RESPONDENT RESPONSIBLE:
Counsel

QUESTION No. 1
Page 1 of 1

Other than Mr. Alvarez, please identify any persons, including experts whom the Attorney General has consulted, retained, or is in the process of retaining with regard to evaluating the Company's Application in this proceeding.

RESPONSE:

None.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 2
Page 1 of 1

For each person identified in (prior) response to Interrogatory No. 1 above, please state (1) the subject matter of the discussions/consultations/evaluations; (2) the written opinions of such persons regarding the Company's Application; (3) the facts to which each person relied upon; and (4) a summary of the person's qualifications to render such discussions/consultations/evaluations.

RESPONSE:

Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 3
Page 1 of 1

For each person identified in response to Interrogatory No. 1 above, please identify all proceedings in all jurisdictions in which the witness/persons has offered evidence, including but not limited to, pre-filed testimony, sworn statements, and live testimony. For each response, please provide the following:

(a) The jurisdiction in which the testimony or statement was pre-filed, offered, given, or admitted into the record;

(b) The administrative agency and/or court in which the testimony or statement was pre-filed, offered, admitted, or given;

(c) The date(s) the testimony or statement was pre-filed, offered, admitted, or given;

(d) The identifying number for the case or proceeding in which the testimony or statement was pre-filed, offered, admitted, or given; and,

(e) Whether the person was cross-examined.

RESPONSE:

Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objection

QUESTION No. 4
Page 1 of 1

Identify and provide all documents or other evidence that the Attorney General may seek to introduce as exhibits or for purposes of witness examination in the above-captioned matter.

RESPONSE:

Objection. The question seeks information which is or may be protected by work product and/or attorney-client privilege. Without waiving this objection, the Attorney General states that he has not yet identified any such documents, and will provide such information as soon as practicable prior to the hearing in this matter.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 5
Page 1 of 1

Please provide copies of any and all presentations made by Mr. Alvarez within the last three years involving or relating to the following: 1) demand side management; and 2) costs of participating in PJM, including capacity and energy market evaluations.

RESPONSE:

Mr. Alvarez has made no such presentations within the last three years.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 6
Page 1 of 1

Please confirm that Mr. Alvarez is not offering any opinions regarding any of the other aspects of the Company's Application in these proceedings.

(a) If the response is in the negative, please state Mr. Alvarez's position.

RESPONSE:

Confirmed.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objection

QUESTION No. 7
Page 1 of 1

Please confirm that, other than the opinions offered by Mr. Alvarez, the Attorney General is not taking a position on any of the other aspects of the Company's filing in these proceedings.

(a) If the response is in the negative, please explain the Attorney General's position.

RESPONSE:

Objection. The question seeks information which is or may be protected by the work product and/or attorney-client privileges. Without waiving this objection, the Attorney General states that in the event he asserts any position regarding the "other aspects of the Company's filing in these proceedings," he may assert any such position in his final brief or final comments in the instant docket.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 8
Page 1 of 1

Please identify all proceedings in all jurisdictions in which Paul Alvarez has offered evidence, including but not limited to, pre-filed testimony, sworn statements, and live testimony and analysis for the last three years. For each response, please provide the following:

(a) the jurisdiction in which the testimony, statement or analysis was pre-filed, offered, given, or admitted into the record;

(b) the dockets by name and number; and,

(c) whether a final commission decision order was issued and what date.

RESPONSE:

Objection. The question: is overbroad; seeks information which is in the public domain; is designed to harass and oppress; is argumentative; is irrelevant; and assumes facts not in evidence. Duke Energy Kentucky, Inc. (DEK) is just as capable of performing the research necessary to obtain these documents as is the Attorney General. Without waiving these objections, see Appendix A to the Direct Testimony of Paul J. Alvarez in the instant docket.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objection

QUESTION No. 9
Page 1 of 3

Please provide copies of the documents that are relevant to Mr. Alvarez's testimony in Case No. 2019-00277 listed in Appendix A: Curriculum Vitae of Paul Alvarez attached to Mr. Alvarez's testimony:

(a) Critique of Smart Meter Benefits Claimed by Puget Sound Energy. November 22, 2019

(b) Critique of Smart Meter Benefits Claimed by Rockland Electric Company. October 11, 2019

(c) Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. October 7, 2019

(d) Investigation into Distribution Planning Processes September 6, 2019

(e) Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation Performance in the Public Interest Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform. December 8, 2014.

(f) The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. July 8, 2019

(g) Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

(h) Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018

(i) Measuring Distribution Performance" Benchmarking Warrants your attention. With Sean Ericson. April 2018

(j) Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. October 2017.

(k) Integrated Distribution Planning: An Idea Whose Time has Come November 2014.

(l) Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the

Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

(m) Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January 2012.

(n) Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

(o) A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

(p) Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

(q) The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

(r) NASUCA Annual Meeting. Grid Modernization: Basic Technical Challenges Advocates should Assert. Orlando, FL. Nov. 13, 2018

(s) NARUC Committee on Energy Resources and the Environment. How big data can lead to better decisions for utilities, customers, and regulators. Washington DC. February 15, 2016.

(t) National Conference of Regulatory Attorneys 2014 Annual Meeting. Smart Grid Hype & Reality. Columbus, Ohio. June 16, 2014.

(u) NASUCA 2013 Annual Conference. A Review and Synthesis of Research on Smart Grid Benefits and Costs. Orlando. November 18, 2013.

(v) IEEE Power and Energy Society, ISGT 2013. Distribution Performance Measures that Drive Customer Benefits. Washington DC. February 26, 2013.

(w) Great Lakes Smart Grid Symposium. What Smart Grid Deployment Evaluations are Telling Us. Chicago. September 26, 2012.

(x) Mid-Atlantic Distributed Resource Initiative. Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities. Philadelphia. April 20, 2012.

(y) DistribuTECH 2012. Lessons Learned: Utility and Regulator Perspectives. Panel Moderator. January 25, 2012.

(z) DistribuTECH 2012. Optimizing the Value of Smart Grid Investments. Half-day course. January 23, 2012.

QUESTION No. 9
Page 3 of 3

(aa) NARUC Subcommittee on Electricity. Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators. St. Louis. November 13, 2011.

RESPONSE:

Objection. The question: is overbroad; seeks information which is in the public domain; is designed to harass and oppress; is argumentative; is irrelevant; and assumes facts not in evidence. DEK is just as capable of performing the research necessary to obtain these documents as is the Attorney General. Without waiving this objection, the Attorney General has attached hereto the documents referenced in subparts (l), (m), and (t), as these documents refer to peak-time rebates.

# Technical and Economic Concepts Related To The Smart Grid –

# A Guide For Consumers

SmartGrid consumer collaborative

October 8, 2013

# TABLE OF CONTENTS

## FOREWORD

### About This Document

This guide was commissioned as a companion piece to “Smart Grid Economic and Environmental Benefits,” a related report from the Smart Grid Consumer Collaborative (SGCC). This guide has been designed to help people unfamiliar with the electric distribution utility industry to understand the technical and economic fundamentals behind the concepts presented in that report. Many consumers will find this guide valuable as a stand-alone piece. The related report is not required reading for this document; however, the report may make more sense for many readers once the concepts presented in this guide are understood.

### About the Smart Grid Consumer Collaborative

SGCC is a consumer-focused nonprofit organization formed to promote an understanding of the benefits of modernized electrical systems among all stakeholders in the United States. Membership is open to all consumer and environmental advocates, technology vendors, research scientists, and electric utilities for sharing research, best practices, and collaborative efforts of the group. Learn more at smartgridcc.org.

### About the Wired Group

This document was prepared for the SGCC by the Wired Group, a consultancy helping clients to unleash the latent value in distribution utility businesses. Learn more at wiredgroup.net.

### Acknowledgements

The SGCC would like to thank the many companies and organizations that helped formulate insights from the research reviewed and provided feedback on the content, themes, and layout of this document. Only by continuing to collaborate on consumer issues will we be able to fully realize the promise of Smart Grid. If you are not a member, we invite you to join us as we continue to listen, collaborate, and educate going forward.

October 8, 2013

Patty Durand, Executive Director
Smart Grid Consumer Collaborative

# 1. INTRODUCTION

Most people have only a cursory understanding of how electricity arrives at their homes and businesses. They understand that electricity is delivered via wires in their neighborhoods but don't recognize the size, scope, and complexity of the effort required to do so in a reliable and cost-effective manner.

Distribution utilities go to great effort to ensure electricity is delivered reliably and efficiently. They have managed the laws of physics so well over the last century that consumers rarely give electric delivery a second thought. However, stakeholder interest in the distribution utility business is increasing. Consumers and businesses are demanding more flexibility and ever-greater reliability from their electric grids, environmental advocates are demanding utility distribution services that support reductions in environmental impact, and businesses and low-income consumer advocates continue to prioritize low costs above all else. The different stakeholders maintain competing interests that utilities, regulators, and governing boards strive to reconcile.

Smart Grid capabilities are available to reduce environmental impact and increase flexibility, reliability, and customer choice. They can also reduce operating costs and "lost" electricity, as indicated in the SGCC's companion report, "Smart Grid Economic and Environmental Benefits." However, Smart Grid capabilities can be costly to implement. Increasingly, stakeholders will be asked for their input on the kind of distribution grid they want, how much they are willing to spend on it, and the trade-offs they would prioritize.

As stakeholders endeavor to answer these questions collectively and strike a balance between their competing interests, they are increasingly motivated to gain a better understanding of the technical and economic concepts central to modern electric distribution utility operations and business models. This document attempts to help nontechnical readers better understand these concepts so that they can gain new perspectives and better place their specific objectives into a broad and well-rounded context.

The components of this document have been selected for presentation as a result of their relevance to the Smart Grid investments that many utilities have made or are considering. The components are ordered to match that of the SGCC's companion report, "Smart Grid Economic and Environmental Benefits." However, there is no prerequisite to read that work to obtain value from this document. The Smart Grid–related concepts presented here include:

- The Basics of Traditional Ratemaking
- How Integrated Volt/VAr Control Works to Benefit Customers
- Time-Varying Rate Primer
- Technical Challenges of Significant Amounts of Customer-Sited Generation

## 2. THE BASICS OF TRADITIONAL RATEMAKING

The SGCC's "Smart Grid Economic and Environmental Benefits" report discusses the conservation benefits and operating and maintenance expense benefits of some capabilities. In this section we help readers understand the traditional ratemaking process, the incentives it offers to utilities, and how these incentives are not always in alignment with some Smart Grid benefits. We offer three potential opportunities to address the issues traditional ratemaking presents to the maximization of Smart Grid benefits for customers.

### How Traditional Ratemaking Works

The goal of traditional ratemaking is to enable utilities to cover their costs. In the case of investor-owned utilities, the goal is to enable recovery of costs plus earn enough profit to attract capital for grid investment. Investor-owned utilities typically present their case for an increase in rates to state regulators in a proceeding called a "rate case." Municipal and cooperative utilities present their cases for rate increases to their governing boards. Although a vast oversimplification, a rate case generally addresses two questions:

- What are the utility's costs?
- Given anticipated sales volumes, what rates must be charged to cover those costs?

For the sake of simplicity, we ignore the revenue and cost of the electricity itself, and focus here on distribution grid costs and the revenues required to maintain and invest in it. (In most cases, the cost of the electric commodity itself is passed through to customers with no markup.) The mathematics behind the rate determination (with details omitted for clarity) look like this:

$$\text{Price per kWh} = \frac{\text{Anticipated utility costs}}{\text{Anticipated kWh sales volumes}}$$

Let's consider a municipal utility that is presenting a rate case to its governing board. The utility presents details indicating that its annual costs are $100 million and that it expects to sell 2 billion kilowatt hours (kWh) annually. The utility is thus requesting a price per kWh of $0.05:

$$\frac{\text{Anticipated utility costs}}{\text{Anticipated kWh sales volumes}} = \frac{\$100\text{ million}}{2\text{ billion kWh}} = \$0.05$$

The governing board approves the utility's request. Now let's see what happens to the utility under each of the following scenarios:

- The cost and sales volume forecasts were accurate
- The cost forecast was accurate, but the sales volume forecast was high
- The sales volume forecast was accurate, but the cost forecast was high

### *Cost and Sales Volume Forecasts Were Accurate*

When the cost and sales volume forecasts used to request a rate increase turn out to be accurate, the utility is "made whole" (that is, it covers its costs). The utility is not overcompensated or undercompensated.

| | |
|---|---|
| Revenue (2 billion kWh x $0.05/kWh) | $100 million |
| Less: Costs | $100 million |
| Overcompensation/Undercompensation | $ 0 |

### *The Cost Forecast Was Accurate, but the Sales Volume Was Less Than Forecast*

When sales volumes are less than forecast – for any reason – the utility will not collect the revenues it needs to recover its costs. Let's assume actual sales volumes are 5 percent less than forecasted sales volumes. In this situation, the utility is undercompensated.

| | |
|---|---|
| Revenue (1.9 billion kWh x $0.05/kWh) | $ 95 million |
| Less: Costs | $100 million |
| Undercompensation | $ –5 million |

Conversely, if sales volumes are greater than forecast, the utility will collect more revenue than it needs to recover its costs. Sales volumes can vary from the forecast for a variety of reasons, such as an economic boom or bust, atypical weather, or energy efficiency programs. Some reasons sales volumes might be less than forecast are from Smart Grid capabilities, including time-varying rates and continuous application of Integrated Volt/VAr Control (also known as IVVC, which will be explained in more detail in section 3). The conservation value of these capabilities is described in the "Smart Grid Economic and Environmental Benefits" report available from the SGCC.

This simplified example indicates how utilities using traditional ratemaking methods are penalized when sales volumes drop, and why traditional ratemaking issues should be addressed if the conservation benefits of some Smart Grid capabilities are to be maximized.

### *The Sales Volume Forecast Was Accurate, but the Costs Were Less Than Forecast*

When costs are less than forecast – for any reason – the utility will collect more revenue than it needs to cover costs. Let's assume actual costs turn out to be 4 percent lower than forecasted costs. In this situation the utility is overcompensated.

| | |
|---|---|
| Revenue (2 billion kWh x $0.05/kWh) | $100 million |
| Less: Costs | $ 96 million |
| Overcompensation | $ 4 million |

Conversely, if costs are greater than forecast, the utility will have spent more than it collects in revenues. Costs can be less than forecast for a variety of reasons, such as staff cuts or project postponements. Costs can also be less than forecast as a result of Smart Grid capabilities – via reductions in meter reading, outage restoration, and billing/collection/bad debt expenses, to name just a few.

This simplified example indicates how utilities are rewarded for reducing costs when using traditional ratemaking methods. After a subsequent rate case, the cost reduction benefits that the utility enjoyed before the rate case are transferred into customer benefits, in the form of lower rates.

## Three Potential Solutions to Traditional Ratemaking Limiters of Smart Grid Benefits

There are at least three ways to help utilities overcome the limits that traditional ratemaking places on realizing Smart Grid benefits. These include:

- Reflecting anticipated sales volume reductions in forecasts used for ratemaking
- Providing economic rewards for utilities documenting maximum Smart Grid benefits
- Continuing dialog with stakeholders about how to improve ratemaking in instances of sales volume reductions

### *Reflect Anticipated Sales Volume Reductions in Forecasts Used for Ratemaking*

Sales volume reductions from Smart Grid investments can be estimated. Continuing our example, assume a utility estimates sales volume reductions from Smart Grid capabilities at 5 percent of sales. When the utility reflects this change in its sales volume forecast, a different rate per kWh is determined:

$$\frac{\text{Anticipated utility costs}}{\text{Anticipated kWh sales volumes}} = \frac{\$100\text{ million}}{1.9\text{ billion kWh}} = \$0.053$$

Though the price for distribution services per kWh has increased ($0.053 versus $0.050), the price increase can be more than offset by customers using less electricity as a result of Smart Grid capabilities. Here's an example of how this works for a specific customer using 1,000 kWh per month, with a 5 percent volume reduction and a price for the electricity itself of $0.07 per kWh.

| | Bill before volume reduction | Bill after volume reduction |
|---|---|---|
| Cost for Electricity | 1,000 kWh x $0.070 = $70.00 | 950 kWh x $0.070 = $66.50 |
| Cost for Distribution Services | 1,000 kWh x $0.050 = $50.00 | 950 kWh x $0.053 = $50.35 |
| **Total Bill** | **$120.00** | **$116.85** |

### *Provide Economic Rewards for Utilities Documenting Maximum Smart Grid Benefits*

From an economic perspective, many Smart Grid investments are no different than utility energy efficiency program investments. The utility invests money in energy efficiency programs, and customers benefit through reduced electricity usage and other global benefits (such as delayed or avoided construction of new generating plants). The same can be said of Smart Grid capabilities.

For years, many states have authorized investor-owned utilities to be rewarded for outstanding energy efficiency program performance through performance-based payment mechanisms. In summary, a state regulator will say to a utility: "We understand reductions in sales volumes from energy efficiency programs can harm your opportunity to cover your costs and/or earn a rate of return you require to raise capital. To compensate for these reductions, we will offer you an incentive if your energy efficiency programs perform well." It might be reasonable to consider similar performance-based payment mechanisms for Smart Grid capabilities that reduce sales volumes.

### *Continue Dialog about How to Improve Ratemaking in Instances of Sales Volume Reductions*

Variations on traditional ratemaking processes are available that help utilities recover costs when faced with sales volume reductions. One of these is "decoupled" ratemaking. Regulators in 16 states use this approach in place of traditional ratemaking.[1] Decoupled ratemaking "decouples" a utility's revenues from sales volumes, making them indifferent to sales volume changes. It works like this: when sales volumes drop below forecasted levels, utilities are allowed to increase their rates without a rate case, thereby holding revenues constant. Further, when sales volumes increase above forecasted levels, utilities must decrease their rates, again holding revenues constant. In this way revenues do not vary with sales volume, and no overcompensation or undercompensation results.

1 National Resources Defense Council, "Gas and Electric Decoupling."

## 3. HOW INTEGRATED VOLT/VAR CONTROL WORKS TO BENEFIT CUSTOMERS

The SGCC's "Smart Grid Economic and Environmental Benefits" report indicates that Integrated Volt/VAr Control (IVVC) offers some of the greatest economic and environmental benefits of any Smart Grid capability. For those interested in the details of how IVVC can offer such large benefits, we describe how it works below. We'll begin with two technical electricity concepts: voltage and power factor (or VAr).

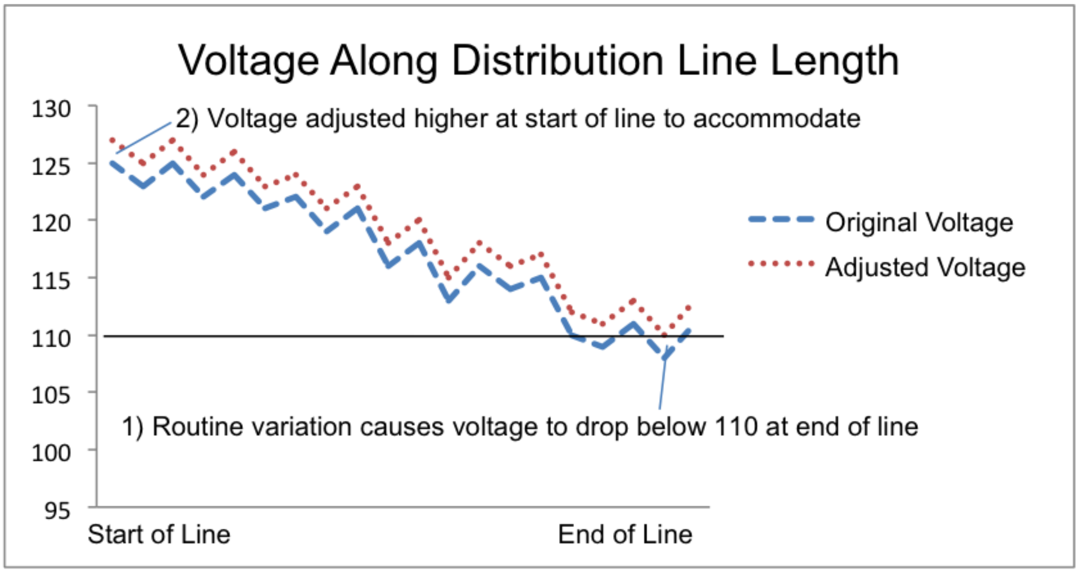
### Voltage

Electric voltage is analogous to water pressure. When water pressure (electric voltage) increases, more water (electric current) flows through a pipe (wire). Equipment running on electricity is designed by manufacturers to operate within a specific range of voltages. Most home appliances designed for use in North America, for example, are designed to operate within a voltage range of 110 to 120 volts. (In Europe, the range is 220 to 240 volts, which is why special adapters are required to use North American appliances in Europe.) High voltage can cause damage to appliances or cause them to operate inefficiently, whereas low voltage can cause appliances to work ineffectively or erratically.

One characteristic of voltage is that it drops as the length of a distribution line from the community substation increases. Utilities use various types of equipment to help keep voltage within the 110 to 120 volt range along the length of the distribution line, but doing so as customer loads change from season to season, day to day, and even hour to hour is a constant challenge. Utilities typically set the voltage higher at a community substation (the start of a distribution line) than they otherwise might to ensure the voltage delivered to customers at the end of the distribution line is comfortably above 110 volts (say, 115 volts). They do this to accommodate changing conditions that could otherwise cause occasional voltage drops below 110. Figure 1 illustrates the situation.

*Figure 1. Adjustments for voltage violations at end of distribution line*




Increasing voltage all along a distribution line to avoid voltage violations at the end is not the most efficient solution, as many electric loads (lighting, televisions, etc.) use more electricity at higher voltages than at lower voltages. Thus, customers served by higher voltages use slightly more energy, pay slightly higher bills, and generate slightly more carbon emissions than customers served at lower voltage levels. Note that the average of the adjusted voltage in Figure 1 is about 120.

## Power Factor

Power factor is a measure of how useful electricity is. At a power factor of 1.0 (also called "unity"), 100 percent of the electricity available to a customer can be used to illuminate a light bulb or run a piece of equipment. Certain customer electrical equipment types can introduce power factor reductions into the distribution grid, making electricity less effective at serving all customer loads. In fact, some utilities measure customers' power factor impacts and levy a charge on such customers.

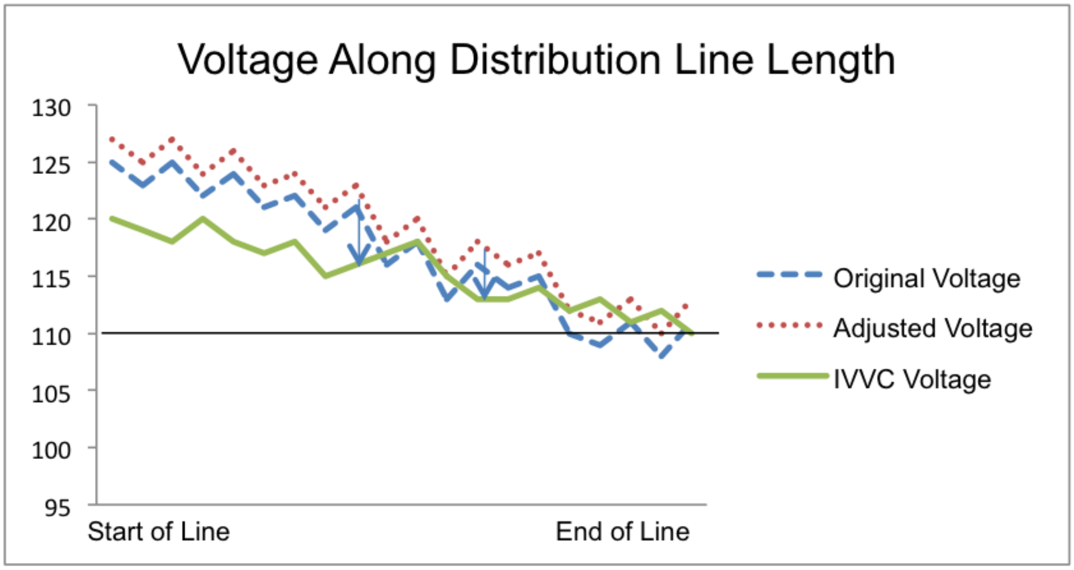
An analogy comparing power factor to the productivity of a manufacturing company may be helpful. The owners of such companies prefer for overhead costs (such as legal costs and accounting) to be as low as possible, making as great a proportion of the company's resources as possible available for productive activity (making steel or dishwashers, for example). The difference between unity (1.0) and measured power factor (for example, 0.95) in a utility's electricity can be considered undesirable overhead. The lower the measured power factor, the lower the productive portion of energy in the electricity a utility delivers. Customers understandably benefit when power factor is as close to 1.0 as possible, as they prefer the electricity they purchase to be as useful and productive as possible. Utilities strive to deliver electricity to customers with a power factor as close to 1.0 as possible, with 0.98 or 0.99 representing excellent performance.

Utilities have been correcting power factor for decades using devices called capacitor banks, or “cap banks” for short. Cap banks are placed around the grid where utilities need them to keep the power factor close to 1.0. However, power factor fluctuates from season to season, day to day, and even hour to hour as customers turn on and off equipment that impacts power factor. This variability makes power factor correction difficult. To compound the difficulty, power factor and voltage influence each other continuously in real time.

## Integrated Volt/VAr Control

Integrated Volt/VAr Control (or IVVC) is a Smart Grid capability that can deliver significant efficiency benefits to customers. It allows a utility to continuously optimize voltage and power factor all along a distribution line. As described above, improving power factor reduces undesirable overhead in the electricity customers purchase. The closer power factor is to unity (1.0), the less electricity a customer must buy for a given amount of utility. IVVC reduces the variability in voltage along a distribution line and the rate at which voltage drops along the length of a line. This enables the voltage to be lowered along the entire length of a distribution line, as shown in Figure 2; note that the average of the IVVC voltage in Figure 2 is about 115, versus 120 for the original voltage.

*Figure 2. Impact of IVVC on average distribution line voltage*




The 4 percent reduction in average voltage – from 120 to 115 – along a distribution line may not seem like much, but most research indicates electric usage drops between 0.5 percent and 0.9 percent for each 1 percent reduction in voltage. Using a conservative estimate of 0.75 percent, the 4 percent voltage reduction translates to a 3 percent electricity usage reduction for every customer served by a distribution line with IVVC.

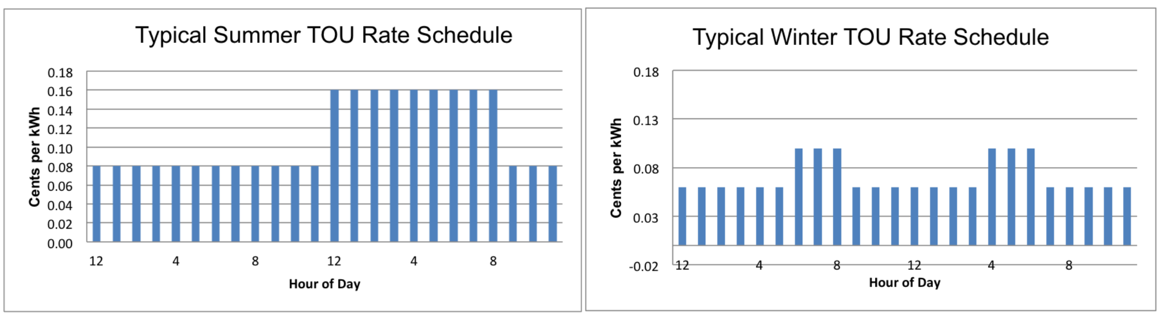
## 4. TIME-VARYING RATE PRIMER

The SGCC's "Smart Grid Economic and Environmental Benefits" report identifies several benefit drivers, challenges, and opportunities for increasing the benefits of time-varying rates, including customer participation rates, participant usage shifting, and structural winners and losers. Below we describe the most common types of time-varying rate designs and the pros and cons of each design. We also include a more detailed discussion of some of the challenges and opportunities of time-varying rates.

### Time-Of-Use Rates

Time-of-use (TOU) rates are the simplest form of time-varying rates. Two time periods – peak and off-peak – are defined and priced differently. Some utilities add a third time period (mid-peak), and most utilities vary the prices for winter and summer.

*Figure 3. Typical summer and winter time-of-use rate schedule*

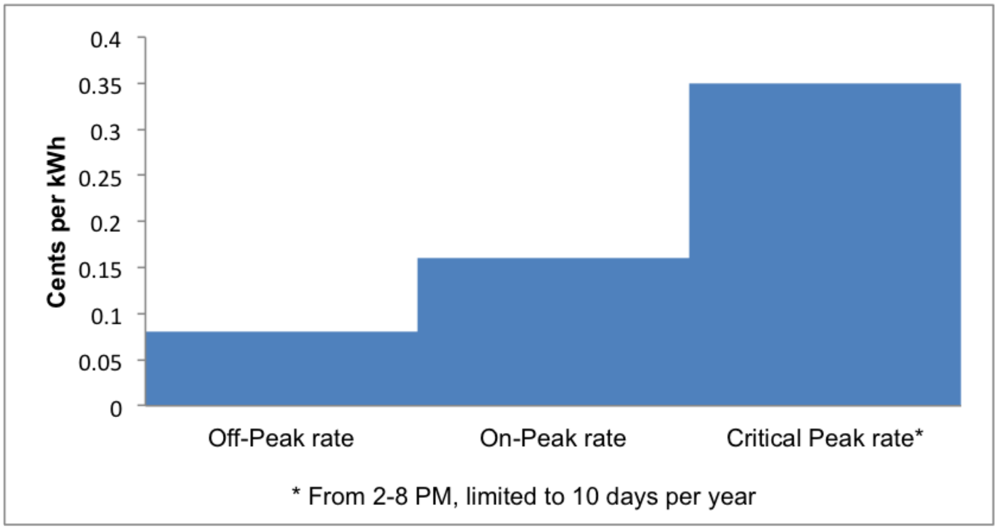



Though TOU rates are simple to understand, customers participating in them have demonstrated less load-shifting behavior than when using other types of time-varying rates. As described in the "'Revenue Neutral' Rate Design" section below, some TOU participants are natural winners because they normally use less energy during peak periods. These participants' bills are likely to drop a bit with no change in behavior. This can cause problems for a utility as revenues drop with no corresponding drop in costs from changed behavior.

## Critical Peak Price Rates

Critical Peak Price (CPP) rates are an enhanced version of TOU rates. In addition to assigning higher prices during defined periods, CPP rates enable a utility to declare a limited number of days annually (generally 10 or so) on which rates are set dramatically higher for certain predefined hours (such as 2 p.m. to 8 p.m.). This is done to better reflect the dramatically higher costs of electricity on critical peak days. These dates are not set in advance but vary with conditions (generally the weather). Participating customers are notified of such days approximately one day in advance via text message, e-mail, or automated phone call.

*Figure 4. Typical Critical Peak Price rate structure*




CPP participants demonstrate greater load-shifting behavior than TOU rate participants,[2] but there are still natural winners for which to account in rate design. Although CPP rates are designed to be revenue neutral, customers seem to focus on the dramatically higher rates for the few hours rather than the slightly lower rates for thousands of other hours annually. Convincing customers to voluntarily participate in CPP rates, therefore, can be more difficult.

2 Faruqui, Ahmad, and Jenny Palmer, *The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity,* March 12, 2012: 4.

## Peak-Time Rebate Rates

Peak-Time Rebate (PTR) rates were developed in response to the difficulty in getting customers to embrace CPP rates. They are also useful in cases where time-varying rates have been ordered by a regulator to be the default rates (also called opt out rates, as a customer must take action to avoid them), with the potential adverse satisfaction impact such an order portends.

PTR rates are similar to CPP rates in that certain "critical peak" days are declared one day in advance. However, rather than requiring participants to pay a dramatically higher rate on those days, participants receive a bill credit reflecting the change in behavior the participant demonstrates. Baseline usage levels are created for each individual customer, and the reduction in each participant's actual usage on critical peak days relative to his or her baseline determines rebate size. If a customer chooses not to conserve on a critical peak day, there is no reward, but neither is there a penalty (unlike CPP rates, in which failure to conserve on a critical peak day can cause customers' bills to increase).

The research indicates that rate-shifting behavior under PTR may be greater than that of TOU rates, but it is likely not as great as that of CPP rate participants.[3] There also appears to be a significant measurement issue, with many customers paid rebates they did not deserve, and other customers unpaid for rebates they did deserve.[4] These discrepancies can be mitigated by examining behavior response over all declared peak days, but delayed rebate payment is not as effective a feedback mechanism as immediate bill credit.

## Opportunities to Increase Time-Varying Rate Benefits

There are several opportunities to increase the benefits of time-varying rates in practice. Perhaps the greatest opportunity is to increase customer participation in such rates. This will require a change in public perceptions about time-varying rates, a tall order to be sure. Because time-varying rates change how customers pay for their electricity, there is customer satisfaction risk in attempting to increase time-varying rate participation, and it is understandable that neither regulators nor utilities are very interested in taking on this risk. A related opportunity is ensuring that utilities can recover their costs in the face of sales volume reductions from large-scale participation in time-varying rates. We examine these opportunities individually.

3 Faruqui and Palmer, *The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity:* 4.

4 George, Stephen S. "Peak Time Rebates: The Promise vs. the Reality." Presentation to the National Town Meeting on Demand Response and Smart Grid, June 28, 2012.

### *Public Perception*

Public perception of time-varying rates is generally incorrect and unfavorable. Some of these perceptions include the following.

| Perception | Reality |
|---|---|
| Time-varying rates are simply a ploy for utilities to make more money. | Utilities and regulators ensure new rate designs are “revenue neutral”; that is, the utility collects the same amount of revenue in total from the customer base irrespective of which rates they choose (all else being equal). In reality, most utilities lose money on time-varying rates due to reductions in energy use by participants. |
| Time-varying rates are part of a government plot/an assault on my individual/customer rights. | There are no laws requiring utilities to charge their customers a flat rate per unit of use, or requiring utilities to insulate customers from cost fluctuations related to time of day or day of year. |
| Time-varying rates involve a lot of effort and inconvenience for a small economic reward. | Rewards are a function of rate designs. Customers from many utilities report significant savings from use shifting, which can be made easier with enabling technologies such as energy displays or programmable or remotely controlled thermostats. |
| Time-varying rates are unfair to people with health issues who must maintain the temperature of their living spaces within a narrow range. | Few utilities or regulators mandate specific rates. In almost all cases these customers can simply request a different rate from their utilities. |
| Low-income customers have fewer/smaller loads to control and therefore can’t save money on time-varying rates. | Research indicates low-income customers are actually more likely to save money with time-varying rates than other customers due to increased price sensitivity.[5] |
| Time-varying rates will cause many customers’ electric bills to rise. | The bills of a minority of customers who fail to shift usage may go up, but many more customers appreciate the opportunity to reduce their bills. |

5 Wood, Lisa, and Ahmad Faruqui, “Dynamic Pricing and Low-Income Customers: Correcting Misconceptions about Load-Management Programs,” *Public Utilities Fortnightly* (November 2010): 60–64.

However inaccurate, these widely held perceptions make regulators and utilities hesitant to advocate for time-varying rates. Regulators could order utilities to make time-varying rates the "default" rate on which each customer is placed unless he or she specifically instructs otherwise. These "opt out" programs (as a customer must take action to opt out of the default rate) would lead to dramatically higher participation.

Utilities, and retail electric providers in restructured states, could unilaterally and aggressively promote time-varying rates for customers to select on a voluntary basis. However, few utilities wish to take on the risk to customer satisfaction with these programs, called "opt in" programs (as a customer must take action to select them). And finally, there is no reward (and in many cases there is outright disincentive) for utilities to take customer satisfaction risk to increase time-varying rate participation.

### *Lack of Utility Incentives/Presence of Utility Disincentives*

Many utilities have no incentive to change the negative perceptions among consumers about time-varying rates. Expecting utilities to take significant customer satisfaction risks with no opportunity for gain would be illogical. In fact, most utilities' sales volumes fall as time-varying rate participation rises, creating a significant disincentive under traditional ratemaking processes. See the earlier section on "Traditional Ratemaking" for more information.

### *"Revenue Neutral" Rate Design*

Most utility regulators and governing boards require the various rate options a utility may wish to introduce to be designed as "revenue neutral"; that is, utilities will collect the same overall revenue no matter which rate options their customers choose, all else being equal. Although this concept sounds logical in principle, it introduces some challenging issues when it comes to time-varying rate designs, including the issue of rate "cherry picking."

Although time-varying rates can be designed to be revenue neutral for customers on average, some customers will turn out to be better off, some worse off, and some about the same, assuming no change in usage behavior or shift in usage to off-peak price periods. If you are a customer in the "better off" group, you are more likely to choose the optional rate than a customer in the "worse off" group, again assuming no change in use. Furthermore, as a member of the "better off" group, you would save money even if your usage behavior did not change (making you a "free rider"). An example will help readers better understand these concepts.

Consider a time-varying rate incorporating a higher peak-period price between the hours of 2 p.m. and 8 p.m. on weekdays. A customer who is typically out of the house during those hours due to his or her occupation would be more likely to participate in the time-varying rate. As described above, changes in usage behavior among those participating in time-varying rates (switching and/or reduction) are critical to reducing costs to the benefit of all customers. If only those customers who benefit from the new rate participate in it and do not change usage behaviors, utility revenues will drop with no corresponding reductions in utility costs.

To address this potential limitation, a utility could:

- make a time-varying rate the default rate, encouraging participation by both "worse off" and "better off" customers in relatively equal proportions;[6]
- make the price difference between peak and off-peak periods moderate at first and grow the difference over time (to reduce the number of "worse off" customers who opt out);[7]
- offer only a Peak-Time Rebate version as its time-varying rate. (Peak-Time Rebates are earned based on behavior changes, but measurement issues loom large.)[8]

6 Khoury, D., and L. Tan, "The DRA's Responses to the Residential Rate Design OIR Questions." Report in response to Administrative Law Judge ruling in California PUC docket R.12-06-013. May 29, 2013: 38.

7 Ibid.

8 George, Stephen S. "Peak Time Rebates: The Promise vs. the Reality." Presentation to the National Town Meeting on Demand Response and Smart Grid, June 28, 2012.

## 5. TECHNICAL CHALLENGES OF SIGNIFICANT AMOUNTS OF CUSTOMER-SITED GENERATION

The SGCC's "Smart Grid Economic and Environmental Benefits" report indicates that significant amounts of customer-sited generation present reliability and efficiency challenges to the distribution grid. As customer-sited generation levels are currently insufficiently high to study reliability and efficiency challenges at scale, we present descriptions of the technical challenges utility engineers are beginning to confront as the level of customer-sited generation increases. From there we describe the types of capabilities in which investments can be made to manage the technical customer-sited generation challenges to avoid the reliability and efficiency impairment associated with customer-sited generation.

### Technical Challenges Utility Engineers Are Beginning to Confront

As the proportion of customer-sited generation rises relative to distribution grid capacity, utility engineers are beginning to wrestle with impacts to reliability and efficiency. The technical challenges include:[9]

- Upstream protective devices (circuit breakers) can trip, causing outages
- Increased variation in voltage and harmonics can degrade power quality
- Increased variation in load and phase volatility can reduce grid efficiency

We will examine each of these and associated Smart Grid solutions individually.

#### *Upstream Protective Devices (Circuit Breakers) Can Trip, Causing Outages*

The electrical panel in your home or car includes a variety of breaker sizes (or, if your home is old enough, a variety of fuse sizes). Circuit breaker and fuse sizes are indicated by numbers in amps (such as 10, 15, or 20). The higher the number, the greater the disturbance the circuit breaker or fuse can accommodate before it trips. When a circuit breaker or fuse trips, it disconnects the wires beyond it (for example, wires to electrical outlets, clothes dryer, or air conditioner) from the system to protect the wires and equipment above it (for example, those out of your home and on to the distribution grid).

Note that on your electrical panel, different-sized circuit breakers are used for different equipment. A series of wall outlets might be protected by a 10-amp circuit breaker, while a bigger load (such as a clothes dryer or air conditioner) might be protected by a 40-amp circuit breaker. If a 10-amp circuit breaker were to be used on a clothes dryer, it would unnecessarily trip all the time; if a 100-amp circuit breaker were used on a clothes dryer it might not trip when it should, creating a dangerous situation. Circuit breaker sizing is like the story of Goldilocks and the three bears; one does not want them undersized or oversized, but just right.

9 Electric Power Research Institute. *Integrating Smart Distributed Energy Resources with Distribution Management Systems* (white paper), September 2012: 4–8.

Fuses and circuit breakers on the distribution grid serve the exact same function but on a much larger scale. Like the fuses and circuit breakers in your home, those on the distribution grid are sized appropriately to normal conditions. Large amounts of customer-sited generation on a distribution line could send electricity "backward" toward the substation. (Distribution grids have been designed to distribute electricity in one direction only. They have not been designed to accommodate two-way electrical flow.) Sending electricity backward through a circuit breaker or fuse is likely to be perceived by the device as a fault, causing it to trip and disconnecting the grid below it as a protective measure. Customers below the tripped device would experience an outage. Smarter grid designs, smarter protective devices, and automated systems are required if grid reliability is to be maintained as customer-sited generation grows.

### *Increased Variation in Voltage and Harmonics Can Degrade Power Quality*

Many types of customer-sited generation introduce voltage, power factor, and harmonic frequency variability into the distribution grid. The "set it and forget it" approach to grid equipment settings practiced by utilities with traditional distribution grids will not likely be able to maintain high power quality on portions of the grid where customer-sited generation levels are high. As was discussed in the section on Integrated Volt/VAr Control (IVVC), high voltage and low power factor on the distribution grid can cause customers to use more energy than they might otherwise. IVVC can help manage some of the power quality challenges introduced by high levels of customer-sited generation – 24 hours a day, 365 days a year.

### *Increased Variation in Phase and Load Volatility Can Reduce Grid Efficiency*

For a variety of reasons, central stations are configured to generate electricity in three phases. For optimum grid efficiency, these phases must be maintained equidistant from one another (measured in milliseconds) as they travel down distribution lines. Though phase balancing is a continuous concern, it is generally addressed periodically when problems arise. Smart Grid distribution automation devices provide an opportunity to continuously monitor phase balance in real time. Software applications can be written that interpret phase balance data and automatically adjust field equipment to reestablish phase balance 24 hours a day, 365 days a year. This advance could be particularly important as levels of customer-sited generation on the system increase, bringing with it potentially harmful effects on phase balance and grid efficiency.

Like phase balancing, load balancing is a continuous concern that is only addressed periodically. It involves identifying optimum distribution line configurations so that no one distribution line becomes overloaded during times of peak demand. Load balancing is an optimization problem, similar to a transportation system planner designing bus routes. Electricity can be distributed to homes and businesses along many optional paths (distribution lines). The challenge is to choose the paths offering the greatest value (in the case of electricity, reliability and efficiency) despite multiple asset and operations constraints.

As with bus route redesign, once optimum load balance has been established it is not generally reexamined until inefficiencies and reliability deteriorate to the point at which rebalancing becomes necessary. Load balancing software applications offer the possibility to rebalance continuously as the loads on the distribution grid change in real time. These applications could be extremely helpful as increases in customer-sited generation increase the variability of loads on the grid hour by hour and even minute to minute.

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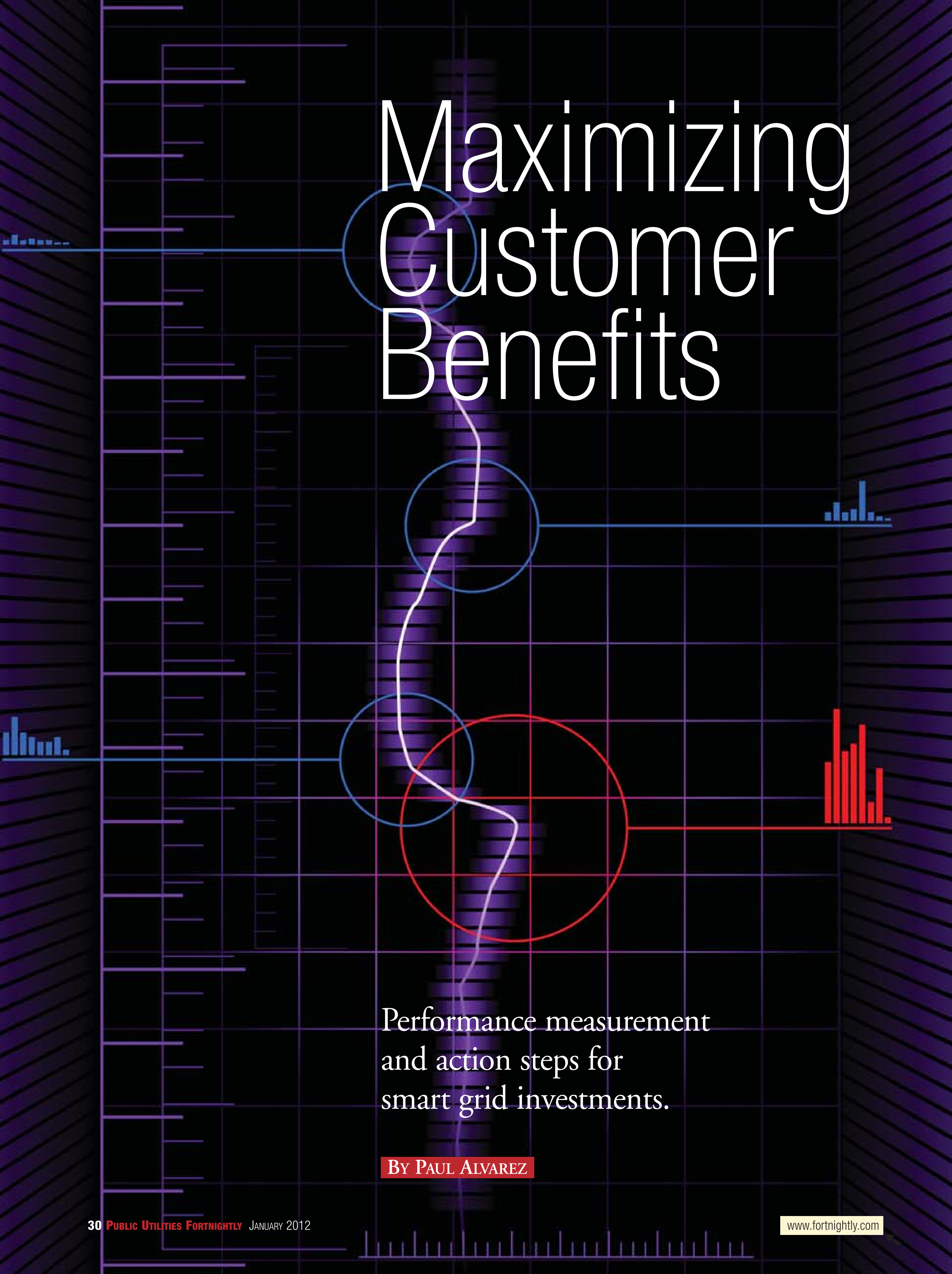

# Maximizing Customer Benefits

Performance measurement and action steps for smart grid investments.

