Sierra Club Residential Rate Proposal
Prepared by EcoShift Consulting, LLC
Rulemaking 12-06-013

SIERRA CLUB
FOUNDED 1892

Prepared by
EcoShift Consulting, LLC

eco·shift
CONSULTING
http://www.ecoshift.com

Table of Contents

Executive Summary

This document details Sierra Club's proposed rate design for Rulemaking 12-06-013. This Rulemaking is intended to "examine current residential electric rate design, including the tier structure in effect for residential customers, the state of time variant and dynamic pricing, potential pathways from tiers to time variant and dynamic pricing, and preferable residential rate design to be implemented when statutory restrictions are lifted." (Order Instituting Rulemaking ("**OIR**"), 2013). The Sierra Club has commissioned EcoShift Consulting, LLC to analyze potential rate design alternatives, determine a rate design that meets the specifications of the Rulemaking while achieving positive environmental outcomes, and to prepare testimony to justify the proposed rate design.

This report details the Sierra Club's proposed rate design, which attempts to maximize GHG reductions from electricity while maintaining the key elements of rate design including fairness and cost causation. The Sierra Club's proposed rate design will help California achieve the GHG reduction goals set forth in the California Global Warming Solutions Act (AB 32, 2006) and will set the foundation for the additional deeper post-2020 emission reductions called for under Executive Order S-3-05.

A rate structure that functions to significantly reduce greenhouse gas pollution and reliance on fossil fuels benefits all ratepayers. From increased wildfires to a reduced snow pack to sea level rise, California's economy, environment, and the health and safety of its residents are already being impacted by climate change. With atmospheric concentrations of greenhouse gas pollution recently passing 400 parts per million, a level the Earth has not experienced since the much warmer Pliocene Era 3 million years ago, the severity of climate impacts to California will only increase. However, the extent and severity of future impacts depends on if and how rapidly California and the rest of the world reduce greenhouse gas pollution. It is incumbent upon the California Public Utilities Commission (**CPUC**) to demonstrate national leadership and implement a rate structure that provides significant conservation opportunities, reinforces the Loading Order, and reduces greenhouse gas pollution. Designed and executed properly, rate design reform will move California to a modern grid that leverages the capabilities of smart meters by providing price signals that encourage conservation, facilitates deployment of distributed generation (**DG**) solar photovoltaics (**PV**) and adoption of energy efficiency (**EE**) measures, and reduces energy use during peak periods.

In contrast, rate design changes such as the imposition of fixed charges undermine achievement of California's environmental objectives and mark a step backward in state efforts to fight climate change and reap the environmental and economic benefits of robust deployment of DG PV and EE. Fixed charges also result in a significant and inequitable subsidization of rates from lower income customers that consume less electricity to more affluent high energy consumers. Marginal cost and cost-causation principles should allocate costs to customers based on their impact on the grid. Because high energy users, particularly at peak periods, have a greater impact on peak generation capacity requirements, transmission congestion, and other aspects of transmission and distribution, these users should be responsible for a greater share of those costs.

With these considerations in mind and after analysis of a number of potential rate designs, the Sierra Club proposes a hybrid 3-tiered, 3-time-of-use (**TOU**) period rate design. The proposal more strongly encourages energy conservation and adoption of DG PV and energy efficiency retrofits than the existing rate design while minimizing potential bill impacts. The proposal results in minimal bill increases or decreases for aggregated groups of income levels and maintains the existing levels of CARE subsidy. The hybrid design also has important advantages over a rate structure that relies on time-of-use alone, particularly in reducing overall energy usage and supporting DG PV.

Our key findings, based on empirical comparisons of rate design alternatives, are as follows:

- TOU rates create important incentives for load shifting and more efficient air conditioning.
- Tiered rates create important incentives for energy conservation and DG PV.
- A combination of tiered and TOU rates is essential to maximize conservation outcomes and achieve state clean energy objectives. For example, TOU rates in combination with elimination or flattening tiers would likely significantly reduce the economic incentive for adoption of DG PV. Combining TOU rates with tiers avoids this outcome.
- TOU rates modestly reduce GHGs through load shifting but can result in slightly increased electricity use overall. GHG reductions from TOU rates also depend upon the specific mix of baseload and peak energy sources, which is expected to change as more solar comes online. If TOU time periods do not track these shifts, the GHG benefits of load shifting could be reduced over time. Rate design with a tiered component will encourage overall conservation and provide added resiliency from impacts to the efficacy of TOU rates from changes to net load from increased penetration of renewable resources.
- Flattening tiers are likely to result in increased consumption. Conservation estimates using constant elasticities that purport to show conservation from flatter tiers are based on simplifying assumptions that are not supported by basic economic theory.
- Tiered rates coupled with TOU improve equity. Flattening or eliminating tiers increases bills for lower income households and reduces bills for higher income households. TOU rates provide customer opportunity to further minimize energy bills by shifting usage.
- Combining TOU rates with tiers more closely aligns rates to marginal cost of electricity consumption as compared to the current rate structure or a TOU-only approach.
- A 3-tier/3-TOU rate structure minimizes bill shock. A rate that uses only two tiers or only two TOU periods will result in higher differentials between peak/off peak and Tier 1 and Tier 2, or a greatly increased Tier 1 rate. Three TOU periods and three tiers significantly reduced this differential.
- Fixed customer charges have negative impacts on incentives for DG solar PV, air conditioning upgrades, and conservation.

As part of our analysis, we also show how various electricity rate structures that incorporate a TOU rate structure would impact GHG emissions by calculating:

- Levelized cost of electricity purchased from the grid (**LCOE-G**) compared to levelized cost of electricity from DG PV (**LCOE-PV**) for current and proposed electricity rate designs.
- Simple payback period (**SPP**) for replacement of air conditioning (**AC**) units under current and proposed rate design for customers in climate zones that require cooling.

- Change in total energy consumption resulting from the proposed rate design.

The Sierra Club rate design proposal is set forth in accordance with questions identified in the November 26, 2012 Scoping Memo and Ruling of Assigned Commissioner Peevey. We also identify areas of CPUC action related to rate design but not specifically covered in this proceeding that would enable more effective achievement of energy conservation outcomes.

1. Description of Proposed Rate Design

Please describe in detail an optimal residential rate design structure based on the principles listed above and the additional principles, if any, that you recommend. For purposes of this exercise, you may assume that there are no legislative restrictions. Support your proposal with evidence citing research conducted in California or other jurisdictions.

We propose the following 3-tier, 3-TOU period rate design with no customer or demand charges. We maintain the current structure of tiered rates in our design, in that the baselines for Tier 1 is up to 100% of baseline usage, Tier 2 is 100%-130% of baseline usage, and Tier 3 is above 130% of baseline usage. Due to time constraints and limitations of bill calculators provided by the investor –owned utilities (**IOUs**) in this proceeding, we only modeled results for customers in PG&E territory.

Table 1. Seasonal variations in TOU electricity prices per Tier for NonCARE and CARE customers.

	Proposed Rate		Current Rate	
	NonCARE	**CARE**	**NonCARE**	**CARE**
Tier 1				
Summer Peak	0.2285	0.1332	0.1285	0.0832
Summer/Winter Part Peak	0.1585	0.0982	0.1285	0.0832
Summer/Winter Off Peak	0.0793	0.0586	0.1285	0.0832
Tier 2				
Summer Peak	0.3044	0.1456	0.1460	0.0956
Summer/Winter Part Peak	0.2344	0.1106	0.1460	0.0956
Summer/Winter Off Peak	0.1553	0.0711	0.1460	0.0956
Tier 3				
Summer Peak	0.3935	0.1747	0.2956	0.1247
Summer/Winter Part Peak	0.3235	0.1397	0.2956	0.1247
Summer/Winter Off Peak	0.2444	0.1002	0.2956	0.1247
Tier 4				
Summer Peak			0.3356	0.1247
Summer/Winter Part Peak			0.3356	0.1247
Summer/Winter Off Peak			0.3356	0.1247
Customer Charge/Month	0.0	0.0	0.0	0.0
Minimum Bill/Month	0.0	0.0	4.5	3.5

The rate design was generated using the following parameters in the PG&E bill calculator:

- Current Tier 1 rates

- 40% increase of Tier 2 rates
- $0.10 TOU peak surcharge
- $0.03 TOU part-peak surcharge
- $0.04912 TOU off-peak credit
- 1:1 ratio between winter and summer part-peak
- CARE discounts: Tier 1 - 35%, Tier 2 - 45%, Tier 3 - 60%, TOU - 50%
- 55% Baseline Allowance, using current rate date of 7/1/12
- No minimum bill, customer charges, or demand charge

Because we were interested in a rate design with 3 tiers and TOU, we were forced to modify the PG&E bill calculator. We did so by creating a 3-tier rate using the PG&E bill calculator, specifying peak and part-peak surcharges for Non-CARE customers, applying a discount to CARE customers, adding these charges to the bill output in the PG&E bill calculator, calculating the weighted additional revenue, and finally calculating an off-peak credit to balance this additional revenue.

The particular rates per kilowatt-hour are a function of our design parameters, the structure of the calculator, and assumptions about utility costs needing to be recovered. In the future, as average cost of service increases, and the cost of PV and efficiency measures change, the mix of grid resources evolves, or unintended consequences arise, these specific prices will need to be adjusted to accommodate these changing conditions, within the framework of the overall design principles and policy objectives.
This proposed rate design was determined based on the analysis and literature review described in the remainder of the document. The guiding principles of our approach are described in Sections 1.1. and 1.2., below.

1.1 Review of Impacts of Dynamic Pricing on Consumption and Greenhouse Gases

The literature strongly suggests that TOU pricing can incentivize load-shifting between time periods, **but does not result in absolute reductions in electricity consumption** and, while currently leading to GHG reductions in California, has **uncertain consequences for the carbon intensity of electricity, especially in the long run**. In order to maintain incentives for conservation, the tiered system should remain intact while incorporating TOU pricing. Consideration should also be given for how to couple electricity pricing with carbon intensity to help meet the objectives of other public policies in California aimed at maximizing greenhouse gas (**GHG**) reductions.

Most research on demand response concludes that dynamic pricing structures lead to load shifts in electricity consumption to off-peak, but do not lead to overall reductions in electricity consumption (e.g., EPRI 2008; Faruqui and George 2005; Thorsnes 2012). These studies find that consumers are substituting peak electricity consumption with off-peak electricity consumption. In other words, dynamic pricing leads to a substitution effect, not an overall consumption effect and hence, dynamic pricing does not seem to encourage absolute conservation. There are a few exceptions to this finding (e.g., Filippini 2011; Alcott 2011). However, these studies are exceptions to the conclusions of most of the relevant literature, which finds that peak and off-peak energy are essentially substitutes. Many of these studies are reviewed in Appendix A. **The lack of an overall consumption effect from dynamic pricing is a compelling argument for maintaining an increasing block tier system in combination with a dynamic rate structure.**

Some research suggests that load shifting is important for meeting environmental objectives in California (Zivin et al. 2012; McCarthy and Yang 2010). It could lead to lower GHG emissions because electricity produced during peak hours (peak-power) in California currently has a higher marginal carbon intensity than electricity produced during off-peak or shoulder periods. Likewise, peak-power can be associated with higher levels of criteria air pollutants (Razeghi et al. 2011), which makes it more difficult for regions to meet ambient air quality standards. However, most other regions across the US have electricity carbon intensities that are lower during peak demand periods than during off-peak. For example, US average off-peak emissions are roughly 1.26 lbs CO_2e/kWh, and peak emissions are 1.13 lbs CO_2e/kWh (Zivin et al. 2012). The main driver of this phenomenon appears to be the presence of a higher proportion of baseload coal-fired generation, with its higher carbon intensities, serving off-peak demand. One can envision two scenarios that could lead to an increase in the relative carbon intensity of off-peak electricity compared to peak electricity in California.

First, the carbon intensity of PG&E baseload electricity is heavily influenced by electricity provided from nuclear power plants, which have relatively low carbon intensities. It is not outside of the realm of possibility that these sources could be taken offline for significant durations due to a number of circumstances, such as equipment upgrades, repair delays, accidents, or extended regulatory compliance. The current uncertainty around the future of the San Onofre plant is a current example of this issue.

Second, not all peak power comes from carbon emitting sources. For example, as solar energy power production continues to grow, peak-power will have an increasingly lower carbon intensity in the long run. Also, PG&E currently relies on hydropower and pumped hydropower to meet a portion of peak energy needs.

Load shifting to off-peak periods at the present time lowers the carbon intensity of electricity in PG&E territory according to values in the peer-reviewed technical literature, as well as estimates that we have made based on the best available data. In this analysis we used values based on the CSI avoided cost model of 1.058 lbs/MWh for peak and 0.876 lbs/MWh off-peak (see Section 2.4.1 for details). However, in some circumstances load shifting to off-peak periods may not have the same magnitude of GHG reductions, and could even lead to higher emissions at some point in the future. Therefore, while load shifting has important benefits, it cannot substitute for a rate design that also encourages overall electricity conservation, such as California's current tiered rates. For further information about price responsiveness, see Appendix A.1 and A.2.

1.2. Review of Heterogeneity of Elasticities in Dynamic Pricing

Elasticities, both for changes in tiered rates (own-price elasticity) and TOU rates (substitution elasticity) are heterogeneous for different types of users. Responsiveness to dynamic pricing is not uniform among all types of users, and a rate design should take advantage of these variations to maximize effectiveness. From basic economic theory we know that the more necessary the consumption and the less available and suitable the substitutes, the more inelastic the demand. In general, participants in hotter climates respond more than those in cooler climates (Herter, 2010; Charles River Associates, 2007; Faruqui and George, 2005). In addition, higher income households seem to be more price responsive than lower income households (Charles River Associates, 2005; Faruqui and George, 2005). Households with all major appliances are more responsive: Midwest Power Systems' 1991-1992 residential TOU program found an elasticity of substitution of 0.39 for households with all major appliances, while those with no major appliances exhibited no shifting and an estimated elasticity of substitution of 0 (Baladi and Herriges 1993). Results from California's SPP showed a statistically-significant elasticity of substitution of 0.11 for households with central air conditioning, but a value of only 0.04 for those without (Charles River Associates 2005). Faruqui and Wood (2008) also found that values for central air conditioning users were about 2.5 times higher than for non-users. The own-price elasticity for households with central or room AC (-0.64) was 8 times higher than that of households without AC (-0.08) (Reiss and White, 2002). Faruqui and George (2005) also found that customers who use 200% of average electricity conserved more energy on critical peak days than those who use 50% of the average. For these reasons, assuming some differential between elasticities, both own-price and substitution elasticities, across tiers is important. Our analysis reflects this complexity supported by the literature. For more details on variations by users types, see Appendix 3. While it isn't possible to create different rates for different types of users, it is important to note where customer response to electricity pricing may be greatest. ***In summary, we should expect varying responses to pricing from different types of users. There should be greater response from dynamic pricing in hotter climates and in households with all major appliances. For this reason, we focus part of our analysis on potential adoption of high efficiency AC units in hotter climate zones.***

2. Explanation of Proposed Rate Design

Explain how your proposed rate design meets each principle and compare the performance of your rate design in meeting each principle to current rate design. Please discuss any cross-subsidies potentially resulting from the proposed rate design, including cross-subsidies due to geographic location (such as among climate zones), income, and load profile. Are any such cross-subsidies appropriate based on policy principles? Where trade-offs were made among the principles, explain how you prioritized the principles.

2.1. Impacts on Low-income and medical baseline customers

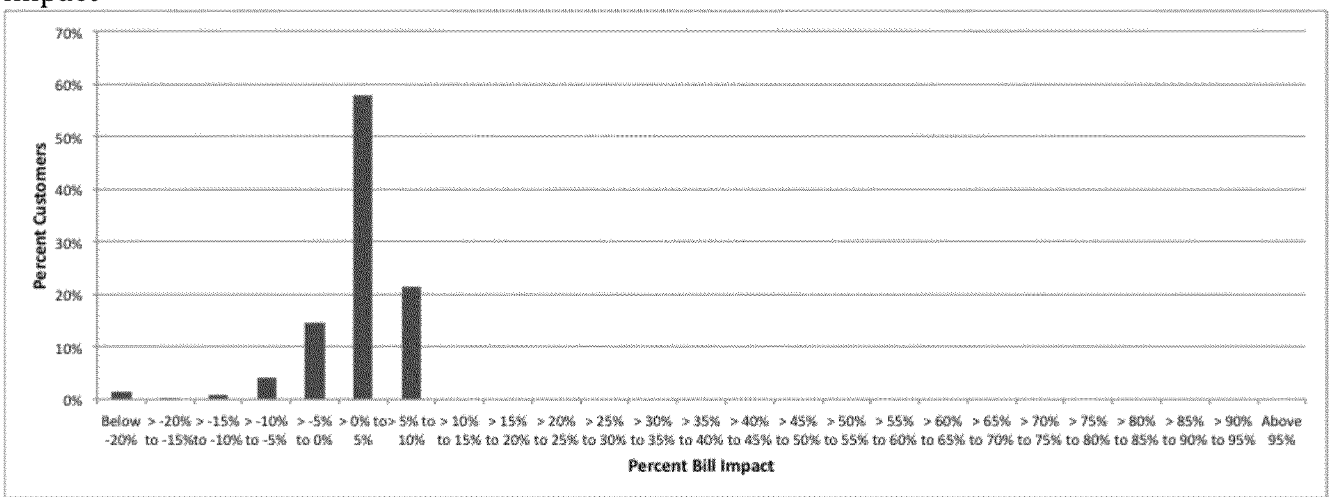
Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;

Sierra Club's position is that a new rate design should not increase rates for medical or low-income customers. Therefore, our proposed rate design is not intended to increase or decrease rates for these groups. Using the PG&E bill calculator output, we found that CARE subsidies remain nearly unchanged, and bill impacts overall are minimal under our proposed rate design. There is a slight decrease of rates (-0.7%) for high income households, and a corresponding slight increase for low income households, but the change overall is minimal (Table 2) as shown in Table 2.[1] Overall, the PG&E Bill Calculator output shows a very slight bill increase for the majority of both Non-CARE and CARE customers (Figures 1 & 2). We found this type of result in nearly all of the rate designs we ran, and the bill decreases for high income households in this rates design was one of the lowest of the rate designs we tested. We assume this to be an effect of flattening tiers, probably because the highest users are slightly more likely to be wealthy (according to the PG&E Bill Calculator Correlation tab, this relationship is significant with a 0.23 correlation coefficient). Given the constraints of input parameters in the PG&E bill calculator, we had difficulty maintaining the CARE subsidy exactly equivalent to current, however, it was our intent to do so.

Table 2. PG&E Bill Impacts by Income Group

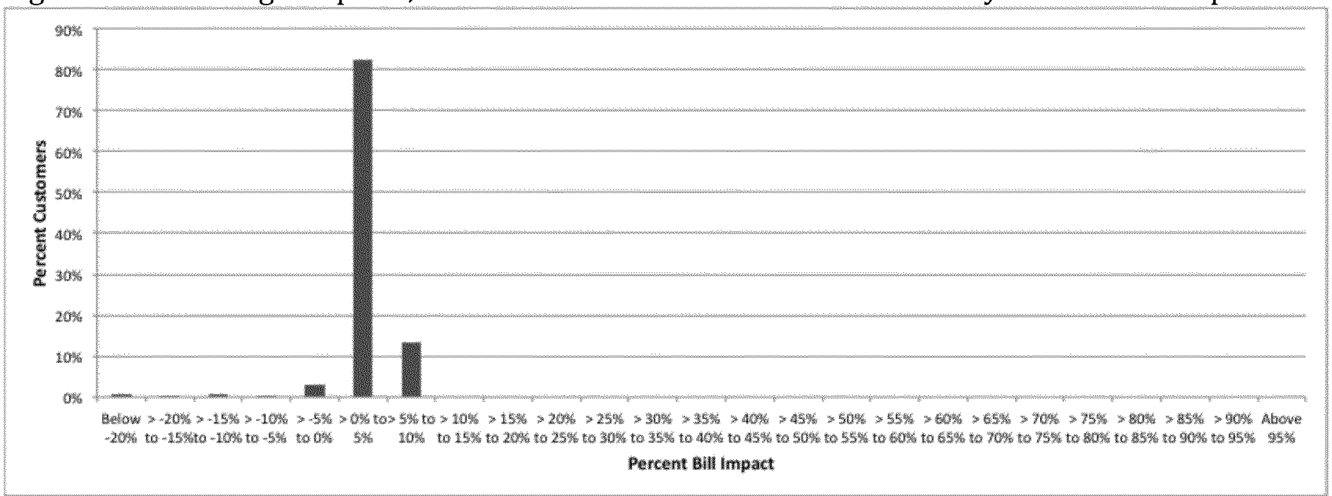
Income Range	Non-CARE	CARE	All Customers
0 to 30K	1.5%	0.3%	0.8%
30K to 60K	1.7%	0.0%	1.2%
60K to 75K	1.7%	-0.5%	1.5%
75K to 100K	0.9%	-0.1%	0.8%
100K to 500K	-0.7%	-1.6%	-0.7%
Average	0.5%	0.0%	0.4%

Figure 1. Rate Design Impacts, Non-CARE Customers: Percent of Customers by Percent Bill Impact



[1] According to the PG&E model, 3% of CARE customers earn 100-500k/year, and 5% earn 75-100k/yr. We found this to be an odd result, which we assume could be a result of imperfect matching income data to customer billing data.

