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Posted Date: 6 January 2025

doi: 10.20944/preprints202501.0347.v1

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Article

Using Investments in Solar Photovoltaics as Inflation Hedges

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Abstract: Mainstream strategies for protecting wealth from inflation involve diversification into traditional assets like common stocks, gold, fixed-income securities, and real estate. However, a significant contributor to inflation has been the rising energy prices, which have been the main underlying cause of several past recessions and high inflation periods. Investments in distributed generation with solar photovoltaics (PV) present a promising opportunity to hedge against inflation, considering non-taxed profits from PV energy generation. To investigate that potential, this study quantifies the return on investment (ROI), internal rate of return (IRR), payback period, net present cost, and levelized cost of energy of PV by running Solar Alone Multi-Objective Advisor (SAMA) simulations on grid-connected PV systems across different regions with varying inflation scenarios. Case studies are San Diego, California; Boston, Massachusetts; Buenos Aires, Argentina; and Santiago, Chile. Historical inflation data is also imposed on San Diego to assess PV system potential in dynamic inflammatory conditions, while Boston and Santiago additionally analyze hybrid PV-battery systems to understand battery impacts under increasing inflation rates. Net metering credits vary by location. The results showed PV could be used as an effective inflation hedge in any region where PV started economic and provided increasingly attractive returns as inflation increased, particularly when taxes were considered. The varying values of the ROI and IRR underscore the importance of region-specific financial planning and the need to consider inflation when evaluating the long-term viability of PV systems. Finally, more capital-intensive PV systems with battery storage can become profitable in an inflationary economy.

Keywords: solar energy; photovoltaics; energy economics; inflation; inflation hedge; investments

1. Introduction

Inflation, the increase in price over a given period of time and the corresponding decline in purchasing power, is a significant economic phenomenon that has both short-term and long-term effects on markets and individual financial stability [1]. The government identifies the most commonly purchased goods and services to measure the average consumer's cost of living over a specific time period and is referred to as the consumer price index (CPI) [1]. Inflation is measured by the percentage change in the CPI over a specific period of time, typically one year. High inflation is characterized by a rapid increase in these prices over the same time period that results in a decline in the purchasing power of money [2].

In North America, inflation trends have historically centered around the Federal Reserve's target of maintaining a 2% inflation rate, a benchmark considered optimal for balancing economic growth and maintaining purchasing power [3]. Recent years have seen deviations from this target, however, due to unprecedented events like the COVID-19 pandemic, which led to significant economic disruptions [4,5].

In order to reduce the economic distress of working-class households due to the surge of unemployment during COVID, the U.S. government introduced \$1.9 trillion stimulus package following past economic models that had worked before during times of financial crisis [6]. This influx of capital, combined with supply-side disruptions such as labor shortages and shifts from service to goods consumption, propelled inflation rates well beyond the Federal Reserve's 2% target. By March 2021, inflation had escalated to 7% by the end of the year and climbing up to 9% by mid-2022 [6]. Moreover, geopolitical conflicts such as the Russia-Ukraine war further exerted inflationary pressures by disrupting global grain and energy supplies [7,8]. These factors have not only challenged the Federal Reserve's capacity to control inflation but also heightened investor anxiety, who are growing more concerned about the sustained inflation threat in the future [9].

Whether the inflation rate increases in the near future or not, it raises the question of what the average investor should do to hedge against inflation or, rather, what the best method is to secure a positive real return [10]. This is especially important for emerging market economies where inflation acceleration is likely to be greater than that in developed countries due to the significant role of food in their economies and their generally higher growth rates [11]. Latin American countries like Argentina, Brazil, Chile, Mexico, and Peru have had average annual inflation rates of 347%, 345%, 56%, 28%, and 343%, respectively, since 1970 and continue to face a high risk of inflation in the face of external shocks and political instability [10]. The triple-digit inflation numbers have been seen again in Argentina, rising to 276.2% in February 2024, leading to a cost-of-living crisis plunging the population deeper into poverty [12]. With the elections coming up, the inflation can worsen due to uncertainty, as usually seen in such regions due to inflation being intertwined with political cycles [12]. While the current inflationary scenario in other Latin American countries is not as bad, they still suffer from political environments and institutional frameworks similar to Argentina that can trigger hyperinflation in the future, underscoring the importance of inflation hedges in these economies [10,13,14].

Mainstream strategies of protecting wealth from inflation involve diversification into traditional assets like common stocks, gold, fixed-income securities, and real estate because these assets have received the most significant attention in the literature [15–17]. Historically, gold has been advertised as an ideal inflation hedge; however, gold's effectiveness as an inflation hedge has been uncertain post the 2008 financial crisis, with studies suggesting varying outcomes, with some arguing that outliers influenced the positive relationship between gold and inflation [15]. On the other hand, real estate, especially indirect instruments like real estate investment trusts (REITs) that pool investor funds to invest in income-producing mortgages, may serve as a partial inflation hedge in the long run [15]. Stocks are also commonly used as an inflation hedge and studies show that while stocks appear to perform poorly as an inflation hedge in the short run [18], several studies since the 1990s have presented more favorable evidence hedging for long-term horizons of at least 5 years [15].

As studies have shown, there is no universal strategy to protect against inflation and the results vary for different investors seeking different returns for different time frames [19]. Moreover, there remains a noticeable gap in the literature regarding inflation hedge effectiveness in emerging and frontier markets where these hedges are of much more importance for protection against the worst effects of inflation on poverty (i.e., Argentina). Most of the studies testing the effectiveness of traditional hedges are limited to regions in developed countries, namely USA, UK, Canada, and Japan [15]. This can be partly attributed to the lack of these traditional financial instruments to hedge with. For instance, countries like Argentina and Chile did not even have an equity index during hyperinflation periods in the past [10]. While countries like Chile and Mexico have developed 30-year government bond indices, offering some long-term investment and hedging opportunities, most of the nations in the region do not have such instruments [10]. The only bond markets available to investors in these countries is the world bond index in local currency [10]. This

gap underscores the importance of exploring alternative unconventional inflation hedges that can perform under a broader range of economic scenarios.

A significant contributor to inflation has been the rising energy prices which have been the main underlying cause in several recessions and high inflation situations in the past. The energy price shock during 1973–1974 was the leading cause of triggering the deep recession and high inflation of the mid-1970s [20]. This energy price shock had a significant impact on the overall price level. In fact, the abnormal inflation of 1974 can be fully explained by this event along with the removal of general price controls. When the Iraq War started in 2003, there was a clear trend reversal in energy prices, especially oil [21]. This shift highlighted the strong connection between oil prices and the global balance of its supply and demand. Energy prices are highly volatile and responsive to changes in market conditions, such as oil price fluctuations, geopolitical tensions, or supply chain disruptions [22]. The energy inflation rate can sometimes account for more than half of the overall inflation rate when it spikes [22,23]. As energy costs are an integral component of production and transportation costs, increases in energy prices can lead to higher costs of goods and services across the economy creating a ripple effect increasing inflationary pressures across a broad range of sectors.

Investments in distributed electrical general of technology particularly solar photovoltaics (PV) present a promising opportunity to hedge against inflation, specifically inflation related to energy costs [24]. The potential of PV as an inflation hedge, however, has not been explored fully in literature despite it being a very accessible form of investment throughout the world offering considerable returns on investment [25,26]. By generating their own electricity, homeowners can avoid the rising costs of energy from traditional sources of energy by locking in a price per kilowatt-hour that will not change for the lifetime of the system no matter the inflation. Moreover, apart from being a potential inflation hedge, adoption of PV systems also offers substantive reductions in carbon emissions and other environmental benefits [27,28].

In order to overcome these past limitations, this study quantifies the return on investment on PV by running simulations on grid connected PV systems across different regions with varying inflation scenarios. Case studies are presented for San Diego, California; Boston, Massachusetts; Buenos Aires, Argentina; and Santiago, Chile. Inflation is the primary factor for grid electricity price escalation, with future grid prices assumed to increase at the same rate as the annual average inflation. Historical inflation data are projected for San Diego to assess PV system potential in current and future conditions, while Boston and Santiago also analyze hybrid PV-battery systems to understand battery impacts under increasing inflation rates. Net metering credits vary by location. Simulations are conducted using Solar Alone Multi-Objective Advisor (SAMA) software V1.03, with input parameters including meteorological data, grid escalation rates, residential load data, and economic factors. Inflation rates are modeled to increase from 0% to 10% over the project's lifetime (flat rates). Economic profitability is evaluated using internal rate of return (*IRR*), payback period (*PP*), return on investment (*ROI*), net present cost (*NPC*), and levelized cost of energy (*LCOE*). These metrics provide insights into the financial performance of PV systems under varying inflation scenarios, investigating the effectiveness of PV as an inflation hedge. Simulation results and SAMA outputs are presented in Section 3 in tables and cash flow charts to show how varying inflation can affect PV economic profitability. In Section 4, using Tornado plots, the results are then compared to returns on other traditional hedges over similar time horizons and the use of PV as an inflation hedge is discussed.

2. Methods

2.1. Case Studies

Investigating the impact of inflation on the economic behavior of PV systems, several case studies across the American continent are chosen, as pointed out in Figure 1. The Inflation rate is considered the main driver for the escalation of grid electricity prices, i.e., grid prices are considered to be increased same as annual average inflation in the future. Grid connected PV system is investigated in San Diego-California, Boston-Massachusetts, Buenos Aires-Argentina, and Santiago-Chile. San Diego-CA is run using the historical data on inflation, in order to quantify the potential of PV in the current and future inflationary climate. In Boston-U.S. and Santiago-Chile, in addition to the grid-connected PV system, a hybrid grid-connected PV and battery system is also investigated to see the impact of batteries when Inflation rates are increasing. Net metering credits for Buenos Aires [29] and Santiago [30] is a one-to-one exchange, while for San Diego is true up rates [31] and Boston [32] is 60% of the sum of the following per kWh charges: basic service charge, distribution charge, transmission charge, and transition charge. Examining these varied contexts aims to provide a comprehensive understanding of how grid inflation rates influence the adoption and economic viability of PV systems across different geographical, climatic, and regulatory landscapes.

