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Research paper

A universal optimization framework for commercial building loads using DERs from utility tariff perspective with tariff change impacts analysis

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ABSTRACT

To accommodate the changes in the nature and the pattern of electricity consumption with the available resources, utilities have introduced variety of tariffs over the years. This paper develops a comprehensive optimization framework that addresses the challenges associated with the diversity of utility tariffs for commercial loads. Optimization of commercial building net load through Battery Energy Storage System (BESS) and renewable energy resources is modeled and explored for minimizing billing cost for different tariffs. Cost functions are formulated for each possible commercial utility tariff type, engendering the universal cost function format. An algorithm is developed to apply the optimization model and generate the desired optimal outputs (e.g., optimal net load and BESS power, costs and savings, etc.). The results for several building loads and all tariff types are compared and analyzed to present the findings. An impacts analysis is performed to observe how different changes in tariffs affect the optimizations results. Results exhibit that for same building load and renewable generation, the tariff type can have an overwhelming impact on costs and savings. Tariffs without Time of Use (TOU) charges or peak demand charge components offer lower savings opportunity from BESS optimization. Price change sensitivities showed the complicated dynamics among TOU price components on savings and historical trend analysis as an effective tool to predict future savings. Tradeoff between energy and demand charge heavy tariff options are also discussed for user benefit. The recent change in TOU time periods presents limited desired benefits while the modified tariff proposed in this paper exhibit significant improvement in terms of utility operation.

1. Introduction

1.1. Background and motivation

The nature and pattern of electrical loads have changed significantly over the years. The utilities have developed numerous types of tariffs accordingly that would facilitate their operation with the existing generation, transmission, and distribution resources. Concepts such as Time of Use (TOU) and different types of energy and demand charges have been introduced to mitigate the limitations of these resources. Additionally, highly distinctive load patterns and consumption amount have motivated the utilities to introduce separate tariffs for residential and commercial sectors.

The recent adoption of high renewable penetration into the grid has made the change in electrical load even more severe and rapid. To accommodate these fundamental and long-lasting changes both TOU time periods and rate structure are being changed by various utilities. For example, the highest cost On-Peak period used to be 12 PM to 6 PM which is now shifted to 4 PM to 9 PM in response to high solar production in California. Innovative tariffs such as Critical Peak Pricing (CPP) are introduced to encourage the customers reduce their regular consumption on specific hours of specific days experiencing higher grid stress. Customers are being offered choices between options with higher energy charge and lower demand charge, or with higher demand charge and lower energy charge. Additionally, these tariffs go through changes in prices on a regular basis.

Commercial buildings are one of the largest electricity users in the U.S. as they consume about 35% of the total electricity consumption (U.S. Department of Energy—Energy Information Administration, 2020). As one of the largest electricity users in the U.S., commercial building loads offer great potential for optimization with the help of distributed energy resources (DERs) such as

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Nomenclature

Sets and Indices

t	Timestep
T'	Total number of timesteps
d	Day number in billing month
D	Total number of days in billing month
$\mathbb{P}^G$	Set of grid power values for all timesteps
$\boldsymbol{T}^{On}$	Set of On-Peak period timesteps
$\boldsymbol{T}^{Mid}$	Set of Mid-Peak period timesteps
$\boldsymbol{T}^{Off}$	Set of Off-Peak period timesteps
$\boldsymbol{T}^{CPP}$	Set of CPP event hour timesteps
$\boldsymbol{T}^{Tot}$	Set of all timesteps

Parameters

Δt	Duration of each timestep
γ	Self-discharging rate of BESS
E^{Bmin}/E^{Bmax}	BESS minimum/maximum stored energy limit
P^{B+max}/P^{B-max}	BESS maximum charge/discharge power
E^B_{init}	Initial stored energy of the BESS
P^S_t	Solar generation at t
P^L_t	Building load at t
α_t	Energy charge at t
β	Time independent peak demand charge price
$\alpha^{On}/\alpha^{Mid}/\alpha^{Off}$	On/Mid/Off-Peak energy charge prices
$\beta^{On}_t/\beta^{Mid}_t/\beta^{Off}_t$	On/Mid/Off-Peak demand charge at t
$\beta^{On}/\beta^{Mid}/\beta^{Off}$	On/Mid/Off-Peak period demand charge prices
α^{CPP}	CPP energy charge price
β^{CPP}	CPP demand charge price discount
α^{Flat}	Flat energy charge price
η^+/η^-	Charging/discharging efficiency of BESS

Variables

E^B_t	Energy stored in BESS at t
P^B_t	BESS power at t
P^{B+}_t/P^{B-}_t	BESS charging/discharging power at t
P^G_t	Power drawn from the grid at t
P^{SB}_t	Solar power fed to BESS at t
P^{SL}_t	Solar power fed to load at t
P^{BL}_t	BESS power fed to load at t
δ_t	Binary variable at t

Vectors and Matrices

$\boldsymbol{\alpha}$	Energy charge vector
$\boldsymbol{P^G}$	Grid power vector
$\boldsymbol{\beta^{On}}/\boldsymbol{\beta^{Mid}}/\boldsymbol{\beta^{Off}}$	On/Mid/Off-Peak period demand charge matrices
$\boldsymbol{\alpha_{non-CPP}}$	Energy charge vector on a non-CPP event day
$\boldsymbol{\alpha_{CPP}}$	Energy charge vector on a CPP event day
$\boldsymbol{\beta^{On}_{non-CPP}}/\boldsymbol{\beta^{Mid}_{non-CPP}}/\boldsymbol{\beta^{Off}_{non-CPP}}$	On/Mid/Off-Peak period demand charge matrices on a non-CPP event day
$\boldsymbol{\beta^{On}_{CPP}}/\boldsymbol{\beta^{Mid}_{CPP}}/\boldsymbol{\beta^{Off}_{CPP}}$	On/Mid/Off-Peak period demand charge matrices on a CPP event day
$\boldsymbol{\alpha_d}$	Energy charge vector for dth day in billing month
$\boldsymbol{\alpha_{weekday}}$	Energy charge vector for weekdays
$\boldsymbol{\alpha_{weekend}}$	Energy charge vector for weekends
$\boldsymbol{\beta^{On}_{weekday}}/\boldsymbol{\beta^{Mid}_{weekday}}/\boldsymbol{\beta^{Off}_{weekday}}$	On/Mid/Off-Peak demand charge matrices for weekdays
$\boldsymbol{\beta^{On}_{weekend}}/\boldsymbol{\beta^{Mid}_{weekend}}/\boldsymbol{\beta^{Off}_{weekend}}$	On/Mid/Off-Peak demand charge matrices for weekends
$\boldsymbol{\beta^{On}_d}/\boldsymbol{\beta^{Mid}_d}/\boldsymbol{\beta^{Off}_d}$	On/Mid/Off-Peak demand charge matrices for dth day in billing month
$\boldsymbol{\alpha_{month}}$	Energy charge vector for billing month period
$\boldsymbol{\beta^{On}_{month}}/\boldsymbol{\beta^{Mid}_{month}}/\boldsymbol{\beta^{Off}_{month}}$	On/Mid/Off-Peak demand charge matrices for billing month period

solar generation and battery energy storage systems (BESS) that would largely benefit both the customers behind the meter and utility operators. But these extremely diverse and highly complex tariffs create a major challenge for formulating appropriate optimization strategy for such DER integrated buildings. Moreover, changes that the tariffs go through can have significant impact over the DER optimization of building loads that eventually lead to DER investment and grid operation decisions of customers and utilities, respectively. Therefore, in order to design an optimal strategy for reducing building loads with DERs, utility tariff is an important aspect that needs to be considered. A universal objective function that captures all the different components of these tariffs can be highly beneficial to reduce the complexity of optimization that arises with the diversity of the tariffs.

1.2. Related works

Many research works have been done on the optimization of the building or other loads using DERs such as solar generation, BESS, and electric vehicles (EV). Minimizing the energy cost of the building-integrated microgrid is the main objective in most of the literature. Two-layer optimization is performed on a commercial building microgrid that minimizes utility billing cost through optimal BESS scheduling and investment cost through optimal BESS sizing (Moghimi et al., 2018). Thermal modeling and interactive load management of buildings through bidirectional information exchange with grid is shown in Razmara et al. (2018). The compromise between user comfort and energy optimization is executed for commercial buildings in terms of electricity prices to provide least cost solutions regardless of environment conditions (Yu et al., 2019; Wang et al., 2018, 2019; Xu et al., 2018). Deployment of vehicle-to-grid (V2G) strategies with coordinated EV charging on commercial building load optimization are assessed for different charging levels and tariffs from different utilities (Yusuf and Ula, 2019, 2020; Tavakoli et al., 2018). However, all these works deal with TOU energy costs only. While most commercial tariffs include demand cost which charges for the peak demand that occurs within the whole billing month or a specific period of the day within the billing month.

Demand charges are also analyzed in a limited number of works. Effects of the tariffs on the optimal PV generation sizing and economic feasibility of different BESS technologies are shown for commercial building loads (Christiaanse et al., 2021; Lee and Chen, 2007; Wu et al., 2020). Optimal BESS dispatch strategy is explored for commercial buildings with various types of tariffs with demand charges (Meinrenken and Mehmani, 2019;

Sun et al., 2018; Nguyen and Byrne, 2017). Bi-level optimization is executed to achieve electricity cost reduction by coordinated BESS dispatch and temperature setpoint control of a commercial building (Meinrenken and Mehmani, 2019). Break-even analysis of a BESS integrated to a commercial building is presented with comparison to tariffs from two different utilities (Sun et al., 2018). Results of electricity cost savings optimization are analyzed to attain the ideal BESS ratings for a commercial tariff user (Nguyen and Byrne, 2017). Nonlinear energy conversion processes of multi-energy systems (MES) have been modeled as piece-wise linear process and then used to optimize the utility costs of building loads along with possible carbon tax costs (Hurwitz et al., 2020). The tariff types used in these works are diverse. TOU energy rate with a single time independent demand charge is used in Wu et al. (2020), TOU energy charge with TOU demand charge is applied in Lee and Chen (2007), Meinrenken and Mehmani (2019), Sun et al. (2018) and Hurwitz et al. (2020), TOU energy charge with both TOU demand and time independent demand charge is adopted in Nguyen and Byrne (2017) and flat energy charge with a time independent demand charge is exercised in Christiaanse et al. (2021). These works handle the optimizations using various unrelated approaches. Thus, necessitating an optimization function that is able to deal with these varying demand charges in a consistent way.

