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Research paper

A guide to residential energy storage and rooftop solar: State net metering policies and utility rate tariff structures

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ABSTRACT

Federal and state decarbonization goals have led to numerous financial incentives and policies designed to increase access and adoption of renewable energy systems. In combination with the declining cost of both solar photovoltaic and battery energy storage systems and rising electric utility rates, residential renewable adoption has become more favorable than ever. However, not all states provide the same opportunity for cost recovery, and the complicated and changing policy and utility landscape can make it difficult for households to make an informed decision on whether to install a renewable system. This paper is intended to provide a guide to households considering renewable adoption by discussing relevant factors that influence renewable system performance and payback, summarized in a state lookup table for quick reference. Five states are chosen as case studies to perform economic optimizations based on net metering policy, utility rate structure, and average electric utility price; these states are selected to be representative of the possible combinations of factors to aid in the decision-making process for customers in all states. The results of this analysis highlight the dual importance of both state support for renewables and price signals, as the benefits of residential renewable systems are best realized in states with net metering policies and above-average electric utility rates.

1. Introduction

Residential electricity consumers are considering rooftop photovoltaic (PV) and behind-the-meter (BTM) battery energy storage systems (BESS) now more than ever. The initial investment tax credit (ITC) passed in 2005 has since expanded to include both PV and BTM energy storage, paired together or standalone, and has been raised to 30% of the total system cost from now until 2032 [1]. The ITC, combined with rising utility rates, more frequent extreme weather events, and a worldwide focus on decarbonization and resilience has led many households to consider both renewable energy generation and storage for their homes. Though interest is high, adoption rates continue to be stifled by the large upfront cost and the complicated task of determining whether a system would be financially beneficial for a household. States and utilities have various and changing policies, incentives, and compensation mechanisms for BTM energy storage and rooftop solar which can be difficult to navigate. The objective of this study is to determine which combinations of existing utility rate structures and net metering policies provide favorable project economics for rooftop solar and BTM energy storage, and to serve as a guide for households considering installing residential energy systems across the U.S., as well as utilities and policymakers working to increase access to renewable energy systems.

There are a number of open-source tools available to evaluate and size residential energy systems that are inclusive of rate tariff, net metering policy, tax incentives, and solar resource, including the Energy Storage Evaluation Tool (ESET) [2], the System Advisor Model (SAM) [3], QuESt [4], and more. The intent of this study is not to replicate the capabilities of these tools, but instead to provide a comparative analysis of the economic feasibility of residential energy systems across the U.S. The results and insights from this analysis can be used to inform households looking to decide whether a renewable system could be economically viable in their area; policymakers weighing the merits of potential net metering policies and financial incentives; utilities designing rate tariffs and renewable pilot programs; and advocates working to make renewable energy systems more favorable for the communities they serve. The primary contribution of this work is to provide these energy system stakeholders with a comprehensive guide to understanding the factors that determine whether residential PV and BTM battery systems are economically favorable, as well as a reference set of case studies to compare policy and rate scenarios against their own state's renewable landscape. The novelty of this approach is the state-level evaluation of the nexus of these physical, policy, and economic factors as they impact the viability of a project, intended to empower these stakeholders and decision-makers.

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Section 2 provides a background of the various factors considered in this analysis that influence the performance and compensation of renewable energy systems, such as solar resource, installation cost, the retail price of electricity, the utility rate structure design, net metering policies, financial incentives, and installation logistics. The methodology used in this study is presented in Section 3, which discusses the five representative cases selected for this analysis, (1) Massachusetts, (2) Colorado, (3) Rhode Island, (4) Georgia, and (5) Tennessee, chosen to reflect the circumstances of the greatest number of states; the additional parameters required to perform the analysis, which include the normalized solar irradiance and residential load profile; and last, the optimization methodology, which introduces the Graph-Based Optimization Modeling Language (GBOML) model used in this analysis, selected for its ability to rapidly perform multi-objective optimizations over a year-long time horizon at hourly timesteps for a range of system and operational configurations as well as optimization objectives [5]. The limitations of this study are then presented, followed by the system configurations modeled in this analysis, which include a base case without a system, a battery-only system, and a PV-plus-battery system. The operational configurations describe how the net metering constraints are modeled, including the no-export scenario, PV-only export, and PV and battery-export. Then the optimization scenarios are described, the first minimizing the yearly electricity bill given a system configuration, rate tariff, and net metering policy, and the second sizing the renewable system based on the installation cost of the system, rate tariff, and net metering policy, while also minimizing the yearly electricity bill.

The results for each of the five cases, three net metering scenarios, and two optimizations are then presented in Section 4. The results of this analysis highlight that current rate tariff structures, net metering policies, installation costs, and financial incentives are not yet economically favorable for battery-only residential systems without access to additional revenue opportunities. Adding rooftop PV to the system improves this economic picture, though not every state provides sufficient mechanisms for cost recovery. These results are discussed in greater detail in Section 5, as well as how these representative cases can be used as a reference for households, policymakers, utilities, and advocates living in other states. Appendix A.1 [6–11] can be used as a reference to both compare the factors considered in this analysis and to determine which representative case studies most closely align with the circumstances of a particular state such that the results of this analysis provide actionable insights for those living in any U.S. state.

2. Background

Households may consider rooftop solar and BTM energy storage as a way to lower their electric utility bills, reduce their reliance on utility-generated electricity, or increase their resilience in light of more frequent extreme weather events exacerbating the risk of grid outages. Whatever their motivations, households must evaluate a number of factors that influence the installation cost, performance, and financial benefits of a system in order to make an informed decision of whether to proceed. A selection of these factors is introduced in the following sections.

2.1. Solar resource

A top concern for most prospective rooftop solar owners is whether their home gets enough sun to generate enough electricity to be worthwhile. Global Horizontal Irradiance (GHI) is used to measure the amount of solar resource at a given location, given in units of kWh per m^2 per day. Typical GHI values in the northernmost states are <4.00 kWh/m^2/day, as GHI increases toward the equator [6]. Many southern states have GHI values between 4.50 and 5.00 kWh/m^2/day, and states like California, Arizona, and New Mexico in the Southwest see GHI values 5.25 and over [6]. While an important consideration, a low GHI does not necessarily mean a solar array is poor choice, it just means that in order to generate a comparable amount of electricity as an array located in an area of high GHI, a larger system, or more panels, are required. Appendix A.1 provides an approximate range of GHI values for each state, though it is important to note that GHI may vary considerably across a state, especially for the larger states. GHI maps and location lookups can provide more precise estimates for a specific location.

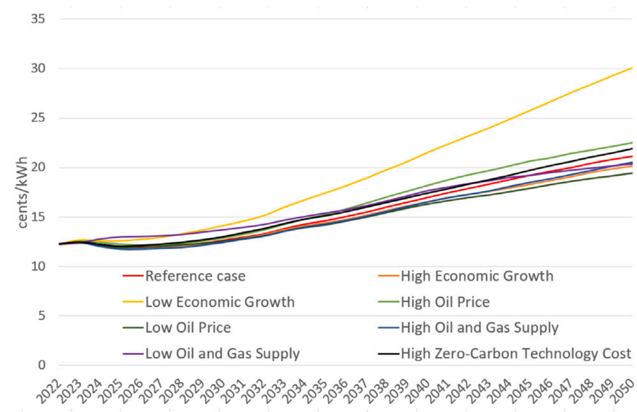


Fig. 1. Nominal electricity price forecast [7].

2.2. Installation cost

Often the primary consideration for households is the installation cost of the system. Fortunately, the cost of both solar and energy storage technologies has declined rapidly in the past decade. The supply chain issues from the global pandemic that led to increasing installation costs have begun to plateau in 2023 [12]. The average installation price of residential solar in 2023 is roughly $3.25 per Watt, or half of what it was in 2010 [12]. The average installation cost of residential BTM energy storage is roughly $1450 per kWh [9]. A typical residential solar array might be 7.5 kW, which would cost $24,375 at $3.25 per W; likewise, a 13.5 kWh energy storage system would cost $19,575 at $1450 per kWh. Appendix A.1 provides the average installation cost of residential PV and BTM energy storage in each state. The installation cost of both residential solar and storage is projected to continue declining over the next two decades [13].

2.3. Retail price of electricity

To determine a project's economic viability, the cost of a system's installation must be weighed against its potential to provide cost savings or revenue. The retail price of electricity delivered by the utility is used to determine the cost savings of the electricity generated on-site by the system. Every kWh generated by a rooftop solar array is a kWh not purchased from the utility, just as energy stored in a battery can be used when the price of utility electricity is elevated. The average retail price of electricity is roughly $0.12/kWh in the U.S, with prices as low as $0.08/kWh in Idaho and as high as $0.30/kWh in Hawaii [7]; Appendix A.1 provides the average retail price of electricity in each state. The greater the price of electricity, the greater the potential for savings from a renewable system. By extension, the higher a monthly electric utility bill, the more a project can provide savings by generating electricity on-site. The retail price of electricity is not static, however, and is projected to increase in the coming decades for all forecasted scenarios, as shown in Fig. 1 [7].