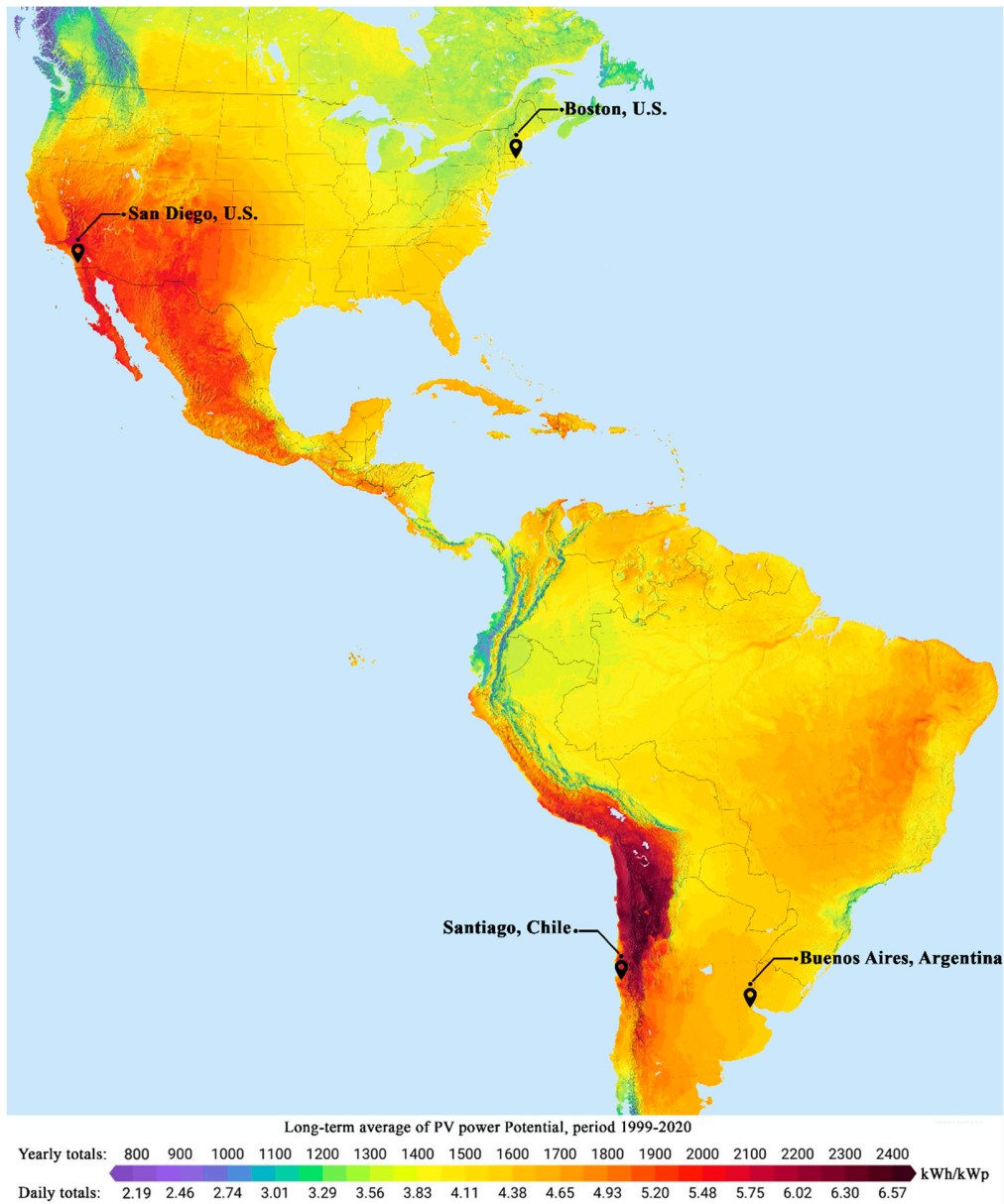


Figure 1. Case study locations across American continent on the PVOUT map using SolarGIS [33]).

2.2. Simulations

Solar Alone Multi-Objective Advisor (SAMA) software V1.03, as an open-source microgrid optimizer [34–37] is used for analysis. The input parameters are listed in Table 1. Other inputs not mentioned in Table 1 such as capital costs of PV and battery systems are derived from previous study [34].

Table 1. Input data for SAMA optimizations and simulations.

Type	Data	Specifications	Value	Unit	Ref.
Meteorological	Irradiation (GHI, DNI, DHI)	Obtained from NSRDB	-	W/m ²	[38]

	Azimuth	Azimuth for San Diego	180	-	[39]	
		Azimuth for Boston	180		[40]	
		Azimuth for Buenos Aires	0		[41]	
		Azimuth for Santiago	0		[42]	
	Tilt	Tilt angle of PV for San Diego	28.1	-	[39]	
		Tilt angle of PV for Boston	35.3		[40]	
		Tilt angle of PV for Buenos Aires	30.28		[41]	
		Tilt angle of PV for Santiago	29.1		[42]	
	Soiling	Losses in percentage	5%	%	[43]	
	Temperature	Obtained from NSRDB	-	°C	[38]	
Grid	Grid escalation rate (as result of inflation)		Starting from 0 up to 10%	%	-	
Load	Residential load	Hourly data for U.S.	-	kW	[44]	
		Annual consumption for Argentina	3,500	kWh	[45]	
		Annual consumption for Chile	2,100	kWh	[45]	
Costs	General	Rebate for renewables	30% for U.S.	%	[46]	
Economic rates	Nominal discount rate	U.S.	5.5	%	[47]	
		Argentina	40	%	[48]	
		Chile	6	%	[49]	
	Inflation rate Considered for project life time	U.S.	2	%	[50]	
		Argentina (average of inflation from 2004 to 2029-25 years)	38	%	[51]	
		Chile	3	%	[52]	
Utility rates	San Diego-CA	Seasonal tiered rate	Summer (June 1 – October 31)	\$/kWh	[53]	
			Tier 1 = Up to 234 kWh			0.404
			Tier 2: Above 234 kWh			0.509
			Winter (November 1-May 31)			
			Tier 1: Up to 343 kWh			0.404
			Tier 2: Above 343 kWh			0.509
			Surcharge rate			0.0003
	State regulatory fee	0.0013	\$/kWh	[55]		
	Franchise Fees	1.1% + 5.78	%	[56]		
	California climate credit	2*60.70	\$/yr.	[57]		
	Boston-MA	Monthly fixed rates	Monthly base charge Tax Exempt for residential use [58]	10	\$/mo	[59]
			Hourly charges		\$/kWh	
			Delivery	0.14703		
			Supply Monthly January	0.39502		
February			0.39008			
March			0.23984			
April			0.15791			

			May	0.13984		
			June	0.13463		
			July	0.15500		
			August	0.14251		
			September	0.11796		
			October	0.11787		
			November	0.16375		
			December	0.26010		
			Rebate	19.3		
	Buenos Aires- Argentina	Fixed rate	Residential price	0.020	\$/kWh	[60]
	Santiago-Chile	Fixed rate	Residential price	0.179	\$/kWh	[61]

2.3. Economic Analysis

Anticipating that grid electricity prices will rise with inflation annually (at the same rate over the lifetime of the project), average inflation rates are increased annually from 0% to 10% for the U.S. (i.e., if 2% annual average inflation rate inflation is considered, then in each year onward electricity prices will increase 2%). In this economic analysis, the concept of electricity price increase based on inflation simulates the impact of inflation on project costs. The value 0% to 10% for inflation rates in the U.S. is chosen based on looking into historical trends of inflation rates [62]. The forecasted inflation rate for U.S. is 2% [50]. U.S. average inflation rate scenarios listed below correspond to historical periods, when U.S. experienced almost the same inflation rates (based on the data in [63]), except for the 8-10% scenarios, which are considered as hypothetical excessive inflation conditions:

- 0% average Inflation: The Great Depression (1921-1945).
- 2% Inflation: Federal Reserve Target (1996-2020).
- 4% Inflation: The Great Moderation (1980-2004).
- 6% Inflation: The Great Inflation (1967-1991).
- 8-10% Inflation: Excessive Inflation hypothetical scenarios.

Given that the U.S. has experienced all these scenarios (except for the excessive inflation conditions), the results presented in this paper can provide valuable insights that guide future investments in PV systems, especially in the context of economic uncertainty. Similar to the U.S., inflation has increased from 0% to 10% for Chile analysis considering historical inflation trends there [52] and forecasted inflation rate of 3% [52]. In contrast, Argentina, with historically higher inflation rates, had its inflation rates increased from 7.5% to 20%, aligning with a forecasted future inflation rate of 10% [51].

To evaluate the economic profitability of PV systems, *IRR*, *PP*, and *ROI* are used in addition to the *NPC* and *LCOE*, considering the real discount rate, which is discussed in the following paper [34]. For economic analysis, the costs are the energy system costs accumulated over its lifetime, while revenues are savings from not buying the electricity from the grid due to PV energy generation. The *IRR* is calculated by setting the net present value (*NPV*) to zero, as shown in the following formula, where C_t represents the net cash flow during period t .

$$NPV = \sum_{t=0}^n \frac{C(t)}{(1+IRR)^t} = 0 \quad [\text{\$}] \quad (1)$$

Net cash flow (C_t) is determined using Equation 2, where I_{Cost} is the initial investment at the start of the project ($t=0$), M_{Cost} is the maintenance and operation costs of energy system parts over their lifetime, R_{Cost} includes costs for replacing system components over the project lifetime, G_{Cost} represents costs or revenues

from grid usage (positive values indicate costs, negative values indicate revenues), and A_{Cost} is the savings from not purchasing electricity from the grid or from selling to the grid due to the hybrid energy system generation, as calculated by Equation 3. All the above-mentioned costs are in USD. $E_{load}(h)$ stands for electrical load in each hour (h) in kWh, G_{Cost}^{Hourly} presents the hourly electrical rate in \$/kWh, $G_{Cost}^{Adjustment}$ is grid adjustment costs in \$/kWh, $G_{Cost}^{Monthly}$ is the grid monthly costs (service charges) in \$, R_{tax} represents the grid sale tax rate, and R_{rebate} is the electricity rebate rate.

$$C(t) = \begin{cases} -I_{Cost} & t = 0 \\ -M_{Cost}(t) - R_{Cost}(t) - G_{Cost}(t) + A_{Cost}(t) & \text{for } t = 1, 2, \dots, n \end{cases} \quad [\$] \quad (2)$$

$$A_{Cost} = (\sum_{h=1}^{8760} E_{load}(h) \times G_{Cost}^{Hourly}(h) \times G_{Cost}^{Adjustment} + \sum_{t=1}^{12} G_{Cost}^{Monthly}) \times (1 + R_{tax} - R_{rebate}) \quad [\$] \quad (3)$$

Discounted PP is calculated using Equation 5, where C_i is the net cash flow (revenues minus costs) in year i , and CCF_t is the cumulative cash flow at year t , calculated using Equation 4. CCF_t is the sum of all net cash flows from the start of the project up to year t .

$$CCF_t = \sum_{i=0}^t C_i \quad [\$] \quad (4)$$

$$PP = \min\{t \mid CCF_t \geq 0\} \quad [\text{years}] \quad (5)$$

ROI is calculated using Equation 6, whereas Total Net profits (V_P) is calculated using Equation 7 in \$ and total costs (C_{total}) are all costs ($I_{Cost} + M_{Cost} + R_{Cost} + G_{Cost}$) accumulated through life time of project in \$. Total Avoided costs (A_{Cost}^{total}) stands for all A_{Cost} accumulated over the lifetime of the project, Salvage value ($V_{salvage}$) represents the remaining value of a power system component at the end of the project's lifetime, and Grid Revenues (V_{Grid}) is revenues achieved through grid (if any-when G_{Cost} is negative).

$$ROI = \frac{V_P}{C_{total}} \quad (6)$$

$$V_P = A_{Cost}^{total} + V_{salvage} + V_{Grid} - C_{total} \quad (7)$$

The ROI looks at the return over the PV's lifetime, while the IRR only provides a year of return. In the first year, they are the same.

3. Results

The PV on grid results from the SAMA analysis are shown for San Diego California (Figure 2), Boston Massachusetts (Figure 3), Santiago-Chile (Figure 4) and Buenos Aires-Argentina (Figure 5). All the result figures show the cash flow as a function of year over the lifetime of a PV system (25 years). Figure 2 is instructive for how a PV investment operates. In year zero, the large negative red value is from the initial investment of the system. Then, for years 1 through 25, small negative maintenance and operating costs are dwarfed by the avoided grid costs by supplying solar electricity (the amount saved compared to when the user for providing electricity fully relied on the grid). On top of this, a basic line graph is also used to show the total system costs with different grid inflation rates reflecting both costs and revenues (avoided costs). For example, in Figure 2, considering a grid inflation rate of 2% in San Diego (which is typical for grid inflation rates based on the target inflation rate in U.S. [50]), the blue line crossing the zero of the y-axis indicates that the PV system has paid for itself – and then earns increasingly large quantities of money (profit) after 9th year of operation. Also, in this case, the total accumulated profit of the PV system in San Diego can reach up to \$30,000. If the solid line never crosses the zero y axis, the PV system never pays for itself. Similar results are shown for Boston (Figure 3), where inflation rates of 2% yield 6 years instead of 9

years for San Diego. This is due to higher NM credits offered in Boston. In both Figures 2 and 3 for the U.S., by increasing inflation rates from 0% to 10%, the economic profitability of PV systems is being increased, as grid users need to pay more expensive prices for grid electricity each year. The increase in inflation rates from 0% to 10% leads to reducing the *PP* of the project from 10 years to 6 years in San Diego and 6 years to 5 years in Boston. These same trends continue in Santiago, Chile (Figure 4), where the PV project is profitable, exhibiting a *PP* of 13 years for 0% and 8 years for 10%. However, Argentina's economic situation is different due to higher inflation rates. Considering average lifetime inflation rates from 7.5% up to 20% for Buenos Aires, Argentina, shown in Figure 5, it can result that the PV project is not reaching profit and *PP* is not observed until inflation rates reach 12.5%. The reason behind this is the low-cost electricity prices in Argentina (\$0.02/kWh) and grid credits for NM.

