BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations.	Rulemaking 12-06-013 (Filed June 21, 2012)

OPENING COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON PARTIES' RESIDENTIAL RATE DESIGN PROPOSALS

Gregory Heiden
Attorney for the
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 355-5539
e-mail: gregory.heiden@cpuc.ca.gov

July 12, 2013

TABLE OF CONTENTS

SB_GT&S_0165179

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations.	Rulemaking 12-06-013 (Filed June 21, 2012)

OPENING COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON PARTIES' RESIDENTIAL RATE DESIGN PROPOSALS

I. INTRODUCTION

Pursuant to the Administrative Law Judge's June 24, 2013 Ruling, the Division of Ratepayer Advocates ("DRA") hereby submits its Opening Comments on parties' residential rate design proposals.

II. SUMMARY AND RECOMMENDATIONS

Herein, DRA provides a brief summary of the parties' May 29, 2013 rate design proposals along with a few general observations. DRA's support or disapproval of other parties' proposals will be elaborated upon in the discussion section.

Many parties support transitioning to default time-of-use ("TOU") rates at some point in the future.[1] These include DRA, the Environmental Defense Fund ("EDF"), the National Resources Defense Council ("NRDC"), the Sierra Club, the California Large

[1] DRA Residential Rate Design OIR May 29, 2013 Proposal (RROIR Proposal), p. 3; EDF RROIR Proposal, p. 6: NRDC RROIR Proposal, p. 2, Sierra Club RROIR Proposal, p. 2, CLECA RROIR Proposal, p. 1, CFC RROIR Proposal, p. 1.

Energy Consumers Association ("CLECA"), and the Consumer Federation of California ("CFC"). These parties recognize that the TOU rate structure, with some form of baseline protection and discount for customers on the California Alternative Rates for Energy ("CARE"), meets most of the Commission's rate design principles:

- Basic needs are met at an affordable rate (Principle #1);
- Rates are based on marginal costs (Principle #2),
- Rates reflect cost-causation (Principles #3),
- Transparent incentives are provided that encourage energy conservation (Principles #4 and #8),
- Rates encourage both coincident and non-coincident peak reduction (Principle #5);
- Rates are understandable and provide choice (Principle #6),
- Rates mitigate cross-subsidies (Principle #7);
- Rates are economically efficient (Principle #9),

A. Transition Plans

The majority of parties note that a number of years will be required to unwind the current tiered structure, with high inclining block rates, and to move towards a more cost-based rate. They further acknowledge that a carefully designed transition plan is necessary to prevent unacceptable bill impacts.[2] When parties first filed their rate proposal on May 29, 2013, very few parties presented specific transitional plans and transitional rate structures. Whereas, DRA presented the most comprehensive and feasible transitional plan with a clear end-target of default TOU rates. Subsequently, the IOUs made supplemental filings that provided transitional plans and rates pursuant to an ALJ's ruling on June 13, 2013 directing parties to submit additional information. Unfortunately, the July 1, 2013 filings by Pacific Gas & Electric ("PG&E") and San Diego Gas & Electric ("SDG&E") were incomplete. PG&E did not show bill impacts for

[2] For instance, DRA RROIR Proposal, p. 3., SCE, on p. 43, PG&E on p. 7, NRDC on p. 20, EDF pp. 27-28, CLECA on p. 5.

CARE customers for its end state default two-tier rate or for its TOU rate. SDG&E did not show bill impacts comparing current rates with its end state proposed rates, but instead broke up the bill impacts into five separate steps. The bill impacts for each step were significant enough to conclude that the cumulative bill impacts for their final proposed end state rate would be totally unacceptable.

In contrast to the IOUs' transitional rate plans, DRA's rate proposal would result in less bill impacts to the majority of the customers. SDG&E's proposal would have the most severe bill impacts to customers, which SDG&E attempts to moderate by presenting a five-stage transition plan. SDG&E's severe bill impacts are mostly caused by its proposal to recover all delivery rates through fixed charges, which SDG&E calls basic service fees ("BSFs"). DRA also designs its transitional rates to minimize unnecessary revenue shortfalls that may result from customers self-selecting the most beneficial rate options for them.

B. Cost-Based Rates

Parties also vary widely on what kind of rate is cost-based. The three Investor-Owned Utilities ("IOUs"), which are PG&E, Southern California Edison ("SCE"), and SDG&E, assert that a rate structure that incorporates substantial fixed charges would best reflect costs.[3] DRA believes that the IOUs' rate plans, with an emphasis on fixed charges combined with mild tiered-rates, are not truly cost-based. Remarkably, those rate plans do not reflect how the cost of energy varies with time of use. Their plans appear to be a veiled attempt to protect their revenue streams, and they would undermine utility incentives to manage their distribution costs. They also would reduce the potential for economic energy efficiency and self-generation. Furthermore, the IOUs' assertions that their proposals would promote customer acceptance[4] contradicts their own survey which indicates a customer aversion to both customer and demand charges.

---

[3] PG&E Proposal, pp. 43-47; SCE Proposal, pp. 15-16; SDG&E Proposal, pp. 23-28.

[4] SCE Proposal on p. 67

DRA's proposed default TOU rate structure without fixed charges better reflects the cost of providing electricity services than do the IOUs' proposals. Indeed, only a small portion of distribution costs truly are fixed in the sense that they do not vary with the size of the customer.[5] The TOU rate will work effectively to influence customers' behavior in reducing energy usage when electricity is expensive because most customers are familiar with the time-of-use concept.

C. Time Varying Rates

It is important to draw a clear distinction between TOU rates, which DRA supports as a default, and dynamic rates such as Critical Peak Pricing ("CPP"), which DRA opposes as a default rate design for residential customers.

TURN's aversion to TOU rates appear to be based on analyses that group TOU and dynamic pricing rates together.[6] DRA, like TURN, opposes ***default*** CPP because it is not an effective tool for large-scale deployment and it fails to meet most of the rate design principles. Specifically, DRA finds that CPP is inferior to TOU in encouraging conservation and energy efficiency, and in its ability to promote customer understanding and participation.

TOU is very different from CPP. TOU is predictable, and it is easy for customers to plan for and understand. In contrast, CPP focuses on a few event days, is mostly triggered by hot days, and is very unpredictable. TOU prices provide clear price signals to enhance customers' incentives to make both short term and long term financial

---

[5] As measured either by maximum (e.g., design) demand or actual demand.

[6] TURN, Proposal, p. 11, p. 42.

decisions in conserving energy or using energy efficiently. They are likely to be more effective than CPP, over time, to help the utilities to avoid future costly new plants or new procurement needs and mitigate unnecessary rate hikes.[7]

D. Summer Bill Impacts and Exemptions

DRA shares TURN's and other parties' concerns over high summer month TOU bill impacts in hot areas. In addition to enhanced outreach and assistance with energy efficiency measures, the utilities' balanced payment plans should continue to be available. In addition, the utilities should develop short-term crediting mechanisms (e.g. SNAP credits)[8] to help customers cope with abnormally high bills caused by air conditioning use during sustained hot weather. DRA's proposal includes exemptions for medical baseline and other vulnerable customer groups, and retains significant CARE discounts. DRA also emphasizes outreach and education that target customers with the largest adverse bill impacts so that they can opt out to a tiered rate option if that is more economical for them. All of these measures will mitigate many of the concerns of TURN and Greenlining/Center for Accessible Technology ("CforAT").

E. Recommendations

In summary, DRA recommends that the Commission:

1) Adopt DRA's transitional default Introductory TOU rate (with a three-tier opt-out option) and proposed gradual movement toward a cost-based default TOU rate (with a two-tier opt-out option).
2) Reject the IOUs' proposals for fixed charges. The IOUs collectively are proposing the introduction of a number of new residential fixed charges,

---

[7] While CPP may induce more demand reduction per participant in the short run, TOU rates are more likely to have a larger impact in the longer run. This is because of the ability of TOU rates to garner more participation and to increase customer propensity to make investments that shift or reduce energy usage. These benefits of TOU rates are discussed further below.

[8] A "snap credit" is an arrangement whereby customers who experience unusually high summer bills have the option of deferring the high component of their bills over the next 3-6 months. SDG&E proposed this option for customers on CPP in A.10-07-009.

including customer charges, basic service fees, demand-differentiated customer charges, and demand charges.

3) Adopt DRA's recommendations for moderating CARE discounts and reject the IOU proposals to drastically lower CARE discounts.

DRA discusses TOU rates, fixed charge proposals, and CARE discounts in greater detail below.

III. DISCUSSION

A. Fixed Costs and Fixed Charges

Perhaps the most troublesome aspect of the utilities' filings is the emphasis placed on fixed costs and fixed charges. They appear to place greater importance on fixed cost recovery than they do on transitioning to time-varying rates, which is a stated major purpose of this rulemaking.[9] The subjects of fixed costs and fixed charges are extremely complex and better reserved for the general rate cases. If the IOUs want the Commission to sanction what kinds of costs belong in a fixed charge, then this is the wrong proceeding for that discussion.

DRA has a fundamental disagreement with the utilities' assertions on what constitute costs that do not vary with consumption, and whether or not such costs are most appropriately captured through fixed or volumetric rates. DRA has ample evidence, provided in DRA's proposal, as well as in these comments, to demonstrate that, from the perspectives of customer acceptance and pursuit of state policy goals, fixed charges should be rejected.

Specifically, economists agree that reducing the volumetric energy rate by substituting a fixed charge for a per-kWh charge would increase demand, and therefore would be contrary to State energy and environmental policy. In the most egregious example, SDG&E's proposal to collect 100% of distribution costs in a fixed charge,

---

[9] Indeed, the caption in this rulemaking has the words "the Transition to Time Varying and Dynamic Rates."

would shave 7.3 cents off an average volumetric rate of about 18 cents – a 40% reduction.[10] The National Regulatory Research Institute ("NRRI") has indicated that the short-run price elasticity is about 0.2.[11] Given this value, ***implementation of SDG&E's proposal could cause an 8% spike in demand in the short run.***[12] The longer-term increase in demand could be even worse because NRRI has found that the long-run elasticity for residential electricity consumption is several times as large as the short run elasticity.

1. Recovery of "Fixed Costs" in a Marginal Cost World

DRA's largest concern is the utilities' tendency to regard any cost that does not vary with changes in usage or load as a candidate for fixed charge recovery. DRA discusses some specific examples of problematic cost categories, suggested by PG&E and SCE in their May 29th proposals, in Section 2 below. In spite of these suggestions, SCE has limited its fixed monthly charge, in its end-state default tiered rate, to $5 for non-CARE customers in its July 1st filing.[13] PG&E proposes $10 in its July 1st filing. In

---

[10] Response Of San Diego Gas & Electric Company (U902m) To Administrative Law Judge's Ruling Ordering Parties To Submit Additional Information For Rate Design Proposals, Confirming Workshop Date, And Setting Forth Format For Comments; July 1, 2013, Attachment B, p. 3.

[11] An NRRI literature survey, "How to Induce Customers to Consume Energy Efficiently: Rate Design Options and Methods", p. 63, by Adam Pollock and Evgenia Shumilkina of the National Regulatory Research Institute, confirms that the long-run price elasticity effect is likely to be greater than the short-run effect, and identified electricity demand elasticity is about 0.7 in the long run and 0.2 in the short run.

[12] Elasticity is defined mathematically as $e = (dQ/Q)/(dP/P)$. In words, it is the percentage change in quantity demanded as a function of the percentage change in price. For a 40% price decrease, an elasticity of 0.2 would result in an *increase* in demand of 40% x 0.2 = 8%.

[13] Both SCE and PG&E propose that monthly fixed charges for CARE customers be 20% less than those of non-CARE customers. SCE proposes a fairly aggressive demand-differentiated customer charge for its optional TOU rate of $15 per month for customer below 5 kW and $20 per month for customers above that amount. It also included a bill impact analysis in its May 29th filing for a demand-differentiated customer charge on its optional TOU rate that ranged from $20 to $30. DRA assumes that SCE decided, in its July 1st filing, to scale this back to $15 and $20 moderate bill impacts. The May 29th filing also contains bill impacts for a tiered rate with a $5 monthly charge, but it is unclear whether this was intended to be the transitional or end-state rate.

contrast, SDG&E proposes two alternatives in its July 1st filing: either a basic service fee of $38.24 per month or a demand-graduated basic service fee that ranges from $15 per month to $65.17 per month. SDG&E's July 1st proposal is addressed in Section 3 below.

In general, the utilities, in their May 29th filings, tend to treat the fixed charge as a "catch all" for any cost that does not relate to marginal energy or demand costs. If they had their way, they might like to put the entire equal percentage of marginal costs ("EPMC") markup into a fixed charge. SCE's distribution fixed access charge, described in Section 2 below, may be a veiled attempt to do so. The SDG&E proposal to include all distribution costs in its basic service fee effectively would do the same. The SCE and SDG&E proposals are discussed in Sections 2 and 3 below respectively.

DRA emphasizes that, from a theoretical perspective, the only costs that could possibly belong in a fixed customer charge are ones that vary strictly with the number of customers.[14] Costs that vary with demand, or that do not vary with either changes in demand or in the number of customers, do not belong in a fixed charge. Any non-marginal costs normally are captured in revenue allocation in the EPMC markup.[15] In rate design, they are recovered by selectively scaling marginal cost revenue to achieve revenue reconciliation. In the past, this scaling normally has been done on the volumetric rate. But whether both the volumetric and customers charges should be scaled proportionally, or in some other manner, is clearly a subject for the general rate cases.

The issue of what costs truly vary strictly with changes in the number of customers always has been problematic.[16] The other issue, which DRA raised in its May 29th comments (in Appendix A), is that many of the candidate costs are sunk from the viewpoint of existing customers, and there is little they can do to influence these costs.