2.4. Utility rate structure

For residential customers, utility rate tariffs are typically either the same price regardless of when electricity is used (flat rate) or change

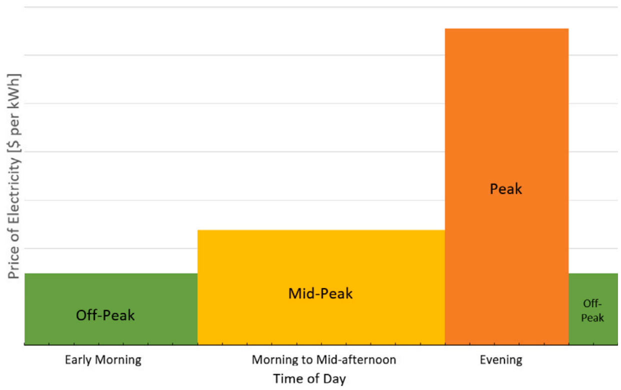


Fig. 2. Time-of-use rate structure.

based on the time of day (time-of-use: TOU or time-of-day: TOD) rate. Additional rate designs include step rates, which increase in price as usage increases; demand rates, which include demand charges based on the maximum power usage during the billing period; and rates that combine one or more of these mechanisms. Time-of-use rates are becoming more commonplace as utilities recognize them as a mechanism to incentivize customers to use electricity when it is more abundant, such as the middle of the day when wind and solar production is high, but use is minimal; and disincentivize use when resources are scarce and use is high. TOU rates vary in structure and scale across the country according to the generation and load mix of a utility service territory, however they typically resemble the general structure shown in Fig. 2.

Early morning and late at night are typically the least expensive times to use electricity; morning to mid-afternoon is more expensive; an evening is the most expensive. In some regions, winter peak times may occur during the early morning. While TOU rate structures can provide households the opportunity to save on their electricity bills if they are able to change their energy use behaviors, such as running the dishwasher or clothes dryer at night rather than after work, they provide even greater savings for those with solar and energy storage systems.

Though nearly all of the U.S. allows time-of-use rates (D.C. and Rhode Island being the exception) [11], not every utility offers them. Appendix A.1 highlights the states in which the largest utility in the state does not offer a TOU rate, as of the latest update of the NREL dataset on April 4th, 2023 [11]. This rate tariff structure provides considerable opportunity for cost savings by system owners whose rooftop solar generates electricity during times of mid to high prices as well as revenue for energy storage systems engaging in energy arbitrage, charging either from solar generation or while the price of electricity is low, and discharging when the price of electricity is high. In either situation, these opportunities are limited if either the rooftop solar or the energy storage system are restricted from exporting to the grid, which are determined by a state's net metering policies.

The generated electricity from a rooftop solar array is typically coincident with the mid-peak price period, with limited generation in the hours before and after mid-peak as the sun rises and sets. Utilizing solar generated electricity during these times prevents the household from paying the higher, mid-peak price of electricity. An energy storage device can increase these savings even further, by storing the excess solar production during the sunlight hours to be used instead of utility electricity for the duration of the peak price period, preventing the household from paying the highest price of electricity. If the household use is higher than the generated or stored electricity, the system will not eliminate the mid- and peak-price utility electricity entirely, though it will reduce the amount purchased from the utility. In addition to these savings, the off-peak price of electricity in a TOU rate is typically lower than the flat rate price of electricity, such that switching from a flat rate provides cost savings since renewable system owners are likely to purchase most of their utility electricity at these lower prices.

In addition to cost savings, TOU rates also provide system owners with the opportunity to generate revenue from energy arbitrage. While solar may generate excess electricity that can be sold during the early hours of the peak period, energy storage is uniquely suited to take full advantage of the price variability. Most storage devices can either be configured manually by setting a charging/discharging schedule or by inputting or selecting the appropriate rate tariff from a database within the system owner's battery management smartphone app. After scheduling or selecting the TOU rate, these settings can be tailored to the owner's resilience preferences by restricting the battery from discharging past a set state of charge. Once configured, a TOU rate provides the system owner with the opportunity to generate revenue from energy arbitrage that is proportional to the difference in off-peak and peak pricing; the greater the difference in price, the greater the opportunity to generate revenue from energy arbitrage.

2.5. Net metering policies

Net metering is the fundamental enabling policy for residential rooftop solar owners. To participate, the electric meter at the owner's residence is replaced with a bi-directional meter that can measure both the electricity consumed by the residence as well as the electricity exported from the residence. This allows system owners to receive credit for the electricity production of their solar arrays in excess of their consumption, ensuring that no amount of generated electricity is curtailed, or wasted. Nearly every state allows some form of net metering for rooftop solar arrays, however not all states have statewide net metering policies [10].

Net metering for BTM energy storage is still relatively uncommon; only AZ, CA, CO, HI, MA, and NY have net metering policies that allow energy storage to export stored electricity back to the grid for compensation [11]. Energy storage has historically been regarded with additional operational and grid safety concerns, as batteries can act as both a load while charging and as a generator while discharging. The dual nature of energy storage is such that many utilities and regulatory bodies have erred on the side of caution, either reviewing system designs as if the batteries were operated to export their full capacity at all times, or simply restricting them from exporting to the grid entirely [14,15]. This restriction prevents system owners from accessing the full revenue from energy arbitrage as well as grid operators from utilizing the combined capacity of residential BTM energy storage as a grid asset.

Fortunately, utilities and regulators alike have begun to recognize the role that BTM energy storage can play to support a more resilient grid of the future. Some utilities in states without BTM energy storage net metering policies are piloting programs to study grid-integration of BTM energy storage, such as Portland General Electric's Smart Battery Pilot Program, approved by the Oregon Public Utility Commission, which allows BTM energy storage to export electricity to the grid when called upon during a "Peak Time Event", as communicated by the utility [16]. In this pilot program, system owners are compensated in bill credits of $1.70 per kWh exported during the event window, which typically lasts three hours [16]. Pilot programs like these provide revenue opportunities for system owners in states other than the six with enabling policy; it is therefore important to review all the utility offerings that may apply to a project. Note, however, that many pilot programs have targets or caps, after which enrollment is restricted. While these pilots can be great opportunities, they should not be considered as a guaranteed revenue stream, as access may be limited, and a program may reach capacity before the prospective system comes online.

2.6. Financial incentives

The ITC has dramatically accelerated solar adoption across the nation by providing system owners with a 30% tax credit on the total cost of a solar, energy storage, or combined systems [1]. This credit applies to the system itself, the balance-of-system equipment (wires, inverters, mounting hardware, etc.), as well as the labor [17]. However, the 30% ITC does not reduce the upfront cost of a solar and energy storage system; recouping these costs requires the system owner to file IRS form 5695 with their tax return, after which the credit is levied against the owner's tax liability, with any excess credits rolled over to the next tax year—which means it may take several years to receive the full credit, depending on the owner's tax liability [17]. While the ITC does not directly improve residential access to renewable systems by lowering the upfront cost of installation, the credit can substantially reduce a project's payback period, or the point at which the system has saved or provided revenue to the owner in an amount totaling the initial cost of the system.

At the state level, many offer financial incentives for renewable energy systems in addition to the ITC, however these vary greatly by technology. A quick search of state-level financial incentives for energy storage using the Database of State Incentives for Renewables & Energy Efficiency returns 57 results at time of writing, whereas the same search for solar photovoltaics returns 426 results [18]. With that in mind, most states offer a property tax exemption such that the installation of solar panels that would raise the value of a property are exempt from increasing the property taxes for the system owner [19]. In addition, several states offer sales tax exemptions such that the purchase of a renewable system is exempt from sales tax [20], which can substantially reduce the upfront cost of the system. States may also offer financing or loan programs as well as upfront rebates or grant programs for the purchase of a renewable system, many of which target low-to-middle income (LMI) buyers specifically, or offer additional incentives for income-qualified buyers. Last, many utilities also offer rebates or incentives that can either reduce the upfront purchase price or improve the payback period of a renewable system. Navigating all the various financial mechanisms may seem a daunting task; fortunately, most installers are familiar with the local incentives applicable in their region and will oftentimes even take the burden of applying for and listing the incentives as itemized discounts on the final system invoice. However, this is not always the case, so it is important to be aware of all the financial opportunities available, and to self-advocate so as not to miss any opportunities for savings.

2.7. Installation logistics

Both rooftop solar and BTM energy storage require adequate space for installation and access for safety regulations. The placement of rooftop solar panels will depend on the orientation of the residence with respect to the cardinal directions; a south-facing rooftop is preferable for solar installations in the northern hemisphere, the reverse is true in the southern hemisphere. East- and west-facing rooftops can also be used; however, the amount of solar generation will be reduced. The installer will review past utility bills to adequately size the system for the residence, and then provide sample drawings of potential panel placement to fit the rooftop configuration of the residence. The age and condition of the roof are important, as it is undesirable to need to replace the rooftop after installing panels—however, this can be done if needed, though it increases the cost of a roof replacement. Additionally, if the roof is covered by a warranty, it is also important to verify that the mounting hardware used to install the solar panels will not void the warranty.

Residential BTM energy storage is commonly installed either in the residence's garage or mounted to an outside wall nearby the electrical panel. The battery and solar panel inverters as well as any monitoring systems will also need space to be mounted. As battery systems generate heat, it is important that the mounting location has adequate ventilation and is not crowded or inaccessible. The National Fire Protection Association maintains fire standards that restrict energy storage systems from being installed anywhere other than: garages, exterior walls or outdoors at least 3 ft from doors and windows, utility closets, or storage or utility spaces [21]. If mounting outside, additional considerations may be required to protect the systems from inclement weather or other hazards such as flooding, if applicable. If participating in a net metering program, the electric meter for the residence will be swapped, and an emergency shutoff switch may also be installed adjacent to the meter.

