implies new power demand profiles, which can be obtained through the original power demand profiles and the BESS operation simulation (charge/discharge process). The new energy profiles (injected or required from the grid) can be calculated using Eqs. (3) and (4). Due to the difference between peak and off-peak electric energy tariffs, this paper also proposes to evaluate flexible loads in order to shift peak consumption.

Economic analysis

The economic analysis of the return on investment for the insertion of a simulated BESS in the PU can be done through simulations of indicators such as payback time calculations (discounted payback), net present value (NPV), internal rate of return (IRR) and levelized cost of storage (LCOS) (Jülch et al., 2015).

In contrast to the levelized cost of energy (LCOE), which calculates the per-unit cost of generating electricity over the entire life cycle of a system, the LCOS is specifically dedicated to assessing the cost associated with the storage component of an energy system. It evaluates the cost of storing a unit of electricity over the lifetime of a storage system. LCOS plays a pivotal role in evaluating the economic feasibility of energy storage solutions, particularly in applications where storage is a critical component, such as in renewable energy integration.

The examination of these economic metrics provides a comprehensive insight into the financial ramifications associated with the incorporation of BESS within a PU. These metrics serve as valuable tools for informing stakeholders, policymakers, and researchers in their decision-making processes regarding the feasibility and long-term advantages of adopting such energy storage solutions

$$P(k) = -I + \sum_{k=0}^{N} \frac{(R_k - C_k)}{(1+i)^k} \tag{21}$$

$$NPV = P(N) \tag{22}$$

$$NPV = 0 = -I + \sum_{i=0}^{N} \frac{(R_k - C_k)}{(1+IRR)^k} \tag{23}$$

$$LCOS = \frac{\sum_{t=1}^{t=n} \left[\frac{I + O\&M_n}{(1+MRA)^n}\right]}{\sum_{t=1}^{t=n} \left[\frac{BESSc\ (n)}{(1+MRA)^n}\right]} \tag{24}$$

where:

$P(k)$ = Present value of year k [US$];
R_k = Revenue from year k (benefits) [US$];
C_k = Costs from year k (expenses) [US$];
N = BESS lifespan;
i = Annual interest rate employed;
I = Initial investment;
MRA = Minimum rate of attractiveness;
$O\&M\ (n)$ = BESS operation and maintenance cost per cycle [US$];
$BESSc\ (n)$ = BESS storage capacity per cycle (considering degradation) [kWh];
n = Number of cycles in its useful life;
t = Number of cycles used.

The net metering system is utilized in Brazil. In accordance with this scheme, the energy credits can be generated by the PU via energy injection into the grid. These energy credits are initially compensated in the utility bill of the unit itself (at the time of use period in which they were produced), followed by compensation in other time of use periods. If there are still remaining credits at the end of the utility billing cycle, they can be compensated onto other consumer units of same ownership within the same energy utility area (remote self-consumption). Energy credits can be used for a period of up to 60 months (Agência Nacional De Energia Elétrica, ANEEL, 2021c; BRASIL, 2022a). This work considers the current legislation (Conselho Nacional De Política Fazendária - CONFAZ, n.d.; Agência Nacional De Energia Elétrica, ANEEL, 2021c; BRASIL, 2022a; BRASIL, 2022b), contemplating the new Brazilian legislation for distributed PV generation.

In this study, the annual revenues (annual avoided energy expenses) due to the insertion of the BESS in the PU correspond only to the annual avoided energy expenses in the public building PU added to the annual avoided energy expenses due to remote self-consumption at other public consumer units of same ownership (fed at medium voltage). The annual cost can be attributed to the operation and maintenance expenses (O&M). To account for the escalating electricity rates and the declining cost of batteries, a sensitivity analysis is conducted.

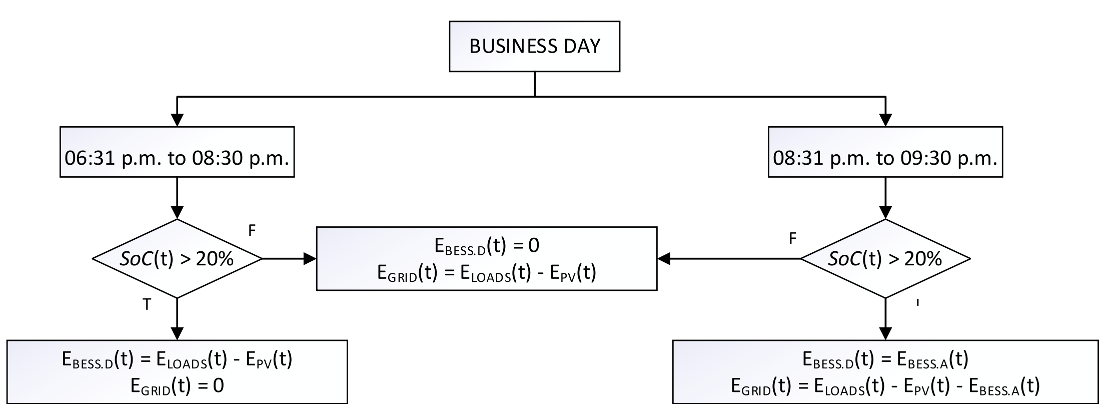


Fig. 7. Simplified schematic diagram of the proposed BESS discharging strategy.

Results

Public building PU without BESS

Figs. 8 and 9 present, for the city of Florianópolis-Brazil, the monthly evolution of the daily average measured and satellite derived GHI and ambient temperature data for the analyzed period. Additionally, these figures provide comparisons between the daily average GHI data from NASA, NREL, and the Brazilian Solar Energy Atlas databases, along with the corresponding mean daily temperature values derived from INMET and NASA data sources.

