Critical Peak Electricity Pricing for Sustainable Manufacturing: Modeling and Case Studies

Yong Wang ^a, and Lin Li ^{b,*}

^a Department of Systems Science and Industrial Engineering, Binghamton University,
Binghamton, NY 13902, USA

^b Department of Mechanical and Industrial Engineering, University of Illinois at Chicago,
Chicago, IL 60607, USA

Abstract

Critical peak pricing (CPP) is an electricity demand response technology that has great potential to lower the electricity cost and eliminate the need for more GHG emitting power plants. Many utilities start to offer CPP as the default electric service for industrial customers in their market design. When a manufacturing customer defaults to CPP, it is vital to understand what it is and how it will influence their energy budget and facility operations. In addition, given the option to opt-out to a time-of-use (TOU) rate, it is not always easy to tell whether the switch will result in higher bills or more GHG emissions. These questions will be answered in this paper. Specifically, we will model and compare both CPP and TOU rates to gain more accurate knowledge regarding annual electric costs and GHG emissions. With these results, manufacturing enterprises will be able to make more informed decisions on which service to choose and how to use electricity while fulfilling their role for sustainability by enrolling. The case study results show that for industrial customers with production flexibility, with proper rescheduling of electric use, they can save money by adopting CPP, while contributing to reducing GHG emissions. The savings on the annual electric bill can be 30.45% with a simultaneous GHG emissions reduction of 5.63% for an average industrial customer.

Keywords: Manufacturing; Sustainability; Critical peak pricing; Time-of-use; Demand response

1. Introduction

Climate change is a global threat facing the human race. It has caused serious impacts that harm economies around the world [1, 2]. Reducing greenhouse gas (GHG) emissions is the key to tackling the challenge [3-5], i.e., bioelectrochemical technique was reviewed in [4] to reduce carbon dioxide emissions. Combating climate change has become an indispensable main topic of the high-level international and intergovernmental events such as Asia-Pacific Economic Cooperation (APEC) Summit [6], the G-20 Summit [7], and the United Nations Climate Summit [8]. The seriousness of the challenge has urged both developed and developing countries to take solid actions to curb GHG emissions. For example, among a series of recent plans revealed to fight climate change, European Union has set a target of 20% cut in GHG emissions by 2020 compared with 1990 [9]. The U.S. pledged to cut total GHG emissions by 26%-28% below its 2005 level in 2025 [10]. China pledged to reach its emission peak by 2030. These three economies jointly contribute about 50% of the world's total GHG emissions [11].

Electricity generation is a major source of GHG emissions worldwide. For example, in the U.S, it is responsible for 38% of total energy-related emissions in 2013 [12]. Electric demand

* Corresponding author. Tel: +1 312-996-3045; Fax: +1 312-413-0447. Address: ERF 3057, 842 W Taylor St, Chicago, IL 60607-7022, USA. Email: linli@uic.edu.

oscillates vastly from season to season in a year and from hour to hour in a day [13]. The demand typically peaks from late afternoon to early evening during summer months, when extremely hot weather prompts high air-conditioning use that strains the electric grid. As an example, the total electric load of California Independent System Operator (CAISO) in the U.S. during year 2012 [14] is shown in Figure 1. The capacity reserved for the peak load is used only occasionally and then idled for the rest of the year. In the case of CAISO, the top 10% of the electric capacity is only needed for 67 hours, which is only 0.76% of the time in the year. The electric price during peak hours can be extremely high. In some cases, the electric charges of the top 12 peak hours during a year can account for as high as 23% of a customer's annual electric bill [15].

Figure 1. Hourly total electric load on the CAISO market (Raw data is in [14])

New technologies that can constructively reduce GHG emissions start to emerge in the electric power industry. One such technology is demand response [16-18]. Demand response emerges as a smart grid technology to better balance electricity supply and demand. It encourages electric customers to reduce or shift electricity usage during peak hours in exchange for various economic benefits [19, 20]. By doing so, the need for more expensive and more GHG-intensive peaking power plants can be avoided. According to a staff report of the U.S. Federal Energy Regulatory Commission (FERC) [21], as much as 150 GW of the peak load could be reduced by 2019 through demand response in the U.S., which is equivalent to the capacity of 2,000 peaking power plants! Demand response also provides a viable way to integrate intermittent renewable sources as their market penetrations continue to increase [22]. This in turn helps decrease GHG emissions.

The introduction of demand response has been boosted in the past few years by the advancement of enabling technology. Both U.S. and EU have invested heavily to promote the deployment of smart meters [23, 24]. The adoption of smart meters in developing countries such as China is also catching up [25]. Demand response has many different forms of implementation [16, 26, 27]. Two such forms are time-of-use (TOU) pricing and critical peak pricing (CPP).

Unlike the flat rates where the price of electricity stays constant throughout the day, dynamic pricing is more commonly adopted in demand response programs to represent the dynamic cost of power generation [28-30]. For example, the electric charges in TOU pricing are differentiated by on-, mid-, and off-peak periods, with the on-peak price being the highest and the off-peak price being the lowest [31]. The time and pricing blocks are kept unchanged every workday for a season or a year. CPP is an overlay on the TOU pricing. It imposes a much higher rate during a period called the critical peak in an event day, when the electricity use is significantly high. With CPP, the time and duration of the critical peak period within an event

day are predetermined, so is the maximum number of event days per year, but the specific dates when the events will occur are not. The customers will be informed one day ahead of the event. Although the electric price is much higher during the critical-peak period in event days, the customers are offered discounted prices during other days in the rest of the year. Therefore, it enables the customers to significantly reduce their total electric bill by restraining electric use during CPP events. Many customers embracing sustainability leadership are at the vanguard of CPP applications [32-35].

Utility companies usually create different tariffs for residential and business customers, highlighting the different characteristics specific to each of these two sectors [36, 37]. This paper studies CPP for business applications, with a special focus on industrial manufacturing customers. More specifically, we start with a literature review of CPP for industrial demand response. Then, we collect typical CPP tariffs from several utility companies that represent a wide range of tariff design. We also analyze the common components presented in the CPP tariffs and their differences with TOU tariffs. The detailed rate schedule information is tabulated for future reference. After that, we conduct a survey of CPP events and characterize their patterns. Case studies using a series of manufacturing systems have been conducted to illustrate how to choose between CPP and TOU rates when both options are provided to industrial customers. Finally, the economic and environmental benefits from adopting CPP have been quantified.

2. Brief literature review of CPP research

Related research on CPP demand response programs in the U.S. has been previously conducted by some researchers and organizations. For example, Herter et al. [38-40] studied customer response during CPP events in California. Aghaei and Alizadeh [41] investigated the application of a new form of CPP demand response program announced by U.S. FERC in the cost-emission-based unit commitment problem. Faruqui et al. [42] analyzed two dynamic pricing rates and an enabling technology in Michigan. Steve et al. [43] develop econometric models to examine the responses of participants in CPP programs in Minnesota and South Dakota. Wolak [44] reported an experiment that evaluates the performance of CPP programs in Washington DC for households that differ in terms of income levels, electricity using appliance holdings, and whether they own a smart thermostat. On the other hand, dynamic pricing in Europe and China are mainly focused on TOU tariffs [45-47] and the data of CPP programs is limited. The progress of pioneer work in dynamic pricing in Asia (e.g., China, Japan, Korea, and Indonesia) is summarized in [48].

In addition, all the above-mentioned efforts focus on residential programs targeting household applications. The CPP programs targeting industrial customers have been largely neglected. Industrial electricity use is fundamentally different from residential electricity use [39, 40, 49]. For example, electricity is a major form of energy source in manufacturing activities. Manufacturing processes such as machining and assembly involve utilizing equipment that is much more energy-intensive. Business customers together contribute 83% to the potential peak demand reduction for CPP programs in 2012 in the U.S.; in comparison, the contribution of residential customers is only 17% [50]. Besides, most of manufacturing businesses run multiple shifts [51-53] and have less flexibility with their production processes than the operation of residential appliances such as air conditioners, refrigerators, washers, dryers, and ovens [54, 55].