Figure 2. Rate Design Impacts, CARE Customers: Percent of Customers by Percent Bill Impact



2.2. Rates should be based on marginal cost

The wholesale marginal cost of electricity is higher during peak demand times. The highest peak demand occurs during peak summer hours. In addition, there are higher demand and higher wholesale prices when customers use more electricity overall. Therefore, **combining a TOU rate with a tiered system achieves the goal of basing rates on marginal cost** because this approach addresses both peak summer demand and high usage.

Longer term, California faces significant changes to its generation mix within the next ten-year planning horizon. Several existing Southwest and Pacific Northwest coal generators will be decommissioned. There is a reasonable possibility that one or both of California's nuclear stations will not be relicensed. The ultimate availability and external costs and risks associated with advanced oil and gas extraction techniques have not been adequately determined. Finally, if California expects to meet its climate emission reductions targets and transition to a more diffused energy production network, the CPUC must begin that transition now. A rate structure that is focused on minimizing long term marginal cost and risk should be encouraging:

- Overall electricity reduction as a priority over peak load reduction
- Distributed generation and long-lasting energy efficiency measures, which reduce the need for marginal investments in new generation and transmission infrastructure to meet peak loads.

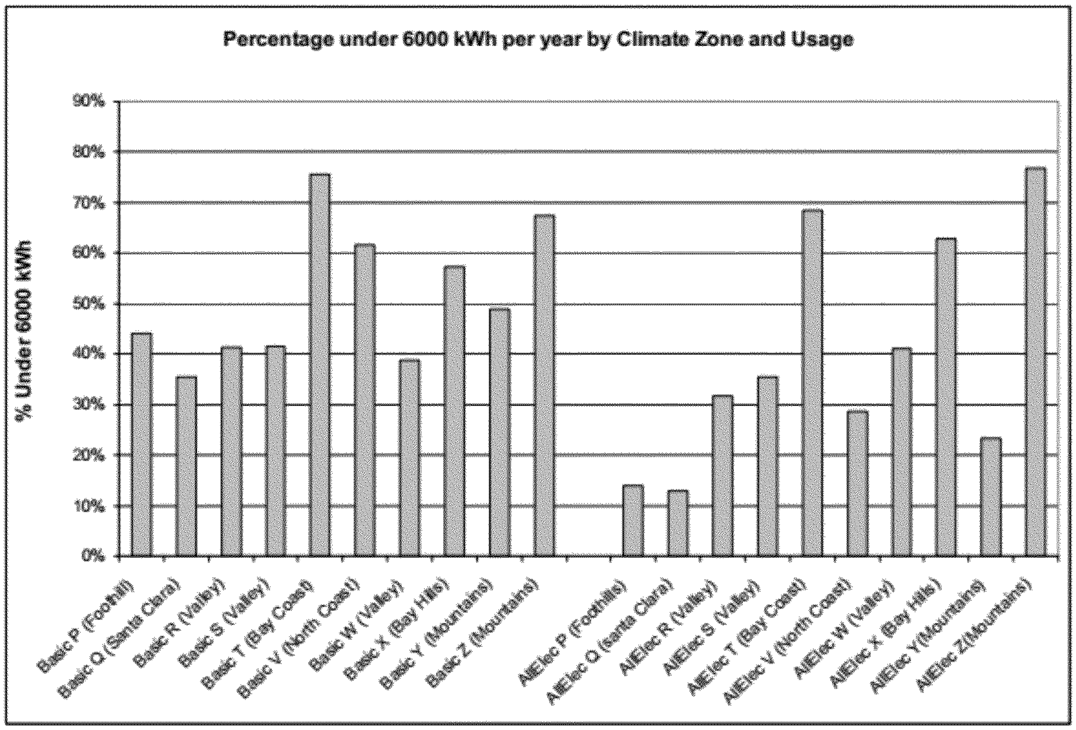
Our proposed rate structure simultaneously provides incentives to both reduce overall consumption, and to reduce system peak demand in the context of aligning rates with the marginal cost of electricity generation.

2.3. Rates should be based on cost-causation principles

Sierra Club disagrees with the way in which some IOUs have previously characterized cost causation. By comparing current and proposed rates to an 'average cost of service' and demonstrating the extent to which rates deviate from this 'average cost of service' in the bill calculators provided in this proceeding, the IOUs suggest that rates for low use customers would have to increase significantly in order to base rates on cost-causation principles. In effect, this suggests that we should move back towards the declining block rate regime of half a century ago while ignoring the reality that cost causation, now and increasingly going forward, is related to risk as well as direct cost. Cost causation is also related to a fundamental long-term transformation in how electricity and grid infrastructure and services are developed, produced, and consumed.

The fundamental problem is a tendency to assume that all customers have equal impacts on the electrical grid. This is clearly not the case. For example, the variation between baseline rate tier allocations in the different state climate zones has little to no relationship to cost causation; climate zones with higher usage have more impacts on the grid but are allowed a larger baseline allocation (Figure 3).

Figure 3.



Source: Marcus et. al. (2002)

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That discrimination is enhanced by uniform T&D charges, which assume that all climate zones are equally responsible for contributing to simultaneous peak demand. This is clearly not the case, given highly differential cooling demand across climate zones. Under current rate practices, this discrimination will only intensify as distribution grids become more stable on peak, and less reliant on long-distance wheeling over the regional grid, due to increased penetration of distributed generation and peak-targeted energy efficiency.

2.3.1 Fixed Charges are Contrary to Cost-Causation Principles

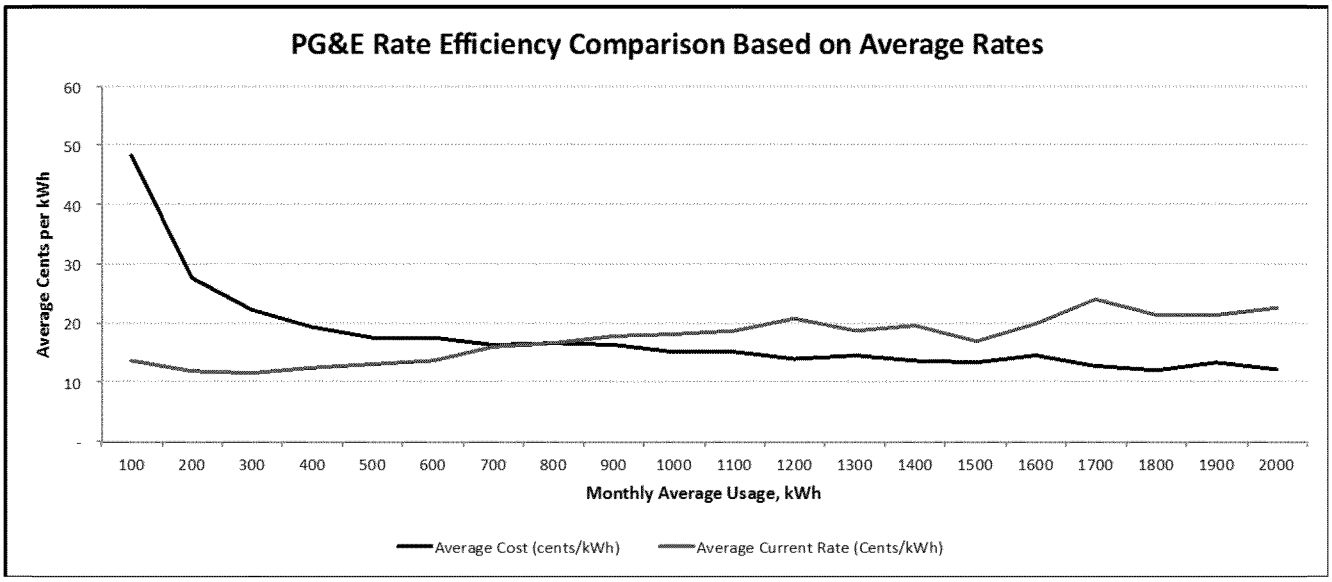
To align rates with current IOU methods for cost-causation, utilities may argue for a network user access fee in the form of punitive fixed monthly charges. There are two compelling reasons why the CPUC should reject fixed monthly charges as contrary to cost-causation:

First, fixed monthly charges interfere with the economic advantage conferred by a tiered rate design. In order to minimize long-term system cost and risk, the CPUC should be encouraging minimal residential use of energy, rather than punishing consumers who have reduced their load and peak demand on the power system. The impact of a high monthly charge would be particularly noticeable in climate zones that tend to use less energy than the system average, and thus grid costs would be further shifted towards customers who use less electricity.

Second, a well-designed regulated monopoly utility should accurately emulate both the risk and reward of a commodity or service being offered in a highly competitive market. Essentially every commodity and service on offer in competitive markets includes a fixed cost component, which is recovered over time in sales of that commodity or service. There is no compelling reason why a public service utility should be permitted to extort a fixed fee for access to that commodity or service. Oil companies do not charge customers a monthly refinery access fee to be able to buy gasoline. Hotels do not generally charge guests a fixed monthly building access fee if they ever want to reserve a room. In the case of a critical commodity such as electricity, universal access is a right, which should not be compromised by fixed monthly charges.

The PG&E bill calculator provides a useful visual presentation of why fixed costs are regressive. The output for rate efficiency, which compares current rates to an 'average cost of service rate' shows that, if customers were charged a fixed fee only for electricity, low usage customers would pay an extremely high fee per kWh consumed. The red line shows the current progressive tier rate effect--higher rates as a customer consumes more; the black line shows a fixed charge effect where customers effectively pay 25 to 45 cents/kWh who use the least energy (100 to 200 kWh per month) decreasing to only about 12 cents/kWh for customers using up to 2000 kWh per month.

Figure 4. Comparing Current PG&E Rates to an Average Cost Rate



The customers with highest consumption, and therefore highest cost causation, pay a rate that is below the average cost of service for residential customers overall, a cost recuperated from customers who consume the least energy. In addition to being inequitable, this perverse outcome undermines the policy objectives of California's loading order.

2.3.2. Basing Rate Design on Current and Emerging Sources of Cost Causation

The declining marginal costs and increasing economies of scale that have historically characterized the electric utility industry no longer reflect current and emerging reality. Internalized costs and risks are now highly volatile, long-term marginal costs are rising, and the necessity of drastically reducing carbon emissions, with shift to increased distributed generation and a need for a highly adaptive electricity distribution network, will require a fundamental change in how we create and use our electric infrastructure.

Therefore, residential rate structures must begin to encourage that transformation, and reflect the current and emerging sources of cost causation. A strongly tiered rate structure with TOU periods will move California closer to this goal. A rate design based on current and emerging sources of cost causation would have some or all of the following features:

- The lowest cost and risk infrastructure resources would be allocated to the customers that impose the lowest marginal impact on the system. For example, in the case of PG&E, the lowest tier rate would be based in part on a 100% allocation of fully depreciated hydroelectric resources, and would be exempted from paying for incremental capital additions to distribution infrastructure.
- The fixed overhead of costs related to nuclear power decommissioning and industry deregulation would be allocated to higher usage customers. Absent high usage customers, it is unlikely that these system costs would have been incurred.
- Instead of collecting public benefit charges on a fixed fee basis, high usage customers would pay a higher percentage of these costs, and efficiency programs would preferentially target those same high-use customers.

- Transmission costs would be recovered from the energy producers that rely on the high-voltage grid to energize distribution feeders, instead of being charged directly to end-use consumers. At least in the short-term, distributed generators and base tier customers would be exempt from transmission charges, pending a detailed review of the balance of costs and benefits in an increasingly distributed network.
- Current base rate energy allocations are higher in climate zones with higher energy and coincident peak demand, imposing a higher relative portion of system costs on customers in climate zones with lower energy and coincident peak demand. In a rate design based on cost causation, these allocations would be established on a system-wide basis, instead of allocated on a climate zone basis. This does not fully mitigate the current discrimination against customers in mild climate zones, which are often uncorrelated or inversely correlated with system peak periods, but it would help to move residential rates towards actual cost causation.
- Marginal electricity rates in every time-of-use period would reflect long-run marginal cost.
- High marginal costs would be matched with universal access to cost reduction opportunities. These cost reductions include direct installation or indirect pooling and virtual sharing of distributed generation and energy efficiency infrastructure, and by installation of intelligent, customer-controlled system response technology that can provide valuable ancillary grid support and stabilization services. Some of these features are discussed elsewhere in this proposal.

We realize that some of these approaches are in tension with other goals of equitable rate design, and, since we have insufficient data, we are unable to model the impact of all these ideas or determine exactly how they would be implemented. Rather, our goal in presenting these concepts is to emphasize that: ***(1) an antiquated approach to cost causation should not drive current rate design; and (2) a rate design that combines tiered rates and TOU should achieve some of the current and emerging sources of cost causation.*** Furthermore, some of the above ideas, such as allocating fixed costs toward higher volume consumption, are already embodied to some degree in the existing rate structure.

2.4. Rates should encourage conservation and energy efficiency

EcoShift has performed extensive analysis on the impact of proposed rate designs on energy conservation, adoption of distributed generation (**DG**) PV, and energy efficiency upgrades by utility customers. Our model uses outputs from the PG&E bill calculator developed for this proceeding to compute the following information for each customer in the customer sample:

- Levelized cost of electricity purchased from the grid (**LCOE-G**) compared to levelized cost of electricity from DG PV (**LCOE-PV**) for current and proposed electricity rate designs.
- Simple payback period (**SPP**) for replacement of air conditioning (**AC**) units under current and proposed rate design for customers in climate zones that require cooling.
- Change in total energy consumption and load shifting resulting from the proposed rate design, and associated changes in GHG emissions.

We use this information to estimate potential changes in aggregated customer demand and customer incentivize to adopt DG PV and AC upgrades, as well as the greenhouse gas emission reductions associated with the changes.

We analyzed impacts of over 65 potential rate designs. We began by broadly exploring impacts of TOU rates with varying period differentials, and variations on these rates with baseline credits. We then explored tiered-only rates with varying changes to the current tiered structure, and then we began adding TOU peak surcharges/off-peak credits to these rates. We also explored varying customer charges, and we attempted to hold CARE rates constant in every analysis. Our goal was to find a rate design that encourages conservation and energy efficiency while minimizing bill impacts. In general, we found that:

- TOU rates create important incentives for load shifting and more efficient air conditioning.
- Tiered rates create important incentives for energy conservation and DG PV.
- A combination of tiered and TOU rates is essential to maximize conservation outcomes and achieve state clean energy objectives. For example, TOU rates in combination with elimination or flattening tiers would likely significantly reduce the economic incentive for adoption of DG PV. Combining TOU rates with tiers avoids this outcome.
- TOU rates modestly reduce GHGs through load shifting but can result in slightly increased electricity use overall. GHG reductions from TOU rates also depend upon the specific mix of baseload and peak energy sources, which is expected to change as more solar comes online. If TOU time periods do not track these shifts, the GHG benefits of load shifting could be reduced over time. Rate design with a tiered component will encourage overall conservation and provide added resiliency from impacts to the efficacy of TOU rates from changes to net load from increased penetration of renewable resources.
- Flattening tiers are likely to result in increased consumption. Conservation estimates using constant elasticities that purport to show conservation from flatter tiers are based on simplifying assumptions that are not supported by basic economic theory.
- Tiered rates coupled with TOU improve equity. Flattening or eliminating tiers increases bills for lower income households and reduces bills for higher income households. TOU rates provide customer opportunity to further minimize energy bills by shifting usage.
- Combining TOU rates with tiers more closely aligns rates to marginal cost of electricity consumption as compared to the current rate structure or a TOU-only approach.
- A 3-tier/3-TOU rate structure minimizes bill shock. A rate that uses only two tiers or only two TOU periods will result in higher differentials between peak/off peak and Tier 1 and Tier 2, or a greatly increased Tier 1 rate. Three TOU periods and three tiers significantly reduced this differential.
- Fixed customer charges have negative impacts on incentives for DG solar PV, air conditioning upgrades, and conservation.

Our results show these effects by varying aspects of rate design around our proposed rate, using the scenarios listed in Table 2.1. We present these scenarios to demonstrate how important each aspect of our rate design is in order to achieve the outcomes of our proposed rate design. Before describing our method and result for each of the three analyses (DG PV, AC, and consumption/conservation), we discuss the greenhouse gas emission factors used and the importance of these factors.

Table 2.1 Proposed Rate and Variations Used for Analysis in Section 2.4.

	Proposed Rate	Proposed Rate Without TOU Pricing	Proposed Rate Without Tiers	Proposed Rate with $10 Cust. Charge
Non-CARE Tier 1				
Summer Peak	0.228	0.128	0.296	0.228
Summer/Winter Part Peak	0.158	0.128	0.228	0.158
Summer/Winter Off Peak	0.079	0.128	0.157	0.079
Non-CARE Tier 2				
Summer Peak	0.304	0.204	0.296	0.304
Summer/Winter Part Peak	0.234	0.204	0.228	0.234
Summer/Winter Off Peak	0.155	0.204	0.157	0.155
Non-CARE Tier 3				
Summer Peak	0.393	0.293	0.296	0.322
Summer/Winter Part Peak	0.323	0.293	0.228	0.252
Summer/Winter Off Peak	0.244	0.293	0.157	0.173
Customer Charge ($/Month)	0.0	0.0	0.0	10.0
CARE Tier 1				
Summer Peak	0.133	0.083	0.148	0.133
Summer/Winter Part Peak	0.098	0.083	0.114	0.098
Summer/Winter Off Peak	0.059	0.083	0.078	0.059
CARE Tier 2				
Summer Peak	0.146	0.096	0.148	0.146
Summer/Winter Part Peak	0.111	0.096	0.114	0.111
Summer/Winter Off Peak	0.071	0.096	0.078	0.071
CARE Tier 3				
Summer Peak	0.175	0.125	0.148	0.150
Summer/Winter Part Peak	0.140	0.125	0.114	0.115
Summer/Winter Off Peak	0.100	0.125	0.078	0.075
Customer Charge ($/Month)	0.0	0.0	0.0	8.0

2.4.1. Greenhouse gas emission factors used in calculations

It is widely believed that load shifting will lead to environmental benefits. However, to better understand the extent of potential benefits, it is important to carefully evaluate how the GHG intensity of electricity may change with rate design. Some regions, like California, have carbon intensity values that are higher on peak than off peak, but in places such as the Midwest United States, where coal fired power plants constitutes a large share of baseload electricity generation, off peak electricity has a higher GHG intensity. While PG&E currently has a higher GHG intensity on-peak, there are several scenarios where that could become the inverse over time (nuclear power plant retirement, increased solar energy).

Understanding the GHG impacts of any proposed rate design required an estimate of how the GHG intensity of electricity changes as a function of system demand. However, estimating changes to marginal GHG emissions is not straightforward, as there is no agreed-upon method of accounting for life cycle emissions (Weber et al. 2010). There is also not a clear way of predicting the precise relationship between electricity demand and the marginal power plants that are used to deliver electricity at the margins. Using average emissions factors to estimate GHG impacts does not give an accurate assessment of the impacts of changes in overall consumption or load shifting. Reducing electricity use at different times of the day and year will have different GHG benefits which result from the generation facility that would displaced.

Our approach focuses on the marginal carbon intensity of electricity, which is complicated by the fact that there are two primary ways of defining marginal emissions, distinguished based on their temporal horizons.

First, some treat the marginal carbon intensity of electricity as the change in GHG from adding additional power generation infrastructure to the grid. In other words, if system demand for power expanded, what kinds of resources would be deployed in the long run? These are typically treated as a combined-cycle gas turbine (**CCGT**), which have very high efficiencies and therefore the lowest carbon intensities of all fossil fuel power generation sources.

Second, some view the marginal emissions factor as the change in emissions as a function of hourly, daily, or seasonal system demand (or capacity factor). Here it would be more appropriate to see marginal emissions as the result of an additional existing older and less efficient powerplant with relatively low fixed costs and relatively high marginal costs, which only operates during peak load periods. We argue that this second definition of the marginal emissions factor provides a better estimation of the GHG impacts from changes in rate design because it deals with existing peaker power plants that are used for load following. Given that natural gas power plant profitability is strongly influenced most by market heat rate and therefore power plant efficiency, most single-cycle gas turbines (**SCGT**) are utilized only when wholesale electricity prices are highest, at peak demand. For these reasons we determined that the carbon intensity of a SCGT is the most appropriate proxy resource for marginal generation in the peak period for this analysis. Based on this assumption, we used the California Solar Initiative (**CSI**) Avoided Cost Model (2010) to estimate marginal emissions factors, which was used to develop the primary emissions scenario using 2009 hourly data. These are represented in the first column of Table 3, where using the best available data, we estimated four marginal emissions factors for each of these time periods: summer peak, summer part-peak, summer off-peak, winter part-peak, and winter off-peak.