---

[14] i.e., revenue cycle services costs such as metering and billing costs fit this description.

[15] The exception to this general principle is the many miscellaneous revenue accounts allocated predominantly by sales. Some are discussed in the next section.

[16] Arguably, some distribution costs vary jointly with kW and numbers of customers. However, to DRA's knowledge no satisfactory methodology for teasing out this relationship has been proposed.

The fact that the Commission, in almost every rate design case that has been litigated,[17] has adopted the "New Customer Only" (or "NCO") method of reflecting marginal customer hookup costs should indicate that it regards the existing hookups serving existing customers as sunk costs. The methodology only includes the cost of new hookups, and is highly influenced by the new customer growth rate. Clearly existing customers have no influence on new hookups or the customer growth rate, and thus embedding a price signal in rates that reflects this cost serves little purpose.

PG&E states, in its May 29th comments (on page 43), that costs that vary with numbers of customers traditionally have included those associated with revenue cycle services ("RCS"), which in turn "include the costs of connecting a customer to the grid and maintaining that connection and service to the account—including metering, preparing and sending bills, processing payments, providing service center resources, and other grid-related costs." DRA acknowledges that the agreed upon definition of marginal customer costs, which includes the costs of the final line transformer and service drop as well as metering and billing costs, has been established for purposes of revenue allocation. But clearly the costs of the transformer and service drop vary with design demand.[18] Thus, while it might be appropriate to use this agreed upon definition for revenue allocation, it is questionable whether it works for establishing fixed charges.

The issue is that revenue allocation is done at an aggregate level where the marginal costs are based on typical customers who impose an average amount of load to the utilities. Whereas, a fixed customer charge would be imposed on all customers – both large and small. And it would be unfair to impose on a small customer, which has less than average load, a cost that represents that of a typical customer with average load.

---

[17] See Decisions 92-12-057, 95-12-053, 96-04-050, 97-03-017, and 97-04-082, which apply to both gas and electric utilities and include PG&E, SCE, and SDG&E.

[18] Costs of final line transformers per customer served can vary by a factor of ten among residential customers. In dense neighborhoods of smaller homes, 12-15 customers may be served from a single transformer. At the other extreme, large homes on large lots may be served by larger transformers serving two or less customers per transformer.

As indicated in Appendix A of DRA's May 29th comments, DRA is skeptical of imposing any kind of customer charge. Nevertheless, if one were to do so, it must be acknowledged that the only costs that unambiguously do not vary with customer size, demand, or volumetric usage are those of the meter and the billing services. Whereas, the costs of final line transformer and service lines do vary with customer size. Indeed, customers that consume more kilowatt-hours ("kWh") require larger transformers. Similarly, they have larger homes that tend to be spaced further apart, requiring longer and more costly service lines.

This fact is not reflected in the various cost curves that the utilities presented in their May 29th filings.[19] These cost curves show the variation in the cost of serving a customer by customer size. The utilities' curves are based on the assumption that the fixed costs include final line transformer and service line costs, all the RCS costs and, in some cases, certain public purpose program costs and/or upstream distribution "infrastructure" costs. This assumption implies, incorrectly, that the cost of serving a small customer, on a per kWh basis, is much higher than that of serving a larger one.

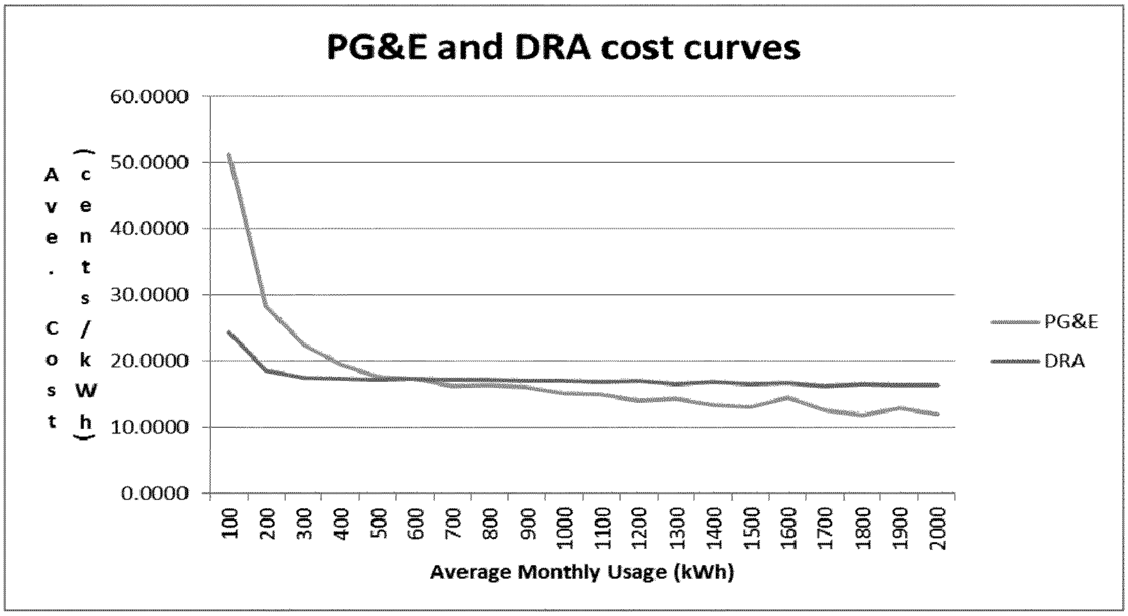
DRA does not agree with the utilities' characterization of costs. As an example, DRA has recast PG&E's costs to reflect the fact that only meter and billing services costs are the same for all customers and do not vary with demand.[20] Recasting the costs in this manner results in the curve shown in Figure 1, which also includes PG&E's representation of its costs for comparison. In the figure below, the costs that DRA regards as not varying with volumetric usage are about one third of what PG&E shows.

---

[19] PG&E Proposal, Section 2.1.4; SCE, page 19; and SDG&E, page 15

[20] DRA has used the marginal costs from the A.10-03-014 settlement in constructing this graph Basically, DRA constructed a cost function that categorized the meter and billing costs as fixed costs and everything else as variable costs modeled as TOU volumetric costs. Then it applied this cost function to the same 8,000 customer load profiles contained in PG&E's bill impact model. Generally, as can be seen from Figure 1, there is very little variation in the cost of service by size of customer, for those customers who use more than 200 kWh per month (the vast majority). In particular, there is no evidence that the cost of service declines with usage above 200 kWh (as might be inferred, incorrectly, from the PG&E cost curve in Figure 1).

Figure 1



If transformer and service line costs were deemed not to be recoverable in a customer charge, DRA understands that the utilities would argue that ideally a demand charge should be used to recover transformer and service line costs. Indeed, demand-related distribution costs are recovered in this manner from larger nonresidential customers. But DRA believes that demand charges are not appropriate for smaller customers, and that is why they are not employed in the small commercial sector. The next best rate element for recovery of non-customer-related distribution costs is a volumetric rate since non-coincident demand is normally highly correlated with volumetric consumption.[21]

The RROIR survey[22] shows that customers are mildly averse to demand charges. The survey stated that it is "possible that [the] concept was confusing and respondents did not understand that it varies based on kW demand levels, which made demand charges

[21] At least, when customers with rooftop solar panels are excluded.

[22] PG&E RROIR Proposal filing, Appendix A, "Hiner & Partners, Inc., Residential Rate Design OIR Customer Survey Key Findings", May 29, 2013, Slides 18-19.

appear low relative to monthly service fee”.[23] The survey also found that even small demand charges affect customer preferences to sign up for a certain rate plan. For the only utility in the survey that had a demand charge, only 17% of customers realized that it was on the bill.[24] This leads DRA to conclude that a demand charge approach would be ineffective in curtailing load, similar to a fixed charge.

The utilities, knowing that imposing demand charges in the residential sector could be problematic, appear to have developed an alternative, and that is demand-differentiated (i.e., graduated) monthly customer charges. DRA sees two obvious problems with this solution. First, customer charges are even less appealing to customers than demand charges. The RROIR survey demonstrated that fixed monthly customer charges were the bill element that had the largest adverse impact on customer preferences to sign up for a certain rate plan.[25] DRA’s rate design proposal (in Appendix A) also explained how fixed customer charges are so disliked that they only are sustainable in competitive industries where there is monopoly power.

The second problem is that conflating customer charges and demand charges into a single demand-differentiated customer charge might be extremely confusing to customers. It’s somewhat like a fixed charge that really isn’t fixed – so what is it? DRA also doubts that customers would understand the difference between non-coincident demand, captured in the demand-differentiated fixed charge, and coincident demand, captured in the utilities’ optional volumetric TOU rates.

DRA also is unclear about whether the demand charge element of the customer charge would be ratcheted.[26] If it were, then a third problem would arise: customers would not understand why their bills are not based on their highest demand in the month

---

[23] RROIR Survey, Slide 26.

[24] RROIR Survey, Slide 38.-

[25] RROIR Survey, Slide 18.

[26] A “ratchet” is an approach where the demand charge (or the demand-differentiated customer charge) is based on the customer’s highest demand generally in the most recent 12-month period.

to which the bill applies. They would not understand why they are being penalized for something they did months in the past, and they might feel that such a demand/customer charge is a trap from which it would be difficult to escape. The biggest mistaken assumption that the utilities make is that the customers sufficiently understand the utilities' cost structures that they will comprehend attempts to unbundle them in this manner. Yet, trying to show this unbundling in a charge that conflates two forms of cost incurrence into one is confusing.

There are other problems with fixed monthly charges. One is that fixed charges that recover a large percentage of the utility's revenue requirement would reduce the utilities' incentives to control costs. Such charges reduce the incentive to conserve energy since they necessarily would require a reduction in volumetric rates. PG&E denies the latter because customers allegedly react to their ***total*** bills, and not to the volumetric rates that would be reduced with a customer charge.[27] However, PG&E fails to acknowledge that imposing a fixed charge would decrease the total bill for large users. DRA noted that Dr. Faruqui appears to believe that there is some evidence that the price elasticity of electricity varies by usage level.[28] If this is true, then a fixed charge that shifts costs to smaller users will in fact ***increase*** aggregate usage.

2. Attempts to Recover Fixed Costs as Though They Were Marginal Costs

There are two instances in the utilities' May 29th filings that incorrectly characterize fixed costs as marginal costs to be recovered through fixed charges. The first is SCE's identification of distribution grid costs that it believes are not customer-related but are nevertheless fixed, and recoverable through a fixed access charge. The second is PG&E's proposal to recover CARE and Energy Efficiency program costs through a fixed charge. DRA discusses these two proposals in this section.

---

[27] PG&E, p. 85.

[28] DRA May 29, 2013 RROIR Proposal, p. 23, fn. 33.

SCE includes a fixed distribution grid access charge in Table II-7 on page 36 of its May 29th filing.[29] In this table, SCE distinguishes the grid access charge from a customer charge that presumably would be based on marginal customer costs. SCE does not explain what this access charge is, but DRA is concerned that SCE may have in mind something like the fixed "grid infrastructure charge" that SCE, in its 2002 GRC, unsuccessfully promoted. This charge of $24 would have recovered almost two-thirds of SCE's distribution revenue requirement (A02-05-004, ORA testimony, page 1-3).

DRA notes, however, that SCE's illustrative end-state default tiered rate design, in its July 1st filing, only includes a fixed charge of $5, which is not large enough to capture any grid access costs that SCE apparently sees as fixed. Thus, DRA is unclear about SCE's true intentions. DRA suspects that SCE refrained from including the fixed access component of its distribution grid in its fixed monthly charge to moderate bill impacts, but that it nevertheless sees the access charge as a legitimate element of a true cost-based rate. Since this kind of thinking may re-emerge as this proceeding evolves, DRA discusses it herein.

The biggest problem with the grid infrastructure charge, or any kind of fixed distribution access charge, is that neither concept is truly a marginal cost since neither varies with demand. Nor does it vary with changes in the number of customers since SCE would include a separate rate element for that. Since it varies neither with changes in demand nor with changes in the number of customers, it actually is a sunk cost associated with utility's historical investments and thus is part of the utility's general overhead. Such costs normally are allocated to classes using the EPMC approach.

In rate design, such costs generally are recovered by scaling the rate elements that are based on marginal costs. For example, if a $5 customer charge is employed, and it recovers 15% of the marginal cost revenues, then 15% of such grid infrastructure costs

---

[29] Note, SCE also includes in Table II-7 a variable charge associated with design demand or connected load. DRA assumes that SCE would see this latter component as alternatively recoverable through a demand-graduated monthly service fee.

would be recovered through the customer charge and 85% would be recovered through the volumetric rate. Policy considerations also have been employed in the past for recovering such costs entirely through the volumetric rate. One such reason is to encourage energy conservation. Exactly how overhead and sunk costs are recovered through rates is a very complex issue. Thus, DRA would urge the Commission to defer such issues to the general rate cases.

SCE's grid infrastructure charge and fixed grid access charge appear to be a departure from the long-standing EPMC methodology to something called "Ramsey Pricing," where the difference between the revenue collected using marginal costs and the authorized revenue requirement is allocated to customers based on their elasticities of demand. In fact, in SCE's testimony in the 2002 GRC, it stated that, "for rate design, grid infrastructure costs are best recovered through rate components that are relatively inelastic, such as customer charges. This is consistent with Ramsey pricing principles, so that these costs do not distort customer energy consumption decisions." [30] Using Ramsey pricing in rate design is a significant departure from Commission practice in marginal cost ratemaking.