Therefore, studies show that it is still challenging to simultaneously coordinate production activities, energy consumption, and environment impacts to achieve manufacturing sustainability [56-58].

It should be mentioned that related work on non-residential CPP has been previously conducted by a few researchers and organizations. Examples include [59-61]. However, all these efforts focus on evaluating the load impacts of such programs from the utility's perspective. The assessment of the benefits to customers, especially industrial manufacturing customers, is limited.

Some of our initial work have modeled the dynamics of typical manufacturing systems [62]. The TOU based electricity cost of manufacturing systems [63, 64] is analyzed. With the modeling result, we have also discussed whether it is economical for an industrial customer to switch from the flat rate to the voluntary TOU rate [65, 66]. However, as smart meter penetration increases in the U.S., many utilities are in a transition to fade out the flat rate, and replace it by mandatory TOU or CPP rates. Therefore, it would be worthwhile to take into account this new trend, which has been largely neglected in our previous work.

According to the nationwide FERC demand response survey [50], TOU pricing is currently the most prevalent time-varying rate. In comparison, CPP is relatively new, but its adoption is gaining momentum. Many utilities start to offer CPP as the default electric service in their market design, unless customers explicitly opt-out to a TOU rate. When a manufacturing customer defaults to CPP, it is vital to understand what it is and how it will influence their energy budget and facility operations. In addition, given the option to opt-out to a TOU rate, it is not always easy to tell whether the switch will result in higher bills. These questions will be answered in this paper. Specifically, we will model and compare both CPP and TOU rates to gain more accurate knowledge regarding annual electric costs and related GHG emissions. With these results, manufacturing enterprises will be able to make more informed decisions on which service to choose and how to use electricity while fulfilling their role for sustainability by enrolling.

3. Industrial CPP in California

As mentioned in the previous section, CPP programs are more commonly available in the U.S. than in the other parts of the world. Based on the U.S. FERC survey results [50], we list the numbers of customers enrolled in the business CPP programs by state in Figure 2. The figure shows there are 11 states providing CPP programs for business customers. California has the most enrolled customers, making up over 75% of the total. In addition, no other states have kept a detailed, transparent, long-term record of CPP events as well as easily accessible GHG emission data of their generators. Therefore, we will focus on examining CPP programs offered in California as case studies to gain the insights for manufacturers that are currently enrolled or considering enrolling in CPP in other states as well as for utilities that are currently offering or considering offering CPP in other states.

Figure 2. Numbers of business customers enrolled in CPP by state (Raw data is in [50])

There are three major utilities in California, Pacific Gas & Electric (PGE), Southern California Edison (SCE), and San Diego Gas & Electric (SDGE). They are all investor-owned utilities operating in the CAISO grid and regulated by California Public Utilities Commission (CPUC) [67, 68]. They have each designed CPP based on their own pricing models. We will examine the industrial CPP programs of all three. Although the rate schedule terms of the three utility vary, they all have some key elements in common. All three utilities automatically place industrial customers on CPP by default, but customers are allowed to opt out to a TOU rate. However, participation in one of the two rates is mandatory. Table 1 lists the names of the default CPP and corresponding optional TOU rates of PGE, SCE, and SDGE for industrial customers.

In Table 1, the first two columns list the utility names as well as the tariffs that contain the CPP and TOU clauses. The tariff names will be used as the index for further analysis in subsequent tables. Utilities usually divide the customers into several categories based on the customers' peak demand (the Demand Range column in Table 1), and design a different tariff for each category. For example, in SCE, the tariffs TOU-GS-1, TOU-GS-2, TOU-GS-3, and TOU-8 are applicable to industrial customers with peak demand in the intervals $[0, 20]$ kW, $(20, 200]$ kW, $[200, 500]$ kW, and $(500, \infty)$ kW, respectively. The customer's peak demand is the measured highest demand during the billing month by a demand meter with a 15-minute metering interval. These tariffs are extracted from the publically available rate books on the associated official websites of these three utilities. Note that cancelled, closed, and expired tariffs are excluded from the list.

Table 1. Industrial CPP and TOU tariffs of PGE, SCE, and SDGE

Utility	Tariff Name	TOU Clause	CPP Clause	Demand Range (kW)
PGE [69]	A-1	TOU	PDP	$[0, 200)$
	A-6	TOU	PDP	$[200, 500)$
	A-10	TOU	PDP	$[200, 500)$
	E-19	TOU	PDP	$[500, 1000)$
	E-20	TOU	PDP	$[1000, \infty)$
SCE [70]	TOU-GS-1	Option A	Option CPP	$[0, 20]$
	TOU-GS-2	Option B	Option CPP	$(20, 200)$
	TOU-GS-3	Option B	Option CPP	$[200, 500]$
	TOU-8	Option B	Option CPP	$(500, \infty)$
SDGE [71]	AL-TOU	EECC	EECC-CPP-D	$[20, \infty)$

Figure 3. (a) TOU and (b) CPP charge profiles of PGE's A-6 tariff during summer months (Raw data is in [69])

As an example, the TOU and CPP electric charge profiles of Pacific Gas & Electric Company's (PGE) A-6 tariff during summer months are shown in Figure 3. Two auxiliary green lines are drawn to highlight the differences during mid- and on-peak periods.

Detailed pricing information of the TOU rates identified in Table 1 is summarized in Table 2. These rates can be explained as follows:

- (i) All three utilities divide the entire year into two seasons, with May through October or June through September being the summer season, and the rest being the winter season.
- (ii) The division of the on-, mid-, and off-peak periods varies. But on-peak periods generally consist of afternoon and early evening hours, off-peak periods consist of night hours, and mid-peak periods are in between. For all three utilities, off-peak periods also include all day of Saturdays, Sundays, and non-weekend holidays.
- (iii) Most TOU rates contain the energy charge, the demand charge, and the customer charge. A customer's monthly bill is the sum of these three components. The energy and demand charges in the summer months are usually higher than those during the same period in the winter months. The energy and demand charges are collected for bundled services including electricity generation, transmission, and distribution.
- (iv) The energy charge is applied to the energy (in kWh) portion of electric use. The total daily energy charge is rendered by adding the three components corresponding to the on-, mid-, and off-peak periods, respectively.
- (v) The demand charge is applied to the demand (in kW) portion of electric use. The total monthly demand charge is rendered by adding the four components: the on-, mid-, off-peak period charges and the base charge. The on-, mid-, and off-peak-period components apply to the maximum demand during any on-, mid-, and off-peak hours of the month, respectively. The base component applies to the maximum demand during any time of the month.
- (vi) The monthly customer charge represents the costs for various services such as meter reading, account billing, and call centers. It is fixed for a certain tariff, no matter how much electricity is use. However, for different tariffs in the same utility company, the customer charge increases as the demand range ramps up.

Detailed pricing information of the CPP rates is summarized in Table 3. These rates are further explained as follows:

- (i) Each CPP rate is superimposed on the corresponding TOU rate of the same utility, but the CPP rate also contains many additional clauses that are more complicated. In general, customers will pay an energy surcharge or adder for the portion used within the critical-peak period during the event days, and they will receive discounts or credits for electricity use on non-event days during the summer months.
- (ii) Each CPP event lasts for four hours (14:00-18:00) for PGE and SCE customers, and seven hours (11:00-18:00) for SDGE customers. During a CPP event, the energy charge can be an order of magnitude higher than the corresponding TOU summer on-peak rates.
- (iii) The credits are applied to days in summer months only. The credits may apply to on-peak periods only, both on- and mid-peak periods, or all three periods. The credits could be in the form of energy charge discounts, demand charge discounts, or both.
- (iv) The number of CPP event days per year may be fixed or variable. For PGE, the number will be in the range [9, 15]. For SCE, there will be exactly 12 events per year. For SDGE, a maximum of 18 CPP events may be called. The event day can be any day year round for PGE and SDGE, and any non-holiday weekdays for SCE.