The solar energy resource in Florianópolis is abundant and well distributed throughout the year. The annual average daily measured GHI was 4.4 kWh/m^2, which coincides with values obtained through the different databases (4.3 kWh/m^2 (NASA), 4.5 kWh/m^2 (NREL) and 4.4 kWh/m^2 (Brazilian Solar Energy Atlas)). Despite the city being located in the region with the lowest solar irradiation in Brazil, it presents great potential for the use of solar PV energy. In the analyzed period, little difference was observed between measured data and the main available databases. Considering that the interannual variability of the Brazilian average daily solar irradiation availability is approximately 6 %, the measured values of solar irradiation can be considered satisfactory. Regarding annual average ambient temperature, measured data compared to values from NASA (21.7 °C) and INMET (21.1 °C) presented differences of 1.5 °C and 0.9 °C, respectively.

Fig. 10 illustrates, for the PU without BESS, the progression of measured irradiance, required (positive values) and injected (negative values) measured PU power demand in 15-minute intervals during the week spanning from March 4th to March 10th. Notably, five discernible peaks in power demand align with the e-Bus charging periods of electric buses, with the last peak coinciding with peak tariff hours. The findings reveal instances where PV generation fell short of power demand, resulting in power flow from the utility grid to the PU. Conversely, during periods of elevated PV generation, the PU contributed surplus power to the grid. It is worth noting that during weekends and public holidays, when activities at the Solar Energy Research Laboratory were minimal, nearly all the energy generated by the PV systems was injected into the grid.

The monthly evolution of the measured power demand injected (orange)/required (blue) from the PU, in 15-minute intervals can be observed in Fig. 11. During business days, the required power demand from grid exhibited elevated levels, attributed to the necessity of 75 kW power to charge the e-Bus. On non-business days, particularly when the e-Bus batteries remained uncharged, the PU required power demand was below 10 kW (sum of air conditioning appliances, computers, power electronics laboratory and LED lighting systems). Furthermore, the injected power into the utility grid displayed monthly variations, with its peak values occurring between the months of October and December.

Fig. 12 illustrates the measured monthly progression of power demands, both injected and required, delineated between peak and off-peak hours. In Fig. 13, the measured monthly energy consumption of the PU during peak and off-peak hours is depicted, alongside the monthly injection of energy during off-peak periods. Measured power demands required from the grid ranged between 85.34 kW to 96.29 kW, while the measured power demands injected into the grid varied between 46.90 kW to 72.53 kW. The annual energy consumed by the PU was approximately 77 MWh, of which 16.3 MWh (21.3 %) was consumed in peak hours and 60.6 MWh (78.7 %) during off-peak hours. The off-peak surplus of energy injected into the utility grid was approximately 70 MWh. The total PV excess energy corresponded to approximately 91 % of all the PU energy consumption (peak + off-peak).

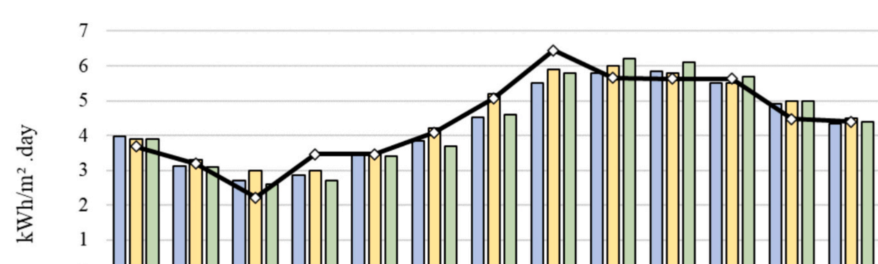
During five months within the studied timeframe, the quantity of surplus PV energy injected into the grid surpassed the energy consumption of the PU. In these particular months, under the framework of the Brazilian net-metering system, there existed the potential for reducing consumption at the Solar Energy Research Laboratory and other university owned consumer units.

Public building PU with BESS

The sizing of the simulated BESS was determined based on the PU required/injected power demand profiles. Table 2 provides a concise overview of the technical specifications, while Table 3 summarizes its operational parameters.

The simulated PU required/injected PU power, in 15-min intervals for the week between March 4th and March 10th, is presented in Fig. 14, alongside the BESS SoC and charge/discharge power. It can be observed that, on business days and during off-peak hours, the surplus PV energy that would be fed into the utility grid by the PU would be used to charge the BESS. In periods when PV generation was greater than PU demanded power and with full SoC, there would be a power flow from the PU to the utility grid (exporting surplus PV energy). The BESS supplements its charge from the grid, as demonstrated on Wednesday, to ensure a full SoC when entering peak hours. This necessity arises from lower irradiance levels, leading to a reduced surplus of the PU PV energy. During peak hours on business days, the BESS would supply the PU demanded power and subsequently would discharge to the utility grid all its remaining stored energy. On non-business days the charging/discharging process would be interrupted, and therefore all the surplus PV energy at the PU would be injected into the utility grid.

Fig. 15 presents the monthly power demands (injected/required) during peak and off-peak hours considering the simulated BESS. Throughout peak hours, there would be an average reduction of 92.7 % in required power demands, while during off-peak hours, an increase of up to 47 % can be expected, occurring due to the need to complete BESS charging via energy from the utility grid. It can be noticed that during



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Year
NASA	4.0	3.1	2.7	2.9	3.5	3.9	4.5	5.5	5.8	5.9	5.5	4.9	4.3
NREL	3.9	3.3	3.0	3.0	3.5	4.2	5.2	5.9	6.0	5.8	5.5	5.0	4.5
ATLAS	3.9	3.1	2.6	2.7	3.4	3.7	4.6	5.8	6.2	6.1	5.7	5.0	4.4
Measured	3.7	3.2	2.2	3.5	3.5	4.1	5.1	6.5	5.7	5.6	5.6	4.5	4.4

Fig. 8. Daily GHI for Florianópolis-Brazil.

