Decision **PROPOSED DECISION OF ALJSALJs McKINNEY and HALLIGAN (Mailed 4/21/2015)**

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)

(See Service List for Appearances)

DECISION ON RESIDENTIAL RATE REFORM FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY AND TRANSITION TO TIME-OF-USE RATES

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ATTACHMENT A - Acronym List

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ATTACHMENT B - 2015 Expected Revenue Requirement Changes
ATTACHMENT C - Service List

DECISION ON RESIDENTIAL RATE REFORM FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY AND TRANSITION TO TIME-OF-USE RATES

1. Summary

California has long been a front-runner in developing and implementing innovative policies to make energy use more efficient, and an effective, cost-based rate structure is one of the foundations of promoting conservation. In recent years, our residential ratepayers invested billions in the largest installation of advance metering infrastructure (AMI) in the country. This decision marks the culmination of a three-year long examination of proposed rate reforms for the three major investor-owned utilities in California, a critical first step in the process of optimizing use of this installed AMI and new energy efficiency technologies. This change will allow for the more accurate allocation of costs and for energy rates to more fairly reflect the cost of service. We expect that the time-of-use (TOU) rates approved by this decision will reduce overall electricity costs for all customers in the long-term.

This decision balances the need for immediate rate reform for customers who currently pay substantially more than the cost of service, with the need for customer acceptance and understanding of rate changes as well as the other rate design principles developed in this proceeding. We direct Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, to take the next steps in residential rate reform. This reform is intended to make rates more understandable to customers and more cost-based, and to encourage residential customers to shift usage to times of day that support a cleaner more reliable grid.

We find that the first step in rate reform must be a narrowing of the existing usage tiers so that electricity prices will be more in line with cost and so that customers can better understand their electricity rates. Because it is difficult to explain other components of electricity rates while the steeply inclining tier differentials are in place, we find that the imposition of new fixed charges or default TOU rates, should occur after the tiers have been consolidated and narrowed.

By statute, the Commission is tasked with ensuring that utility rates are "just and reasonable."[1] Historically, the determination of just and reasonable has emphasized cost-causation. In recent years, changes in energy use to protect the environment have become increasingly important. Moreover, changes in the grid and technology have expanded the ability of energy producers and consumers to evaluate and respond to rates. These changes have also shifted costs to a subset of customers who are unable to employ new technologies. This makes protection of vulnerable customers of particular importance in any new rate design. In this proceeding, the parties developed 10 rate design principles by which to balance and compare existing and proposed rate designs.

For over a decade, low-tier residential rates have been frozen in compliance with legislation following the electricity crisis, resulting in residential rates that neither reflect cost of service nor provide a useful price signal to customers. The rate freeze resulted in unfair prices for many customers, and may have elicited some investments in energy efficiency (EE) that were uneconomic. The longer this steep tier differential continues, the harder it is to move back to fair rates that reflect costs and allow customers to make smart decisions. In

[1] The Commission is also responsible for ensuring that every public utility furnishes and maintains "adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities" as necessary "to promote the safety, health, comfort and convenience of its patrons, employees and the public." California Public Utilities Code Section 451.

addition, long-standing Commission policy, as well as the changing technology landscape, make time-variant pricing a viable and important element of future residential rate designs.

California's electricity needs have changed over the last decade and will continue to do so. Impacts on the grid that need to be considered include not just peak usage periods, but also the deepening afternoon valleys resulting from increased deployment of solar, and the need for flexible ramping capacity. A default TOU rate must be flexible enough to address these changes while providing a degree of consistency for customers. The goal of this Commission is to ensure that default TOU is implemented in a meaningful way that benefits and empowers electricity customers. Developing appropriate rate designs in this new paradigm will be challenging, but this decision will provide sufficient time and guidance to accomplish our goal.

In balancing the ten rate design principles, we find that the most important action to be taken is consolidation and narrowing (flattening) of the tiers. All three of the major rate components being considered in this proceeding (tier consolidation, fixed charges, and TOU periods) must work together. The most important tool for balanced rate design is a price signal that customers can understand and respond to in a way that reduces the costs and environmental impacts of energy use. Bringing the price signal in line with costs and policy considerations is the first step in fulfilling a maximum number of rate design principles.

Because of the implementation of the rate freeze in accordance with Assembly Bill (AB) 1X,[2] users in the lower tiers pay significantly below the cost of generation, while users in the higher tiers pay significantly above cost. These

[2] AB 1X (First Extraordinary Session, Ch. 4, 2001)

prices are so far from cost that immediate change is necessary. Although any change will require an incremental increase in rates for lower tier usage, we believe that low-usage customers should continue to pay a lower rate than high usage customers, and therefore this decision maintains a higher rate for high usage.

To this end, this decision finds that the investor-owned utilities (IOUs) must promptly take the following actions:

(1) Continue the tier consolidation process (as described by this decision), including adjusting California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA); discounts to reflect tier convergence.

(2) Implement a minimum bill for summer 2015.

(3) Institute a special outreach program to educate lower tier customers on no-cost and low-cost conservation measures.

(4) Promptly begin the process of improving rate comparison tools and educational materials so that customers can more readily understand their energy bills.

(5) Promptly begin the process of designing TOU pilots (both opt-in and default), as well as study design for TOU opt-in rates.

In addition to the steps above which should begin immediately, this decision sets a course for residential rate reform over the next few years, including the following requirements.

(1) The IOUs must evaluate opt-in and pilot TOU rates in preparation for widespread enrollment in TOU.

(2) The IOUs must file a residential rate design window (RDW) application no later than January 1, 2018 that proposes default TOU rate structure to begin in 2019.

(3) The IOUs may include a fixed charge as part of the Residential RDW application.

(4) The IOUs must provide regular updates on progress toward rate reform and the Residential RDW application, including

presenting an annual update, regular workshops, and quarterly reporting.

Separately from this proceeding, in their individual GRC Phase 2 proceedings, the IOUs should work to identify fixed costs for purposes of calculating a fixed charge.

A third phase of this proceeding is opened (i) to examine specific legal issues related to default TOU rates, (ii) to determine what information and supporting documentation should be included in the Residential RDW application in order for parties, the Commission and the public to evaluate the proposed rate changes, and (iii) to consider the restructuring of the CARE rate under AB 327. A workshop will be held at the start of Phase 3 to determine the extent to which CARE restructuring should be included in the scope.

2. Background

2.1. Residential Rate Design in California

Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (Investor-Owned Utilities [IOUs]) file General Rate Cases (GRCs) approximately every three years seeking changes in revenue requirements.

A GRC is made up of two separate proceedings which are often compared to the making and serving of a pie. GRC Phase 1 sets the utility's revenue requirement (or the "pie"). The revenue requirement is the amount of revenue to be recovered in rates. This includes all current operation and maintenance costs, expenses, fuel expenses, taxes, depreciation, interest payments, and a component for return on equity. Next, during Phase 2 of each IOU's GRC, we determine the marginal cost for each service provided and the responsibility of each customer

for those costs. We then allocate the authorized revenue requirement between the customer classes and set the actual rates or prices for each tariff.

Then, the GRC Phase 2 addresses allocation of the costs in the pie to different customer classes (the "dividing of the pie"). GRC Phase 2 also sets the rate design for collecting each customer's allotted share of the pie served to their customer class. Importantly, this means that once the revenue requirement pie is set, the changes in GRC Phase 2 cannot increase the size of the pie. The IOUs may also file RDWs annually to request changes that were not addressed in the last GRC.

Rulemaking (R.) 12-06-013 will not change the total revenue requirement. It will also not change the revenue allocation between customer classes, or the amount of revenue requirement for which the residential class is responsible. Rather, this proceeding will change the rate design rules for residential customers that make up the entire slice of pie for which they are already responsible.

Each utility's current revenue requirement and residential class' allocation of that revenue requirement have already been determined. Our review in the instant proceeding is limited to considering the appropriate rate design for the residential class. Historically, in setting electric rates, we have sought to design and set rate structures that are based on marginal cost and that allow each utility to recover its costs of service in a manner that ensures that costs specific to each class of customer are recovered from that same customer class. To the extent possible, and allowing for certain subsidies to promote certain societal programs, we have also sought to ensure that each customer pays for electric service in proportion to their use. Over the past 14 years, however, this has been challenging due to several limitations imposed on the Commission following the energy crisis of 2000-2001.

2.1.1. Common Rate Design Terminology

The terminology of rate design is arcane and full of acronyms. As a result, parties sometimes do not have a common understanding of a rate design term. For the most part, this can be resolved by agreeing to a common set of definitions such as the one in this proceeding.[3]

We have attached a list of common acronyms and definitions to this decision as Attachment A.

As a threshold matter, it is necessary for the reader to understand the following terms:

- Opt-In Rate: A voluntary rate that the customer can choose to be on. The burden is on the customer to affirmatively choose the tariff.
- Opt-Out Rate: A voluntary rate the customer can choose to leave. The burden is on the customer to affirmatively leave the tariff. A voluntary default tariff can is also an opt-out tariff.
- Mandatory Rate: A rate that the customer cannot opt-out of.
- Default Rate: The rate the customer is automatically put on if the customer does not affirmatively choose a different tariff. For residential customers, this is a voluntary (not mandatory) rate.

In addition, however, there are some terms, such as "fixed costs" that are rightly the subject of litigation.

2.1.2. History of Residential Rates

2.1.2.1. Legislative Foundation for Inverted Block Rates

The utilities' total bundled rates have been tiered since lifeline rates were implemented in California in 1976. The Warren-Miller Lifeline Act sought to provide California's residential customers with necessary amounts of gas and

[3] ALJ Ruling Requesting Rate Design Proposals, March 19, 2013, Attachments C and D.

electricity at a fair cost but also encourage conservation of energy. This was revised by the 1982 Baseline Act which set baseline rates at 15 - 25% less[4] than the system average rate (SAR).[5] The inverted rate relationship of the two prices results from the same legislative mandate.

The establishment of baseline rates created the inclining or inverted block structure in California: a two-tiered residential rate structure, with the upper-tier rate set moderately above the lower-tier rate, which is common around the world. Inverted block structures charge ratepayers based on an increasing rate per kWh within each successive tier, or "block" of use. Although an inclining block rate can promote conservation, this structure assumes that almost all customers will exceed the first tier and utilities can recover more of their costs in the second tier.

By mid-1988, six years after the Baseline Act, the tier differential between the second and first tier had widened to as much as 1.74:1.[6] In response to such high winter bill complaints,[7] Senate Bill 987[8] mandated a reduction in non-baseline residential rates and narrowed the differential between the two tiers (baseline and non-baseline).[9] It also enacted Pub. Util. Code Section 739.7,[10]

[4] 1982 Stats. ch. 1541 (AB 2443 Sher) (The Baseline Act was a revision to the Miller-Warren Energy Lifeline Act, 1975 Stats. ch. 1010).

[5] The system average rate (SAR) is calculated by dividing the annual revenue requirement of the IOUs by their annual retail sales. This metric provides a normalized basis for assessing trends in utility costs. Because the value represents the average cost per kilowatt hour, it necessarily departs from the actual rates and trends experienced by different customer classes. The manner in which cost recovery is allocated across customers is considerably more complex.

[6] PG&E's mid-1988 ratio approximated 1.74:1 for electric service, SDG&E's electric tier differential exceeded 1.40:1, and SCE's tier ratio was approximately 1.53:1. See D.93-06-087, 50 CPUC 2d 1, 31 (PG&E); D.93-06-088, 50 CPUC 2d 118, 128 (SDG&E); D.96-04-050; 65 CPUC 2d 362, 431 & fn. 48 (SCE).

[7] D.88-10-062 at 1-3, 29 CPUC 2d 448, 449-450.

[8] SB 987 (Dills, 1988).

[9] See D.93-06-087, 50 CPUC 2d 1, 31.

[10] Unless otherwise specified, all section references are to the Public Utilities Code.

which mandated that the "Commission shall reduce high non-baseline residential rates as rapidly as possible."[11] After this, tier differentials declined to 1:1.5.[12]

In 1992, Assembly Bill (AB) 1432[13] amended Section 739.7 to mandate that the Commission "shall retain an appropriate inverted rate structure," because "[i]t was never the intention of the Legislature that the Commission eliminate inverted residential rates. Inverted residential rates provide conservation incentives for residential customers and also provide reasonable rates for the domestic consumption of gas and electricity."[14]

2.1.2.2. AB 1890 and the Energy Crisis

Four years later, in 1996, AB 1890[15] deregulated the electric industry in California. Rates were capped at the slightly above-cost levels in effect in 1996, with an additional 10% decrease in rates for residential and small business customers, to be re-evaluated in 2001. The utilities were meant to recover their stranded costs in the intervening years through innovation and reduction in costs, but wholesale market manipulation and the 2000-2001 energy crisis quickly created a gap between the wholesale costs to procure power and the retail rates the utilities were allowed to charge.

On February 1, 2001, AB 1X from the First Extraordinary Session (Ch. 5, First Extraordinary Session 2001) was enacted implementing measures to address the rapidly rising energy costs resulting from the 2000-2001 energy crisis. With AB 1X mandating that all residential electricity use up to 130 ~~percent~~% of

[11] See D.96-04-050 at 184, 65 CPUC 2d 362, 431 & fn. 48 ("Since SB 987 was enacted in June 1988, we have reduced residential tier ratios considerably. PG&E's mid-1988 ratio of 1.74:1 for electric service has been reduced to 1.15:1. SDG&E's electric tier differential has been reduced from over 1.40:1 to 1.265:1. Edison's tier ratio has similarly been reduced to the current level of 1.15:1.").

[12] *Ibid.*

[13] AB 1432 (Moore, 1002).

[14] *Ibid.*

[15] AB 1890 (Peace, 1996).

baseline be capped at levels in effect on February 1, 2001, the Commission was required to develop a rate design methodology that would enable the IOUs to fully recover their residential revenue requirements.

Consequently, in 2001, the Commission also replaced the two-tiered structure with a five-tiered structure,[16] as these statutory restrictions required the first two tiers to remain frozen as a customer protection. This required all future residential rate increases to be allocated to rates in non-CARE Tiers 3 through 5, above the Tier 2 (130 ~~percent~~% of baseline) threshold. Consumption in Tiers 1 and 2 represent the majority of electricity usage in the state, so upper-tier rates increased to levels well above the average cost of service in order to recover costs, leading to the current steeply tiered structure.

To protect low-income households against these escalating costs, the Commission also froze rates for the California Alternate Rates for Energy (CARE) program at July 2001 levels, after increasing the CARE discount from 15 to 20 ~~percent~~%.

Over time, the rate tier differentials have continued to widen. Between 2001 and 2010, the system average differential between the Tiers 2 and 3 expanded from about 5 cents to 15 cents, and the differentials between Tiers 3 and 4 and Tiers 4 and 5 expanded from about 4 and 2 cents per kilowatt-hour (kWh), respectively, to about 13 and 7 cents per kWh. Between 2000 and 2009, the Tier 5 rate nearly doubled, increasing from 24.5 cents per kWh at the height of the energy crisis to 44.3 cents per kWh at the end of 2009.

With the enactment of SB 695 in 2009,[17] Section 739.1 was amended and ~~Sec.~~Section 739.9 was added to begin allowing limited annual Tier 1 and Tier 2 rate increases for both CARE (from 0 to 3 ~~percent~~%) and non-CARE customers

[16] D.01-05-064.
[17] Exh. PG&E-04 at 1-5. SB 695 (Kehoe, 2009).

(from 3 to 5 ~~percent~~%). In addition, D.10-05-051 consolidated Tiers 4 and 5 into a single Tier 4. The utilities have thereby realized some progress toward narrowing the disparity between upper- and lower-tiered rates.

As a result, as of January 2014, residential rates for lowest and highest tiers were as follows:

Utility/Date	Tier 1 (per kWh)	Tier 4 (per kWh)	Residential Average Rate (per kWh)
SCE 11/1/3[18]	13.2 cents	29.5 cents	17.6 cents
SDG&E 1/1/14[19]	15.0 cents	36.9 cents	21.1 cents
PG&E 1/28/14[20]	13.2 cents	36.4 cents	17.5 cents

2.2. Procedural History

2.2.1. The Order Instituting Rulemaking (OIR)

The Commission initiated this OIR, "to examine current residential electric rate design, including the tier structure in effect for residential customers, the state of time variant and dynamic pricing, potential pathways from tiers to time variant and dynamic pricing, and preferable residential rate design to be implemented when statutory restrictions are lifted."[21] At that time, the Commission was, and continues to be, interested in exploring improved residential rate design structures in order to ensure that rates are both equitable and affordable while meeting the Commission's rate and policy objectives for the residential sector. Currently, residential electricity rates have an "inclining block" structure consisting of multiple tiers based on usage. By statute, Tier 1 is equal to the "baseline quantity" which is defined as 50% to 60% of average residential consumption of electricity[22] As a customer's energy usage increases

[18] Exh. SCE-03 at 16-17.
[19] Exh. SDG&E-03 at CF-15.
[20] Exh. PG&E-04 at 1-5.
[21] OIR at 1.
[22] Section 739.

into higher tiers, the price paid for that energy also increases. This increase is made without regard to the cost to provide the increased amount of electricity.

On November 26, 2012, the assigned Commissioner issued the original Scoping Memo and Ruling. Over the next ten months, a variety of parties actively participated in the proceeding to examine residential rate structures. Those parties included: California Large Energy Consumers Association (CLECA); Center for Accessible Technology (CforAT) and The Greenlining Institute (Greenlining); Distributed Energy Consumer Advocates; Office of Ratepayer Advocates (ORA);[23] Environmental Defense Fund (EDF); Interstate Renewable Energy Council, Inc. (IREC); Natural Resources Defense Council (NRDC); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); San Diego Consumers' Action Network (SDCAN); Sierra Club; Solar Energy Industries Association (SEIA); The Vote Solar Initiative (Vote Solar); Utility Consumers' Action Network (UCAN), Southern California Edison Company (SCE); and The Utility Reform Network (TURN). PG&E, SDG&E and SCE are referred to collectively herein as the investor-owned utilities (IOUs).

As part of the proceeding, the utilities each developed a "Rate Impact Calculator" designed to help parties understand the impact of different rate design proposals. The calculators were developed over a period of several months with the input of all interested parties. Although the final calculators do not provide all of the modeling abilities that the parties sought, the calculators represent a useful tool for comparing rate structures that has been used and cited by various parties. During the same period, the parties worked with the utilities to develop a customer survey to explore how well residential customers understand their rates. The bill impact calculators and the customer survey were

[23] The Office of Ratepayer Advocates was formerly known as the Division of Ratepayer Advocates (DRA). *See* Stats. 2013, Ch. 356, § 42.

moved into the evidentiary record pursuant to a later ruling. (*See*, Amended Scoping Memo and Ruling of Assigned Commissioner, dated January 6, 2014.)

On October 7, 2013, AB 327 (Perea, 2013) was signed into law, lifting many of the restrictions on residential rate design. With its passage, the utilities can now propose residential rates that are more reflective of cost, in keeping with the Commission's principle that rates should be based on cost-causation. AB 327 also contains limits designed to protect certain classes of vulnerable customers.

For purposes of today's decision, the relevant provisions of AB 327 are (1) setting the CARE effective discount rate between 30% and 35%, and (2) allowing an increase in rates for Tiers 1 and 2.

2.2.2. Phase 2

In light of the new rate structures permitted by AB 327, on October 25, 2013, the assigned Commissioner issued a ruling (October 2013 ACR) opening Phase 2 of this proceeding and inviting utilities to submit interim rate change proposals for summer 2014 in order to promptly stabilize and begin to rebalance tiered rates. Longer-term rate design was reserved for Phase 1.

The IOUs submitted their Phase 2 Proposals on November 22, 2013. A Phase 2 prehearing conference (PHC) was held on December 5, 2013. Parties filed protests to the Phase 2 Proposals on December 23, 2014 and the IOUs filed their replies on January 3, 2014.

On January 6, 2014, the assigned Commissioner issued the Amended Scoping Memo and Ruling (January 2014 Scoping Memo). The January 2014 Scoping Memo re-categorized Phase 1 as ratesetting, rather than quasi-legislative. The January 2014 Scoping Memo also presented the rate design proposal of Energy Division (Staff Proposal). The Staff Proposal was based on review of rate design proposals and other documents filed by parties during the course of this

proceeding, the bill impact calculators provided by the IOUs, and additional research.[24] Importantly, the Staff Proposal demonstrates the considerable effort and thought that parties put into this proceeding prior to passage of AB 327. Although the Staff Proposal is part of the record, it was not subject to any type of cross-examination and serves only as a reference tool. The Staff Proposal should not be considered evidence which can be relied on for the truth of the statements therein.

At a Phase 2 PHC on January 8, 2014 the IOUs were instructed to simplify their Phase 2 Rate Change Proposals so that the proposals could be adequately reviewed and analyzed prior to summer 2014.

A Second Amended Scoping Memo and Ruling was issued on January 24, 2014 (January 24, 2014 Scoping Memo) and set the procedural schedule, including evidentiary hearings, for Phase 2.

As directed by the January 24, 2014 Scoping Memo, the IOUs filed their simplified Phase 2 Proposals on January 28, 2014. Over the next few weeks, the IOUs worked with other parties to arrive at settlements.

Over the course of the following months, partial settlements were reached between each of the three IOUs and many of the active parties to the proceeding.

The Phase 2 Settlement Rates (1) retained the current multi-tier rate structure, (2) retained current CARE discounts, or begin the gradual glide path toward the CARE effective discount maximum of 35%, and (3) did not institute new fixed customer charges.

Although no party formally objected to the settlement, a one day evidentiary hearing was held on March 27, 2015, 2014. The Phase 2 settlements were adopted in D.14- 06-029.

[24] A revised Staff Proposal was filed on May 9, 2014 to incorporate corrections from parties. *See* ALJ Ruling Issuing Corrected Energy Division Proposal, Attachment B.

2.2.3. Phase 1

On February 13, 2014, the assigned Commissioner issued a Ruling (Phase 1 ACR) directing the IOUs to file rate design proposals for 2015 through 2018 (Phase 1 Testimony). The Phase 1 ACR also set a prehearing conference for March 14, 2014. The IOUs served their Phase 1 Testimony on February 28, 2014.

During the same period, On March 10, 2014, the assigned Administrative Law Judges (ALJs) issued a ruling on the Rate Design Element Inventory (Rate Design Element Inventory Ruling). ORA, SCE, SDG&E, TURN and UCAN filed comments on the Rate Design Element Inventory Ruling, and parties discussed the rate design elements included in the inventory at the March 14, 2014 PHC for Phase 1.

On April 15, 2014, Assigned Commissioner issued a Third Amended Scoping Memo and Ruling (Third Amended Scoping Memo) to finalize the Phase 1 schedule, set the Phase 1 scope, direct the IOUs to serve additional Phase 1 testimony and provide additional information regarding specific rate design elements to be evaluated in Phase 1. The Third Amended Scoping Memo scheduled evidentiary hearings for November 3 - 21, 2014. The Third Amended Scoping Memo also included a revised Rate Design Element Matrix that applies to both Phase 1 and Phase 2.

For the most part, the scope of this proceeding was defined by the objectives set forth in the OIR and the IOUs' responsive rate design proposals. As we stated in the OIR, this rulemaking is intended to examine whether the current tiered rate structure continues to support the underlying statewide energy goals, facilitates the development of technologies that enable customers to better manage their usage and bills, and whether the rates result in inequitable treatment across customers and customer classes. In addition, the Third

Amended Scoping Memo identified the specific issues to be resolved in Phase 1 as follows:

1. Should the Commission adopt a Fixed Customer Charge?
2. Are the utilities' proposed Fixed Customer Charges reasonable, compliant with law and the optimal rate design principles developed in this proceeding?
3. Are the utilities' proposed reductions in baseline quantities reasonable, compliant with law and Rate Design Principles and in the public interest? Do they support Commission and state policies?
4. Is flattening tiers, including a reduction in the number of tiers and tier rate differentials, reasonable and consistent with law and Rate Design Principles? Does it support Commission and state policies?
5. Are the utilities' proposed opt-in tariffs and pilot programs for untiered TOU rates, reasonable, compliant with law and Rate Design Principles? Do they support Commission and state policies?
6. How should any revenue collection shortfalls be treated between customer groups on different tariffs?
7. In what type of proceeding should the Commission review residential TOU periods?
8. What requirements should be set for short-term outreach programs to communicate changes in rate design in the near-term (including untiered TOU pilot and opt-in outreach, changes to tiers and fixed charges, changes to the California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA), and medical baseline programs)? Where should funding for this outreach come from? What metrics should be used to evaluate the effectiveness of the outreach programs?
9. Does the two-tier minimum set in Section 739.9(c) apply to optional and default TOU rates?
10. At a minimum, what must IOUs do to comply with the Section 745(a)(5) requirement to provide each customer

with a calculation of expected annual bill impacts under each available tariff? Should this service be offered starting in 2015 as a means of customer education and outreach regarding rate options?

11. In light of the changes to the tier-structure permitted by the passage of AB 327, what, if any, implementation steps are necessary to begin including greenhouse gas (GHG) costs in residential rates pursuant to the direction in ~~Decision~~ D.12-12-033 that GHG costs should be included in residential rates once restrictions on lower tier rates are removed?

12. Is SCE's Phase 1 Proposal for 2015-17 reasonable under the law and the Rate Design Principles? Elements of SCE's Phase 1 Proposal include: changes to the Fixed Customer Charge; reduction in the number of tiers and the differential between tiers; changes to CARE, medical baseline and FERA programs necessitated by changes in the overall residential rate structure; corresponding changes to any other tariffs; and creation of memorandum accounts to track certain expenses related to the Phase 1 Proposal such as outreach expenses and TOU opt-in rate expenses.

13. Is PG&E's Phase 1 Proposal for 2015-17 reasonable under the law and the Rate Design Principles? Should PG&E's Phase 1 Proposal for 2015-17 be adopted? Elements of PG&E's Phase 1 Proposal include: Fixed Customer Charge; reduction in the number of tiers and the differential between tiers; untiered TOU pilot or opt-in rates; changes in the Baseline Percentage; changes to CARE, medical baseline and FERA programs necessitated by changes in the overall residential rate structure; corresponding changes to any other tariffs; and creation of memorandum accounts to track certain expenses related to the Phase 1 Proposal such as outreach expenses.

14. Is SDG&E's Phase 1 Proposal for 2015-17 reasonable under the law and the Rate Design Principles? Should SDG&E's Phase 1 Proposal for 2015-17 be adopted? Elements of SDG&E's Phase 1 Proposal include: changes to the Fixed

Customer Charge; reduction in the number of tiers and the differential between tiers; untiered TOU pilot and opt-in rates; changes in the Baseline Percentage; changes to CARE, medical baseline and FERA programs necessitated by changes in the overall residential rate structure; corresponding changes to any other tariffs; and creation of memorandum accounts to track certain expenses related to the Phase 1 Proposal such as outreach expenses and TOU pilot expenses.

15. Default TOU rates are permitted by law starting in 2018. SDG&E has proposed a default TOU rate for 2018 and has identified certain areas for further evaluation prior to implementation. Are there other factual issues that must be resolved before a decision is made to implement default TOU rates? What existing and new data, metrics and resources should be used to evaluate rates before authorizing default TOU rates and, if applicable, after implementation of default TOU rates? Are there specific conditions (for example, achieving minimum customer education and outreach requirements), that should be met prior to implementation of default TOU rates?

Pursuant to the Third Amended Scoping Memo, the IOUs served Additional Supplementary Testimony on May 16, 2014 and Additional Optional Testimony on June 13, 2014.

On July 11, 2014, the assigned ALJs issued an email Ruling Requiring Additional Supplementary Testimony from SDG&E and PG&E regarding estimated load reduction associated with Energy Efficiency Demand Response and Distributed Generation programs, and NEM Bill Impacts, respectively. On August 28, 2014, the ALJs issued a Ruling Requesting Briefing on Default TOU Pilots.

Intervenor Testimony was served on September 15, 2014 by ORA, TURN, UCAN, Vote Solar, CforAT/Greenlining, Sierra Club, EDF, NRDC, TASC, CFC, SEIA and CALSEIA. On October 6, 2014, following the passage of Senate Bill

(SB) 1090, which amended ~~PU~~Public Utilities Code Section 745, the ALJs issued a Ruling Requiring Additional Testimony and directing the IOUs to either identify the portions of their existing testimony concerning SB 1090 or serve additional testimony responsive to Section 745. Parties' Additional Testimony on SB 1090 issues and Rebuttal Testimony were concurrently served on October 17, 2014.

A PHC was held on October 23, 2014 to address witness scheduling and other issues in preparation for hearing. By email ruling on October 24, 2014, the ALJs granted TURN's request to present supplemental written testimony regarding the bill impact analysis of SCE's rate design proposals and limited surrebuttal testimony on regarding new information present in the rebuttal testimony served by ORA. TURN served supplemental testimony on October 30, 2014 and surrebuttal testimony on November 7, 2014.

Between November 3, 2014 and November 24, 2014, the Commission conducted 15 days of evidentiary hearings. On December 1, 2014, pursuant to an ALJ ruling issued November 19, 2014, the IOUs served supplemental testimony regarding rate design project timelines.

Opening and Reply Briefs were filed on January 5, 2015 and January 26, 2015, respectively.

2.2.4. Public Participation

In order to obtain public input regarding the Commission's rulemaking and the rate design proposals submitted by the IOU, the ALJs conducted public participation hearings (PPHs) throughout California in September and October, 2014. Sixteen PPHs were held between September 16, 2014 and October 14, 2014 in the communities of San Diego, El Cajon, San Francisco, Fontana, Temple City, Palmdale, Chico and Fresno. The PPHs were attended by a total of 870 people, with at least 370 people providing public comment. In addition to the PPHs, the

Commission's Public Advisor received more than twelve thousand letters and email messages from IOU customers and community groups. The Commission also received numerous communications from civic leaders and elected officials. The comments from the public ranged from statements of total opposition to the IOUs requests and recommendations that the Commission deny the requests outright, to support for individual elements of the rate design proposals. Speakers and commenters were particularly opposed to the IOUs' proposals for fixed charges and expressed concern regarding the impacts on low-income customers. Support for the rate design proposals generally centered around the desire to reduce the highest tier rates.

We summarize a subset of the comments that were made most frequently:

> "I'm a member of the Area Agency on Aging Advisory Committee for Monterey County. . . . I'm here to ask you to not approve the changes in the rate structure or the CARE program for PG&E. I'm 70 years old. I live on a fixed income. I'm representing more than just me. I'm representing an awful lot of senior people in Monterey County. All my costs are going up, particularly my housing, my food, very basic costs. . . . I would like you to consider that the aging population, the senior population, is one of the fastest growing in the country."

> "SCE's request is ludicrous. At a time when the middle class is struggling to survive Edison wants to reduce the number of tiers thereby driving up the price for those who conserve electricity. And on top of this they want to increase the monthly charge to $10. Ridiculous, absolutely ridiculous. While the middle class struggles to keep its head above water they want more of our money. Thieves says I. You must stop this theft of the American family."

> "Now that PG&E is facing a big fine, suddenly it is demanding a huge 12-percent increase in gas charges for all individuals. And now double the monthly electric minimum and force electric customers into an expensive Tier 2 instead of a—for the present—moderate Tier 2? Who's making this decision? CPUC management and PG&E management are not living on minimum wage, to say the least."

> "Under the current rate structure, thousands of low-income seniors, particularly those here in East County, are subsidizing some of SDG&E's wealthiest customers who are fortunate enough to live in La Jolla and some of the other beach communities."
>
> "Why do the CPUC and Governor Brown want to reward the customers who over-use our resources with lower kWh rates while penalizing us SCE customers who try to conserve and lessen unnecessary use of power resources? With R.12-06-013, SCE customers who conserve on their use of resources will pay ***more than 23% higher*** rates per kWh in Tier 1 and ***more than 28% higher*** rates in Tier 2. Mega users of SCE power in Tier 3, however, will pay ***24% less*** per kWh. Tier 4 users will pay ***18% less*** per kWh. Can anyone at the CPUC actually rationalize this SCE proposal as fair? **NO.** Does it truly create rate structure and renewable energy policies to better serve customers? **NO.** I see it as "**REWARD the rich** at the conservationists' expense!" Does that seem equitable? **NO.**"
>
> "The worst scenario is that the low income seniors are going to be forced to start eating dog and cat food again. The worst scenario is that you're going to find some seniors in their apartments or wherever they live frozen to death. You're going to find that. You're going to find low income families chopping up their furniture just to keep the kids warm. This is what's going to happen. This is the future of seniors, low income families, and handicapable people."
>
> "I feel that the current structure is for the rates is unfair. [sic] It assumes that if you are in Tier 1, you are not—you're poor. Many of the people that are in Tier 1 live closer to the coast. Therefore, they don't have the electrical rates for air conditioning and services that we do out on the East County. The truth is if you live in Tier 1, you probably live close to the ocean or do not need the air conditioning. I live in Ramona. And I am in Tier 3 and Tier 4. No matter how hard we conserve and try, we cannot get out of Tier 3 and Tier 4."

While we cannot accord the comments the same weight as evidence presented in sworn testimony of witnesses subject to cross-examination, we value the input and incorporate it into our deliberations. These comments provide

valuable assistance in understanding the perspective of customers and others who are affected by our decisions.

3. Legal Review for Rate Design Proposals

3.1. Statutory Law

Rate designs must comply with a wide variety of laws designed to protect consumers, ensure reliability of the electricity grid, promote clean energy, and ensure safety. The rates approved in this decision must comply with long-standing laws and with the changes to law made by AB 327. The following statutes are of particular relevance in evaluating the rate change proposals.

- Section 451 which requires that rates be "just and reasonable."
- Section 382(b), as amended by AB 327, states that "electricity is a basic necessity" and that "all residents of the state should be able to afford essential electricity." Section 382(b) directs the Commission to ensure that low-income ratepayers are not "jeopardized or overburdened by monthly energy expenditures."
- Section 739 defines baseline quantity and, in Section 739(d)(1), requires that the Commission "establish an appropriate gradual differential between the rates for the respective blocks of usage."
- Section 739.1, which was amended by AB 327, addresses the CARE program. Section 739.1(c) requires the average effective CARE discount to be between 30-35% "of the revenues that would have been produced for the same billed usage by non-CARE customers."
- Section 739.9, which, pursuant to AB 327, replaced the prior Section 739.9, requires that any increases to electrical rates, including reductions in the CARE effective discount, "be reasonable and subject to a reasonable phase-in schedule relative to the rates and charges in effect prior to January 2014."

3.2. The Rate Design Principles

Rate design proposals must also adhere to the Rate Design Principles (RDP) developed in this proceeding to evaluate residential rate design options.

The initial OIR set forth a preliminary list of principles for optimal rate design. (OIR at 20-21.) The OIR list echoed Commission decisions, such as D.08-07-045, and was similar to the "Bonbright principles."[25] After extensive input from the parties, including a workshop and written comments, the RDP were adopted by the Commission in the Phase 2 Decision:

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
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;
6. Rates should be stable and understandable and provide customer choice;
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
8. Incentives should be explicit and transparent;
9. Rates should encourage economically efficient decision-making;
10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

4. The Evidentiary Record; and Central Legal Issues

In the course of this proceeding, we have held ~~2~~two days of workshops and 15 days of evidentiary hearings and ~~8~~eight days of PPHs, and one all-party meeting. The exhibits admitted into the evidentiary record stand literally 3.5 feet

[25] The "Bonbright Principles" include rate attributes such as fair apportionment of costs among customers, encouragement of efficient use of energy, rate stability, and ability to meet revenue requirement under the fair return standard. *See*, Bonbright, James C, *Principles of Public Utility Rates*, Columbia University Press, New York NY, 1961.

tall. Numerous papers are cited in the evidentiary record. And yet, what is most surprising about this proceeding is the degree to which evidence does not provide a complete answer to even the most basic questions about changes to rate design for residential customers.

This lack of direct evidence highlights the degree to which our pursuit of reformed residential rates, particularly TOU rates, has brought us to uncharted waters. As a result, a significant order of this decision will be to direct the IOUs to start mapping the transition to TOU rates.

Rate design should be based on science, not art. Thus, an important component of this decision is to direct the utilities to gather evidence on customer acceptance and to develop a comprehensive outreach strategy before implementing default or default TOU rates.

4.1. Customer Understanding of Electricity Rates

4.1.1. Hiner Study

In 2013, PG&E, SCE and SDG&E jointly commissioned Hiner & Partners to conduct a survey of their customers in order to develop a better understanding of customer knowledge of and preferences for various types of rate plans. The study surveyed 4,283 electric customers from the three IOUs, comprising several groups. The largest was a "Core" group, designed to be representative of the IOUs' populations, and was provided with educational information on rate structures. Additionally there was an "Unexposed" group, similar to the "Core" but not provided any educational information about the rate structures during the survey, and several "Supplemental" groups including Spanish speakers, solar customers and customers with high engagement in utility programs.

The Hiner study found that customers generally have a poor understanding of rates, stating that "customer awareness of existing rates is

modest at best, especially about the tiered rates most currently have".[26] Before receiving educational information about rate plans, 58% of respondents in the "Core" group reported that they had heard about tiered rates and 40% were aware of TOU rates.

Only 50% of customers believed that they were currently on a tiered rate plan. 19% responded that they were currently on a TOU rate plan, however according to IOU data, as of April 2015, only 3.4% of PG&E's residential customers are on TOU rates, while SCE and SDG&E have 0.52% and 0.6% of residential customers on TOU rates respectively.[27] According to the study, "75% of customers have tried to save money by shifting their electricity use" and "despite most customers knowing they are not on a TOU rate, many believe they have saved money by shifting."[28] 21% of "Core" respondents were unsure of what type of rate plan they are currently on [29] and the most common answer when asked if their current rate plan includes a monthly service fee or demand charge was "not sure."[30]

Among "Supplemental" groups, SmartRate and PG&E solar customers were much more aware of TOU rates than the Core group[31] and Seniors were also more knowledgeable about existing rate plans.[32] The study found that Spanish speakers were less informed about current rates[33] and households with a disabled member have a similar knowledge of rate plans as the Core group.[34]

[26] PG&E Rate Design Proposal, Appendix A, Hiner & Partners Key Findings at 7.
[27] April 2015 IOU Supplemental Filings.
[28] PG&E Rate Design Proposal, Appendix A, Hiner & Partners Key Findings at 11.
[29] *Id.* at 7.
[30] *Id.* at 12.
[31] *Id.* at 37.
[32] *Id.* at 40.
[33] *Id.* at 36.
[34] *Id.* at 41.

4.1.2. Customer Understanding

The level of customer understanding was further demonstrated at the 16 PPHs held in this proceeding and the voluminous public comments filed with the Public Advisors Office. Customers must have "confidence that rates are fair and reasonable."[35] CforAT argues at length that the comments of the public at the PPHs and in letters and emails filed with the Public Advisors Office demonstrate that customers do not have understanding of their bills or confidence that their rates are fair and reasonable.

We agree that residential customer understanding of rates should be a key objective of this proceeding.

4.2. Conservation and Rate Design

4.2.1. Overview

Energy conservation refers to reducing energy consumption through using less of an energy service. Energy efficiency refers to using less energy to provide the same service. California has various policies that support energy conservation and energy efficiency. In this proceeding, parties have categorized energy efficiency into (i) behavioral changes (such as turning out the lights) and (ii) investments (such as purchasing energy efficient appliances). In addition, rooftop solar photovoltaic (PV) can be used to reduce the amount of grid-supplied energy used by a customer, but this is not the same as reducing overall energy use.[36]

The purpose of conservation includes reducing pollution and greenhouse gas (GHG), and reducing energy and infrastructure costs. In this proceeding we did not examine the degree to which California's existing programs for

[35] CforAT OB at 19.

[36] A customer who installs solar may actually increase usage to maximize perceived benefits from having their own energy source.

conservation and energy efficiency have been effective in achieving those goals, but these are areas of ongoing examination by the Commission.

Assuming that customers change the amount of energy they use based on the price of the energy, then the proposed rate design changes could increase or decrease conservation. For example, if the price of gasoline goes up, car owners drive less. The relationship between the price and changes in usage are not always easy to determine.

Conservation and energy efficiency are supported by RDP #4 (rates should encourage conservation and energy efficiency) and #5 (rates should encourage reduction of both coincident and non-coincident peak demand), but must be balanced against the other eight RDPs. In addition, we are required by statute to make a specific finding on conservation before authorizing any fixed charge: that the fixed charge will not "unreasonably impair incentives for conservation and energy efficiency."

In this proceeding, parties focused on two tools for evaluating whether changes in rate design will change the incentives for conservation in a way that customers will respond to.

(1) Price Elasticity – the measure of how much customer demand for energy (kWh) will change in response to the price.

(2) Payback Period – the measure of the amount of time it takes to pay for an energy efficiency or PV investment.

Both measures were the subject of substantial testimony.

The utilities assert that their rate design proposals, including tier reduction and proposed fixed customer charges, will not impair incentives for customers to conserve energy or invest in energy efficiency measures. The utilities explain that while higher-usage customers have a greater incentive to conserve under steeply tiered rates, lower-usage customers have a lesser incentive to conserve.

Because of this, they maintain that consumption may decrease slightly in the lower tiers under the new rate design proposals.

ORA, TURN, NRDC, and SEIA all argue that the utilities' proposals would negatively impact conservation incentives by decreasing the rates of those who have the most discretionary usage, higher-users, and increasing the rates of those whose discretionary usage is more limited. They also argue that the utilities' proposals would reduce the incentive for customers to invest in energy efficiency and demand response measures by increasing the payback periods associated with those investments.

4.2.2. Balancing State Policies for Conservation and for Cost-Based Rates

The legislature and the Commission both recognized that adjusting residential rates to better reflect cost causation may impact existing incentives for conservation. Among the many goals articulated in AB 327, is to give the Commission the ability to "address current electric rate inequities, protect low income users, and maintain robust incentives for renewable energy investments. [37] In addition, pursuant to Section 739.9 (e)(2), prior to adopting any changes to residential rate design, the Commission must find that the rate design it adopts does not "unreasonably impair incentives for conservation and energy efficiency." This requirement is consistent with various policies and programs developed by the State of California and the Commission that seek to increase reliance on non-fossil based generation to reduce greenhouse gas emissions and promote conservation and energy efficiency.

The Commission's goals are articulated in part in Energy Action Plan and Energy Action Plan II, adopted on May 8, 2003, and October 2005, respectively

[37] Letter to State Assembly Members regarding AB 327, from Gov. Edmund G. Brown Jr., October 7, 2013.

and call for all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand and establish a goal of decreasing per capita electricity use through increased energy conservation and efficiency measures. The Energy Action Plan also identifies a "loading order" that places energy efficiency as "the resource of first choice for meeting California's energy needs." The loading order is codified in ~~PU~~Public Utilities Code Section 454.5 (b)(9)(C).

4.2.3. Measuring Elasticity of Customer Demand

Each of the utilities' rate design proposals includes an assessment of the impacts of their rate design proposals on conservation of electricity by the residential class. A customer's price elasticity of demand can be measured by calculating the customer's percent change in consumption given a ~~one percent~~1% change in price. Determining the price elasticity of demand for residential customers is particularly difficult given the current tiered rate structure. Parties disagree on whether customers understand what their electric rates are at any given moment during the month. For this reason, parties did not agree on whether customers respond to a marginal price set by the highest tier of usage, or a marginal price tied to the average bill. Parties also disagreed on what price elasticity should be modeled.

In its Opening Testimony, PG&E presented the results of an Excel-based model evaluating the impact of its proposed rate design on conservation. PG&E compared the impact of its proposed 2018 rates to its 2014 rates under four scenarios, calculated the percentage change in prices between each tier, and then applied price elasticities to estimate changes in sales by tier. PG&E then summed the changes over all the tiers to estimate the effect on usage from its proposal.[38]

[38] Exh. PG&E-101 at 2-66.

In its first scenario, PG&E assumed a price elasticity of demand of -0.2 for all tiers. Given the uncertainty regarding the price elasticity assumption, however, PG&E also modeled four alternate elasticity assumptions. We refer to this approach as the PG&E method. Several parties, including ORA and TURN, criticized PG&E's approach on the basis that it not only assumes that customers know what tier they are in, but also assumes that customers know the price of each tier and when they move from one tier to another.

In Joint Rebuttal Testimony, PG&E and SCE witness Faruqui provided more detailed analysis of customer response to price for PG&E and SCE's rate proposals. Witness Faruqui used three different methodologies: (i) a Tier-Specific methodology, (ii) an Average Price methodology, and (iii) a Marginal Price methodology.[39]

Under the Tier-Specific methodology, the price change in each tier is assumed to affect the conservation in that tier. For each tier, the percentage change in price between each tier is multiplied by an estimated price elasticity to determine the percentage change in consumption in that tier. The change in consumption for each tier is then combined to obtain the overall net change in consumption attributable to the rate design change. Dr. Faruqui's Tier-Specific analysis assumes a price elasticity of -0.13 in the first tier and -0.26 in all other tiers. TURN disagrees with this methodology because it assumes that customers know the tier prices and what tier they are in.

The Average Price methodology assumes that customers respond to changes in their bill and increase consumption if their bill decreases and vice versa. Under this approach, each customer's bill under the new rate is compared

[39] The PG&E analysis was based on 12 months of consumption data from approximately 6700 customers in calendar year 2011. The SCE analysis was based on 12 months of consumption data from 8213 customers from calendar year 2013.

to its bill under the old rate and then multiplied by an estimated price elasticity to obtain the percentage change in consumption. Dr. Faruqui's Average Price methodology uses a consumption-weighted average of the price elasticities used in the tier-specific methodology, resulting in a price elasticity of -0.18 for PG&E. For SCE, the average price elasticity was -0.17.[40]

The Marginal Price methodology offered by the joint PG&E/SCE testimony compares the new price of each customer's marginal (i.e., highest) tier to the old price of the marginal tier. The percentage change in price is multiplied by an estimated price elasticity to estimate the percentage change in the customer's total consumption. This approach assumes that customers respond to the actual price they avoid when reducing consumption

Dr. Faruqui's Marginal Price methodology uses a price elasticity for the first tier of -0.13, and class consumption-weighted average of the tier specific price elasticities (-0.13 and -.26), resulting in a price elasticity of -0.18 for PG&E and -0.9 for SCE. Dr. Faruqui's Marginal Price methodology also uses income elasticity variables of 0.16 for PG&E and 0.15 for SCE, meaning that for a 10-~~percent~~% bill increase in the inframarginal tiers, a customer's electricity consumption would decrease by 1.6 or 1.5 ~~percent~~% for PG&E and SCE customers, respectively. Dr. Faruqui's analysis included the utilities proposed fixed charges converted to a levelized charge and added to the price of the first tier. Dr. Faruqui suggests that the marginal tier price method correctly models the way that customers would respond to changes in price if they accurately understand the actual impact of changes in usage on their bill. [41]

TURN and NRDC take issue with the Marginal Price methodology used by PG&E and SCE because it includes an income "expenditure" variable based on

[40] Exh. PG&E-111 at 9.
[41] RT Vol 17 at 2357-2359, PG&E/Faruqui.

the assumption that customers also respond to the amount of money spent to reach the marginal tier according to their income elasticity – the higher the bill to reach the marginal tier, the less electricity will be consumed. Dr. Faruqui states that the application of an income elasticity variable means that "the same reduction in electric consumption would be realized through either a 10% increase in a customer's bill or a 10% decrease in overall household income."[42]

TURN points out that for a customer with an annual income of $60,000, the application of this income elasticity variable would mean that a $6,000 reduction in income would be assume to result in a 1.6% reduction in electric usage. That same customer would be assumed to reduce their electric usage by the same amount (1.6%) if their bills increase by as little as $72 per year. According to TURN, assuming identical changes consumption under scenarios presenting significantly different economic impacts to a customer is not reasonable. Dr. Faruqui acknowledged that he has not included this variable in his prior analyses of tiered rates and that he could not name a study that had used such a variable.[43] Dr. Faruqui also acknowledged that his methodology could lead to results that appear difficult to reconcile. [44]

We agree with TURN and others that the use of the "expenditure" variable is not appropriate for calculation of customer response to electricity prices. However, we find that, aside from the use of the expenditure variable, the Marginal Price methodology may be an appropriate model for some customer behavior.

Under the joint PG&E/SCE analysis, PG&E's rate design proposals would result in a decrease in annual residential consumption of 0.6 ~~percent~~% using the

[42] *Id.* at 2362, 2368.
[43] *Id.* at 2371.
[44] *Id.* at 2368-69, 2371.

Tier-Specific methodology, a decrease in consumption of 1.2 percent% using the Average Price methodology, and an increase in annual residential consumption of 1.2 percent% using the Marginal Price methodology. PG&E also finds that across all methodologies "reducing the CARE discount has the effect of reducing consumption since it represents an overall increase for the residential class."[45]

The joint PG&E/SCE analysis find that for SCE customers, consumption will decrease by 0.5 percent% using the Tier-Specific methodology, decrease by 1.1 percent% using the Average Price methodology, and increase by 1.8 percent% using the Marginal Price methodology.

Conservation Impacts : PG&E "Table 2"[46]

	Collapse to Two tiers	Introduce Fixed Charge	Reduce CARE Discount	Total
Tier Specific	-0.2%	0.2%	-0.6%	-0.6%
Average Price	-0.4%	-0.2%	-0.6%	-1.2%
Marginal Price	1.3%	0.9%	-1.0%	1.2%

Conservation Impacts: SCE "Table 5"[47]

	Collapse to Two Tiers	Increase Customer Charge	Reduce Baseline Allowance	Total
Tier Specific	-0.3%	0.1%	-0.2%	-0.5%
Average Price	-0.8%	-0.2%	-0.1%	-1.1%
Marginal Price	1.6%	0.6%	-0.3%	1.8%

In addition to endorsing the approach and findings of Dr. Faruqui, SCE performed an analysis of conservation impacts based on changes in average bills.

[45] Exh. PG&E-111 at 13.
[46] *Id.* at 14.
[47] *Id.* at 18.

Using this approach, SCE determined that customers make decisions regarding conservation based solely on changes to the average bill. According to SCE, a $10 per month or 10% bill impacts essentially serve as proxies for when customers would notice a change. Neither PG&E nor SCE analyzed the conservation impacts of rate design proposals submitted by any other party.

SDG&E performed a separate analysis of the conservation impacts of its residential rate design proposals using the tier-specific methodology built in to the PG&E bill impact calculator. SDG&E did not conduct an analysis using the average rate or marginal tier methodologies. In its analysis, SDG&E used a -0.1 price elasticity for all tiers, assuming that customers would respond to changes in lower tier prices in the same manner they respond to higher tier prices.[48] [49] SDG&E calculated the impacts of including the proposed fixed charges using two different methodologies: a levelized or "all-in" approach similar to PG&E's and SCE's and a second approach that applied the fixed charge to all tiers.

Upon request from TURN, SDG&E also modeled the impacts of retaining a -0.1 price elasticity for the first tier and substituting -0.2 as the price elasticity for all other tiers to compare SDG&E's results to those of PG&E and SCE's. Applying these modified inputs to SDG&E's model results in a 0.27% increase in consumption for non-CARE customers.

Conservation ~~Impact~~Impacts: SDG&E Table[50]

	2015-2017 kWh Percent Change
SDG&E Scenario 1 (-0.1 elasticity, fixed charge in bottom tiers)	-0.36%
SDG&E Scenario 1 (-0.1 elasticity, fixed charge in all tiers)	-0.32%

[48] RT Vol. 15 at 1955: 5-14, SDG&E/Willoughby.

[49] SDG&E based its residential elasticity estimate on the residential sales models developed for the purpose of submitting residential sales forecasts to the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) process. *See* Exh. SDG&E-113.

[50] Exh. SDG&E-113, Appendix A at 2-3.

SDG&E Scenario 2 (-0.2 elasticity, fixed charge in bottom tiers	-1.41%
SDG&E Scenario 2 (-0.2 elasticity, fixed charge in all tiers	-0.91%

SDG&E did not analyze the conservation impacts of the rate design proposals submitted by any other party.

Dr. Faruqui did not perform his own independent analysis on SDG&E's proposed rate reforms. [51] However, upon review of SDG&E's analysis, Dr. Faruqui finds that "SDG&E's rate design proposals would increase conservation incentives for the lower-tier sales, which constitutes nearly 70 ~~percent~~% of SDG&E's residential sales, and would reduce those incentives to some extent for upper-tier sales."[52] He admitted, however, that he "had not had an opportunity to review the underlying model in detail."

Each of the IOUs acknowledges that under their proposals residential rates are expected to increase for both non-CARE and CARE residential customers whose usage terminates in ~~tiers~~Tiers 1 and 2 while decreasing rates for ~~tier~~Tier 3 and ~~tier~~Tier 4 customers. However, they maintain that those ~~tier~~Tier 1 and ~~tier~~Tier 2 customers may "seek additional engagement"[53] or ways to save or manage their energy use using existing EE and/or DR programs while customers whose usage terminates in ~~tiers~~Tiers 3 and 4 will see bill reductions, and those customers "may have reduced incentives to increase participation in EE or DR over what that participation is today." [54]

[51] RT at 1953: 20-12.
[52] Exh. PG&E-111 at 21.
[53] SCE OB at 132.
[54] Exh. UCAN-104 at 24.