Table 2. Detailed TOU rates (Note: Empty cells are interpreted as zero or not applicable)

Utility	Tariff	Months	On-peak	Mid-peak	Off-peak	Energy Charge (\$/kWh)			Demand Charge (\$/kW)				Other Monthly Charge (\$)
						On-peak	Mid-peak	Off-peak	On-peak	Mid-peak	Off-peak	Base (any time)	
PGE	A-1	May-Oct	12-18	8:30-12;18-21:30	21:30-8:30	0.2547	0.24562	0.21801					19.975232
		Nov-Apr		8:30-21:30	21:30-8:30		0.17359	0.15381					
	A-6	May-Oct	12-18	8:30-12;18-21:30	21:30-8:30	0.58648	0.2723	0.15207					26.08776
		Nov-Apr		8:30-21:30	21:30-8:30		0.17408	0.14207					
	A-10	May-Oct	12-18	8:30-12;18-21:30	21:30-8:30	0.17989	0.17198	0.14792				14.28	169.790688
		Nov-Apr		8:30-21:30	21:30-8:30		0.1308	0.11017				6.47	
	E-19	May-Oct	12-18	8:30-12;18-21:30	21:30-8:30	0.16594	0.11342	0.07903	18.37	4.25		12.99	629.236224
		Nov-Apr		8:30-21:30	21:30-8:30		0.10645	0.08296		0.22		12.99	
	E-20	May-Oct	12-18	8:30-12;18-21:30	21:30-8:30	0.15145	0.10722	0.07807	17.91	3.89		12.65	1028.731136
		Nov-Apr		8:30-21:30	21:30-8:30		0.10094	0.07925		0.25		12.65	
SCE	TOU-GS-1	Jun-Sep	12-18	8-12;18-23	23-8	0.24438	0.19989	0.17031					27.208
		Oct-May		8-21	21-8		0.16766	0.15631					
	TOU-GS-2	Jun-Sep	12-18	8-12;18-23	23-8	0.1457	0.09447	0.06933	19.9	5.82		12.71	267.53
		Oct-May		8-21	21-8		0.09973	0.07503				12.71	
	TOU-GS-3	Jun-Sep	12-18	8-12;18-23	23-8	0.14656	0.09156	0.06538	20.36	5.97		15.77	432.01
		Oct-May		8-21	21-8		0.09337	0.07077				15.77	
SDGE	AL-TOU	May-Oct	11-18	6-11;18-22	22-6	0.12849	0.11807	0.08777	21.1			20.77	[20,500] kW:87.83; [500,12000] kW: 349.31
		Nov-Apr	17-20	6-17;20-22	22-6	0.11845	0.10184	0.07896	7.14			20.77	

Table 3. Detailed CPP rates (Note: Empty cells are interpreted as zero or not applicable)

Utility	Tariff	Discount Months	Energy and Demand Charge Credits	Adder During CPP Events	Event Days per Year	Event Time Period	Notification Time
PGE	A-1	May-Oct	Energy Charge (\$/kWh): All periods 0.00977	Energy Charge (\$/kWh): 0.60	[9,15]	14-18, Year round, any day of the week	By 14:00 day ahead
	A-6	May-Oct	Energy Charge (\$/kWh): On-peak 0.10830; Mid-peak 0.02166	Energy Charge (\$/kWh): 1.20			
	A-10	May-Oct	Energy Charge (\$/kWh): All periods 0.00702 Demand Charge (\$/kW): 2.6	Energy Charge (\$/kWh): 0.90			
	E-19	May-Oct	Demand Charge (\$/kW): On-peak 6.37; Mid-peak: 1.38	Energy Charge (\$/kWh): 1.20			
	E-20	May-Oct	Demand Charge (\$/kW): On-peak 6.10; Mid-peak: 1.24	Energy Charge (\$/kWh): 1.20			
SCE	TOU-GS-1	Jun-Sep	Energy Charge (\$/kWh): All periods 0.03776	Energy Charge (\$/kWh): 1.37453	12	14-18, Year round, non-holiday weekdays	By 15:00 day ahead
	TOU-GS-2	Jun-Sep	Demand Charge (\$/kW): On-peak 10.75	Energy Charge (\$/kWh): 1.37453			
	TOU-GS-3	Jun-Sep	Demand Charge (\$/kW): On-peak 11.44	Energy Charge (\$/kWh): 1.37453			
	TOU-8	Jun-Sep	Demand Charge (\$/kW): On-peak 11.93	Energy Charge (\$/kWh): 1.37453			
SDGE	AL-TOU	May-Oct	Demand Charge (\$/kW): On-peak 11.30	Energy Charge (\$/kWh): 1.39243	[0,18]	11-18, Year round, any day of the week	By 15:00 day ahead

- (v) All three utilities notify customers on a day-ahead basis when a CPP event will occur the next day. Most likely customers will be notified through phone calls or emails. Some utilities also use additional communication tools such as SMS texts, pagers, fax, and utility websites.
- (vi) Severe weather is the mostly quoted CPP event trigger. For example, the weather condition in PGE tariffs is based on the average of the day-ahead maximum temperature forecasts for San Jose, Concord, Red Bluff, Sacramento and Fresno. Events on non-holiday weekdays will be triggered at 98 °F (36.7 °C), and will be triggered at 105 °F (40.6 °C) on holidays and weekends. A CPP event can also be triggered on a day-ahead basis by high load, high prices, a major system outage, or to meet annual event limits for a calendar year.
- (vii) All three utilities provide a one-time guaranteed bill protection for default CPP customers for the first 12 consecutive months. This means that if a customer ends up paying more at the end of the first 12 consecutive months on a CPP rate, the utility will compensate the customer for all charges that exceed the customer's previous rate plan. The one-year bill protection works as a stimulus to encourage customers to enroll and find out if CPP is a good fit for their businesses.

4. CPP events

PGE, SCE, and SDGE are required to regularly report the operation status of their demand response programs to CPUC. We have examined the available reports and extracted the historical CPP event data from 2005 to 2014 for each of the three utilities [72, 73]. These data are tabulated in Tables A1 through A3 in Appendix. A summary of these three utilities in the CAISO grid is shown in Table 4. These data will be used for case studies in Section 5 to calculate the annual electric bills of manufacturing systems and the corresponding GHG emissions.

Table 4. Summary of the numbers of CPP events in the CAISO grid

Utility	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Sum
PGE	9	15	12	11	12	9	9	11	9	10	107
SCE	12	12	12	12	12	12	12	12	12	12	120
SDGE	5	11	11	0	8	4	2	9	4	6	60
CAISO Total	26	38	35	23	32	25	23	32	25	28	287

Based on Tables 4 as well as A1 through A3, we plot the numbers of historical events of the utilities by month and by weekday in Figures 4 through 7. Based on these historical event data, we observe the following:

- (i) SCE issued the most CPP events while SDGE issued the least in the ten-year record.
- (ii) With a list of federal holidays [74] in Table A4 in Appendix, we find that no event of PGE or SCE fall in an observed holiday; while for SDGE, only one event date, 9/3/2007, is also an observed holiday (Labor Day). Based on the figures, we also find that no event of PGE or SCE fall during the weekend, while SDGE issued five Saturday events. This may be due to the relatively small reserved capacity of SDGE and its service area is densely populated.
- (iii) Although all three utilities' tariffs claim CPP events may be called year round, in reality such events only occurred during the months of May through October, with an exception of a February event in SDGE.