Table 1
Scenario cases.

Case	State	Electricity price	Rate tariff	Solar net metering	Battery net metering
1	MA	High	TOU	YES	YES
2	CO	Medium	TOU	YES	YES
3	RI	Medium	Flat	YES	NO
4	GA	Low	TOU	Yes, at avoided cost	NO
5	TN	Low	TOU	NO	NO

In addition to the operational, safety, and logistic considerations when placing residential PV and BTM energy storage, local permitting and zoning ordinances must also be followed. Permitting and inspection are required to ensure the safe and correct installation of renewable systems. While the installer will typically handle all the permitting requirements, these increase the soft costs of the system, or those not related to the physical technology. Considerable effort is ongoing to streamline and standardize the permitting process to lower the soft costs of solar and expedite this process; SolarAPP+ is an example of such a standardized permitting portal in use in over 125 jurisdictions [22]. Inspection of the system may also be coordinated by the installer, but the system owner may be required to be present to grant access. Zoning implications may concern the visual, auditory, odor, or environmental impacts of a system, and vary considerably by jurisdiction [23].

3. Methodology

The economic feasibility of rooftop solar and BTM energy storage depends on a number of factors which vary across the U.S. The potential combinations of the selected factors considered in this analysis are compiled in Table 1 to form a set of case studies to demonstrate how each influences the economic viability of a project. The states chosen for case studies were selected to account for all possible combinations of PV and battery net metering policies and to be representative of available rate structures and range of electricity prices. Also considered in this analysis are the state average installation costs of PV and residential BTM BESS (Appendix A.1), the approximate annual GHI in each state (Appendix A.1), represented by the normalized solar irradiance profile of each location simulated by SAM; and the hourly residential load profile representative of a typical house in each state, simulated by EnergyPlus. This section describes each case study and why it was selected; the additional parameters required for this analysis; and the methodology of this analysis using GBOML [5].

3.1. Cases

3.1.1. Massachusetts

Massachusetts was chosen as a representative case for this analysis as it is one of the few states that offers a net metering program for energy storage as well as solar [10,11]. The state has a relatively high average retail price of electricity, at $0.1906 per kWh [7]. The time-of-use rate used in this analysis for MA is based off the largest utility in the state, Eversource, and is shown in Table 2 [24]. The average installation cost of solar in MA is $3.54 per W [8], and the average installation cost of energy storage is $1488 per kWh [9], both slightly above average for the U.S.

Table 2
Massachusetts time-of-use rate, eversource.

Period	Time	Rate [$/kWh]
On peak	1:00 p.m.–7:00 p.m. Weekdays	0.3084
Off peak	7:00 p.m.–1:00 p.m. Weekdays, Weekends	0.10065

Table 3
Colorado time-of-use rate, Xcel energy.

Season	Period	Time	Rate [$/kWh]
Winter (Oct–May)	On peak	3:00 p.m.–7:00 p.m. Weekdays	0.10858
	Shoulder	1:00 p.m.–3:00 p.m. Weekdays	0.08623
	Off peak	7:00 p.m.–1:00 p.m. Weekdays, Weekends	0.06387
Summer (June–Sept)	On peak	3:00 p.m.–7:00 p.m. Weekdays	0.17246
	Shoulder	1:00 p.m.–3:00 p.m. Weekdays	0.11816
	Off peak	7:00 p.m.–1:00 p.m. Weekdays, Weekends	0.06387

3.1.2. Colorado

Colorado was chosen as a representative case for this analysis as it also offers solar and battery net metering [10,11], however it has a lower average retail price of electricity, only $0.109 per kWh [7]. The time-of-use rate used in this analysis for CO is based off the largest utility in the state, Xcel Energy [25], and is shown in Table 3. The average installation cost of solar in CO is $3.44 per W [8], and the average installation cost of energy storage is $1407 per kWh [9], both around average for the U.S.

3.1.3. Rhode Island

Rhode Island was chosen as a representative case for this analysis because it is one of the few states that does not offer a time-of-use rate for electricity. RI also does not have a battery net metering program [10,11]. RI has a relatively high average retail price of electricity, at $0.1844 per kWh [7], which was used in place of a utility-specific rate in this analysis. The average installation cost of solar in RI is $3.61 per W [8], and the average installation cost of energy storage is $1882 per kWh [9], both above average for the U.S.

3.1.4. Georgia

Georgia was chosen as a representative case for this analysis because while solar net metering and time-of-use rates are both allowed, neither is required to be offered in the state [10,11]. Georgia has a slightly below-average retail price of electricity, at $0.1043 per kWh [7]. The largest utility in the state, Georgia Power, has a "Nights & Weekends" time-of-use rate tariff that contains a peak window from 2:00 to 7:00 p.m. on weekdays from June through September, at $0.231385 per kWh; off-peak pricing is $0.059187 per kWh [26], shown in Table 4. This large, seasonal peak window and substantial price difference between on- and off-peak make this an interesting rate tariff for investigation. Georgia Power also does not offer standard solar net metering, instead it credits system owners under the RNR-Instantaneous Netting program for exported electricity at the "Solar Avoided Energy Cost" rate of $0.028982 per kWh, with a $0.04 per kWh renewable generation adder approved by the Public Service Commission in 2022 [27]. Georgia Power announced on June 26th, 2021, that its RNR-Monthly Netting program had reached its 5000-applicant cap [28]. Unlike the Instantaneous Netting program, the original Monthly Netting program was more akin to traditional net metering in that system owners were compensated based on the time-of-use rate schedule, however that program only has a 15-year lifetime, after which all customers will be transferred to the instantaneous netting program with the reduced compensation rate [21]. The average installation cost of solar in GA is $3.20 per W [8], and the average installation cost of energy storage is $1397 per kWh [9], roughly average for the U.S.

3.1.5. Tennessee

Tennessee was chosen as a representative case for this analysis because the state does not allow solar net metering [10,11]. The state does offer a time-of-use rate, shown in Table 5, from Memphis Light [29]. The average retail price of electricity is $0.0978 per kWh [7], which is low enough to not provide much incentive for households to generate their own electricity. However, the average installation price of solar and residential energy storage are also much lower than the national average, at $2.97 per W for solar [8], and $992 per kWh for energy storage [9], which should lower the payback period for a renewable system.

3.2. Additional parameters

3.2.1. Normalized solar irradiance

In order to represent the variance in GHI between states, described within Appendix A.1, and to simulate the hourly generation of a rooftop solar system, normalized hourly irradiance data is required for each location. The SAM was used to generate the normalized hourly irradiance profile [3], or the equivalent of the power generated each hour by a 1 kW solar array, with the tilt angle of the panels in the array equal to the latitude of each location. Normalizing this generated data to a 1 kW array allows it to be imported into the GBOML simulation, such that it can be scaled to the size of the residential system by multiplying it by the capacity of the system, or 7.5 kW for this analysis. The normalized irradiance data is reflective of the location and tilt angle, described in Appendix A.2.

3.2.2. Residential load profiles

For each case study, a representative load profile was used to simulate the hourly energy demand of the house. These data were simulated in EnergyPlus, the whole-building energy simulation software that models energy consumption from HVAC, plug, and process loads for a given building configuration [30]. For each case, the representative load profile was selected based on climate zone, heating system, and foundation type. TMY3 weather data were selected for the capital of each state in this analysis for the EnergyPlus simulations [30]. All load profiles used represent single family detached homes, reflective of 62.4% of all homes in the U.S. [31]. The climate zone is indicative of the climate and moisture levels of the region, both of which are key factors that impact the heating and cooling load of a building. The most common heating fuel type reported in the Residential Energy Consumption Survey data was used to select the heating system type for each case [31], described in Appendix A.2. Load profiles for both gas and electric heating system types were used in Georgia due to the near-even split of households using each. Slab foundation types were assumed in all cases for simplicity and to limit the number of variables between cases. A four-person household was assumed in each case.

3.3. Optimization methodology

The Graph-Based Optimization Modeling Language was used to simulate the annual utility-purchased electricity (electricity exchanged), PV generation (electricity generated), and PV and battery capacity for each case and to optimize the electricity dispatch of each household using the most cost-effective combination of utility-purchased electricity, PV-generated electricity, and battery-stored electricity for the given rate tariff design and combination of PV and battery net metering policies. GBOML utilizes mixed-integer linear programming that incorporates both algebraic and object-oriented modeling methods to efficiently solve the energy system optimization problem under investigation in this analysis [5]. The optimization problem can be broken into four nodes: the house, the grid, the PV array, and the battery, represented in Fig. 3.

The nodes are described by a set of parameters (black), and both internal and external variables (blue). In GBOML, parameters are used to

Table 4
Georgia time-of-use rate and solar avoided energy cost, georgia power.

Season	Period	Time	Rate [$/kWh]	Solar avoided energy cost [$/kWh]
Summer (June–Sept)	On peak	2:00 p.m.–7:00 p.m. Weekdays	0.11006	
	Off peak	7:00 p.m.–2:00 p.m. Weekdays, Weekends	0.011766	0.068982
Non-Summer	All hours	All hours	0.011766	

Table 5
Tennessee time-of-use rate, memphis light.