North American cities, particularly Boston and San Diego, benefit from stable economic conditions, higher electricity prices, and favorable NM credits, resulting in quicker payback periods and higher profitability. In North America, increasing inflation rates from 0% to 10% significantly enhances profitability, reducing the payback period more effectively in Boston than in San Diego. Santiago, Chile, follows a similar trend to North American cities like San Diego and Boston, though less pronounced. Like North American case studies, Santiago benefits from abundant solar resources and high grid electricity prices. These factors make grid-tied PV systems profitable in Chile. Buenos Aires, however, requires higher inflation rates to reach profitability due to lower baseline electricity prices. South American cities, specifically Buenos Aires, face solar economic challenges even with high inflation, as low electricity prices delay profitability.

Table 2 details the simulation results of different case studies for on-grid PV systems. The optimal system size in San Diego is 8.8 kW PV with a 7.3 kW inverter. The data reveals that inflation significantly impacts the *NPC* and *LCOE*. For instance, at a 0% inflation rate, the *NPC* is \$48,049, which rises to \$117,330 at a 10% rate. The *LCOE* follows a similar trend, increasing from \$0.15/kWh to \$0.37/kWh as inflation escalates from 0% to 10%. This is because NM credit per kWh sold to the grid for grid-connected PV is relatively inexpensive, and users on optimum PV systems still need to pay \$25,731 over 25 years to the utility. Increasing the inflation can escalate this amount even more, where with 10% yearly inflation, users would have to pay \$95,000. In contrast, Boston's optimal system size is slightly smaller, at 7.6 kW PV with a 6.3 kW inverter. The *NPC* for Boston remains relatively stable across different inflation rates, starting at \$19,287 for 0% inflation and only increasing to \$19,290 at 10% inflation. This is because the grid-connected PV system benefits from favorable NM credits by offsetting grid costs (Boston exhibits almost zero grid costs). With an optimal system size of 1.2 kW PV and a 1 kW inverter, Santiago, Chile, also enjoys low grid payments in different inflation scenarios (\$16 for a 0% inflation rate and \$60 for 10% inflation over the project's lifetime). Like Boston, this leads to slight increases in *NPC* from \$4,151 at 0% inflation to \$4,195 at 10%, and the *LCOE* remains constant at \$0.07/kWh. Buenos Aires, Argentina, presents a different scenario with higher inflation rates and less annual electrical consumption, with an optimal system size of 2.25 kW PV and a 1.9 kW inverter. The higher inflation rates in Argentina, starting at 7.5% and going up to 20%, impact the *NPC* and *LCOE* slightly due to NM credits earned by the PV system. For instance, the *NPC* increases from \$7,978 at 7.5% to \$8,037 at 20%. The *LCOE* remains constant at \$0.07/kWh despite these higher inflation rates.

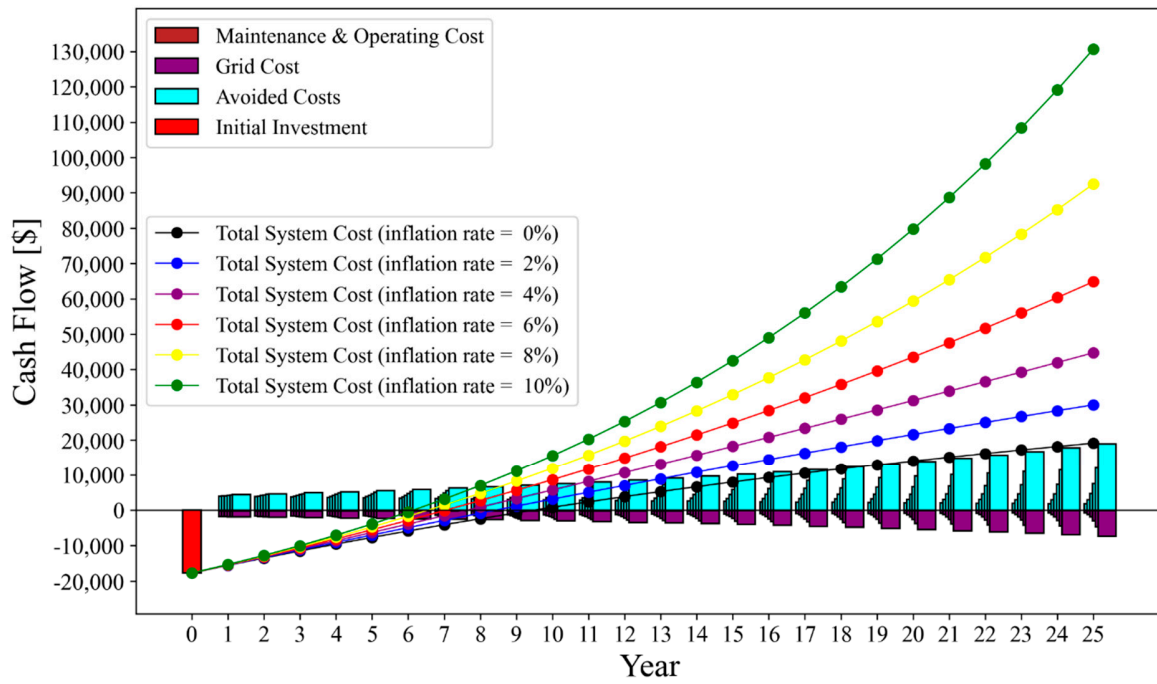


Figure 2. Cash flow chart of PV-Grid system for different inflation rates San Diego, CA.

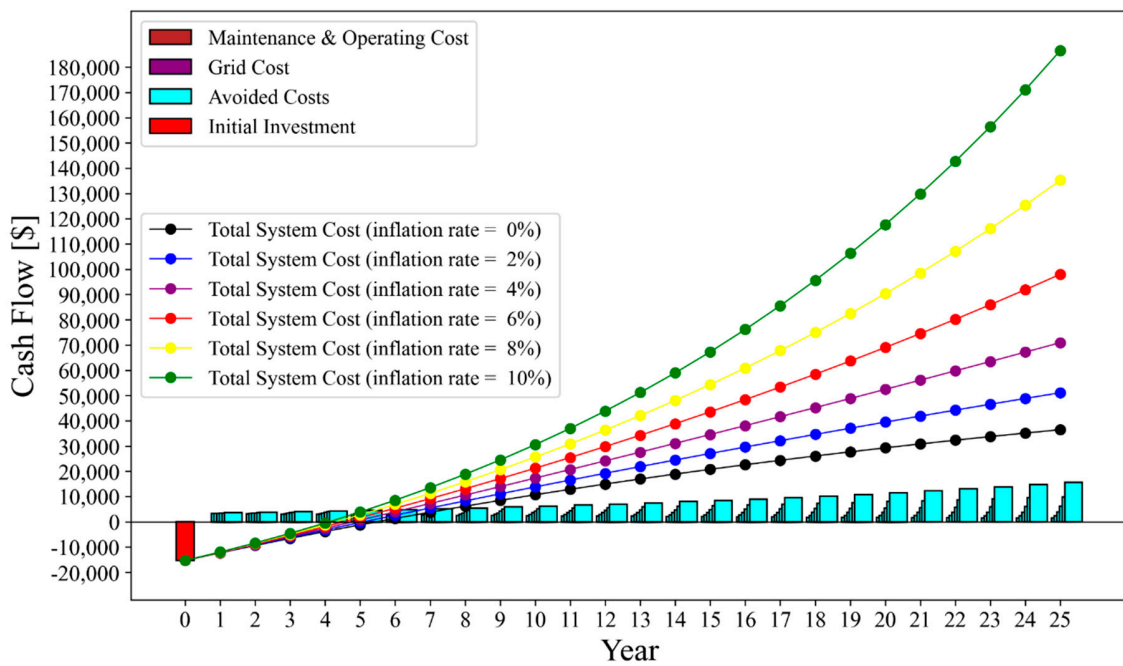


Figure 3. Cash flow chart of PV-Grid system for different inflation rates Boston, MA.

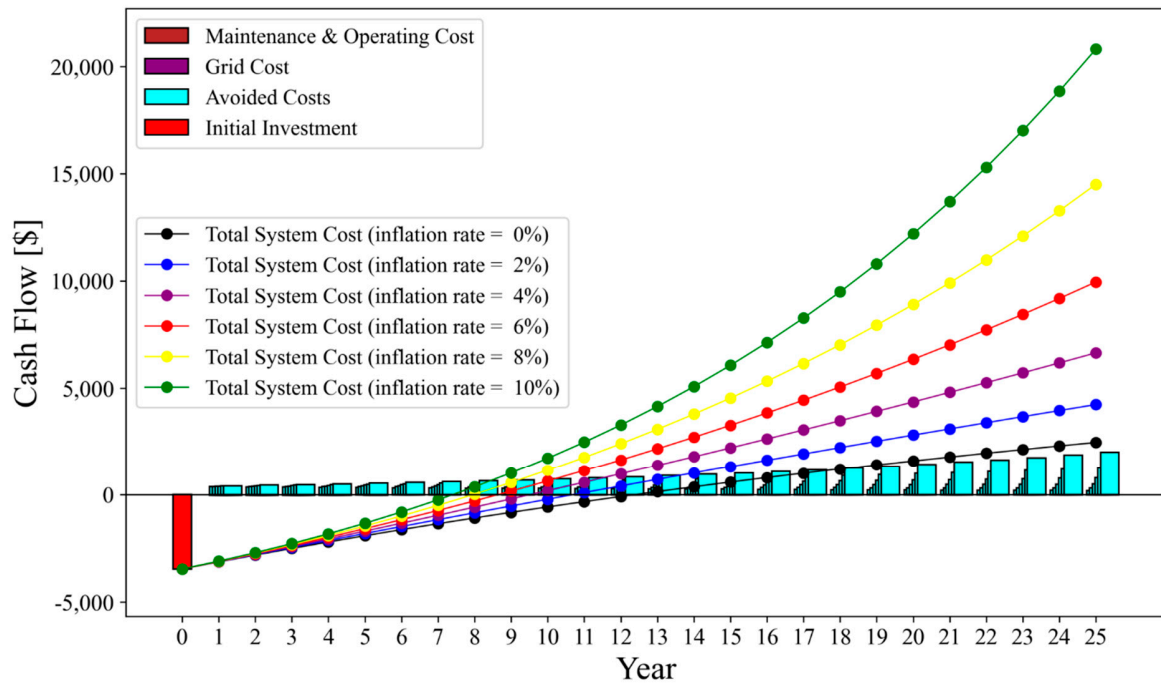


Figure 4. Cash flow chart of PV- Grid system for different inflation rates Santiago, Chile.