Critical Peak Pricing (CPP) has been introduced by the utilities to provide monetary rewards to the consumers for reducing their usage during grid congestion. The impacts of V2G on commercial buildings are investigated during CPP events (Yusuf et al., 2021). However, only the effect of a high CPP energy rate is presented in the paper during the CPP event hours while the benefits derived from lower demand charge at non-CPP event hours are not shown.

Efforts have been placed on designing new tariffs based on the modification of the current ones to achieve deeper interactions between customers and utilities and better grid management. In Biroon et al. (2020, 2019), sensitivity analysis of net grid power with maximum demand charge is performed to find a suitable tariff pricing that maximizes customer profit and grid capacity release. Incentive pricing to maximize the benefits from participating in energy communities are also studied (Grzanic et al., 2021; Paudyal and Ni, 2019). A fair pricing mechanism based on forecasted power demand is used to reduce bills for low energy consumers (Aurangzeb et al., 2021). Adjustment of tariff levels is also explored to increase the penetration of DER (Alaskar et al., 2020). A segmented energy tariff is designed to flatten the load demand profile (Li et al., 2020). But these proposed electricity tariffs are modified over and compared to TOU energy charges alone or TOU energy charges with a single time independent peak demand charge. Without comparing them to the other major categories that are exercised by most utilities, the potential of these proposed tariffs will not be fully explored. This comparison can be performed easily through a universal cost function.

1.3. Summary of contributions

From the discussions above we can see that, extensive research has been done on the electricity cost optimization of building loads using DERs. However, they have overlooked to address the fact that there are numerous tariffs of diverse types that require distinct optimization objective function consistent with system model based on their type. These works have focused on individual tariff-based optimizations and to the best of the authors' knowledge no work has been done yet on a comprehensive optimization framework that addresses the issue of this complexity and diversity of utility tariffs and aims to solve it. Much attention is needed on this topic since an optimization strategy for one type of tariff will not be suitable for the other type and may end up incurring a higher non-optimal cost. Several critical but unresolved issues regarding the tariffs and optimization include: (1) How can we address the diversity of tariffs when formulating an optimization strategy for buildings equipped with DERs such as solar and BESS? (2) How various tariff components impact the costs and savings from the optimization of different buildings? (3) How different changes in tariffs impact the results of the optimization? This paper attempts to address these issues and bridge the gap that persist in the existing literature. The main contributions of this paper can be summarized as follows:

(1) The paper classifies commercial tariffs from major US utilities into six universal types and derives a convex optimization objective or cost function for each type. This includes cost function derivations for complex tariff types that are practiced but not found in literature, such as tariffs with both time independent and TOU demand charge components or Critical Peak Pricing (CPP). In fact, CPP is becoming a common demand response tool for utilities and requires attention. Derivations are performed in a novel and systematic way, ensuring consistency, while their convex form yield a guaranteed global minimum cost.

(2) A comprehensive framework is suggested for performing building load optimization with DERs by developing a single universal cost function that is applicable to all available commercial tariffs. By using this cost function within the proposed framework, it becomes feasible to optimize the load of any commercial building, regardless of its tariff. This capability is not achievable through existing methods.

(3) We analyze how tariff changes affect optimization results and propose a modified tariff with better benefits. The results reveal how price components and TOU periods impact costs, savings, and net load characteristics of commercial buildings with DERs. This sort of analysis has not been conducted previously and is unique. The analysis can benefit consumers making DER investment decisions and utilities designing better tariffs. An example is shown by proposing an improved tariff that addresses the infamous "Duck Curve" problem in high-solar-penetration areas like California. Our proposed tariff outperforms existing tariffs in this regard.

This endeavor can help on investment decision or resource planning of the commercial building owners and help the utilities to develop improved tariffs for better grid operation while researchers can gain benefit from the optimization cost function formulation that considers the diversity of commercial tariff types.

The authors would like to emphasize that the goal of the paper is not to propose a new optimization algorithm that delivers higher precision or faster convergence, rather to address the issue of diversity of tariff types that have not been considered in prior efforts. This paper is an extended and more detailed version of a previous publication by the same authors (Hasan et al., 2021).

1.4. Paper organization

This paper is organized as follows: Section 2 describes the methodology of this work, Section 3 gives an overview of the system considered and shows detailed modeling of BESS and system power balance, Section 4 describes the types of utility tariffs and formulates cost functions for each type leading to the universal cost function, Section 5 presents the formulation of optimization problem, Section 6 develops the algorithm for carrying out optimization and generating results, Section 7 discusses the results obtained from the optimization, Section 8 analyzes the impacts of tariff changes on optimization results, Section 9 draws the conclusion and talks about the scope of future works.

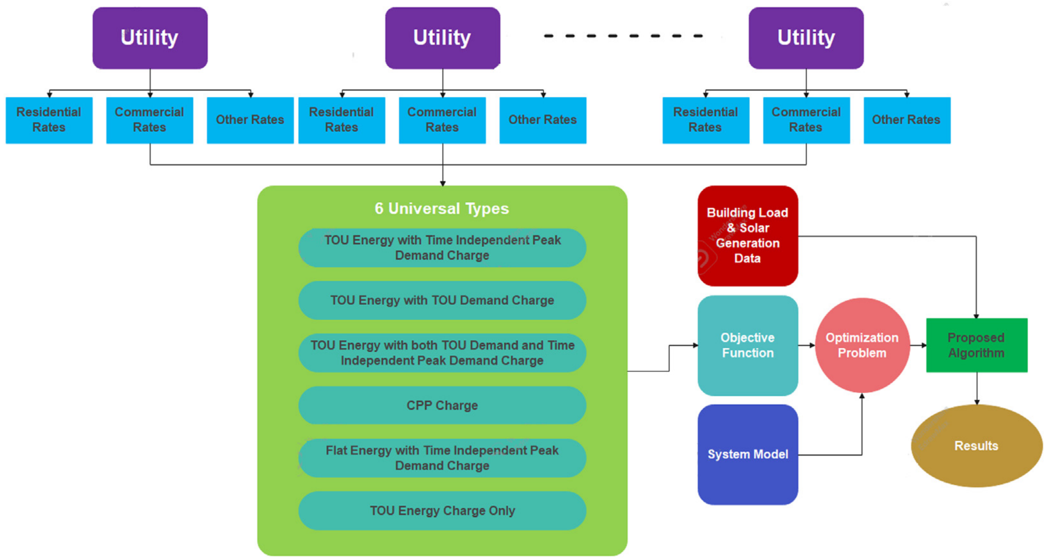

Fig. 1. Illustration showing methodology of this study.

2. Methodology

In this section, a summary of the methodology of this study is presented. The methods are described in detail in subsequent sections. Commercial tariffs currently exercised by 13 large investor-owned utilities (IOU) were reviewed to understand various types of tariffs in the USA. Ten of them rank among the largest ones in the USA and three of them are among the largest ones in California by revenue. One is the local municipal utility of the city of Riverside. The rationale behind the selection of these particular utilities is because of they serve a large number of territories and customers. Also, they are pioneers in introducing new tariffs and smaller utility companies follow them. After thorough examination of the tariffs, they were categorized into six universal types. Despite their differences in terminologies, values, periods, etc., their core concepts remain the same, and all major commercial utility tariffs can be covered with these six types. These are:

A. Time of Use (TOU) energy charges with single time independent peak demand charge,
B. TOU energy charges with TOU demand charges,
C. TOU energy charges with both TOU demand charges and additional time independent demand charge,
D. Critical Peak Pricing (CPP) rate,
E. Flat energy charge with a time independent demand charge,
F. TOU energy charges only.

Then objective functions for each of these rates is derived and consequently the universal objective function. The universal objective function is then integrated with our system model to formulate the optimization problem. The building load and solar generation data are then used to solve the optimization problem to obtain the optimal results by following the steps of our proposed algorithm. Fig. 1 presents an illustrated depiction of the methodology.

Data for three commercial buildings are collected for applying the optimization. All these buildings fall under different types of commercial tariffs. These buildings differ in electrical usage and functionality. Among them two of the buildings have actual onsite solar generation and one of them have actual BESS integrated. All the building load data that are used are actual data. For the buildings which did not have solar or BESS, National Renewable Energy Laboratory's (NREL) REopt was used to find the ideal solar or BESS size for the corresponding building (REopt Lite). The actual building load data and if available, actual solar data were given as inputs to get the output ideal size. As the size of solar or BESS from the simulated output value may not be easily available in the real world, reasonably close commercially available sizes were selected. Then NREL's System Advisor Model (SAM) was used to generate the solar profile for the site where a solar generation was absent (System Advisor Model). These buildings are located within different utility territories in California and are eligible to participate in California Public Utility Commission's (CPUC) Net Energy Metering (NEM) program. NEM program allows customers to export excess renewable energy to the grid and reduce utility cost by receiving credits for the exported energy at the retail rate of their respective tariff. Table 1 summarizes the characteristics of the buildings that were used for the optimization which are: average daily energy usage, load factor (average load divided by maximum load), tariff type, solar and BESS size.

3. System configuration and modeling

3.1. Overview of the system

The system considered here is a commercial building equipped with a renewable generation such as solar and BESS. Fig. 2 shows the block diagram of the system configuration. A portion of the building load is satisfied by the power drawn from the utility grid. The remaining portion is satisfied by a fraction of the renewable generation (solar in this case) and power discharged from the BESS. The power generated from the solar inverter is branched out to two portions. One branch delivers power directly to the building load as mentioned. The other branch charges the BESS. The BESS then discharges power to the building load as required. To ensure a higher percentage of renewable generation within the power mix, the BESS does not store any energy from the grid to avoid energy produced from fossil fuel.