By Paul Alvarez

Scores of investor-owned utilities (IOUs) have invested hundreds of millions of dollars to improve distribution capabilities. Now those utilities are beginning to consider how best to utilize the new capabilities. Other IOUs are in testing and strategy development phases. And regulators are considering what role they should play in encouraging IOUs to make prudent grid investments while minimizing risks and maximizing benefits for distribution customers.

As more utilities make smart grid business cases public, and as more independent smart grid performance evaluations are completed,[1] a picture of the principal smart grid customer benefits, costs, risks, and drivers is emerging. Many observers, from the Maryland PSC to the governor of Illinois, have concluded—correctly in the author's opinion—that the business case for the smart grid is far from being a "no brainer," and that significant post-deployment efforts are required if benefits are to be maximized. It's becoming increasingly clear that most investments in smart grid capabilities are different from traditional generation, transmission, and distribution investments in one fundamental respect: commissioning doesn't automatically translate to customer value.

Traditional utility investments are made, more often than not, to replace aging assets or to meet increases in demand for capacity. Once the case for investment is made, procurement proceeds, assets are placed into service, and customers enjoy the value in terms of improved reliability, reduced emissions, and similar benefits. Many, if not most, smart grid capabilities are different in that utilities must make concerted, post-commission efforts—in organizational changes, operating process redesigns, and customer program development—to maximize value for customers. Variation in time-of-use pricing program designs and adoption rates will impact the level of benefits received by both participating and non-participating customers. The extent and design of interactive volt/VAR control deployment will impact the degree of improvement in distribution efficiency. And the vigor and timing of meter-related staff reductions will impact the amount of O&M savings realized.

To summarize, smart grid benefits are driven in large part by utilities' design and post-commission implementation choices. In the case of IOUs, these choices are in turn driven largely by regulation. As a result it's appropriate for customers to ask some tough questions related to the smart grid:

- Is my utility maximizing the value of smart grid investments? And how would I know?
- Who should take the lead in measuring benefits—regulators or IOUs?
- What can regulators do to encourage IOUs to make prudent investments and maximize benefits for customers?
- What can IOUs do to maximize benefits for customers?

Answering these questions will require regulators to establish the conditions necessary to encourage and enable IOUs to maximize customer benefits, and IOUs must make the organizational and operational changes—and develop the customer programs—necessary to maximize those benefits. Failure on the part of either party will result in missed opportunities, needlessly long customer payback periods, and ineffective use of smart grid investment grants funded by U.S. taxpayers.

**Smart grid differs from traditional investments in one critical respect: Commissioning doesn't automatically translate to customer value.**

### Measuring Benefits

Though safety and environmental benefits have been documented in smart grid implementations, three types of benefits appear to be the most tangible for customers: economic benefits, reliability improvements, and customer service enhancements.

- *Economic Benefits:* Publicly available information from comprehensive and independent evaluations of smart grid deployment performance, combined with reviews of publicly available smart grid business cases, make it fairly clear that 80 percent to 90 percent of the economic benefits of full smart grid deployments available to customers come from three sources: meter reading and management savings; time-differentiated rate implementation; and distribution efficiency. Though every utility's experience will vary with situational characteristics and deployment variables, measuring economic benefits in just these three areas is likely to satisfy the 80/20 rule *(see Figure 1)*.

Measuring meter reading and management savings from AMI deployment is relatively straightforward. The accounts of departments for which reductions in force are anticipated as a

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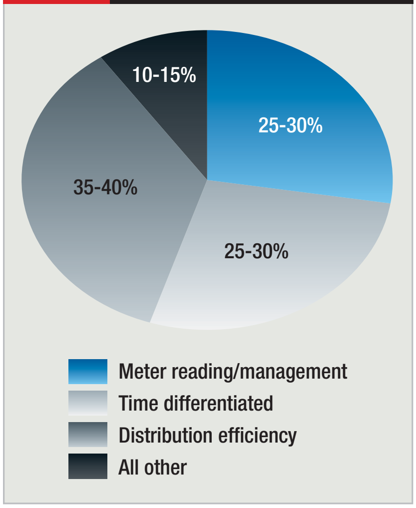
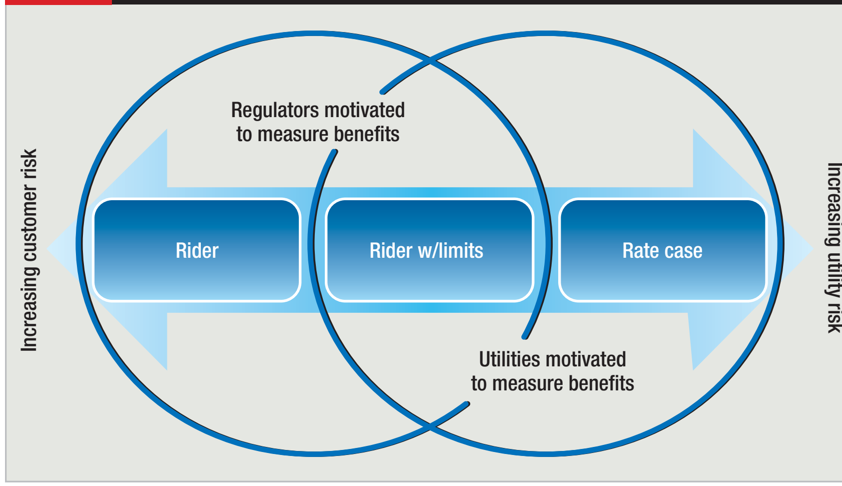
**FIG. 1 TOP SMART GRID BENEFITS**




Source: Author's analysis, MetaVu Inc.

**FIG. 2 SMART GRID COST RECOVERY APPROACHES**




Source: Author's analysis, MetaVu Inc.

result of smart grid deployments can simply be compared pre- and post-deployment to quantify savings. Dollar amounts can be translated into metrics for additional precision, including, for example, meter reading and management costs per meter.

AMI deployments also offer value through time differentiated rates. The most appropriate performance measurement approach should consider the circumstances under which such rates are offered. For example, performance can be measured through customer adoption percentage—likely more appropriate in the case of voluntary or opt-in time differentiated rate offers—though utilities might argue that time differentiated rate participation is only partly under utility control. Another approach is to measure overall impact on demand relative to a baseline—likely more appropriate for default or opt-out rate offers, but useful for measuring the performance of voluntary rate offers as well.

Getting customers to adopt time-differentiated rate offers on a voluntary basis has proven extremely challenging, as most designs increase customer risk and effort. The peak time rebate approach, which features carrots instead of sticks, warrants strong consideration as a result. Some of the research on time-differentiated rate designs indicates that carrot approaches can be just as effective as stick approaches in modifying customer usage behavior.[2]

Integrated volt/VAR control offers significant improvements in aggregate distribution efficiency, reducing the usage of customers located on treated feeders by a couple of percentage points through reduced voltage and optimized power factor. Performance can be evaluated by measuring energy accepted by substations and comparing it to sales volumes billed. Such a measure would also include metering errors, billing errors, and theft, but these revenue capture issues are also subject to improvement through smart grid investments and warrant measurement and performance management efforts.

■ *Reliability Improvements:* Most smart grid deployment plans include improved capabilities in distribution automation and status monitoring designed to improve grid reliability. Independent assessments have confirmed that significant improvements in reliability—moderate double digits as a percentage—are indeed available from these capability improvements. Existing reliability metrics such as SAIDI, SAIFI, and MAIFI[3] are likely sufficient to measure these improvements over time, though observers are cautioned that improvements in SAIDI (resulting from increased sectionalization, for example) can come at the expense of MAIFI performance. "Customer minutes out" is another performance metric that warrants consideration for this reason. Of course normalization for weather will still be an important component of reliability measurements.

**Smart grid benefits are driven in large part by utilities' design and post-commissioning implementation choices.**

Beyond statistics, however, it's difficult for individual customers to perceive even fairly significant improvements in reliability. The issue is simply one of scale; a 99.95 percent reliability rating translates to only 4.4 hours of customer outage a year. Even a 20 percent improvement on 4.4 hours of outage amounts to less than an hour's improvement annually. This fact, combined with the infrequent nature of outages, makes reliability improvements extremely difficult for customers to perceive.

■ *Customer Service Enhancements:* Customer service enhancements, generally made possible by AMI and two-way meter communications, can be difficult to measure. Quantifying the percentage of eligible customers that access a new capability is a reasonable metric for some enhancements, such as in the case of detailed energy usage information being made available via secure web page. However performance on other potential customer service enhancements isn't so easily measured. Consider for example, a proactive outage information service. Such a service would combine smart grid capabilities with today's communications technologies to text or e-mail information on outages to affected customers. Simple descriptions of new customer service enhancements implemented as part of smart grid deployments might have to suffice as a yes-or-no performance measure in some instances, with emerging best practices serving as useful benchmarks as to what is feasible and valuable. Another service enhancement that a subset of customers would appreciate is prepayment; AMI provides capabilities that facilitate the operation of pay-as-you-go programs.

## Communicating Benefits

Smart grid benefits can be significant in the aggregate but insufficiently large for individual customers to perceive. Even customer service enhancements, which one might consider to be readily perceptible, are known only to customers that have accessed them or been exposed to them. And even these customers might not relate the enhancements to smart grid investments. Accordingly, documentation and communication of benefits to customers should be a conspicuous component of post-deployment optimization plans and is critical to confirming smart grid merits and value to customers.

One way to think about smart grid benefit communications: If a benefit isn't communicated, it's as if the benefit had never been created from a customer's perspective. Even the U.S. government understands this concept; what driver hasn't seen a road construction project adorned with "this project funded by the *American Reinvestment and Recovery Act*" signs?

This isn't to suggest that communications shouldn't be conspicuous before smart grid deployment as well. In fact, providing stakeholders with realistic expectations about smart grid value and capabilities before investments are made is perhaps more critical than post-deployment communications. Stakeholder engagement can help utilities prioritize smart grid investments by understanding the value constituencies place on various capabilities and benefits.

## Benefits and Cost Recovery

Three distinct approaches to smart grid investment cost recovery appear to be emerging: special-purpose riders; special-purpose riders with limits based on anticipated economic benefits; and traditional rate case prudency reviews.

The approach to smart grid cost recovery has significant implications for the roles regulators and IOUs should play in measuring and communicating benefits. Figure 2 depicts the relationship of each approach on the customer-utility risk continuum, and what it means for leadership of benefit measurement and communication efforts.

Some commissions have authorized special-purpose riders to encourage utilities to make smart grid investments. In many cases regulators specify rider characteristics designed to help manage and control smart grid deployment costs. However these riders typically contain few or no quantified provisions designed to maximize benefits for customers. Accordingly, smart grid riders can result in somewhat greater risk to customers than other smart grid cost recovery approaches. In these situations regulators are advised to take a leading role in ensuring that post-deployment benefits are measured, maximized, and communicated to customers.

Other commissions have authorized special purpose riders with built-in customer risk management features. To date, these features have consisted of revenue requirement limitations based on economic benefits that IOUs have suggested would be generated by smart grid investments. Anticipated economic benefits recognized in this manner have included smart grid-related reductions in operations and maintenance spending, improvements in revenue capture, and reduced depreciation expenses associated with beneficial deferral of capital benefits.

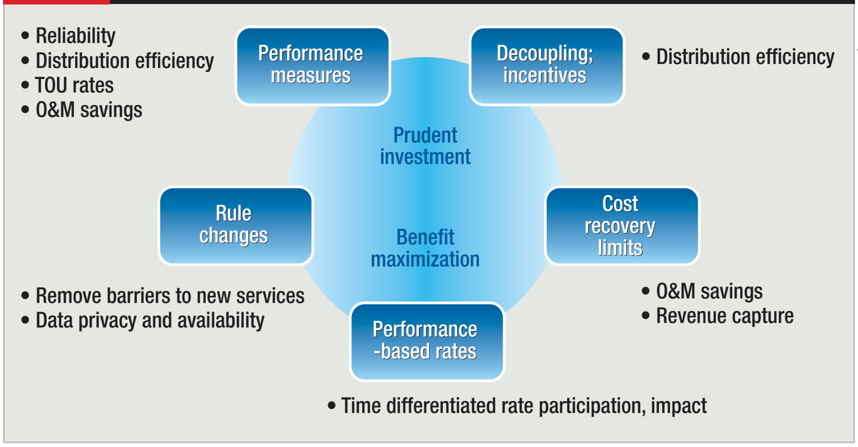
**Some types of smart grid capabilities reduce sales volumes and therefore an IOU's opportunity to earn its authorized rate of return.**

An interesting attribute of this approach is that it balances customer and utility risk for post-deployment performance. In so doing, utility shareholders are exposed to increased risk in exchange for increased profit opportunities. To the extent an IOU fails to achieve predetermined levels of benefit, shareholders pay the difference. And to the extent an IOU delivers greater benefits than anticipated, IOU shareholders benefit. In the "rider with limits" case, both regulators and utilities are motivated to measure, maximize, and communicate benefits to customers.

Still other commissions have elected to take no pre-deployment stance on the recovery of smart grid investments, preferring instead to subject IOUs to traditional prudency reviews as part of routine rate case proceedings. This approach can serve to discourage IOU investment in all but the most traditional grid capabilities, as cost recovery of investments in capabilities later determined to have been imprudent could be disallowed. However the approach does minimize risks for customers.

Combination approaches are also available; the Illinois legislature recently approved an act[4] that offers the state's IOUs the benefits of a rider but retains prudency reviews and adds a performance-based ratemaking component. In the event IOUs fail

**FIG. 3 POLICIES FOR MAXIMIZING SMART GRID BENEFITS**




Source: Author's analysis, Metalu Inc.

to hit reliability and revenue enhancement targets, authorized rates of return on smart grid investments can be docked 500 basis points. However, the performance-based measures incorporated in the Illinois legislation fail to include any of the top three economic benefit opportunities—meter reading and management savings; time-differentiated rate implementation; and distribution efficiency.

In smart grid cost recovery frameworks that put utilities at risk, IOUs are encouraged to take a leadership role in smart grid benefit measurement, maximization, and communication, as doing so can result in a significant reduction in cost recovery risk.

## Action Steps for Regulators

Though their numbers appear to be dropping, there exist some regulators and staffs that are hesitant to provide IOUs with incentives or change rules to encourage activities and investments that arguably could be categorized as IOUs' social responsibilities. Although this sentiment is understandable, it ignores the reality of the regulatory compact and IOUs' responsibilities to their shareholders.

Regulators increasingly are embracing the concept of shared responsibility for shaping electric distribution systems and services in a manner that creates the greatest value for utility customers for the least cost. Open and informal interactions with multiple stakeholders are likely to lead to the best outcomes and the most appropriate rulings and rule changes required to release the potential of the smart grid.

The reality is that post-investment regulatory actions will be required to ensure that the benefits of smart grid investments are maximized for customers. Several types of smart grid benefits increase IOUs' risk or reduce their opportunities to earn authorized rates of return—or both—particularly in states where decoupling hasn't been introduced. Other types of smart grid benefits will accrue to shareholders until recognized in a general rate case. Further, regulatory rule changes might be required to enable other types of smart grid benefits. Examples of smart grid capabilities and benefits that should prompt regulator action include:

- Distribution efficiency and time-differentiated rates will reduce utility sales volumes.
- Operations and maintenance expense reductions and revenue capture improvements accrue to shareholders until recognized in a general rate case—absent special cost recovery mechanisms.
- Some anticipated economic benefits might not be possible without thoughtful regulatory rule changes.
- New regulatory rules might be required to encourage certain types of customer service enhancements.

Some types of smart grid capabilities reduce sales volumes and therefore a utility's opportunity to earn its authorized rate of return, absent decoupling or some sort of incentive opportunity. In fact two of the three smart grid capabilities that yield the greatest economic benefits—distribution efficiency and time differentiated rates—will reduce utility sales volumes. Prepayment programs are also likely to reduce sales volumes. Utilities will understandably be reluctant to maximize such benefits. Some would argue that investments in distribution efficiency, time differentiated rate capabilities, and even prepayment programs are the economic equivalent of demand-side management (DSM) programs because, like DSM programs, the utilities make the investment and take the revenue risk while customers benefit. To address utility disincentives to maximizing these customer benefits, regulators could consider decoupling or performance-based ratemaking.

**Smart grid benefits can be significant in the aggregate, but insufficiently large for individual customers to perceive.**

On the other side of the coin, some types of smart grid benefit accrue to shareholders until recognized in a general rate case. Examples of these types of benefits include operations and maintenance spending reductions—*i.e.*, in meter reading—and improved revenue capture—for example, through improved meter accuracy or reduced theft. Regulators are encouraged to consider revenue requirement reductions, such as the rider limitations described earlier, to ensure customers receive economic benefits in the absence of a timely rate case that would recognize such benefits.

Some smart grid capabilities might not deliver benefits with-

## Smart Grid Performance Measurement

Several sets of guidelines are emerging as the standards in smart grid performance measurement. "A Methodological Approach for Measuring the Costs and Benefits of Smart Grid Demonstration Projects," available from The Electric Power Research Institute,5 provides a valuable guide to cost and benefit quantification. The "Smart Grid Maturity Model," developed by the U.S. Department of Energy and Carnegie Mellon University, is ideal for assessing the ability of a utility organization to maximize the value of smart grid investments; the model examines leading indicators, such as the existence and sophistication of smart grid-related operations planning, training, performance measurement, incentives, and similar processes. And the Environmental Defense Fund has weighed in with "Evaluation Framework for Smart Grid Deployment Plans," which describes a relevant set of outcome reporting metrics—lagging indicators—that could serve to benchmark any electric distribution company's performance improvement efforts, regardless of smart grid status.

State regulators have been busy considering smart grid benefits as well. Several orders and investigative dockets provide helpful background for regulators (and IOUs) considering smart grid benefit maximization:

Illinois Statewide Smart Grid Collaborative Report, Sept. 30, 2010, including an excellent summary of smart grid cost recovery issues.

Colorado PUC order C11-0406, concluding an investigatory docket that addressed smart grid and advanced metering technologies and associated benefit maximization.

California PUC order 08-12-009, addressing access to, and the privacy and security of, customer energy usage data.

Oklahoma Corporation Commission order 576595, approving Oklahoma Gas and Electric's smart grid rider with adjustments for anticipated benefits, and mandating customer communications.

Illinois Power Agency Act 097-0616, which reduces the authorized rate of return on smart grid investments in cases in which certain anticipated benefits aren't achieved.–*PA*

out thoughtful regulatory rule changes. For example many utilities included remote service disconnect capabilities in their AMI designs, along with associated economic benefits in their business cases. Most states' rules require utilities to contact customers before service is disconnected for reason of non-payment. In most of these states, this requirement has been prescribed to mean in-person contact, versus a phone call, generally to offer a final opportunity to meet a payment plan obligation, or to post a disconnection notice. As a result of these requirements, remote disconnect capabilities don't result in cost savings in instances of non-payment. If thoughtful compromises can't be reached, associated cost savings won't be realized.

Other smart grid capabilities might require new regulatory rules. One of these is proactive outage information, in which enhanced smart grid outage management information can be combined with automated outbound phone messaging, e-mailing, and texting capabilities to keep customers informed about the status of an outage. Although this might sound like a valuable service, customers could come to rely upon the accuracy of such communications and take certain actions based on them. It's easy to envision how inadvertent inaccuracies in such communications could cost customers money; consider a customer with a freezer full of food who fails to receive a notice about an outage while out of town on vacation or business. Utilities are understandably reluctant to offer new services that might subsequently be transformed into utility obligations and result in potential liabilities. New regulatory rules might help overcome utility resistance to such service improvements.

Another example of a smart grid capability that will require new rules to maximize customer benefits is increased data availability. Regulators will need to establish rules about the privacy and security of energy usage data, as well as rules related to accessing such data by customers and authorized third parties.

To summarize, regulators have many tools at their disposal to encourage utilities to make prudent investments in distribution capabilities while minimizing risks and maximizing benefits to customers.

**Utilities are understandably reluctant to offer new services that might transform into obligations and liabilities.**

### Action Steps for IOUs

Regulators and customers will demand that the benefits of smart grid investments are maximized, and utilities should understand this and act accordingly. Increasing use of emerging measurement standards is contributing to a growing body of knowledge around electric distribution business performance, going beyond reliability and incorporating everything from distribution efficiency and customer service improvements to time differentiated rate participation and impact. Utilities can expect that their feet will be held to the fire.

Utilities will need to make significant organizational and operational changes to truly maximize the value of smart grid investments. From service centers to distribution control centers, from engineering to marketing, and from distribution capacity planning to business systems, roles and responsibilities will need to be

**FIG. 4 CHANGE MANAGEMENT COMPONENTS**

Suggested components of change management plans for smart grid deployment.

| Organizational structure | Process and governance | Systems and tools | Capabilities and resources |
|---|---|---|---|

Customer program and service department

Source: Author's analysis, MetaVu Inc.

modified, operating processes will need to be changed, and programs will need to be developed. A few examples:

- Performance-based ratemaking might dramatically increase the responsibilities of marketing or distribution operations for utility financial performance.
- Smart grid capabilities make possible new frontiers in DSM program portfolios, features, designs, and promotions, and facilitate pre-payment programs.
- Business systems departments will need to develop electrical engineering understanding, while field services personnel will need to learn new information technology skills.
- Resources will need to be reduced in some functions and increased in others.
- New applications and systems integration will be needed to help employees and functions maximize the value of smart grid data.
- Organizational realignments, operating process changes, and incentive modifications will be required to maximize the value of smart grid capabilities.
- Regulatory administration will need to identify and pursue the rule and incentive modifications necessary to enable and encourage maximization of smart grid benefits.

A comprehensive and formal change management plan should be part of every utility's post-deployment optimization strategy and include organizational, operational, systems, capabilities, and customer program enhancement components *(see Figure 4)*.

Regulators are currently pre-occupied with a great number of critical issues, namely FERC transmission orders, new and proposed EPA regulations, and associated jurisdictional issues. IOUs face their own challenges, including flat or declining usage, capital constraints, and regulatory uncertainty. However utility customers will be served well if both parties focus some of their resources on maximizing the value of smart grid benefits through regulatory and operational changes. This focus likely will be rewarded with both improved smart grid economics and enhanced services for customers.

### Endnotes:


1. The results of independent evaluations of two smart grid deployments led by the author for MetaVu Inc. are available on Colorado and Ohio PUC websites.
2. Ahmad Faruqui and Sergici, Sanem, "Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment," *Journal of Regulatory Economics*, 2011, vol. 40, issue 1, pp. 82-109.
3. SAIDI = system average interruption duration index; SAIFI = system average interruption frequency index; MAIFI = momentary average interruption frequency index.
4. Illinois Public Act 097-0616
5. EPRI, report #1020342.

# Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment

Wired Group

National Conference of Regulatory Attorneys

Columbus, Ohio, June 16, 2014

Paul Alvarez, President, Wired Group

palvarez@wiredgroup.net

# Our Smart Grid Thesis

- A smarter grid can indeed deliver customer benefits in excess of costs and help prepare for future challenges
- Utilities are sub-optimizing benefits by a significant margin
  - Utility organizational and operational changes are significant
  - Customer engagement is extremely difficult
  - Regulatory and governance structures inhibit benefits
    - 70% of benefits stem from capabilities that reduce sales volumes*
    - Rate case timing impacts rate recognition of O&M/revenue benefits
    - IOUs are rewarded for process (investment), not outcomes (performance)
- Significant regulatory changes are needed in the near term
- Dramatic regulatory changes are advised in the long term

* Ideal case scenario

# Smart Grid Systems and Capabilities

<u>Smart Meters</u>

- Auto Meter Reading
- Time-Varying Rates
- Prepayment
- Revenue Assurance
- Outage Management

<u>Distribution Automation</u>

- Fault Location
- <u>Fault Isolation</u>
- <u>Integrated Volt-VAr Control</u>
- <u>Customer-Sited Generation Management</u>

<u>Communications Networks</u>

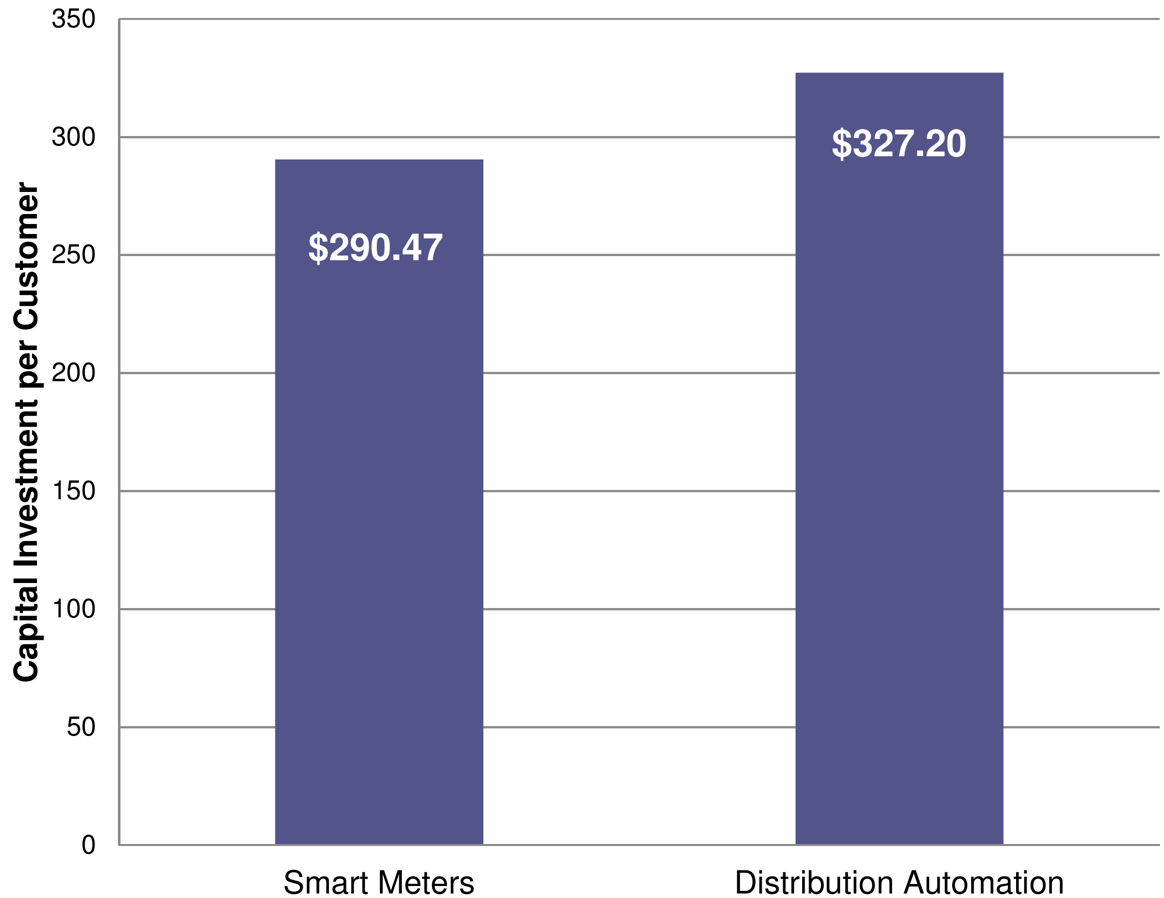
# Potential Smart Grid Benefits

- Direct
  - Economic
    - Energy Conservation
    - Demand Reduction
    - O&M Cost Reductions
    - Revenue Assurance
  - Non-Economic
    - Reliability
    - Customer Choice
    - Customer Service
- Indirect
  - Economic Productivity
  - Environmental

# Smart Grid Value Proposition Matrix

| Systems | Capabilities | Benefits | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Direct | | | | | | | Indirect | |
| | | Economic (in $) | | | | | | | | |
| | | Energy Conservation | Demand Reduction | Operations & Maintenance Cost Reduction | Revenue Assurance | Improved Reliability (in percent) | Increased Customer Choice | Enhanced Customer Service | Economic Productivity | Environmental (in lbs. CO2e) |
| Smart Meters | Meter Reading | | | | | | | | | |
| | Time-Varying Rates | | | | | | | | | |
| | Prepayment | | | | | | | | | |
| | Revenue Assurance | | | | | | | | | |
| | Outage Mgmt. | | | | | | | | | |
| Distribution Automation | Fault Location | | | | | | | | | |
| | Fault Isolation | | | | | | | | | |
| | IVVC | | | | | | | | | |
| | Customer-Sited Gen | | | | | | | | | |

# System Capital Costs per Customer




Source: SGIG Application Data

1. Identified projects as AMI, DA, or Both
2. Noted customers covered
3. Removed the "Both" projects
4. Divided costs by customers covered

$7.25 per month over 10 years at 10% ROR, 6% interest rate, 50/50 D to E ratio

# Cost-Benefit Scenarios and Assumptions

## Typical Case

- Typical of where most utilities are today
- Sub-optimal utility operating characteristics pre- or post-deployment
- Low customer participation

## Ideal Case

- Designed to represent what utilities could reasonably be expected to achieve
- Optimal pre- and post-deployment operating characteristics
- Moderate customer participation

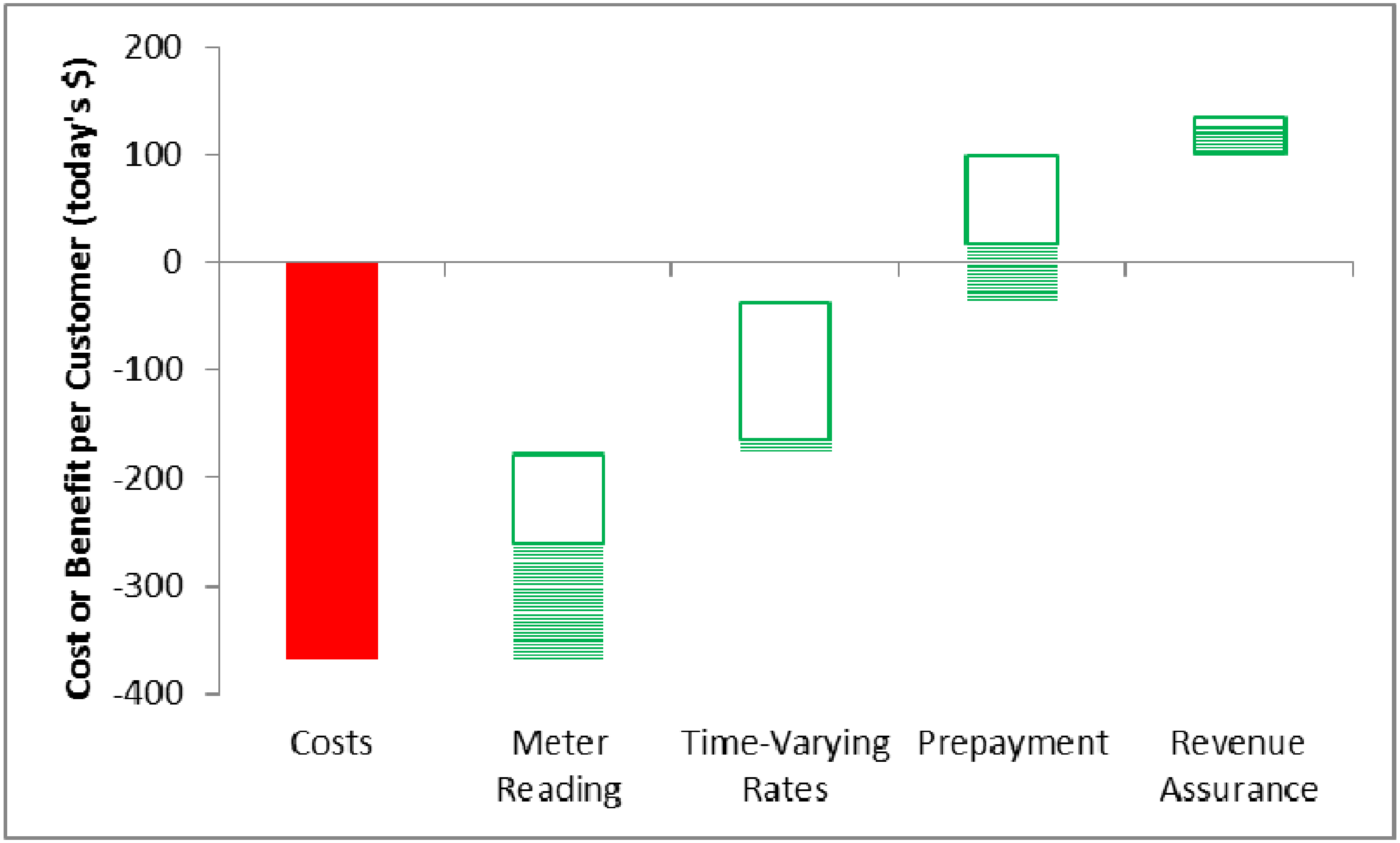
**Average Costs**: From DOE SGIG proposals but includes Present Value of 10 years' worth of operating costs @ 4% of capital/year

**Energy and Capacity values**: U.S. averages

**$ Benefits per year**: Allocated across all customers (not just participants)

**Reliability Benefits**: Not translated into $ nor incorporated in $ benefits

# Smart Meter Benefit-Cost/Customer, 10 years




Typical Deployment

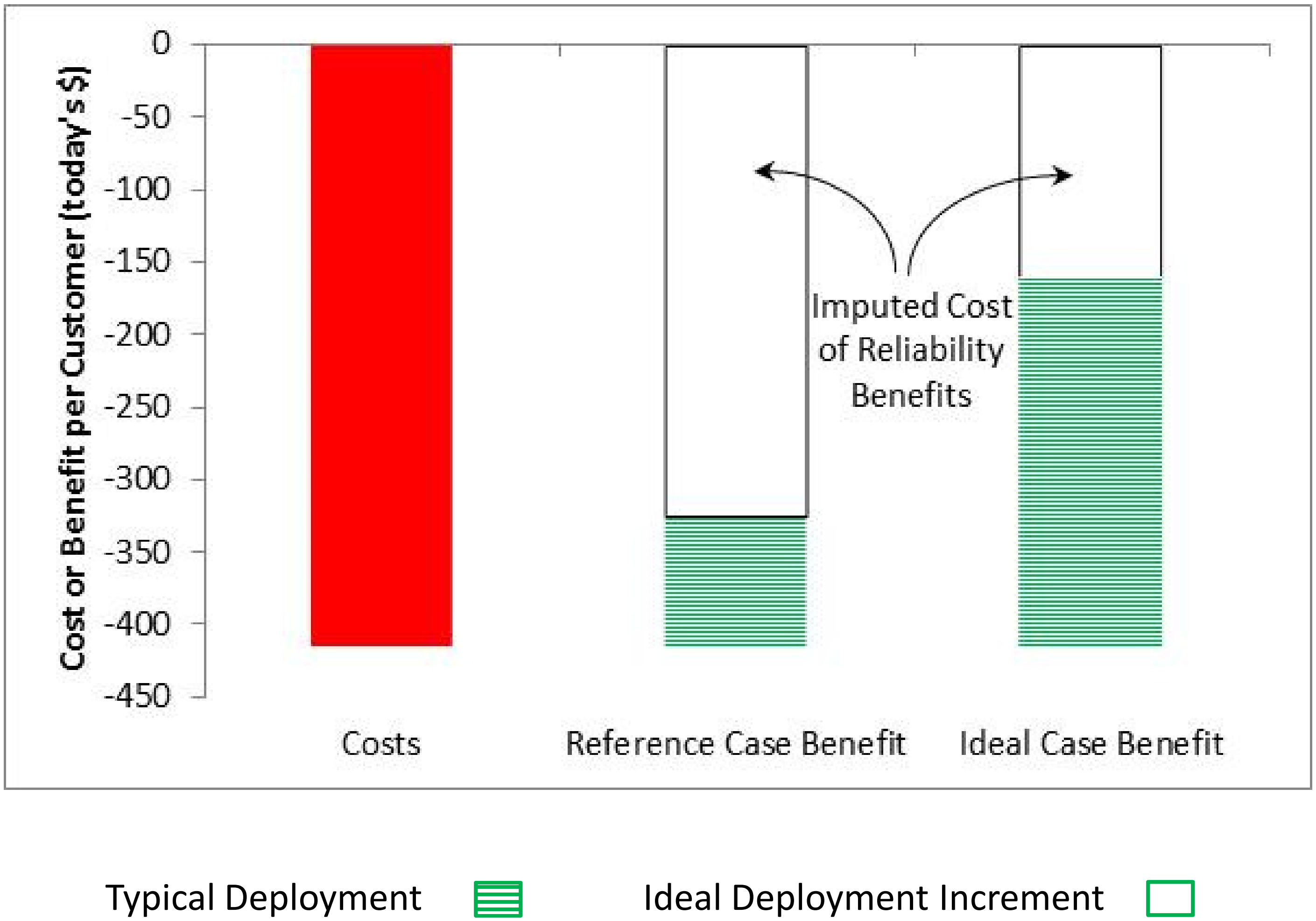
Ideal Deployment Increment

# Smart Meter Ideal Case Details

| Systems and Costs (Present Value) per Customer | Capabilities and Annual Benefits per Customer, per Year (Ideal Case) | Benefits | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Direct | | | | | | | | Indirect | |
| | | Economic (in $) | | | | | | | | | |
| | | Energy Conservation | Demand Reduction | Operations & Maintenance Cost Reduction | Revenue Assurance | **ECONOMIC TOTALS** | Improved Reliability (in percent) | Increased Customer Choice | Enhanced Customer Service | Economic Productivity | Environmental (in lbs. CO2e) |
| Smart Meters $369 | Meter Reading | | | 23.92 | | **23.92** | | | YES | | |
| | Time-Varying Rates | 6.15 | 13.83 | | | **19.99** | | YES | | | 110 |
| | Prepayment | 4.23 | | 15.00 | | **19.23** | | YES | YES | | 76 |
| | Revenue Assurance | | | | 4.44 | **4.44** | | | | | |
| | Outage Mgmt. | | | | | | 4.5% | | YES | Some | |
| | **TOTALS** | **10.39** | **13.83** | **38.92** | **4.44** | **67.58** | **4.5%** | **YES** | **YES** | **Some** | **186** |

Observations: 1) Customer engagement is required for a favorable benefit-cost ratio
2) Customer engagement capabilities involve significant sales volume reductions

# Distribution Automation Benefit-Cost/Customer

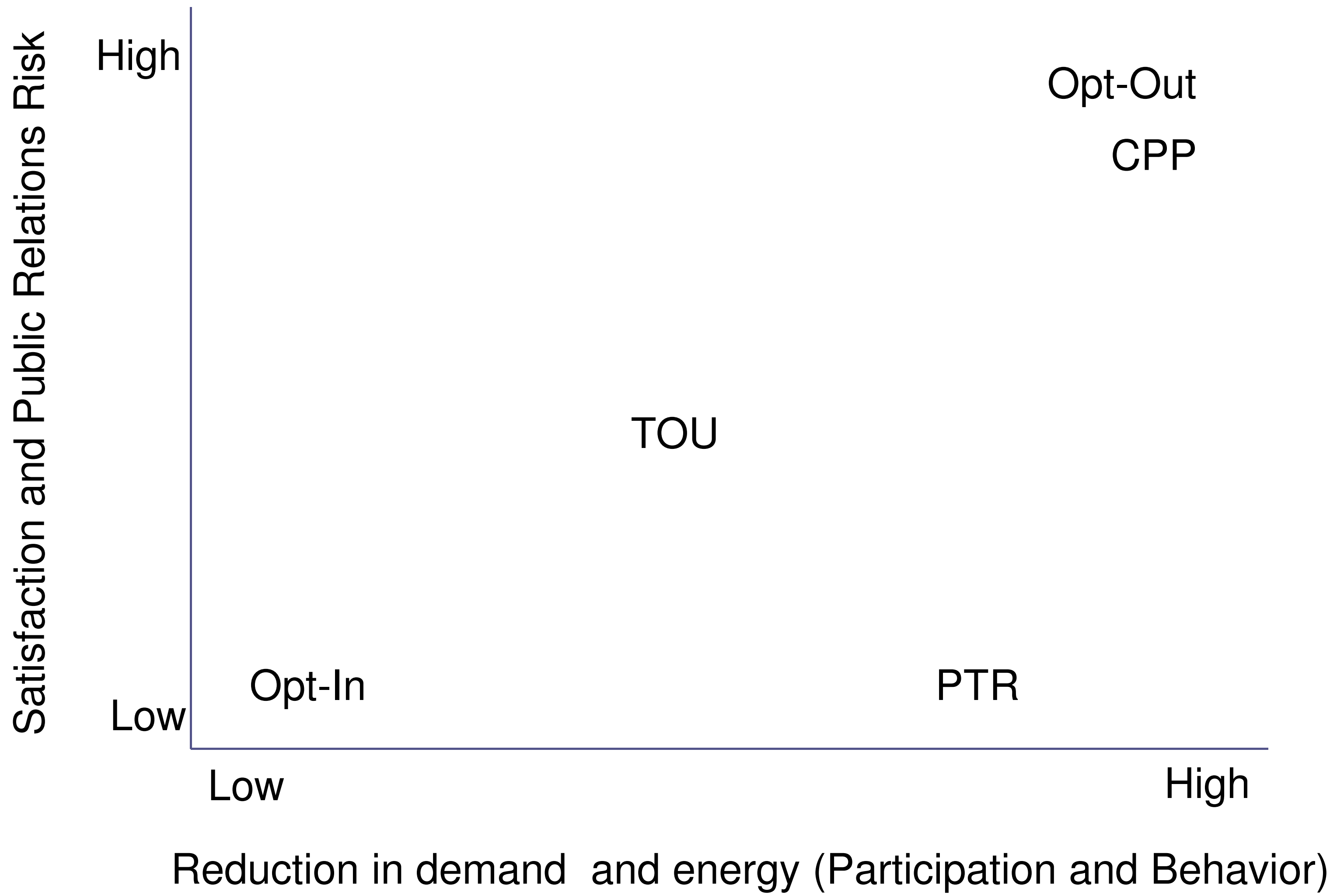


# Distribution Automation Ideal Case Details

| Systems and Costs (Present Value) per Customer | Capabilities and Annual Benefits per Customer, per Year (Reference Case) | Benefits | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Direct | | | | | | | | Indirect | |
| | | Economic (in $) | | | | | Improved Reliability (in percent) | Increased Customer Choice | Enhanced Customer Service | Economic Productivity | Environmental (in lbs. CO2e) |
| | | Energy Conservation | Demand Reduction | Operations & Maintenance Cost Reduction | Revenue Assurance | ECONOMIC TOTALS | | | | | |
| Distribution Automation $80 | Fault Location | | | | | | 4.8% | | | Some | |
| | Fault Isolation | | | | | | 22.9% | | | High | |
| | IVVC | 20.77 | 11.24 | | | 32.01 | YES | | | Some | 372 |
| | Customer-Sited Gen | | YES | | | YES | YES | YES | | | YES |
| | **TOTALS** | **20.77** | **11.24** | | | **32.01** | **27.7%** | **YES** | | **HIgh** | **372** |

Observations: Energy conservation benefits from using IVVC continuously are almost double the benefits from using it during peak periods

# Time-Varying Rate Types, Introduction Methods



# Utility Organization and Operating Systems

**Competencies**

- Project Management
- Change Management
  - Organizations & budgets
  - Processes & systems
  - People
- Innovation

**Business Functions**

- Distribution Control Centers
- Distribution Engineering
- Field Service Centers
- Information Technology
- Customer Care Centers
- Marketing

# RIIO Utility 8-year Plan Components

- Overall goals and associated performance targets
  - Safety; Reliability; Environmental; Customer Service; Customer Satisfaction; Social Obligations
- Revenue requirements
- Capital vs. expense spending
- Energy efficiency performance metrics and targets
- Incentive proposals for each performance target
- Overall Innovation incentive proposal and cost to consumers if awarded (a utility plan competition)

# Is the Thesis Proven?

- A smarter grid can indeed deliver customer benefits in excess of costs and help prepare for future challenges
- Utilities are sub-optimizing benefits by a significant margin
  - Utility organizational and operational changes are significant
  - Customer engagement is extremely difficult
  - Regulatory and governance structures inhibit benefits
    - 70% of benefits stem from capabilities that reduce sales volumes*
    - Rate case timing impacts rate recognition of O&M/revenue benefits
    - IOUs are rewarded for process (investment), not outcomes (performance)
- Significant regulatory changes are needed in the near term
- Dramatic regulatory changes are advised in the long term

* Ideal case scenario

# Thank You!

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720-308-2407 mobile

*Please call with comments, questions, and input!*

*Domains: Smart Grid, Demand Response, and Renewable Energy*
*Services: Visioning, Planning, Execution, Evaluation*
*Clients: Utilities, Regulators, Governing Boards, Suppliers, Associations*

To download evaluation reports in the public domain visit www.wiredgroup.net/Reference_Work_Resources.html

*"Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment"* available on Wired Group website & Amazon.com

# Appendix:  Distribution Performance

Wired Group

# A Tale of Two Utilities

| | FP&L | SDG&E |
|---|---|---|
| Dist. Rate/kWh | $0.044 | $0.051 |
| These Utilities are Peers! | | |
| kW/Customer | 4.8 | 3.9 |
| Customers/Mile | 64 | 62 |
| Dist. Revenue/Customer/Yr. | $973 | $598 |
| Distribution Assets/Customer | $1,516 | $2,013 |

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 10
Page 1 of 1

Please provide copies of any and all documents, analysis, summaries, white papers, work papers, spreadsheets (electronic versions with cells intact), including drafts thereof, as well as any underlying supporting materials created by Mr. Alvarez:

(a) as part of his evaluation of the Company's PTR-Pilot Program, and

(b) any other aspect of the Company's Application in the above-styled proceeding reviewed by Mr. Alvarez.

RESPONSE:

Mr. Alvarez has not created any documents, analysis, summaries, white papers, work papers, spreadsheets, or underlying supporting materials as part of his evaluation of the Company's proposed PTR-Pilot.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 11
Page 1 of 1

Please provide copies of any and all documents not created by Mr. Alvarez, including but not limited to, analysis, summaries, cases, reports, evaluations, etc., that Mr. Alvarez relied upon, referred to, or used in the development of his testimony.

RESPONSE:

Objection. All documents not created by Mr. Alvarez utilized in the development of his testimony are properly cited and available to the Company. DEK is just as capable of performing the research necessary to obtain these documents as is the Attorney General. Notwithstanding this notice and objection, the Attorney General attaches separately the July, 2019 PJM locational marginal price report for the DEOK zone cited on page 18 of the Alvarez testimony, an Excel spreadsheet, as Attachment DEK 11-1.

The Attorney General also attaches a Customer (smart meter) Education and Communications Plan from Baltimore Gas & Electric Company (BGE)[DEK Attachment 11-2], which includes extensive information on that utility's Smart Energy Rewards program (a peak-time rebate program typical of those required by the Maryland Public Service Commission ), and associated market research results, program inputs, and bill samples. Mr. Alvarez states that the attached Customer Education and Communications Plan contributed to Mr. Alvarez's knowledge about such programs.