The other serious issue about this grid infrastructure cost is how SCE calculated it in 2002. It was calculated as the difference between the replacement cost of the existing distribution system[31] and the marginal cost calculated using the standard approach developed by the National Economic Research Associates.[32] For a system that is fairly new, this would be equivalent to placing the entire EPMC multiplier into a fixed charge. TURN characterized a similar proposal in SCE's previous GRC as an "embedded cost

[30] A.02-05-004, Exh. SCE-14, page 15.

[31] The Commission has repeatedly rejected proposals to base marginal costs on the replacement cost new ("RCN") methodology. See, for example, D.92-12-058 which rejected an RCN methodology for determining the marginal cost of gas transmission.

[32] This is an approach where 15 years of cumulative investments are regressed against 15 years of cumulative changes in demand.

methodology dressed up to look marginal." [33] Clearly, whether this grid infrastructure cost is legitimately a part of the marginal cost structure is a threshold issue for even considering it, and this is not an issue for this proceeding.

The other example of considering costs that do not vary with load as candidates for fixed charge recovery comes from PG&E's May 29th comments. On pages 43-44, PG&E states that the costs of energy efficiency and low-income programs do not vary with the volumetric usage of non-participants. Thus, customers should pay these through a fixed charge. However, the costs of these programs do not vary any more with changes in the number of customers than they do with changes in sales. Given a choice, these costs should continue to be collected in volumetric rates as the Commission has decided in numerous proceedings.[34]

This ratemaking treatment is based on a policy that energy efficiency programs are a public good. It is because of this benefit that P.U. Code Sections 381(a) & (b) describe how energy efficiency ("EE"), research and development ("RD&D"), and the development of renewable program costs are to be collected on the basis of usage and charged through distribution rates:

> **381**. (a) To ensure that the funding for the programs described in subdivision (b) and Section 382 are not commingled with other revenues, the commission shall require each electrical corporation to identify a separate rate component to collect the revenues used to fund these programs. The rate component shall be a nonbypassable element of the local distribution service and **collected on the basis of usage.**

[33] A.00-01-009, Protest of the Utility Reform Network, Feb. 11, 2000, p. 3.

[34] In A.07-12-006, the Commission examined similar arguments from SDG&E, SoCal Gas, and PG&E ("IOUs") that CARE and public purpose program costs do not vary with the volumetric usage of non-participants, and in that case the IOUs argued that these costs should be allocated by the equal percent of base revenue ("EPBR") allocation method. This allocation method would allocate fewer costs to industrial and commercial customers. After extensive litigation by consumer groups the Commission rejected making the proposed changes to the allocation of CARE and public purpose program costs and concluded: "Applicant have not substantiated that its EPBR method is more reasonable that the cost allocation methods currently being used to recover the costs of PP programs. Therefore, it should not be adopted." (D.09-03-024, p. 18)

> (b) The commission shall allocate funds collected pursuant to subdivision (a), and any interest earned on collected funds, to programs that enhance system reliability and provide in-state benefits as follows:
>
> (1) Cost-effective energy efficiency and conservation activities.
>
> (2) Public interest research and development not adequately provided by competitive and regulated markets.
>
> (3) In-state operation and development of existing and new and emerging eligible renewable energy resources, as defined in Section 399.12.

Closely related to Energy Efficiency programs are other programs that also provide environmental benefits. The Commission likewise has allocated the costs of those programs by equal cent per kWh or therm. These programs include the Natural Gas Vehicle Program ("NGV") and gas Self Generation Incentive Program ("SGIP"). The Commission has stated:

> The Legislature has declared that the pursuit of cleaner air and relief from global warming is in the public interest. There is nothing in the hearing record which suggests that these benefits, as well as the strategic advantage of lowering our dependence upon foreign oil, will not be realized by the successful implementation of this program. To the extent that they are, they will be enjoyed by all Californians in their capacity as ratepayers.[35]

> The fixed infrastructure costs associated with the NGV program result in air quality benefits enjoyed by all Californians in their capacity as ratepayers and, as such, should be recovered on **an equal cents per therm basis** over all volumes sold by PG&E to all customer classes consistent with the intent of Public Utilities Code 740.3(c).[36]

---

[35] D.91-07-018, 40 CPUC 2d, pp. 738-739.

[36] 40 CPUC 2d at 744, Finding of Fact #13, emphasis added.

The Commission further stated, in a PG&E 2007 Biennial Cost Allocation Proceeding ("BCAP"), that:

> Consistent with our view that all customers should pay for programs that provide environmental benefits, we include wholesale customers in the allocation of SGIP costs as well as EG customers and adopt PG&E's proposal to allocate the costs on an equal cents per therm basis.[37]

As indicated above, PG&E also proposes that the cost of low-income programs be recovered through the monthly fixed charge. This is contrary to statute and Commission policy. Like Energy Efficiency, CARE is one of the major Public Purpose Programs ("PPPs") whose costs are to be allocated based on equal cents per kWh. P.U. Code Section 327(a) (7) states:

> For electrical corporations and for public utilities that are both electrical corporations and gas corporations, allocate the costs of the CARE program on an **equal cents per kilowatt hour or equal cents per therm basis** to all classes of customers that were subject to the surcharge that funded the program on January 1, 2008. (Emphasis added.)

There are other examples of costs that do not vary with usage that the Commission has determined should be recovered on a volumetric basis, and it has done so on public interest grounds. One such example is the Department of Water Resources ("DWR") bond charges. The Commission has concluded that the period of the energy crisis and the prices paid for power had little relationship to the cost of producing that power. Thus, the Commission found the strict use of the principle of "cost causation" to allocate bond-related costs at this level of detail to be unwarranted and, accordingly, adopted DRA's recommendation to allocate the cost based on equal cents per kWh. The Commission stated:

---

[37] D.05-06-029, mimeo, p. 18.

> Moreover, ORA provides several rationales for assessing the bond charge on a simple equal cents per kWh basis. In particular, ORA notes the expected duration of the bond charges of 20 years. ORA concludes that with the "inevitable changes in customers and circumstances" that will occur over this time period, these charges will be paid by customers who did not even live in California during the crisis and that some who did will not pay these charges if they move away. In light of the inability to link bond costs to a customer's consumption, ORA concludes that a simple per kWh charge is fairest.[38]

DRA recommends that the Commission continue this policy of allocating the costs of Public Purpose Programs, such as Energy Efficiency and CARE, on an equal cents per kWh basis. These programs benefit ratepayers broadly, and thus non-exempt ratepayers should pay for these programs equally for each unit of energy usage, regardless of their size. Given the Commission and State policy on how these costs should be allocated to classes, it makes the most sense to recover them through volumetric rates.

3. SDG&E's Analysis of its Distribution Costs is Especially Suspect

As stated above, SDG&E's July 1st supplemental filing contains two alternative rate designs for distribution costs. One collects all distribution costs through a $38.24 fixed charge and the other collects them through a demand-differentiated fixed charge ranging from $15 to $65.17.

Collecting all distribution costs in a $38 fixed charge is contrary to every party's understanding of a typical utility cost structure. In fact, it contradicts what SDG&E itself stated in its July 1st filing:

> "To move towards accurate price signals the rate structure for Distribution recovery would need to move away from the current volumetric energy rate ($/kWh) structure towards one that reflected the distribution cost structure; that is, recovery of

[38] D.02-10-063 as modified by D.02-12-082, p. 4.

> customer costs through fixed charges and distribution demand through a noncoincident demand charges."

Including the demand-related costs in a fixed charge that is not demand-differentiated is contrary to any reasonable characterization of a typical utility's cost structure.

DRA is still attempting to find out the underlying assumptions that SDG&E used in its July 1, 2013 filing, including those used in the demand-differentiated fixed charge. DRA is concerned that SDG&E's erroneous calculation of its marginal customer costs, as presented in its most recent GRC Phase 2 proceeding (A.11-10-002), may somehow be reflected in this rate design. SDG&E's GRC marginal costs were severely inflated in two ways. First, SDG&E persisted in using the "rental method" for calculating the marginal customer costs, a method that the Commission has rejected in litigated marginal cost proceedings since 1992, because it overstates costs.[39] Second, SDG&E analysis of its customer service costs imputed the identical cost ($160.43 per customer) for all customers, ranging from the largest commercial customer to the smallest residential customer.[40] For residential customers, SDG&E's value was 379% of the average of the corresponding costs of PG&E and SCE.

The net result of these methodological errors is that SDG&E's filed marginal costs ($259.05 per customer year) were well above those of SCE, which used the same rental methodology, as well as those of PG&E, which used the Commission-adopted "NCO" methodology. In its A.11-10-02 testimony, DRA proposed a nearly 70% reduction to

---

[39] See, for example, Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal.PUC LEXIS 270, D.96-04-050, FOF 37 and 38. These findings are consistent with Commission findings in Decisions 92-12-057, 95-12-053, 97-03-017, and 97-04-082 spanning both gas and electric utilities and including PG&E, SCE, SDG&E, and SoCalGas. While these decisions are old, they are among the most recent Commission decisions to address marginal cost issues. The Commission has generally adopted "black box" settlements of marginal cost issues since 2000.

[40] Streetlight customers were the only exception. See, Table 3-3 "Comparative Customer Service Costs" p. 3-11, DRA Testimony in A.11-10-002, filed May 18, 2012. In contrast, SCE's customer service costs for its largest customers were 30 times those for its residential customers, and PG&E's large commercial customer service costs were 274 times those of its residential customers.

SDG&E's proposed marginal customer cost to a value of about $6.50 per customer month, which is about one-sixth of SDG&E's proposed $38 customer charge.

DRA also notes that one of the inputs to the $38 customer charge is the share of the distribution revenue requirement allocated to residential customers. This in turn is affected by the magnitude of the marginal customer costs. To the extent that the $38 per month was derived using a revenue requirement that in turn was calculated using a $259 per customer year marginal customer cost, the residential class share of the revenue requirement itself is inflated as well.

4. Other Issues

All the utilities have presented the fixed costs of other utilities across the country as a justification for introducing fixed charges. Providing this information has little value to the Commission in determining whether there should be fixed charges. The utilities have provided no information on how many of those utilities use marginal cost pricing or even of how utilities functionalize different elements of their embedded costs. Further, California is a leader among states in its environmental policy. Fixed charges, as adopted by the jurisdictions that are less environmentally conscious, do not promote conservation. Accordingly, the Commission should not follow the example of out-of-state utilities with high fixed charges.

Recovering certain marginal customer costs through minimum bill charges would allow maintaining volumetric rates that would encourage energy conservation. Yet PG&E argues, on page 45, that a minimum bill is no substitute for a fixed customer charge. It bases this assertion on a hypothetical example of two customers who both consume small amounts of electricity and thus trigger the minimum bill provision. But one customer consumes more electricity than the other one. PG&E states that it is unfair to charge the two customers the same a minimum bill when they consumed different amounts of electricity. Yet PG&E has a proposal in its 2012 Rate Design Window application to set minimum bills only for distribution costs. If this proposal is adopted, PG&E's hypothetical would no longer apply. A low-usage customer would be required to pay the minimum bill for distribution ***plus*** the generation rates times kWh usage. Thus the two hypothetical customers would pay different total bills.

B. Time-Varying Rates

1. The IOUs

In reading the parties' May 29th comments, DRA was surprised that PG&E and SCE do not present some form of time-varying rate as their ideal. This form of rate design is closer to cost of service than either flat or tiered rates. Clearly their graphs, such as Figure 1 above, which show costs by customer size, omit one major variable that drives costs – and that is time of use. SDG&E, in contrast, provided a whole menu of options as its ideal, but it is unclear which rate option would be the default rate.

a) PG&E and SCE

As discussed in the prior section, PG&E and SCE especially put most of the emphasis on promoting cost structures that would support large fixed monthly charges that would create a secure revenue stream. Yet, these utilities do not appear to oppose time-varying rates on cost or conceptual grounds, as TURN seems to. Rather, their reticence to embracing TOU rates as the default tariff appears to stem from a fear about how customers would react to default TOU rates. DRA's response to TURN's comments is in the next section.

PG&E's Rate Design Reform Proposal would offer customers two basic rate options: (1) a standard tiered rate, and (2) an optional, non-tiered TOU rate.[41] PG&E believes that it can encourage the "innovators" and "early adopters" to opt into the TOU rate by educating and providing them "a variety of tools to help them understand their energy use".[42] It believes that, "under this approach, problems with backlash from highly resistant customers can be avoided."[43] PG&E furthermore states, based on survey

[41] PG&E, p. 10.

[42] PG&E, pp. 12, 13.

[43] PG&E p. 14.

SB_GT&S_0165201

findings, that "… customers that have opted into alternative rate plans are more satisfied." Moreover, it states that "there is no compelling evidence …that defaulting customers to a TOU rate plan is a successful approach to engaging customers in the behaviors a TOU rate is designed to encourage." [44] To substantiate these claims, PG&E explains how Hydro One customers (in Ontario, Canada) have much lower satisfaction levels with TOU rates than the customers of two utilities in Arizona that have offered TOU rates on a voluntary basis.[45]

SCE looks at the world in much the same way. It states "… by establishing a reformed rate structure, SCE's rate design proposal will facilitate the implementation of cost-based, optional, understandable, non-tiered, time-variant rate structures." [46] In other words, it wants to fix the problems with the current highly inverted tiered rates first before launching into TOU. DRA, in contrast, sees no reason why the unwinding of the tier structure and gradual introduction of TOU cannot occur simultaneously through an Introductory TOU rate. SCE makes reference to Arizona Public Service ("APS"), which, as of 2012, had over 50% of its residential customers enrolled in one of its TOU rate options.[47] SCE acknowledges that it could take several years for education and outreach efforts to produce significant customer migration. But it expects that, over time, "customers with higher cost to serve load patterns will remain on the tiered rate, which should ultimately be adjusted in future GRC rate design proceedings to include a cost premium relative to the cost-based TOU rate." [48]

Fostering customer acceptance in the transition to time-varying rates clearly is important. But DRA is concerned that offering TOU rates on a voluntary basis will result in a very low adoption of TOU rates after spending millions of dollars on advertising.