3.2. Battery energy storage system (BESS) modeling

The BESS is modeled by taking many real-world operational constraints into considerations. The stored energy at each time step can be calculated with the following equation:

$$E^B_{t+1} = (1-\gamma)\, E^B_t + P^B_t.\Delta t \tag{1}$$

Table 1
Characteristics of the buildings used in optimization.

Characteristics	Building 1	Building 2	Building 3
Average daily usage (kWh)	11,223	1660	13,451
Load factor	0.28	0.34	0.81
If real solar	Yes	Yes	No
If real BESS	No	Yes	No
Solar size (Real)	800 kW	220 kW	–
BESS size (Real)	–	100 kW/ 500 kWh	–
Solar size (Simulated)	–	–	650 kW
BESS size (Simulated)	150 kW/ 500 kWh	–	120 kW/ 320 kWh
Actual tariff type	Type A	Type B	Type C

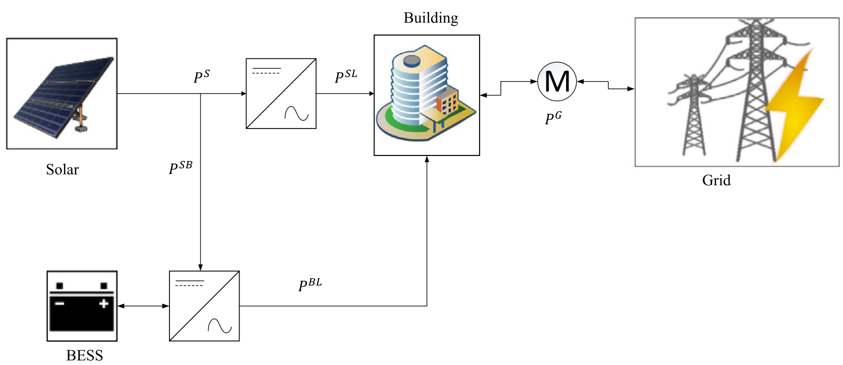

Fig. 2. System configuration block diagram.

The typical value for γ for Li-ion battery is 1%–2% over a month (BU-802b). So, if Δt becomes small like 15 min or 1-minute then $\gamma \approx 0$ and we can rewrite the equation as:

$$E^B_{t+1} = E^B_t + P^B_t.\Delta t \quad (2)$$

To expand the lifetime and maintain heath of the BESS battery cells, certain limits are imposed on the range of SOC or depth of discharge. The battery must maintain its stored charge within this limit during every time step. Then,

$$E^{Bmin} \leq E^B_t \leq E^{Bmax} \quad (3)$$

The BESS power can be written in terms of charging and discharging power separately as:

$$P^B_t = P^{B+}_t - P^{B-}_t \quad (4)$$

These two power quantities should also be within some limits depending on the size, application, and manufacturer specification of the BESS inverter. It can be modeled with the following inequality conditions:

$$0 \leq P^{B+}_t \leq P^{B+max} \quad (5)$$

$$0 \leq P^{B-}_t \leq P^{B-max} \quad (6)$$

But charging and discharging cannot happen simultaneously. This condition can be modeled by the following equation:

$$P^{B+}_t P^{B-}_t = 0 \quad (7)$$

3.3. System power balance

As mentioned in Section 3.1, the building load is satisfied by the sum of power drawn from the grid, a part of solar power and the power discharged from the BESS. The rest of the solar power is used to charge the battery. There should also be no power flowing back to the unidirectional solar inverter. So, for each time step t, the system should obey the following power balance equations:

$$P^{B+}_t = \eta^+ P^{SB}_t \quad (8)$$

$$P^S_t = P^{SB}_t + P^{SL}_t \quad (9)$$

$$P^L_t = P^{SL}_t + P^{BL}_t + P^G_t \quad (10)$$

$$P^{BL}_t = \eta^- P^{B-}_t \quad (11)$$

$$P^{SL}_t \geq 0 \quad (12)$$

4. Formulation of cost functions

In this section, the cost functions or the objective functions of the optimization problems are formulated for different utility tariffs. The following subsections show detailed formulations for each of the six types of tariffs mentioned in Section 2. Each subsection describes in detail how each type of tariff works and then a cost function is derived mathematically based on that along with the universal cost function by combining each of their unique tariff component. Some jargons used in the tariffs may vary by utility company and location, but the main idea remains the same. This paper uses the traditional technical terms such as On-Peak, Mid-Peak, and Off-Peak times, etc. While formulating the cost functions, careful attention is paid to derive them in a way so that they become convex and can be solved conveniently and efficiently with the available optimization tools. Only the costs related to usage are taken into account, fixed costs such as line or meter charge, taxes etc. are not considered.

4.1. Type A: Time of use (TOU) energy charge with a single time independent demand charge

In this utility tariff the energy charge is decided based on the period of the day and how much stressed is the grid at that period. Typically, they are separated into three non-overlapping time periods: On-Peak, Mid-Peak, and Off-Peak where the price of the energy charge is from highest to lowest, respectively. Customer is billed based on the energy usage at each period over the billing month. For demand, utilities measure the moving average of the load in kW for a certain duration, usually 15 min. The maximum demand that occurs within the billing month, irrespective of the time period, is multiplied by the demand charge in \$/kW to obtain the demand cost of that month. Then both energy and demand cost are added to get the total bill for monthly usage.

The total time period $\boldsymbol{T^{tot}}$ can be written as,

$$\boldsymbol{T^{tot}} = \boldsymbol{T^{On}} \cup \boldsymbol{T^{Mid}} \cup \boldsymbol{T^{Off}} = \{0, 1, \ldots, T' - 1\} \tag{13}$$

where,

$$\boldsymbol{T^{On}} \cap \boldsymbol{T^{Mid}} = \boldsymbol{T^{Mid}} \cap \boldsymbol{T^{Off}} = \boldsymbol{T^{Off}} \cap \boldsymbol{T^{On}} = \varnothing \tag{14}$$

Energy charge α_t can be written as,

$$\alpha_t = \begin{cases} \alpha^{On}, & t \in \boldsymbol{T^{On}} \\ \alpha^{Mid}, & t \in \boldsymbol{T^{Mid}} \\ \alpha^{Off}, & t \in \boldsymbol{T^{Off}} \end{cases} \tag{15}$$

Then we can write the cost function or the objective function as:

$$f\left(P_t^G\right) = \Delta t \sum_{t=0}^{T-1} \alpha_t P_t^G + \beta max(\mathbb{P}^{\boldsymbol{G}}) \tag{16}$$

where,

$$\mathbb{P}^{\boldsymbol{G}} = \{P_t^G | t \in \boldsymbol{T^{tot}}\} \tag{17}$$

We propose to present α_t and P_t^G in vectorized forms as,

$$\boldsymbol{\alpha} = \begin{bmatrix} \alpha_0 \\ \alpha_1 \\ . \\ . \\ \alpha_{T'-1} \end{bmatrix} \text{ and } \boldsymbol{P^G} = \begin{bmatrix} P_0^G \\ P_1^G \\ . \\ . \\ P_{T'-1}^G \end{bmatrix} \tag{18}$$

Then we can rewrite the cost function as:

$$f\left(\boldsymbol{P^G}\right) = \Delta t \boldsymbol{\alpha^T} \boldsymbol{P^G} + \beta \max(\boldsymbol{P^G}) \tag{19}$$

4.2. Type B: TOU energy charges with TOU demand charges

Just like the energy charge mentioned in Section 4.1, the demand charge is also time-dependent in this case. Instead of the maximum demand within the whole billing period, the customer is billed for the maximum demand of each of the three peak periods within the billing month. The main complexity here is that instead of the largest power value from the vector $\boldsymbol{P^G}$ we must pick the maximum value from each of the TOU time periods and then minimize each of them in a way so that the total cost becomes minimum. To resolve it, this paper proposes to introduce three diagonal matrices $\boldsymbol{\beta^{On}}$, $\boldsymbol{\beta^{Mid}}$ and $\boldsymbol{\beta^{Off}}$ to represent On-peak, Mid-Peak and Off-Peak period demand charges, respectively.

$$\boldsymbol{\beta^{On}} = \begin{bmatrix} \beta_0^{On} & \cdots & 0 \\ \vdots & \ddots & \vdots \\ 0 & \cdots & \beta_{T'-1}^{On} \end{bmatrix}, \boldsymbol{\beta^{Mid}} = \begin{bmatrix} \beta_0^{Mid} & \cdots & 0 \\ \vdots & \ddots & \vdots \\ 0 & \cdots & \beta_{T'-1}^{Mid} \end{bmatrix}$$
$$and\ \boldsymbol{\beta^{Off}} = \begin{bmatrix} \beta_0^{Off} & \cdots & 0 \\ \vdots & \ddots & \vdots \\ 0 & \cdots & \beta_{T'-1}^{Off} \end{bmatrix} \tag{20}$$

where, the diagonal entries of these matrices can be written as:

$$\beta_t^{On} = \begin{cases} \beta^{On}, & t \in \boldsymbol{T^{On}} \\ 0, & otherwise \end{cases}$$
$$\beta_t^{Mid} = \begin{cases} \beta^{Mid}, & t \in \boldsymbol{T^{Mid}} \\ 0, & otherwise \end{cases} \tag{21}$$
$$\beta_t^{Off} = \begin{cases} \beta^{Off}, & t \in \boldsymbol{T^{Off}} \\ 0, & otherwise \end{cases}$$

The off-diagonal elements in these matrices are all zero. Now, the cost function can be written as:

$$f\left(\boldsymbol{P^G}\right) = \Delta t \boldsymbol{\alpha^T} \boldsymbol{P^G} + \max\left(\boldsymbol{\beta^{On}} \boldsymbol{P^G}\right) + \max\left(\boldsymbol{\beta^{Mid}} \boldsymbol{P^G}\right) + \max(\boldsymbol{\beta^{Off}} \boldsymbol{P^G}) \tag{22}$$

4.3. Type C: TOU energy charges with both TOU demand charges and a time independent demand charge

This tariff is a combination of the tariffs described in the previous two subsections. It has both TOU demand charges for the maximum demand of each of the peak periods in the billing month and a time independent demand charge for the maximum peak happening within the whole billing month. We can write the cost function for this rate as:

$$f\left(\boldsymbol{P^G}\right) = \Delta t \boldsymbol{\alpha^T} \boldsymbol{P^G} + \max\left(\boldsymbol{\beta^{On}} \boldsymbol{P^G}\right) + \max\left(\boldsymbol{\beta^{Mid}} \boldsymbol{P^G}\right)$$
$$+ \max\left(\boldsymbol{\beta^{Off}} \boldsymbol{P^G}\right) + \beta \max(\boldsymbol{P^G}) \tag{23}$$

where the notations have the same meaning as shown in the previous two subsections.