- (vi) The by-month data appears to be approximately normally distributed for all three utilities and their sum. The patterns in Figures 4 through 6 reveal that the maximum number of events appears to shift from July and August to August and September. Figure 7 shows that about 96% of the total 287 events in CAISO occurred in June through September. It also shows that August has the most CPP events called, followed by July, September, and June.
- (v) The by-weekday data is approximately uniformly distributed for PGE and SCE events, and they are slightly skewed towards Thursday and Friday for SDGE and CAISO events.

Figure 4. Numbers of historical events in PGE (a) by month and (b) by weekday

Figure 5. Numbers of historical events in SCE (a) by month and (b) by weekday

Figure 6. Numbers of historical events in SDGE (a) by month and (b) by weekday

Figure 7. Numbers of historical events in CAISO (a) by month and (b) by weekday

5. Modeling electric bills and GHG emissions under CPP

5.1 Electric bills

We have previously modeled the electricity cost of manufacturing systems under the TOU rate in [62-65]. In this section, we model the annual electricity cost under the CPP rate. Tables 1 through 3 reveal that the CPP rate is essentially a TOU rate with extra terms. Therefore, this section utilizes our previous research work, and we only document the differences below.

For month m ($m = 1, 2, \dots, 12$) of a year, the total electric bill c_m is the sum of all three components: the energy charge $c_{m,E}$, the demand charge $c_{m,D}$, and the customer or other charge $c_{m,O}$, i.e.,

$$c_m = c_{m,E} + c_{m,D} + c_{m,O} \quad (1)$$

The monthly customer charge $c_{m,O}$ is fixed and always known for a specific CPP program of a specific utility. For example, for the SCE TOU-GS-2 tariff in Table 2, $c_{m,O} = \$267.53/\text{month}$.

We assume the manufacturing system operates during weekdays only. There is no operation during weekends or holidays. The number of workdays and the number of CPP event days in month m ($m = 1, 2, \dots, 12$) are denoted by w_m and v_m , respectively. For example, for the SCE TOU-GS-2 tariff, in August 2014, ten days fall in weekends and there are no federal holidays. So the number of workdays in that month is $w_8 = 21$ days. There are three event days (8/4/2014, 8/22/2014, and 8/28/2014) based on Table A2. Therefore, $v_8 = 3$ days.

The demand of the manufacturing system is denoted by d . For example, suppose a manufacturing system contains four machines that each has a power of 25 kW. Then, the combined system power demand is $d = 100$ kW.

Let h_{CRI} , h_{ON} , h_{MID} , and h_{OFF} be the work hours during the critical-, on-, mid-, and off-peak periods, respectively, during a workday in month m . For example, for the SCE TOU-GS-2 tariff, on the event date 8/4/2014, if a production runs two 8-hour work shifts from 8:00 to 24:00, then based on the detailed information in Tables 2 and 3, $h_{CRI} = 4$ hours (from 14:00 to 18:00), $h_{ON} = 6$ hours (from 12:00 to 18:00), $h_{MID} = 9$ hours (from 8:00 to 12:00 and from 18:00 to 23:00), and $h_{OFF} = 9$ hours (from 23:00 to 8:00 next day).

The energy use during the critical-, on-, mid-, and off-peak periods are equal to the power demand multiplied by corresponding time periods, i.e., $d \cdot h_{CRI}$, $d \cdot h_{ON}$, $d \cdot h_{MID}$, and $d \cdot h_{OFF}$, respectively. Let $p_{m,ON,E}$, $p_{m,MID,E}$, and $p_{m,OFF,E}$ be the energy prices during the on-, mid-, and off-peak periods, respectively, during a workday in month m . For example, for the SCE TOU-GS-2 tariff, on the event date 8/4/2014, based on the detailed information in Tables 2 and 3, $p_{m,ON,E} = \$0.1457/\text{kWh}$, $p_{m,MID,E} = \$0.09447/\text{kWh}$, and $p_{m,OFF,E} = \$0.06933/\text{kWh}$.

Let $p_{m,CRI,E}^{adder}$ be the energy charge adder during the critical-peak period of a CPP event day. For example, for the SCE TOU-GS-2 tariff, on the event date 8/4/2014, based on the detailed information in Tables 2 and 3, $p_{m,CRI,E}^{adder} = \$1.37453/\text{kWh}$.

Let $p_{m,ON,E}^{credit}$, $p_{m,MID,E}^{credit}$, and $p_{m,OFF,E}^{credit}$ be the energy charge credits during the on-, mid-, and off-peak periods, respectively, during a workday in month m . For example, for the SCE TOU-GS-2 tariff, on the event date 8/4/2014, based on the detailed information in Tables 2 and 3, $p_{m,ON,E}^{credit} =$

$p_{m,MID,E}^{credit} = p_{m,OFF,E}^{credit} = \$0/\text{kWh}$ because this tariff involves only demand credit and no energy credit. For the PGE A-6 tariff, however, $p_{m,ON,E}^{credit} = \$0.10830/\text{kWh}$, $p_{m,MID,E}^{credit} = \$0.02166$, and $p_{m,OFF,E}^{credit} = \$0/\text{kWh}$.

The monthly energy charge $c_{m,E}$ is the discounted TOU-based energy charge $c_{m,E}^{disc}$ plus the adder $c_{m,E}^{adder}$ during CPP events, i.e.,

$$c_{m,E} = c_{m,E}^{disc} + c_{m,E}^{adder} \quad (2)$$

where

$$\begin{aligned} c_{m,E}^{disc} = & w_m \cdot d \cdot [h_{ON} \cdot (p_{m,ON,E} - p_{m,ON,E}^{credit}) \\ & + h_{MID} \cdot (p_{m,MID,E} - p_{m,MID,E}^{credit}) \\ & + h_{OFF} \cdot (p_{m,OFF,E} - p_{m,OFF,E}^{credit})] \end{aligned} \quad (3)$$

and

$$c_{m,E}^{adder} = v_m \cdot d \cdot h_{CRI} \cdot p_{m,CRI,E}^{adder} \quad (4)$$

Let d_{ON} , d_{MID} , and d_{OFF} be the maximum demands during any on-, mid-, and off-peak periods, respectively, in month m . For example, for the SCE TOU-GS-2 tariff, in August 2014, if a production system with $d = 100$ kW runs one work shift from 8:00 to 16:00, then $d_{ON} = d_{MID} = 100$ kW, and $d_{OFF} = 0$ kW because it does not involve off-peak hours (from 23:00 to 8:00 next day). Let d_{BASE} be the maximum base demand during any time period in month m . It is defined as

$$d_{BASE} = \max(d_{ON}, d_{MID}, d_{OFF}) \quad (5)$$

Let $p_{m,ON,D}$, $p_{m,MID,D}$, and $p_{m,OFF,D}$ be the demand prices during on-, mid-, and off-peak periods, respectively, in month m . Let $p_{m,BASE,D}$ be the base demand charge during any time period in month m . For example, for the SCE TOU-GS-2 tariff, on the event date 8/4/2014, based on the detailed information in Tables 2 and 3, $p_{m,ON,D} = \$19.9/\text{kW}$, $p_{m,MID,D} = \$5.82/\text{kW}$, $p_{m,OFF,D} = \$0/\text{kW}$, and $p_{m,BASE,D} = \$12.71/\text{kW}$.

Let $p_{m,ON,D}^{credit}$, $p_{m,MID,D}^{credit}$, and $p_{m,OFF,D}^{credit}$ be the demand charge credits during the on-, mid-, and off-peak periods, respectively, during a workday in month m . For example, for the SCE TOU-GS-2 tariff, on the event date 8/4/2014, based on the detailed information in Tables 2 and 3, $p_{m,ON,D}^{credit} = \$10.75/\text{kW}$, and $p_{m,MID,D}^{credit} = p_{m,OFF,D}^{credit} = \$0/\text{kW}$.