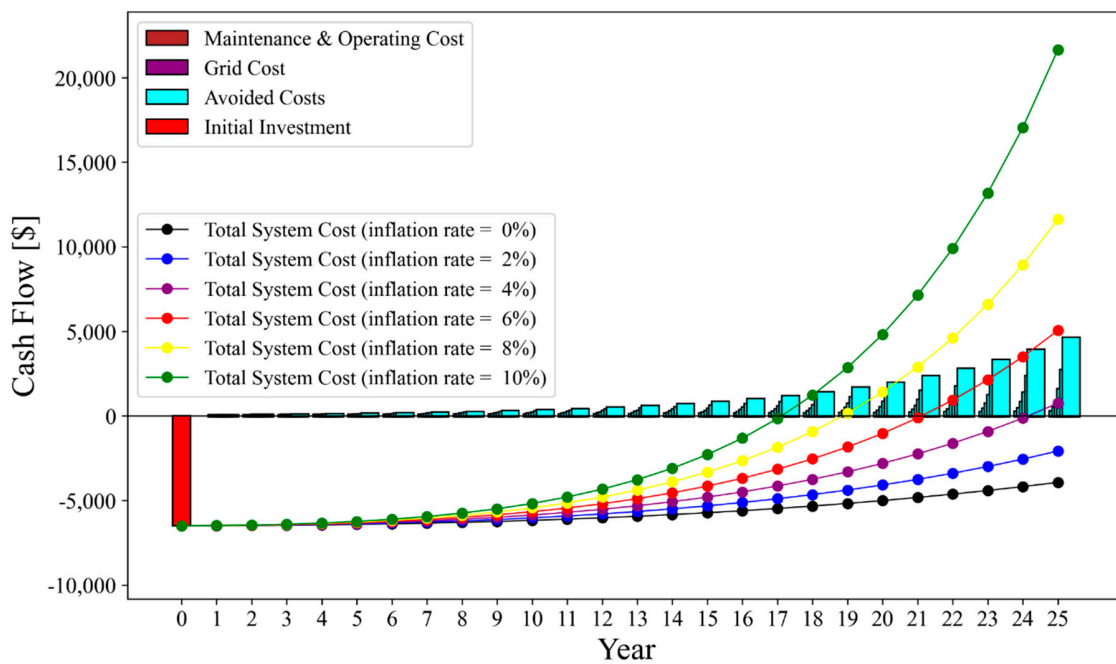


Figure 5. Cash flow chart of PV- Grid system for different inflation rates Buenos Aires, Argentina.

Table 2. Impact of different inflation rates on PV-Grid system.

San Diego (SD): Optimal size system: 8.8 kW PV, 7.27 kW inverter

Boston (Bo): Optimal size system: 7.6 kW PV, 6.31 kW inverter						
Santiago Chile (Sa): Optimal size system:1.2 kW PV, 1.03 kW inverter						
Buenos Aires-Argentina (Ag): Optimal size system:2.25 kW PV, 1.9 kW inverter						
Inflation rates (U.S. and Chile)	0%	2%	4%	6%	8%	10%
Inflation rates (Argentina)	7.5%	10%	12.5%	15%	17.5%	20%
NPC [\$]	SD: 48,049.46 Bo: 19,287.38 Sa: 4,151.35 Ag: 7,978.74	SD: 54,802.68 Bo: 19,287.68 Sa: 4,155.64 Ag: 7,982.98	SD: 63,952.89 Bo: 19,288.09 Sa: 4,161.48 Ag: 7,989.43	SD: 76,447.45 Bo: 19,288.65 Sa: 4,169.49 Ag: 7,999.27	SD: 93,617.3 Bo: 19,289.42 Sa: 4,180.52 Ag: 8,014.3	SD: 117,330.17 Bo: 19,290.49 Sa: 4,195.8 Ag: 8,037.21
Total Solar Cost [\$]	SD: 22,318.37 Bo: 19,286.22 Sa: 4,135.37 Ag: 7,969.51	SD: 22,318.37 Bo: 19,286.22 Sa: 4,135.37 Ag: 7,969.51	SD: 22,318.37 Bo: 19,286.22 Sa: 4,135.37 Ag: 7,969.51	SD: 22,318.37 Bo: 19,286.22 Sa: 4,135.37 Ag: 7,969.51	SD: 22,318.37 Bo: 19,286.22 Sa: 4,135.37 Ag: 7,969.51	SD: 22,318.37 Bo: 19,286.22 Sa: 4,135.37 Ag: 7,969.51
NPC for only Grid connected system [\$]	SD: 67,167.22 Bo: 55,761.52 Sa: 6,609.79 Ag: 4,049.17	SD: 84,795.5 Bo: 70,396.33 Sa: 8,387.22 Ag: 5,908.46	SD: 108,680.77 Bo: 90,225.64 Sa: 10,804.39 Ag: 8,737.75	SD: 141,295.99 Bo: 117,302.45 Sa: 14,116.19 Ag: 13,053.52	SD: 186,115.35 Bo: 154,511.01 Sa: 18,681.23 Ag: 19,641.7	SD: 248,014.3 Bo: 205,898.87 Sa: 25,003.42 Ag: 29,692.92
Total Grid avoidable cost [\$]	SD: 69,183.06 Bo: 53,768.92 Sa: 6,609.79 Ag: 4,049.17	SD: 87,340.4 Bo: 67,880.77 Sa: 8,387.22 Ag: 5,908.46	SD: 111,942.53 Bo: 87,001.49 Sa: 10,804.39 Ag: 8,737.75	SD: 145,536.61 Bo: 113,110.74 Sa: 14,116.19 Ag: 13,053.52	SD: 191,701.1 Bo: 148,989.68 Sa: 18,681.23 Ag: 19,641.7	SD: 255,457.77 Bo: 198,541.23 Sa: 25,003.42 Ag: 29,692.92
Total Grid unavoidable cost [\$]	SD: -2,015.84 Bo: 1,992.59 Sa: 0 Ag: 0	SD: -2,544.91 Bo: 2,515.56 Sa: 0 Ag: 0	SD: -3,261.76 Bo: 3,224.14 Sa: 0 Ag: 0	SD: -4,240.62 Bo: 4,191.71 Sa: 0 Ag: 0	SD: -5,585.75 Bo: 5,521.33 Sa: 0 Ag: 0	SD: -7,443.47 Bo: 7,357.64 Sa: 0 Ag: 0
Total avoided costs by hybrid energy system [\$]	SD: 67,167.22 Bo: 55,761.52 Sa: 6,609.79 Ag: 4,049.17	SD: 84,795.5 Bo: 70,396.33 Sa: 8,387.22 Ag: 5,908.46	SD: 108,680.77 Bo: 90,225.64 Sa: 10,804.39 Ag: 8,737.75	SD: 141,295.99 Bo: 117,302.45 Sa: 14,116.19 Ag: 13,053.52	SD: 186,115.35 Bo: 154,511.01 Sa: 18,681.23 Ag: 19,641.7	SD: 248,014.3 Bo: 205,898.87 Sa: 25,003.42 Ag: 29,692.92
Total grid earning for PV system [\$]	SD: 11,320.65 Bo: 37,621.68 Sa: 4,376.23 Ag: 2,385.08	SD: 14,291.8 Bo: 47,495.63 Sa: 5,553.03 Ag: 3,480.26	SD: 18,317.52 Bo: 60,874.24 Sa: 7,153.4 Ag: 5,146.79	SD: 23,814.63 Bo: 79,142.66 Sa: 9,346.09 Ag: 7,688.91	SD: 31,368.68 Bo: 104,246.87 Sa: 12,368.52 Ag: 11,569.54	SD: 41,801.39 Bo: 138,917.69 Sa: 16,554.34 Ag: 17,490.01
Total grid costs for PV system [\$]	SD: 36,552.75 Bo: 37,622.84 Ag: 2,394.31 Sa: 4,392.2	SD: 46,146.15 Bo: 47,497.08 Ag: 3,493.73 Sa: 5,573.3	SD: 59,144.65 Bo: 60,876.11 Ag: 5,166.72 Sa: 7,179.51	SD: 76,894.02 Bo: 79,145.1 Ag: 7,718.67 Sa: 9,380.21	SD: 101,284.95 Bo: 104,250.07 Ag: 11,614.33 Sa: 12,413.67	SD: 134,970.68 Bo: 138,921.95 Ag: 17,557.71 Sa: 16,614.77
Total grid credits [\$]	SD: 2,015.84 Bo: 0 Sa: 0 Ag: 0	SD: 2,544.91 Bo: 0 Sa: 0 Ag: 0	SD: 3,261.76 Bo: 0 Sa: 0 Ag: 0	SD: 4,240.62 Bo: 0 Sa: 0 Ag: 0	SD: 5,585.75 Bo: 0 Sa: 0 Ag: 0	SD: 7,443.47 Bo: 0 Sa: 0 Ag: 0
LCOE [\$/kWh]	SD: 0.15 Bo: 0.07 Sa: 0.07 Ag: 0.07	SD: 0.17 Bo: 0.07 Sa: 0.07 Ag: 0.07	SD: 0.2 Bo: 0.07 Sa: 0.07 Ag: 0.07	SD: 0.24 Bo: 0.07 Sa: 0.07 Ag: 0.07	SD: 0.3 Bo: 0.07 Sa: 0.07 Ag: 0.07	SD: 0.37 Bo: 0.07 Sa: 0.07 Ag: 0.07