Table 3. GHG intensity per TOU period by electricity grid scale (lbs/MWh)

TOU Period	Calculation based on CSI Avoided Cost Model PG&E (2010)	WECC (Zivin et al. 2012)	US Total (Zivin et al. 2012)	McCarthy & Yang 2010
Summer Peak	1.058	0.815	1.125	1.632
Summer Part Peak	0.987	0.844	1.162	1.555
Summer Off Peak	0.876	0.782	1.258	1.438
Winter Part Peak	0.922	0.844	1.162	1.448

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Winter Off Peak	0.854	0.782	1.258	1.427

Other data included in Table 3 include the marginal emissions factors from the Western Energy Coordinating Council (**WECC**) and US totals (Zivin et al. 2012). We include these for comparative purposes but do not consider them to be the best representation of marginal emissions rates in California. The WECC values include other states in the Western US that have very different generation mixes than California, and the U.S. totals are shown to illustrate the possibility that peak load shifting can result in increased GHG emissions when there is a different generation mix. It has been common for GHG emission analysts to use the lowest common denominator emissions factor (e.g., highest GHG intensity) to ensure that there is no leakage where electricity markets result in electricity (and associated emissions) exchanges across grid regions and subregions. This is the preferred practice of the US EPA for example in their life cycle analyses of the Renewable Fuel Standard.

The final column shows marginal GHG intensities developed from research that found that marginal electricity production in California is more carbon intensive than gasoline (McCarthy and Yang 2010). This has important implications for Battery Electric Vehicles (**BEVs**) and Plug-in Hybrid Electric Vehicles (**PHEVs**). The efficiency of BEVs and PHEVs more than offset these emissions on a per mile traveled basis compared to the internal combustion engine. However, it is still important to note that marginal electricity is very carbon intensive. Without a significant change in the generating resource mix, the result could be an erosion of significant gains that could otherwise be realized by transitioning the automobile fleet to a mix with more BEVs and PHEVs, a policy priority of the California Air Resources Board (**CARB**) through their Zero-Emission Vehicle Program. **Rate design should incentivize charging behaviors for BEVs and PHEVs which utilize low carbon electricity to maximize the benefits of these programs**. As such, TOU pricing gives customers an incentive to charge BEVs and PHEVs off-peak. Forthcoming valuation of storage and ancillary services that may be provided on-peak by BEVs and PHEVs are another system-wide benefit of TOU pricing.

In sum, **there is great variation in how grid GHG intensity changes throughout the day and season, which is sensitive to assumptions about marginal power generation sources, season, as well as location.** Table 3 presents four sets of marginal GHG emission factors scenarios that we extracted from publicly available primary data and the peer reviewed technical literature that we find most suitable for estimating the marginal GHG emissions associated with changes to electricity demand. We have documented the justifications for the selected emissions factors in Appendix B. Perhaps the most critical variations of these estimates are (a) differences in magnitude, because this determines the overall GHG savings that can be expected and (b) differences in the ratio between peak and off-peak emission factors, because this determines the GHG value of reducing peak loads while increasing overall demand through TOU pricing. In comparing peak and off-peak GHG emission factors, we see that the four estimates show a 17% decrease, a 4% decrease, a 12% increase, and a 12% decrease, respectively. **The relatively small differential in marginal emission factors may come as a surprise, and it suggests that the greenhouse gas benefit of switching load from peak or off-peak is beneficial, but not of greater benefit as compared to overall efficiency and conservation.** We explore results using all of these options, while relying on the CSI avoided cost model as a base case simply because its focus is most similar to this proceeding. We have applied these estimates below to understand the magnitude of rate design GHG impacts resulting from potential adoption of solar PV and energy efficiency measures and electricity conservation.

2.4.2. Rate Design Impacts on Incentive for Distributed Generation PV

It is our position that proposed rate design should avoid flattening tiered rate structures because this will result in economic disincentives for DG PV installation among electricity users who consume significantly above the baseline. These customers are most likely to install solar PV because high monthly bills make the payback period of DG PV shorter. We have built a model to analyze and demonstrate this effect, and ***the results show that that a TOU rate without tiers does not encourage adoption of DG***. This is because the cost effectiveness of installing a PV system is a function of total utility bill otherwise faced by the customer. According to our analysis, creating a differential between peak and off-peak hours while flattening or eliminating tiers reduces the monthly bill of high electricity users, making a DG PV system less attractive. Conversely, flattening tiered rates does not measurably increase the incentive to install PV among low use customers.

2.4.2.1. Approach and Methods – PV Analysis

The key metrics that inform PV adoption under a net metering policy regime are the levelized cost of energy (LCOE) from the utility versus the LCOE from PV over the life of the system. This is the basis for our model, which compares the average cost per kWh of purchased electricity from the utility PG&E, and the average cost of electricity per kWh generated through DG PV, both expressed as levelized costs of energy. While consumers may be motivated by various reasons to adopt PV, the economics fundamentally shape broad deployment patterns. If the LCOE from PV over the life of the modules is lower than the LCOE from the utility, then it makes economic sense for a resident to install PV. If the LCOE from PV is more expensive, customers will only install PV if they are willing to risk a net financial loss on PV energy production.

To make a comparison with the cost of DG PV, we calculated the cost of grid electricity over a 25-year time period to match the typical warranty of a PV module. The LCOE of electricity purchased from the grid is the net present value (NPV) of all electricity purchases by a household for 25 years divided by the total kWh consumed. To compute this figure, we used computed bills under current and proposed rates for each customer in the PG&E customer sample data. We calculated net present value of this bill over 25 years, and divided this by 25 times the current annual consumption. The result is an average real cost of electricity for the next 25 years, which can be compared "apples to apples" to the LCOE for PV. We chose to assume no annual increase or decrease in consumption since this would be difficult to justify. In addition, some annual rate of increase in the cost of electricity should be assumed, and we used 2% for our baseline analysis.[2]

Similarly, we calculated the LCOE of DG PV energy, which is a product of the installed total cost of a PV system after rebates and the cost of financing, divided by the total kWh produced over the

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[2] The standard number that CPUC and CEC studies use is 3% real escalation, plus 2% general inflation. We selected this as a very conservative assumption, so that the cost-effectiveness of DG PV would not be potentially inflated. However, we do believe that the future cost of fossil fuel electricity may be significantly higher.

lifetime of the module. PV modules make up about a third of the system cost, while the balance is made up by system components, installation, operation and maintenance, and the cost of incremental electricity as module output slowly degrades over time. Almost all PV installations require at least some financing, a major additional lifecycle cost component. Operating and maintaining PV is not a major cost, but the typical system needs an inverter replacement every ten to fifteen years, which also requires a visit from an electrical technician. It is also necessary to add the cost of some energy purchased from the grid to the LCOE from PV.

PV systems in California are currently designed to offset net utility bills in response to current net metering tariffs[3], but over time module degrades in energy output at a rate of roughly 1% per year. Therefore, one must purchase increasing electricity from the grid in order to make up for this decline in production over the modules' life. Finally, the annual energy production of the modules will vary by climate region based on the amount of solar insolation the area receives; the greater the solar resource, the smaller the system required to balance energy demand. To account for this variation we computed solar insolation in kWh/kW using the National Renewable Energy Laboratories PVWatts2 Calculator. We calculated values for reference cities using default values for panel efficiency, aspect and tilt, and matched these values to the county and climate zone of each customer in the sample data. All of these factors play a significant role in shaping financial incentives for PV adoption and are included in our model.

We conducted our analysis of the LCOE from PG&E electricity and PV under current and proposed rates. Values for the LCOE from grid electricity were produced using data from PG&E on the average monthly bills faced by each of the customers in the sample, as computed by the PG&E bill calculator. Other parameters were taken from the relevant literature, and sensitivity analysis was used where an exact figure could not be attained. In our baseline model, we make the following assumptions, which we vary in the sensitivity analysis described in subsequent sections:

- 6% discount rate
- 5% finance rate
- 2% annual increase in cost of electricity[2]
- $6.06/W installed, system cost (see below for explanation)
- 30% federal tax incentive
- We assume no California Solar Initiative rebate, since this program is slated to end soon.

The parameter for the installed cost of PV was the estimated using the California Solar Initiative (CSI) database in the first quarter of 2013 (CSI 2013). We found the cost per installed watt for systems less than 10kWh, in the residential sector, under all ownership types combined (Table 4). While the price of installed PV has continued to decline over the past year, it is unclear whether such price declines will continue in the near term. While imports of PV from China have been an important driver of low prices for customers, it is also the case that many of the PV manufacturers have been selling below cost to liquidate inventory. Suntech is the latest example of a company that was selling below cost, and is now in bankruptcy (Bradsher 2013). PV panel

[3] System sizing in California is driven by the NEM tariff, not best practice, which would be to maximize utilization of roof space. This is part of why installation costs in CA are more expensive than in Germany.

inventory remains higher than demand (Kaften 2013). For these reasons the cost of PV modules will likely not fall further in the near-term and may even increase. However, there is potential for the soft costs of residential PV installations to decline, as evidenced by current install costs in Germany (Seel et al. 2013). Therefore, we use the current average for installs in PG&E territory as an estimate the cost of PV installations.

Table 4. Cost/Watt of DG PV - CSI Cost by Quarter Database

Q4, 2012 (most recent available)	PG&E Territory	All California
<10 kW, residential, host customer party	$ 6.23	$ 6.30
<10 kW, residential, third party	$ 5.77	$ 5.92
<10 kW, residential, all	$ 6.06	$ 6.10

While several of our model assumptions could be subject to debate, modifying these assumptions would not alter our overall conclusions since these assumptions do not impact the relative impact of rate scenarios on the incentive to install DG PV.

To summarize the effects of a given rate design on adoption of PV, we summed the weighted yearly kWh consumption of all customers in the PG&E customer sample data with an LCOE of PV which is lower than the LCOE of electricity purchased from the utility. Using information the customer sample, we were also able to compute this figure for customers in different climate zones and with different levels of electricity consumption. Finally, we computed payback periods for customers at various levels of electricity usage.

2.4.2.2. Results – PV Analysis

We found that our proposed rate would increase the total kWh with an economic incentive for Non-CARE customers for DG PV by 707 GWh per year, from 7,915 under current rates to 8,622 under our proposed rate (Figure 5)***. This is the equivalent of a potential annual savings of 292,568 metric tons of CO_2/yr, or 4.82% of overall residential GHG emissions from electricity in PG&E territory. Removing the tiered component of our rate design would decrease the total GWh with economic incentive for DG PV by 5,209 GWh/yr, while adding a $10 customer charge would result in decrease of 2,628 GWh.*** We computed changes in GHG emissions by applying marginal emissions factors to consumption in each TOU for sample customers with incentives for PV under old and new rates, and weighting this to the population. These are calculations of *potential* savings of electricity and GHGs, assuming all customers with an economic incentive to install DG solar PV do so.

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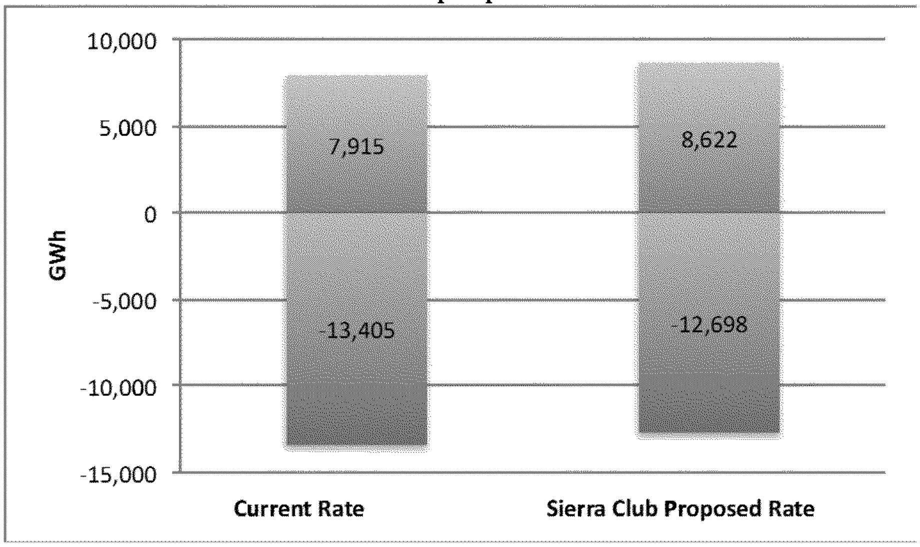
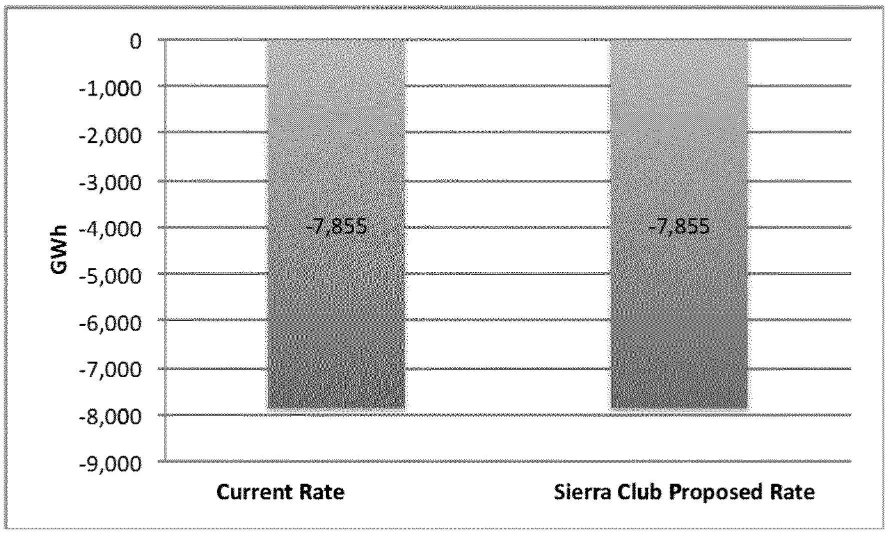
Figure 5. Total Non-CARE GWh in PG&E territory with economic incentive to install DG PV under current and proposed rates.



For CARE customers, there is no economic incentive under current or proposed rates (Figure 6), and therefore the remainder of this section focuses exclusively on Non-CARE customers.

Figure 6. Total CARE GWh in PG&E territory with economic incentive to install DG PV under current and proposed rates.

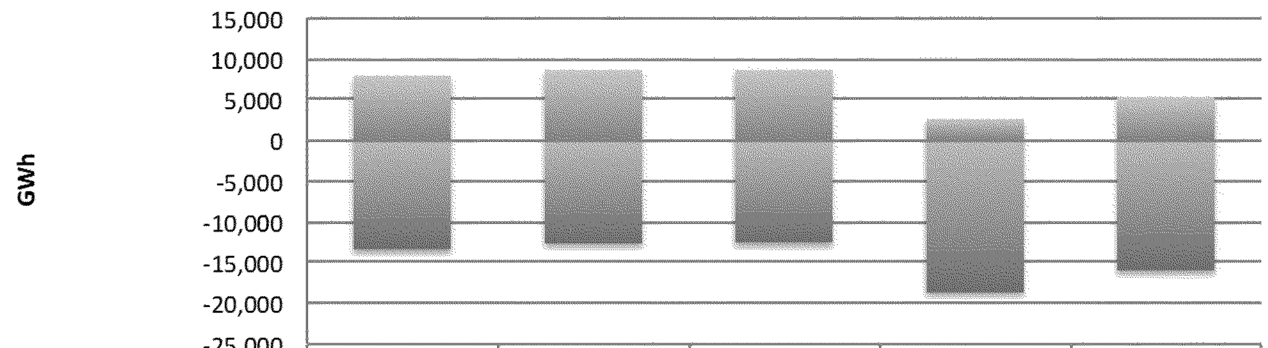


We also show how this value compares to several other rate designs we tested (Figure 7). We repeated this type of sensitivity analysis for multiple rate designs, and the results were always similar. From this analysis, we conclude that:

- Flatter tiers or the absence of tiers greatly reduces the incentive for customers to install DG PV.
- Collecting the revenue requirement through fixed charges greatly reduces the incentive for customers to install DG PV.

- TOU rates do not have a strong effect on the incentive for customers to install DG PV. The reason for this was described at the beginning of Section 2.4.

Figure 7. Total GWh in PG&E territory with economic incentive to install DG PV, comparison of various rate designs.



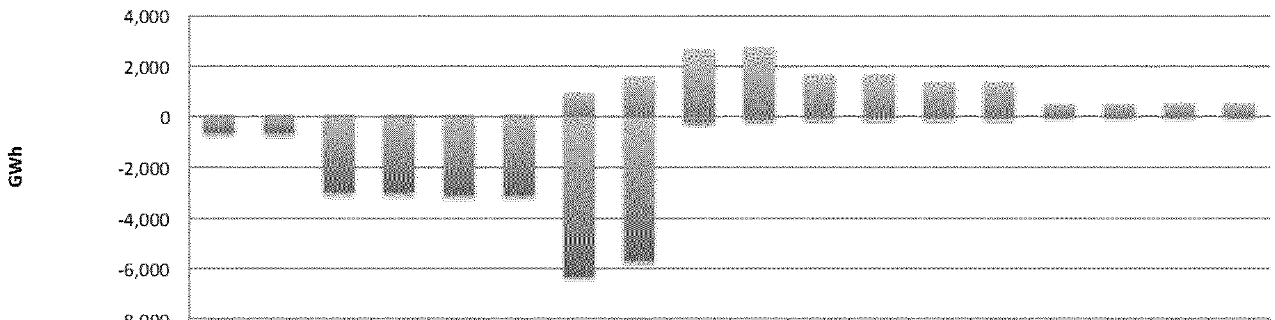
	Current Rate	Sierra Club Proposed Rate	With No TOU	With No Tiers	With $10 Customer Charge
GWh Below Breakeven	-13,405	-12,698	-12,654	-18,714	-16,047
GWh Above Breakeven	7,915	8,622	8,665	2,606	5,273

Next, we looked at how these results vary between customers with various usage levels. We separated PG&E customers in the sample cohort into 8 customer types (Table 5). We find that customer types 3 and 4, (those consuming 130% to 250% beyond baseline) show the largest increase in incentive to install PV under our proposed rate structure (Figure 8). In general, customers with very high usage (customer types 5 and above) are almost all incentivized to install PV under both current and proposed rates. These high usage customers would be the ones to lose their overall incentive to install PV under the alternative scenarios shown in Figure 7. Low usage customers (customer types 0-2) are generally unaffected by the rate change; they do not have an economic incentive to install PV under either scenario. **We also see that variations on our rate design that include no tiers or that add a customer charge drastically increase the average payback period for customers with an economic incentive to install DG solar PV (Table 6).**

Table 5. Definitions of customer types used in this analysis.

Customer Type	Definition
0	Customer consuming <=50% of baseline quantity in at least 6 months
1	Customer consuming >50% of baseline quantity in at least 6 months
2	Customer consuming >100% of baseline quantity in at least 6 months
3	Customer consuming >130% of baseline quantity in at least 6 months
4	Customer consuming >200% of baseline quantity in at least 6 months
5	Customer consuming >250% of baseline quantity in at least 6 months
6	Customer consuming >300% of baseline quantity in at least 6 months
7	Customer consuming >400% of baseline quantity in at least 6 months
8	Customer consuming >500% of baseline quantity in at least 6 months

Figure 8. Total GWh above and below the breakeven point, by customer type.
(C and P denotes Current and Proposed rate)



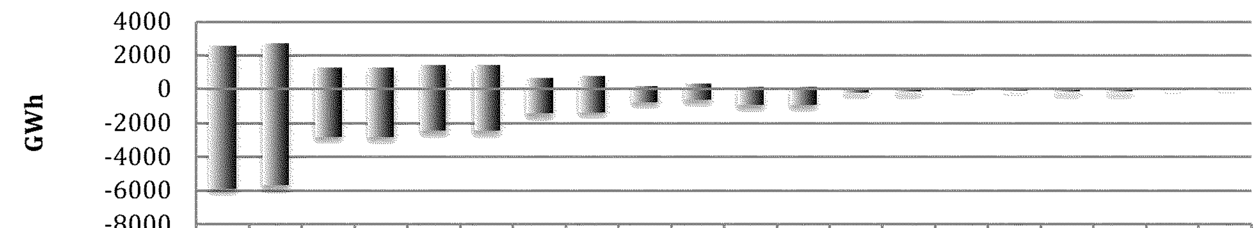
	0(C)	0(P)	1(C)	1(P)	2(C)	2(P)	3(C)	3(P)	4(C)	4(P)	5(C)	5(P)	6(C)	6(P)	7(C)	7(P)	8(C)	8(P)
Below Breakeven	-655	-655	-3,025	-3,023	-3,122	-3,120	-6,341	-5,722	-227	-142	-28	-28	-8	-9	0	0	0	0
Above Breakeven	22	22	64	66	20	22	990	1,609	2,668	2,753	1,701	1,701	1,397	1,396	518	518	535	535

Table 6. Average discounted payback period (yrs) for customers with economic incentive to install DG solar PV, by customer types, for various rate designs

Customer Type	Current Rate	Proposed Rate	Proposed Rate Without TOU Pricing	Proposed Rate Without Tiers	Proposed Rate with $10 Cust. Charge
1	22.98	22.47	23.20	24.45	21.86
2	23.07	23.42	23.50	24.47	24.80
3	23.72	23.65	24.04	24.38	24.58
4	21.87	21.71	21.97	24.30	24.32
5	19.41	19.89	20.13	24.25	24.25
6	17.47	18.13	18.67	24.75	23.23
7	14.97	16.13	16.78	24.55	22.21
8	13.45	15.24	15.42	24.66	21.84

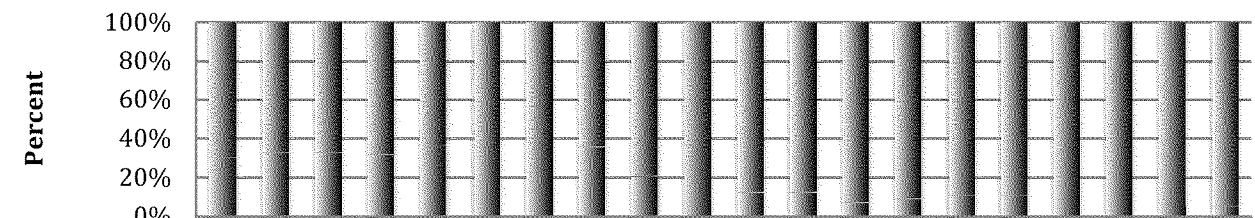
Finally, we examine the impacts of proposed rates on different PG&E climate zones, both in total GWh and, to make comparisons across climate zones easier, in percent of total GWh above and below the breakeven point. This analysis shows that Zone W has a large increase in incentivized PV, probably because of high solar insolation values. Zones R, X, and Y also show substantial increases.