4.4. Type D: Critical peak pricing (CPP)

Critical Peak Pricing or CPP rates offer lower demand charges in non-CPP event days in exchange for very high energy charges in CPP event days. CPP events are usually called when electricity demand peaks due to extreme weather conditions. They are usually the hottest summer days, with an average of 12–15 days per summer season determined by the utility company. The CPP event hours comprise the evening hours and early part of the night, namely, 4 PM to 9 PM. The customers are generally notified a day before the CPP event day.

A non-CPP day will have the energy charge vector $\boldsymbol{\alpha_{non-CPP}} = \boldsymbol{\alpha}$ just like the other rates. For a CPP day, we modify $\boldsymbol{\alpha}$ as $\boldsymbol{\alpha_{CPP}}$ where the energy charge α_t for timestep t needs to be modified when t is within the CPP event hours. The CPP event hours may overlap with part of the other peak periods. Thus, the energy charge α_t for a CPP event day can be written as:

$$\alpha_t = \begin{cases} \alpha^{On}, & t \in \boldsymbol{T^{On}} \backslash \boldsymbol{T^{CPP}} \\ \alpha^{Mid}, & t \in \boldsymbol{T^{Mid}} \backslash \boldsymbol{T^{CPP}} \\ \alpha^{Off}, & t \in \boldsymbol{T^{Off}} \backslash \boldsymbol{T^{CPP}} \\ \alpha^{CPP}, & t \in \boldsymbol{T^{CPP}} \end{cases} \tag{24}$$

The demand charge matrices for the non-CPP days $\boldsymbol{\beta^{On}_{non-CPP}}$, $\boldsymbol{\beta^{Mid}_{non-CPP}}$ and $\boldsymbol{\beta^{Off}_{non-CPP}}$ need to be modified. We can do that by replacing the tth diagonal element in the demand charge matrices from the previous subsections with the actual charge minus the discount charge offered by the utility company when t falls under the CPP event hours. The On-Peak demand charge β_t^{On} for a non-CPP event day can be written as:

$$\beta_t^{On} = \begin{cases} \beta^{On}, & t \in \boldsymbol{T^{On}} \backslash \boldsymbol{T^{CPP}} \\ \beta^{On} - \beta^{CPP}, & t \in \boldsymbol{T^{On}} \cap \boldsymbol{T^{CPP}} \\ 0, & otherwise \end{cases} \tag{25}$$

The Mid-Peak and Off-Peak demand charges β_t^{Mid} and β_t^{Off} for timestep t can be derived in a similar manner.

The same matrices for CPP days $\boldsymbol{\beta^{On}_{CPP}}$, $\boldsymbol{\beta^{Mid}_{CPP}}$ and $\boldsymbol{\beta^{Off}_{CPP}}$ are the same as the other TOU demand matrices shown in the previous subsections. So, we get two cost functions:

$$f\left(\boldsymbol{P^G}\right) = \Delta t \boldsymbol{\alpha_{non-CPP}}^{\boldsymbol{T}} \boldsymbol{P^G} + \max\left(\boldsymbol{\beta^{On}_{non-CPP}} \boldsymbol{P^G}\right) + \max\left(\boldsymbol{\beta^{Mid}_{non-CPP}} \boldsymbol{P^G}\right)$$
$$+ \max\left(\boldsymbol{\beta^{Off}_{non-CPP}} \boldsymbol{P^G}\right) + \beta \max(\boldsymbol{P^G}) \tag{26}$$

Table 2
Summary of tariff components of different tariff types.

Tariff component		Type A	Type B	Type C	Type D	Type E	Type F
Energy charge	On-Peak	✓	✓/✘	✓/✘	✓/✘	✘	✓
	Mid-Peak	✓	✓	✓	✓	✘	✓
	Off-Peak	✓	✓/✘	✓/✘	✓/✘	✘	✓
	CPP	✘	✘	✘	✓	✘	✘
	Flat	✘	✘	✘	✘	✓	✘
Demand charge	Time independent	✓	✘	✓	✓	✓	✘
	On-Peak	✘	✓/✘	✓/✘	✓/✘	✘	✘
	Mid-Peak	✘	✓/✘	✓/✘	✓/✘	✘	✘
	Off-Peak	✘	✓/✘	✓/✘	✓/✘	✘	✘
	CPP discount	✘	✘	✘	✓	✘	✘

* ✓: Present, ✘: Absent, ✓/✘: May or may not be present.

and $$f\left(\boldsymbol{P^G}\right) = \Delta t \boldsymbol{\alpha_{CPP}}^{\boldsymbol{T}} \boldsymbol{P^G} + \max\left(\boldsymbol{\beta^{On}_{CPP}} \boldsymbol{P^G}\right) + \max\left(\boldsymbol{\beta^{Mid}_{CPP}} \boldsymbol{P^G}\right) + \max\left(\boldsymbol{\beta^{Off}_{CPP}} \boldsymbol{P^G}\right) + \beta \max(\boldsymbol{P^G}) \tag{27}$$

where Eqs. (26) and (27) represent the cost functions for non-CPP days and CPP days, respectively. We should note that, the discounted rates at non-CPP days are also provided during the same hours as the CPP event hours at CPP days.

4.5. Type E: Flat energy charge with a time independent demand charge

For a flat energy rate with a monthly peak demand charge the variable α_t becomes a constant independent of time. We can represent the energy charge vector $\boldsymbol{\alpha}$ using the single scalar value α^{Flat}, where TOU energy charges from other tariff types become $\alpha^{On} = \alpha^{Mid} = \alpha^{Off} = \alpha^{Flat}$. The cost function then becomes:

$$f\left(\boldsymbol{P^G}\right) = \Delta t.\alpha^{Flat}.\boldsymbol{1^T}\boldsymbol{P^G} + \beta \max(\boldsymbol{P^G}) \tag{28}$$

where **1** denotes a vector of size T' with all elements as 1.

4.6. Type F: TOU energy charges only

This tariff type has no demand charges. The energy charge part is similar to type A. We can just remove the demand charge part from Eq. (19) and the cost function then becomes:

$$f\left(\boldsymbol{P^G}\right) = \Delta t\, \boldsymbol{\alpha^T}\boldsymbol{P^G} \tag{29}$$

4.7. The universal cost function

The universal cost function can now be represented with a format like similar to Eqs. (23), (26) and (27) which capture all the energy and demand charge components. We just need to apply the equations based on whether the tariff type is CPP or not, whether the day of optimization is a CPP event day or not and which of the energy or demand charge components are present, with the modifications described above. Based on the tariff type and component, we can just insert the applicable energy and demand charge values if present or make them zero if absent. We modify the sets of the timestamps of different peak periods too, as required. Table 2 summarizes the tariff components for each of the tariff type which we can use to apply to our universal cost function.

5. Optimization problem formulation

Using the universal cost function formulated in Section 4 as the objective function and the BESS modeling and power balance equations from Sections 3.2 and 3.3 of Section 3 as constraints, we can now derive the optimization problem for each of the tariffs described before.

But Eq. (7) in the model is a nonlinear equality condition which makes the problem nonconvex and difficult to solve. We can resolve it by introducing a binary variable $\delta_t \in \{0,1\}$ to the power limit constraints of Eqs. (5) and (6) and perform a convex relaxation on the binary variable. So, we reformulate them as:

$$0 \le P^{B+}_t \le \delta_t P^{B+max} \tag{30}$$

$$0 \le P^{B-}_t \le (1-\delta_t) P^{B-max} \tag{31}$$

$$0 \le \delta_t \le 1 \tag{32}$$

We can now write the optimization problem as shown below:

$$\min_{\boldsymbol{P^G}} f(\boldsymbol{P^G})$$

subject to:

$$E^B_{t+1} = E^B_t + P^B_t.\Delta t, \forall t \in \boldsymbol{T^{tot}} \tag{33}$$

$$E^{Bmin} \le E^B_t \le E^{Bmax}, \forall t \in \boldsymbol{T^{tot}} \tag{34}$$

$$P^B_t = P^{B+}_t - P^{B-}_t, \forall t \in \boldsymbol{T^{tot}} \tag{35}$$

$$0 \le P^{B+}_t \le \delta_t P^{B+max}, \forall t \in \boldsymbol{T^{tot}} \tag{36}$$

$$0 \le P^{B-}_t \le (1-\delta_t) P^{B-max}, \forall t \in \boldsymbol{T^{tot}} \tag{37}$$

$$0 \le \delta_t \le 1, \forall t \in \boldsymbol{T^{tot}} \tag{38}$$

$$P^{B+}_t = \eta^+ P^{SB}_t, \forall t \in \boldsymbol{T^{tot}} \tag{39}$$

$$P^S_t = P^{SB}_t + P^{SL}_t, \forall t \in \boldsymbol{T^{tot}} \tag{40}$$

$$P^L_t = P^{SL}_t + P^{BL}_t + P^G_t, \forall t \in \boldsymbol{T^{tot}} \tag{41}$$

$$P^{BL}_t = \eta^- P^{B-}_t, \forall t \in \boldsymbol{T^{tot}} \tag{42}$$

$$P^{SL}_t \ge 0, \forall t \in \boldsymbol{T^{tot}} \tag{43}$$

By applying the appropriate parameter values, we can use this optimization model to obtain the optimal operation, for any commercial tariff, given a building load and a solar generation profile.