**Kimberly A. Curry**
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BGE Legal Department

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An Exelon Company

**PUBLIC VERSION**

April 3, 2013

David J. Collins, Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, MD 21202

**Re: Case No. 9208**
**Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Cost**

**Baltimore Gas and Electric Company Phase 4 Customer Education and Communication Plan**

Dear Mr. Collins:

It has come to Baltimore Gas and Electric Company's (BGE) attention that an attachment to its February 27, 2013 Phase 4 Customer Education and Communication Plan (Plan) inadvertently contained confidential information. The February 27, 2013 filing (Maillog 145678) has now been designated as a confidential filing. BGE submits for filing this public version of the Plan that contains redacted information to be placed in the Commission's public files. Thank you for your assistance.

This Plan, filed pursuant to Ordering Paragraph 4 in Order No. 83531 in Case No. 9208, completes the Communications Plan, which BGE has divided into four phases. The Commission approved Phases 1 through 3 on July 18, 2011. This Phase is a consensus product, representing input from the Working Group established by the Commission in Order No. 83531. The Working Group convened four times throughout 2012 and 2013. The Working Group consists of the Staff of the Public Service Commission, BGE, the Office of People's Counsel, Potomac Electric Power Company, the Maryland Energy Administration, and AARP.

Respectfully submitted,

*/s/ Kimberly A. Curry*

Kimberly A. Curry

Attachments

BALTIMORE GAS AND ELECTRIC COMPANY (BGE)
IMPLEMENTATION - PHASE 4
SPRING 2013 – SPRING 2014
SMART ENERGY REWARDS PROGRAM AND OTHER SMART METER FUNCTIONS INTRODUCED

**BACKGROUND:**

**Educating and Communicating About Smart Meters in Phases**.
BGE's smart meter education and communication effort encompasses four phases:

- *Phase 1 (Winter 2011 – Spring 2012)*: Designed to educate BGE employees and inform customers about the new smart meter system and the meter installation process.
- *Phase 2 (Spring - Summer 2012)*: Targeted customer communications by installation community that focus on the actual installation of the new meters. In this plan, Phase 2 was targeted to customers who would receive the new metering system prior to the availability of the online energy manager portal. Phase 2 took place between Fall/Winter 2011 and Spring/Summer 2012.
- *Phase 3 (Fall 2012 - Spring 2013):* Expanding as additional communities are installed to an increasingly robust information and education campaign around the online energy manager portal launch and home energy reports, which use the data generated by the meters to help customers understand and modify their energy consumption. Phase 3 includes the customer communication targeted by installation community identified in Phase 2, but adds new messages associated with the new online energy manager portal called the BGE Smart Energy Manager. Phase 3 also targets educational materials to customers about the online energy manager web portal to those customers who have had the new meter installed in Phase 2. Phase 3 takes place between Spring/Summer 2012 and Spring 2013.
- *Phase 4 (Spring 2013 - Spring 2014)*: Smart Energy Rewards (dynamic pricing) bill credit program and other meter-enabled features that were not available in Phase 3 and not reflected in the communications plan for previous phases.

The first three phases were addressed in BGE's customer education and communication plan that was approved by the Maryland Public Service Commission (PSC) on June 15, 2011. Phase 4 of the plan, outlined in this document, serves as a continuation and complement to the original plan and calls upon some of the same references and research.

BGE is currently in Phase 3 of implementing the customer education plan. As of mid-February 2013, BGE has installed more than 230,000 electric smart meters and performed approximately 55,000 gas meter upgrades (customers for whom BGE delivers both electricity and gas typically receive both upgrades at the same time). This represents approximately 20 percent of the total installations that will be required.

Installation has taken place in Anne Arundel, Calvert, Prince George's and Montgomery counties and BGE is preparing to install meters in Baltimore and Howard counties in the first half of 2013. By Spring 2013, BGE expects to have installed smart meters in 400,000 homes and small businesses, approximately 30 percent of total installations. (Installation map and schedule included in the appendix. Note the time periods indicated on the schedule, e.g. May - October 2013, refer to the time period within which BGE expects to **start** installing meters in a particular segment of the service territory. As the dates are subject to change based on certain business decisions as well as unforeseen situations, BGE cannot provide a definite start or end time for installations in a specific area. This schedule, currently available on BGE.com, is updated when any changes are made).

**Customer Research**

In early December 2012, BGE conducted preliminary research with customers who have smart meters by means of focus groups. The objective was to gather overall feedback on the first phases of the plan and gather useful insight and customer preferences for upcoming phases. The focus groups included current PeakRewards$^{SM}$ customers as well as customers who do not participate in PeakRewards$^{SM}$. PeakRewards$^{SM}$ is a voluntary program in which participants help offset electricity demand during periods of "peak" electricity use, by allowing BGE to temporarily modify the settings on their air conditioner or water heater.

The focus groups included customers from diverse income and age groups. Three focus groups were held with PeakRewards$^{SM}$ customers and three groups with non-participants. Groups in each of these two categories were further broken down as follows:

- Customers age 65 and older
- Customers with a household income of less than $50,000
- Customers with a household income of more than 75,000 (these groups included a cross section of middle and upper income participants)

As installations had primarily been in Anne Arundel County at the time of recruitment, the participants all came from that area. To test the upcoming phase, customers were shown draft BGE Smart Energy Rewards (dynamic pricing bill credit program) communications materials. This BGE communication and education plan reflects the insights and preferences gleaned from that research. Focus group feedback included the following main themes:

- Keep information brief, bulleted and to-the-point
- Clarify the differences between BGE Smart Energy Rewards and PeakRewards$^{SM}$, particularly the savings customers can achieve through Energy Savings Days that do not require cycling or enrollment in the direct load control program
- Emphasize money savings over other benefits, including energy conservation or other potential benefits to the environment
- Give customers specific ways they can reduce energy and save through SER, and help them quantify the savings they can expect to achieve by reducing energy usage during these periods
- Emphasize the *additional savings* that PeakRewards$^{SM}$ customers can expect with SER, for those customers who may be reluctant to pursue savings beyond their PeakRewards$^{SM}$ incentives
- Reassure customers that they are in control of their own savings, and no enrollment is required to participate

A complete report of the focus group results is included in the appendix.

**Meter Opt-Out/Deferrals**

The PSC's decision on January 7, 2013, to initiate additional proceedings to determine whether to allow customers to retain their existing analog meter, or to receive an alternatively-installed AMI meter, is expected to result in a decision later in 2013. Until that time, customers are able to exercise their options under the Commission's orders of May 2012 and notify BGE if they do not want a new smart meter installed at this time. BGE has been using the term "deferral" when removing these customer's meters, and not "opt out," to differentiate and emphasize to customers that this is not a permanent opt out and that they will need to take some additional action if there is a future opt-out option.

As the PSC has determined that customers will need to pay the related costs of any opt-out provision, BGE will not automatically opt out the customers who have previously requested not to have a meter restored. Customers will need to contact BGE again to let the utility know that they are choosing to opt out based on the PSC-determined terms and costs. From customer activities in other states such as California, BGE anticipates that a portion of customers who have deferred meter installation may change their minds if there is a cost involved.

BGE will broadly communicate the PSC opt-out decision and related steps to all customers, both those who currently have meters and those scheduled to receive a meter. In preparation for the PSC announcement, BGE has crafted messages reflecting the two possible scenarios being reviewed by the PSC:

- Option for customers to retain their existing analog meter, and the additional cost associated with that option
- Option for customers to have a new meter installed to "operate in an RF-free or near RF-free manner," and the additional cost associated with that option

When the final decision is announced, we will update messaging in all communications including postcard mailings, website, fact sheets and direct mail letters. These materials will be distributed among the PSC Working Group for fast-track review prior to distribution.

In the interim, we are following the order to allow customers to defer their meter installation. Customers deferring under the order prior to installation simply do not receive a new meter. For those who defer after a new meter has been installed, BGE swaps the new meter for a traditional meter similar to the one the customer had previously. While these are digital meters that are very similar in appearance to smart meters, they do not have two-way communication capabilities. Many customers currently have these digital meters, as analog meters are an older model that have not been used for some time when utilities need to install or replace meters.

BGE provides deferral information on our website, and BGE representatives who attend community meetings are briefed on the process so they can respond to customers. Installers also carry copies of a letter outlining the information customers need if they would like to defer installation. This information has been updated to acknowledge the PSC January order. (A copy of this letter is included in the appendix). At the time of the deferral order in May 2012, there was also substantial media coverage publicizing BGE's deferral process, and local news articles on meter installation continue to reference this information.

Approximately 11,000 BGE customers have requested that BGE not install a meter at their home. This includes customers who contacted BGE prior to the May PSC hearing and deferral order, as well as those who deferred after the order. These customers are from all areas of BGE's territory, including areas where the utility has not started installing smart meters. In areas where installation is underway, approximately 2.5 percent of customers have deferred meter installation. Customers who have contacted BGE with concerns about the meters cite health and privacy concerns as the main drivers for deferring installation, along with the belief that BGE will be able to control their appliances with the meter without their consent.

There are several instances where customers have called with questions or misinformation, when customer representatives have been able to provide accurate information to address these concerns. These customers are satisfied and do not defer their installation. There have also been cases where customers who have deferred meter installation have called to say they have changed their minds. In those cases, BGE sends them a letter to acknowledge their requested change and our understanding that they do, in fact, wish to have a smart meter installed. There have been approximately 100 of these cases so far.

Installers also carry smart meter fact sheets that they provide to customers who are present at the time of installation and have questions. There is anecdotal evidence from installers that some customers who are initially reluctant to go through with the installation change their minds after viewing some of the information on the fact sheet that addresses their concerns.

Current messages:

- On January 7, 2013, the PSC issued an order that Maryland utilities should provide customers with an additional option related to the installation of smart meters in their homes. The PSC will conduct additional proceedings to determine whether the preferred course is to allow customers the option of retaining their current meter or to require all customers to receive a smart meter with the option to have that meter installed to operate in an "RF-free" or near RF-free manner. The PSC will require that customers who select the ultimately approved option pay the related costs.
- As the PSC continues proceedings to determine opt-out specifics, BGE customers who wish to defer meter installation can continue to do so by contacting BGE via email or letter. Customers who have already requested a meter deferral do not have to take further action at this time. BGE will communicate any next steps when the PSC makes a final determination.
- BGE customers who wish to defer installation, or customers requesting removal of meters already installed, should provide the following information via letter or email:

    1. *Name(s)*
    2. *Address*
    3. *Account Number*
    4. *Phone Number*
    5. *Email Address*

- Emailed deferrals should be sent to smartmeterdeferral@bge.com.
- Letters should be sent to:

Smart Meter Deferral
BGE
P.O. Box 1475
Baltimore, MD 21203

- For more information on the PSC's order on the opt-out issue, visit the PSC website at www.psc.state.md.us and access Order Nos. 84926 and 85294, and Case Nos. 9208 and 9294.

**PSC Smart Grid Work Group.** As directed, BGE is participating in the Smart Grid Implementation Work Group composed of BGE, Maryland Public Service Commission Staff, Maryland Office of People's Counsel, Maryland Energy Administration, AARP, Montgomery County Office of Consumer Protection and Department of Environmental Protection and Pepco to develop this additional component of the Advanced Metering Infrastructure Customer Education Plan for BGE's Maryland service territory. The proposed plan is being submitted for review and approval by the Commission.

## I. PHASE 4 OBJECTIVES

- Educate customers who already have smart meters about the availability and benefits of the BGE Smart Energy Rewards customer credit program, under which customers may receive bill credits for voluntarily reducing their usage below baseline levels during critical peak periods that BGE will call Energy Savings Days. BGE Smart Energy Rewards is the official name of the program and will be referred to as such in customer communications. We will abbreviate the name as "SER" in this report but this acronym will not be used in customer materials.
- Link the installation of smart meters to the now-available benefits including SER, service restoration confirmation and remote turn on/turn off. These features are all part of what BGE refers to as a "release," a technical milestone when all necessary systems are ready to broadly support and process specific activities.
- Using customer input gathered in BGE's previous pilot program and from focus groups conducted by BGE in December 2012, encourage customers to participate in "Energy Savings Days" (the name preferred by focus group participants to describe peak events) to receive credits and reduce peak load (consistent with health and safety).
- Gather and note customers' preferences for notification about peak events and savings feedback.
- Integrate customers enrolled in the PeakRewards$^{SM}$ demand response program into the broader SER credit program while maintaining their original enrollment incentives. (PeakRewards$^{SM}$ is BGE's direct load control program, in which customers give BGE the authority to reduce the peak-time usage of central air conditioning and hot water heaters by 50, 75, or 100 percent in return for bill credits).
- Educate customers on new smart meter functions and features, including remote turn-on and turn-off of service and remote confirmation of service restoration after power outages in cases where BGE would previously have attempted to call customers, such as customers whose homes are on small feeders.

## II. KEY MESSAGES

***SER***
***(Customer communications begin Spring 2013, program begins Summer 2013)***

- BGE SER is a voluntary new program that can help you earn credits on your BGE bill, helping you reduce your summer energy bills.
- By reducing the electricity use in your household during specific times of high electricity demand, known as "Energy Savings Days," you can receive a bill credit that will lower your bill that month. (Bill samples included in the appendix).
- You always have the choice of whether or not to reduce usage on an Energy Savings Day, and you will never be penalized for not reducing on those days.
- If you are currently enrolled in BGE's PeakRewards$^{SM}$ program, you will remain enrolled in that program and you can continue to participate in PeakRewards$^{SM}$ as you have before. You will retain your bill credits and smart thermostat/outdoor switch. In addition, you can potentially earn additional credits for additional usage savings on Energy Savings Days.
- If you are a PeakRewards$^{SM}$ customer, you will be cycled at 50 percent on Energy Savings Days. You will have unlimited overrides for Energy Savings Days cycling during non-emergency events, but you will be cycled at your chosen level (50%, 75%, 100%) during emergency cycling events when BGE and utilities in the region have been asked to reduce usage across the system as there is danger of the type of strain on the system that could lead to brownouts and blackouts.
- You can choose how we notify you about Energy Savings Days (opportunities to earn a bill credit) including email, text messages, and phone messages. If you do not tell us how you prefer to be notified, we will provide you with notification by phone and also by email if we have your email contact on file. You may also easily opt-out of receiving these messages altogether.
- Your BGE SER credit will be shown both on your normal monthly bill and online on your "My Account" page. You can also choose how we give you immediate feedback about your savings, including email, text and phone messages. In addition to these feedback methods, we will also periodically mail you a hard copy report outlining your overall savings through BGE SER.

***Additional meter features***
*(**Features available Summer 2013, customer communications begin at the time of feature availability**)*

- When you move in or out of a home with a smart meter, BGE will no longer have to come to your home to start or stop electric service. This new service will ensure accurate billing for you and the previous and future occupants of your home.
- In the event of an outage, smart meters may assist BGE with customer communication during service restoration because we can communicate directly with your meter to confirm that your service has been restored. In cases where BGE would typically have to call customers on the phone to confirm restoration of power, this feature could be particularly helpful.
- All customers will still need to call BGE to report an outage and to provide any additional information that might be helpful, such as reports on downed wires.

BGE will use the following communication channels to provide these messages:

***For SER:*** bge.com, *Connections (BGE's bill insert newsletter)*, direct communications (brochure, email), paid media and earned media coverage in specific areas where the majority of customers are able to participate in the program (e.g. Anne Arundel County). This information will also be included in smart meter presentations given to community groups.

***For remote turn on/turn off:*** bge.com, new service applications, materials for new customers, annual BGE consumer reference guide

***For service restoration confirmation (meter "pinging"):*** storm and outage related communications including press releases, bge.com messages and customer contact center talking points. This information will also be included in smart meter presentations given to community groups.

## III. CHALLENGES

- Customer awareness of the SER credit program, why they should participate, and how to participate.
- Potential confusion on relationship between the SER credit program and their PeakRewards$^{SM}$ optional enrollment in load control program.
- Convincing both PeakRewards$^{SM}$ and non-PeakRewards$^{SM}$ customers that they are in total control of their SER participation, and will not be penalized for non-participation, an issue that BGE determined was a high priority for our customers based on the December 2012 focus groups.
- Reaching non-English-speaking customers.
- Reaching vulnerable customer populations, including seniors, disabled, and limited-income.
- Educating customers about how to reduce electricity usage and still be comfortable in their homes and businesses; along with clarifying that customers who depend on electricity for medical reasons should carefully consider participation in the program and ensure that they do not attempt to reduce usage of any equipment necessary to maintaining their health, including air conditioning and fans. Tips will be provided on other ways to reduce overall electricity use to earn a bill credit, e.g. reducing lighting, not turning on dishwashers, washing machines and dryers during Energy Savings Days.
- Potential customer perception that added smart meter capabilities may increase the risk of privacy and data security breaches.
- Customer concerns about cost of smart meters.

When BGE SER becomes available in Summer 2013, approximately 400,000 customers with activated smart meters will be able to participate in the program. (In this case, "activated" is used to mean that the meter is communicating through the new network and the information used for billing. Internally, BGE uses the term "certified" to describe this status, but will use activated in this plan and with customers for ease of customer understanding and consistency with neighboring utilities).

Multiple communication channels will be needed to reach segmented audiences, including PeakRewards$^{SM}$ customers, who now have smart meters. To help ensure retention in the PeakRewards$^{SM}$ program, it will be emphasized to those particular customers that they will continue to receive at least their minimum PeakRewards$^{SM}$ credit, plus have the opportunity to earn credits through additional voluntary peak period load reduction efforts that do not require cycling. All customer communications will seek to simplify program features and benefits descriptions. Recently conducted focus group testing (December 2012) of SER communications materials has yielded valuable feedback and customer preferences that will be reflected in the customer communications currently in production.

In Spring 2014, BGE plans to repeat these communications tactics for the customers who are newly able to participate in the program in Summer 2014. Materials will be revised and overall changes made to reflect insights and customer feedback from the Summer 2013 activities. Ongoing research and the potential for revised communication materials will be shared with the working group for their review and input.

## IV. APPROACH

### Customer Awareness / Community Outreach and Education

**Installation Communications.** Customers whose meters are installed during Phase 4 will receive a postcard two to four weeks prior to their meter installation, and a door hanger and welcome kit when installation is complete that includes information about the online Smart Energy Manager. In addition, they will receive a variety of communications, outlined below under "Communications Channels," on the BGE SER program, how it works and what they need to do in order to participate.

### Communications Channels

**BGE.com.** The BGE website will be augmented with additional information about BGE SER and details about the bill credits. When they are introduced in Summer 2013, descriptions of the additional smart meter features that are pertinent to the customer will also be incorporated into the website content. In addition to the smart grid page on the BGE website, which is directly accessible through bge.com/smartgrid, the remote turn-on and turn-off capability will be included in bge.com general information on setting up a new BGE account and moving service. The ability to determine whether restoration of service has occurred after power outages will be included on bge.com/smartgrid when discussing smart meter-related features. Through the BGE.com "My Account" feature, customers will be able to select their notification preferences for Energy Savings Days and related information. If a customer does not select a notification preference, BGE plans to notify customers of Energy Savings Days through the phone number and via email information already captured in BGE's database. Efforts will be made prior to the launch of SER to get current contact information for customers, including an outbound call campaign taking place in February and March 2013. When customers call the contact center, reps are also updating their contact information. Customers will be informed in the BGE SER "Get Started Kit" and in periodic emails that these will be their default communications options. Customers can update their notification preferences at any time or they can opt-out of receiving any messages about the Energy Savings Days.

**Digital/Social Media/Content Syndication.** Additional content will be prepared and disseminated via social media channels including Facebook, Twitter and YouTube to highlight the new SER rebate program and encourage customers to participate. Customer testimonials and video clips will be incorporated and distributed, providing opportunities for online discussions, posts and feedback from customers as they access the new features. In order to access this information, customers would have to "follow" or "friend" BGE, or specifically search for BGE information on YouTube or other social media channels. Customers who are not following BGE on social media can also read related information on BGE's topical blog, posted on BGE.com and promoted through banner ads and in BGE's *Connections* newsletter. Information will also be disseminated by non-electronic methods outlined in this plan. BGE will track the volume of activity on these social media channels.

**Email Blast**. Customers with an activated meter will be sent a graphically-enhanced email with web links containing high level features and benefits of the SER program. Emails will be customized to PeakRewards$^{SM}$ customers and to those not enrolled in PeakRewards$^{SM}$. Based on the feedback from our December 2012 focus group research, the content of these messages will be brief and emphasize customer control over their decision to participate in these programs. A call to action will provide customers with a link to the video and more details on the website.

**Awareness Direct Mailer.** Customers with an activated smart meter will receive an awareness mailer (bifold, card-stock mailer with easy-open seal, as opposed to envelope-style mailer, as focus group participants indicated this was their preference). It will highlight SER program benefits, and provide a link to bge.com. The email will also invite customers with smart phones to scan a special code, called a QR code, for more information they can view on their iPhone.

**Preview Postcard.** Shortly after receiving the email and the awareness mailer, customers will receive a postcard to remind them that they are eligible for SER and alert them to look out for a Get Started Kit with more information. They will also be provided with a QR code so smart phone users can scan it to view the video on their iPhone and a link to the specific section of bge.com devoted to smart grid and SER.

**Telephone Campaign.** Customers with activated smart meters will receive a live phone call to draw their attention to the SER Get Started Kit they are about to receive and answer any questions they might have about SER. Callers will leave a voicemail after the first attempt at contacting customers live, including a call-back number if the customer would like to follow up for more information on the program.

**Get Started Kit.** After the awareness mailer and preview postcard**,** customers will receive SER materials through the mail, customized for current PeakRewards$^{SM}$ customers and customers who are not enrolled in PeakRewards$^{SM}$. PeakRewards$^{SM}$ customers will receive additional information on the combined savings from both programs and how the savings will be presented on their bill. Customers not enrolled in PeakRewards$^{SM}$ will receive information encouraging them to participate in SER along with some general information or FAQs on how BGE SER differs from PeakRewards$^{SM}$, as they may have some familiarity with that program.

While the initial communications are intended to inform customers that the program is coming and get them interested, The Get Started Kit will include a more thorough explanation of how the program works and how customer bill credits are calculated and displayed on the bill. This information will also be available on BGE.com in the section on SER, with a link to BGE's tariff information. BGE's tariffs, the regulations regarding BGE's service and rates, are currently posted on bge.com.

**Mail, Phone, Email and Text Notifications and Updates**. If customers have provided contact preferences, they will receive a reminder through those channels to get ready to participate in the first Energy Savings Day. As this is a new program, we want to ensure that customers understand what to look out for and what to do when it is an Energy Savings Day, so they are ready to act when they receive the Energy Savings Day notice. In ongoing program communications and other customer communications, including contact center interaction, customers will be given the opportunity to sign up for emails so they can continue to be notified of Energy Savings Days by email, and also receive ongoing communications from BGE about SER. Paper reports, phone messages, email and text messages also will be used to notify customers of the credit they have earned by participating in the program. If a customer does not earn any credits during an Energy Savings Day, they will still receive a notification letting them know this and providing them with tips on ways to save during the next opportunity.

**Online Smart Energy Manager**. The online BGE Smart Energy Manager (detailed in Phase 3 of BGE's Smart Meter Communication Plan, pages 32-41) will include a new feature linked to the SER program, which will allow customers to view how much money they saved by reducing their energy use during peak events.

The online BGE Smart Energy Manager is expected to evolve over time as more features are added. When the Energy Savings Days credit program is introduced in Summer 2013, customers can log on to the Smart Energy Manager for the following:

- Usage and "Bill" Data Presentment – presentation of hourly consumption data from the previous day.
- Energy Budget Tracking – a tool that allows customers to set a budget for their energy costs and track performance against it throughout the month.
- Savings Summaries – feedback on the amount of money that a customer has saved through BGE SER.
- Comparison to Others – feedback on how a customer's usage compares with similar households. Social norms have been shown to significantly change consumer behavior.
- Tips on how to increase credits and safely reduce energy use.

**BGE Smart Energy Rewards Introductory Video.** A short video (three to five minutes) will feature a step-by-step explanation of how the Energy Savings Day credit program works and how customers can take advantage of the benefits. Based on focus group feedback (December 2012), the video will be short and fact-based, given that customers did not favor a testimonial approach. There will also be a short version (less than 1 minute) of this video created for promotion purposes as well. Both will be available on YouTube and downloadable from BGE.com/smartgrid. This video will be referenced in the SER email updates that customers receive and shown at community presentations and open houses.

**Outreach to PeakRewards℠ Customers.** To alleviate any confusion on the part of customers enrolled in the PeakRewards℠ direct load control program, those with new smart meters will receive direct communication, including letters and email messages about the how the PeakRewards℠ program will function in relation to BGE SER, in addition to the PeakRewards℠ version of the Get Started Kit. Information about how PeakRewards℠ integrates with SER will also be included on the Peak Rewards website. Customers who do not currently have activated smart meters but who hear about SER and would like to learn more can also find information on the PeakRewards℠ website, and on bge.com/smartgrid. PeakRewards℠ enrollees who have not yet had smart meters installed will also be kept aware through emails about the upcoming transition and what to expect when they get their smart meters.

The communications will stress that PeakRewards℠ customers can retain their bill and thermostat and/or outdoor switch, plus they will have additional ways to save during Energy Savings Days. The communications will let customers know that they have the choice of whether or not to seek additional credits through SER any time an Energy Savings Day is called.

The main message points to these customers is that the PeakRewards$^{SM}$ A/C program helps make saving energy easy since BGE will automatically reduce your air conditioning use on Energy Savings Days. In addition to this automatic cycling as part of the PeakRewards$^{SM}$ program, you can save energy in other ways to earn additional summer bill credits. We will provide specific examples of savings as a guide for customers. If they participate in both programs (BGE SER + PeakRewards$^{SM}$), the summer bill credits applied to their BGE bill could be even larger. The communications will also inform customers that they will be automatically cycled at 50 percent during non-emergency events.

Customers who participate in both PeakRewards$^{SM}$ and BGE SER will see the credits they have earned from both programs on their bill.

**Media Outreach**

The launch of BGE SER will mark an important milestone in the functionality and interactivity of customers with the emerging smart meter infrastructure. Media activities will include:

- Additional talking points, FAQs, fact sheets and key messages about the program and how it works
- Preparation of BGE spokespeople for potential interviews on TV, radio, print and online publications about BGE SER and its functionality and significance to consumers. (While we plan to primarily promote the program in areas where customers can participate, we are often contacted by the general media with questions about smart meters and related benefits).
- Messaging about additional smart meter capabilities, including remote turn on and turn off and service restoration confirmation.
- Supporting messages on BGE's continued commitment to security and customer data privacy as we introduce more meter-related features. Spokespeople will reinforce current messages, including:
  *BGE is taking every precaution to protect your data. Our activities include:*
  - *Hiring 3rd party security audit firms to review our policies, procedures and technology and recommend improvements*
  - *Using good "hackers" to attempt to break into our systems so that we can correct any potential issues identified*
  - *BGE has implemented cyber-security programs to address cyber-security threats and risks that are intended to be up-to-date and flexible, now and in the future.*

**Advertising**

**Community-specific advertising** will be placed in areas **where installations have already taken place or will happen shortly** during Phase 4, and will be augmented to include the features and benefits now available to the majority of customers in that particular area. BGE will continue along the current plan, which includes community newspapers, billboards, radio stations where appropriate and local access cable advertising.

While advertising in 2013 will continue to focus on meter installation and the BGE Smart Energy Manager - the online tool customers can use to better understand and manage their energy use - there will also be some SER-specific advertising in communities where meters have been installed to the majority of residents, to encourage customers to participate in the program. When meter installations are complete in

2014, BGE will have the opportunity to promote SER more broadly, including advertising on radio, television and newspapers, across BGE's entire central Maryland service area. BGE will also pursue partnerships with public service broadcasts to inform customers about Energy Savings Days.

Ongoing advertising evaluation will measure the number of households potentially exposed to the ad campaign in its various forms (print, outdoor, and cable) and the number of times each household may have seen the ads. Evaluation will include a detailed breakout within the service territory to ensure optimum coverage of customers with the appropriate levels of advertising, based on whether they had earlier installations or are receiving them during the final phase. Evaluation will include focus groups and phone surveys. Program effectiveness will also be measured using metrics jointly developed by BGE and Pepco in conjunction with the PSC working group, and approved by the Commission.

BGE's ongoing customer communications campaigns will be adjusted to incorporate mentions of SER benefits introduced during Phase 4.

BGE will also start referencing smart meters and the related programs (BGE Smart Energy Manager as well as SER) in other communications about the ways BGE customers can manage their energy and save money, including the "BGE Smart Energy Savers Program" (a group of energy efficiency programs BGE offers including the Home Energy Check Up and Energy Star appliance rebates).

**Engagement with Community Organizations**

Community engagement will continue to closely follow BGE's installation map, with events concentrated in areas that will shortly receive meters or where meter installation is currently under way. At this point in the installation (Spring - Summer 2013) materials for community events will now include information on the SER program and new meter capabilities relating to remote turn on and turn off, and determining whether service has been restored following power outages.

BGE will continue to contact organizations that serve vulnerable customer populations, including limited-income, senior and non-English-speaking customers, to make sure these customers have access to information on smart meters and related features. (A representative list of organizations BGE has contacted or will contact throughout deployment was included in the plan appendix. Examples include Meals on Wheels Anne Arundel County, an organization that home-delivers food to seniors in need, Korean Community Service Center, an organization providing social services and programs to community members of Korean descent, including recent immigrants, and the Maryland Hispanic Chamber of Commerce, an advocacy organization for Hispanic-owned businesses and business owners.)

When open house events are scheduled for a particular community, BGE emails an event invitation to several community and civic organizations in the area. The event is also sent to the community calendar for local news services (*Patch*) and BGE promotes the events through its social media channels, Facebook and Twitter.

BGE also receives requests from organizations across the service territory to speak to their members about smart meters. BGE attempts to respond to all such requests and works with the organizations to align their timing with availability of BGE staff to support. We have fulfilled requests from a variety of organizations, including the Bowie Senior Computer Club, Green Haven Improvement Association, Ferndale Senior

Center and the Greater Severna Park Council. We have received very positive feedback from these presentations, where in addition to common questions such as how the smart meter will affect their bill, and will the meter control their appliances, attendees often pose new questions that are then added to our Frequently Asked Questions handouts and online “Common Questions.” Recent examples include:

> Q: ***How will the smart meter rollout affect customers with solar panels (photo-voltaic cells)?***
>
> A: *Customers with solar panels will receive their smart meters at the same time as all other customers in their neighborhoods, consistent with the deployment schedule available on BGE.com.*
>
> Q: ***I have a surge protector attached to my current meter; what will happen when the smart meter is installed?***
>
> A: *Installers will re-attach your surge protector to the smart meter, and it will function as it did with your previous meter.*

All outreach and materials on SER will include messaging for customers who depend on electricity for medical equipment or the stability of their health. Customers should ensure that all of their medical and health needs are being met. If curtailing electricity, in whatever capacity, compromises their health, these customers should carefully consider not reducing their usage on Energy Savings Days. Tips will be provided on ways these customers can earn SER bill credits without jeopardizing their health, such as, waiting until after the savings period to run the dishwasher or washing machine. These messages will be incorporated into general materials and outreach on this program, including the Get Started Kit, and stressed in events with community organizations that support special needs audiences.

The fact that SER usage reduction is voluntary and not mandatory for BGE customers will also be stressed. Per the focus group (December 2012) preference, these issues will be addressed in all program communications, including the FAQs of the Get Started Kit, in program fact sheets and in community presentation speaker materials.

*The following are supplemental tactics in addition to those outlined in Phase 3 (Phase 3 tactics attached for reference).*

| Details on Campaign Tactics for Phase 4 Deployment | | | |
|---|---|---|---|
| **Tool** | **What** | **Why** | **When** |
| **BGE Smart Energy Rewards (SER) Email** | Introduce high level benefits of SER | Generate initial interest in program | Beginning Spring 2013 |
| **BGE Smart Energy Rewards (SER) mailer** | General awareness mailer to reinforce Smart Meter communications and explain the SER program that will be available starting Summer 2013 | Provide program details and encourage customers to participate | Beginning Spring 2013 |
| **BGE Smart Energy Rewards (SER) postcard** | Confirmation of eligibility for SER and encouragement to look out for Get Started Kit | | Beginning Spring 2013 |
| **BGE Smart Energy Rewards (SER) Get Started Kit** | Materials introducing SER, its features and benefits, and instructions for accessing credit information | Fully equip customers to maximize the benefits of the SER program and earn credits, in addition to managing their electricity costs to a greater degree than before | Beginning Spring 2013 |
| **BGE.com** | SER write up on the smart grid page, specific SER page, new info on additional smart meter functions, including remote turn on/turn off on the "new service" page | Provide information on new BGE programs and offerings related to smart meters. Allow customers to update notification preferences for upcoming Energy Savings Days and savings feedback | Beginning Spring 2013 |

| | | | |
|---|---|---|---|
| **Telephone campaign** | Automated message to customers by phone | Phone call to all eligible customers prior to the Energy Savings Day, informing them of their eligibility for SER and reminding them to read their Get Started Kit | Spring 2013 |
| **Mail/Phone/email/text notifications and updates** | Based on customer contact preferences, periodic program information, including reminders about Energy Savings Days and Savings Days credit summaries | Make sure customers are aware of program and have opportunity to participate in Energy Savings Days; encourage future participation by providing participation results | Beginning Spring 2013 |
| **Email to community organizations** | Program announcement, invitation to visit BGE.com | Encourage orgs to encourage members to participate | Beginning Spring 2013 |
| ***Connections*** | Newsletter included in bill insert and sent via email to online bill pay customers. Program announcement, reminder to review Get Started Kit and visit BGE.com | Increase readership of welcome packet and encourage customers to participate | Spring 2013 |
| **Bill message** | Reminder message on eligible customers' bills | Encourage customers to review Get Started Kit or visit BGE.com for program information | Beginning Spring 2013 |
| **Bill message** | Reminder message on eligible customers' bills | Encourage customers to review Get Started Kit or visit BGE.com for program information | Beginning Spring 2013 |

| | | | |
|---|---|---|---|
| **BGE Smart Energy Rewards (SER) outreach materials** | -Video with "how to" information on SER<br><br>-Fact sheet<br><br>Speaker presentation slides | Provide customers with opportunities to learn about SER and ask questions of BGE experts at events, meetings and community venues. | 2013 –2014 |
| **Media materials** | Expanded talking points, key messages and FAQs focusing on SER and increased meter functionality | Media venues will provide increased opportunities for educating customers and providing a forum for questions and in depth information sharing through media channels | 2013 - 2014 |
| **PeakRewards$^{SM}$ enrollee notifications and materials** | Notifications to enrollees in demand response (who have smart meters) to explain the transition to SER and underscore benefits to remaining enrolled and active | PeakRewards$^{SM}$ enrollees will have questions about continuation of bill credits, and reasons for continuing their participation in cycling and demand response efforts | 2013 - 2014 |
| **Advanced Metering Capabilities communications** | Updates to the BGE Consumer Reference Guide and to service applications; messages in storm and outage communications | New smart meter functionality will produce added benefits to customers, including remote turn on/turn off for customers who move and service restoration confirmation in specific situations (when BGE would typically call customers) | Summer 2013 |

## V. RESEARCH AND EVALUATION

BGE's ongoing measurement and evaluation of the customer education and outreach program will continue through this phase, using metrics coordinated and established with Pepco and the PSC working group, and approved by the Commission. Metrics from the previous phase of the plan which will also be included in this section include customer awareness and customer satisfaction.

The metrics from the previous phase of the plan were recently approved and are included in the appendix. Based on that approved submission, the metrics are broken down as follows:

> *"Phase II A metrics are designed to measure the realization of projected benefits associated with implementation of new AMI functionalities, such as continued implementation of operational efficiencies relating to remote connection and disconnection of meters and meter reading, customer service, customer interaction with web-based tools and the results of those interactions, as well as customer responses to and participation in dynamic pricing activities. Phase II B metrics are under further development by the Utilities and will be proposed at a later date after review and input with the Working Group. These Phase II B metrics will focus on capacity and energy benefits due to web-based energy management tools, dynamic pricing events, and conservation voltage reduction. Also, additional financial impacts may be included. The instant filing is comprised of Phase II A metrics. The Plan provides an introduction to the Phase II A metrics that were developed by the Working Group."*

## VI. PHASE 4 SER BUDGET (PENDING APPROVAL)

The funds outlined on the following page will cover the period when BGE will develop and deploy materials focused on BGE SER. This budget does not include funds directed to the communication of additional meter capabilities such as remote turn on/turn off, as those messages will be incorporated into regular BGE communications and materials including information on bge.com, service applications and the annual Consumer Reference Guide.

Given BGE's installation schedule, approximately 70 percent of customers will not yet have meters when some of these features are introduced in 2013. Therefore, there will also be a need for updated communications materials that cover meter installation as well as the program that will be available to these customers, the BGE Smart Energy Manager. **The funds for these materials are not included in this budget as they were a part of the previous budget included with BGE's approved communications plan covering Phases 1-3.** The budget below focuses **specifically on materials that highlight SER** for customers who are able to participate in that program. This budget is incremental to the previously approved Phase 1-3 budget.

*All figures in $1,000s*

| Communications Vehicle | 2013 | 2014 |
|---|---|---|
| Telephone Campaign | 400,000 | 1,200,000 |
| E-Mail Blast | 3,000 | 12,000 |
| Awareness Mailer (includes production and mailing) | 57,000 | 170,000 |
| Postcard (includes production and mailing) | 31,000 | 110,000 |
| Get Started Kit – Peak Rewards and non-Peak Rewards (includes production and mailing) | 850,000 | 2,275,000 |
| Advertising in areas where customers are able to participate in SER, encouraging them to look out for and participate in Energy Savings Days. Broken down as follows:<br><br>Print – 15%<br>TV/Cable – 25% (zone-specific cable buys)<br>Outdoor – 30%<br>Digital/Web – 30% | 400,000 | 750,000 |
| Videos (one long format for community meetings and presentations, one short format for link from program materials) | 34,000 | 10,000 |
| Customer Notifications (Energy Savings Days alerts and savings reports, sent via mail, email and text) | 1,500,000 | 2,000,000 |
| Program Management and Staffing<br><br>(Agency administrative fees, program contract staff to assist with customer notifications, etc.) | 200,000 | 200,000 |
| Annual Totals | 3,475,000 | 6,727,000 |
| BGE Smart Energy Rewards Communications Total | 10,202,000 | |

**Appendix (Separate Document)**

I. BGE Smart Meter Installation Map and Schedule

II. BGE Customer Focus Group Report December 2012

III. Bill Samples for SER and SER-Peak Rewards Customers

IV. Smart Energy Manager (SEM) Overview and Screenshots

V. Community Organizations

VI. BGE Communications Plan Phase 3 Tactics

VII. BGE/Pepco Phase II A Metrics

VIII. Letter to Customers on Meter Deferral Option (Carried and Hand Delivered by Meter Installers)

## BGE Smart Meter Communications Plan Phase 4 Appendix

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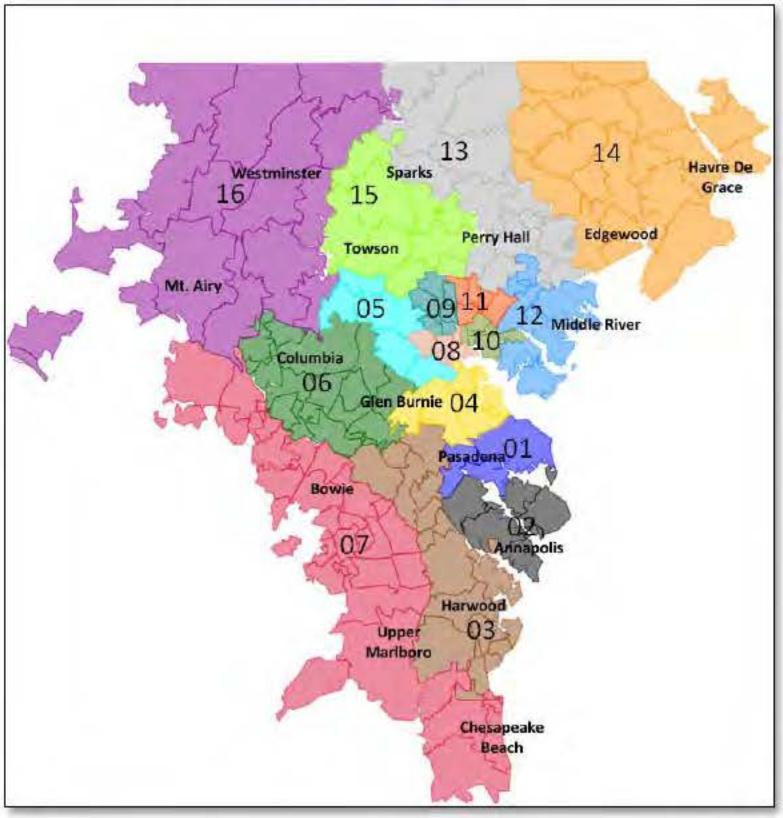
VII. BGE/Pepco Phase II A Metrics

VIII. Letter to Customers on Meter Deferral Option (Carried and Hand Delivered by Meter Installers)

# I. BGE Smart Meter Installation Map and Schedule

# Smart Meter Installation Schedule




| Segment | County | *Estimated Start Window |
|---|---|---|
| 1 | NE Anne Arundel County | May - Oct 2012 |
| 2 | East Anne Arundel County | July - Dec 2012 |
| 3 | SW Anne Arundel County | Aug 2012 - Jan 2013 |
| 4 | NW Anne Arundel County | Dec 2012 - May 2013 |
| 5 | SW Baltimore County | Jan - Jun 2013 |
| 6 | Howard County | Mar - Aug 2013 |
| 7 | Calvert County | Sep 2012 - Feb 2013 |
| 7 | Montgomery County | Oct 2012 - Mar 2013 |
| 7 | Prince George's County | Sep 2012 - Mar 2013 |
| 8 | Baltimore City | Mar - Aug 2013 |
| 9 | Baltimore City | May - Oct 2013 |
| 10 | Baltimore City | May - Oct 2013 |
| 11 | Baltimore City | June - Nov 2013 |
| 12 | Baltimore County | July - Dec 2013 |
| 13 | Baltimore County | Jan - June 2014 |
| 14 | Cecil County | Mar - Aug 2014 |
| 14 | Harford County | Mar - Aug 2014 |
| 15 | Baltimore County | June - Nov 2014 |
| 16 | Carroll County | Aug - Dec 2014 |
| 16 | Frederick County | Aug - Dec 2014 |

| SEGMENT | COUNTY | TOTAL ELECTRIC METERS | TOTAL GAS METERS |
|---|---|---|---|
| S 01 | NE AA Co. | 43,026 | 13,372 |
| S 02 | E AA Co. | 58,375 | 18,160 |
| S 03 | SW AA Co. | 74,156 | 31,828 |
| S 07 CV | CV, PG, MG Cos. | 8,865 | - |
| S 07 PG | CV, PG, MG Cos. | 81,183 | 7,566 |
| S 07 MG | CV, PG, MG Cos. | 13,690 | 1 |
| S 04 | NW AA Co. | 65,075 | 38,954 |
| S 05 | SW BL Co. | 88,027 | 61,991 |
| S 06 | HW Co. | 114,148 | 51,999 |
| S 08 | SW BC Co. | 62,057 | 45,203 |
| S 09 | NW BC Co. | 87,666 | 68,059 |
| S 10 | SE BC Co. | 64,232 | 49,797 |
| S 11 | NE BC Co. | 82,893 | 68,686 |
| S 12 | SE BL Co. | 99,789 | 58,551 |
| S 13 | NE BL Co. | 68,814 | 34,928 |
| S 14 | HR, CC Cos. | 97,907 | 44,593 |
| S 15 | W BL Co. | 98,559 | 54,169 |
| S 16 | CR, FR Cos. | 61,143 | 16,318 |

## II. BGE Customer Focus Group Report December 2012

SMARTENERGY > EFFICIENCY
CHOICE
INNOVATION
SAVINGS
MANAGEMENT

# SER Communications Focus Groups

BGE

December, 2012

# Table of Contents

# Introduction

## Background

- Smart Energy Rewards (SER) is one of BGE's Smart Grid Initiative programs scheduled to launch in the summer of 2013. This new program offers customers rebates for reducing energy usage during specific peak times, typically the hottest days during the summer. Focus groups were commissioned to review materials that are being developed to communicate this new program to customers.

## Methodology

- Six focus groups were held on December 11 and 12, 2012 at the facilities of Observation Baltimore in Catonsville because this is the focus group facility in closest proximity to the area where smart meters have been installed. A total of 50 customers participated in these groups.
- Since customers must have a certified smart meter installed by June 2013 in order to participate in the program, only customers who have already had these meters installed were invited to participate. To represent the opinions of both PeakRewards$^{SM}$ and non-PeakRewards$^{SM}$ participants, three focus groups were held with each group, including: one focus group comprised of senior citizens, one with those of limited income, and one with a cross-section of middle and upper-income residential customers.
  - For the senior group, participants were required to be age 65 or older.
  - Participants in the limited income group were required to have a household income under $50,000.
  - Household income was required to be over $75,000 for the group that represented a cross-section of middle and upper-income residential customers.
  - Participants were recruited from lists supplied by BGE and were required to correctly identify whether or not they are current PeakRewards$^{SM}$ participants.
- The focus groups were audio and video taped. The audio recordings were transcribed and analyzed and are the primary basis upon which this report is based. It should be noted that focus groups are a qualitative technique utilized to gain a deep understanding of feelings and motivations for opinions. A variety of biases are inherent in the technique and findings are based on the views of a small number of individuals and should be viewed with the acknowledgement of these shortfalls.

# Executive Summary

## Energy Conservation

- Focus group participants do many things to conserve energy in their homes, including using CFLs, replacing windows, installing energy-efficient appliances and HVAC systems, increasing insulation, regulating the temperature and unplugging devices when not in use. PeakRewards$^{SM}$ program participants are particularly likely to engage in these types of behaviors.
- Saving money is the principal motivator behind energy conservation practices, although some individuals also wish to do their part to help avoid brown-outs or black-outs or to minimize their impact on the environment.
- Lack of funds is the most significant barrier to engaging in more energy conservation practices.
- BGE can motivate customers to be more energy efficient by playing an advisory role and providing tips and reminders and also by offering monetary incentives for behavior modification.

## smart meters

- Although most customers who have had smart meters installed at their home are aware of this, few have any idea why these meters were installed or what opportunities or benefits are associated with this equipment.
- Customers remember receiving various communications from BGE concerning smart meters, but they generally only recall receiving notice that the equipment would be installed and then a confirmation that it had been completed.