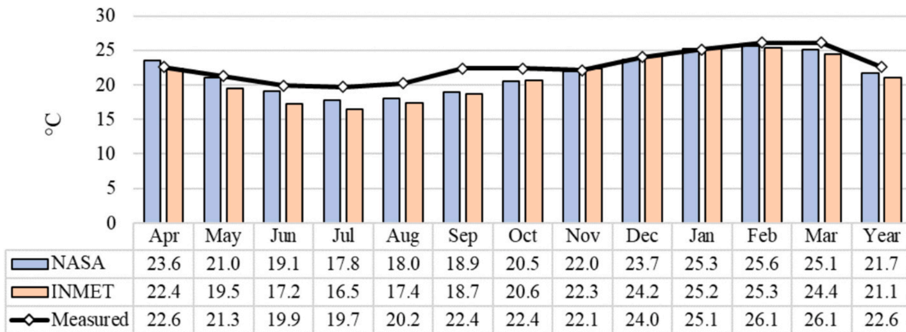


Fig. 9. Daily ambient temperature for Florianópolis.

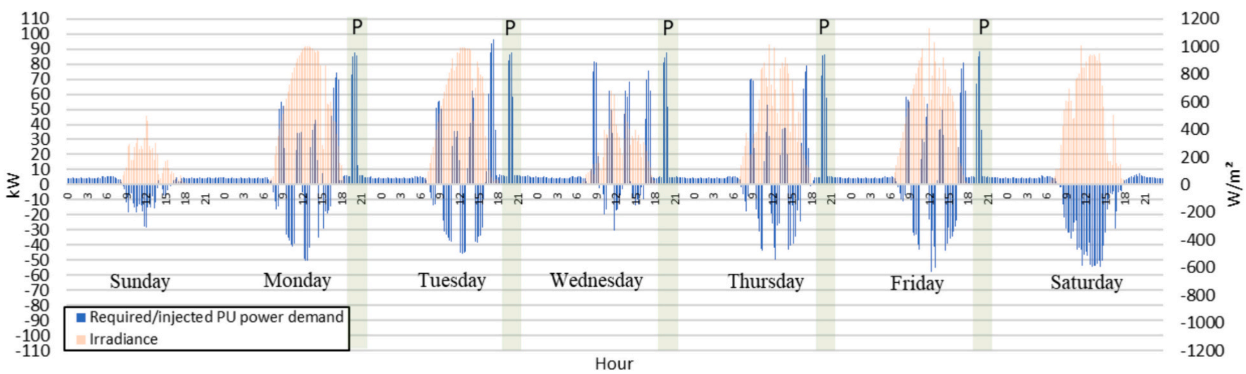


Fig. 10. Measured irradiance and required/injected PU power demand for the PU without BESS.

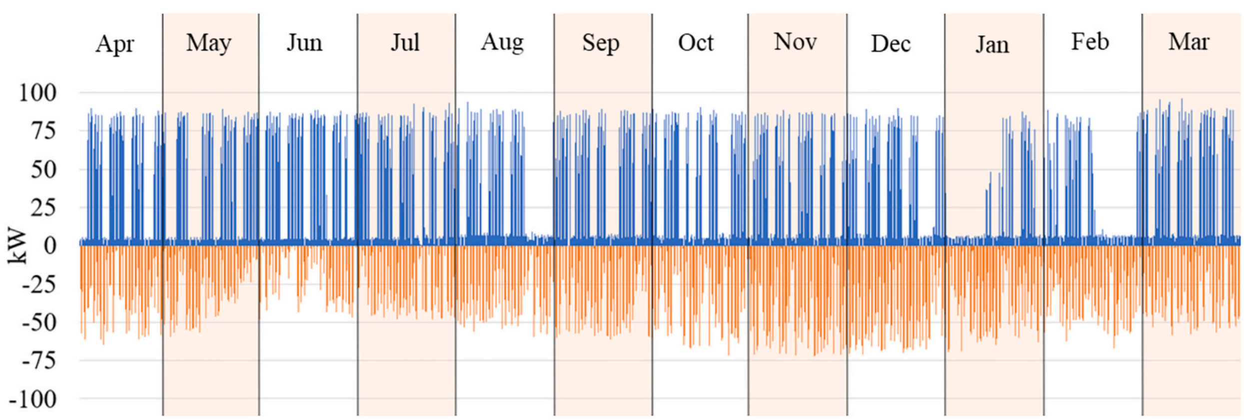


Fig. 11. Measured power demand injected (orange)/required (blue) from the PU, in 15-minute intervals.