The monthly demand charge $c_{m,D}$ is the discounted TOU-based demand charge $c_{m,D}^{disc}$ plus the base demand charge $c_{m,D}^{base}$ during CPP events, i.e.,

$$c_{m,D} = c_{m,D}^{disc} + c_{m,D}^{base} \quad (6)$$

where

$$\begin{aligned}
c_{m,D}^{disc} = & d_{ON} \cdot (p_{m,ON,D} - p_{m,ON,D}^{credit}) \\
& + d_{MID} \cdot (p_{m,MID,D} - p_{m,ON,D}^{credit}) \\
& + d_{OFF} \cdot (p_{m,OFF,D} - p_{m,ON,D}^{credit})
\end{aligned} \tag{7}$$

and

$$c_{m,D}^{base} = d_{BASE} \cdot p_{m,BASE,D} \tag{8}$$

Therefore, the annual electric bill c is rendered by adding up the bills from January to December of the year, i.e.,

$$c = \sum_{m=1}^{12} c_m \tag{9}$$

5.2 GHG emissions

Suppose a day is evenly discretized into 24 slots, with $t = 1$ being the first slot, and $t = 24$ being the last. The slot duration is equal to one hour. Let $s_{n,t}$ be the status of the manufacturing system during time slot t in the n th day of a year. It is defined as

$$s_{n,t} = \begin{cases} 1, & \text{if the system is in production during time } t \\ 0, & \text{otherwise} \end{cases} \tag{10}$$

For example, if a production runs two 8-hour work shifts on Monday, 9/8/2014 (which is the 251st day in 2014) from 8:00 to 24:00 midnight, then $s_{251,t} = 1$ for $t = 1, 2, \dots, 8$ and $s_{251,t} = 1$ for $t = 9, 10, \dots, 24$. The energy consumption (in kWh) of the manufacturing system during the n th hour ($t = 1, 2, \dots, 24$) of a day is

$$e_{n,t} = s_{n,t} \cdot d \cdot 1 = s_{n,t} \cdot d \tag{11}$$

Studies have shown that GHG emission intensity for generating electricity also varies with time [75]. Let $r_{n,t}$ be the hourly GHG marginal emission rate (in kg/kWh) during time slot t in the n th day of the year. For the n th day ($n = 1, 2, \dots, 365$) of a year, the total GHG emissions (in kg) corresponding to the energy consumption is

$$g_n = \sum_{t=1}^{24} r_{n,t} \cdot e_{n,t} \tag{12}$$

Therefore, the annual GHG emissions (in kg) is rendered by adding up the emissions from the first day to the last day of the year, i.e.,

$$g = \sum_{n=1}^{\text{Num of days in a year}} g_n \tag{13}$$

6. Case studies

In this section, we calculate the annual electric bill and GHG emissions of manufacturing systems under CPP and TOU rates listed in Section 3 with case studies. Then we examine the financial and environmental impacts when manufacturers switch among different production schedules and when they opt out from a default CPP to the corresponding TOU rate.

For each of the ten tariffs listed in Table 1, we consider six different scenarios listed in Table 5. For each scenario, we consider three different daily production schedules that are commonly

adopted in manufacturing plants: one work shift (8 hours), two work shifts (16 hours), and three work shifts (24 hours). Under Scenario 1, the customer adopts the CPP rate and the production schedule starts at 8:00 in the morning. Scenario 2 differs from Scenario 1 in that the customer can reschedule the production within a certain time range so that one- and two-shift productions will never start earlier than 6:00 and never end later than 2:00 next day. Scenario 3 differs from Scenario 1 in that the customer can reschedule the production so it starts at any optimal time. Scenarios 4, 5, and 6 differ from Scenarios 1, 2, and 3, respectively, in that the customer opts out from CPP to the corresponding TOU rate. By rescheduling the starting time, the customer may take advantage of the lower prices during the off-peak period and avoid (or partially avoid) the electric use during the critical- or on-peak periods. Thus, the total electric bill can be lowered without affecting the total production. The best starting time for Scenarios 2, 3, 5, and 6 can be obtained by doing a quick one-time search with a step size of 15 minutes (same as the metering interval).

Table 5. Six different scenarios

Scenario	Rate	Production shift start time
CPP1	CPP	8:00 in the morning
CPP2	CPP	Optimal starting time within the range: 1-shift (6:00 and 18:00); 2-shift (6:00 and 10:00); 3-shift (any time)
CPP3	CPP	Optimal starting time (any time)
TOU1	TOU	8:00 in the morning
TOU2	TOU	Optimal starting time within the range: 1-shift (6:00 and 18:00); 2-shift (6:00 and 10:00); 3-shift (any time)
TOU3	TOU	Optimal starting time (any time)

6.1 Electric bill savings

The values of the parameters used in Section 5 are all available in the tables in Sections 3 and 4. After applying Equations (1) through (9) for the six scenarios listed in Table 5, the results of the calculated electric bills are shown in Tables 6 and 7. The power demands of the manufacturing systems used in the case studies are also given in the table. These power demands are chosen in a way so that they all fall in the demand ranges of the examined tariffs listed in Table 1. Unlike TOU, which applies on a daily basis, the impact of the CPP rate depends on the number of events and the specific dates when these events are called, both of which are highly variable from year to year. Therefore, the multi-year long-term average impact is more meaningful than the impact of a single year. Thus, we calculate every value in Table 6 to represent the estimated average annual electricity bill of the manufacturing system during the ten-year record from 2005 to 2014, using currently effective rates.

The results in Tables 6 and 7 shows that the bill ramps up as the system power demand increases across different tariffs within the same utility. As the number of production shifts during a workday increases, the average annual bill will undoubtedly also increase. This is evidenced by comparing the one-shift bill values with the corresponding two-shift and three-shift values. In all the cases, the bills of the two- and three-shift production are approximately doubled and tripled, respectively, in comparison to that of the one-shift production.

Table 6. Average annual electric bills of the CPP scenarios

Utility	Tariff	System Power (kW)	1-Shift Electric Bill (\$)			2-Shift Electric Bill (\$)			3-Shift Electric Bill (\$)		
			CPP1	CPP2	CPP3	CPP1	CPP2	CPP3	CPP1	CPP2	CPP3

PGE	A-1	100	42,882	38,751	36,664	84,101	83,207	76,069	120,526	120,526	120,526
	A-6	400	224,702	141,583	118,458	412,667	402,756	269,639	530,812	530,812	530,812
	A-10	400	172,746	154,447	146,589	294,598	291,230	258,807	395,589	395,589	395,589
	E-19	800	457,566	304,111	262,262	650,878	642,138	442,858	780,885	780,885	780,885
	E-20	1200	605,280	431,676	383,945	881,266	869,758	632,625	1,070,707	1,070,707	1,070,707
SCE	TOU-GS-1	15	6,040	5,064	4,790	11,517	11,385	9,659	15,981	15,981	15,981
	TOU-GS-2	100	49,153	37,761	33,134	71,541	70,294	53,680	86,213	86,213	86,213
	TOU-GS-3	400	199,861	154,737	136,233	285,885	281,105	214,869	341,237	341,237	341,237
	TOU-8	1200	611,012	452,469	390,907	872,756	858,139	634,983	1,040,653	1,040,653	1,040,653
SDGE	AL-TOU	1200	692,087	592,672	504,249	1,021,222	1,005,174	823,278	1,238,239	1,238,239	1,238,239