---

[44] PG&E, p. 15.

[45] PG&E, p. 71.

[46] SCE, p. 16.

[47] SCE, p. 47.

[48] SCE p. 47.

For example, SCE explains how it initiated a proactive residential customer outreach campaign in 2011 and 2012 to encourage enrollment in the currently available tiered TOU rate. The campaign was focused on 90,000 customers who would likely benefit from the offering. The campaign resulted in an overall adoption rate of only 4.8% of the targeted population.[49] SCE acknowledges that it would take years of such activity to reach a meaningful penetration of TOU rates. In fact, it took some 20 years for APS to reach its 50% adoption rate. DRA acknowledges that a recent pilot program at the Sacramento Municipal Utilities District has attracted about 15% of the participants onto an opt-in TOU rate in a single year. But the same pilot also included customers that were placed on TOU rates on a default basis in a single year, and over 90% of them have thus far not opted out.[50]

One of the reasons why opt-in TOU rates generally lead to a slow adoption rate is that, according to the RROIR survey, 40% of customers are risk averse and not willing to gamble on a higher bill for potential saving.[51] The survey also indicates that bill protection would increase customers' willingness to try TOU rates. But none of the utilities have demonstrated a clear transition plan that would show the rate of customer adoptions of TOU rates if they were offered on a voluntary basis.

As stated above, PG&E offers the experience of Hydro One to make its case against default TOU. However, it is important to note that Hydro One made such rates ***mandatory***, and no party in this proceeding (including DRA) is proposing mandatory time-varying rates. DRA very deliberately included in both its transitional and end-state TOU rates a non-TOU alterative that customers could elect. Offering any kind of rate on a mandatory basis will lead to problems. Yet, in spite of the negative initial reactions of

---

[49] SCE, p. 47, FN75.

[50] Sacramento Municipal Utility District, Interim Result from SMUD's Smart Pricing Options Pilot, Presented at the CRRI 26th Annual Western Conference, June 19-21, 2013, by Dr. Stephen S. George, Freeman, Sullivan & Co. and Ms. Jennifer Potter, SMUD, Slide 8.

[51] "Hiner & Partners, Inc., Residential Rate Design OIR Customer Survey Key Findings" ("RROIR Survey"), May 29, 2013, Slide 31.

Hydro One customers to such a rate, the RROIR survey showed that 50% of Hydro One respondents believed that TOU is the best rate, compared to 22% of California utility respondents. About 55% of the respondents from the two Arizona utilities with high TOU adoption rates believe that TOU is the best rate.[52]

PG&E especially has interpreted the results of the RROIR Survey more pessimistically than is warranted. It states, "respondents preferred flat and two tier rate plans the most."[53] While this may be truer of flat rates, the RROIR actually indicates that 1% more of respondents preferred TOU rates to tiered rates. It indicated that 22% would choose TOU rates compared to 21% for tiered rates if both were offered on a voluntary basis.[54] Surprisingly, 75% of respondents say that they have tried to save money by shifting their energy use, despite the fact that most customers currently are not on a TOU rate.[55] Yet they seem to understand the concept of shifting load. In contrast, customers really hated the fixed monthly service fee, which is where the utilities are placing most of their emphasis.[56]

Though they understand the concept of load shifting, very few realize that they must be on a TOU rate to save money when they do so. PG&E notes that:

> 74 percent of PG&E respondents have *shifted* usage to try to save money on their bill. However, only 22 percent *believed* they were on a TOU rate, and less than 2 percent actually are on a TOU rate. A large group of customers think that shifting usage can save them money on their bill, **but few understand that they must make an active choice for a rate plan option that rewards this behavior**. [57]

[52] RROIR Survey, Slide 33.

[53] PG&E, p. 70.

[54] RROIR Survey, Slide 7.

[55] RROIR Survey, Slide 11.

[56] RROIR Survey, Slide 18.

[57] PG&E, p. 66, emphasis added.

This statement highlights the fact that, for TOU rates to be effective, they must be a default rate option. Though a majority of customers have tried shifting their usage, they didn't make the effort to opt-in for a TOU rate.

The reticence of the utilities to offer TOU rates on a default basis could postpone the benefits of time-varying rates for a decade or more, reducing the probability that the Smart Meter systems will ever pay for themselves through demand response. These deferred benefits are clear. Data from PG&E's 2014 GRC (Phase 2) indicate that it is 40% less expensive, in fuel costs alone, to generate electricity during off-peak summer hours than during summer peak hours. This saved fuel results in reduced greenhouse gas emissions. In addition, the cost of generation capacity, if correctly assigned to the summer peak period, makes summer peak generation more than twice as expensive as off-peak generation.

b) SDG&E

DRA appreciates the effort that SDG&E exerted to describe what a fully cost-based rate might look like, and we recognize that this is SDG&E's "ideal" rate design. However, what it has presented could never be implemented in the real world because it would be far too complicated to explain to customers. Unbundling all the rate elements will only confuse customers. Would they understand choices between rate elements such as demand-differentiated customer charges and pure non-coincident demand charges, coupled with coincident demand charges, CPP/PTR, or flat commodity rates with a premium? Interestingly, there is no choice that avoids a fixed monthly basic service fee, even though such charges are difficult to sustain in unregulated markets in other industries that are competitive.

As stated above, it is very difficult to ascertain from SDG&E's proposal which of these would be the default rate. It appears that customers merely would be presented with a dizzying menu of choices and forced to make a choice. Revenue shortfalls from customers self-selecting the option on which they would be "structural benefiters" is not addressed.

One of the choices that SDG&E would offer is a non-coincident demand charge that would recover the entire cost of the distribution system that is not customer-related. SDG&E defines the distribution system as including "substations, circuits, feeders, and applicable O&M." It goes on to state: "The distribution costs utilities incur to provide service to customers is therefore best measured on the basis of a customer's individual maximum demand, distinct from demand at peak system capacity need."[58] TURN's May 29th comments contain a good discussion about how non-coincident demand is a poor representation of loads on substations, major circuits, and feeders.[59] The loads on such elements of the distribution system reflect enough coincidence to be better represented by a time-varying volumetric rate that is based on coincident loads at the generation level. The alternative choice that SDG&E would offer would be a demand-differentiated customer charge. But this again has the deficiency of being based on non-coincident demand, which could be appropriate for equipment very close to the customer's home, but not for equipment further upstream on the distribution system.

2. TURN

Of the fifteen parties submitting proposals, TURN had the bulk of the criticism of TOU rates. Notwithstanding this criticism, TURN supports voluntary TOU rates, though it did not propose a specific TOU rate design.[60] DRA agrees with TURN's dislike of default dynamic pricing, but finds that many of TURN's concerns with default TOU are based on conflating TOU with dynamic pricing, and are therefore misplaced. TURN's comments on TOU rates appear to discount the wide variation in the cost and environmental impacts of energy usage in different time periods. Further, TURN's comments also seem to not account for the fact that TOU periods and pricing can easily adapt to changing electricity usage and distributed generation patterns. Finally, TURN's

[58] SDG&E May 29th comments, pp. 24 – 25.

[59] TURN May 29th comments, pp. 73 ff.

[60] TURN, May 29, 2013 errata, p. 11

comments on air conditioner cycling seem not to appreciate that the non-dispatchable nature of TOU rates can be complementary to and supplement dispatchable demand response programs such as air conditioner cycling and voluntary CPP.

In its proposal, TURN often uses "TOU" and "dynamic pricing" interchangeably. For example, TURN states:[61]

> "The OIR touts the fact that TOU could be desirable because off-peak generation is "less expensive, more efficient and cleaner." But shifting a small portion of residential peak load due to dynamic pricing produces relatively small environmental, reliability or cost benefits …"

The problems with dynamic pricing cannot be used refute TOU pricing. TOU is a very different rate design from dynamic pricing and TOU has different and arguably greater benefits. TURN does not distinguish the impacts of dynamic pricing programs, which typically operate fewer than 100 hours, from TOU pricing, which provides a signal to conserve over 600 to 800 summer peak hours. For example, in arguing against "TOU and/or CPP pricing," TURN states: [62]

> "Given California's resource adequacy procurement requirements, spikes in wholesale prices due to peak load conditions occur only in the top 100 or so hours. Any potential emissions reductions due to load shifting result from the difference in heat rates between marginal units and shoulder peak units, which are both likely to be natural gas fired generators. Simply put, the net emissions reduction over 100 hours is small."

This statement may be true, but again, it does not apply to TOU, which, unlike dynamic pricing, does not reflect fluctuating wholesale prices but does elevate prices over a predictable set of 600 to 800 hours. In contrast, dynamic pricing programs, such

---

[61] Ibid

[62] Id, p. 42

as CPP, typically operate in less than 1% of the hours of the year, making their potential to shift a large amount of electric usage from dirty to clean resources much more limited.

Furthermore, TURN fails to acknowledge that conserving energy during the summer peak period is more valuable than doing so during the off-peak hours. Thus, even if usage merely is shifted from peak hours to off-peak hours, and no electricity is saved on a net basis, there is a significant economic and environmental benefit to society. The following statements by TURN downplay the greater value of energy reductions during the peak period:[63]

> "Since TOU rates could significantly reduce the economic benefits of conservation and degrade the value of investments in efficiency measures that produce savings outside of peak periods, there is no guarantee that any peak period environmental savings will not be more than offset by the environmental impacts of increased off-peak usage.
>
> Moreover, TOU or CPP pricing may actually negatively impact the economics of energy efficiency investments for end-uses that do not operate disproportionately on-peak (for example, any lighting or refrigeration that operates extensively during off-peak periods)."

The conclusions drawn above do not consider the fact that off-peak generation has smaller environmental impacts than peak-hour generation. For example, PG&E's 2014 GRC Phase 2 workpapers indicate an average "effective market heat rate" of 9,100 Btu/kWh over its 774-hour summer peak period, compared with a corresponding average of 5,900 Btu/kWh during summer weekday non-peak hours.[64] When usage is shifted

---

[63] TURN, RROIR Proposal, pp. 2-43

[64] DRA Appendix D, footnote 39, p. D-5 stated the off-peak heat rate as 5,400. The value of 5,900 represents a more conservative estimate, using PG&E data from the 6x16 CAISO peak period where applicable. Even with this more conservative calculation, the weekday average effective market heat rate for non-peak hours is 34% below the average peak period effective market heat rate.

from a peak hour to an off-peak hour, emissions would be reduced in proportion to the marginal heat rate because a commensurate amount of natural gas is conserved.

Further, TURN incorrectly downplays the reliability and net benefits potentially obtainable from TOU rates. As shown in DRA's Appendix D, according to a Brattle Group regression "meta-analysis" of 151 pricing studies, a TOU rate design with a peak to off-peak price ratio of 2.5 would result in a 9.6% reduction in peak demand. While DRA's Appendix D discusses several caveats with respect to that finding, the 9.6% peak reduction assumes no technological enhancement. Addition of technology could offset factors tending to reduce response, potentially resulting in a peak reduction even higher than 9.6%.

This benefit is especially valuable because of the closing of San Onofre Nuclear Generating Station ("SONGS") and the Once-Through Cooling ("OTC") power plants. Thus, TURN is incorrect in stating: "In light of the fact that new conventional generation is being constructed primarily to address specific local reliability concerns, rather than system-wide peak demand, it is not reasonable to assume that time differentiated pricing would yield any reduction in new conventional power plant development." [65] TURN's characterization that "new conventional generation is being constructed primarily to address specific local reliability concerns" may no longer be true, in the light of SONGS and OTC. TURN also fails to acknowledge the fact that the TOU rates and time periods can, and should, shift over time to reflect changes in "net load." TURN states: "Shifting residential peak further towards evening hours may turn out to be less desirable in the coming years, as demonstrated by the ISO's 'duck curve.' In order to provide any benefits, dynamic pricing may need to send mixed messages to residential customers, encouraging them to reduce their usage in the middle of hot summer days but shift more

[65] TURN, RROIR Proposal, p. 43

usage into the middle of spring days. The potential for customer confusion is significant."[66]

This argument might have merit if TOU rates were constrained to perpetually retain the current noon-6:00 PM summer peak period, but this clearly is not the case. As the ISO "duck curve" shows, the peak net demand hour is likely to migrate to the early evening with the increasing penetration of rooftop solar generation. In this case, the peak period will need to shift over time to reflect this new reality, perhaps to 4:00 PM to 8:00 PM during the summer months. If the shift is gradual, well publicized, and explained, it should not cause customer confusion.

C. Transition

All parties recognize that a transition is needed, and it may take many years to modify the existing rate structures to better reflect costs. Yet only DRA has carefully thought through the transition that would be needed to make its overall plan feasible. In designing its rates, DRA attempted to minimize rate shock, and to minimize potential revenue shortfalls, while providing to customers understandable rate structures and rate choices. These objectives are accomplished using a transitional Introductory TOU rate that has the same basic rate design as does the opt-out rate, but is augmented by a time-of-use ("TOU") surcharge and credit.[67] DRA also notes that several years would be required to gradually move towards a cost-based TOU rate, with a baseline credit, that would be offered concurrently with its opt-out counterpart two-tiered non-TOU rate.[68]

The utilities, in contrast, offer transition rates that have worse bill impacts than DRA's. Below, DRA highlights the transition rate bill impacts of SCE, SDG&E, and PG&E.

---

[66] Id.

[67] DRA Responses to the Residential Rate Design OIR (RROIR) questions, p. 12 (C. Transition Plan Rates; 1) Introductory TOU Rate and p. 17, Table 2: Illustrative Introductory TOU and Opt-Out Tiered Rates.