Figure 9. Total GWh above and below the breakeven point, by PG&E climate zone. (See Figure 11 for a key of climate zone letters, C and P in parentheses denotes Current and Proposed rate).



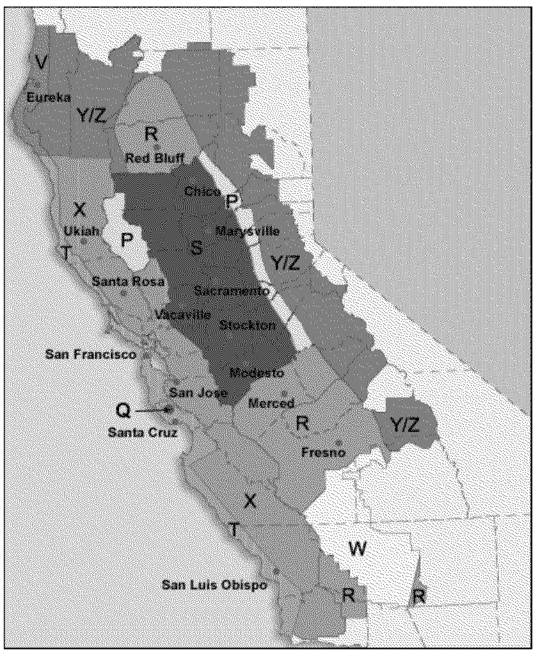
	X(C)	X(P)	S(C)	S(P)	T(C)	T(P)	R(C)	R(P)	W(C)	W(P)	P(C)	P(P)	Y(C)	Y(P)	Q(C)	Q(P)	V(C)	V(P)	Z(C)	Z(P)
Below Breakeven	-5918	-5744	-2805	-2824	-2469	-2461	-1470	-1370	-767	-652	-945	-942	-217	-213	-64	-64	-178	-178	-45	-45
Above Breakeven	2617	2792	1355	1336	1426	1433	676	776	203	318	137	140	17	21	8	8	0	0	3	2

Figure 10. Percent of GWh above and below the breakeven point, by PG&E climate zone. (See Figure 11 for a key of climate zone letters, C and P in parentheses denotes Current and Proposed rate).



	X(C)	X(P)	S(C)	S(P)	T(C)	T(P)	R(C)	R(P)	W(C)	W(P)	P(C)	P(P)	Y(C)	Y(P)	Q(C)	Q(P)	V(C)	V(P)	Z(C)	Z(P)
Below Breakeven	69.3%	67.3%	67.4%	67.9%	63.4%	63.2%	68.5%	63.8%	79.1%	67.2%	87.3%	87.1%	92.6%	91.1%	88.7%	88.7%	100.0	100.0	94.5%	94.8%
Above Breakeven	30.7%	32.7%	32.6%	32.1%	36.6%	36.8%	31.5%	36.2%	20.9%	32.8%	12.7%	12.9%	7.4%	8.9%	11.3%	11.3%	0.0%	0.0%	5.5%	5.2%

Figure 11. PG&E Climate Zone Map



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In sum, our proposed rate design compares favorably to current rates and variations on this rate design in creating an economic incentive for DG PV.

2.4.3. Rate Design Impacts on Incentive for Air Conditioning Efficiency Upgrades

We created a similar model to study impacts of potential rate designs on the payback period of air conditioning units (AC). We focused on AC as a proxy for other comprehensive energy efficiency upgrades because (a) the literature shows that households in hotter climates and households with AC have higher elasticities under dynamic pricing schemes, and (b) AC units consume a large portion of household electricity.

Our results in this section differ from those in the section above on PV. ***We found that TOU rates are very important for lowering payback periods for AC unit upgrades because a large percent of AC usage occurs during the peak period.*** When peak rates are high, the cost of running AC units goes up, and thus the simple payback period to upgrade to a higher efficiency AC unit goes down. In other words, it takes a short time to pay off the costs of installing a higher efficiency AC unit with electricity savings under TOU pricing. The greater the differential between peak and off-peak, the stronger the effect we observe, although increasing the differential between TOU periods should be careful to also avoid significant short-term bill impacts.

2.4.3.1 Approach and Methods – AC Energy Efficiency

Our model determined which customers in the sample data are likely users of AC units, based on cooling degree days (**CDD**) of a representative city matched to the county and climate zone given in the customer sample. For these customers, yearly kWh needed to run an AC of varying Seasonal Energy Efficiency Ratio (**SEER**) values (a standard rating of AC efficiency) was computed based on CDD and an assumption that AC units are used during 50% of CDD.[4]

Our calculation is based on the scenario in which a customer replaces an AC unit at end of life. It is not common for customers to replace AC units with higher efficiency units before end of life, and therefore our calculation estimates the simple payback period of replacing an AC unit with minimum Title 24 standard (SEER 13), versus a high efficiency AC unit (SEER 20). Under this scenario, we computed costs of running both the low and high efficiency units by allocating costs to the highest tier of usage of a given customer, assuming that 50% of AC usage is at the summer peak rate, and 30% is at the summer/winter part-peak rate, and 20% is at the summer/winter off peak rate.[5] These calculations were used to compute the payback period for a SEER 20 for each customer in the sample, as well as the total weighted kWh with a positive return under varying payback periods. In a similar fashion to our analysis of DG PV, several assumptions were

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[4] This is an estimate based on information in the 2009 California Residential Appliance Saturation Study: http://www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-ES.PDF

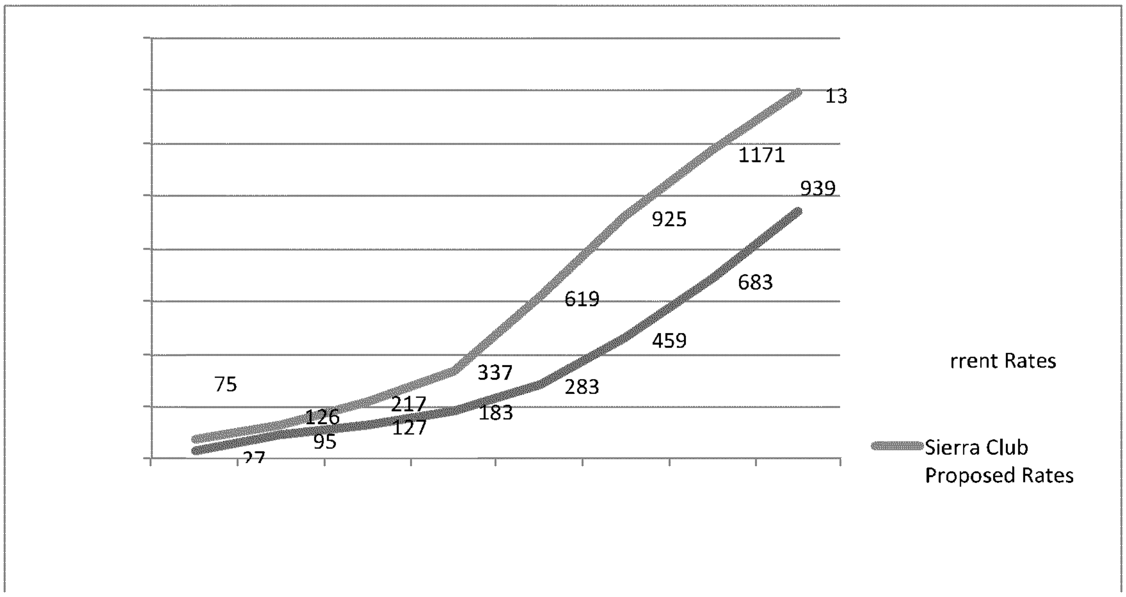
[5] This is an estimate based on data from the National Climate Data Center for reference cities in climate zones where cooling is required. www.ncdc.noaa.gov/cdo-web/

necessary to arrive at our conclusions, and while discussion around these assumptions could improve accuracy of results, our conclusions would remain unchanged since our model does an excellent job *of comparing relative impacts on energy efficiency behavior across various rate scenarios,* rather than predicting an exact outcome of any one scenario.

2.4.3.2. Results - AC Energy Efficiency

Our results show that our proposed rate roughly doubles the total GWh savings with a positive economic return at any payback period between 3 and 10 years (Figure 12). Or, put in different terms, our proposed rate cuts the systemwide payback period of a high efficiency upgrade by about three years.

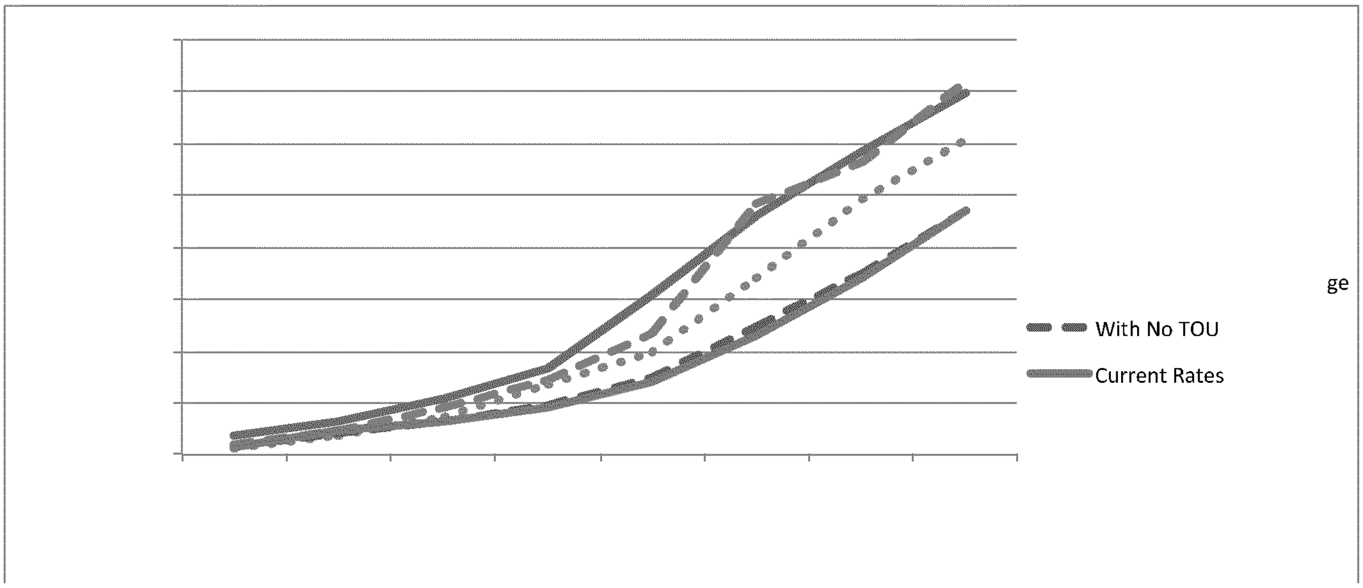
Figure 12. Total GWh savings with a positive economic return at payback periods between 3 and 10 years.



If we compare our proposed rate to a series of variations (Figure 13), we come to the following conclusions:

- Removing tiers from our rate design has almost no impact on the payback period for AC upgrades
- Removing TOU rates from our design makes payback for AC upgrades similar to the current rates.
- Adding a customer charge drastically increases the payback period provided by proposed rates.

Figure 13. Potential electricity use reduction under various payback period scenarios.



The greenhouse gas savings associated with this potential is given in Table 7, for each of the payback period scenarios.

Table 7. Total Potential GHG Saving in mTons and Percent of all Residential GHGs, under varying payback period thresholds

Threshold Simple Payback Period	3	4	5	6	7	8	9	10
Total Potential GHG reductions (mTons)	34,365	57,848	99,411	154,410	283,513	423,406	536,411	640,039
Percent of All Residential GHGs	0.57%	0.95%	1.64%	2.54%	4.67%	6.97%	8.83%	10.54%

2.4.4. Analysis of Rate Design Effects on Electricity Consumption

2.4.4.1 Approach and Methods – Electricity Consumption

We utilized the sample ratepayer data to consider the effects of TOU and tiered rate structures on electricity consumption. Conceptually, we treated each tier, time of use period, and season as a separate good. Each "good" in this case has its own price elasticity of demand that we apply to changes in price to estimate changes in quantity demanded, and an elasticity of substitution to account for shifting consumption among alternatives. We used the approach in the model provided in the PG&E Bill Calculator, in which there are one pair of substitutes for the winter season because there are two TOU periods, while the summer season has two pairs of substitutes because the shoulder period provides a substitute for the peak period and the off-peak period provides a substitute for the shoulder period.

Own-price elasticity is the percent change in quantity demand corresponding to a given percent change in price. Substitution elasticity represents the ease that consumption in one period can substitute for consumption in another. Our calculation first estimates the change in consumption due to a change in tiered rates using own-price elasticities, and then estimates substitution between TOU periods based on substitution elasticities. This approach is consistent with the literature that suggest that tiered pricing effects overall consumption, while TOU pricing only effects substitution between periods. This approach is also consistent with the PG&E Bill Calculator Energy Conservation calculations. The model allows selection of separate elasticities for each TOU-tier combination and its available substitutes. We assumed that the tiering proportions are equal across TOU overall as a simplifying assumption. For example, 60% of Non-CARE Summer energy consumption is Tier 1. So we assume 60% of each category (on-peak, part-peak, and off-peak) is Tier 1. We use the same GHG emission factors that we describe in prior sections to compute GHG impacts of changes in energy consumption.

We constructed our own model instead of using the PG&E Energy Conservation calculator because we saw multiple deficiencies in its approach, as follows:

First, the Energy Conservation tab uses a two-step process to first calculate the own-price effect of changing tiered rates and then to calculate the substitution effect of TOU pricing. While we agree that this is an appropriate approach given the complexity of the calculations involved, we do not agree with the intermediate rate used to calculate impacts. A 'flat' rate is used at the intermediate step, and the calculation of this flat rate does not seem to include baseline credits or account for fixed charges; for example we got a fixed rate of 16 cents for Non-Care and 10.4 cents for CARE regardless of variations in calculator inputs of baseline credits and fixed charges. Since, as our results show, much of the conservation effect is based on calculating the own-price effect, using this generalized flat rate likely leads to erroneous results. For example, in one rate design we tested, the flat rate given by the PG&E calculator was 16.0 cents (Non-CARE) and 10.4 (CARE), while in another the values were 29.1 cents and 19.0 cents. The consumption impact varied from 1.3% decrease to an 18.7% increase, however the goal was to test two different TOU rates, which should not show a dramatic consumption impact. Our results below show that the flat rate calculation below has a dramatic and probably unjustified impact on conservation calculations. In addition, it was impossible to use this 'flat rate' approach when calculating conservation impacts of a combined tiered and TOU rate structure, such as that which we propose. We corrected this deficiency in the calculations embedded in our model: the only difference between our intermediate rate and our proposed rate was the removal of peak/part-peak surcharges and off-peak credits (see below).

Second, the Energy Conservation tab of the PG&E Bill Calculator uses constant own-price and substitution elasticities across all tiers. ***Constant own-price elasticity across all consumption groups is very likely not an accurate representation of residential energy use behavior, is a simplifying assumption to ease calculation, and inherently assumes that flat rates are better for energy conservation.*** This assumption drastically affects the outcomes of the analysis, and we demonstrate this impact below. Assuming constant elasticity across all tiers means that a customer will change tier 1 usage based on a change in price at the same rate that a customer would change tier 4 usage. This is unlikely to be true for several reasons: (1) Customers who change energy use will do so at the margin; i.e. a customer can only change tier 1 usage if there is no usage in any other tier, so, for high use customers, usage in the highest tier will change and usage in lower tiers will not change at all; (2) Tier 1 energy usage is subsistence/necessity energy usage and thus there is likely less possibility that a customer will be able to reduce. On the other hand, usage in the upper tiers is more likely discretionary usage, and thus there is likely more potential for increases or decreases in consumption based on price; (3) Elasticities are inherently related to the level consumption on a demand curve and thus elasticities values are likely different depending on how much electricity is being consumed; assuming constant elasticity assumes a the demand curve is a line, which is highly unlikely to represent reality (4) There is strong support from the literature for varying elasticities across user types. For example, the own-price elasticity for households with central or room AC (-0.64) was 8 times higher than that of households without AC (-0.08) (Reiss and White, 2002). Substitution elasticities were also found to be much higher in households with AC as compared to those without in several studies: (0 versus 0.39, Baladi and Herriges, 1993; 0.04 versus 0.11, Charles River Associates, 2005). Faruqui and George (2005) also found that customers who use 200% of average electricity conserved more energy on critical peak days than those who use 50% of the average. For these reasons, assuming some differential between elasticities, both own-price and substitution elasticities, across tiers is important. Our analysis reflects this complexity supported by the literature.

A third deficiency in the PG&E Energy Conservation calculations is that the model assumes substitution can only occur from the peak period to the part-peak period, and from the part-peak period to the off-peak period. In other words, there is no potential in the model for a customer to substitute from the peak period to the off-peak period, which clearly does not reflect reality. Unfortunately, we were unable to address this deficiency in our model due to unavailability of estimates for substitution elasticity across multiple substitutes. We note this issue to point out the overall likelihood of understated overall substitution.

The below results are in the form of the change in quantity demanded, and the percent change in quantity demanded. Results are then converted into GHGs. We also separate the total change in demand into the two components of the analysis: the own-price effect of changing the tiered structure, and the substitution effect of TOU pricing. We do this in order to note which rate design component is driving the result, for reasons we discuss below.

We begin our presentation of results using the simplifying assumption of constant own-price elasticity (-0.2) and a substitution elasticity of (-0.2) in our analysis. We also test our model under heterogeneous elasticities to demonstrate a scenario that more likely reflects variations in customer elasticity. Our initial values of -0.2 are consistent with values found in the literature. While they may be slightly high for short-run behavior, over the long run, the literature is quite clear that elasticities can be much higher than what we use here (see Appendix A for more information). Therefore we also test our model using long-run elasticities suggested by the literature.

2.4.4.2 Results – Electricity Consumption

Our base case results show that our preferred rate design reduces GHGs by 99,552 metric tons (mTons) per year, which is equivalent to a 0.15%/yr decrease in overall electricity use in the residential sector, or 43.5 GWh/yr (Table 8). While this is a relatively small reduction overall, ***it represents a 10.59% reduction in peak consumption and 6.44% reduction in part-peak consumption.***

Of the total reduction in GHGs, about half is due to the change in tiers, and half is due to the effect of TOU pricing. Our proposed rate design flattens the existing tiered rate design by eliminating tier 4 while raising Tiers 2 and 3 slightly. Whether or not flattening tiers leads to a reduction in consumption is a result of whether constant elasticities are used, an issue we explore further below. The GHG benefit of TOU pricing is a result of a sharp reduction in peak and part peak consumption, accompanied by an increase in off-peak consumption. The result is a slight net increase in consumption, and a net decrease in GHGs due to higher marginal intensity of peak power.