LCOE for only Grid connected system [\$/kWh]	SD: 0.48 Bo: 0.37 Sa: 0.18 Ag: 0.06	SD: 0.61 Bo: 0.47 Sa: 0.23 Ag: 0.08	SD: 0.78 Bo: 0.6 Sa: 0.29 Ag: 0.12	SD: 1.02 Bo: 0.78 Sa: 0.38 Ag: 0.18	SD: 1.34 Bo: 1.03 Sa: 0.51 Ag: 0.27	SD: 1.79 Bo: 1.38 Sa: 0.68 Ag: 0.41
Grid avoidable cost per kWh	SD: 0.5 Bo: 0.36 Sa: 0.18 Ag: 0.06	SD: 0.63 Bo: 0.45 Sa: 0.23 Ag: 0.08	SD: 0.81 Bo: 0.58 Sa: 0.29 Ag: 0.12	SD: 1.05 Bo: 0.76 Sa: 0.38 Ag: 0.18	SD: 1.38 Bo: 1.0 Sa: 0.51 Ag: 0.27	SD: 1.84 Bo: 1.33 Sa: 0.68 Ag: 0.41
Grid unavoidable cost per kWh	SD: -0.01 Bo: 0.01 Sa: 0 Ag: 0	SD: -0.02 Bo: 0.02 Sa: 0 Ag: 0	SD: -0.02 Bo: 0.02 Sa: 0 Ag: 0	SD: -0.03 Bo: 0.03 Sa: 0 Ag: 0	SD: -0.04 Bo: 0.04 Sa: 0 Ag: 0	SD: -0.05 Bo: 0.05 Sa: 0 Ag: 0
Solar Cost per kWh	SD: 0.09 Bo: 0.11 Sa: 0.11 Ag: 0.11	SD: 0.09 Bo: 0.11 Sa: 0.11 Ag: 0.11	SD: 0.09 Bo: 0.11 Sa: 0.11 Ag: 0.11	SD: 0.09 Bo: 0.11 Sa: 0.11 Ag: 0.11	SD: 0.09 Bo: 0.11 Sa: 0.11 Ag: 0.11	SD: 0.09 Bo: 0.11 Sa: 0.11 Ag: 0.11
Operating Cost	SD: 1,826.17 Bo: 239.02 Sa: 38.74 Ag: 71.28	SD: 2,232.87 Bo: 239.03 Sa: 38.99 Ag: 71.49	SD: 2,783.92 Bo: 239.06 Sa: 39.32 Ag: 71.79	SD: 4,422.79 Bo: 239.09 Sa: 39.77 Ag: 72.27	SD: 4,570.4 Bo: 4254.43 Sa: 40.4 Ag: 72.99	SD: 5,998.46 Bo: 239.2 Sa: 41.27 Ag: 74.09
Initial Cost	SD: 17,726.05 Bo: 15,318.53 Sa: 3,470.13 Ag: 6,492.74	SD: 17,726.05 Bo: 15,318.53 Sa: 3,470.13 Ag: 6,492.74	SD: 17,726.05 Bo: 15,318.53 Sa: 3,470.13 Ag: 6,492.74	SD: 17,726.05 Bo: 15,318.53 Sa: 3,470.13 Ag: 6,492.74	SD: 17,726.05 Bo: 15,318.53 Sa: 3,470.13 Ag: 6,492.74	SD: 17,726.05 Bo: 15,318.53 Sa: 3,470.13 Ag: 6,492.74
Total operation and maintenance cost	SD: 4,592.32 Bo: 3,967.7 Sa: 665.24 Ag: 1,476.77	SD: 4,592.32 Bo: 3,967.7 Sa: 665.24 Ag: 1,476.77	SD: 4,592.32 Bo: 3,967.7 Sa: 665.24 Ag: 1,476.77	SD: 4,592.32 Bo: 3,967.7 Sa: 665.24 Ag: 1,476.77	SD: 4,592.32 Bo: 3,967.7 Sa: 665.24 Ag: 1,476.77	SD: 4,592.32 Bo: 3,967.7 Sa: 665.24 Ag: 1,476.77
Total Money paid to the Grid (25 years) [USD]	SD: 25,731.09 Bo: 1.16 Sa: 15.97 Ag: 9.23	SD: 32,484.31 Bo: 1.46 Sa: 20.27 Ag: 13.47	SD: 41,634.52 Bo: 1.87 Sa: 26.11 Ag: 26.11	SD: 54,129.08 Bo: 2.43 Sa: 34.12 Ag: 29.76	SD: 71,298.93 Bo: 3.2 Sa: 45.15 Ag: 44.79	SD: 95,011.8 Bo: 4.27 Sa: 60.43 Ag: 67.7
Total Net profit (V_p) [\$]	SD: 19,117.76 Bo: 36,474.14 Sa: 2,458.45 Ag: -3929.58	SD: 29,992.82 Bo: 51,108.65 Sa: 4,231.57 Ag: -2074.52	SD: 44,727.89 Bo: 70,937.54 Sa: 6,642.90 Ag: 748.32	SD: 64,848.54 Bo: 98,013.80 Sa: 9,946.70 Ag: 5,054.24	SD: 92,498.05 Bo: 135,221.59 Sa: 14,500.71 Ag: 11,627.40	SD: 130,684.13 Bo: 186,608.38 Sa: 20,807.62 Ag: 21,655.70
IRR (%)	SD: 8.03 Bo: 16.17 Sa: 5.36 Ag: -4.83	SD: 10.43 Bo: 18.66 Sa: 7.68 Ag: -2.03	SD: 12.78 Bo: 21.12 Sa: 9.95 Ag: 0.58	SD: 15.10 Bo: 23.56 Sa: 12.18 Ag: 3.07	SD: 17.39 Bo: 25.99 Sa: 14.40 Ag: 5.49	SD: 19.67 Bo: 28.41 Sa: 16.60 Ag: 7.86
Pay Back Period [years]	SD: 10 Bo: 6 Sa: 13 Ag: None	SD: 9 Bo: 6 Sa: 11 Ag: None	SD: 8 Bo: 5 Sa: 10 Ag: 25	SD: 8 Bo: 5 Sa: 9 Ag: 22	SD: 7 Bo: 5 Sa: 8 Ag: 19	SD: 7 Bo: 5 Sa: 8 Ag: 18
ROI (%)	SD: 39.79 Bo: 189.11 Sa: 59.22	SD: 54.73 Bo: 264.98 Sa: 101.83	SD: 69.94 Bo: 367.78 Sa: 159.63	SD: 84.83 Bo: 508.14 Sa: 238.56	SD: 98.80 Bo: 701.01 Sa: 346.86	SD: 111.38 Bo: 967.36 Sa: 495.92

	Ag: -49.25	Ag: -25.99	Ag: 9.37	Ag: 63.18	Ag: 145.08	Ag: 269.44
PV Power [kWh/yr]	SD: 14873.44 Bo: 10475.02 Sa: 2182.23 Ag: 3637.54	SD: 14873.44 Bo: 10475.02 Sa: 2182.23 Ag: 3645.62	SD: 14873.44 Bo: 10475.02 Sa: 2182.23 Ag: 3645.62	SD: 14873.44 Bo: 10475.02 Sa: 2182.23 Ag: 3645.62	SD: 14873.44 Bo: 10475.02 Sa: 2182.23 Ag: 3645.62	SD: 14873.44 Bo: 10475.02 Sa: 2182.23 Ag: 3645.62
Annual power bought from Grid	SD: 4736.43 Bo: 5845.21 Sa: 1395.45 Ag: 2069.58	SD: 4736.43 Bo: 5845.21 Sa: 1395.45 Ag: 2069.58	SD: 4736.43 Bo: 5845.21 Sa: 1395.45 Ag: 2069.58	SD: 4736.43 Bo: 5845.21 Sa: 1395.45 Ag: 2069.58	SD: 4736.43 Bo: 5845.21 Sa: 1395.45 Ag: 2069.58	SD: 4736.43 Bo: 5845.21 Sa: 1395.45 Ag: 2069.58
Annual Power sold to Grid	SD: 10647.42 Bo: 6881.70 Sa: 1390.37 Ag: 2061.60	SD: 10647.42 Bo: 6881.70 Sa: 1390.37 Ag: 2061.60	SD: 10647.42 Bo: 6881.70 Sa: 1390.37 Ag: 2061.60	SD: 10647.42 Bo: 6881.70 Sa: 1390.37 Ag: 2061.60	SD: 10647.42 Bo: 6881.70 Sa: 1390.37 Ag: 2061.60	SD: 10647.42 Bo: 6881.70 Sa: 1390.37 Ag: 2061.60
RE (%)	SD: 75.09 Bo: 63.22 Sa: 60.02 Ag: 62.79	SD: 75.09 Bo: 63.22 Sa: 60.02 Ag: 60.12	SD: 75.09 Bo: 63.22 Sa: 60.02 Ag: 60.12	SD: 75.09 Bo: 63.22 Sa: 60.02 Ag: 60.12	SD: 75.09 Bo: 63.22 Sa: 60.02 Ag: 60.12	SD: 75.09 Bo: 63.22 Sa: 60.02 Ag: 60.12

If utilities alter rate structures to discourage distributed generation [64], it may become advantageous for prosumers to add batteries to the system to enable greater self-consumption. This can be seen in the reduction in PV system size for Boston, Massachusetts, and Santiago, Chile, as seen in Table 3. The optimum PV system size shrunk from 8.8 kW to 7.7 for Boston. The PV system size reduction came with the additional costs of a battery of 11 kWh and 3 kWh for Boston and Santiago, respectively. These batteries need to be replaced every 7.5 years. The impact this has on the economics can be observed in Figure 6 for Boston, showing a system with PV on the grid with battery and a PV-BT-grid system for Santiago, Chile (Figure 7). In both cases, a saw-tooth pattern is observed in the total system cost due to the battery replacement costs. This can cause some interesting phenomena such as the 6% inflation rate in Santiago where the payback time is at first 15 years, then a battery must be purchased, which pushes the total cost negative, but which is quickly recovered so that after year after 17 a profit is made on the system. Comparing Figure 2 to Figure 6 and Figure 5 to Figure 7 so that the impacts of batteries can be discerned shows an increase in the payback time and a decrease in the total value of the system over time. The inflating economy (increasing inflation rates) can potentially make PV-battery systems profitable; however, PV grid-tied systems remain more economical than PV-BT-grid systems. This is due to batteries' high capital costs and short replacement cycles. Notably, inflation and the resulting increase in inflation rates have a more intense impact on the profitability of PV-BT-grid systems in Boston and Santiago. Comparing PV-grid systems with PV-BT-grid systems reveals that increasing inflation rates reduces the payback period (PP) more significantly for PV-BT-grid systems. In Boston, the PP for PV-grid systems decreases from 6 to 5 years (a 1-year reduction), while for PV-BT-grid systems, it decreases from 10 to 6 years (a 4-year reduction). Similarly, in Santiago, the PP for PV-BT-grid systems decreases from 20 to 12 years (an 8-year reduction), compared to a 5-year decrease for PV-grid systems. This indicates that in the future, with reduced battery costs and extended lifetimes, the self-consumption profit provided by batteries could make these systems even more profitable.

Table 3 lists the simulation results of different case studies in detail for on-grid PV-battery systems. In Boston, the optimal system size for a PV-battery-grid setup is 7.7 kW PV with an 11-kWh battery and a 6.88 kW inverter. Santiago's optimal configuration is smaller due to lower electrical load, with a 1.25 kW PV, 3.006 kWh battery, and a 1.07 kW inverter. NPC for Boston starts at \$33,602 with 0% inflation and rises to

\$34,092 at 10% inflation. Santiago's *NPC*, starts at \$8,759 with 0% inflation and increases to \$8,765 at 10% inflation. These slight increases in *NPC* are because of low grid payments in both case studies. *LCOE* for both case studies remains constant at \$0.16/kWh in Boston and \$0.18 in Santiago. Grid-connected PV-battery systems exhibit higher *NPC* and *LCOE* compared to only systems due to battery initial and lifetime replacement costs added.

Table 3. Impact of different inflation rates on PV-Bat-Grid system.