Season	Period	Time	Rate [$/kWh]
Summer (June–Sept)	On peak	1:00 p.m.–7:00 p.m. Weekdays	0.14597
	Off peak	7:00 p.m.–1:00 p.m. Weekdays, Weekends	0.06584
Fall/Spring (Oct–Nov, Apr–May)	All hours	All hours	0.06584
Winter (Dec–Mar)	On peak	4:00 a.m.–10:00 a.m. Weekdays	0.09891
	Off peak	10:00 a.m.–4:00 a.m. Weekdays, Weekends	0.06584

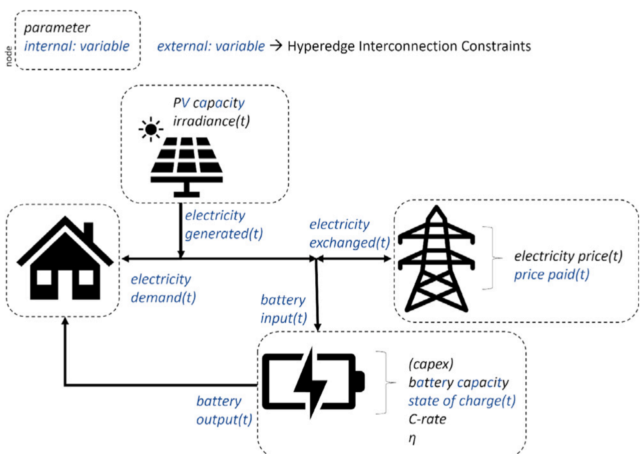


Fig. 3. GBOML optimization problem representation. Note that PV and battery capacity are multicolored as they can either be a specified parameter or a variable depending on the optimization problem. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

define the characteristics of the nodes, such as the solar irradiance; PV capacity; electricity price; the rate at which the battery can charge and discharge, or its C-rate; its efficiency, η; and the capital expenditure, or capex, required to purchase the PV or battery. Internal variables rely on the parameters of the nodes, and include the price paid for electricity and the state of charge of the battery. The external variables are related to each other via the hyperedge interconnection constraints that define the optimization problem: the grid electricity exchanged, PV electricity generated, battery input, and battery output are all optimized to meet the electricity demand of the house at the lowest price paid. The PV and battery capacities are written in both blue and black because they can either be considered a parameter if defined in the problem statement or as a variable if the capex is added to the problem such that both the price paid for electricity and the price paid for the system are simultaneously optimized to be as low as possible. This problem definition, described in Section 3.3.4, will allow for the optimal sizing of the renewable system based on the relative price of electricity, the demand of the house, and the operating constraints that influence the payback of the system, such as any net metering constraints and the timing and scale of the rate tariff used to define the electricity price.

The granularity of this analysis is modeled at the hourly level in order to maintain compatibility between the capacity units for batteries (kWh) and PV systems (kW). Simulations are run for the duration of a year, with the 2023 calendar year used for any seasonal varying time-of-use rates. The methodology employed in this analysis is described in further detail in the following sections, with the operational configurations and equations explicitly defined in Appendices A.3 and A.4.

3.3.1. Limitations

For the purpose of this analysis, only the volumetric, or per-kWh charges of each rate tariff are included. The taxes and fees included on a typical utility bill do not vary based on usage and are therefore excluded from this discussion. Note that this analysis simulates an economically optimized dispatch while reserving roughly 20% of the battery's capacity in case of an outage, corresponding with the default setting in the Tesla app. However, this may not reflect the preferences of all households; those that experience frequent, prolonged outages may choose to reserve a greater portion of their battery's capacity for resilience, while others who rarely experience outages may elect for nearly all of their battery's capacity to be used for time-of-use bill management. The economic dispatch in this analysis also does not limit the number of charge/discharge cycles and will discharge at the manufacturer's maximum specified C-rate if economically advantageous. It is important to note that the lifespan of a battery can be reduced by excessive cycling, rapid charge/discharge rates, and high depth of discharge. Conversely, reserving a large portion of a battery's capacity and keeping the average state of charge relatively high can also have a negative impact on battery lifetime [32]. In order to remain as agnostic as possible of battery chemistry and to present an upper limit based on economic dispatch, the effects of battery cycling behavior are not considered in this analysis.

3.3.2. System configurations

Three potential system configurations were modeled for each case: (1) no system, which was used to establish a baseline for grid electricity exchanged and annual utility bill, or price paid; (2) BESS-only, in which the household has a 13.5 kWh BTM battery (reserving roughly 20% capacity in case of outage, leaving a usable capacity of 10.5 kWh), with a 90% round trip efficiency, η, and a C-rate of 0.347, corresponding to a typical Tesla Powerwall battery; (3) BESS & PV, in which the same battery is paired with a 7.5 kW rooftop PV array. These three configurations were chosen to represent the potential systems that households may consider in order to reduce their electricity bills, increase their resilience and energy independence, and take advantage of numerous financial incentives and net metering policies, in addition to any other energy and equity benefits.

3.3.3. Operational configurations

The three policy configurations modeled in this analysis are (1) no grid export allowed, representing states in which neither PV net metering nor battery net metering policies exist and renewable system owners may only operate their systems to offset their own consumption; (2) PV net metering policies are in place, in which PV systems are allowed to export excess PV-generated electricity, but BESS must only be

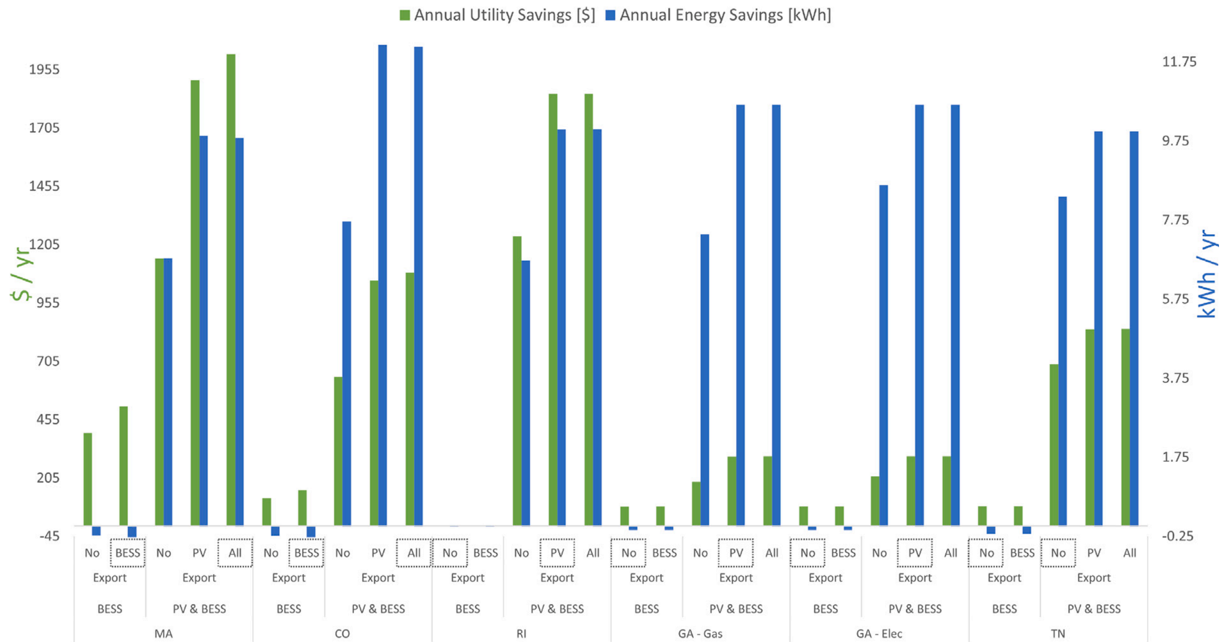


Fig. 4. Annual utility and energy savings of each state annual utility charge optimization. States' net metering policies are boxed for comparison with unboxed "what-if" policy scenarios.

used to increase the self-consumption of PV-generated electricity or for TOU bill management; and (3) PV & BESS net metering, in which both PV and BESS are allowed to export excess PV-generated electricity or BESS-stored electricity when it is financially advantageous. The GBOML definitions of these configurations are provided in Appendix A.3.

3.3.4. Optimizations

There were two optimization problems solved for each case in this analysis, (1) minimize the electricity price paid given the specified system configuration, and (2) minimize electricity price paid while simultaneously sizing the system configuration to minimize the capital expenditure. These two optimizations allow for an exploration of both the potential savings of a typical residential renewable system as well as a direct exploration of whether the existing market price of renewable systems are economically favorable, given the policy structure defining their cost-recovery mechanisms. These optimization equations are defined in Appendix A.4. The system configuration optimizations were bounded such that the PV capacity could not exceed 10 kW to still remain feasible for rooftop configurations, and the BESS capacity could not exceed 21 kWh, or the equivalent of two Tesla Powerwalls.

To compare energy use and annual utility charges for the simulated cases, a baseline no-system case was first simulated for each. Next, the possible system and net metering policy combinations were simulated for each state to provide a "what-if" comparison of potential to actual policy landscape in the representative states. Both optimization problems were also investigated for each system and policy combination.