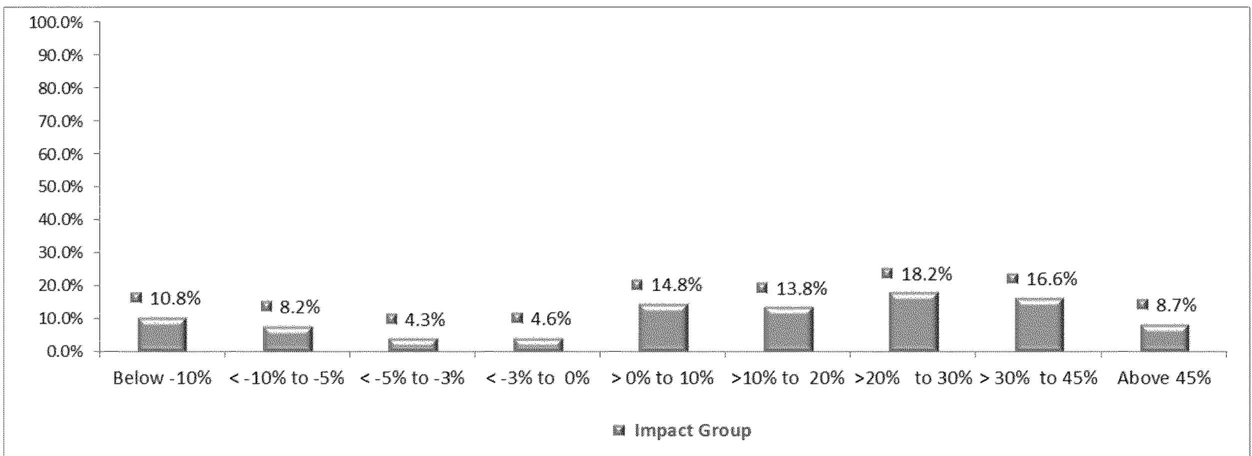
[68] Id., at p. 11.

1. SCE's Transitional Rate Bill Impacts

SCE presents an illustrative transitional three-tiered rate design with a $5 fixed charge and a 20% CARE discount.[69] However, the bill impacts of SCE's proposal (in Figure 2) are much worse than are those of DRA's transitional Introductory TOU (in Figure 3) and DRA's opt-out 3-tier rate option (in Figure 4). Furthermore, DRA designed its Introductory TOU and the opt-out rate so that their bill impacts would be very similar. This can be seen by comparing Figure 3 and Figure 4. This similarity indicates that a large element of the bill impact comes from revising the current tier structure and reducing CARE discount, and not from the TOU component. This also mitigates any revenue shortfalls caused by customers who self-select the rate option that may benefit them most.

Figure 2

SCE Illustrative Transitional Rate Bill Impact (combined CARE & non-CARE)



[69] SCE Proposal, p. 44.

Figure 3

DRA Transitional Illustrative Introductory TOU Rate Bill Impact (Combined CARE & non-CARE)

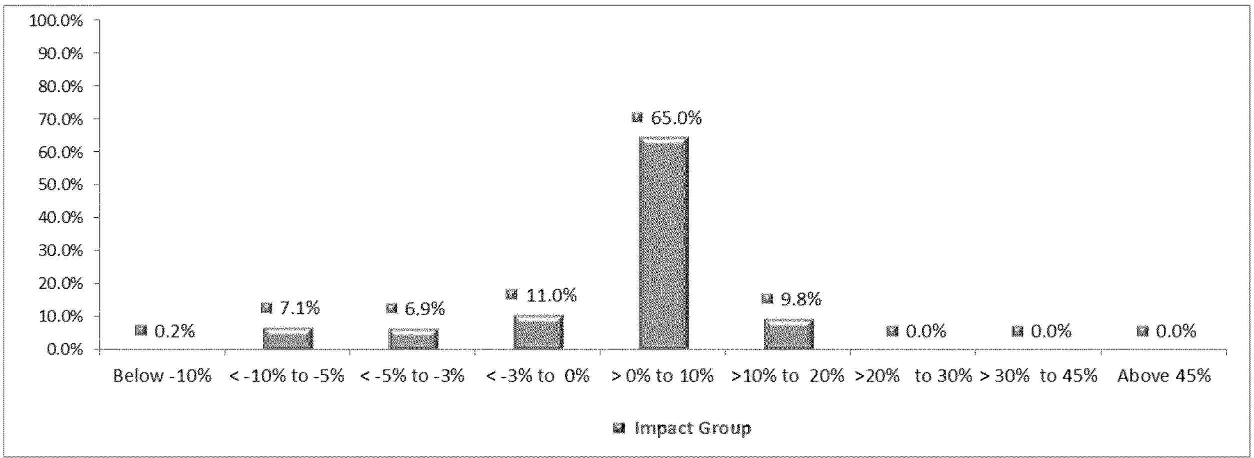
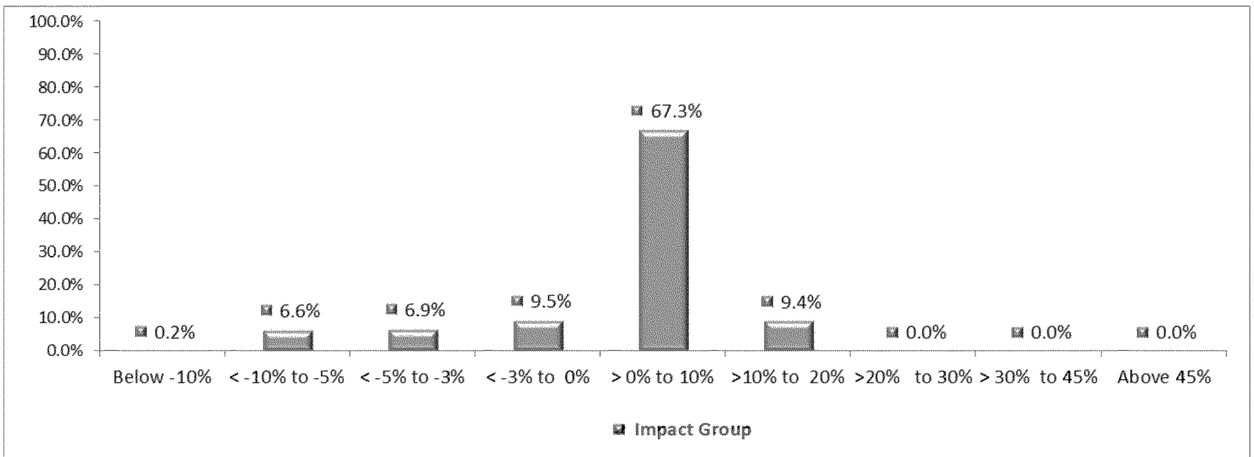


Figure 4

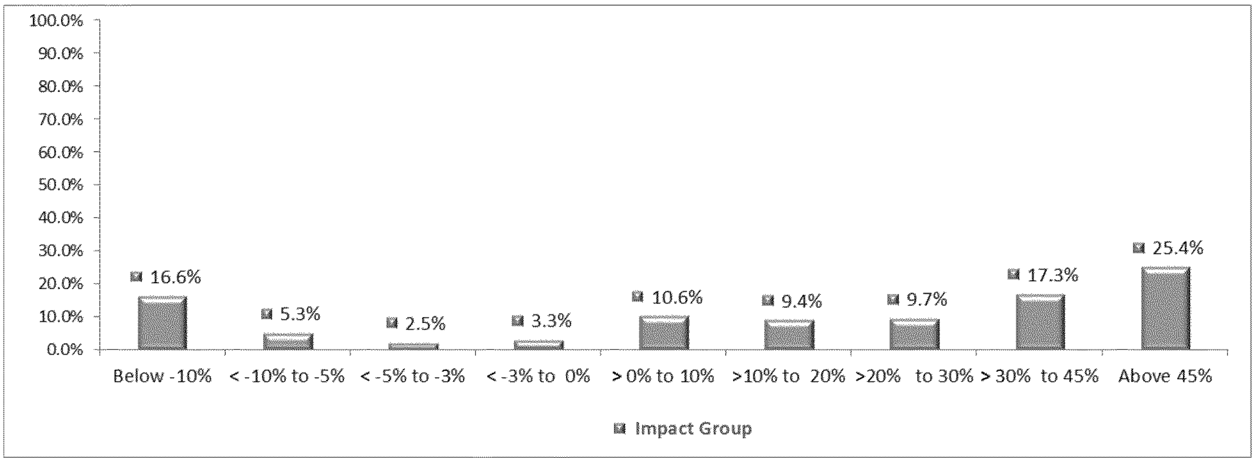
DRA Illustrative Transitional Opt-Out Rate Bill Impact (Combined CARE & non-CARE)



SCE's transitional three-tier rate would allow customers to choose an alternative TOU rate. In its July 1, 2013 supplemental filing, SCE shows the optional transitional TOU rate with demand-differentiated customer charges of $5 and $10 for non-CARE customers.[70] SCE's bill impacts are severe for a large percent of customers: 9% would see bill increase between 20% to 30% and 17% would see bill increases of 30% to 45%, and 25% would see bill increases of 45% or more. The differential between the highest tier and lowest tier (8 cents/kWh) on the default tiered rate schedule is substantially smaller than the on-peak and off-peak rate differential (16.2 cents/kWh) in the optional TOU rate. [71] Thus large flat-load customers, who are hurt by the tier differential but not by the TOU rate differential, would opt out to the TOU rate, creating revenue shortfalls.

Figure 5

SCE Illustrative Opt-out (TOU) Rate Bill Impact
(Combined CARE & non-CARE)



2. SDG&E's Transitional Rate Bill Impact

In its July 1, 2013 supplemental filing, SDG&E describes a desire to recover all distribution costs through a basic service fee ("BSF"). It further shows an illustrative five-step transition from the current volumetric distribution rate of 7.3 cents/kWh to a $38.25/month BSF. In each step, SDG&E envisions approximately a $7.5 increase in the

[70] SCE July 1, 2013 additional information on rate proposal, p. A-28. The $5 customer charge is for customers with demand less than 5 kW, and $10 is for customers with demand equal or greater than 5 kW. CARE customers would have a uniform $4/month customer charge.

[71] Id., pp. A-27 & A-28.

BSF that is offset by about a 1.5 cent/kWh reduction in the volumetric distribution rate.[72] Even with this multiple step, gradual transition, the bill impacts to customers in each step are substantial. For instance, in Step 1, SDG&E showed that more than 70% of customers (CARE and non-CARE) would see bill increases. About 30% of customers would see bill increases of more than 20%.[73]

SDG&E does not show the cumulative bill impacts of all five steps, but they undoubtedly would be quite substantial. DRA suspects that SDG&E's demand-graduated customer charge proposal may be some combination of the $12.67 BSF and $6.96 non-coincident demand charge shown in its bill impact model as a "cost-based rate."

SDG&E Cost-Based Rates		
-	**Non-CARE**	**CARE**
SCHEDULE DR		
Basic Service Fee $/Month	12.67	12.67
Non-Coincident Demand $/kW	6.96	6.96
On Peak Demand $/kW		
Summer	6.97	6.97
Winter		
Summer Energy $/kWh		
On Peak	0.1209	0.1158
Semi Peak	0.1059	0.1008
Off Peak	0.0900	0.0849
Winter Energy $/kWh		
On Peak	0.1044	0.0993
Semi Peak	0.0952	0.0900
Off Peak	0.0823	0.0772

[72] See SDG&E July 1, 2013 filing to provide additional information for its rate proposal, p. 3.

[73] Id., p. 4

If so, the bill impacts would be considerable. They are shown in the next two figures. As indicated, a large percentage of customers would receive bill impacts over 100%.

Figure 6

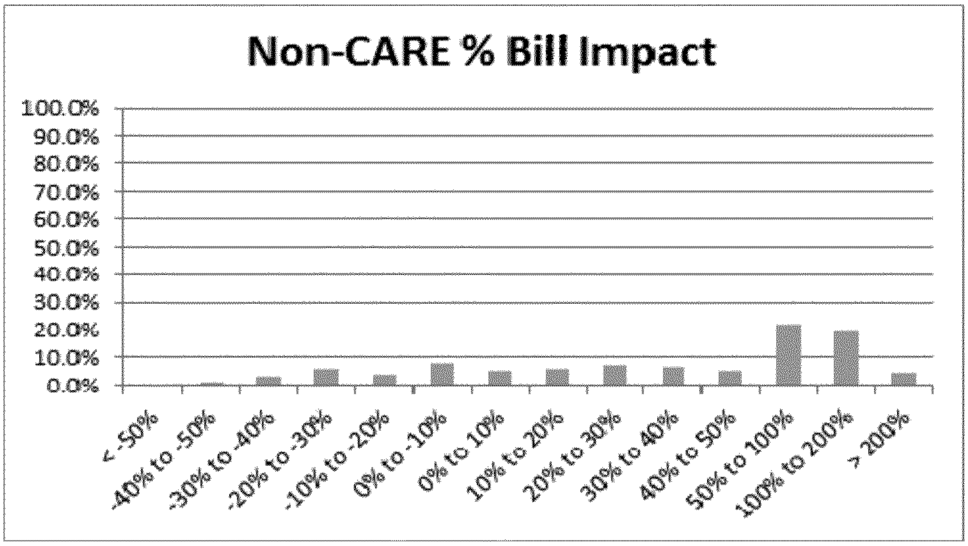
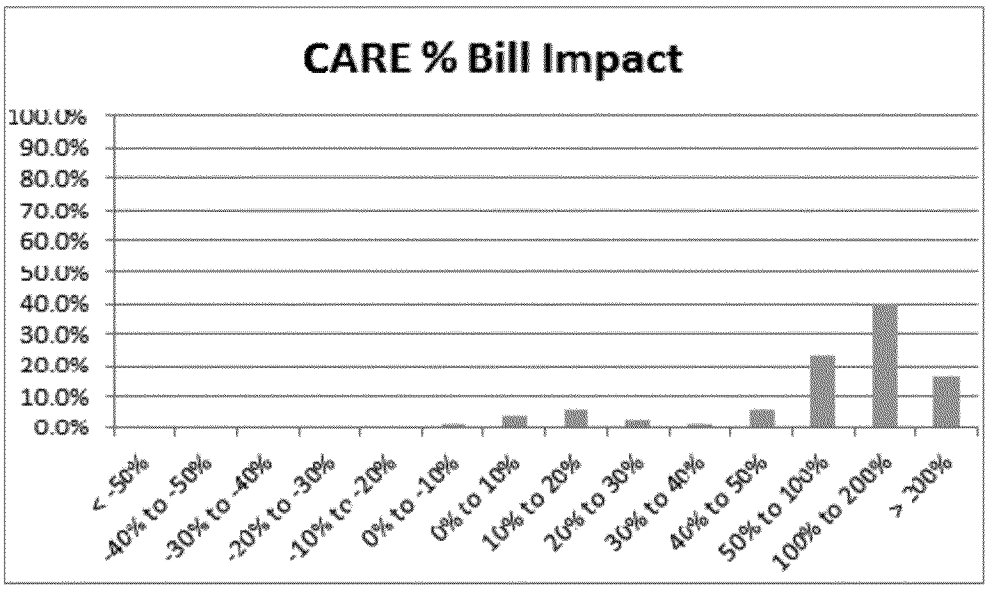


Figure 7



Even with a five-step transition period, for a customer to receive bills that are more than double what they currently receive, on top of whatever revenue requirement increases occur in that time period, is unacceptable. DRA suspects that the bill impacts of the alternative flat $38.25 BSF would be even worse.