6. Algorithm

For our proposed method we do the optimization on a day-by-day basis instead of doing a monthly optimization. We do this for a few reasons. Firstly, the day ahead prediction of load and solar can be produced more accurately and easily for a shorter time resolution such as 15 min. For this sort of time resolution, month ahead prediction will contain more inaccuracy. Secondly, doing a monthly optimization with this 15-minute data resolution would be computationally exhaustive. Without a very high processing power and sufficiently large memory device, the optimization will require much more computational time to solve. Lastly, since customers under CPP tariff are notified about the CPP event one day before it takes place, day ahead optimization would be the most reasonable approach for CPP.

Since we are doing a daily optimization, the total number of timesteps considered T' will be 96 in the case of 15-minute resolution. The vectors and matrices introduced in Section 4 will have corresponding sizes. We can write the daily building load profile and solar generation profile in vectorized form as:

$$\boldsymbol{P^L} = \begin{bmatrix} P_0^L \\ P_1^L \\ . \\ . \\ P_{T'-1}^L \end{bmatrix} \text{ and } \boldsymbol{P^S} = \begin{bmatrix} P_0^S \\ P_1^S \\ . \\ . \\ P_{T'-1}^S \end{bmatrix} \tag{44}$$

In this section, we will refer to the daily energy charge and demand charges as $\boldsymbol{\alpha}$ and $\boldsymbol{\beta}$ in general. To calculate the actual monthly usage bill, we will need to get new vectors and matrices that will accommodate the monthly calculation. We can create the new matrices of size $(D \times T', D \times T')$ and vectors of length $D \times T'$ for the monthly bill calculation.

When we are doing the optimization, we must consider the day of the week and the season. On-Peak, Mid-Peak and Off-Peak hours and prices typically vary depending on day of the week and season. Consequently, the elements of the sets $\boldsymbol{T^{On}}$, $\boldsymbol{T^{Mid}}$, and $\boldsymbol{T^{Off}}$ will be different though the elements of $\boldsymbol{T^{tot}}$ will be the same. Similarly, energy charges α^{On}, α^{Mid}, and α^{Off} and demand charges β^{On}, β^{Mid}, and β^{Off} will also vary. Typically, government holidays also have identical periods and prices as weekends.

The energy charge vector for the month $\boldsymbol{\alpha_{month}}$ will then become:

$$\boldsymbol{\alpha_{month}} = [\boldsymbol{\alpha_0^T \alpha_1^T} \ldots\ldots \boldsymbol{\alpha_{D-1}^T}]^{\boldsymbol{T}} \tag{45}$$

where,

$$\boldsymbol{\alpha_d} = \begin{cases} \boldsymbol{\alpha_{weekday}}, \, d \text{ is a weekday} \\ \boldsymbol{\alpha_{weekend}}, \, d \text{ is a weekend/holiday} \end{cases} \tag{46}$$

We can get the On-Peak TOU demand charge matrix for the month $\boldsymbol{\beta_{month}^{On}}$ by:

$$\boldsymbol{\beta_{month}^{On}} = \begin{bmatrix} \boldsymbol{\beta_0^{On}} & \cdots & 0 \\ \vdots & \ddots & \vdots \\ 0 & \cdots & \boldsymbol{\beta_{D-1}^{On}} \end{bmatrix} \tag{47}$$

where,

$$\boldsymbol{\beta_d^{On}} = \begin{cases} \boldsymbol{\beta_{weekday}^{On}}, \, d \text{ is a weekday} \\ \boldsymbol{\beta_{weekend}^{On}}, \, d \text{ is a weekend/holiday} \end{cases} \tag{48}$$

And $\mathbf{0}$ is a square matrix of size (T', T') with all elements as zeros.

Similarly, we can find the other TOU demand matrices $\boldsymbol{\beta_{month}^{Mid}}$ and $\boldsymbol{\beta_{month}^{Off}}$, which represent the Mid-Peak and Off-Peak TOU demand charge matrix for the billing month, respectively.

If we are dealing with a CPP rate structure in the summer season, then Eqs. (45) and (47) will be a little different. The $\boldsymbol{\alpha_d}$ will be $\boldsymbol{\alpha_{CPP}}$ if dth day is a CPP event day. On the other hand, $\boldsymbol{\beta_d^{On}}$, $\boldsymbol{\beta_d^{Mid}}$ and $\boldsymbol{\beta_d^{Off}}$ will be replaced by $\boldsymbol{\beta_{non-CPP}^{On}}$, $\boldsymbol{\beta_{non-CPP}^{Mid}}$ and $\boldsymbol{\beta_{non-CPP}^{Off}}$, respectively if dth day is a non-CPP event day.

We can then calculate the monthly usage bills by using the applicable cost function just by using the appropriate power vector of the right size and parameters $\boldsymbol{\alpha_{month}}$ and $\boldsymbol{\beta_{month}}$.

$$Monthly\ Usage\ Bill = f(\boldsymbol{X}; \boldsymbol{\alpha_{month}}, \boldsymbol{\beta_{month}}) \tag{49}$$

where $\mathbf{X}$ is the appropriate power vector of length $D \times T'$. We can now calculate the monthly usage bill for a building load alone, a building net load with solar or net load with solar and BESS optimization. To better understand the effects of the optimization, we define two types of savings, $Savings^{Solar}$ and $Savings^{BESS}$. $Savings^{Solar}$ shows the savings if only the solar is added without any BESS optimization. $Savings^{BESS}$ shows the effect of BESS optimization, that is, the additional savings we make through BESS optimization when solar is already present in the system. We can write them as:

$$Savings^{Solar} = f\left(\boldsymbol{P_{month}^L}; \boldsymbol{\alpha_{month}}, \boldsymbol{\beta_{month}}\right) - f(\boldsymbol{P_{month}^L} - \boldsymbol{P_{month}^S}; \boldsymbol{\alpha_{month}}, \boldsymbol{\beta_{month}}) \tag{50}$$

$$Savings^{BESS} = f\left(\boldsymbol{P_{month}^L} - \boldsymbol{P_{month}^S}; \boldsymbol{\alpha_{month}}, \boldsymbol{\beta_{month}}\right) - f(\boldsymbol{P_{month}^G}; \boldsymbol{\alpha_{month}}, \boldsymbol{\beta_{month}}) \tag{51}$$

To run the optimization, we must get values of the other parameters E^{Bmax}, E^{Bmin}, E_{init}^B, P^{B+max}, P^{B-max}, η^+ and η^-. Variables $\boldsymbol{P^{SL}}$, $\boldsymbol{P^{SB}}$, $\boldsymbol{P^{B+}}$ and $\boldsymbol{P^{B-}}$ need to be declared similar to vectors shown in Eq. (44) which represent the solar power fed to the load, solar power fed to the BESS, BESS charging and discharging power vectors for the day, respectively.

Now that we have described all the necessary variables and parameters, the algorithm for the optimization process can be written as:

7. Results and discussions

Using the data and parameters for the three buildings mentioned in Section 2, the building load optimizations were performed for their corresponding tariffs for a month. The data used are from the summer months and the rates used are summer season rates. For all these tariffs the daily On-Peak hours are from 12 PM to 6 PM on weekdays, Mid-Peak hours are from 8 AM to 12 PM and from 6 PM to 11 PM on weekdays and the remaining hours are all Off-Peak Hours. At the start of each simulation, it is assumed that all the BESS have their initially stored energy E_{init}^B at 50% of the total capacity. The limits for maximum and minimum stored energy for each is assumed to be 90% and 20% of their total capacity, respectively. For the simulations in this work MATLAB based convex optimization toolbox CVX has been used (Grant and Boyd, 2013). Type D or CPP has four months in the summer season (June to September) and total 12 CPP event days in the summer season. So, on average each month will have three CPP days. The three highest demand days (day numbers 9, 12, and 20) for building 1 are selected as CPP event days in this simulation. The CPP event hours take place from 4 PM to 9 PM.

Fig. 3 shows the results of the optimization for each type of tariffs for a month. To observe the effects of the optimization, we compare the amount of power drawn from the grid in three different scenarios: the actual building load (no action taken), the unoptimized net load (solar added), and the optimized net load (solar with BESS optimization performed). These are referred to as the actual building load, the unoptimized net load, and the optimized net load, respectively. For better understanding, zoomed in versions of the plots for a day are also presented. In subplot (g), we can observe the optimized net load curve above the unoptimized net load curve around 7 to 8 AM, and 9 AM to 12 PM, meaning the BESS is charging during those hours. Then the optimized net load curve goes below the unoptimized net load curve around 12 PM, indicating discharging of BESS. The discharge continues till 6 PM. This energy shift from lower cost Mid-Peak period to higher cost On-Peak period is observed as the optimization strategy tries to minimize the cost. Therefore, BESS starts charging in the morning when the solar power is sufficient and the energy prices are low. Then it transitions to discharging at noon when On-Peak period starts. Around 10 PM, there is a peak reduction resulting from the BESS optimization, which aims to reduce the time-independent peak demand cost. Subplot (h) shows a similar energy shift, with less discharge and an additional peak reduction after the maximum peak reduction