4.2.4. Other Estimates of Price Elasticity

Several parties argue that customers in the low usage tiers[55] should be assumed to have lower price elasticity than customers in the higher usage tiers. For example, TURN asserts that elasticity may be less for small customers, or customers living in apartments or mobile homes. [56] NRDC and TURN both cite a study of British Columbia Hydro (BC Hydro) residential customers comparing the impact of a newly-introduced two-tiered rate with the existing non-tiered rate. [57] The study found that, under the tiered rate, consumption by the large customers fell. Specifically, the authors found a price elasticity between -0.08 and -.13 for large customers (i.e., those customers consuming above the 1350 kWh/bimonthly ~~tier~~Tier 1/~~tier~~Tier 2 threshold).[58] However, as shown in the chart below, the study notes that with the introduction of a second tier in fiscal year 2010, customers with consumption below the 1350 kWh/bimonthly ~~tier~~Tier1/~~tier~~Tier2 threshold experienced very little rate variation, in real terms, throughout the study period (FY 2005 – FY 2012). Not surprisingly, average consumption of small users also remained virtually unchanged during the study period. Consequently, with little variation in either price or consumption the researchers could not estimate a price elasticity for small customers. The authors acknowledge that their analysis does not consider the effect that suppressing

[55] The term "small customers" is sometimes used in this proceeding and in AB 327. This proceeding did not address a definition for "small customers." For purposes of this discussion of elasticity we treat "small" and "low usage" as synonymous.

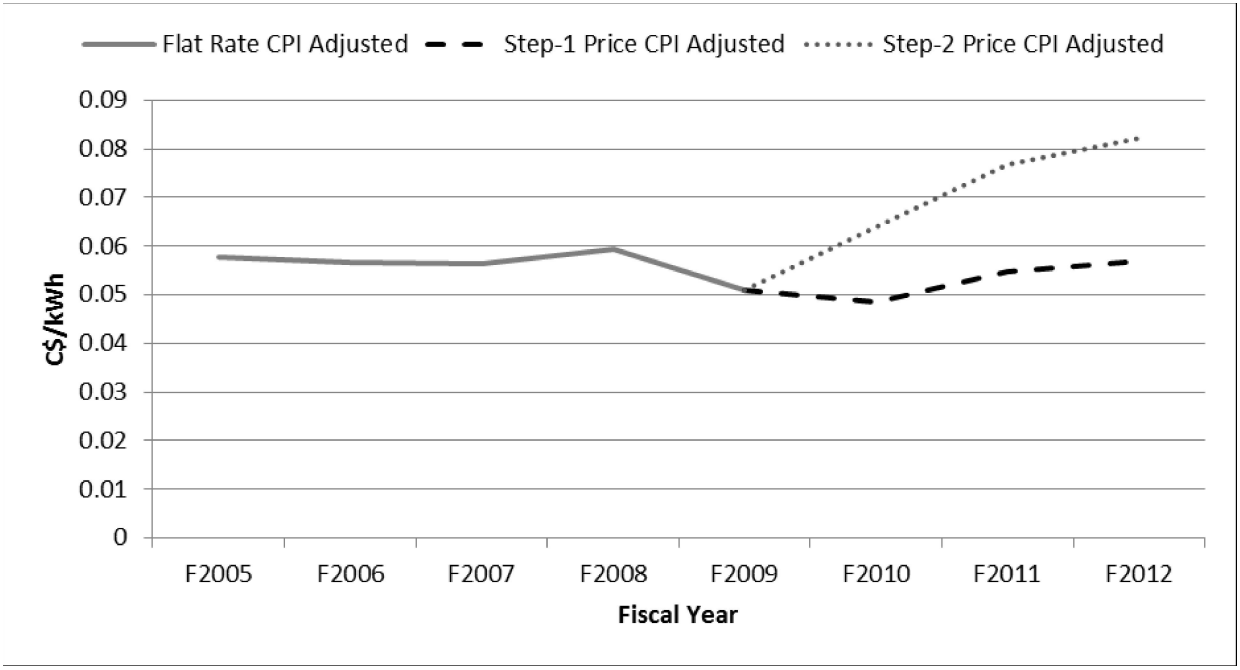
[56] Exh. TURN-201 at 39; Exh. TURN-207, Attachment WBM-6 (Michael Li, Ren Orans, Jenya Kahn-Lang & C. K. Woo, ARE RESIDENTIAL CUSTOMERS PRICE-RESPONSIVE TO AN INCLINING BLOCK RATE? EVIDENCE FROM BRITISH COLUMBIA, CANADA, June 2014); *accord* TURN OB at 6 n.5.

[57] Exh. TURN-207, Attachment WBM-6 (Michael Li, Ren Orans, Jenya Kahn-Lang & C. K. Woo, ARE RESIDENTIAL CUSTOMERS PRICE-RESPONSIVE TO AN INCLINING BLOCK RATE? EVIDENCE FROM BRITISH COLUMBIA, CANADA, June 2014).

[58] *Id*. at 227.

prices for ~~tier~~Tier 1 customers may have had on their consumption.[59] If a flat rate had extended through 2012, small customers would have paid higher rates than they paid under the new tiered rate. Presumably the elasticity of small customers is not zero, and small customers would have consumed less than they actually did in 2010 through 2012. Without an estimate of this effect, it is not possible to conclude that the introduction of tiered rates by BC Hydro reduced consumption overall. However, the study did find that customers living in single-family detached houses have more elasticity than customers in town houses, apartments, or mobile homes.[60]

BC Hydro 2 Step Rate



TASC agrees that different elasticity assumptions should be applied to different tiers based on the fact that lower tier usage typically serves necessary energy needs while higher tier usage is more discretionary for most households.

[59] *Id*. at 224 – 225.
[60] *Id*. at 14.

[61] TASC suggests that a more appropriate price elasticity for ~~tiers~~Tiers 1 and 2 is -0.08, the price elasticity coefficient used in the CEC's California Energy Demand 2014-2024 Final Forecast.[62] TASC reports that using this revised elasticity value in PG&E's scenario 1 results in significantly less conservation – an overall reduction of approximately -0.5 %in usage - compared to the 3.9 % reduction in usage estimated by PG&E.

CforAT cautions that efforts to encourage greater conservation among low-usage and CARE customers should not be used "as cover for reduced conservation among high-usage customers." CforAT notes that the IOUs primary argument that their proposals increase conservation is based on an assumption that the increased rates in their proposals will result in increased conservation by lower tier customers. CforAT argues that the IOUs ignore the fact that customers in ~~tiers~~Tiers 1 and 2 typically have less discretionary usage overall and may not be able to conserve.

CALSEIA, TURN, Sierra Club and others also disagree with the IOUs' assertions that as low- and medium-usage customers' bills increase, they may consider energy efficiency and solar options as a method of managing their bills. PG&E, for example, states that the number of residential customers for whom rooftop solar makes economic sense would actually increase as a result of PG&E's residential rate proposal. Based on their analysis of payback periods (discussed in more detail below) CALSEIA and Sierra Club maintain that the payback period for low and medium-usage customers remains higher than most people are willing to wait to break even on an investment. CALSEIA notes that customers with average usage of 250 kWh per month or 500 kWh per month who consider 50% offset solar systems in 2018 will have capital recovery periods of

[61] Exh. TASC-105 at 9.
[62] *Id.* at 10.

10.8 -12.9 years under the IOUs rate proposals.[63] These parties also note that lower marginal tier prices will reduce the incentive for customers to buy new appliances (since it weakens the payback period) and thereby weakens the impact of improved appliance standards. Other parties note that a majority of low-usage customers are apartment dwellers and/or CARE customers, which limits their ability to install rooftop solar.

4.2.5. TURN Combined Methodology

Due to the limitations of the utilities' bill impact calculators and the unwillingness of the utilities to model other parties' conservation scenarios, TURN prepared its own conservation analysis. TURN developed a combined methodology based on its assertion that customers respond both to change in their bill and the price of incremental usage in the marginal rate tier.

TURN's approach includes a combination of average and incremental rates to reflect its position that customers respond both to changes in their bill and the price of incremental usage in the marginal rate tier. TURN used a -0.05 elasticity value for customers who remain in the first tier and a -0.2 elasticity value for customers above baseline.[64] TURN argues that a -0.05 elasticity value for customers who remain entirely in the first tier is reasonable.

Under TURN's analysis, PG&E's 2018 two-tier rate design would increase consumption by 4.88% under the marginal price approach, increase consumption by 1.44% under the average price approach (excluding the fixed charge) and increase consumption by 2.34% under the combined method incorporating both approaches.[65]

[63] Exh. CALSEIA-106, Appendix A.
[64] Exh. TURN-201 at 40. Aside from an earlier discussion of price elasticity as low as -0.08 for large customers in the BC Hydro study, TURN does not include a rationale for choosing such a low price elasticity estimate for low usage customers.
[65] Exh. TURN-201 at 40-41.

TURN applied the same analytical approach to its proposed ~~3~~three-tier rate structure (with no customer charge), and found that its proposal would increase load by 2.43% under the marginal price approach and decrease load by 0.24 % under the average price approach, or produce a net increase of 1.09% under a method incorporating both approaches.[66]

Percentage Increase in Consumption (PG&E 2 Tier vs. TURN 3 Tier)

	PG&E 2 Tier Rate (excluding fixed charge)	TURN 3 Tier Rate (excluding fixed charge)
Marginal Price	4.88%	2.43%
Average Price	1.44%	-0.24%
Combined	2.34%	1.09%

As noted above, TURN disregarded PG&E's model because the elasticity estimates incorporated into the model assume that customers know what their rates are at any given moment. TURN also notes that the utilities' model produces illogical results by estimating that baseline usage could decline while usage in ~~tiers~~Tiers 3 and 4 simultaneously increase, explaining that "this is a physical impossibility."

TURN claims that under the Average Rate method with no customer charge, a 50-50 average and incremental rate, as well as the incremental rate method (and PG&E's elasticity method which TURN does not support), the TURN ~~3~~three-tier rate proposal is superior to PG&E's in terms of either not increasing consumption or increasing it less than PG&E's method.[67]

4.2.6. ORA TOU Analysis

ORA maintains that TOU rates better align customer energy efficiency and DG with the IOUs avoided costs. ORA used PG&E's Bill Impact Calculator model to estimate total and peak period load reduction under ORA's proposed

[66] TURN OB at 6.
[67] Exh. TURN-201 at 40.

TOU rate. The models used in PG&E's Bill Calculator are the Brattle Group's 3-period (Summer) and 2-period (Winter) PRISM models. After updating the consumption data to reflect PG&E's E-TOU rate design model, ORA assumed an elasticity of substitution of -0.2 and an own-price elasticity of -0.04, based on elasticity of substitution estimates reported in recent studies from -0.07 to -0.4 and own price elasticity assumptions reported from -0.02 to -0.1.[68] ORA then presented high and low case scenarios to show the extreme values for the two elasticity inputs using the rates.

ORA Table 7-2[69]

	Elasticity assumptions used in PG&E Conservation Tab		Low Case		High Case	
	Substitution Elasticity -0.2 Own-price Elasticity -.0.04		Substitution Elasticity -0.07 Own-price Elasticity -.0.02		Substitution Elasticity -0.4 Own-price Elasticity -.0.1	
Season	Consumption Change %	Change in usage (kWh/season)	Consumption Change (%)	Change in usage (kWh/season)	Consumption Change (%)	Change in usage (kWh/season)
Summer Peak	-11.34%	(396,073,648)	-4.22%	(147,480,267)	-22.00%	(768,321,131)
Summer Partial-Peak	-3.47%	(94,194,294)	-1.32%	(35,956,786)	-7.57%	(205,792,014)
Summer Off-Peak	3.44%	340,300,813	1.09%	108,206,485	6.09%	602,859,105
Summer Total	-0.93%	(149,967,130)	-0.47%	(75,230,568)	-2.30%	(371,254,040)
Winter Partial-Peak	-1.32%	(23,603,769)	-0.04%	(7,896,406)	-2.54%	(45,497,982)
Winter Off-Peak	0.04%	46,361,304	0.14%	19,244,617	0.77%	102,850,241
Winter Total	0.15%	22,757,535	0.08%	11,348,211	0.38%	57,352,259
Annual Total	-0.41%	(127,209,595)	-0.20%	(63,882,357)	-1.01%	(313,901,781)

[68] Exh. ORA-101 at 7-9 (citing Ahmad Faruqui & Sanem Sergici Arcturus: *International Evidence on Dynamic Pricing*, ELECTRICITY JOURNAL, VOL. 26, ISSUE 7: 55-56 (2013).

[69] Exhibit 101 at 7-10.

Based on this, ORA estimates that its proposed TOU rate for PG&E would result in a 0.4% decrease in total load consumption and an 11% decrease in peak load consumption.

4.2.7. Do Customers Understand their Rates?

ORA disagrees with the IOUs' assertion that customers only react to average bills and suggests that the average price methodology is not consistent with the goals of promoting a better understanding of rate design.

However, if customers only react to average bills, ORA agrees that a fixed charge would increase conservation because it would increase the bill. Furthermore, ORA notes that of the methodologies analyzed by Faruqui, only the average price methodology shows the introduction of a fixed charge increasing consumption.[70] This result is borne out by the joint PG&E/SCE analysis, with the average price methodology showing decreased conservation associated with the introduction of, or increases to, the fixed charge. However, ORA maintains that this method inappropriately assumes that customers don't understand their rates.

ORA suggests that because the utilities have spent "billions of dollars on the mass-implementation of Advanced Metering and Smart Grid initiatives that provide easier access to more granular consumption data…" new rates should be introduced "assuming that the utilities will adequately inform customers about their rate structures and choices."[71] ORA notes that while the utilities cite one paper by Kochiro Ito to support their assertions, this paper relies on studies and data from 1997 to 2007, well before the utilities invested in advanced metering and smart grid initiatives.

[70] ORA OB at 58.
[71] *Id.*

Because it disagrees with the IOUs regarding whether customers react to average bills, ORA finds the joint PG&E/SCE Tier-Specific and the Marginal Price methods more useful in estimating the conservation effects of ORA's rate design. ORA notes that for two out of the three joint PG&E/SCE methodologies, adding a fixed charge, or increasing an existing fixed charge will increase consumption. Based on the models, a fixed charge would result in a consumption increase nearly as large as collapsing the tiers and reducing the CARE discount. For SCE increasing the fixed charge will have a larger change than reducing baseline.

NRDC also maintains that customers react only to the highest tier and that no price changes in tiers other than the marginal tier will affect a ~~customers~~customer's conservation decision.[72] NRDC argues that if customers are only responding to their total bill or average rate, they would not alter their consumption regardless of whether the utility's rate design was 20 cents ~~per~~/ kWh or a fixed charge of $105/month plus 1 cent/kWh. NRDC argues that this outcome is implausible, and that it is more plausible that customers only respond to the highest tier price.

NRDC claims that Faruqui's calculations lead to a significant understatement of the usage increase for price decreases and an overstatement of the usage reduction for price increases.

CforAT states simply that "many customers simply pay their bills with no thought to the formula by which they are calculated, and nothing except potentially increased education efforts is likely to change this reality."[73]

[72] NRDC OB at 12.
[73] CforAT OB at 18.

4.2.8. Energy Efficiency, DR, DG Impacts

In response to the ALJs' request that the utilities quantify and discuss the impacts of any proposed rate design changes over the period 2015-2017 on customer participation and load impact in Energy Efficiency (EE) , Demand Response (DR), and Distributed Generation (DG) program, the utilities generally responded that they did "not have an expectation of what the specific changes in customer participation and/or to load impacts to its EE, DR, and DG programs… it does expect that some customers will seek out ways to manage their usage."[74]

The IOUs explained that EE and DR program participation is driven by multiple factors such as advertising and rebate levels and therefore isolating the impact of rate changes would be difficult. ORA agrees, and suggests that we leverage the current evaluations conducted through the Commission's EE and DR program. For example, ORA notes that many EE evaluations focus on program attribution, or what is referred to as the Net-to-Gross (NTG) ratio.[75] In these evaluations, the evaluator focuses on the customer's motivation for participation in EE programs in order to better estimate the impact of the EE program itself on the participant's behavior. ORA suggests that the impact of rate changes could be included in the NTG evaluations.

While the utilities did not quantify the impact of their rate design proposals on EE, DR, and DG programs, several parties representing solar interests analyzed the impact of the utilities' proposals on the payback periods of certain EE upgrades.

UCAN maintains that over the next four years, lower-tier customers who have been protected or sheltered from the incentive to engage in EE and DR will

[74] Exh. SDG&E-105 at 7 (Willoughby).

[75] The net energy savings reflect the impact caused by the EE program after other factors that influenced the customers' decisions are netted out. The gross energy savings reflect the total conservation achieved regardless of what caused it.

face increasing incentives to do so while upper–tier customers who have faced twice the price of lower-tier customers and have been clearly incentivized to engage in EE and DR programs will face reduced incentives to engage in these programs. UCAN admits that "there is clearly a trade-off between flattening the rate all way to 20 ~~percent~~% and reducing the current benefits of the tiered structure for conservation purposes versus preserving some conservation potential in the tiered structure …"[76]

TURN claims that not only will all the utilities' rate design proposals increase consumption by decreasing the higher tier rates, the impacts of the utilities' proposals could wipe out as much as three years' of conservation spending in increased usage.[77] To put the percentage increases or decreases into perspective, TURN explains that "PG&E's rate design will essentially cancel out 1 to 3 years' worth of the millions of dollars that PG&E spends on residential energy efficiency."[78] Under TURN's analysis, PG&E rate design proposals would increase overall residential class consumption between 514 - 1,071 Gigawatt hours (GWh) per year.[79] According to TURN, when compared to the energy efficiency program savings goal recently adopted for PG&E of 697 GWh in 2015, the effect of PG&E's rate design proposal in this proceeding would essentially negate PG&E's energy efficiency program efforts for 2015.[80]

4.2.9. Payback Periods

The solar parties, along with NRDC and TURN maintain that understanding how rates impact payback periods informs whether a proposed rate design is consistent with the principle that rates encourage conservation and

[76] Exh. UCAN-101 at 25.
[77] Exh. TURN-201 at 1.
[78] *Id.* at 40.
[79] *Id.* at 41 (Table 12).
[80] TURN RB at 6-7 (citing PG&E OB at 4, Exh. TURN-201 at 41, and D.14-10-046 at 10).

energy efficiency. In their view, payback periods are an important metric to evaluate the potential impacts of alternative rate designs because any rate–driven changes in monthly bill savings will necessarily affect a homeowner's interest in entering a solar lease or purchasing a new water heater or AC system. As the price of a kilowatt hour rises or falls, so does the savings from conserving (or generating) that kilowatt hour. Moreover, customers with the lowest payback periods are most likely to invest in a given technology. According to NRDC, even if tiered rates introduce cross-subsidies, state policy goals and legislation strongly endorse the energy efficiency benefits of tiered rates. They argue that the unambiguous loading order priority and the principle of conservation and efficiency in this proceeding support the argument that even if there is some remaining cross-subsidy, it is appropriately supported by explicit state policy goals.[81] These parties suggest that the Commission should retain a minimum of a three-tiered rate structure with a steeper differential between tiers. These parties assert that all California residents benefit from the positive health and environmental effects of increased renewable generation and the IOUs' proposed changes to residential rate design threaten the economic attractiveness of renewable technologies.

Sierra Club maintains that potential solar or EE customers generally discount future savings at a very high rate, meaning that they expect to recoup their investment in new technology very quickly. Sierra Club analyzed the impact of the proposed rate design changes on investments in energy efficiency and distributed generation using models designed to test the conservation impact on each of four common upgrades: 1) on-site PV; 2) upgrading a central AC unit upon the end-of-life of an existing unit; 3) changing 100% of the light bulbs in a

[81] NRDC OB at 11.

residence to LED lamps; and 4) replacing an electric resistance water heater with an efficient electric heat pump, for electric only customers. Sierra Club finds that PG&E customers whose air conditioners could currently be repaid in ~~6~~six years or less would see their payback period increase by an average of 4.1 years under PG&E's proposed tiered rates, and 3.7 years under proposed TOU rates, and that the overall potential savings with a 10-year payback from this measure or less are cut roughly in half under PG&E's proposed rates.[82] Sierra Club also finds that the utilities' tier flattening proposals would eliminate all the potential savings from installing LEDs that can be paid back in under two years, across all utilities and all proposed rates.[83]

4.2.10. **Payback Periods for Solar PV**

The solar parties emphasize that the residential rate tariffs and the net energy metering (NEM) tariffs work together to determine a customer's bill and accordingly, support or undermine a residential customer's solar investment.[84] As a result, changes to the residential rate structure necessarily affect the monthly savings provided by NEM. They argue that higher tiered rates that raise the marginal price for the average kWh of sales encourage conservation and energy efficiency in ways that flatter rates cannot and that large reductions in bills to large customers and large increases in bills to small customers would send a clear signal that California is not prioritizing energy efficiency.[85]

Sierra Club cites an NREL survey finding that "50% of non-adopters [homeowners who did not have PV] would require a payback period of 6 years

[82] Sierra Club OB at 10.
[83] Exh. Sierra Club-101 (Corrected) at 21.
[84] Vote Solar OB at 7.
[85] NRDC OB at 8.

or less to seriously consider adopting" and that solar market penetration curves flatten significantly as payback periods increase.[86]

CALSEIA measured the payback period for each of the utilities proposal for customers with different levels of consumption and with systems that offset different proportions of usage. CALSEIA finds that the capital recovery period under the utilities' proposals are 9.2 years to 10.8 years for customers with 750 kwh or more of gross monthly consumption, compared to capital recovery periods of 5.6 years to 8.1 years under the current rate structure.[87] The capital recovery periods for customers with smaller usage would be longer.

CALSEIA also claims that the utilities' rate design proposals would reduce the monthly bill savings of existing solar customers by 26%-40%.[88] The utilities acknowledge these concerns, admitting that "[T]he average customer payback periods for customers installing new solar NEM facilities will increase slightly,"[89] and "SCE recognizes that payback period can provide information on customer adoption of solar."[90] This is true for both host-owned systems and PPAs. PG&E further acknowledged that "changes that negatively impact the payback period for host-owned systems also negatively impact PPA customers."[91] IREC agrees, noting that with the anticipated reduction in the Federal Investment Tax Credit from 30% to 10% after 2016, it will take roughly a 20% price decline by 2017 for customer-sited solar facilities to be as attractive to customers then as they are now, given no changes in rates; tier flattening and fixed customer charges would further limit the market."[92] Vote Solar claims that the Commission should not

[86] Sierra Club OB at 7.
[87] CALSEIA OB at 5.
[88] *Id.* at Table 2.
[89] Exh. PG&E-101 (Part 2) at D-32.
[90] Exh. SCE-106 at 107.
[91] RT Vol. 11 at 1267-1268, PG&E/Halperin.
[92] IREC OB at 6.

change the rate structures customers that solar customers relied on in making their investments.

CALSEIA, TURN, and Sierra Club disagree with the utilities' assertions that as low- and medium-usage customers' bills increase, they may consider energy efficiency and solar options as a method of managing their bills. PG&E, for example, states: the number of residential customers for whom rooftop solar makes economic sense would actually increase as a result of PG&E's residential rate proposal. CALSEIA and Sierra Club maintain that the payback period for low- and medium-usage customers remains higher than most people are willing to wait to break even on an investment. CALSEIA notes that customers with average usage of 250 kWh per month or 500 kWh per month who consider 50% offset solar systems in 2018 will have capital recovery periods of 10.8 - 12.9 years under the IOUs' rate proposals.[93] Other parties note that a majority of low-usage customers are apartment dwellers and/or CARE customers, which limits their ability to install rooftop solar.

4.2.11. Conservation and Fixed Charges

The impact of the proposed fixed charges on conservation effort was also actively debated in this proceeding. According to TURN and ORA, along with the solar parties, high fixed charges in particular will lead to energy efficiency programs that are less effective or more costly, or both.[94] ORA and TURN explain that the IOUs collectively spend more than a billion dollars a year on EE programs. According to ORA, a rate structure with a fixed charge will reduce customers' potential bill savings from investing in EE and DG and will shorten the payback period for these investments, resulting in either higher rebates raising program costs or lower penetration of the programs or both. ORA

[93] Exh. CALSEIA-106, Appendix A.
[94] Exh. TURN-101 at 33.

maintains that this outcome is inconsistent with the Energy Action plan, the SB 32 goals, and the requirements of Section 739.9(e)(2).

ORA suggests that the Commission should design the rate structure to promote conservation when possible to increase EE investment at no additional cost to ratepayers. In ORA's view, this is particularly important to low-income customers because higher volumetric energy rates help compensate for market barriers to customer energy efficiency due to split incentives and lack of access to capital. CALSEIA and TASC agree.

Regarding fixed charges, TASC also used PG&E's model to compare the effect of a fixed charge on conservation and found a 1.9 % reduction in usage,[95] nearly ~~4~~four times that of PG&E's proposal, when TASC assumed no monthly fixed charge.[96]

4.2.12. Discussion

Based on the studies and analysis presented in this proceeding, it is clear that the proposed rate design changes will reduce the structural incentives for conservation present in the existing rates to some degree. The issue we consider here is whether the impacts associated with the proposed rate design changes are unreasonable and whether they unreasonably impair incentives for conservation such that the proposals must be rejected. To make this analysis, we consider first the evidence on price elasticity and methodology, and consider generally whether the rate design proposals in this proceeding are consistent with law and the RDP.

Later in this decision we examine the conservation of effects of fixed charges and tiered rates in more detail. Finally, in Section 10, we look at each

[95] TASC OB at 12-14.
[96] Exh. TASC-105 at 12.

IOU's specific proposal and determine whether, when taken as a whole, the proposal is consistent with law and the RDP.

Our approach balances the principles of rates based on marginal cost (RDP 2) cost causation (RDP 3), and economically efficient decision-making, with the our concerns regarding conservation (RDP 4), gradualism (RDP 6) and customer acceptance (RDP 10).

The analyses used to determine the conservation impacts rely on varying assumptions about how customers respond to electricity prices. However, considered as a whole,, the various analyses presented show relatively small percentage increases or decreases in conservation. Because the utilities have made no efforts to compare the conservation impacts of their own proposals with those put forward by the other parties, it is not possible to compare parties' proposals against each other and find that one method produces significantly better conservation results than the other methods.

With the exception of ORA, most parties, including TURN, maintain that the joint PG&E/SCE tier-specific methodology presented by the utilities are based on unrealistic assumptions regarding consumer behavior and should not be relied upon. We agree. The PG&E model is also based on the PG&E Bill Impact Calculator and suffers from the same flaw. Even if customers know the rates associated with each of the tiers they face, they are unlikely to know at any given time in a month which tier they are in. PG&E's witness Keane acknowledged that few customers actually know what usage tier they are in at any point during the billing cycle and that instead "customers notice and respond to significant changes in bills triggered by usage billed at high marginal tier prices.[97] [98]

[97] RT Vol. 10 at 1056-1058, PG&E/Keane.
[98] Exh. TURN-201 at 37.

Reviewing the results of the joint PG&E/SCE marginal price methodology supporting their proposals, PG&E and SCE find increases in consumption (reductions in conservation) of 1.2% and 1.8%, respectively. As with the other methods, this average increase in consumption is a result of assumed decreases in conservation by high users and assumed increases in conservation by lower usage customers. Of the total estimated increase in consumption, the most significant percentage is related to the collapsing to two tiers, with the fixed charge contributing a slightly lower percentage increase. According to Dr. Faruqui, the marginal price methodology is best represented by customers who "study their bill carefully and understand specifically their marginal tier and the price of that tier."[99]

However, we can see from the results of the Hiner study that at least half of the utility's customers do not know that their rates are tiered or how a tier structure works. Many other customers do not know what tier they are in, or which tier they would likely end up in during a given billing cycle.[100] These findings are inconsistent with the assumption that customers study their bill carefully and understand the price of their marginal tier.

The Hiner study findings are consistent with the average price methodology. The average price approach is also supported by Dr. Ito's findings, albeit based on older data that preceded the investments in advanced metering and smart grid.[101]

TURN concludes that customers will either respond to average bills, or to the highest marginal tier price, and theorizes that customers react to a combination of average and marginal tier rates. TURN was only able to analyze

[99] Exh. PG&E-111 at 6.
[100] Exh. PG&E-109 at 1-24.
[101] ORA OB at 58.

the effect of conservation on PG&E's proposed rate design in detail due to the limitation of the utilities' bill calculator models and the fact that the utilities declined to assist TURN in preparing additional scenarios. However, TURN's conclusions make intuitive sense. A customer is most likely to notice changes in their bill from one period to the next. That same customer, to the extent they were concerned about high bills, would then be expected to notice the price of the next unit of output to evaluate whether they should or could conserve energy and reduce their bills.

Based on the analyses provided, we conclude that the average price methodologies best represents our understanding of customers' response to rate changes for tiered rates. The average price methodologies presented by the joint PG&E/SCE analysis, and TURN's analysis of PG&E's proposal result in estimated impacts on consumption of -1.2 %, -1.2% and -0.24%, respectively, indicating that the rate design proposals may result in a slight increase in conservation. Although we find that the average price methodology is the most representative of customers' response to including block rates, we also agree that there is a sub-group of customers who respond to their marginal (highest tier) rate.

We also agree that with TURN, TASC, NRDC, CforAT and other parties that customers with low usage (usage that currently does not exceed Tiers 1 and 2), are less likely to have discretionary electricity use that can be adjusted in response to higher rates. However, we did not find that the evidence presented in this proceeding clearly shows a correlation between electricity usage and elasticity. Rather, we believe that in the absence of additional evidence on this subject, the utilities' price elasticities for customers whose usage does not rise above the lowest tiers are unreasonably optimistic. Although parties did not

provide definitive evidence that low-usage customers have lower price elasticity, parties did provide compelling evidence that we should not assume that customers who only have usage in the lower tiers are able respond to price changes at the same price elasticity as customers with higher usage. As TURN, TASC, Sierra Club and CforAT point out, customers in the lowest usage tier simply do not have as much ability to reduce consumption on their baseline usage as customers with higher tier usage. There will be exceptions of course, but most parties accept that baseline quantities, generally defined as 50-60% of average usage in each geographic zone, are calculated to represent the amount of electricity needed for essential usage that cannot be avoided without potential detrimental impacts to health and safety. Therefore, while we cannot find with certainty that the rate design proposals will decrease (or increase) conservation, we can find that any impacts to conservation from the proposed rate design changes would be relatively small and would not unreasonably impact conservation.

Furthermore, while any negative impacts to conservation may be relatively small, TURN correctly points out that these impacts have the potential to effectively offset or negate some portion of energy efficiency program savings. We recognize that our adopted residential rate design will potentially affect, to some degree, the economic attractiveness of energy efficiency measures and solar investments. However, we also believe that our adopted rate design must be as cost-based as possible.

The argument that we must maintain a steeply tiered rate structure to avoid any negative impact on conservation incentives is belied by the language in the rulemaking itself. Despite various parties' assertions to the contrary, when we issued D.01-05-064 and created the current tiered structure, we did so

primarily to ensure that the utilities could collect their revenue requirement when faced with unreasonable prices during the energy crisis of 2000-2001. Energy conservation, while extremely important, was not the primary objective at the time.

Even if tiered rates reduce net consumption across the residential customer class, they do so while introducing significant economic inefficiencies. To the extent customers respond to average prices, customers whose average rates are lower than the class average rate will consume more than they otherwise would under a flat rate. This excess consumption imposes costs on others in the form of environmental externalities and undercollection of costs to serve that must be recovered from other ratepayers. These customers will not invest in energy efficiency measures or self-generation technologies that may be cost-effective if they were paying the true cost of electricity. Conversely, customers whose average rates are higher than the class average rate will consume less than they otherwise would under a flat rate. This underconsumption may result in various types of welfare losses. These customers may forego consumption that would have provided comfort (e.g., space heating or cooling) or other forms of consumer utility. In extreme circumstances, some customers paying above the average rate may reduce consumption to the point that it harms their health and well-being. Other customers may invest in energy-efficiency measures whose cost per kWh saved exceeds the true social cost of electricity, resulting in a wasteful allocation of resources. Over-investment in energy efficiency would be particularly severe for measures that save energy primarily in off-peak hours when the energy saved has little value.

If customers respond primarily to marginal prices, only those customers who remain in the first two tiers most months of the year would consume more

than the socially optimal level. Since relatively few customers remain in the lower tiers most months of the year, excess consumption would occur for a smaller share of the population than in the case if customers respond primarily to average price. However, because upper tier rates are much higher than average rates and affect a substantial share of the population, the losses due to non-cost effective energy efficiency investments and foregone consumption are larger if the marginal price effect is dominant.

Based on this, we find that as a whole the rate design proposals are consistent with the RDP and do not unreasonably impair incentives for conservation.

4.3. Income and Usage Correlation

The correlation between household income and electricity usage has been the subject of debate throughout this proceeding. Because there are many factors which influence usage, including climate and household size,[102] it is difficult to assess the particular impact that income has on usage. While there is agreement that there is some correlation between income and usage, parties disagree on whether this correlation is strong or significant.[103]

Determination of whether there is or is not a correlation can vary depending on whether one looks at data on a California-wide basis, on a climate zone basis, or on house-hold basis. Since the start of this proceeding there have been significant advances in geographic information system (GIS) mapping that could improve our ability to assess the correlation between income and usage. For the present, we summarize the discussion of the issue in this proceeding, broken down chronologically. To provide context, this summary reaches back to

[102] TURN Proposal at 19; SCE OB at 10.
[103] PG&E Proposal at 37 ("While there is a positive correlation between income and usage, that correlation is weak").

the rate design proposals and comments filed by parties in summer 2013 (prior to passage of AB 327).

4.3.1. 2013 Rate Design Proposals and Responses

TURN's original rate design proposal submitted on May 30, 2013 (TURN proposal) sets the stage for the debate.[104] In that proposal, TURN refers to an "established" correlation between income and usage, while granting that such correlation is imperfect.[105] To support its argument, TURN cites data from the CEC's 2009 Residential Appliance Saturation Study (RASS) showing that the average low-income household uses less energy than the average high-income household in California.[106]

In their proposal, TURN also breaks down the RASS data by income quartile to show that 8% of low-income households and 20% of moderate-income households are "high" energy users (defined as using over 8,350 kWh/year), compared with 41% of high-income households. However, the same data indicate that 53% of low-income households are either "high" or "moderate" energy users (defined as over 3,360 kWh/year) while 73% of moderate-income households are either "high" or "moderate" energy users.[107]

Apart from the RASS data, TURN also reviewed PG&E's and SCE's non-CARE rate data for municipalities across California. They found that those communities with the highest average energy rates (and therefore highest average usage), tended to be communities with high median incomes, while those communities with the lowest average rates tended to have low median incomes.[108]

[104] TURN does refer to an earlier CPUC literature review on the subject, published in June, 2012.
[105] TURN Proposal at 14.
[106] *Id.* at 15-16.
[107] *Id.* at 16.
[108] *Id.* at 20-25.

PG&E presented their own rate design proposal on May 29, 2013 (PG&E proposal). In their proposal they also refer to the CEC's RASS data. PG&E came to several conclusions based on their analysis of the RASS data pertaining to PG&E customers:

- Of the 865,000 non-CARE lower income households with annual incomes between $30,000 and $60,000, over one-third had high usage[109] and paid an average annual rate that exceeded the residential class average.
- Of the ~~1~~one million non-CARE moderate income households in the $60,000 to $100,000 annual income range, over half had high usage and paid an average annual rate that exceeded the residential class average.
- In contrast, over 40~~ percent~~% of the nearly 1.1 million higher -income households with incomes exceeding $100,000 per year had low usage and paid an annual average rate below the residential class average.[110]
- Approximately 57% of PG&E's non-CARE customers using energy at Tier 3 rates and above were moderate or low-income customers.[111]
- Statistically there is a correlation coefficient of only 0.33 when comparing income and usage, which is "relatively weak."[112]

TURN's response to the PG&E proposal pointed out that because the coefficient of 0.33 was calculated across all of PG&E's territory, it reflects variations in usage that may be due to climate rather than income and is therefore not an appropriate calculation.[113] TURN argued that once the RASS

[109] PG&E defines high usage as 1/12 for each month with Tier 3 or above usage for each customer.
[110] PG&E Proposal at 37.
[111] *Id.* at 35.
[112] *Id.* at 38.
[113] TURN Opening Comments of July 12, 2013, at 45.

data were segregated by climate zone, the empirical relationship between income and usage became clearer.[114]

PG&E's response to the TURN proposal focused on TURN's analysis of average energy usage and median community income, arguing that comparing averages of usage and income was an unreliable method for determining if there was a significant correlation between those variables.[115] PG&E noted that TURN did not present individual household income-to-usage estimates to buttress its conclusions. PG&E pointed to its own rate design proposal as containing such household-level data, with more data points overall, leading PG&E to conclude that its results were "far more credible" than TURN's.[116]

PG&E also follows up on TURN's analysis of average usage and median income by community, and shows that there is usage variability among communities with similar median incomes. This leads PG&E to argue that "there is a wide range of average rates paid by households in every city. Even in the cities… with median annual incomes above $100,000, there are significant percentages of customers paying low average rates."[117]

Finally, PG&E calculates correlation coefficients for the income-usage relationship for individual communities in its territory using the RASS data. PG&E found that "the correlations are generally positive, but weak, with many in the range from 0.20 to 0.40. While there are a couple of cities with correlations above 0.50, there are also three cities with correlations below 0.10 (one of which is very slightly negative)."[118]

[114] *Id.* at 45-46.
[115] PG&E Opening Comments of July 12, 2013, at 14 (citing a 2012 CPUC literature review stating that the correlation between income groupings and average electricity use may appear to be more significant than correlation between actual income and electricity use).
[116] *Ibid.*
[117] *Id.* at 17.
[118] *Id.* at 19.

TURN's reply to PG&E's response seeks to refine the original TURN analysis on average community usage by grouping cities into three climate zones and then examining the relationship between usage and income. Calling the correlations "clear and robust," TURN argues that their reanalysis "shows the strongest correlations for cities with household incomes below $100,000 per year in the hot zone, significant correlations in the cool zone and weaker correlations in the mid zone."[119]

In its reply comments, TURN also points out that PG&E's criticism of its approach was focused on the average community-oriented comparisons and did not address TURN's other analysis showing that the high-income proportion of usage cohorts increased as usage increased.[120] TURN also reviewed city-level data provided by PG&E to determine correlations between average rates and median household income in each distinct climate area. This analysis found correlations of 0.46 in the hot zone, 0.75 in the mid climate zone, and 0.65 in the cool climate zone.[121]

SDCAN's rate design proposal argued that the RASS data showed that the association between income and usage was "significant" and that the richest customers on average used more energy. SDCAN states that the causal link between income and usage is that richer households tend to have larger homes requiring more air conditioning and other energy-consuming amenities such as swimming pools.[122]

SCE's rate design proposal stated that the relationship between income and usage is "weak."[123] In their response to TURN's Proposal, SCE states that

[119] TURN Reply Comments of July 26, 2013, at 25.
[120] *Ibid*.
[121] *Id.* at 22-25.
[122] SDCAN Proposal at 28.
[123] SCE Proposal at 59.

there is no perfect correlation between income and usage and that "inevitably" some low-income and middle-income customers would use as much energy as high-income customers.[124]

ORA's response to SCE's Proposal argues that SCE's CARE customers consume 16% less energy than its non-CARE customers and that low-income customers tend to use less energy than high-income customers on a per-person basis.[125] CforAT/Greenlining's response is similar, stating that 64% of PG&E's CARE customers and 60% of SCE's CARE customers have average usage that is captured by Tier 1.[126]

In SDG&E's rate design proposal, they note that some low-income high-usage customers are subsidizing high-income low-usage customers in their territory under the current tiered rate structure.[127] CFC refers to an assumption that low-income customers are low-usage customers, but does not explicitly support the assumption.[128]

While not explicitly saying so, the CforAT/Greenlining rate design proposal implies that low-usage customers are likely to be low-income customers.[129] NRDC's rate design proposal describes the correlation between income and usage as "logical"[130] and states that in California usage is generally income-related.[131]

[124] SCE Opening Comments of July 12, 2013, at 18, 43.
[125] ORA Opening Comments of July 12, 2013, at 46-47.
[126] CforAT/Greenlining Opening Comments of July 12, 2013, at 3.
[127] SDG&E Proposal at 39.
[128] CFC Proposal at 8.
[129] CforAT Proposal at 65 ("[i]n a number of prior rate design proceedings, CforAT and Greenlining have expressed concern that the IOUs' efforts to reduce the rates charged to upper-tier customers would be accompanied by corresponding rate increases on low-income and/or low-usage customers, including customers who have the least ability to pay").
[130] NRDC Proposal at 39.
[131] *Id.* at 38.

Sierra Club's rate design proposal included an analysis of the PG&E bill calculator model showing that high usage was associated with higher income with a correlation coefficient of 0.23.[132] In their response to PG&E's Proposal, Sierra Club states that "[s]ince the PG&E bill calculator shows that collapsing tiers results in a bill decrease for the wealthiest customers, it follows that the wealthiest customers are more likely to be the highest electricity users."[133]

4.3.2. Staff Proposal position on the Income/Usage Relationship

On January 3, 2014, Energy Division submitted the Staff Proposal for Residential Rate Reform in Compliance with R.12-06-013 and Assembly Bill 327 (Staff Proposal). The Staff Proposal granted that there was considerable debate concerning the correlation between income and usage.[134]

The Staff Proposal stated that while there was an "imperfect" correlation the fact remained that some low-income customers were in a high-usage cohort and some high-income customers were in a low-usage cohort. The Staff Proposal concluded that PG&E's approach to using household-level data was preferable to TURN's averaging approach, and that "the correlation of income with usage is not strong enough to support the generalized argument that low-income households are harmed by default TOU."[135]

IREC responded to the Staff Proposal's conclusions and stated that they generally supported TURN's position that there was a strong correlation between income and usage.[136]

[132] Sierra Club Proposal at 7.
[133] Sierra Club Opening Comments of July 12, 2013, at 14-15.
[134] Staff Proposal at 37.
[135] *Id.* at 40.
[136] IREC Comments on Staff Proposal at 4.

4.3.3. Evidentiary Hearings and Briefs on Income/Usage

The debate concerning the relationship between income and usage continued during the evidentiary phase of the proceeding. We summarize here some of the arguments that were not duplicative of the arguments heard in earlier phases of the proceeding.

TURN broke down the statewide RASS survey data, as supplied by the IOUs in their recent GRC Phase 2 proceedings, to calculate a general correlation between income and energy usage for SCE and SDG&E.[137] For SCE, their analysis shows that high tier usage generally increases with income, with some variability.[138] For SDG&E their findings are similar.[139]

TURN also uses data from PG&E's bill calculation model to show that "there is less variation in usage by income in hot climates, though customers under $30,000 to $60,000 use less than those above in most of the four hotter zones;"[140] and that "while the utilities tend to claim that income and usage are relatively unrelated, the bill calculation models for PG&E show that higher income customers tend to use more."[141] For example, TURN states that "in the largest [PG&E] region, Zone X, 38% of non-CARE customers earn over $100,000, and they use 90% more than non-CARE customers earning less than $60,000."[142]

TURN further refers to national-level data from the Bureau of Labor Statistics and the Energy Information Administration to argue that there is a positive correlation between income and energy usage.[143]

[137] *See generally* Exh. TURN-207, attachments WBM-9 and WBM-10.
[138] *Id.* at 381-382.
[139] *Id.* at 443.
[140] Exh. TURN-201 at 20.
[141] *Id.* at 29.
[142] *Id.* at 19.
[143] *Id.* at 29.

IREC states that the correlation between income and usage is "is almost certainly underestimated" by the IOUs.[144] While they do not independently analyze a particular data set to arrive at an estimate of such correlation, they do critique PG&E's calculation. IREC states that while PG&E arrived at a relatively mild income-usage correlation coefficient of 0.33, it did not perform this analysis by comparing customers within climate zones or by striking NEM customers from the data set.[145] These omissions, in IREC's view, make PG&E's estimated correlation figure unreliable.

PG&E repeats many of its arguments from earlier phases of the proceeding and argues that the correlation between income and usage is weak, with a correlation coefficient of 0.33.[146] PG&E points to data that indicates that there are "significant numbers" of low-income households that consume large amounts of energy.[147] PG&E also refers to the CEC's RASS data as supporting a conclusion that household size helps to determine usage as well.[148]

Like PG&E, SCE grants that there is some correlation between usage and income, but they argue that there are many low-income households with high electricity consumption and many wealthy customers with low consumption.[149] SCE argues that the "proper correlation" to consider is between household size and usage, not between income and usage.[150] SCE further states that it is somewhat illogical to divide usage cohorts strictly, as customers may migrate between usage cohorts over the course of a year due to factors such as weather or employment status.[151]

[144] IREC OB at 16.
[145] *Id.* at 16-17.
[146] PG&E OB at 12; RT Vol. 12 at 1381: 1-21, PG&E/Quadrini.
[147] Exh. PG&E-101 at 1-11 & n.25.
[148] *See* Exh. PG&E-116.
[149] SCE OB at 115.
[150] *Id.* at 10.
[151] SCE RB at 77.

While TURN did find higher correlation coefficients when comparing a community's average rate to that community's median income, we believe that using household-level data rather than city-wide averages is a preferable method for quantifying correlations between income and usage as average city-wide comparisons eliminates a considerable amount of the variability found at the household level. As a result, measuring correlations at the city-wide level does not provide an accurate indication of the prevalence of low-income, high-usage households and high-income, low-usage households.

SDG&E argued during evidentiary hearings that there are working families and fixed-income seniors in their territory that are burdened by high-usage energy rates.[152] They further argue that in their territory there are high-usage as well as low-usage CARE customers.[153]

This evidence leads us to conclude that low-income and moderate-income ratepayers are not universally low or high users of energy. According to the record, energy usage patterns are heterogeneous within the low-income and moderate-income classes, and we therefore decline to conclude that rate design proposals that impact low-usage customers necessarily impact low-income and moderate-income ratepayers on a class-wide basis.

4.4. GHG Reduction

Reduction in GHG emissions has frequently been cited as a reason to employ TOU rates.[154] Because California relies on natural gas peaker plants and

[152] RT Vol. 13 at 1594-1595 SDG&E/Winn.

[153] SDG&E OB at 48.

[154] *See, e.g.,* Exh. SDG&E-117, SMUD SmartPricing Options Interim Evaluation at 1 of 195 (SMUD "has committed ... reduce the greenhouse gas emissions that contribute to global warming and lower the cost to serve our region."); D.08-07-045 (stating that "[b]y linking retail rates to wholesale market conditions, dynamic pricing can discourage customers from consuming polluting power. Conversely, if other time periods are dominated by non-emitting and low-cost resources such as nuclear, water and wind, dynamic pricing could signal to customers that the supply of power is clean."); Exh. EDF-102 at 13.

older less efficient natural gas plants to supply energy during summer peaks, it seems intuitive that a shift in energy demand away from peak periods will also reduce GHG emissions. However, the California Independent System Operator (CAISO) system is interconnected to other states in the Western Electricity Coordinating Council (WECC) region.[155] When WECC-wide emissions are considered, the evidence that TOU rates will necessarily lead to GHG reductions is not so clear.

Parties who analyzed the potential of TOU rates to achieve GHG reductions reference two measures of emissions levels:

- "Emissions intensity" or "emissions rate," which is a measure of pounds of CO_2 per MWh of electricity generated.
- "Heat rate," which is a measure of the amount of fuel energy used to generate a unit of electricity. Heat Rate is typically expressed as Btu/kWh. A lower heat rate means a more efficient generator or pool of generating resources.

During the 2013 portion of this proceeding, parties suggested that the appropriate way to measure the GHG emissions reduction from a TOU rate load shift would be to compare the heat rate for the peak period hour in which usage was decreased to the heat rate in the hour to which the use was shifted. For example, "a kWh shifted from 3:00 PM, when the marginal heat rate is 10,000 Btu per kWh, to say, 9:00 PM, when the marginal heat rate is 7,000 Btu per kWh, conserves 3,000 Btu of natural gas, and avoids the corresponding GHG emissions that would otherwise occur."[156] Energy Division's 2014 Staff Proposal applied this approach.

[155] WECC is the Federal Energy Regulatory Commission-approved non-profit entity that oversees reliability of the Western Interconnection's bulk electric system, which includes California. WECC includes 13 other western states, two Canadian provinces, and Baja, Mexico. https://www.wecc.biz/Pages/home.aspx.

[156] DRA's Responses to the Residential Rate Design OIR Questions, June 5, 2013, at 24 n.40 (cited by Energy Division Staff Proposal at 53 n.87).

In contrast, TURN cited a study that examined whether GHG emissions reductions from changes in energy use could be part of a state implementation plan for California Air Quality Management Districts.

At the time of the evidentiary hearings, however, both ORA and TURN advocated WECC-wide analysis as the best way to determine if TOU rate structures could reduce GHG emissions. They argue that because WECC-wide dispatch is impacted by California's electric loads, changes in dispatch and the amount of incremental GHG in the western region of the United States should be taken into account when evaluating whether TOU rates can reduce GHG emissions.

As TURN explains, "electric systems in the WECC are interconnected and engage in substantial amounts of power transactions among each other. Load and generation in one portion of the WECC thus affect the generation used to meet load in other parts of the WECC. To assess the influence of changes in load in California on incremental CO_2 emissions, it is thus important to assess these impacts over the entirety of the WECC."[157]

TURN and ORA both discuss WECC-wide studies of GHG emissions in their testimony that other organizations had conducted, because WECC-wide dispatch models are complex and time-consuming to run. Both ORA and TURN relied on models run for other purposes when calculating the impact of load shifts on GHG emission rates, and they agreed that this approach is less than optimal.

[157] Exh. TURN-204 at 11.

TURN witness Woodruff evaluated three existing production cost simulation modeling studies[158] and concluded that "there is neither a strong nor consistent relationship between incremental CO_2 emissions in the Western United States and electric loads in California."[159] Witness Woodruff found that there was a positive link between load and emissions during annual peak hours – meaning that emissions decrease as load decreases, but the correlation was less strong at other times, and in the spring there was actually a negative correlation.[160] The 2020 PG&E study found that the highest average hourly incremental emissions (lbs/MW) occurred around midnight in the spring months. Witness Woodruff theorized that this high emissions level was the result of coal plants operating at the margin during these offpeak hours and increasing their dispatch to meet the new demand. He also reasoned that "increasing amounts of renewable generation in California (and elsewhere in the WECC) may serve to increase the amount of remaining coal generation that is dispatchable.

The WECC-wide model evaluated by ORA showed a correlation between load shift and emissions, but, unlike TURN's conclusions, it found that there was no indication of a GHG increase as a result of TOU rates.

Both ORA and TURN explained that the modeling studies they evaluated do not draw conclusions about how much energy customers will conserve as a result of TOU rates; instead, they only assume that customers will shift load from one time period to another.

[158] The three studies used were: (i) PG&E 2020 study performed in 2013; (ii) CAISO studies performed at the direction of the Commission in 2014 examining system conditions in 2022; and (iii) CAISO studies performed at the direction of the Commission in the Long-Term Procurement (LTPP) dockets for 2024

[159] TURN OB at 68 (citing Exh. TURN-204 at 2-4).

[160] *Ibid.*

ORA and EDF both argue that TOU rates will likely lead to overall reductions in usage, not just a shift from peak, but these load reductions were not modeled rigorously. EDF's assessment that TOU rates will lead to GHG reductions is based in part on an assumption that TOU rates will reduce total consumption. We believe a more rigorous method for forecasting load reduction is necessary before forecasts such as EDF's can be used to demonstrate GHG reductions as a significant goal of TOU rates. At this time we do not have adequate information on the extent to which customers might reduce total consumption under TOU rates.

SDG&E argues that an evaluation of the GHG emission impacts of TOU rates should be limited to plants under contract.

We agree with TURN and ORA that the California-based heat rate comparison method is not sufficient to evaluate the impacts of load shift on GHG emission rates in the west. Our discussion therefore focuses on the analysis of TURN and ORA. We note, however, that the GHG reduction impact of TOU rates is not limited to an incremental increase or decrease in emissions intensity at the time of load shift. TOU rates can also be structured to reduce GHG emissions in other ways, such as allowing a greater proportion of intermittent renewables to be integrated into the grid.

Parties argued that TURN's study is flawed for several reasons. EDF argued that TURN's study does not take into account the possible coal plant retirements expected from the EPA Clean Power Plan. TURN counters that some coal plant retirements are part of the model used. In addition, the EPA Clean Power Plan may change before it is approved.

TURN argues that ORA's model supports TURN's own argument that there is not a clear correlation between load shifting and GHG reduction.

For ORA's and TURN's studies, questions were raised about how modeling assumptions, such as forced outages (which are generated randomly using a methodology embedded in the production cost model) and coal plant retirements could have skewed the studies' results.

In sum, none of the models evaluated by parties provides a sufficient basis for finding that GHG emissions will increase or decrease due to load shifts caused by TOU rates in California. However, we agree with TURN's primary recommendation that the Commission should conduct more detailed analysis and modeling to clarify the impacts that load shifting will have on overall GHG emissions. Such analysis should also provide information sufficient to determine highly sensitive variables and assumptions that could skew the results. As information on TOU response becomes available, modeling of GHG reductions must also consider the potential for load reductions in addition to load shifts. Most importantly, we do not want to inadvertently increase GHG emissions by fostering increased reliance on out-of-state coal plants with higher GHG-emissions rates. However, we must recognize California's challenge to integrate increasing amounts of renewable energy into the grid, the role that TOU rates may have in supporting efficient renewable integration, and the complex interactions between resources over which the Commission has significant influence, and those, like the composition of out-of-state baseload generators, over which we do not.

4.5. Expected Long-Term Cost Savings from TOU Rates

Long-term cost savings have also been cited as a benefit of TOU rates.[161] ORA argues that time-of-use rates will result in significant long-term cost savings

[161] D.08-07-045 at 2-3.

due to deferral of system upgrades and the need for new generation.[162] ORA estimates that TOU rates (as proposed by ORA in May 29, 2013 filing) would result in a 2,400 MW peak load reduction, "which is equivalent to the size of one nuclear power plant."[163]

Likewise, EDF argues through their own analysis that there will be significant system cost savings on the order of $500 million a year if only half of customers take service on TOU rates.[164]

The amount of potential long-term cost-savings from TOU rates, as estimated by EDF and ORA, is significant. No other parties in this phase attempted to quantify cost-savings from TOU-induced load shifts. Several of the solar parties cited potential long-term cost savings, but without mentioning specific studies or forecast amounts. The utilities did not attempt to measure cost savings of TOU rates in this proceeding.