3. PG&E's Transitional Bill Impacts

In its July 1, 2013 filing, PG&E also presented partial bill impacts that would result from its proposed end state two-tiered rate and TOU rate. Both proposed rate schedules include customer charges of $10 per month for non-CARE customers and $8 per month for CARE customers.

PG&E's proposed rates would result in unacceptable bill increases for residential customers. PG&E's proposed two-tier rate would result in bill increases of $10 or more per month for 59% of non-CARE customers. Twenty-six percent would experience bill increases of $15 or more per month. The bill impacts from PG&E's proposed TOU rates would be even worse, as 62% of customers would receive bill increases of $10 or more per month; 43% would receive bill increases of $15 or more per month; and 17% would receive bill increases of $19 or more per month.

PG&E does not show bill impacts for CARE customers, but the bill impacts for CARE customers clearly would be even worse than those for non-CARE customers. For example, PG&E increases its non-CARE tier 1 rates by 15% and increases its CARE tier 1 rates by 45%. This would result in larger bill increases for CARE customers.

D. CARE

1. IOUs' Proposals to Reduce CARE Discount to 20% will Cause Substantial Bill Impacts and Make Energy Less Affordable.

a) Bill impacts with a 20% CARE discount

SCE and PG&E[74] propose capping the CARE discount at a maximum of a 20% discount. This would be a drastic reduction to the existing CARE discount, and it would result in unacceptable bill impacts for many CARE customers. The IOUs also propose

[74] For example in its May 29th Proposal, SCE states: "Third, SCE proposes to address the growing CARE subsidy as follows:…The ultimate goal, subject to the Commission's assessment of need, should be to achieve a bill discount approaching 20% (same for all three major IOUs) relative to a non-CARE customer's bill". (SCE, p. 16)

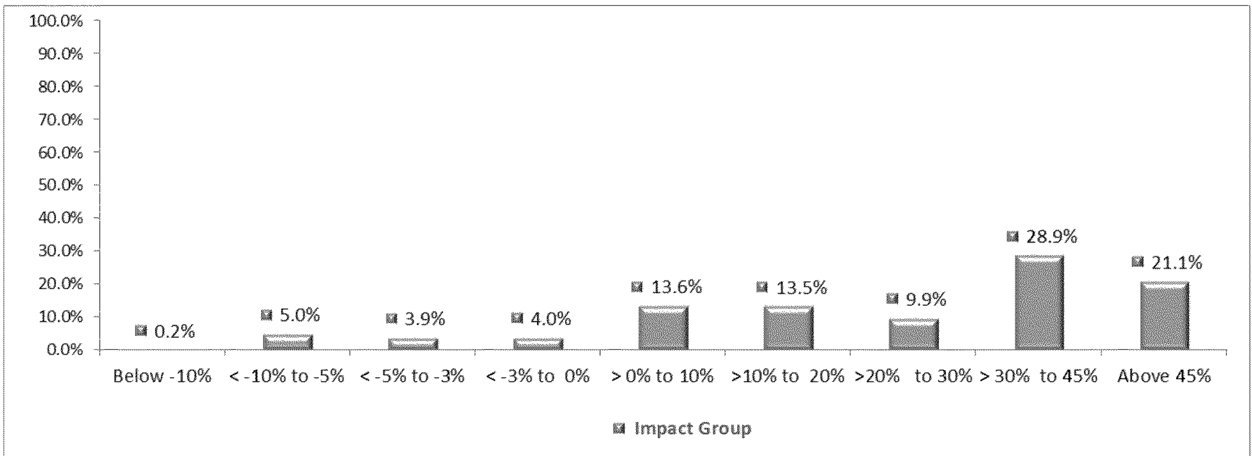
eliminating the current exemptions whereby CARE customers do not have to pay for the CARE surcharge, the DWR bond charge, and the California Solar Initiative ("CSI") costs. This is contrary to several years of Commission precedent and is ill advised.

DRA proposes that the CARE discount be a minimum of 30% for SCE and SDG&E, and at least 35% for PG&E. DRA bases its recommendation on bill impacts, the continuing stagnant economy, and the energy burden of low income customers.

SCE is the only IOU that included bill impacts in its May 29th comments. These bill impacts clearly are unacceptable for CARE customers.[75] SCE's transitional rate would result in almost 30% CARE customers seeing bill increases of 30 to 45%, and more than 20% would see increases of 45% or more, as shown in Figure 8 below.

Figure 8

CARE Customer Percent Bill Impact with SCE 3-Tier Transitional Rates (with $5 customer charge)



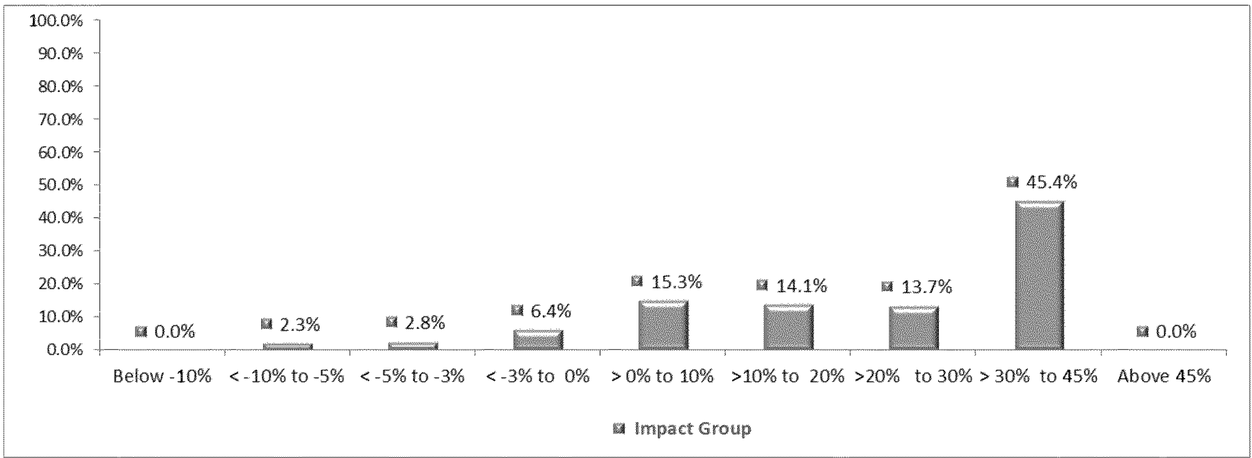
Even if we revise SCE's transitional rate by retaining the current customer charge of less than one dollar, 45% would still see a 30 to 45% bill increase, though no customer would receive increases above 45%, as shown in Figure 9 below.

[75] It appears that SCE's proposed rates still include the exemptions for the DWR Bond Charge, CSI, and the CARE surcharge in its rate calculation, but intends to exclude these exemptions in the future.

SB_GT&S_0165217

Figure 9

CARE Customer Percent Bill Impact with SCE 3-Tier Transitional Rates but Retain Current customer charge



DRA also examined the actual dollar impacts of SCE's proposal in Figure 10. SCE's transitional rate would result in bill increases of $0 to $10 per month for 43% of customers; bill increases from $10 to $15 per month for 39% of customers, and bill increases of $15 to $20 per month for 5% of customers. These bill impacts are mitigated somewhat by reducing SCE's $5 customer charge back to its current level but not by a large amount, as shown in Figure 11 below.

Figure 10

CARE Customer Dollar Bill Impact with SCE 3-Tier Transitional Rates (with $ 5 Current customer charge)

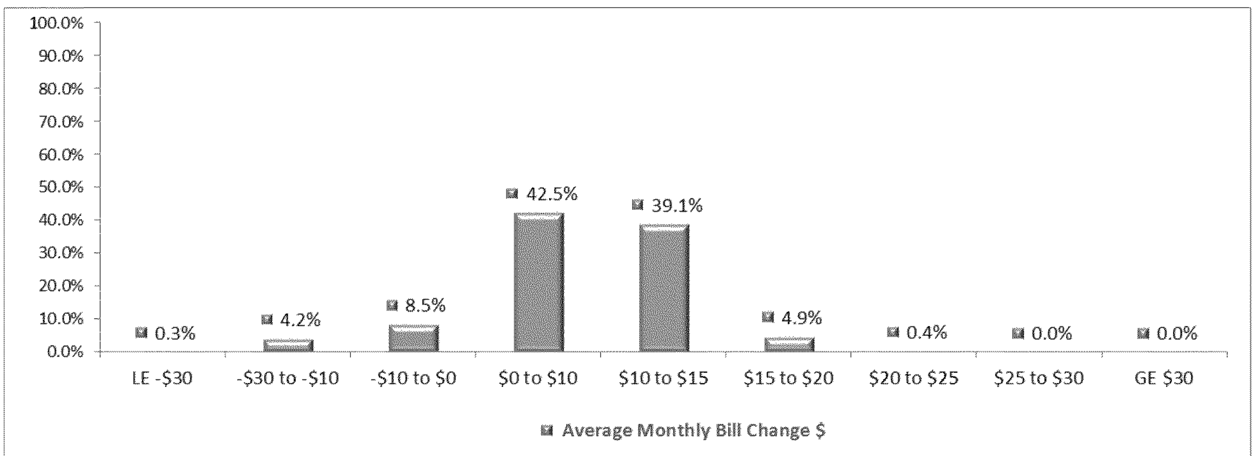
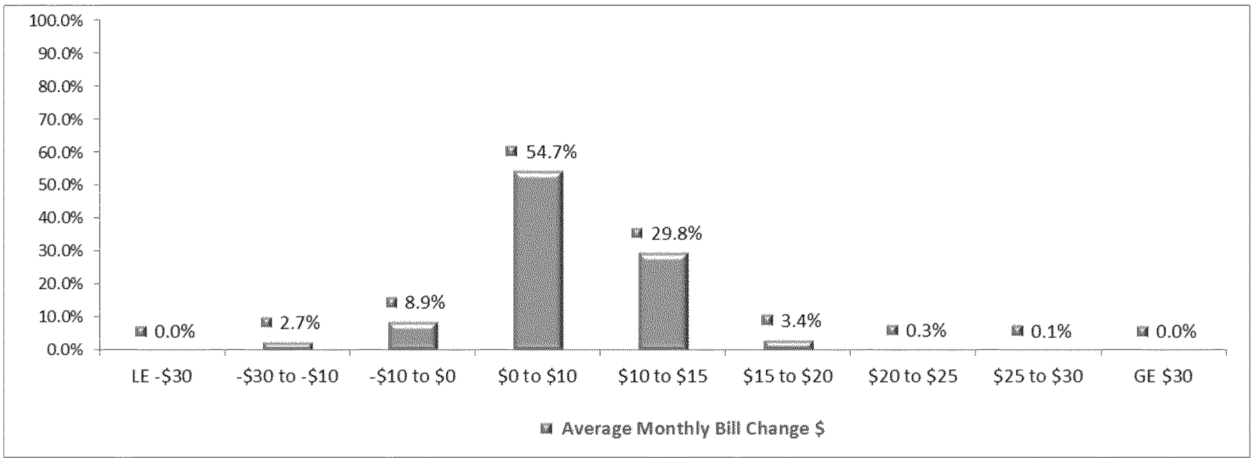


Figure 11

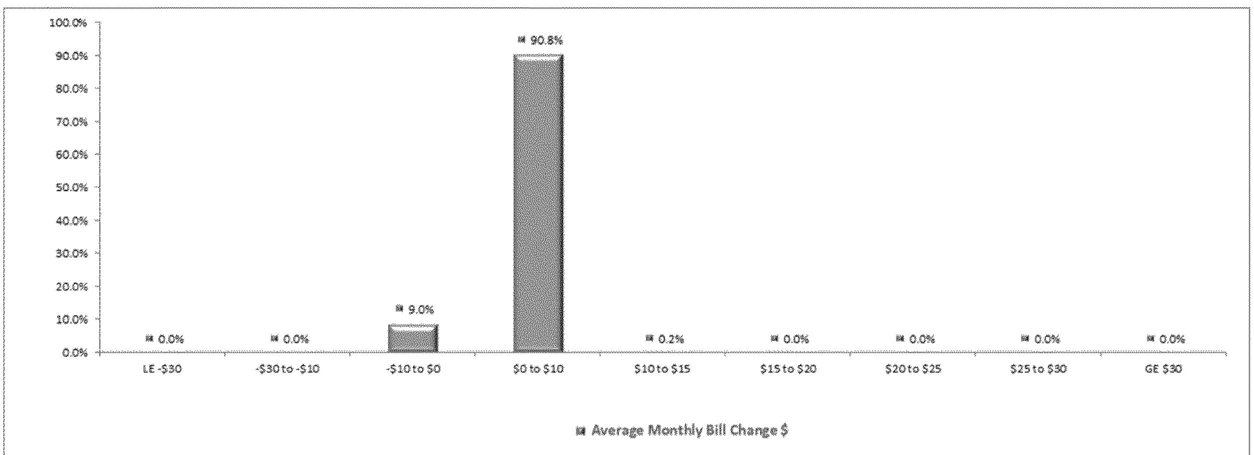
CARE Customer Dollar Bill Impact with SCE 3-Tier Transitional Rates but Retain Current customer charge



The bill impacts of DRA's proposal on CARE customers are more moderate as shown below in Figures 12 and 13.