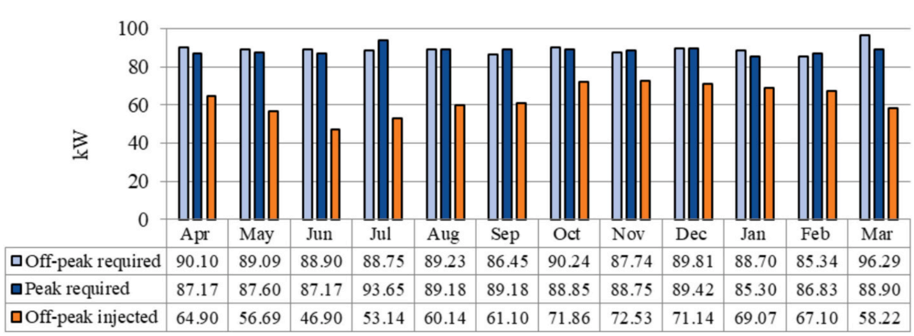
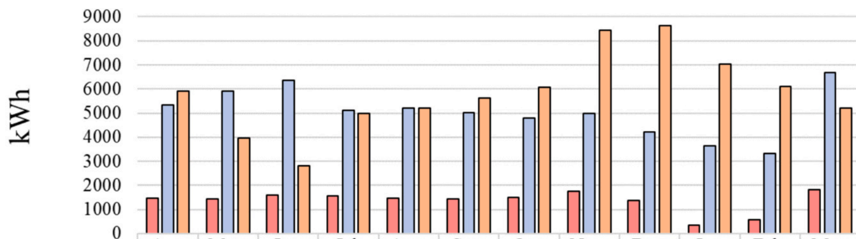


Fig. 12. Off-peak/peak required and off-peak injected measured power demands.



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Peak consumption	1465	1435	1598	1563	1485	1425	1509	1753	1372	352	574	1834
Off-peak consumption	5347	5910	6348	5105	5209	5028	4791	4972	4219	3643	3338	6692
Off-peak injected	5910	3960	2810	4996	5216	5640	6062	8435	8627	7031	6096	5200

Fig. 13. Measured off-peak/peak energy consumption and off-peak injected energy into the grid.

Table 2
BESS technical data.

Variable	Value	Unit
Rated storage capacity	150	kWh
Rated charge/discharge power	100	kW
Roundtrip efficiency	88	%
Lifespan	6000 cycles @ 80 % *DoD*	
Minimum SoC	20	%

Table 3
Summary of BESS and grid operation.

Time period	System point	Operation	Operation values
06:01 a.m. to 05:15 p.m.	Grid BESS	Injected Charge	Fixed power = 0 kW Power range (between min and max of surplus PV power < 100 kW)
05:16 p.m. to 06:30 p.m.	BESS	Charge	Fixed power = 100 kW
06:31 p.m. to 08:30 p.m. [first 2 h of peak tariff]	Grid BESS	Consumption Discharge	Fixed power = 0 kW Power range (between min and max of PU required power)
08:31 p.m. to 09:30 p.m. [last hour of peak tariff]	BESS	Discharge	Fixed power = 100 kW

November and December these values exhibited an elevation, which can be attributed to e-Bus tests being carried out at unscheduled times. In the remaining months, the values consistently remained in the 100 to 120 kW range, representing an increase of, on average, 22 %. The off-peak injected power exhibited variability within the range of 47 to 72 kW, with its peak value representing approximately 69 % of the installed capacity of the PU PV system.

The simulated monthly energy consumption and injected energy into the utility grid during peak and off-peak hours is presented in Fig. 16 in comparison with the original profiles. The adoption of the BESS results in increased monthly off-peak energy consumption, increasing by 7 % (4.27 MWh), contingent upon the days throughout the year when BESS charging necessitates supplementation from the utility grid. In January and February consumption would be lower than in the other months due to vacation and Carnaval periods, resulting in reduced e-Bus usage. The integration of the BESS leads to a reduction of the annual surplus of PV energy injected into the grid, primarily attributed to its utilization for BESS charging purposes. In this case, the surplus PV energy injected into the grid would be 45.1 MWh (36 % reduction), and the energy consumed during peak hours would be reduced to 0.52 MWh (96.8 % reduction), as compared to the values shown in Fig. 13. Regarding the injection of stored energy into the grid during peak hours, the cumulative amount would be 9.8 MWh. the highest values would occur in January and February due to the vacation period when the e-Bus was not in use.

e-Bus time shiftable nature

The e-Bus represents the greatest load for the PU and an opportunity to shift peak consumption was analyzed. Fig. 17 presents, in 15-min intervals for the week between March 4th and March 10th, the evolution of simulated PU required/injected power and BESS SoC and charge/discharge power. This case pertains to the scenario in which the final daily full charge of the e-Bus occurs during off-peak hours, specifically from 09:31 p.m. to 10:30 p.m. During peak hours, with the shift of the last e-Bus charging period, the BESS would provide energy to deduct the PU required power demand and then fully discharge its energy at its nominal power.

Fig. 18 exhibits the monthly energy consumption and injected energy into the utility grid, considering the simulated BESS and considering e-Bus peak shift. Shifting the last e-Bus charging period would not modify