TURN asserts that there are "no credible estimates of cost savings under default TOU rates."[165]

TURN argues that the estimates of ORA and EDF are "deeply flawed."[166] TURN contends that for the ORA and EDF predicted cost-savings to occur, there would need to be significant customer response in the form of predictable load reductions that mirror both system and circuit-level peaks" resulting in the reduction of the need to build incremental new generating capacity. As a specific example, TURN points out that EDF's analysis assumes that all distribution circuit-peaks take place during the summer peak and does not account for the fact that some distribution circuits are winter peaking. EDF also did not break its

[162] Exh. ORA-201 at 1-3.
[163] *Id*. at 1-3 n.~~5~~5.
[164] Exh. EDF-101 at 8.
[165] TURN OB at 63.
[166] *Id.* at 64.

cost savings estimate out by avoided generation, distribution, and transmission costs. During evidentiary hearings, EDF witness Fine acknowledged that the estimate of reduced generation needs on which EDF relied was a "very back of the envelope calculation."[167] In addition to arguing that the ORA and EDF estimates are flawed, TURN contends that any cost-savings estimates should include the estimated cost of TOU implementation, and costs that might result from unpredicted customer load shifts.[168]

Finally, TURN contends that because the current LTPP proceeding has not identified the need for additional generation in the immediate future, it is unreasonable to calculate avoided costs of generation when current forecasts do not show a need for additional generation in the immediate future. TURN's point is well taken, but we believe that need for specific types of additional generation may change over the next few years.

The cost savings expected from avoided investment in distributed, generation and transmission is one of the most frequent arguments made in favor of default TOU. Quantifying these savings, however, remains theoretical. Therefore, we direct the IOUs to develop methodology for estimating these savings resulting from TOU. However, we do not rely on these specific figures of either EDF or ORA when directing IOUs to implement default TOU. We expect that quantification of these savings may overlap with savings attributed to other Commission programs for demand side management, such as EE.

[167] RT Vol 24 at 3747, EDF/Fine.
[168] TURN OB at 63.

4.6. Implementation of Residential Time of Use Rates in other Jurisdictions

4.6.1. Overview

TOU rate designs are considered beneficial because they are potentially the most cost-based rate design, they can be designed to allow customers to respond when reducing load could reduce the need for additional infrastructure, they could potentially reduce overall GHG emissions by reducing the need to run peaker plants and less efficient fossil fuel plants on hot afternoons. By flattening the load curve, TOU rates could also improve grid reliability.

The Commission has previously found that "Dynamic pricing can lower costs by more closely aligning retail rates and wholesale system conditions, thereby promoting economically efficient decision-making."[169] Despite this finding for dynamic rates (which can include real-time pricing), California has yet to attempt wide-spread rollout of residential TOU rates. TOU rates are time-varying, but not dynamic. TOU rates have consistent peak and off-peak periods from day to day and are therefore easier for the average residential customer to understand and respond to.

Although we have long known that energy costs vary by time of day,[170] leading the Commission to adopt default TOU rates for Commercial & Industrial customers, TOU rates for residential customers were not possible until wide-spread installation of smart meters made it possible to track customers'

[169] D.08-07-045 at 2.

[170] The electricity required by residential, industrial, and commercial consumers is not constant. Customer needs vary daily and seasonally, but in predictable patterns. During the peak load periods, many consumers simultaneously use large amounts of electricity. To meet loads during these periods, utilities must have extra power plants in reserve. These peaking power plants generally are more expensive to run than base-load units. Their costs also must be amortized over much fewer hours. This makes the cost of electricity produced during the peak period relatively higher. Any electricity that the utility procures in the market also reflects these economics. *See* Exh. ORA-101 at 1-6.

usage by time. In fact, this capability was one of the primary reasons supporting the rollout of residential smart meters.[171] Because residential meters that efficiently track usage by time are relatively new, there are few existing examples of residential TOU programs on which to base assumptions about rate design, and even fewer examples of default residential TOU rates.

Parties supporting TOU rates include: SDG&E, UCAN, SEIA, Sierra Club, NRDC, EDF, and ORA. Although these parties differ on when and how default TOU should be rolled out to residential customers, they all agree that the benefits of TOU weigh in favor of default or wide-scale TOU being made available in the coming years.

UCAN notes that TOU rates are "efficient and equitable" to all customers.[172] TOU rates inform customers when costs are high and when costs are low, enabling customers to make economical usage and investment decisions. It is also equitable to all individuals because customers large and small receive the same price signals.[173] UCAN provided the following chart, which concludes that a TOU rate meets the RDP better than a tiered rate.[174]

R1206013 Rate Design Principles	Tiered Rate	TOU Rate
1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.	Y*	Y*
2. Rates should be based on marginal cost.	N**	Y
3. Rates should be based on cost-causation principles.	N***	Y
4 Rates should encourage conservation and energy efficiency.	Y/N	Y/Y
5. Rates should encourage reduction of both coincident and	N/N	

[171] *See, e.g.,* D.07-04-043 at 4 ("a first important step for achieving [demand response] is to 'issue decisions on the proposal for statewide installation of [advanced metering infrastructure] for small commercial and residential time-of-use (TOU) customers by mid-2006 and expedite adoption of concomitant tariffs for any approved meter deployment.'); *see also* Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis, February 19, 2004, Appendix A at 3.

[172] UCAN OB at 33.

[173] *Ibid*.

[174] UCAN RB at 29-30.

R1206013 Rate Design Principles	Tiered Rate	TOU Rate
non-coincident peak demand.		Y/[N][175]
6. Rates should be stable and understandable and provide customer choice.	Y/N/N	Y/Y
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals.	Y*****	Y
8. Incentives should be explicit and transparent.	Y*	Y*
9. Rates should encourage economically efficient decision-making.	N	Y
10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.	Y/Y/Y****	Y/Y/Y****

**The ability to make sure low income and medical baseline customers have access to electricity is not dependent to the rate structure since any rate can offer a discount on the energy prices, e.g., CARE. The same holds for incentives which can be explicit and transparent regardless of rate structure, DR or TOU. These incentives can be offered outside the rate as well but available to customers on the DR/TOU rate.*
***Tiered rates are not as easily based on marginal costs as TOU except for the customer charge. The energy charge can be based on marginal costs overall but not individual tier prices which are arbitrary.*
****Tiered rates are not as easily based on cost causation principles as TOU except for the customer charge. Actions by customers cannot be traced back to utility costs incurred or saved except on TOU.*
*****Cross subsidies are harder to avoid on a tiered rate structure which has the following characteristic: setting the lower tier rates lower results in higher upper tier prices to meet revenue requirement target. Any attempt to reduce or cap the lower tier price for policy reasons or to mitigate bill impacts results in cross subsidies to upper tier customers.*
******Both the tiered and TOU rate structure require customer education and outreach. Parties differ with respect to which is more understandable and that will depend on the quality of the educational efforts. Bill impacts can be mitigated in either case but TOU rates have a closer relationship to cost. Therefore, bill impacts will be easier to explain based on actual usage and utility costs and not just a consequence of tier structure. For example, doing laundry on weekends saves nothing on bill under tiered rate DR. But the same action on TOU can result in monthly savings based on the difference between on-peak and off-peak energy prices.*

Despite its obvious benefits, many parties have concerns about a TOU rate structure, and are particularly concerned about default TOU rates. Concerns range from lack of customer acceptance, impacts on low-income customers, customer inability to respond to TOU price signals, locked-in TOU periods

[175] Although UCAN argues that TOU rates can reduce non-coincident peak demand, we do not believe the TOU rate structures under consideration in this proceeding would be able to target non-coincident peak demand.

exacerbating load curve, and potential negative impact on economics of rooftop solar.

For a residential TOU rate structure to be successful, it must be understood and accepted by customers. In order to better understand how this can be accomplished, the next section summarizes residential TOU programs that have already been implemented and studied.

4.6.2. Other Residential Time of Use Programs

Time-of-use (TOU) rates have been a fixture in California energy policy for over 30 years. Beginning in the late 70s, TOU rates were made mandatory for the largest industrial customers, depending on their demand.[176] The passage of time and the advent of advanced metering saw mandatory TOU rates rolled out to smaller and smaller customers.[177] The ability to enable time differentiated rates and potentially reduce peak demand was cited by the Commission as a major benefit of smart meters and part of the justification for their expense.[178]

Beginning in 2011, the Commission ordered mandatory TOU for the rest of the non- residential rate classes,[179] citing that "dynamic pricing can lower costs, improve system reliability, cut greenhouse gas emissions, and support modernization of the electric grid.[180] Nearly all non-residential customers in California will be on mandatory TOU rates before the end of 2015.

[176] D.85-05-059 (ordered three major utilities to implement mandatory TOU for customers with demands greater than 500 kW).

[177] D.01-05-064 modified by D.01-08-021 *and* D.01-09-062 (Commission required mandatory TOU rates for all customers with maximum demand greater than 200 kW who received new meters through a program funded by the CEC).

[178] D.03-06-032, Appendix A (California Demand Response: A Vision for the Future (2002-2007)).

[179] D.10-02-032, *modified by* D.11-11-008 (defaulted PG&E's small and medium non-residential customers to TOU rates); D.13-03-031 (same for SCE); and D.12-12-004 (same for SDG&E.

[180] D.08-07-045 at 4.

Opt-in TOU rates for residential customers have a long history in California and have been offered by the three major utilities since the mid-80s. PG&E's first standard residential TOU tariff, E-7, was made available as an optional rate starting in 1986, for those who agreed to install and pay a monthly charge for an interval meter. As noted in the testimony of several parties (PG&E, SCE, SG&E, EDF, ORA, SEIA, UCAN, TURN) , both opt-in and default residential TOU rates have been piloted around the world and examining the results of these programs can provide important insights on best practices.

Arizona Public Service (APS) is a model for utilities seeking customer adoption of opt-in rates, with over 50% of their residential customers on TOU rates as of 2015, an average of 5% peak load reduction and 76% of the customers satisfied with the utility's service.[181] They seem to have found the most success in targeting customers with larger than average bill. However, this level of enrollment took almost 20 years to achieve.[182] Salt River Project (SRP), also in Arizona, boasts high opt-in acceptance with 30% of its customers on a TOU rate as of 2015. SRP has offered TOU rates since 1980, but has drawn many new customers with its 'EZ-3' rate, which has a shorter peak period and a higher peak to off-peak ratio than its legacy rate. [183]

Many parties[184] have discussed SMUD's SmartPricing Options (SPO) pilot as a landmark study due to its scientific rigor and use of experimental design. The Final Evaluation, released in September 2014, found a 5.8 % peak load

[181] SEIA cites a 5% demand reduction from 40% of APS residential customers who are volumetric rates. SEIA 101 at 24.

[182] Chuck Meissner, Arizona Public Service, "Residential Time-of-Use Pricing," presentation from APSC Webinar, January 2014.

[183] Loren Kirkeide, *Effects of Three-Hour On-Peak Time-of-Use Plan on Residential Demand during Hot Phoenix Summers*, THE ELECTRICITY JOURNAL, VOL. 25, ISSUE 4, at 48-62.

[184] PG&E, SCE, SDG&E, EDF, ORA, SEIA, UCAN, and TURN.

reduction from the customers chosen for the default pilot,[185] similar to the load reductions demonstrated by customers in APS territory and in the 2003 California Statewide Pricing Pilot,[186] which were both opt-in programs. Customers in the opt-in portion of the pilot were able to achieve 12% peak load reductions.[187] Most notably, the default portion of the pilot had only a 4 % drop out rate, smaller than the 5% of the opt-in participants who chose to leave the program.[188]

In Ontario, Canada, the Ontario Energy Board (OEB) embarked on the world's largest default TOU rollout by requiring all of the distribution utilities in the province offer default TOU rates by 2011. Currently 97% of residential customers in the province are on TOU rates. An evaluation of the program found an average 3.3% reduction in summer on-peak usage since the change.[189] This was a multi-year effort, with the OEB focusing on increasing TOU enrollment starting in 2005 with opt-in rates and aggressive marketing campaigns by the OEB and the utilities.

Despite the long history of policy support for TOU rates in California, the various California pilot projects, and the near ubiquity of smart meters, adoption of TOU rates are still extremely low in California.[190] The only other jurisdiction to deploy large scale default TOU has been in ENEL's service territory in Italy. The Italian Authority for Electricity and Gas made TOU rates mandatory in 2010. In

[185] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.
[186] Charles River Associates, IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT, March 16, 2005, at 1.1.
[187] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.
[188] *Id.* at 73.
[189] Brattle Group, IMPACT EVALUATION OF ONTARIO'S TIME-OF-USE RATES: SECOND YEAR ANALYSIS, December 16, 2014 at 37.
[190] PG&E 3.4%, SCE 0.52%, SDG&E 0.60% of customers on TOU rates, IOU Supplemental Filings April 1, 2014.

order to transition people to the new rates, a 'transition' rate with a very small peak to off-peak differential was in place until 2012. As the differentials increased, response to the program also increased. However, the very small difference between the periods led to a smaller customer response, only about 1% peak load reduction.[191]

Two other smaller jurisdictions are cited by PG&E as providing insight into default TOU. In Washington state, Puget Sound started full-scale default TOU in 2001, but terminated the program in 2002 due to customer backlash. In Connecticut a planned default TOU rollout by United Illuminating resulted in 50% of customers ultimately opting out. The phased rollout started in 2008 by defaulting the largest residential customers first (over 4,000 kWh per month). Fifty percent of customers opted out. Rollout of the program was terminated before customers below 2,000 kWh per month were defaulted to the rate.

Another approach to introducing TOU rates has been to offer consumer choice between rates. The two Arizona utilities each offer several different TOU structures to provide their customers with choice. Both have a ~~'~~"traditional~~' 7~~" seven-hour peak period rates, as well as ~~3~~ three-hour peak period rates with higher price differentials between the periods. SEIA asserts that APS's success was due to offering a variety of TOU rate designs.[192] SRP's ~~'~~"EZ-3~~'~~" rate, has experienced rapid growth since its introduction in 2005, despite the higher peak rate. A study between their ~~7~~ seven-hour TOU and ~~3~~ three-hour TOU found a much stronger peak reduction response from EZ-3 participants but SRP believes

[191] Simone Maggiore & Ricera Sistema Energenico. "Impact of a mandatory time-of-use tariff on residential customers in Italy," presentation from Espoo, November 2012.
[192] Exh. SEIA-101 at 24.

it is better to maintain both options to reduce peak across the whole period, especially considering 'snapback' in usage at end of the shorter peak period.[193]

The price differential between on and off-peak rates has been shown to impact the amount of load shift or reduction from customers on TOU rates. Through analysis of 34 different TOU programs and pilots, the Brattle Group found that on-peak to off-peak ratio is positively correlated with peak load reduction (for example a ratio of 2:1 yields 4-5% peak load reduction and a 5:1 ratio should yield 9% reduction).[194] A steep price differential, however, will result in significant negative impacts on customers who do not shift load out of peak periods. The SMUD pilot set on-to-off peak prices on a cost-basis, resulting in a price differential of about 19 cents. In contrast, the other default programs have had flatter on-to-off peak price ratios,[195] presumably as a means of gaining customer acceptance. Information on balancing these three principles (cost-causation, customer acceptance, and reduction in peak load) is not readily available for these existing programs, but will be important in designing any default TOU rate for residential customers in California.

Parties disagree about the conclusions to be drawn from these pilots. PG&E asserts that SMUD, APS and SRP are all located in areas with higher A/C saturation[196] than PG&E, and therefore there are no conclusions to be drawn about these pilots for PG&E. SDG&E concludes that "studies and experience in Canada, Arizona and California have shown that residential customers can successfully be transitioned to TOU with positive results through default

[193] Loren Kirkeide, *Effects of Three-Hour On-Peak Time-of-Use Plan on Residential Demand during Hot Phoenix Summers*, THE ELECTRICITY JOURNAL, VOL. 25, ISSUE 4: 48-62

[194] Ahmad Faruqui & Sergici Sanem, *Arcturus: International Evidence on Dynamic Pricing*, ELECTRICITY JOURNAL, VOL. 26, ISSUE 7: 55-56 (2013).

[195] 1.4:1 for Ontario at the beginning of the program and 1.03:1 for ENEL at the beginning of its program.

[196] PG&E OB at 64.

rates."[197] ORA believes that the SMUD study showed that "most customers found TOU rates easy to understand"[198] while TURN believes the very same study shows that "customers placed on TOU rates didn't understand how they were being charged for their usage."[199] It is clear that there is disagreement about the inferences that should be drawn from the SMUD pilot. Nonetheless, the SMUD pilot represents the most significant and relevant experience with TOU pilot design available today. As such, the IOUs are highly encouraged to engage with SMUD to ensure that key lessons learned from the SMUD pilot are applied by the IOUs.

4.6.3. Comparison of Default TOU vs. Opt-In TOU

Parties have debated the load reduction potential of default time of use rates over those of opt-in time-of-use rates. PG&E, in particular, has asserted that opt-in programs create more system demand response.[200] There are several factors in this analysis. Firstly, as seen above, peak load reduction is a factor of the price differential between rates.[201] Currently, the few default options that have been implemented have had fairly small peak differentials, with the notable exception of SMUD.

Enrolling sufficient customers in opt-in TOU rates has been challenging for other utilities. APS, after 20 years, has a 53% enrollment rate. The IOUs in this proceeding have not predicted significant enrollment in opt-in TOU. The SMUD study revealed that although opt-in TOU customers individually tend to reduce

[197] Exh. SDG&E-101 at CY-10-12.
[198] Exh. ORA-101 at 1-11.
[199] TURN OB at 61.
[200] PG&E Supplemental Filing, February 28, 2014 at 2-61 (Figure 2-19).
[201] Ahmad Faruqui & Sanem Sergici, *Arcturus: International Evidence on Dynamic Pricing*, ELECTRICITY JOURNAL, VOL. 26, ISSUE 7: 55-65 (2013).

more, in the aggregate, the default rate produced three times the load reduction.[202]

ORA provided the following summary of enrollment and load response.

ORA Table Summarizing Residential TOU Load Impacts[203]

Study	off-peak $	on-peak $	Price ratio	kW peak reduction/ participant	peak load reduction	Average Usage	Opt-in/ Default	Enabling Technology	Total Customers
APS	2.0	21.0	10.5	0.2	5%	3.8	Opt-in	no	1,200,000
EDF	4.6	5.8	1.3	1.0	45%	2.2	Opt-in	no	5,700,000
OGE	4.2	23	5.5	1.5	11%	5.0	Opt-in	yes	750,000
SRP	7.2	21.2	2.9	1.4	11%-13%	9.9	Opt-in	no	970,000
ENEL	2.99	12.42	4.2	0.0	1%	0.6	Default	no	25,000,000
Hydro One	5.3	10.2	1.9	0.0	3%	1.2	Default	yes	4,500,000
PSE	4.7	6.25	1.3	0.1	4%	2.1	Default	no	945,000
UI	7.5	11.45	1.5	0.0	9%-10%	1.7	Default	no	325,000

While Ontario and ENEL have shown modest peak load reduction effects, SMUD's default TOU rate has shown an average of 5.8% peak load reduction, which is comparable to peak load reductions found in optional programs with large peak differentials. This does not look particularly impressive when compared to the 12% peak load reduction from the opt-in participants, but according to SMUD, [w] hen the differential enrollment rates are factored into the equation, default plans offered to the same population of customers as opt-in plans are likely to produce much higher aggregate load reductions."[204]

Because SMUD was only able to recruit 17.5% of the targeted customers on to the opt in TOU rate, the absolute load reduction provided by default TOU would be nearly three times greater than opt in TOU due to the much larger number of participants. In the SMUD pilot, the dropout rate for the customers

[202] Exh. ORA-101 at 1-20.
[203] *Ibid.*
[204] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.

spending at least some time on the default TOU rate was 4%, which was lower than the dropout rate of 5% for opt in TOU participants. The average peak period load reduction for default TOU participants in SMUD's study was 5.8%. Opt in customers provided a larger average reduction of 11.9%.

4.7. Specific Legal Issues Applicable to this Decision

4.7.1. Default TOU Pilots

AB 327 gave the Commission the authority to direct the IOUs to employ TOU rates starting no earlier than January 1, 2018. In 2014 testimony and workshops, parties raised the idea of implementing a default TOU pilot prior to employing default TOU. The assigned ALJs asked the parties to brief whether the express prohibition on default TOU prior to January 1, 2018 would apply to a pilot with limited enrollment. Parties consistently agreed that the statutory language prevents the Commission from authorizing a default TOU pilot prior to January 1, 2018. No party suggested an alternative interpretation of the language. Therefore, the assigned ALJs ruled that the January 1, 2018 restriction applies to default pilots.[205]

4.7.2. Requirement for a Baseline Tier for Default Residential Rate

The Commission is required to set a baseline quantity of electricity that represents the amount "necessary to supply a significant portion of the reasonable energy needs of the average residential customer."[206] The statue defines "baseline quantity" as "a quantity of electricity or gas allocated by the commission for residential customers based on from 50 to 60 ~~percent~~% of average

[205] ALJ E-mail Ruling Setting Prehearing Conference, October 15, 2014, at 3.
[206] Section 739(2)(b).

residential consumption of these commodities,[207] . . . In establishing the baseline quantities, the commission shall take into account climatic and seasonal variations in consumption and the availability of gas service."[208]

Section 739.9(c) requires that the Commission "require each electrical corporation to offer default rates to residential customers with at least two usage tiers." The first tier shall include electricity usage of no less than the baseline quantity established pursuant to [Section 739(d)(1)]. There is a clear exception for Section 745(c) (default TOU) rates.

Section 739(d)(1) requires the Commission to "require that every electrical and gas corporation file a schedule of rates and charges providing baseline rates. The baseline rates shall apply to the first or lowest block of an increasing block rate structure which shall be the baseline quantity. In establishing these rates, the commission shall avoid excessive rate increases of residential customers, and shall establish an appropriate gradual differential between the rates for the respective blocks of usage."

Parties raised several questions in connection with this requirement for a baseline tier.

First, some parties suggest that a baseline tier is required for default TOU. The clear language of Section 739.9(c), however, has an exception for the TOU rate structure as described in Section 745. Section 745, the time variant pricing exception including TOU rates, only requires a baseline tier for particular customers, such as medical baseline customers. Thus, based on the clear language of the statute, we find that a baseline tier is not statutorily required for default TOU rates. There are, however, policy reasons why a baseline tier (or

[207] The statute requires that for all-electric customers the baseline be set at 60-70% of average residential consumption during the winter heating season.
[208] Section 739(a)(1).

baseline credit or excess surcharge) is desirable. These policy reasons are examined in the section on TOU Rates below.

Second, if a baseline tier is required by law, should the differential between tiers be set to take into account the amount of the fixed charge? The concept of including the fixed charge amount as part of the ~~tier~~Tier 1 rate for purposes of calculating the tier differential is known as the "composite tier methodology." Based on the Commission's interpretation of the statute, we have consistently required the IOUs to use the composite tier methodology. There is sound reason for doing so. Below is a chart comparing rates with and without using the composite tier differential method. It is clear that, if the utilities are not required to use the composite tier differential, the rates will essentially be flat, with no differential between the tiers. For example, under PG&E's scenario 1(B) from its April 2015 Supplemental Filing, a San Francisco customer would have a lower ~~tier~~Tier 2 rate than ~~tier~~Tier 1 rate. Because the law requires a baseline tier, we agree with long-standing Commission precedent that the calculation should be made with the composite tier. Otherwise, we allow the utilities to effectively avoid the law.

Comparison of PG&E Scenario 1a (Fixed Charge with a composite tier differential) and Scenario 1b (Fixed Charge without a composite tier differential)

Summer 2018 San Francisco 30-day Non-CARE bill with usage of 130% of baseline	PG&E Scenario 1a	PG&E Scenario 1b
Monthly Service Fee (MSF)	$10.42	$10.42
Tier 1 Energy	$33.60	$37.38

Charges		
Tier 2 Energy Charges	$14.81	$13.42
Total Bill	$58.83	$61.22
$/kWh of Tier 1 + MSF	$0.210	$0.228
$/kWh of Tier 2	$0.235	$0.213
Actual Differential	$0.025	($0.015)

4.8. Bill Impact and Rate Modeling Assumptions

4.8.1. Adequacy of Modeling

The IOU's rate change proposals require complex utility rate design models to develop rates as well as bill impact models to evaluate the impact of the proposed rates on customers. At the start of this proceeding we directed the IOUs to develop rate impact calculators to assist parties in understanding and testing the impacts of different rate design scenarios. The bill impact calculators were used in evaluating the Phase 2 Settlement for 2014. However, as time passed, the data in the bill impact calculators has become stale. Parties and the assigned ALJs have also requested modeling that was outside the capacity of the bill impact models.

In addition, although the bill impact calculators included a function to address price elasticity, the assumptions behind this function do not align with our findings that customers generally respond to their average bill or to their highest tier rate. PG&E's bill impact calculator instead applied separate price elasticity assuming that a customer responded to their specific tier of usage as the month progressed.

We acknowledge that the capacity and value of the bill impact calculator results are increasingly less reliable as time passes. The bill impact calculators have served a useful purpose of allowing us to compare different rate structures, but the results of the bill impact calculators are illustrative only and cannot be relied on to reflect what actual rates will look like.

To support their rate change proposals, the IOUs were directed to provide two sets of forecast rates. The first included no revenue requirement changes. The second set included a 2.1 annual increase to reflect forecast CPI. The annual CPI was based on the average for the prior three years. However, during evidentiary hearings numerous parties objected that a 2.1 annual increase was not realistic. In addition, these parties pointed out that even if the average increase is 2.1%, it is likely that in some years the revenue requirement increase will be significantly higher than average.

In light of this, the assigned ALJs directed the IOUs to provide a significant amount of updated information for different rate design scenarios, ranging from three tiers with no fixed charge to two tiers without a fixed charge. This supplemental information also included examples of TOU rates assuming three hour and six hour peak periods. Because most parties found the rates modeled with a 2.1 annual increase to be of limited value, we did not require the IOUs to include an assumed increase in the April 2015 Supplemental Filing.

Portions of the April 2015 Supplemental Filing are added to the record. Because parties did not have an opportunity to respond to the April 2015 Supplemental Filing, we have given it limited weight. In addition, the April 2015 Supplemental Filing included updated electricity burden and energy burden calculations. After reviewing this data, we are concerned by the sample size and some of the results. We therefore have not relied on this data.

We find the April 2015 Supplemental Filing provides a reasonable approximation of different rate structures, sufficient to allow comparison. We also find that the April 2015 Supplemental Filing pertaining to post-2015 rate changes is useful for illustrative purposes but should not be relied on as an accurate prediction of actual rates.

For 2015, the IOUs included expected revenue increases. Therefore, the 2015 rates included in Appendix B are a reasonable estimate of the 2015 rates customers will face. This decision addresses concerns about unexpected or large revenue requirement increases by setting certain caps on rate changes after 2015.

5. Consolidation and Narrowing of Tiered Rates

At its most basic level, tiered rates (or inclining block rates) result in a subsidy from high-use customers, who pay more than the cost of energy services, to low use customers, who pay less than the cost of energy services. This price structure is the opposite of the declining price structure that consumers are familiar with for other commodities. The inclining block structure is designed not to reflect cost but to promote policy goals.

In this proceeding, two policy arguments have been made in favor of inclining block rates: (i) conservation and (2) protection of low income customers.

As discussed above, by conservation we mean an overall reduction in the customer's energy use. Any conservation resulting from the inclining block structure is necessarily limited by the difficulty customers have understanding the price structure. UCAN describes inclining block rate as achieving conservation through "brute force."[209] Moreover, incenting overall conservation is not the only way that energy use can be reduced or made cleaner. Reduction

[209] UCAN OB at 33.

of peak use, integrating renewables, and shifting use to times when energy is more reasonably available cannot be incented by the tiered rate.

Conservation in response to tiered rates could take a variety of forms, such as efficient behavior changes (like remembering to turn out the lights), or energy efficiency investments (such as buying Energy Star appliances or adding insulation). The primary argument in support of the steep tiers is that high-usage customers who are able to will purchase rooftop solar or make other significant purchases of energy efficiency technology in order to reduce overall consumption.

Incenting high-use customers to make significant investments in EE has a downside for customers who are unable to make similar investments. When high-use customers invest in significant EE to avoid paying high tier electricity prices, the result is a smaller pool of customers to cover the allocated revenue requirement. For the customers who do not, or cannot, invest in solar PV or other technologies, the price of energy continues to rise. For the customers who do invest in solar, the inclining block rate no longer provides them with a motivation to conserve energy. Indeed, solar customers may choose to reduce conservation given they no longer pay the utility for all of their electricity.

Similarly, the steep tiers may incent high-usage customers to purchase rooftop solar. Under the current steep tiers, customers who are unable to invest in solar are responsible for much of the cost of service for these solar customers. In addition, once solar is installed, customers are no longer motivated to conserve by steep tiered rates. Indeed, solar customers may choose to increase energy usage now that they no longer pay the utility for the electricity.

The inclining block structure also means that low-usage customers have less incentive to conserve than they would if they paid prices that were closer to

cost. The IOUs assert that there is also a potential for these low-usage customers to conserve more energy. This decision finds that the IOUs should provide educational materials to ~~tier~~Tier 1 and ~~tier~~Tier 2 customers facing higher rates so that they respond to the new rates with no-cost and low-cost conservation strategies.

Strikingly, the record does not reflect a correlation between the steepness of the inclining block rate and customer conservation. Thus a mild differential is sufficient to maintain a conservation price signal. In addition, the current EE subsidy program, consisting of about $1 billion collected from California ratepayers annually, does not include the steep tiers in its evaluation of whether EE measures are cost-effective.

In sum, we find that although a tiered rate may provide a price signal that encourages customers to conserve, the actual extent of any resulting conservation is not clear. There is evidence in the record that shows that the current steep tier differentials are used by vendors to market EE products and rooftop solar to high-usage customers. A knowledgeable customer who is aware of the price structure and has the wherewithal to track it, might also be incented to use less overall energy. However, there is no evidence that a steep differential will lead to a stable, beneficial amount of conservation.

The second policy argument, that low-income customers will be disproportionately impacted by increased low-tier rates, is similarly weak. The correlation between income and usage was argued at length in this proceeding, and as discussed at length in Section 3.3, we are able to conclude (i) that there is only a weak correlation between income and usage, and (ii) that there are low income and middle class customers who currently paying above-cost prices for their electricity. Compared to high income customers, low income and middle

class customers with high usage are more impacted by the current price structure. Low income and middle class customers are less likely to be able to afford significant energy efficiency improvements. They may not have the flexibility to make behavioral changes to reduce overall energy use. And, they may not have sufficient credit or property interest to qualify for rooftop solar programs.

The state and the Commission have developed specific programs to help low income customers with energy bills. The inclining price structure may provide a hidden additional subsidy to some low income customers, but programs such as CARE and FERA are specifically designed to alleviate the energy burden of these low income customers. In keeping with the rate design principles of transparency and limiting cross-subsidies, CARE and FERA, not inclining price blocks, are the appropriate mechanism for addressing the energy burden of low income customers.

Several arguments were made in favor of a flatter, or flat, volumetric rate. A flatter rate structure is more cost-based than inclining block rate. A single-tier flat rate would also less confusing to the customer. Flatter tiers could encourage customers to switch to a TOU rate where they would have greater opportunity to save money by changing usage patterns.

However, neither flat rates nor tiered rates are designed to reflect the actual cost of energy. Because energy prices vary by time of day, only a time of use or time variant rate structure can provide price signals that are indicative of actual energy costs.

5.1. Limitations of Tiered Rates

The tiered rate structure results in "[i]nefficient, above-cost pricing is deceptive and forces customers to conserve or pay excessive costs without ever revealing what energy actually costs."[210]

There is ample evidence against steep tiers. Most importantly, a steep tiered rate is more volatile.[211] This volatility is felt most acutely in areas such as Central Valley where a few hot summer days can cause a bill to double month over month.[212]

Parties in this proceeding almost universally support a change to the current tiered structure.

TURN recognizes that the current tiered rate structure needs to be reformed in the coming years and proposes a comprehensive reform that would establish three tiers of usage for each utility.

NRDC agrees with many parties that there are some real issues with the current rates that likely make them unsustainable.[213] ORA supports gradually reducing the number of tiers in the current tiered rate structure to two as part of a transition to default TOU.[214] UCAN also supports redesigning the current tiered rate structure to achieve rates "that are efficient, cost-based and fair to all customers"[215] SEIA, CALSEIA and IREC all recognize the need to change the current tiered structure and present proposals to reduce the number of tiers.[216] VoteSolar states that it supports the tiered rate proposals of SEIA, CALSEIA and

[210] *Id.* at 7.
[211] Exh. PG&E-101 at 2-14.
[212] *Id.* at 2-15.
[213] NRDC OB at 16
[214] ORA OB at 1.
[215] UCAN OB at 7.
[216] Exh. SEIA-101 at ii; Exh. CALSEIA-101 at 4; Exh. IREC-101 at 2.

IREC and TASC also supports SEIA's proposal.[217] EDF agrees that reforming the current tiered rate structure is necessary, stating that "maintaining status quo tiered rates does not solve the problem of ever growing peak demand."[218] CforAT proposes moving from the current four tiered rate structure to one with three tiers, however CforAT is concerned that "changes in rate design that increase Tier 1 costs and/or shift necessary usage out of Tier 1 risk non--compliance with affordability obligations."[219]

5.2. Reasonable Number of Tiers

We find that a residential rate structure with at least two tiers and a moderate differential should be available to residential customers. This rate structure will maintain the price signal that increased usage means increased cost for the customer. There is also significant legislative direction that a tier structure should be maintained. Currently, each IOU has four tiers. The IOUs propose to reduce the number of tiers to two.

The active parties in this proceeding are divided on whether two or three tiers are preferable. In addition to the three utilities, ORA, UCAN, and IREC support two tiers. NRDC, Sierra Club, CALSEIA, CforAT, TURN and SEIA support a three-tier structure. TURN prefers a three-tier structure, but also proposed an alternative two-tier structure.

The two-tier structure has advantages over multi-tier rates. First, as evidenced by the Hiner study, customers prefer simple rate structures. Second, most customers do not understand the current four tier structure. Third, a two-tier structure makes it easier to change other components of residential rate design to promote more efficient use of electricity and other state policy goals.

[217] Vote Solar OB at 2; TASC OB at 4.
[218] EDF OB at 4-5.
[219] CforAT OB at 53.

NRDC and Sierra Club argue that a three-tier structure will incent additional conservation and support a steeper tier structure. NRDC argues that customers respond to the highest tier (not the average bill price), so a high tiered rate will incent more conservation. [220] Sierra Club and NRDC also point out that because high usage customers use large amounts of energy, they are the most likely to have opportunities to reduce usage, but low usage customers have fewer opportunities to save energy.[221] NRDC argues that its three-tier structure, "allows for lower bills for all customers with below-average usage, along with higher average conservation incentives, while still significantly reducing rates in the higher tiers from today's levels."[222]

TURN argues that a three-tier structure with no customer charge will incent more conservation than a two-tier structure with a fixed charge.[223]

A three-tier rate, however, would unfairly penalize large households. As PG&E points out, large households generally have higher usage than small households – even though on a per capita basis the large households may use less energy. Under the current multi-tier structure, these large households fall into a higher tier and thus pay more per kWh. A three-tier rate structure will continue this asymmetry, but a two-tier system will prevent members of large households from paying a disproportionate share of electricity costs.

We find that a two-tiered structure will minimize the risk of large households paying a disproportionate share of electricity costs. In addition, a two-tiered structure will be the easiest for customers to understand and accept.

[220] NRDC OB at 12.
[221] *Id.* at 16.
[222] *Id.* at 17 (citing Exh. NRDC-101 at 32).
[223] TURN OB at 2; *id.* at 6 (finding that PG&E's proposed 2018 rate, including fixed charge, would increase load by 1.44 under the average price approach and that TURN's proposed three-tier rate without a fixed charge would decrease load by .24% under the average price approach).

This is essential given this proceeding's emphasis on increasing customer understanding electricity rates.

5.3. Reasonable Tier Differential

Parties provided a wide range of proposals for how to set the tier differentials in either a two or three tiered rate. In this proceeding, the term "tier differential" refers to the percentage difference in price between two tiers. For example, a 20% differential means that the second tier price is equal to 120% of the first tier price.

The utilities have proposed a 20% end state differential and make several arguments to support this proposal. As a group, the IOUs do not provide a rationale or methodology for selecting 20%. SCE does assert that according to its calculations, a 20% differential is reflective of cost. For the most part, however, the IOUs appear to rely on prior Commission decisions (some of which date back to the 1980s) and on the Section 739(d)(1) requirement for "gradual" tier differentials.

The utilities cite Section 739(d)(1), which states that the tier differential should be "gradual." PG&E argues that, based on history, a 1.2 to 1 ratio would be appropriately gradual,[224] and that steep tiers are inequitable.[225]

Several parties, such as ORA and UCAN, find the 1.2:1 ratio acceptable, but argue that it may take a longer than 2018 to reach this differential. UCAN also recommends the 1.2:1 ratio only if it is paired with a program of direct incentives for conservation. ORA supports the 1.2:1 differential only if default TOU is implemented as an incentive for conservation during peak periods.

[224] PG&E RB at 9 (stating that prior to the 2000-2001 energy crisis, the ratio was set at 1.15 to 1).

[225] *See generally, e.g.*, PG&E OB at 21.

Other parties, including TURN, SEIA, TASC, IREC, Vote Solar, Sierra Club and NRDC argue for a steeper differential. TURN argues that regardless of the number of tiers, the differential should be 40 – 50%,[226] and proposes a 1:1.6 differential for its two-tier rate. NRDC argues that a high top tier is necessary because customers only respond to the highest price (not the average price).[227]

Aside from SCE's estimate that a 20% differential is representative of cost, only two parties, SEIA and IREC, provided analysis tying their proposed tier differentials to cost. SEIA and IREC provide extensive arguments against the 20% tier differential.

Although the utilities have justified the 20% differential in part on history, SEIA points out that there has been a "[d]ramatic shift in policy since there were 2 tiers with 15% differential."[228] SEIA cites a plethora of Commission and state programs and policies that have been enacted that support the "increasing importance of renewable energy and energy efficiency technologies" including RPS in 2003, CSI in 2006, Energy Action Plan in 2003, and AB 32 (California Global Warming Solutions Act of 2006). SEIA argues that using 1980s and 1990s decisions as a roadmap for establishing tier differentials is "illogical."[229]

IREC argues that "gradual" tiering is only relevant if there are at least three tiers.[230] For a two tier rate, there is only one differential. There must be a second differential to make a comparison and determine if the two, when looked at together, are gradual. Based on this, IREC proposes a much steeper differential.

[226] TURN RB at 19-20.
[227] NRDC OB at 13. This decision addresses the average cost method and marginal tier method in Section 2 and finds that the average cost method is the more appropriate measure for residential customers.
[228] SEIA OB at 4-6.
[229] *Id.* at 6.
[230] IREC OB at 13.

SEIA and IREC each propose a steeper differential where the highest tier is based on a "marginal cost" calculation.[231]

SEIA proposes a three-tier rate structure with tier differentials of 1.7 to 1.35 to 1.0, where "each IOU's marginal capacity costs would be allocated to upper tiers, with more being allocated to the third tier than the second tier."

SEIA seeks to use marginal utility "capacity" costs as the basis for a high-usage tier. The capacity component is defined as "generation capacity and primary distribution capacity."[232]

SEIA asserts that marginal capacity costs should not be allocated to baseline usage – not because a customer whose energy use is limited to baseline quantity does not incur such capacity costs but because "peak-related *marginal* usage is generally in higher tiers."[233] SEIA argues that this rate would be cost-based "because it collects in the upper tiers the marginal capacity costs that are driven by customer usage during peak periods when system demand peaks."[234] SEIA uses load factor, a ratio that compares the ratio of a customer's average demand to their peak demand, to argue that high usage customers "peakier" load profiles. More specifically, SEIA asserts that these customers have lower load factors and demand more power than others during peak periods and therefore demand more services *at the margin* from the IOU. These customers should, according to SEIA, pay higher tier rates to account for the marginal strain they put on an IOU's generation and distribution system. SEIA supports this conclusion with a finding for SCE territory that the load factor for a single family

[231] SEIA OB at 12-13 ("peak-related *marginal* usage is generally in higher tiers.").
[232] Exh. SEIA-101 at 39.
[233] SEIA OB at 12 (emphasis original).
[234] *Ibid*.

home in a mild coastal zone was 0.44, but that this load factor dropped to 0.30 in moderate or hot inland zones.[235]

IREC proposes a tier differential based on another marginal cost calculation. IREC's proposal would be a two-tier rate, with an approximately 2:1 differential.[236] IREC argues that the utility's upper tier in a two-tier system should recover marginal generating capacity costs and overall generation costs. Unlike SEIA, IREC only focuses on marginal generation capacity costs, and does not appear to include distribution costs in its calculation of a high-usage tier rate. IREC's proposed baseline tier would recover all other costs and the tier differential ratio would reflect the difference between the two.[237]

IREC's rationale is that once the generation and marginal generation capacity costs are averaged for each utility, they equal a higher tier rate that is 110% - 120% larger than the rate that recovers all other utility costs. IREC argues that the approximately 2:1 ratio therefore reflects marginal pricing and maintains appropriate conservation incentives.[238]

IREC refers to this methodology as "long-run" marginal pricing because it accounts for the procurement costs of an entire marginal power plant or resource, rather than simply a unit of energy purchased at the margin. IREC argues that this will lead to cost signals that will reduce future procurement that would occur if prices were set only on the basis short-term marginal costs.[239]

SEIA and IREC have different rationales for their proposals for steep tier differentials. SEIA connects high usage to high demand, and therefore higher marginal demand costs, meaning that it would be appropriate to charge

[235] Exh. SEIA-101 at 38 (referring to SCE data that is not in the record).
[236] IREC calculates the differential assuming a 50% baseline for all three IOUs, but if the IOUs have different baselines the differential would need to be recalculated.
[237] IREC OB at 12.
[238] Exh. IREC-101 at 14-17.
[239] IREC OB at 10-12.

high-usage customers more to cover those increased demand costs. IREC takes a more abstract view and simply reasons that if the marginal cost of electricity (the higher tier cost) is higher than the cost of building a new plant, then there will be less incentive to build more plants and therefore "long-run" marginal costs will decline.

Although both SEIA and IREC argue that their proposals are cost-based, the link between their methodologies and cost-causation is attenuated. Certainly making higher-usage rates more expensive than marginal utility costs (either generation, distribution or both) should in theory create a disincentive for marginal procurement of various kinds. This would theoretically limit utility costs over time. But, high marginal generation costs are driven by peaky less efficient demand curves. A more direct solution would be a TOU rate that reduces the peakiness of the load curve and thus reduces the marginal generation cost.

In addition, high-usage customers are efficient customers: it costs utilities less to serve at the margin than low-usage customers.[240] Therefore, charging high-usage customers more for each kWh of energy they use (i.e., an inclining block rate structure) is economically inefficient and does not reflect true marginal cost-based pricing.[241]

Both approaches also fail to support cost causation. With regard to SEIA's proposal: coincident residential demand is just that – demand amongst all customers that coincides at one time. To say that high-usage customers should

[240] Note that SEIA fundamentally disagrees with EDF on this empirical point, as SEIA cites data from SCE showing that inland customers (who are presumed to be higher-usage customers) generally have less efficient load profiles. In the absence of complete evidence on the relative load profiles of high-usage vs. low-usage customers, the Commission cannot say who is correct but my view is that high-usage customers generally are more efficient customers and are not necessarily more "peaky" than low-usage customers.

[241] Exh. EDF-101, Appendix B at 7.

bear responsibility for the marginal generation and demand distribution costs associated with this coincident demand from *all* customers does not comply with principles of cost causation. All customers, to some extent, are causing the need for expanded infrastructure to cope with high levels of coincident demand. While SEIA does try to empirically connect high usage with high demand, therefore making their proposal more accommodating of cost causation, they offer little evidence of this relationship.

IREC's proposal is also not well-aligned with the principle of cost causation. High-usage customers are not solely responsible for the generation and marginal generation capacity costs of a utility (i.e., the construction of new energy facilities), and therefore they should not be required to shoulder the entire burden of such costs.

A two-tier rate with 20% differential will encourage overall conservation while reducing bill volatility. Twenty percent is an increase over the last tier differential approved by this Commission. It is aligned with the Commission's principle for cost-based ratemaking and at the same time retains a price signal to customers that increased usage will result in increased price. Because low usage customers will pay closer to the cost of service, they may elect to conserve more.

In addition, the flatter tier structure will result in fairer and more equitable pricing for all residential customers. Low usage customers will pay prices that are closer to the costs incurred to serve them. High usage customers will see a price decrease, but will still pay more than the cost of service.

Because low income customers can be found in both the low usage and high usage tiers, the costs and benefits under this flatter tier structure will mirror that of residential customers as a whole. For low income customers, programs to protect against high bills continue to be available, such as the CARE, FERA and

medical baseline programs, the Energy Savings Assistance (ESA) Program,[242] and other programs for low-income customers that address non-energy burdens.[243]

Before determining that a two-tier rate with a 20% differential is reasonable, complies with state law, and is consistent with the RDPs, however, we must consider all aspects of the rate design changes approved in this decision. For example, as discussed in Section 3.7.2 if a fixed charge is implemented, the differential between Tier 1 and Tier 2 must be calculated using the composite tier method.

5.4. Reasonable Glidepath for Consolidation of Tiers

The reduction in tier differential and the number of tiers will have to be carefully coordinated to minimize undue burdens on lower tier customers. The largest bump in rates will come for ~~tier~~Tier 2 customers when ~~tiers~~Tiers 2 and 3 are combined. In particular, this transition will be difficult for SCE and PG&E.

In addition, the illustrative rates reviewed in this proceeding do not include actual revenue requirements increases. A large revenue requirement increase allocated to the residential class at the same time as tiers are being narrowed could also result in an increase that is not reasonable for lower tier customers.

However, the glidepath to reach an approved end-state cannot be determined until the end-state number of tier and tier differential has been approved, and the time period for reaching the end state have been set. Then the options for glidepaths (including the timing of tier consolidations) can be evaluated. Although all three IOUs will be on a glidepath to the same target tier differential, the timing of the tier reductions and tier differential changes will be

[242] A program that provides direct financial incentives to lower-income households to invest in upgrades and technology that enhances energy efficiency.
[243] Exh. PG&E-109 at 2-9.

different. The glidepaths are examined in the context of each IOU's separate proposal in Section 10.

5.5. Baseline Quantities and the Amount of Usage in Each Tier

The Commission is required to set a baseline quantity of electricity that is "necessary to supply a significant portion of the reasonable energy needs of the average residential customer."[244] By statute, this baseline quantity must be equal to 50 and 60% of the "average residential consumption" in each geographic area.[245] Baseline quantities are set differently for each Climate Zone and are designed to take into account seasonal variations in consumption.[246]

During the period that the AB 1X rate freeze on lower tiers was in place, adjustment of the baseline percentage was one of the few means of reducing rate pressure on high use rates. For example, because Tier 1 is set at 100% of baseline, if the baseline quantity is reduced from 60% to 55%, the number of customers in Tier 1 will be reduced. With the passage of AB 327, the Commission now has discretion to adjust the lower tier rates. With that discretion, the need to adjust baseline quantities has become less important.[247] Indeed, in this proceeding some parties (Vote Solar) parties took no position on baseline, and others professed no preference (IREC). Other parties, such as ORA, argue that further reductions are not necessary now that tiers can be modified to more accurately reflect cost.[248]

SCE and SDG&E asked for reduced baseline quantities.[249] PG&E asked that no changes to baseline quantities or guidelines be made in this proceeding.

[244] Section 739(2)(b).
[245] The statute requires that for all-electric customers the baseline be set at 60-70% of average residential consumption during the winter heating season.
[246] Section 739(a)(1).
[247] Recall that reductions to 50% were driven by the need to reduce pressure on upper tier rates while AB 1X restrictions were still in place. (SEIA OB at 17.) This is no longer necessary.
[248] ORA OB at 25.
[249] SCE OB at 20-23.

Table Showing Current and Proposed Baseline Percentages

	Current	Proposed	Difference
PG&E	52.5%	52.5%	None
SCE	53%	50%	3%
SDG&E	Between 52% and 55% for Basic customers	50%	2% - 5%

Several parties ask that the baseline quantities be adjusted to the 55% midpoint between 50% and 60%.[250] CforAT states that the baseline quantity is the best representation we have of "amount of energy sufficient to meet basic needs." CforAT acknowledges that baseline formula is not perfect (for example, it does not take into account household size), but finds that baseline quantity is the best available estimate of essential usage.[251] Therefore, CforAT argues that baseline be set in the middle of the statutory range of 50-60%.[252]

SEIA would also set the baseline quantity at mid-point (55%) through gradual transition, arguing that the midpoint gives the Commission the most flexibility to adjust up or down as necessary as conditions change.

ORA argues that a decrease to 50% would run the risk that in between GRCs the calculated baseline would fall below the statutorily required minimum baseline.

We agree that changes to baseline quantity are best addressed in each utility's periodic Phase 2 GRC revenue allocation and rate design proceedings. The need to lower baseline to decrease pressure on upper tier rates is gone. We also agree that, if tiers are flattened significantly (such as two-tiered rate with 20% differential), then low usage customers should not be subject to the

[250] CforAt OB at 2.
[251] CforAT OB at 52 (citing SCE, PG&E, and SDG&E statements in agreement).
[252] *Id.* at 54.

additional rate and billing impacts that would result from reducing baseline quantities.

SCE currently has a baseline allowance of 53% for standard service in all climate zones. As part of this proceeding, SCE proposes to reduce its baseline allowance to 50% in 2016.[253]

Considering SCE's proposed rate change as a whole, we believe that a decrease in baseline allowance is not warranted at this time. Currently, SCE's baseline is within the middle range for baseline allowances. The primary objective of reducing the baseline allowance is to take another step toward bringing upper tier and lower tier rates back in line with cost. However, we find that tier flattening between now and 2019 will have a more significant bill impact on lower usage customers than additional incremental baseline adjustments. We therefore deny SCE's request to reduce SCE's baseline quantity.

However, for SDG&E, a different analysis applies. Because we approve SDG&E's consolidation of Tiers 1 and 2, so that the consolidated Tier 1 includes usage up to 130% of baseline, the decrease to the baseline quantity will be offset. UCAN and other parties acknowledge that because SDG&E's Tier 1 will include up to 130% of baseline it is reasonable. Therefore, we approve SDG&E's proposal to reduce the baseline quantity to 50%.

5.6. Seasonal Rates

Several parties, including SCE, SDG&E, and SEIA, advocate seasonally differentiated tiered rates. Tiered rates differentiated by season are a type of TOU rates that is based on time of year rather than time of day.

[253] SCE OB at 64.

Currently, SCE's and PG&E's current residential tiered rates do not include any difference in charge based on season; customers are charged the same rate regardless of the time or season they use energy.

SDG&E recently began seasonally differentiating its high tier rates (~~tiers~~Tiers 3 and 4). [254] SDG&E proposes to expand seasonal pricing to Tiers 1 and 2.

SCE proposes to adopt seasonally differentiated tiered rates for the first time and would use these rates for the interim period between the end of 2018 and "the earliest time the IOUs could undertake default TOU pilots."[255] SCE argues that implementing seasonally differentiated tiered rates as a predecessor to default TOU (should it be ordered) would assist customers with the transition by allowing them to grow "accustomed to seeing higher rates in summer and lower rates in winter".[256] SCE contends that seasonally differentiated rates were adopted as part of the transition to mandatory TOU rates for its commercial customers (SCE's 2009 GRC Phase 2) and recommends a similar path be taken for residential customers.

SDG&E proposes to seasonally differentiate rates in all tiers to "better reflect the costs of providing commodity services."[257] SDG&E proposes to transition to a two-tiered, seasonally differentiated rate structure. Currently, the commodity component of SDG&E's Tier 3 and 4 rates is seasonally differentiated, with higher rates in the summer and lower rates in the winter. Due to lower tiers being subject to legislative caps prior to AB 327, Tier 1 and 2 rates do not have

[254] Exh. SDG&E-107 at CF-26 (stating that seasonal rates reflect the difference in cost of service between summer and winter and that D.14-01-002 approved SDG&E's uncontested proposal to limit the summer/winter total rate differential to 75% of the summer/winter commodity differential).
[255] SCE OB at 154.
[256] SCE RB at 88.
[257] Exh. SDG&E-107 at CF-26/Fang.

any seasonal differentiation. D.14-01-002 set the "summer/winter total rate differential at 75% of commodity rate differential for residential tiered rate schedules."[258] SDG&E's current Tier 3 summer rates are 0.3 cents higher than winter; Tier 4 summer rates are 0.35 cents higher.

SEIA supports the move to seasonally differentiated rates and recommends that the Commission "encourage PG&E and SCE to explore seasonally-differentiated IB rates in future GRC Phase 2 cases" to reflect the significant seasonal dimension of the IOUs' marginal costs.[259] SEIA argues that seasonally differentiated tiered rates would provide customers with the appropriate price signals to reduce usage during summer months and would bring rates closer to the utilities' cost of service.