Table 7. Average annual electric bills of the TOU scenarios

Utility	Tariff	System Power (kW)	1-Shift Electric Bill (\$)			2-Shift Electric Bill (\$)			3-Shift Electric Bill (\$)		
			TOU1	TOU2	TOU3	TOU1	TOU2	TOU3	TOU1	TOU2	TOU3
PGE	A-1	100	42,595	39,747	37,661	83,526	82,632	78,063	120,947	120,947	120,947
	A-6	400	240,389	145,449	118,458	432,995	421,428	275,162	551,140	551,140	551,140
	A-10	400	174,147	163,552	155,693	291,158	287,790	270,775	395,013	395,013	395,013
	E-19	800	437,022	304,111	262,262	609,790	601,050	442,858	739,797	739,797	739,797
	E-20	1200	627,312	440,604	383,945	872,482	860,974	641,553	1,061,923	1,061,923	1,061,923
SCE	TOU-GS-1	15	5,931	5,449	5,176	11,299	11,167	10,430	16,148	16,148	16,148
	TOU-GS-2	100	50,154	37,761	33,134	69,243	67,996	53,680	83,915	83,915	83,915
	TOU-GS-3	400	204,969	154,737	136,233	277,798	273,018	214,869	333,150	333,150	333,150
	TOU-8	1200	628,689	452,469	390,907	850,847	836,230	634,983	1,018,745	1,018,745	1,018,745
SDGE	AL-TOU	1200	728,332	592,672	504,249	1,039,421	1,023,373	823,278	1,256,439	1,256,439	1,256,439

To more intuitively show the differences among the bills under the six scenarios for each tariff, we also calculated the savings on the average annual electricity bills by switching from one scenario to another and listed the results in Tables 8 through 10. Careful observation of the numbers suggests that:

- (i) Table 8 shows the comparison results for one-shift production. We first examine the switch CPP1→CPP2. it represents that the customer reschedule production so that the starting time is changed from 8:00 to the best time within a certain range that will lead to the lowest electric bill, while keeping enrolled in the default CPP. The best start time is 18:00 for PGE, SCE, and SDGE tariffs. All ten cases in Table 8 show positive values and the average is over 22%, which translate into significant savings ranging from several thousand to several hundred thousand dollars. The average annual saving of the switch is \$74,806.
- (ii) Then we examine the switch CPP1→CPP3 in Table 8. The switch represents that the customer reschedule production so the starting time is changed from 8:00 to the best time that will lead to the lowest electric bill, while keeping enrolled in the default CPP. The best start time is 23:00 for both PGE and SCE tariffs, and it is 22:00 for the SDGE tariff. All ten cases in Table 8 show positive values and the average is over 30%. The average annual saving of the switch is \$104,410.

- (iii) The switch CPP1→TOU1 in Table 8 represents that the customer opts out from the default CPP to the TOU rate, while keeping production from 8:00 to 16:00 unchanged. The average saving is negative, which means the customer will actually suffer from economic losses by conducting such a switch, assuming no production rescheduling. Similar results are also observed for the switches with production rescheduling, i.e., CPP2→TOU2 and CPP3→TOU3.
- (iv) For two-shift production, Table 9 shows that both CPP1→CPP2 and CPP1→CPP3 can still achieve positive savings, although the saving magnitudes are smaller than in Table 8. This is because 2-shift production will run 16 hours per day, which leave less flexibility for production rescheduling to take advantage of the lower prices during off-peak periods. Unlike in Table 8, the switches CPP1→TOU1 and CPP2→TOU2 will result in positive average savings, and the switch CPP3→TOU3 will result in a negative average saving.
- (v) For three-shift production, the pattern in Table 10 is quite different from that of Table 8. The switches CPP1→CPP2 and CPP1→CPP3 have no impact on the total bill, and the savings of all ten cases are 0%. This is because the business process has no flexibility since the production has to run 24 hours a day. The electric bill is fixed no matter when the starting time is. For the same reason, the switches CPP1→TOU1, CPP2→TOU2, and CPP3→TOU3 result in exactly same values for all ten cases, and the average savings are all positive.
- (vi) To sum up, the customers who run one- or two-shift productions can significantly lower their electric bills in the default CPP programs by adjusting their production schedules. Whether the customer should keep enrolled in the CPP or opt out to the TOU should be decided on a case-by-case basis, and it is usually irrelevant to when the production starts.

Table 8. Savings (in %) on the average annual electric bills for one-shift production by switching between scenarios

Utility	Tariff	1-Shift Electric Bill Saving (%)				
		CPP1→CPP2	CPP1→CPP3	CPP1→TOU1	CPP2→TOU2	CPP3→TOU3
PGE	A-1	9.63	14.50	0.67	-2.57	-2.72
	A-6	36.99	47.28	-6.98	-2.73	0.00
	A-10	10.59	15.14	-0.81	-5.89	-6.21
	E-19	33.54	42.68	4.49	0.00	0.00
	E-20	28.68	36.57	-3.64	-2.07	0.00
SCE	TOU-GS-1	16.17	20.69	1.81	-7.62	-8.05
	TOU-GS-2	23.18	32.59	-2.04	0.00	0.00
	TOU-GS-3	22.58	31.84	-2.56	0.00	0.00
	TOU-8	25.95	36.02	-2.89	0.00	0.00
SDGE	AL-TOU	14.36	27.14	-5.24	0.00	0.00
mean		22.17	30.45	-1.72	-2.09	-1.70

Table 9. Savings (in %) on the average annual electric bills for two-shift production by switching between scenarios

Utility	Tariff	2-Shift Electric Bill Saving (%)				
		CPP1→CPP2	CPP1→CPP3	CPP1→TOU1	CPP2→TOU2	CPP3→TOU3
PGE	A-1	1.06	9.55	0.68	0.69	-2.62

	A-6	2.40	34.66	-4.93	-4.64	-2.05
	A-10	1.14	12.15	1.17	1.18	-4.62
	E-19	1.34	31.96	6.31	6.40	0.00
	E-20	1.31	28.21	1.00	1.01	-1.41
SCE	TOU-GS-1	1.15	16.13	1.90	1.92	-7.98
	TOU-GS-2	1.74	24.97	3.21	3.27	0.00
	TOU-GS-3	1.67	24.84	2.83	2.88	0.00
	TOU-8	1.67	27.24	2.51	2.55	0.00
SDGE	AL-TOU	1.57	19.38	-1.78	-1.81	0.00
mean		1.51	22.91	1.29	1.35	-1.87

Table 10. Savings (in %) on the average annual electric bills for three-shift production by switching between scenarios

Utility	Tariff	3-Shift Electric Bill Saving (%)				
		CPP1→CPP2	CPP1→CPP3	CPP1→TOU1	CPP2→TOU2	CPP3→TOU3
PGE	A-1	0.00	0.00	-0.35	-0.35	-0.35
	A-6	0.00	0.00	-3.83	-3.83	-3.83
	A-10	0.00	0.00	0.15	0.15	0.15
	E-19	0.00	0.00	5.26	5.26	5.26
	E-20	0.00	0.00	0.82	0.82	0.82
SCE	TOU-GS-1	0.00	0.00	-1.05	-1.05	-1.05
	TOU-GS-2	0.00	0.00	2.67	2.67	2.67
	TOU-GS-3	0.00	0.00	2.37	2.37	2.37
	TOU-8	0.00	0.00	2.11	2.11	2.11
SDGE	AL-TOU	0.00	0.00	-1.47	-1.47	-1.47
mean		0.00	0.00	0.67	0.67	0.67

6.2 GHG emissions reduction

The hourly GHG emissions rate $r_{n,t}$ that measures carbon intensity of electricity on the California grid can be derived from an electricity generation dispatch model called PLEXOS [76]. As an example, the hourly marginal emissions rates in 2008 are shown in Figure 8. Detailed information of nearly all generators in the Western Electricity Coordinating Council (WECC) as well as the transmission paths are integrated in PLEXOS. The PLEXOS software is licensed by the CAISO and commonly used in California for modeling market redesign and technology upgrade efforts.