Boston (Bo): Optimal size system: 7.7 kW PV,11.022 kWh battery, 6.88 kW inverter						
Santiago-Chile (Sa): Optimal size system: 1.25 kW PV,3.006 kWh battery, 1.07 kW inverter						
Escalation rates	0%	2%	4%	6%	8%	10%
NPC [\$]	Bo: 33,602.37 Sa: 8,759.37	Bo: 33,650.12 Sa: 8,759.93	Bo: 33,714.82 Sa: 8,760.69	Bo: 33,803.16 Sa: 8,761.73	Bo: 33,924.56 Sa: 8,763.17	Bo: 34,092.22 Sa: 8,765.17
Total Solar Cost [\$]	Bo: 19,714.94 Sa: 4,306.24	Bo: 19,714.94 Sa: 4,306.24	Bo: 19,714.94 Sa: 4,306.24	Bo: 19,714.94 Sa: 4,306.24	Bo: 19,714.94 Sa: 4,306.24	Bo: 19,714.94 Sa: 4,306.24
NPC for only Grid connected system [\$]	Bo: 55,761.52 Sa: 6,609.79	Bo: 70,396.33 Sa: 8,387.22	Bo: 90,225.64 Sa: 10,804.39	Bo: 117,302.45 Sa: 14,116.19	Bo: 154,511.01 Sa: 18,681.23	Bo: 205,898.87 Sa: 25,003.42
Total Grid avoidable cost [\$]	Bo: 53,768.92 Sa: 6,609.79	Bo: 67,880.77 Sa: 8,387.22	Bo: 87,001.49 Sa: 10,804.39	Bo: 113,110.74 Sa: 14,116.19	Bo: 148,989.68 Sa: 18,681.23	Bo: 198,541.23 Sa: 25,003.42
Total Grid unavoidable cost [\$]	Bo: 1,992.59 Sa: 0	Bo: 2,515.56 Sa: 0	Bo: 3,224.14 Sa: 0	Bo: 4,191.71 Sa: 0	Bo: 5,521.33 Sa: 0	Bo: 7,357.64 Sa: 0
Total avoided costs by hybrid energy system [\$]	Bo: 55,761.52 Sa: 6,609.79	Bo: 70,396.33 Sa: 8,387.22	Bo: 90,225.64 Sa: 10,804.39	Bo: 117,302.45 Sa: 14,116.19	Bo: 154,511.01 Sa: 18,681.23	Bo: 205,898.87 Sa: 25,003.42
Total grid earning for PV-BT system [\$]	Bo: 22,111.54 Sa: 1,985.8	Bo: 27,914.8 Sa: 2,519.79	Bo: 35,777.86 Sa: 3,245.99	Bo: 46,514.84 Sa: 4,240.96	Bo: 61,269.44 Sa: 5,612.45	Bo: 81,646.66 Sa: 7,511.84
Total grid costs for PV-BT system [\$]	Bo: 22,293.47 Sa: 1,987.88	Bo: 28,144.48 Sa: 2,522.44	Bo: 36,072.24 Sa: 3,249.4	Bo: 46,897.56 Sa: 4,245.42	Bo: 61,773.56 Sa: 5,618.34	Bo: 82,318.44 Sa: 7,519.73
Total grid credits [\$]	Bo: 0 Sa: 0	Bo: 0 Sa: 0	Bo: 0 Sa: 0	Bo: 0 Sa: 0	Bo: 0 Sa: 0	Bo: 0 Sa: 0
LCOE [\$/kWh]	Bo: 0.16 Sa: 0.18	Bo: 0.16 Sa: 0.18	Bo: 0.16 Sa: 0.18	Bo: 0.16 Sa: 0.18	Bo: 0.16 Sa: 0.18	Bo: 0.16 Sa: 0.18
LCOE for only Grid connected system [\$/kWh]	Bo: 0.37 Sa: 0.18	Bo: 0.47 Sa: 0.23	Bo: 0.6 Sa: 0.29	Bo: 0.78 Sa: 0.38	Bo: 1.03 Sa: 0.51	Bo: 1.38 Sa: 0.68
Grid avoidable cost per kWh	Bo: 0.36 Sa: 0.18	Bo: 0.45 Sa: 0.23	Bo: 0.58 Sa: 0.29	Bo: 0.76 Sa: 0.38	Bo: 1 Sa: 0.51	Bo: 1.35 Sa: 0.68
Grid unavoidable cost per kWh	Bo: 0.01 Sa: 0	Bo: 0.02 Sa: 0	Bo: 0.02 Sa: 0	Bo: 0.03 Sa: 0	Bo: 0.03 Sa: 0	Bo: 0.05 Sa: 0
Solar Cost per kWh	Bo: 0.11 Sa: 0.11	Bo: 0.11 Sa: 0.11	Bo: 0.11 Sa: 0.11	Bo: 0.11 Sa: 0.11	Bo: 0.11 Sa: 0.11	Bo: 0.11 Sa: 0.11
Operating Cost	Bo: 791.0 Sa: 203.46	Bo: 857.71 Sa: 203.49	Bo: 861.61 Sa: 203.54	Bo: 866.93 Sa: 203.6	Bo: 874.24 Sa: 203.68	Bo: 884.34 Sa: 203.79
Initial Cost	Bo: 19,407.85 Sa: 5,181.74	Bo: 19,407.85 Sa: 5,181.74	Bo: 19,407.85 Sa: 5,181.74	Bo: 19,407.85 Sa: 5,181.74	Bo: 19,407.85 Sa: 5,181.74	Bo: 19,407.85 Sa: 5,181.74
Total operation and maintenance cost	Bo: 5,924.62 Sa: 1,235.69	Bo: 5,924.62 Sa: 1,235.69	Bo: 5,924.62 Sa: 1,235.69	Bo: 5,924.62 Sa: 1,235.69	Bo: 5,924.62 Sa: 1,235.69	Bo: 5,924.62 Sa: 1,235.69
Total Money paid to the Grid (25 years) [USD]	Bo: 181.93 Sa: 2.08	Bo: 229.68 Sa: 2.64	Bo: 294.38 Sa: 3.41	Bo: 382.72 Sa: 4.45	Bo: 504.12 Sa: 5.89	Bo: 671.78 Sa: 7.88

Total net profit (V_p) [\$]	Bo: 22,159.15 Sa: -2,149.58	Bo: 36,746.21 Sa: -372.71	Bo: 56,510.82 Sa: 2,043.70	Bo: 83,499.29 Sa: 5,354.46	Bo: 120,586.45 Sa: 9,918.06	Bo: 171,806.64 Sa: 16,238.25
IRR (%)	Bo: 8.94 Sa: -4.23	Bo: 11.84 Sa: -0.57	Bo: 14.58 Sa: 2.50	Bo: 17.21 Sa: 5.26	Bo: 19.76 Sa: 7.82	Bo: 22.25 Sa: 10.26
Payback period	Bo: 10 Sa: None	Bo: 7 Sa: None	Bo: 7 Sa: 20	Bo: 6 Sa: 15	Bo: 6 Sa: 14	Bo: 6 Sa: 12
ROI (%)	Bo: 63.15 Sa: -23.32	Bo: 104.58 Sa: -4.04	Bo: 160.53 Sa: 22.16	Bo: 236.61 Sa: 58.06	Bo: 340.53 Sa: 107.53	Bo: 482.88 Sa: 176.02
PV Power [kWh/yr]	Bo: 10612.85 Sa: 2273.16	Bo: 10612.85 Sa: 2273.16	Bo: 10626.64 Sa: 2273.16	Bo: 10626.64 Sa: 2273.16	Bo: 10626.64 Sa: 2273.16	Bo: 10626.64 Sa: 2273.16
Annual power bought from Grid [kWh]	Bo: 3144.40 Sa: 631.57	Bo: 3144.40 Sa: 631.57	Bo: 3144.40 Sa: 631.57	Bo: 3144.40 Sa: 631.57	Bo: 3144.40 Sa: 631.57	Bo: 3144.40 Sa: 631.57
Annual power sold to the Grid [kWh]	Bo: 4027.37 Sa: 630.91	Bo: 4027.37 Sa: 630.91	Bo: 4027.37 Sa: 630.91	Bo: 4027.37 Sa: 630.91	Bo: 4027.37 Sa: 630.91	Bo: 4027.37 Sa: 630.91
RE (%)	Bo: 75.88 Sa: 76.87	Bo: 75.88 Sa: 76.87	Bo: 75.42 Sa: 76.87	Bo: 75.42 Sa: 76.87	Bo: 75.42 Sa: 76.87	Bo: 75.42 Sa: 76.87

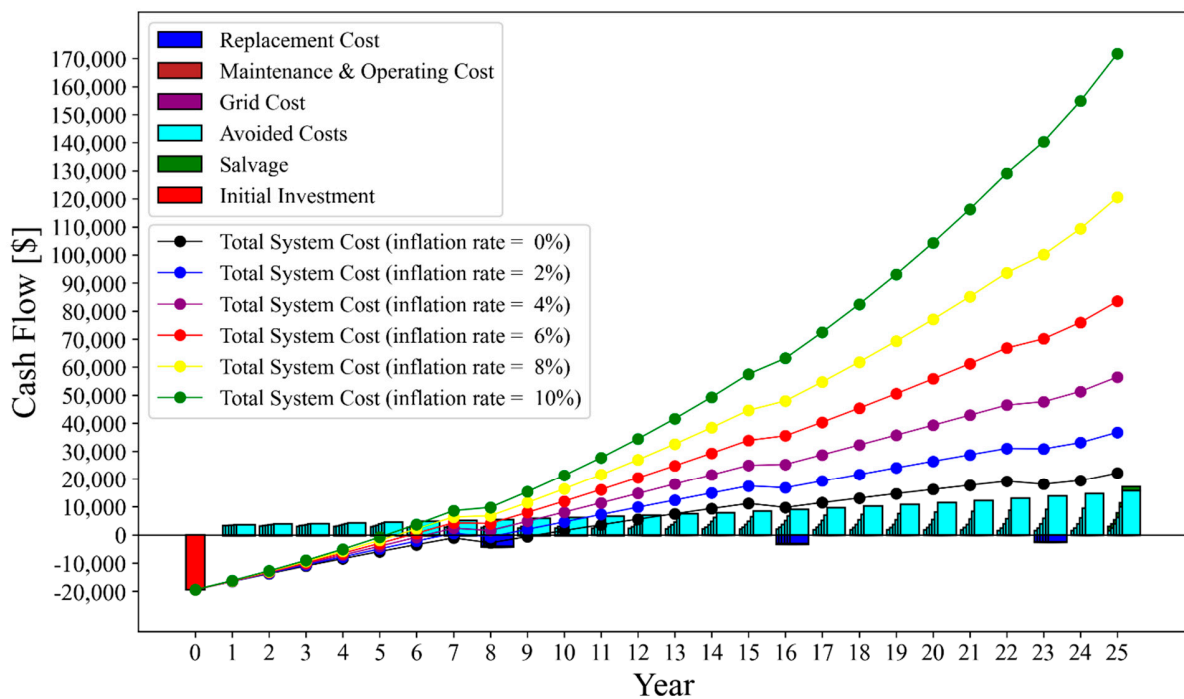


Figure 6. Cash flow chart of PV-Bat-Grid system for different inflation rates-Boston-MA.

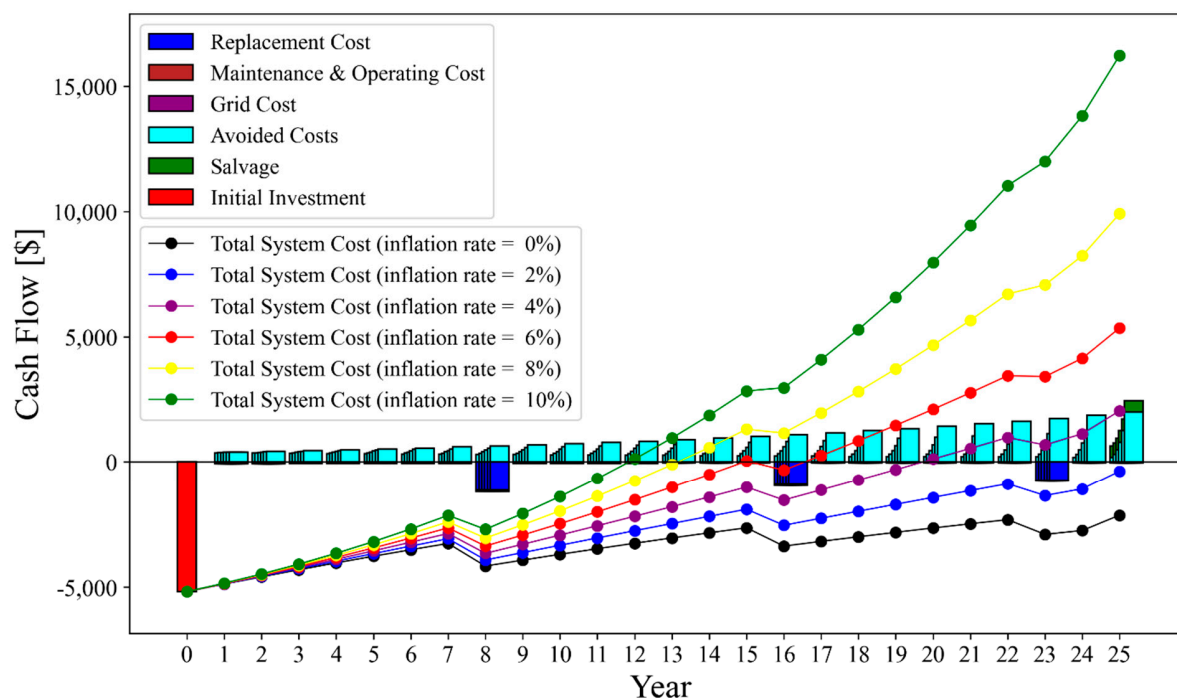


Figure 7. Cash flow chart of PV-BT-Grid system for different inflation rates-Santiago-Chile.

4. Discussion

According to the results in the previous section, investing in PV systems can indeed be considered an inflation hedge, particularly in regions where electricity prices are high and expected to rise due to inflation. The paper's analysis demonstrates that as inflation rates increase, the economic profitability of PV systems generally improves because users save more on grid electricity costs, which tend to rise with inflation. In areas where energy costs are high and rising, investing in PV systems can lock in lower and more stable electricity prices compared to volatile fossil fuel markets for the next 20 years and act as a hedge. Furthermore, countries or regions with supportive regulatory frameworks offering rebates and incentives for PV adoption can make them more effective as an inflation hedge. The paper would encourage emerging market economies that face rising traditional energy costs and have abundant solar resources to benefit from PV adoption.