On the other hand, ORA opposes further exploration of seasonally differentiated rates at this time. ORA argues that, since PG&E and SCE don't currently have seasonally differentiated rates and SDG&E's residential rates are already the highest among the three IOUs, adding seasonal differentiation to lower tiered rates would cause SDG&E's summer rates to be significantly higher than the other utilities.[260]

Additionally, ORA contends that higher summer generation costs can be better reflected by TOU rates.

SDG&E and SCE argue that seasonally differentiated rates in all tiers would be way for customers to learn about and understand time-differentiated rates. But, ORA argues that, since about 40% of SDG&E's customers never experience usage outside of Tiers 1 and 2, and therefore aren't familiar with seasonally differentiated rates, adding this complexity will cause unnecessary

[258] D.14-01-002 at 37.
[259] Exh. SEIA-101 at 38 (referring to SCE data that is not in the record).
[260] Exh. ORA-101 at 5-11.

confusion at a time when other significant rate changes will be going into effect.[261]

We generally agree with SDG&E, SCE and SEIA that residential rates should include a seasonal component as they become more cost-based. We therefore approve SDG&E's proposal for seasonal rates in all tiers starting as early as 2015. As noted by SDG&E in its testimony, seasonal rates are already in place for its customers using Tier 3 and Tier 4 amounts of energy and therefore many of its customers are familiar with the concept of seasonal tiered rates. Further, employing seasonality in tiered rates will, as SDG&E suggests, move such rates closer to cost and encourage more economically efficient decision-making.[262] We direct SCE and PG&E to explore seasonally differentiated rates for 2016, to be proposed in the next applicable GRC or RDW.

6. Residential Time of Use Rates

6.1. Overview

Earlier in this decision we examined existing opt-in and default residential TOU programs. We found there are many demonstrated benefits from existing programs, and many potential benefits for California if a well-designed default TOU rate is implemented.

For example, it is well-established that TOU rates are more cost-based than flat or tiered rates. TOU rates enable the customer to better understand electricity resources and make a positive difference in the environment by adjusting their use. TOU rates can also reduce the cost of infrastructure by reducing the need for peaker plants.

[261] ORA OB at 23.
[262] Exh. SDG&E-109 at CF-44-45.

It is also well-documented that the larger two IOUs, have been very slow to explore the value of residential TOU rates despite its priority as a state policy goal.

We can no longer allow the larger two IOUs to prevent California from transitioning to a superior rate design for residential customers. Therefore, we direct the IOUs to move quickly to prepare themselves and their customers for the implementation of TOU rates. Specifically, the IOUs should quickly and thoroughly evaluate all areas of transition to default TOU, including but not limited to: load shift and load reduction, customer acceptance, appropriate parameters of residential default TOU, customer classes who are not able to respond and should remain on tiered default rate, and measure of environmental and cost savings from load shift and load reduction.

Based on the benefits demonstrated by the evidentiary record, we approve default TOU rates, to be implemented on a schedule that provides sufficient time and resources to design a rate that is acceptable to customers while achieving reductions and shifts in load that benefit the entire state.

It has been said that rate design is both a science and an art. For a default TOU rate to be successful, the design should be based on empirical evidence that supports both measurable benefits of TOU on the grid, and the acceptance and understanding of TOU rates by the residential customer.

6.2. Customer Acceptance Concerns

6.2.1. Identifying Customer segments Prior to Authorizing Default TOU

The first step in customer acceptance is to identify different types of customers within the residential customer class, including those who are

explicitly exempted from default TOU by statute. Section 745 provides three separate rules regarding customers.

Section 745(c)(1) requires three specific groups of customers to be identified because they are not subject to default time-of use rates without their affirmative consent: (i) medical baseline customers; (ii) customers requesting third-party notification pursuant to Section 779.1(c); and (iii) customers who cannot be disconnected without an in-person visit.[263] The IOUs should have records that make identifying these customers straightforward.

Section 745(c)(1) also allows the Commission to identify additional customer groups to be made exempt from default TOU. Further analysis, as described below, is necessary before the Commission can identify additional customer groups. But, based on the record as discussed below, we believe that careful analysis to identify these potential other customer groups is warranted.

By statute, the Commission must also identify "senior citizens" and "economically vulnerable customers" in hot climate zones so that the Commission can ensure that TOU rates do not cause unreasonable hardship for them.[264] Identifying these two groups of customers will be more difficult. The statute does not define seniors, and the utilities do not track the age of their customers. The term "economically vulnerable customers" could be interpreted to mean CARE and FERA customers, or it could be defined to include other

[263] Section 745(c)(1) provides: "Residential customers receiving a medical baseline allowance pursuant to subdivision (c) of Section 739, customers requesting third-party notification pursuant to subdivision (c) of Section 779.1, customers who the commission has ordered cannot be disconnected from service without an in-person visit from a utility representative (Decision 12-03-054 (March 22, 2012), Decision on Phase II Issues: Adoption of Practices to Reduce the Number of Gas and Electric Service Disconnections, Order 2 (b) at page 55), and other customers designated by the commission in its discretion shall not be subject to default time-of-use rates without their affirmative consent."

[264] Section 745(c)(2) requires that the Commission "ensure that any time-of-use rate schedule does not cause unreasonable hardship for senior citizens or economically vulnerable customers in hot climate zones."

low-income customers who do not qualify for these programs. In addition, not all ratepayers eligible for CARE or FERA have identified themselves by signing up for the programs. The statue also does not define "hot climate zones."

Once senior citizens and economically vulnerable customers in hot climate zones have been identified, the next step will be to determine if these customers will face unreasonable hardship from TOU rates. After that step is completed, the Commission could decide to add these customers to the exempt list pursuant to 745(c)(1), or could direct the IOUs to take other measures to eliminate the "unreasonable hardship."

Section 745(d), added by SB 1090 in 2014, requires consideration of evidence related to customer groups that are similar, but perhaps not identical, to those identified by Section 745(c)(2). Section 745(c)(2) customers appear to be a subset of Section 745(d) customers.[265]

Table Comparing Section 745(c)(2) and Section 745(d) Customers

745(c)(2)	745(d)
Senior citizens in hot climate zones	
economically vulnerable customers in hot climate zones	
	Customers located in hot, inland areas
	Customers living in areas with "hot summer weather"

As with Section 745(c)(2), identifying Section 745(d) customers is the first step in an analysis that must be performed in connection with implementing

[265] Section 745(d) provides "The commission shall not require or authorize an electrical corporation to employ default time-of-use rates for residential customers unless it has first explicitly considered evidence addressing the extent to which hardship will be caused on either of the following: (1) Customers located in hot, inland areas, assuming no changes in overall usage by those customers during peak periods. (2) Residential customers living in areas with hot summer weather, as a result of seasonal bill volatility, assuming no changes in summertime usage or in usage during peak period."

default TOU. After identifying the customers, evidence must be gathered regarding the "extent to which hardship will be caused" by default TOU (a) assuming no change by hot, inland area customers during peak periods, and (b) assuming no change by customers in areas with hot summer weather during the summer or during peak periods. This evidence must then be "explicitly" considered before the Commission can require or authorize an electrical corporation to "employ" default TOU.

Several parties provided insight into additional potentially vulnerable customer groups that might need to be exempted from default TOU without the customer's affirmative consent.

CforAT cites customers in hot climates who cannot reasonably avoid air conditioner usage, such as "people with disabilities, seniors who do not work outside of their home, people with infants."[266] CforAT provided extensive evidence on how customers with difficulty affording energy may not be able to shift their energy use.[267]

In addition to segmenting customers by income, usage, location, air conditioning requirements, there are other customer characteristics that cannot be controlled for that do impact customer acceptance levels. For example, at one extreme there are customers who will be interested in adopting TOU rates because they are interested in new technology and energy efficiency. At the other extreme, there are customers who will not be happy with any change in rate structure.

Creative data mining, such as identifying customers who are structural winners or losers, or customers with load profiles that show it is unlikely that they will be able to shift use, should be done now rather than waiting until the

[266] CforAT OB at 77 (citing Exh. CforAT-101 at 53).
[267] Exh. CforAT-101 at 51.

next decade. For example, ORA asserts that for small commercial customers the IOUs were required to proactively contact the top 10% most impacted customers and provide them with information and integrated solutions to reduce their energy usage.[268] In moving toward default TOU rates, the IOUs must start to identify statutorily required customer groups (senior citizens), customers explicitly exempted by statute, and vulnerable customers who may need to be categorized as exempt or be provided with additional outreach. The IOUs must also start identifying customer segments that will benefit or be interested in participating in TOU rates.

6.3. Customer Protections Included in TOU Rate Structure

6.3.1. Optional, not Mandatory, TOU Rate

Consistent with our statutory obligations pursuant to AB 327, it is important to remember that any default TOU rate derived from this decision will be optional and it is essential that the IOUs provide a menu of well-designed optional tariffs, including a tiered rate, for residential customers to opt into. Most parties in this proceeding have advocated this "menu" of options, to promote customer choice,[269] and we agree that a menu of choices for customers is part of the goal of this proceeding and AB 327. This decision does not endorse mandatory TOU for residential customers.

[268] ORA OB at 83 (apparently referring to D.10-02-032 at 79 (requirement to contact 10% most impacted customers unaffected by subsequent modification of decision in D.11-11-008)).

[269] *See, e.g.,* RT Vol. 23 at 3666 (EDF witness Fine testifying that "a variety of tariff options and programs should be available to meet the variety of needs of customers."); s*ee also* SEIA OB at 27 (SEIA recommending menu of TOU options); ORA OB at 28 ("customer choice is at the heart of Rate Design Principle #6.").

6.3.2. Mild Differential between On-Peak and Off-Peak Rates

ORA points out that TOU rates can be structured to initially have a mild differential, which will avoid adverse bill impacts.[270] This structure is similar to the "TOU-Lite" rate adopted by settlement for the roll out of mandatory TOU to small commercial customers.

The Commission has previously authorized TOU-Lite rates: a tariff that is intended to be revenue neutral with other tariffs for the same customer class and has on and off peak rates set to a specified differential instead of attempting to reflect actual costs for energy in the peak period. The purpose of this mild differential is to be an introductory rate that allows for customers to learn and understand the new rate structure before they are subject to differentials that could produce significant rate shock for the unaware.

The residential TOU rates being developed in this proceeding are not an attempt to match real-time prices in the wholesale market. Like tiered rates, they are a methodology for allocating responsibility for the recovery of the residential class' revenue requirement among residential customers. Unlike tiered rates, TOU rates do provide a price signal that allows customers to make energy decisions that align with grid needs. Thus the TOU rate approach approved in this decision is more cost-based than tiered rates.

SCE and PG&E argue that ORA's proposal for default TOU rates in 2018 does not provide enough detail or guidance. For example, how would the mild differential be set, and when would it be adjusted closer to peak period cost?[271] We agree that ORA does not provide a sufficiently detailed TOU rate proposal for us to adopt at this time. Furthermore, before a rate could be approved, we

[270] Exh. ORA-101 at 1-1 (citing PG&E's Schedule A-1 for small business customers starting with a 4 cents/kWh differential).
[271] SCE OB at 154.

would need to understand bill impacts. Most importantly, we would need to meet the requirements of Section 745 for avoiding hardship to certain customer groups. Rather, ORA's proposal is a framework for moving toward implementation of default TOU rates that are based on the evidence and supported by state policy goals.

During the TOU-Lite transition period, we would expect to see less load-shifting than we would with a full cost-based peak price. The IOUs pointed this out, and we do not disagree. However, during the transition, it is more important to ensure customer acceptance of the new rate structure and understanding of the directional price signal. The TOU-lite structure will be more acceptable to customers, less volatile, and avoid other potential issues. The shift toward more cost-based peak period prices may be made later, through steps spelled out in Residential RDW application as modified by data and experience gathered during the course of pilot implementation and ongoing review of the glidepath transition between 2015 and 2019.

6.3.3. Baseline Credit in TOU Rates

A baseline credit should be part of the default TOU rate. An analysis of the legal requirements contained in Section [3.3.2] (Requirement for a Baseline Tier for Default Residential Rates) found that the baseline credit is not required for default TOU by law. However, the policy reasons for implementing a baseline credit are applicable to default TOU. In addition, for both opt-in and default TOU, a baseline credit will make the TOU rate structure more comparable to the opt-in tiered rate.[272]

[272] *See, e.g.*, DRA [ORA] Residential Rate Design Proposal, May 29, 2013, at 37, 45, and 48; *see also* Revised Energy Division Staff Proposal on Residential Rate Reform, May 8, 2014, at 12-13, 23 (published by ALJ Ruling Issuing Corrected Energy Division Proposal, May 9, 2014).

There are three primary arguments to include a baseline credit in optional and default TOU rate designs. The most important is that, because the baseline amount takes into account the climate zone the customer lives in, including a baseline credit allows the TOU rate to be differentiated by climate zone. Second, a baseline credit will provide more opportunity for low usage customers to benefit from a TOU rate. Without a baseline credit in the TOU rate, these customers would likely opt for a tiered rate that includes a baseline credit. Similarly, without a baseline credit, the TOU rate rewards large customer who switch to TOU even without load shift.[273]

PG&E and SDG&E support untiered (no baseline) opt-in TOU. PG&E argues that tiered TOU rates are harder for customers to understand.[274] A baseline credit also reduces alignment with cost causation and sends a less economically efficient price signal.[275] Introducing a baseline credit also means that customer will not be rewarded as much for reducing at peak times. While we agree with these parties that it appears to create a two-rate structure, one cannot draw an apples-to-apples comparison between the current ~~4~~four-tier rates and a simple baseline credit, because the latter is not a whole rate structure. Rather, the baseline credit should be viewed as an adjunct or overlay to a TOU rate that provides some incremental measure of relief to customers who need it based on climate zone. In this sense, we support the baseline credit concept as a supplemental customer protection.

There is not a clear statutory requirement for a baseline credit in optional TOU rates. However, because we find that policy reasons support the baseline

[273] TURN OB at 46 (citing TURN 201 at 60 and CforAT RB at 15).
[274] PG&E RB at 74.
[275] PGE RB at 72 ("If a small customer can actually shift load and do better on an untiered TOU rate than under an E-1 rate with a baseline tier, it should be on TOU. If not, it should not be on the subsidized E-1 rate).

credit in default TOU, and because a baseline credit will allow for the best comparison of optional rate with a future default TOU rate, a baseline credit must be part of the design for default TOU and at least one optional TOU rate offered by the IOU.

Because a baseline credit is required by this decision for default TOU, each IOU must offer at least one opt-in TOU rate and pilot with a baseline credit. This approach is supported by SEIA[276] and ORA.

TURN supports keeping a baseline credit in any TOU rate to reduce the risk of large users opting in and thereby lowering their bill without making change to their usage. Whether a large user is actually able to accomplish this depends on other aspects of the rate structure and how the baseline credit is calculated.

To calculate the baseline credit rate, ORA proposes to take the difference between the weighted average of non-baseline and the baseline rate.[277] PG&E agrees with this calculation of baseline credit,[278] and no party disagreed with using this methodology. Sierra Club did propose an alternate method of simply setting the credit at 10 cents. We find that ORA's calculation method, as supported by PG&E, is reasonable.

There are different ways to apply the baseline credit to a TOU rate schedule. ORA proposes (and SCE has in place) a methodology that applies a straight credit to a TOU rate.[279] SCE applies a straight credit, but mandates a ceiling for the credit equal to one cent less than the super-off-peak rate. TURN's

[276] SEIA OB at 27.
[277] ORA OB at 67.
[278] PG&E RB at 77-78.
[279] Exh. ORA-101 at 3-17; ORA OB at 67, 69, 72; Exh. SEIA-101, Attachment RTB-3 (describing SCE's methodology).

proposal would raise all TOU rates by equal percentages to recover the revenue paid out as a credit.[280]

Alternatively, SEIA and ORA also suggest that the rate be presented as an untiered rate with an excess usage charge for all usage over baseline.[281]

We find that the baseline credit on any default TOU rate and on at least one available TOU optional rate and on any opt-in or default pilot rates, is an essential element of wide-scale TOU adoption for residential customers.

6.3.4. Bill Protection for Default TOU

By statute, one year of bill protection is required for customers defaulted to TOU rates. ORA states that such protection will prevent customers from being harmed in the first year of a new rate. If, at the end of the year, a customer would have been better off on the previous rate plan, the customer will be credited the difference on their bill. ORA recommends that this bill protection be made available on a semi-annual (rather than annual) basis for customers.[282] We agree that this proposal merits consideration and direct the utilities to consider this option in their design of default TOU rates.

SDG&E proposes that its bill protection will include a monthly "shadow bill." A shadow bill will allow customers to see how their electricity bill under the new rate differs from the bill they would have had under the old rate.[283] A shadow bill is required by statute and we find that an accurate shadow bill is an important part of customer education and outreach for default TOU.

[280] Exh. TURN-201 at 60.
[281] *Id.* at 28; Exh. ORA-101 at 1-12.
[282] ORA OB at 80.
[283] Exh. SDG&E-102; Exh. CAW-7.

6.3.5. Outreach and Education for TOU Rates

Without adequate customer outreach and education, the protections set forth above will not be meaningful.[284]

An important part of the roll out of default TOU and optional rates is a robust bill comparison tool. Section 745 requires a shadow bill be provided to customers prior to any default TOU rate. But we believe the need for a shadow bill or bill comparison tool goes beyond preparing customers for default TOU.

Currently, neither SCE nor SDG&E have an online bill comparison tool that will allow customers to compare rates based on their actual interval data. PG&E does have an online bill comparison tool available to individual residential customers based on their actual usage.[285] It is essential that the bill comparison and online web tools available to customers are accurate, useful, and customer-friendly. We have concerns that these bill comparisons are not effective. In addition, a web-based tool will only reach the customers who use the web and are interested enough to take the steps to try the bill comparison. Although we support having such a web-based tool available at any time for customers to explore rate options, we believe that to properly educate customers about their rate options a paper bill comparison should be provided to customers twice per year beginning in 2016. We therefore instruct the utilities to immediately begin developing this tool (if it does not already exist) and begin design of rate comparisons.

[284] ORA at 79 (discussing need to "execute effective outreach and education programs" for both tiered and TOU rates).

[285] SDG&E was developing this tool in connection with its Smart Pricing rate (Schedule TOU-DR-P) and it should be available now. SDG&E Supplemental Testimony of Caroline Winn at 3. PG&E My Energy also includes this ability. Exh. PG&E-155 at 2. SCE does not have this capability and does not currently have plans to implement it. SCE estimates it would take 18 months to implement it. Exh.SCE-126 at 2-3.

In the Section 9 (Marketing, Outreach and Education), we discuss measurable goals for ensuring that all outreach and education for rate reform are effective.

6.4. Concerns About the Changing Load Curve

Energy uses and generation sources evolve over time, and have been doing so even more rapidly in recent years due to increases in distributed generation and renewable resources, as well as the proliferation of new technologies that allow customers to monitor their energy usage. Put succinctly: "It is widely acknowledged that system conditions are changing rapidly with the addition of major quantities of intermittent renewable resources including the rapid penetration of rooftop solar."[286] The Commission is well-aware of these anticipated changes, as well as the possibility of unexpected changes, in the load curve.[287]

At the same time, however, AB 327 requires default TOU periods that are "appropriate" for ~~5~~five years. There are excellent policy reasons for requiring a five -year term for TOU periods for default TOU rates. A constantly changing TOU period would cause customer confusion. It would also make it difficult for customers to evaluate investments in energy efficiency improvements and rooftop solar.

Many parties in this proceeding have made the assumption that a default TOU program would take the form of a rate with a single on/off/part peak structure applicable to all customers who do not specifically opt out. This single on/off/part peak structure would be set in a GRC and, because of AB 327, would

[286] TURN OB at 59.

[287] The possibility of shifts in usage periods was dramatized in the famous "duck curve" in 2012 – the year this proceeding was opened. While historically the state has focused on reduction of the afternoon peak, the duck curve showed that an increasingly steep incline in the evening could soon become a larger problem. The duck curve is emblematic of the risk of solving for yesterday's problem.

hold constant for five years. In essence, customers on the default rate would move en masse with on/off peak periods designed to cover the exact time periods that were identified ~~5~~five years ago.

This assumption misses the entire point of default TOU.[288] TOU should be a flexible customer-empowering tool to make the load curve more manageable. As EDF describes it, using TOU to "increase customers' ability to be an active part of the grid will be critical to ensuring that California achieves its emission reductions, renewables and other landmark clean energy policies."[289]

Although it would be unrealistic to expect vast numbers of residential customers to accept a multi-period complex TOU structure today, there are structures and mechanisms that can be developed that will allow customer understanding of TOU, customer acceptance of the rate, and useful tools to assist in smoothing out the load curve.

Rate design has never limited itself to relying on soon-to-be-outdated data. Policy has long required utilities and the Commission to use creative approaches to develop reasonable and just rates that support state policy goals.

A wide-scale TOU rate for residential customers must be flexible enough to account for load shifts from year to year, while providing customers with certainty required by AB 327. This can be accomplished through the menu of rate options proposed by many parties, as well as a mechanism for regularly updating TOU periods while providing customers the certainty of a specific TOU period for five years. Default TOU periods and rate structure should take into account the most recent peak and off-peak periods as determined through the GRC or RDW process.

[288] As EDF put it, "one place where this conversation has been stilted is a failure to think about the rate diversity of customers." RT PGE RB at 72. Vol 23 at 3666, EDF/Fine.
[289] Exh. EDF-102 at 21.

Options for design of TOU rates that must be considered going forward include:

- a default TOU rate with mild differential intended only to minimize the impact of residential customers on peak periods;
- tranches of default TOU rates with complementary TOU periods that considered together address grid needs, but do not impose unreasonable hardship on individual customers; and
- changing the default rate for new customers annually to reflect new TOU periods, but allowing already enrolled customers to keep their legacy TOU period structure for the five year period suggested by AB 327.[290]

Each of these rate designs may pose challenges, but the record does not reflect any reasons not to explore them.

EDF envisions a menu of TOU rate options, including options to provide needed ramping resources to "manage intermittent renewables and the sunset."[291] EDF does not suggest a mechanism for these periodic adjustments to TOU periods and rates, but does suggest that using the current three-year GRC Phase 2 schedule would not be sufficient.[292] EDF cites the NEST thermostat as an example of emerging technologies that can "push new programming from a central desk without requiring the customer to be aware of peak price changes.[293] This suggests that with adequate education and enablement tools customers could respond to changes in TOU periods without needing to carefully track TOU period changes. Although this does not seem practical for the average residential customer in the immediate future, it does point to a promising future

[290] Through its experience with the PCIA, the Commission already has experience with rates that are vintaged by year. Similarly, ARB uses vintaging of cap and trade GHG allowances as part of its AB 32 compliance program.
[291] RT Vol. 23 at 3697, EDF/Fine
[292] RT Vol. 23 at 3698, EDF/Fine.
[293] RT Vol. 23 at 3699, EDF/Fine.

for a menu of TOU rates that can make meaningful needed impacts on the load curve.

Having a menu of alternative TOU and non-TOU rates for customers to choose from, and encouraging customers to be on the rate that is best suited for their energy use, would also reduce the percentage of energy use tied to a default TOU rate. This lets customers who are the most educated about rates take advantage of new and innovative rates and technologies to reduce use during periods with high prices (including real time pricing or matinee rates for customers who have the enthusiasm and interest).

Residential rate structures in other jurisdictions already offer a variety of TOU rate options with different TOU periods. For example, Salt River Project offers a variety of TOU rates, including one with a 1 – 8 p.m. peak and one with a 3 – 6 p.m. peak. Arizona Public Service offers three different TOU rates and two different TOU periods, Electricité de France has multiple TOU rates available with different TOU periods.[294]

EDF points out that if TOU periods are not adjusted over time, rates will not accurately reflect cost.[295] This argument also applies to allowing multiple TOU rates to co-exist at the same time. However, although there is tension between creating a strictly cost-based rate and allowing for changing TOU periods, a balance can be achieved between cost-causation and the goal of increasing reliability by having residential rates that reduce the peaks (or valleys) in the load curve.

As discussed above, TOU rates are not the same as real-time pricing, and they should not be assumed to reflect real time energy costs. Rather, they are

[294] Exh. PG&E-101 at 2-59 n.69(a).
[295] Exh. EDF 102 at 21.

rates created from averaging prices and costs over extended periods of time.[296] Rates are both cost-based and policy-based. TOU rates represent the average of hourly marginal costs over defined groups of hours with similar load characteristics, and can be set by a differential that sends a price signal. As such, unlike real-time pricing, the TOU approach is closer to being cost-based, and addresses the other RDP and the statutory requirements for residential TOU. This rate can be designed in a way to collect sufficient revenues from customers on TOU to cover their costs as a group and be revenue neutral with rest of residential class.

The process of identifying peak and off-peak periods for the purpose of setting TOU periods was intentionally removed from this proceeding. We note that to date the IOUs have allocated marginal generating capacity costs and recommended time periods based on their analysis of Loss of Load Expectation (LOLE), Loss of Load Probability (LOLP), and top 250 hours. The Long Term Procurement Proceeding (LTPP) already forecasts load curves for the purpose of assuring sufficient generation resources. Furthermore, the IEPR, released every two years by the CEC, with input from the CPUC and CAISO, forecasts future peak and total loads in order to provide more detailed analysis of load curves in the future.[297] We expect that going forward the IOUs will refine the process for identifying TOU periods for their residential rates. TOU periods will be identified in GRC Phase 2 or RDW proceedings for each utility, and the method

[296] *See, e.g.*, RT Vol. 12 at 1374, PG&E/Quadrini, (stating that TOU rates are difficult to get imme diate customer engagement because time of use is "over a very long period of time. And everything's averaged . . .").

[297] The CAISO has identified recommended TOU periods to address operational needs for 2020, but determining residential rate designs that are acceptable to customers remains subject to the protections of ratesetting proceedings at the Commission.

for selecting these hours will be based on the methodology for identifying peak/off peak periods adopted in that proceeding.[298]

We direct the IOUs to explore options and return with reasonable proposals as part of their Residential RDW application.

6.5. Concerns That Wide-Scale TOU Will Not Support Existing Economic Structures for Solar or IOU EE Programs

6.5.1. Energy Efficiency and Other Utility Programs

Some parties have expressed concern that EE and other demand side programs will be negatively impacted by TOU rates that reduce the monetary incentive for participation. For example, TOU rates could be in competition with a DR program. Another example is the difficulty in determining whether behavior changes incented by TOU rates or by EE behavior programs paid for by ratepayers.

Utilities have already invested ratepayer money in the technology necessary for TOU rates. They have been studying default and residential TOU for years at ratepayer expense.[299] As ORA points out, TOU rates will "better align" EE and DG benefits with IOUs' avoided costs."[300]

These special programs should not be the driver for rate design.[301]

[298] SEIA argues that TOU periods should be determined in GRC Phase 2 proceedings. "TOU periods are not just used for rate design, but are also integral assumptions used in calculating marginal costs and in allocating revenues among customer classes." SEIA OB at 33. It's important for Commission to have actual historical data, not just forecasts for setting TOU periods. *Ibid.*

[299] ORA OB at 85 (asking whether ratepayers should continue to fund such studies if they do not provide "lessons learned.").

[300] Exh. ORA-201 at 1-2.

[301] ORA OB at 85 (asking, "why should ratepayers continue to fund such studies?" if they do not provide some "lessons learned.").

6.5.2. Existing NEM and Rooftop Solar

Consistent with Public Utilities Code Section (Pub. Util. Code §) 2827, the Commission established NEM tariffs in 1995 to encourage the installation of distributed generation on the customer side of the meter. Customers who install and operate small (1 megawatt (MW) or less) renewable generation facilities that meet certain technical requirements were allowed to participate in a NEM tariff.

The NEM tariff is an overlay to the customer's otherwise applicable tariff. Under the NEM tariff customer-generators receive a financial credit for power generated by their on-site system that is fed back into the power grid. The financial credit is used to offset the customer-generator's electricity bill. The majority of NEM customers use on-site photovoltaic solar generators to provide some or all of their electricity, and feed power back to the power grid when they generate more than they need at a given time. The net surplus electricity compensation rate established by the Commission represents the amount paid by the utilities per kWh to procure power at peak times.[302]

Among other things, AB 327 requires the Commission to adopt a reasonable transition period for customers who took service under NEM tariffs before July 1, 2017 or prior to reaching the statutory net metering trigger level. D.14-03-041 established a transition period of 20 years from the date of interconnection of the customer's solar PV system.

In this proceeding the utilities have proposed to close certain existing optional tiered tariffs. PG&E proposes to close E-6 and EL-6 to new participants on January 1, 2015, and to eliminate E-7, EL-7, E-8 and EL-8 on January 1, 2016 and replace them with a new opt-in TOU rate schedule, E-TOU. E-7, EL-7, E-8

[302] On October 11, 2009, Governor Schwarzenegger signed into law AB 920, requiring California utilities to compensate NEM customers for electricity produced in excess of on-site load over a 12-month period ("net surplus compensation").

and EL-8 have been closed to new customers since 2008 and 2003, respectively. Customers on closed schedules E-6, EL-6, E-7, and EL-7 would be migrated to E-TOU and customers on closed schedules E-8 and EL-8 would be migrated to E-1/EL-1. SDG&E has two TOU rates that may be used by NEM customers: 1) DR-TOU, a three-tiered TOU rate with three TOU periods, and 2) DR-SES, a non-tiered rate with three TOU periods. SDG&E proposes new optional TOU rate schedules that are flat rates with three summer TOU periods. SDG&E's new tariff would also add a third winter tier and a Demand Differentiated Monthly Service Fee (DDMSF) instead of the existing small minimum bill. SCE's original proposal to eliminate its existing opt-in TOU rate schedule, TOU-D-T has been superseded by our recent decision, D.14-12-048, approving a settlement agreement in SCE's rate design window proceeding. Pursuant to D.14-12-048, SCE will keep TOU-D-T open until the effective date of the decision addressing SCE's 2018 GRC application.

Vote Solar, and SEIA argue that because the residential rate tariffs and the NEM tariff work jointly to determine a customer's bill, the Commission should require the utilities to retain all existing TOU rate schedules. They maintain that all TOU tariffs that are currently open to new customers should remain open and that the existing rate structures for these tariffs should be maintained (i.e., customer charges should not be added and tier differentials should not be adjusted).[303]

These parties argue that because solar customers made investments based on these rate structures and rate differentials, customers that are currently on TOU rates should be grandfathered onto those rate structures. Vote Solar argues that making significant changes to rate structures, by, for example, adding a new

[303] Exh. Vote Solar-101 at 4.

demand charge or customer charge, could have significant impacts on the customer's PV investment.

SEIA suggests that the Commission keep E-6 open to new customers and keep E-7 available to existing NEM customers and "evolve" both of these tariffs over a period of time to a simpler rate structure. SEIA supports gradual changes to E-7 to make it more revenue neutral with E-1, and changes to the tier structure of E-6 and E-7.

Under this proposal, rate schedules that are already closed, such as PG&E's E-7 and E-8, would remain closed, but existing customers could remain on those schedules with the existing rate schedules and rate structures unless they chose to migrate to another tariff. To the extent that the Commission decides to close currently open TOU tariffs, Vote Solar requests that the Commission grandfather those existing NEM customers that are currently taking service under the tariff and that grandfathered customers should be permitted to continue service on closed TOU rates for a period consistent with the payback period established by D.14-03-041.[304] This approach would allow grandfathered customers to remain on their existing TOU rate schedule for 20 years from the original year of interconnection of the renewable distributed generation system. Vote Solar emphasizes that the "rate levels" of any grandfathered tariffs would change only with adjustments in overall revenue requirements, and that the "rate structures" would remain the same for the life of the grandfathered TOU tariff.

Vote Solar also suggests that PG&E's proposal to close E-7 and E-8 is an impermissible collateral attack on prior Commission decisions, in violation of Section 1708 and would be unfair to NEM customers already grandfathered on those rates. They maintain that although E-7 and E-8 rates are not considered

[304] Vote Solar OB at 14.

revenue neutral, and are therefore subsidized rates, the rate principles identified by the Commission in this proceeding permit cross-subsidies where they are supported by explicit state policy goals. According to Vote Solar, residential customers should continue to be allowed to benefit from the policies and rate differentials provided by the Commission and the state at the time these customers made their decision to invest in residential solar.[305]

Finally, Vote Solar recommends that we adopt a "solar friendly" TOU option in addition to the utilities' proposed TOU rate options. The "solar friendly" TOU rate structure would consist of a "volumetric rate structure without a customer charge or minimum bill." Vote Solar's "solar friendly" option would also have a tiered rate structure with significant rate differentials between the top tier and lower-tier rates. The rate structure should be "revenue neutral with the default tariff."[306] Vote Solar suggests that this solar friendly tariff would encourage investment in PV and encourage these customers to select a TOU rate.

The utilities generally, and PG&E and SDG&E specifically, maintain that the Commission should permit them to close the existing tiered TOU tariffs. PG&E maintains that customers under both E-6 and E-7 are not fully covering their cost of service.[307] PG&E proposes to restructure E-6 in 2015 by adding a fixed customer charge and reducing the number of tiers from four to three. PG&E would then close E-6 in 2016, and customers would have the option of moving to its new E-TOU rate.

PG&E argues that the solar parties' proposal relies on the false assumption that customers have a reasonable expectation that their public utility rates will

[305] *Id.* at 22.
[306] Exh. Vote Solar-101 at 18.
[307] PG&E RB at 80.

never change in the future.[308] PG&E maintains that its E-6, E-7 and E-8 are far below cost and heavily subsidized by other customers.[309] PG&E explains that under the existing tiered TOU rates, low-usage customers' peak rates can actually be smaller than the off-peak rates paid by upper-tier usage customers, even though the cost to provide service to each is the same.

The solar parties describe E-6 as a "revenue-neutral" rate, but note that any undercollections are picked up by the larger residential class (E-1). However, they suggest that the undercollection may not be a subsidy because the E-6 population is considered lower cost to serve. [310] PG&E states that although E-6 was designed to be revenue neutral with the E-1 tariff, this is different from being cost-based.[311] E-6 was designed as if all residential customers were on E-6. In reality, there are a significant number of solar customers on E-6 who pay less than other customers, meaning E-6 is not revenue neutral on a customer basis, only on a class basis.[312]

The utilities' existing, optional TOU rates are similar to the existing default rates in that they are comprised mostly of volumetric rates with significant differentiation between upper and lower tiers and no or little minimum bill or fixed charge. At the time these optional TOU rates were developed and approved, tiered rates were required. The solar parties' proposals regarding optional TOU rates would generally perpetuate the cost-subsidies and inefficiencies associated with the existing steeply-tiered TOU rates. In this decision, we find that fewer tiers and more cost-based rates are appropriate for both default and TOU rates.

[308] PG&E OB at 70.
[309] *Id.* at 71.
[310] Vote Solar OB at 18.
[311] PG&E RB at 82.
[312] *Id.* at 83.

We also find the solar parties' contentions regarding customers' reliance on existing rates and rate structures to be unreasonable. In fact, while D.14-03-041 recognized that customers who invest in renewable generation systems and participate in NEM tariffs should have an opportunity to recoup their initial investment and allowed these customers to retain the benefit of the existing NEM tariff for 20 years, D.14-03-041 also specifically acknowledged that the rates and charges paid by a customer are dependent on the underlying residential tariff and confirmed that the instant proceeding "is expected to result in significant changes to the residential rate structure."[313] Vote Solar's reliance on D.06-12-025 as a precedent is also unreasonable, as that decision merely reopened existing TOU tariffs on an interim basis, pending a decision in PG&E's GRC. Moreover, as we described above, rates and rate structures change periodically, mostly gradually, through periodic revenue requirement and revenue allocation proceedings, but occasionally abruptly, as the Commission found necessary in D.01-05-064.

However, we are also sympathetic to the challenges faced by individual customers who have elected to install rooftop solar. As Vote Solar and others point out, these individual TOU customers may have made the investment in solar assuming that the TOU rate would not change. Rooftop solar installations are often designed to maximize generation during the TOU rate peak periods that were in place at the time of installation. In keeping with the RDPs of customer acceptance and energy efficiency, we believe the impact of changing or closing TOU tariffs should be mitigated. This is consistent with Section 745's recommendation that default TOU periods be designed to be appropriate for at least five years.

[313] D.14-03-041 at 17.

In this proceeding, we find it appropriate to approve PG&E's request to close E-6 in 2016, and PG&E's and SDG&E's requests for new TOU tariffs, consistent with our discussion above. We also approve PG&E's request to eliminate E-8. However, given the number of significant changes we are adopting, including tier flattening and increased use of fixed customer charges and minimum bills, and given the need for customer acceptance, we also find that the transition period from the closed E-6 and E-7 tariffs and SDG&E's TOU tariff should be five years from the date the tariff is closed to new customers. E-8 has been closed for well over five years and may be eliminated in 2016. The minimum bill or fixed charge approved for the default tariff must also apply to existing TOU rates including E-6 and E-7.

6.5.3. Revenue Shortfall and Structural Winners

6.5.3.1. Structural Winners and Losers

In this proceeding, the term "structural winner" refers to a customer who will see a reduced electricity bill by moving to TOU, without making any change in the time or quantity of their electricity use. Given that the current tiered rate structure relies on upper tier customers for the majority of the residential revenue requirement, there are many customers who will be structural winners on TOU rates.

In fact, structural winners will have a positive experience on TOU, making for greater customer acceptance. PG&E intends to market first to high usage customers who are more likely than low-usage customers to benefit from the TOU structure.

On the other hand, too many structural winners will mean an undercollection that needs to be recovered from somewhere.

Table comparing Peak/Offpeak rates with and without a baseline credit[314]

TOU schedules with 1.6:1 peak to off-peak differential	Off-Peak Summer up to 100% of Baseline	Peak Summer up to 100% of Baseline	Off-Peak Summer over 100% of Baseline	Peak Summer over 100% of Baseline
Baseline credit of roughly 4 cents	$0.194	$0.311	$0.233	$0.350
No baseline credit	$0.210	$0.336	$0.210	$0.336

6.5.3.2. **Revenue Shortfall**

A revenue shortfall occurs when the revenues collected from a group of customers is less than the revenue that was forecast. The revenue shortfall will be amortized and included in future rates to make up for the undercollection. A revenue shortfall between classes can result when, for example, residential customers as a whole use less power than predicted. Depending on the structure of the rate when implemented, the undercollected amount could then be recovered from just the residential class in future years, or it could be recovered from all customer classes.

In this proceeding we are primarily concerned with revenue shortfalls between different groups of customers within the residential class. The opt-in TOU rates are purportedly designed to be revenue neutral to the residential class, but, because historically the revenue collection has been premised on collecting more than cost of service from high-usage customers, it is likely that high-usage customers will shift to TOU and low-usage customers will remain on the tiered rate.

CforAT describes the revenue shortfall problem as follows: "Customers on TOU may pay less because (a) they are structural winners, or (b) they are able to

[314] This chart is based on the April 1, 2015, IOU supplemental filings. This example compares non-CARE customers in the same Climate Zone. It assumes that neither customer changes the times they use electricity. Assumes no monthly service fee.

shift load. In either case, these customers are paying less, resulting in reduced revenue for IOU. Even though reduced peak usage as a result of changed behavior is expected to reduce system costs in the long-run, in the meantime must collect the shortfall in some other way."[315] Revenue shortfall between tariffs arises "most starkly" when the TOU rate differs substantially from inefficient tiered rates.[316]

PG&E states that its proposed "E-TOU is designed to be revenue neutral in the sense that it is designed as if the entire residential population is on it. That makes it revenue neutral to the entire population."[317] However, PG&E estimates a revenue shortfall of $300 million if all residential customers who benefit from being on E-TOU switched. TURN asserts that PG&E E-TOU is therefore NOT revenue neutral.[318]

PG&E's potential $300 million revenue deficiency assumes that TOU customers do not change their usage patterns. If TOU customers shift load patterns to use less energy during peak periods, the revenue deficiency for PG&E would be even larger.

SDG&E estimated potential for $132 million in undercollections for non-CARE customers.[319] If there was a shift in customer usage, the figure would be larger.[320] SCE did not provide a specific estimate, but does state that it expects migration to TOU could result in a revenue deficiency.

Regardless of how one defines "revenue neutral rate," we find these estimates of possible revenue deficiencies should be addressed. We direct the

[315] CforAT OB at 73.
[316] SCE OB at 155.
[317] TURN OB at 52 (citing RT Vol. 12 at 1369, PG&E/Quadrini).
[318] *Ibid.*
[319] *Id.* at 51-52 (citing RT Vol. 14 at 1791-92, SDG&E/Fang).
[320] *Ibid.*

utilities to focus on reducing the potential for undercollection when designing TOU rates.

First, the IOUs should model a range of revenue deficiencies which can then be used to set a TOU rate that is more likely to meet its allotted revenue requirement.

Second, as discussed above, a baseline credit will make the TOU rate more appealing to low-usage customers.

Third, inclusion of a fixed charge in the TOU rate will reduce the risk of undercollection. Likewise, a revenue shortfall is less likely to occur once the tiered rate is closer to cost-based.[321]

In the event there is an undercollection, the recovery must be apportioned fairly. Until the magnitude of undercollection is better understood, any undercollection should be spread to the entire residential class.

SEIA proposes a "virtuous cycle" in which if there was an undercollection from the TOU customer group, the undercollection would be recovered from non-TOU residential customers. This would encourage enrollment in TOU, and would penalize the customers who remained on tiered rates.

CforAT argues that this would punish the very customers who are the least able to make adjustments to their time of use.[322] CforAT argues that many of these customers are low-income for whom it is already difficult to afford electricity. Even if low-income and low-usage are only somewhat correlated, there is still a group of low-usage low-income customers who may not be able shift load for TOU rate.

[321] PG&E RB at 79
[322] CforAT OB at 73.

SCE does not support "virtuous cycle" proposal.[323] SCE argues that before a "large-scale movement to cost-based TOU" it is essential to reform the tier structure.[324] Otherwise, customers who are under the currently "punitive" high tiers, will be the ones to be incented to move to TOU rates, resulting in significant undercollection from tiered rate customers as a group. The revenue shortfall solution adopted in SCE RDW A.13-12-015 will recover shortfalls from within the entire residential class over an appropriate period of time."[325] This is consistent with ORA's position, that "flattening or reducing the differential for residential tiered rates is helpful to prepare for default TOU rates."[326] PG&E also agrees with ORA that undercollection should be made up by the entire residential class.[327]

Although we agree that a virtuous cycle would make the TOU rate more attractive, we agree with SCE, ORA and CforAT that recovery from the entire residential class is the only fair solution until such time as the IOUs can demonstrate a reduced risk of undercollection.

6.5.4. Impact of Load Reduction on Cost Savings and GHG Reduction not Demonstrated

Intuitively, TOU is assumed to reduce peak usage, thereby eliminating the peak periods during which expensive, higher polluting generation resources must be brought online. This in turn should result in reduced infrastructure costs and GHG emissions would be reduced because California will be able to make better use of the cleanest energy sources.

[323] SCE RB at 87 n.328.
[324] SCE OB at 150.
[325] ORA OB at 65 (citing D.14-12-048).
[326] RT Vol. 22 at 3475, ORA/Kao.
[327] PG&E RB at 79.

As we noted at the beginning of this decision, there are few studies that actually evaluate and document these expected benefits.

For example, no studies were cited in this proceeding that demonstrate a clear correlation between reduced peak use and reduced GHG emissions. Indeed, TURN's analysis suggests that GHG emissions could increase as a result of increased use of out-of-state coal to support shifts in energy use.

Similarly, the estimates of long-term cost-savings rely on many assumptions and further study would be necessary for a decision could rely on specific cost-savings estimates.

We certainly agree with parties that the available evidence on these issues is disappointingly inconclusive. However, this is not a reason to put off large-scale roll out of TOU. Instead, we direct the IOUs, as part of Residential RDW application, to prepare better studies of the potential for cost savings and GHG reduction. To ensure that the studies are truly useful to the Commission, other parties, and the public, we direct the utilities to design the studies in consultation with Energy Division and interested parties, as part of Phase 3 of this proceeding.

6.6. TOU Pilots and Optional Tariffs

6.6.1. What Should be Studied in TOU Pilots and Optional Tariffs?

Throughout this proceeding, in written testimony, briefs and other filings, and in evidentiary hearings, parties have identified many categories of information to consider for residential TOU. Here is a partial list.

- Peak period length and times for the on-peak period.[328]

[328] SDG&E RB at 27.

- Most effective way to communicate and implement TOU programs.[329]
- Customer adoption and retention rates.
- Costs of educating customers and responding to inquiries.
- Effective means of educating and recruiting customers for TOU optional rates.
- Pattern in usage shift owing to migrations from tiered rates to TOU rates.[330]
- Estimating revenue shortfall.[331]
- Opt in pilot should use randomized treatment design to simulate benefits of a default pilot.[332]
- Cost estimates for outreach, education, marketing, billing and IT modifications.
- Quantify variability of bill and load impacts across key geographic, demographic and segments as well as for varying rate designs and outreach messaging.[333]
- Section 745 requirements.
- Different peak period hours and price-ratio combinations to test differences in customer acceptance and engagement under each variation.[334]
- Model range of revenue deficiencies based on different assumed levels of adoption and levels of migration between optional and default tariffs.[335]
- Comparing TOU opt in structures and acceptance by Climate Zone.[336]

[329] ORA OB at 70.
[330] *Id.* at 71 (citing SCE OB on legality of pre-2018 default pilot).
[331] CforAT OB at 4-5, 72-79.
[332] ORA OB at 71 (citing SDG&E OB on legality of pre-2018 default pilot).
[333] *Id.* at 72 (citing PG&E opt-in pilot description).
[334] PG&E OB at 63; *id.* at 67 (citing Exh. PG&E-109 at 5-7; RT Vol. 12 at 1423 PG&E/Mandelman).
[335] TURN OB at 53.
[336] RT Vol. 12 at 1423, PG&E/Mandelman.

- Identify customers to be categorically exempted from default TOU.
- Time period over which a mild TOU differential become more cost-based.
- Load reduction in relation to relatively low (44%) AC saturation.[337]
- Marketing message to gain engagement with diverse customer segments.[338]
- Effectiveness of marketing, education and outreach for non-English speakers.
- Lessons to reduce costs for wider-scale outreach and operations.[339]
- Test system operationality.[340]
- Effective marketing, education and outreach for customers with and without AC.
- Test comparative rate presentation to develop most effective presentation.
- Long-term implications of different rate structures on the load forecasts used in distribution planning and on the procurement of new generation resources.[341]
- Long-term revenue requirement implications of different rate structures both in terms of stranded assets and future new investments.
- Tradeoffs between energy bill consequences and incentives for private investment in Distributed Energy Resources.

[337] PG&E OB at 65.
[338] *Ibid.*
[339] *Ibid.*
[340] *Ibid.*
[341] Exh. EDF-101 at 26..

6.6.1.1. Default TOU Pilots Generally

AB 327 authorized default TOU as early as 2018, provided that certain requirements are met. ORA, Sierra Club, and EDF contend that default TOU should start in 2018, without a separate TOU Pilot.

However, a number of active parties argue for a two-year default pilot prior to any large-scale implementation of default TOU.[342] These parties state that a default TOU pilot would allow further study of the topics above. Their proposal would also significantly delay any move to default TOU without any assurance of progress being made toward an improved rate design

While the timeline proposed by these parties would prevent default TOU from being implemented earlier than 2022 (or more likely, 2023), the parties did not offer any specific objectives or criteria for evaluating TOU during this period of time. The timeline included one year to design a pilot, an advice letter for approval, and then another nine months during which no activity was specified, but no progress would be made toward better understanding default TOU.

We find that this proposed timeline is not reasonable. However, we recognize that agreement between diverse parties on an approach to default TOU design has significant value. We find that a collaborative approach, such as that recommended by the parties, will benefit the design and roll out of default TOU.

We therefore authorize and direct a working group to develop study parameters and pilot design on a more expedited schedule. We expressly authorize the working group to select a consultant, to be hired by the IOUs, to advise on and document the study parameters and pilot designs. We expect

[342] *See* Joint Motion for Admission of Joint Exhibit 101 into Evidence filed December 2, 2014; *see also* SCE OB at 151; PG&E OB at 7, 63-66; SEIA OB at 34-35; TURN OB at 53-55, 82-85; UCAN OB at 5, 33-37; CforAT OB at 4-5, 77-79; Vote Solar OB at 25-26; CUE OB at 4-5; IREC OB at 27-28; TASC RB at 23; *cf.* SDG&E OB at 59-62 (although SDG&E did not support all aspects of the specific proposal of the first 10 parties to the joint proposal).

parties, including ORA, to work together to form the working group and report back at the first Phase 3 PHC. We expect the process of pilot design to be completed in 2015, and submitted for approval by each utility through a ~~tier~~Tier 3 advice letter.

6.6.1.2. Is Default TOU Pilot Required by Statute?

SB 1090, passed in 2014, added new conditions to be met prior to authorizing or requiring default TOU. The Commission must consider "the extent to which hardship will be caused on . . . customers located in hot, inland areas, assuming no change in overall usage by those customers during peak periods [and] [r]esidential customers living in areas with hot summer weather, as a result of seasonal bill volatility, assuming no change in summertime usage or in usage during peak periods."[343]

TURN asserts that this language should be interpreted to require a default pilot prior to any "commitment to transition to default TOU rates."[344] The language of the statute requires the findings to be made prior to *authorizing or requiring* the utilities to *employ* TOU rates. The statute does not preclude the Commission from ordering the IOUs to file default TOU rates, provided that the SB 1090 analysis is completed before default rates are authorized or required to be employed.

TURN correctly points out that, "At this time, there is no basis for the Commission [to] conclude that these requirements have been satisfied . . ."[345] but this is not the finding we must make before taking the next step toward default TOU. If TURN were correct, and the Commission had to make these additional findings before any step toward default TOU, this would effectively prevent any

[343] Section 745(d).
[344] TURN OB at 53.
[345] *Ibid.*

step toward default TOU. If this is what the legislature intended, they would have drafted the statute with more clarity. We understand the legislature's intent in passing SB 1090 is require a study to prevent hardship to customers in hot areas before any wide-scale default TOU rates are implemented.

The record for this proceeding includes only limited information on the SB 1090 findings as well as other important areas that should be studied before the utilities employ default TOU. We agree with TURN that it is important to study these impacts and determine how to mitigate them before default TOU is employed. On the other hand, we do not believe that the Legislature intended SB 1090 to create an infinite loop that would prevent default TOU from ever being implemented. Rather, the legislature seeks to have certain study done before default TOU is implemented to protect customers. We direct the utilities to take steps toward implementing default TOU rates, including performing the statutorily-required studies and studies that will provide important information about customer acceptance and response to TOU rates.

TURN cites SDG&E's witness Winn stating that a default pilot would be would be useful to make sure that time of use was implemented properly, and that because of SB 1090 SDG&E was seeking to implement default TOU only after default TOU pilot.[346] TURN cites SDG&E witness Winn and Willoughby as "needing insight from 2018 pilot."[347]

Similarly, SDG&E's witness George said that the SMUD study should not be relied on as the basis of default TOU.[348] George cites the need to test demand response in the absence of selection bias.[349]

[346] SDG&E OB at 60 (citing RT Vol. 13 at 1573-74, SDG&E/Winn).
[347] RT Vol. 15 at 1972, SDG&E/Willoughby.
[348] RT Vol. 16 at 2139-2144, 2181, SDG&E/George.
[349] SDG&E OB at 61.

Selection bias will primarily address shifts in load, or other changes in load, that are a response to the new TOU rate. As has been shown, customers who opt-in to TOU rates are often more responsive than customers who are defaulted. However, the amount of load flattening that can be achieved by residential TOU will take time to assess. The immediate goal of default TOU is customer acceptance and education.

Despite the arguments of several parties, we are not convinced that a default TOU pilot is necessary. Had these parties demonstrated that there were significant benefits of a default pilot compared to the current optional rates and pilots, then further consideration of their argument might be warranted. As ORA points out, these parties do not provide any details or explanations how such data would be developed or used to meet Section 745.[350] In addition, these parties do not address the fact that their proposal will be expensive and cause a delay in implementation of default TOU. Although we agree with their arguments that a default TOU pilot could provide additional data, the record does not show that the additional data would be beneficial or necessary.

It is not necessary to have default pilot to determine if TOU rates would impose a hardship on certain customer groups.[351] SB 1090 requires evidence to be gathered that *assumes no change in usage*. None of the parties advocating a default TOU pilot prior to default TOU have explained how information gathered from the pilot could provide information that is more informative on the SB 1090 findings than analysis of existing usage data. The utilities already have the data necessary to evaluate how customer bills would have differed if they had been on TOU instead of tiered rates. In contrast, an attempt to use a default TOU pilot to obtain this data would be skewed by customers who change their usage pattern

[350] ORA RB at 27.
[351] *Id.* at 28.

as a result of knowing they are on a TOU rate. Thus the best data to use is the data that already exists.

After careful review, we find that only a few of the recommended study topics would require a default TOU. These topics can and should be studied on an ongoing basis once default TOU is implemented. We expect that the design of TOU rates will need to be monitored and updated on an ongoing basis, and these studies will assist with that process. Notably, systems operability, customer retention rates and load shift will be best studied using a default TOU pilot.

However, because we agree there are benefits to default TOU pilots, we require each IOU to include a default TOU rate in its design of pilots approved by this decision. The purpose of this default TOU pilot will be primarily to study aspects of TOU that are directly impacted by the self-selection bias, and to fine-tune customer education and test system operability prior to full rollout of default TOU.

We agree with TURN that the determination of whether default TOU rate structure complies with statute is a "fact-specific analysis"[352] that cannot be completed on the record of this proceeding. We therefore find it is imperative that the IOUs promptly take the next steps to propose default TOU rates and to develop benchmarks and prepare evidence to properly evaluate the proposals.