## PeakRewards$^{SM}$ Experience

- Most customers participate in PeakRewards$^{SM}$ in order to obtain bill credits (which they consider a fair value since most have never noticed the cycling of their air conditioning units or hot water heaters other than during the extreme event of two summers ago). Some participate in the program because they also want to help avoid brown-outs or rolling black-outs or to lessen their impact on the environment.
- Most PeakRewards$^{SM}$ participants have no concern regarding how many times per summer their units are cycled because they don't notice when it happens anyway, particularly since most are at work during cycling events.

# Executive Summary

## SER Program Communications

- Although they generally found the communications materials they reviewed attractive and consistent (and conveying a little softer and friendlier image for BGE), most focus group participants did not grasp the SER program concept after reading these materials. The most common mistaken assumptions were:
  - Customers would not be taking any voluntary action; BGE would be cutting off customers' electricity on savings days.
  - In order to participate, customers will need to enroll in the SER program.
  - The SER program is either the same or is a supplement to the PeakRewards$^{SM}$ program.
- The email communication was considered attractive and pleasing to the eye; the most frequent complaint was that it did not clearly explain exactly what BGE wants customers to do in order to conserve energy and earn rewards.
- The awareness letter was considered too long; customers did not want to read so much even though they had many questions about the SER program – especially what actions customers specifically need to take. To encourage them to open the envelope, they suggested including a message on the front about money or information about their account. Customers particularly liked the "save $10" graphic in the letter and suggested it be placed in a more prominent location. They were least interested in the bottom portion of the letter that discusses some benefits of conserving energy such as reducing the need for additional power plants because they felt these were benefits for BGE rather than for customers.
- The postcard was liked much better than the letter because it is shorter and doesn't have to be opened. It was also considered attractive and customers thought it was a good idea to mention on the postcard that a Welcome Kit would soon be sent to customers because they will be more likely to open that envelope if they are expecting it.
- Few said they would scan the bar code that was included on the letter or postcard or click on the link in the email in order to watch a video on the new SER program. Most would prefer that additional information be delivered in a text format.
- Those interested in a video thought it needed to be only a couple of minutes long and should explain the program and what customers need to do. It was also suggested that an explanation of smart meter capabilities be included. Few were interested in seeing customer testimonials, most often because they would not trust that they were genuine.
- After listening to program details, most said they would be interested in participating. PeakRewards$^{SM}$ participants appeared somewhat less interested in the program than others because they do not believe there are many additional things they can do to conserve energy so their rewards will not be significant.

# Executive Summary

## SER Program Communications (continued)

- Customers were very reassured to learn they would be in control and BGE would not be shutting off their power as part of the SER Program. They also like the idea that there is no sign-up process in order to participate, but they are concerned about receiving sufficient notice of savings days in case they want to override cycling and they want to understand how the benchmark for their typical electrical consumption will be calculated.
- PeakRewards$^{SM}$ participants suggested there needs to be some guaranteed floor amount of reward in order to encourage participation.
- Most customers said they would answer a courtesy phone call from BGE, especially if the caller immediately makes it clear that he or she is calling from BGE and the purpose of the call is to identify opportunities for customers to save money on their monthly bill and to answer any questions they may have about the SER program.
- The Welcome Kit was considered attractive, but many did not notice the table of contents on the brochure and it was felt the envelope should clearly identify that it contains a Welcome Kit. Including a personalized letter was generally considered to be a nice touch that made customers feel as though BGE is looking out for them. Multiple customers also said they would not open anything sent standard mail because they would know it is junk mail. Most important to include in the brochure would be specific cost saving measures customers can take and what they might expect to save in exchange for engaging in particular behaviors.
- Sample bills were generally considered easy to understand, but it was suggested that SER program savings be better highlighted. Looking as the examples also caused some PeakRewards$^{SM}$ customers to wonder whether they could ever save sufficient power to earn a reward under the program in addition to what they currently get from PeakRewards$^{SM}$.
- The most popular names for the days on which customers can earn bill credits with the SER program are Energy Savings Days and Smart Energy Reward Days because these names straight-forwardly describe what is happening on these days. Many also liked the name, Reduce Your Use Days because it is descriptive, as well as catchy and attention-grabbing. There was concern that any use of "peak" or "reward" would cause customers to confuse the SER program with the PeakRewards$^{SM}$ program and using the word "program" made them think they have to enroll in order to participate.

# Executive Summary

## Conclusions

- Focus group participants found the communications materials they reviewed attractive and eye catching, but they had a difficult time understanding exactly what the SER program is and how it works. They were particularly likely to assume the program somehow involves BGE controlling their power use rather than themselves proactively taking action to reduce their usage.
- Customers were particularly prone to assume the SER program was actually some version of the PeakRewards$^{SM}$ program and any reference to "peak" or "rewards" quickly took them down this path.
- There was a broad assumption that customers need to enroll in the SER program in order to participate. They like the idea that no action has to be taken on their part before they can participate, but had to be reminded numerous times that there is no enrollment procedure.
- Overall, customers wanted less text in any communication, with an option of where to go if they are interested in obtaining more information. If they are sufficiently interested to seek out additional information, most would prefer a text rather than a video format for this additional information.
- A postcard is preferable to a letter because customers will be likely to at least read the headings on it – particularly if it uses the popular "money" and/or "savings" words. This format also reduces customer effort; they don't have to open a postcard.
- A multi-pronged campaign utilizing many forms of communication appears warranted since different customers pay attention to different forms of communication. Also, it seems as though they need to hear something multiple times before they begin to absorb it.
- Over and over, customers requested specific examples of what they could do to conserve energy and how much various types of behaviors would save them.
- Conserving energy is much less important to most customers than saving money. Focusing more on the savings aspect will be more likely to get their attention.
- A majority of customers seem to know little to nothing about smart meters, so a program made possible by smart meters probably needs to explain what the devices are.
- Current participants appear very satisfied with PeakRewards$^{SM}$ and they are unlikely to discontinue their participation in the program because it guarantees them a specific amount of savings and most have experienced little or no discomfort as a result of their participation. PeakRewards$^{SM}$ customers would be the first ones to be interested in a new energy savings program; however, once they discover details of the program, their enthusiasm may dim because they may not think they will be very likely to earn many rewards beyond what they currently accrue with PeakRewards$^{SM}$.

# Detailed Findings

# Energy Conservation

- Participants do a variety of things to conserve energy at their homes, including: replacing light bulbs with CFLs, replacing windows, installing new energy-efficient appliances, heating, and air conditioning units, better insulating their homes, keeping the temperature high in summer and low in winter, unplugging devices when not in use, and participating in the PeakRewards℠ program.

*The light bulbs would be one thing. I am in the PeakRewards℠ program, which I think is a way to help conserve energy. (PR Senior)*

*I'm in PeakRewards℠, too, and I also keep my heat down really low and use little space heaters. Also, I live by myself now, so I got rid of my big refrigerator and I use a mini fridge and I never have lights on in more than one room at a time. (PR Ltd. Income)*

*We use the CFL bulbs and I guess about two years ago, put in a programmable thermostat so that we could adjust it and regulate the temperature during the day. (Non-PR Middle-Upper Income)*

*I put 12" insulation in my cellar. I got new air conditioning and a new heater and new windows and all the light bulbs and stuff. (Non-PR Senior)*

*I've changed all my light bulbs. In the last two years, I've put in a new energy efficient furnace. I put in a new air conditioning pump system. I also replaced all my windows with triple pane windows and I bought the best programmable thermostat I can buy. And I watch the lights. (Non-PR Senior)*

*I have the light bulbs that I've replaced and I also unplug my toaster and blender – things that I have on my counter top – until I use them. (Non-PR Senior)*

- Children (and some spouses) are sometimes less likely to collaborate on energy conserving behaviors, objecting to home temperatures, or leaving too many lights on.

*My wife is the energy hog. (Non-PR Middle-Upper Income)*

*I think I pay more attention to that than my husband. (Non-PR Senior)*

*My girlfriend likes to leave lights on everywhere. (PR Middle-Upper Income)*

*My kids have the lights on all over the house. I'm always telling them to turn the lights off. (Non-PR Ltd. Income)*

*My son could care less how many lights are on. I care. (PR Ltd. Income)*

# Energy Conservation

- Saving money is the principal motivator to taking steps to conserve energy. This is why many customers participate in the PeakRewards℠ program and why they regulate the temperature of their home. Taking action to avoid brown-outs or black-outs or to help the environment is a secondary motivation for some customers and is more likely to be a consideration for PeakRewards℠ participants than for non-participants.

  *There is concern for the environment, but, you know, money is first. (PR Ltd. Income)*

  *I care about the environment, but I have to admit that it is about the cost. (PR Middle-Upper Income)*

  *Money and the bill really encourage me to conserve. The way things are now, you have to conserve because everything is getting so expensive. (Non-PR Ltd. Income)*

  *It comes down to the dollars. (Non-PR Middle-Upper Income)*

- Many do not feel they are doing all they possibly could to be more energy efficient due to insufficient funds. Things like replacing windows or better insulating the home are just not affordable for everyone.

  *Some of it is cost. For example, replacing windows is pretty expensive to do. (PR Senior)*

  *I'm retired and I only have so much money to spend. (Non-PR Senior)*

  *It's the money. I would do solar panels, a windmill, I'd have chickens. (PR Middle-Upper Income)*

- BGE can motivate customers to be more energy efficient by playing an advisory role, providing tips, reminders, and advice through advertising such as bill inserts, and offering rebates (e.g., for installing energy efficient appliances). Offering rewards for behavior modification would also encourage change.

  *I know you can call consultants and you can go through the house and audit what you have – that is always available – but I think just giving people reminders would be a big help. A lot of people leave windows open in the wintertime or doors half closed. That is just throwing money out the window. (PR Senior)*

  *Offer some kind of bonus if you cut your bill by a certain amount. (PR Ltd. Income)*

  *They could provide more tips about what we can do to be more energy efficient. I know that they have things that they send out from time to time. (Non-PR Middle-Upper Income)*

# Smart Meters

- A majority (but not all) of the customers who participated in focus groups are aware they have had a smart meter installed at their home – especially those who had to be present for the installation – but few seemed knowledgeable on the benefits or capabilities of the equipment. Only a handful has visited the BGE website to obtain more information either on the meters or on their own electrical usage.

*It is going to eliminate those meter readers walking around the neighborhood. (PR Senior)*

*Is that the new meter that they're putting out? (Non-PR Ltd. Income)*

*We have smart meters. They have already installed them in our neighborhood. (PR Senior)*

*I just got on the BGE site yesterday and saw what you can see on your BGE account using the smart meter. You can see down to the hour how many kilowatt hours you're using. It's really neat. (PR Ltd. Income)*

- Customers generally recalled receiving various communications from BGE concerning smart meters such as postcards, phone calls, emails, and a door hanger. Most only remembered that these communications were either a notice to expect an installer or a confirmation that a meter had been installed. Although a few customers were aware of community meetings related to smart meters, no one attended these meetings.

*They just put a note on my door. (PR Middle-Upper Income)*

*I saw the hanger on my door about a month later because I don't use that door. (Non-PR Ltd. Income)*

*Just that it was going to be installed – that's all I remember. (Non-PR Middle-Upper Income)*

*It was just notifying me that they were going to be in the neighborhood and I came home one day and had a new meter. (PR Middle-Upper Income)*

*All I remember is something coming in the mail saying someone is coming around to install it. I think I got a telephone call, too. They were coming to install it so you knew that somebody was coming. But as far as it's real purpose, I don't know. (PR Senior)*

*I do recall that they were putting those out (community meetings), but it just was not a convenient time or place for me. (PR Senior)*

# PeakRewards℠ Experience

- Many customers primarily participate in PeakRewards℠ for the cost savings.

  *Credit (PR Senior)*

  *It helps. It helps (keep costs down). Thank you, PeakRewards℠. (PR Ltd. Income)*

  *It just makes sense. (PR Ltd. Income)*

  *For me, it's saving money. (PR Middle-Upper Income)*

- Some also like doing their part to help avoid brown-outs or rolling black-outs, or lessening their impact on the environment. Others just said it is easy because they feel no impact from participating because they're never home anyway.

  *I feel like it is like getting a flu shot and a lot of people don't get flu shots and the reason flu is an epidemic is because 60% of the people don't get flu shots. It is the same thing. I do not really want to have a brown-out because it is really hard on your electric-driven mechanical stuff. If they reduce the voltage to 95 volts or something, you are going to be burning up compressors and stuff. The other reason is I sure as heck don't want a rolling blackout where they are going to shut my electricity off for 6 to 8 hours because they are overloaded. Some of us have to do something to prevent catastrophic failure or a shut down. (PR Senior)*

  *My primary reason is energy conservation and getting paid made it easy. PR Senior)*

  *I'm never really home, so, for me, if you're going to turn it off and I'm not home and you're going to give me a credit, then go ahead and do that. (PR Ltd. Income)*

- Everyone who participates in PeakRewards℠ believes the summer credits are a fair value. One customer said it is like getting one month free.

  *I've suggested it to people. (PR Middle-Upper Income)*

  *I think it is a good deal. (PR Senior)*

  *You end up getting about a month for free. (PR Middle-Upper Income)*

# PeakRewards℠ Experience

- No one recalled experiencing a PeakRewards℠ air conditioning cycling event more than a few times over the past summer; some were not aware any events had taken place at all and no one said cycling has had a negative impact on their lifestyle or comfort level other than a couple of years ago when there was an extended time period of cycling on one particular day.

  *I think maybe twice. (PR Ltd. Income)*

  *How would you even know? (PR Ltd. Income)*

  *I never know it's happening. (PR Senior)*

  *I have no idea. (PR Middle-Upper Income)*

  *I like that when it happens, I don't even notice it. (PR Middle-Upper Income)*

  *One time last year, it really did. It was one of those hot days and I do the 100% so it was pretty darn warm by the time it went back on again, but you know, you sign up for that so you know it's going to happen. You can't really complain. (PR Ltd. Income)*

  *I noticed it one time two summers ago. It was crazy hot and my thermostat said it was 85 in the house and we knew we couldn't turn it on because BGE was controlling it. It was a big deal, but we'll remember this when the credits come in. (PR Middle-Upper Income)*

- Most customers don't really care how many times per summer they are cycled because they don't notice it anyway. Most of the time, they are at work when cycling occurs. Some might object if cycling occurred during the night, when they need it cool in order to sleep well, but since it is done in the afternoon, it is not a problem.

  *I recall that I never noticed it. (PR Senior)*

  *As long as they do it during work hours, they could do it every day. You don't care. (PR Middle-Upper Income)*

  *For me, it just can't be off at night while I'm trying to sleep. Everything else is OK, but I've got to be able to sleep. (PR Ltd. Income)*

  *We're at work in the hottest point in the day anyway usually. (PR Ltd. Income)*

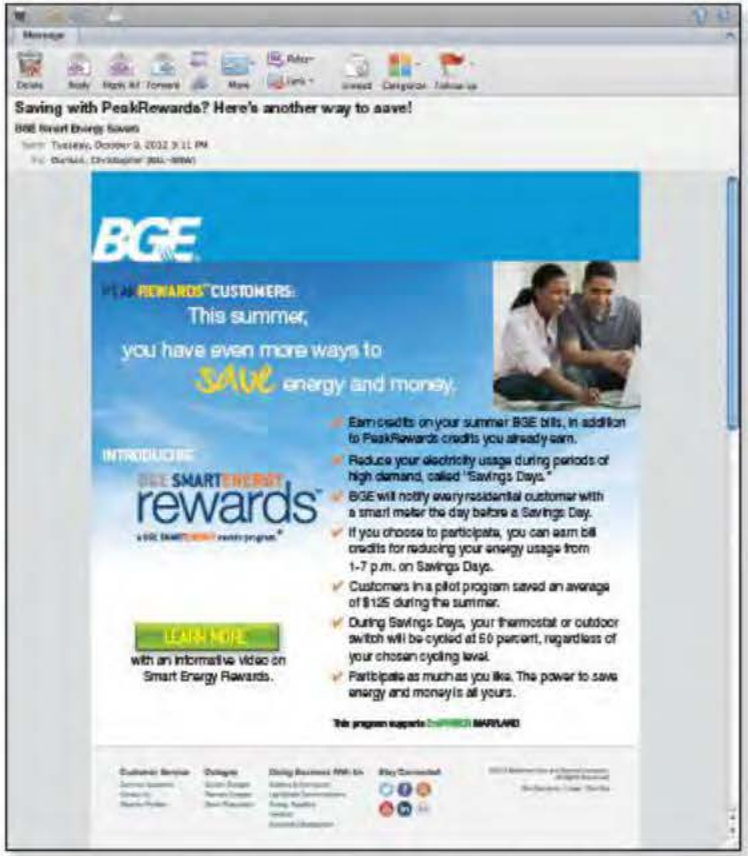
# SER Program – Email

- Based on the initial email communication, customers who currently participate in PeakRewards℠ generally interpreted the SER program as a supplement to the PeakRewards℠ program (or even "PeakRewards℠ on steroids"), where they would be asked to opt in to be cycled on more days.

  *Is this a supplemental program offered in addition to PeakRewards℠? That's what it looks like. (PR Ltd. Income)*

  *The way I read this, it is PeakRewards℠ on steroids. It says in here "during savings days your thermostat or outdoor switch will be cycled at 50% regardless of your chosen cycling level." So, if you're already participating in PeakRewards℠, the only time that they cycle it now is for issues or areas where there is a brown out or an extreme call for energy. Maybe this is a preplanning thing where they're going to use this type of program to start cycling you earlier than what's needed so it doesn't get to the brown-out stage. (PR Middle-Upper Income)*

  *This is not PeakRewards℠? This is a new program? (PR Senior)*




- No one seemed to recognize that there was any action required on their part other than to agree to additional cycling. There was also concern that all electricity to the home would be cut off for a period of time.

  *The question is, what are they going to shut off? Right now, it is the air conditioning. It could be a water heater. Suppose I had both at 50%? The question remains, what is it that they are going to shut off? What is this outdoor switch? What does it control? Does it control all of the electricity in the house? (PR Senior)*

  *What I am gathering is that they are going to do PeakRewards℠ from 1 to 7. It does not seem real clear whether that would be every day of the week. (PR Middle-Upper Income)*

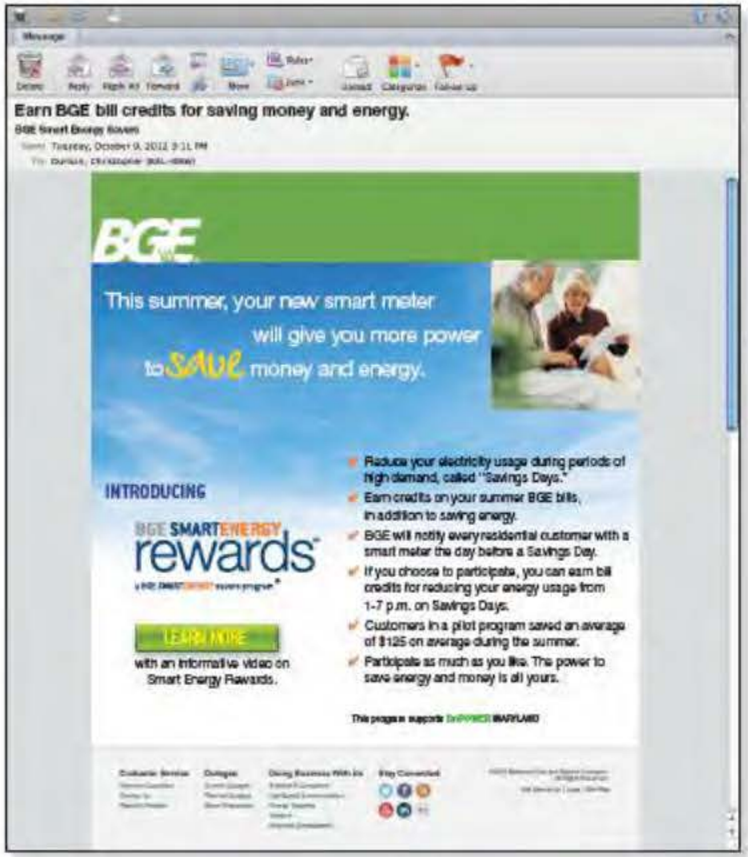
# SER Program – Email

- Some non-PeakRewards℠ customers wondered if the email was describing PeakRewards℠; they interpreted the program to involve BGE cutting off power to customers at peak usage times.

  *I'm guessing they'll shut it down. They'll reduce the amounts you're able to pull from the net with this program. (Non-PR Middle-Upper Income)*

  *I think they might want to change the wording because so many people associate that smart rewards with, "Hey, I'm going to cut it off and you're going to get so much credit." (Non-PR Senior)*

- Some understood from the email that customers would be given bill credits if they conserve energy, but didn't know exactly how they were supposed to do this and there was a pervasive concern that if customers did not voluntarily curtail their power usage, BGE would do it for them. There was also a question of who was eligible to participate in the program – what if they purchase their power from a supplier other than BGE?




*It looks like BGE is trying to reduce the usage during peak hours so they're offering you specific credits so they're not having a huge influx of people using electricity for whatever reason during the day. (Non-PR Middle-Upper Income)*

*It says "if you choose to participate" so if you didn't choose to participate, what would happen? (Non-PR Senior)*

*When you don't do your part, they do it for you because someone told me that, with the smart meter, you don't have to turn it off or down because they can automatically do it from the company. (Non-PR Ltd. Income)*

*Now what if you don't use BGE anymore – can you still do this? (Non-PR Ltd. Income)*

# SER Program – Email

- There was significant confusion after reading the email. Some said they had to read the message multiple times and still were not totally clear on how the program works. They wanted to know exactly what "savings days" are and what happens on these days. Would all of their power be turned off? Is the $125 in savings in addition to the PeakRewards℠ bill credits? Do customers pick the days on which they are willing to be cycled? Do customers have to contact BGE either to sign up for the program or agree to be cycled on each individual savings day? What is an outdoor switch? Will cycling occur every day? What is a bill credit?

*It is not giving me enough information. I would disregard this in its entirely at this point. (PR Senior)*

*I can offer at least three scenarios on what this can mean and that infuriates me. (PR Senior)*

*It says "participate as much as you like." I think the wording is unclear. (PR Middle-Upper Income)*

*It says customers in the pilot program saved an average of $125 during the summer. Is that in addition to what they saved with the PeakRewards℠? They make it sound like two different things. If it's in addition, it peaks my interest. (PR Middle-Upper Income)*

*It's not clear if it's different than PeakRewards℠. (PR Ltd. Income)*

*It says "savings day" but you don't know exactly what that means and how it would be implemented. (PR Ltd. Income)*

*Is it BGE's choice how much energy I use or is it your own choice? You know, do you specifically make sure you try to do less during 1 and 7 or is it something they're doing on their end to force you? (PR Ltd. Income)*

*It says "earn credits for your summer BGE bill in addition to PeakRewards℠ credits you may have already earned." If you already have existing points already earned under PeakRewards℠, is this going to roll over and then the Smart Energy Rewards program picks up or are they two different things? (PR Ltd. Income)*

*What confuses me is what exactly is a credit? How do you get a bill credit? What is it? Is it energy saved? Is it money that you get reduced at your percentage? I don't understand what it is. (Non-PR Middle-Upper Income)*

*This doesn't say "you do it." It just says "by reducing." It doesn't say they don't do it. It doesn't say you don't do it. (Non-PR Ltd. Income)*

*It has the incentive of $125, but that is not enough for them to turn off my power or minimize it at a critical time. The savings is not worth it. (Non-PR Senior)*

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# SER Program – Email

- The subject line of the email was considered enticing; most said they would be likely to open an email with such a subject line. Others said there needs to be greater emphasis on the saving money aspect, the message needs to speak specifically to them, or it needs to be clear it is about something other than PeakRewards$^{SM}$.

  *This is catchy – the "save." That shows me this is something different. (PR Ltd. Income)*

  *Yes, because it says "saving money." (Non-PR Ltd. Income)*

  *I would – for saving money. (Non-PR Middle-Upper Income)*

  *This is blanket emailing. If it was specific to me – if they said, "Hey, you could have saved $25 on your last electricity bill," I would have clicked it open. Otherwise, this is one of a thousand emails I'm getting a day and if it looks like it even hints at there being extra work, I'm not going to do it. (PR Middle-Upper Income)*

  *It definitely needs to differentiate that this is something different because if I see PeakRewards$^{SM}$, I'll just delete it because I'm already enrolled. (PR Middle-Upper Income)*

- The email was generally considered attractive from a design point of view because it is very bright, very "summery," and pleasing to the eye. The major complaint was with the content which does not clearly specify what BGE wants customers to do.

  *It's very summery – it's nice and bright. (Non-PR Middle-Upper Income)*

  *It will get your attention. (Non-PR Ltd. Income)*

  *I think it's too busy. It seems like there's a lot of redundancy. (PR Middle-Upper Income)*

- Many said they would click on the "learn more" button in the email, but they would rather see an information page than watch a video. In fact, a shorter email with more concrete information, especially on actions required by customers, and a link to additional information was generally desired.

  *I want to hit the "learn more" button, but I want to have it in writing. I don't want a production on video because it takes too long. (PR Senior)*

  *I don't want to watch a video; I'd rather go right to the facts. (PR Middle-Upper Income)*

# SER Program – Awareness Letter Envelope



- There were mixed opinions of the awareness letter envelope. Some objected to the amount of white space, saying it looked like junk mail, while others thought the envelope was bright and attractive or the "BGE" or "rewards" got their attention. Some participants said they get offers to save money from suppliers multiple times per week and they would assume this envelope contained another such offer.

  *Too much white space; it looks like junk mail. It looks like one of those value packs sent to you or something. (PR Ltd. Income)*

  *You don't often see a block like that on the left hand side unless it is some sort of junk mail letter. (PR Ltd. Income)*

  *I like the green so I would look at it. It's colorful. (Non-PR Senior)*

  *I'd probably be more inclined to open it because it says "BGE" on it. (Non-PR Senior)*

  *It says "rewards" so it would interest me to know what the rewards are. (Non-PR Ltd. Income)*

  *Probably four times a week, I get offers to save money on my energy bill if I will buy my energy from somebody else, which I already do. (PR Senior)*

- To encourage them to open the envelope, it was suggested that it either look more like a BGE monthly bill, include a message such as "information about your account," or mention money.

  *I know places have starting doing this – putting at the top, like, "information about your account" so I know that it's pertinent to something I already have. I'd want to open it because it might be something that I'd want to look into. (PR Middle-Upper Income)*

  *Make it look like your billing envelope. We all would recognize that. (PR Senior)*

  *If they put $125 in big text on the front – save $125 – I might open it. That's why we do all these programs. (PR Ltd. Income)*

  *It needs to say "money" for me because rewards – rewards in what way? (Non-PR Middle-Upper Income)*

# SER Program – Awareness Letter

- Most customers thought the awareness letter was too long; they did not want to read that much. Even so, they wanted more specific information as to what actions customers specifically need to take and PeakRewards[SM] customers wondered how the new program ties in with the current PeakRewards[SM] program.

  *It's way too much. I wouldn't have read this. (PR Ltd. Income)*

  *It's almost like an awareness letter. There needs to be a lot less. It needs to catch your attention and make you more interested and then if you decide to go, follow the QR code or go to the website where you can get more information. (PR Ltd. Income)*

  *I'm already tired of reading it. I would have put it down by now. (Non-PR Middle-Upper Income)*

  *It's the same program we had before, but they're trying to make us feel guilty and participate voluntarily. (Non-PR Senior)*

  *What I would like to know is, on these super duper savings days, you would assume that they are also doing PeakRewards[SM] where they are going to cycle us. This is over and above – right? But they don't tell you exactly if they are going to compensate you for doing that and how they are going to do it. They mentioned credits, but there is no scheduled credits. (PR Senior)*

  *Because they are going to turn your electricity off; you are going to save that way. (PR Senior)*

- Customers liked the "Save $10" graphic, but suggested it be placed higher in the letter. The laptop graphic was considered unnecessary and the "Save $10" graphic would be better positioned in this spot.

  *I'd say lose the laptop image and put the $10 up there and move the video presentation up to the middle. (PR Middle-Upper Income)*

  *It gets your attention. (PR Senior)*

  *I think the "Save $10" is pretty good, but I was late in noticing it. I could have easily missed that. (PR Middle-Upper Income)*


# SER Program – Awareness Letter

- The letter made customers want to know more about the new rewards program, but they still had many questions after reading and discussing it They were particularly interested in understanding how much they have to modify their behavior in order to accrue a reward, but also why BGE wants them to use less power since it means less income for BGE, exactly what is a smart meter, and they also wondered what would be the benchmark to which their energy usage would be compared.

  *It says simple energy practices like turning lights off and unplugging appliances can be a big difference, but like he said, there is no benchmark. You don't know if you go from where you're at, to here, if you go from 10% less of your usage, then you get this credit or 5% less than what you're currently using. There's no understanding of what you have to do besides turning off some lights. (PR Ltd. Income)*

  *What's the actual goal that you have to hit before you can start saving $10 a day or whatever it is? (PR Ltd. Income)*

  *So $10 means what – just shutting off one light bulb or does it mean cutting off the AC for two hours? (PR Senior)*

  *Where does that $10 come in – from what we do in this program or from what we do in our normal practices? (PR Middle-Upper Income)*

  *What does it mean about reducing – you have to do it on your own by turning your air off and don't have any electric running during those hours? How can you reduce in the summer? (Non-PR Senior)*

  *It's a little bit of a dichotomy for BGE to say that we're teaching you ways to cut your bill because most companies want to charge more. There is a "What's in it for me?" as a consumer, but also some skepticism in saying, "Why is this important?" Why would BGE want to do this? (Non-PR Middle-Upper Income)*

  *You haven't told me what a smart meter is yet. You said there is a meter out there, but what is a smart meter? Tell me what it is. (Non-PR Middle-Upper Income)*

- Some customers were not interested in the bottom portion of the letter which discusses other ways that saving energy helps, such as reducing the need for additional power plants, because they believe these are primarily benefits for BGE rather than for customers.

  *All the benefits they are telling me here are all benefits to BGE and not to me – reduce additional power plants, reduce additional power lines – these are all BGE benefits. If they don't manage their company correctly, that's not my problem. (Non-PR Senior)*

# SER Program – Postcard


- The postcard was better received than the awareness letter; most considered it just the right length. Customers like postcards because they don't have to open them and there is not as much reading required.

  *I like this better than the letter; I don't have to open it. (Non-PR Middle-Upper Income)*

  *It's easier to flip over and I can read that while I'm walking back from the mailbox. I'm more likely to read that than the other one. (Non-PR Senior)*

  *It's just right. (Non-PR Ltd. Income)*

  *I like it because it's shorter. (Non-PR Senior)*

- It was suggested that mentioning on the postcard that a Welcome Kit is coming soon in the mail serves as an alert notice, which will make customers more likely to open the Welcome Kit envelope when it arrives.

  *I noticed something else – "Look for a Smart Energy Rewards Welcome Kit coming soon in the mail." Just seeing that would actually make me look for that in the mail. (PR Middle-Upper Income)*

  *One thing they didn't do very well is this little piece right here that says "Look for Smart Energy Rewards Welcome Kit coming soon in the mail." I think that should have been a little bit bigger just to alert people that you are going to get more. (PR Senior)*

- The postcard was considered attractive. It was described as colorful and eye catching and blue is a calming color, but also needs to include a phone number to call for more information because everyone does not have internet access.

  *It's bright and makes you want to stop and read it. (Non-PR Ltd. Income)*

  *It grabs your attention in a better way than that envelope did. (PR Ltd. Income)*

  *There's no phone number anywhere is there? (PR Ltd. Income)*

# SER Program – Postcard

- Even after reviewing an email, letter, and postcard, customers were still confused as to how the SER program works and how they enroll in it. One customer said it sounds like the Budget Billing program.

  *It introduces the program, but it doesn't tell me anymore about it. (Non-PR Senior)*

  *It doesn't really specify what you have to do, though. Like, they'll contact you and let you know, but then it's kind of like, what's the next step? How do I say I want to participate? Do I have to go online or do I have to call somebody? (Non-PR Middle-Upper Income)*

  *I guess the only confusion that I have is on the savings days. Every day during the summer will they be notifying me the day before a savings day? That's going to mean a call every day does it not? (Non-PR Senior)*

  *What I have read thus far says it will balance itself out at a point of time in the year and either you credit them or there's a credit to you. It's just a matter of words, because, basically, that is what they said, and I'm on the budget program and I just can't see the difference between the two. (Non-PR Ltd. Income)*

- The use of graphics was considered more appropriate on the postcard than on the letter, but again, it was suggested that "Save $10" be emphasized more.

  *I think it's more appropriate for a postcard than in a letter because, you know, you have limited space on a postcard and it's catchier (to use graphics). (PR Ltd. Income)*

  *I still think that they should move up this $10 per savings day and the $125. (PR Middle-Upper Income)*

  *I like the fact that they have "savings" highlighted up here. (Non-PR Senior)*

  *The picture of the person turning off the switch tells me that I have control, but I'm not sure that's the case. (Non-PR Senior)*

- Few said they would scan the bar code on the letter or postcard in order to view a video on the new program. Some thought this was just a gimmick that is currently popular, but soon will fade; others don't have a smart phone or don't know how to do this.

  *I would, just out of curiosity. (PR Middle-Upper Income)*

  *Personally, I am not into all that. I do have a smart phone and I use the computer, but I don't want to play games doing stuff like that. (PR Senior)*

  *I think it's kind of faddish, honestly. (PR Ltd. Income)*

# SER Program – Video

- Older people showed the greatest interest in watching a video on the new program; however, most thought nearly five minutes was far too long; a video should be no longer than 90 seconds to two minutes and should just stick to the facts of how the new program works.

  *Probably I'd watch it. (Non-PR Senior)*

  *I'd like to get the details so that I can make an intelligent decision. (PR Senior)*

  *It should be under two minutes. (PR Ltd. Income)*

- Customers were least interested in seeing customer testimonials because this would seem like an infomercial and they would not trust that the testimonials came from "real" customers.

  *You can get anybody to do a testimonial. (Non-PR Middle-Upper Income)*

  *As long as it's not biased (include testimonials). (Non-PR Senior)*

  *Really, if you want to know how somebody feels about the program, you would ask somebody you know that's done it. Those are the people you believe. You wouldn't trust somebody that BGE put up there because you wouldn't know whether they're a real customer or not. (PR Ltd. Income)*


Smart Energy Rewards Video Presentation

Approximate Length: 4 minutes, 45 seconds.

- Information some customers would like to see added to the video is an explanation of what a smart meter is and how it works.

  *The only thing I might add is what we mentioned earlier and that is what is the smart meter and how does it work? I mean, I don't know that that's been clearly explained to most of the customers. At least, from my perspective, I haven't received much information on that. (Non-PR Middle-Upper Income)*

  *Why would I have a smart meter if I'm not going to use it? (Non-PR Ltd. Income)*

# SER Program Details

- After the details of the SER program were explained to participants, most said they would be interested in it, although some current PeakRewards$^{SM}$ customers showed less interest because they don't think there is much they can do to better conserve energy so their rewards would be small.

  *If you are not already a big user, I don't see how you are going to get very much more out of this. You already turn the lights out and don't run your TV. (PR Senior)*

  *I would volunteer to do it, but I doubt I would get much out of it. If their goal is to cut down on the power usage, I don't think I'm going to have a big reduction. (PR Senior)*

  *I'm going to save less than $125 in the summer because I'm already 33% below the average for my house according to BGE. There's not much more I can do outside of just turning the AC off completely or not using heat. (PR Ltd. Income)*

  *I don't think I would save any money on it. (PR Ltd. Income)*

- Non-PeakRewards$^{SM}$ customers were very reassured to learn they would be in control and BGE would not be shutting off their power.

  *Okay, I've got my finger on the switch. (Non-PR Senior)*

  *So they don't have any remote control over anything that's in your house or reducing it or turning off your electricity? You have to actually physically go around and do something different during that day? That's interesting. (PR Middle-Upper Income)*

  *The part that I thought was missing in some of the advertisements was putting the consumer in the driver's seat and that's what you're explaining now as to what this program does, but that was not clear. I think that, or at least I'm hearing in this group, that people still have that thought of the old BGE programs where the devices were installed and they controlled when things were on and off. (Non-PR Middle-Upper Income)*

- Customers like the idea that there is no sign-up process for the program because it makes it easier for them – they don't have to take any action.

  *We already have all of our information. Why should we waste time for a sign-up process? (PR Senior)*

  *Because I'm already a BGE customer, I would appreciate that actually – have it so I don't have to go through the step of opting in. (Non-PR Middle-Upper Income)*

# SER Program Details

- Current PeakRewards$^{SM}$ customers expressed the greatest concerns about the program after hearing the explanation. Some were concerned about having sufficient time after a notification if they wanted to over-ride cycling on a savings day. Others wanted to clearly understand how the benchmark for their typical electrical usage is established and if this number is recalculated over time, causing them to need to conserve more and more in order to earn a reward. In multiple groups, these customers pointed out that there is no guarantee of a certain amount of reward such as with the PeakRewards$^{SM}$ program and suggested that there needs to be some guaranteed floor amount of reward in order to encourage them to participate.

  *I guess the biggest concern would be how can you override it? (PR Middle-Upper Income)*

  *What is the benchmark against which my reduction is being measured? What is normal for me? Are they going to average over a week/month/summer? (PR Senior)*

  *One thing I did not get out of what you said, how do I save money – especially if I am already at a certain level? I know what I am getting with PeakRewards$^{SM}$. You sign up for $25, $50 or $75 – whatever your dollar rebate you are getting. But here, you have no idea. I still did not hear you tell us how we, as individuals, are going to save money. (PR Senior)*

  *I can see people taking advantage of it, using as much energy as they can on a non-savings day so that they can get the most money out of it. (PR Middle-Upper Income)*

  *One thing they might consider doing, just like they do with PeakRewards$^{SM}$, it was a really simple way for most of us to understand. If they gave us some rebate for participating, at least $5, then probably everybody or most of us at this table would at least sign up because you know you are going to get $5 off and you may get more depending on how they compute it. (PR Senior)*

- "Peak demand" was believed to be the times of highest electrical usage – when people are using the most power.

  *To me, peak demand means it's a very hot day – a working day – so all the offices and grocery stores would be pulling in all this electricity to cool and that is putting a huge strain on the power grid. (PR Middle-Upper Income)*

  *Peak is like when most people are really running it because it's so humid or hot outside and that's where the demand is – where everyone is running it. (Non-PR Ltd. Income)*

BGE®

# SER Program – Telemarketing

- Most customers said that if they received a courtesy phone call from BGE after receiving various communications pieces about the SER program, they would take the call because they thought it would be helpful to speak with a live person in order to get questions about the program answered. In fact, one current PeakRewards℠ customer said he only signed up for PeakRewards℠ because someone called him.

  *I think the call would serve as a nice reminder, honestly, because sometimes things come up in life and that phone call would be a nice reminder of, oh yeah, this is happening, so I wouldn't mind the phone call. (Non-PR Middle-Upper Income)*

  *I think it would be very useful to me. The only reason I signed up for PeakRewards℠ is because of a call to me. I probably trashed the mail flyers; it was the call that actually signed me up. (PR Middle-Upper Income)*

- In order to encourage them to stay on the phone, the BGE person making the call needs to quickly establish he or she is calling from BGE and indicate the purpose of the call is to identify opportunities for customers to save money on their monthly bill. It was also suggested that a pre-call, indicating someone would be calling, would encourage response.

  *They should say "Are you interested in saving money on your electric bill? (PR Ltd. Income)*

  *It should be like, "Hello, this is BGE. I want to save you money." (PR Middle-Upper Income)*

  *I would start by saying there is a way to save money; I wouldn't even use the Smart Rewards Program because that sounds so commercial. (Non-PR Senior)*

  *A pre-call just to say I'm going to call you at whatever time because knowing that it's not just an unsolicited call would make me more likely to answer it. (PR Middle-Upper Income)*

BGE SMARTENERGY rewards

5 BGE courtesy phone call

Information to the customer on the call would include:

1. Description of program including:
   - When it will launch
   - Offer of bill credits for reducing electricity during designated periods
   - Frequency of opportunities to save
   - Average savings per customer, per summer
   - Methods of alerting you to savings periods
   - All BGE customers notified of savings periods, but participation is voluntary
   - Changes in monthly bill to reflect bill credits
2. Notice that Welcome Kit will be arriving in the mail.
3. Question about customer's interest in the program.
4. Invitation for questions from customer.

# SER Program – Welcome Kit

- Most customers were complimentary of the size and design of the welcome kit envelope, but they said it needs to indicate the program name and the fact that it is the welcome kit customers were told to expect.

  *I like the style of the envelope. I like that "save" is set apart. I like "new ways" so we know it's a new thing to save plus PeakRewards℠. That covers a lot of information right there. (PR Middle-Upper Income)*

  *If it's a welcome packet, the envelope should say "welcome pack" or "welcome packet" because unless I'm expecting a welcome kit from other correspondence, recycle. (PR Ltd. Income)*

  *It is deficient. It should say right up here in big letters, "Your Welcome Kit." (PR Senior)*

  *If this program has a different name from PeakRewards℠, then that name needs to be on here, too. (PR Senior)*

  *It should say "here is your welcome kit" somewhere on here and probably mention the Energy Savings Rewards program somewhere, too. (Non-PR Middle-Upper Income)*

  *This doesn't tell me that it's the welcome kit that I've been told I'm going to get. (Non-PR Middle-Upper Income)*

  *It's got to say "welcome kit" across it. Otherwise, it gets trashed. (Non-PR Senior)*

- Multiple customers questioned what type of postage would be used for the mailing because they would immediately trash anything that used bulk-rate postage because this is always junk mail.

  *I would look at the postage stamp to see if it says "standard mail." If it says "standard mail," it gets tossed. (Non-PR Senior)*

  *What is the postage on it? First class, I would open it. Pre-sorted junk, I probably wouldn't open it. (PR Senior)*

# SER Program – Welcome Kit

- Customers liked the idea of including a personalized letter in the welcome kit because it makes them feel important or that BGE is trying to look out for them.

  *Yes, because it means that they are sending it to me. It's not a mass mailing and I assume they're mailing it first class because I automatically toss anything bulk mail or standard. (PR Middle-Upper Income)*

  *Personalized makes you feel important. (Non-PR Ltd. Income)*

  *It makes you feel as if they're looking out for your best interests. (Non-PR Ltd. Income)*

- Questions customers would like answered in a welcome kit booklet are how smart meters work and what they can do for customers, as well as responses to frequently asked questions, and what exactly they can personally do to save money – especially specific scenarios such as if they turn off four lights for six hours, they will save a specific amount of money, on average. They also want to see an explanation of what bill credits are and contact information in case they have additional questions.

  *The smart meter itself is so new and this, to my knowledge, is the first program BGE is rolling out with the smart meter, so it might be good to just talk about some of the benefits of the meter. (Non-PR Middle-Upper Income)*

  *I'm not sure what is in each of these chapters, but, again, it's how am I going to save money? Because this is my house, this is my electric bill that I'm paying. How am I going to get below the target? Give me a discussion of the 14 days and that sort of thing because I'm going to start quantifying like, if I can do a 10% savings, that's so many kilowatt hours for a dollar, blah, blah, blah. (PR Ltd. Income)*

  *I really hope the "Tips during Savings Days" are going to say if I turn off four lights, I am going to save four cents or whatever. (PR Senior)*

  *Contact information for questions. (PR Ltd. Income)*

WELCOME LETTER


WELCOME LETTER

# SER Program – Welcome Kit

- Multiple customers said they did not notice the table of contents on the brochure and said it needs to stand out more. Some also said the language identifying the various sections needs to be simpler. One suggestion was that the table of contents should specifically answer these questions: (1) What is this program? (2) What do customers need to do in order to participate in the program? (3) What do customers get out of the program?

*I didn't see it; I had to go searching. Even though you told me where to look, I never saw it. The color blue and the smaller print or the same size print made it disappear to my eye. (Non-PR Middle-Upper Income)*

*When I look at the contents, there is no kind of progression or anything. It should be more like who, what, where, when, and how. Answer those interrogatories if you don't want to have to answer a lot of questions. It's kind of not that evident when you read it with the language that they're using. (Non-PR Middle-Upper Income)*

*I didn't see the table of contents; it's too close to the picture. It doesn't stand out from the rest of it. Move it to the right some and away from the picture. (Non-PR Senior)*

*I would change the format a little. Put bullets in front of each one or have an introduction and the page numbers should be lined up to the right. (PR Middle-Upper Income)*


# SER Program Communications Overall

- It was generally thought that all of the communications pieces that were reviewed in focus groups were consistent in appearance and style and looked like BGE (although a little softer and friendlier BGE than in the past). The only inconsistency pointed out was that the SER logo was not consistently shown in the same colors and customers would also like to see a phone number to call for more information.

  *It seems consistent to me with all their other communications. (PR Senior)*

  *I think they're trying to soften their image. After paying a fortune for electricity over the years, they're trying to change the image to wanting to help us save money. (PR Middle-Upper Income)*

  *It's probably a little softer and friendlier than some of the previous material I've seen. I think it portrays a different image. I think it's good. (Non-PR Middle-Upper Income)*

  *The one thing that I was really curious about is why they would have two different color logos for this program because color in a logo seems to be something that should be consistent. I looked at all the different communications and its kind of back and forth and the envelopes don't even have the logo of the program on it. When you're trying to brand a new program, I would think you would want to be consistent with that until maybe it gained some traction. (Non-PR Middle-Upper Income)*

- It was suggested that communications need to better emphasize how: easy and voluntary program participation is, customers have total control over whether or not they participate, customers do not need to sign up in order to participate, savings are accrued only on specific days, and SER is completely different from the PeakRewards$^{SM}$ program. Most of all, customers advocated a strong emphasis on the opportunity to save money.

  *I think the voluntary nature of the program – that you don't have to sign up for it. You have control over whether you participate or not. That's been in there, but I'm not sure I'm 100% sure that I feel like that was always consistent. (Non-PR Middle-Upper Income)*

  *When I hear "program" I think its something I have to let you guys know I want to participate in, so if you could just make it more clear that you can just live your life and if you happen to use less electricity, you're going to save money regardless, whether you try or not. If you do try, you have the opportunity to save more money. (Non-PR Middle-Upper Income)*

  *Going back to what was missing – the fact that it's not something that you sign up for. The fact is, this is coming. (PR Ltd. Income)*

  *They should differentiate between the two different programs (PeakRewards$^{SM}$ and SER). (Non-PR Ltd. Income)*

  *Say this program is controlled by you. (Non-PR Ltd. Income)*

# SER Program – Bill Review

- Customers indicated the bills they reviewed were easy to understand, but suggested that savings be better highlighted (perhaps in green) or some message such as, "Congratulations, you saved $20 this month" be included. It was also suggested that cumulative savings earned under the program be displayed on the bill to reinforce behavior.