Inflation plays a crucial role in the financial viability of grid-connected PV systems, with varying impacts across different locations. It significantly affects the financial viability of PV systems, with higher inflation generally improving *total net profit*, *ROI*, and *IRR* but also increasing *NPC*, *LCOE*, and *operating costs*. San Diego, Boston, and Santiago exhibit significant positive impacts from inflation, while Boston maintains stable payback periods, and Buenos Aires presents opportunities under higher inflation rates.

In San Diego, a substantial rise in costs when inflation increases underscores the importance of accounting for inflation in financial models and planning. Despite this, the PV system in San Diego still shows favorable financial performance due to sizable, avoided costs offered by the PV system, which is \$67,167 at 0% inflation increased to \$248,014 at 10% yearly inflation. PV economics in San Diego enjoys higher *IRR* and net profit, along with a shorter payback period compared to only relying on the grid in an

inflationary environment, highlighting the resilience and long-term benefits of PV-grid-connected investments in this region. At 0% inflation, grid-connected PV exhibits an *IRR* of 8.03% with an *ROI* of 39.79%, while they are increased to 19.67% and 111.38%, respectively, if the inflation rate is 10%. Additionally, *PP* decreased from 10 years to 7 years with an increasing inflation rate to 10%, indicating quicker recouping of investment costs. Boston's PV systems are less sensitive to inflation as *NPC*, *LCOE*, and the project's payback period (5-6 years) are not affected by inflation that much, making it a lower-risk environment for investment. At 0% inflation, the *IRR* and *ROI* of the project are 16.17% and 189.11%, respectively, which are increased to 28.41% and 967.36% in the presence of 10% inflation. These metrics highlight Boston as a favorable environment for grid connected PV, with consistent tolerance on inflationary pressure and even much higher profits.

Like San Diego and Boston in the U.S., Santiago's financial metrics benefit significantly from higher inflation rates. This suggests that inflation can be leveraged for better financial returns. The *IRR* and *ROI* metrics improve with higher inflation rates, reaching 16.6% and 495.9%, respectively, at 10% inflation. This indicates that while the initial costs and *NPC* are relatively low, the financial returns improve significantly in a higher inflation environment, making PV investments more attractive over time. Inflation's impact on Buenos Aires' financial metrics is more volatile. Higher inflation rates can transform the financial outlook from negative to highly positive, emphasizing the need for thorough risk assessments. In scenarios with higher inflation, avoided costs increase substantially from (\$4,049 of 0% to \$29,692 of 10% yearly inflation), leading to improved *IRR* (up to 7.86%) and shorter payback periods (up to 18 years). This volatility necessitates strategic investments and close monitoring of local economic indicators and inflation trends to make informed decisions. Investors should consider higher inflation scenarios to leverage improved financial returns.

Boston's *IRR* for grid-connected PV-battery systems improves with inflation, going from 8.94% at 0% inflation to 22.25% at 10% inflation. Santiago's *IRR* also increases, albeit starting from a negative value at lower inflation rates and reaching 10.2% at 10% inflation. This trend indicates that higher inflation can enhance the financial attractiveness of hybrid PV-battery systems, especially in Boston. The payback period for Boston decreases from 10 years at 0% inflation to 6 years at 10% inflation, while Santiago's payback period becomes feasible only at higher inflation rates, reducing from 20 years at 4% inflation to 12 years at 10% inflation. These figures highlight how inflation can accelerate the return on investment for hybrid PV-battery systems, particularly in Boston. Finally, *ROI* for Boston rises from 63.2% at 0% inflation to 482% at 10% inflation. Santiago's *ROI* improves from -23.3% to 176% over the same range. This underscores the superior economic performance of PV-battery in inflationary contexts, especially in regions like Boston with higher initial costs and energy prices. When comparing the PV-grid system with the PV-Battery-Grid system, only the PV system offers superior financial performance in both case studies and higher returns compared to the PV-BT-grid system. While PV with battery provides enhanced energy self-consumption. Battery storage adds substantial initial investment cost and replacement costs to the project, making PV-BT-grid less attractive than a PV-grid system. However, it is still profitable in an inflammatory economy.

4.1. Sensitivity Analysis

PV-Battery systems exhibit higher sensitivity to inflation changes compared to grid-connected PV systems, with greater improvements in *total net profit*, *IRR*, *ROI*, and reductions in *PP* under high inflation scenarios. Figure 8 illustrates the results of a sensitivity analysis on *IRR* for a PV system in San Diego-CA, with a base value *IRR* of 10.4% (vertical axis is plotted). The PV system cost, set at a base of \$2,950/kWdc (shown in parentheses according to NREL 2022 benchmark [65]), shows that an increase to \$3,500/kWdc significantly decreases the *IRR*, indicating that higher initial costs negatively affect profitability. Conversely, a reduction in cost to \$1500/kWdc (due to the ongoing trend in PV cost reductions [66–69])

substantially increases the *IRR*, demonstrating that lower costs greatly enhance profitability. Inflation rates, with a base of 2%, also influence the *IRR*; a rate of 0% results in a decrease, reflecting lower electricity price increases over time, whereas a rate of 10% boosts the *IRR*, showing that higher inflation, leading to higher electricity prices, improves the economic attractiveness of the PV system. ITC set at a base of 30% (currently offered by U.S. government [70]), is another crucial factor. A drop to 0% significantly decreases the *IRR*, highlighting the importance of this incentive in making PV investments highly attractive. An increase to 50% raises the *IRR*, further illustrating the positive impact of higher tax credits on PV system profitability. NM credits, with a base assumption of a 1:1 ratio, also play a role. Reducing the credits by 50% (mimicking recent NM credit reductions [71–73]) results in a decrease in *IRR*, indicating that less favorable net metering policies negatively affect the financial returns of the PV system, while increasing the credits by 50% results in an increase, showing that more favorable net metering policies enhance the financial attractiveness of the system. The sensitivity analysis demonstrates that the *IRR* of the PV system is most sensitive to changes in the system cost and inflation rates, followed by ITC and net metering credits.

Figure 9. presents a sensitivity analysis on *ROI* for a PV system in San Diego-CA, with a base value *ROI* of 54.7% (the respective axis is plotted). Starting with inflation rates, set at a base of 2% (shown in parentheses), the analysis shows that eliminating inflation (0%) decreases the *ROI*, reflecting the reduced financial benefit of avoiding higher electricity prices. On the other hand, an inflation rate of 10% significantly boosts the *ROI*, indicating that higher inflation rates enhance the economic attractiveness of PV investments due to increased savings from avoided electricity costs. The cost of the PV system is another critical factor. With a base cost of \$2,950/kWdc, an increase to \$3,500/kWdc markedly reduces the *ROI*, demonstrating the negative impact of higher initial costs on the investment's profitability. Conversely, lowering the cost to \$1,500/kWdc substantially increases the *ROI*, underscoring the importance of cost reductions in improving the financial returns of PV systems. NM credits, assumed at a 1:1 ratio in the base scenario, also influence the *ROI*. A reduction in credits by 50% results in a decreased *ROI*, showing that less favorable net metering policies diminish the financial benefits of PV systems. Conversely, increasing the credits by 50% enhances the *ROI*, indicating that more favorable net metering policies improve the investment's attractiveness. ITC is set at 30% in the base case, significantly impacting the *ROI*. Eliminating the ITC (0%) leads to a considerable drop in *ROI*, highlighting this incentive's crucial role in financially viable PV investments. Increasing the ITC to 50% raises the *ROI*, further emphasizing the positive effect of higher tax credits on the profitability of PV systems. The sensitivity analysis reveals that the *ROI* of the PV system is highly sensitive to changes in inflation rates and PV system costs, followed by net metering credits and the ITC. Higher inflation rates, lower system costs, and more favorable net metering policies and tax credits significantly improve the *ROI*, making PV investments more attractive. This analysis highlights the importance of financial incentives, cost reductions, and inflation considerations in promoting the adoption of PV systems.

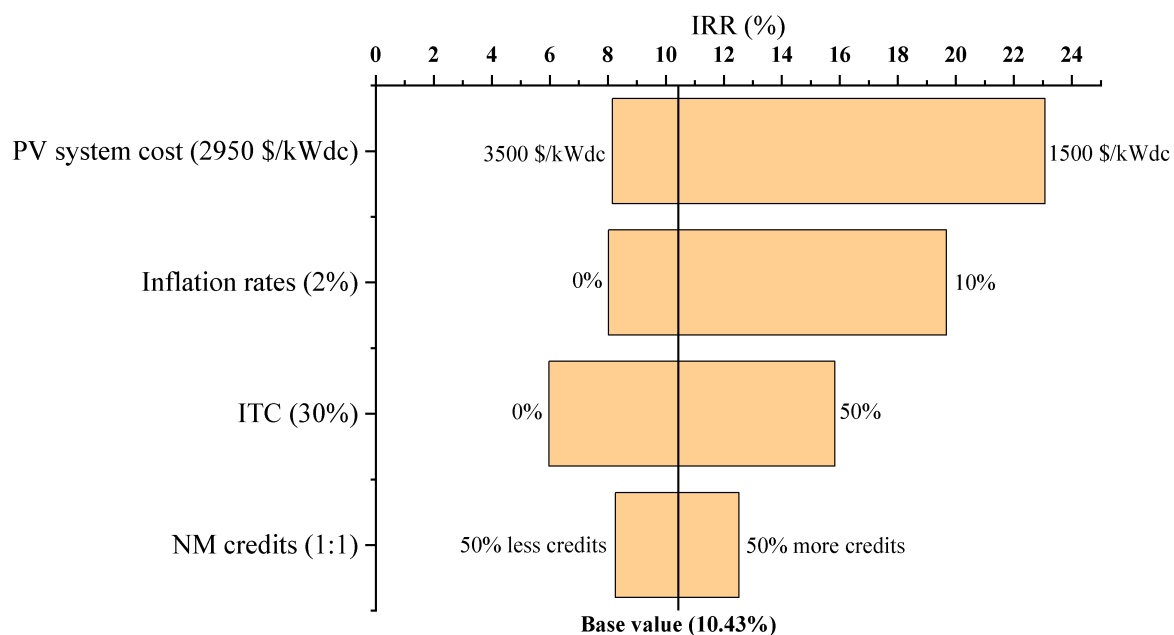


Figure 8. Impact of varying parameters on IRR.

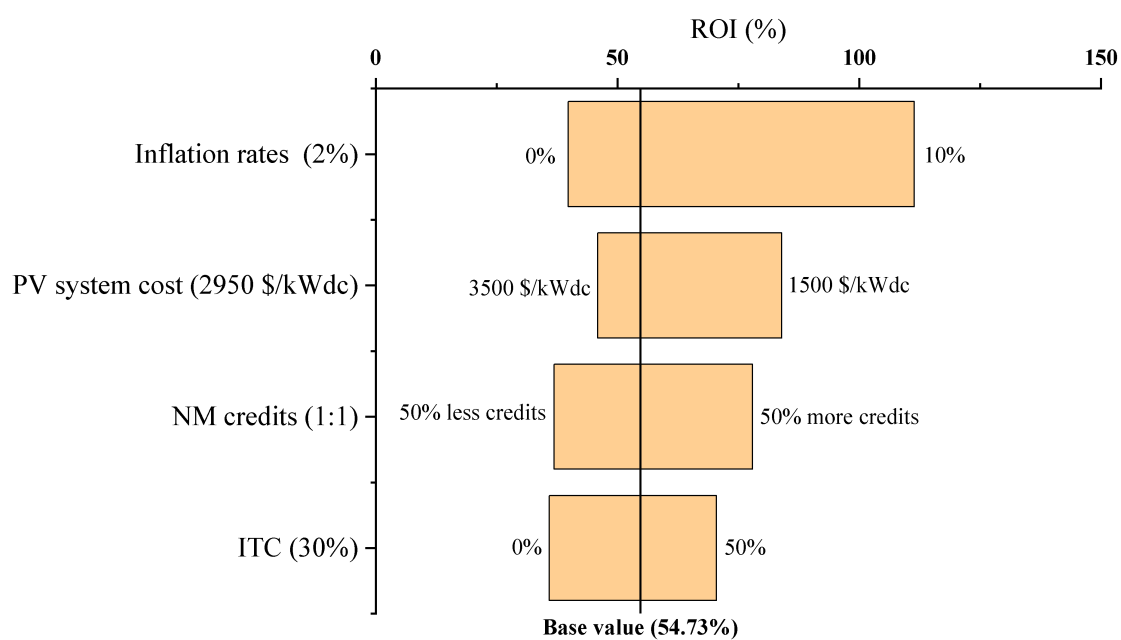


Figure 9. Impact of varying parameters on ROI.