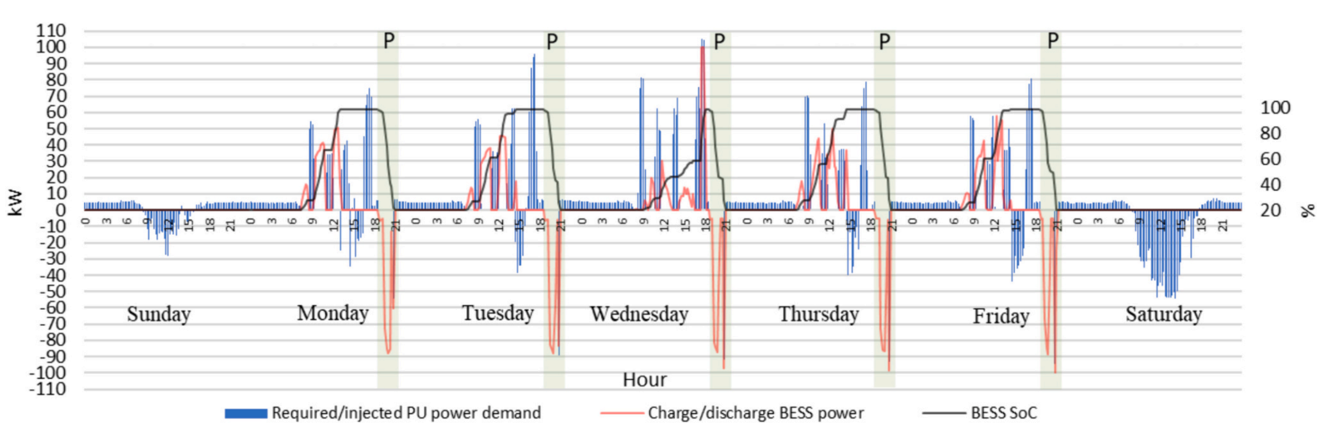
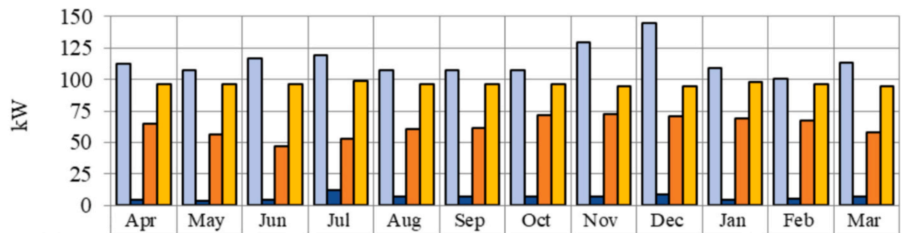


Fig. 14. Simulated PU required/injected power demand and BESS SoC and charge/discharge power.



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Off-peak required	112.19	107.68	116.74	119.30	107.58	107.10	107.58	129.04	144.59	109.22	100.58	113.34
Peak required	4.75	3.79	4.56	12.53	6.82	6.72	6.86	6.86	8.74	4.32	5.42	6.62
Off-peak injected	64.90	56.69	46.90	53.14	60.14	61.10	71.86	72.53	71.14	69.07	67.10	58.22
Peak injected	96.45	96.64	96.54	98.85	96.40	96.16	96.35	94.53	94.96	97.74	95.87	94.91

Fig. 15. Off-peak/peak required and injected measured power demands considering the simulated BESS.

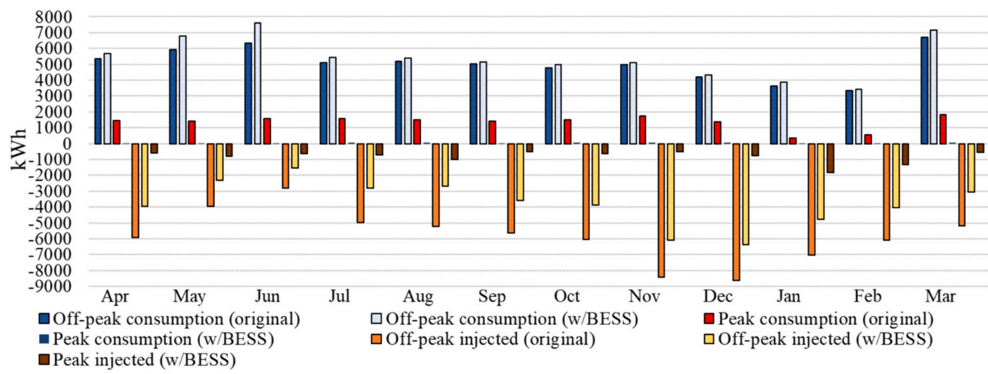


Fig. 16. Off-peak/peak energy consumption and injected energy into the grid considering the simulated BESS in comparison with the original profiles.

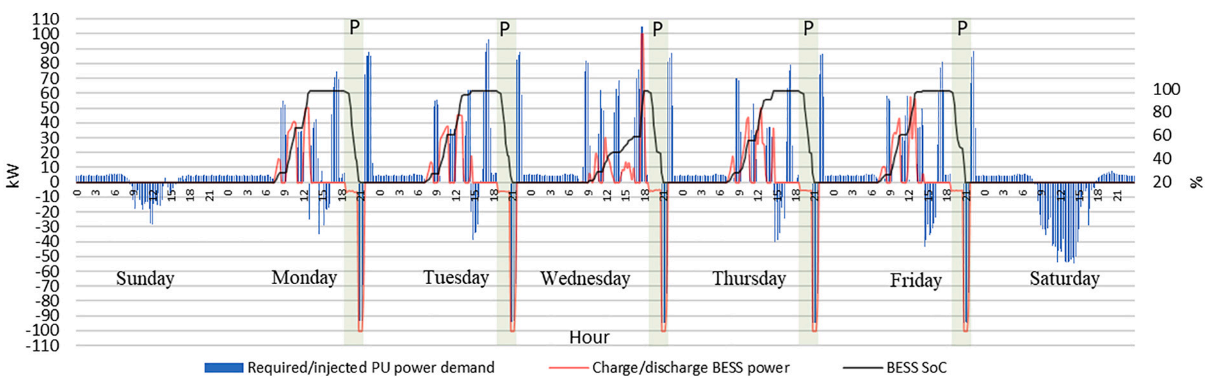
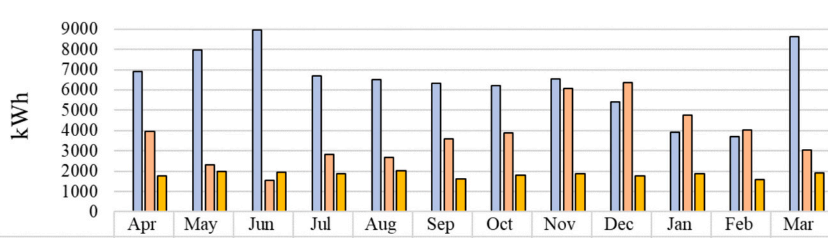


Fig. 17. Simulated PU required/injected power demand and BESS SoC and charge/discharge power considering e-Bus peak shift.