Algorithm

Select tariff type
Select Season
Get parameters E^{Bmax}, E^{Bmin}, E^{B}_{init}, P^{B+max}, P^{B-max}, η^{+} and η^{-}.
if (Tariff type=CPP rate) and (Season=Summer) then:
    Get $\boldsymbol{\alpha}_{CPP}$, $\boldsymbol{\beta}_{CPP}$, $\boldsymbol{\alpha}_{non-CPP}$, and $\boldsymbol{\beta}_{non-CPP}$
else
    Get $\boldsymbol{\alpha}$, $\boldsymbol{\beta}$
endif
Declare empty vectors $\boldsymbol{P}^{G}_{month} = [\ \ ]$, $\boldsymbol{P}^{L}_{month} = [\ \ ]$, $\boldsymbol{P}^{S}_{month} = [\ \ ]$
for each day d=0,1, ……., D-1 do:
    if (Tariff Type=CPP) then:
        if (Day d=CPP Event Day) then:
            Get $\boldsymbol{\alpha}_{CPP}$, $\boldsymbol{\beta}_{CPP}$
        else
            Get $\boldsymbol{\alpha}_{non-CPP}$, $\boldsymbol{\beta}_{non-CPP}$
        endif
    elseif (Day d==weekday) then:
        Get $\boldsymbol{\alpha}$, $\boldsymbol{\beta}$ for weekday
    else
        Get $\boldsymbol{\alpha}$, $\boldsymbol{\beta}$ for weekend and holiday
    endif
    Get $\boldsymbol{P}^{L}$, $\boldsymbol{P}^{S}$ for day d
    Declare variables $\boldsymbol{P}^{G}$, $\boldsymbol{P}^{SL}$, $\boldsymbol{P}^{SB}$, $\boldsymbol{P}^{B+}$ and $\boldsymbol{P}^{B-}$
    Initialize E^{B}_{0}=E^{B}_{init}
    Run Optimization
    Run the optimum BESS operation according to $\boldsymbol{P}^{B+}$ and $\boldsymbol{P}^{B-}$
    Update $\boldsymbol{P}^{G}_{month} = \begin{bmatrix} \boldsymbol{P}^{G}_{month} \\ \boldsymbol{P}^{G} \end{bmatrix}$
    Update $\boldsymbol{P}^{L}_{month} = \begin{bmatrix} \boldsymbol{P}^{L}_{month} \\ \boldsymbol{P}^{L} \end{bmatrix}$ and $\boldsymbol{P}^{S}_{month} = \begin{bmatrix} \boldsymbol{P}^{S}_{month} \\ \boldsymbol{P}^{S} \end{bmatrix}$
    Update E^{B}_{init}=E^{B}_{T-1}
endfor
Calculate the unoptimized monthly cost $f(\boldsymbol{P}^{L}_{month}; \boldsymbol{\alpha}_{month}, \boldsymbol{\beta}_{month})$
Calculate the unoptimized monthly cost with only solar added $f(\boldsymbol{P}^{L}_{month} - \boldsymbol{P}^{S}_{month}; \boldsymbol{\alpha}_{month}, \boldsymbol{\beta}_{month})$
Calculate the optimized monthly cost with solar and BESS added $f(\boldsymbol{P}^{G}_{month}; \boldsymbol{\alpha}_{month}, \boldsymbol{\beta}_{month})$
Calculate $Savings^{Solar} = f(\boldsymbol{P}^{L}_{month}; \boldsymbol{\alpha}_{month}, \boldsymbol{\beta}_{month}) - f(\boldsymbol{P}^{L}_{month} - \boldsymbol{P}^{S}_{month}; \boldsymbol{\alpha}_{month}, \boldsymbol{\beta}_{month})$ and
$Savings^{BESS} = f(\boldsymbol{P}^{L}_{month} - \boldsymbol{P}^{S}_{month}; \boldsymbol{\alpha}_{month}, \boldsymbol{\beta}_{month}) - f(\boldsymbol{P}^{G}_{month}; \boldsymbol{\alpha}_{month}, \boldsymbol{\beta}_{month})$

due to the TOU demand charge in Mid-Peak period of type B. These changes take place due to the TOU demand charge in Mid-Peak period of type B. In subplot (i), the energy shift is also similar to subplot (g) despite the Mid-Peak demand charge, as both the time-independent peak demand charge and the On-Peak demand charge are much higher than the Mid-Peak demand charge price. Subplot (j) reveals a delayed BESS discharging, starting 4 PM, when the higher CPP event hours begin, and continues until the end of CPP event hours at 9 PM. In subplot (k), only peak reduction is observed while energy shift is absent. On the other hand, in subplot (l), energy shift alone can be observed while peak reduction is missing. This is expected as the tariffs have flat energy charge and no peak demand charge, respectively. A tariff with a flat energy charge presents no opportunity of savings from energy shift. Similarly, without peak demand charge there is option of savings from peak reduction.

Table 3 summarizes the optimization results from all the simulations using building 2 data. We see that the without any DERs the cost can vary widely, just because of tariff type and charges. This comparison gives an idea even for the same net load how much impact the tariff components have on the billing costs. We can also see that the $Savings^{Solar}$ percentage variation for different tariffs. The main factor behind this variation is the On-Peak energy prices as of the solar power is generated during this period. If we look at the $Savings^{BESS}$ we can see that tariff type E and F have much lower savings percentage. This is expected as the TOU energy charge and peak demand charge component is missing in these two tariffs, respectively. Therefore, BESS optimization loses the opportunity for energy shifting and peak reduction for these types, respectively. Type B also has somewhat lower $Savings^{BESS}$ percentage compared to others. This is because of the smaller difference among the TOU price components. This results in lower savings due to energy or peak shifted from higher price period to lower price period.

8. Analysis of impacts of utility tariff changes on optimization results

In this section, we will analyze how different changes in utility tariffs impact the optimization results discussed in the previous section. For this purpose, we will investigate the effects of three different changes. First, how the price change of the energy and demand charges impact on the savings. Second, how the choice of demand charge heavy or energy charge heavy tariff options plays out for different building types. Lastly, how the time shifts in the TOU periods affect the building net load. The first two scenarios are analyzed from the perspective of building user benefit. The last scenario is analyzed from the perspective of utility's interest. The analyses are presented in the following subsections.

8.1. Analysis of impacts due to price changes

An important issue with the utility rates is that the prices of these charges often change. To understand how these changes impact the savings and how much benefit we can receive in the future from this optimization, an analysis was done on the building 2 load data using historical and forthcoming values of tariff Type B published by the utility. This tariff has three energy and three demand charge components. The year of our actual analysis in previous sections is chosen as the base year values. Five years of tariff data is available and price of each tariff component has increased every year. To understand each individual components effect, we choose one component and change its values for the past and future years, while keeping the other components fixed at the base year values. We run the optimization and compare the results for all the different cases. The base year is denoted as year zero while negative and positive values denote past and future values, respectively. Table 4 shows the energy and demand charge values for each year.

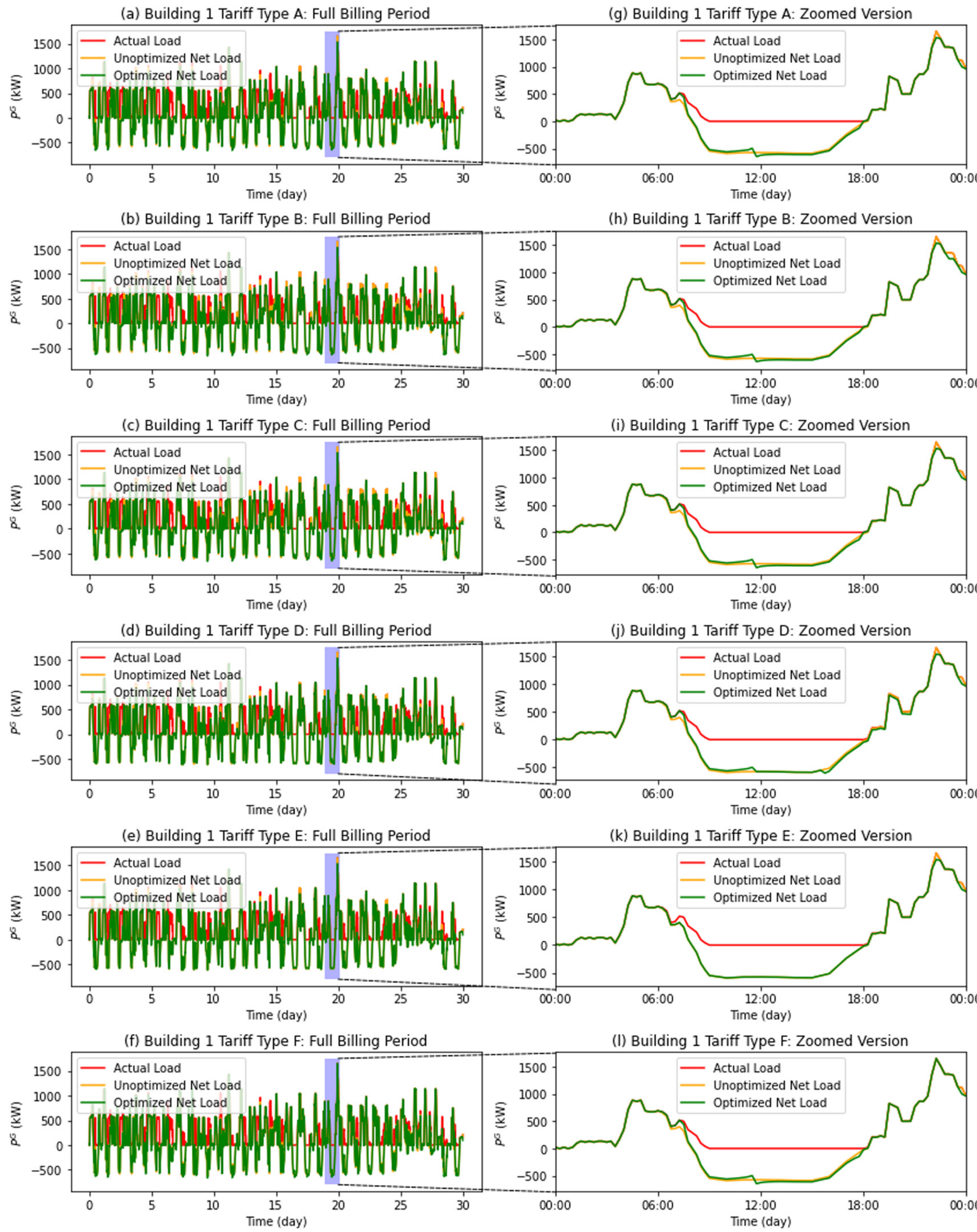

Fig. 3. Results from optimization showing the power drawn from grid before optimization (actual load), after adding solar (unoptimized net load) and after optimization with solar and BESS (optimized net load) for tariff type: (a) A, (b) B, (c) C, (d) D, (e) E, and (f) F using Building 1 data. (a)–(f) show the results for full billing period. (g)–(l) show the zoomed versions of a day for better understanding of (a)–(f), respectively.