4. Results

The results of each optimization problem are summarized in separate tables. Fig. 4 and Table 6 focus on the first optimization problem to minimize the price paid for electricity by optimizing the electricity dispatch, assuming that system owners had either 10.5 kWh of BESS for economic dispatch, or 10.5 kWh of BESS and a 7.5 kW rooftop PV system. The upfront system cost without incentives is provided for each system configuration and state case. The results of the optimization for each combination of system, net metering policy, and state case can be summarized by: the annual utility-purchased electricity, in kWh, representing the portion of the household demand that was unmet by the renewable system; the annual electricity supplied to the house by the battery, in kWh; the annual electricity supplied to the battery to charge the battery, in kWh, which can be provided either by utility-purchased electricity or PV-generated electricity and is always higher than that provided by the battery due to inherent inefficiencies in the charge/discharge cycle; the annual electricity generated by the PV system, in kWh, based on the normalized generation profile of a 1 kW array in each case location; the annual volumetric utility charges from any utility-purchased electricity, offset by any revenue from PV- or BESS-exported electricity; the annual utility savings from the system, or the difference between the baseline annual utility charges with no system and the charges with the system; and the simple payback period, or the number of years required for the combined utility savings to cover the upfront cost of the system. Note that in all cases, the utility charges are representative of the per-kWh charges for electricity, and not inclusive of any recurring taxes or fees, such that in every case these values will be less than the sum of actual utility bills for the year. For each state case, both a BESS-only and a PV & BESS configuration are investigated for each combination of net metering policies. Scenarios that are representative of the actual policy landscape in each state are in bold in Tables 6 and 7, such that a "what-if" comparison can be made with the other net metering scenarios.

Table 7 contains the results of the annual utility charges and system configuration optimization, whereby in each scenario, the PV & BESS configuration were economically sized to result in the lowest annual utility charges after economically optimizing the electricity dispatch, based on the annualized capital expenditure required to purchase rooftop PV (annualized $/kW), and BESS (annualized $/kWh). Like in the previous optimization, each state case was simulated for all net metering policies for comparison with the actual state policies, represented by the bold entries in the table. For many of the state scenarios, the combination of annual household electricity demand, rate tariff design and price of electricity, purchase price of a PV & BESS configuration, and net metering policies resulted in no system being the most economical decision. For scenarios where a system was determined to be worthwhile, the optimized system size is reported as-is and not adjusted to reflect market-available capacities of PV or BESS, or to have sufficient capacity to reserve 20% for resilience. The results

Table 6
Annual utility charges optimization results.

Sys	NM	Simulation results	Case 1: MA	Case 2: CO	Case 3: RI	Case 4: GA		Case 5: TN
			TOU ∣ Gas	TOU ∣ Gas	Flat ∣ Gas	TOU ∣ Gas	TOU ∣ Elec	TOU ∣ Elec
None	N/A	Yearly demand [kWh]	10,840	11,073	10,777	11,731	20,526	21,783
		Utility purchase [kWh]	10,840	11,073	10,777	11,731	20,526	21,783
		Annual utility charges [$]	$1554	$853	$1987	$241	$351	$1622
BESS	None	**Upfront system cost [$]**	**$20,088**	**$18,995**	**$25,407**	**$18,860**	**$18,860**	**$13,392**
		Utility purchase [kWh]	11,063	11,303	**10,775**	**11,824**	**20,617**	**21,970**
		Supplied BY battery [kWh]	2033	2098	**1**	**851**	**861**	**1713**
		Supplied TO battery [kWh]	2256	2328	**0**	**944**	**952**	**1900**
		Annual utility charges [$]	1155	735	**1987**	**158**	**268**	**1537**
		Annual utility savings [$]	$400	$118	**$0**	**$82**	**$83**	**$85**
		Simple payback w ITC [yr]	–	–	–	–	–	–
		Payback with state & Utility incentives [yr]	–	–	–	–	–	–
	BESS	Utility purchase [kWh]	**11,123**	**11,355**	10,773	11,823	20,618	21,969
		Supplied BY battery [kWh]	**2604**	**2594**	4	871	871	1726
		Supplied TO battery [kWh]	**2888**	**2877**	0	963	963	1914
		Annual utility charges [$]	**1042**	**700**	1987	156	267	1536
		Annual utility savings [$]	**$512**	**$153**	$1	$84	$84	$86
		Simple payback w ITC [yr]	–	–	–	–	–	–
		Payback with state & Utility incentives [yr]	–	–	–	–	–	–
PV& BESS	No Export	**Upfront system cost [$]**	**$46,638**	**$44,795**	**$52,482**	**$48,860**	**$42,860**	**$35,667**
		Utility purchase [kWh]	4051	3349	4047	4336	11,886	**13,441**
		Supplied BY battery [kWh]	2988	3412	2929	2986	2682	**2973**
		Supplied TO battery [kWh]	3316	3787	3251	3314	2974	**3299**
		Generated by PV [kWh]	7117	8099	7052	7724	8932	**8668**
		Annual utility charges [$]	408	214	746	51	134	**929**
		Annual utility savings [$]	$1146	$639	$1241	$190	$211	**$693**
		Simple payback w ITC [yr]	28.5	–	29.6	–	–	–
		Payback with state & Utility incentives [yr]	19.5	–	24.1	–	–	–
	PV	Utility purchase [kWh]	953	−1,117	**731**	**1060**	**9853**	11,793
		Supplied BY battery [kWh]	2033	2098	**1**	**851**	**861**	1713
		Supplied TO battery [kWh]	226	2328	**0**	**944**	**952**	1900
		Generated by PV [kWh]	10,110	12,420	**10,045**	**10,764**	**10,764**	10,177
		Annual utility charges [$]	−355	−199	**135**	**−57**	**53**	779
		Annual utility savings [$]	$1910	$1052	**$1852**	**$297**	**$298**	$843
		Simple payback w ITC [yr]	17.1	29.8	**19.8**	–	–	–
		Payback with state & Utility incentives [yr]	11.7	22.7	**16.1**	–	–	–
	PV& BESS	Utility purchase [kWh]	**1013**	**−1065**	728	1059	9854	11,793
		Supplied BY battery [kWh]	**2604**	**2594**	4	871	871	1728
		Supplied TO battery [kWh]	**2888**	**2878**	0	963	963	1914
		Generated by PV [kWh]	**10,110**	**12,420**	100,445	10,764	10,764	10,178
		Annual utility charges [$]	**−468**	**−233**	134	−58	53	778
		Annual utility savings [$]	**$2022**	**$1087**	$1853	$299	$299	$843
		Simple payback w ITC [yr]	**16.2**	**28.9**	19.8	–	–	–
		Payback with state & Utility incentives [yr]	**11.1**	**22.0**	16.1	–	–	–

Sys: System Configuration, NM: Net Metering Policy.

of each scenario in Table 7 are presented in the same manner as the first optimization, with the addition of the system size. Table 7 does not contain a BESS-only set of rows as in the previous optimization as there was no case where a BESS-only system was economically advantageous.

4.1. Massachusetts

Massachusetts has both PV and BTM BESS net metering policies, allowing excess PV-generated electricity to be exported to the grid and energy storage to engage in energy arbitrage, both of which provide additional value to renewable system owners on top of reducing utility-purchased electricity. Massachusetts has an above-average retail price of electricity, above-average installation cost of solar, and roughly average installation cost of energy storage. The representative load profile modeled in EnergyPlus for Massachusetts for a gas-heated four-person household resulted in a yearly demand of 10,840 kWh and $1554 of yearly volumetric utility charges with the TOU rate tariff from Eversource.

4.1.1. Annual utility charges optimization results

For a BESS-only system in MA, 10.5 kWh of battery capacity participating in energy arbitrage and peak load reduction could provide $512 in annual utility savings, with a simple payback period exceeding its lifetime. A PV & BESS configuration in MA with both systems able to export excess electricity could provide $2022 in annual savings and have a simple payback period of just over 16 years with the 30% ITC. The state of Massachusetts offers a maximum of $1000 Residential Renewable Energy Income Tax Credit that can be claimed over three years of tax liability [18]. In addition, many utilities in the state offer some form of rebate for residential solar, which vary between $0.10/W and $1.50/W, and is most commonly $1.20/W, capped at 50% of the system cost [18]; for a 7.5 kW system, the typical incentive would be a $9000 rebate. At least one utility also offers a rebate for energy storage, a flat $300 from Taunton Municipal Lighting Plant [18]. With both these state and utility incentives combined, the simple payback period for the BESS-only case still exceeds its lifetime, but the PV & BESS case is brought to just over 11 years.

Table 7
Annual utility charges & system configuration optimization results.