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Peak consumption	0	0	0	0	0	0	0	0	0	0	0	0
Off-peak consumption	6921	7983	8955	6677	6498	6310	6203	6547	5397	3920	3709	8612
Off-peak injected	3971	2319	1552	2810	2663	3603	3865	6081	6356	4770	4035	3056
Peak injected	1760	1969	1955	1875	2021	1618	1801	1861	1772	1881	1597	1910

Fig. 18. Off-peak/peak energy consumption and injected energy into the grid considering the simulated BESS and e-Bus peak shift.

the amount of surplus PV energy injected into the grid by the PU during off-peak hours. However, off-peak energy consumption would increase would increase by approximately 28 % (17.13 MWh) while the measured injected/required power demands would not change significantly. During peak hours, consumption would be nullified and the total energy injected into the grid would be 22.02 MWh (125 % increase).

Fig. 19 portrays the monthly evolution of the energy that would be used to charge the simulated BESS at the PU. Approximately 85 % of the total energy required would be supplied from the surplus PV energy generated at the PU while the remaining 15 % would be supplemented by the grid. Between August to February, 90 % of the energy stored in the BESS would have been provided by the PU PV surplus. During April and March, this percentage would be between 80 % and 85 % whereas during May and June, it would be 65 % and 50 %. This observed decrease is a caused by the least amount of monthly PV energy surplus, as shown in Fig. 11. In June, approximately half of the PU surplus energy would be used to charge the BESS, resulting in a greater amount of grid supplied energy to complete the BESS SoC. Conversely, in August, the largest amount of surplus of PV energy injected into the grid could be observed due to the fact that the e-Bus was under maintenance (Fig. 11).

Economic analysis for the public PU

The results suggest that the adoption of a BESS in the PU would alter the following profiles: power demand, energy consumption and surplus of PV energy injected into the utility grid. These factors will strongly influence the evaluation of the reduction/increase of the PU electric energy expenses. In the analysis of the financial attractiveness of the return on investment the case considering the e-Bus peak shift was considered.

Table 4 presents, for the PU, the monthly energy expenses (peak + off peak) with and without the simulated BESS, considering the assumptions presented in Tables 2 and 3. Additionally, it presents the avoided expenses (benefits). It can be observed that in the period between November and February, the PU energy expenses (without BESS) are low due to the high amount of PV energy injected into the grid. During other months there is a significant reduction in energy expenses (with BESS). The annual benefit that would be provided by the BESS for the public PU would be US$2564.70.

Table 5 presents the monthly evolution of avoided energy expenses (benefits) due to the remaining energy credits compensated in other consumer units (remote self-consumption) for the case with and without the simulated BESS, considering the assumptions presented in Tables 2 and 3. The total benefits promoted for other consumer units is also presented. The findings show that the avoided energy expenses with remote self-consumption would be higher in the period between October and February, due to the high amount of energy injected into the grid, leading to more energy credits being compensated. Furthermore, the annual benefits provided by the BESS with remote self-consumption for other public consumer units would be US$1799.46. The total annual benefits would add up to US$ 4364.16.

The variables used to analyze the financial attractiveness of the ROI (Return On Investment) of the BESS are shown in Table 6. Table 7

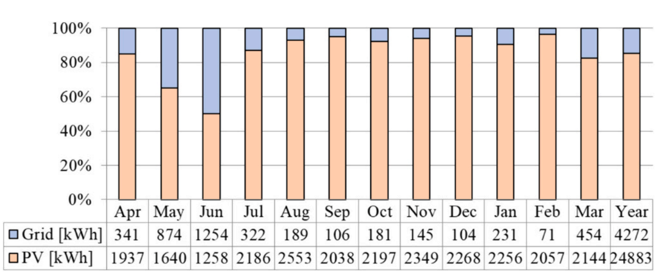


Fig. 19. BESS charging energy source.

Table 4
PU energy expenses (with and without the simulated BESS) and the energy benefits provided by the BESS for the PU.

Month	PU energy expenses		Energy benefits promoted by the BESS for the PU (US$)
	Without BESS (US$)	With BESS (US$)	
Apr	298.90	8.57	290.33
May	537.87	201.29	336.58
Jun	709.56	344.51	365.06
Jul	421.78	67.13	354.64
Aug	391.38	44.91	346.47
Sep	280.38	7.53	272.85
Oct	198.65	5.22	193.43
Nov	5.56	5.54	0.02
Dec	4.68	4.58	0.10
Jan	3.28	3.30	−0.02
Feb	3.39	3.10	0.29
Mar	605.82	200.87	404.95
Total	3461.25	896.55	2564.70

Table 5
Avoided energy expenses with remote self-consumption (with and without the simulated BESS) and to total benefits provided by the BESS for other consumer units.

Month	Avoided energy expenses with remote self-consumption		Benefits provided by the BESS for other consumer units (US$)
	Without BESS (US$)	With BESS (US$)	
Apr	0.00	0.00	0.00
May	0.00	0.00	0.00
Jun	0.00	0.00	0.00
Jul	0.00	0.00	0.00
Aug	0.00	0.00	0.00
Sep	0.00	0.00	0.00
Oct	0.00	101.61	101.61
Nov	45.20	411.78	366.58
Dec	172.73	690.54	517.81
Jan	226.93	692.74	465.81
Feb	146.27	493.92	347.65
Mar	0.00	0.00	0.00
Total	591.13	2390.59	1799.46

Table 6
Variables assumed for economic analysis.