Figure 8. Hourly marginal emission rate profile of the CA grid (Raw data is in [76])

After the schedules have been determined in Section 5.1 and the electric bills are calculated, we apply Equations (10) through (13) for the six scenarios listed in Table 5 to obtain the associated GHG emissions. The results of the average annual GHG emissions of the CPP scenarios are shown in Table 11. The average annual GHG emissions of the TOU scenarios are exactly the same as in the corresponding CPP scenarios. This is because the GHG emissions are only determined by the production schedule and system power, and they have nothing to do with the differences in the pricing information in Tables 2 and 3. Therefore, the switches CPP1→TOU1, CPP2→TOU2, and CPP3→TOU3 will not lead to any changes in GHG emissions.

Table 11. Average annual GHG emissions of the CPP scenarios

Utility	Tariff	System Power (kW)	1-Shift GHG Emissions (kg)			2-Shift GHG Emissions (kg)			3-Shift GHG Emissions (kg)		
			CPP1	CPP2	CPP3	CPP1	CPP2	CPP3	CPP1	CPP2	CPP3
PGE	A-1	100	93,967	90,835	88,677	186,330	185,714	180,705	275,585	275,585	275,585
	A-6	400	375,869	363,339	354,707	745,320	742,858	722,740	1,102,338	1,102,338	1,102,338
	A-10	400	375,869	363,339	354,707	745,320	742,858	722,649	1,102,338	1,102,338	1,102,338
	E-19	800	751,739	726,678	709,414	1,490,641	1,485,716	1,445,298	2,204,676	2,204,676	2,204,676
	E-20	1200	1,127,608	1,090,016	1,064,121	2,235,961	2,228,574	2,167,947	3,307,014	3,307,014	3,307,014
SCE	TOU-GS-1	15	14,095	13,625	13,302	27,950	27,857	27,099	41,338	41,338	41,338
	TOU-GS-2	100	93,967	90,835	88,677	186,330	185,714	180,662	275,585	275,585	275,585
	TOU-GS-3	400	375,869	363,339	354,707	745,320	742,858	722,649	1,102,338	1,102,338	1,102,338
	TOU-8	1200	1,127,608	1,090,016	1,064,121	2,235,961	2,228,574	2,168,457	3,307,014	3,307,014	3,307,014
SDGE	AL-TOU	1200	1,127,608	1,090,016	1,064,190	2,235,961	2,228,574	2,168,492	3,307,014	3,307,014	3,307,014

To show the differences among the bills under the three CPP scenarios for each tariff, we calculated the reductions on the average annual GHG emissions by switching from one scenario to another in Tables 12 and 13. Careful observation of the numbers suggests that:

- Table 12 shows the comparison results for one-shift production. We first examine the switch CPP1→CPP2. All ten cases in Table 12 show positive values and the average is 3.33%, which is equivalent to an average annual GHG emissions reduction of 18,216.20 kg. For the switch CPP1→CPP3, higher GHG emissions reduction can be achieved. The average is 5.63%, or 30,757.71kg.
- For two-shift production, Table 13 shows that both CPP1→CPP2 and CPP1→CPP3 can still achieve positive GHG emissions reductions, although with smaller margins, i.e., 0.33% and 3.03%, respectively.

- (iii) For three-shift production, the switches CPP1→CPP2 and CPP1→CPP3 have no impact on the GHG emissions and the reductions for all ten cases are 0%. The reason is similar to the unchanged electric bills.
- (vi) Combining the findings in Section 5.1, we conclude that the customers who run one- or two-shift productions can both lower their electric bills and contribute to the GHG emissions reduction in the default CPP programs by properly adjusting their production schedules.

Table 12. Average annual GHG emissions reductions (in %) for one-shift production by switching between CPP scenarios

Utility	Tariff	1-Shift GHG Reduction (%)		1-Shift GHG Reduction (kg)	
		CPP1→CPP2	CPP1→CPP3	CPP1→CPP2	CPP1→CPP3
PGE	A-1	3.33	5.63	3132.62	5290.55
	A-6	3.33	5.63	12530.49	21162.19
	A-10	3.33	5.63	12530.49	21162.19
	E-19	3.33	5.63	25060.98	42324.38
	E-20	3.33	5.63	37591.47	63486.58
SCE	TOU-GS-1	3.33	5.63	469.89	793.58
	TOU-GS-2	3.33	5.63	3132.62	5290.55
	TOU-GS-3	3.33	5.63	12530.49	21162.19
	TOU-8	3.33	5.63	37591.47	63486.58
SDGE	AL-TOU	3.33	5.62	37591.47	63418.28
mean		3.33	5.63	18216.20	30757.71

Table 13. Average annual GHG emissions reductions (in %) for two-shift production by switching between CPP scenarios

Utility	Tariff	2-Shift GHG Reduction (%)		2-Shift GHG Reduction (kg)	
		CPP1→CPP2	CPP1→CPP3	CPP1→CPP2	CPP1→CPP3
PGE	A-1	0.33	3.02	615.61	5625.38
	A-6	0.33	3.03	2462.44	22580.55
	A-10	0.33	3.04	2462.44	22671.38
	E-19	0.33	3.04	4924.89	45342.76
	E-20	0.33	3.04	7387.33	68014.14
SCE	TOU-GS-1	0.33	3.04	92.34	850.18
	TOU-GS-2	0.33	3.04	615.61	5667.85
	TOU-GS-3	0.33	3.04	2462.44	22671.38
	TOU-8	0.33	3.02	7387.33	67504.56
SDGE	AL-TOU	0.33	3.02	7387.33	67469.14
mean		0.33	3.03	3579.78	32839.73

7. Conclusions

In this paper, we have performed a detailed analysis of CPP, a demand response technology that has the potential to lower energy cost for customers and reduce the need for more GHG emitting

power plants. Case studies in California have been used to illustrate how to choose between CPP and TOU electric rates for manufacturing applications, when both options are available to industrial customers. However, the insights gained in this paper are also meaningful for industrial customers that are currently enrolled or considering enrolling in CPP in other states or countries.

Based on the theoretical development and the case studies in this paper, we conclude that:

- (i) Whether a manufacturing customer will experience a saving or a loss on the average annual electric bill when choosing one rate over the other depends on whether they have the flexibility to shift production so the electric use during the high-cost periods can be at least partially avoided.
- (ii) The case studies reveal that the lowest electric bill for industrial customers with one- and two-shift productions will be achieved under the CPP rate with proper rescheduling of the production to avoid such high-cost periods. In addition to the financial savings due to the rescheduling actions, significant environmental benefits such as reduced GHG emissions associated with the avoided demand during peak hours can also be achieved. The savings on the annual electric bill can be 30.45% with a simultaneous GHG emissions reduction of 5.63% for an average industrial customer.
- (iii) The average annual electric bill or GHG emissions cannot be lowered for industrial customers requiring three-shift operation through rescheduling the whole block of production. Whether the customer should keep enrolled in the CPP or opt out to the TOU should be decided on a case-by-case basis. Under such circumstances, intelligent scheduling strategies that involve more detailed adjustments of the sequences of individual processes may be required, and the utilization of buffers between processes to create additional production flexibility may be needed. Some of our initial work has been done in this area using particle swarm optimization and just-for-peak buffers [63, 77], the methods established has been applied to manufacturing applications under the TOU rate. Extending these methods from TOU to CPP will be conducted in a future work.
- (iv) Although the results presented in Section 6 are limited to the specific programs examined, the proposed approach in Section 5 is a general one. For different CPP and TOU rate details, the approach can be followed to achieve the solutions on a case-by-case basis. With the calculated results, manufacturing enterprises will be able to make more informed decisions on which service to choose and how to use electricity while fulfilling their role for sustainability by enrolling.