*I want it bigger and bolder with a bigger heading at the top that says "Savings Rewards." (Non-PR Senior)*

*Maybe a different color. If you're saving money, highlight that somehow. (PR Middle-Upper Income)*

*Highlight the money you saved in green. (PR Middle-Upper Income)*

*If green seems to be the theme for this thing, would they want to green that in (the amount of savings on the bill)? (Non-PR Middle-Upper Income)*

*I would put more in here. You have all this blank space. You can have double asterisks and you could say, "Congratulations, you participated in the energy savings program and saved $20 during this period" all in caps. (Non-PR Middle-Upper Income)*

*If this is the first time you ever did it, you say, "Congratulations, you participated" and then maybe for next month, if you had another $20 you saved, "You've now saved a total of $40 since participating in the program" and you can run your total on it. (Non-PR Middle-Upper Income)*

*I think a running total would be beneficial because you can see how much you're saving throughout the summer and it may be motivation for however many months you have left to try and save even more. (Non-PR Middle-Upper Income)*


# SER Program – Bill Review

- Some customers believe the concept of what a kilowatt hour actually is needs to be explained; others wants savings tips printed right on the bill.

  *Why can't they break a kilowatt hour down for you because a lot of people don't know what a kilowatt hour is. (Non-PR Ltd. Income)*

  *Give us an example, say if a light bulb is on five hours that equals so many kilowatts. (Non-PR Ltd. Income)*

- Some PeakRewards$^{SM}$ customers wondered why they would not be getting additional SER savings on top of their guaranteed PeakRewards$^{SM}$ savings, but no current participants said they would discontinue their participation in the PeakRewards$^{SM}$ program in favor of the new program because the PeakRewards$^{SM}$ program offers a guaranteed amount of savings and many believe they save more with PeakRewards$^{SM}$ than they will with the SER program.

  *I would have been thinking I get another $17.50 on top of my $25. (PR Ltd. Income)*

  *It shows 14 kilowatts saved at $1.25 each. You would have to save roughly, what, about 25 of these to even do anything on top of your PeakRewards$^{SM}$? (PR Ltd. Income)*

  *I'd have to put a windmill on my house and sell it back to BGE in order to get anything out of this. (PR Ltd. Income)*

  *I would never give up PeakRewards$^{SM}$ because it's guaranteed money. (PR Ltd. Income)*

  *At least you're guaranteed for whatever you've signed up for to begin with with PeakRewards$^{SM}$. (PR Middle-Upper Income)*

  *I am staying with PeakRewards$^{SM}$ because you know what you get. (PR Senior)*

  *I think it is fairly obvious that you make more money from the PeakRewards$^{SM}$. (PR Senior)*

- Suggestions of additional ways to find out how much they are saving, besides on their bill, were through a smart phone app and online in the customer account section of the BGE website.

  *Smart phone or online. (Non-PR Senior)*

  *I would like to be able to go in and look at the 1:00 to 7:00 every single day so that I could calculate what my needs are and I'd like to also be able to set up my own set of practices. (Non-PR Senior)*

# SER Program – Event Name

8 event names

- Two names for the days on which customers can earn bill credits were most popular – Energy Savings Days and Smart Energy Reward Days.
- Energy Savings Days was thought by some to most clearly define what customers are doing on those days. They thought this name was most to-the-point.

*It's the most to-the-point. (PR Ltd. Income)*

*It sort of captures everything and zips to the point. (PR Ltd. Income)*

*I like Energy Savings Days because it does both – you're having savings and you're saving energy. (Non-PR Ltd. Income)*

- Those who preferred Smart Energy Reward Days thought it was comprehensive and they liked the "smart" and "reward" aspects, although some suggested that using "reward" might confuse some people into thinking it was referring to something associated with PeakRewards$^{SM}$.

*I like Smart Energy Reward Days. To me, it means use your energy smarter and be rewarded for it. In those four words, I sort of have an idea that there is something good behind it. (PR Middle-Upper Income)*

*I like Smart Energy Reward Days because it's comprehensive. All of your verbiage and your marketing materials are talking about smart energy rewards on particular days and times. I like it. (Non-PR Senior)*

*I like Smart Energy Reward Days because it includes my incentive in terms of I'm getting a reward and it also has to do with my energy and I think signifying the days lets me know it's going to be more than once. (Non-PR Middle-Upper Income)*

Discuss a name for the days on which customers can earn bill credits.

- Energy Savings Days
- Peak Events
- Savings Days
- Smart Energy Reward Days
- Pay Day
- Save Power Days
- Reduce Your Use Days

Q: Which of these do you think best describes these events and why?

Q: Are there any you really don't care for?

# SER Program – Event Name

8 event names

- Some customers liked the name, Reduce Your Use Days, because it sounds catchy, gets their attention, and is very descriptive.

  *It's catchy and it describes the activity that you're supposed to carry out. (PR Ltd. Income)*

  *It feels more altruistic – like I'm saving the world. (PR Ltd. Income)*

  *It's nothing about money or anything, though. It's just like, "Be a good person day." (PR Ltd. Income)*

  *I like the last one. I agree with the idea that it should be tied with the name of the program and all that, but that got my attention – like I have to reduce my energy use today. (PR Senior)*

  *I like Reduce Your Use – it is very plain and understandable. (PR Senior)*

- Pay Day and Peak Events were the least liked names. Peak Events made some customers feel as though there were some impending disaster, while others thought it sounded too much like PeakRewards$^{SM}$, which would be confusing. Pay Day felt inappropriate associated with BGE.

  *Pay Day – that's a candy bar. (PR Middle-Upper Income)*

  *Pay Day is related to our job, not to a program. (Non-PR Middle-Upper Income)*

  *Peak Events sounds like something is going to happen. (PR Ltd. Income)*

  *Peak Events doesn't make sense. (Non-PR Ltd. Income)*

Discuss a name for the days on which customers can earn bill credits.

- Energy Savings Days
- Peak Events
- Savings Days
- Smart Energy Reward Days
- Pay Day
- Save Power Days
- Reduce Your Use Days

Q: Which of these do you think best describes these events and why?

Q: Are there any you really don't care for?

# Discussion Guide

# Discussion Guide

**BGE SER/PeakRewards Focus Groups Moderator's Guide**

**For use with PeakRewards$^{SM}$ Customers – Tuesday, December 11, 2012**

**I. INTRODUCTION**

INTRODUCE SELF AND PURPOSE OF DISCUSSION. The purpose of our meeting today is to discuss current and new programs that BGE offers or will be offering to its customers to help them potentially save money on their electric bills as well as to reduce supply demand in Maryland, eliminating the need for some power plants. Your observations and feedback will help BGE develop the appropriate materials to use when communicating features and benefits of these programs. We're not going to try and sell you anything tonight – your participation here is strictly for research purposes.

**SELF DISCLOSURES AND GROUND RULES (10 minutes)**

- ASCERTAIN EVERYONE HAS SIGNED DISCLOSURE AND UNDERSTANDS THIS MEANS USING NO SOCIAL MEDIA – TWEETING OR ANYTHING ELSE – ABOUT GROUP CONTENT
- Independent consultant asked to guide this discussion
- Market research only, findings reported as a whole, nothing attributed to any individual
- Thank for time and participation
- Explain audio recording and any observers
- No right or wrong answers, want to hear from everyone
- We are not here to sell you any products or services
- Encourage participation, respond to moderator or others in the group
- Speak up, clearly, one at a time
- Tent cards, bathrooms, refreshments

As we go around the room, please introduce yourself to the group by giving us your first name and since we are here to talk about matters related to energy efficiency, *briefly* tell us about one energy efficiency measure that you take to conserve or curtail energy usage within your household. For example, I replaced my old light bulbs with CFL bulbs.

**II. ENERGY CONSERVATION** (5 minutes)

1. What are some other energy efficient or energy conservation behaviors your household takes?
   - Who specifically in your household does these things?
   - Who is less likely to collaborate and why?

# Discussion Guide

2. What motivates you to conserve or be energy efficient? Why do you do it?
    - Do you feel like you are doing all you can do and if not, what's holding you back from doing more?
    - What role do you see for BGE to motivate you to conserve or be more energy efficient?

**I. SMART METERS** (5 minutes)

**<u>Let's discuss smart meters</u> …**

3. Do you know about Smart Meters? What do you know about them?
4. How interested are you in them and what they can do for you?
5. Do you recall getting any communications from BGE about Smart Meters? What were those communications? PROBE:
    - postcard and door hanger
    - Types of channel: mail, email, phone message, etc.
    - Did the materials provide you with helpful information?
    - Did they tell you what you could do if you wanted more information?
6. Did anyone go to the BGE website specifically for smart meter information?
    - Was the communication helpful? Why? Why not?
7. Did you attend any of the community meetings related to smart meters?
    - Were they helpful? Why? Why not?

**II. PeakRewards$^{SM}$ and SER Discussion**

**A. PeakRewards$^{SM}$ Experience (only Tuesday Groups)** (5 minutes)

All of you in this room participate in the BGE PeakRewards$^{SM}$ program where BGE has installed either an outdoor switch or programmable thermostat which allows them to cycle the compressor on your air conditioner or electric heat pump during periods of peak electric demand in the summer months in exchange for credits on your BGE bill.

8. What's been the most important reason to participate in PeakRewards?

# Discussion Guide

9. Thinking back to this past summer, how many times did you experience a PeakRewards A/C cycling event?
    - How did cycling impact your lifestyle and comfort level while at home?
    - Do you believe the PeakRewards$^{SM}$ summer credits are a fair value considering your experience during peak demand periods?
    - How many times per summer are you willing to be cycled?

**B. SER Program (for PeakRewards$^{SM}$ Customers on Thursday)** (30 minutes)

BGE is planning to introduce a new voluntary program called Smart Energy Rewards. Before I go into the details of the new program, I'd like to show you some examples of some communications pieces that are being developed to introduce it.

The first thing I'd like to show you is an email communication. PASS OUT HAND-OUT PACKAGE, OPEN TO PAGE 2, **EMAIL** (10 minutes)

10. So, based just on this email, what do you think this program is?
11. Tell me about the appearance of this email – what do you think of it? PROBE:
    - Is it attractive?
    - Is anything confusing or just not completely clear to you?
12. Take a look at the subject line – Savings with Peak Rewards? Here's another way to save! – would that get your attention? How likely would you be to open an email with a subject line like this?
13. Does this message make you want to know more about this program?
    - How many would click on the "learn more" button?
    - What additional information would you be interested in finding?

The next thing I want to show you is an introductory letter that would be mailed out to customers. TURN TO PAGE 3 OF PACKAGE – **AWARENESS LETTER ENVELOPE**

14. Let's start with just the appearance of the envelope – what do you think of it?
    - What do you think of the message on the envelope? Would it make you want to open it? Why? Is it inviting? Friendly?

# Discussion Guide

TURN TO PAGE 4 OF PACKAGE – **AWARENESS LETTER** (10 minutes)

15. Now take a look at the next page. This is the letter that would be inside the envelope.
    - What do you think of the length – too long, too short, just right?
    - How helpful are the graphics?
16. Tell me about the content of the letter.
    - What is your understanding of how this new program works?
    - Is there anything you don't completely understand – anything that needs more clarification?
17. Does this letter make you want to know more about this rewards program?
    - How many would scan the bar code with their smart phone to see the video on the new program?
    - Where (else) would you go to get more information on the program?
    - What additional information would you be interested in finding?

TURN TO PAGE 5 OF PACKAGE – **POSTCARD FRONT AND BACK** (5 minutes)

18. Now take at look at the next page. This is a postcard that would be sent to customers.
    - What do you think of the length – too long, too short, just right?
    - How helpful are the graphics?
19. Does this postcard make you want to know more about this rewards program?
    - Why?
    - Would you scan the bar code with your smart phone to see the video on the new program? Would you be more or less likely to notice and use the bar code on the postcard versus on the letter? Why?

TURN TO PAGE 6 OF PACKAGE – **VIDEO STORYBOARD EXCERPT** (5 minutes)

I also want to give you an idea what will ultimately be a video that would you see if you clicked on the link in the email we first looked at or scanned the barcode on the postcard or in the letter we just looked at.

20. How interested would you be in watching this video?
21. What information would you expect to get from the video?
    - Would you want to hear from BGE customers who have experienced the program?

# Discussion Guide

22. The video is planned to include an explanation of how the program works, how you can achieve savings, how you would see your savings reflected on your BGE bill and then show customer testimonials.

    - Would you add or delete anything?

**Describe Smart Energy Rewards (SER) program) and how it is different from PeakRewards$^{SM:}$** (10 minutes)

Smart Energy Rewards is a voluntary new program that can help you earn credits on your BGE bill, helping reduce your summer energy bills. This program is made possible by the new smart meter installed at your home. Here's how it works:

- Approximately 6-12 times per summer, the Smart Energy Rewards program will notify customers in advance of a Savings Day.
- Savings Days coincide with the hottest days of the summer.
- During a Smart Energy Rewards Savings Day, customers can earn bill credits for reducing their electric usage during the hours of 1:00p – 7:00p. Regardless of what level of cycling you signed up for under the PeakRewards$^{SM}$ program, the PeakRewards$^{SM}$ air conditioning thermostat or switch will be cycled at 50% on Savings Days.
- Smart Energy Rewards allows customers to have unlimited overrides for Savings Day cycling.
- Overrides are not allowed during Emergency cycling events. During emergency events, regional demand for electricity is close to surpassing regional supply and BGE is required by the regional grid manager to activate its' PeakRewards$^{SM}$ program. This type of event is usually called to avoid potential brownouts and rolling blackouts area-wide. You will be cycled up to your chosen cycling level — 50%, 75% or 100%.
- If you are currently enrolled in BGE's PeakRewards℠ program, you will remain enrolled and you can continue to participate as you have before. You will retain your summer bill credits and PeakRewards$^{SM}$ thermostat and/or outdoor switch, plus you will have additional ways to save during peak demand periods. If you participate in both programs (Smart Energy Rewards + PeakRewards$^{SM}$), your savings could be even larger.
- During the pilot program, customers were able to modify their lifestyle and save up to $125 per summer.
- There is no penalty for customers who choose not to participate or change their energy consumption behavior.

23. So now that you know a bit more about the program, what do you think about it?
24. How many think they might be interested in participating in this program? Why or why not?
25. What concerns might you have about this new Smart Energy Rewards program?

    - Did it sound as though you would be subject to more cycling under the new program? Is that concerning?

26. In your mind, what is meant by peak demand? What would be some examples of this?

# Discussion Guide

**Telemarketing Call** (5 minutes)

27. If someone from BGE were to call you once you had received the information we've been looking at to further explain the program and answer any questions you might have, would you take the call?
    - Would you find it helpful to speak to a live person?
28. TURN TO PAGE 7 – **OUTBOUND CALL SUMMARY**: Here is a summary of what someone from BGE would plan to cover in the phone call to you.
    - Would this be a good way to help you understand the program?
    - What should they say when you first pick up the phone to make you interested in hearing more?

**Welcome Kit** (10 minutes)

TURN TO PAGE 8 – **WELCOME KIT ENVELOPE**: If you signed up for this program, you would be sent a welcome kit. Since it hasn't been fully developed, we're trying to give you an idea of what that would include – an envelope, a cover letter, and a brochure.

29. This first page we're looking at is the envelope. What do you think of it? What of the size of it? Would you be inclined to open it?
30. TURN TO PAGE 9 – **WELCOME KIT CONTENT SPREAD**: The next page in your packet gives you an idea of the contents of the welcome kit. Tell me first just about the overall appearance of these pieces. Attractive? Inviting?
31. Do you think including a personalized letter adds value to the package? Why or why not?
32. What questions would you want answered in a booklet like this?
33. Take a look at the Table of Contents to get an idea of what would be covered in the package. Is anything missing?
34. Thinking about all of the communications pieces we've been looking at today:
    - Were they consistent in appearance and style? Did anything stand out as being different?
    - Was something missing that you think should be in there? What?
    - Should there be a stronger focus on a particular area?
    - Are the materials consistent with the image you have of BGE? Why or why not?

**C. PeakRewards$^{SM}$ Bill Credit Guarantee** (5 minutes)

I want to spend a few minutes talking about a Bill Credit Guarantee. By that, I mean customers will be guaranteed to earn what they receive today from the PeakRewards$^{SM}$ program based on their cycling level and number of devices, but they could earn more with Smart Energy Rewards.

- Just like the current program, bill credits are spread equally over the four-month period of June through September, each year. If you signed up for 50% cycling, you get \$12.50 per month for a total of \$50. With 75% cycling, you get \$18.75 per month for a total of \$75. If you signed up for 100% cycling, you get \$25 per month for a total of \$100.
- Smart Energy Rewards credits will be \$1.25 per kilowatt hour reduced during the peak event hours of 1:00p – 7:00p on weekdays. Customers that participated during peak event days in the pilot program received an average of \$10 per day.
- TURN TO PAGE 10 – **SAMPLE BILLS**: The first bill on this page shows you what your bill would look like if you were participating in both PeakRewards$^{SM}$ and Smart Energy Rewards. The second one shows what the bill will book like with just PeakRewards$^{SM}$ with no Smart Energy Rewards credits if customers don't do additional actions to reduce energy use during the SER hours.

35. How understandable are these bills?
36. Is it clear what benefits you are getting and why?
37. What would you change to make it easier for customers to understand?
38. Since BGE is introducing the new Smart Energy Rewards program, what is the value you see continuing with PeakRewards? (Probe if necessary – Would you consider not participating in PeakRewards to focus on the voluntary actions to earn bill credits or do you see value in both programs?

**I. Event Name Testing** (10 minutes)

Now I'd like you to consider all the subject matter we just covered to come up with a name for the days on which customers can earn bill credits. This name needs to meet two important criteria: #1 – it positively gets your attention and #2 – it is appropriate and consistent with what we just covered. In other words, the name isn't confusing or inconsistent with what you already know about the program. TURN TO PAGE 11 – **EVENT NAME TESTING**

- Energy Savings Days
- Peak Events
- Savings Days
- Smart Energy Reward Days
- Pay Day
- Save Power Days
- Reduce Your Use Days

# Discussion Guide

39. Which of these do you think best describes these events and why?
40. Are there any you really don't care for? Why?

CHECK IN BACK ROOM FOR ANY ADDITIONAL QUESTIONS FOR PARTICIPANTS.

41. Is there any other advice you'd like to give us on this topic tonight?

That's all the questions I have. You've been extremely helpful and I thank you for your time.

# III. Bill Samples for SER and SER-Peak Rewards Customers

-*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

Name [redacted]
Service
Address [redacted]
Account # [redacted]

[redacted]

**Summary**

| | | |
|---|---|---|
| **Billing Date:** | | September 28, 2012 |
| **Previous Balance** | | $134.46 |
| **Payments Received** | | |
| September 24, 2012 | -$134.46 | |
| **BGE Outstanding Balance** | | $0.00 |
| **Charges/Adjustments this Period** | | |
| BGE Electric | | 84.17 |
| BGE Gas Delivery Service | | 18.85 |
| BGE Gas Commodity | | 8.75 |
| Smart Energy Rewards/Peak Rewards | | 30.00 cr |
| **Total Charges This Period** | | $81.77 |
| **BG*Easy* withdrawal on Oct. 22, 2012** | | **$81.77** |

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 29, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 571 | 19.7 | 73 |
| Aug 12 | Actual | 32 | 923 | 28.8 | 80 |
| Sep 11 | Actual | 30 | 452 | 15.1 | 72 |

**Gas Usage Profile**

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 16 | 0.6 | 73 |
| Aug 12 | Actual | 32 | 16 | 0.5 | 80 |
| Sep 11 | Actual | 30 | 4 | 0.1 | 72 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards/PeakRewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| August 29, 2012 | 12.1 | x | 1.25 | $15.12 |
| September 5, 2012 | 5.9 | x | 1.25 | $7.38 |
| September 12, 2012 | 2.3 | x | 1.25 | $2.88 |
| September 19, 2012 | 3.7 | x | 1.25 | $4.62 |
| | | | **Total** | **$30.00** |

Congratulations, you earned more than your minimum monthly guaranteed PeakRewards summer credit of $25.00.

Adj Annual Usage Ele 6,573 kWh Gas 423 therms

**You may keep this portion of your invoice to record your payment.**

**Account Number** [redacted]

[redacted]

You are enrolled in **BG*Easy*.**

| Withdrawal Amount | Withdrawal Date |
|---|---|
| **$81.77** | **Oct. 22, 2012** |

**No payment is required. It will be automatically withdrawn.**

Automatic Payment Plan

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 49182 | - | 48611 | = | 571 |

| | | |
|---|---|---|
| **BGE Elec Supply** | 571 kWh x .0986200 | 56.31 |
| **BGE Electric Delivery Service** | | |
| Customer Charge | | 7.50 |
| EmPower MD Chg | 571 kWh x .0020300 | 1.16 |
| Distribution Chg | 571 kWh x .0274500 | 15.67 |
| RSP Chg/Misc Cr | 571 kWh x .0047700 | 2.72 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 571 kWh x .0001490 | .09 |
| Franchise Tax | 571 kWh x .0006200 | .35 |
| **Total BGE Electric Amount** | | **$84.17** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**Gas Details** Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | Previous Reading | | Units | | Therm Factor | | Therms Used |
|---|---|---|---|---|---|---|---|
| 668 - | 653 | = | 15 | x | 1.041 | = | 16 |

| | | | |
|---|---|---|---|
| **BGE Gas Delivery Service** | | | |
| Customer Charge | | | 13.00 |
| EmPower MD Chg | 16 therms x | .0161000 | .26 |
| Distribution Chg | 16 therms x | .3454000 | 5.53 |
| Franchise Tax | 16 therms x | .0040200 | .06 |
| **Total BGE Gas Delivery Service Amount** | | | **$18.85** |
| **BGE Gas Commodity** | | | |
| Gas Commodity | 1.66 therms x | .5907000 | .98 |
| | 14.34 therms x | .5419000 | 7.77 |
| **Total BGE Gas Commodity Amount** | | | **$8.75** |

[redacted]

| BGE [redacted]ation | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

[redacted]

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 | |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

** (These are third-party services and processing fees may apply.)*

Name [redacted]

Service Address [redacted]

Account # [redacted]

[redacted]

**Summary**

| | |
|---|---|
| **Billing Date:** | October 10, 2012 |
| **Previous Balance** | $118.66 |

**Payments Received**

| | |
|---|---|
| September 21, 2012 | -$82.23 |
| October 3, 2012 | -$36.43 |

| | |
|---|---|
| **BGE Outstanding Balance** | $0.00 |

**Charges/Adjustments this Period**

| | |
|---|---|
| BGE Electric | 67.25 |
| BGE Gas Delivery Service | 14.10 |
| BGE Gas Commodity | 1.66 |
| Smart Energy Rewards/Peak Rewards | 12.50 cr |
| **Total Charges This Period** | $70.51 |

| | |
|---|---|
| **BG*Easy* withdrawal on Nov. 2, 2012** | **$70.51** |

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** November 7, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Oct 12 | Actual | 41 | 451 | 11.0 | 70 |
| | Prior month profile data not available | | | | |
| | Previous year profile data not available | | | | |

**Gas Usage Profile**

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Oct 12 | Actual | 41 | 3 | 0.1 | 70 |
| | Previous month profile data not available | | | | |
| | Previous year profile data not available | | | | |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **42 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards/PeakRewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 25, 2012 | 6.8 | x | 1.25 | $8.50 |
| | | | **Total** | **$8.50** |
| | | | **Adjusted Total** | **$12.50** |

Your total has been adjusted to your monthly PeakRewards guarantee of $12.50. Visit BGE.com/SmartEnergyRewards for energy savings tips.

Adj Annual Usage Ele 451 kWh Gas 3 therms

You may keep this portion of your invoice to record your payment.

| Account Number | [redacted] |
|---|---|

You are enrolled in BG*Easy*.

| Withdrawal Amount | Withdrawal Date |
|---|---|
| $70.51 | Nov. 2, 2012 |

No payment is required. It will be automatically withdrawn.

Automatic Payment Plan

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 29, 2012 - Oct 9, 2012 Days Billed: 41

Meter Read on October 9 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 16112 | - | 15661 | = | 451 |

| | | | |
|---|---|---|---|
| **BGE Elec Supply** | 352 kWh x | .0986200 | 34.71 |
| | 99 kWh x | .0896400 | 8.87 |
| **BGE Electric Delivery Service** | | | |
| Customer Charge | | | 7.50 |
| EmPower MD Chg | 451 kWh x | .0020300 | .92 |
| Distribution Chg | 11 kWh x | .0274500 | .30 |
| | 440 kWh x | .0274600 | 12.08 |
| RSP Chg/Misc Cr | 451 kWh x | .0047700 | 2.15 |
| **State / Local Taxes & Surcharges** | | | |
| MD Universal Svc Prog | | | .37 |
| Envir Srchg | 451 kWh x | .0001490 | .07 |
| Franchise Tax | 451 kWh x | .0006200 | .28 |
| **Total BGE Electric Amount** | | | **$67.25** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**Gas Details** Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 29, 2012 - Oct 9, 2012 Days Billed: 41

Meter Read on October 9 Meter # [redacted]

| Current Reading | Previous Reading | Units | Multiplier | Therm Factor | Therms Used |
|---|---|---|---|---|---|
| 269 - | 266 = | 3 x | 1.125 x | 1.048 = | 3 |

| | | | |
|---|---|---|---|
| **BGE Gas Delivery Service** | | | |
| Customer Charge | | | 13.00 |
| EmPower MD Chg | 3 therms x | .0161000 | .05 |
| Distribution Chg | 3 therms x | .3454000 | 1.04 |
| Franchise Tax | 3 therms x | .0040200 | .01 |
| **Total BGE Gas Delivery Service Amount** | | | **$14.10** |
| **BGE Gas Commodity** | | | |
| Gas Commodity | 0.15 therms x | .5907000 | .09 |
| | 2.20 therms x | .5419000 | 1.19 |
| | 0.66 therms x | .5803000 | .38 |
| **Total BGE Gas Commodity Amount** | | | **$1.66** |

| **BGE Contact [redacted]ion** | **Baltimore** | **Outside Area** |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

[redacted]

| **Other BGE Bill Payment Options** | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 | |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

* *(These are third-party services and processing fees may apply.)*

Name [redacted]
Service
Address
Account # [redacted]

[redacted]

**Summary**

| | |
|---|---|
| **Billing Date:** | September 28, 2012 |
| **Previous Balance** | $453.01 |
| **Payments Received** | |
| September 11, 2012 -$200.00 | |
| **BGE Outstanding Balance** | $253.01 |
| **Charges/Adjustments this Period** | |
| BGE Electric | 97.81 |
| BGE Gas Delivery Service | 16.65 |
| BGE Gas Commodity | 5.47 |
| Late Payment Charge On Electric | 3.43 |
| Late Payment Charge On Gas | 0.35 |
| Smart Energy Rewards/Peak Rewards | 12.50 cr |
| **Total New Charges Due Oct. 22, 2012** | $111.21 |
| **Total Amount Due (Prior and New)** | **$364.22** |

A late charge will be applied to payments received after Oct. 22, 2012.

A late payment charge is applied to the unpaid balance of your BGE charges. The charge is up to 1.5% for the first month; additional charges will be assessed on unpaid balances past the first month, not to exceed 5%.

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 29, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 673 | 23.2 | 73 |
| Aug 12 | Actual | 32 | 1138 | 35.6 | 80 |
| Sep 11 | Actual | 32 | 801 | 25.0 | 72 |

**Gas Usage Profile**

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 10 | 0.3 | 73 |
| Aug 12 | Actual | 32 | 11 | 0.3 | 80 |
| Sep 11 | Actual | 32 | 12 | 0.4 | 72 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards/PeakRewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 12, 2012 | 6.7 | x | 1.25 | $8.38 |
| September 19, 2012 | 3.3 | x | 1.25 | $4.12 |
| | | | **Total** | **$12.50** |

Your total has been adjusted to your monthly PeakRewards guarantee of $12.50. Visit BGE.com/SmartEnergyRewards for energy savings tips.

Adj Annual Usage Ele 7,020 kWh Gas 138 therms

**Please detach here and return this portion with your payment.**

**Account Number** [redacted]

**Please Pay by October 22, 2012**

| Amount Due | Amount Paid |
|---|---|
| **$364.22** | |

A late charge will be applied to payments received after Oct 22, 2012.

**Please make check payable to BGE and include account number. Thank you!**

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 64892 | - | 64219 | = | 673 |

| | | |
|---|---|---|
| **BGE Elec Supply** | 673 kWh x .0986200 | 66.37 |
| **BGE Electric Delivery Service** | | |
| Customer Charge | | 7.50 |
| EmPower MD Chg | 673 kWh x .0020300 | 1.37 |
| Distribution Chg | 673 kWh x .0274500 | 18.47 |
| RSP Chg/Misc Cr | 673 kWh x .0047700 | 3.21 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 673 kWh x .0001490 | .10 |
| Franchise Tax | 673 kWh x .0006200 | .42 |
| **Total BGE Electric Amount** | | **$97.81** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**Gas Details** Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | Units | | Therm Factor | | Therms Used |
|---|---|---|---|---|---|---|---|---|
| 3171 | - | 3161 | = | 10 | x | 1.041 | = | 10 |

| | | |
|---|---|---|
| **BGE Gas Delivery Service** | | |
| Customer Charge | | 13.00 |
| EmPower MD Chg | 10 therms x .0161000 | .16 |
| Distribution Chg | 10 therms x .3454000 | 3.45 |
| Franchise Tax | 10 therms x .0040200 | .04 |
| **Total BGE Gas Delivery Service Amount** | | **$16.65** |
| **BGE Gas Commodity** | | |
| Gas Commodity | 1.03 therms x .5907000 | .61 |
| | 8.97 therms x .5419000 | 4.86 |
| **Total BGE Gas Commodity Amount** | | **$5.47** |

[redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

[redacted]

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 | |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

** (These are third-party services and processing fees may apply.)*

Name [redacted]
Service
Address
Account #



[redacted]

**Summary**

| | | |
|---|---|---|
| **Billing Date:** | | September 28, 2012 |
| **Previous Balance** | | $150.30 |
| **Payments Received** | | |
| September 24, 2012 | -$150.30 | |
| **BGE Outstanding Balance** | | $0.00 |
| **Charges/Adjustments this Period** | | |
| BGE Electric | | 104.82 |
| BGE Home Contracts | | 8.43 |
| PeakRewards Air Conditioning Credit | | 18.75 cr |
| **Total Charges This Period** | | $94.72 |
| **BG*Easy* withdrawal on Oct. 22, 2012** | | **$94.72** |

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 727 | 25.1 | 73 |
| Aug 12 | Actual | 33 | 1143 | 34.6 | 80 |
| Sep 11 | Actual | 30 | 488 | 16.3 | 72 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

Adj Annual Usage Ele 13,355 kWh Gas 0 therms

**You may keep this portion of your invoice to record your payment.**

**Account Number** [redacted]

You are enrolled in **BG*Easy***.

| Withdrawal Amount | Withdrawal Date |
|---|---|
| $94.72 | Oct. 22, 2012 |

**No payment is required. It will be automatically withdrawn.**

**Automatic Payment Plan**

[redacted]

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Philadelphia, PA 19101-3070

Old$ Diff = $0.00 Cur$ Diff = -$0.22 New$ Diff = $0.00 Out of Bal = -$0.22

[redacted]

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 68281 | - | 67554 | = | 727 |

| | | |
|---|---|---|
| **BGE Elec Supply** | 727 kWh x .0986200 | 71.70 |
| **BGE Electric Delivery Service** | | |
| Customer Charge | | 7.50 |
| EmPower MD Chg | 727 kWh x .0020300 | 1.48 |
| Distribution Chg | 727 kWh x .0274500 | 19.96 |
| RSP Chg/Misc Cr | 727 kWh x .0047700 | 3.47 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .37 |
| Envir Srchg | -727 kWh x .0001490 | -.11 |
| Franchise Tax | 727 kWh x .0006200 | .45 |
| **Total BGE Electric Amount** | | **$105.04** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

[redacted] [redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | | P.O. Box 13070, Philadelphia, PA 19101-3070 |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)* * | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)* * | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

* *(These are third-party services and processing fees may apply.)*

**Non-Commodity Supplier Charges**

BGE Home Contracts

Billing Date: Sep 25, 2012

| | |
|---|---|
| Surgeguard | $8.43 |
| **Total Non-Commodity Supplier Amount** | **$8.43** |

All inquiries on above supplier billing should be directed to BGE Home Contracts at (888) 243-4663.

Name [redacted]
Service
Address
Account # [redacted]

[redacted]

**Summary**

| | | |
|---|---|---|
| **Billing Date:** | | September 28, 2012 |
| **Previous Balance** | | $180.79 |
| **Payments Received** | | |
| September 21, 2012 | -$180.79 | |
| **BGE Outstanding Balance** | | $0.00 |
| **Charges/Adjustments this Period** | | |
| BGE Electric | | 204.72 |
| Smart Energy Rewards/Peak Rewards | | 37.50 cr |
| Credit For Water Heater Control | | 7.00 cr |
| **Total Charges This Period** | | $160.22 |
| **Total Amount Due by Oct. 22, 2012** | | **$160.22** |

A late charge will be applied to payments received after Oct. 22, 2012.

A late payment charge is applied to the unpaid balance of your BGE charges. The charge is up to 1.5% for the first month; additional charges will be assessed on unpaid balances past the first month, not to exceed 5%.

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 26, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 30 | 1473 | 49.1 | 73 |
| Aug 12 | Actual | 33 | 1627 | 49.3 | 80 |
| | Previous year profile data not available | | | | |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **55 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards/PeakRewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 19, 2012 | 0 | x | 1.25 | $0.00 |
| | | | **Total** | **$0.00** |
| | | | **Adjusted Total** | **$37.50** |

You earned your minimum monthly guaranteed PeakRewards summer credit of $37.50. Visit BGE.com for energy saving tips.

Adj Annual Usage Ele 6,041 kWh Gas 0 therms

**Please detach here and return this portion with your payment.**

Account Number [redacted]

**Please Pay by October 22, 2012**

| Amount Due | Amount Paid |
|---|---|
| $160.22 | |

A late charge will be applied to payments received after Oct 22, 2012.

**Please make check payable to BGE and include account number. Thank you!**

[redacted]

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Philadelphia, PA 19101-3070

[redacted]

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 27, 2012 - Sep 26, 2012 Days Billed: 30

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 18549 | - | 17076 | = | 1473 |

| | | | |
|---|---|---|---|
| **BGE Elec Supply** | 1473 kWh x | .0986200 | 145.27 |
| **BGE Electric Delivery Service** | | | |
| Customer Charge | | | 7.50 |
| EmPower MD Chg | 1473 kWh x | .0020300 | 2.99 |
| Distribution Chg | 1473 kWh x | .0274500 | 40.43 |
| RSP Chg/Misc Cr | 1473 kWh x | .0047700 | 7.03 |
| **State / Local Taxes & Surcharges** | | | |
| MD Universal Svc Prog | | | .37 |
| Envir Srchg | 1473 kWh x | .0001490 | .22 |
| Franchise Tax | 1473 kWh x | .0006200 | .91 |
| **Total BGE Electric Amount** | | | **$204.72** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

[redacted] [redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 | |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

** (These are third-party services and processing fees may apply.)*

Name [redacted]
Service
Address
Account # [redacted]



[redacted]

## Summary

| | |
|---|---|
| **Billing Date:** | September 28, 2012 |
| **Previous Balance** | $267.39 |
| **Payments Received** | |
| September 18, 2012 | -$267.39 |
| **BGE Outstanding Balance** | $0.00 |
| **Charges/Adjustments this Period** | |
| BGE Electric | 194.28 |
| BGE Gas Delivery Service | 13.00 |
| BGE Home Contracts | 12.32 |
| PeakRewards Air Conditioning Credit | 12.50 cr |
| **Total Charges This Period** | $207.10 |
| **Total Amount Due by Oct. 22, 2012** | **$207.10** |

A late charge will be applied to payments received after Oct. 22, 2012.

A late payment charge is applied to the unpaid balance of your BGE charges. The charge is up to 1.5% for the first month; additional charges will be assessed on unpaid balances past the first month, not to exceed 5%.

### Important Information About Your Bill

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

## Electric Usage Profile

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 1395 | 48.1 | 73 |
| Aug 12 | Actual | 33 | 1846 | 55.9 | 80 |
| Sep 11 | Actual | 30 | 963 | 32.1 | 72 |

## Gas Usage Profile

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 0 | 0.0 | 73 |
| Aug 12 | Actual | 33 | 0 | 0.0 | 80 |
| Sep 11 | Actual | 30 | 0 | 0.0 | 72 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

### Important Information About Your Bill

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

Adj Annual Usage Ele 19,496 kWh Gas 271 therms

**Please detach here and return this portion with your payment.**

**Account Number** [redacted]

**Please Pay by October 22, 2012**

| Amount Due | Amount Paid |
|---|---|
| $207.10 | |

A late charge will be applied to payments received after Oct 22, 2012.

**Please make check payable to BGE and include account number. Thank you!**

[redacted]

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Philadelphia, PA 19101-3070

[redacted]

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 58539 | - | 57144 | = | 1395 |

| | | |
|---|---|---|
| **BGE Elec Supply** | 1395 kWh x .0986200 | 137.57 |
| **BGE Electric Delivery Service** | | |
| Customer Charge | | 7.50 |
| EmPower MD Chg | 1395 kWh x .0020300 | 2.83 |
| Distribution Chg | 1395 kWh x .0274500 | 38.29 |
| RSP Chg/Misc Cr | 1395 kWh x .0047700 | 6.65 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 1395 kWh x .0001490 | .21 |
| Franchise Tax | 1395 kWh x .0006200 | .86 |
| **Total BGE Electric Amount** | | **$194.28** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**Gas Details** Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | Units | | Therm Factor | | Therms Used |
|---|---|---|---|---|---|---|---|---|
| 3540 | - | 3540 | = | 0 | x | 1.041 | = | 0 |

| | |
|---|---|
| **BGE Gas Delivery Service** | |
| Customer Charge | 13.00 |
| **Total BGE Gas Delivery Service Amount** | **$13.00** |

[redacted]

| **BGE Contact Information** | **Baltimore** | **Outside Area** |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

[redacted]

| **Other BGE Bill Payment Options** | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 | |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

** (These are third-party services and processing fees may apply.)*

Name
Service
Address
Account # [redacted]



**Non-Commodity Supplier Charges**

BGE Home Contracts

Billing Date: Sep 25, 2012

| | |
|---|---|
| Water Heater Cntr | $12.32 |
| **Total Non-Commodity Supplier Amount** | **$12.32** |

All inquiries on above supplier billing should be directed to BGE Home Contracts at (888) 243-4663.

Name [redacted]
Service
Address
Account #

[redacted]

**Summary**

| | | |
|---|---|---|
| **Billing Date:** | | September 28, 2012 |
| **Previous Balance** | | $91.53 |
| **Payments Received** | | |
| September 14, 2012 | -$91.53 | |
| **BGE Outstanding Balance** | | $0.00 |
| **Charges/Adjustments this Period** | | |
| BGE Electric | | 77.23 |
| Smart Energy Rewards | | 25.00 cr |
| **Total Charges This Period** | | $52.23 |
| **Total Amount Due by Oct. 22, 2012** | | **$52.23** |

A late charge will be applied to payments received after Oct. 22, 2012.

A late payment charge is applied to the unpaid balance of your BGE charges. The charge is up to 1.5% for the first month; additional charges will be assessed on unpaid balances past the first month, not to exceed 5%.

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 29, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 30 | 519 | 17.3 | 73 |
| Aug 12 | Actual | 32 | 626 | 19.6 | 80 |
| Sep 11 | Actual | 30 | 301 | 10.0 | 72 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| August 30, 2012 | 3.2 | x | 1.25 | $4.00 |
| September 6, 2012 | 6.8 | x | 1.25 | $8.50 |
| September 13, 2012 | 2.4 | x | 1.25 | $3.00 |
| September 20, 2012 | 7.6 | x | 1.25 | $9.50 |
| | | | **Total** | **$25.00** |

Adj Annual Usage Ele 14,329 kWh Gas 0 therms

**Please detach here and return this portion with your payment.**

| Account Number | [redacted] |
|---|---|

**Please Pay by October 22, 2012**

| Amount Due | Amount Paid |
|---|---|
| $52.23 | |

A late charge will be applied to payments received after Oct 22, 2012.

**Please make check payable to BGE and include account number. Thank you!**

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

-*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 27, 2012 Days Billed: 30

Meter Read on September 27 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 85098 | - | 84579 | = | 519 |

| | | |
|---|---|---|
| **BGE Elec Supply** | 519 kWh x .0986200 | 51.18 |
| **BGE Electric Delivery Service** | | |
| Customer Charge | | 7.50 |
| EmPower MD Chg | 519 kWh x .0020300 | 1.05 |
| Distribution Chg | 519 kWh x .0274500 | 14.25 |
| RSP Chg/Misc Cr | 519 kWh x .0047700 | 2.48 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 519 kWh x .0001490 | .08 |
| Franchise Tax | 519 kWh x .0006200 | .32 |
| **Total BGE Electric Amount** | | **$77.23** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

[redacted] [redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |

Send Correspondence Only to: P.O. Box 1475, Baltimore, MD 21203

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | | P.O. Box 13070, Philadelphia, PA 19101-3070 |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

** (These are third-party services and processing fees may apply.)*

*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*

[redacted]

Name [redacted]
Service
Address
Account #

**Summary**

| | |
|---|---|
| **Billing Date:** | September 28, 2012 |
| **BGE Outstanding Balance** | $122.23 |

**Charges/Adjustments this Period**

| | |
|---|---|
| BGE Electric | 74.72 |
| Late Payment Charge On Electric | 1.50 |
| **Total New Charges Due Oct. 22, 2012** | $76.22 |
| **Total Amount Due (Prior and New)** | **$198.45** |

A late charge will be applied to payments received after Oct. 22, 2012.

A late payment charge is applied to the unpaid balance of your BGE charges. The charge is up to 1.5% for the first month; additional charges will be assessed on unpaid balances past the first month, not to exceed 5%.

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 29, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 30 | 491 | 16.4 | 73 |
| Aug 12 | Actual | 33 | 693 | 21.0 | 80 |
| | Previous year profile data not available | | | | |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 13, 2012 | 0 | x | 1.25 | $0.00 |
| September 20, 2012 | 0 | x | 1.25 | $0.00 |
| | | | **Total** | **$0.00** |

Adj Annual Usage Ele 1,184 kWh Gas 0 therms

**Please detach here and return this portion with your payment.**

**Account Number** [redacted]

**Please Pay by October 22, 2012**

| Amount Due | Amount Paid |
|---|---|
| **$198.45** | |

A late charge will be applied to payments received after Oct 22, 2012.

**Please make check payable to BGE and include account number. Thank you!**

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 27, 2012 Days Billed: 30

Meter Read on September 27 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 87808 | - | 87317 | = | 491 |

| | | |
|---|---|---|
| **BGE Elec Supply** | 491 kWh x .0986200 | 48.42 |
| **BGE Electric Delivery Service** | | |
| Customer Charge | | 7.50 |
| EmPower MD Chg | 491 kWh x .0020300 | 1.00 |
| Distribution Chg | 491 kWh x .0274500 | 13.48 |
| RSP Chg/Misc Cr | 491 kWh x .0047700 | 2.34 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 491 kWh x .0001490 | .07 |
| Franchise Tax | 491 kWh x .0006200 | .30 |
| Local Tax | 491 kWh x .0025210 | 1.24 |
| **Total BGE Electric Amount** | | **$74.72** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

[redacted] [redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 | |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

*(These are third-party services and processing fees may apply.)*

Name [redacted]
Service
Address
Account # [redacted]

[redacted]

**Summary**

| | |
|---|---|
| **Billing Date:** | September 28, 2012 |
| **BGE Outstanding Balance** | $52.45 cr |
| **Charges/Adjustments this Period** | |
| BGE Electric | 19.43 |
| **Total Charges This Period** | $19.43 |
| **No Amount Due - Credit Balance** | **$33.02 cr** |

**Important Information About Your Bill**

$33.02 credit balance to be applied to future billings.

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 29, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 85 | 2.9 | 73 |
| Aug 12 | Actual | 32 | 98 | 3.1 | 80 |
| Sep 11 | Actual | 32 | 73 | 2.3 | 72 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

Adj Annual Usage Ele 421 kWh Gas 0 therms

**You may keep this portion of your invoice for your records.**

**Account Number** [redacted]

**No amount is due on this bill.**

| Amount Due | Amount Paid |
|---|---|
| $0.00 | |

($33.02) Credit balance to be applied to future billings.

**Please do not return the stub.**

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

-*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 81163 | - | 81078 | = | 85 |

| | | |
|---|---|---|
| **BGE Elec Supply** | 85 kWh x .0986200 | 8.38 |
| **BGE Electric Delivery Service** | | |
| Customer Charge | | 7.50 |
| EmPower MD Chg | 85 kWh x .0020300 | .17 |
| Distribution Chg | 85 kWh x .0274500 | 2.33 |
| RSP Chg/Misc Cr | 85 kWh x .0047700 | .41 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 85 kWh x .0001490 | .01 |
| Franchise Tax | 85 kWh x .0006200 | .05 |
| Local Tax | 85 kWh x .0025210 | .21 |
| **Total BGE Electric Amount** | | **$19.43** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

[redacted] [redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | | P.O. Box 1475, Baltimore, MD 21203 |

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | | P.O. Box 13070, Philadelphia, PA 19101-3070 |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)* * | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)* * | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

* *(These are third-party services and processing fees may apply.)*

*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

Name
Service
Address
Account # [redacted]

[redacted]

**Summary**

| | |
|---|---|
| **Billing Date:** | September 28, 2012 |
| **Previous Balance** | $158.07 |
| **Payments Received** | |
| September 25, 2012 | -$158.07 |
| **BGE Outstanding Balance** | $0.00 |
| **Charges/Adjustments this Period** | |
| BGE Electric | 188.94 |
| Smart Energy Rewards/Peak Rewards | 25.00 cr |
| **Total Charges This Period** | $163.94 |
| **Total Amount Due by Oct. 22, 2012** | **$163.94** |

A late charge will be applied to payments received after Oct. 22, 2012.

A late payment charge is applied to the unpaid balance of your BGE charges. The charge is up to 1.5% for the first month; additional charges will be assessed on unpaid balances past the first month, not to exceed 5%.

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 29, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 30 | 1355 | 45.2 | 73 |
| Aug 12 | Actual | 32 | 1311 | 41.0 | 80 |
| Sep 11 | Actual | 30 | 429 | 14.3 | 72 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards/PeakRewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 13, 2012 | 1.3 | x | 1.25 | $1.62 |
| September 20, 2012 | 2.7 | x | 1.25 | $3.38 |
| | | | **Total** | **$5.00** |

Your guaranteed PeakRewards credit is $25.00.

Adj Annual Usage Ele 19,259 kWh Gas 0 therms

**Please detach here and return this portion with your payment.**

**Account Number** [redacted]

**Please Pay by October 22, 2012**

| Amount Due | Amount Paid |
|---|---|
| **$163.94** | |

A late charge will be applied to payments received after Oct 22, 2012.