Variable	Value	Unit	Reference
BESS cost (I)	550	US $/kWh	(EPE – Empresa de Pesquisa Energética, 2021; GREENER, 2021)
Annual O&M expenses	0.5	% of I	(GREENER, 2021)
BESS inverter reinvestment cost after 10 years	15	% of I	(GREENER, 2021)
Annual interest rate applied	6	%	(GREENER, 2021)
Tariff annual increase	5.2	%	(Montenegro et al., 2019)
Off-peak energy tariff	0.0818	US $/kWh	(Agência Nacional De Energia Elétrica, ANEEL, 2021d)
Peak energy tariff	0.2614	US $/kWh	(Agência Nacional De Energia Elétrica, ANEEL, 2021d)
Annual PV energy injected into the grid degradation	0.5	%	(Jordan et al., 2016)

exhibits, for the period between 2022 and 2030, the expected BESS cost

Table 7
Expected values for BESS cost (EPE – Empresa de Pesquisa Energética, 2021; GREENER, 2021).

Year	BESS cost (US$/kWh)
2022	551
2023	478
2024	441
2025	404
2026	368
2027	349
2028	349
2029	349
2030	331

values for the Brazilian market (EPE – Empresa de Pesquisa Energética, 2021; GREENER, 2021).

In order to assess the influence of BESS cost on the economic feasibility of the system, Table 8 presents the evolution of NPV, IRR, and discounted payback as a function of the BESS cost. For this sensitivity analysis, standard BESS costs ranging from 184 US$/kWh to 551 US $/kWh were employed. According to the findings, for the assumptions considered in this work, the venture would not present a financially attractive return on investment. Acceptable values of IRR are those surpassing the specified annual interest rate (6 %). In such instances, the NPV turns positive, indicating financial gain. Even in the scenarios with lower BESS costs, the Payback period remain relatively high, ranging from 12 and 19 years. Only when costs fall below 225 US$/kWh would the system Payback period be <10 years. A reduction of approximately 27 % in BESS costs is necessary for these systems to exhibit viability. However, BESS costs are expected to decrease in the coming years, as shown in Table 7. Financial attractiveness can be achieved for BESS costs of US$ 408 (expected value for the year 2025).

The LCOS values found for the evolution of BESS costs are demonstrated in Table 9, for MRA ranging between 0 % and 10 %. Values that are lower than the tariff delta are considered interesting for financial gain. However, the greater the tariff delta the more attractive the system becomes. The MRA also presents visible impact over the LCOS, values over 10 % would be viable only for a BESS cost of 276 US$/kWh or lower.

To analyze the impact that electricity prices have on the BESS NPV, Fig. 20 presents the NPV values as a function of BESS costs for different cases of rising electricity prices. The sensitivity analysis encompasses scenarios with electricity price variations of +25 %, +50 %, +75 %, and + 100 %. NPV demonstrates favorability when it exceeds zero ($y = 0$), with increased energy tariffs augmenting the attractiveness of investments. For the case of +25 % increase, the system present viability for BESS costs up to 478 US$/kWh. These findings substantiate the significant impact of electricity pricing on the economic feasibility of such systems.

The cost of BESS is observed to exert a substantial influence on the financial implications of integrating these systems. In a general case, larger applications present higher upfront costs, which can potentially influence negatively the viability of these systems. Under such circumstances, conditions such as electricity rates play a crucial role in determining the economic feasibility and must be evaluated.

Table 8
NPV, IRR and the discounted payback period as a function of the BESS cost.

BESS cost (US$/kWh)	NPV (US$)	IRR (%)	Discounted payback (years)
551	−24,409.76	2.41	–
478	−11,869.71	4.07	–
441	−5599.68	5.04	–
404	670.34	6.12	19.75
368	6940.37	7.36	17.66
331	13,210.39	8.80	15.66
276	22,615.43	11.49	12.75
184	38,290.50	18.74	7.5

Discussion

As a result of this study, the total annual benefits provided by the BESS would represent 126 % of the annual PU original energy expenses. This study has shown that the implementation of BESS is feasible under certain conditions. Electricity rates analyzed for the base case are located in the first quartile among Brazilian energy utilities, being 59 % below national average (Agência Nacional De Energia Elétrica, ANEEL, 2023). This suggests that, despite the current storage market costs, BESS may have financial appeal in some regions of Brazil. Additionally, public prosumer units are optimal candidates for implementation of BESS given that they frequently include a wide range of consumer units at the municipal, state, or federal levels, allowing for maximum energy benefits for net-metering regulations.

In the Brazilian context, commercial electricity tariffs during off-peak hours are, on average, notably lower than tariffs imposed on residential consumers (Agência Nacional De Energia Elétrica, ANEEL, 2023). Conversely, average peak tariffs exhibit a slight increment for commercial consumers (Agência Nacional De Energia Elétrica, ANEEL, 2023). Consequently, this presents a greater rate period discrepancy for commercial consumers, rendering this category particularly suitable for the integration of BESS in behind the grid applications. Such integration proves advantageous for storing energy during off-peak rates for subsequent utilization during peak periods.

For commercial prosumers, the cost for implementing BESS will have to decrease for it to become feasible. Currently in Brazil, the tax burden on battery systems can reach up to 80 % and up to 40 % price reductions are anticipated by the end of the decade (GREENER, 2021). Further decrease in costs can come from government applied subsidies or other tax exemptions in order to boost BESS. Instances of these incentives are presently implemented on a global scale. The United States offers investment tax credits of 30 % that can add up to reach 50 % of BESS costs (https://pv-magazine-usa.com/2022/11/28/which-ira-credits-offer-greatest-motivation-to-invest-in-clean-energy/, 2022). Germany offers incentives that can cover up to 30 % of BESS costs (IRENA, 2021) and Australia provides solar battery interest-free loans to reduce upfront BESS costs (Australian Government, n.d.).