PG&E points out that the language of Section 745 needs to be clarified before we can determine if findings are made. Specifically, uses terms like "senior citizen" "hardship" and economically vulnerable customers" and "hot climate zones."[353] Clarifying these terms will not happen through a default TOU. Rather, needs to be done by the Commission through this proceeding at an

[352] TURN OB at 54-55.
[353] PG&E RB at 85-87.

earlier date. PG&E recommends it be done through the "collaborative workshop process."[354] This issue will be addressed in Phase 3.

6.7. Default TOU Progress Reporting

Despite the installation of sufficient AMI technology over the last five years, PG&E and SCE have established a pattern of avoiding wide deployment of residential TOU. Despite the fact that this proceeding to examine time-variant rates was opened more than two years ago, and prior proceedings[355] stated that it is Commission policy to encourage time-variant pricing, and despite the fact that in 2012 the legislature passed AB 327 which expressly permits implementation of default TOU, the utilities have taken remarkably few steps in that direction

In this proceeding, we directed the IOUs to provide us with a roadmap for the years from 2016 through 2018. Only SDG&E proposed default TOU for 2018. By the time of evidentiary hearings, SDG&E had determined that it would not seek authorization of default TOU in this proceeding. No party provided evidentiary support for specific TOU structures.

During Evidentiary Hearings and in briefs PG&E and SCE estimated that it would take a minimum of 18 months to design a default TOU, and an additional 24 months to implement it. Meanwhile, IOUs could implement a fixed charge in 30 days. Meanwhile, IOUs could implement a fixed charge in 30 days. In a world where the NEST programmable thermostat was the most hyped tech holiday gift for 2014,[356] the argument that it takes three years to design a pilot that could lead to increasing participation in TOU to meaningful levels is not reasonable.

[354] *Id*. at 86.
[355] *See*, e.g., D.08-07-045; R.02-06-001; A.07-12-009.
[356] http://www.extremetech.com/extreme/194595-extremetechs-2014-holiday-gift-guide-high-tech-futuristic-gift-ideas-for-geeks-and-nerds.

The parties propose two different timelines for default TOU: (i) default TOU starting in for all customers in 2018 (ORA), and (ii) default TOU starting after a default TOU pilot and additional hearings (the ten parties).

We agree with ORA that the record does not reflect any basis for delaying default TOU past 2018. Additional procedural steps are necessary, however, before default TOU rates can be employed. Based on this, we find that default TOU rates should begin in 2019.

The benefits of TOU are well-documented, as is the fact that enrollment in an opt-in TOU rate is slow, making default TOU the strongest option for demand response. But the details of implementing default TOU in California need further study and refinement. We are confident that California's IOUs can accomplish the needed study and propose appropriate default TOU rates for 2019.

We therefore direct the IOUs to begin preparing a residential rate design window application to be filed January 1, 2018 with the goal of review and approval no later than December 1, 2018.

Based on the record in this proceeding, however, the IOUs will need much collaborative assistance to help them meet that goal.

We believe that the utilities must be held to a strict timeline for evaluating default TOU, and that the IOUs must do more than file regular progress reports. As described in the Next Steps section, progress towards default TOU must be considered in the overall context of residential rates. For this reason, we direct the IOUs to hold an annual residential rates forum to report on the status of residential rate reform in their service territory. The annual Residential Electric Rate Summit (RERS) will be held each fall, beginning in 2015.

6.8. Opt-In TOU Rates Proposed in This Proceeding

6.8.1. Existing Opt-In TOU Tariffs and Pilots

As discussed above, the utilities already have optional TOU rates for residential customers. Because prior to AB 327 all residential rates were required to be tiered, existing TOU rates included a complex system of tiered and TOU rates for different times of the day and month. In this proceeding we directed the IOUs to offer untiered TOU rates.

The current tiered TOU rates are confusing and result in counter-intuitive rates. PG&E provides an example of its current tiered TOU rate which for Summer has three different time periods and twelve different rates to keep track of. "For example, a customer could desire, on the 26th of the month to use outdoor lighting to enhance night time security between the hours of 2:00 a.m. and 4:00 a.m. However, because it is near the end of the month, this customer is required to pay a high tiered rate that bears no absolutely no relation to the actual cost."[357]

Example of the Twelve Separate Rates with Current TOU[358]

Summer Energy Rate	Peak	Part-Peak	Off-Peak
Baseline Usage	0.287	0.175	0.101
101 – 130% of BQ	0.305	0.193	0.119
131%-200% of BQ	0.478	0.366	0.291
Over 200% of BQ	0.518	0.406	0.331

On the other hand, a baseline credit (or excess usage surcharge) can be considered a tiered rate because the customer pays two rates: a lower rate for low usage kWh, and a higher rate for kWh usage. Parties have argued both that any tiering is confusing for the customer and that a baseline credit is not

[357] Exh. PG&E-101 at 2-54.
[358] *Ibid.* (Table 2-11).

confusing. As discussed above, we find that a baseline credit is an important part of TOU rate design. In addition, situations such as the one described by PG&E will not arise when the second tier is structured as a consistent surcharge or credit.

TURN's testimony included a mock TOU bill that includes a baseline tier and two higher tiers.[359] The mock TOU bill would be even easier to understand if it included only a baseline tier.

Figure 2: Exemplary Bill Format for TOU Rate with Baseline Credit Based on SDG&E Bill

ELECTRIC CHARGES — Amounts ($)

Electricity Delivery (Details below) 500 kWh

SUMMER USAGE	Baseline	1-30% over Baseline	31-100% over Baseline	More than 100% over Baseline		
kWh used	336	101	63			
kWh used	$.03919	$.05996	$.18655			
Charge	$13.17	$6.04	$11.79		=	$31.00

DWR Bond Charge 500 kWh x $0.00515 = $ 2.58

Electricity Generation (Details below) 500 kWh

SUMMER USAGE	On-Peak	Semi-Peak	Off-Peak	Peak Shift Period Adder		
kWh used	114	147	239	13		
kWh used	$.08500	$.07146	$.05570	$0.91000		
Charge	$9.69	$10.51	$18.84	$11.83	=	$45.34

Total Electric Charges $78.91

TAXES AND FEES ON ELECTRIC CHARGES — Amounts ($)

use same format as SDG&E's existing bills; Attachment RWH-6 bills are formatted similarly to existing bills[2]

Each of the IOUs already has some options for residential customers to enroll in TOU rates. Changes to these existing TOU rates and periods and for new TOU rate options are currently under review in other proceedings, and some new TOU rates have been approved while R.12-06-013 has been pending.

[359] Exh. TURN-201 at 62.

Given the priority to study these optional TOU rates in order to design better default TOU rates, it is essential that the utilities now establish a consistent approach to implementing, studying and closing optional TOU rates.

Based on the record in this proceeding, we direct the utilities to follow the following TOU opt-in rate design guidelines going forward:

(1) Offer a menu of different residential rates designed to appeal to a variety of residential customers.

(2) Include baseline credit in at least one opt-in TOU rate.

(3) Changes to TOU periods should be made in rate design windows or GRC Phase 2 proceedings.

(4) TOU tariffs should include a legacy provision that allows subscribers to remain on their existing TOU tariff (with its original TOU periods) for at least five years. When TOU tariffs are closed, they must be discontinued gradually. The discontinued tariff should be closed to new customers. Existing customers (legacy tariff customers) should be permitted to remain on their TOU tariff for the longer of (i) five years from the date of enrollment, or (ii) one year after tariff has been terminated (the legacy tariff term).

(5) SDG&E's DDMSF TOU pilot proposal should not be implemented until further study of standard TOU rates is accomplished.

6.8.2. PG&E Proposed Opt-In TOU Rate and Proposed TOU Pilot

PG&E proposes to introduce a new opt-in TOU rate without tiers: Schedule E-TOU (for non-CARE households) and Schedule E-TOU CARE (for CARE households).[360] PG&E states that it wants E-TOU to be a non-tiered rate as it "provides more accurate price signals, better incents load shifting and is easier for customers to understand."[361]

[360] Exh. PG&E-101 at 2-52.
[361] *Id*. at 2-53.

There would only be two periods (peak and off-peak) during two seasons (summer and winter). PG&E proposed to use the same TOU periods as Schedule E-6. E-TOU would be a seasonally differentiated rate, with different rates and peak periods for Summer and Winter.

Summer Peak: 1 pm – 7 pm, weekdays (except holidays)

Summer Off-Peak: all other Summer hours.

Winter Peak: 5 pm – 8 pm, weekdays (except holidays)

Winter Off-Peak: all other Winter hours.[362] [363]

The E-TOU schedule would include a $5/month service fee, and E-TOU CARE would include a $2.50/month service fee.[364]

PG&E proposes a price differential between periods that is equal to the difference in the marginal costs per kWh for each respective time period.[365] PG&E states that this is the same methodology used for E-6. The table below shows an illustrative 2015 rate. For non-CARE rates, the differential between Summer peak and off-peak is approximately 1.75:1, and for Winter the rates are 1.1:1.

Illustrative E-TOU Rates[366]

Non-CARE	**Monthly Service Fee**	**On-Peak Rate**	**Off-Peak Rate**
Summer	$5	$0.319	$0.182
Winter	$5	$0.183	$0.169
CARE	**Monthly Service Fee**	**On-Peak Rate**	**Off-Peak Rate**
Summer	$2.50	$0.207	$0.118
Winter	$2.50	$0.119	$0.110

[362] *See* A.14-11-014.

[363] PG&E filed its rate change proposal in this proceeding in February 2014. Currently, PG&E has a rate design window pending in which it requests that the TOU periods for E-TOU (once E-TOU is approved) be modified to have a peak period of 4-9 p.m., weekdays, with a summer period of June – September.

[364] Exh. PG&E-101 at 2-5.

[365] *Id.* at 2-53.

[366] *Ibid.*

PG&E did not include a definition of summer and winter in its testimony, but review of E-6 Tariff shows that the current definitions are: Summer: May 1-October 31st and Winter: November 1-April 30th.[367]

PG&E did not provide details on the methodology used to arrive at the "marginal costs per kWh."

PG&E describes the E-TOU rate as "revenue neutral" but did not provide details on how undercollections from E-TOU would be collected. As noted above, given the current steeply tiered rate structure, undercollections could be significant.

The E-TOU is fully ~~un-tiered~~untiered and does not include a baseline credit. As discussed above, we find that a baseline credit (which may be presented as an excess usage surcharge) is an essential aspect of residential TOU given the migration risk caused by the current steeply tiered default rate. In addition, it is essential that all IOUs begin studying residential TOU rates with a focus on TOU periods, duration of TOU periods, customer acceptance and customer response. Finally, the baseline credit is a means to make TOU a reasonable alternative to the default tiered rates for low-usage customers.

We agree with PG&E that E-TOU rate will support movement of more customers to time-variant rates.[368] Based on the evidence in this proceeding, we agree that a two-period TOU rate will be the most understandable and acceptable to residential customers. Therefore, we believe that PG&E E-TOU proposal, as modified below, is reasonable, fair and consistent with the law.

We approve PG&E's proposed E-TOU rate with the following modifications:

[367] PG&E Schedule E-6 at Sheet 4.
[368] PG&E OB at 55.

- Undercollections can be made from the residential rate class as whole over a reasonable amortization period.
- Time periods offered must remain available to customers for a minimum of five years after enrollment, but can be modified through RDW or GRC process for future customers.
- So that we can better understand the degree to which E-TOU rate is cost-based, going forward PG&E must provide documentation of marginal cost of kWh it is using in setting the TOU rates.
- Enrollment can be capped if migration from tiered default rate to E-TOU suggests that a significant revenue shortfall is likely. PG&E must file a Tier 2 Advice Letter to request a cap.
- E-TOU must include a baseline credit.

PG&E proposes a two-phase TOU pilot. The first phase would be an optional rate, beginning as early as 2016, and the second phase would be a default rate.[369] PG&E states that it will use the pilots to study "how PG&E's 4.7 million residential customers might respond to mass market implementation of TOU rates (whether opt-in or default), and thus what rate structure, communications and operational preparations are advisable to achieve a widespread and successful PG&E TOU program in the future."[370]

For PG&E's TOU pilots, we direct them to be designed to allow study of TOU as further determined through the workshop process set forth in Section 11. The pilot design should include both opt-in and default TOU.

6.8.3. SDG&E Proposed Opt-In TOU Rate and TOU Pilots

SDG&E proposes a new, optional, ~~un-tiered~~untiered TOU rate beginning in 2015. Unlike the other TOU rates discussed in this decision, the SDG&E Opt-In rate would consist of a volumetric TOU rate designed to recover commodity costs **and** a DDMSF for the recovery of distribution and demand

[369] *Id.* at 63.
[370] *Ibid.*

costs. Demand differentiated rates are used in the commercial setting, but SDG&E is the only party to propose that demand-differentiated rates should be used for residential customers.

SDG&E argues that including a DDMSF would result in a rate that is more reflective of cost. If customers response to the DDMSF price signal as SDG&E hopes, it would result in reductions of coincident and non-coincident demand.[371]

SDG&E's proposed DDMSF would be a fixed $/month adder and would vary by the level of a customer's non-coincident demand (for example, 0-3kW = $X, 3-6kW = $Y, etc.). SDG&E proposes to apply the DDMSF to a customer's monthly hourly maximum demand. SDG&E proposes to institute a super-off peak exemption for the DDMSF, explaining that "demand during the super off-peak period would be excluded from the determination of maximum demand for the application of DDMSF."[372]

SDG&E argues that its proposed optional TOU rate would provide a more accurate price signal than either the default TOU rate or the optional tiered rate and would lead to greater reductions in coincident and non-coincident demand. SDG&E also contends that the optional TOU rate would give customers more ways to reduce their bills; in addition to reducing usage, customers could also shift the time of day they use electricity and/or level out load.

As shown in the table below, SDG&E's illustrative DDMSF could be over $70 for some residential customers. The corresponding volumetric rate would be much lower. Several parties argue that this type of high monthly service fee would be too large, and the methodology too complex for residential customers to readily accept it.[373] To understand the calculation of the demand charge a

[371] SDG&E OB at 53.
[372] Exh. SDG&E-108 at CF-48/Fang.
[373] TURN OB at 47.

customer must understand the difference between energy (kilowatt hours) and capacity (kilowatts). TURN points out that even SDG&E witness Winn admitted that few residential customers understand the difference between energy and capacity.[374]

Table CF-12: SDG&E Proposed DDMSF for Optional and Experimental TOU Proposals[375]

Max kW range	Customer Costs ($/month)	Distribution Demand Costs ($/month)	Proposed Monthly Service Fee ($/month)
Up to 3kW	$14.56	$13.29	$27.84
3kW up to 6kW	$14.56	$33.97	$48.53
6 kW and above	$14.56	$65.15	$79.71

We commend SDG&E for its willingness to explore the variety of TOU rates, at this time the focus of residential TOU must be on studying rate designs with volumetric TOU rates and fixed charges as set forth in AB 327. The rate component variables for study at this time are price differential between periods, number of periods, duration of time of periods. For this reason, we do not authorize SDG&E to start DDMSF pilots at this time. Instead, we direct SDG&E to first focus on pilots that will allow it to study the impact of volumetric TOU rate without a separate demand charge.

In its 2015 RDW (A. 14-01-027), SDG&E proposed changes to its current TOU periods, specifically to "change the current off-peak period to a super off--peak period previously available only to EV rates."[376] According to the A.14-01-027 Testimony of David Barker (which was submitted as an Appendix to SDG&E's Supplemental Testimony in this proceeding), SDG&E's proposed TOU periods are:

[374] *Id.* at 48-49 (citing RT Vol. 13 at 1565-70, SDG&E/Winn).
[375] Exh. SDG&E-108 at CF-2/Fang.
[376] Exh. SDG&E-107 at CF-43/Fang.

Summer on-peak: 2 p.m. – 9 p.m. non-holiday weekdays

Winter on-peak: 5 p.m. - 9 p.m. non-holiday weekdays

Super off-peak: 12 a.m. – 6 a.m. daily

Semi-peak: All other times

SDG&E also proposes to add two experimental TOU rates in 2015, in order to study customer response to different TOU structures. These rates will have shorter summer on-peak periods (four hours as opposed to seven hours); Experimental TOU A has a proposed summer on-peak from 2~~pm~~ p.m.-6~~pm~~ p.m. and Experimental TOU B has a proposed summer on-peak from 5~~pm~~ p.m.-9~~pm~~ p.m. The off-peak periods for summer and winter would be the same across all three optional TOU rates.[377]

SDG&E's proposed rates for its experimental TOU rates would be the same as its optional TOU rates and would include the DDMSF, except with a higher summer on-peak period rate to "reflect the recovery of equivalent costs through the shorter" period.[378]

Proposed Optional and Experimental TOU Rates with 2015 RDW TOU Periods[379]

TOU Period	Optional TOU - Proposed Rate (cents/kWh)	Experimental TOU – Proposed Rate (cents/kWh)
On-Peak: Summer	17.9	27.9
Semi-Peak: Summer	15.2	15.2
Super Off-Peak: Summer	11.1	11.1
On-Peak: Winter	11.3	11.3
Semi-Peak: Winter	10.0	10.0
Super Off-Peak: Winter	8.7	8.7

[377] Exh. SDG&E-111 at LW-4/Willoughby.
[378] Exh. SDG&E-108 at CF-3/Fang.
[379] *Id.* at CF-4/Fang.

SDG&E proposes to recover any undercollection from the pilots and opt-in TOU from the residential class as a whole. For the reasons set forth above, we agree that this is the appropriate treatment of revenue undercollections at this time. In order to mitigate the risks of too many high-usage customers migrating to these optional TOU rates, we direct SDG&E to monitor enrollment. SDG&E should filed a Tier 2 advice letter to cap the opt-in and pilot rates in the event that significant undercollection is likely.

SDG&E's proposed TOU rate is more complex than the PG&E opt-in TOU rate. Like PG&E's E-TOU, it is seasonally differentiated, and it does not include a baseline credit. Unlike PG&E's E-TOU, it has more than two time periods. As noted, the record shows that customers generally prefer simpler rates. Nonetheless, because the purpose of this TOU pilot is to study customer acceptance and response, we agree that more than three TOU periods may be acceptable. We direct SDG&E to take the steps necessary to offer this TOU pilot to its customers as early as possible. However, we approve it with the following modifications/clarifications:

- No DDMSF
- Undercollections can be made from the residential rate class as whole over a reasonable amortization period.
- Time periods offered must remain available to customers for a minimum of five years after enrollment, but can be modified through RDW or GRC process for future customers.
- So that we can better understand the degree to which residential TOU rates are cost-based, going forward SDG&E must provide documentation of marginal cost of kWh it is using to set the TOU rates.
- Enrollment can be capped if migration from tiered default rate to the opt-in TOU rate suggests that a significant revenue shortfall is likely. SDG&E must file a Tier 2 Advice Letter to request a cap.

- At least one opt-in tariff must include a baseline credit.

For SDG&E's pilots, we direct them to be designed to allow study of TOU as further determined through the workshop process set forth in Section 11. The pilot design should include both opt-in and default TOU.

6.8.4. SCE Proposed Opt-In TOU Rate and TOU Pilots

A new, optional, untiered TOU rates became effective for SCE residential customers in 2015.[380] [381] The new rate has three time of use which do not differ by season.

On-Peak	Super Off-Peak Period	Off-peak
2-8 weekdays except holidays	10 pm to 8am	All other hours

The new rate, TOU-D, has options for both low usage and high usage customers. Option A, for low-usage customers, includes a small customer charge equal to that of SCE's default residential rate and a baseline credit.

The baseline credit is set using customers' baseline zone allocations (in kWh) multiplied by a cent-per-kilowatt value established as the difference between the average of the non-baseline energy rate(s) of the default rate, and the Tier 1 energy rates.[382]

Option B, for higher usage customers such as EV owners, has less differentiated summer and winter peak periods, no baseline credit, and a $16 monthly fixed charge. SCE stated that these features will provide seasonal bill stability for Option B customers. CARE customers who choose TOU-D will receive a 30% discount off their total bill.

[380] *See* A.13-12-015 (2013 Rate Design Window).
[381] Exh. SCE-101 E-33.
[382] A.13-12-015, Joint Motion for Approval of Settlement Agreement, August 14, 2014, Appendix A (Settlement Agreement Resolving SCE's 2013 Rate Design Window Application § 4(e)(iii)(c)).

A.13-12-015 was settled by the parties. The settlement addressed the concern regarding deficiency from customers moving from SCE's default residential rate to TOU-D by setting an initially cap open enrollment on TOU-D to 200,000 customers. SCE is permitted to seek a higher enrollment cap in a future Rate Design Window or GRC Phase II.[383]

For consistency with SDG&E and PG&E opt-in TOU, we direct SCE to ensure that the following terms are addressed by its opt-in TOU tariff program.

- Undercollections can be made from the residential rate class as whole over a reasonable amortization period.
- Time periods offered must remain available to customers for a minimum of five years after enrollment, but can be modified through RDW or GRC process for future customers.
- So that we can better understand the degree to which residential TOU rates are cost-based, going forward SCE must provide documentation of marginal cost of kWh it is using in setting the TOU rates.
- At least one opt-in tariff must include a baseline credit.

SCE did not propose an opt-in TOU pilot for 2015. We therefore direct SCE to develop a TOU pilot on the terms similar to PG&E's and SDG&E's proposed pilots.

7. Recovery of Customer Fixed Costs Through Monthly Service Fee

7.1. Generally

7.1.1. A Fixed Charge is Reasonable for Fair Residential Rate Design

Currently, fixed costs are included in volumetric rates. There are two problems with this approach. First, high use customers are paying more than

[383] *Id.* at § 4(e)(iii)(a).

their share of fixed costs. Second, NEM customers and vacation home owners often do not have volumetric usage and thus often do not pay anything towards fixed costs incurred on their behalf.

The first problem, the subsidy, cannot be solved until a fixed charge is implemented and this decision sets forth the timeline for doing so.

The second problem, customers with little or no usage not paying anything toward recovery of fixed costs can be resolved with a minimum bill.

Parties generally agree that the cost of providing electric service to residential customers has both fixed and variable elements. No party in this proceeding denies that utilities have fixed costs, or the existence of customer-related fixed costs. Instead, the debate centers on how the utilities should recover these fixed costs.

Currently, for residential customers, the vast majority of the utility's costs, including those that do not vary with usage, are collected through variable energy charges. In this proceeding, each of the utilities has proposed a new or increased "fixed charge" or "monthly service fee" designed to collect certain fixed costs from all residential customers. The utilities maintain that the proposed fixed charges would better link cost recovery to cost causation, reduce cross subsidies, and ensure some degree of cost recovery from all customers.

7.1.2. The History of Fixed Charges in California

PG&E and SDG&E currently have minimum bills in place for residential customers as approved by prior Commission decisions. For PG&E, the current residential minimum bill is $4.50/month[384] and for SDG&E it is $0.17/day (approximately $5/month).[385] SCE does not have a minimum bill.

[384] D.11-05-047 at 18 (referring to the minimum bill somewhat confusingly as a "minimum charge").
[385] Exh. SDG&E-107 at CF-27, CF-28.

As TURN points out, the Commission has regularly considered the question of fixed charges in the past and almost always rejects them for residential IOU customers due to their interference with conservation and efficiency signals. This issue came to a head over twenty-five years ago in 1987, when the Commission authorized a fixed charge of $4.80 for SDG&E customers.[386] The decision was reversed less than a year later[387] with the Commission citing many customer complaints about the charge.

Notably, SCE was granted the ability to assess a fixed charge, but it currently equals less than $1/month.[388]

SCE cites Commission decisions from 1993[389] and from 1996[390] (authorizing its own fixed charge) as evidence that the Commission is supportive of fixed charges. With respect to the decision implementing the SCE fixed charge, the Commission held that "a customer charge is fairer to customers because it reduces the subsidies built into the current energy charge method of collecting residential customer costs."[391] In D.93-06-087, the Commission stated that a residential customer charge "is consistent with and supported by our well-established principle of marginal cost-based rate design," would "collect revenues more closely in proportion to cost causation thereby reducing subsidies," and "better inform customers of the system costs their consumption causes, and promote greater overall economic efficiency."[392]

In D.11-05-047, the Commission rejected PG&E's proposal for a $3 fixed charge, holding in part that because a fixed charge "cannot be avoided by a

[386] D.87-12-009.
[387] D.88-07-023.
[388] Exh. PG&E-111 at 16; Exh. NRDC-101 at 46; *see generally* D.96-04-050.
[389] D.93-06-087.
[390] D.96-04-050.
[391] D.96-04-050 at 107-108.
[392] D.93-06-087 at 27.

customer's reducing usage or being more energy efficient, the customer charge offers no conservation price signal." In D.14-06-007, the Commission rejected SDG&E's proposal for a $5 fixed charge for its residential gas service, even though SDG&E made the same cost causation argument that they make now. The Commission held that "SDG&E's argument that a $5 per month charge sends a significant 'cost causation' signal for fixed costs is not persuasive when weighed against the dilution of conservation and energy efficiency price signals."

7.1.3. Change in Law Regarding Fixed Charges

Public Utilities Code Section 739.9(e) gives the Commission the authority to adopt new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of the "fixed costs" of providing electric service to residential customers. Fixed charges are defined in the statute as "any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, or other charge not based upon the volume of electricity consumed."[393] Our authority is currently limited by Section 739 (f) to a maximum fixed charge for non-CARE customers beginning January 1, 2015 of $10 per month and a maximum $5 per month fixed charge for CARE customers. Beginning January 1, 2016, the maximum allowable fixed charge may be adjusted by no more than the annual percentage increase in the Consumer Price Index (CPI) for the prior calendar year.

Section 739.9 (e) provides the following direction to the Commission:

> (e) The Commission may adopt new or expand existing, fixed charges for the purpose of collecting a reasonable portion of the fixed costs of providing electric service to residential customers. The Commission shall ensure that any approved charges do all of the following: 1) reasonably reflect an appropriate portion of the different costs of serving small and large customers; 2) not

[393] Section 739.9(a).

unreasonably impair incentives for conservation and energy efficiency; and 3) not overburden low-income customers.

The statute does not require the Commission to approve any new or expanded fixed charges.[394]

7.2. Calculating Fixed Costs

Currently, there is no agreed-upon method for identifying and calculating the IOU's fixed costs. Parties concede that there are fixed costs associated with providing residential electric service, but disagree on policy bases as to the level of those costs and whether those costs should be recovered by fixed charges. For the most part, the parties' arguments regarding which cost elements should be considered fixed costs generally reflect how such an allocation would impact their rates. The utilities argue for a fairly broad interpretation of fixed costs while the solar parties generally argue for a narrow interpretation of fixed costs, as that would load more costs into the volumetric rates, which their constituents' avoid.

We periodically evaluate various proposals for calculating the utilities' fixed costs during part of each electric utility's GRC cycle. First, we establish the utilities' revenue requirements, that is, the amount of revenues to be recovered in rates. This includes all current and operation and maintenance costs, expenses, fuel expenses, taxes, depreciation, interest payments, and a component for return on equity. Those revenue requirement amounts for each of the three electric utilities are determined in Phase I of their GRCs.

Next, during Phase 2 of each electric utility's GRC, we determine the marginal cost for each service provided and each customer class' responsibility for those costs. We then allocate the authorized revenue requirement between

[394] *Id.* at (g).

the customer classes and set the actual rates or prices for each tariff. As we consider the proposed fixed charges in this proceeding, each utility's current revenue requirement and each utility's residential class' allocation of that revenue requirement have already been determined. Our review in the instant proceeding is limited to considering the appropriate rate design for the residential class. Historically, in setting electric rates, we have sought to design and set rate structures that are based on marginal cost and that allow each utility to recover its costs of service in a manner that ensures that costs specific to each class of customer are recovered from that same customer class. To the extent possible, and allowing for certain subsidies to promote certain societal programs, we have also sought to ensure that each customer pays for electric service in proportion to their use. Over the past fourteen years, however, this has been challenging due to several limitations imposed on the Commission following the energy crisis of 2000-2001.

Many of the GRCs and cost allocation proceedings in the last decade have been settled. In most recent proceedings in which marginal customer costs have been litigated, including PG&E GRCs D.92-12-057, and D.97-03-017; SDG&E GRC D.96-04-050; SoCalGas/SDG&E Biennial Cost Allocation Proceeding D.00-04-060 the Commission has adopted the new customer only (NCO) method of calculating customer costs. In these decisions, we have consistently found that it is more efficient to charge customers an up-front amount that reflects the cost of the equipment because customer-hookup equipment is not available to other customers at different locations if one customer reduces his or her use of the meter and another customer increases their load. Although customers continue to benefit from the equipment after it is installed, for purposes of establishing marginal costs that simulate pricing in a competitive market, we have found that

the relevant unit of output is new customer hookups, as the only time the cost of customer access is marginal is when the customer is deciding to connect to the system.

In this proceeding, each of the utilities proposes a monthly service fee of $5 and $2.50 for its non-CARE and CARE rates beginning in 2015, increasing to $10 and $5, respectively, for non-CARE and CARE by 2017.[395] In 2017 and 2018, the monthly service fees would be adjusted according to the year-over-year change in the California CPI. These charges would replace any current residential minimum bill amounts.

Each of the utilities proposes a slightly different methodology for calculation of the fixed charge or "monthly service fee" (referred to herein as a fixed charge). Their calculations generally follow the methodologies used by each of the utilities in their most recent GRC Phase 2 applications.

7.2.1. PG&E Fixed Cost Calculation

PG&E's proposal in its last GRC, and its proposal in this proceeding, is based on the NCO method, also called the one-time hookup method for calculating marginal customer costs. The NCO method relies on forecasts of customer counts and assigns the cost of new hookups to each customer class based on the number of new customers and estimated replacements for that class. Ongoing costs are assigned based on the total number of customers in that class. PG&E calculates the marginal customer costs noted above and multiplies them by the Equal Percentage of Marginal Cost Multiplier (EPMC) to reflect actual average sunk costs per residential customer.[396] The EPMC process in

[395] PG&E proposes to increase its monthly service fee to $10 and $5 for, respectively, non-CARE and CARE, in 2016; SDG&E's and SCE's proposals are more gradual, reaching the maximum in 2017.
[396] Exh. PG&E-109 at 1-35, 1-36.

utility revenue allocation is essentially the markup of the marginal cost to reflect the fixed charges.

PG&E maintains that its methodology for calculating fixed costs includes categories of costs that do not vary with usage, including "customer access and revenue cycle service costs such as the costs of connecting a customer to the grid and maintaining that connection and service to the account—metering, preparing and sending bills, processing payments, providing service and contact center resources, and other grid-related costs."[397] PG&E also includes the maintenance of existing infrastructure such as transformers, services, and meters for existing customers in its calculation of fixed costs, as well as general capacity-related costs associated with generation, transmission, and distribution assets.[398]

PG&E states that its fixed costs to serve residential customers are approximately $11.49 per residential customer per month.[399]

PG&E suggests that AB 327's $10.00 limit on the maximum allowable fixed monthly charge makes the issue of which costs are fixed somewhat moot in this proceeding because even if you define fixed costs to include just the EPMC-adjusted residential marginal customer costs, they would exceed the statutory limitation of $10. As support, PG&E refers to its estimate of marginal cost for the residential customer class submitted in its 2014 GRC Phase II proceeding, in which it estimated that its EPMC-adjusted marginal customer cost is $198.09 per customer-year, or $16.51 per customer month.

SCE and SDG&E's proposals for calculating customer costs are generally based on the rental method, consistent with the proposals filed in each of their recent GRC applications. The rental method includes calculating an annualized

[397] PG&E OB at 30.
[398] *Id.*
[399] PG&E OB at 31.

capacity value, or "rental charge" for customer hookups, which is then assigned to each class on the basis of the total number of customers in the class. The capacity value is calculated by applying a real economic carrying charge to customer access equipment investment costs.

7.2.2. SCE Fixed Cost Calculation

SCE and SDG&E's proposals for calculating customer costs are generally based on the rental method, consistent with the proposals filed in each of their recent GRC applications. The rental method includes calculating an annualized capacity value, or "rental charge" for customer hookups, which is then assigned to each class on the basis of the total number of customers in the class. The capacity value is calculated by applying a real economic carrying charge to customer access equipment investment costs.

SCE argues that Section 739.8 places no requirement of customer-specificity when calculating what "fixed costs" might be, and that the statute requires no specific focus on marginal customer-related costs when calculating the "fixed costs" of an IOU.[400]

In SCE's opinion, fixed costs should reflect customer, and portions of generation/transmission capacity and grid-related fixed costs of service, i.e., costs that do not vary with customer usage.[401] SCE offers several different methodologies to determine the average fixed cost per residential customer, each of which results in average fixed costs greater than $10/month.[402] SCE's marginal customer cost methodology (which includes the cost of the final line transformer, service drop, meter and panel, and customer services (i.e., call

[400] SCE OB at 83.
[401] Exh. SCE-101 at 27.
[402] SCE OB at 84.

center)) results in a cost of $13.30/customer/month.[403] For comparison, SCE also applies an EPMC scalar to its marginal customer cost estimate from a 2013 settlement adopted in D.13-03-031 to reach a cost of $17.30/customer/month.[404] SCE argues that certain costs of distribution infrastructure should be included in the calculation of fixed costs, including the financing costs associated with the distribution grid, and the cost for components of the distribution grid such as poles, conductors, and transformers that are required to serve customers. When factoring in these components, SCE arrives at a figure of $76/customer/month.[405]

Finally, , to estimate the average fixed costs for low-usage or no-usage customers, SCE provided an estimate of what its costs of distribution and transmission would be if no one was actively drawing any energy. SCE states that a zero-demand state represents 38% of its distribution costs and therefore 38% of SCE's distribution costs should be considered "fixed" and divided amongst all SCE customers accordingly.[406] When calculating the fixed cost per customer in this manner, SCE obtained fixed customer costs of $17 per month; fixed distribution service costs of $10 per month; and fixed generation capacity/transmission costs of $8 per month.[407] SCE argues that because each of its methodologies results in a figure in excess of $10/month, the $10/month fixed charge should be imposed.[408]

SCE currently has a fixed charge of approximately $1 per month, which recovers approximately 1% of SCE's residential revenue requirement. SCE's increased fixed charge would recover approximately 8% of SCE's residential

[403] *Ibid.*
[404] *Ibid.*
[405] SCE OB at 85.
[406] Exh. SCE-101 at 28.
[407] SCE OB at 85.
[408] *Id.* at 83-84.

revenue requirement. The increased fixed charges would offset, on a dollar-for-dollar basis, customers' variable energy rates, reducing seasonal bill volatility and provide an appropriate price signal to customers.

7.2.3. SDG&E Fixed Cost Calculation

Currently, SDG&E's residential customers are subject to a minimum bill of approximately 0.14 and 0.11 cents per day for non-CARE and CARE customers. SDG&E proposes to replace this minimum bill with a monthly service fee of $5 per month in 2015, increasing to $7.50 in 2016 and $10 in 2017, with an annual CPI adjustment occurring in 2018 and later. Although in SG&E's opinion, a distribution rate structure designed to reflect clear and accurate prices signals would consist of a monthly service fee to recover distribution-related customer costs along with a non-coincident demand charge to recover demand-related distribution costs,[409] in this proceeding SDG&E proposes only the monthly service fee, and would continue to recover the residual distribution and demand costs through the volumetric ($ per kWh) distribution rate.

Using figures from its 2012 GRC Phase 2 application, SDG&E estimates the average distribution customer costs for residential customers to be $10.64 per month and distribution demand costs to be $5.85 per kW per month. Updating for current revenues, SDG&E calculates average distribution customer costs of $14.56 per and distribution demand costs of $8 per kW per month.

SDG&E explains that its fixed customer cost estimate of approximately $15/month is a conservative estimate, and that the number could have been closer to $40/month if it had exercised the full discretion

[409] SDG&E's preferred non-coincident demand charge would recover demand-related distribution costs through a dollar per kW charge structure based on distribution usage, differentiated by customer class and voltage level.

allowed under AB 327.[410] SDG&E also suggests that the appropriate forum to address specific methodologies for determining fixed costs and charges is in each utility's GRC Phase 2 proceeding.[411]

SDG&E recommends that the fixed charge revenues be used to reduce the upper tier rates until a 20% differential is reached between the upper tier and the lowest tier. SDG&E would exclude master-metered customers from the fixed charge, because the cost of service to master-metered customers differs from separately-metered customers because the cost is dependent upon the number of customers behind each meter. SDG&E would retain the current minimum bill charge for master-metered customers but would increase the current minimum bill from $0.17 per day to $.30 per day for non-CARE customers. Master-metered CARE customers would continue to see a minimum bill of $0.17 per day in 2015 with annual CPI adjustments beginning in 2016.

7.2.4. Party Positions on Fixed-Cost Calculation

Several parties including ORA, TURN, and IREC disagree with the IOUs' proposed methodologies for calculation of fixed customer costs. These parties maintain that customer-specific costs should only include maintaining or replacing the meter, billing, customer accounts, and customer service and that it is inappropriate to include any load-carrying or demand-related costs in a fixed cost methodology.[412]

They further argue that customer-related fixed costs that vary with the size and/or usage of the customer should be excluded from a fixed charge.[413]

[410] Exh. SDG&E-109 at CF 23-24.
[411] *Id.* at CF-24.
[412] UCAN OB at 25; IREC OB at 19; OB at 16.
[413] NRDC OB at 40.

TURN argues that while marginal customer costs vary by utility, if calculated using the NCO method previously used by the Commission, marginal customer costs would be less than the $10 per month claimed by the IOUs. For example, TURN's recent PG&E GRC Phase 2 testimony estimated PG&E's fixed customer costs of $60 per customer year. [414]

In the same case, PG&E claimed that customer costs were $70 per customer year. In this proceeding, PG&E calculates a $10 per customer month cost, by adding the EPMC scalar to the $70 per customer year figure, plus about $103 per customer in non-marginal costs.[415] Similarly, NRDC notes that PG&E's GRC Phase 2 fixed cost estimate per customer was $6.49/month in 2014 dollars, and that this was arguably an "overestimate" as shared service drop costs were included.[416]

SDG&E also justifies its proposed $10 fixed charge based on its litigation position in its 2012 Phase 2 GRC. As with the PG&E estimates, other parties challenged SDG&E's position. In that proceeding, UCAN estimated marginal customer costs of $89.10 per customer year ($7.42 per month) and ORA estimated $77.68 per customer year ($6.47 per month).[417]

While we are persuaded that collecting customer-related fixed costs separately from capacity costs and energy is reasonable, we agree with TURN that the record is not sufficient to reach definitive findings on the exact definition and amount of fixed customer costs. We find that the evidence in this case is insufficient to determine precisely which costs are customer-related, and of among the universe of customer-related costs,

[414] Exh. TURN 204 at 49.
[415] PG&E RB at 30-31.
[416] Exh. NRDC-101 at 52.
[417] Exh. TURN-207, Attachment WBM-10 at 444.

which costs should be considered fixed. This is a determination that should take place in each IOU's Phase 2 GRC proceeding.

7.3. Analysis of Fixed Charges for Residential Rates

7.3.1. Party Positions on Fixed Charges in Residential Rates

Regardless of which methodology is used to calculate the amount of fixed costs that could be recovered through a fixed charge, many parties oppose any rate structure with a fixed charge. These parties point out that fixed charges to reflect fixed costs are permitted, but not required, by statute. The IOUs point out that Fixed Charges to reflect fixed costs would bring rates closer to being cost-based. Parties who favor fixed charges point out that not only are they cost based but they are used by many other utilities. Opposing parties argue that, implementing a new fixed charge is universally unpopular with ratepayers. Moreover, in light of the significant bill impacts from tier flattening, it is not reasonable to implement new or increased fixed charges until the impacts of tier flattening are complete.

The utilities argue that their proposed fixed charges will bring rates more in line with its costs to serve, and reduce intra-class subsidies, and reduce bill volatility. In addition, California's small electric utilities and many municipal utilities and investor owned utilities across the country already use a fixed charge to recover a portion of fixed costs.

While no intervenor denies that utilities have fixed costs, with the exception of UCAN, each of the non-utility parties is opposed to the imposition of a fixed charge. The non-utility parties oppose fixed charges for several reasons. First, ORA argues that most competitive markets do not recover fixed costs using fixed charges. Instead, they generally mark up the volumetric prices

they charge to cover fixed overhead, which is analogous to what the EPMC markup does in the case of distribution costs.[418] ORA's Opening Testimony referred to a paper written by the Regulatory Assistance Project, regarding how competitive markets work which finds: "In competition, a consumer who does not consume a product or service does not nevertheless pay for the mere ability to consume it. Thus, as a general matter, prices should be structured so that, if a consumer chooses not to purchase a good or service, he or she has no residual obligation to pay for some portion of the costs to provide that good or service."[419]

These parties also contend that that fixed charges are inconsistent with marginal cost ratemaking because fixed charges, as proposed by the utilities, represent sunk costs and do not reflect the marginal cost that a customer would incur for the next increment of electricity purchased.

In contrast to the IOUs' arguments regarding cross-subsidies, CFC, along with TURN, argue that fixed charges require both large and small residential users to pay the same fixed cost and note that the Commission has, in the past, adopted different customer charge amounts for small and large customers. CFC agrees with IREC and others that, to the extent that smaller users tend to be the least well-off, the fixed charge is a regressive charge.

CFC also supports the conclusion of Sierra Club and ORA that fixed charges are a disincentive to rooftop solar and other renewables.[420]

According to ORA, a significant problem with fixed charges is that there is no meaningful way for customers to respond to a fixed charge other than by terminating service.[421] Because customers can respond to variable rates by

[418] ORA OB at 29.
[419] *Id.* at 32.
[420] CALSEIA OB at 16.
[421] ORA OB at 28.

reducing consumption, ORA, NRDC, maintain that variable rates are more efficient.[422]

ORA is correct that customers cannot avoid these costs unless they terminate service, and unless that customer does terminate service, the utility cannot avoid incurring these costs either.

Sierra Club also argues that the proposed fixed charges would violate the requirement of AB 327 by "unreasonably impairing" incentives for conservation and energy efficiency. Sierra Club points out that the Commission has rejected lower proposed fixed charges for impairing conservation incentives as recently as 2011 and 2014. In 2011, in D.11-05-047, the Commission rejected PG&E's application for a residential fixed charge on the basis that because a "fixed charge cannot be avoided by a customer's reducing usage or being more energy efficient," it offers no conservation price signal.[423] Subsequently, in D.14-06-007, the Commission rejected SDG&E's request for a $5 fixed customer charge for residential gas service, holding that SDG&E's argument that the "$5 per month charge sends a "significant "cost causation signal for fixed costs is "not persuasive when weighed against the dilution of conservation and energy efficiency price signals.[424]

NRDC witness Chernick calculates that for every $1/month increase in the fixed charge, the average energy rate would be reduced by about $1. - $/MWh, or about 1~~ percent~~%, which means that "a $10 month fixed charge would reduce the average energy charge by about 10-11%; assuming roughly proportional distribution of the rate reduction across tiers, the reduction in the conservation incentive would be similar."[425]

[422] RT Vol. 17 at 2337, NRDC/Chernick.
[423] D.11-05-047 at 33.
[424] D.14-04-007 at 41.
[425] Exh. NRDC-101 at 49-50.

CforAT argues that the utility proposals for fixed charges should all be rejected because none of the utilities has met it burden to show that its proposal is just and reasonable.

7.3.2. Differentiating Fixed Charge for Small and Large Customers

Although § 739.9(e) does not define "small" or "large" customers, in the context of fixed charges for residential customers, "large" and "small" most likely refers to a customer's usage level or type of dwelling. The utilities each propose to differentiate fixed charges by providing a 50% fixed charge discount to CARE customers, regardless of the usage characteristics of the individual customer. They suggest that because CARE customers generally use less energy than non-CARE customers, providing a lower fixed charge for CARE customers is a reasonable and practical means of complying with Section 739.9(e)(1).

Sierra Club, CforAT and CFC also object to a fixed charge, arguing that fixed charges would disproportionally impact low-income customers in both TOU and tiered rates because any fixed or customer charge will represent a larger percentage of their bill relative to a higher usage customer.

These parties also suggest that if fixed charges are not differentiated by customer size, fixed charges will result in a cross-subsidy of single-family homeowners by apartment dwellers and residents of multi-family buildings.

7.4. Fixed Charges as a Reflection of Cost Causation

A fundamental principle of rate design that we seek to achieve is that rates should reflect the cost of service, so that customers receive bills roughly consistent with how the utility incurs costs to serve those customers. Currently, for PG&E, SDG&E and SCE, the vast majority of costs are collected through volumetric, or variable energy charges. The Commission has previously

considered fixed charges for the large electric IOUs several times in recent years, but has generally declined to adopt them based on a combination of legal and policy reasons. With the passage of AB 327, there is no longer a legal impediment to adopting fixed charges, so our primary consideration here are the relevant policies in favor or against fixed charges.

The utilities maintain that there are certain fixed costs that should be collected separately to provide more accurate price signals to consumers and eliminate the cross-subsidies present in an all-volumetric rate design.

PG&E argues that an all-volumetric design means that low-usage customers are not paying their fair share of the fixed costs that they impose on PG&E's system, while high-usage customers pay an unfairly high share of such costs.[426] SDG&E states that fixed charges would send more accurate price signals to consumers and would end cost-shifting from low-usage to high-usage customers, encouraging more efficient investments in DR and EE technology, and therefore increasing overall benefits to the environment and consumers.[427]

The utilities suggest a broad interpretation of the categories of costs that do not vary with customer usage, including customer access and revenue cycle service costs, such as metering, preparing and sending bills, processing payments and providing service center resources and other grid-related costs. The utilities also suggest that capacity-related costs associated with generation, transmission and distribution assets are driven by customers' coincident and non-coincident demands on the electric system. Each of these costs are currently collected through volumetric rates. Non-bypassable costs associated with programs like CARE and FERA, and those that provide incentives for energy efficiency such as SGIP and CSI are also collected through volumetric rates.

[426] Exh. PG&E-101 at 2-6.
[427] Exh. SDG&E-106 at CY-3-4.

The utilities argue that where certain costs are fixed and cannot be avoided, adopting a rate structure to recover these costs through monthly service fees, rather than through volumetric rates, best reflects cost causation and is more equitable. The utilities acknowledge that fixed charges are not necessary for revenue stability or cost recovery, but maintain that fixed charges would provide bill stability for customers.

Other parties, including ORA and TURN, maintain that the current approach – where fixed costs are collected through volumetric rates – is more consistent with the majority of the rate design principles and marginal cost ratemaking and should be retained. They maintain that fixed charges would violate most of the rate design principles articulated in this proceeding, because the fixed charges would be the same regardless of the amount of electricity used, would provide no incentive to conserve, and are not based on cost causation. In particular, they argue that fixed charges are antithetical to the Commission's conservation and energy efficiency efforts. They also argue that fixed charges have a disproportionally negative impact on low-income customers, and would create a new cross-subsidy, with low-income, low-use, multifamily customers subsidizing higher usage customers. These same parties emphasize that customers overwhelmingly oppose fixed charges.

Our support for fixed customer charges in the past has been based on the concept that recovery of fixed costs through a fixed charge would price a more accurate price signal to customers. In the regulated electricity industry, utilities remain required to provide "service or residual access" to customers regardless of whether they decide to purchase electricity at any given time.

This residual access carries with it certain costs. Collecting these fixed costs through volumetric energy rates blends the cost of residual access with the

capacity and generation costs associated with customer demand. Unbundling customer charges from volumetric energy rates would resolve the concern that higher-usage customers contribute significantly more toward fixed customer costs than lower usage customers. Unbundling customer charges from volumetric rates would also resolve any concerns regarding extremely low and zero usage customers essentially acting as free riders with respect to the fixed customer costs associated with providing them with residual access to utility service.

7.5. Discussion

As discussed above, while we have supported fixed charges previously, we have also reduced the amounts requested by the utilities in recognition of certain marginal cost differences identified by ORA.[428] At that time, we found that it would only be appropriate to include the "marginal cost of billing, accounting, and other ongoing customer-related services."[429]

In this proceeding, the utilities each have proposed to set fixed charges at the maximum amount permitted by AB 327. TURN and other parties maintain that the IOUs' estimates of their fixed customer costs are too high. As noted above, in presenting their proposed fixed cost calculations, each of the utilities relied, in part, on their litigation positions from previous Phase 2 GRC proceedings to justify their customer cost amounts.

However, as is noted by TURN and ORA, due to the limitations imposed on the Commission by AB 1X, recent Phase 2 GRC proceedings have focused primarily on marginal customer costs for purposes of revenue allocation rather than residential rate design. In addition, many of these proceedings have been resolved through settlements. As a result, the marginal cost figures ultimately

[428] D.96-04-050 at 115.
[429] *Id.* at 113.

approved by this Commission in the GRC decisions have often been reverse engineered from settled revenue allocation outcomes with very little true agreement as to the actual fixed costs of serving residential customers.

More recently, we have expressed concern regarding the potential impacts of a fixed charge on conservation incentives. In D.11-05-047 and D.14-06-007, in particular, we declined to approve proposed fixed charges in part due to concerns that such charges would reduce the incentives for conservation. However, as part of the package of rate reform proposals that we are considering in this proceeding, including tier flattening, and the potential for increased use of TOU rates, we find that fixed charges have the potential to assist in our movement toward rates that better reflect cost causation.

The utilities maintain that their proposed fixed charges would not unreasonably impair conservation in part based on their findings that customers respond primarily to average prices as opposed to specific elements of the individual bills. TURN agrees that there would be limited impacts on conservation with a fixed charge if customers are only affected by their average bills, but TURN suggests that the Commission should not assume that customers cannot be educated.

Our approved structure cannot be fully compliant with all of the principles set forth in the scoping memo, and we must balance the competing rate design principles. In this area, we give significant weight to the need to better align rates with cost causation, and provide customers with clear cost signals. There are fixed costs associated with providing electricity service to residential customers. Customers should not be able to avoid those fixed costs. We recognize that adoption of a fixed charge would have a modest dampening impact on conservation incentives because customers would not be able to avoid

the fixed charge. However, we determine that the impact is likely to be small. And, although we acknowledge that a fixed charge would represent a larger percentage of the monthly bill for those customers whose usage is lower, we disagree with the proposition that fixed charges will disproportionally impact low-income or low-usage customers, because, along with a fixed charge, these customers would see lower volumetric rates than would be necessary with a minimum bill.

Despite these findings, however, we remain concerned regarding customer acceptance of a fixed charge. As noted by many parties, the Commission has considered, and rejected, fixed charges in prior proceedings due to its concerns about customer acceptance (*see* D.89-12-057 and D.93-06-087). In this proceeding, the record demonstrates that customers have expressed their opposition to fixed charges in comments, at PPHs, through customer surveys, and in previous rate proceedings. The findings of the Hiner study commissioned by the utilities to obtain "customer input into alternative electric rate plans as part of the Residential Rates OIR," also demonstrate that customers strongly disfavored rate options with fixed charges[430] and that "a monthly service fee was the most important attribute of rate plans for the participants and that participants had a strong preference for rate designs that did not include a fixed charge." PG&E witness Pitcock agreed that the Hiner Study revealed that "a monthly service fee was not favorable."[431]

Furthermore, there is nothing on the record to demonstrate that customers are likely to understand that a new fixed charge would represent only a change in rate design, as opposed to an additional charge. To the contrary, the record demonstrates that customers tend to believe that the fixed charge would be an

[430] Exh. TASC-102 at 18-19 (concerning Hiner study).
[431] RT Vol. 12 at 1458, PG&E/Pitcock.

additional charge. Utility witnesses Pitcock, Garwacki, and Winn each acknowledged customer opposition to fixed charges at the PPHs but claimed that customers were "misinformed" and did not understand fixed charges. Since the majority of customers' bills will increase as a result of the rate redesign we are undertaking, it is reasonable to conclude that customers would interpret any bill increase to be at least partially related to a fixed charge.

As is reflected in RDP #10, we want to ensure that customers understand and accept residential rate structures, and that rates are stable and understandable. As noted by many parties, in the past, the Commission has rejected rate elements that were otherwise reasonable, when they have resulted in widespread customer hostility. The record in this case demonstrates that customers are concerned about fixed charges. In light of this concern, and in the interest of adopting a roadmap that includes stable and understandable rates, we find that it is reasonable to defer the implementation of fixed charges until the IOUs have completed the tier convergence and tier flattening adopted in this decision.

As many parties have noted, the Commission previously adopted, and then rescinded, a customer charge for SDG&E. As in this decision, the decision to institute a customer charge was based on a "commitment to cost-based rates and equal percent of marginal cost (EPMC) revenue allocation."[432] An overwhelmingly hostile response to the customer charge motivated the Commission to repeal the charge. In the decision repealing the charge, the Commission determined that "considerable weight must be given to the ability of residential customers to both understand the principles behind the rates they are charged and accept those principles as reasonable."[433] Consumer acceptance and

[432] D.88-07-023 at 2-3.
[433] *Id.* at 5.

understanding is incorporated into the rate design principles in this proceeding, including principles 6 and 10.

Based on this, we agree that a fixed charge representative of fixed customer-related costs should be a part of residential rate design. However, when examined with the other rate changes proposed for 2015 and the roadmap period, we believe that it is necessary to approve employing a minimum bill rather than a fixed charge in the immediate future.

Based on the record in this proceeding, it is very clear that customers are unlikely to understand or accept the need for fixed charges without customer education. Combining a new fixed charge with other significant rate design changes would only exacerbate the issue. Certain parties agree, for example, UCAN acknowledges that "introducing a customer charge, though a reasonable way to recover customer-related costs, could still be ill-timed when SDG&E's low-usage customers' bills are increasing so rapidly over the next four years... "[434]

We find that further movement toward separate collection of fixed costs is appropriate, but we will temper this movement through the use of a minimum bill in the near term consistent with our need for a gradual, understandable transition to a new rate structure. Therefore, while we support a fixed charge approach for the long term, we believe it is reasonable to adopt a minimum bill approach in the short term, to avoid customer confusion and allow for a gradual transition to our preferred rate structure.