**Please make check payable to BGE and include account number. Thank you!**

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 27, 2012 Days Billed: 30

Meter Read on September 27 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 63540 | - | 62185 | = | 1355 |

| | | | |
|---|---|---|---|
| **BGE Elec Supply** | 1355 kWh x | .0986200 | 133.63 |
| **BGE Electric Delivery Service** | | | |
| Customer Charge | | | 7.50 |
| EmPower MD Chg | 1355 kWh x | .0020300 | 2.75 |
| Distribution Chg | 1355 kWh x | .0274500 | 37.19 |
| RSP Chg/Misc Cr | 1355 kWh x | .0047700 | 6.46 |
| **State / Local Taxes & Surcharges** | | | |
| MD Universal Svc Prog | | | .37 |
| Envir Srchg | 1355 kWh x | .0001490 | .20 |
| Franchise Tax | 1355 kWh x | .0006200 | .84 |
| **Total BGE Electric Amount** | | | **$188.94** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

[redacted] [redacted]

| **BGE Contact Information** | **Baltimore** | **Outside Area** |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

| **Other BGE Bill Payment Options** | | |
|---|---|---|
| **BG*Easy*** Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | | P.O. Box 13070, Philadelphia, PA 19101-3070 |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)* * | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)* * | | 1-800-989-6669 |
| Pay-by-Phone * | | 1-888-232-0088 |

* *(These are third-party services and processing fees may apply.)*

Name [redacted]
Service
Address
Account # [redacted]



[redacted]

**Summary**

| | | |
|---|---|---|
| **Billing Date:** | | September 28, 2012 |
| **Previous Balance** | | $144.93 |
| **Payments Received** | | |
| September 24, 2012 | -$144.93 | |
| **BGE Outstanding Balance** | | $0.00 |
| **Charges/Adjustments this Period** | | |
| BGE Electric | | 134.40 |
| BGE Gas Delivery Service | | 19.58 |
| BGE Gas Commodity | | 9.81 |
| Smart Energy Rewards | | 25.00 cr |
| **Total Charges This Period** | | $138.79 |
| **BG*Easy* withdrawal on Oct. 22, 2012** | | **$138.79** |

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 29, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 417 | 14.4 | 73 |
| Aug 12 | Actual | 34 | 805 | 23.7 | 80 |
| Sep 11 | Averaged | 32 | 519 | 16.5 | 75 |

**Gas Usage Profile**

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 18 | 0.6 | 73 |
| Aug 12 | Actual | 34 | 22 | 0.6 | 80 |
| Sep 11 | Averaged | 32 | 3 | 0.1 | 34 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **42 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.781 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.239 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.269 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 6, 2012 | 10.0 | x | 1.25 | $12.50 |
| September 20, 2012 | 10.0 | x | 1.25 | $12.50 |
| | | | **Total** | **$25.00** |

Adj Annual Usage Ele 5,673 kWh Gas 480 therms

You may keep this portion of your invoice to record your payment.

**Account Number** [redacted]

You are enrolled in **BG*Easy*.**

| Withdrawal Amount | Withdrawal Date |
|---|---|
| **$138.79** | Oct. 22, 2012 |

No payment is required. It will be automatically withdrawn.

Automatic Payment Plan

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

-*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - TOU - Schedule RL

Billing Period: Aug 29, 2012 - Sep 13, 2012 Days Billed: 29

**BGE Electric Supply Energy**

Meter Read on September 13 Meter # [redacted]

| Summer | Current | Previous | kWh | Rates | Amount |
|---|---|---|---|---|---|
| Peak | 14883 | 14737 | 146 | .1392500 | 20.33 |
| Intermed | 6022 | 5954 | 68 | .0802200 | 5.45 |
| Off Peak | 18779 | 18576 | 203 | .0738800 | 15.00 |

**BGE Electric Delivery Service**

| | | |
|---|---|---|
| Customer Charge | | 12.00 |
| EmPower MD Chg | 417 kWh x .0020300 | .85 |
| Distribution Chg | 417 kWh x .0261100 | 10.89 |
| RSP Chg/Misc Cr | 417 kWh x .0047700 | 1.99 |

**State / Local Taxes & Surcharges**

| | | |
|---|---|---|
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 417 kWh x .0001490 | .06 |
| Franchise Tax | 417 kWh x .0006200 | .26 |
| **Total BGE Electric Amount** | | **$67.20** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**Electric Details** Electric Choice ID: [redacted]

Residential - TOU - Schedule RL

Billing Period: Sep 14, 2012 - Sep 27, 2012 Days Billed: 29

**Gas Details** Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 29, 2012 - Sep 27, 2012 Days Billed: 29

Meter Read on September 27 Meter # [redacted]

| Current Reading | | Previous Reading | | Units | | Therm Factor | | Therms Used |
|---|---|---|---|---|---|---|---|---|
| 9604 | - | 9587 | = | 17 | x | 1.041 | = | 18 |

**BGE Gas Delivery Service**

| | | |
|---|---|---|
| Customer Charge | | 13.00 |
| EmPower MD Chg | 18 therms x .0161000 | .29 |
| Distribution Chg | 18 therms x .3454000 | 6.22 |
| Franchise Tax | 18 therms x .0040200 | .07 |
| **Total BGE Gas Delivery Service Amount** | | **$19.58** |

**BGE Gas Commodity**

| | | |
|---|---|---|
| Gas Commodity | 1.24 therms x .5907000 | .73 |
| | 16.76 therms x .5419000 | 9.08 |
| **Total BGE Gas Commodity Amount** | | **$9.81** |

[redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |

Send Correspondence Only to: P.O. Box 1475, Baltimore, MD 21203

[redacted]

| Other BGE Bill Payment Options | |
|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 |
| Hand Deliver to Dropbox *(No Cash)* | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | 1-800-989-6669 |
| Pay-by-Phone* | 1-888-232-0088 |

* *(These are third-party services and processing fees may apply.)*

BGE®

Name [redacted]
Service
Address
Account #



**Electric Details (continued)**

**BGE Electric Supply Energy**

Meter Read on September 27 Meter # [redacted]

| Summer | Current | Previous | kWh | Rates | Amount |
|---|---|---|---|---|---|
| Peak | 14883 | 14737 | 146 | .1392500 | 20.33 |
| Intermed | 6022 | 5954 | 68 | .0802200 | 5.45 |
| Off Peak | 18779 | 18576 | 203 | .0738800 | 15.00 |

**BGE Electric Delivery Service**

| | | |
|---|---|---|
| Customer Charge | | 12.00 |
| EmPower MD Chg | 417 kWh x .0020300 | .85 |
| Distribution Chg | 417 kWh x .0261100 | 10.89 |
| RSP Chg/Misc Cr | 417 kWh x .0047700 | 1.99 |

**State / Local Taxes & Surcharges**

| | | |
|---|---|---|
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 417 kWh x .0001490 | .06 |
| Franchise Tax | 417 kWh x .0006200 | .26 |
| **Total BGE Electric Amount** | | **$67.20** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

[redacted]

Name
Service
Address [redacted]
Account # [redacted]



## Summary

| | | |
|---|---|---|
| Billing Date: | | September 28, 2012 |
| Previous Balance | | $144.93 |
| **Payments Received** | | |
| September 24, 2012 | -$144.93 | |
| **BGE Outstanding Balance** | | $0.00 |
| **Charges/Adjustments this Period** | | |
| BGE Electric | | 134.40 |
| BGE Gas Delivery Service | | 19.58 |
| BGE Gas Commodity | | 9.81 |
| Smart Energy Rewards/Peak Rewards | | 25.00 cr |
| **Total Charges This Period** | | $138.79 |
| **BG*Easy* withdrawal on Oct. 22, 2012** | | **$138.79** |

**Next Scheduled Reading** October 29, 2012

### Electric Usage Profile

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 417 | 14.4 | 73 |
| Aug 12 | Actual | 34 | 805 | 23.7 | 80 |
| Sep 11 | Averaged | 32 | 519 | 16.5 | 75 |

### Gas Usage Profile

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 18 | 0.6 | 73 |
| Aug 12 | Actual | 34 | 22 | 0.6 | 80 |
| Sep 11 | Averaged | 32 | 3 | 0.1 | 34 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **42 hours**. Find out more at www.bge.com.

### Important Information About Your Bill

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

### Important Information About Your Bill

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.781 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.239 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.269 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

**Smart Energy Rewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 6, 2012 | 10.0 | x | 1.25 | $12.50 |
| September 20, 2012 | 10.0 | x | 1.25 | $12.50 |
| | | | **Total** | **$25.00** |

Adj Annual Usage Ele 5,673 kWh Gas 480 therms

You may keep this portion of your invoice to record your payment.

Account Number [redacted]

You are enrolled in BG*Easy*.

| Withdrawal Amount | Withdrawal Date |
|---|---|
| $138.79 | Oct. 22, 2012 |

No payment is required. It will be automatically withdrawn.

Automatic Payment Plan

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - TOU - Schedule RL

Billing Period: Aug 29, 2012 - Sep 13, 2012 Days Billed: 29

**BGE Electric Supply Energy**

Meter Read on September 13 Meter # [redacted]

| Summer | Current | Previous | kWh | Rates | Amount |
|---|---|---|---|---|---|
| Peak | 14883 | 14737 | 146 | .1392500 | 20.33 |
| Intermed | 6022 | 5954 | 68 | .0802200 | 5.45 |
| Off Peak | 18779 | 18576 | 203 | .0738800 | 15.00 |

**BGE Electric Delivery Service**

| | | |
|---|---|---|
| Customer Charge | | 12.00 |
| EmPower MD Chg | 417 kWh x .0020300 | .85 |
| Distribution Chg | 417 kWh x .0261100 | 10.89 |
| RSP Chg/Misc Cr | 417 kWh x .0047700 | 1.99 |

**State / Local Taxes & Surcharges**

| | | |
|---|---|---|
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 417 kWh x .0001490 | .06 |
| Franchise Tax | 417 kWh x .0006200 | .26 |
| **Total BGE Electric Amount** | | **$67.20** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**Electric Details** Electric Choice ID: [redacted]

Residential - TOU - Schedule RL

Billing Period: Sep 14, 2012 - Sep 27, 2012 Days Billed: 29

**Gas Details** Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 29, 2012 - Sep 27, 2012 Days Billed: 29

Meter Read on September 27 Meter # [redacted]

| Current Reading | | Previous Reading | | Units | | Therm Factor | | Therms Used |
|---|---|---|---|---|---|---|---|---|
| 9604 | - | 9587 | = | 17 | x | 1.041 | = | 18 |

**BGE Gas Delivery Service**

| | | |
|---|---|---|
| Customer Charge | | 13.00 |
| EmPower MD Chg | 18 therms x .0161000 | .29 |
| Distribution Chg | 18 therms x .3454000 | 6.22 |
| Franchise Tax | 18 therms x .0040200 | .07 |
| **Total BGE Gas Delivery Service Amount** | | **$19.58** |

**BGE Gas Commodity**

| | | |
|---|---|---|
| Gas Commodity | 1.24 therms x .5907000 | .73 |
| | 16.76 therms x .5419000 | 9.08 |
| **Total BGE Gas Commodity Amount** | | **$9.81** |

[redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

[redacted]

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 | |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

** (These are third-party services and processing fees may apply.)*

BGE

Name [redacted]
Service
Address
Account # [redacted]



## Electric Details (continued)

### BGE Electric Supply Energy

Meter Read on September 27 Meter # [redacted]

| Summer | Current | Previous | kWh | Rates | Amount |
|---|---|---|---|---|---|
| Peak | 14883 | 14737 | 146 | .1392500 | 20.33 |
| Intermed | 6022 | 5954 | 68 | .0802200 | 5.45 |
| Off Peak | 18779 | 18576 | 203 | .0738800 | 15.00 |

### BGE Electric Delivery Service

| | | |
|---|---|---|
| Customer Charge | | 12.00 |
| EmPower MD Chg | 417 kWh x .0020300 | .85 |
| Distribution Chg | 417 kWh x .0261100 | 10.89 |
| RSP Chg/Misc Cr | 417 kWh x .0047700 | 1.99 |

### State / Local Taxes & Surcharges

| | | |
|---|---|---|
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 417 kWh x .0001490 | .06 |
| Franchise Tax | 417 kWh x .0006200 | .26 |
| **Total BGE Electric Amount** | | **$67.20** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

Name [redacted]
Address

Account # [redacted]



[redacted]

**Summary**

| | | |
|---|---|---|
| **Billing Date:** | | September 28, 2012 |
| **Previous Balance** | | $144.93 |
| **Payments Received** | | |
| September 24, 2012 | -$144.93 | |
| **BGE Outstanding Balance** | | $0.00 |
| **Charges/Adjustments this Period** | | |
| BGE Electric | | 134.40 |
| BGE Gas Delivery Service | | 19.58 |
| BGE Gas Commodity | | 9.81 |
| Smart Energy Rewards | | 25.00 cr |
| **Total Charges This Period** | | $138.79 |
| **BG*Easy* withdrawal on Oct. 22, 2012** | | **$138.79** |

**Summary of Charges by Service Address**

| | | Current Charges |
|---|---|---|
| 1 | [redacted] | $96.59 |
| 2 | | $67.20 |

**Smart Energy Rewards Credit Details**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 20, 2012 | 20 | x | 1.25 | $25.00 |
| | | | **Total** | **$25.00** |

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

Adj Annual Usage Ele 5,673 kWh Gas 480 therms

**You may keep this portion of your invoice to record your payment.**

**Account Number** [redacted]

You are enrolled in **BG*Easy*.**

| Withdrawal Amount | Withdrawal Date |
|---|---|
| $138.79 | Oct. 22, 2012 |

**No payment is required. It will be automatically withdrawn.**

**Automatic Payment Plan**

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

-*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

[redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

[redacted]

| Other BGE Bill Payment Options | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | | P.O. Box 13070, Philadelphia, PA 19101-3070 |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

** (These are third-party services and processing fees may apply.)*

**Name** [redacted]
**Address**

**Account #** [redacted]



## Detail of Accounts

1 **Premise Number** [redacted]
**Service Address** [redacted]

**Next Scheduled Reading** October 29, 2012
**Current Charges** $96.59

### Electric Details

Electric Choice ID: [redacted]

Residential - TOU - Schedule RL

Billing Period: Aug 29, 2012 - Sep 27, 2012 Days Billed: 29

### Electric Usage Profile

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 417 | 14.4 | 73 |
| Aug 12 | Actual | 34 | 805 | 23.7 | 80 |
| Sep 11 | Averaged | 32 | 519 | 16.5 | 75 |

### Important Messages

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

### BGE Electric Supply Energy

Meter Read on September 27 Meter # [redacted]

| Summer | Current | Previous | kWh | Rates | Amount |
|---|---|---|---|---|---|
| Peak | 14883 | 14737 | 146 | .1392500 | 20.33 |
| Intermed | 6022 | 5954 | 68 | .0802200 | 5.45 |
| Off Peak | 18779 | 18576 | 203 | .0738800 | 15.00 |

### BGE Electric Delivery Service

| | | |
|---|---|---|
| Customer Charge | | 12.00 |
| EmPower MD Chg | 417 kWh x .0020300 | .85 |
| Distribution Chg | 417 kWh x .0261100 | 10.89 |
| RSP Chg/Misc Cr | 417 kWh x .0047700 | 1.99 |

### State / Local Taxes & Surcharges

| | | |
|---|---|---|
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 417 kWh x .0001490 | .06 |
| Franchise Tax | 417 kWh x .0006200 | .26 |
| **Total BGE Electric Amount** | | **$67.20** |

### Gas Details

Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 29, 2012 - Sep 27, 2012 Days Billed: 29

Meter Read on September 27 Meter # [redacted]

| Current Reading | | Previous Reading | | Units | | Therm Factor | | Therms Used |
|---|---|---|---|---|---|---|---|---|
| 9604 | - | 9587 | = | 17 | x | 1.041 | = | 18 |

### Gas Usage Profile

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 18 | 0.6 | 73 |
| Aug 12 | Actual | 34 | 22 | 0.6 | 80 |
| Sep 11 | Averaged | 32 | 3 | 0.1 | 34 |

### BGE Gas Delivery Service

| | | |
|---|---|---|
| Customer Charge | | 13.00 |
| EmPower MD Chg | 18 therms x .0161000 | .29 |
| Distribution Chg | 18 therms x .3454000 | 6.22 |
| Franchise Tax | 18 therms x .0040200 | .07 |
| **Total BGE Gas Delivery Service Amount** | | **$19.58** |

### BGE Gas Commodity

| | | |
|---|---|---|
| Gas Commodity | 1.24 therms x .5907000 | .73 |
| | 16.76 therms x .5419000 | 9.08 |
| **Total BGE Gas Commodity Amount** | | **$9.81** |

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

*Detail of Accounts - Continued*

2 **Premise Number** [redacted]
**Service Address** [redacted]

**Next Scheduled Reading** October 29, 2012
**Current Charges** $67.20

**Electric Details** Electric Choice ID: [redacted]

Residential - TOU - Schedule RL

Billing Period: Aug 29, 2012 - Sep 27, 2012 Days Billed: 29

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 417 | 14.4 | 73 |
| Aug 12 | Actual | 34 | 805 | 23.7 | 80 |
| Sep 11 | Averaged | 32 | 519 | 16.5 | 75 |

**Important Messages**

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**BGE Electric Supply Energy**

Meter Read on September 27 Meter # [redacted]

| Summer | Current | Previous | kWh | Rates | Amount |
|---|---|---|---|---|---|
| Peak | 14883 | 14737 | 146 | .1392500 | 20.33 |
| Intermed | 6022 | 5954 | 68 | .0802200 | 5.45 |
| Off Peak | 18779 | 18576 | 203 | .0738800 | 15.00 |
| **BGE Electric Delivery Service** | | | | | |
| Customer Charge | | | | | 12.00 |
| EmPower MD Chg | | | 417 kWh x | .0020300 | .85 |
| Distribution Chg | | | 417 kWh x | .0261100 | 10.89 |
| RSP Chg/Misc Cr | | | 417 kWh x | .0047700 | 1.99 |
| **State / Local Taxes & Surcharges** | | | | | |
| MD Universal Svc Prog | | | | | .37 |
| Envir Srchg | | | 417 kWh x | .0001490 | .06 |
| Franchise Tax | | | 417 kWh x | .0006200 | .26 |
| **Total BGE Electric Amount** | | | | | **$67.20** |

**Name**
**Address** [redacted]

[redacted]

**Account #** [redacted]



## Summary

| | |
|---|---|
| **Billing Date:** | September 28, 2012 |
| **Previous Balance** | $144.93 |

**Payments Received**

| | |
|---|---|
| September 24, 2012 | -$144.93 |
| **BGE Outstanding Balance** | $0.00 |

**Charges/Adjustments this Period**

| | |
|---|---|
| BGE Electric | 134.40 |
| BGE Gas Delivery Service | 19.58 |
| BGE Gas Commodity | 9.81 |
| Smart Energy Rewards/Peak Rewards | 25.00 cr |
| **Total Charges This Period** | $138.79 |
| **BG*Easy* withdrawal on Oct. 22, 2012** | **$138.79** |

## Summary of Charges by Service Address

| | | Current Charges |
|---|---|---|
| 1 | [redacted] | $96.59 |
| 2 | | $67.20 |

### Smart Energy Rewards Credit Details

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 6, 2012 | 10.0 | x | 1.25 | $12.50 |
| September 13, 2012 | 10.0 | x | 1.25 | $12.50 |
| | | | **Total** | **$25.00** |

### Important Information About Your Bill

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

Adj Annual Usage Ele 5,673 kWh Gas 480 therms

**You may keep this portion of your invoice to record your payment.**

**Account Number** [redacted]

You are enrolled in **BG*Easy*.**

| Withdrawal Amount | Withdrawal Date |
|---|---|
| **$138.79** | **Oct. 22, 2012** |

**No payment is required. It will be automatically withdrawn.**

**Automatic Payment Plan**

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

[redacted]

| BGE Contact Information | Baltimore | Outside Area |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*fine*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

[redacted]

| Other BGE Bill Payment Options | | |
|---|---|---|
| **BG*Easy*** Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | P.O. Box 13070, Philadelphia, PA 19101-3070 | |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)* * | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)* * | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

* *(These are third-party services and processing fees may apply.)*

Name [redacted]
Address

Account # [redacted]



## Detail of Accounts

1 Premise Number [redacted]
Service Address

Next Scheduled Reading October 29, 2012
Current Charges $96.59

### Electric Details

Electric Choice ID: [redacted]

Residential - TOU - Schedule RL

Billing Period: Aug 29, 2012 - Sep 27, 2012 Days Billed: 29

### Electric Usage Profile

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 417 | 14.4 | 73 |
| Aug 12 | Actual | 34 | 805 | 23.7 | 80 |
| Sep 11 | Averaged | 32 | 519 | 16.5 | 75 |

### Important Messages

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

### BGE Electric Supply Energy

Meter Read on September 27 Meter # [redacted]

| Summer | Current | Previous | kWh | Rates | Amount |
|---|---|---|---|---|---|
| Peak | 14883 | 14737 | 146 | .1392500 | 20.33 |
| Intermed | 6022 | 5954 | 68 | .0802200 | 5.45 |
| Off Peak | 18779 | 18576 | 203 | .0738800 | 15.00 |

### BGE Electric Delivery Service

| | | |
|---|---|---|
| Customer Charge | | 12.00 |
| EmPower MD Chg | 417 kWh x .0020300 | .85 |
| Distribution Chg | 417 kWh x .0261100 | 10.89 |
| RSP Chg/Misc Cr | 417 kWh x .0047700 | 1.99 |

### State / Local Taxes & Surcharges

| | | |
|---|---|---|
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 417 kWh x .0001490 | .06 |
| Franchise Tax | 417 kWh x .0006200 | .26 |
| **Total BGE Electric Amount** | | **$67.20** |

### Gas Details

Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 29, 2012 - Sep 27, 2012 Days Billed: 29

Meter Read on September 27 Meter # [redacted]

| Current Reading | | Previous Reading | | Units | | Therm Factor | | Therms Used |
|---|---|---|---|---|---|---|---|---|
| 9604 | - | 9587 | = | 17 | x | 1.041 | = | 18 |

### Gas Usage Profile

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 18 | 0.6 | 73 |
| Aug 12 | Actual | 34 | 22 | 0.6 | 80 |
| Sep 11 | Averaged | 32 | 3 | 0.1 | 34 |

### BGE Gas Delivery Service

| | | | |
|---|---|---|---|
| Customer Charge | | | 13.00 |
| EmPower MD Chg | 18 therms x | .0161000 | .29 |
| Distribution Chg | 18 therms x | .3454000 | 6.22 |
| Franchise Tax | 18 therms x | .0040200 | .07 |
| **Total BGE Gas Delivery Service Amount** | | | **$19.58** |

### BGE Gas Commodity

| | | | |
|---|---|---|---|
| Gas Commodity | 1.24 therms x | .5907000 | .73 |
| | 16.76 therms x | .5419000 | 9.08 |
| **Total BGE Gas Commodity Amount** | | | **$9.81** |

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*Detail of Accounts - Continued*

| | | | |
|---|---|---|---|
| 2 | **Premise Number** [redacted] | **Next Scheduled Reading** | October 29, 2012 |
| | **Service Address** [redacted] | **Current Charges** | $67.20 |

**Electric Details** Electric Choice ID: [redacted]

Residential - TOU - Schedule RL

Billing Period: Aug 29, 2012 - Sep 27, 2012 Days Billed: 29

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 417 | 14.4 | 73 |
| Aug 12 | Actual | 34 | 805 | 23.7 | 80 |
| Sep 11 | Averaged | 32 | 519 | 16.5 | 75 |

**Important Messages**

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**BGE Electric Supply Energy**

Meter Read on September 27 Meter # [redacted]

| Summer | Current | Previous | kWh | Rates | Amount |
|---|---|---|---|---|---|
| Peak | 14883 | 14737 | 146 | .1392500 | 20.33 |
| Intermed | 6022 | 5954 | 68 | .0802200 | 5.45 |
| Off Peak | 18779 | 18576 | 203 | .0738800 | 15.00 |
| **BGE Electric Delivery Service** | | | | | |
| Customer Charge | | | | | 12.00 |
| EmPower MD Chg | | | 417 kWh x | .0020300 | .85 |
| Distribution Chg | | | 417 kWh x | .0261100 | 10.89 |
| RSP Chg/Misc Cr | | | 417 kWh x | .0047700 | 1.99 |
| **State / Local Taxes & Surcharges** | | | | | |
| MD Universal Svc Prog | | | | | .37 |
| Envir Srchg | | | 417 kWh x | .0001490 | .06 |
| Franchise Tax | | | 417 kWh x | .0006200 | .26 |
| **Total BGE Electric Amount** | | | | | **$67.20** |

[redacted]

Name
Service
Address
Account # [redacted]

**Summary**

| | |
|---|---|
| **Billing Date:** | January 13, 2012 |
| **BGE Outstanding Balance** | $168.23 |
| **Charges/Adjustments this Period** | |
| BGE Electric | 80.01 |
| Castlebridge Energy Grp LLC | 184.70 |
| Late Payment Charge On Electric | 1.60 |
| **Total New Charges Due Feb. 6, 2012** | $266.31 |
| **Total Amount Due (Prior and New)** | **$434.54** |

A late charge will be applied to payments received after Feb. 6, 2012.

A late payment charge is applied to the unpaid balance of your BGE charges. The charge is up to 1.5% for the first month; additional charges will be assessed on unpaid balances past the first month, not to exceed 5%.

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** February 9, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Jan 12 | Actual | 33 | 2212 | 67.0 | 0 |
| Dec 11 | Actual | 29 | 1381 | 47.6 | 0 |
| Jan 11 | Actual | 33 | 3375 | 102.3 | 0 |

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

Adj Annual Usage Ele 19,436 kWh Gas 0 therms

**Please detach here and return this portion with your payment.**

**Account Number** [redacted]

**Please Pay by February 6, 2012**

| Amount Due | Amount Paid |
|---|---|
| $434.54 | |

A late charge will be applied to payments received after Feb 6, 2012.

**Please make check payable to BGE and include account number. Thank you!**

[redacted]

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Dec 8, 2011 - Jan 10, 2012 Days Billed: 33

| **BGE Electric Delivery Service** | | |
|---|---|---|
| Customer Charge | | 7.50 |
| EmPower MD Chg | 2212 kWh x .0020300 | 4.49 |
| Distribution Chg | 2212 kWh x .0271200 | 59.99 |
| RSP Chg/Misc Cr | 2212 kWh x .0026900 | 5.95 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .37 |
| Envir Srchg | 2212 kWh x .0001520 | .34 |
| Franchise Tax | 2212 kWh x .0006200 | 1.37 |
| **Total BGE Electric Amount** | | **$80.01** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**Electric Supplier Charges**

Castlebridge Energy Grp LLC

Billing Period: Dec 8, 2011 - Jan 10, 2012

| | |
|---|---|
| EnergyCharge | 184.70 |
| State Tax | .00 |
| **Total Electric Supplier Amount** | **$184.70** |

All inquiries on above supplier billing should be directed to Castlebridge Energy Grp LLC at (443) 524-2885.

[redacted]

| **BGE Contact Information** | **Baltimore** | **Outside Area** |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | P.O. Box 1475, Baltimore, MD 21203 | |

[redacted]

| **Other BGE Bill Payment Options** | | |
|---|---|---|
| **BG*Easy*** Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | | P.O. Box 13070, Philadelphia, PA 19101-3070 |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

* *(These are third-party services and processing fees may apply.)*

Name [redacted]
Service [redacted]
Address [redacted]
Account # [redacted]



[redacted]

**Summary**

| | |
|---|---|
| **Billing Date:** | September 28, 2012 |
| **Previous Balance** | $134.46 |
| **Payments Received** | |
| September 24, 2012 -$134.46 | |
| **BGE Outstanding Balance** | $0.00 |
| **Charges/Adjustments this Period** | |
| BGE Electric | 84.17 |
| BGE Gas Delivery Service | 18.85 |
| BGE Gas Commodity | 8.75 |
| Smart Energy Rewards/Peak Rewards | 30.00 cr |
| **Total Charges This Period** | $81.77 |
| **BG*Easy* withdrawal on Oct. 22, 2012** | **$81.77** |

**Important Information About Your Bill**

**Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

**Next Scheduled Reading** October 29, 2012

**Electric Usage Profile**

| Month/ Year | Type of Reading | Days | kWh | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 571 | 19.7 | 73 |
| Aug 12 | Actual | 32 | 923 | 28.8 | 80 |
| Sep 11 | Actual | 30 | 452 | 15.1 | 72 |

**Gas Usage Profile**

| Month/ Year | Type of Reading | Days | Therms | Avg. Daily Use | Avg. Temp |
|---|---|---|---|---|---|
| Sep 12 | Actual | 29 | 16 | 0.6 | 73 |
| Aug 12 | Actual | 32 | 16 | 0.5 | 80 |
| Sep 11 | Actual | 30 | 4 | 0.1 | 72 |

Hot weather can significantly impact your bill. During the current bill period, the temperature at BWI Airport was at or above 85 degrees a total of **50 hours**. Find out more at www.bge.com.

**Important Information About Your Bill**

**BGE Supply Price Comparison Information:** The current price for Standard Offer Service (SOS) electricity is 8.964 cents/kWh, effective through May 31, 2013. SOS electricity will cost 10.474 cents/kWh beginning June 1, 2013 through September 30, 2013. The weighted average price of SOS electricity will be 9.508 through September 30, 2013. The price for SOS from October 1, 2013 through May 31, 2014 will be set in May 2013.

Smart Energy Rewards/PeakRewards Credit Details

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| August 29, 2012 | 2.4 | x | 1.25 | $3.00 |
| August 30, 2012 | 2.4 | x | 1.25 | $3.00 |
| September 5, 2012 | 2.4 | x | 1.25 | $3.00 |
| September 6, 2012 | 2.4 | x | 1.25 | $3.00 |
| September 12, 2012 | 2.4 | x | 1.25 | $3.00 |
| September 13, 2012 | 2.4 | x | 1.25 | $3.00 |

Adj Annual Usage Ele 6,573 kWh Gas 423 therms

You may keep this portion of your invoice to record your payment.

**Account Number** [redacted]

[redacted]

You are enrolled in BG*Easy*.

| Withdrawal Amount | Withdrawal Date |
|---|---|
| $81.77 | Oct. 22, 2012 |

No payment is required. It will be automatically withdrawn.

Automatic Payment Plan

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

[redacted]

.*- Demonstration Powered by HP Exstream 01/17/2013, Version 7.0.613 32-bit -*-

**Electric Details** Electric Choice ID: [redacted]

Residential - Schedule R

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | | Previous Reading | | kWh Used |
|---|---|---|---|---|
| 49182 | - | 48611 | = | 571 |

| | | | |
|---|---|---|---|
| **BGE Elec Supply** | 571 kWh x | .0986200 | 56.31 |
| **BGE Electric Delivery Service** | | | |
| Customer Charge | | | 7.50 |
| EmPower MD Chg | 571 kWh x | .0020300 | 1.16 |
| Distribution Chg | 571 kWh x | .0274500 | 15.67 |
| RSP Chg/Misc Cr | 571 kWh x | .0047700 | 2.72 |
| **State / Local Taxes & Surcharges** | | | |
| MD Universal Svc Prog | | | .37 |
| Envir Srchg | 571 kWh x | .0001490 | .09 |
| Franchise Tax | 571 kWh x | .0006200 | .35 |
| **Total BGE Electric Amount** | | | **$84.17** |

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00596 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

**Gas Details** Gas Choice ID: [redacted]

Residential - Schedule D

Billing Period: Aug 28, 2012 - Sep 26, 2012 Days Billed: 29

Meter Read on September 26 Meter # [redacted]

| Current Reading | Previous Reading | | Units | | Therm Factor | | Therms Used |
|---|---|---|---|---|---|---|---|
| 668 - | 653 | = | 15 | x | 1.041 | = | 16 |

| | | | |
|---|---|---|---|
| **BGE Gas Delivery Service** | | | |
| Customer Charge | | | 13.00 |
| EmPower MD Chg | 16 therms x | .0161000 | .26 |
| Distribution Chg | 16 therms x | .3454000 | 5.53 |
| Franchise Tax | 16 therms x | .0040200 | .06 |
| **Total BGE Gas Delivery Service Amount** | | | **$18.85** |
| **BGE Gas Commodity** | | | |
| Gas Commodity | 1.66 therms x | .5907000 | .98 |
| | 14.34 therms x | .5419000 | 7.77 |
| **Total BGE Gas Commodity Amount** | | | **$8.75** |

[redacted]

| **BGE Contact Information** | **Baltimore** | **Outside Area** |
|---|---|---|
| Report Power Outages | | 1-877-778-2222 |
| Emergency Service | 410-685-0123 | 1-800-685-0123 |
| Customer Service | 410-685-0123 | 1-800-685-0123 |
| Collection/Turn-Off Notices | 410-685-2200 | 1-800-685-2210 |
| Hearing/Speech Impaired (TTY-TTD) | | 1-800-735-2258 |
| Weather*line*® | | 410-662-9225 |
| Additional BGE Services | | www.bge.com |
| Send Correspondence Only to: | | P.O. Box 1475, Baltimore, MD 21203 |

**Other BGE Bill Payment Options** [redacted]

| | | |
|---|---|---|
| BG*Easy* Automatic Payment Plan | 410-685-0123 | 1-800-685-0123 |
| Payments Only to: | | P.O. Box 13070, Philadelphia, PA 19101-3070 |
| Hand Deliver to Dropbox *(No Cash)* | | 2 Center Plaza |
| America's Cash Express *(Pay-in-Person)** | | 888-FIND-ACE |
| Global Express *(Pay-in-Person)** | | 1-800-989-6669 |
| Pay-by-Phone* | | 1-888-232-0088 |

*(These are third-party services and processing fees may apply.)*

BGE

Name [redacted]
Service
Address
Account #



**Smart Energy Rewards/PeakRewards Credit Details (Cont)**

| Event Date | kWh Saved | | $/kWh | Credits |
|---|---|---|---|---|
| September 14, 2012 | 2.4 | x | 1.25 | $3.00 |
| September 17, 2012 | 2.4 | x | 1.25 | $3.00 |
| September 18, 2012 | 2.4 | x | 1.25 | $3.00 |
| September 19, 2012 | 2.4 | x | 1.25 | $3.00 |
| | | | **Total** | **$30.00** |

Congratulations, you earned more than your minimum monthly guaranteed PeakRewards summer credit of $25.00.

# IV. Smart Energy Manager (SEM) Overview and Screenshots

# Smart Energy Manager (SEM) Capability

**Goal:** Present energy usage and cost data for AMI customers via a web portal and printed home energy reports. In addition, track and analyze meter usage, estimation of bills, and energy profiling. Additional upgrades to authenticated pages on BGE.com for a new look and feel.

## What *customers* can expect:

After October 2012, residential customers who have received their smart meters will be able to:

- Track and analyze usage and cost data (limited features for small commercial)
- Compare usage to "like" customers
- Receive personalized usage and cost savings tips
- Receive printed and electronic home energy reports
- Have access to interval usage data