Table 8. Effect of Proposed Rate on Electricity Consumption and GHGs

	Total Effect	Effect of Tiering	Effect of TOU
Change in kWh			
Total	(43,466,548)	(128,995,614)	85,529,067
Peak	(333,499,511)	(13,418,752)	(320,080,759)
Part Peak	(318,134,741)	(21,766,079)	(296,368,662)
Off Peak	608,167,704	(93,810,783)	701,978,488
Percent Change in kWh			
Total	-0.15%	-0.44%	0.29%
Peak	-10.59%	-0.43%	-10.21%
Part Peak	-6.44%	-0.44%	-6.02%
Off Peak	2.88%	-0.44%	3.34%
Change in GHGs (mTons)			
Total	(99,551.70)	(56,765.78)	(42,785.92)
Peak	(189,092.98)	(7,608.38)	(181,484.60)
Part Peak	(158,735.47)	(10,860.33)	(147,875.14)
Off Peak	248,276.75	(38,297.06)	286,573.82

We also modeled the long run impacts of the TOU pricing component in our rate design by using higher substitution elasticities. There is evidence that, over time, participants increase their responsiveness to demand response rates, which can be attributed to learning and long term changes in behavior and appliance holdings. Filippini (2011), Espey and Espey (2004), Bohi (1981), and a study by Baltimore Gas and Electric (cited in Faruqui and Palmer, 2011) all show long run substitution elasticities 2 to 3 times higher than short run elasticities (See Section 7). Therefore, consistent with this literature, we modeled results at substitution elasticity of -0.5, which is two and half times the base case (short-run) elasticity (Table 9). ***Results show significant conservation effects due to TOU pricing over the longer-term, with a total reduction of GHGs just under 268,000 metric tons/yr, the equivalent of 184 GWh/yr, or a 24.5% reduction in peak consumption, a 15.7% reduction in part-peak consumption, and a 0.63% reduction in overall consumption.***

Table 9. Effect of Proposed Rate on Long Run Electricity Consumption and GHGs

	Proposed Rate Design		
	Total Effect	Effect of Tiering	Effect of TOU
Change in kWh			
Total	(184,786,721)	(128,995,614)	(55,791,106)
Peak	(769,679,755)	(13,418,752)	(756,261,003)
Part Peak	(775,219,210)	(21,766,079)	(753,453,131)
Off Peak	1,360,112,244	(93,810,783)	1,453,923,027
Percent Char Percent			
Total	-0.63%	-0.44%	-0.19%
Peak	-24.45%	-0.43%	-24.12%
Part Peak	-15.69%	-0.44%	-15.32%
Off Peak	6.45%	-0.44%	6.93%
Change in GI GHGs			
Total	(267,957.82)	(56,765.78)	(211,192.04)
Peak	(436,405.56)	(7,608.38)	(428,797.18)
Part Peak	(386,800.84)	(10,860.33)	(375,940.51)
Off Peak	555,248.58	(38,297.06)	593,545.64

When we compared our preferred rate to the same test rates we used in the two previous sections, we see some results that demonstrate the advantages of our proposal (Tables 10 & 11).

First, our proposed rate conserves more energy than under similar rates with customer charges (Table 10). ***We use the example of a $10 customer charge to illustrate that customer charges remove a variable cost from customer bill, which results in an increase in consumption and an increase of over 140,000 metric tons of GHGs compared to our proposed rate.*** For the purposes of presenting calculations in this analysis, this impact is shown under the "effect of tiering," simply because is the where the first impact of the rate is calculated.

Table 10. Effect of Proposed Rate and Variation with Customer Charge on Electricity Consumption and GHGs

	Proposed Rate Design			Proposed Rate with $10 Customer Charge		
	Total Effect	Effect of Tiering	Effect of TOU	Total Effect	Effect of Tiering	Effect of TOU
Change in kWh						
Total	(43,466,548)	(128,995,614)	85,529,067	291,341,931	198,910,420	92,431,511
Peak	(333,499,511)	(13,418,752)	(320,080,759)	(313,876,245)	24,021,232	(337,897,478)
Part Peak	(318,134,741)	(21,766,079)	(296,368,662)	(277,598,127)	34,868,874	(312,467,001)
Off Peak	608,167,704	(93,810,783)	701,978,488	882,816,303	140,020,314	742,795,990
Percent Change in kWh						
Total	-0.15%	-0.44%	0.29%	1.00%	0.68%	0.31%
Peak	-10.59%	-0.43%	-10.21%	-9.97%	0.76%	-10.65%
Part Peak	-6.44%	-0.44%	-6.02%	-5.62%	0.71%	-6.28%
Off Peak	2.88%	-0.44%	3.34%	4.19%	0.66%	3.50%
Change in GHGs (m Tons)						
Total	(99,551.70)	(56,765.78)	(42,785.92)	43,922.45	88,179.53	(44,257.08)
Peak	(189,092.98)	(7,608.38)	(181,484.60)	(177,966.66)	13,619.95	(191,586.61)
Part Peak	(158,735.47)	(10,860.33)	(147,875.14)	(138,509.45)	17,398.06	(155,907.51)
Off Peak	248,276.75	(38,297.06)	286,573.82	360,398.56	57,161.52	303,237.05

Second, compared to a similar rate without TOU peak surcharges/off-peak credits, our rate delivers higher net GHG savings because TOU pricing encourages load shifting to less GHG intensive electricity (see Table 11). Although total electricity conservation is higher in the non-TOU rate, when this total is converted into GHGs, our proposed rate is superior due to the 10.6% reduction in peak demand.

Table 11. Effect of Proposed Rate and Variations on Electricity Consumption and GHGs[6]

	Proposed Rate Design			Proposed Rate with no TOU			Proposed Rate with Tiers Removed		
	Total Effect	Effect of Tiering	Effect of TOU	Total Effect	Effect of Tiering	Effect of TOU	Total Effect	Effect of Tiering	Effect of TOU
Change in kWh									
Total	(43,466,548)	(128,995,614)	85,529,067	(128,995,614)	(128,995,614)	-	(759,613,926)	(699,703,741)	(59,910,185)
Peak	(333,499,511)	(13,418,752)	(320,080,759)	(13,418,752)	(13,418,752)	-	(328,121,392)	(66,161,314)	(261,960,078)
Part Peak	(318,134,741)	(21,766,079)	(296,368,662)	(21,766,079)	(21,766,079)	-	(333,450,163)	(114,885,038)	(218,565,125)
Off Peak	608,167,704	(93,810,783)	701,978,488	(93,810,783)	(93,810,783)	-	(98,042,371)	(518,657,389)	420,615,018
Percent Change in kWh									
Total	-0.15%	-0.44%	0.29%	-0.44%	-0.44%	0.00%	-2.60%	-2.40%	-0.21%
Peak	-10.59%	-0.43%	-10.21%	-0.43%	-0.43%	0.00%	-10.42%	-2.10%	-8.50%
Part Peak	-6.44%	-0.44%	-6.02%	-0.44%	-0.44%	0.00%	-6.75%	-2.33%	-4.53%
Off Peak	2.88%	-0.44%	3.34%	-0.44%	-0.44%	0.00%	-0.46%	-2.46%	2.05%
Change in GHGs (mTons)									
Total	(99,551.70)	(56,765.78)	(42,785.92)	(56,765.78)	(56,765.78)	0.00	(392,445.37)	(306,571.18)	(85,874.18)
Peak	(189,092.98)	(7,608.38)	(181,484.60)	(7,608.38)	(7,608.38)	-	(186,043.61)	(37,513.22)	(148,530.39)
Part Peak	(158,735.47)	(10,860.33)	(147,875.14)	(10,860.33)	(10,860.33)	0.00	(166,377.20)	(57,322.66)	(109,054.54)
Off Peak	248,276.75	(38,297.06)	286,573.82	(38,297.06)	(38,297.06)	0.00	(40,024.55)	(211,735.30)	171,710.75

To demonstrate problems with using constant elasticities as well as calculation procedures that may give in unrealistic results, we describe in detail the model intricacies and tests we used to reach our conclusions above, which is that ***results showing reductions in consumption through flatter tiers are incorrect***. The flawed assumption in the PG&E Bill Calculator approach is using constant elasticities across tiers, and this is magnified by a flawed method that uses an intermediate step of calculating conservation effects based on an imaginary 'flat rate'. We show (1) the impact of intermediate calculation step, and (2) why constant elasticities give unrealistic results.

(1) It is important to first note that the large majority of the modeled conservation effect using constant elasticity is a result of flattening tiers, rather than of TOU pricing. In other words, the intermediate step in the model described in the methods section is responsible for the suggested conservation impact. This calculation is very sensitive to the intermediate rate chosen. Simply as an exercise, Table 12 shows the results using the flat rate generated by the PG&E calculator (18.1 cents Non-Care, 9.3 cents CARE) and using an alternative flat rate generated by our model (20.2 cent Non-CARE, 10.1 cents CARE). The difference between these two flat rates is due to calculation procedures in the models and is somewhat arbitrary, so we show this result to point out the dramatic effect of this calculation, rather than to suggest that one is correct. The result is that our intermediate flat rate shows as much as double the conservation effect from flattening tiers, with only about a two-cent difference in the two flat rates,

[6] The "effect of tiering" in the scenario with no tiers shows the calculations related to the flattening of tiers from the current rate design.

even though the final rates is the same for both models. We present these results only to show that the supposed conservation effects from flattening tiers are an artifact of an intermediate step in the calculations both in our model and the PG&E model. In addition, customers never actually face this intermediate rate, so assuming they react to it independently is highly questionable, especially when the impact on final results is so great.[7]

(2) We also demonstrate how sensitive the supposed conservation from flatter rates is to assumptions about elasticity across tiers. Table 13 shows results for the non-Tiered rate using constant and two versions of heterogeneous elasticity, and one can see that the varying assumptions are enough to flip the result of the non-tiered case from a large GHG savings to additional GHG emissions. Moreover, our proposed rate is not as sensitive to these simplifying assumptions because it does not involve dramatic flattening of tiers, which makes the results of our proposed rates more robust.

In summary, this method of calculation can erroneously suggest dramatic conservation benefits of flatter rate design, which is due to (1) a highly sensitive intermediate calculation and (2) a simplifying and unrealistic assumption of constant elasticities. The heterogeneous elasticities we use in Table 13 are a better representation of customer behavior.

Therefore, we conclude that (1) our proposed rate has important conservation impacts that may not be present under other variations of this rate design, (2) long-run conservation benefits of the TOU component may be much greater than short-run benefits (3) under constant elasticity our rate reduces GHG emissions by over 99,000 metric tons, while under the two versions of heterogeneous elasticities, reductions are slightly lower, at over 70,000 metric tons (4) the substitution effects of a rate design should be judged independently of price effects and (5) methods for calculating price effects in the context of switching from tiered to TOU rates are incomplete evolving, however assuming constant elasticity is not justified.

Table 12. Effect of Variation Proposed Rate – Without Tiers, Under Two Different Intermediate Flat Rates

[7] The change in sign of the total percentage effect of TOU pricing under the proposed and 'without tiers' rates is also an artifact of this intermediate calculation.

	Proposed Rate with Tiers Removed			Proposed Rate with Tiers Removed, Alternate Flat Rate		
	Total Effect	Effect of Tiering	Effect of TOU	Total Effect	Effect of Tiering	Effect of TOU
Change in kWh						
Total	(759,613,926)	(699,703,741)	(59,910,185)	(1,465,281,533)	(1,534,654,888)	69,373,355
Peak	(328,121,392)	(66,161,314)	(261,960,078)	(400,308,791)	(160,828,863)	(239,479,928)
Part Peak	(333,450,163)	(114,885,038)	(218,565,125)	(455,295,328)	(228,085,843)	(227,209,484)
Off Peak	(98,042,371)	(518,657,389)	420,615,018	(609,677,414)	(1,145,740,182)	536,062,768
Percent Change in kWh						
Total	-2.60%	-2.40%	-0.21%	-5.02%	-5.26%	0.25%
Peak	-10.42%	-2.10%	-8.50%	-12.71%	-5.11%	-8.02%
Part Peak	-6.75%	-2.33%	-4.53%	-9.21%	-4.62%	-4.82%
Off Peak	-0.46%	-2.46%	2.05%	-2.89%	-5.43%	2.69%
Change in GHGs (mTons)						
Total	(392,445.37)	(306,571.18)	(85,874.18)	(703,039.34)	(672,728.24)	(30,311.10)
Peak	(186,043.61)	(37,513.22)	(148,530.39)	(226,973.60)	(91,189.37)	(135,784.23)
Part Peak	(166,377.20)	(57,322.66)	(109,054.54)	(227,172.67)	(113,804.97)	(113,367.70)
Off Peak	(40,024.55)	(211,735.30)	171,710.75	(248,893.07)	(467,733.90)	218,840.83

Table 13. Effect of Proposed Rate and Proposed Rate Without Tiers, Under Different Elasticity Assumptions

Constant Own-Price Elasticit (-0.2)						
	Proposed Rate Design			Proposed Rate with Tiers Removed		
	Total Effect	Effect of Tiering	Effect of TOU	Total Effect	Effect of Tiering	Effect of TOU
Change in kWh						
Total	(43,466,548)	(128,995,614)	85,529,067	(759,613,926)	(699,703,741)	(59,910,185)
Peak	(333,499,511)	(13,418,752)	(320,080,759)	(328,121,392)	(66,161,314)	(261,960,078)
Part Peak	(318,134,741)	(21,766,079)	(296,368,662)	(333,450,163)	(114,885,038)	(218,565,125)
Off Peak	608,167,704	(93,810,783)	701,978,488	(98,042,371)	(518,657,389)	420,615,018
Percent Char Percent						
Total	-0.15%	-0.44%	0.29%	-2.60%	-2.40%	-0.21%
Peak	-10.59%	-0.43%	-10.21%	-10.42%	-2.10%	-8.50%
Part Peak	-6.44%	-0.44%	-6.02%	-6.75%	-2.33%	-4.53%
Off Peak	2.88%	-0.44%	3.34%	-0.46%	-2.46%	2.05%
Change in GI GHGs						
Total	(99,551.70)	(56,765.78)	(42,785.92)	(392,445.37)	(306,571.18)	(85,874.18)
Peak	(189,092.98)	(7,608.38)	(181,484.60)	(186,043.61)	(37,513.22)	(148,530.39)
Part Peak	(158,735.47)	(10,860.33)	(147,875.14)	(166,377.20)	(57,322.66)	(109,054.54)
Off Peak	248,276.75	(38,297.06)	286,573.82	(40,024.55)	(211,735.30)	171,710.75

Heterogeneous Elasticity (Tiers 1&2: -0.2, Tiers 3&4: -0.4)						
	Proposed Rate Design			Proposed Rate with Tiers Removed		
	Total Effect	Effect of Tiering	Effect of TOU	Total Effect	Effect of Tiering	Effect of TOU
Change in kV kWh				kWh		
Total	23,442,553	(62,179,450)	85,622,003	(190,872,300)	(130,110,499)	(60,761,802)
Peak	(326,605,073)	(6,072,793)	(320,532,280)	(269,076,726)	(1,620,583)	(267,456,143)
Part Peak	(307,025,350)	(10,299,405)	(296,725,945)	(239,549,510)	(16,634,093)	(222,915,418)
Off Peak	657,072,975	(45,807,253)	702,880,228	317,753,936	(111,855,823)	429,609,759
Percent Char Percent				Percent		
Total	0.08%	-0.21%	0.29%	-0.65%	-0.45%	-0.21%
Peak	-10.37%	-0.19%	-10.20%	-8.55%	-0.05%	-8.50%
Part Peak	-6.21%	-0.21%	-6.02%	-4.85%	-0.34%	-4.53%
Off Peak	3.12%	-0.22%	3.34%	1.51%	-0.53%	2.05%
Change in GI GHGs				GHGs		
Total	(70,134.51)	(27,282.44)	(42,852.07)	(142,371.33)	(54,882.28)	(87,489.05)
Peak	(185,183.86)	(3,443.25)	(181,740.61)	(152,565.50)	(918.86)	(151,646.64)
Part Peak	(153,192.36)	(5,138.96)	(148,053.41)	(119,524.84)	(8,299.69)	(111,225.15)
Off Peak	268,241.71	(18,700.23)	286,941.94	129,719.02	(45,663.72)	175,382.74

Heterogeneous Elasticity (Tier 1: -0.01, Tier 2: -0.2, Tier 3: -0.3, Tier 4, -0.4)						
	Proposed Rate Design			Proposed Rate with Tiers Removed		
	Total Effect	Effect of Tiering	Effect of TOU	Total Effect	Effect of Tiering	Effect of TOU
Change in kV kWh				kWh		
Total	21,125,729	(64,489,785)	85,615,514	235,163,908	297,783,814	(62,619,906)
Peak	(326,843,766)	(6,327,118)	(320,516,647)	(230,337,786)	40,733,827	(271,071,613)
Part Peak	(307,410,009)	(10,696,049)	(296,713,960)	(171,898,186)	54,433,954	(226,332,141)
Off Peak	655,379,503	(47,466,618)	702,846,121	637,399,881	202,616,033	434,783,847
Percent Char Percent				Percent		
Total	0.07%	-0.22%	0.29%	0.81%	1.02%	-0.21%
Peak	-10.38%	-0.20%	-10.20%	-7.32%	1.29%	-8.50%
Part Peak	-6.22%	-0.22%	-6.02%	-3.48%	1.10%	-4.53%
Off Peak	3.11%	-0.23%	3.34%	3.02%	0.96%	2.04%
Change in GI GHGs				GHGs		
Total	(71,153.12)	(28,301.96)	(42,851.15)	43,840.00	132,971.54	(89,131.55)
Peak	(185,319.20)	(3,587.45)	(181,731.75)	(130,600.67)	23,095.93	(153,696.60)
Part Peak	(153,384.29)	(5,336.87)	(148,047.43)	(85,769.76)	27,160.19	(112,929.94)
Off Peak	267,550.37	(19,377.64)	286,928.02	260,210.42	82,715.43	177,494.99

Therefore, we conclude that (1) our proposed rate has important conservation impacts that may not be present under other variations of this rate design, (2) long-run conservation benefits of the TOU component may be much greater than short-run benefits (3) under constant elasticity our rate reduces GHG emissions by over 99,000 metric tons/yr in the near-term and approximately 268,000 metric tons/year as participant responsiveness increases over the long-run (4) under two version of heterogeneous elasticities, reductions are slightly lower (5) the substitution effects of a rate design should be judged independently of price effects and (6) our understanding of price effects in the context of switching from tiered to TOU rates is evolving, however assuming constant elasticity is not justified.

2.5. Reduction of Coincident and Non-Coincident Demand

Rates should encourage reduction of both coincident and non-coincident peak demand

A rate design that encourages reduction of coincident peak demand will price electricity higher at times of highest system demand. A TOU rate component helps achieve this goal. A rate design that encourages reduction of non-coincident peak demand will aim to reduce an individual user's peak demand, regardless of when the highest system demand occurs. A tiered rate achieves this goal, while a TOU rate may not. For these reasons, combining a TOU rate and tiered rate will achieve the goals or encouraging reduction of both coincident and non-coincident peak demand. In addition, rates that encourage DG PV will lead to reduction in both coincident and non-coincident peak demand.

2.6. Stable, Understandable, Customer Choice

Rates should be stable and understandable and provide customer choice

The proposed rate design is stable, understandable and provides consumer choice. Retention of the tiered structure maintains existing consumer understanding that costs of electricity increase with significantly increased consumption. Incorporation of time of use provides an understandable signal that energy consumption is more costly during daytime hours than nighttime, especially in late spring through early autumn. By incorporating both features, the proposed rate design increases customer choice by allowing a customer to minimize utility bills by both reducing overall electricity use and/or shifting remaining use to off peak periods where feasible. Importantly, as set forth more fully in Section 6, enabling technologies can help customer understanding of rates, and dynamically adjust loads to respond to rate signals, as desired by individual customers. See Section 7 for information on customer choice, and Section 9 for information on how rates may change over time.

2.7. Avoiding Cross-Subsidies

Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals

Our proposed rate design maintains cross subsidies that provides cheaper electricity to medical baseline and low-income customers. This is a policy goal of the State of California, and our rate resign is not meant to augment or decrease this subsidy.

Our rate design also incorporates TOU pricing to better reflect the cost of energy at the time it is consumed. This reduces a significant cross subsidy in existing rate design in which customers who use electricity more heavily during off-peak hours currently subsidize those who consume more heavily in on-peak hours. To the extent that customers are allowed to opt out of TOU rates, this cross-subsidy would be maintained, and for this reason Sierra Club raises this issue to inform the Commission's implementation of TOU rates.

In addition, by avoiding fixed charges, our proposed rate design avoids cross-subsidies of low usage customers to high usage customers that are inherent in these charges.

To the extent that there are additional cross-subsidies reflected in Sierra Club's proposed rate design, they support state policy goals of encouraging solar PV generation, energy efficiency, and conservation.

2.8. Incentives should be explicit and transparent

See section below on innovative technology and services.

2.9. Rates should encourage economically efficient decision-making

Economically efficient decision-making can be encouraged in two ways:

First, rates can encourage economically efficient decision-making by providing the right price signals to customers to make choices that will save money over the long term and benefit society through the reduction of greenhouse gas emissions and air pollution. This could occur through conservation, adopting energy efficient behavior or technologies, or installing of DG PV. When residential customers make capital investments like DG solar PV and efficiency, they look at cost savings to make an efficient and rational decision. In this regard, our rate design is specifically meant to achieve these goals. See Section 2.4 for more information.