Sys	NM	Simulation results	Case 1: MA	Case 2: CO	Case 3: RI	Case 4: GA		Case 5: TN
			TOU | Gas	TOU | Gas	Flat | Gas	TOU | Gas	TOU | Elec	TOU | Elec
		System size	1.18 kW PV	0.96 kW PV	1.39 kW PV			
		Utility purchase [kWh]	9275	9493	9018			
		Generated by PV [kWh]	1565	1580	1759			
		Annual utility charges [$]	1319	735	1663			
	No export	Annual utility savings [$]	$235	$119	$324	NONE	NONE	**NONE**
		Upfront system cost [$]	$4177	$3302	$5018			
		Simple payback w ITC [yr]	12.5	19.5	10.8			
		Payback with state & Utility incentives [yr]	6.4	13.8	8.0			
		System size	10 kW PV	10 kW PV	**10 kW PV**			
		Utility purchase [kWh]	−2,640	−5,487	**−2616**			
		Generated by PV [kWh]	13,480	16,561	**13,393**			
PV & BESS		Annual utility charges [$]	−459	−391	**−482**			
	PV	Annual utility savings [$]	$2013	1245	**$2470**	**NONE**	**NONE**	NONE
		Upfront system cost [$]	$35,400	$24,400	**$36,100**			
		Simple payback w ITC [yr]	12.3	19.4	**10.2**			
		Payback with state & Utility incentives [yr]	6.4	13.7	**8.2**			
		System size	**10 kW PV**	**10 kW PV**	10 kW PV			
		Utility purchase [kWh]	**−2640**	**−5487**	−2,616			
		Generated by PV [kWh]	**13,480**	**16,561**	13,393			
		Annual utility charges [$]	**−459**	**−391**	−482			
	PV & BESS	Annual utility savings [$]	**$2014**	**1245**	$2470	NONE	NONE	NONE
		Upfront system cost [$]	**$35,400**	**$24,400**	$36,100			
		Simple payback w ITC [yr]	**12.3**	**19.4**	10.2			
		Payback with state & Utility incentives [yr]	**6.4**	**13.7**	8.2			

Sys: System Configuration, NM: Net Metering Policy.

4.1.2. Annual utility charges & system configuration optimization results

In Massachusetts, both PV and BESS net metering policies result in a capex-optimized system of 10 kW rooftop solar, but no battery capacity. The annual savings from energy arbitrage and peak load reduction of $512 is insufficient to pay back the purchase price of the battery system within its lifetime. The 10 kW PV system has an estimated simple payback period of just over 12 years with the ITC, which may be reduced to as little as under 6 years with the addition of state and utility incentives.

4.2. Colorado

Colorado also has PV and BESS net metering policies, but with a near-average retail price of electricity compared to the high electricity rates of Massachusetts. Colorado has a slightly less expensive average installation cost of PV and BESS, as well as a higher approximate GHI, leading to higher annual PV electricity generation. The representative load profile modeled in EnergyPlus for Colorado for a gas-heated four-person household resulted in a yearly demand of 11,073 kWh and $853 of yearly volumetric utility charges with the TOU rate tariff from Xcel Energy.

4.2.1. Annual utility charges optimization results

The lower rate tariff in Colorado provides less opportunity for energy arbitrage and peak load reduction, resulting in the BESS-only system providing just $153 in annual savings that is unable to make up the cost of the system. The PV & BESS configuration in Colorado generates nearly 2500 kWh more electricity than the system in Massachusetts due to the improved solar resource but results in only about half the annual utility savings due to the lower rate tariff. While the difference in annual savings between MA and CO is roughly $1000, the systems provide near-equivalent percentage savings. The simple payback period for the PV & BESS configuration with the ITC is just under 29 years, not accounting for the battery's replacement at 10 years. With the addition of the City of Boulder Solar Grant Program of $1.00/W [18], that payback period is reduced to 22 years. If Colorado did not have PV or BESS net metering policies, households could see approximately 4.3 MWh of PV-generated electricity curtailed annually, $447 less annual savings, and they would be unable to pay back the system within its lifetime.

4.2.2. Annual utility charges & system configuration optimization results

In Colorado, the ITC is not enough to result in a non-zero capex-optimized renewable system. However, the City of Boulder's $1.00/W Solar Grant Program for low-income residential customers reduces the cost of ownership such that a 10 kW PV rooftop array is capex-optimized, with a payback period of just under 14 years. Without financial incentives for BESS, energy arbitrage and peak load reduction does not provide sufficient revenue to result in a payback period less than the system's lifetime.

4.3. Rhode Island

Rhode Island has a flat rate tariff and PV net metering, but no BESS net metering policies. Rhode Island has a comparable average utility retail price of electricity to Massachusetts, with higher installation costs of both PV and BESS. The representative load profile modeled in EnergyPlus for Rhode Island for a gas-heated four-person household resulted in a yearly demand of 10,777 kWh and $1987 of yearly volumetric utility charges with a flat rate tariff at the state-average retail rate.

4.3.1. Annual utility charges optimization results

With Rhode Island's flat rate tariff, there is no opportunity for energy arbitrage or peak load reduction, and therefore no economic dispatch of a battery system. Any non-zero entries in the BESS-only rows of Table 6 are the product of the GBOML model assuming the 10.5 kWh of available BESS capacity discharges just once after installation, and then sits idle for the remainder of the simulation. The PV & BESS case with PV net metering provides $1852 in annual utility savings, or 93% savings on volumetric charges. The payback period of this system is just under 20 years with the ITC, and just over 16 years with the addition of the state's Small Scale Solar Grant of \$0.65/W and \$2000 per storage project [18], not accounting for the battery's replacement at 10 years. If Rhode Island did not have PV net metering, the system would only be able to provide \$1241 or 62% savings, and the payback period would likely exceed the system's lifetime with the ITC, but be reduced to just under 21 years with the addition of state incentives. The impact of the state's PV net metering policy for the household is nearly 3 MWh of solar electricity generation, \$611 in annual savings, and nearly seven fewer years to payback the system.

4.3.2. Annual utility charges & system configuration optimization results

Despite the flat rate tariff, the average retail price of electricity in Rhode Island is high enough that a capex-optimized system of a 10 kW PV array is able to provide an estimated \$2470 in annual savings, with a payback period of under 9 years with both federal and state incentives. Note that the Small Scale Solar Grant caps at 7.5 kW capacity, and systems that exceed that are awarded the maximum \$5000 grant [18]. Even if Rhode Island did not have net metering policies, a small, 1.39 kW PV system is still economically optimal, with a payback period of less than 8 years with federal and state incentives. The benefit of the net metering policy in this state is that roughly the same payback period is achieved with a 10 kW PV system that is able to provide more than seven times the renewable electricity generation and annual utility savings for the household.

4.4. Georgia

Georgia has a roughly average retail electricity price, but no PV or BESS net metering policies. Georgia Power offers compensation for PV-exported electricity at the solar avoided energy cost that is less than the peak price of electricity, but more than the off-peak price. The representative load profile modeled in EnergyPlus for Georgia for a gas-heated four-person household resulted in a yearly demand of 11,731 kWh and \$241 of yearly volumetric utility charges with the TOU rate tariff from Georgia Power. The electric-heated representative load profile modeled in EnergyPlus for Georgia had a yearly demand of 20,526 kWh and \$351 in yearly volumetric utility charges.

4.4.1. Annual utility charges optimization results

The BESS-only system provided roughly same annual utility savings for both the gas and electric heating profiles, implying that the battery's capacity and rate tariff design play a larger part than the household's demand. Georgia does not have BESS net metering policies, however, the "what-if" scenario did not provide any additional savings with BESS net metering for either heating profile. The electricity dispatch plots in Fig. 5(b) demonstrate that the added ability of the battery to export to the grid leaves it unable to meet the household's demand throughout the duration of the peak price (gray shaded region), such that the additional revenue from export would be quickly lost by the peak price of electricity paid immediately after. This result is likely due to the limited residential battery capacity compared to the typical household load such that there are seldom instances where the battery has excess capacity available to export to the grid.

The PV & BESS configuration provided approximately \$298 in annual utility savings for both gas and electric heating profiles. While the system provides an 85% and 52% savings for gas and electric heating profiles, respectively, the volumetric utility charges from Georgia Power are so low that the system is unable to achieve a payback within its lifetime.

4.4.2. Annual utility charges & system configuration optimization results

The low utility price of electricity, combined with Georgia Power's rate design only having a TOU rate in the summer months from June-September and a flat rate otherwise, do not provide enough economic opportunity for a capex-optimized renewable system. The authors were unable to find any state or utility incentives that could improve the economic outlook for such a system.

4.5. Tennessee

Tennessee has the lowest utility rate of the states simulated in this analysis and does not have either PV or BESS net metering policies. The installation cost of PV and BESS are well below average, and Tennessee has greater GHI than MA and RI, though less than CO and AL. The representative load profile modeled in EnergyPlus for Tennessee for an electric-heated four-person household resulted in a yearly demand of 21,783 kWh and \$1622 of yearly volumetric utility charges with the TOU rate tariff from Memphis Light.

4.5.1. Annual utility charges optimization results

While Tennessee does have a TOU rate, the low price and seasonal tariff design that is flat-rate for four months of the year does not have enough opportunity for peak shaving for the BESS-only system to provide more than \$85 in annual savings, far below what is required to payback such a system. As with GA, the "what-if" scenario of BESS net metering did not result in additional savings, suggesting the BESS capacity was only able to provide peak load reduction, and was not large enough to adequately engage in energy arbitrage. The PV & BESS configuration provided \$693, or 43% savings, however this is too low to result in a payback period within the system's lifetime. The seasonal variation in the state's TOU rate with a morning peak in the winter, Fig. 6(a), and an afternoon peak in the summer Fig. 6(b), provides less opportunity for a renewable system to provide utility savings, as the morning peak in the winter occurs primarily before the solar array begins producing electricity.