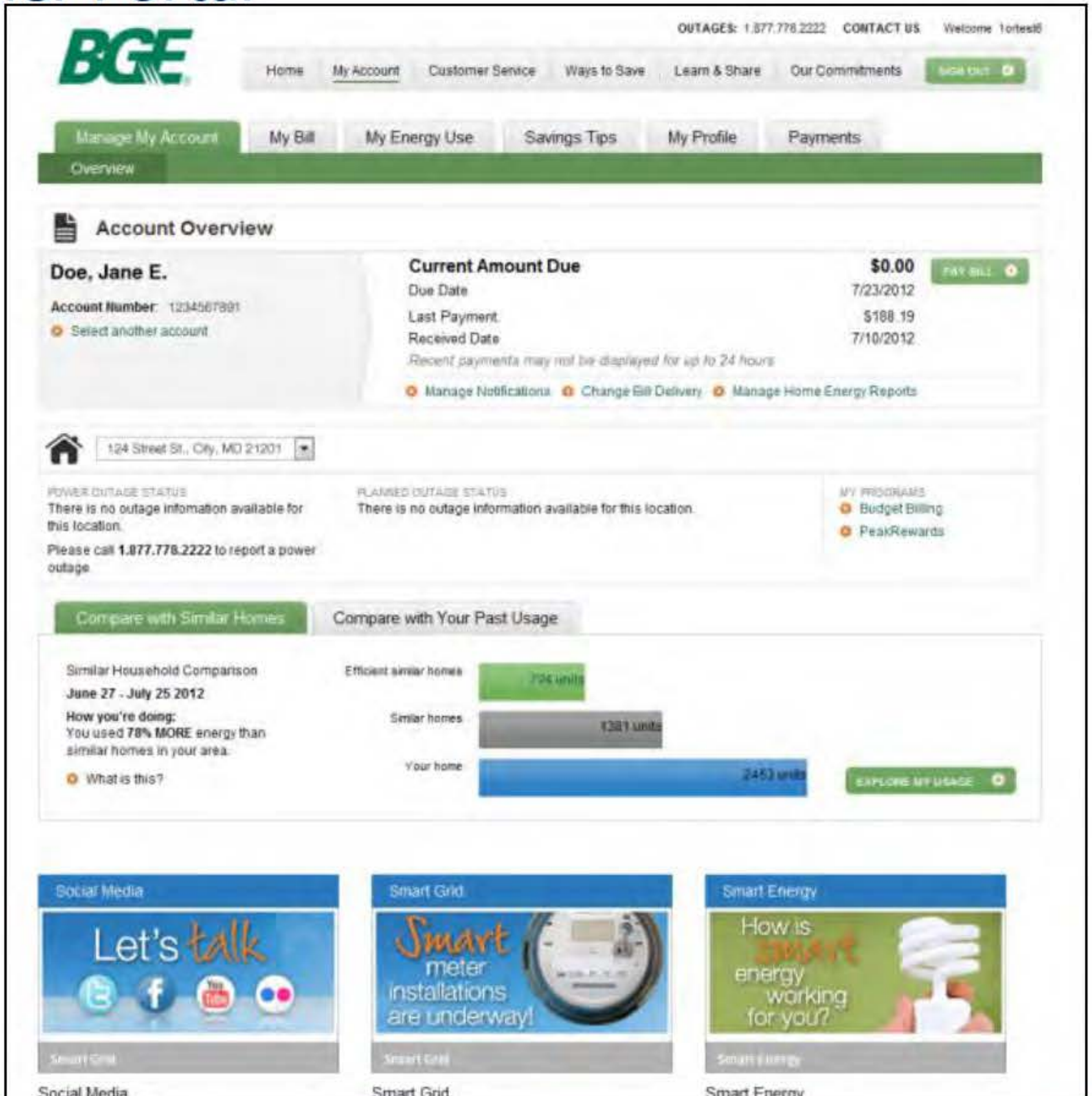
Home Energy Reports


Customer Portal

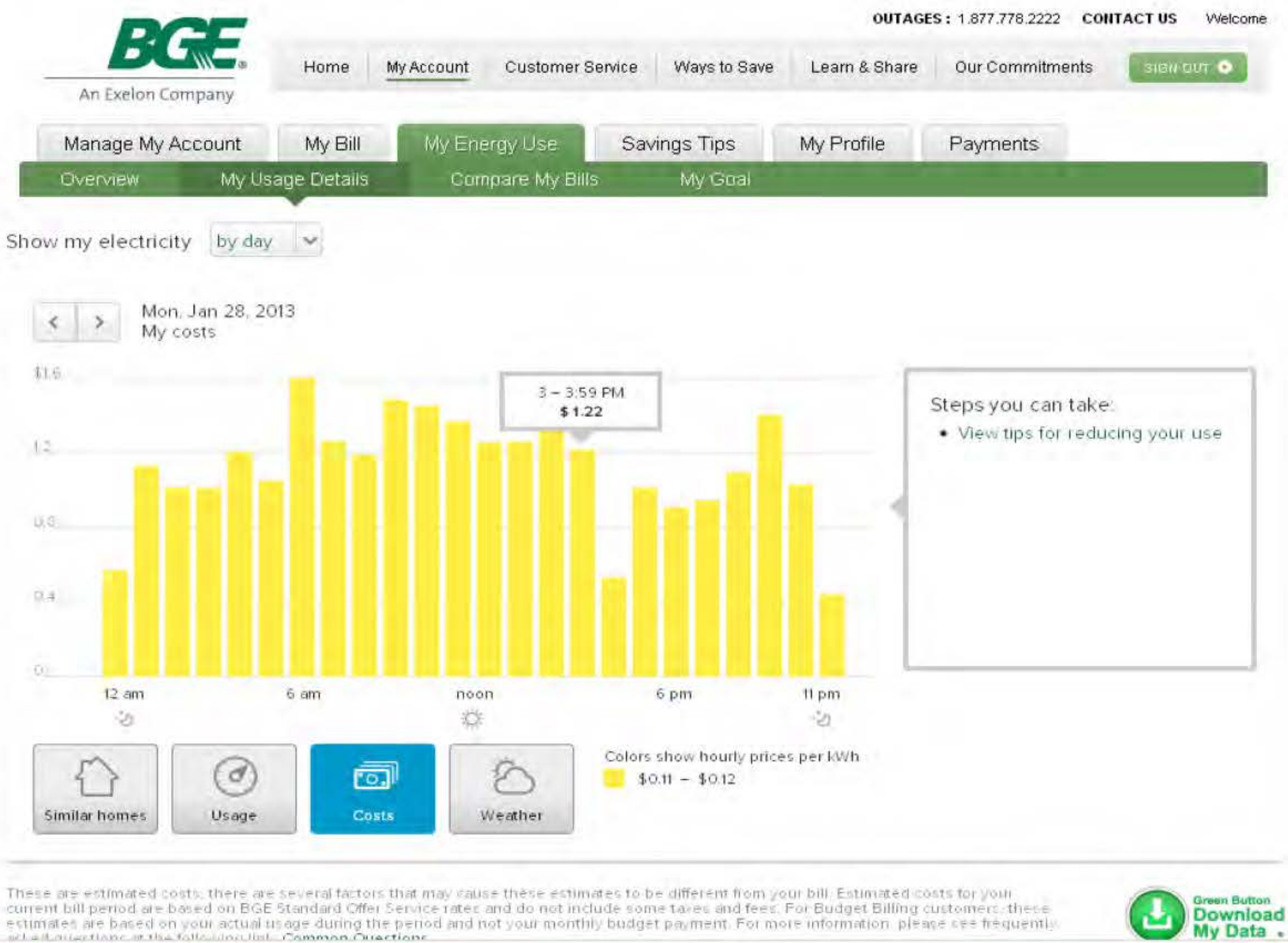

**Status:** *Delivered in October 2012*

An Exelon Company

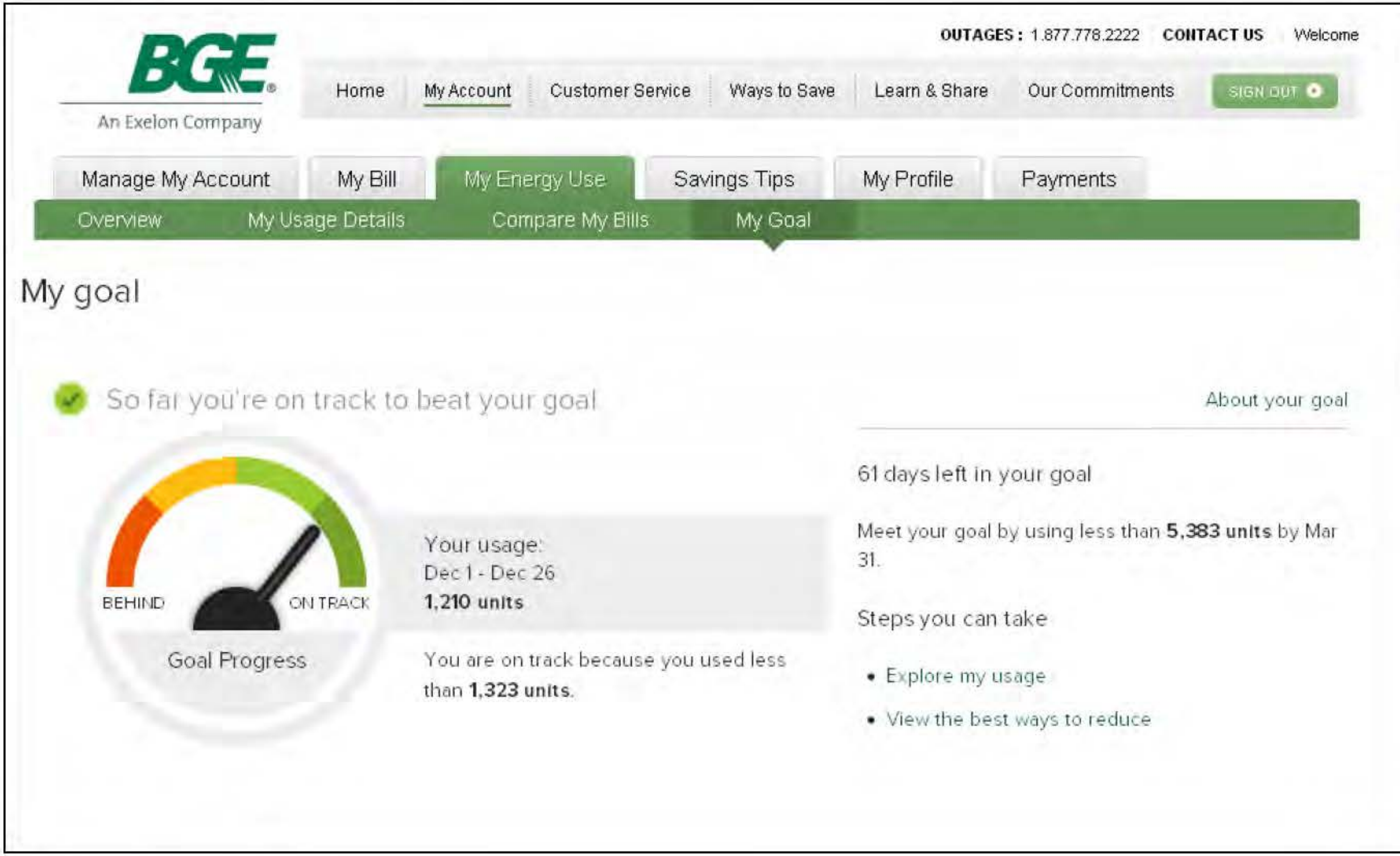
# SEM Customer Portal



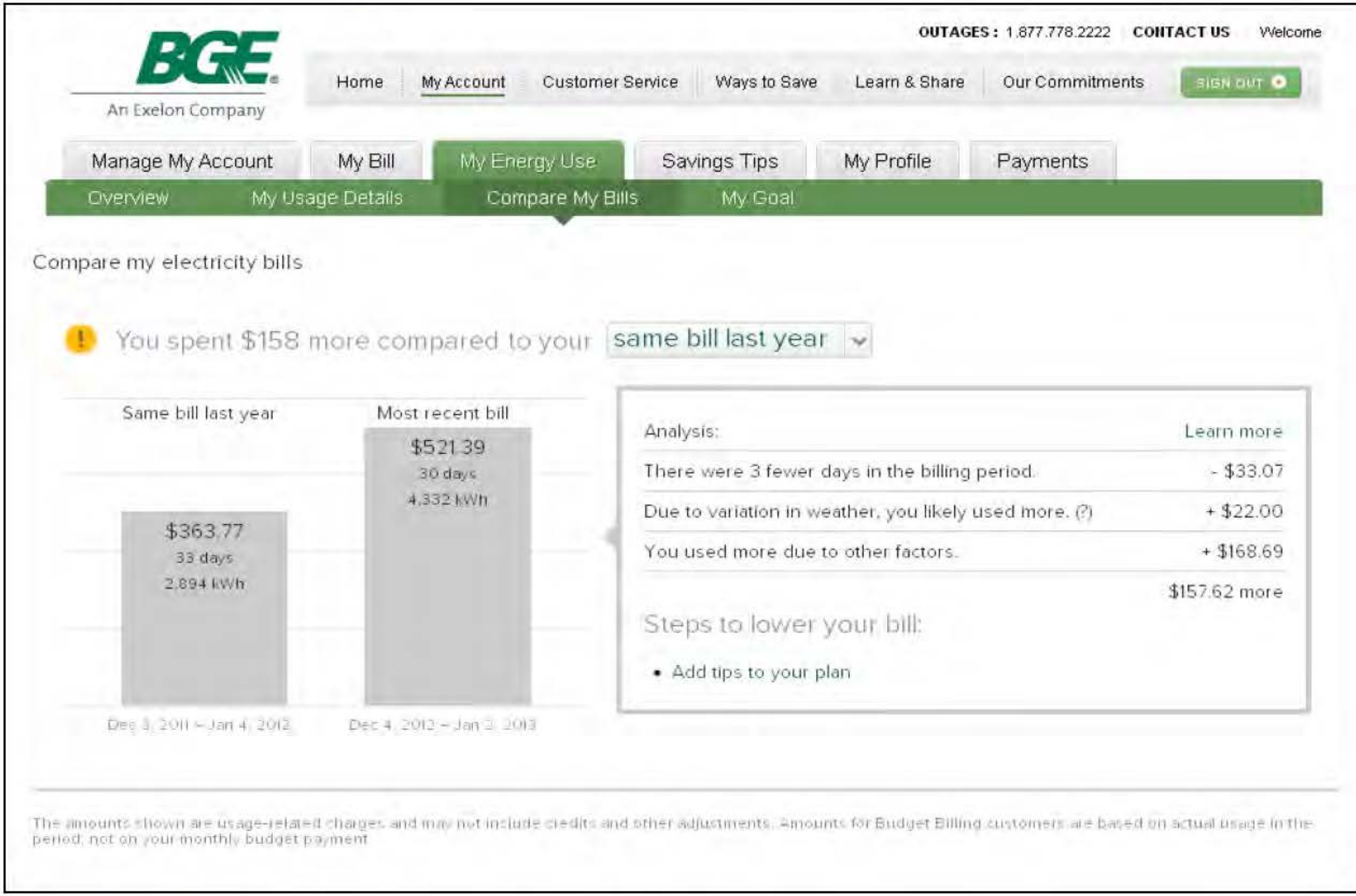
# SEM My Usage Details



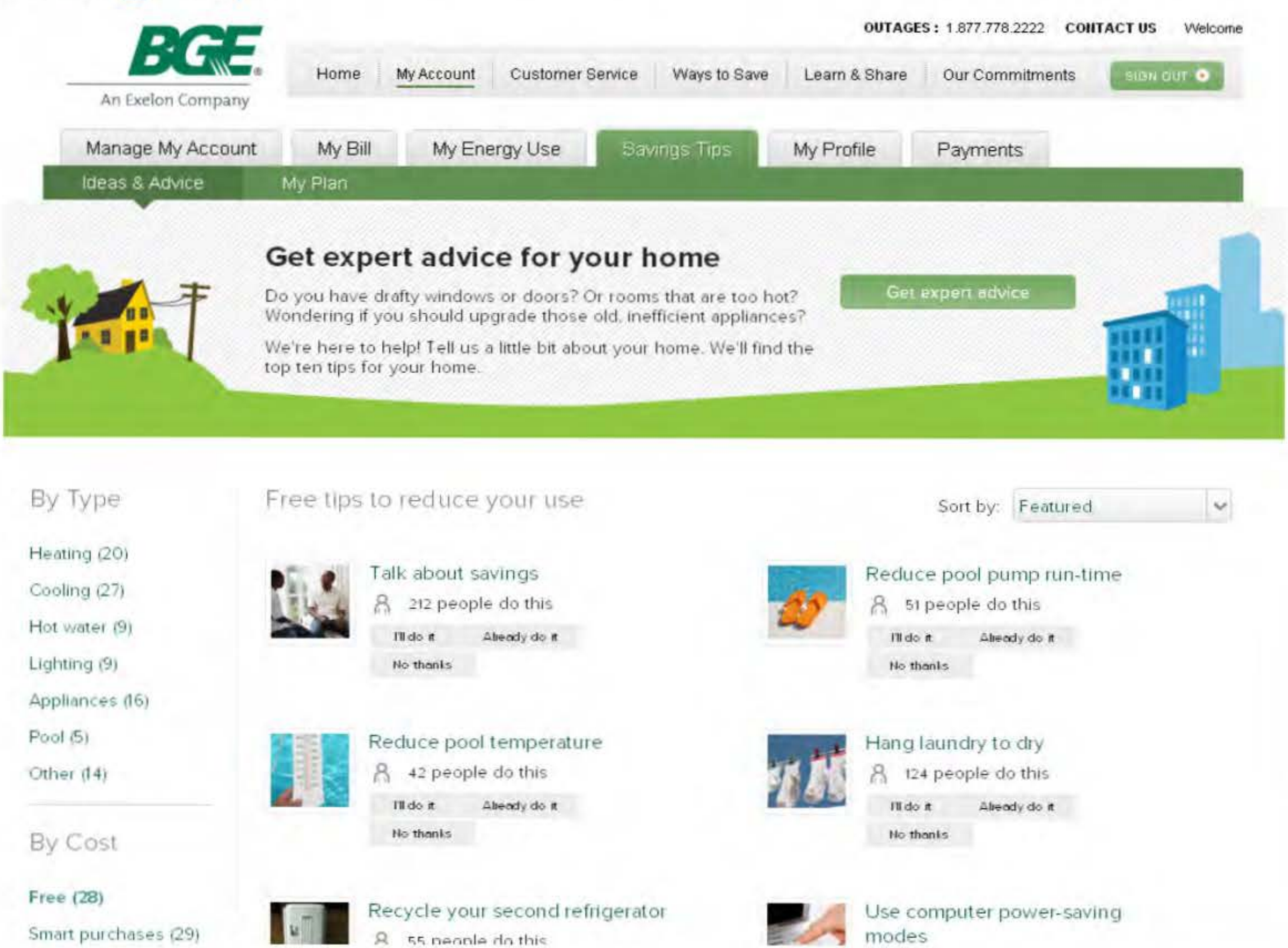
# SEM My Usage Details



# SEM Compare My Bill



# SEM Savings Tips



# Home Energy Report (Front)

**Home Energy Report**
Account number: [redacted]
Report period: 12/07/12–01/07/13

We are pleased to provide this personalized report to help you save energy. This report is made possible by your BGE smart meter.

The purpose of this report is to:
- **Provide information on your energy use**
- **Help you track your progress**
- **Share energy efficiency tips**

[redacted]

To learn more or to unsubscribe from Home Energy Reports, visit **BGE.com/SmartEnergyManager** or call 800.685.0123

## Last Month Household Comparison | You used **10% MORE** energy than efficient similar homes.


* This energy index combines electricity (kWh) and natural gas (therms) into a single measurement.

How you're doing:

**GOOD** ☺

**Similar Homes:** Approximately 100 occupied, nearby homes (avg 0.12 mi away) that have gas heat

**Efficient Similar Homes:** The most efficient 20 percent of similar homes

**Are we comparing you correctly?**
Tell us more about your home:
**BGE.com/SmartEnergyManager**

## An Average Day Last Month

**On average, you used the most from 4 pm – 12 am.**
Think about what uses electricity during this time.


Do you use more on weekdays or weekends? Find out at **BGE.com/SmartEnergyManager**

**Turn over** for savings →

# Home Energy Report (Back)

## Avoid surprises in your bill with email or text alerts

Get alerted if your energy use is unusually high and you're on track for a higher bill. Follow the tips provided to lower your use – and your bill. Now **that's** smart.

Sign up at **bge.com/SmartEnergyManager**

Action Steps | **Personalized tips chosen for your home**

### Quick Fix
Something you can do right now

☐ **Plan for a year of savings**
Start off the new year by talking with your household members, friends, and neighbors about saving energy. By committing to do a few key things, you can realize significant energy savings.

For example, agree to turn off lights in unoccupied rooms and use only the light you need. Devise a plan to run only full loads in your dishwasher, clothes washer, and dryer.

Finally, depending on the season, raise or lower your thermostat when you are away from home.

**SAVE UP TO $435 PER YEAR**

### Smart Purchase
Save a lot by spending a little

☐ **Install efficient showerheads**
Showering accounts for 40% of your hot water use, but you can cut costs without sacrificing comfort.

Install an efficient showerhead with a flow rate no greater than 2.5 gallons per minute to conserve hot water while maintaining water pressure.

When you schedule a Quick Home Energy Check-up, we'll install energy efficiency measures, including an efficient low-flow showerhead, at **no charge.** To schedule a Check-up, call **(877) 685-7377**.

**SAVE UP TO $125 PER YEAR**

### Great Investment
A big idea for big savings

☐ **Improve your home's insulation**
Over 45% of a home's heating and cooling can be lost through the walls, roof and floor.

If you improve your home's insulation in these areas, you can significantly reduce your heating and cooling bills and keep comfortable in all seasons.

With our Home Performance with ENERGY STAR® Program you could be eligible for rebates of **up to $2,000** for measures such as air sealing and insulation. For details, visit **BGESmartEnergy.com**.

**SAVE UP TO $335 PER YEAR**

## V. Community Organizations

## Appendix V: Community Organizations

### Outreach and Materials to Community, Advocacy and Social Services Organizations

BGE will make specific effort to reach out to community, advocacy and social services organizations in the region, particularly those at the local and county level, that serve and support vulnerable populations, to fully brief them on the smart grid implementation plan, gather input and recommendations on reaching their specific audiences/members/clients, ensure they are stocked with educational materials and utilize their own outreach and client education channels to the extent feasible. Newsletter and website content will be provided. In addition, we will look for opportunities to feature a smart grid display and/or educational materials table at their outreach and community fairs and client events. Outreach to limited-income households could be reinforced through kiosk messages at MTA transfer sites, in churches and at other venues. In addition, the unemployed and those applying for assistance can be reached via social services agency DVDs, print materials and other communications vehicles.

**Examples of organizations could include, but will not be limited to, the following:**

Interdenominational Ministerial Alliance
Greater Baltimore Board of Rabbis
Chesapeake Habitat for Humanity
CHAI Housing Assistance
United Seniors of MD
Esperanza Center
Answers for the Aging
Lighthouse Ministries
Bowie Senior Center
Anne Arundel Dept. of Social Services
Celebramos Communidad
Community Action Council
Jewish Community Services
Baltimore Urban League
National Federation of the Blind
The Salvation Army
MD Health & Human Services Department
Montgomery County Volunteer Center
BRAC communities in Maryland
Family & Children's Services of Central Maryland
Human Rights Campaign
Catholic Charities of Baltimore
Kennedy Krieger Institute
Spanish Speaking Community of Maryland
Horizon Foundation of Howard County Inc.
Y of Central Maryland
United Way of Central Maryland
Enoch Pratt Free Library
Goodwill Industries of the Chesapeake
Living Classrooms Foundation
Maryland Works Inc.
Meals on Wheels
Life Inc.
National Minority AIDS Council
Washington Office on Latin America (WOLA)
Rebuilding Together Baltimore
Association of Baltimore Area Grant Makers
Greater Baltimore Committee

### Environmental

- Greenfest 2011, Howard Community College, 2,000 attendees
- Baltimore Green Week/ EcoFest, an outdoor festival with music, yoga classes, bike rides and more than 100 vendors and exhibitors
- Maryland Green Show, an event with 125 exhibitors that includes participation by environmental nonprofit organizations, featured speakers, demonstrations and eco-friendly products for sale

**Fairs and Festivals**

- Harford County Farm Fair
- Carroll County 4-H Festival
- Howard County Fair
- Maryland State Fair
- Anne Arundel County Fair
- Maryland Seafood Festival
- Senior Expos
- Montgomery County Agricultural Fair

**Home Shows**

- Maryland Home and Garden Show
- Annapolis Home and Remodeling Expo
- Howard Live! Luxury Home Show
- The Mid-Maryland Home Show
- Montgomery County Housing Fair

**Cultural**

- Latino Fest, Baltimore County
- Maryland Irish Festival
- Baltimore Greek Festival

**Libraries**

- Anne Arundel County Public Library System
- Baltimore County Public Library System
- Calvert Library System
- Carroll County Public Library System
- Enoch Pratt Free Library System
- Harford County Library System
- Howard County Library System
- Montgomery County Public Libraries
- Prince George's County Memorial Library System

**Universities**

- Anne Arundel Community College
- Baltimore City Community College
- Baltimore International College
- Bowie State University
- Capitol College
- Carroll Community College

- College of Notre Dame of Maryland
- Community College of Baltimore County
- Essex, Catonsville, Dundalk Community Colleges
- Coppin State University
- Goucher College
- Harford Community College
- Howard Community College
- Johns Hopkins University
- Loyola University
- McDaniel College
- Montgomery College
- Morgan State University
- Ner Israel Rabbinical College
- Prince George's Community College
- St. John's College
- Sojourner-Douglass College
- Stevenson University
- Towson University
- UMBC
- United States Naval Academy
- University of Baltimore
- University of Maryland at Baltimore

**Museums**

- Reginald F. Lewis Museum of Maryland African American History and Culture Annapolis Maritime Museum
- Babe Ruth Museum
- Baltimore Museum of Art
- Baltimore Museum of Industry
- Baltimore & Ohio Railroad Museum
- Dundalk-Patapsco Neck Historical Society
- Fire Museum of Maryland
- Havre de Grace Decoy Museum
- Howard County Center for African American Culture
- Jewish Museum of Maryland
- Maryland Science Center
- National Great Blacks in Wax Museum
- National Historical Society of Maryland
- Port Discovery
- Radio and Television Museum
- The Visionary Arts Museum
- The Walters Art Gallery

**Additional Opportunities**

**Other locations and events** we will consider at the regional and community/neighborhood level include:

- Community centers, e.g., Jewish Community Center
- Senior centers
- Homeowners' associations
- YMCAs
- Information displays at county centers/offices
- Media milestone events at specific milestones in the implementation program
- First meter installation in customer home or community
- Kiosk or information booth in high-traffic shopping mall venues during busy shopping seasons (holidays, back to school, etc.)
- Meter installations in area notables' homes
- Media photo opportunities in schools
- Tie-ins with significant retail / public venue events
- Home improvement store events

## <u>Geographic-Specific Approach</u>

BGE will undertake a methodical outreach process synchronized with the implementation schedule and geography to ensure that community leaders are briefed, community services agencies are stocked, community organizations are engaged and customers are educated – all prior to installations beginning in each community. The following are examples **(not a full list)** of individuals and organizations that could be informed and engaged.

### Examples of Community Outreach/Briefing Targets

### <u>Anne Arundel County</u>

**Businesses**
Fort Meade Alliance, Annapolis and Anne Arundel Chamber of Commerce, BWI Corridor Chamber of Commerce, Anne Arundel Economic Development Corp., among others

**Public Officials**
Mayor, city council, state senators and delegates

**Environment**
Chesapeake Bay Foundation, Severn River Association, Severn River Land Trust, Oyster Recovery Partnership, among others

**Community and Neighborhood Associations**
Chesapeake Homeowners Network, Crofton First Neighborhood Association, Arnold Preservation Council, Hallmark Woods Property Owners Association, among others

**Population Segments Requiring Special Attention**
Anne Arundel County Department of Aging and Disabilities, United Seniors of Maryland, Meals on Wheels/Anne Arundel County, the Arc of Anne Arundel, Brooklyn Park Senior Activity Center, among others

**Faith-Based**
Leaders of churches, synagogues, mosques, including St. Mary's Church (Annapolis), St. Johns the Evangelist Church at Severn Run, Davidsonville United Methodist Church, Severna Park Evangelical Presbyterian, Holy Trinity Catholic Church of Glen Burnie, among others

**Non-English-Speaking Populations**
Maryland Hispanic Chamber of Commerce, Asian Pacific American Affairs, Northwest Chinese American Association, Katipunan Filipino American Association of Maryland, among others

**Baltimore City**

**Businesses**
Greater Baltimore Committee, Apartment Builders & Owners Council, Property Owners Association of Greater Baltimore, Baltimore City Chamber of Commerce, among others

**Public Officials**
Mayor, city council, state senators and delegates

**Environment**
Parks & People, Blue Waters Baltimore, Environmental Maryland, Watershed 246/Canton, among others

**Community and Neighborhood Associations**
South Baltimore Neighborhood Association, Broadway Area Business Association, Baltimoreans United in Leadership Development, GEDCO, Greater Homewood, Southeast Baltimore Development Corporation, Muslim Community Cultural Center of Baltimore, Baltimore Neighborhood Energy Challenge, among others

**Population Segments Requiring Special Attention**
Associated Jewish Charities of Baltimore, Our Daily Bread, Center for Urban Families, Family & Children Services, among others

**Faith-Based**
Awaken Baltimore, Baltimoreans United in Leadership Development (BUILD), leaders of churches, synagogues, mosques that include St. Matthews United Methodist Church, The Cathedral of Mary Our Queen, Bethel AME, ARIEL Jewish Russian Center and Synagogue

**Non-English-Speaking Populations**
Baltimore Hispanic Chamber of Commerce, Esperanza Center, Baltimore Asian Trade Council, Maryland Hispanic Chamber of Commerce, among others

## Baltimore County

**Businesses**
Baltimore County Chamber of Commerce, Dundalk Renaissance Corp., Pikesville Chamber of Commerce, Greater Towson Committee, among others

**Public Officials**
County executive, county council, state senators and delegates

**Environment**
Back River Restoration Committee, Jones Falls Watershed Association, Gunpowder Valley Conservancy, Habitat for Humanity of the Chesapeake, among others

**Community and Neighborhood Associations**
Perry Hall Improvement Association, North Point Peninsula Community Coordinating Council, Edmonson Heights Civic Association, Greater Arbutus Community Alliance, among others

**Faith-Based**
Leaders of churches, synagogues, mosques that include Beth El Congregation, New Shiloh Baptist Church, Grace Fellowship Church, Church of the Nativity, and a number of synagogues in the northwest section of the county

**Population Segments Requiring Special Attention**
Baltimore County Department of Aging, AtEaze Senior Center, Parkville Senior Center, Trinity House, among others

**Non-English-Speaking Populations**
Hispanic Business Association

## Calvert County

**Businesses**
Chesapeake Advanced Networking, Bay Business Group, Calvert County Chamber of Commerce, Solomon's Business Association, Calvert County Commission for Women, among others

**Public Officials**
County executive, county commissioners, state senators and delegates
**Environmental**
American Chestnut Land Trust, Patuxent Tidewater Land Trust, St. Mary's River Watershed Association, Friends of Myrtle Point Park, Isaak Walton League, Southern MD Chapter, among others

**Community and Neighborhood Associations**
Tri-County Council for Southern MD, Drum Point Homeowners Association, Calvert County Watermen's Association,  Beverly Beach Community Association, among others

**Population Segments Requiring Special Attention**

Concerned Black Men of Calvert County, Calvert County Office on Aging, Friends of Calvert County Seniors, End Hunger in Calvert County Inc., among others

**Faith-Based**
Leaders of churches and faith communities, including All Saints Parish, Christ Church, Chesapeake Church, First Baptist Church of Calvert County, among others

**Non-English-Speaking Populations**
St. John Vianney Family Life Center**,** Tri-County Community Action Committee**,** Calvert County Family Center

**<u>Carroll County</u>**
**Businesses**
Home Builders Association of Maryland/Carroll County, Carroll County Chamber of Commerce, Carroll County Department of Economic Development, Westminster Rotary Club, Kiwanis Club of Westminster, among others

**Public Officials**
County council, state senators and delegates mayors, and town councils

**Environment**
Beaver Run Fish and Game Club, Forest and Stream Club Inc., Piney Run Preservation Association, Friends of Hashawha and Bear Branch Council, among others

**Community and Neighborhood Associations**
Linton Springs Civic Association, Village of Tall Oaks Homeowners Association, Brandywine Station Homeowners Association, Irongate Community Association, among others

**Faith-Based**
Leaders of churches, synagogues, mosques, including St. John's Catholic Church, Calvary Bible Church, First Presbyterian Church of Westminster, LifePoint Church, among others

**Population Segments Requiring Special Attention**
The Salvation Army, Carroll County Bureau of Aging, Partnership for a Healthier Carroll County, The Shepherd's Staff, Community Foundation of Carroll County, among others

**Non-English-Speaking Populations**
Mission of Mercy, St. Johns Catholic Church (Spanish)

**<u>Harford County</u>**

**Businesses**
Harford County Chamber of Commerce, Harford Community College, Havre de Grace Chamber of Commerce, Maryland Small Business Development Center, among others

**Public Officials**
County executive, county council, state senators and delegates, mayors and town councils

**Environment**
Harford Bird Club, Deer Creek Watershed Association, Inc., Lower Susquehanna Heritage Greenway, Eden Mill Nature Committee, among others

**Community and Neighborhood Associations**
Community Foundation of Harford County, Glen Arm Community Association, White Marsh Civic Association, Bulle Rock Community Association, among others

**Faith-Based**
Leaders of churches, synagogues, mosques, including Edgewood Assembly of God, St. Margaret Catholic Church, Mountain Christian Church, First Baptist Church of Havre de Grace, among others

**Population Segments Requiring Special Attention**
Harford County Department of Aging, The Shelter Group, Harford County Department of Community Services, Disability Commission, Salvation Army, among others

**Non-English-Speaking Populations**
Hispanic Ministries for the Archdiocese of Baltimore

**Howard County**

**Businesses**
Howard Technology Council, Howard County Economic Development Authority, Howard County Chamber of Commerce, The Columbia Board, civic clubs such as Rotary Club of Elkridge, among others

**Public Officials**
County executive, county council, state senators and delegates

**Environment**
Center for Watershed Protection, Patapsco River keeper, Chesapeake Climate Action Network, Howard County Conservancy, among others

**Community and Neighborhood Associations**
Greater Elkridge Community Association, Ellicott City Residents Association, Columbia Association, Howard County Citizens Association, among others

**Faith-Based**
Leaders of churches, synagogues, mosques, including First Baptist Church of Guilford, Chinese Bible Church of Howard Co., Bridgeway Community Church, Korean Presbyterian Church, among others

**Population Segments Requiring Special Attention**
Howard County Office on Aging, The Arc of Howard County, Rebuilding Together of Howard County, Community Action Council, among others

**Non-English-Speaking Populations**
Korean American Community Association of Howard County, Conexciones, Korean American Grocers Association (KAGRO) of Maryland, Alianza de la Comunidad, among others

**Montgomery County**

**Businesses**
Montgomery Housing Partnership, Montgomery County Chamber of Commerce, Montgomery County Department of Economic Development, Montgomery County Business Roundtable for Education, Hispanic Chamber of Commerce of Montgomery County, Montgomery County Public Schools, among others

**Public Officials**
County executive, county council, state senators and delegates

**Environment**
Anacostia Watershed Society, Montgomery County Sierra Club, Potomac Conservancy, Greater Sandy Spring Green Space, Inc., Montgomery County Department of Environmental Protection, among others

**Community and Neighborhood Associations**
Association of Neighbors (Hispanic), Clarksburg Civic Association, Western Montgomery County Citizens Advisory Board, White Flint Park Citizens Association, Montgomery County Commission on Common Ownership Communities, among others

**Faith-Based**
Leaders of churches, synagogues, mosques (selected based on area served by BGE) including, Hindu Temple of Metropolitan Washington, From the Heart Church Ministries, The Sanctuary at Kingdom Square, Montgomery Korean Baptist Church, among others

**Population Segments Requiring Special Attention**
Montgomery County Office of Consumer Protection, Montgomery County Department of Housing and Community Affairs, Montgomery County Office on Aging, Montgomery County Commission for Women, Maryland Vietnamese Mutual Association, Eastern Montgomery Emergency Assistance, The Senior Connection of Montgomery County, Inc., among others

**Non-English-Speaking Populations**
Montgomery County Office of Community Partnerships Casa de Maryland, Asian American Health Initiative, Organization of Chinese Americans Greater Washington D.C. Chapter, Maryland Multicultural Youth Centers, among others

**Prince George's County**

**Businesses**
Bowie State University, Prince George's Chamber of Commerce, Baltimore Washington Corridor Chamber of Commerce, Greater Bowie Chamber of Commerce, among others

**Public Officials**

County executive, county council, state senators and delegates, mayors and town councils (selected based on area served by BGE), including, Mayor of Bowie G. Frederick Robinson, Bowie Mayor Pro Tem James Marcos, Delegate Ulysses Currie, Sen. Paul Pinsky, among others

**Environment**
Green Bowie, Citizens Concerned for a Cleaner County, Patuxent Riverkeeper, The Patuxent River Commission, among others

**Community and Neighborhood Associations**
Korean Community Service Center, Church Road Civic Association, Citizens Association of South Bowie, Columbia Park Civic Association, Gunpowder Citizens Association, among others

**Faith-Based**
Leaders of churches, synagogues, mosques (selected based on area served by BGE), including Bowie Unitarian Universalist, Fellowship First Baptist Church of Glenarden, Jericho City of Praise, Integrity Church International, among others

**Population Segments Requiring Special Attention**
Collington Episcopal Life Care Community, Prince George's County Administration on Aging, Bowie Senior Center, Big Brothers Big Sisters of the National Capital Area, among others

**Non-English-Speaking Populations**
Latino Health Initiatives, Korean American Association of Southern Maryland, Maryland Multicultural Youth Centers/Latin American Youth Center, Hispanic Latino Chamber of Commerce, among others

# VI. BGE Communications Plan Phase 3 Tactics

| Details on Campaign Tactics for Phase 3 Deployment | | | |
|---|---|---|---|
| **Tool** | **What** | **Why** | **When** |
| **Door hanger** | Door hanger version 2 after installation is completed | Inform customer about new meter and online smart energy manager tool | Spring/Summer 2012 – Spring/Summer 2013 |
| **Online Smart Energy Manager** | Online tool showing customer energy usage data; energy budget tracking capabilities | Allow customers to understand usage patterns and how to conserve energy to lower their bills | Beginning in Spring/Summer 2012 |
| **Home energy reports** | Printed reports mailed to customer homes that provide similar usage information and conservation tips as online energy manager tool | Allow customers to understand usage patterns and how to conserve energy to lower their bills | Beginning in 2012 |
| **BGE.com** | New sections on booking smart meter speakers, and new features for mobile phone users | Provide information on new BGE programs and offerings related to smart meters | Beginning Spring/Summer 2012 |
| **In-school educational module** | PowerPoint presentation, video and other instructional tools | Help students understand smart meter features so they can influence family conservation behaviors | 2012 – 2014 |
| **BGE Electric Vehicles** | Cars that run on electricity | Show connection between smart meters and electric vehicles | 2012 – 2014 |
| **Business/retail/employer materials** | Posters, pamphlets and worksite presentations | Continued customer education, field questions | 2012 – 2014 |

| | | | |
|---|---|---|---|
| **E-newsletter** | Customer updates via e-mail | Continued customer education, FAQs | 2012 – 2014 |
| **Smart meter introductory video** | Video | Provide overview of smart meter implementation, online smart energy manager and what customers can expect in the future | 2012 – 2014 |
| **Quick-take smart meter video vignettes** | Short Videos | Provide information on specific areas of customer interest, “cost,” “reliability” etc. | 2012 – 2014 |
| **E-Mail and SMS** | Customers can opt in to receive updates via email and text message | Provide details on smart meter tools; continue to address potential customer concerns about smart meters | 2012 – ongoing |

# VII.  BGE/Pepco Phase II A Metrics

**Kimberly A. Curry**
Assistant General Counsel

2 Center Plaza
110 W. Fayette Street
Baltimore, Maryland 21201
410.470.1305
443.213.3206 Fax
kimberly.a.curry@constellation.com

***Via Electronic Filing***

November 13, 2012

David J. Collins, Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 Saint Paul Street
Baltimore, Maryland 21202-6806

**Re: Case No. 9208: In the Matter of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Cost**

**Case No. 9207: In the Matter of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure**

**Advanced Metering Infrastructure Phase II A Performance Metrics Reporting Plan**

Dear Mr. Collins:

Pursuant to Order Nos. 83531 and 83571 in Case Nos. 9208 and 9207 respectively, Baltimore Gas and Electric Company (BGE) and Potomac Electric Power Company (Pepco) (Utilities) submit this Advanced Metering Infrastructure (AMI) Phase II A Performance Metrics Reporting Plan on behalf of the Working Group established by the Commission in those Orders. Ordering Paragraph 5 in Order Nos. 83531 and 83571 directed BGE and Pepco and the stakeholders in these cases to develop and submit for approval a comprehensive set of metrics to allow the Commission to assess the progress and performance of the two companies' Smart Grid Initiatives.

The Working Group met several times from January 2012 to August 2012 to discuss the development of Phase II metrics (the plan for Phase I was submitted to the Commission in May of 2011). The recent Working Group meetings were actively attended by the Staff of the Public Service Commission, BGE, Pepco, the Office of People's Counsel, the Maryland Energy Administration, Montgomery County Office of Consumer Protection, and AARP. After much discussion and input from the stakeholders, the Working Group was able to reach consensus on a set of metrics that are designed to collect data on a range of factors associated with Smart Grid deployment. As described in more detail in the Phase II A Plan appended hereto, these metrics/details are divided into four categories: (Communications & Education, Financial Cost/Benefits, Operational, and Dynamic Pricing Event Details).

Because some of the metrics discussed will be evident and measurable in the near-term, and some will not manifest themselves until future programs are developed in more detail and deployment is well underway, Phase II metrics have been divided into two phases (A and B). Phase II A metrics are designed to measure the realization of projected benefits associated with implementation of new AMI functionalities, such as continued implementation of operational efficiencies relating to remote connection and disconnection of meters and meter reading, customer service, customer interaction with web-based tools and the results of those interactions, as well as customer responses to and participation in dynamic pricing activities. Phase II B metrics are under further development by the Utilities and will be proposed at a later date after review and input with the Working Group. These Phase II B metrics will focus on capacity and energy benefits due to web-based energy management tools, dynamic pricing events, and conservation voltage reduction. Also, additional financial impacts may be included. The instant filing is comprised of Phase II A metrics. The Plan provides an introduction to the Phase II A metrics that were developed by the Working Group.

Due to differing business case assumptions and deployment schedules, certain metrics will not be applicable to both Utilities and certain metrics will be applicable during differing time periods for the Utilities. These differences are discussed in more detail in the attached Advanced Metering Infrastructure Performance Metrics Reporting Plan, and identified in the metrics spreadsheet appended as Attachment 1 to the Plan. The spreadsheet provided in Attachment 1 to the Plan contains a detailed listing of the AMI Phase II A Metrics including: definitions, calculations, initial reporting period, and frequency of reporting for each Phase II A Metric.

The Working Group respectfully requests Commission approval for these consensus documents.

Respectfully submitted,

*/s/ Kimberly A. Curry*

Kimberly A. Curry

KAC:jdb

Attachments

# Advanced Metering Infrastructure Performance Metrics Reporting Plan Phase II A

*Submitted by:*

**Potomac Electric Power Company**
**Baltimore Gas and Electric**

BGE

pepco

# Table of Contents

Acronyms

| Acronym | Definition |
|---|---|
| AMI | Advanced Metering Infrastructure |
| BGE | Baltimore Gas and Electric Company |
| CVR | Conservation Voltage Reduction |
| DOE | The Department of Energy |
| DP | Dynamic Pricing - Peak-Time Rebates |
| HTA | Hard to Access |
| kW | Kilowatt |
| kWh | Kilowatt-hour |
| LMP | Locational Marginal Price |
| MD | Maryland |
| MEA | Maryland Energy Administration |
| MW | Megawatt |
| MWh | Megawatt-hour |
| O&M | Operations and Maintenance |
| OCP | Montgomery County Office of Consumer Protection |
| OER | Office of External Relations |
| OPC | Maryland Office of People's Counsel |
| Pepco | Potomac Electric Power Company |
| PHI | Pepco Holdings Inc. |
| PJM | Regional Transmission Operator |
| PLC | Peak Load Contribution |
| R | Residential Rate – Non Time-of-Use |
| RL | Residential Rate – Time-of-Use |
| RPM | Reliability Pricing Model |
| SEM | Smart Energy Manager |
| SMS | Text Message |
| SOS | Standard Offer Service |
| UCAP | Unforced Capacity |
| VRR | Variable Resource Requirement |

## II. Introduction

This is the second installment of the Advanced Metering Infrastructure (AMI) Performance Metrics Report regarding the AMI deployments of BGE and Pepco (Utilities) in Maryland. The Utilities submitted the first AMI Performance Metrics Reporting Plan on May 18, 2011, in which they documented and defined the Phase I Deployment metrics developed and agreed upon by the Working Group, which consists of Commission Staff, representatives of the Maryland Office of People's Counsel (OPC), Maryland Energy Administration (MEA), Montgomery Office of Consumer Protection (OCP), AARP, Pepco and BGE. The Commission approved the Phase I Metrics Plan in a letter dated August 17, 2011. In general, the Phase II metrics will measure the realization of projected benefits associated with implementation of new AMI functionalities such as, continued implementation of operational efficiencies relating to remote connection and disconnection of meters and meter reading, outage management, customer service, customer interaction with web-based tools and the results of those interactions, as well as customer responses to and participation in dynamic pricing activities. The Working Group consensus on tracking and reporting these metrics does not imply agreement on how these metrics will be used by the various Parties to examine the cost effectiveness or success of AMI or Dynamic Pricing Programs.

It should be noted that throughout this document and attached spreadsheets, "dynamic pricing" specifically refers to Peak Time Rebate (PTR) Programs that the Commission has approved[1]. Peak Time Rebate Programs allow customers to receive a bill credit for each kWh that they reduce below their baseline usage during the event hours, but their underlying rate structure does not change.

[1] Order No. 83571 in Case No. 9207 and Order No. 83531 in Case No. 9208.

The Working Group categorized the Phase II metrics into two sections: Phase II A and Phase II B. Phase II A metrics reflect metrics that the Utilities and the Working Group have agreed are measurable at this time and for which reporting requirements can be proposed. These specific metrics will be described in more detail in this report. Phase II B metrics require further development of measurable outcomes and are under development by the Utilities and will be proposed at a later date after review and input with the Working Group. These Phase II B metrics are intended to focus on capacity and energy benefits due to web-based energy management tools, conservation voltage reduction, outage management impacts, and additional financial impacts associated with the smart metering system and the associated Dynamic Pricing Programs.

Specifically, the Phase II A metrics being proposed in this filing will reflect the implementation of programs and functionalities after the installation and activation of the new smart meters and associated communications network. While the Utilities intend to use the Phase II A metrics to evaluate the projected benefits of AMI meters and Dynamic Pricing Program, some of the metrics in Phase II A are descriptive or qualitative in nature and are not measured against specific targets. The insights provided by such metrics are intended to help the Utilities better understand customer trends and behaviors and may be used by the Utilities to tailor communications and operational strategies.

It should also be noted that the Phase II A metrics were developed without consideration of the potential for a customer to opt-out of smart meter use or installation. The Commission issued an interim order allowing for the opt-out option, but has not yet resolved whether a permanent program should be implemented or the details of such a program.[2] The Utilities will track those opt-out requests that are received from customers during this interim policy. However, these metrics do not address any changes

[2] Order No. 84926 in Case Nos. 9207 and 9208 issued on May 25, 2012.

that may be necessary pending the resolution of the opt-out policy. If or when the Commission adopts a formal opt-out policy, additional metrics may be developed.

Certain metrics in Phase II A are denoted with a **. These metrics were not proposed in the Utilities' original business cases to justify the costs and benefits of smart meter deployment; however, the Working Group has agreed that it is appropriate to report them at this time.

## III. Phase II A Metrics

The Working Group has identified objectives and projected benefits for the AMI and Dynamic Pricing Programs. Phase II A will track impacts and results of the Customer Education Plan, customer interaction and engagement with energy management tools, dynamic pricing event statistics, and data related to remote operations. The metrics spreadsheet is provided as Attachment 1. Since Pepco has proposed to implement dynamic pricing for small business customers, as well as residential customers, and BGE's Dynamic Pricing Programs are limited to residential customers at this time, Pepco will provide a breakdown of residential vs. small business for any metrics that apply.

Phase II A metrics are categorized into four sections:

- Communications and Education
- Financial Cost/Benefits
- Operational
- Dynamic Pricing Event Details

Each of these four sections of Phase II A metrics is covered in more detail below, with brief descriptions of what the metrics intend to evaluate.

## 1. Communications and Education

The communications and education metrics provide a basis for analysis of the effectiveness of Customer Education Programs and an assessment of the degree of customer awareness of and participation in dynamic pricing events and the use of energy management tools.

The communications and education metrics are broken into three metric categories:

- Disputes/Inquiries
- Customer Engagement
- Dynamic Pricing Engagement

Each is covered in more detail below, with specific individual metrics included in each of the three categories.

### a. Disputes/Inquiries

Disputes refer specifically to customer disputes handled by the Office of External Relations (OER) within the Commission. The measurement will be the count of these disputes filed with the Public Service Commission relating to smart meters and/or dynamic pricing that are referred to and categorized by the Utilities. The Utilities will provide qualitative comments to describe the disputes.

Inquiries refer to calls made directly to the Utilities seeking information, seeking assistance, or providing feedback on the Utilities' dynamic pricing offerings. The Utilities will monitor and track the types of inquiries by category to provide more granularity as the Dynamic Pricing Programs move forward.

### b. Customer Engagement

Customer engagement metrics capture statistics related to interaction with web-based energy management tools[3] and other educational materials. The Utilities have developed enhanced web-based information to reflect the more detailed customer usage data from the smart meters, including graphs of the customers' interval data, hourly and daily, as well as a bill-to-date summary, which provides a projection of the customers' monthly bill based on existing usage patterns. Comments and qualitative discussion will provide insights on customer trends and address apparent data anomalies. For instance, the average time spent on the web portal may initially be higher but taper off as customers learn to effectively navigate the portal. Or the opposite may be true and customers may spend less time on the web portal initially and then begin spending more time on the web portal as they learn to use the data to conserve energy. Periodic surveys and focus groups will be conducted in Phase II B to help the Utilities better understand customer behaviors.

### c. Dynamic Pricing Engagement

Dynamic pricing engagement metrics will measure how customers react during peak events, the number of rebates and the rebate amount customers received after each peak event. These statistics will provide the Utilities valuable insight into customer behavior and participation levels. Furthermore, these metrics will be crucial to the determination of the value of these programs in the wholesale markets. Dynamic pricing engagement metrics are the quarterly or annual totals for dynamic pricing events. The Utilities will report event details in a separate spreadsheet. Section 4 of this report provides more details on this separate spreadsheet.

[3] It should be noted that the measurement of the customer electricity and gas (BGE only) usage impacts associated with using the web-based programs will be proposed in Phase II B metrics.

## 2. Financial Cost/Benefits

Financial Cost/Benefits Metrics in Phase II A will measure direct O&M savings and avoided O&M costs, monetized value of PJM energy resources, and certain avoided infrastructure costs due to dynamic pricing events.

Phase II A Financial Cost/Benefits metrics are broken into two metric categories:

- Dynamic Pricing Benefits
- O&M Savings

### a. Dynamic Pricing Benefits

Dynamic pricing benefits, noted here, include wholesale market revenues and avoided distribution and transmission infrastructure costs associated with reductions in consumers' demand for electricity during dynamic pricing events. The wholesale energy market revenues are derived from energy reductions dispatched by PJM in the PJM energy market during dynamic pricing events. With regard to the methodology to capture avoided transmission and distribution costs associated with demand reduction during dynamic pricing events, the Utilities have agreed to use the methodology developed by BGE. The Utilities have different calculations for determining asset value based on company accounting and availability of replacement cost data. This methodology is intended to capture the avoided cost of transmission and distribution infrastructure due to reductions in energy use during dynamic pricing events. BGE's Smart Energy Savers Program®, which includes programs in support of EmPOWER Maryland, part of which is focused on achieving peak demand reductions, much like the Smart Grid Dynamic Pricing Program, through the direct control of air conditioning and water heater loads. The program is called PeakRewards℠. The avoided T&D cost methodology developed by BGE for these Phase II A metrics has been employed in its PeakRewards℠ Program. The avoided cost methodology was used in BGE's original PeakRewards$^{SM}$ business case filing (October 2007) at the Commission, and in subsequent EmPOWER MD updates to the business case. The Commission did recognize and relied upon BGE's avoided T&D cost methodology as part of their November 2007 approval of the PeakRewards$^{SM}$ Program. A detailed methodology is provided in Attachment 2 to this report.

### b. O&M Savings

Pepco will capture the savings associated with remote connect/disconnect operations for non-payment. Currently, Pepco sends out a technician to disconnect for non-payment and reconnection following credit-related disconnections. After AMI is installed and activated, Pepco will send out an employee with a different classification to inform the customer of the disconnect and, if the customer is still going to be disconnected after the employee visit, call office personnel to perform the activity remotely. Pepco will reconnect remotely when the customer's account is current or the cause of the disconnection has been satisfied. BGE will propose metrics to reflect these operational impacts in Phase II B.

## 3. Operational

The operational metrics in Phase II A will count the number of remote connects and disconnects enabled by the activation of AMI meters for such events that are not related to credit-related disconnections and reconnections. Pepco currently does not disconnect or reconnect for move-in/move-out; so while the remote operations can be counted, there is no quantifiable change from current practices. BGE currently sends a technician for many move-in/move-out jobs so the installation and activation of AMI meters will have a quantifiable impact on the number of truck rolls for remote operations. Both Utilities will also report a count of instances where a meter was remotely disconnected for non-payment after a premise visit as per the current regulations and the Commission's order[4].

## 4. Dynamic Pricing Event Details

In addition to the quarterly and annual dynamic pricing engagement metrics, the Utilities will provide dynamic pricing event details in a separate spreadsheet along with third-quarter metrics reports on November 15th of each year after they first become available. The dynamic pricing event details spreadsheet is provided as Attachment 3. These additional statistics will include:

- Number of events – Date and Day of week
- Start time and End Time
- Emergency and Non-Emergency
- Duration of event
- Number of customers eligible, contacted and participated
- Average participant credit and reported in dollars at the 25%, 50% and 75% quartiles
- Participant reduction in Load (kW, highest hourly)
- Participant reduction in Energy (kWh, sum for event hours)

The Working Group will discuss the potential for reporting additional details about demographic and usage profiles of those customers that earned a credit in Phase II B.

[4] Order No. 83571 in Case No. 9207 and Order No. 83531 in Case No. 9208.