Second, to the extent that the rates customers face reflect the cost of electricity generation, they will maximize net economic benefit to society. In this regard, the literature suggests that real-time pricing or critical peak pricing most accurately reflect marginal cost (Faruqui & Sergici, 2010). However, these rate design options are more difficult for customers to understand, and are less stable (Bonbright et al. 1998 cited in Herter 2007). For these reasons, Sierra Club's proposal is a rate design that is more understandable and stable than real time or critical peak pricing, while still attempting to align rates with marginal cost as well as avoiding significant bill impacts, especially for low income customers (see Section 2.1).

2.10. Customer Education and Outreach

Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

See Section 7.

3. Value of Net Energy Metered Customers

How would your proposed rate design affect the value of net energy metered facilities for participants and non-participants compared to current rates?

Net Energy Metering (NEM) is a California success story. California's NEM program has created tens of thousands of jobs in the State, allowed families of diverse income levels to save on their electricity bills, and decreased California's reliance on fossil fuels by generating on-site clean energy with minimal environmental impact. Given these many benefits, the Commission should adopt a rate design proposal that further encourages deployment of rooftop solar. A rate design proposal that negatively impacts the value proposition of NEM would frustrate achievement of California's energy and environmental goals and create undue havoc on the expectations and investments of existing NEM participants. Accordingly, the Commission should fully understand the impacts to NEM from rate design proposals and adopt a proposal that will facilitate more expansive deployment of rooftop solar.

Unfortunately, the timing of this OIR and that of a separate proceeding currently tasked with evaluating the costs and benefits of NEM are not well-aligned. Pursuant to Decision 12-05-036, the Commission is currently evaluating the costs and benefits of net energy metering (NEM) under the existing rate structure as part of Rulemaking 10-05-004. As the existing rate structure may change significantly as contemplated under this docket, the resulting NEM study may be of limited value. Once the NEM study is complete, this model could be used to evaluate relative cost and benefits of other rate regimes. Notably, the NEM study underway at the PUC is limited to cost and benefits under them narrow Ratepayer Impact Method (RIM) that excludes consideration of the many societal benefits of NEM, such as job creation and avoided environmental costs resulting from reduced extraction and combustion of fossil fuels. The Commission should also account for these important benefits in considering the impact of a rate design proposal on NEM.

Accordingly, at this juncture, it is difficult to state with certainty how the proposed rate design would affect the value of NEM facilities for participants and non-participants. As set forth above, the rate proposal would make NEM an economically efficient investment for a wider range of customers. However, in some circumstances, in particular for high-energy consumers currently subject to Tier 4 rates, NEM value may decrease. This is evidenced by the slightly lengthened payback periods for high usage customers resulting from our rate design (Table 6). Although NEM value could lower for these customers, the overall value proposition of NEM would remain positive for these customers given their overall high energy consumption and likely high consumption during summer peak periods.

A January 2013 study by Crossborder Energy concluded that existing rate design does not produce a cost shift from NEM participants to non-participants (Beach and McGuire, 2013). The study also found that "TOU rates reduce the costs of NEM for non-participating ratepayers by more closely aligning the utility's marginal rates with its marginal costs to serve residential customers." (p.38). As the proposed rate design incorporates TOU to better align marginal costs, it would likely have a beneficial impact on non-NEM participants.

4. Low Income and Customers with Medical Needs

How would your proposed rate design structure meet basic electricity needs of low-income customers and customers with medical needs?

See Section 2.1.

5. Unintended Consequences

What unintended consequences may arise as a result of your proposed rate structure and how could the risk of those unintended consequences be minimized?

Consequences of this rate design could be higher bills for customers with lower than average overall usage but higher than average usage in peak periods. These consequences could be mitigated through phased in TOU rates, transitional "shadow billing," and additional assistance could be provided to these customers, as described in Section 2.7.

6. Innovative Technologies and Services

For your proposed rate structure, what types of innovative technologies and services are available that can help customers reduce consumption or shift consumption to a lower cost time period? What are the costs and benefits of these technologies and services?

According to the literature, customer response to TOU pricing is enhanced greatly by enabling technologies and/or other means of providing information. In some cases, discussed below, responsiveness to dynamic pricing was 2 to 3 times greater when enabling technologies were used. Therefore, enhanced systems should be included in any future dynamic pricing rate design.

There are many options for enabling technologies, and Sierra Club proposes a program of enabling devices that includes the following characteristics. The literature review below suggests that including these options is critical for the success of any dynamic pricing program, and the reduction of system costs should far outweigh the cost of subsidized or free enabling technology:

- Free in-home devices, smart phone applications, and web applications that interactively explain customer electricity rates.
- Free or heavily subsidized smart controls for AC units/thermostats and major household appliances that can be programed to support load shifting, alert/shut off during during peak demand under certain conditions, as well as display cost of usage at different times.

Literature on Effectiveness of Enabling Devices

Several studies have found that enabling technologies enhance the impact of demand response rate schemes. Enabling technologies can either provide information only, or they can also provide end-use controls. Information turns out to be particularly important. In fact, Byrne et al. (1985 cited in Sovacool 2009) found in "a random sample of 414 Delaware residents, matched with utility records," that "merely telling consumers that peak consumption was more expensive reduced electricity use all year round." Here we provide evidence of the effectiveness of enabling technologies.

Charles River Associates (2005) found, in their study of the California SPP, that enabling technologies - smart thermostats - were responsible for about two thirds of the demand reduction from one of the sample groups. Herter (2006) found that households with end-use controls dropped 41% of baseline load compared to 13% without end-use controls during CPP events.

Faruqui et al. (2010) conducted a review of studies on the effectiveness of in-home devices (IHDs), and found that they improved load shifting by roughly 7% on average. One study of particular relevance to this literature review focused on a trial in Ontario in which groups of participants were subject to either an IHD, TOU rates, or both. Results showed that IHDs were responsible for ⅓ of load-shifting on normal days, and almost ⅔ of load shifting on very hot days (Hydro One Networks 2008). RMI (2006) studied a pilot in Ontario, Canada in which customers were given automated demand response systems and CPP-fixed rates. Customers reduced load compared to customers without enabling technology on standard tiered rates, in two study years. The authors point out that customers with enabling technology consistently reduced more than twice the load of residential customer without the technology. Alcott (2011) found similar results when a randomly selected group of participants were given "Pricelights", glowing plastic orbs that change colors to indicate the current electricity price. Thus, reducing the cost of observing and responding to energy prices can substantially affect households' behavior.

However, enabling technologies (or even the rates themselves) may not be as important as the information they provide. Therefore, enabling technologies should be accompanied with an information campaign. For example, Byrne et al. 1985 found that merely telling customers that peak electricity was more expensive reduced annual electricity use. Other studies have found similar results, including a study of residents of Twin Rivers, NJ who were given daily information about energy use and showed a 10-15% drop in consumption (Socolow 1978). Kempton et al. (1994) found that detailed information about electricity use resulted in a 10.5% reduction in a US sample; bi-monthly meter readings resulted in 8-10.4% reductions in a Norwegian sample and 4.9% reduction in a Finnish sample. In addition, since only 41% of those surveyed look at electricity use when paying their bills, there are ample opportunities for savings based on improved information. Schultz et al. (2007) also showed that household energy consumption can be reduced just through messaging of social normative information, without any financial incentive. Becker et al. (1979) gave feedback three to four times a week or continuously that informed households of the cost of their consumption every half hour. This frequent, credible feedback about electricity prices resulted in 10–13% less electricity use than control groups.

In conclusion, enabling devices and/or provision of information are critical to the maximum effectiveness of dynamic pricing schemes.

7. Transition to New Rate Structure

Describe how you would transition to this rate structure in a manner that promotes customer acceptance, including plans for outreach and education. Should customers be able to opt to another rate design other than the optimal rate design you propose? If so, briefly describe the other rate or rates that should be available. Discuss whether the other rate(s) would enable customers opting out to benefit from a cross-subsidy they would not enjoy under the optimal rate.

Rate design changes are most effective, and limit the potential for unintended new cross-subsidies, where the ability to opt-out is limited. In reviewing the literature, it is clear that: (1) A mandatory or opt-out program is likely to achieve much greater benefits than a voluntary (opt-in) program since participation rates will be low in voluntary programs; and (2) Short run (often defined as 1-3 or 1-5 years) impacts of dynamic pricing are much less significant than long term impacts. This is because installation of energy efficient and load-shifting enabled appliances that allow customer to maximize benefits of a dynamic price structure may take several years. For this reason, except for limited circumstances, it would be most effective for customers to be given time to react to new rates before allowing a customer to opt-out of a rate design.

Therefore, Sierra Club proposes a strong outreach, education, and enabling device program to accompany transition to a new rate design. In addition, Sierra Club is open to and supportive of a of a phased implementation of new rate designs, so long as the timeline and eventual end point of new rate designs are clear and stable, as we discuss below. Consistent with Public Utilities Code Section 745(d)(3), a residential customer would not be subject to a default time-variant rate without bill protection "unless that residential customer has been provided with at least a year of interval usage data from an advanced meter and associated customer education, and following the passage of this period, is provided with not less than one year of bill protection during which the total amount paid by the residential customer for electric service shall not exceed the amount that would have been payable by the residential customer under the customer's previous rate schedule." Sierra Club supports this kind of customer notification and bill protection during a transition phase, to assist in customer education and achieving greater demand response.

Given the importance of maximum and sustained participation in a time variant rate structure, the Commission should consider appropriate limits on the ability to opt-out of the proposed rate. One possibility would be to only allow a customer to opt-out after three years of using the new rate design to allow adequate time for customer response. Another possibility could be to limit the ability of high energy users to opt-out but allow opting-out for lower energy users. In either case, the opt-out rate design would be the same as the current 4-tier or 3-tier structure in effect for each of the IOUs. Access to the full range of enhanced demand response programs suggested in this document would be available to customers in the new rate design, but customers in the old rate design would only have access to regular conservation and efficiency programs. This would be to discourage opting out, since customers that opt out would be gaining a cross-subsidy through the use of cheaper peak electricity.

Opt-out provisions would not apply to customers receiving a medical baseline allowance and those customers requesting third-party notification under Section 779.1 of the Public Utilities Code. Pursuant to Public Utilities Code Section 745(d)(3), these customers would not be subject to mandatory or default time-variant pricing.

If a phased implementation is preferred by the CPUC, Sierra Club recommends that the timeline and eventual end point of new rate designs be clear and stable. This is necessary to provide needed certainty for customers, and to the solar PV and energy efficiency industries. One way to implement a phased approach is to start with a rate design similar to the tiered structure now in place, and add increasing TOU peak surcharges and off-peak credits over time. For example, every six months the peak surcharge could increase by 3 cents/kWh until the new rate design is fully implemented. This would reduce sudden impacts of rate changes on the customers who will be most affected. However, if this approach is adopted, the time period for opt-out should be reexamined to allow adequate time for long-run behavior change under TOU rates.

Literature on Mandatory, Opt-Out, and Opt-In Programs

Program participation rules are critical in demand response programs, especially given that most voluntary (opt-in) programs have had low participation (Alexander 2010). There may be very different conservation and substitution effects of demand response pricing depending on participation rules, which the literature has not adequately examined, probably due to the lack of existing programs. Most research has been on "pilot programs [that] are based on a relatively small group of volunteers who receive extensive education and 'hand holding' during the relatively short pilot programs." (Alexander 2010: 42). For example, Alcott (2011:826) gives the following caveat to his findings, "this experiment would not be very useful in understanding the effects of a mandatory, population-wide real-time pricing program because it is an opt-in program."

Faruqui and Sergici (2009) suggest that effectiveness of a voluntary program would be half to one tenth that of a default program. Train and Mehrez (1994:264) suggest that, "optional TOU rates can be used to increase welfare relative to a status quo of standard rates but not as much as would be possible with mandatory TOU rates."

On the other hand, mandatory programs could put undue burdens on certain groups. For example, Alexander (2010) points out that elderly and sick are forced to pay more for electricity when they are also told they should maintain safe air temperatures. For higher participation rates, and to avoid burdening disadvantaged groups, an opt-out program may be appropriate, or at least a mandatory program with opt-out permissions under certain circumstances such as a disability requiring a customer to remain at home.

Literature on short run versus long run effects

Charles River Associates (2007: 6-8) found, in their study of the California SPP, that TOU rate inducing behavior may not be sustainable in the long-run. "The reduction in peak-period energy use resulting from TOU rates in the inner summer of 2003 equaled –5.9 percent. …. In 2004, the TOU rate impact almost completely disappeared (-0.6 percent)". They suggest that this is because the price increases are relatively modest.

On the other hand, there seems to be more evidence that, over time, participants increase their responsiveness to demand response rates, which can be attributed to learning and long term changes in behavior and appliance holdings. Schwarz et al. (2002), based on Duke Power's eight years of RTP experience, reported that the firms collectively exhibited an hourly elasticity of substitution just under 0.2 in 1995, but it increased to 0.25 by 1999, and Taylor and Schwarz (1990) also found increases in elasticity over time based on the analysis of time-series data from Duke Power's residential TOU rate. Over time, ratepayers exhibited an increase in elasticity of maximum demand, measured by the cross-price elasticity of peak energy with respect to the demand charge, and in the substitution of off-peak for peak energy.

Several other studies concur, including Filippini (2011) who shows that long-run elasticities are higher than short-run elasticities. Estimated short run elasticities for users in 22 Swiss cities varied between 0.77 and 0.84 during the peak period and between 0.75 and 0.65 during the off-peak period. Estimated long-run price elasticities were larger, varying between 1.60 and 2.26 during the peak period and between 1.27 and 1.65 during the off-peak period. Espey and Espey (2004) found short-run elasticities of electricity demand are in between 0 and -1, with the median being -0.28. While long-run estimates are -0.81, with few estimates are beyond -1.5. Early research by Bohi (1981) had put these estimates to be 0.25 and 0.66 respectively, for the short- and long-run. Finally, Baltimore Gas and Electric conducted an econometric analysis of a PTR pilot program which revealed substitution elasticity between peak and off-peak hours of –0.096 in 2008 (18% reduction) and –0.120 in 2009 (33% reduction)(cited in Faruqui and Palmer, 2011), which suggests that customers became more responsive in the second year of the pilot.

In general, there is much more evidence that supports long-run increases in elasticity, rather than the opposite. This suggests that impacts of dynamic rates can increase over time, which may be attributed to learning, as users adjust their lifestyles to rates or acquire appliances that allow demand management.

8. Legal Issues and Barriers

Are there any legal barriers that would hinder the implementation of your proposed rate design? If there are legal barriers, provide specific suggested edits to the pertinent sections of the Public Utilities Code. If there are legal barriers, describe how the transition to your proposed rate design would work in light of the need to obtain legislative or other regulatory changes and upcoming general rate cases.

The Sierra Club's proposal for a hybrid TOU/Tiered rate structure furthers California's energy and environmental statutory objectives. By providing additional economic incentives for adoption of energy efficiency and rooftop solar, the Sierra Club proposal reinforces the Loading Order, which requires investment "first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply." (Pub. Utilities Code § 454.5.) For this reason, the proposal also furthers state policy to modernize the electricity grid though "[d]eployment and integration of cost-effective distributed resources and generation, including renewable resources" and "[d]evelopment and incorporation of cost-effective ...energy-efficient resources." (Pub. Utilities Code § 8360(c) & (d).) Incorporation of TOU rates also consistent with California's grid modernization policy and leverages the substantial investment in smart meters by enabling "[i]ncreased use of cost-effective digital information and control technology" and "[i]ntegration of cost-effective smart meter appliances and consumer devices." (Pub. Utilities Code § 8360(a) & (f).)

With regard to statutory restrictions on rate structure, the proposed rate design maintains the Tier 1 tier and existing level of CARE subsidies. However, the proposed rate design does contemplate a 40% increase of Tier 2 rates. Under the PG&E rate structure, Tier 2 is 101-130% of baseline. Under Public Utilities Code § 739.9(a), the Commission may only "increase the rates charged residential customers for electricity usage up to 130 percent of the baseline quantities ... by the annual percentage change in the Consumer Price Index from the prior year plus 1 percent, but not less than 3 percent and not more than 5 percent per year." Accordingly, the proposed rate structure calls for a larger increase to Tier 2 rates than permitted under existing law. The conflict between the proposed rate design and Section 739.9 could be resolved by limiting the applicability of Section 739.9(a) to increases up to baseline usage rather than 130% of baseline usage where a rate design also incorporates a TOU component. This would provide added flexibility to alter rate design, but make that flexibility contingent on incorporation of a combined TOU/Tiered structure.

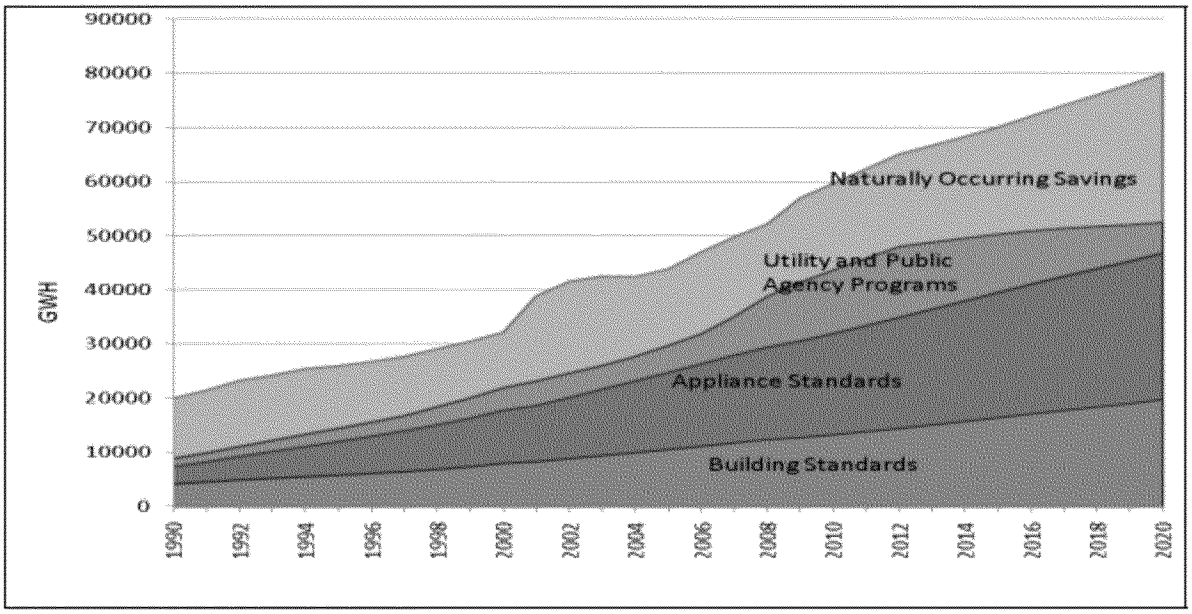
Public Utilities Code § 745(d) allows the Commission to approve default time variant pricing after January 1, 2014 if a number of conditions are met, including providing residential customers "the option to not receive service pursuant to time-variant pricing and incur no additional charges as a result of the exercise of that option." Sierra Club currently proposes introducing TOU rates in a manner that is consistent with existing law. However, as discussed in Section 7 of this proposal, the benefits of a TOU rate structure would be more fully realized if the ability to opt-out was narrowed, perhaps by limiting the ability of high energy consumers to opt-out. This modification to TOU implementation could require revisions to Public Utilities Code § 745(d).

8.1. Control and Disposition of the Public Benefits Charge

Control and disposition of the Public Benefits Charge (PBC) needs to be comprehensively re-examined and reformed to reflect program results, emerging best practices, and the changing relationship of stakeholders.

A serious examination and restructuring of efficiency and distributed generation regulatory policy is critical to realizing the full potential of this rate design proposal. Current utility-operated efficiency programs have had a modest and declining impact on long-term energy efficiency infrastructure, compared to other approaches (Kavelec and Gorin 2009:8) (Figure 14)

Figure 14: Efficiency/Conservation Consumption Savings by Source



Source: California Energy Commission, 2009

In the residential sector, the PBC currently funds overwhelmingly target cheap, short-term efficiency measures, instead of focusing on maximizing the life-cycle savings of long-term equipment investments. Seventy-six percent of the roughly 1 million MWh/year in new residential efficiency savings reported for 2010-2011 were for residential lighting, essentially all of it for compact fluorescent lighting (CFL) (CPUC, 2012). Residential lighting accounts for about a quarter of residential electric load in California, largely off-peak, and these are short-term savings, which vanish as state lighting codes kick in over the next four years. Training of California contractors and materials/equipment suppliers in preparation for 2020 net-zero building codes, and best-practice, high performance building efficiency techniques (e. g. Milne and Kohout 2010) remains largely *ad hoc*. Energy Upgrade California, the most ambitious current residential energy retrofit program in the state, could, under other circumstances, be an excellent investment proposition for most residential customers, but not as currently structured (Bell 2011). One fundamental cause of the current situation is a “no-losers” policy for demand-side utility efficiency investment assures that incentives are set well below the life-cycle value of long-lived energy equipment and residential design choices.