7.6. Minimum Bill

As an alternative to the fixed charge, the minimum bill charge is a mechanism that is designed to recover a minimum level of revenue, recognizing

[434] UCAN RT at 6.

that some costs are still incurred to maintain service even in the event that a customer does not use energy. As noted by several parties, AB 327 authorizes the Commission to consider minimum bills as an alternative to fixed charges.[435] The majority of parties who opposed the fixed charge proposal generally recommend adoption of a minimum bill instead.

For example, although it is committed to a rate design based on marginal costs, ORA acknowledges that a rate design based entirely on variable energy rate may under-recover the utilities' fixed costs.[436] Therefore ORA recommends that the best way to charge marginal costs while assuring the recovery of certain fixed costs is through a minimum bill applied to all residential customers.[437]

For customers with no or very low usage, the minimum bill would function like a customer charge and collect a portion of the utilities' fixed costs. Customers who use more energy (and whose bills exceed the minimum bill amounts) pay no minimum bill but instead pay for customer access and usage through volumetric rates. SDG&E and PG&E already have minimum bills in place for residential customers. PG&E has a residential minimum bill of $4.50 per month and SDG&E has a minimum bill of $0.17 per day or approximately $5 per month.

Because minimum bills apply only to that percentage of customers whose usage is less than the minimum kWh of usage, the minimum bills collect less revenue to contribute to fixed cost recovery. A minimum bill therefore requires the continued recovery of most fixed costs through the volumetric rate.

[435] § 739.9(h) ("The commission may consider whether minimum bills are appropriate as a substitute for any fixed charges.").
[436] ORA OB at 44.
[437] Exh. ORA-101 at 2-17.

7.6.1. Amount of Minimum Bill

ORA recommend that the size of the minimum bill be determined in subsequent GRCs or rate design proceedings. TURN believes that it would be reasonable to set a minimum non-generation bill in the range of $8-$10 for non-CARE customers, with 50% off that amount for CARE customers, noting that this would collect about 100-150 kWh of non-generation costs at baseline rates from non-CARE customers.

ORA agrees that certain ongoing variable costs such as billing, maintenance and customer services could be recovered in a fixed charge, but recommends that they be recovered through a minimum bill instead because most competitive markets do not recover such costs using fixed charges.[438] However, the parties disagree on whether Section 739.9 sets a cap on minimum bills. Several parties, including ORA,[439] argue that, because minimum bills were seen by the Legislature as an alternative to fixed charges, they should therefore be subject to the $5 CARE and $10 non-CARE caps.[440] Although the foregoing argument is conclusory, IREC quite reasonably suggests "[i]t would be illogical to read the statute to carefully prescribe what the Commission may do in regard to fixed charges, but then [leave] the Commission's discretion unfettered through an alternative, minimum bill approach."[441] While we do not agree with IREC and ORA, the IOU response is too clever by half.[442] We instead find that the plain language of the statute is subject to only one reasonable interpretation.

[438] *See, e.g.*, ORA OB at 29.
[439] *See, e.g. id.* at 27; SEIA OB at 25; Sierra Club OB at 21; IREC OB at 23.
[440] ORA OB at 27.
[441] IREC OB at 24.
[442] *See* SCE RB at 47-50 and especially at 48-49, where SCE propounds a granular distinction between a "minimum charge *mechanism*" and a "fixed charge *mechanism*," based on a purported "catch-all" definition of minimum bills in § 739.9(a). The other IOUs and intervenors did not substantively address this issue.

Section 739.9(a) defines "fixed charge" broadly, but without mention of minimum bills; Subdivision (e) sets out narrower criteria for permissible fixed charges. By contrast, subdivision (h) provides that the Commission "may consider whether minimum bills are appropriate as a *substitute* for any fixed charge;" not whether minimum bills may *qualify* as a fixed charge under ~~section~~Section 739.9(a).[443] From this statutory scheme, we infer that the Legislature's unstated premise is that fixed charges exclude minimum bills. Accordingly, ~~section~~Section 739.9(h) does not authorize the Commission to uncritically apply fixed charge provisions—such as the section 739.9(f) maximums—to minimum bills. Rather, subdivision (h) contemplates the use of minimum bills where the *effect* of the substitution would be commensurable and similar to the intended effect of a fixed charge, as defined by ~~section~~Section 739.9(e) and related subdivisions. Moreover, IREC wrongly supposes that the failure to apply the fixed charge caps to minimum bills will result in "unfettered" Commission discretion.[444] We do not read subdivision (h) to abrogate all other constraints. For example, Section 739.1 would still apply. We therefore find that the Section 739.9(f) caps on fixed charges are not applicable to minimum bills. In dictum, however, we observe that the Legislature's choice of fixed charge caps may limit the range of permissible minimum bills.

7.6.2. Approval of Minimum Bill

To ensure maximum customer understanding of the preferred rate structure change, encourage customer adoption and increase the likelihood of success, today's decision adopts a minimum bill provision as part of a gradual transition to a rate structure that includes TOU rates, flatter tiers, and fixed charges.

[443] Emphasis added.
[444] IREC OB at 24.

The minimum bill would ensure that all customers contribute some amount to fixed costs. It also avoids the potential negative impact on conservation associated with a fixed charge, and it protects lower-usage customers whose fixed costs might be lower. As discussed above, while we believe any negative impact on conservation associated with a fixed charge is likely to be small, a gradual approach beginning with a minimum bill will allow us to monitor any conservation and energy efficiency impacts associated with the tier flattening separate from any potential impacts associated with a fixed charge.

While the need to ensure that all customers contribute remains, we view the need to mitigate the potential conservation and bill impacts to be transitory. As we set a rate structure for residential rates for the foreseeable future, including a shift to a flatter, two-tiered system and the increased use of TOU rates, we recognize rates and bills will increase for lower users and decrease for the highest users relative to current rates, all other elements remaining the same.

In this situation, due to the necessary changes in tiered rates, customers are unlikely to be able to differentiate the increases in their bills caused by the tier flattening from any perceived increase in their bill caused by a fixed charge. Customers will not be able to compare their prior tiered rates with the updated tiered rates; the majority of customers will simply see an increase in their bills. These customers are likely to associate that increase with a new fixed charge. The minimum bill provision will allow customers to become familiar with the new tier structure first, followed by a fixed charge once tier flattening is complete and default TOU is adopted such that a fixed charge to collect marginal-cost-based customer costs is necessary and appropriate. Although we agree with CforAT that it is beyond dispute that the record in this proceeding

shows substantial customer hostility to fixed charges on residential bills,[445] we disagree with CforAT's contention that customer hostility cannot be cured with customer education.

Finally, although we are deferring the implementation of any fixed charges to a later date, we find that it is reasonable to adopt the utilities' proposed fixed charge amounts for use as a minimum bill. For PG&E and SDG&E, whose minimum bills currently exceed the proposed fixed charge amounts for 2015 and 2016, the minimum bill shall begin at $5 in 2015, increasing to the $10 maximum by 2018. The future minimum bill and fixed charge amounts shall be subject to review by the Commission and the parties through the utilities' GRC Phase 2 applications.

Although we find in the discussion below that the statutory limits on fixed charges do not apply to minimum bills, given the disagreement regarding the appropriate amount of fixed customer costs, it is reasonable to adopt a minimum bill amount for all three utilities that is consistent with the statutory limit for fixed charges. Future proposed minimum bill and/or fixed customer charge amounts shall be subject to review by the Commission and the parties through the utilities' GRC Phase 2 applications.

Table: Adopted Minimum Bill for CARE Customers (per month)

	PG&E	SCE	SDG&E
2015	$5.00	$5.00	$5.00
2016	$5.00	$5.00	$5.00
2017	$5.00	$5.00	$5.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

[445] CforAT RB at 14.

Table: Adopted Minimum Bill for Non-CARE Customers (per month)

	PG&E	SCE	SDG&E
2015	$10.00	$10.00	$10.00
2016	$10.00	$10.00	$10.00
2017	$10.00	$10.00	$10.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

This minimum bill shall remain in effect and subject to review in each electric utility's GRC Phase 2 until such time as the utility has received approval for a fixed charge. A utility's application for a default TOU tariff shall include a proposal for an appropriate level of a fixed charge associated with the default tariff(s) as well as any optional tiered rates that are available.

7.7. Zero Minimum Bill

PG&E proposes to retain a zero minimum bill amount that would apply to delivery charges on all residential rate schedules to ensure no negative bills (as with PG&E Schedules E-7, AL-7 and EL-8).

Marin Clean Energy (MCE) recommends that the Commission reject PG&E's request. MCE notes that the Commission adopted Rules of Conduct for Electrical Corporations Relative to Community Choice Aggregation Programs ("Code of Conduct") in D.12-12-036. Rule 18 of the adopted Code of Conduct states: " [a]n electrical corporation shall not, through a tariff provision or otherwise, discriminate between its own customers and those of a CCA in matters relating to any product or service that is subject to a tariff on file with the Commission. … This restriction does not apply to optional rates, programs and services authorized or approved by the Commission that are only available to bundled service customers."[446]

[446] MCE OB at 5.

The ZMB provision, which states "total delivery charges cannot be less than zero," currently exists on several PG&E rate schedules, including E-7, E-8, EL-7, EL-8 and CARE-eligible commercial E-CARE rates where there is the potential for the non-generation portion of the charges to sum to a total negative charge (i.e., a credit). The ZMB applies to both bundled and CCA customers under these existing rate schedules. According to MCE, for bundled customers, the ZMB has less of an effect because any non-generation-related bill credits are carried over and applied against the bundled customers' generation-related charges. However, for unbundled customers on these rate schedules, if these customers' delivery charges are negative, PG&E employs this ZMB provision to zero-out the non-generation portion of the bill. MCE maintains that by refusing to carryover the excess credits associated with the delivery charges of an unbundled customer's bill toward their generation charges, PG&E is increasing the bills of some unbundled customers and shifting these customer's excess credits to other customers.

In this proceeding, we approve an increase in the minimum bill amount for CARE and non-CARE residential rate schedules. In light of this decision, PG&&E has not sufficiently justified the need to retain the ZMB. Moreover, to the extent that the ZMB would only affect those customers taking service from a CCA, we agree with MCE that application of the ZMB is inconsistent with Rule 18 of the Code of Conduct concerning CCAs.

8. CARE, FERA, Medical Baseline

8.1. CARE

AB 327 mandates that the IOUs maintain an average effective CARE discount between 30 and 35%. Any utility that currently has an average effective

discount greater than 35% is instructed to reduce its discount level to between 30 and 35% on "a reasonable phase-in schedule." PG&E and SDG&E both currently have effective CARE discounts above 35%. In summer 2014 PG&E and SDG&E began a gradual reduction to the statutory level and propose to continue the glidepath over the next four years to reach the statutory level by 2018.

IOU Proposed Transitions for Average CARE Effective Discount

	PG&E[447]	SCE[448]	SDG&E[449]
2013	47%	31%	30%
2014	48.4%	32%	39%
2015	43.2%	31%	38%
2016	39.8%	32%	36%
2017	37.3%	32%	34%
2018	34.7%	32%	34%

PG&E, SCE and SDG&E all proposed to implement a fixed charge for CARE customers at a 50% discount off the non-CARE fixed charge and on the same transition schedule. SCE and SDG&E proposed the same amounts and timeline; while PG&E moves to $5/month a year earlier.

IOU Proposed Fixed Charges for CARE Customers (per month)

	PG&E[450]	SCE[451]	SDG&E[452]
2015	$2.50	$2.50	$2.50
2016	$5.00	$3.75	$3.75
2017	Begin annual CPI adjustment	$5.00	$5.00
2018	Begin annual CPI adjustment	Begin annual CPI adjustment	Begin annual CPI adjustment

[447] Exh. PG&E-109 at 2-4 (Table 2-1).
[448] Exh. SCE-101 at ii/Garwacki (Table 1).
[449] Exh. SDG&E-109, Attachment C/Fang.
[450] Exh. PG&E-109 at 2-4 (Table 2-1).
[451] Exh. SCE-101 at ii/Garwacki (Table 1).
[452] Exh. SDG&E-109, Attachment C/Fang.

PG&E's and SCE's CARE rates currently have three tiers (as opposed to four tiers in their non-CARE rates) and both utilities provide a discount off the corresponding non-CARE volumetric rate for each tier. PG&E and SCE proposed to continue providing the CARE discount in the same manner but have proposed to redefine the CARE tier boundaries in 2015 in order to align them with non-CARE tiers (see table below). After 2015, both utilities propose to transition CARE rates to a two-tiered rate structure by 2018 on the same schedule that they have each proposed for non-CARE rates.

PG&E and SCE's Proposed Change to CARE Tier Definitions in 2015 (% of Baseline Quantity)

	Current CARE Tiers	Proposed 2015 Care/non-CARE Tiers[453] [454]
Tier 1	0-100%	0-100%
Tier 2	100-130%	100-200%
Tier 3	Over 130%	Over 200%

SDG&E's current CARE rate is structured differently from the other utilities'. SDG&E's CARE volumetric rate is provided at a discount off the corresponding non-CARE rate for each tier (similar to PG&E and SCE), but, in addition to discounted volumetric rates, SDG&E's CARE rate also includes a flat 20% discount off of energy charges.

Unlike PG&E and SCE, SDG&E proposed to simplify its CARE rate structure by removing the discount from volumetric rates (with the exclusion of the exemption from DWR-BC, CSI and CARE charges) and providing it as a line-item discount off a bill calculated at standard rates, beginning in 2015. SDG&E argues that by providing the CARE discount as a line-item bill discount, "all tiers will receive a more equitable discount level and more accurate information regarding the costs associated with their electricity demand."[455]

[453] PG&E OB at 6 (Table 1).
[454] Exh. SCE-101 at ii/Garwacki (Table 1).
[455] Exh. SDG&E-107 at CF-36.

8.1.1. Party Positions on CARE

As discussed in Section 5, the non-utility parties (with the exception of UCAN) oppose fixed charges for both CARE and non-CARE customers. ORA and CforAT both expressed concern that PG&E's proposal to reduce its CARE discount to 35% by 2018 will result in unacceptably large bill impacts to CARE customers. ORA argues that PG&E CARE customers have already experienced a significant increase in rates, asserting that between May 2014 and January 2015, PG&E's CARE Tier 1 rates increased by 24%, Tier 2 rates increased by 22% and Tier 3 rates increased by 18%.[456] ORA proposes a longer transition period in which PG&E reduces its CARE discount by 1-2% per year until it reaches the mandated 35%, with reductions "subject to bill impact evaluations in the rate design proceedings."[457]

CforAT argues that none of the IOUs' proposals give adequate consideration to what low-income customers can actually afford to pay and that the utilities fail to show that their proposals will allow for affordable supplies of electricity to meet basic needs. CforAT contends that, according to the chart provided in PG&E's Opening Brief,[458] "40% of low-income households would see a bill increase between $5-$10 in 2016, about 35% would see a similar increase in 2017 and 39% would see a similar increase in 2018."[459] CforAT asserts that CARE discounts should be calculated as a line-item discount off of standard rates and argues that Tier 1 rates "should be set so that, in conjunction with a 35% line-item discount, CARE customers with usage within Tier 1 have a mean energy burden that does not exceed 5%."[460]

[456] ORA RB at 5.
[457] ORA OB at 52.
[458] PG&E OB at 37 (Figure 5).
[459] CforAT RB at 20.
[460] CforAT OB at 64.

PG&E acknowledges that most CARE customers would see bill increases as a result of its proposals, but argues that CARE rates must be gradually increased in order to comply with the effective discount range mandated by AB 327 and that these increases are reasonable and "modest for the vast majority of CARE customers."[461]

ORA is not opposed to SDG&E's proposal to apply a line-item CARE discount in the future; however, because ORA proposes to decrease the non-CARE upper tier rates more slowly than SDG&E's proposal, applying a line-item discount would result in the CARE Tier 3 rate initially increasing and then decreasing as the non-CARE tier rate differential is decreased. ORA proposes to hold the upper tier CARE rate at its current level through 2016. ORA also proposes to reduce SDG&E's effective CARE discount from 38% to 36% in 2017 (as opposed to 2016) because of the other major changes in rate design that will be taking place in 2015 and 2016.[462]

TURN proposes to implement a CARE discount off corresponding non-CARE rates that is allocated unevenly across three tiers. Tier 1 rates would be established at a 40% discount, Tier 2 rates at a 30% discount and Tier 3 rates would collect any residual discount to achieve an average effective discount of 35%. TURN argues that this structure provides "the largest discounts for basic and essential usage while encouraging conservation via higher prices for upper tier usage."[463]

TURN also asserts that the Commission should adopt an average effective CARE discount of the maximum 35% for all utilities. This would require SCE to increase its proposed average effective discount of 32%. TURN argues that

[461] Exh. PG&E-109 at 2-7.
[462] ORA OB at 53.
[463] TURN OB at 41.

offering the maximum discount permitted is reasonable considering the significant bill impacts to CARE customers of SCE's rate design proposals.[464]

SCE argues that TURN's proposal to provide greater discounts to Tier 1 rates should not be considered because it would restructure the CARE discount and is therefore outside the scope of this proceeding.[465] SCE also contends that TURN provides no basis for its proposal to require SCE to increase its effective CARE discount to 35% and it should be rejected. TURN contends that if the Commission will not consider its proposal to change the structure of the CARE discount, then it should also not consider SDG&E's proposal to convert the CARE to a line-item discount.

8.1.2. Discussion of CARE Rate Adjustments

We approve the proposed CARE discount glide paths for both SDG&E and PG&E. After reviewing the bill impact tables below, we find that the reductions in the discount are moderated to the extent possible.

The bill impact tables show that CARE customers in SCE's territory will see a reduction in their bills. The majority of SDG&E CARE customers will see an increase under $5. However, PG&E CARE customers with high usage will see significant increases. PG&E's CARE discount is currently significantly above the statutory limit. With each percentage discount decrease, the actual dollar amount increase for high usage customers is significant, even when mitigated by the tier consolidation. When the discount has been reduced to meet the statutory limit, approximately 80% of PG&E CARE customers will see an increase over $30, and 3% will see an increase over $50.

However, given these concerns regarding impacts of CARE rate changes, we find that is reasonable to minimize the risk of significant financial impacts on

[464] *Id.* at 42.
[465] SCE OB at 98.

CARE customers by not applying the fixed charge to these customers. We therefore do not approve a fixed charge for the CARE program in this decision. CARE customers will be required to have a minimum bill equal to 50% of the minimum bill for non-CARE customers.

We agree that SDG&E's proposal to remove the CARE discount from volumetric rates (with the exclusion of the exemption from DWR-BC, CSI and CARE charges) and apply it as a line-item discount off a bill calculated at standard rates, beginning in 2015, will simplify the CARE rate structure. We therefore approve this approach for SDG&E.

Other structural changes to the CARE program, such as a discount that ranges from 30% to 40% depending on usage (suggested by TURN), or a discount that differs by income (suggested by CforAT/Greenlining), is outside the scope of today's decision. Phase 3 of this proceeding will include a workshop on CARE rate restructuring to determine if these proposed structural changes should be included in Phase 3 and if other considerations are necessary to accommodate a fixed charge in CARE customer rates.

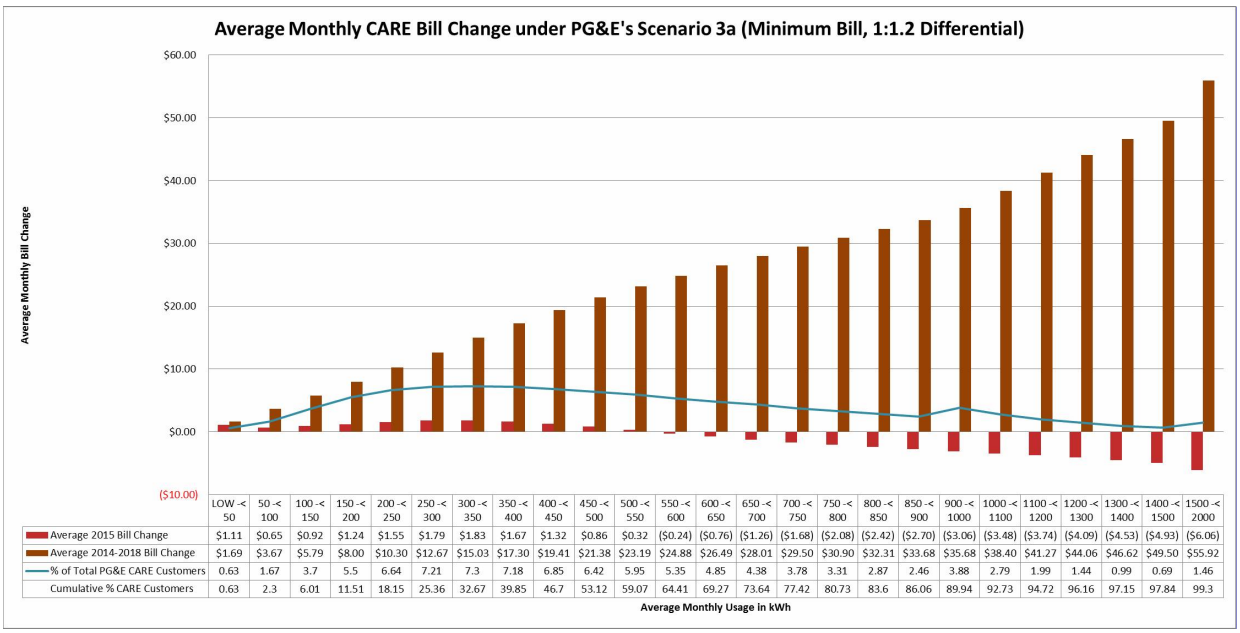
Table Showing PG&E Proposed Glidepath for CARE rates with minimum bill (no fixed charge)[466]

	May 2014	March 2015		December 2015		2016		2017		2018	
	Rate	Rate	% Change YOY[467]	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY
0 – 100% of BQ[468]	$0.086	$0.109	26.7%	$0.116	6.4%	$0.119	2.6%	$0.126	5.9%	$0.131	4%
100 -130% of BQ	$0.099	$0.123	24.2%	$0.131	6.5%	$0.138	5.3%	$0.151	9.4%	$0.157	4%
130 – 200% of BQ	$0.140	$0.167	19.3%	$0.131	-21.6%	$0.138	5.3%	$0.151	9.4%	$0.157	4%
Over 200% of BQ	$0.140	$0.167	19.3%	$0.167	0%	$0.160	-4.2%	$0.151	-5.6%	$0.157	4%

[466] PG&E Supplemental Filing of 4/1/15, Appendix A at 8, Scenario 3a. The PG&E bill impact graphs are based on PG&E's Scenario 3a, a minimum bill scenario that closely matches the rate reform that we order in this Decision. Because the ordered reform is somewhat different than the scenario modeled by PG&E, the billing impacts will not be exactly the same. The reform we order today will lessen the immediate bill impacts on low-usage customers and stretch out the bill reductions seen by high-usage customers over a greater number of years. Nevertheless, the graphs below give us some indication of the billing impacts of the ordered rate reform.

[467] Includes revenue requirement increases throughout 2015 – the rest of the rates do not assume any revenue requirement increases to show the effect of rate reform in isolation from revenue requirement increases.

[468] BQ = Baseline Quantity.



	LOW -< 50	50 -< 100	100 -< 150	150 -< 200	200 -< 250	250 -< 300	300 -< 350	350 -< 400	400 -< 450	450 -< 500	500 -< 550	550 -< 600	600 -< 650	650 -< 700	700 -< 750	750 -< 800	800 -< 850	850 -< 900	900 -< 1000	1000 -< 1100	1100 -< 1200	1200 -< 1300	1300 -< 1400	1400 -< 1500	1500 -< 2000
Average 2015 Bill Change	$1.11	$0.65	$0.92	$1.24	$1.55	$1.79	$1.83	$1.67	$1.32	$0.86	$0.32	($0.24)	($0.76)	($1.26)	($1.68)	($2.08)	($2.42)	($2.70)	($3.06)	($3.48)	($3.74)	($4.09)	($4.53)	($4.93)	($6.06)
Average 2014-2018 Bill Change	$1.69	$3.67	$5.79	$8.00	$10.30	$12.67	$15.03	$17.30	$19.41	$21.38	$23.19	$24.88	$26.49	$28.01	$29.50	$30.90	$32.31	$33.68	$35.68	$38.40	$41.27	$44.06	$46.62	$49.50	$55.92
% of Total PG&E CARE Customers	0.63	1.67	3.7	5.5	6.64	7.21	7.3	7.18	6.85	6.42	5.95	5.35	4.85	4.38	3.78	3.31	2.87	2.46	3.88	2.79	1.99	1.44	0.99	0.69	1.46
Cumulative % CARE Customers	0.63	2.3	6.01	11.51	18.15	25.36	32.67	39.85	46.7	53.12	59.07	64.41	69.27	73.64	77.42	80.73	83.6	86.06	89.94	92.73	94.72	96.16	97.15	97.84	99.3

Table showing SCE Proposed Glidepath for CARE rates with $5 minimum bill (no fixed charge)[469]

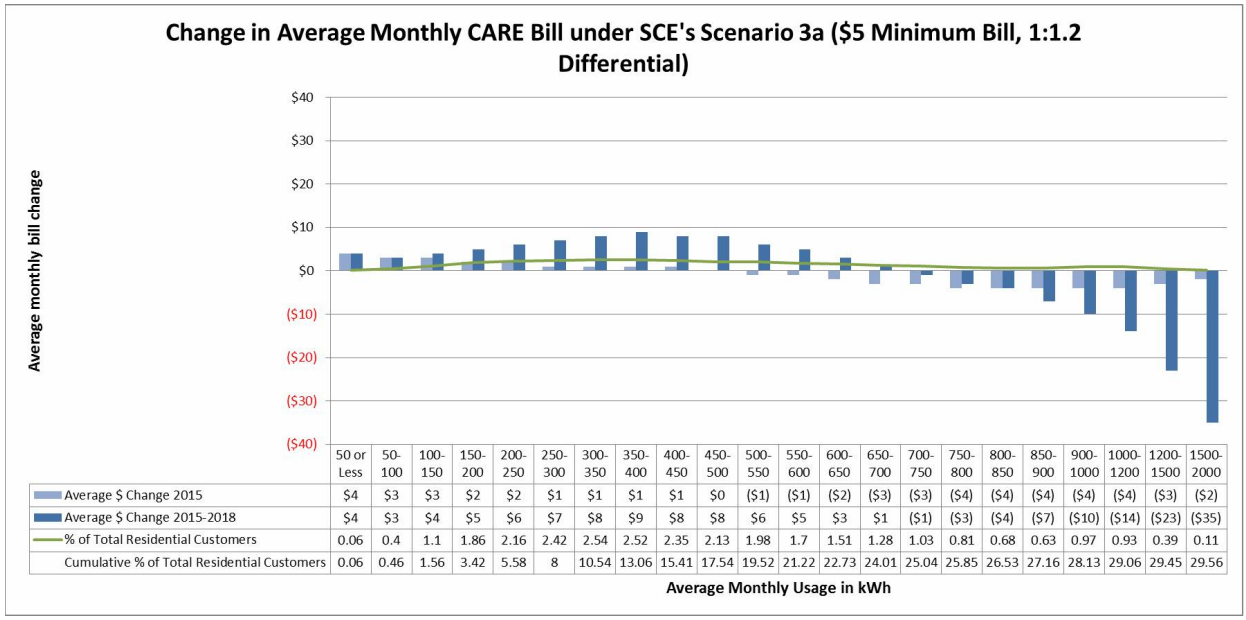
Scenario 3a – Minimum Bill of $5 – CARE rates[470]												
	Jan 2014	Jan 2015	2015 w/ Pending RRQ[471]		EOY 2015		2016		2017		2018	
	Rate	Rate	Rate	% Δ	Rate	% Δ	Rate	% Δ	Rate	% Δ	Rate	% Δ
0 – 100% of	$0.088	$0.097	$0.105	8.2%	$0.110	4.8%	$0.123	11.8%	$0.129	4.9%	$0.134	3.9%

[469] SCE Supplemental Filing of 4/1/15, Scenario 3a. The SCE bill impact graphs are based on SCE's Scenario 3a, a minimum bill scenario that closely matches the rate reform that we order in this Decision. Because the ordered reform is somewhat different than the scenario modeled by PG&E, the billing impacts will not be exactly the same. The reform we order today will lessen the immediate bill impacts on low-usage customers and stretch out the bill reductions seen by high-usage customers over a greater number of years. Nevertheless, the graphs below give us some indication of the billing impacts of the ordered rate reform. The graph use 2015 rates under the current four-tiered structure, calculated with 100% of SCE's 2015 pending revenue requirement added, as the base and show bill impacts to the end of 2015 as well as cumulative impacts through the end of 2018.

[470] SCE Supplemental Filing of April 1, 2015, Attachment B, Scenario 3a

[471] These rates were provided by SCE in its April 1, 2015 Supplemental Filing and represent 2015 rates under the current four-tiered structure with 100% of SCE's 2015 pending revenue requirement added.

BQ[472]												
100 -130% of BQ	$0.110	$0.125	$0.137	9.6%	$0.169	23.4%	$0.162	- 4.1%	$0.169	4.3%	$0.163	- 3.6%
130 – 200% of BQ	$0.200	$0.200	$0.216	8.0%	$0.169	- 21.8%	$0.162	- 4.1%	$0.169	4.3%	$0.163	- 3.6%
Over 200% of BQ	$0.200	$0.200	$0.216	8.0%	$0.225	4.2%	$0.199	- 11.6%	$0.169	- 15.1%	$0.163	- 3.6%

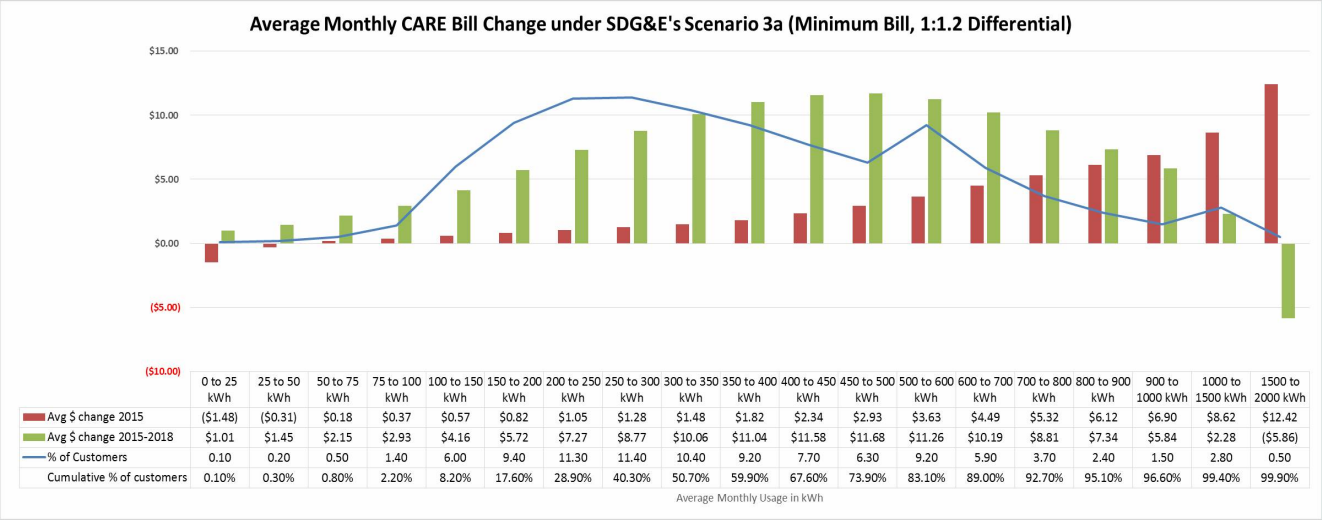


	50 or Less	50-100	100-150	150-200	200-250	250-300	300-350	350-400	400-450	450-500	500-550	550-600	600-650	650-700	700-750	750-800	800-850	850-900	900-1000	1000-1200	1200-1500	1500-2000
Average $ Change 2015	$4	$3	$3	$2	$2	$1	$1	$1	$1	$0	($1)	($1)	($2)	($3)	($3)	($4)	($4)	($4)	($4)	($4)	($3)	($2)
Average $ Change 2015-2018	$4	$3	$4	$5	$6	$7	$8	$9	$8	$8	$6	$5	$3	$1	($1)	($3)	($4)	($7)	($10)	($14)	($23)	($35)
% of Total Residential Customers	0.06	0.4	1.1	1.86	2.16	2.42	2.54	2.52	2.35	2.13	1.98	1.7	1.51	1.28	1.03	0.81	0.68	0.63	0.97	0.93	0.39	0.11
Cumulative % of Total Residential Customers	0.06	0.46	1.56	3.42	5.58	8	10.54	13.06	15.41	17.54	19.52	21.22	22.73	24.01	25.04	25.85	26.53	27.16	28.13	29.06	29.45	29.56

[472] BQ = Baseline Quantity.

Table showing SDG&E Proposed Glidepath for CARE rates with $5 minimum bill (no fixed charge)[473]

	Jan-14	Feb-15		Dec-15		2016		2017		2018
	Rate	**Rate**	**% Change YOY**	**Rate**	**% Change YOY**	**Rate**	**% Change YOY**	**Rate**	**% Change YOY**	**Rate**
0 – 100% of BQ	$0.100	$0.112	12.00%	$0.127	13.39%	$0.143	12.60%	$0.153	6.99%	$0.158
100 -130 % of BQ	$0.116	$0.131	12.93%	$0.127	-3.05%	$0.143	12.60%	$0.153	6.99%	$0.158
130 – 200% of BQ	$0.176	$0.199	13.07%	$0.217	9.05%	$0.204	-5.99%	$0.202	-0.98%	$0.193
Over 200% of BQ	$0.176	$0.199	13.07%	$0.217	9.05%	$0.204	-5.99%	$0.202	-0.98%	$0.193



	0 to 25 kWh	25 to 50 kWh	50 to 75 kWh	75 to 100 kWh	100 to 150 kWh	150 to 200 kWh	200 to 250 kWh	250 to 300 kWh	300 to 350 kWh	350 to 400 kWh	400 to 450 kWh	450 to 500 kWh	500 to 600 kWh	600 to 700 kWh	700 to 800 kWh	800 to 900 kWh	900 to 1000 kWh	1000 to 1500 kWh	1500 to 2000 kWh
Avg $ change 2015	($1.48)	($0.31)	$0.18	$0.37	$0.57	$0.82	$1.05	$1.28	$1.48	$1.82	$2.34	$2.93	$3.63	$4.49	$5.32	$6.12	$6.90	$8.62	$12.42
Avg $ change 2015-2018	$1.01	$1.45	$2.15	$2.93	$4.16	$5.72	$7.27	$8.77	$10.06	$11.04	$11.58	$11.68	$11.26	$10.19	$8.81	$7.34	$5.84	$2.28	($5.86)
% of Customers	0.10	0.20	0.50	1.40	6.00	9.40	11.30	11.40	10.40	9.20	7.70	6.30	9.20	5.90	3.70	2.40	1.50	2.80	0.50
Cumulative % of customers	0.10%	0.30%	0.80%	2.20%	8.20%	17.60%	28.90%	40.30%	50.70%	59.90%	67.60%	73.90%	83.10%	89.00%	92.70%	95.10%	96.60%	99.40%	99.90%

[473] SDG&E Supplemental Filing of 4/1/15.

8.2. FERA

In 2004, the Commission issued D.04-02-057, ordering PG&E, SCE and SDG&E to implement a program to provide rate relief to low-middle income customers with larger households. Under the current FERA program, residential customers who meet established income and household size requirements are charged the Tier 2 rate for energy usage in Tier 3. We recognize that, because the current program is predicated on existing tier definitions, transitioning to a two-tiered rate structure requires modifications to the current FERA program.

PG&E and SCE both proposed to transition FERA to a percentage discount off a bill calculated at standard rates. Under their proposals, eligible customers would receive a discount regardless of which tier(s) their energy usage falls in. PG&E and SCE employed similar methodologies to calculate the amounts of their proposed line-item FERA discounts. Both utilities calculated the average discount that all FERA program participants have received over the last five years and proposed to establish that percentage as the FERA discount. Using this methodology, PG&E's proposed line-item discount is 12.5% and SCE proposed a 10% line-item discount.[474] SDG&E did not include any changes to the FERA program in its original proposal, however they support SCE's proposal for a line-item discount of 10%.[475] The IOUs contend that their proposals would simplify the structure of the FERA discount and allow all eligible customers to benefit from the program, regardless of the amount of energy they consume.

Additionally, SCE proposed to recover any revenue loss resulting from providing the FERA discount from non-CARE customers in the residential class. This would be a change from SCE's current method of recovering FERA-related

[474] Exh. PG&E-101 at 2-22; SCE RB at 53.
[475] Exh. SDG&E-109 at CF-42/Fang.

revenue losses from all customer classes. SCE argues that, because the FERA discount is only provided to residential customers and there is no statutory requirement to recover its costs outside the residential class, any revenue shortfall should be recovered from non-CARE residential customers.[476]

Several parties opposed the IOUs' proposed modifications to the FERA discount. ORA and TURN both support providing FERA as a line-item discount off a bill calculated at standard rates; however both parties contend that the IOUs' methodology of calculating the amount of the discount is unfair. ORA and TURN assert that the IOUs' methodology understates the average discount for customers who actually receive a benefit from the FERA program. They argue that, because the IOUs' calculations include program participants with usage only in Tiers 1 and 2 (and, therefore, do not receive any discount), the resulting discounts are significantly less than the average discount received by customers with Tier 3 usage.

ORA proposed a 20% line-item FERA discount, arguing that the disparity between the IOUs' proposed FERA discount (10%-12.5%) and CARE discounts (30%-35%) is too wide considering how close the qualifying income ranges of the two programs are.[477] TURN proposed a 15% line-item FERA discount, justifying it as the midpoint between CARE and non-CARE rates.[478] TURN stated that it would not oppose the 20% discount proposed by ORA but feels that 15% is also reasonable. SCE refutes ORA and TURN's contention that the FERA discount should be established relative to the CARE discount, arguing that the Commission never intended the two discounts to be linked.[479] SCE also argues that TURN's proposed 15% discount, which equates to the maximum discount an

[476] Exh. SCE-101 at 45.
[477] ORA OB at 54.
[478] TURN OB at 43.
[479] SCE RB at 55.

SCE customer could achieve under the current structure, is not a reasonable basis for establishing a discount for customers at all usage levels.

CforAT also opposed the IOUs' FERA proposals, recommending that the Commission adopt CforAT's three-tiered rate proposal and maintain the existing FERA structure. CforAT argued that the IOUs' proposed FERA discounts are not based on an evaluation of what eligible customers can afford to pay for basic energy needs. CforAT echoes ORA and TURN's argument that, because the current benefits of the FERA program are not spread equally, using the average effective discount is not a reasonable methodology to determine a flat discount. CforAT is also concerned that by transitioning the FERA program to a line-item discount, the IOUs' proposals would significantly impact how the benefits of the discount are distributed among eligible customers. CforAT argues that customers who currently receive a significant FERA discount, due to their usage being very close to the upper limits of Tier 3, will experience a reduction in benefits and this can't be "'offset' by the fact that other households would see a greater benefit."[480]

A 10% discount for all FERA customers is reasonable. 10% is a reasonable amount compared to the CARE discount of 30%-35%. Because 10% is the average discount for all FERA customers it is reasonably equivalent to the discount provided in the past, even though in the past the discount was 0% for the FERA customers in Tiers 1 and 2. Importantly, by using the average discount for all FERA customers, rather than the average discount for Tier 3 FERA customers, this calculation avoids requiring a larger amount of funds to be collected from other ratepayers to subsidize this program.

[480] CforAT OB at 67.

In addition, we agree with SCE that any undercollection in the FERA discount should be funded by the non-CARE residential class and not from all customer classes. We direct SCE to make this change as part of its advice letter filing for 2015 rates.

8.3. Medical Baseline

The Medical Baseline program provides eligible customers of the three IOUs with a higher baseline allocation to cover additional energy needs required by medical equipment. PG&E and SDG&E also currently provide discounted rates to their Medical Baseline customers, while SCE does not. All three utilities proposed to maintain their existing, higher medical baseline allowances.

SDG&E's Medical Baseline customers are currently exempt from the Department of Water Resources Bond Charge (DWR-BC) and pay reduced rates in addition to receiving a higher baseline allowance. SDG&E's non-CARE Medical Baseline customers pay the CARE rate prior to the existing 20% line item discount (current SDG&E CARE rates are structured as a lower volumetric rate with an additional 20% line item discount on the bill).

In 2001, D.01-09-059 adopted rate increases for SDG&E's customers in order to recover the Department of Water Resources (DWR) revenue requirement, but exempted CARE and Medical Baseline customers form these increases.[481] SDG&E explains that at the time of this D.01-09-059, its CARE discount was provided only through a 20% line-item discount, meaning that CARE customers paid the same volumetric rates as non-CARE customers. In implementing D.01-09-059, SDG&E left CARE rates unchanged (a DWR-BC charge was not added) and began charging Medical Baseline customers the CARE volumetric rates. At the time of implementation, this meant that

[481] D.01-09-059 at 56 (Conclusion of Law 20).

non-CARE Medical Baseline customers were simply paying their previous non-CARE residential rate with an exemption from the DWR-BC charge; however as additional rate discounts were adopted for CARE customers in subsequent years, these discounts "have inadvertently been provided to non-CARE Medical Baseline customers."[482]

SDG&E proposes to gradually remove this discount by transitioning non-CARE medical baseline customers to non-CARE rates over four years. Under this proposal, rates would increase by 25% of the differential between non-CARE and Medical Baseline rates each year.[483]

PG&E Medical Baseline customers currently pay Tier 3 rates for their Tier 4 usage, which is currently equivalent to a 4 cent/kWh discount for usage over 200% of baseline. PG&E proposes to maintain this level of discount by providing a 4 cent/kWh discount on usage over 200% of baseline for these customers.

SCE does not propose any changes to its existing Medical Baseline program, which simply allocates a higher baseline to eligible customers.

8.3.1. Discussion

TURN is concerned that PG&E's proposal to provide its Medical Baseline discount as a 4 cent/kWh discount on usage over 200% of baseline would result in declining block rates in 2018 if a two-tier default rate is adopted. Medical Baseline customers would be charged less for usage above 200% of baseline than for usage up to 100% and usage between 100-200%. TURN asserts that this would violate the inclining block rate requirement in Public Utilities Code § 739.7. TURN recommends that the Commission increase the tier differential in a

[482] Exh. SDG&E-110 at CF-43/Fang.
[483] SDG&E OB at 52.

two-tiered rate or adopt TURN's proposed ~~3~~three-tier rate and apply the 4 cent/kWh to Tier 3.[484]

PG&E argues that very few non-CARE Medical Baseline customers exist who have monthly usage in excess of 200% of the higher baseline allocated to them and that TURN's proposal to adopt a ~~3~~three-tiered rate structure would be "an extreme response to a situation that affects so few customers and so little usage."[485] PG&E states that a Medical Baseline customer would have to use more than 1,700 kWh/month in order to exceed 200% of baseline;[486] however PG&E does not provide any data regarding the number of customers who currently fit this description. PG&E proposes that the Commission provide a "lower credit to all medical baseline usage exceeding 100% of baseline in 2018 that, at the very least, provides the same total benefit currently provided to medical baseline customers."[487]

CforAT argues that the IOUs' proposals to leave the Medical Baseline program relatively unchanged are not sufficient to ensure that these customers have access to affordable electricity under their proposed changes in rate design. CforAT asserts that increases in lower-tier rates would result in higher bills for all Medical Baseline customers and that the utilities have not adequately considered or analyzed the impacts of their proposals on Medical Baseline customers.[488] CforAT is opposed to SDG&E's proposal to transition non-CARE Medical Baseline customers to non-CARE rates. ORA supports maintaining all existing Medical Baseline discounts at current levels.

[484] TURN OB at 45.
[485] PG&E RB at 43.
[486] *Id.* at 44.
[487] *Ibid.*
[488] CforAT OB at 71.

Given the limited scope of this proceeding, for purposes of today's decision, we find that no changes should be made to the Medical Baseline program, except as necessary to ensure Medical Baseline customers continue to have access these special rates. We find the proposals of the utilities are reasonable and will be sufficient to maintain the same approximate discount that Medical Baseline customers are currently entitled to. We therefore approve the IOUs proposals, with the exception of SDG&E's proposal to discontinue the CARE discount currently provided to Medical Baseline customers. Even though this CARE discount is in addition to the required Medical Baseline discount, we find that any changes that would reduce the discount should be examined in SDG&E's GRC.

9. Volumetric GHG Rate Offset

Under the California Air Resource Board's (ARB) economy-wide greenhouse gas (GHG) Cap-and-Trade Program, ARB annually grants the state's electric IOUs an allocation of GHG allowances, which the utilities are required to sell in ARB's quarterly allowance auctions. These mandatory allowance sales generate substantial proceeds that "must be used exclusively for the benefit of retail ratepayers of…electric distribution [utilities], consistent with the goals of AB 32,"[489] the Global Warming Solutions Act of 2006.

In D.12-12-033 and subsequent implementing decisions, the Commission adopted a framework of rules regarding how the electric IOUs should distribute these proceeds in accordance with ARB's Cap-and-Trade Regulation and the parameters of Public Utilities Code Section 748.5. We required the three large electric IOUs to distribute these proceeds in the following manner: 1) compensate emissions-intensive trade-exposed entities in a manner similar to

[489] California Cap on GHG Emissions and Market-Based Compliance Mechanisms, Title 17, California Code of Regulations, Section 95892.

ARB's Industry Assistance program; 2) offset GHG costs in the electricity rates of small businesses through a volumetrically calculated credit known as the small business California Climate Credit; 3) neutralize GHG costs from residential electricity rates through a volumetrically calculated rate adjustment; and 4) return all remaining proceeds to households as an equal, semi-annual bill credit known as the residential California Climate Credit.

The issue relevant to the present proceeding is whether it is appropriate to discontinue the volumetric GHG rate offset for residential customers. Under the Cap-and-Trade Program, owners and operators of large sources of GHG emissions (including electric utilities and power plants) must submit compliance instruments – GHG allowances and a limited number of offsets – to ARB to account for their emissions. This requirement has the effect of creating a cost to emit carbon pollution, and this cost results in both an increase in the cost to produce electricity from fossil-fueled resources and in wholesale electricity prices. The electric utilities' revenue requirements increase correspondingly, and at present all customers, except residential customers, experience these GHG costs in the generation component of their electric rates.

In D.12-12-033, we reasoned that it was appropriate, at that time, for the three large electric IOUs to use allowance proceeds to offset all volumetric GHG costs that the IOUs would otherwise have included in upper tier rates. Though this approach violated our fundamental objective of preserving a carbon price signal in rates, we found that it was temporarily justified because statutory restrictions prevented the equitable allocation of costs, including carbon costs, among residential customers, and we wished to avoid adding to the disproportionate cost burden born by upper tier customers. We did not allow PacifiCorp or Liberty Utilities to use allowance proceeds in this manner, because

neither utility was subject to the same historic statutory limits on ratemaking; thus, their residential customers have experienced full GHG costs in rates since we authorized the utilities to begin introducing both allowance proceeds and GHG costs in rates in April 2014.[490]

AB 327 lifted the statutory restrictions that effectively prevented the utilities from including carbon costs in lower tier rates. The Commission envisioned that such a statutory change would trigger the introduction of GHG costs in residential rates and the discontinuation of the volumetric GHG rate offset. In D.12-12-033 we found that "future changes to the current residential tiered-rate structure that result in the reduction or elimination of the existing differences in cost burden between lower-tier and upper-tier residential rates would appear to eliminate the need to offset GHG costs in residential rates."[491] We further concluded that, should the difference between lower and upper-tier residential rates be substantially reduced or eliminated, "the carbon price signal should be fully reflected in residential rates, and all remaining revenue should be returned on a non-volumetric basis."[492]

Because it is now permissible to include GHG costs in both lower and upper tier rates, and this proceeding continues the process of narrowing the tiered rate differentials, we directed parties to brief whether the residential volumetric GHG rate offset should continue. If the volumetric GHG rate offset is eliminated, GHG costs will be reflected in residential customers' electricity rates, as is currently the case for the residential customers of PacifiCorp and Liberty Utilities. Additionally, if we discontinue permitting the utilities to use allowance proceeds for the residential volumetric credit, the size of the Climate Credit will

[490] D.12-12-033 at 108-109, 114.
[491] *Id.* at 179 (Finding of Fact 107).
[492] *Id.* at 114.

be correspondingly larger – residential customers will still receive the same total amount of allowance revenue; they will simply receive it all as the California Climate Credit, which will not affect rates or mute the carbon price signal.[493]

Aside from the IOUs, parties (ORA, TURN,[494] NRDC, SEIA and Sierra Club) argued that the volumetric credit should be eliminated and that the equal-per-account Climate Credit should be used as the mechanism to return all allowance proceeds to residential customers. As CALSEIA contends, in D.12-12-033 the Commission declared its intent to distribute GHG allowance proceeds equally per account, thereby preserving the "incentives the Cap-and-Trade program is intended to provide."[495]

The IOUs argue that the volumetric credit should not be eliminated at this time. SCE argues that while AB 327 lifted the rate freeze on the lowers tier, the volumetric return should continue until the "completion of tier-flattening,"[496] which, according to SCE's Phase 1 Opening Brief, is signaled by a two-tiered rate differential of 30 percent%.[497] PG&E argues that eliminating the volumetric return will "make residential electric bills more volatile," and thereby derail ARB's plan to smoothly and moderately transition to carbon price signals under its own schedule for phasing out the free allowances.[498] SDG&E contends that the Commission should address the allocation of GHG proceeds in a separate proceeding.[499]

[493] It is important to note that the allowance proceeds are held by the IOUs on behalf of their ratepayers, and therefore the Climate Credit should not be treated as a reduction in a customer's bill for purposes of calculating rate impacts and energy burdens. *See*, Phase 2 Decision.
[494] TURN RB at 56.
[495] CALSEIA RB at 8 (citing D.12-12-033 at 59).
[496] SCE RB at 92.
[497] SCE OB at 164.
[498] PG&E OB at 79.
[499] *See* SDG&E OB at 66.

As noted by NRDC and others, the volumetric credit "mute[s] the carbon price signal in upper-tier residential rates."[500] This defeats one of the goals of the Cap-and-Trade Program and also the Commission's primary policy objective in D.12-12-033 to ensure that rates reflect a carbon price signal. AB 327 enables the Commission and the electric utilities to reflect GHG costs in electric rates in an equitable manner across rate tiers, and this decision sets forth a process for the utilities to flatten rate tiers and eliminate the distortions that D.12-12-033 concluded were the sole basis for justifying the residential volumetric GHG rate offset.

For these reasons, we find that the volumetric credit for upper tier residential customers should be eliminated starting January 1, 2016. The IOUs' 2016 ERRA Forecast filings should reflect that the residential volumetric GHG rate offset will be eliminated in 2016.

ORA also proposed a specific methodology for allocating embedded GHG compliance costs to customers. ORA supports recovering GHG costs using an equal cents per kilowatt hour adder that would be applied to the rates for all tiers or TOU periods."[501] By eliminating the volumetric credit, the GHG costs will be reflected in residential rates in the same manner that similar other procurement-related costs recorded in ERRA will be recovered in rates. It is unnecessary to establish separate rules that would result in GHG costs being apportioned to rate tiers in a manner different from other procurement-related costs tracked in ERRA.

[500] NRDC OB at 47.
[501] ORA OB at 90.

10. Marketing, Education and Outreach (MEO)

10.1. Summary

In this proceeding we have repeatedly raised the importance of providing adequate marketing, education and outreach to customers so that they can understand and respond appropriately to their electricity rates. RDP #10 provides in part that "[t]ransitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates." Customer understanding is also an essential part of Section 745.

MEO is a large topic and is raised by numerous other utility programs. In some proceedings, MEO has been handled in separate applications. [502] In others, the Commission has unilaterally directed the IOUs to use a specific state-wide administrator. Historically, each utility has handled its own MEO.

In this proceeding, parties have identified a need for outreach and education on a local level, as well as the need for consistent state-wide messaging.

In the February 13, 2014 scoping memo we required the IOUs to address plans for outreach, but stated that "the specific details of outreach programs are likely beyond the scope of Phase 1, but it is necessary to have some information on utility plans in order to make this determination."

For example, PG&E's MEO proposal includes plans for (i) general awareness outreach, (ii) direct outreach to most impacted customers, and (iii) hard to reach customers.[503]

Based on the information provided, we find that there is a sufficient basis for the IOUs to move ahead with MEO plans related to summer 2015 and 2016

[502] *See, e.g.*, A.13-08-025, et al.
[503] PG&E OB at 71-73.

rate changes, but that a more robust review is necessary for long-term MEO plans to inform residential customers about their electric rates.

10.2. 2015 Outreach

Because 2015 rate changes occurring in the next few months, we direct the IOUs to quickly begin outreach to the most impacted customers. The IOUs took steps for the summer 2014 rate reform to inform impacted customers, and the IOUs have described similar outreach plans for 2015 rate changes.[504] We direct the IOUs to implement these outreach plans for 2015 rate changes. To the extent applicable, PG&E should work with ORA as agreed to in Exhibit Joint ORA-PG&E 1.

10.3. Long-Term Outreach

In testimony and in briefs, the IOUs are generally enthusiastic about MEO to improve customer understanding of their rates and to develop innovative MEO strategies. However, at least two significant problems remain: (i) lack of robust bill comparison tools, and (ii) weak metrics to track customer understanding.