Figure 12

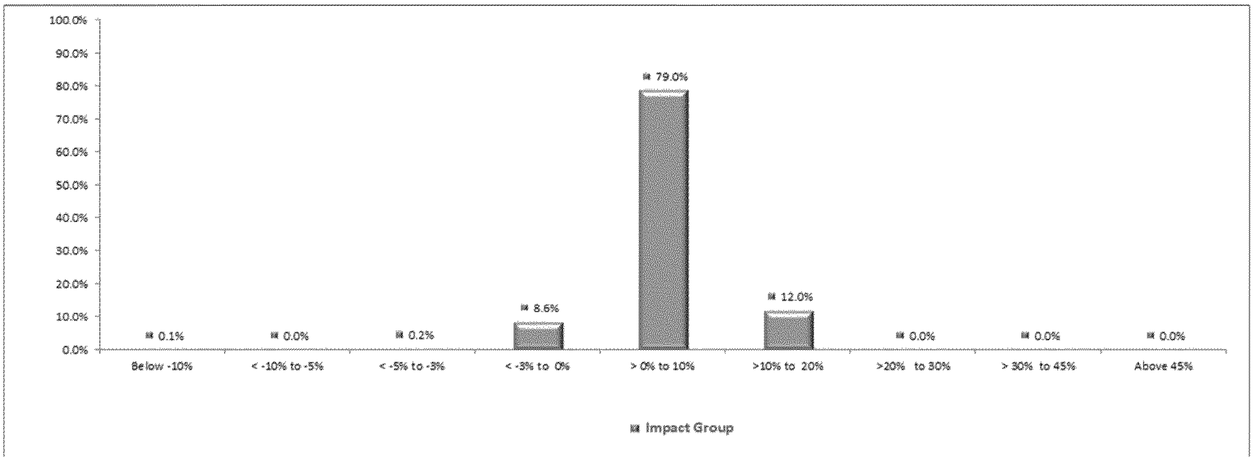
CARE Customer Dollar Bill Impact with DRA's Transitional Introductory Rates



SB_GT&S_0165219

Figure 13

CARE Customer Percent Bill Impact with DRA's Transitional Introductory Rates



b) DRA's proposed CARE discount and the state of the economy

DRA supports 30% as an appropriate average CARE discount for SCE and SDG&E, which is slightly more than the statutory minimum discount of 24% to 25% including the exclusions. DRA is open to examining different approaches that would provide larger CARE discounts to the customers with the smallest incomes, but does not have a proposal in this OIR. SCE described the history of the CARE program and some of the events that triggered changes to this program, and concludes that the CARE discount for SCE should be decreased from the current effective discount of 31% to 20%. DRA disagrees and asserts that it is preferable to control the total size of the CARE shortfall and to try to limit its expansion. To accomplish this goal, it may be more appropriate to target more of the CARE discount to the neediest customers in the future. DRA thus proposes to set the CARE discount at a minimum of 30% for SCE and SDG&E. Many customers remain in need and California still has more unemployment than the national average.[76] The sluggish economy accounts in part for the increase in CARE customers over the last few years, and as more people obtain jobs, the number of customers on CARE should decline as well as the total CARE shortfall.

c) CARE Eligibility Requirements

SCE implies that eligibility requirement of income up to 200% of the federal poverty guideline is overly generous, but also notes that the cost of living in California is greater than the average in the United States. It also gives examples of the ranges of the cost of living of some of the counties in its service territory[77].

There are other indices such as the Elder Economic Security Standard Index ("Elder Index", which calculates the minimum costs for living in California by county. This study is designed to calculate the minimum requirements of Elderly people, and it specifically is focused on the cost of living in California.[78] This study shows that, in several high cost counties, a person would need in excess of 200% of the poverty level to live. For example, single seniors renting an apartment in Alameda County in 2011 needed 239% of the federal poverty guideline to meet basic needs. In San Francisco County, 268% of the federal poverty guideline was needed. Los Angeles County had a slightly less expensive cost of living, but 224% of the federal poverty guideline level was needed. And even in a more rural county such as Tulare, 191% of the federal poverty guideline level was needed to meet basic needs. Poor people and elderly people on fixed incomes need help paying their utility bills. This index shows that the CARE program eligibility requirement of income up to 200% of the federal poverty guideline for California is not excessive.

---

[76] In April 2013, the unemployment rate in California was 9%, and the National unemployment rate was 7.5%.

[77] "SCE acknowledges the cost of living in its service territory is higher than average, ranging from a low of 113 in the city of Riverside to a high of 146 for Orange County relative to the national average index of 100" (SCE May 29th Proposal, p. 42).

[78] The Elder Index is calculated by the Insight Center at the University of California at Los Angeles.

d) Preserving current exemptions for CARE customers.

The current minimum CARE discount includes three long-standing exemptions for CARE customers—the CARE surcharge, the DWR bond charge, and California Solar Initiative ("CSI") Costs. As for removing the exemption from the CARE surcharge, it makes no sense for CARE customers to pay for part of their own CARE discount. It is also appropriate to maintain the exemption from paying the DWR bond charge and CSI costs because of long-standing precedent. There is no reason for CARE customers to bear part of a burden of wholesale market disruptions that they didn't create and are least able to pay for. As noted in one decision, CARE customers have not paid DWR bond charges since their inception in 2002:

> "However, we will continue to exempt CARE customers and Medical baseline customers from the bond charge, as suggested by AReM/WPTF in their comments on the draft Alternate Decision. As AReM/WPTF notes, there is a "clear and continuous policy of the Commission to protect the interests of CARE and medical baseline customers so that they are…exempt from rate increases arising from the wholesale market price disruptions"". (D.02-10-063 as modified by D.02-12-082, p. 19)

Similarly, CARE customers have never paid for CSI costs:

> "We do, however, exempt CARE customers from the costs of this program as a matter of equity, especially since CARE customers are the least likely to be beneficiaries of the incentives". (D.06-01-024, pp. 19-20)

Both of these exemptions have been approved by the Commission in numerous rate cases going back to 2002 on Bond Charges and to 2006 on CSI. It would be inadvisable for the Commission to reverse this practice now.

e) Many CARE customers already incur high energy burden based on the KEMA affordability study

Both PG&E and SCE compared their proposals to the status quo, and they concluded that the consequent increase in the energy burden for low-income customers is very small. SCE states: "Although reversing the current inequities will necessarily lead to some increases for low-usage and some low-income customers, the available metrics do not indicate significant energy burden impacts. SCE's proposal increases the average energy burden of CARE customers from 1.2% to 1.3%."[79] PG&E states: "The figures show that the impact of an illustrative four year transition period on the bill-to-income ratios of non-CARE customers is insignificant, while the similar impact on CARE customers' ratios is slightly larger but still very modest and manageable."[80] They state that the energy bill is a small fraction of the household's disposable income in an attempt to downplay the potential bill impact of their proposals. SCE states: "The percentage of household income applied to electricity bills is generally quite small relative to other household budget items, ranging from 1% to 2%."[81]

DRA disagrees with two premises of the IOUs' explanation. First, it does not matter that the energy bill is a small percentage of the household income. For many low income customers, their income first goes to pay for the rent and food. After paying for those very basic needs, they try to pay the utility bills. Sometimes, paying the utility bills results in forgoing some meals.[82] If customers cannot pay their energy bills, the consequences of service disconnection could be quite detrimental as energy is essential for health and safety.

[79] SCE, May 29, 2013 filing, p. 45

[80] PG&E, May 29, 2013 filing, p. 81 and see Figure 4-5 on p. 82

[81] SCE, May 29, 2013 filing, pp. 44-45.

[82] Greenlining/CforAT cited multiple stories for people who struggle on3 daily basis. (See Appendix E "Data/Stories Gathered Thru Individual Outreach" p. 1-10 to Greenlining/CforAT Rate Design Proposal)

Second, the IOUs' energy burden presentation relies on relatively aggregated data, and thus the impact to customers is muted. As Greenlining/CforAT noted, the 2007 KEMA California Low-Income Needs Assessment ("Needs Assessment") Report ("Report") shows a substantial number of low-income customers with high energy burdens. Greenling points out that the KEMA Report is a bit stale. Since it reflects pre-2007 conditions, it "predates the extreme economic difficulties that have beset California since the economic collapse in 2008." The economic conditions have not yet returned to normal. Moreover, KEMA states that "The data published in 2007 showed many vulnerable customers already at risk of facing, or actually facing, unaffordable energy bills based on then-current rates and other economic pressures."[83] The Report is based on a representative sample of 1,500 homes visited and surveyed in late 2003-2004. From its representative sample, KEMA projects that 43% of customers below 200% of the Federal Poverty Level have an average energy burden of 8.4%,[84] **even after receiving the CARE discount at current level**. Nationally, and in many states, "affordable" energy is defined as costing less than 6% of a household's annual income.

California customers below 200% Federal Poverty Level bear 30% higher energy burdens than the national average. As Greenlining/CforAT shows, the levels of arrearages and disconnections for PG&E's and SCE's CARE customers demonstrate that a substantial number of CARE customers continue to struggle to pay their bills, despite the CARE discount.[85]

DRA has proposed to reduce the CARE discount slightly from the current effective CARE discount. To reduce it further to the level suggested by the IOUs would be harmful, could cause increased disconnection rates, and could create public health and safety hazards. The IOUs should work on creative solutions to ensure that energy is

---

[83] Greenlining/CforAT, May 29, 2013 filing, p. 7.

[84] KEMA Report

[85] Greenlining/CforAT May 29, 2013 filing, pp. 58-59.

accessible to all. For example, the utilities could target high energy usage low-income households with effective energy efficiency programs so that their energy bill can decrease. This also would be helpful in reducing total CARE revenue shortfall. Until then, reducing the CARE discount too drastically is not the answer.

f) IOUs' attack on CARE energy usage is unfounded

SCE argued that the low CARE rates have resulted in CARE customers increasing their energy usage.[86] However, on average, SCE's CARE customers continue to use substantially less energy than non-CARE customers. SCE's own bill calculator model shows that CARE's average monthly usage is 509 kWh, while non-CARE usage is 589kWh/month, or 16% higher.

Furthermore, as TURN noted, the KEMA 2009 Residential Appliance Saturation Study (RASS) shows that almost half of low-income customers use less than 300 kWh/month, which is roughly equivalent to the average baseline allowance.[87] In contrast, only 11% of the more affluent household has the same amount of energy,[88] as shown in Figure 14.

---

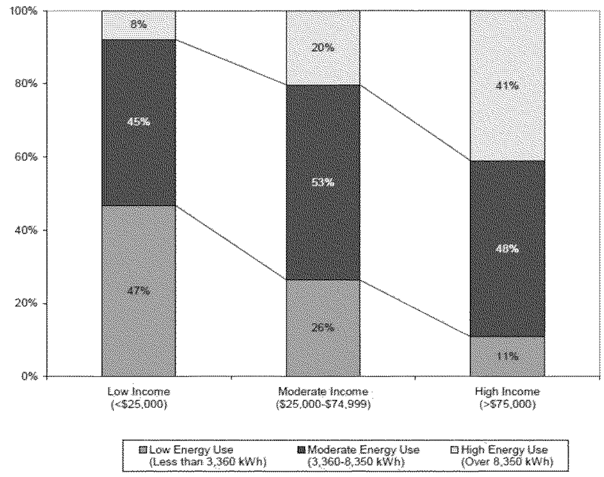
[86] SCE May 29, 2013 filing, p. 41.

[87] TURN May 29, 2013 filing, p. 16.

[88] TURN May 29, 2013 filing, pp. 15-16.

Figure 14

Figure ES-35: Electricity Consumption Compared With Income



Source: *2010 California Residential Appliance Saturation Survey*

In addition, low-income households have a substantially higher number of residents in the same household and yet consume less electricity. Figure 15 below shows that, though households with annual incomes of less than $25,000 have 6.38 average household members, they only use 4,313 kWh in contrast to 5,887 and 8,013 kWh for the other two income levels. Therefore, these households already use less energy per person for their daily needs than do the higher income households.