4.2. Tax Advantages of PV Systems: Enhancing Their Role as a Robust Inflation Hedge

The impact of taxes further enhances the attractiveness of PV systems as an inflation hedge. When an investor invests in traditional financial instruments like savings accounts, bonds, or stocks, they are

required to pay taxes on the profits earned. These taxes can significantly reduce the net returns on these investments, especially in an inflationary environment where maintaining the value of your returns is crucial. In contrast, the profits from PV electricity generation in any type of net metering arrangement do not incur taxes. When users generate their own electricity with a PV system, they effectively save on the cost of purchasing electricity from the grid. This cost-saving is not considered taxable income, making the net benefit of PV systems even more favorable. This tax advantage means that the savings realized from avoiding the inflated electricity prices of the grid are fully retained by the investor, amplifying the overall financial benefit of the PV system.

For instance, in the case of Boston, for a grid-connected PV system and considering a 2% annual inflation rate, the user will benefit from \$51,108.65 net profits over 25 years. While if they have gained this amount by investing in a saving account and interest profits are earned in each year, they needed to pay \$7,666 in taxes, considering 10% Federal tax rate on interests and the fact that each year's gains is less than \$11,600 [74,75], and 5% state tax [76]. Considering these taxes on the investment can reduce *IRR* of project from 18.7% (which is for tax-free PV investment) to 15.5% (which is for normal saving account investment subject to tax) and *ROI* from 265% to 225.2%. Similarly, considering gaining this profit by long-term investing in bonds or stocks will contribute to 15% Federal capital gain taxes [77] and 5% state tax [76], which equals to \$10,222. This will reduce *IRR* to 14.4% and *ROI* to 212%, compared to tax-free PV investment.

This tax-free profit makes PV systems an even more compelling investment in inflationary periods. The study already demonstrates that PV systems offer significant economic benefits by reducing payback periods and increasing profitability as inflation rises. When one factor in the tax advantage, the case for PV systems becomes even stronger. Not only do they provide a hedge against rising electricity costs, but they also offer a tax-efficient way to improve financial returns, further enhancing their role as a robust inflation hedge.

4.3. Historical Inflation Projection (Verification of average inflation projection)

Two distinct approaches were compared in Table 4 for San Diego, U.S. case study: one using a flat escalation rate based on the average inflation rate from 1999 to 2023, and another employing a historical inflation projection that considers year-by-year inflation data [63] over the same period illustrated in Figure 10. The analysis revealed that both methods—escalating grid prices with a flat rate of 2.54% (the average inflation rate) and using detailed historical inflation projections (Figure 10)—produced similar results. This similarity in outcomes provides strong verification for using the average inflation rate as a valid and reliable method in economic analyses of grid-connected PV systems. The comparable results indicate that the flat average inflation rate simplifies the projection process and effectively mirrors the more detailed historical approach.

This verification is particularly important because it confirms that previous analyses conducted with the average inflation rate are sound and reflective of real-world economic conditions. The finding that the historical inflation projection yields similar results to the average rate reinforces the robustness of the earlier analyses and supports the continued use of this method in future studies. Moreover, the analysis underscores the potential of PV investments as a hedge against inflation. The *IRR* of 10.98% and the *ROI* of 11.07% achieved under the historical inflation scenario demonstrate the financial stability and resilience of PV systems in an inflationary environment. This further validates the effectiveness of using an average inflation rate in economic projections, as it captures the long-term financial benefits of PV investments.

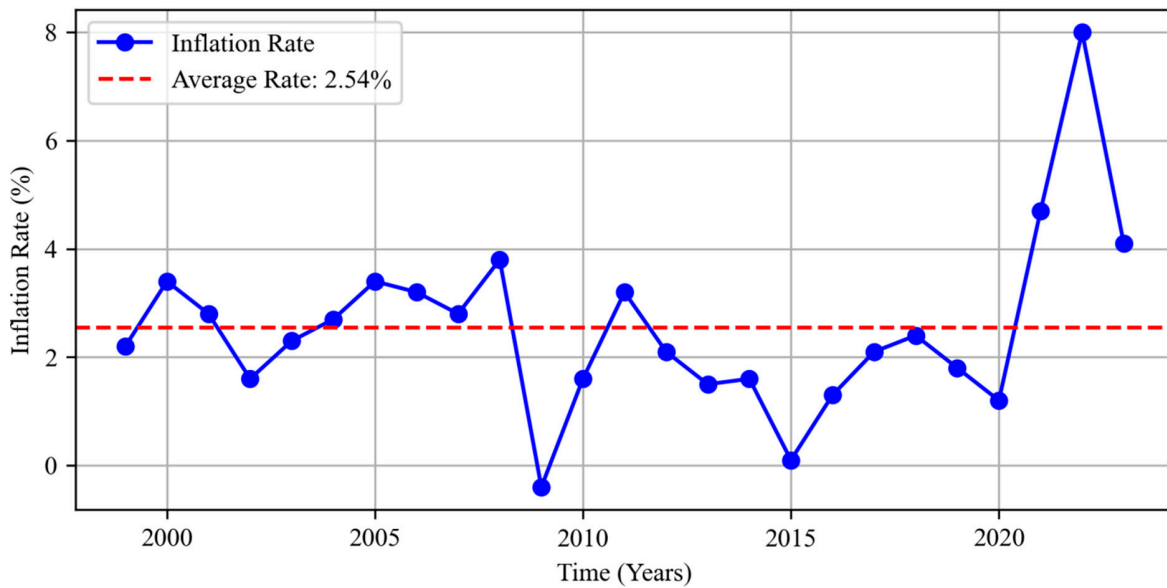


Figure 10. Inflation in U.S. from 1999 to 2023 (based on the data from [63]).

Table 4. Historical year-by-year inflation projection vs average inflation projection.

Parameters	Historical inflation projection	Average inflation rate= 2.54%
NPC [\$]	56,343.10	57,003.19
NPC for only Grid connected system [\$]	88,816.54	90,539.61
Total Grid avoidable cost [\$]	91,482.13	93,256.91
Total Grid unavoidable cost [\$]	-2,665.59	-2,717.30
Total avoided costs [\$]	88,816.54	90,539.61
Total grid earning for PV system [\$]	14,969.52	15,259.93
Total grid costs for PV system [\$]	48,334.43	49,272.13
Total grid credits for PV system [\$]	2,665.59	2,717.3
LCOE of PV energy system [\$/kWh]	0.18	0.18
LCOE for only Grid connected system [\$/kWh]	0.64	0.65
Grid avoidable cost per kWh [\$/kWh]	0.66	0.67
Grid unavoidable cost per kWh [\$/kWh]	-0.02	-0.02
Operating Cost [\$]	2,325.63	2,365.39
Total Money paid to the Grid [\$]	34,024.73	34,684.82
IRR (%)	10.98	11.07
PP (years)	9	9
Net profit (V_P) [\$]	32,473.44	33,536.42
ROI (%)	57.64	58.83

4.4. Limitations and Future Studies

This study has several limitations. The geographic scope is limited to specific regions (San Diego, Boston, Buenos Aires, and Santiago), which may not be generalizable to other locations with different economic conditions and inflation rates. The inflation modeling assumes an increase from 0% to 10% over

the project's lifetime, which may not capture more complex inflation scenarios or sudden economic shocks, such as COVID 19 economic shock [78–80].

Additionally, the study assumes that future grid prices will increase at the same rate as the annual average inflation, which may not accurately reflect future market dynamics. It is well known that inflation is not the only parameter affecting the escalation of electricity prices. Other parameters such as oil price shocks [81–83], and supply chain issues [84] could also affect electricity prices. When considering grid-connected PV with battery storage, the initial high costs, replacement costs and lifetime of batteries are highlighted as challenges, and the analysis might not fully account for future technological advancements [85,86] and cost reductions [87–93] in battery storage. For San Diego, historical inflation data is used to assess PV system potential, which might not fully represent future economic conditions, as future inflation is uncertain [94,95].

These limitations underscore the need for caution when generalizing the findings and suggest areas for further research to provide a more comprehensive understanding of the impact of inflation on PV systems. Future studies on this topic could leverage Monte Carlo simulation [96–99] to account for complex scenarios for future inflation, thus considering uncertainty in economic conditions. This approach would enable a more robust risk assessment, helping to identify the likelihood of various outcomes and providing deeper insights into the resilience of PV investments under different inflation scenarios.

5. Conclusions

This study highlights the potential of PV systems as a viable inflation hedge across diverse geographic regions—San Diego (California), Boston (Massachusetts), Santiago (Chile), and Buenos Aires (Argentina). The study reveals that while PV investments generally demonstrate significant profitability as an inflation hedge, the extent of this profitability is highly dependent on local economic conditions, particularly inflation rates, electricity prices, and NM policies.

In North American cities like San Diego and Boston, the study demonstrates that grid-tied PV systems benefit significantly from relatively stable economic environments, higher electricity prices, and favorable NM credits. These factors contribute to shorter PP and greater long-term profitability. San Diego experiences significant cost increases with higher inflation (a situation similar to the Great Inflation era) but still benefits from PV investments compared to grid reliance due to substantial avoided costs benefited from PV generation. Boston shows stable financial metrics, making it a predictable and attractive market for PV investments. Santiago exhibits trends similar to those observed in North American cities, though to a lesser extent. The city benefits from high solar resources and elevated grid electricity prices, making grid-tied PV systems profitable and showing potential for improved returns with increasing inflation. Buenos Aires presents a different scenario. The city's low baseline electricity prices and high inflation rates challenge the financial viability of PV systems. The study shows that only when inflation rates are high, the PV system in Buenos Aires begins to show profitability. This is a sophisticated example that regions with extremely low electricity costs and volatile economic conditions can still achieve profitability through PV investments during higher inflation. Moreover, the inclusion of batteries in PV systems introduces additional complexity. While batteries can enhance self-consumption and potentially improve profitability in inflationary environments, their high initial costs and frequent replacement cycles often extend the PP and reduce the overall financial return. This is evident in the Boston and Santiago case studies, where the addition of batteries increased the PP and reduced the total value of the system over time. However, as battery technology advances and costs decrease, PV-Battery systems' financial performance is expected to improve. The study also emphasizes the tax advantages of PV systems, particularly in inflationary periods. Unlike traditional investments that are subject to taxation, the profits generated from PV electricity

generation under net metering arrangements are not taxed because they are savings on electricity costs. This makes PV investments even more attractive as an inflation hedge. This tax benefit amplifies the overall financial return of PV systems, particularly in regions with high and rising electricity costs.

These insights underscore the potential for PV systems to serve as a robust hedge against inflation, particularly in regions with supportive regulatory frameworks and rising electricity costs, the importance of region-specific economic models, and the need to consider inflationary trends when evaluating the long-term viability of PV systems. Future research should explore more complex inflation scenarios and consider technological advancements in battery storage to provide a more comprehensive understanding of the impact of inflation on PV systems.

Acknowledgements: This work was funded by the Thompson Endowment and the Natural Sciences and Engineering Research Council of Canada.

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