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Appendix A

Table A1. Historical CPP event dates of PGE (Raw data is in [72, 73])

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7/1/2005	6/21/2006	6/13/2007	5/15/2008	6/29/2009	7/16/2010	6/21/2011	7/9/2012	6/7/2013	6/9/2014
7/12/2005	6/22/2006	7/3/2007	5/16/2008	6/30/2009	8/16/2010	7/5/2011	7/10/2012	6/28/2013	6/30/2014
7/13/2005	6/23/2006	7/5/2007	6/20/2008	7/13/2009	8/23/2010	7/29/2011	7/11/2012	7/1/2013	7/1/2014

7/14/2005	6/26/2006	7/6/2007	7/7/2008	7/14/2009	8/24/2010	8/23/2011	7/12/2012	7/2/2013	7/7/2014
7/15/2005	7/17/2006	7/9/2007	7/8/2008	7/16/2009	8/25/2010	8/29/2011	8/2/2012	7/9/2013	7/14/2014
7/18/2005	7/18/2006	8/1/2007	7/9/2008	7/21/2009	9/1/2010	9/2/2011	8/8/2012	7/19/2013	7/25/2014
8/5/2005	7/20/2006	8/21/2007	8/14/2008	7/27/2009	9/2/2010	9/6/2011	8/9/2012	9/9/2013	7/28/2014
8/8/2005	7/21/2006	8/22/2007	8/27/2008	8/10/2009	9/3/2010	9/7/2011	8/10/2012	9/10/2013	7/29/2014
9/29/2005	7/24/2006	8/28/2007	8/28/2008	8/11/2009	9/28/2010	9/20/2011	8/13/2012	10/18/2013	7/31/2014
	7/25/2006	8/29/2007	8/29/2008	8/18/2009			10/1/2012		9/12/2014
	7/26/2006	8/30/2007	9/4/2008	8/27/2009			10/2/2012		
	8/9/2006	8/31/2007		8/28/2009					
	8/31/2006								
	9/1/2006								
	9/22/2006								

Table A2. Historical CPP event dates of SCE (Raw data is in [72, 73])

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7/21/2005	6/29/2006	6/7/2007	7/9/2008	6/18/2009	6/30/2010	6/21/2011	6/29/2012	7/1/2013	7/8/2014
7/22/2005	7/10/2006	6/22/2007	7/10/2008	7/15/2009	7/16/2010	7/5/2011	7/12/2012	7/3/2013	7/14/2014
7/25/2005	7/13/2006	7/3/2007	7/21/2008	7/17/2009	8/6/2010	7/19/2011	7/23/2012	8/21/2013	7/30/2014
8/26/2005	7/14/2006	7/5/2007	8/1/2008	7/20/2009	8/12/2010	8/1/2011	8/7/2012	8/28/2013	8/4/2014
8/29/2005	7/17/2006	7/6/2007	8/5/2008	7/22/2009	8/16/2010	8/3/2011	8/9/2012	8/30/2013	8/22/2014
8/30/2005	7/19/2006	8/15/2007	8/6/2008	7/27/2009	8/18/2010	8/12/2011	8/13/2012	9/4/2013	8/28/2014
8/31/2005	7/25/2006	8/16/2007	8/11/2008	7/28/2009	8/23/2010	8/16/2011	8/20/2012	9/6/2013	9/8/2014
9/15/2005	7/26/2006	8/17/2007	8/12/2008	8/20/2009	8/24/2010	8/18/2011	8/27/2012	9/19/2013	9/11/2014
9/20/2005	7/27/2006	8/21/2007	8/27/2008	8/27/2009	8/25/2010	8/23/2011	8/29/2012	9/23/2013	9/15/2014
9/22/2005	8/23/2006	8/29/2007	8/28/2008	8/28/2009	9/2/2010	8/26/2011	9/10/2012	9/30/2013	9/16/2014
9/28/2005	8/24/2006	8/30/2007	8/29/2008	9/1/2009	9/20/2010	9/6/2011	9/20/2012	10/4/2013	9/22/2014
9/29/2005	8/25/2006	8/31/2007	9/3/2008	9/2/2009	9/27/2010	9/23/2011	9/28/2012	10/17/2013	9/23/2014

Table A3. Historical CPP event dates of SDGE (Raw data is in [72, 73])

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
7/21/2005	6/27/2006	8/15/2007	None	8/27/2009	8/25/2010	8/27/2011	8/9/2012	8/29/2013	2/7/2014
7/22/2005	6/29/2006	8/16/2007		8/28/2009	8/26/2010	9/7/2011	8/11/2012	9/4/2013	5/15/2014
8/26/2005	6/30/2006	8/17/2007		8/29/2009	9/27/2010		8/13/2012	9/5/2013	7/31/2014
9/29/2005	7/12/2006	8/21/2007		8/31/2009	9/28/2010		8/14/2012	9/6/2013	9/15/2014
9/30/2005	7/13/2006	8/29/2007		9/3/2009			8/21/2012		9/16/2014
	7/14/2006	8/30/2007		9/4/2009			8/30/2012		9/17/2014
	7/18/2006	8/31/2007		9/24/2009			9/14/2012		
	7/21/2006	9/3/2007		9/25/2009			9/15/2012		
	7/22/2006	9/4/2007					10/2/2012		
	7/24/2006	9/5/2007							
	9/6/2006	10/24/2007							

Table A4. Observed federal holidays (Raw data is in [74])

(Note that if a holiday falls during the weekend, it may be observed on a different day.)

Holiday	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
New Year's Day	12/31/2004	1/2/2006	1/1/2007	1/1/2008	1/1/2009	1/1/2010	12/31/2010	1/2/2012	1/1/2013	1/1/2014
Martin Luther King, Jr. Day	1/17/2005	1/16/2006	1/15/2007	1/21/2008	1/19/2009	1/18/2010	1/17/2011	1/16/2012	1/21/2013	1/20/2014
Presidents' Day	2/21/2005	2/20/2006	2/19/2007	2/18/2008	2/16/2009	2/15/2010	2/21/2011	2/20/2012	2/18/2013	2/17/2014

	5	6	7	8	9	0	1	2	3	4
Memorial Day	5/30/200 5	5/29/200 6	5/28/200 7	5/26/200 8	5/25/200 9	5/31/201 0	5/30/201 1	5/28/201 2	5/27/201 3	5/26/201 4
Independence Day	7/4/2005	7/4/2006	7/4/2007	7/4/2008	7/3/2009	7/5/2010	7/4/2011	7/4/2012	7/4/2013	7/4/2014
Labor Day	9/5/2005	9/4/2006	9/3/2007	9/1/2008	9/7/2009	9/6/2010	9/5/2011	9/3/2012	9/2/2013	9/1/2014
Columbus Day	10/10/20 05	10/9/200 6	10/8/200 7	10/13/20 08	10/12/20 09	10/11/20 10	10/10/20 11	10/8/201 2	10/14/20 13	10/13/20 14
Veterans Day	11/11/20 05	11/10/20 06	11/12/20 07	11/11/20 08	11/11/20 09	11/11/20 10	11/11/20 11	11/12/20 12	11/11/20 13	11/11/20 14
Thanksgiving Day	11/24/20 05	11/23/20 06	11/22/20 07	11/27/20 08	11/26/20 09	11/25/20 10	11/24/20 11	11/22/20 12	11/28/20 13	11/27/20 14
Christmas Day	12/26/20 05	12/25/20 06	12/25/20 07	12/25/20 08	12/25/20 09	12/24/20 10	12/26/20 11	12/25/20 12	12/25/20 13	12/25/20 14

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