Figure 15

Table ES-7: Comparison of Household Characteristics by Income

	Low Income (<$25,000)	Moderate Income ($25,000-$74,999)	High Income (>$75,000)
Percentage of Population	24%	40%	36%
Dwelling Size	1,149	1,420	1,942
Dwelling Age	37.8	36.7	33.9
Percentage Single Family	41%	58%	75%
Percentage Own	42%	65%	84%
Number of People	6.38	4.30	3.78
Annual Electric Household Consumption	4313	5887	8013
Annual Gas Household Consumption	249	316	437
Central Air Conditioning Saturation	45%	53%	61%
Gas Heating Saturation	68%	78%	84%
Pool Saturation	19%	22%	28%
Average Number of Computers per Home	0.93	1.48	2.17
Work at Home	13%	17%	32%
Programmable Heating Thermostat	57%	63%	78%
Dwellings With CFLs	83%	87%	85%

Source: *2010 California Residential Appliance Saturation Survey*

g) DRA supports a need-based CARE discount if it can be properly executed.

Greenlining and CforAT recommend retaining the aggregate CARE discount but moving toward an income-based CARE discount. [89] DRA agrees with this proposal in concept. TURN notes that there are challenges, such as cost-of-living variations in different geographical areas, in implementing needs-based CARE discount rates.[90] DRA acknowledges that it may not be easy to implement but it is worth trying. It is likely to be more effective in promoting affordability to the customers who need more help. DRA recommends that the IOUs start collecting data from customers to identify their family size and income levels, and families with seniors only. However, an income-based CARE discount program should not necessarily require up-front income documentation. The customers could provide "good faith" income statements where they explicitly state,

[89] Greenlining/CforAT, May 29, 2013 filing, pp. 57 & 60.

[90] TURN May 29, 2013 filing, pp. 54-55.

"in good faith," what their incomes are. The current CARE program's income verification is executed mostly by self-certification. To add a request for customers to provide "good faith" income levels would be an improvement to make it possible to scale up assistance to the families who need it the most.

h) DRA objects to proposals to include Energy Efficiency as part of the CARE discount.

PG&E seems to suggest that the low income energy efficiency program fund be counted toward the CARE discount.[91] If PG&E indeed proposes to do so, the Commission should reject this. The CARE discount rate was designed to ensure that low income customers have access to affordable energy. While Energy Efficiency may be expected to provide some energy bill relief in most circumstances, many CARE customers will continue to experience a high energy burden. To count Energy Efficiency as part of the CARE discount would jeopardize affordable energy rates for CARE customers.

Furthermore, as mentioned earlier, the CARE population, with its 30-40% discounted rates, is using less electricity than the non-CARE population.[92] Therefore, the available headroom, out of which meaningful savings could be extracted through EE, becomes smaller. The CARE discount itself should continue to be used to reduce electricity rates for low income customers to secure their energy needs.

The Environmental Defense Fund ("EDF") also hints at redirecting some of the CARE discount for EE purposes:

> Given large energy use inefficiencies in CARE customers' households, high use CARE recipients could be allowed to re-direct a portion of their subsidy to purchase energy

[91] PG&E May 29, 2013 filing, p. 42. PG&E's proposal states the following: "Likewise, the CARE statute makes clear that CARE assistance can be provided as a rate discount or through other forms of assistance such as energy efficiency measures, and that the level of CARE assistance should assist eligible low income customers to pay their energy bills"

[92] TURN p. 14-15.

> efficient items, so long as the investment results in at least as much bill savings as would occur under the allowable subsidy.[93]

EDF's conclusion regarding the CARE usage is contrary to the KEMA Report mentioned earlier as well as the specific data used by the IOUs in the bill calculator models.[94] EDF's proposal presents two pie charts showing that CARE customers use a higher percentage of their usage in Tier 1 than do Non-CARE customers. EDF seems to rely on this to suggest that "CARE customers use more Tier 1 energy than non-CARE customers." [95] However, EDF also notes "This is partly an artifact of the greater Tier 1 baseline allocation in climate zones with a larger CARE customer population, such as the Central Valley."[96]

Indeed, the proportion of CARE and medical baseline customers living in the more extreme weather climate zones is higher than the proportion of non-CARE customers.[97] For PG&E, 36% of its customers in its five climate zones with the highest baseline quantities in the summer are CARE customers. Whereas, 22% of customers in the five climate zones with the lowest baseline quantities in the summer are CARE customers. [98] Moreover, there is ample evidence that CARE customers tend to conserve more. For these reasons, DRA recommends that the Commission reject EDF's recommendations.

---

[93] EDF May 29, 2013 filing, p. C-11.

[94] For example, SCE showed an average CARE usage of 509 kWh per month in contrast to non-CARE's usage of 589 kWh. These have not been normalized to account for the fact that more CARE customers live in hotter zones than non-CARE customers in percentage.

[95] EDF Proposal, C-1.

[96] Ibid.

[97] PG&E data in bill calculator model, High BL Zones: P, R, S, W, V; Low BL Zones: Q, T, Z, X, Y.

[98] The hotter zone baseline allowance is almost double those in the cool zones. (PG&E 2014 GRC 2, PG&E-1, p 3-46.)

i) DRA disagrees with IREC's proposal to use CARE funding as a source for CARE customers to participate in green/clean energy.

IREC proposes that "Clean CARE" participants pay non-CARE retail rates and receive bill credits from the shared distributed generation ("DG") facility assigned to them.[99] This is as risky a proposition as counting EE for the CARE discount. Again, the CARE discount is intended to secure adequate energy for low-income customers. On the other hand, the renewable DGs may or may not achieve cost savings equivalent to the CARE discount. Many DG projects are not proven technologies or may not yet be economic. To ask CARE customers to exchange their CARE discount, which is a guaranteed savings level, for potentially unreliable DG savings is a gamble not worth pursuing at this time. DRA does not object to providing DG programs to low income customers, but the funding should come from a separate program source that is not part of the CARE funding. If the Commission does not adopt DRA's recommendation, then the Commission only should approve IREC's proposal with the following conditions:

- CARE customers must be guaranteed that their bills will not be worse off than the status quo, meaning that their bills net the solar discount must be the same as they would receive under CARE rates.
- Non-participants should be no worse off as a result of this new Program.

E. Legislative Changes

The three utilities took an overly broad approach to addressing the legislative changes necessary to implement their rate design proposals. They recommend changes to, or complete elimination of, Public Utilities ("P.U.") Code Sections ("§§") 739.1, 739.9 and 739(d)(1). This approach would eliminate many legislative mandates that ensure ratepayers affordable and reliable essential residential energy services, and thus it

[99] IREC p. 3.

would not be in public interest. Each of the IOUs' specific statutory changes proposals are discussed in more detail below.

Rather than eliminating certain sections, DRA recommends that they be modified. Specifically, DRA proposes modifying P.U. Code §§ 739.1(b)(2), 739.9(a), and 745(d). These P.U. Code provisions were drafted in response to the 2001 energy crisis and were subsequently revised in 2009 through Senate Bill ("SB") 695. DRA recommends revising certain provisions of these code sections to make the statutory framework flexible enough to accommodate changes to make rates more consistent with the rate design principles established in this proceeding. DRA's proposed changes to the PU Code are discussed after the utilities modifications to the statute are presented below.

1. Review of IOUs' Proposed Statutory Changes

a) P.U. Code §739.9

This section pertains to non-CARE tier 1 and tier 2 rate protections. All three utilities recommended removing this section entirely. Only §739.9(a) requires modification to implement the IOUs' and DRA's proposals. It places limits on annual increases to non-CARE tier 1 and tier 2 rates. It should be modified to make those limitations less restrictive. P.U. Code §§739.9(b-c) should not be deleted or modified because they contain important baseline protections for non-CARE customers. Affordable baseline rates are essential for ensuring all Californians have access to an essential service. The concept of baseline rates was created by the Warren-Miller Energy Lifeline Act of 1976, which required the Commission to designate a baseline quantity of gas and electricity, necessary to supply a significant portion of the reasonable energy needs of the average residential customer, at affordable rates below average cost. This Act highlights the need and utility of affordable baseline rates.

b) P.U. Code §739.1

This section pertains to CARE rates. SDG&E and PG&E propose removing this section entirely and SCE proposes deleting only subsection (b)(2-5). Only P.U. Code §739.1(b)(2), which relates to CARE tier 1 and tier 2 rate increases, requires modification to implement the IOUs' and DRA's proposals. DRA acknowledges that more flexibility is required to allow changes to low-usage CARE rates, but completely deleting all CARE rate protections is not the proper remedy. Maintaining a majority of the CARE protections is crucial for ensuring that energy rates in California remain manageable for all residents. Because CARE customers already have a high energy burden, it is especially important to retain a cap on the annual increase of CARE baseline rates.[100]

P.U. Code §739.1(g) is a CARE mandate that states: "It is the intent of the Legislature that the commission ensure CARE program participants are afforded the lowest possible electric and gas rates." SCE proposes to revise the statute with the following less restrictive language: "It is the intent of the Legislature that the commission ensure CARE program participants receive affordable electric and gas service that does not impose an unfair economic burden on those participants." SCE's proposal should be rejected because it lacks a clear and implementable directive regarding the need to ensure that low-income individuals continue to have affordable access to essential electricity and gas services.[101] The current CARE mandate is crucial for ensuring that economically disadvantaged Californians have access to electricity, which is a basic necessity, at a price they can afford. P.U. Code §739.1(g) should not be replaced with the language that SCE suggests.

c) P.U. Code §739(d)(1)

This code section contains important baseline rate mandates and should not be modified. PG&E recommends changing P.U. Code §739(d)(1) because it believes this statute is inconsistent with its proposal to have a large differential between Tier 1 and Tier 2 rates. The provision of this section, about which PG&E concerned, states, "In establishing these rates, the commission shall avoid excessive rate increases for

[100] See Section B above, for a more complete discussion of the high energy burden affecting CARE customers.

[101] More details about the need for affordable CARE rates can be found in Section B above.

residential customers, and shall establish an appropriate gradual differential between the rates for the respective blocks of usage." The language in this statute is not specific enough to interfere with PG&E's proposal.

2. Review of DRA's Proposed Statutory Changes

A large majority of the Parties' rate design proposals would be statutorily implementable if DRA's recommended modifications to P.U. Code §§ 739.1(b)(2), 739.9(a), and 745(d) are accepted. The following statutory changes proposed by DRA, in its May 29th comments, will help achieve the above listed rate design principles in the following ways:

- Modify P.U. Code §739.1(b)(2) to allow CARE baseline rates to increase by inflation or some other measure while still maintaining a cap on annual rate increases. This will make CARE baseline rates more cost-based while also ensuring that low-income customers continue to have access to a baseline amount of electricity at an affordable rate. Maintaining a cap on annual rate increases will help avoid rate shock by requiring that rate increases happen incrementally. TURN and SEIA/Vote Solar proposed similar changes to P.U. Code §739.1(b)(2).
- Revise the provision of P.U. Code §739.9(a) pertaining to rate increases for 101% to 130% of baseline to allow for higher rate increases to facilitate combining the current Tiers 2 and 3, while still maintaining a limitation on yearly increases. This will result in a rate design that is more based on cost-causation principles, avoids rate shock, and also encourages conservation and energy efficiency by rewarding low usage customers. Both consumer and environmental intervenors in this proceeding (TURN, Sierra Club, EDF and SEIA/Vote Solar) recommended similar modifications.
- Replace "consistent with Part 1 of the P.U. Code" with "consistent with baseline protections" in P.U.C. §745(d). This section currently mandates that the use of default time-variant pricing must be consistent with Part 1 of the P.U. Code, which includes §739.9(a) and §739.1(b)(2). DRA's proposed modification of the statute would retain the rate increase protections for low-usage customers after the transition to an Introductory tiered/TOU rate. By transiting to time varying

> rates, many of the Commission's rate design principles will be fulfilled. These include creating rates that encourage conservation, energy efficiency and the reduction of both coincident and non-coincident peak demand.

DRA's proposed legislative changes should be accepted because they will aid DRA's rate design proposal in complying with the following rate design principles:

> 1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs are met at an affordable cost,
>
> 2. Rates should be based on marginal cost.
>
> 3. Rates should be based on cost-causation principles.
>
> 4. Rates should encourage conservation and energy efficiency.
>
> 5. Rates should encourage reduction of both coincident and non-coincident peak demand.
>
> 10. The transition to new rate structures should emphasize customer education and outreach to enhance customer understanding and acceptance of the new rates, and it should minimize and appropriately consider the bill impacts associated with such a transition.

3. Conclusion

All three of the IOUs took an overly broad approach to addressing the legislative changes necessary to implement their rate design proposals. Wholesale elimination of every P.U. Code section that even slightly interferes with a rate design proposal is an unnecessary overreach. The IOUs' recommended approach is contrary to the public interest because it would eliminate many protections that ensure residential ratepayers receive safe, reliable and affordable electricity service. DRA suggests that modification of the relevant subsection of the Code should be assessed before the deletion of an entire P.U. Code Section is considered.

IV. CONCLUDING REMARKS

DRA's greatest concern is how the utilities seem to have turned this proceeding into one about basic service fees rather than one about transitioning to time-varying rates. Not only do they emphasize such fees, but the foundation for such fees in their own cost structures is weak. They do recognize the need to transition to time-varying rates, but their expectations that a natural transition will occur if such rates are offered on an optional basis may be overly optimistic.

DRA is also concerned about the attacks on the CARE discount. We recognize that recent circumstances have led to CARE discounts that significantly exceed the current statutory amount. But unwinding the current discounts will create significant bill impacts on California's most vulnerable customers. It also must be recognized that those customers disproportionally live in the hotter climate zones of the state. Thus, if the Commission desires to transition to cost-based rates, then perhaps it should seek an end goal of a discount somewhat more moderate than the current discounts but more generous than the current statutory amount.

Respectfully submitted,

/s/ Gregory Heiden

____

Gregory Heiden

Attorney for the Division of Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Ave.
San Francisco, CA 94102
Phone: (415) 355-5539
Fax: (415) 703-4592

July 12, 2013