Fig. 4 shows the effect of price on $Savings^{Solar}$, that is, savings from solar. It can be seen that the $Savings^{Solar}$ values are highly impacted by On-Peak energy and demand charge changes. It is somewhat less impacted by Mid-Peak energy and demand charge changes. There is almost no change in $Savings^{Solar}$ values due to Off-Peak energy and demand charge changes. This is expected since most of the solar is produced during the On-Peak period, while the solar production is much less in the Mid-Peak period and there is almost no solar production during Off-Peak period.

Fig. 5 shows the effect of price on $Savings^{BESS}$. Here we see that increase in On-Peak energy charge causes $Savings^{BESS}$ to decrease while Mid-Peak energy charge causes it to increase. This scenario is reversed in the case of demand charges. Savings stays same for Off-Peak energy and demand charge change as shifting energy or peak from this period does not result in any additional savings from optimization. The reason behind the unexpected behavior of On and Mid-Peak change is because energy and peak reduction from one period through battery optimization causes to increase the energy and peak in other periods, which makes it less obvious if our optimal solution will end up with a higher or lower savings. Here, this type of analysis can be very useful as we can predict the future possible savings by assessing the trend.

Table 3
Summary of optimization results.

Optimization parameters and results	Type A	Type B	Type C	Type D	Type E	Type F
Building	Building 2	Building 2	Building 2	Building 2	Building 2	Building 2
Energy charge ($/kWh)	On-Peak: 0.3397 Mid-Peak: 0.13837 Off-Peak: 0.07637	On-Peak: 0.1079 Mid-Peak: 0.0874 Off-Peak: 0.0755	On-Peak: 0.10258 Mid-Peak: 0.07566 Off-Peak: 0.05727	On-Peak: 0.07817 Mid-Peak: 0.07422 Off-Peak: 0.0724 CPP: 0.4	Flat rate: 0.139	On-Peak: 0.22617 Mid-Peak: 0.18317 Off-Peak: 0.15457
Demand charge ($/kW)	Monthly Peak: 11.87	On-Peak: 7.06 Mid-Peak: 3.13 Off-Peak: 1.53	On-Peak: 21.73 Mid-Peak: 4.17 Monthly Peak: 19.02	On-Peak: 16 Mid-Peak: 5.16 Monthly Peak: 17.52 CPP discount: 4.11	Monthly Peak: 10.58	–
Costs without DER ($)	10,573	6,803	12,879	12,077	9,295	9,360
Cost after solar addition ($)	3,746	3,478	7,893	7,905	5,585	4,089
Optimized cost with both solar and BESS ($)	2,149	2,928	6,098	6,689	5,436	3,699
$Savings^{Solar}$ ($)	6,827 (65%)	3,325 (49%)	4,986 (39%)	4,172 (35%)	3,096 (33%)	5,271 (56%)
$Savings^{BESS}$ ($)	1,597 (15%)	550 (8%)	1,795 (14%)	1,221 (10%)	149 (2%)	389 (4%)

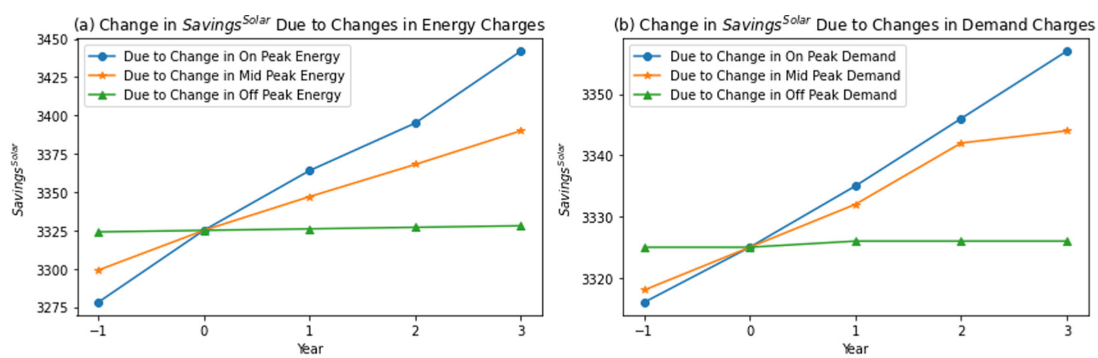

Fig. 4. $\boldsymbol{Savings^{Solar}}$ Due to changes in: (a) Energy charges and (b) Demand charge.

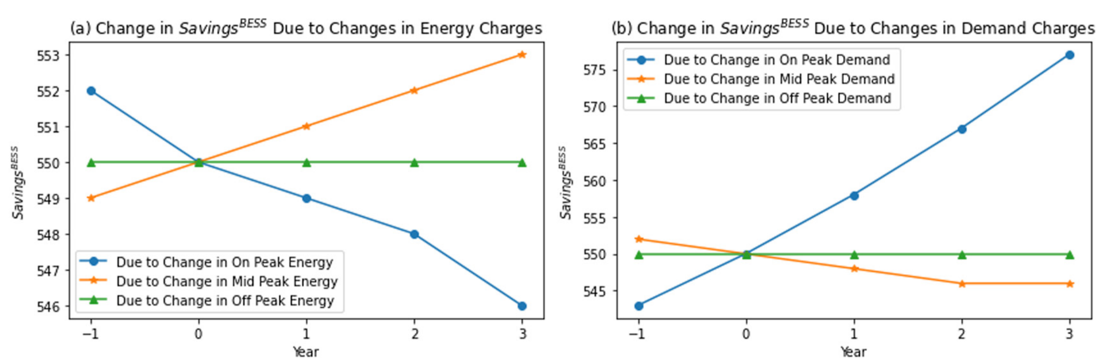

Fig. 5. $\boldsymbol{Savings^{BESS}}$ Due to changes in: (a) Energy charges and (b) Demand charge.

Table 4
Energy and demand charge prices over the years.

Year	Energy charge ($/kWh)			Demand charge ($/kW)		
	On Peak	Mid Peak	Off Peak	On Peak	Mid Peak	Off Peak
−1	0.1049	0.0845	0.0734	6.97	2.93	1.42
0	0.1079	0.0874	0.0755	7.06	3.13	1.53
1	0.1104	0.0898	0.0773	7.16	3.34	1.65
2	0.1124	0.0922	0.0787	7.27	3.64	1.82
3	0.1154	0.0946	0.0808	7.38	3.69	1.85

8.2. Analysis of impacts due to changes in energy charge heavy and demand charge heavy tariff options

Utilities sometimes provide options under the same tariff. One option contains higher demand charges and lower energy charges while the other contains higher energy charges and lower demand charges. To compare the user benefits between these two options we use both for our optimization on buildings 1 and 3 and compare the savings. These two buildings we were chosen since they have similar daily consumption but contrasting load factors. Load factor is an indicator of how efficiently the energy is used. A low load factor means that the average load is lower compared

Table 5
Demand heavy and energy heavy options for the applied rate.

Charge	Demand option	Energy option
On peak energy ($/kWh)	0.12158	0.49669
Mid peak energy ($/kWh)	0.11337	0.19008
Off peak energy ($/kWh)	0.0867	0.12325
Monthly peak demand ($/kW)	14.98	10.3
On-Peak demand ($/kW)	34.68	4.98

to the peak load within a period. This translates to the fact that while the average consumption of the building can be satisfied with a lower capacity system, the utility needs to increase the capacity due to accommodate the peak load. A high load factor implies that the capacity to satisfy the peak load does not need to be increased to as much as the low load factor scenario. We apply the optimization using the options that is found in a type C rate. Table 5 shows the prices for these options. The option with higher demand charges is named as demand option while the option with higher energy charges is named as energy option. The TOU demand charge in this rate is On-Peak Demand charge only.

Table 6 summarizes the results of the optimization on buildings 1 and 3 using the rates shown in Table 5.

We analyze the results from two perspectives. First, we assume that the customers can choose between the options. Comparing the unoptimized costs in table we see that, without any DERs, buildings with low load factor do not benefit much from the choice between the options. Though buildings with high load factors can benefit from choosing the demand option. Buildings who have existing solar generation should choose the energy option if their load factor is low but should choose the demand option if their load factor is high, because it would help lower their cost. Buildings with both solar and BESS should also make the same decision based on load factors. Now we assume that the utility decides for the customers which option they fall under, and customers do not have any authority over it. Buildings with low load factors receive higher benefits from adding solar than buildings with high load factors, regardless of the tariff option. The savings from adding solar is higher for energy options while savings from BESS optimization is higher from demand options for both type of buildings.