Implementation of battery solutions for on-grid applications have been scarce in Brazil. Regulatory frameworks governing the deployment of BESS in the country remain absent, either for consumers in the regulated energy market or the wholesale environment, and the country lacks incentive programs for such applications. The implementation of public policies concerning the regulation of behind-the-meter BESS in Brazil is imperative to harmonize costs with market supply and demand. However, all the potential and stacked benefits of BESS have to be taken into account in order to justify the substantial financial investments required, and with the declining costs of batteries alongside rising electricity tariffs, increased adoption of BESS is expected in the near future.

Conclusion

This study proposes a method to evaluate the energy and economic impacts of an energy storage system in the context of commercial public buildings based on techniques for measuring the electric energy demand and the surplus PV energy injected by the PU into the grid. Empirical data, including ambient temperature and solar irradiation, were employed to assess the solar radiation resource. In BESS simulations, PU power flows were utilized. The developed method is applicable to medium voltage consumers in Brazil and other countries under time-based electricity tariffs. The selected case location is Florianópolis, Brazil and simulations were carried out for a PU with annual electricity consumption of 77 MWh (16.3 MWh during peak hours^{-21}%) and 70 MWh annual surplus of PV energy injected into the utility grid.

Table 9
LCOS for different BESS costs and different MRAs.

MRA		LCOS (US$/kWh)										
		0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
BESS Cost (US$/kWh)	551	0.127	0.143	0.161	0.179	0.197	0.217	0.237	0.257	0.278	0.300	0.321
	478	0.110	0.124	0.139	0.155	0.171	0.188	0.205	0.223	0.241	0.260	0.279
	441	0.101	0.115	0.128	0.143	0.158	0.173	0.189	0.206	0.223	0.240	0.257
	404	0.093	0.105	0.118	0.131	0.145	0.159	0.174	0.189	0.204	0.220	0.236
	368	0.085	0.096	0.107	0.119	0.132	0.145	0.158	0.172	0.186	0.200	0.215
	331	0.076	0.086	0.096	0.107	0.119	0.130	0.142	0.155	0.167	0.180	0.193
	276	0.063	0.072	0.080	0.089	0.099	0.109	0.119	0.129	0.139	0.150	0.161
	184	0.042	0.048	0.054	0.060	0.066	0.072	0.079	0.086	0.093	0.100	0.107

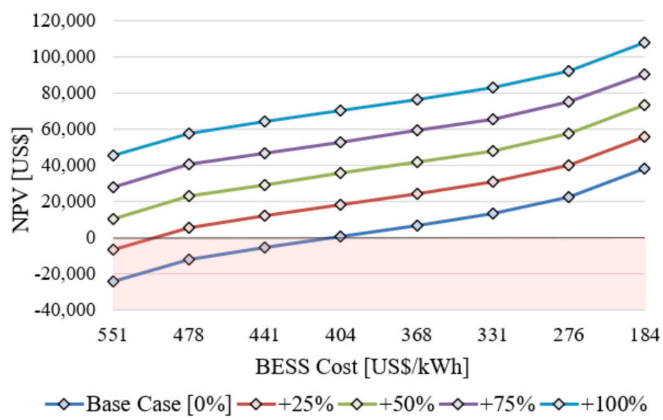


Fig. 20. NPV as a function of the BESS cost for different electricity prices ranging from the base case (0 %) up to a + 100 % increase.

Based on the required/injected power demand and energy profiles, a BESS was specified and sized. Its charging/discharging process was defined, considering the maximum use of the surplus of PV energy and the highest reduction of the PU's electric energy expenses. Results showed that a BESS with a nominal power of 100 kW and a storage capacity of 150 kWh would be suitable to be inserted in the PU. The simulation of a BESS yielded favorable energy results, with annual self-consumption of the PU increasing by nearly 30 %. An economic assessment for the public prosumer unit was carried out. Under the current analyzed conditions, the insertion of a BESS would not present financial attractiveness of return on investment. The results also showed that said attractiveness can be achieved when BESS cost reduce to US$ 408 (expected value for the year 2025).

The present work aimed to contribute with new knowledge regarding the uptake of BESS to ensure the dispatchability of PV generation systems in Brazil and fill the gaps that still exist in the National Electrical Energy Agency's Regulations (ANEEL) and the Brazilian Technical Standards. The knowledge acquired is indispensable in the evaluation of the impacts provided by the adoption of BESS on the electric energy expenses of PU's, an integral part of the evaluation of the financial attractiveness of BESS in public buildings.

This study's scope is not exhaustive, subsequent research efforts may consider taking into account certain facets and potentialities within the system application, such as: a) Uncertainties regarding energy consumption and the solar resource. In the future, better predictability techniques for these variables can be incorporated in to the method; b) Other BESS functions, such as control of contracted power demand, outage protection, linearization of intermittent sources and supply quality support (voltage support), frequency support, and power factor correction. In the meantime, a 100 kW and 200 kWh BESS has been recently installed at the Solar Energy Research Laboratory and will provide useful data to further studies, seeking new evidence to corroborate existing findings and further advance this field.

CRediT authorship contribution statement

G.X.A. Pinto: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Validation, Visualization, Writing – original draft, Writing – review & editing. **H.F. Naspolini:** Conceptualization, Formal analysis, Investigation, Methodology, Project administration, Visualization, Writing – original draft. **R. Rüther:** Conceptualization, Formal analysis, Funding acquisition, Investigation, Methodology, Resources, Supervision, 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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