4.5.2. Annual utility charges & system configuration optimization results

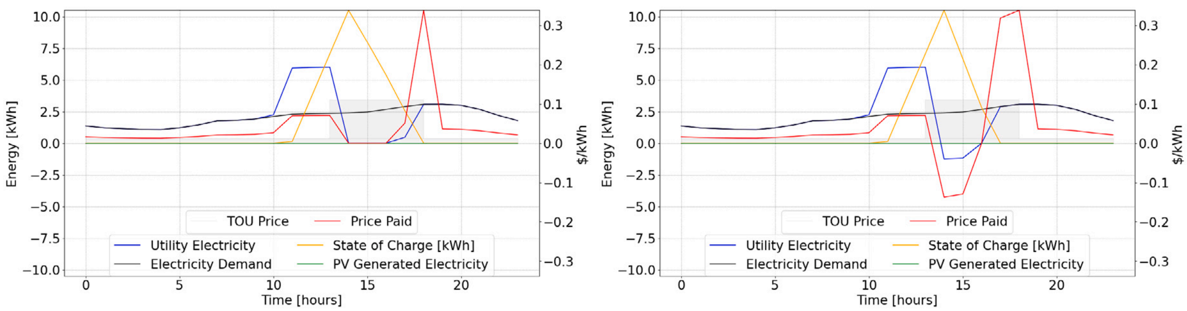
Despite the installation costs of both PV and BESS being below the national average, the low electricity price and rate tariff design are such that a capex-optimized system is not possible in Tennessee. The authors were unable to find any state or utility incentives that could improve the economic outlook for such a system.

5. Discussion and conclusion

The results of this analysis highlight that current rate tariff structures, net metering policies, installation costs, and financial incentives are not yet economically favorable for battery-only residential systems without access to additional revenue opportunities. While BTM energy storage is technically capable of providing a myriad of grid services, such as frequency regulation, voltage support, and even grid investment deferral, market and regulatory structures do not yet allow customers to be compensated for such services. As there are presently insufficient opportunities for BTM energy storage to provide revenue to system owners, economic optimizations favor PV-only systems in states where offsetting utility-purchased electricity outweighs the upfront cost of rooftop PV installations. These results are discussed by optimization, below.

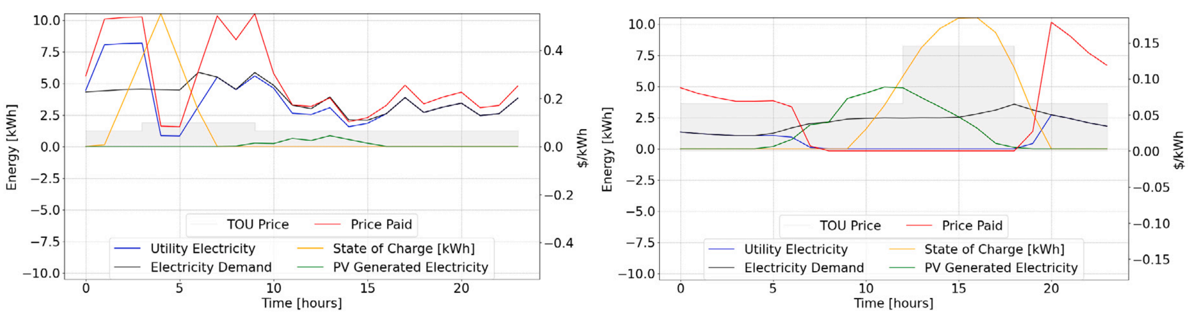
5.1. Annual utility charges optimization results

In each of the five representative cases, the annual utility charge optimizations for the BESS-only systems did not result in sufficient savings to pay back the system within the battery's 10-year lifetime, even with the ITC, state, and utility incentives, where applicable. In this analysis, the BESS were economically dispatched to reduce household peak load to avoid the most expensive electricity prices, and to engage in energy arbitrage, charging when electricity prices are low, and discharging when electricity prices are high and exporting to the grid for additional revenue, if allowed by BESS net metering policies. These economically unfavorable results are due to a number of factors, (1) the installation cost of battery technologies is still too high; (2) the TOU rate designs in this analysis did not contain sufficient price differentials between high and low-price electricity or favorably scheduled high



(a) No Net Metering (b) BESS Net Metering

Fig. 5. Georgia case study: Electricity dispatch and pricing of BESS-only system without BESS net metering 5(a) and "what-if" with net metering 5(b) for the electric heating load profile.



(a) Winter (b) Summer

Fig. 6. Tennessee case study: Winter 6(a) and summer 6(b) dispatch of PV & BESS in Tennessee with no net metering policy. Note that the right $/kWh axis range differs between these two plots.

and low-price periods; (3) while the ITC provides a 30% tax credit for standalone storage, few and insufficient state and utility incentives are available to offset the high purchase price of battery energy storage.

The addition of a 7.5 kW rooftop solar array improves the economic feasibility of the annual utility charge optimizations considerably in most cases. In states with moderate- to high-priced electricity, the ability to self-generate between 7–9 MWh of renewable electricity annually could save between $600–$1250 in annual utility charges. In Georgia, with a much lower price of electricity, this self-generation amounts to only roughly $200 in annual savings and is inadequate considering the purchase price of the system. In Tennessee, with no net metering policies, the system is unable to provide enough utility savings to pay back the cost of the system within its lifetime. For states with net metering policies, an annual average of 3 MWh of self-generated electricity is no longer need to be curtailed, but could instead be exported back to the utility to further reduce household utility bills as well as support the local grid. The additional revenue from exported electricity leads to a nearly 40% average reduction in payback period and nearly $600 increase in annual utility savings. In Georgia, where exported electricity is compensated at the solar avoided energy cost, only $86-$108 in additional utility savings is provided, and the payback period of the system still exceeds its lifetime. The impact of a BESS net metering policy for a combined PV & BESS configuration provides between $35-$112 in annual utility savings for Colorado and Massachusetts, marginally improving the payback period of the system. The relative capacity of a residential battery compared to a typical household load is such that the majority of the battery's capacity is used to provide peak load reduction, with little remaining capacity available for additional revenue opportunities from energy arbitrage. Household energy behaviors, rate schedule, and price differential may improve this opportunity; however, BESS net metering policies are likely to only benefit households who are already purchasing a system, rather than provide the additional revenue stream that results in economic feasibility.

5.2. Annual utility charges & system configuration optimization results

The five state cases simulated in this analysis are intended to be representative of typical combinations of rate tariff structures and net metering policies across the U.S. The volumetric, or per-kWh utility charges and the installation cost of PV and BESS were the primary factors considered in these economic optimizations, such that the value of resilience, energy independence, energy access, or environmental impact were not considered. Notably, these additional energy equity benefits of renewable systems can be primary drivers for households. The value of resilience in areas with frequent grid outages and extreme weather events can spur energy storage adoption where the rate tariff and policy landscape does not yet provide sufficient economic return. Likewise, those seeking energy independence, improved energy access where grid connection may not be a guarantee, or improved air quality and health outcomes in asthma-prone regions of high pollution are likely to pursue renewable systems regardless of market maturity.

The contribution of this work is to provide those considering renewable systems, regardless of motivation, with the tools to make the economic case for adoption. The results of the five cases presented in this analysis represent an idealized, economically optimized dispatch, annual utility savings, and simple payback period. These results can be used as a benchmark, however the amount of energy storage capacity chosen to be held in reserve for resilience varies based on household preference and outage history, which impacts the revenue potential for systems with energy storage. The results of this analysis support that the additional revenue potential in states with net metering policies, when combined with above-average electricity prices and TOU rate structures, provide a favorable economic outlook for prospective renewable system owners. Conversely, in states with low-price electricity or without net metering policies, it is difficult for renewable systems to be economically favorable without substantial financial incentives.

This work also highlights that residential energy storage requires access to additional market mechanisms and revenue streams to be considered economically advantageous. While BTM energy storage is technically capable of providing numerous services to the grid, the enabling market and regulatory structures have yet to allow battery-owners to be compensated for these services. As it stands, the additional energy and equity benefits of energy storage, rather than economics, drive the majority of adoption.

This analysis must be recognized as a snapshot in time. The price of electricity is projected to continue rising over the next two decades, in all scenarios nearly doubling or more by 2050. In turn, the price of battery energy storage and solar technologies are projected to continue their declining trends as the markets mature, becoming more affordable every year. National decarbonization goals, in concert with state renewable energy portfolio standards to rapidly increase the percentage of the electricity fuel mix that comes from renewable sources, are likely to lead to more widespread net metering policies and additional financial incentives. These trends in price, policy, and financial incentives forecast a brighter economic outlook for renewable systems with each passing year. The authors hope that this work provides a foundation for households to further their understanding of residential renewable systems, to be empowered to seek out local installers, and be able to actively engage in these conversations and decision-making processes as informed stakeholders in their energy system. Additionally, the authors hope that utilities, policymakers, and advocates find this work informative as to the value of net metering policies, the impact of thoughtful rate structure design, the potential financial benefit of renewable systems for residential ratepayers, and the need for state and local financial incentives in lieu of additional market and regulatory structures allowing energy storage to serve and be compensated for the multiple use cases it can provide.

CRediT authorship contribution statement

Jessica Kerby: Writing – original draft, Software, Methodology, Investigation, Conceptualization. **Bethel Tarekegne:** Writing – review & editing, Supervision, Project administration, Conceptualization.