Section 745(c) has specific requirements for bill comparison that must be met before default TOU is implemented. The bill comparison tools currently available, and the plans for more robust tools, differ substantially for each IOU.

SCE does not currently have any bill comparison tool available to customers. In its opening brief SCE argued at length that customers are not interested in a bill comparison tool. SCE therefore has no immediate plans to develop a customer-facing bill comparison tool. SCE estimates that it will take 18 months to develop such a tool once directed to by the Commission.

[504] *See, e.g.*, SCE OB at 156.

SDG&E recently rolled out an online tool to allow customers to compare tariff options. This tool is part of SDG&E's Smart Pricing Program and is intended to empower the customer, not burden the customer.[505] The tool became available after evidentiary hearings. SDG&E states that it "plans to provide personalized tailored solutions and communications based on its understanding of customer preferences[.]"[506]

PG&E currently has an online site, MyEnergy, where customers can view their past usage and compare which residential rate will be most cost-effective for their usage profile, save them the most money, and customers can review past usage. During evidentiary hearings, however, TURN's cross-examination of PG&E witness Pitcock revealed that the website provided potentially misleading information on reasons for bill increases. PG&E states that this problem has been addressed, and PG&E is constantly improving the tools available on MyEnergy.

We find that the bill comparison tool is an essential piece of the MEO for residential customers. We commend PG&E and SDG&E on already developing these tools, and we direct SCE to immediately begin to develop a similar tool that provides individual customers with bill comparison information tailored to their individual usage.

However, the confusing information from the MyEnergy website identified by TURN during evidentiary hearings has raised a significant concern about the quality of educational materials for individual customers on the IOU websites. As TURN puts it "PG&E offers an example of how customer education efforts can serve to mislead rather than inform."[507] We therefore direct the IOUs to

[505] SDG&E OB at 63.
[506] *Ibid*.
[507] TURN OB at 87.

include a live demonstration of their website and bill comparison tools as part of an annual residential rate reform summit to be held at the Commission.

A second concern is the availability and quality of metrics to measure customer understanding. The IOUs propose several metrics commonly used to evaluate marketing campaigns such as click-through rates. Click-through rates, however, will not help us evaluate whether customers understand their electric bills. It is worth noting, again, that the Hiner study had one finding that all parties agree with: customers generally do not understand their electricity rates.

ORA proposes the following metrics which are taken from D.13-12-038 (Decision on Phase 2 Issues: Statewide Marketing, Education, and Outreach Plans for 2014 and 2015) and Resolution E-4381 (Pacific Gas and Electric Company requests approval of its proposed metrics for its Peak Day Pricing and Time-of–Use customer education and outreach activities for non-residential customers).[508] ORA's list includes:

- The extent of customer exposure to advertising.
- Website activity: length of time, number of pages visited.
- Number and quality of key strategic partners that IOUs are able to coordinate with.
- Percent of escalated customer complaints received.
- Increase in the number of Californians that understand the benefits of modifying their energy use and know where to go to learn more about energy and energy management options.

ORA and PG&E stipulated to a joint exhibit "to represent their consensus view of development of the detailed outreach plan on a collaborative basis involving Commission staff and stakeholders."[509] PG&E notes that this collaborative process would include performance metrics and coordination with

[508] ORA OB at 88-89.
[509] PG&E OB at 74 (citing Joint Exhibit ORA-PG&E-1).

third-party marketers, such as Center for Sustainable Energy (CSE), under the Statewide ME&O decision (D.13-12-038). Although we commend ORA and PG&E for their agreement to a collaborative process, we do not make specific finding at this time as to the extent to which marketing should be coordinated with CSE. SCE agrees that the workshop process would be beneficial.[510]

TURN recommends that the IOUs be directed to "track awareness through approaches that measure the accuracy of customer responses to specific question that remain relatively constant over a series of years. This type of approach would allow the utilities and the Commission to better understand whether customer awareness is improving, declining, or remaining constant."[511] TURN also points out that metrics should play a role in evaluating whether expenditures are reasonable.[512]

We agree that the metrics suggested by ORA and the IOUs will be useful, but a metric to evaluate customer understanding, as suggested by TURN, must be one of the primary measures for assessing MEO success.

We find that the IOUs must move quickly to (i) improve bill comparison tools and (ii) develop a metric that will measure changes in customer understanding year over year. The bill comparison tool should not be limited by the timing or other requirements of Section 745(c).

The development of this long-term MEO program will be addressed in Phase 3 and will include workshops and/or working groups, as well as regular updates to the Commission.

[510] SCE RB at 91.
[511] TURN OB at 90.
[512] *Ibid*.

10.4. Tier 1 and Tier 2 Customer Education on Conservation Opportunities

For over a decade, low tier residential rates have been frozen in compliance with legislation. As a result, Tier 1 and Tier 2 customers have paid substantially less than cost to provide them with electricity for the last ten years. This decision will raise rates for these customers so that they pay a greater portion of the cost to serve them. Because these customers will have the significant bill impacts from the rate changes approved in this proceeding, we find that special additional educational materials should be provided to these customers to assist them in responding to rate increases.

The IOUs posit that as these customers begin to pay closer to cost of service, they will be motivated to conserve energy. Other parties suggest that these customers' conservation options may be limited by financial obstacles. A focused educational campaign should be focused on these low tier customers to inform them of affordable means to reduce energy use by behavior modification or inexpensive energy efficiency tools such as products to control vampire plug loads.

In addition, outreach to low-income customers should promote the energy efficiency improvement opportunities provided through existing Commission programs.. This outreach should be coordinated with the state-wide marketing of these programs as appropriate. For example, The Energy Savings Assistance (ESA) program, available to participants including those living in single-family, multi-family, and mobile homes with household incomes at or below 200% of the Federal Poverty Guidelines (FPG). The program provides weatherization measures and services including 1) Appliances: refrigerators, microwaves, clothes washers, 2) Water Conservation: water heater blankets, pipe insulation,

low flow shower heads, 3) Enclosure: insulation, air/envelope sealing, weather stripping), 4) HVAC: furnace repairs/replacements, air conditioning, infiltration, 5) Lighting, 6) Energy Education, and 7) Other miscellaneous measures such as smart strips and pool pumps. For program year 2014, the Commission approved a cumulative IOU ESA program budget of approximately $390 million. The Single-Family Affordable Solar Homes (SASH) and Multifamily Affordable Solar Housing (MASH) programs provide rebates for the installation of solar PV systems on low-income properties. The SASH program provides rebates for eligible low-income home owners, while the MASH program provides rebates for eligible low-income multifamily housing. On January 29, 2015, the Commission adopted D.15-01-027, implementing AB 217 (Bradford, 2013), which extended the MASH and SASH programs until 2021, authorized an additional $108 million in program funding, and set a capacity goal of 50 MW of solar PV installed at low-income customer housing across both programs.

We direct the IOUs to begin developing these materials and to work with other parties (such as ORA) to form an MEO Working Group. This campaign directed at energy savings for tier 1 and 2 customers should begin as soon as possible, but in no event later than January 2016. In the long-term, this campaign should be modified based on lessons learned to help this group of customers take advantage of existing direct incentive programs.

10.5. Cost Recovery

Because Phase 1 is not addressing details of the IOUs' specific long-term outreach proposals, the IOUs provided limited information on the expected cost of their MEO plans. As more specific MEO programs are developed, it will be useful for the utilities to provide more detailed budget forecasts.

In the meantime, the IOUs have requested memorandum accounts to track expenditures related to outreach. These memo accounts would be subject to reasonableness review, with the burden on the utility to show that the expenditures were incremental, verifiable and reasonable.

We agree that memorandum accounts are needed at this time to track expenditures and we therefore authorize the IOUs to implement, via advice letter, the requested memo accounts.

11. Approvals of IOU Rate Changes

11.1. Summary

AB 327 expanded the permissible residential rate structures to include flattening of the existing tiered rates, monthly fixed charges representing the fixed costs to serve the customer of up to $10, and default TOU rates starting in 2018.

The proposals of the utilities can be divided into immediate ranges to be implemented for 2015 (2015 Rates) and long-term rate design plans through 2018 (Roadmap).

All three utilities proposed to flatten tiered rates and implement a fixed on a glidepath beginning in 2015 and continuing through 2018. In conjunction with the structural changes to the tiers, the utilities proposed adjustments to related residential schedules like CARE, FERA and SmartRate. SDG&E and PG&E also propose specific glidepaths to reduce the CARE discounts to meet the statutory range of 30% – 35%. No utility proposed default TOU for 2018.[513] The utilities did propose to have pilots and opt-in rates to study TOU.

In addition, the utilities proposed marketing, outreach, and education programs to educate customers about their options for electricity rates.

[513] SDG&E initially proposed default TOU, but by the time of evidentiary hearings in November SDG&E had modified its proposal.

In reviewing the rate change requests, it is essential to look at the bill impacts of the requested rate changes on a cumulative basis. As set forth in more detail, we find that, when considered as a whole, the rate design changes and associated rates, as approved, are fair and reasonable, and are consistent with the RDPs and law. Our analysis considers the 2015 rate changes and the rate directions for the Roadmap. In addition, we consider the impacts of the significant rate reform made in summer 2014 as part of the cumulative impact analysis.

As discussed in the preceding section of this decision, our analysis is based on the 10 RDP, AB 327, and other statutory requirements. To avoid repetition, we've grouped the RDP as follows for this analysis.

Cost Of Service RDP	Affordable Electricity RDP	Conservation	Customer Acceptance
2 Rates should be based on marginal cost; 3 Rates should be based on cost-causation principles 7 Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals; 8 Incentives should be explicit and transparent; 9 Rates should encourage economically efficient decision-making;	1 Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;	4 Rates should encourage conservation and energy efficiency; 5 Rates should encourage reduction of both coincident and non-coincident peak demand;	6 Rates should be stable and understandable and provide customer choice; 10 Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

11.1.1. **Affordability Requirements**

11.1.1.1. **Overview**

Affordability of essential amounts of electricity is of particular concern. RDP #1 sets forth the principle that low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) can be met at an affordable cost. Section 382(b), sets a statutory

requirement that low-income ratepayers not be "jeopardized or overburdened by monthly energy expenditures."

This decision retains the requirement that Tier 1 cover baseline quantities of electricity. In addition, we must determine if the Tier 1 per kWh rates proposed for these baseline quantities are affordable.

This decision also preserves significant assistance to low-income customers. It makes necessary changes to FERA and medical baseline programs to reflect changes in the tier structure, but maintains the overall protections for these customer groups. This decision also continues the transition to the legislatively-mandated CARE discount range of 30%-35% in compliance with Section 739.1

11.1.1.2. Affordability of Changed Rates

Affordability analysis is framed by state law including Section 451 (requiring just and reasonable rates) and Section 382(b) (requiring reduced rates for certain low income customers and endeavoring to provide essential electricity at an affordable cost).

The burden is on the IOUs to justify proposed rate changes by showing they meet the law, including affordability requirements. The bill impact and energy burden analyses provided by the IOUs support our finding that the rates approved for 2015, and the direction of rates during the Roadmap period, are affordable.

CforAT argues that none of the rate designs proposed by the IOUs are just and reasonable.[514] Instead, CforAT states that its preferred rate design would consist of a three-tier structure with baseline quantities set at 55% of average. Tier 1 rates should be set at a level which, in conjunction with a CARE discount

[514] CforAT OB at 1.

of 35%, results in a mean energy burden for CARE customers that does not exceed 5%. Furthermore, they suggest that rates for Tier 2 and Tier 3 be held in a constant ratio to each other, and that there be no increased customer charge. A high-usage surcharge should apply to non-CARE customers with usage over 400% of average.[515]

The design proposed by CforAT would not meet all the legal requirements and Rate Design Principles. In particular, current rate design does not reflect cost of service, which makes it difficult to argue that current rate design is "just and reasonable" as required by Section 451. Moreover, by passing AB 327, the Legislature indicated its support for making residential rates more reflective of cost.

11.1.2. **Affordability Requirements**

CforAT uses a 5% energy burden (combined gas and electricity) as a benchmark for "high energy burden." This benchmark is used by the Low Income Needs Assessment (LINA).[516] However, neither the Commission nor state law has adopted a specific benchmark or test to determine whether a customer's energy burden is "high" and whether energy burden by itself can be used to evaluate affordability of electricity

SCE also points out that high usage customers bear the highest energy burden.[517] SCE provided data showing that the higher the average monthly bill,

[515] CforAT OB at 2-4.

[516] The full name of the LINA Report is the "Needs Assessment for Energy Savings Assistance and the California Alternate Rates for Energy Programs," prepared by Evergreen Economics, December 2013. An earlier low income needs assessment known as the KEMA Report" is also referenced. The full name of the "KEMA Report" is the "Final Report on Phase 2 Low Income Needs Assessment" prepared by KEMA for the Commission, September 7, 2007. Portions of the LINA Report are included in the evidentiary record within Exh. CforAT-01 (Revised Prepared Testimony of Henry J. Contreras Addressing Affordability Issues for Vulnerable Customers for Summer 2014).

[517] SCE OB at 92.

the greater percentage of households requesting bill extensions or alternative payment arrangements.[518] The chart below is excerpted from SCE's opening brief. The chart shows that for CARE customers in particular, the amount of the average monthly bill has a strong effect on the likelihood that the household will request a bill extension. While the chart below depicts the relationship across SCE's territory, the patterns holds with nearly every baseline territory.[519] These data suggest that tiered rates may actually exacerbate the problem of customers seeking bill extensions or alternative payment arrangements because tiered rates increase the bills of households using more than roughly the average level of consumption within each baseline territory. A flatter rate structure would reduce bills for households falling on the right-hand side of the chart, which should alleviate the financial strain that these households experience from their electricity bills.

The LINA study found that the mean energy burden for low income households is already 8%.

11.2. Default Rate Structure

11.2.1. Generally

After reviewing the rate proposals as a whole, based on the record in this proceeding, we find that the most important first step to reforming rates is to reduce the number of tiers and the differential between tiers to a reasonable amount.

The record in this proceeding shows that flattening tiered rates is reasonable and supports cost of service ratemaking. By retaining a 20% tier, and ensuring that the IOUs educate customers about the distinction between tiers, the new rates will continue to promote conservation. Reduction in the number of

[518] *Id*. at 118 – 120.
[519] SCE-106, Appendix E.

tiers may make the tiered rate more understandable to customers and assist in encouraging additional conservation from low-usage customers who will now see rates that are more related to cost.

The record in this proceeding also shows that a monthly charge to cover fixed cost would support cost of service ratemaking (provided IOUs are able to better document and identify customer-related fixed costs). The record also reflects that while a fixed monthly fee is used in the rate structure of many utilities, implementing a fixed charge at this time would be confusing to customers, and would not be acceptable without significant education and the ability to show customers that the fixed charge is not causing their electricity rates to increase.

In addition, adding a fixed charge at the same time as flattening the tiers would have negative bill impact on most customers. First, by holding off on fixed charge we continue to keep volumetric rates higher, and therefore more likely to incent conservation. Second, the combination of the fixed charge and flattened tiers would have an excessive impact on low-usage customers. For example, PG&E's Supplemental Response estimated the cumulative bill impacts between 2014 and 2018 for those customers using less than 300kWh/month in a scenario where a 1:1.2 ratio is achieved by 2018 with a $10 fixed charge introduced in 2016. PG&E's calculations show that average bill increases for these customers would range between 46% to 169% over that four-year period.[520]

By holding off on approving a fixed charge we continue to keep volumetric rates higher, and therefore more likely to incent conservation.

We therefore evaluate and approve modified 2015 Rates and a Roadmap rate structure for each utility separately below.

[520] PG&E Supplemental Response of April 3, 2015, Vol. 1 at 4.)

Each utility proposed its own timeline based on current rate structure, with the goal of achieving two tiers with a 20% differential by 2018.

UCAN and ORA argued that the glidepath towards tier flattening should be slower to avoid rate shock. The statute does not require a set timeline. Because this decision makes flattening of tiered rates the first step in rate reform, and holds other reforms until AFTER tier flattening is completed, we believe that 2019 is an appropriate target for tier flattening. Recall that high tier users will continue to pay rates well above cost and have been doing so for the last decade. The desire to protect low-usage customers from increases must be weighed against the need for timely relief for customers who have long paid more than their share of energy costs.

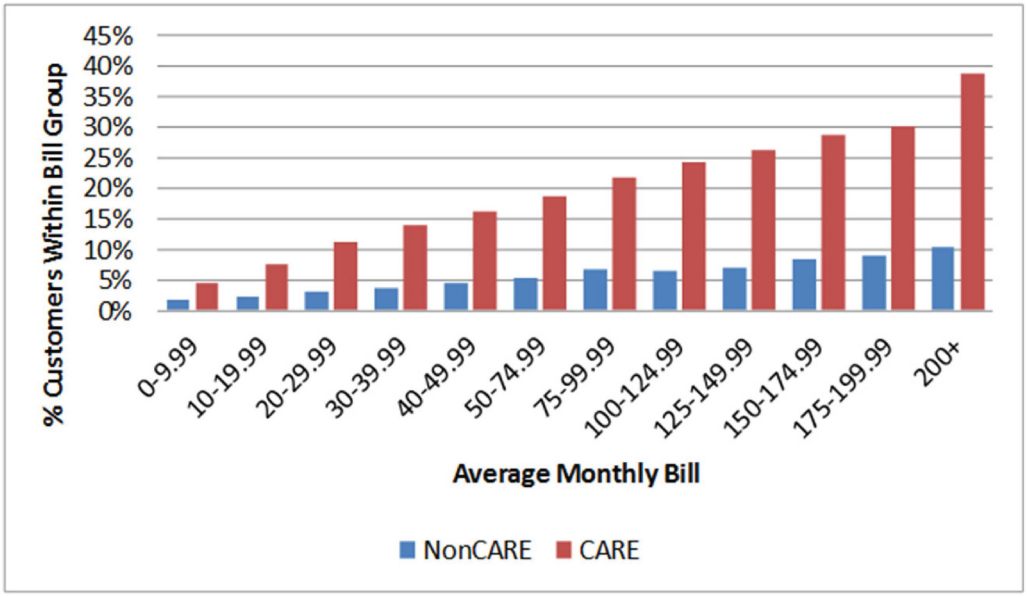
ORA proposed system of caps tied to revenue increases, but we aren't going to do that because confusing, creates uncertainty in roll out of other rate reforms, and make ratesetting unnecessarily difficult for the next few years.

Tracking usage in arrears is another method for assessing affordability. SCE provided data showing that the higher the average monthly bill, the greater percentage of households requesting bill extensions or alternative payment arrangements.[521] The chart below is excerpted from SCE's opening brief. The chart shows that for CARE customers in particular, the amount of the average monthly bill has a strong effect on the likelihood that the household will request a bill extension. While the chart below depicts the relationship across SCE's territory, the patterns holds with nearly every baseline territory.[522] These data suggest that tiered rates may actually exacerbate the problem of customers seeking bill extensions or alternative payment arrangements because tiered rates increase the bills of households using more than roughly the average level of

[521] SCE OB at 118 – 120.
[522] SCE-106, Appendix E.

consumption within each baseline territory. A flatter rate structure would reduce bills for households falling on the right-hand side of the chart, which should alleviate the financial strain that these households experience from their electricity bills.

Percentage of CARE and non-CARE Customers, By Bill Range, Granted Bill Extensions



11.2.2. **PG&E**

PG&E proposes to flatten its current four-tiered structure to two tiers with a 20% differential between the tiers by 2018. Reduction in the number of tiers would be accomplished in two steps: first, reducing from four tiers to three tiers in 2015 by combining the usage levels for Tier 2 and Tier 3; second, by reducing to two tiers in 2018 by collapsing the top two tiers into Tier 2.[523] Except as otherwise noted, the tables below reflect the data filed by PG&E as part of the April 2015 Supplemental Filing. Note that these illustrative rates therefore do not include any revenue requirement increases beyond 2015. PG&E states that it expects to have $0 in residential revenue requirement changes in 2015.

[523] PG&E OB at 15.

11.2.2.1. Recovery of Fixed Costs in Rates

For non-CARE customers, 2018 illustrative rates with a fixed charge and calculated with a composite tier set at a 1:1.2 differential would be $0.160 for Tier 1 and $0.235 for Tier 2 (representing all usage over 100% of baseline in 2018).[524] For non-CARE customers, 2018 illustrative rates without a fixed charge but with a $10 minimum bill applied to Tier 1 would be $0.195 for Tier 1 and $0.235 for Tier 2 (representing all usage over 100% of baseline).[525]

Including a fixed charge in 2015 keeps PG&E's Tier 1 rates roughly 8% lower than they would be in a minimum bill scenario in 2015. However, a fixed charge actually results in greater average bills for the vast majority of low-usage customers by the end of 2015 despite the lower Tier 1 rate. The same result holds for cumulative bill impacts between 2014 and 2018.

Table comparing PG&E's proposed 2015 Non-CARE Rates: fixed charge vs. minimum bill[526]

Summer 2015 Rate Change with a Fixed Charge and with composite tier differential	March 2015	EOY 2015	Summer 2015 Rate Change without a Fixed Charge and with a Minimum Bill	March 2015	EOY 2015
Fixed Charge	$0	$5	Minimum Bill	$0	$10
0 – 100% of BQ	$0.164	$0.164	0 – 100% of BQ[527]	$0.164	$0.179
100 -130% of BQ	$0.187	$0.223	100 -130% of BQ	$0.187	$0.223
130 – 200% of BQ	$0.275	$0.223	130 – 200% of BQ	$0.275	$0.223
Over 200% of BQ	$0.335	$0.310	Over 200% of BQ	$0.335	$0.310

PG&E proposes a monthly service fee that would begin in 2015 at $5.00 for non-CARE customers and $2.50 for CARE customers, and during the Roadmap Period would increase to the maximum permitted by statute.

[524] PG&E Supplemental Filing of April 1, 2015, Appendix A at 4, Scenario 1a.
[525] *Ibid.*
[526] PG&E Supplemental Filing of April 1, 2015, Appendix A at 4 (Scenario 1a); *id.* at 8 (Scenario 3a).
[527] BQ = Baseline Quantity.

As noted throughout this decision, the bill impacts associated with consolidating and narrowing tiers will be significant throughout the transition period. During this time, customers should be able to focus on understanding and responding to the change in tiered rates. We therefore find that it is not appropriate to allow a fixed charge during the transition period. Instead, we find that a minimum bill set at $10 for non-CARE customers and $5 for CARE customers, should be implemented with the 2015 summer rate change. Revenue from the minimum bill should be applied to Tier 1. The minimum bill amount will increase as follows:

Table : PG&E Adopted Minimum Bill for Non-CARE Customers (per month)

	PG&E non-CARE	PG&E CARE
2015	$10.00	$5.00
2016	$10.00	$5.00
2017	$10.00	$5.11
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

11.2.2.2. Consolidation of Tiers (PG&E)

In April 2015 Filing, PG&E inexplicably reduced the glidepath for the minimum bill scenarios to end in 2017 instead of 2018, as shown below. Instead of reaching the tier structure by 2018, the transition would be completed in 2017. PG&E did not offer an explanation for the change in transition period. However, extending the transition period one year, without making other changes to the timing of the ~~tiers~~Tiers 2 and 3 consolidation, would not significantly reduce the bill impacts on low tier customers.

The most significant bill impact for lower tier customers will occur when ~~tiers~~Tiers 2 and 3 are consolidated, regardless of whether a fixed charge is included in the rate structure or not. As the table below demonstrates, PG&E's

proposed collapse of ~~tiers~~Tiers 2 and 3 in 2015 results in an increase of the price of ~~tier~~Tier 2 by 19.25%.

To reduce the rate shock of such an increase, we direct PG&E to reduce the differential between ~~tiers~~Tiers 2 and 3 before combining these tiers. This approach is also recommended by ORA.[528] ORA also points out that the ~~tier~~Tier 2 customers were already impacted by a large rate increase in summer 2014.

Table showing PG&E Proposed Glidepath for Non-CARE rates with minimum bill (*no fixed charge*).[529]

	May 2014	March 2015		December 2015		2016		2017		2018
	Rate	Rate	% Change YOY[530]	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY	Rate
0 – 100% of BQ[531]	$0.136	$0.164	20.6%	$0.179	9.15%	$0.188	5%	$0.195	3.7%	$0.195
100 -130 % of BQ	$0.155	$0.187	20.6%	$0.223	19.25%	$0.224	0%	$0.235	4.9%	$0.235
130 – 200% of BQ	$0.320	$0.275	-14.1%	$0.223	-18.9%	$0.224	0%	$0.235	4.9%	$0.235
Over 200% of BQ	$0.360	$0.335	-6.9%	$0.310	-7.5%	$0.280	-9.7%	$0.235	-16.1%	$0.235

[528] ORA OB at 7.

[529] PG&E Supplemental Filing of April 1, 2015, Appendix A at 4 (Scenario 1a); *id*. at 8 (Scenario 3a). The PG&E bill impact graphs below are all based on PG&E's Scenario 3a, a minimum bill scenario that closely matches the rate reform that we order in this Decision. Because the ordered reform is somewhat different than the scenario modeled by PG&E, the billing impacts will not be exactly the same. The reform we order today will lessen the immediate b ill impacts on low-usage customers and stretch out the bill reductions seen by high-usage customers over a greater number of years. Nevertheless, the graphs below give us some indi cation of the billing impacts of the ordered rate reform.

[530] Includes revenue requirement increases throughout 2015 – the rest of the rates do not assume any revenue requirement increases to show the effect of rate reform in isolation from revenue requirement increases. All of the graphs are based on the following rate table, as modeled by PG&E. Note that for the sake of graphical ease, the graphs only include PG&E customers consuming on average less than 2000 kWh/month (over 99% of all PG&E customers).

[531] BQ = Baseline Quantity.

11.2.2.3. Revenue Requirement Increases (PG&E)

The final variable for determining a smooth glide path and avoiding sharp year over year rate increases is the treatment of revenue requirement changes during the transition period. For the April Supplemental Filing, the IOUs were not required to include an assumed or forecast revenue requirement increase beyond 2015. Therefore setting specific rules for treatment of future increases is of paramount importance.

PG&E proposed that (i) for revenue requirement increases, all rates (non-CARE and CARE, in every tier) would increase on an equal cents per kWh basis in order to collect the incremental revenue amount; and (ii) for revenue requirement decreases, the non-CARE Tier 1 and 2 rates, as well as all CARE rates, would remain at their then-current levels and non-CARE Tier 3 rates would be decreased so at to collect the lower revenue amount.[532]

In contrast, ORA proposes that for rate changes in 2016 or later, the cumulative change in rates applicable to baseline usage (Tier 1) should either (i) be limited to the change in the residential class average rate (RAR) plus three percent over a given 12-month period, OR (ii) allow tiers to move on an equal percent basis but cap the Tier 1 rate at RAR plus 3% relative to May 1 rates.[533]

ORA argues that without such a cap, increases on lower tier rates could be unacceptably high and lead to rate shock. ORA also argues that applying increases on an equal percent basis, instead of an equal cent basis as proposed by PG&E, is necessary because an equal cents basis would cause lower tier customers to face disproportionately high rate increases.[534] ORA cites several past settlements and Commission decisions that align with its proposals.

[532] ORA OB at 10 (citing Exh. PG&E 101 at 2-69).
[533] *Id.* at 6.
[534] *Id.* at 10-11; 13.

ORA proposes that any revenue requirement decreases be treated the same across all tiers. We find that although this symmetrical approach to revenue requirements would typically be desirable, in this instance the priority is narrowing the tiers in a timely manner without undue customer confusion or rate shock. Therefore, we approve PG&E's proposal for revenue requirement decreases.

Based on the changes we are making to PG&E's proposed rate design, and the principles of rate reform, we find that the following revenue requirement treatment, containing aspects of ORA's and PG&E's proposals, as well as a cap applied for the Tier 1 rate increases, is reasonable:

- Revenue Requirement Increases: allow tiers to move on an equal percent basis, except that Tier 1 increases are capped at RAR plus 5% relative to May 1 rates.
- Revenue Requirement Decreases: the non-CARE Tier 1 and 2 rates, as well as all CARE rates, would remain at their then-current levels and non-CARE Tier 3 rates would be decreased so as to collect the lower revenue amount.
- The glidepath should be no steeper than necessary to reach 1.2:1 by 2019. The glidepath shall continue until the later of (i) January 1, 2019 or (ii) the year the 1.2:1 tier ratio is achieved.

After reviewing the tier consolidation glidepath proposed by PG&E for a tiered rate with a minimum bill, we have determined that the bill impact on Tier 2 customers in 2015 would be too severe. Extending the glidepath by additional years would not mitigate this initial bill impact for Tier 2 customers. We therefore direct PG&E to update its rate for the following glidepath. The Tier 1 advice letter containing the updated tariff sheets for summer 2015 should also include the forecast rates for the new glidepath. The tier differentials for years

2015 – 2018 in the table below are suggested, and each IOU is directed to use these suggested differentials as a guideline for its glidepath.

Approved Glidepath for Tier Consolidation (PG&E)

	Current	2015	2016	2017	2018	2019
Number of Tiers	4 tiers	4 tiers	3 tiers	3 tiers	2 tiers	2 tiers
Usage covered			Baseline 101 – 200% BQ Over 200% BQ	Baseline 101 – 200% BQ Over 200% BQ	Baseline > 100% BQ	Same as 2018
Suggested Tier Differential		1:1.18:1.5:1.91	1:1.23:1.81	1:1.23:1.5	1:1.3	1:1.2

Based on this, we approve the continued tier narrowing on the glidepath approved above and a minimum bill of $10 for summer 2015. We find that a fixed charge reflecting a portion of fixed costs attributable to residential customers, as determined in a GRC Phase 2, is acceptable, but should not be implemented until the tier collapse is completed.[535]

PG&E must retain the four tier structure for the remainder of 2015. In its advice letter filing, PG&E should include a revised glidepath that (i) extends to 2019, (ii) narrows the ratio between ~~tiers~~Tiers 2 and 3 in 2015 but does not combine ~~tiers~~Tiers 2 and 3 until 2016, (iii) uses the suggested 2015 -2018 tier differentials above as a guideline, and (iv) applies revenue requirement changes as described above.

As discussed above, we direct PG&E to explore and propose seasonal tiered rates.

11.2.2.4. Energy Burden Analysis

As we noted in this proceeding's Phase 2 Decision: "[e]nergy burden is the ratio of the customer's cost for electricity and gas compared to the customer's income."[536] We further noted that "CforAT/Greenlining use a 5% energy burden

[535] As described above, the later of 2019 or the date the tier ratio reaches 1:1.2.
[536] Phase 2 Decision at 46.

(combined gas and electricity) as a benchmark for 'high energy burden.' This benchmark is used by the Low Income Needs Assessment (LINA) Report, but neither the Commission nor state law has adopted a specific benchmark or test to determine whether a customer's energy burden is 'high' and whether energy burden by itself can be used to evaluate affordability of electricity."[537]

We continue to employ the energy burden metric as an assessment of the general affordability of the rate design reforms. While we do not specifically hold that a 5% mark is the appropriate threshold for determining affordability, we continue to use it as a guideline for examining the impacts of rate reform on the affordability of energy.

PG&E's minimum bill rate reform proposal from the April Supplemental Filing is the most similar to the rate structure ordered in this decision. Generally, the average energy burdens for non-CARE customers in cool and moderate climate zones remain under 5%. Customers with the highest usage continue to have the highest energy burdens. However, the energy burden data provided by PG&E may not be reliable given that some of the sample sizes are as small as six customers. There are other affordability metrics in the evidentiary record that demonstrate reducing rates for high tier customers will reduce some energy burdens.

In light of this, we approve changes for 2015, but direct PG&E to update forecast energy burdens for 2015 and the remaining years using a reasonable sample size. This information must be included in the Tier 1 AL implementing summer 2015 rates.[538]

[537] *Id.* at 47.

[538] Original data from PG&E's Supplemental Filing, April 3, 2015, Energy Burden for Scenario 3a at 1-10. We note that PG&E's data is somewhat suspect given the very small sample sizes for some of their usage cohorts. For example, for CARE customers in the "Other" climate group the usage cohorts with burdens > 5% had sample sizes between 1 and 11. We have doubts about the significance of statistics divined from such small samples.

11.2.2.5. Adjustments to CARE and FERA programs (PG&E)

As discussed in Section 7, we approve PG&E's proposed glidepath for the CARE 30 – 35% average discount. We are also approving a minimum bill for CARE customers. As with the non-CARE rates, PG&E only provided illustrative rates for the minimum bill scenario with a glidepath ending in 2017. As with the non-CARE rates, we direct PG&E to extend the glidepath until 2019, and not to combine ~~tiers~~Tiers 2 and 3 in 2015. As discussed in Section 7, we approve PG&E's proposal to modify FERA in light of the reduced number of tiers.

11.2.2.6. Adjustments to SmartRate (PG&E)

SmartRate (Schedule E-RSMART) is PG&E's optional demand response program for residential customers. It is an "overlay" rate, meaning that it applies certain supplemental charges and credits to the underlying rates that the customer would be charged under any of the applicable residential tariffs.[539] Specifically, SmartRate participants pay higher prices for power during certain hours in the summer (Smart Day event hours). In turn, credits are applied to the participating customer's usage during other parts of the day. Specifically, there are two separate credits applied to usage from June through September (other than Smart Day event hours). The "participation credit" applies to only to usage above 130% of baseline. Currently, 130% of baseline is the boundary between Tier 2 and Tier 3. Because PG&E's rate restructuring approved in this decision will make changes to tier usage amounts, the "participation credit" will have to be modified. For this reason, PG&E proposes that the participation credit apply to all usage above 100% of baseline. Because the participation credit would apply to an increased number of kWh, PG&E asks that the credit be reduced from 1 cent/kWh to 0.75 cents/kWh for customers on existing tariffs. PG&E asks that

[539] Exh. PG&E-101 at 2-22.

its E-TOU rate proposed in this proceeding apply a smaller credit of 0.5 cents/kWh. PG&E argues that these changes will preserve the approximate magnitude of the currently effective SmartRate participation credit, and that the reductions reflect the increased number of kWh that will now be eligible for credits under SmartRate.

No parties commented on PG&E's proposal. In light of the other rate changes approved in this decision we agree with PG&E that SmartRate should be adjusted. PG&E's proposal is reasonable and consistent with the law and RDP. We therefore approve PG&E's proposed reduction of the SmartRate discount, concurrent with the combination of Tiers 2 and 3.

11.2.3. SCE

Like PG&E, SCE proposes to flatten its current four-tiered structure to two tiers with a 20% differential between the tiers by 2018. Reduction in the number of tiers would be accomplished in three steps beginning with a move to three tiers as part of summer 2015 rate reform. Except as otherwise noted, the tables below reflect the data filed by SCE as part of the April 2015 Supplemental Filing. Per the March 30, 2015 ALJ ruling requesting supplemental information, we assume the illustrative rates shown here include projected revenue requirement increases through 2015, but not beyond. SCE's expected 2015 rate increases are listed in Attachment B.

SCE Proposed Tier Flattening Glidepath

Current	2015	2016	2017	2018
4 tiers	3 tiers	3 tiers	2 tiers	2 tiers
	Baseline 101 – 200% BQ Over 200% BQ	Same as 2015.	Baseline Non-baseline	Same as 2017

11.2.3.1. Recovery of Fixed Costs in Rates

For SCE non-CARE customers, 2018 illustrative rates with a fixed charge and calculated with a composite tier set at a 1:1.2 differential would be $0.17 for Tier 1 and $0.24 for Tier 2 (representing all usage over 100% of baseline)). For SCE non-CARE customers, 2018 illustrative rates without a fixed charge but with a $10 minimum bill applied to Tier 1 would be $0.20 for Tier 1 and $0.24 for Tier 2 (representing all usage over 100% of baseline).

Table comparing SCE's proposed Summer 2015 Non-CARE Rates: Fixed Charge vs. Minimum Bill[540]

Summer 2015 Rate Change with a Fixed Charge and with composite tier differential	January 2015	EOY 2015	Summer 2015 Rate Change without a Fixed Charge and with a Minimum Bill	January 2015	EOY 2015
Fixed Charge	$0.94	$5	Minimum Bill	$0.94	$10
0 – 100% of BQ	$0.149	$0.151	0 – 100% of BQ[541]	$0.149	$0.164
100 -130% of BQ	$0.193	$0.247	100 -130% of BQ	$0.193	$0.25
130 – 200% of BQ	$0.257	$0.247	130 – 200% of BQ	$0.257	$0.25
Over 200% of BQ	$0.312	$0.329	Over 200% of BQ	$0.312	$0.333

SCE proposes a monthly service fee that would begin in 2015 at $5.00 for non-CARE customers and $2.50 for CARE customers, and during the Roadmap Period would increase to the maximum permitted by statute.

As noted throughout this decision, the bill impacts of consolidating and narrowing tiers will be significant throughout the transition period. During this time, customers should be able to focus on understanding and responding to the change in tiered rates. We therefore find that it is not appropriate to allow new

[540] SCE Supplemental Filing of April 1, 2015 (Scenario 1a; Scenario 3a).
[541] BQ = Baseline Quantity.

or increased fixed charge during the transition period.[542] Instead, we find that a minimum bill set at $10 for non-CARE and $5 for CARE customers, should be implemented with the summer rate change.

Unlike the other two utilities, SCE currently has a fixed "basic charge" of $0.031 per day, which equates to approximately $0.94 per month, for non-CARE customers, and $0.024 per day, equating to approximately $0.73 per month, for CARE customers. SCE requests an increase in the monthly service fee that beginning in 2015 to $5.00 for Non-CARE customers and $2.50 for CARE customers, and during the Roadmap Period the monthly service fee would increase to the maximum permitted by statute. SCE also requests a minimum bill that would be the same for all customers (CARE and non-CARE). For the reasons discussed above, we do not approve an increased fixed charge for 2015. We do approve a minimum bill, starting as early as 2015, at the amounts set forth below. Revenue from the minimum bill should be applied to Tier 1.

SCE Adopted Minimum Bill (per month)

	SCE non-CARE	SCE CARE
2015	$10.00	$5.00
2016	$10.00	$5.00
2017	$10.00	$5.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

11.2.3.2. Consolidation of Tiers (SCE)

For lower tier customers the most dramatic bill impact resulting from tier collapse will occur when ~~tiers~~Tiers 2 and 3 are consolidated, regardless of whether a fixed charge is included in the rate structure or not. When compared with January 2015 rates, SCE's proposed collapse of ~~tiers~~Tiers 2 and 3 in 2015 would result in an increase in the ~~tier~~Tier 2 rates by 28% under the fixed charge

[542] SCE can continue to apply its current fixed charge, but should not increase its fixed charge during the transition period.

scenario and an increase in the ~~tier~~Tier 2 rates by 29.5% under the minimum bill scenario. When compared with rates under the current four-tiered structure calculated with 100% of SCE's pending 2015 revenue requirement added, the price of ~~tier~~Tier 2 rates would increase by 17.6% with a fixed charge and by 19% with a minimum bill. The illustrative rates shown here include projected revenue requirement increases through the end of 2015, but not beyond.

To reduce the rate shock of such an increase, we direct SCE to reduce the differential between ~~tiers~~Tiers 2 and 3 before combining these tiers.

Table showing SCE's Proposed Glidepath for Non-CARE rates with $10 minimum bill no fixed charge[543] [544]

	Jan 2014	Jan 2015	2015 w/ Pending RRQ[545]		EOY 2015		2016		2017		2018	
	Rate	Rate	Rate	% Δ	Rate	% Δ	Rate	% Δ	Rate	% Δ	Rate	% Δ
0 – 100% of BQ	$0.132	$0.149	$0.162	8.7%	$0.164	1.2%	$0.182	11%	$0.191	4.9%	$0.199	4.2%
100 -130% of BQ	$0.165	$0.193	$0.210	8.8%	$0.250	19.0%	$0.239	- 4.4%	$0.251	5.0%	$0.241	- 4%
130 – 200% of BQ	$0.274	$0.257	$0.277	7.8%	$0.250	- 9.7%	$0.239	- 4.4%	$0.251	5.0%	$0.241	- 4%
Over 200% of BQ	$0.304	$0.312	$0.337	8.0%	$0.333	- 1.2%	$0.295	- 11.4%	$0.251	- 14.9%	$0.241	- 4%

[543] This table is based on SCE's April 8, 2015 Supplemental Filing's minimum bill scenario. Because the ordered reform is somewhat different than the scenario modeled by SCE, the billing impacts will not be exactly the same. The reform we order today will lessen the immediate bill impacts on low-usage customers and stretch out the bill reductions seen by high-usage customers over a greater number of years. This table includes revenue requirement increases through the end of 2015; rates after 2015 do not assume any revenue requirement increases to show the effect of rate reform in isolation from revenue requirement increases.

[544] SCE Supplemental Filing, April 1, 2015, Attachment B, Scenario 3a.

[545] These rates were provided by SCE in its April 1, 2015, Supplemental Filing and represent 2015 rates under the current four-tiered structure with 100% of SCE's 2015 pending revenue requirement added.

11.2.3.3. Revenue Requirement Increases (SCE)

The final variable for determining a smooth glide path and avoiding sharp year over year rate increases is the treatment of revenue requirement changes during the transition period. For the final set of bill impact modeling in Phase 1 we did not include an assumed or forecast revenue requirement increase.

SCE did not propose a specific treatment for revenue requirement changes occurring during the transition period. No other party had specific suggestions for treatment of SCE revenue requirement changes.

Based on the changes we are making to SCE's proposed rate design, and the principles of rate reform, we find that the following revenue requirement treatment, containing aspects of ORA's proposal, as well as a cap applied for the Tier 1 rate increases, is reasonable:

- Revenue Requirement Increases: allow tiers to move on an equal percent basis, except that Tier 1 increases are capped at RAR plus 5% relative to May 1 rates.
- Revenue Requirement Decreases: the non-CARE Tier 1 and 2 rates, as well as all CARE rates, would remain at their then-current levels and non-CARE Tier 3 rates would be decreased so as to collect the lower revenue amount.
- The glidepath should be no steeper than necessary to reach 1.2:1 in 2019. The glidepath shall continue until the later of (i) January 2019 or (ii) the year the 1.2:1 tier ratio is achieved.

We find that the treatment set forth for PG&E above is reasonable and should also be applied to SCE. After reviewing the tier consolidation glidepath proposed by SCE for a tiered rate with a minimum bill, we have determined that the bill impact on Tier 2 customers in 2015 would be too severe. Extending the glidepath by additional years would not mitigate this initial bill impact for Tier 2 customers. We therefore direct SCE to update its rate for the following glidepath.

The Tier 1 advice letter containing the updated tariff sheets for summer 2015 should also include the forecast rates for the new glidepath.

The tier differentials for years 2015 – 2018 in the table below are suggested, and each IOU is directed to use these suggested differentials as a guideline for its glidepath.

Approved Glidepath for Tier Consolidation (SCE)

	Current	2015	2016	2017	2018	2019
Number of Tiers	4 tiers	4 tiers	3 tiers	3 tiers	2 tiers	2 tiers
Usage covered			Baseline 101 – 200% BQ Over 200% BQ	Baseline 101 – 200% BQ Over 200% BQ	Baseline Over 100% BQ	Same as 2018
Tier Differential		1:1.34:1:56:1.94	1:1.4:1.76	1:1.37:1.5	1:1.34	1:1.2

Based on this, we approve the continued tier narrowing and a minimum bill of for summer 2015. We find that an increased fixed charge reflecting a portion of fixed costs attributable to residential customers, as determined in a GRC Phase 2, is acceptable, but should not be implemented until the tier collapse is completed.[546]

11.2.3.4. Energy Burden Analysis

In their April Supplemental Response, SCE calculated the estimated electric energy burden for both CARE and non-CARE customers by monthly usage cohort in four different climate groups: Cool (Zones 6, 8 and 16), Warm (Zones 5 and 9), Inland (Zones 10, 13 and 14) and Very Hot (Zone 15). These electric energy burdens represent the estimated percentage of annual income that an average customer in a given usage class pays for electricity over the course of a year.

[546] As described above, the later of 2019 or the date the tier ratio reaches 1:1.2.

We examined the number and percentage of customers who are projected to see electric energy burdens of 5% or more by the end of 2018 under SCE's proposed glidepath to a 1:1.2 tier differential by 2018 with a minimum bill of $10 for non-CARE customers and $5 for CARE customers. By the end of 2018, 128,490, or 4% of SCE's non-CARE residential customers, would have an electric energy burden of 5% or more. By the end of 2018, 11,746, or 1% of SCE's CARE residential customers, would have an electricity energy burden of 5% or more.

We find that these estimates of electricity burden are reasonable and consistent with affordability requirements.

11.2.3.5. Adjustments to Baseline Allowance; Seasonal Rates (SCE)

Considering SCE's proposed rate change as a whole, we believe that a decrease in baseline allowance to 50% is not warranted at this time. Currently, SCE's baseline is under the middle range for baseline allowances. The primary objective of reducing the baseline allowance is to take another step toward bringing upper tier and lower tier rates back in line with cost. However, we find that the tier flattening proposed between now and 2018 will be a significant bill impact on lower usage customers. We therefore deny SCE's request to reduce SCE's baseline allowance.

As discussed above, we direct SCE to explore and propose seasonal tiered rates.

11.2.3.6. Adjustments to CARE and FERA programs (SCE)

As discussed in Section 7 we direct SCE to maintain the current average discount. We are also approving a minimum bill for CARE customers. As with the non-CARE rates, we direct SCE to extend the glidepath until 2019, and not to combine tiers 2 and 3 in 2015.

As discussed in Section 7 we approve SCE's proposal to modify FERA in light of the reduced number of tiers.

Table showing SCE's Approved Tier Flattening Glidepath for CARE rates (*no fixed charge*); with minimum bill.

	2014	2015	2016	2017	2018
0 – 100% of BQ[547]	$0.088	$0.11	$0.122	$0.129	$0.134
100 -130% of BQ	$0.11	$0.169	$0.162	$0.169	$0.163
130 – 200% of BQ	$0.20	$0.169	$0.162	$0.169	$0.163
Over 200% of BQ	$0.20	$0.225	$0.199	$0.169	$0.163

11.2.4. SDG&E

Under SDG&E's current tier structure, the differential between Tier 1 and 2, and the differential between Tier 3 and 4, are very narrow. SDG&E describes it as "essentially an existing two tiered structure with a 50% differential."[548] For this reason, SDG&E's proposal for flattening its four-tiered rate structure is different from that of PG&E and SCE. SDG&E proposes to consolidate Tiers 1 and 2 into a new Tier 1, and consolidate Tiers 3 and 4 into a new Tier 2 in 2015. In addition, beginning in 2015, and continuing until 2018, SDG&E would reduce the differential between the consolidated Tier 1 and the new Tier 2 from approximately 50% to 20%.

SDG&E Proposed Tier Flattening Glidepath

Usage per Tier		Tier 1: up to 130% of BQ Tier 2: above 130% of BQ			
Differential	2.4 cents (Tier 1 and Tier 2) 15-17 cents (Tiers 1&2 and Tiers 3&4) 2 cents (Tiers 3 and 4)	~50%	40%	30%	20%

[547] BQ = Baseline Quantity.
[548] Exh. SDG&E 101 at CY-15.

For non-CARE customers, 2018 illustrative rates with fixed charge would be $0.194 (Tier 1) and $0.342 (Tier 2 (all usage over 100% of baseline)). For non-CARE customers, 2018 illustrative rates without fixed charge but with a minimum bill would be $0.208 (Tier 1) and $0.345 (Tier 2 (all usage over 100% of baseline)).[549]

Table comparing SDG&E's proposed 2015 Non-CARE Rates: fixed charge vs. minimum bill[550]

Summer 2015 Rate Change with a Fixed Charge and with composite tier differential	February 2015	EOY 2015	Summer 2015 Rate Change without a Fixed Charge and with a Minimum Bill	February 2015	EOY 2015
Fixed Charge	$0	$5	Minimum Bill	$0	$10
0 – 100% of BQ	$0.172	$0.194	0 – 100% of BQ[551]	$0.172	$0.208
100 -130% of BQ	$0.202	$0.194	100 -130% of BQ	$0.202	$0.208
130 – 200% of BQ	$0.401	$0.342	130 – 200% of BQ	$0.401	$0.345
Over 200% of BQ	$0.421	$0.342	Over 200% of BQ	$0.421	$0.345

SDG&E proposes a monthly service fee that would begin in 2015 at $5.00 for non-CARE customers and $2.50 for CARE customers, and during the Roadmap Period would increase to the maximum permitted by statute.

As noted throughout this decision, the bill impacts of consolidating and narrowing tiers will be significant throughout the transition period. During this time, customers should be able to focus on understanding and responding to the change in tiered rates. We therefore find that it is not appropriate to allow a fixed charge during the transition period. Instead, we find that a minimum bill set at $10 for non-CARE customers and $5 for CARE customers should be implemented with the summer 2015 rate change.

[549] SDG&E Supplemental Filing, April 1, 2015, Attachment C at 15.
[550] *Id*. (Scenario 1a; Scenario 3a).
[551] BQ = Baseline Quantity.

Table : SDG&E Adopted Minimum Bill (per month)

	SDG&E non-CARE	SDG&E CARE
2015	$10.00	$5.00
2016	$10.00	$5.00
2017	$10.00	$5.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

11.2.4.1. Consolidation of Tiers (SDG&E)

Because the tiers that are being combined are already close together, the bill impacts for lower tier customers will be slightly less than the increase seen in SCE and PG&E tier consolidation proposals. However, when 2014 rate increases are included in the analysis, the ~~tier~~Tier 1 bill impact is more dramatic. In July 2014, ~~tier~~Tier 1 rates were 15.4 cents per kWh. After the change proposed by SDG&E for 2015, the ~~tier~~Tier 1 rate will be 20.8 cents. This is a substantial increase of 20.93~~ percent~~% in just over one year. At the same time, the ~~tier~~Tier 4 rate will decrease by 14.18~~ percent~~% over the same year. UCAN contends that adding two additional years to the glide path (and applying any fixed charge to ~~tier~~Tier 1 only), would improve customer acceptance of the rate changes.

Table showing SDG&E's Approved Tier Flattening Glidepath for Non-CARE summer rates (*no fixed charge*), $10 minimum bill.

Scenario 3a – Minimum Bill of $10 – Non-CARE rates[552]										
	Jan-14	Feb-15		Dec-15		2016		2017		2018
	Rate	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY	Rate
0 – 100% of BQ	$0.150	$0.172	14.67%	$0.208	20.93%	$0.225	8.17%	$0.233	3.56%	$0.241
100 -130% of BQ	$0.173	$0.202	16.76%	$0.208	2.97%	$0.225	8.17%	$0.233	3.56%	$0.241
130 –	$0.35	$0.40	12.01%	$0.34	-13.97%	$0.31	-8.41%	$0.30	-4.11%	$0.28

[552] *Ibid.*

200% of BQ	8	1		5		6		3		9
Over 200% of BQ	$0.378	$0.402	6.35%	$0.345	-14.18%	$0.316	-8.41%	$0.303	-4.11%	$0.289

ORA is also concerned about this substantial ~~tier~~Tier 1 increase. ORA proposes that ~~tiers~~Tiers 3 and 4 be combined in 2015, but that SDG&E wait until at least 2016 to combine ~~tiers~~Tiers 1 and 2. Also, similar to its proposal for PG&E, ORA proposes that the cumulative change in rates applicable to baseline usage (Tier 1) should be capped at the residential class average rate (RAR) plus ~~five percent~~5% compared to August of the prior year.[553] ORA contends that without such a cap, increases on ~~tier~~Tier 1 rates would be unacceptably high. ORA cites the Phase 1 settlement as an example of where a cap on rate increases has been used before.

In addition, the glidepath should be no steeper than necessary to reach 1.2:1 in 2019. The glidepath shall continue until the later of (i) January 1, 2019 or (ii) the year the 1.2:1 tier ratio is achieved. After reviewing the tier consolidation glidepath proposed by SDG&E for a tiered rate with a minimum bill, we have determined that although the rate impacts on lower tier customers are not as severe as the Tier 2 rate impacts for PG&E and SCE customers, a more gradual glidepath should also be used for SDG&E. We therefore direct SDG&E to update its rate for the following glidepath. The Tier 1 advice letter containing the updated tariff sheets for summer 2015 should also include the forecast rates for the new glidepath.

Approved Glidepath for Tier Consolidation (SDG&E)

	Current	2015	2016	2017	2018	2019
Number of	4 tiers	3 tiers	2 tiers	2 tiers	2 tiers	2 tiers

[553] ORA OB at 19.

	Current	2015	2016	2017	2018	2019
Tiers						
Usage covered	Tier 1: 0-100% of BQ Tier 2: 101-130% of BQ Tier 3: 131-200%of BQ Tier 4: 200% + of BQ	Tier 1: up to 100% of BQ Tier 2: 101-130% of BQ Tier 3: above 130% of BQ	Tier 1: up to 130% of BQ Tier 2: above 130% of BQ	Tier 1: up to 130% of BQ Tier 2: above 130% of BQ	Tier 1: up to 130% of BQ Tier 2: above 130% of BQ	Tier 1: up to 130% of BQ Tier 2: above 130% of BQ
Suggested Tier Differential		1:1.13:~~1.9~~2.18	1:1.66	1:1.40	1:1.31	1: 1.20

11.2.4.2. **Revenue Requirement Increases**

SDG&E proposes (i) to apply any reduction in revenue requirements (including from the monthly service fees) to the upper tier; (ii) Adjust any incremental revenue requirement to the lower tier at two times the percentage increase in the residential class average rate; and iii) to direct adjustment to the differential if the target is not met.