We suggest that the benefits of our rate proposal could be much more easily attained with an accompanying restructuring of the Public Benefits Fund. In our proposed rate design (and in current rates), some users who consume electricity well above the baseline have higher bills impacts. It is precisely these customers that also have disproportionate impact on the grid (transmission congestion, need for greater peak capacity, etc.) and have the highest potential benefit (or shortest payback period) of adopting energy efficiency and rooftop solar PV. Therefore, it is in the interest of the State of California to provide these users with better access to programs that can relieve high bills. While this is outside the direct scope of this proceeding, we recommend that the collection and allocation of Public Benefits Funds be shifted to these customers. Public Benefits Funds are currently collected in equal amounts from ratepayers, and equal access to rebates and other programs are provided for all customers. However, for the large majority of customers, these upgrades are not cost effective under current or proposed rates, so funds are collected from ratepayers who have low usage and little impact on the grid, but these ratepayers are least likely to access these funds in the form of rebates.

We propose that high usage customers bear a greater burden of paying into the Public Benefits Fund as well as receive greater support in implementing cost-effective energy efficiency retrofits and DG solar PV installations. While making the programs available to all customers should still be a goal, if a portion of funds is specifically allocated to enhancing these programs for customers with high bill impact, the goals of reduced bill impacts and enhanced energy conservation through energy efficiency and DG PV can both be achieved. We recommend that this approach be implemented in conjunction with new rates structures in order to enhance customer acceptance.

Effective use of the PBF, under our proposed restructuring of without it, may require revisioning the current model for promoting energy efficiency. An alternative institutional framework for administering energy efficiency programs, such as a local government or third-party administrator, which is local, highly motivated, and tightly focused on maximizing the public benefits of efficiency and distributed generation at minimum cost. The PUC could shift most or all of PBC funds going forward to make available to competitive, non-utility efficiency and distributed generation program administered by local governments and other public or non-profit entities which have demonstrated a capacity to effectively administer, implement and monitor these programs.

9. Rate Design Adaptation Over Time

How would your proposed rate design adapt over time to changing load shapes, changing marginal electricity costs, and to changing customer response?

With increased penetration of a variety of renewable energy resources changing load shapes in ways that can be difficult to predict, adaptability should be a key requirement for any rate design proposal. The proposed rate structure is highly adaptable because it maintains flexibility over time by incorporating elements of both dynamic and tiered pricing. Different aspects of the proposed rate structure can be adjusted to respond to changing cost and risk parameters and greater experience with customer response. By containing elements of dynamic and tiered pricing, the Sierra Club proposal is designed to adapt to changes in load shape, marginal electricity costs, and customer response.

<u>Potential Need for Modified TOU Periods to Reflect Renewables Integration</u>

The proposed rate structure assumes the following time of use periods, based on PG&E's current optional residential TOU rate, schedule E-6:

> TIME PERIODS: Times of the year and times of the day are defined as follows:
> Summer (service from May 1 through October 31):
> Peak: 1:00 p.m. to 7:00 p.m. Monday through Friday
> Partial-Peak: 10:00 a.m. to 1:00 p.m.
> AND 7:00 p.m. to 9:00 p.m. Monday through Friday
> Plus 5:00 p.m. to 8:00 p.m. Saturday and Sunday
> Off-Peak: All other times including Holidays.

Winter (service from November 1 through April 30):
Partial-Peak: 5:00 p.m. to 8:00 p.m. Monday through Friday
Off-Peak: All other times including Holidays.
Holidays: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed. DAYLIGHT SAVING TIME ADJUSTMENT: The time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

As net load shape continues to change with increased renewable penetration, it will likely be appropriate to modify peak and partial peak times to more strongly encourage conservation and load shifting during early evening periods to reduce projected future ramping needs. This is a very significant issue both for rate design as well as renewables integration and procurement planning. This modification would require additional data and analysis that was not available using the current bill calculator and publicly available data. The utility parties in this proceeding declined to provide additional information in response to data requests by Sierra Club. Most importantly, by already having 3 TOU periods, the proposed rate design can be easily modified to support renewable integration and decrease reliance on fossil fuels during potential future ramping periods.

10. Safety

How would your proposed rate design structure impact the safety of electric patrons, employees, and the public?

This rate design would have no impact on safety of electric patrons and employees. It would improve the health and safety of the public because it would reduce air pollution and greenhouse gas emissions, as detailed above.

Qualifications

Dr. James Barsimantov. Assistant Project Scientist, Lecturer, University of California, Santa Cruz. Principal, EcoShift Consulting. Total years of relevant experience: 9.

Dr. Barsimantov brings 9 years of experience in environmental policy and economics, with an emphasis on climate planning and economic analysis of energy solutions for the public and private sectors. As Principal of EcoShift Consulting, he has developed several modeling tools for residential and commercial energy efficiency, has completed Climate Action Plans and energy assessments for multiple clients, and has developed a local carbon offset program for the Monterey Bay Region. In his role as Climate Action Manager at UCSC, he was a principal author of the UCSC Climate Action Plan, evaluating different energy efficiency and renewable energy options, and examining the economic consequences of different proposed actions. He worked on the analysis that shifted UCSC from a RECs purchase to developing local GHG reduction projects. He teaches several classes in the Environmental Studies Department at UC Santa Cruz, including Environmental Economics, Political Economy and the Environment, and Sustainability Engineering and Practice. His doctoral research focused on analyzing the effect of economics and environmental policy on resource user behavior. He holds a Ph.D. from UC Santa Cruz and a B.A. from UC Berkeley. Dr. Barsimantov was the lead author of the rate proposal and conducted the economic analysis of rate impacts on DG PV and AC.

Dr. Dustin Mulvaney. Assistant Professor of Sustainable Energy Resources, Department of Environmental Studies, San Jose State University; Principal, EcoShift Consulting. Total years of relevant experience: 7.

Dr. Dustin Mulvaney received his B.S. in Chemical Engineering and M.S. in Environmental Policy Studies from the New Jersey Institute of Technology, and has a doctoral degree in Environmental Studies from the University of California, Santa Cruz. Before his appointment at San Jose State University he was a National Science Foundation Postdoctoral Scholar at the University of California, Berkeley. He previously worked as the engineering group leader for a venture capital start-up that designed and produced environmental remediation technology, as well as for a Fortune 500 specialty chemical manufacturer as a process engineer. His research and consulting experience includes policy analysis in alternative energy and agrifood systems, life cycle assessment (LCA), and projects that utilize Geographic Information Systems (GIS). His work experience in LCA includes a meta-analysis of PV LCAs as part of his postdoctoral appointment at the University of California, Berkeley, as well as the project leader for LCAs for firms producing corn ethanol and seaweed-based ethanol. Dr. Mulvaney is a peer-reviewer for the National Science Foundation as well as several respected energy journals including *the Journal of Solar Energy, the Journal of Integrative Environmental Sciences,* and the *Journal of Environmental Science and Technology*. Dr. Mulvaney was the main author of sections 2.4.1 and Appendix B, and contributed text, research, calculations, and edits to several other sections.

Kevin Bell, Research Fellow, University of California, Santa Cruz, Principal, Convergence Research. Total years of relevant experience: 22.

Kevin Bell has been involved with energy and water resource policy for over thirty years. He was an editor and writer for *Rain* magazine, an early and widely respected periodical focusing on emerging technology and resource policy. At Fair Electric Rates Now, he performed implementation analysis of new, comprehensive Federal energy and water legislation for the Pacific Northwest, and reviewed the economics of nuclear construction projects throughout the region. As Policy Analyst for People's Organization for Washington Energy Resources, he co-authored one of the first consumer resource guides to electric energy policy in the United States, an edition of which remains in press today. His work as a Resource Specialist at the Washington State Energy Office included design standards for the initial residential energy efficiency programs in the Pacific Northwest, along with fieldwork and technical analysis of small hydroelectric sites across Washington. He was Editor of *Solar Washington*, a pioneering renewable energy publication. As a Senior Policy Planner on the Commissioner's staff at the Washington Utilities and Transportation Commission, he designed, co-developed, implemented, and trained electric and gas utility staff on using what became the reference model for risk analysis of integrated resource plans throughout the Pacific Northwest region. As Policy Director for the Northwest Energy Coalition, he managed intervention in regulatory proceedings, delivered expert testimony, performed policy analysis, and represented over seventy consumer, environmental, and utility organizations in regional stakeholder discussions and integrated resource planning processes. He was a principal in the first comprehensive utility decoupling and restructuring negotiation in the Pacific Northwest. His work as an energy and water resource policy consultant and planning analyst has continued as a Principal at Convergence Research. He holds an M.P.A. from Harvard Kennedy School, and a B.A. in Energy Systems from Evergreen State College. Kevin Bell was the lead author of Sections 2.2, 2.3, and 8.1, and contributed text, research, calculations, and edits to other sections.

Dr. Mark Buckley. Managing Director and Senior Economist, ECONorthwest (Portland, OR). Adjunct Professor, Department of Economics, Portland State University. Total years of relevant experience: 14.

Dr. Mark Buckley leads the Natural Resources and Climate practice at ECONorthwest, the oldest and largest economics consulting firm in the Pacific Northwest. His economic consulting experience began in 1998 as an economist at Research Triangle Institute under projects for the U.S. Environmental Protection Agency and U.S. Forest Service. He holds a B.A. in economics from Davidson College and a PhD in environmental studies from University of California, Santa Cruz with a focus on environmental economics. Recently he has conducted economic analyses for the U.S. EPA, USFS, BLM, UNDP, Washington Department of Ecology, and the city of Seattle. He develops economic models and analytical methods for planning and behavior involving scarce resources for public policy decision-making. In particular, he combines microeconomic and game-theoretic techniques with competence in the biophysical aspects of natural systems. Dr. Buckley specializes in bringing a behavioral approach to understanding individual and group incentives to account for decision-making in policy design. His work addresses benefits of watershed-scale river restoration in Utah; improving urban water quality with green infrastructure across the U.S.; adapting water resources to climate change in Hawaii; cost-effective approaches to policy and finance for restoring Puget Sound; water quality trading in the Lake Tahoe Basin; levee setbacks and restoration on the Green River in King County, WA; analyses of cost and risk reduction for large wildfires; landscape-scale restoration in the Sacramento River Valley; coordinating agriculture with development and habitat goals along the

Skagit River; water planning with reclaimed water for King County, Washington; and development of tools for communities to select appropriate water portfolios in coastal California. Dr. Buckley has published research in peer-reviewed journals and edited books. Dr. Buckley built the model used to estimate changes in electricity consumption used in section 2.4.4.

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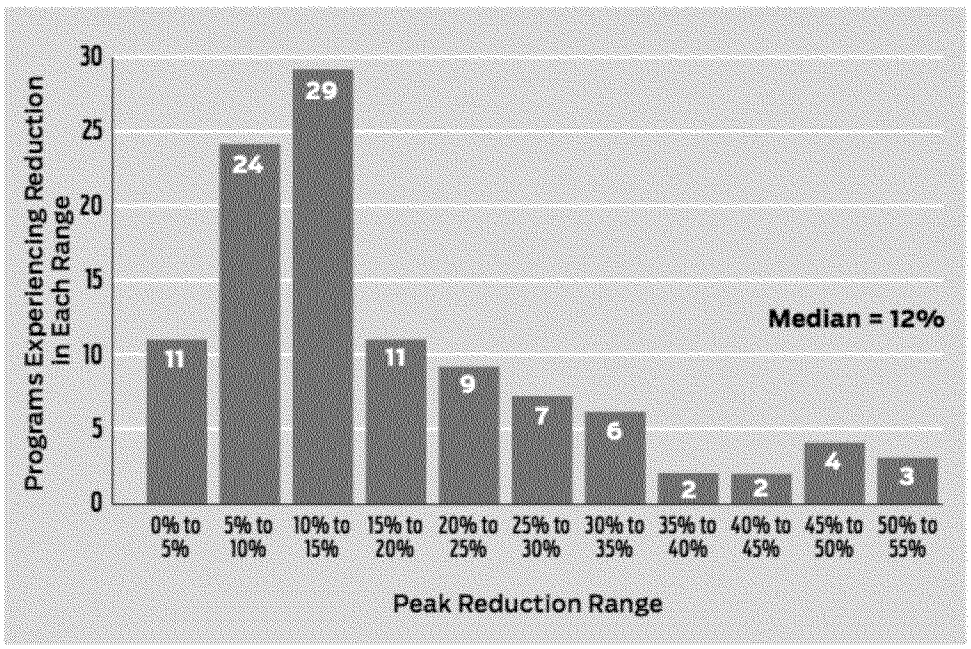
Appendix A: Literature Review on Dynamic Pricing Elasticities & Price Responsiveness

A.1. Literature Summary of Elasticities and Peak Reduction Percentages

Several review papers provide initial insight into the effectiveness of various approaches to dynamic pricing. We briefly present results of these review papers before exploring each of the dynamic pricing approaches and their impacts in greater depth.

Faruqui and Palmer (2011, p. 18) note that in 109 pilot tests of time-varying electricity rates, the median reduction in peak power consumption is 12%. Eleven of the pilot studies demonstrated demand response results in the 0–5% range, while 32 studies showed reductions over 20% (see Figure A.1, Faruqui and Palmer 2011).

Figure A.1: Distribution of 109 Pilot Dynamic Pricing Results (Faruqui and Palmer, 2011



EPRI (2008) compares elasticity results across multiple studies that look different dynamic pricing schemes and user types (see Figure A.2). Faruqui and Sergici (2010) summarize studies looking at various dynamic pricing schemes with and without enabling technologies (Figure A.3 and Table A.1). A synthesis of studies on dynamic pricing found reductions of between 2% to 6% (or elasticities of 0.02 to 0.1) (Faruqui and Sergici, 2009). They attribute this to the fact that electricity bills comprise a smaller percent of total household budget, and customers may see electricity usage as necessary during peak periods.

These review papers give critical insight into the impacts of dynamic pricing overall, showing that, in sum, there are peak load reductions. On the other hand, each study examines various approaches to dynamic pricing, uses different participants characteristics (location/climate,, appliance holdings, income, enabling technology, etc.), and implements different experimental designs. For this reason, care should be taken in interpreting results and drawing conclusions on best practices. In subsequent sections, we take a closer look at these and other results of dynamic pricing studies.

Figure A.2: Topology of Price Estimated Price Response Elasticities (EPRI 2008)

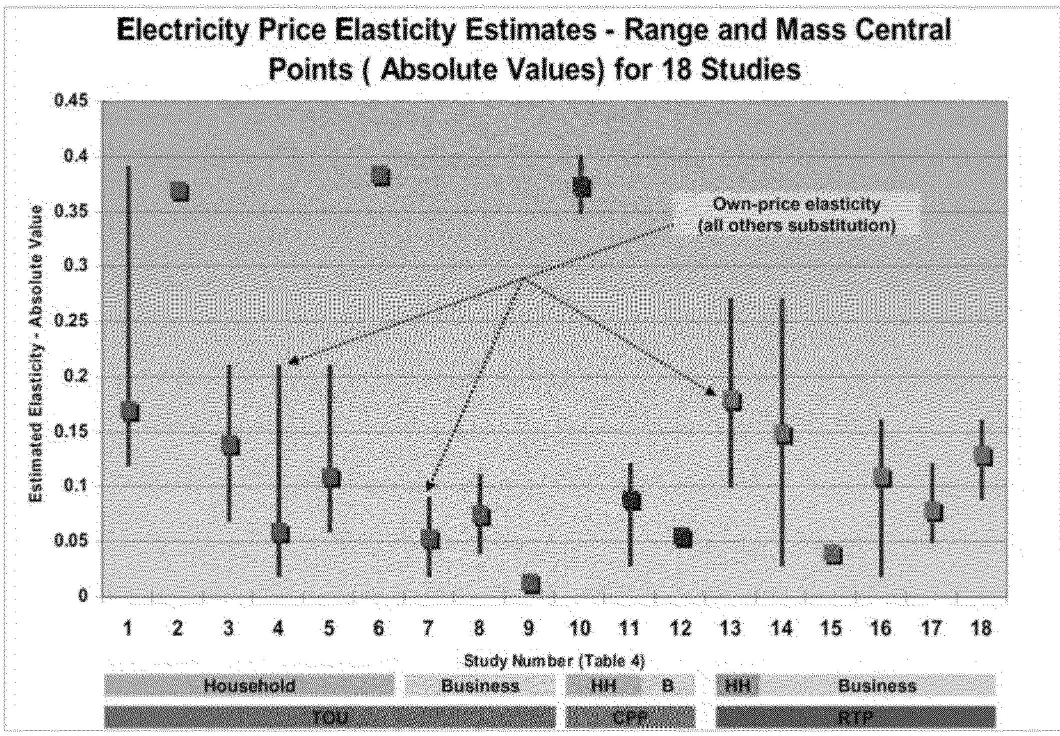


Figure A.3: Percent Reduction in Peak Load Across Dynamic Pricing Studies (Faruqui and Sergici, 2010)

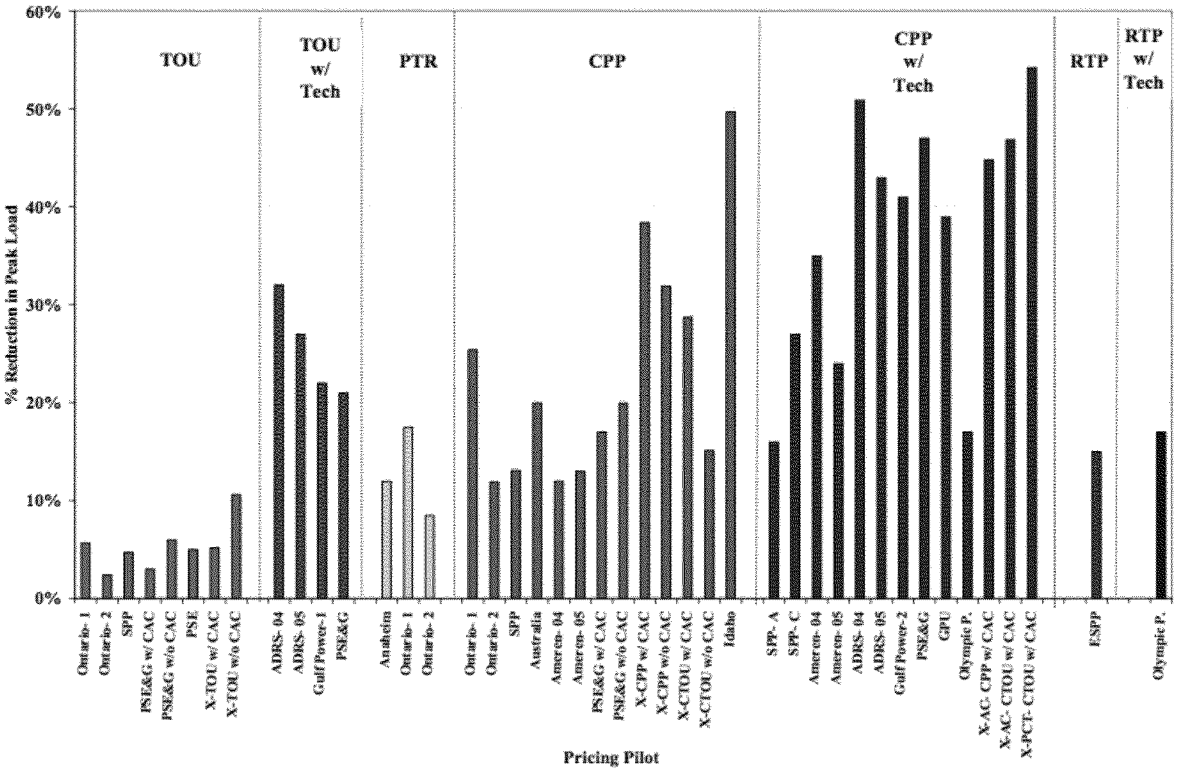


Table A.1: Summary Impacts of Dynamic Pricing Studies with and without Enabling Technologies (Faruqui and Sergici, 2010)

Rate Design	Number of Observations	Mean	95% Lower Bound	95% Upper Bound	Min	Max
TOU	5	4%	3%	6%	2%	6%
TOU w/ Technology	4	26%	21%	30%	21%	32%
PTR	3	13%	8%	18%	9%	18%
CPP	8	17%	13%	20%	12%	25%
CPP w/ Technology	8	36%	27%	44%	16%	51%

A.2. Literature Summary Results on Price Responsiveness

One primary conclusion above, from much of the demand response literature, is that a price differential between peak and off-peak prices can facilitate load-shifting and, perhaps in some cases, conservation. However, the extent to which customers respond more to greater price differentials is subject to considerable debate. Herter's (2010) results show that an increase in CPP price from $0.50/kWh to $0.68/kWh did not significantly increase load shifting. Her conclusion is that demand becomes inelastic after discretionary end uses are switched off during CPP events. In addition, Thorsnes (2012) found no significant variation in peak conservation with price, even though peak to off-peak price ratios varied from 1.0 (no differential) to about 3.5 (peak price range: 18 to 28b/kWh, off- peak price range: 8 to 18b/kWh). Train and Mehrez

(1994) also showed that results of different TOU rate structures were not significantly different from one another, although in this study peak to off-peak ratios did not vary much across rates. On the other hand, Faruqui and Palmer (2011) reviewed results from seven studies (with a total of 33 tests) and found that, "the peak price ratio successfully explains 60 percent of the variation in demand response." (p.18, Figure A.4). In addition, Faruqui and Sergeci (2009) modeled demand response curves that show increasing peak usage drops as peak price increases, and that these results varied considerably based on existence of central air conditioning (CAC) (Figure A.5). Based on these results, it is difficult to find clear conclusions on price responsiveness.