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.

Data availability

Datasets related to this article can be found at https://doi.org/10.25584/2305541, an open-source online data repository hosted at DataHub by Pacific Northwest National Laboratory (PNNL).

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Table 8
Normalized solar irradiance location and tilt angle.

Case	State	Latitude	Longitude	Tilt angle
1	MA	42.359	−71.057	42
2	CO	39.740	−104.992	40
3	RI	41.824	−71.412	42
4	GA	33.748	−84.391	34
5	TN	36.168	−86.722	36

Table 9
Residential load profile model parameters.

Case	State	Climate zone	Heating system system type	Foundation type
1	MA	5B	Gas	
2	CO	5B	Gas	
3	RI	5A	Gas	Slab
4	GA	3A	Both	
5	TN	4A	Electric	

Appendix

A.1. State comparison table

This state comparison table, Table 10, is intended to serve as a reference for households, policymakers, utilities, and advocates to compare relevant factors for renewable system performance and payback between their own and other states. Included factors are the approximate annual global horizontal irradiance [6], the average retail price of electricity [7], the average installation cost of residential solar [8], the average installation cost of residential BTM BESS [9], solar net metering policy [10], BTM BESS net metering policy [11], whether the state has a TOU rate available [11], and whether the largest utility in the state offers a TOU rate [11].

A.2. Additional parameters

The normalized irradiance data used in this analysis for each representative state case is reflective of the capital city's location and tilt angle described in Table 8.

The EnergyPlus load profiles for each representative state case in this analysis were simulated based on the input parameters in Table 9. All load profiles used in this analysis represent single family detached homes, reflective of 62.4% of all homes in the U.S. [31]. The climate zone is indicative of the climate and moisture levels of the region, both of which are key factors that impact the heating and cooling load of a building. The most common heating fuel type reported in the Residential Energy Consumption Survey data was used to select the heating system type for each case [31]. A load profile for both gas and electric heating system types was used in Georgia due to the near-even split of households using each. Slab foundation types were assumed in all cases for simplicity and to limit the number of variables between cases. A four-person household was assumed in each case.

A.3. Operational configuration equations

The optimization configurations are defined in the GBOML model using the equations below. The no-export optimization case in absence of net metering policy is defined as follows:

$$electricity\ exchanged(t) \geq 0 \tag{1}$$

Such that electricity is exchanged with the grid only in one direction and is always positive.

The PV net metering optimization case is defined as follows:

$$electricity\ exchanged(t) \geq -PV\ electricity\ generated(t) \tag{2}$$

Table 10
Factors considered for renewable systems by state [6–11].

State	Approx annual GHI [kWh/m^2/Day]	Average retail price [cents/kWh]	Avg PV installed Cost [$/W]	Avg BESS installed Cost [$/kWh]	Net metering			Largest utility in state TOU
					PV	BESS	TOU	
Alabama	4.50–5.00	10.18	$2.45		Less than retail	X	✓	✓
Alaska	<4.00	20.02	$2.41		✓	X	✓	X
Arizona	5.25–≥5.75	10.73	$2.44	$1340	Net billing	✓	✓	✓
Arkansas	4.50–5.00	9.1	$3.06	$1287	✓	X	✓	✓
California	4.75–≥5.75	19.65	$2.86	$1339	✓	✓	✓	✓
Colorado	4.50–5.75	10.9	$3.44	$1407	✓	✓	✓	✓
Connecticut	4.00–4.25	18.32	$3.22	$1438	✓	X	✓	X
Delaware	4.00–4.50	10.5	$2.75	$1687	✓	X	✓	X
DC	4.25–4.50	12.81	$3.50	$1587	✓	X	X	X
Florida	4.75–5.50	10.67	$2.58	$1304	✓	X	✓	✓
Georgia	4.50–5.00	10.43	$3.20	$1397	Not required	X	✓	X
Hawaii	4.00–≥5.75	30.31	$2.67		Two tariff options	✓	✓	✓
Idaho	4.00–4.75	8.17	$2.93	$1397	Some utilities	X	✓	✓
Illinois	4.00–4.50	10.14	$3.16	$1407	✓	X	✓	✓
Indiana	4.00–4.50	10.36	$3.63	$1537	✓	X	✓	✓
Iowa	4.00–4.50	9.13	$3.45	$1240	✓	X	✓	✓
Kansas	4.25–5.25	10.47	$2.59	$1438	✓	X	✓	✓
Kentucky	4.00 –4.50	9.12	$2.34	$846	✓	X	✓	✓
Louisiana	4.75–5.25	8.82	$3.17		Until cap	X	✓	✓
Maine	<4.00	13.96	$3.45	$1701	✓	X	✓	✓
Maryland	4.00–4.50	11.48	$3.13	$1488	✓	X	✓	X
Massachusetts	<4.00–4.25	19.06	$3.54	$1488	✓	✓	✓	✓
Michigan	<4.00–4.25	12.93	$3.78	$1376	✓	X	✓	✓
Minnesota	<4.00–4.25	11.08	$3.45	$1488	✓	X	✓	✓
Mississippi	4.50–4.75	9.5	$2.64		Less than retail	X	✓	✓
Missouri	4.25–4.75	9.85	$2.85	$1397	✓	X	✓	✓
Montana	<4.00–4.25	9.5	$2.54		✓	X	✓	X
Nebraska	4.00–5.00	8.84	$2.83		✓	X	✓	✓
Nevada	4.50–5.75	8.58	$2.60	$1287	Less than retail	X	✓	✓
New Hampshire	<4.00–4.25	17.37	$3.61	$1736	✓	X	✓	X
New Jersey	4.00–4.50	14.01	$2.95	$1438	✓	X	✓	X
New Mexico	5.00–≥5.75	9.79	$3.39	$1397	✓	X	✓	✓
New York	<4.00–4.25	16.11	$3.48	$1438	VDER tariff	✓	✓	✓
North Carolina	4.25–4.75	9.29	$3.04	$1287	✓	X	✓	✓
North Dakota	<4.00–4.25	8.65	$2.42		✓	X	✓	✓
Ohio	<4.00–4.25	9.76	$2.98	$1389	✓	X	✓	✓
Oklahoma	4.50–5.50	8.52	$2.62	$1389	✓	X	✓	✓
Oregon	<4.00–4.75	8.95	$3.02	$1501	✓	X	✓	✓
Pennsylvania	<4.00–4.25	9.97	$3.06	$1488	✓	X	✓	✓
Rhode Island	4.00–4.25	18.44	$3.61	$1882	✓	X	X	X
South Carolina	4.50–5.00	9.96	$2.89	$1287	✓	X	✓	✓
South Dakota	<4.00–4.75	10.43	$2.39		X	X	✓	✓
Tennessee	4.25–4.75	9.78	$2.97	$992	X	X	✓	✓
Texas	4.75–≥5.75	9.14	$2.77	$1290	Some utilities	X	✓	X
Utah	4.50–5.75	8.34	$2.69	$1488	Cap met	X	✓	X
Vermont	<4.00	16.34	$3.14	$2034	✓	X	✓	✓
Virginia	4.25–7.75	9.14	$3.04	$1488	✓	X	✓	X
Washington	<4.00–4.50	8.75	$3.25	$1637	✓	X	✓	X
West Virginia	4.00–4.25	8.87	$2.92	$1538	✓	X	✓	✓
Wisconsin	<4.00–4.25	11.01	$3.41	$1488	✓	X	✓	✓
Wyoming	4.00–5.00	8.25	$2.57		✓	X	✓	✓

Such that at any given time, t, the exported electricity (negative values of electricity exchanged) does not exceed the electricity generated by the PV array at that time. This ensures that the only exported electricity originates from the PV array, maintaining the PV net metering agreement where there is no BESS net metering.

The PV & BESS net metering case is defined as follows:

$$electricity\ exchanged(t) \geq -(PV\ capacity + BESS\ capacity) \tag{3}$$

Such that the electricity exports (negative electricity exchanged) do not exceed the combined export potential of the PV array and the BESS (PV capacity and BESS capacity).

A.4. Optimization equations

The optimization equations are defined in the GBOML model using the equations below. The annual utility charge optimization equation is defined as follows:

$$Min[price\ paid(t)] \tag{4}$$

The annual utility charges and system configuration optimization equations are as follows:

$$Min[PV\ capacity \times PV\ capex] \tag{7}$$

$$Min[battery\ capacity \times battery\ capex] \tag{6}$$

$$Min[price\ paid(t)] \tag{5}$$

Where the capital expenditure, or capex, of the PV and battery is annualized based on the initial price, the expected lifetime of the technology (life), and the discount rate (r), according to the equation below. The discount rate is used to capture the present value of the initial investment compared to value of the future recouped cost, in order to account for an investment's risk [33]. The weighted average cost of capital for the technology is used as the discount rate for single-family owner-occupied households [34]; according to the latest Annual Technology Baseline (ATB), this puts the discount rate for residential

PV at 4.8% [13]. Residential BTM energy storage is not included in the ATB, so PV's 4.8% is also used for the battery in this analysis. While the actual lifetimes may be greater, the expected lifetime of the battery is set to 10 years, and rooftop PV is set to 25 years. The capex is defined as follows:

$$capex = \frac{system\ price \times r}{1-(1+r)^{-life}} \tag{8}$$

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