Based on the changes we are making to SDG&E's proposed rate design, and the principles of rate reform, we find that the revenue requirement treatment set forth above for PG&E should apply to SDG&E:

- Revenue Requirement Increases: allow tiers to move on an equal percent basis, except that Tier 1 increases are capped at RAR plus 5% relative to May 1 rates.
- Revenue Requirement Decreases: the non-CARE Tier 1 and 2 rates, as well as all CARE rates, would remain at their then-current levels and non-CARE Tier 3 rates would be decreased so as to collect the lower revenue amount.
- The glidepath should be no steeper than necessary to reach 1.2:1 in 2019. The glidepath shall continue until the later of (i) January 1, 2019 or (ii) the year the 1.2:1 tier ratio is achieved.

11.2.4.3. Energy Burden Analysis

In their April 10th Supplemental Response, SDG&E calculated the estimated electric energy burden for both CARE and non-CARE customers by monthly usage cohort in their four different climate groups: Inland, Coastal, Mountain and Desert. We examined both the number and percentage of customers who are projected to see electric energy burdens of 5% or more by the end of 2018 under SDG&E's proposed glidepath to a 1:1.2 tier differential by 2018 with a minimum bill of $10. By the end of 2018, 17,222, or 1.94% of SDG&E's non-CARE residential customers, might have an electric energy burden of 5% or more. By the end of 2018, 726, or less than 1% of SDG&E's CARE residential customers, would have an electricity energy burden of 5% or more. We find that these estimates of electricity burden are reasonable and consistent with affordability requirements.

11.2.4.4. Adjustments to CARE and FERA programs (SDG&E)

As discussed in Section 7 we approve SDG&E's proposed glidepath for the CARE 30 – 35% average discount. We are also approving a minimum bill for CARE customers. SDG&E only provided illustrative rates for the minimum bill scenario with a glidepath ending in 2017. As with the non-CARE rates, we direct PG&E to extend the glidepath until 2019, and not to combine ~~tiers~~Tiers 1 and 2 in 2015. SDG&E should also adjust its FERA discount consistent with our approval of PG&E's proposal as discussed in Section 7, above.

11.2.4.5. SDG&E Seasonal Rate

As discussed above, we find that SDG&E's proposal for seasonal rates in all tiers should be adopted.

11.2.4.6. SDG&E Baseline Reduction Approved

Although we did not approve a baseline allowance change for SCE, for SDG&E, a different analysis applies. The details of SDG&E's proposed baseline allowance reduction, including a five-year glidepath for all-electric customers, are set forth in Exhibit SDG&E 105, CF -1 through CF-6 and Attachment A. Because we approve SDG&E's consolidation of Tiers 1 and 2, so that the consolidated Tier 1 includes usage up to 130% of baseline, the decrease to the baseline will be offset. UCAN and other parties acknowledge that because SDG&E's Tier 1 will include up to 130% of baseline it is reasonable. Therefore, we approve SDG&E's proposal to reduce the baseline to 50% concurrent with the consolidation of Tiers 1 and 2.

11.3. TOU Opt-In Rates for Residential Customers (PG&E, SCE, SDG&E)

As discussed above, the utilities already have optional TOU rates for residential customers. Because prior to AB 327 all residential rates were required to be tiered, existing TOU rates included a complex system of tiered and TOU rates for different times of the day and month. In this proceeding we directed the IOUs to offer untiered TOU rates. A summary of existing TOU rates is provide in the table below.

Utility	Opt-In TOU Tariff	Status/Approvals
PG&E	E-TOU	Approved in this decision. Peak periods being set in A.14-11-014
PG&E	E-6	Closure to new customers approved in this decision. Legacy Tariff for existing customers with 5-year transition to new TOU rate required; transition glidepath to be addressed in A.14-11-014.
PG&E	E-7	Closed to new customers. Legacy Tariff for existing customers with 5-year

Utility	Opt-In TOU Tariff	Status/Approvals
		transition to new TOU rate required; transition glidepath to be addressed in A.14-11-014.
PG&E	E-8	E-8 has been closed to new customers for 20 years. This decision approves eliminating E-8 and transferring existing customers to an alternative TOU rate to E-TOU.
SDG&E	Cost based TOU	This decision directs SDG&E to create a TOU opt-in that does not include DDMSF.
SDG&E	DR-SES EV-TOU EPEV-X; EPEV-Y; EPEV-Z	TOU period changes being considered in A.14-01-027.
SDG&E	DR-TOU	Closed as of January 2015 pursuant to D.12-12-004.
SDG&E	TOU-DR EECC-TOU-DR-P	Available January 1, 2015 pursuant to D.12-12-004
SCE	TOU D (Option A and Option B)	Approved in D.14-12-048.
SCE	CPP PTR SDP	Existing overlay tariffs.

11.4. TOU Pilots

In Section 5 we discussed the proposed TOU pilots for PG&E and SDG&E. We approved the development of these pilots, with specific parameters on the timeline set forth in the Next Steps section. In addition, we directed SCE to develop a similar TOU pilot.

11.5. Cost Tracking: Memorandum Accounts

Each IOU is directed to file a Tier 1 Advice Letter to create a memorandum account to track the costs of (i) TOU pilots, (ii) TOU studies, including hiring of a consultant to assist in developing study parameters, (iii) MEO costs associated with the rate changes approved in this decision, and (iv) other reasonable expenditures as required to implement this decision. These memo accounts

would be subject to review in the utility's next GRC, with the burden on the utility to show that the expenditure were incremental, verifiable and reasonable.

12. Next Steps

12.1. Phase 3

This decision has identified three areas to be addressed in Phase 3: (1) interpretation of the Section 745 conditions that must be met for default TOU, (2) requirements for supporting information and documentation for the Residential RDW applications, and (3) CARE restructuring under AB 327.

A PHC will be scheduled for June 2015.

12.2. TOU Design and study Working Group

We direct the parties to meet and confer regarding implementing a working group to propose and evaluate the study of residential TOU rates and the design of new TOU pilots obtain targeted information. We expressly authorize the working group to select a consultant, to be hired by the IOUs, to advise on and document the study parameters and pilot designs. Parties should be prepared to report on progress at the Phase 3 PHC. We expect the process of pilot design to be completed in 2015, and submitted for approval by each utility through a ~~tier~~Tier 3 advice letter.

12.3. Progress on Residential Rate Reform (PRRR) Reports/Workshops

The purpose of the PRRR is to provide the Commission and interested parties with regular updates on the IOUs' progress on understanding TOU rate impacts. Each PRRR includes a written report and a workshop presenting the written report and answer questions. The PRRR workshop will be scheduled twice per year, with reports due quarterly (November 1, February 1, May 1, and August 1). The PRRR workshops will be held in November and May. Primary

topics covered in the PRRR will include: outreach strategies, metrics, pilot design and results, opt-in TOU results, budget, and updates on other proceedings that will impact residential TOU rate design. The list of topics will be refined at the first PRRR. The first PRRR report will be due November 1. The IOUs should be prepared to present a progress summary at the first PRRR.

The first PRRR workshop will be held in summer 2015 to address creation of a working group or groups, hiring of a consultant to assist in TOU pilot design and TOU study parameters.

12.4. Annual Residential Electricity Rate Summit (RERS)

The Annual Residential Electric Rate Summit (RERS) will provide an opportunity for the Commission and the public to stay updated on the IOUs progress toward reforming residential rates and preparing their Residential RDW applications. Importantly, it will include a forum at which the IOUs will give a high level overview and respond to questions. Workshops geared toward participants in the proceeding, including the September PRRR, can be held on the same day. By coordinating the timing of these workshops, it will be more efficient for parties to attend.

The RERS Forum will put residential rates in in a broader, forward-looking context. The RERS Forum will address residential rates and programs across all relevant proceedings at the Commission and other agencies that impact the design of residential rates and residential customers opportunities to respond to rates. The presentation must include the status and success of outreach programs to educate customers about their rates. We expect that the RERS Forum will be attended by parties, Commission staff, and the public.

At the RERS Forum, each utility will have ten minutes to give a 5 slide presentation, demonstrate currently available online bill comparison tool, and respond to questions from Commission staff. The five slides for the 2015 RERS Forum are:

i. Summary of Summer 2015 rate impacts
ii. outreach materials and metrics
iii. coordination with other proceedings at CPUC and other agencies that impact residential rates
iv. status of meeting Residential RDW application requirements

The first RERS will be in November 2015.

12.5. Residential Rate Design Window

Each IOU must file a Residential RDW application no later than January 1, 2018. The Residential RDW application must include (1) default TOU proposal, (2) fixed charge proposal, and (3) tiered opt-in rate, and (4) at the discretion of the IOU, other optional residential rates. The Residential RDW application must include testimony to support the proposed rate change. Phase 3 will address specific information and supporting documentation that should be included in the Residential RDW application.

At a minimum, the Residential RDW application must include the following information and supporting documentation:

(i) Default TOU:

1. Results of required bill impact studies, including income/usage, GHG reduction, cost savings.
2. Section 745(d) requirements
3. TOU rate design to maximize customer acceptance.
4. Load response studies.

5. Alternative TOU tariff such as multiple TOU periods, matinee pricing, and seasonally differentiated TOU periods that are designed for advance customers.

(ii) if a fixed charge is included it should be supported by:

1. a residential fixed cost allocation approved for this purpose in the utility's last GRC Phase 2.

12.6. Schedule

Deadline	Event
30 days after decision	AL 1 with tariff changes: 2015 summer rate changes Proposed glidepath and bill impacts for tier consolidation after 2015
Quarterly (February 1, May 1, August 1, November 1)	IOUs file quarterly PRRR and host workshop to report on TOU pilot design, opt-in tariff studies, and status of Residential RDW application materials.
Summer 2015	First PRRR workshop to discuss next steps, including creating working groups and hiring of consultant
Semi-annually, May, November	PRRR workshop held each April and November to present PRRR reports and provide opportunity for questions and for parties to meet collaboratively.
Ongoing	Working group to design pilots, design studies of TOU, and to comment on plans for Residential RDW application required materials.
Summer, 2015	Phase 3 Workshop informally discuss scope and schedule for Phase 3 Presentations/proposals on CARE restructuring.
November 1, 2015	Residential Rate Summit: ; Presentation and Q&A on identified aspects of residential rates ; Related technical workshops
January 1, 2016	Submit Tier 3 AL for approval of TOU pilots
May 31, 2016	Progress on Residential Rate Reform (PRRR) Workshop

Deadline	Event
Spring 2016	TOU Pilots approved
Summer 2016	TOU Pilots start
November 30, 2016	Residential Rate Summit: ; Presentation and Q&A on identified aspects of residential rates ; Related technical workshops
May 31, 2017	Progress on Residential Rate Reform (PRRR) Workshop
November 30, 2017	Residential Rate Summit: ; Presentation and Q&A on identified aspects of residential rates ; Related technical workshops
January 1, 2018	Residential RDW application for default TOU
May 31, 2018	Progress on Residential Rate Reform (PRRR) Workshop
November 30, 2018	Residential Rate Summit: ; Presentation and Q&A on identified aspects of residential rates ; Related technical workshops
2019	Residential RDW application rates become effective as approved
May 31, 2019	Progress on Residential Rate Reform (PRRR) Workshop
November 30, 2019	Residential Rate Summit: ; Presentation and Q&A on identified aspects of residential rates ; Related technical workshops

13. Safety Consideration

A significant concern raised throughout this proceeding primarily by CforAT, but also by TURN and ORA is the need to ensure customer access to sufficient amounts of electricity to maintain public safety and health. Access to affordable energy is increasingly important in light of the rate design proposals contemplated in this proceeding. While our objective in this proceeding has been to ensure that rates are both equitable and cost-based, we must simultaneously

consider whether our rates and policies ensure affordable access to electricity for all IOU customers.

As a starting point, we note that utilities are required to offer "such adequate, efficient, just and reasonable service…as [is[necessary to promote the safety, health, comfort and convenience of its patrons, employees and the public…"[554] While Section 451 does not speak directly to the level of service or affordability that is reasonable, many other statutory requirements and Commission policies provide guidance. In particular, as discussed at length above, Section 739 requires the Commission to designate a baseline quantity of electricity necessary to supply a significant portion of the reasonable energy needs of the average residential customer at rates below average cost. In setting those quantities, the Commission takes into account the difference in energy needs between all-electric residences and those residences with both gas and electric service as well as differences in energy use by climate zone and season. By statute, the baseline quantity must be set at 50 to 60 ~~percent~~% of the average residential consumption within each climate zone.[555] The statute also requires that the Commission provide baseline rates that apply to the first or lowest block of an increasing block rate structure. Pursuant to Section 739 (c)1, the Commission is also required to provide higher energy allocations for residential customers with special medical needs or who are dependent on life-support equipment.

In addition to ensuring an adequate quantity of energy, the state and the Commission have developed specific programs to help low income customers with energy bills. Specifically, the Commission's CARE and FERA programs exist to provide rate assistance to low-income electric customers and households

[554] Pub. Util. Code § 451, in pertinent part.
[555] Section 739 (a) 1.

that meet certain annual income levels. Pursuant to Section 382 (b), the Commission is required to ensure that low-income customers are not jeopardized by or overburdened by monthly energy expenditures. The Commission currently complies with the requirement through a combination of low-income rate assistance as well as low-income energy efficiency programs. The Commission also has in place certain policies that seek to minimize the termination of utility services for nonpayment and require third-party notification and/or in person visits for certain customer disconnections.[556]

We discuss the impact of the rate design proposals on CARE and FERA and medical baseline programs and customers at length in this decision and determine that the outcome results in a rate design that is cost-based, substantially fair to all customers, and does not jeopardize customers' access to a sufficient amount of energy.

14. Comments on Proposed Decision

The proposed decision of the ALJs in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

15. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Jeanne M. McKinney and Julie M. Halligan are the assigned ALJs in this proceeding.

[556] Section 779.1, et seq.

Findings of Fact

1. Residential rates for the three IOUs are based on an inclining block price structure, wherein monthly usage is broken into tiers by volume with usage in the lower tiers paying a lower rate than usage in the higher tiers.

2. One purpose of the inclining block rate structure is to encourage residential customers to reduce aggregate electricity consumption.

3. Since 2001, lower usage tier rates have mostly been frozen resulting in most increases in revenue requirements allocated to residential customers with usage in the upper tiers.

4. In 2014, for all three IOUs, the rates charged for electricity usage in Tier 4 were more than double the rates charged for electricity usage in Tier 1.

5. The steep differentials between usage tiers result in lower tier rates substantially below cost of service and upper tier rates substantially above cost of service.

6. SCE currently has a fixed charge of less than $1 for residential customers. SDG&E and PG&E currently do not charge residential customers a fixed monthly fee.

7. Residential customers do not receive price signals that reflect their cost of service.

8. The Hiner study demonstrates that customers do not have a clear understanding of the structure of their electricity rates.

9. Conservation can take the form of behavioral changes or investments in energy efficiency.

10. Rooftop solar is not a form of conservation, but it is a renewable source of energy and a form of demand side energy management.

11. A customer's electricity price elasticity is based on the customer's ability to reduce or shift use, as well as the customer's awareness of the electricity price.

12. If the customer is not aware of the electricity price at a given hour, the price will not incent the customer to shift or decrease usage.

13. Customers with low usage are likely to have less discretionary use than high usage customers.

14. The evidence presented in this proceeding is not sufficient to find a clear correlation between usage and price elasticity.

15. Residential customers who do not understand how the inclining block price increases over the course of the month are more likely to respond to their average bill than the tier price or marginal price.

16. Some customers understand the inclining block price and will therefore respond to the marginal (highest tier) price.

17. The Marginal Price methodology used by Dr. Faruqui could be improved by eliminating the income elasticity variable.

18. There is no evidence that customers who respond the marginal price do so in a way that takes into account the income elasticity variable ("expenditure" variable).

19. Payback periods for energy efficiency investments, and investments in rooftop solar by customers who consume primarily in the lower tiers, by customers who consume primarily in the lower tiers, will be increased if the price of lower tier energy is raised.

20. There are different ways to calculate a payback period, but all result in a shorter payback period for customers who consume primarily in the lower tiers if the price of lower tier energy is raised. Customers with substantial consumption

in the upper tiers will experience longer payback periods as the price of upper-tier energy is reduced.

21. Customers cannot reduce the monthly service fee (fixed charge) by conserving energy.

22. The average price methodology for determining price elasticity reflects most customers' understanding of their energy bills.

23. If the tiered rate structure is flattened, low usage customers are expected to respond to increased average bills by reducing use, and high usage customers are expected to respond by increasing use.

24. If the average price methodology is applied to the original rate proposals of the IOUs, there is no significant change in aggregate usage by customers..

25. We cannot find with certainty that the rate design proposals will decrease or increase conservation.

26. The impacts of the rate design changes on conservation will be small.

27. Because tiered electricity rates increase sharply with increased usage, and because residential customers typically do not know at what point during the month their usage will reach a higher tier threshold, customers can experience unexpected large increases in monthly bills for a small increase in usage. This is particularly true during high-use periods such as summer months.

28. Customers with high use and low income are especially disadvantaged by the current steeply tiered rates.

29. In SCE's service territory, customers with use in the higher tiers are the most likely to ask for bill payment assistance or extensions.

30. In SCE's service territory, the highest electricity burdens are faced by customers with the highest usage.

31. Measuring usage-to-income correlations at the city-wide level does not provide an accurate indication of the prevalence of low-income, high-usage households and high-income, low-usage households.

32. Low-income and moderate-income ratepayers are not universally low or high users of energy.

33. If utilities are not required to use a composite tier differential, rates will be essentially flat.

34. The record in this proceeding is insufficient to conclude that load shifts from TOU rates will have an impact on GHG emissions.

35. It will be valuable to future TOU rate design to further study whether TOU load shift has a significant impact on GHG.

36. If peak use is reduced, the need to build power plants to serve customers for short periods of time will be reduced.

37. The cost of new power plants is part of the revenue requirement and this cost would be reduced if fewer new power plants are needed.

38. Currently, California has sufficient available energy resources to cover peak periods, but this could change in coming years as plants are retired and the population grows.

39. The need for investing in power plants could also increase if more flexible power is needed to support the growing amount of intermittent renewable energy.

40. If the need to build power plants is reduced by shifts in time of use, then increases in the cost of electricity will be mitigated.

41. SMUD's Smart Pricing pilot tested default and opt-in TOU rates during 2012 and 2013 and found that the dropout rate for the customers spending at

least some time on the default TOU rate was 4%, which was lower than the dropout rate of 5% for opt in TOU participants.

42. The average peak period load reduction for default TOU participants in SMUD's study was 5.8%. Opt in customers provided a larger average reduction of 11.9%, but, because SMUD was only able to recruit 17.5% of the targeted customers on to the opt in TOU rate, the absolute load reduction provided by default TOU would be nearly three times greater than opt in TOU due to the much larger number of participants.

43. The Commission has long supported time variant rates.

44. Energy costs vary by time of day.

45. Ratepayers have already invested billions of dollars in advanced metering infrastructure.

46. The investment in advanced AMI was justified by specific forecast cost-savings, and supported by assumptions that AMI would be the basis for programs to assist residential customers make more efficient use of energy.

47. To date, the utilities do not have significant enrollment in TOU rates, and therefore the benefits of AMI technology are not optimized.

48. TOU rates can reflect the predictable changes in energy costs during the day.

49. If there is a fixed charge, calculating the tier differential between ~~tiers~~Tiers 1 and 2, without taking into account the fixed charge, can result in rates where the per kWh price customers pay while in ~~tier~~Tier 1 is higher than the price paid in ~~tier~~Tier 2.

50. Revenue requirement changes after 2015 are not known.

51. ~~An~~A 2.1~~ percent~~% increase in revenue requirement per year does not appropriately reflect the impact on rates of years with significantly higher revenue requirement increases.

52. Tiered rates (inclining block rates) result in a subsidy from high-use customers, who pay more than the cost of energy services, to low use customers, who pay less than the cost of energy services.

53. There is no evidence in this proceeding that conservation is correlated to the steepness of the inclining block rate.

54. The evidence in this proceeding shows a weak correlation between income and usage.

55. Tiered rates cannot incent usage shifts that promote grid reliability needs, such as the need for flexible ramping resources.

56. Tiered rates cannot incent usage shifts that reduce peak load and the need for less-efficient "peaker" plants.

57. Steeply tiered rates provide a financial incentive for high usage customers to invest in energy efficiency improvements and rooftop solar.

58. Steeply tiered rates were not designed as the primary tool to promote rooftop solar investments.

59. Steeply tiered rates are not the most economically efficient method for encouraging customers to invest in energy efficiency improvements or rooftop solar.

60. Low income customers seeking to reduce energy usage may not have the financial or other resources to invest in energy efficiency or rooftop solar.

61. The evidence in this proceeding is insufficient to determine the amount of any increase in conservation by low usage customers as a result of flattening tiers.

62. To the extent tiered rates may promote energy efficiency or conservation, a mild differential between two tiers is sufficient to maintain a conservation signal.

63. Programs such as CARE and FERA are designed to keep energy affordable to low income customers.

64. A steeply tiered rate can result in volatile month-over-month electricity bills.

65. Bill volatility during summer months has been especially pronounced in hot, inland areas that rely on air conditioning.

66. Prior to the 2001 energy crisis there were two tiers.

67. Currently each IOU has four tiers.

68. Customers prefer less complex rates.

69. A two-tier rate is less complex than a three- or four-tiers rate.

70. A mild differential between tiers is closer to cost to serve than a steep differential.

71. There is insufficient evidence in this proceeding to demonstrate that higher use customers are responsible for a greater share of marginal costs than low usage customers.

72. A 20% tier differential is mild.

73. Low income customers with high usage will benefit from the flattened tier structure.

74. There is a positive correlation between household electricity consumption and the number of occupants per household.

75. Under a steep multi-tier rate structure, members of large households pay a disproportionate share of electricity costs.

76. Because baseline quantities are not adjusted for household size, tiered rates tend to penalize larger families and households.

77. A two-tier rate with a 1:1.2 differential meets statutory requirements and is consistent with the RDPs.

78. To minimize the rate shock, the transition from the current 4four-tiered rates must be gradual.

79. A longer transition period would allow more time for the tiers to be combined and narrowed.

80. The timing of tier consolidation has a significant impact on whether the transition to fewer tiers is consistent from year to year.

81. Customers prefer gradual rate structure changes.

82. The transition period to an end-state of two tiers at 1:1.2 should extend to 2019.

83. Tiers should not be combined if the difference between the tiers would result in an unacceptable rate increase for usage in the lower tier.

84. Changes to the default rate structure must be considered holistically.

85. Baseline quantity is intended to represent a portion of the reasonable energy needs of the average residential customer by climate zone.

86. By definition, the average customer uses more electricity than the baseline quantity.

87. When lower tier rates were frozen, changes to the baseline percentage was the only means of decreasing rate impacts on higher tier customers.

88. The baseline quantity must be between 50 and 60% of average residential consumption.

89. Currently, Tier 1 is designed to be equal to 100% of the baseline quantity. Tier 1 is sometimes called the "baseline tier."

90. Any reduction in baseline quantity should take into account other rate changes proposed.

91. SDG&E's tier consolidation proposal would result in 130% of baseline usage, instead of 100%, being in Tier 1 (the baseline tier).

92. For SDG&E, reducing the baseline quantity at the same time that Tier 1 is expanded to 130% would bring the number kWh covered under Tier 1 closer to the number of kWh covered prior to the tier consolidation.

93. Other changes to baseline quantities should be addressed outside of this proceeding.

94. Energy prices differ by season.

95. SCE and PG&E do not currently have seasonally-differentiated rates for residential customers.

96. Differentiating rates by season would reflect the fact that prices differ by season.

97. Residential customers prefer simple rate designs and differentiating rates by season will result in a more complex rate design.

98. SDG&E seasonally differentiates its higher tier rates.

99. There is no reason not to also seasonally differentiate lower tier rates.

100. TOU rates align with the rate design principles better than tiered rates to the extent that they reflect the time variation of marginal energy and capacity costs.

101. For TOU rates to be effective, customers must understand their electricity rate structure.

102. Medical baseline customers, customers requesting third-party notification pursuant to Section 779.1(c), and customers who cannot be disconnected without an in-person visit are exempt from being defaulted to a TOU rate.

103. The evidentiary record in this proceeding did not address whether there are other customer groups that should be exempt from default TOU.

104. In Section 745(c) the terms "senior citizens," "hot climate zones," and "economically vulnerable customers" are not defined.

105. Residential customers need a variety of rate options that includes both TOU and tiered rates.

106. TOU rates frequently have a mild price differential between on and off peak periods.

107. A mild price differential results in a less volatile rate.

108. TOU rates can be designed to be "cost-based" by time of day.

109. A default TOU rate with a mild differential (TOU Lite) will be more acceptable to most customers than a sharply differentiated TOU rate.

110. Some residential customers prefer a sharply differentiated rate.

111. A sharply differentiated rate will allow some customers to save more money by shifting their use.

112. Not all customers are able to shift their energy use to different time periods.

113. The baseline tier can be reflected in TOU rates as a credit or surcharge.

114. Because the baseline quantity is different for each Climate Zone, a baseline credit is a way to account for a customer's energy needs by geographic location.

115. If TOU rates do not include a baseline credit, low usage customers will have an incentive to stay on tiered rates and high usage customers will have an incentive to move to TOU without shifting their usage.

116. As the tier differentials become more narrow, the baseline credit for TOU will become smaller and will have less of an impact on rates.

117. One year of bill protection is required for default TOU.

118. Section 745 requires a shadow bill and a bill comparison tool.

119. A bill comparison tool is the best way for customers to understand how they would be impacted by different rate structures.

120. A bill comparison tool must reflect the individual customer's usage under different rate structures.

121. Reducing peak loads and integrating renewables are two areas in which TOU rates could be used to encourage changes in use to promote the efficiency and reliability of the grid.

122. A default TOU rate that is poorly designed could exacerbate grid reliability concerns and increase the need for certain types of generation.

123. The time periods during which shifts in load are needed will change over time.

124. Residential customers prefer stability in their rates.

125. Residential customers are likely to find default TOU periods that change frequently unacceptable.

126. Section 746(c)(3) of the Public Utilities Code encourages the Commission to approve TOU periods "that are appropriate for at least the following five years."

127. IOUs should set TOU periods in GRCs.

128. TOU periods should be based on grid needs and customer acceptance.

129. There are many ways in which special opt-in rates could incent customer behavior that improves grid reliability.

130. The IOUs should consider a menu of TOU rates for residential customers.

131. The IOUs should encourage each customer to switch to an optional rate that best serves the customer's usage pattern.

132. Customers who opt-in to TOU rates are more likely to reduce or shift their load than customers who are defaulted.

133. There are many programs available that promote energy efficiency.

134. TOU rates will allow residential customers to make more economically efficient decisions about investing in energy efficiency improvements and rooftop solar.

135. TOU rates will help customers align their investments with the IOUs' avoided costs.

136. The NEM tariff was "grandfathered" by D.14-12-048, but because the NEM tariff is an "overlay" rate, NEM customers will be impacted by rate changes in this proceeding.

137. Modifications to the NEM tariff are under consideration in a different proceeding.

138. NEM customers taking service under existing TOU rates may have expected that their rate structure would not change.

139. The times at which additional generation, or reductions in usage, are needed have changed over the last ten years.

140. The TOU periods under existing steeply-tiered TOU tariffs are advantageous to NEM customers who generate at times that were set as "peak."

141. TOU tariffs with outdated TOU periods should be closed to new customers.

142. Customers on TOU tariffs should be permitted to remain on them for up to five years (unless otherwise agreed to by the customer at time of enrollment).

143. Five years is sufficient time for NEM customers to determine how to respond to new TOU periods.

144. Customers on PG&E's E-6, EL-6, E-7, and EL-7 rate schedules and SDG&E's TOU tariff should be permitted a five year transition to new TOU rates.

145. A baseline credit will reduce the risk of revenue shortfall from TOU customers during the transition to flatter tiers.

146. A TOU rate should be designed to be revenue neutral to the residential customer class.

147. At this time there is not sufficient information to accurately predict usage under default TOU and therefore a revenue shortfall is possible

148. If the TOU rate is not properly defined there is a risk of undercollection from customers on the TOU tariffs.

149. A fixed charge will increase the portion of the revenue requirement that utilities can forecast without predicting customer usage.

150. All residential customers should contribute to any revenue shortfall occurring during the transition period.

151. Opt-in TOU tariffs and TOU pilots are a source for information on TOU rates, customer acceptance, load reductions and other factors that should be considered in the design of default TOU.

152. Parties have suggested numerous aspects of TOU rates to study.

153. The majority of the suggested studies can be achieved without a default TOU pilot.

154. An opt-in TOU pilot cannot correct for self-selection bias.

155. The requirements of Section 745(d) can be met using existing data.

156. Default and opt-in pilots should be designed in 2015 to start in 2016.

157. The IOUs must begin the process of designing a default TOU rate promptly.

158. IOU progress toward default TOU should be carefully monitored over the next 6 years.

159. A collaborative process will assist the IOUs in developing an acceptable default TOU structure and menu of optional rates.

160. Because the focus in the next few years is on understanding how residential customers respond to TOU, SDG&E should not deploy DDMSF pilots at this time.

161. An opt-in TOU tariff or pilot will provide more useful data for default TOU rate design if it includes a baseline credit.

162. Under a volumetric rate structure, low usage customers do not pay their share of fixed costs of service.

163. Under a volumetric rate structure, customers with extreme low usage, such as vacation home owners and NEM customers, do not pay their share of fixed costs.

164. A fixed charge to reflect a portion of fixed costs would reduce the current subsidy to vacation homeowners and NEM customers.

165. A fixed charge to reflect a portion of fixed costs would reduce the subsidy to low usage customers.

166. A fixed charge to reflect a portion of fixed costs will decrease volumetric rates.

167. A decrease in the volumetric rate could reduce conservation.

168. Through letters to the PAO and at public participation hearings, customers have indicated that a fixed charge is not popular.

169. It is not clear that customers understand how the fixed charge would impact overall rates.

170. A fixed charge cannot be avoided by a customer's reducing usage or being more energy efficient.

171. Fixed charges are used in other industries and by other utilities, including other electric utilities in California.

172. Customers have accepted fixed charges in contexts outside of their electric bills.

173. Fixed charges must reflect appropriate fixed costs.

174. Fixed costs attributable to the residential customer class are litigated in GRC Phase 2.

175. The GRC Phase 2 allocates cost among different classes of customers to reflect cost causation.

176. Recent GRCs have usually settled the allocation of fixed costs and are therefore not useful as a basis for setting a new rate structure that was not contemplated during the GRC settlement.

177. A fixed charge to reflect fixed costs will send a more accurate price signal to customers.

178. A fixed charge is not intended to incent specific customer behavior, but is intended to assist the customer in making economically efficient decisions regarding energy usage and investments.

179. A minimum bill would reduce the current subsidy to vacation homeowners and NEM customers.

180. A minimum bill will not result in a perceptible impact for customers other than owners of vacant properties and NEM customers who generate the majority of their electricity.

181. PG&E has not sufficiently justified the need to retain the ZMB.

182. PG&E's proposed Zero Minimum Bill provision is inconsistent with Rule 18 of the Code of Conduct concerning CCAs.

183. A fixed charge to reflect a portion of fixed costs will support the rate design principle of cost-causation.

184. The appropriate amount of the fixed charge may vary between small and large customers.

185. Section 739.9(e) allows the commission to consider different fixed charges for small and large customers but does not define "small" and "large."

186. There is not sufficient evidence in the record to define the characteristics of small and large customers for purposes of a fixed charge.

187. The CARE discount was originally set at approximately 15% off otherwise applicable non-CARE rates.

188. Currently, the effective discount rates for CARE have increased to 43.2% (PG&E), 31% (SCE), and 38% (SDG&E).

189. AB 327 allows the CARE discount to be restructured provided that it results in an average effective discount between 30 – 35%.

190. Because FERA is based on a tier structure with a minimum of three tiers, FERA will need to restructured as the tiers are consolidated.

191. Currently, FERA customers only receive a discount on usage above Tier 2.

192. The approximate current discount received by FERA customers is 10% on Tier 3 usage.

193. A flat discount on all FERA usage would result in increased discounts for low usage FERA customers and reduced discounts for high usage customers.

194. Changes to the medical baseline program discount should be minimized in this proceeding.

195. ARB administers the AB 32 Cap-and-Trade program pursuant to which the state grants a direct allocation of GHG allowances to electric utilities on behalf of customers for the dual purposes of protecting customers and of advancing AB 32 objectives. The revenue from the sale of GHG allowances is returned to residential customers through a variety of means, including an off-bill volumetric

return applied to upper tier usage and the California Climate Credit which is made on a per household basis to residential customers.

196. The Climate Credit currently appears as a credit on each residential customer's bill twice per year.

197. The IOUs' GHG compliance obligations result in both an increase in the cost of electricity and these increased costs are currently reflected in the rates of all customers other than residential customers.

198. Because the lower tiers were frozen, the Commission determined it was not fair for upper tier residential customers to bear all of the GHG compliance costs.

199. The lower tiers are no longer frozen so that the upper tiers no longer have to bear all of the GHG compliance costs incurred to supply residential customers with electricity.

200. If the volumetric credit is discontinued, GHG costs will be reflected in the rates of residential customers.

201. If the volumetric credit is discontinued, the amount of the semi-annual per household climate credit will increase.

202. Marketing, education and outreach for rate design changes must be robust and cost-effective.

203. If customers do not understand their electricity rates they cannot respond to price signals.

204. In 2014, each utility provided marketing and outreach to the customers most impacted by summer 2014 rate changes.

205. The outreach model used for summer 2014 rate changes is adequate for 2015 summer rate changes.

206. After summer 2015 rate changes, the IOUs should develop a more specific and robust MEO campaign for the rate changes and pilots.

207. Without metrics that evaluate customer understanding over time it is not possible to determine if MEO is effective.

208. A robust bill comparison tool is an important part of customer education on rate options.

209. The April 2015 supplemental filing pertaining to post-2015 rate changes is useful for illustrative purposes but should not be relied on s an accurate prediction of actual rates.

210. A bill comparison tool that uses generic customer information instead of a customer's own interval data is of limited use in helping customers understand their rate options.

211. An educational outreach campaign focused on low-cost and no-cost energy efficiency options will help lower tier customers in respond to higher rates.

212. By tracking expenditures on outreach specific to the requirements of this proceeding separately, it will be easier to evaluate the costs incurred for these programs.

213. One measure of affordability is the ratio of electricity charges to customer income (electricity burden). The Commission does not have a specific benchmark or metric for identifying what ratio constitutes a "high" electricity burden.

214. This proceeding does not address IOU revenue requirements.

215. Decision 14-06-029, adopted in Phase 2 of this proceeding, approved interim rate change proposals for summer 2014.

Conclusions of Law

1. The legal obligation of the Commission is to establish just and reasonable rates to enable the utility to provide service that is adequate, safe and reliable for the convenience of the public.

2. The changes in rates and charges authorized by this decision are just and reasonable.

3. Public Utilities Code Section 382 (b) requires the Commission to make a finding that customers are not jeopardized or overburdened by monthly energy expenditures.

4. Pursuant to Section 745(c), the Commission may not require or authorize default TOU pricing prior to January 1, 2018.

5. Consistent with our statutory obligation to ensure that rates are affordable, it is reasonable to adopt a baseline quantity for optional TOU rate schedules.

6. A baseline tier is not statutorily required for default TOU rates.

7. Based on record evidence demonstrating that customers frequently do not know what tier they are in, or the price associated with that tier, it is reasonable to conclude that customers respond to an average price as opposed to the price of the highest, or marginal tier.

8. Because none of the parties' showings provide sufficient basis for finding that reducing existing tiered rates from four tiers to two would significantly decrease, or increase, conservation, it is reasonable to conclude that any impacts resulting from the parties' proposed rate design changes would not unreasonably impair conservation.

9. We find that a residential rate structure with at least two tiers and a moderate tier differential should be available to residential customers.

10. The utilities should be required to follow specific procedures, as set forth in this decision, to ensure that the glidepath to a two-tier rate structure with a tier differential is gradual.

11. A composite tier differential is required to comply with the Section 739(d)(1) requirement that the Commission "establish an appropriate gradual differential between rate for the respective blocks of usage."

12. The adopted tier differentials with a composite tier and glidepath to a differential of 1:1.2 complies with the Section 739(d)(1) requirement that the Commission "establish an appropriate gradual differential between rates for the respective blocks of usage."

13. SCE's baseline quantity should not be changed at this time.

14. SDG&E's proposed changes to baseline complies with the Section 739(a)(1) requirement to set the baseline between 50 - 60% of average residential consumption for basic customers and 60-70% for all-electric customers in the winter heating season and should be approved effective as of the date that Tiers 1 and 2 are consolidated.

15. A fixed charge representing a portion of the fixed costs to serve the individual residential customer is reasonable.

16. Adopting a fixed charge at the same time as customers are also facing significant rate impacts associated with tier flattening would be inconsistent with our statutory duty to ensure reasonable rates.

17. A fixed charge should not be implemented until the tier collapse is completed.

18. Adopting a minimum bill in lieu of a fixed charge at this time is reasonable.

19. As part of their next General Rate Case Phase 2, each utility may submit testimony addressing the appropriate level of fixed customer costs, including how these fixed customer costs would be reflected in a residential fixed charge for small and large customers.

20. The adopted minimum bill amount should be applied to all residential rate schedules.

21. Revenues from the adopted minimum bill should be applied to reduce the volumetric rate for ~~tier~~Tier 1 during the transition period from 2015 through 2018.

22. The statutory limits in Section 739.9 regarding fixed charge amounts do not apply to minimum bill amounts.

23. It is reasonable to adopt minimum bill amounts consistent with the statutory limits for fixed charges

24. The CARE discount reduction glidepaths proposed by SDG&E and PG&E are reasonable phase-in schedules and comply with law.

25. SDG&E's proposed line item discount method for calculating a CARE discount of 35% is consistent with Section 739.(1)(c) and should be approved.

26. SCE's proposal to replace the current methodology for calculating the FERA discount with a flat 10% discount to reflect tier flattening is reasonable and should be adopted for PG&E, SDG&E and SCE.

27. The utilities' methodologies for calculating medical baseline should not be changed at this time.

28. The volumetric GHG rate offset for upper tier residential customers should be eliminated starting January 1, 2016. Beginning in 2016, GHG costs should be reflected in residential customer's electricity rates.

29. The IOUs' 2016 ERRA Forecast filings should reflect that the residential volumetric GHG rate offset will be eliminated in 2016.

30. The IOUs' proposed customer outreach plans for 2015 rate changes are reasonable and should be approved.

31. A bill comparison tool that provides individual customers with bill comparison information tailored to their individual usage is an essential piece of the long-term customer outreach program for residential rate design.

32. The IOUs should be required to develop bill comparison tools that provide individual customers with bill comparison information tailored to their individual usage.

33. An outreach and education program to promote low-cost and no-cost energy efficiency options for current Tier 1 and Tier 2 customers will improve the ability of these customers to conserve energy under new rates.

34. The long-term MEO program for residential rate design should include workshops and/or working groups, as well as regular updates to the Commission.

35. The utilities should be authorized to create memorandum accounts to track expenses for rate design outreach.

36. A two-tier rate structure, with a composite first tier, and a tier convergence glide path between 2015 and 2019 no steeper than is necessary to reach a tier differential of 1:1.2 in 2019 is reasonable and should be approved.

37. PG&E's proposed reduction of the SmartRate discount, concurrent with the combination of ~~tiers~~Tiers 2 and 3 is reasonable and consistent with the law and the RDP.

38. Each IOU should be directed to file a Tier 1 Advice Letter to create a memorandum account to track the costs of (i) TOU pilots, (ii) TOU studies,

including hiring of a consultant to assist in developing study parameters, (iii) MEO costs associated with the rate changes approved in this decision, and (iv) other reasonable expenditures as required to implement this decision.

39. PG&E's request to close Schedules E-6 and EL-6 should be granted.

40. PG&E's request to eliminate Schedules E-8 and EL-8 should be approved.

41. PG&E should be authorized to offer the optional E-TOU rate schedule proposed, with the exception that we approve a minimum bill in lieu of a fixed customer charge.

42. In order to provide for a gradual transition to new TOU periods and rate schedules, customers on PG&E's E-6, EL-6, E-7 and EL-7 rate schedules should be allowed to remain on those tariffs for a transition period that extends up to 5 years after the respective tariff is closed to new customers.

43. PG&E's proposal to include a Zero Minimum Bill provision on all residential rate schedules should be denied.

44. We should adopt a baseline credit on any default TOU rate and on at least one available TOU optional rate, as well as any opt-in or default pilot rates.

45. SDG&E's proposed Demand Differentiated Monthly Service Fee for optional TOU rate schedules should not be adopted at this time.

46. Any revenue shortfall resulting from optional TOU rate schedules should be recovered from all residential customers.

47. The ten-party timeline for default TOU is not reasonable.

48. The proposed 2015 rates of PG&E, SCE, and SDG&E, as modified by this decision are reasonable and compliant with law and the RDP.

49. The proposed roadmap for the transition period for each of the IOUs, as set forth in this decision, is reasonable and compliant with law and the RDP.

50. The proposed 2015 rates and roadmap for the transition period, as set forth in this decision for each of the IOUs, should be adopted.

51. The IOUs should endeavor to develop more accurate energy burden and electricity burden ratios in the future.

52. An annual summit on residential rates is reasonable and will help customers, the public, the utilities, the Commission, and stakeholders better understand residential rate reform.

53. The proposed rate designs, combined with existing programs for low-income and vulnerable customers, will ensure an affordable quantity of energy is available for customer health and safety.

54. The IOUs should continue to examine ways to ensure that customer health and safety is not impaired by electricity costs.

55. A third phase of this proceeding should be opened to consider (1) interpretation of the Section 745 conditions that must be met for default TOU, (2) requirements for supporting information and documentation for the Residential RDW applications, and (3) CARE restructuring under AB 327.

56. The new rate design proposals for PG&E, SCE, and SDG&E, as modified by this decision, should be adopted.

57. This order should become effective on the date issued.

O R D E R

IT IS ORDERED that:

1. The 2015 rate changes proposed by Pacific Gas and Electric Company are approved as set forth in Section ~~10~~11 of this decision.

2. The 2015 rate changes proposed by Southern California Edison Company are approved as set forth in Section ~~10~~11 of this decision.

3. The 2015 rate changes proposed by San Diego Gas and Electric Company are approved as set forth in Section ~~10~~11 of this decision.

4. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company shall each file a Tier 1 Advice letters setting forth the new residential rates adopted for 2015 with a requested effective date no later than July 30, 2015. The advice letter shall include revised tariff sheets to implement the 2015 rate designs adopted in this order, subject to the conditions set forth in this decision, including the minimum bill, tier structure, and adjustments to California Alternative Rates for Energy discount. The advice letter shall include documentation sufficient to permit the Commission's Energy Division to determine if the advice letter is in compliance with this decision. The tariff sheets shall become effective on the requested effective date pending disposition by the Commission's Energy Division and the advice letter shall prominently designate that it is "effective pending disposition."

5. The 2016 through 2019 rate design changes set forth above, including the minimum bill, tier rate structure, and California Alternative Rates for Energy (CARE), are approved subject to the conditions set forth in this decision.

6. Rate changes authorized by this decision and made after summer 2015 must be coordinated with other residential rate change filings.

7. Pacific Gas and Electric Company is directed to file a residential rate design window (RDW) application no later than January 1, 2018 proposing default TOU rate for residential customers. The RDW application may include a fixed charge representing a portion of PG&E's fixed costs to serve residential customers as determined in PG&E's previous general rate case. The RDW

application must include information and documentation reasonably sufficient to support the proposed rate.

8. San Diego Gas and Electric Company (SDG&E) is directed to file a residential rate design window (RDW) application no later than January 1, 2018 proposing default TOU rate for residential customers. The RDW application may include a fixed charge representing a portion of SDG&E's fixed costs to serve residential customers as determined in SDG&E's previous general rate case. The RDW application must include information and documentation reasonably sufficient to support the proposed rate.

9. Southern California Electric Company (SCE) is directed to file a residential rate design window (RDW) application no later than January 1, 2018 proposing default TOU rate for residential customers. The RDW application may include a fixed charge representing a portion of SCE's fixed costs to serve residential customers as determined in SCE's previous general rate case. The RDW application must include information and documentation reasonably sufficient to support the proposed rate.

10. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company must each file a Tier 1 Advice letters establishing a new memorandum account to track costs associates with time-of-use rate design, and pilot and study design, including marketing, education and outreach specific to time-of-use rates and other rates required by this decision.

11. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company must initiate the process of forming a working group to address the

issues regarding time-of-use rate design and study as detailed in this decision, and as modified or revised during Phase 3 of this proceeding.

12. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company must collectively provide Energy Division staff with proposed dates for the November 2015 Residential Electricity Rates Summit. Each of PG&E, SCE, and SDG&E is required to prepare and present materials at the Residential Electricity Rates Summit as directed by Energy Division staff, the assigned Administrative Law Judge, or the assigned Commissioner, as applicable.

13. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company must collectively organize and host a workshop to formalize the procedure for quarterly progress reports and future semi-annual Progress on Residential Rate Reform workshops.

14. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southern California Edison Company shall mutually agree and select one utility to hire a qualified consultant to assist with the design and implementation of TOU pilots and studies. The utilities must obtain input on the selection from other members of any working group formed as part of this proceeding to develop the pilot and study design.

15. The residential volumetric greenhouse gas rate offset must be discontinued starting January 1, 2016. The revenue return allocated to the residential class will consist solely of the semi-annual California Climate Credit.

16. The assigned Commissioner and assigned Administrative Law Judge are authorized to take all procedural steps promote the objectives in this decision

and to provide clarification and direction as required to assure the effective, fair and efficient implementation of this decision in this proceeding.

17. All outstanding motions and requests in this proceeding that are not specifically addressed in this decision are denied.

18. A prehearing conference for Phase 3 is scheduled for June 17, 2015 at 1:30 p.m. at the Commission offices in San Francisco, California.

19. Rulemaking 12-06-013 shall remain open.

This order is effective today.

Dated _____, at San Francisco, California.

ATTACHMENT A

Acronym List

ATTACHMENT A

ACRONYM LIST

AB	Assembly Bill
ACR	Assigned Commissioner Ruling
ALJ	Administrative Law Judge
AMI	Advance metering infrastructure
ARB	Air Resources Board
BQ	Baseline Quantity
CAISO	California Independent System Operators
CALSEIA	California Solar Energy Industries Association
CARE	California Alternate Rates for Energy
CCA	Community Choice Aggregation
CEC	California Energy Commission
CforAT	Center for Accessible Technology
CLECA	California Large Energy Consumers Association
CPI	Consumer Price Index
CSE	Center for Sustainable Energy
CSI	California Solar Initiative
CCUE	Coalition of California Utility Employees
DDMSF	Demand Differential Monthly Service Fee
DG	Distributed Generation
DR	Demand Response
DWR	Department of Water Resources
EDF	Environmental Defense Fund
EE	Energy Efficiency
EH	Evidentiary Hearing
EPA	Environmental Protection Agency
EPMC	Equal Percentage of Marginal Cost
ERRA	Energy Resource Recovery Account
ESA	Energy Savings Assistance
EV	Electric Vehicle
FERA	Family Electric Rate Assistance
GHG	Greenhouse Gas
GRC	General Rate Case
IEPR	Integrated Energy Policy Report
IOUs	Investor Owned Utility
IREC	Interstate Renewable Energy Council
kWh	Kilowatt hour
LINA	Low Income Needs Assessment
LOLE	Loss of Load Expectation

LOLP	Loss of Load Probability
LTPP	Long-Term Procurement dockets
MCE	Marin Clean Energy
MEO	Marketing, education, and outreach
MSF	Municipal Sustainability Forum
MWh	Megawatt hour
NEM	Net Energy Metering
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
OEB	Ontario Energy Board
OIR	Order Instituting Rulemaking
ORA	Office of Ratepayer Advocates
PCIA	Power Charge Indifference Adjustment
PHC	Prehearing conference
PPA	Power purchase agreement
PPH	Public Participation Hearing
PRRR	Progress on Residential Rate Reform
RAR	Residential Average Rate
RASS	Residential Appliance Saturation Study
RDP	Rate Design Proposals
RDW	Rate Design Windows
RERS	Residential Electric Rate Summit
SB	Senate Bill
SDCAN	San Diego Consumers' Action Network
SEIA	Solar Energy Industry Association
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SPO	SmartPricing Option
SRP	Salt River Project
TASC	The Alliance for Solar Choice
TOU	Time of Use
TURN	The Utility Reform Network
UCAN	Utility Consumers' Action Network
WECC	Western Electricity Coordinating Council
ZMB	Zero Minimum Bill

(End of Attachment A)

ATTACHMENT B

2015 Expected Revenue Requirement Changes

ATTACHMENT B

2015 Expected Revenue Requirement Changes

PG&E 2015 Residential Rate Changes[557] [1]

	Date	Description	Residential Class Average Rate (cents/kWh)**
1.	January 1, 2015	Annual Electric True-Up Filing, to consolidate previously-approved CPUC and FERC revenue requirement changes (including PG&E's 2014 ERRA Forecast approved in D.14-12-053), and also including the recovery of balances in balancing accounts previously approved for amortization in 2015. (Resolution E-4693, approving Advice 4484-E and Advice 4484-E-A	18.9
2.	March 1, 2015	Consolidated rate changes including (a) FERC-approved decrease to TACBAA rate; (b) FERC-approved increase to TO rates; (c) amortizing year-end 2014 balances in rates approved in Resolution E-4693; and (d) deferring implementation of Schedules AG-R and AG-V (Advice Letter 4596-E).	19.1

** Excludes Climate Credit.

[557] [1] PG&E Supplemental Filing April 14, 2015, at 2.

SCE 2015 Residential Rate Changes[~~558~~2]

	Date	Description	Residential Class Average Rate (cents/kWh)**
1.	January 1, 2015	Implementation of authorized residential rate changes (Advice Letter 3155-E)	17.04
2.	March 2, 2015	Implementation of GHG allowance revenue to EITE customers (Advice Letter 3178-E)	17.13
3.	June 1, 2015 (Earliest Anticipated)	Anticipated implementation of revenue requirement changes pursuant to 2015 ERRA Forecast (A.14-06-011)	18.66
4.	Q3 2015 (Anticipated)	Anticipated implementation of revenue requirement changes pursuant to 2015 GRC Phase 1 (A.13-11-003) and access to SCE's Nuclear Decommissioning Trust (D.14-11-040, Advice Letter 3193-E).	18.56

[~~558~~2] SCE Supplemental Filing April 14, 2015, at 3.

** Excludes Climate Credit.

SDG&E 2015 Residential Rate Changes[~~559~~3]

	Date	Description	Residential Class Average Rate (cents/kWh)**
1.	January 1, 2015***	The rates reflect the implementation of the SDG&E's Consolidated Advice Letter Filing, AL-2685-E, which implements the electric rate adjustments authorized by the CPUC and filed at the FERC through advice letters or decisions effective January 1, 2015.	23.2
2.	February 1, 2015***	Implementation of Advice Letter 2695-E for rates effective February 1, 2015: In compliance with Ordering Paragraph ("OP") 2 of the California Public Utilities Commission ("Commission") Decision ("D.") 15-01-004 approved on January 15, 2015, SDG&E is filing this advice letter to adopt its 1) 2015 Energy Resource Recovery Account ("ERRA") revenue requirement; 2) Ongoing Competition Transition Charge ("CTC") revenue requirement; 3) Local Generation ("LG") revenue requirement, and 4) 2015 vintaged Power Charge Indifference Adjustment ("PCIA") rates.	23.1
3.	GHG****	Implementation of SDG&E's 2015 Greenhouse Gas Revenue and Reconciliation Application (2015 GHG) (A.14-04-018). The rates presented reflect the anticipated impacts of SDG&E's revised updated application as filed which assumed an implementation date of April 1, 2015 without amortization resulting in an incremental increase in revenue requirement of $28 million. On March 26, 2015, CPUC approved SDG&E's 2015 GHG that includes a reduced amortization period from implementation to year-end. As a result, SDG&E anticipates a May 1 implementation, which would mean an 8 month amortization period. Therefore the actual rates reflecting SDG&E's implementation of its 2015 GHG will differ from the rates reflected in these scenarios.	23.4

[~~559~~3] SDG&E Supplemental Filing April 14, 2015, Appendix C.

4.	GHG + ERRA****	Potential ERRA Trigger filing. Currently SDG&E's ERRA Balancing Account is excess of the trigger threshold amount of $82 million. Preliminary estimates of the year-end balance are $90 million. This assumes that SDG&E does not receive funds from the Nuclear Decommissioning Trust Fund that would be used to offset the existing balances in this account as permitted under the SONGS Settlement Agreement approved by the Commission in D.14-11-040. In the event that SDG&E receives the funds from the Nuclear Decommissioning Trust Fund, based on preliminary estimates SDG&E anticipates the balance in the ERRA Balancing Account would then be reduced to below the trigger threshold at which time there would be no need to request recovery of the outstanding balance.	23.8

** Excludes Climate Credit.
*** Represents SDGE's Rate Changes since May 1, 2014 through current rates effective February 1, 2015.
**** Projected Residential Average Rates that reflect the assumptions presented in SDG&E's April 1 response.

(End of Attachment B)

ATTACHMENT C

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(End of Attachment C)

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Input:	
Document 1 ID	file://d:\jt2\Desktop\R1206013 McKinney_Halligan Comment Dec 4-13-15 (8).docx
Description	R1206013 McKinney_Halligan Comment Dec 4-13-15 (8)
Document 2 ID	file://d:\jt2\Desktop\R1206013 McKinney_Halligan Agenda Dec Revision 1 4-13-15 (7).docx
Description	R1206013 McKinney_Halligan Agenda Dec Revision 1 4-13-15 (7)
Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
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Deletions	431
Moved from	0
Moved to	0
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Format changed	0
Total changes	913