Figure A.4. Pilot Results by Peak to Off-Peak Price Ratio (Faruqui and Palmer, 2011)

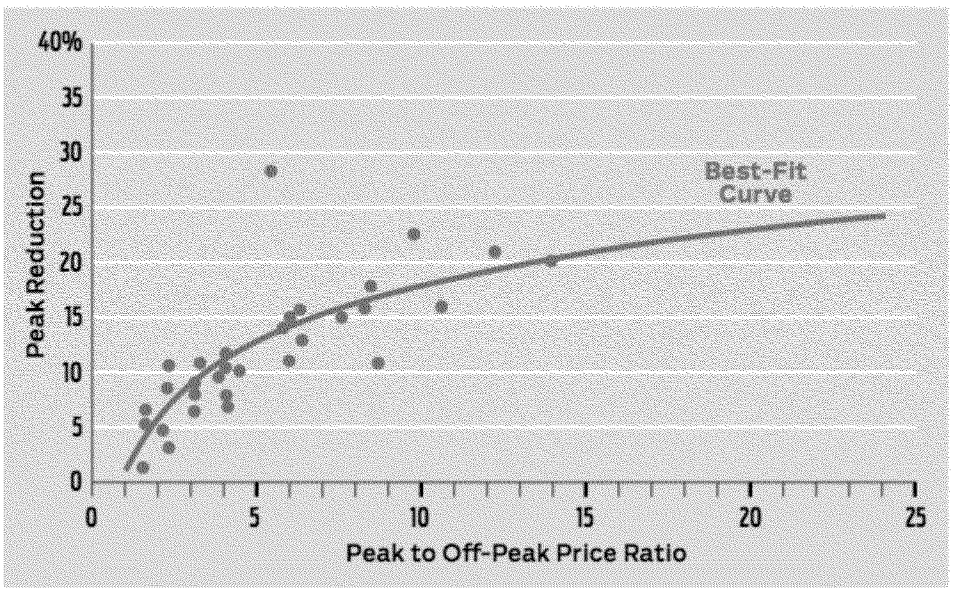
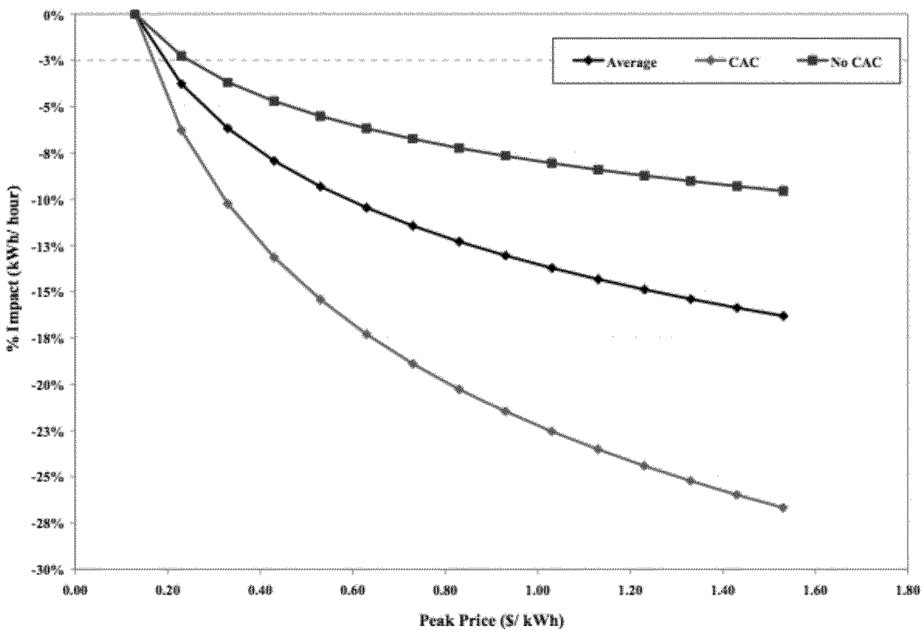


Figure A.5. Residential Demand Response Curves on Critical Days



A.3. Literature Summary on Demand Response by Participant Characteristics

Demand response varies with rate type, climate zone, season, air conditioning ownership, and other customer characteristics. Below are some results by participant characteristics, and, as we describe below, in some cases there are sufficient results to draw robust conclusions.

Results by Climate Zone

In general, participants in hotter climates respond more than those in cooler climates. Herter (2010), based on SPP data, found that the desert climate zone responded most in absolute terms (0.14 kW or 7.7%) than the coastal zone. However, the coastal zone responded most as a percentage of baseline load (0.05 kW or 10%). Her conclusion is that dynamic pricing should be implemented in all climate zones, since hotter climate will provide more load shifting, while users in cooler climates will see more bill savings.

Charles River Associates (2007) found similar results for CPP schemes: "Statewide, the estimated average reduction in peak-period energy use on critical days was 13.1 percent. Impacts varied across climate zones, from a low of –7.6 percent in the relatively mild climate of zone 1 to a high of –15.8 percent in the hot climate of zone 4. The average impact on normal weekdays was -4.7 percent, with a range across climate zones from –2.2 percent to –6.5 percent" (p. 6). Faruqui and George (2005) also found that warmer climate zones responded more. It is not surprising that these studies all found similar results, since they are all based on SPP data.

Seasonal Impacts

Several studies have shown that impacts of dynamic pricing vary by season, with the greatest effects in seasons where peak demand is highest. For example, demand response impacts were lower in the winter than in the summer, and lower during the milder winter months of November, March and April (the "outer winter") than during the colder months of December, January and February (the "inner winter"). Similarly, average impacts on critical days were greater during the hot summer months of July through September (the “inner summer”) than during the milder months of May, June and October (the “outer summer”)(CRA 2005). A study on a sample from New Zealand showed that TOU pricing appears to have no statistically significant effect, averaged over a full year, on daily or peak electricity consumption (Thorsnes, 2012). However, in winter, the peak season for electricity use, peak conservation was between 10–15%.

Results by Income Group

Faruqui and George (2005) detail reductions by several participant characteristics, including income (Table A.2). As in other studies, they found only a substitution effect, not an overall consumption effect. Higher income participants were more price responsive in this study, which concur with Charles River Associates (2005), who found that response in the California SPP was affected by income. In particular, households with incomes greater than $100,000 reduced peak electricity during CPP events by 16.2%, while households with incomes less than $40,000 reduced peak electricity by 10.9%.

On the contrary, Thorsnes (2012), in a TOU study in New Zealand, found that those with higher incomes responded relatively little to participation in the experiment. The question here is what may explain these results. Faruqui and George (2005) also show that groups with more education are more responsive, and income and education are highly correlated. So it could be that these participants were better equipped to understand how to respond. On the other hand, the Thorsnes results may be explained by the fact that high income households see electricity expenditures as a smaller percentage of total income.

Table A.2: Percent impact on energy use by rate period on critical days given a change in customer characteristics.

Variable	Customer Characteristic	Peak Period	Off-Peak Period	Daily Period
None	Average	−13.06	2.04	−2.37
Central A/C	Yes	−17.43	3.21	−2.82
	No	−8.05	0.68	−1.87
Average daily use	200 percent of average	−14.70	1.77	−3.04
	50 percent of average	−12.15	2.21	−1.99
Spa	Yes	−15.84	3.53	−2.13
	No	−12.94	1.93	−2.41
Electric cooking	Yes	−11.53	0.32	−3.14
	No	−14.09	3.16	−1.87
Persons per household	Four	−12.13	1.51	−2.47
	Two	−13.99	2.46	−2.35
Annual income	$100,000	−16.15	2.99	−2.60
	$40,000	−10.92	1.68	−2.00
Housing type	Single family	−13.98	2.72	−2.16
	Multi-family	−11.78	0.43	−3.14
# Bedrooms	Four	−15.67	2.12	−3.07
	Two	−11.59	2.01	−1.96
College education	Graduate	−18.52	3.69	−2.79
	Did not graduate	−8.56	0.93	−1.84

Results by Building Type

By building type, Herter (2010) found that high-use single-family homes responded most (0.15 kW, or 7.8%), and customers in apartments and low-use single family homes responded much less (0.02-0.03 kW or ~3%). This concurs with Faruqui and George's results (2005), which show that larger homes respond more, although Thorsnes (2012) showed that homes with higher occupancy respond less. While these are different variables, there are no clear conclusions in this category either.

Impact of Appliance Holdings

Elasticity of substitution in TOU rates has high variation based on household appliance holdings, a conclusion which holds true across many studies. Five residential TOU pilots funded by the U.S. DOE during 1977-1980 found that average within-day elasticity of substitution was 0.14, but that it varied by 50% in either direction (from 0.07 to 0.21) depending on household appliance holdings (Caves et al., 1984). Midwest Power Systems' 1991-1992 residential TOU program found that households with all major appliances had an elasticity of substitution of 0.39, while those with no major appliances exhibited no shifting and an estimated elasticity of substitution of 0 (Baladi and Herriges, 1993). Results from California's SPP showed a statistically-significant elasticity of substitution of 0.11 for households with central air conditioning, but a value of only 0.04 for those without (Charles River Associates, 2005; Charles River Associates 2007). Faruqui and Wood (2008) also found that values for central air conditioning users were about 2.5 times higher than for non-users. In addition, price elasticities were much lower: close to 0 for non-AC users, and 0.0399 (CPP) and 0.0565 (nonCPP). Faruqui and George (2005) found similar results (Table 2).

These results contrast with results from Thorsnes (2012), in which homes that heated water with electricity responded relatively little to participation in the experiment, which may seem contrary to studies that found higher response with AC. However, water heating may be a necessity and difficult to shift, while cooling in the summer may have more flexibility.

Impact of Education Level

Charles River Associates (2005) found that if the head of the household graduated from college, electricity consumption during a CPP event was reduced by 18.5%, as opposed to only 8.6% for those without a college education. Faruqui and George (2005), using the same dataset, not surprisingly found similar results (Table A.2).

Appendix B: Details on GHG Emission Factors used in calculations

To understand the impacts of rate design on greenhouse gas emissions we used two primary metrics and assessed how the results were sensitive to several assumptions.

First, we wanted to understand better how rate design would affect the carbon intensity of electricity sold by utilities (in lbs CO_2e/kWh). We used several approaches to estimate carbon intensity of electricity, including an estimate derived from actual production/dispatch data. There are also several standard CO_2e emissions factors available in the literature that are used by regulatory entities such as the Environmental Protection Agency (EPA) and the California Air Resources Board (CARB). We used these values as sensitivities to better understand the range of possible GHG impacts from various rate designs.

Second, we wanted to better understand the overall GHG impact of proposed rate designs. For this we estimated changes in electricity demand (kWh), approximated the magnitude of GHG impact based on several of the carbon intensity scenarios described above, and converted these results to metric tons of CO_2e (mTCO_2e) to understand the climate change impact of each scenarios.

There have been several research teams that have investigated the relationship between marginal electricity demand and the marginal carbon intensity of that electricity. Most of these papers are focused on how the temporal and geographic variations in GHG intensity affect the emissions associated with driving electric vehicles.

Holland and Mansur (2008) investigated the conventional wisdom that real time pricing (RTP) would lead to environmental benefits. It is widely accepted that cleaner, more efficient fossil fuel power plants are cheaper to operate and therefore more likely to produce baseload power, while less efficient combustion turbines are less efficient, and less profitable to operate except when wholesale electricity prices are at their highest on peak demand. This is sometimes described as the least cost allocation of electricity. Holland and Mansur (2008) used data from the EPA Continuous Emissions Monitoring System to estimate emissions, which we argue underestimates the carbon intensity of electricity because it does not consider upstream life cycle GHGs. They also treated the entire WSCC grid as one, which combines numerous very high and very low carbon intensity electricity generation sources that vary across subregions of the WSCC. Holland and Mansur concluded that there was a significant variation in environmental impacts with real time pricing because some places would see CO_2, SO_x, and NO_x emissions increase while other places would emissions decrease.

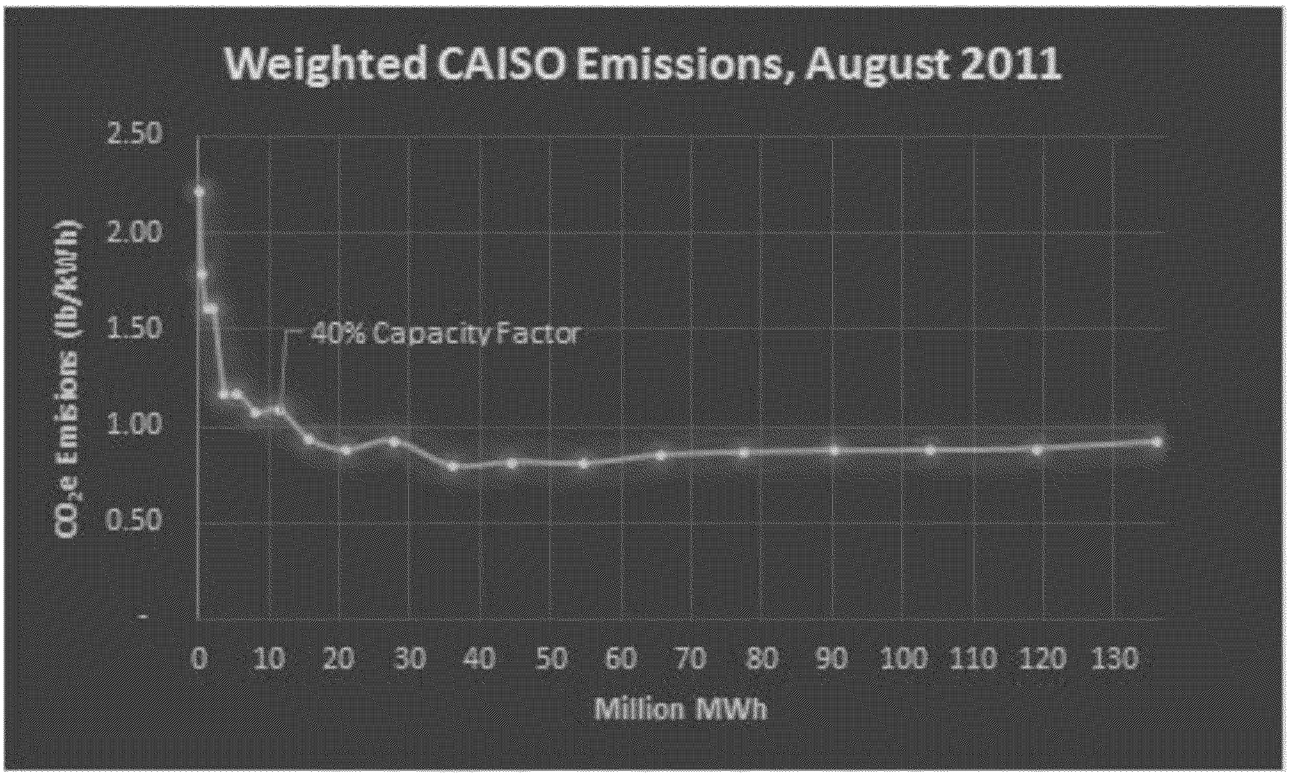
McCarthy and Yang (2010) found significant variations in carbon intensity for marginal electricity in California in the summer, but less variation in the winter;

To give an example, the Moss Landing power plant uses a simple cycle combustion turbine (SCCT) (about 50% less efficient than a CCGT) for its units 6 and 7, which provide peak power at a capacity factor of 0.13.

Figure B.1

Modeled CO2e emission factors (lb/kWh) - Source: CSI Avoided Cost Model 2010.08.06						
	TOU Period					
	Summer Peak	Summer Mid	Summer Off Peak	Winter Mid	Winter Off Peak	Weighted Average
January	-	-	-	0.896	0.849	0.865
February	-	-	-	0.915	0.855	0.877
March	-	-	-	0.864	0.838	0.848
April	-	-	-	0.904	0.836	0.863
May	0.908	0.867	0.842	-	-	0.857
June	0.945	0.902	0.844	-	-	0.875
July	1.224	1.101	0.903	-	-	1.001
August	1.128	1.017	0.891	-	-	0.956
September	1.137	1.024	0.889	-	-	0.960
October	1.002	1.005	0.888	-	-	0.932
November	-	-	-	0.997	0.889	0.926
December	-	-	-	0.965	0.856	0.898
Weighted Average	1.058	0.987	0.876	0.922	0.854	0.905

This modeled weighting can mask several issues. Lower capacity factor fossil fuel resources have significantly higher carbon emissions. For example, in August 2011, resources operating at a capacity factor below 40% produced 8% of system energy, while producing 12% of system CO2e emissions:



Source: QFER CEC-1304 Power Plant Owner Database

In addition, while QFER 1304 data includes contracted coal resources from InterMountain Power, it does not include the carbon embedded in contracted imports from the Pacific Northwest and Pacific Southwest, or from net balancing imports anywhere in the WECC system.

These additional inputs are significant and can vary considerably depending on time of day, time of year, and available regional hydropower reserves in a given year.

We used several secondary sources to estimate the sensitivity of GHG to different marginal emissions factors, represented in Table 3 (p. 3). We examined data developed by Zivin, Kotchen, and Mansur (2012), who produced several hourly estimates of marginal emissions of electricity in the peer-reviewed literature. Their regression approach aimed to estimate marginal emissions using data from the EPA's Continuous Emission Monitoring System (CEMS) from 2007 to 2009, which includes all power plants > 25 MW. They used the Federal Energy Regulatory Commission (FERC) data from their Form 714 which accounts for electricity consumption by planning area. The combined these with the EPA's Emissions & Generation Resource Integrated Database (eGRID) from 2007 to 2009, which tracks emissions from power plants. We took the results reported in Zivin, Kotchen, and Mansur (2012) in Table 2 of their report (p. 28), and aggregated the emissions factors based on the proposed TOU rates. The results for the WECC and US Total are below. However, these factors are based on combustion not life cycle emissions, so may under-report the magnitude of GHG impact.

In Table 3 (p. 15), we also report marginal emissions for the entirety of the WECC interconnection, of which CAMX is a subregion. Because electricity markets are dynamic and geographically heterogeneous, we consider scenarios where electricity and the associated emissions are traded within the WECC as well as throughout the US. There is precedent to use these more wide-scale emissions factors due to leakage in the California Air Resources Board (CARB) Low Carbon Fuel Standard and well as for the EPA's Renewable Fuel Standard (RFS2). In both cases, LCAs of transportation fuels (CARB) and renewable fuels (EPA) respectively are required to use US average emissions factors for electricity when estimating the carbon intensity of new fuel pathways.

Table B.1 below provides marginal GHG intensities for two representative months (February and August) from a study that used the EDGE-CA model to simulate electricity demand to assess how battery electric vehicle (BEV) charging power demand would affect the variability of carbon intensity across the system over time. They assumed a 1% increase in vehicle miles traveled by PHEV and BEVs and Plug-in electric vehicles, and a 0.1-0.3% increase in electricity demand. These particular values represent BEVs recharging according to a baseload changing program, where most BEV charging occurs off-peak and demand for charging is low during the day. Other behavioral practices for charging BEVs will have a unique emissions profile according the this study (McCarthy and Yang 2010). This study is important because it reminds us that existing demand profiles are likely to be sensitive to electric car adoption. As Table B.1. shows there is very little variability in carbon intensity in winter months such as February, in part because of the availability of hydroelectricity. But during the summer times there is significantly more variation in the carbon intensity of electricity.

Table B.1 GHG intensities of marginal electricity demand in California based on an increase of 1% VMT by PHEV or BEV and an increase of 0.1-0.3% electricity (aggregated into February and August from monthly and hourly emissions factors found in McCarthy and Yang 2010).

	February	August
Peak (1pm-7pm)	1.451 lbs CO2e/kWh	1.632 lbs CO2e/kWh
Partial Peak (10am-1pm; 7-9pm)	1.445 lbs CO2e/kWh	1.555 lbs CO2e/kWh
Off-peak (1am-10am; 9pm-1am)	1.427 lbs CO2e/kWh	1.438 lbs CO2e/kWh

We considered using CARB pathway for marginal electricity in California which is based on a "Well-to-Tank" Life Cycle Analysis using a California-modified version of the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) tool developed by Argonne National Labs and modified to reflect a California average electricity mix under contract with the California Energy Commission (CEC). The assumption in this case is that the marginal resource mix is natural gas combusted in combined cycle combustion turbines and renewables. We argue this value for carbon intensity is an underestimate for the reason we give in the preceding paragraph. In fact our concerns about this value are echoed by McCarthy and Yang (2010) who conclude that "the assumptions included in the Low Carbon Fuel Standard (LCFS) misrepresent marginal generation for vehicles in California in the near term. Under the assumptions of this analysis, the LCFS underestimates near-term marginal GHG emissions rates by at least 40%, and likely by more than 60%" (p. 2108).