8.3. Analysis of impacts due to time shift in peak periods.

Grids in places with high solar PV penetration such as California or Hawaii face a problem with high generation ramp rate at evening hours specially in summer. At that time the solar starts to decrease while building loads increase due to higher cooling demand. The net demand increases sharply within a few hours as a result which needs to be satisfied by the other power generation resources. But increasing generation at this fast rate becomes challenging for these resources with generally high start-up or response time. The net demand curve resembles the shape of a duck and is termed as "Duck Curve" (Confronting the Duck Curve). To alleviate this condition the utilities are introducing completely new or adjusting existing TOU time periods. This shift in time is supposed to help reduce the high ramp rate through demand response of customers with load shifting abilities, such as commercial buildings with DERs. This is done by mainly bringing a shift in the legacy 12 to 6 PM On-Peak period in the weekdays. The newly introduced TOU period is administered by defining the On-Peak period from 4 PM to 9 PM and rest of the hours as Mid-Peak on weekdays and making the 4 to 9 as the Mid-Peak period and keeping rest of the hours as Off-Peak on weekends. To examine the effect of this time shift on commercial buildings we apply both the rates with conventional and new time periods into our optimization using building 1 data for tariff type A. We also propose a dynamic rate with varying prices to reduce ramp rates in the evenings. Fig. 6 shows the traditional or legacy rate, recently introduced current rate and the dynamic rate proposed by the authors.

From this figure it can be seen that, in both of the legacy and recently introduced rate, the change in energy price takes place as a large step. Instead, the proposed dynamic rate increases the value linearly for a duration of time, followed by a steady value and finally decrease linearly again for the remaining time, all within the highest cost On-Peak period. The particular durations maybe chosen by the utilities according to the needs of the system resource constrains and Duck Curve requirements. As an example, we have chosen the following dynamics and durations for this study: linear rate increase in the first two hours, then steady rate value for the next hour and decrease linearly again for the last two hours within the ON-Peak period in our proposed rate. This way a sharp change in energy price is avoided and smoothing effect is brought into the price change. To make the proposed rate equivalent to the recent introduced one, we define the On-Peak price in weekdays in a way so that for same energy use within the period, the total energy cost would be same. We do that by keeping the area under the curve during this 5-hour, 4 PM to 9 PM period, same for both cases. As mentioned earlier in this section, during the weekend the same 5-hour time period is considered as Mid-Peak prices. For optimization purposes this weekend Mid-Peak prices follows the same methodology as weekday's On-Peak prices.

The steady On-Peak price for the 6 PM to 7 PM period, $\alpha^{On,proposed}$ can be found by:

$$\frac{1}{2}\left(\alpha^{On,proposed}-\alpha^{Mid}\right)(24\Delta t)=\left(\alpha^{On}-\alpha^{Mid}\right)(20\Delta t) \tag{52}$$

By solving Eq. (52) we get:

$$\alpha^{On,proposed}=\frac{5\alpha^{On}-2\alpha^{Mid}}{3} \tag{53}$$

For our proposed rate, the energy cost at time step t during the 4 PM to 9 PM period on weekdays can be modified as:

$$\alpha_t=\begin{cases}\alpha^{Mid}+\dfrac{\left(\alpha^{On,proposed}-\alpha^{Mid}\right)}{8}(t-64), & 64\le t<72\\ \alpha^{On,proposed}, & 72\le t\le 76\\ \alpha^{On,proposed}+\dfrac{\left(\alpha^{On,proposed}-\alpha^{Mid}\right)}{8}(t-84), & 76<t\le 84\end{cases} \tag{54}$$

Similarly, we can define the Mid-Peak Prices in weekends during similar 4 to 9 PM period. The daily average net load after optimization for these three rates are shown in Fig. 7.

California Independent System Operator (CAISO) uses the three-hour ramp rate between 4 PM and 7 PM to assess the severity of the ramp rate requirements of the Duck Curve. The same three-hour ramp rates of the optimized daily average net load for the three rates are presented in Table 7.

As we can see from Fig. 7 and Table 7, the recent introduced rate does not help much in reducing the ramp rates (2% decrease) while the proposed rate shows a significant improvement (31% decrease) over the other. This is due to the fact that step change and steady value of the legacy and recent introduced rate drives the BESS to discharge power with a sharp change at the transition time between the periods and then continues discharging power at a steady rate. In contrast, a linearly changing rate enables BESS to increase or decrease the discharging power gradually which helps to reduce the fast ramp rate of the net load or the

Table 6
Optimization Results using the tariff options from Table 5.

Building	Building 1		Building 3	
Option	Demand option	Energy option	Demand option	Energy option
Unoptimized cost ($)	115,990	117,200	77,701	104,460
Unoptimized cost with solar ($)	81,921	65,476	62,871	67,551
Optimized cost with solar and BESS ($)	76,052	61,645	58,604	64,492
$Savings^{Solar}$ ($)	34,070 (29%)	51,725 (49%)	14,830 (19%)	36,911 (35%)
$Savings^{BESS}$ ($)	5,869 (5%)	3,831 (3%)	4,267 (5%)	3,059 (3%)

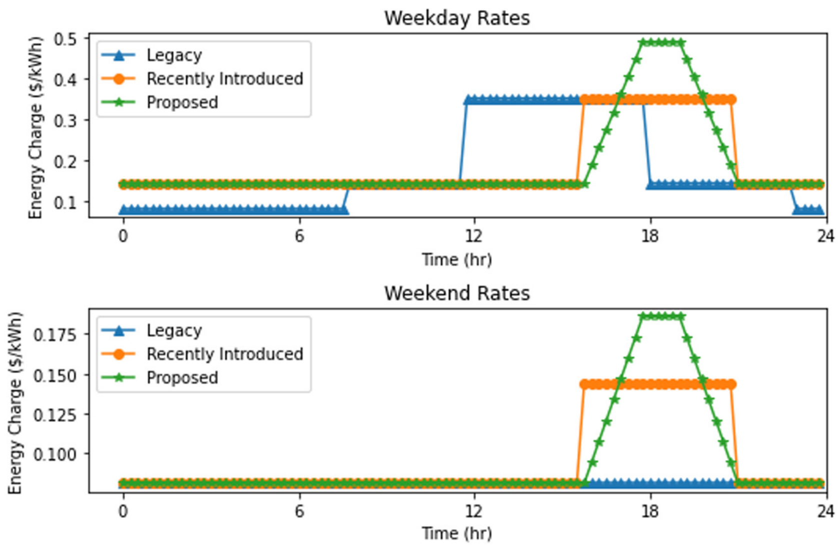

Fig. 6. Legacy, recent introduced and proposed rates.

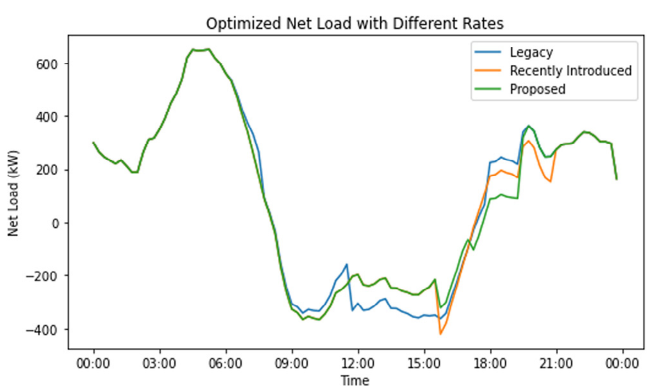

Fig. 7. Optimized net loads for legacy, recent introduced and proposed rates.

Table 7
Three Hour (4PM to 7PM) Ramp Rate for the Three Rates.

Rate	Three Hour Average Ramp (kW)
Legacy	572.92
Recent introduced	561.8
Proposed	393.09

Duck Curve. Utilities can introduce the proposed rate for the commercial buildings with solar and BESS to offset the high Duck Curve ramp rates.

9. Conclusions and future work

In this paper, a comprehensive optimization framework has been developed for commercial buildings equipped with DERs such as solar generation and BESS, to capture the diversity in utility tariff types. In order to do that the following tasks were performed:

- The commercial utility tariffs were categorized into six universal types by conducting thorough investigation of tariffs from the largest utilities in the USA.
- Cost functions were formulated these six tariff types, leading to a single universal cost function, applicable to any tariff.
- A comprehensive framework for optimization was developed by formulating the optimization problem through integration of the universal cost function with the system model, and an algorithm to perform optimization systematically.
- Optimization of commercial buildings were performed using this framework and the results were analyzed.
- An impact analysis was conducted to better understand the relationship between tariff optimization outcomes and changes in price, time periods, and available options.

By examining the results of optimization results and impacts analysis study several new insights were discovered. The key findings from this study can be summarized as:

- Results indicated that costs and savings for a given system can vary greatly depending on the tariff type.
- Flat energy charge, absence of demand charge, and smaller difference among TOU charges result in reduced savings from BESS optimization.
- Savings from solar are most impacted by On-Peak energy and demand charges, and least impacted by Off-Peak period charges.
- The effect of TOU charges on savings from BESS optimization is not immediately apparent, but analysis of past years data can present an insightful trend.

- Comparison between demand charge-heavy and energy charge-heavy tariffs on high and low load factor buildings helped to identify the most beneficial option based on building type and DER savings opportunities.
- Time period change analysis revealed that the more recent time periods introduced by utilities do not effectively achieve flexible ramping in the "duck curve" net load feature, but the proposed modified tariff offers a significant improvement.

This paper uses building load and solar generation data assuming perfect prediction. However, forecasted values may have some inaccuracies which can introduce some discrepancy in the optimization results. Future works can be carried out to see how the level of inaccuracy associate with the level of discrepancy in the optimization results. Increasing EV adoption and on-site EV charging infrastructures in workplaces along with V2G capabilities have significant impact on commercial building loads. Sometimes these EV charging is metered individually or aggregated under the main meter. Separately metered EV charging fall under separate EV tariffs. Further works can be done considering these aspects. Effects of load deferral under different demand response scheme and prospect of other grid ancillary services besides flexible ramping can also be investigated.

CRediT authorship contribution statement

A S M Jahid Hasan: Conceptualization, Methodology, Formal analysis, Software, Writing – original draft. **Luis Fernando Enriquez-Contreras:** Software, Validation, Writing – review & editing. **Jubair Yusuf:** Software, Writing – review & editing. **Sadrul Ula:** Conceptualization, Writing – review & editing, Supervision.

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

The authors do not have permission to share data.

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