Attachment 1

# Phase II A Metrics

| New # | Balance Scorecard Section | Metric Category | Key Metric | Definition | Calculation - BGE | Calculation - Pepco | Metric Available BGE | Metric Available Pepco | PSC Frequency |
|---|---|---|---|---|---|---|---|---|---|
| 35 | Communications & Education | Disputes/Inquiries | Count of OER disputes filed with the Public Service Commission and referred to the Utilities and categorized by the utilities as relating to Smart Meters and/or Dynamic Pricing. | Count of OER disputes filed with the Public Service Commission, referred to the Utilities, and categorized by the Utilities as relating to Smart Meters and/or Dynamic Pricing. Comments field will be used to discuss types of complaints. | Count of OER disputes filed with the Public Service Commission, referred to the Utilities, and categorized by the Utilities as relating to Smart Meters and/or Dynamic Pricing. | Count of OER disputes filed with the Public Service Commission, referred to the Utilities, and categorized by the Utilities as relating to Smart Meters and/or Dynamic Pricing from residential and small business customers.++ | Q4 2012 | Q4 2012 | Quarterly |
| 36 | Communications & Education | Disputes/Inquiries | Number of customer/account inquiries regarding Smart Meters. | Number of customer/account inquiries regarding Smart Meters. (These inquiries are incoming calls to the companies.) | Count of customer/account inquiries regarding Smart Meters. (Count of inquiries will be reported in three categories: Smart Meter Calls, Smart Energy Manager Tools Calls and Smart Energy Rewards Calls) | Count of residential and small business customers/account inquiries regarding Smart Meters. (Count of inquiries will be reported in three categories: Smart Meter Calls, My Account Calls, and Dynamic Pricing Calls). | Q4 2012 | Q4 2012 | Quarterly |
| 37 | Communications & Education | Customer Engagement | Number of customers who have accessed the web-based energy management tool. | Number of customers who have accessed the web-based energy management tool. | Sum of new and returning visitors ("unique visitors") to the web based energy management tool. Note: A new and returning visitor or "unique visitor" is a specific c ient who has accessed a website one or more times during the reporting period. BGE will segment counts by AMI and non-AMI until AMI is fully deployed. | Sum of new and returning residential and small business visitors ("unique visitors") to the web-based energy management tool. Note: A new and returning visitor or "unique visitor" is a specific client who has accessed a website one or more times during the reporting period. | Q4 2012 | Q4 2012 | Quarterly |
| 38 | Communications & Education | Customer Engagement | Number of accounts that have enrolled in the web-based energy management tool. | Number of accounts that have enrolled in the web-based energy management tool. | Number of unique accounts that enrolled in the web based energy management tool. Note: BGE will segment counts by AMI and non-AMI unt l AMI is fully deployed. | Number of unique residential and small business customers that enrolled in the web-based energy management tool. | Q4 2012 | Q4 2012 | Quarterly |
| 39 | Communications & Education | Customer Engagement | Number of accounts that were sent a Usage Report. | Number of accounts that were sent a Usage Report derived by the utilities' web-based energy management tools and/or as requested by the customer. | Number of accounts that were sent a Usage / Energy Report. Note: Detail on Paper vs. Electronic Reports will be provided. Summary reports will be disaggregated and examined in greater detail as part of the communications plan. For BGE this is specifica ly the number of customers who received a home energy report, unusual usage alert, or any other type of future push communication that contains customer specific data and analytics generated from the energy management tools. | Number of residential and small business accounts that were sent a Usage Report. Note: Detail on Paper vs. Electronic Reports will be provided. Summary Reports will be disaggregated and examined in greater deta l as part of the communications plan. PEPCO wi l provide at the customer's request, a copy of their energy usage data as displayed in PEPCO's energy management tool (My Account). | Q4 2012 | Q3 2013 | Quarterly |
| 40 | Communications & Education | Customer Engagement | Average time spent on the web-based management tool per customer. | Average time spent on the web-based management tool per customer. Note: Distribution can be provided as needed or annually. Customer count for this average will come from key metric titled "Number of accounts that have enrolled in the web based energy management tool." | Average duration of visits to the web based energy management tool. Note: BGE will report counts by AMI and non-AMI until AMI is fully deployed. | Average duration of visits to the web-based energy management tool. Note: At time of initial report, PEPCO will have AMI fully deployed. | Q4 2012 | Q4 2012 | Quarterly |
| 41 | Communications & Education | Customer Engagement | Number of web-based management tool logins. | Number of logins to web-based management tool. Note: Distribution can be provided as needed or annually. | Count of total logins to the web based energy management tool. Note: BGE will segment login counts by AMI and non-AMI unt l AMI is fully deployed. | Count of total logins to the web-based energy management tool. | Q4 2012 | Q4 2012 | Quarterly |
| 42 | Communications & Education | Dynamic Pricing Engagement | Number of accounts sent Dynamic Pricing Alert Notifications. | Number of accounts that were sent a Dynamic Pricing Alert per event for all events. | Number of accounts that were sent a Dynamic Pricing Alert per event for all events. | Number of residential and small business accounts that were sent a Dynamic Pricing Alert per event for all events. | Q3 2013 | Q3 2013 | Quarterly |
| 43 | Communications & Education | Dynamic Pricing Engagement | Number of customers eligible for a Dynamic Pricing Rebate. | Number of customers eligible for a Dynamic Pricing Rebate. | Count of residential accounts on the RL (Residential Time-of-Use) or R (Residential Non-Time-of-Use) rate schedules who are eligible for Dynamic Pricing. Does not include any accounts signed up for third party curtailment that is successfully bid into the PJM market. Note: To the extent that the uti ities receive the information from PJM, as to which customers are signed up with 3rd party CSPs, and registered with PJM for DR, that information can be provided. | Count of residential and small business customers who are eligible for Dynamic Pricing. Does not include any customers signed up for third-party curtailment that is successfully bid into the PJM market. Note: To the extent that the utilities receive the information from PJM, as to which customers are signed up with 3rd party CSPs, and registered with PJM for DR, that information can be provided. | Q3 2013 | Q3 2013 | Quarterly |
| 44 | Communications & Education | Dynamic Pricing Engagement | Number of Dynamic Pricing Events. | Number of Dynamic Pricing Events. | Count of Dynamic Pricing Events where customers are notified either a day ahead or same day in the case of an emergency. Note: See additional Event Report for details on type of event declared | Count of Dynamic Pricing Events where customers are notified either a day ahead or same day in the case of an emergency. Note: See additional Event Report for details on type of event declared | Q3 2013 | Q3 2013 | Quarterly |
| 45 | Communications & Education | Dynamic Pricing Engagement | Number of Customers who Received a Dynamic Pricing Rebate. | Number of Customers who Received a Dynamic Pricing Rebate. | Number of unique accounts that received at least one utility paid Dynamic Pricing Rebate. (Report with Details by event will be provided separately in the fall including kWh, rebate amount in dollars, duration, number of customers who earned a rebate, and the 25%, 50% and 75% quartile for rebate amount). | Number of unique residential and small business customers who received at least one utility paid Dynamic Pricing Rebate. (Report with Details by event will be provided separately in the fall including kWh, rebate amount in dollars, duration, number of customers who earned a rebate, and the 25%, 50% and 75% quartile for rebate amount). | Q3 2013 | Q3 2013 | Quarterly |
| 46 | Communications & Education | Dynamic Pricing Engagement | Average utility paid customer rebate. | Average utility paid customer rebate amount in dollars. | Total dollars of Dynamic Pricing Rebates paid out / Number of accounts that received at least one utility paid Dynamic Pricing Rebate. | Total dollars of Dynamic Pricing Rebates paid out to residential and small business customers / Number of residential and small business customers that received at least one utility paid Dynamic Pricing Rebate. | Q3 2013 | Q3 2013 | Quarterly |
| 47 | Communications & Education | Dynamic Pricing Engagement | Average utility paid demand Reduction during Dynamic Pricing Events. | Average utility paid demand Reduction during Dynamic Pricing Events (kW) as compared to the baseline used in rebate calculations. | Total kWh saved / Number of Dynamic Pricing Event Hours / Number of Accounts that received at least one utility paid Dynamic Pricing Rebate. | Total kWh saved / Number of Dynamic Pricing Event Hours / Number of residential and small business customers that received at least one utility paid Dynamic Pricing Rebate. | Q3 2013 | Q3 2013 | Annually |
| 48 | Communications & Education | Dynamic Pricing Engagement | Average utility paid energy Reduction during Dynamic Pricing Events. | Average utility paid Energy Reduction during Dynamic Pricing Events (kWh) as compared to the baseline used in rebate calculations. | Total kWh saved during all Dynamic Pricing Event hours / number of accounts that received at least one utility paid Dynamic Pricing Rebate. | Total kWh saved during all Dynamic Pricing Event hours / number of residential and small business customers that received at least one utility paid Dynamic Pricing Rebate. | Q3 2013 | Q3 2013 | Annually |
| 49 | Financial Cost/Benefits | Dynamic Pricing Benefits | Wholesale Energy Revenues. | Monetized value in PJM of dynamic pricing energy resources (realized as dynamic pricing resource is called). Note: This metric is calculated on a per event basis. | Actual PJM Energy Revenues (Revenues are derived from energy offered into the PJM markets during a Dynamic Pricing Event and are settled monthly). | Actual PJM Energy Revenues (Revenues are derived from energy offered into the PJM markets during a Dynamic Pricing Event and are settled monthly). | Q3 2013 | Q3 2013 | Annually |

| New # | Balance Scorecard Section | Metric Category | Key Metric | Definition | Calculation - BGE | Calculation - Pepco | Metric Available BGE | Metric Available Pepco | PSC Frequency |
|---|---|---|---|---|---|---|---|---|---|
| 50 | Financial Cost/Benefits | Dynamic Pricing Benefits | Avoided transmission infrastructure due to a reduced peak load via Dynamic Pricing Events. | Dollar Value of Avoided Transmission Infrastructure due to Dynamic Pricing Events. | Dollars per kW avoided cost of Transmission * system peak load reductions due to Dynamic Pricing Events. Note: Details on calculation methodology are included in separate excel document. | Dollars per kW avoided cost of Transmission * system peak load reductions due to Dynamic Pricing Events Note: Details on calculation methodology are included in separate excel document. ** | Q1 2014 | Q1 2014 | Annually |
| 51 | Financial Cost/Benefits | Dynamic Pricing Benefits | Avoided distribution infrastructure due to a reduced peak load via Dynamic Pricing Events. | Dollar Value of Avoided Distribution Infrastructure due to Dynamic Pricing Events. | Dollars per kW avoided cost of Distribution * system peak load reductions due to Dynamic Pricing Events Note: Details on calculation methodology are included in separate excel document. | Dollars per kW avoided cost of Distribution * system peak load reductions due to Dynamic Pricing Events. Note: Details on calculation methodology are included in separate excel document. ** | Q1 2014 | Q1 2014 | Annually |
| 52 | Financial Cost/Benefits | O&M Savings (direct savings & avoided costs). Pepco only in Phase II A. BGE will report this metric in Phase II B. | O&M Cost savings due to Remote Connect / Disconnect Operations. | O&M Savings as a result of Remote Connect / Disconnect Operations. | Moved to Phase II B for BGE. | For non-payment only:<br>Disconnect: (2009-2011 average cost of disconnect operations - inflation adjusted) - (Reduced cost for lower classification personnel conduction field visit)<br>Re-Connect: (2009-2011 average cost of connect operations - inflation adjusted) - (Like Cost in current Period) | n/a | Q2 2013 | Quarterly |
| 53 | Operational | Remote Meter Operations | Number of remote electric meter connect operations. | Number of remote electric meter connect operations. | Count of instances where a meter was connected remotely. | Count of instances where a small business or residential meter was connected remotely. | Q1 2014 | Q2 2013 | Quarterly |
| 54 | Operational | Remote Meter Operations | Number of remote electric meter disconnect operations (Total). | Number of remote electric meter disconnect operations (Total). | Count of instances where a meter was disconnected remotely (Total). | Count of instances where a meter was disconnected remotely for residential and small business customers (Total). | Q1 2014 | Q2 2013 | Quarterly |
| 55 | Operational | Remote Meter Operations | Number of remote electric meter disconnect operations (For Non-Payment). | Number of remote electric meter disconnect operations (For Non-Payment). | Count of instances where a meter was disconnected remotely (For Non-Payment).<br>Note: BGE and Pepco w ll be complying with the Maryland Public Service Commission's order to disconnect for non-payment only after a premise visit. | Count of instances where a meter was disconnected remotely (For Non-Payment). Note: BGE and Pepco w ll be complying with the Maryland Public Service Commission's order to disconnect for non-payment only after a premise visit. | Q1 2014 | Q2 2013 | Quarterly |
| | Phase II A | | | | | | | | |
| | | | | | | | | | |
| | ** | Financial Metrics Not in Accepted Business Case | | | | | | | |
| | ++ | Residential phase-in will begin in the summer of 2012 with 5,000 customers. | | | | | | | |

Attachment 2

**Avoided T&D Cost Metrics (Phase II A Metrics)**

**Avoided Transmission Cost**

| | | |
|---|---|---|
| Replacement Cost of Import Capability, 2009 M$ (1) | $ 1,336 | (update to relevant year) |
| Import Capability, MW (2009) | 5,400 | (update to relevant year) |
| Asset Life Discount Factor (2) | 1.816 | |
| Value of Reduced Need for Import Capability, 2009 $/kW | $ 136.32 | |
| Inflation | 2.50% | (use Handy Witman Index most applicable to T&D infrastructure) |
| Weighted Average Cost of Capital | 8.06% | (update WACC to most recent rate case) |

| | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| System Peak Load Reduction, MW (example) (3) | 75 | 175 | 375 | 600 | 600 |
| Growth of System Peak Load Reduction, MW | 75 | 100 | 200 | 225 | - |
| Value of Reduced Need for Import Capability, $/kW | $ 150.47 | $ 154.23 | $ 158.09 | $ 162.04 | $ 166.09 |
| Avoided Transmission Cost, M$ | 11.3 | 15.4 | 31.6 | 36.5 | - |
| Discount Factor (2013 PV) | 1.0000 | 0.9254 | 0.8564 | 0.7925 | 0.7334 |
| Avoided Transmission Cost, PV M$ | 11.3 | 14.3 | 27.1 | 28.9 | - |

**Note (1)**
Transmission assets contributing to import capability include the 500kV and 230 kV system, including:
500 and 230 kV Transmission Lines and Substations
**Note (2)**
Asset Life Discount Factor takes into account the difference in the asset lifes of transmission (45 years) and Smart Grid (10 years).
**Note (3)**
System peak load reduction includes reductions from Dynamic Pricing events. (Note that avoided T&D costs caused by peak load reductions from

Energy Management Tools and Conservation Voltage Reduction were moved to Phase II B metrics.)

**Avoided Distribution Cost**

| | | |
|---|---|---|
| Replacement Cost of Distribution Substations, 2009 M$ (1) | $ 1,138 | (update to relevant year) |
| Unrestricted System Peak Load (Forecast), MW (2009) | 7,345 | (update to relevant year) |
| Asset Life Discount Factor (2) | 1.816 | |
| Functionality Discount Factor (3) | 1.500 | |
| Value of Reduced Need for Distr Substations, 2009 $/kW | $ 56.90 | |
| Inflation | 2.50% | (use Handy Witman Index most applicable to T&D infrastructure) |
| Weighted Average Cost of Capital | 8.06% | (update WACC to most recent rate case) |

| | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| System Peak Load Reduction, MW (example) (4) | 75 | 175 | 375 | 600 | 600 |
| Growth of System Peak Load Reduction, MW | 75 | 100 | 200 | 225 | - |
| Value of Reduced Need for Distribution Infrastructure, $/kW | $ 62.80 | $ 64.37 | $ 65.98 | $ 67.63 | $ 69.32 |
| Avoided Distribution Cost, M$ | 4.7 | 6.4 | 13.2 | 15.2 | - |
| Discount Factor (2013 PV) | 1.0000 | 0.9254 | 0.8564 | 0.7925 | 0.7334 |
| Avoided Distibution Cost, PV M$ | 4.7 | 6.0 | 11.3 | 12.1 | - |

**Note (1)**
Distribution Substations includes all distribution station equipment.
**Note (2)**
Asset Life Discount Factor takes into account the difference in the asset lifes of distribution (45 years) and Smart Grid (10 years).
**Note (3)**
Functionality Discount Factor takes into account that the system peak load reductions cannot be localized to isolate relieve for specific distribution equipment.
**Note (4)**
System peak load reduction includes reductions from Dynamic Pricing events. (Note that avoided T&D costs caused by peak load reductions from Energy Management Tools and Conservation Voltage Reduction were moved to Phase II B metrics.)

| | |
|---|---|
| Discount Rate: | 8.06% |
| 10-Year Asset | |
| Asset Life Discount Factor: | **1.8156** |
| (Resulting transmisson cost discount factor) | |

10-Year T-stat

| Year | Cost | Discount Factor | Present Value |
|---|---|---|---|
| 1 | 1 | 100% | 1 |
| 2 | | 93% | 0 |
| 3 | | 86% | 0 |
| 4 | | 79% | 0 |
| 5 | | 73% | 0 |
| 6 | | 68% | 0 |
| 7 | | 63% | 0 |
| 8 | | 58% | 0 |
| 9 | | 54% | 0 |
| 10 | | 50% | 0 |
| 11 | 1 | 46% | 0.460628036 |
| 12 | | 43% | 0 |
| 13 | | 39% | 0 |
| 14 | | 37% | 0 |
| 15 | | 34% | 0 |
| 16 | | 31% | 0 |
| 17 | | 29% | 0 |
| 18 | | 27% | 0 |
| 19 | | 25% | 0 |
| 20 | | 23% | 0 |
| 21 | 1 | 21% | 0.212178188 |
| 22 | | 20% | 0 |
| 23 | | 18% | 0 |
| 24 | | 17% | 0 |
| 25 | | 16% | 0 |
| 26 | | 14% | 0 |
| 27 | | 13% | 0 |
| 28 | | 12% | 0 |
| 29 | | 11% | 0 |
| 30 | | 11% | 0 |
| 31 | 1 | 10% | 0.097735222 |
| 32 | | 9% | 0 |
| 33 | | 8% | 0 |
| 34 | | 8% | 0 |
| 35 | | 7% | 0 |
| 36 | | 7% | 0 |
| 37 | | 6% | 0 |
| 38 | | 6% | 0 |
| 39 | | 5% | 0 |
| 40 | | 5% | 0 |
| 41 | 1 | 5% | 0.045019583 |
| 42 | | 4% | 0 |
| 43 | | 4% | 0 |
| 44 | | 4% | 0 |
| 45 | | 3% | 0 |

Attachment 3

| | Event Time | | | | Number of Residential Customers | | | | Participant Credit Percentiles ($) | | | Participant Reduction | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Date of Event | Start | End | Duration | Emergency (Y/N) | Eligible | Contacted | Participated | Average Participant Credit | 25% | 50% | 75% | Load (kW) (Highest Hourly) | Energy (kWh) (Sum for Event Hours) |
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## VIII. Letter to Customers on Meter Deferral Option
## (Carried and Hand Delivered by Meter Installers)

BGE
An Exelon Company

Dear BGE Customer,

We understand that you are requesting not to have a smart meter installed.

On Jan. 7, 2013, the Maryland Public Service Commission (PSC) issued an order that Maryland utilities should provide customers with an additional option related to the installation of smart meters in their homes. The PSC will conduct additional proceedings to determine whether the preferred course is to allow customers the option of retaining their current meter or to require all customers to receive a smart meter with the option to have that meter installed to operate in an "RF-free" or near RF-free manner. The PSC will require that customers who select the ultimately approved option pay the related costs.

As the PSC continues proceedings to determine opt-out specifics, BGE customers who wish to defer meter installation can continue to do so by contacting BGE via email or letter. Customers who have already requested a meter deferral do not have to take further action at this time. BGE will communicate any next steps when the PSC makes a final determination.

BGE customers who wish to defer installation, or customer requesting removal of meters already installed, should provide the following information via letter or email:

Name(s)
Address
Account Number
Phone Number
Email Address

Email deferral requests to smartmeterdeferral@bge.com.

Letters should be sent to:

Smart Meter Deferral
BGE
P.O. Box 1475
Baltimore, MD 21203

For more information on the PSC's proceedings on the opt out issue, visit the PSC website at www.psc.state.md.us and access Order No. 85294, and case No. 9208.

Customers can also visit bge.com/smartgrid for more information on BGE's smart meter installation plan and answers to common customer questions.

Sincerely,

Michael Butts,
Director, Smart Grid

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 12
Page 1 of 1

Please clarify if it is Mr. Alvarez's position that a PTR should be part of the default rate/services for Duke Energy Kentucky's residential customers or all customers (residential and non-residential)?

(a) If Mr. Alverez's [sic] opinion is that the PTR should just be an element of the default rate for residential customers only, has Mr. Alvarez performed any analysis or study to determine what the impacts of such a default rate design would be upon the Company's cost of service to its residential customers who would also pay for such a credit though rates?

(1) If the answer is in the affirmative, please provide such analysis.

(b) Has Mr. Alverez [sic] performed any analysis of how a default PTR rate design for residential customers would impact any of the Company's other customer classes?

(c) If Mr. Alverez's [sic] opinion is that the PTR should be an element of the default rate for all customer classes, has Mr. Alvarez performed any analysis or study to determine what the impacts of such a default rate design would be to the customer rates that would also pay for such a credit?

RESPONSE:

It is Mr. Alvarez's position that a PTR program should be made available to all customers with smart meters, including both residential and non-residential customers.

(a) Not applicable.

(b) Mr. Alvarez challenges the implication that a default PTR rate design for residential customers would necessarily impact any of the Company's other customer classes. Such an implication is based on future circumstances and actions not in evidence, and cannot be assumed or implied. However, Mr. Alvarez has not performed any analysis of how a default PTR rate design for residential customers could or might impact any of the Company's other customer classes.

(c) See response to subpart (b), above.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 13
Page 1 of 1

Please refer to Page 7 of Mr. Alvarez's testimony recommending the PTR be added as a routine permanent component of Duke's standard residential rate. Is Mr. Alvarez advocating that the Kentucky Public Service Commission (KYPSC) do that in this case?

(a) If the response is in the affirmative, is Mr. Alvarez aware of the settlement signed by the Kentucky Attorney General and approved by the Commission in Case No. 2016-00152 whereby the parties agreed to establish a *voluntary* PTR Pilot to last two years. (Emphasis added).

RESPONSE:

No.

(a) Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 14
Page 1 of 1

Please refer to page 8 of Mr. Alvarez's testimony where he mentions the Maryland Peak Time Rebate program. Is Mr. Alvarez aware of any other jurisdictions that have approved a default, mandatory, or otherwise non-voluntary peak time rebate rate design for utility residential customers?

(a) If the response is in the affirmative, please provide all such jurisdictions, utilities names, dates of such regulatory order(s), case numbers where such designs were approved/ordered, and a copy of such an order.

RESPONSE:

Mr. Alvarez is not aware of any jurisdiction besides Maryland that have approved a default peak-time rebate rate design. However, he notes that the Massachusetts, California, and Colorado commissions have issued orders which are closely related to default peak-time rebate. See the attached copies of those documents.

The Massachusetts DPU adopted a policy position regarding time-varying rates in its Order in 14-04-C dated November 5, 2014. This order established a policy that all regulated electric utilities offer time-varying rates as the default rate for basic service, though the order provided no deadline for doing so. The Order also established a policy that customers be provided an alternative to time-varying rates, and prescribed that option as a traditional flat rate with a peak time rebate component. This Order is attached [Attachment DEK 14-1].

The California PUC mandated default time-of-use rates for residential customers of Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric by 2019 in R.12-06-013, Decision and Order D.15-07-001 dated July 3, 2015 [Attachment DEK 14-2].

The Colorado PUC approved a settlement agreement mandating default time-of-use rates for residential customers of Public Service Company as part of the utility's smart meter deployment proposal. See the attached settlement agreement dated May 8, 2017 [Attachment DEK 14-3], which was approved by the Colorado PUC in an Order dated June 21, 2017 in Case No. 16A-0588E.

# The Commonwealth of Massachusetts

## DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 14-04-C November 5, 2014

Investigation by the Department of Public Utilities upon its own Motion into Time Varying Rates.

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ORDER ADOPTING POLICY FRAMEWORK FOR TIME VARYING RATES

## I. INTRODUCTION AND PROCEDURAL BACKGROUND

On June 12, 2014, with the issuance of our Order in Modernization of the Electric Grid, D.P.U. 12-76-B (June 12, 2014), the Department of Public Utilities ("Department") set forth a vision for and a path towards a modern electric system in Massachusetts, one that will be cleaner, more efficient and reliable, and will empower customers to manage and reduce their energy costs. D.P.U. 12-76-B at 1. This vision includes the use of time varying electric rates that will provide an incentive for customers to reduce peak energy use in response to price signals and reduce their own electricity bills and the costs of the entire electricity system. See D.P.U. 12-76-B at 11.

On June 12, 2014, the Department issued an Order setting forth its anticipated policy framework for the implementation of time varying rates for basic service customers. See Investigation by the Department of Public Utilities upon its own Motion into Time Varying Rates, D.P.U. 14-04-B (June 12, 2014) ("Interim Order"). As part of the Interim Order, the Department solicited comments from interested persons on the anticipated policy framework. Interim Order at 3, 19. On July 3, 2014, the Department received comments from the Cape Light Compact ("CLC");[1] the Department of Energy Resources ("DOER"); Environment Northeast ("ENE"); ISO New England, Inc. ("ISO-NE"); Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"); the New

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1 The Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, Yarmouth, and the Counties of Barnstable and Dukes, acting together as the Cape Light Compact.

England Clean Energy Council ("NECEC"); NSTAR Electric Company ("NSTAR Electric") and Western Massachusetts Electric Company (collectively, "Northeast Utilities"); the Retail Energy Supply Association ("RESA"); and 47 Coffin Street Ratepayer Advocates ("47 Coffin Street"). On that same date, the Department received joint comments from the Attorney General of the Commonwealth of Massachusetts ("Attorney General"), the Associated Industries of Massachusetts ("AIM"), the Low Income Network ("LEAN"), and the National Consumer Law Center ("NCLC"); and separate joint comments from the Low Income Weatherization and Fuel Assistance Program Network ("Network") and NCLC. The Department appreciates the thoughtful discussion of the wide range of issues presented by stakeholders in response to our Interim Order.

In today's Order, the Department sets forth its final policy framework for the implementation of time varying rates for basic service. After careful consideration of the issues raised by the stakeholders, we conclude that it is appropriate to adopt the basic service time varying rates framework set forth in the Interim Order without modification. Thus, following the deployment of advanced metering functionality, electric distribution companies will offer to basic service customers: (1) a default time of use ("TOU") rate with a critical peak price ("CPP") component; and (2) an option to opt out of the default rate and choose a flat rate[2] with a peak time rebate ("PTR") component. In the sections below, we discuss

[2] The terms "flat," "fixed," and "uniform" are often used interchangeably to describe electricity rates that do not change over a given time period. For the purpose of this Order, the Department uses the term "flat" rate.

several issues related to the framework for time varying rates and the implementation of time varying rates following the deployment of advanced metering functionality.

For most basic service customers, the implementation of time varying rates is several years away. However, today's Order will provide important direction to electric distribution companies as they prepare their grid modernization plans. In addition, our Order will alert competitive suppliers, manufacturers, and others that individual customers, assisted by new technologies (e.g., advanced meters, in-home displays, programmable thermostats, load control devices), will be empowered to respond to the actual varying costs of electricity and save money by altering usage based on price signals that reflect these actual costs. Thus, our Order will provide an opportunity for competitive suppliers to develop a variety of time varying rate products and for manufacturers to develop new technologies to help customers to manage their electricity costs. Finally, the policy framework we adopt today will benefit all customers by reducing peak energy and capacity market costs; increasing system efficiencies and support the distribution system by reducing peak demand; and providing appropriate incentives for distributed resources such as solar photovoltaic generation, electricity storage, and electric vehicles, as well as targeted energy efficiency and demand response. Interim Order at 1; Investigation by the Department of Public Utilities upon its own motion into Time Varying Rates, D.P.U. 14-04, at 1 (January 23, 2014).

## II. TIME VARYING RATES FRAMEWORK

### A. Introduction

The Department received a number of comments expressing general support for the policy framework set forth in the Interim Order (see, e.g., DOER Comments at 1; ENE Comments at 1-3; ISO-NE Comments at 2-3; National Grid Comments at 1, 3; NECEC Comments at 3; 47 Coffin Street Comments at 2). Commenters assert that in addition to other benefits time varying rates for basic service customers will (1) lower wholesale power costs; (2) provide customers with important information about the costs of their electricity usage, which, in conjunction with new technologies, products, and services will enable customers to reduce their energy costs; and (3) lead to increased system efficiencies (see ENE Comments at 1, 5; ISO-NE Comments at 2-3; NECEC Comments at 3; 47 Coffin Street Comments at 2).

The Department also received comments raising concerns about the policy framework set forth in the Interim Order related to: (1) cost, benefit, and market considerations; (2) the impact of time varying rates on low income customers; and (3) the impact of time varying rates on the competitive market (see generally Attorney General/AIM/LEAN/NCLC Comments; Network Comments; Northeast Utilities Comments). Further, some commenters suggest modifications or alternatives to the framework to address specific concerns with the basic service options described in the Interim Order (see, e.g., Attorney General/AIM/LEAN/NCLC Comments at 13; ENE Comments at 3; ISO-NE Comments at 3-5; NECEC Comments at 3-4; Network Comments at 4-5; Northeast Utilities Comments at 1-2, 23-35; 47 Coffin Street

Comments at 4-5). In addition, a number of commenters raise issues they argue are important for successful implementation of time varying rates, including customer engagement and education, rate design concerns, and administrative changes (see, e.g., CLC Comments at 8-10; ENE Comments at 4; ISO-NE Comments at 4-5; National Grid Comments at 4-5; NECEC Comments at 4-5; Northeast Utilities Comments at 21-23; RESA Comments at 14-17; 47 Coffin Street Comments at 7). Finally, certain commenters argue that the Department should address the treatment of customers who opt out of advanced metering functionality (Attorney General/AIM/LEAN/NCLC Comments at 14). Each of these issues is discussed below.

B. Cost, Benefits, and Market Considerations

1. Summary of Comments

Some commenters question the potential costs and benefits (in the form of savings to customers and the system) associated with the Department's framework for time varying rates. These commenters argue that the Department's decision to implement time varying rates as the default option for basic service: (1) may lead to higher costs for customers as a result of the mandatory deployment of advanced metering infrastructure; (2) will preclude the adoption of less costly, shorter term programs that would advance grid modernization objectives; and (3) fails to recognize pilot results that suggest that customers will not respond favorably to time varying rates and not experience sufficient savings (see Attorney General/AIM/LEAN/NCLC Comments at 5-13; Northeast Utilities Comments at 2-8, 13-18). These commenters also suggest that in order to fully explore these and other related issues, the Department should reserve all decisions on the framework for time varying rates until the electric distribution companies complete relevant pilot programs and file their grid modernization plan business case analyses (see Attorney General/AIM/LEAN/NCLC Comments at 4-5; CLC Comments at 3, 7-8; National Grid Comments at 3; Network/NCLC Comments at 3-4; Northeast Utilities Comments at 3-7).

In addition, one commenter argues that our framework for time varying rates will not result in savings for customers or reduce the need for new generation, transmission, and distribution investments, because its load analysis and pilot results suggest that customers are unlikely to shift energy usage significantly in response to price signals, and that any initial price responsiveness is likely to dissipate over time (Northeast Utilities Comments at 10-11, 13-18). That same commenter argues that our framework has the potential to lead to higher basic service costs and additional cross subsidization among customer classes because our framework does not accurately account for the structure of the wholesale electric market and the way basic service is procured (Northeast Utilities Comments at 9-13).

### 2. Analysis and Conclusions

In D.P.U. 12-76-B at 3, 17, the Department required electric distribution companies to achieve advanced metering functionality for all customers. The Department will review the cost of the technology to enable this functionality as part of the companies' grid modernization plans. See D.P.U. 12-76-B at 17-18. Among other things, advanced metering functionality will enable implementation of time varying rates for basic service and unlock the corresponding benefits that such a rate structure provides. As several commenters recognize, time varying rates will increase system efficiencies, provide incentives for peak load reduction, and promote the deployment of distributed energy resources (see, e.g., DOER Comments at 1; ENE Comments at 1, 5; National Grid Comments at 2; NECEC Comments at 3). In addition, time varying rates can help to lower retail energy costs (see DOER Comments at 1; ISO-NE Comments at 2-3). This result is particularly important at a time when energy market prices are on an upward trajectory.[3]

The framework we adopt here does not eliminate the potential for the development of other technologies and programs aimed at reducing peak load, as suggested by some commenters. To the contrary, nothing in this Order precludes companies from proposing load control mechanisms, smart thermostats and appliances,[4] and other innovative technologies and programs in conjunction with the implementation of time varying rates as part of their grid modernization plans. See Interim Order at 6; D.P.U. 12-76-B at 11.

Further, the Department is not persuaded that we should reserve all decisions on the framework for time varying rates until more pilot studies are completed or the business case analyses are filed. The adoption of a policy framework for time varying rates will inform the electric distribution companies' business case analyses and allow them to file more meaningful grid modernization plans. Moreover, as discussed below, with the time varying rates pilots and rollouts in other jurisdictions, as well as the pilots in the Commonwealth, there is

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3 See 2013 Assessment of the ISO New England Electricity Markets, Potomac Economics at 155-160 (June 2014), available at: http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf.

4 Smart thermostats and appliances automatically adjust to save customers money when electricity prices are high.

sufficient information available to support the adoption of the particular time varying rates framework described herein. The Department remains confident that the adoption of time varying rates will benefit customers. See Interim Order at 4-7.

In addition, the Department disagrees with the notion that there will not be enough customer load response to time varying rates to create sufficient savings to customers (see Attorney General/AIM/LEAN/NCLC Comments at 7-9; Northeast Utilities Comments at 13-16). Rather, we continue to expect that customers will respond favorably to a pricing structure that allows them to maximize the value and minimize the cost of their electric service. See Interim Order at 5. Our conclusion is supported by the results of dynamic pricing pilots and deployments, both in Massachusetts[5] and elsewhere, which indicate that customers in aggregate will respond to price signals in a manner that will lower system peak demand and, ultimately, limit the need for future generation, transmission, and distribution investments.

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5 With respect to the Massachusetts pilots, we note Northeast Utilities' argument that the results of NSTAR Electric's smart grid pilot indicate weak aggregate positive customer load response to time varying rates (see Northeast Utilities Comments at 14-16, citing NSTAR Electric Company, D.P.U. 09-33, NSTAR Smart Grid Pilot Final Technical Report at 13, 33, 36-37, 68 (June 30, 2014) ("NSTAR Electric Pilot Report")). We do not, however, view Northeast Utilities' argument as entirely accurate because the pilot results showed a moderately strong response to CPP events. See NSTAR Electric Pilot Report at 18-22. Moreover, shortfalls in customer interest and performance in that pilot appear, at least in part, to be related to the specific technology's performance, which NSTAR Electric tested as an alternative to advanced metering infrastructure ("AMI") technology and customer communication factors. See NSTAR Electric Pilot Report at 37-43, 46-48, and 58-65. Finally, Fitchburg Gas and Electric Light Company, d/b/a Unitil's pilot, though small, showed a strong positive customer load response. See Fitchburg Gas and Electric Light Company, d/b/a Unitil, D.P.U. 09-31, Unitil Energy Savings Management Pilot Evaluation Report at 23-34 (January 2012).

For example, a pilot conducted by Connecticut Light & Power ("CL&P") that included a TOU, CPP, and PTR design similar to the framework adopted here yielded significant load impacts and high satisfaction rates among participants.[6] Results from a pilot conducted by the Sacramento Municipal Utility District ("SMUD") showed significant overall system benefits from a default time varying rates approach with sustained benefits over multiple years.[7] Further, a study conducted on behalf of Oklahoma Gas & Electric ("OG&E") to assess the effectiveness of its time varying rates pilot program identified sustained benefits associated with this rate structure.[8] And in Massachusetts, evaluation reports from smart grid pilots sponsored by NSTAR Electric and Fitchburg Gas and Electric Light Company, d/b/a Unitil

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6 See Brattle Group, Impact Evaluation of CL&P's Plan-it Wise Energy Program: Final Results at 16 (November 2, 2009), available at: http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/PlanItWiseAppendix/$File/Plan-it%20Wise%20Pilot%20Results%20Appendix.pdf (residential customer peak load impacts varied from 1.6 to 23.3 percent and small C&I customer peak load impacts varied from 1.7 to 7.2 percent, depending on rate type and enabling technology); Northeast Utilities, Smart Grid & Dynamic Pricing at Northeast Utilities at 12 (2010), available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/clg/mtrls/2010/may62010/cserna_revised.pdf (overall customer satisfaction for residential customers reported at 5.1 out of 6.0 on its satisfaction scale and 4.1 out of 6.0 for C&I customers; 92 percent of residential and 74 percent of business customers report that they would participate in its pilot again).

7 See Nexant, SMUD SmartPricing Options Pilot Evaluation at 4, 75, 83 (August 6, 2014), available at: https://smartgrid.gov/sites/default/files/doc/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf.

8 See Global Energy Partners, OG&E Smart Study Together Impact Results: Auxiliary Final Report – Summer 2011 at 5-78 to 5-79 (April 23, 2012) ("OG&E Study") (enabling technologies such as smart thermostats, in-home display devices, and direct load control increase demand reductions provided by time variant pricing), available at: https://smartgrid.gov/sites/default/files/doc/files/Chapter_4_Load_Impact_Results_2011.pdf.

provide evidence of customer load response to TOU/CPP price signals. See NSTAR Electric Company, D.P.U. 09-33, NSTAR Smart Grid Pilot Final Technical Report at 13-27 (June 30, 2014) ("NSTAR Electric Pilot Report"); Fitchburg Gas and Electric Light Company, d/b/a Unitil, D.P.U. 09-31, Unitil Energy Savings Management Pilot Evaluation Report at 23-34 (January 2012). We cite these only as examples of many time varying rates pilots showing positive results.[9]

The Department acknowledges that the evidence of customer response to dynamic pricing cited above reflects the specific circumstances of each study and cannot provide an exact estimate of the extent of customer load response that we can expect from implementation of the Department's policy framework for time varying rates in Massachusetts. Nonetheless, in total, the results of these pilots provide persuasive evidence that customers will respond to time varying rates and that individual customer savings will materialize.

Finally, we disagree that our time varying rates framework does not accurately account for the structure of the wholesale electric market and the way basic service is procured (see Northeast Utilities Comments at 9-13). As discussed in Section II.F, below, the implementation of time varying rates will require an evaluation of the procurement process for basic service to determine whether any changes are necessary. Ultimately, we expect that our

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[9] See Faruqui, Ahmad and Jennifer Palmer: "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity," at 7-12, available at: http://www.hks.harvard.edu/hepg/Papers/2012/The%20Arc%20of%20Price%20Responsiveness%20(03-18-12).pdf.

framework will allow basic service suppliers to reduce their risk (i.e., exposure to wholesale market price volatility) by better matching basic service prices with the time varying nature of the wholesale market. The reduced risk premiums for basic service supply also should contribute to lower retail customer prices.

### C. Impact of Time Varying Rates on Low Income Customers

#### 1. Summary of Comments

Certain commenters contend that low income customers will not benefit from time varying rates because these customers: (1) will be unable to shift their electricity use to avoid higher prices during peak usage periods and experience savings (Network/NCLC Comments at 2-4; (2) cannot afford to take advantage of technologies that enable customers to benefit from time varying rates, such as distributed energy resources, electric vehicles, and smart appliances (Northeast Utilities Comments at 19); and (3) will be harmed by the potential increase in basic service prices and the investment costs associated with implementing time varying rates (Northeast Utilities Comments at 19-20).

#### 2. Analysis and Conclusions

The Department acknowledges the importance of the concerns raised by commenters regarding the impact of time varying rates on low income customers. In fact, part of the reason that the Department is adopting the time varying rates framework discussed herein is because the current flat rate basic service offering is relatively burdensome to many customers who can least afford it. See Interim Order at 11. The Department fully expects that a large portion of low income customers in the Commonwealth will benefit from the time varying rates framework we adopt here. See Interim Order at 11 & n.11.

Regarding low income customers' ability to take advantage of technologies, the Department acknowledges that certain enabling technologies, such as electric vehicles, may be cost prohibitive for some consumers. We expect, however, that other innovations such as smart appliances will become more affordable over time as they become ubiquitous. Further, the results of the NSTAR Electric Pilot Report, as well as studies in other jurisdictions, demonstrate that low income customers do have the ability to adjust energy demand in response to price signals in order to save money. [10]

Certain commenters take issue with the Department's conclusion in the Interim Order that low income customers respond to price signals (see Network/NCLC Comments at 1-3, citing Interim Order at 11 n.11; Northeast Utilities Comments at 18-19, citing Interim Order at 11). These commenters suggest that the Department delay the approval of our framework until relevant Massachusetts pilots can be further evaluated to measure the impact on low income customers of time varying rates (Network/NCLC Comments at 3-4; Northeast Utilities

[10] See, e.g., NSTAR Electric Pilot Report at B-4 (results indicate pricing response and demand reductions during peak and CPP periods for low income participants as defined by rate classification); SMUD SmartPricing Report at 36-37 (results indicate pricing response and load impacts for customers who qualify for rate assistance as statistically similar to those who do not qualify); Impact Evaluation of the California Statewide Pricing Pilot, Charles River Associates (March 2005), at 74-77, available at https://www.smartgrid.gov/document/impact_evaluation_california_statewide_pricing_pilot. See also, Spotlight on Low Income Consumers Final Report, Smart Grid Consumer Collaborative (September 2012), at 6-7, available at http://smartgridcc.org/wp-content/uploads/2013/02/SGCC-LI-Spotlight_2.13.pdf.

Comments at 20). We recognize that the number of low income customers who will respond to time varying rates and experience savings will depend on a variety of factors such as income level, usage habits, household demographics, and specific utility rates. We find, however, that there is sufficient information (see n.10, above) about the impact of time varying rates on low income customers to support our conclusion that these customers are likely to benefit from such a rate structure. Although we will not delay adoption of our framework, when we design the actual rates the Department will explore what other mechanisms may be appropriate beyond those tools already available (e.g., low income discount rate) to insulate low income customers from bill volatility.

Moreover, under the Department's time varying rates framework all customers will have the ability to opt out of the default rate offering and switch to a flat rate with a PTR component. This alternative should accommodate customers who conclude that they are unable to benefit under the TOU/CPP default product. See Interim Order at 11.

## D. Impact of Time Varying Rates on the Competitive Market

### 1. Summary of Comments

Some commenters express concern about the impact of time varying rates for basic service on the competitive market (CLC Comments at 2; RESA Comments at 4). In particular, these commenters suggest that the current design of basic service provides a competitive advantage to distribution companies and that such advantage will be exacerbated by a basic service time varying rate offering (CLC Comments at 2-3; RESA Comments at 4). To address this concern, commenters argue that: (1) basic service should be a single product (i.e., a simple TOU rate) (RESA Comments at 4, 6); and (2) the Department should provide competitive suppliers an exclusive period of one to three years to offer time varying rates to customers ahead of any rollout of basic service time varying rates (CLC Comments at 3-4).

Further, these commenters argue that access to customer usage data is essential for competitive suppliers to develop time varying rates offerings (CLC Comments at 4-6; RESA Comments at 7-14). In this regard, the commenters assert that the Department should require electric distribution companies to adopt an electronic data interchange policy that allows competitive suppliers real time access to data in a standardized format across all distribution companies (CLC Comments at 4-5; RESA Comments at 7, 10-11).

2. Analysis and Conclusions

The framework adopted in this Order includes only two basic service time varying rate options, in part to ensure that competitive suppliers have sufficient room to develop their own innovative rate offerings.[11] See Interim Order at 15. We are confident that the policy framework we adopt today will not harm the development of the competitive market and, instead, is likely to provide benefits.[12] See Interim Order at 14-15. In addition, it is our hope that this clear articulation of the Department's policy objectives with respect to time varying

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11 One commenter suggests that basic service should be only one option -- a simple time of use rate (RESA Comments at 4, 6). The Department, however, has determined that it is appropriate for one of the two basic service options to contain a flat rate, as it is consistent with the requirements of G.L. c. 164, § 1B(d). See Interim Order at 10 n.9.

12 As we noted in our Interim Order at 14-15, the deployment of basic service time varying rates will require significant efforts by electric distribution companies and others to educate ratepayers, and the Department expects that such marketing and education efforts also will benefit competitive suppliers.

rates, well in advance of changes to basic service, will help competitive suppliers make important business decisions regarding their participation in the market in Massachusetts.

We will not delay implementation of time varying rates for basic service to provide competitive suppliers with a "head start." Given that statewide implementation of basic service time varying rates will occur only after the deployment of advanced metering functionality, competitive suppliers have ample opportunity to engage the public, and design and market alternative time varying rates offerings.

Finally, the Department agrees that access to standardized data is important for competitive suppliers in their development of time varying rates products. In the Department's grid modernization docket, we directed the electric distribution companies to identify procedures that will allow competitive suppliers access to certain customer usage data without compromising customer confidentiality. See D.P.U. 12-76-B at 34-36. The electric distribution companies are required to submit these procedures as part of their grid modernization plans. D.P.U. 12-76-B at 36. As we determined in that docket, the Department intends to open a separate proceeding on data access and privacy. See D.P.U. 12-76-B at 5, 50; see also Modernization of the Electric Grid, D.P.U. 12-76, Hearing Officer Memorandum (March 26, 2014).[13]

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[13] The electric distribution companies' ability to file grid modernization plans is not contingent on prior completion of a data access/privacy proceeding. D.P.U. 12-76-B at 5, 50.

E. Proposed Modifications/Alternatives to the Time Varying Rates Framework

1. Summary of Comments

Certain commenters take issue with the basic service options in the Interim Order and argue that the Department should allow: (1) electric distribution companies to consider additional time varying rate designs, especially for larger commercial and industrial customers (ISO-NE Comments at 3); (2) the implementation of time varying rates, on an accelerated basis, for commercial and industrial customers who have existing interval meters (ISO-NE Comments at 5; NECEC Comments at 4); and (3) time-differentiated distribution rates or demand charges (ENE Comments at 3). Still other commenters urge the Department to replace the proposed time varying rate structure with an opt-in time varying rate offering. These commenters argue that an opt-in structure is more cost-effective and will avoid confusion and adverse bill impacts (particularly for low income customers) (Attorney General/AIM/LEAN/NCLC Comments at 13; Network Comments at 4-5; Northeast Utilities Comments at 1-2, 23-25).

In addition, certain commenters express concern about the PTR component as part of the Department's flat rate structure (ISO-NE Comments at 4-5; National Grid Comments at 5; 47 Coffin St. Comments at 4-5). These commenters offer several different recommendations in this regard, including that: (1) stakeholders should evaluate the administrative and cost challenges associated with PTR, namely regarding the determination of a customer's baseline energy usage (National Grid Comments at 5); (2) the Department should limit the offering of a PTR component to smaller customers, with a baseline specific to an individual customer's usage, in order to address any potential for gaming (ISO-NE Comments at 4-5); and (3) the Department should eliminate the PTR component and, instead, offer an expanded load interruption program (47 Coffin St. Comments at 5).

2. Analysis and Conclusions

The Department has given careful consideration to the time varying rates options that will be implemented as a result of this Order and the alternatives offered by the commenters. The reasons supporting our time varying rates framework, including the decision to (1) limit time varying rates to basic service and not extend it to distribution service; (2) offer only two basic service time varying rate options; and (3) set the default rate as time varying and the opt-out rate as flat, are outlined in the Interim Order. See Interim Order at 8-14. After carefully weighing all comments, we remain convinced that the basic service options adopted in this Order will be sufficiently robust to encourage widespread response to price signals. See Interim Order at 11. As discussed in Section II.D, above, we fully expect that the competitive market will provide many of the time varying rate options these commenters suggest. In particular, we expect the competitive market will offer time varying rates, on an accelerated basis, for commercial and industrial customers who have existing interval metering.

Further, while we acknowledge that there may be some concerns associated with the implementation of a PTR component for basic service, we find that the potential benefits associated with a PTR offering outweigh these concerns. As discussed below, we expect to establish a stakeholder process in the future to address specific implementation issues.

F. Implementation Issues

1. Summary of Comments

a. Marketing, Outreach and Education

A number of commenters agree that customer engagement and education will be critical to the successful implementation of time varying rates for basic service (see, e.g., ENE Comments at 4; National Grid Comments at 4; NECEC Comments at 4-5; RESA Comments at 14; 47 Coffin Street Comments at 7). Commenters also acknowledge that successful engagement and education strategies will require participation and coordination among multiple stakeholders, including the electric distribution companies, ratepayer advocates, the Department, and competitive suppliers (ENE Comments at 4; National Grid Comments at 4; NECEC Comments at 5; RESA Comments at 14; 47 Coffin Street Comments at 7). Further, commenters assert that outreach, marketing, and education efforts: (1) should be competitively neutral to avoid providing basic service an advantage (RESA Comments at 14-16); (2) should extend to include Massachusetts green communities, senior centers, low income programs, and internet resources (47 Coffin Street Comments at 7); and (3) must ensure customers have a clear and simple understanding of different time varying rate options and their potential benefits and risks (ENE Comments at 4).

b. Other Issues

One commenter argues that the Department should evaluate modifications to the basic service procurement process in order to determine the best way under a time varying rates framework to solicit bids and calculate rates (National Grid Comments at 2-3). Other commenters assert that the Department must finalize a variety of outstanding implementation-related issues, such as rate design and administrative changes, before electric distribution companies can incorporate time varying rates into their grid modernization plans and/or offer time varying rates to customers (CLC Comments at 9-10; ISO-NE Comments at 4-5; National Grid Comments at 4-5; Northeast Utilities Comments at 21-23). Finally, certain commenters argue that the Department should address the treatment of customers who opt out of advanced metering functionality and, therefore, do not have the technology to enable time varying rates (Attorney General/AIM/LEAN/NCLC Comments at 14).

2. Analysis and Conclusions

In the Interim Order at 17-18, the Department acknowledged that the change to time varying rates will require significant customer outreach, marketing, and education to engage customers and provide them with simple, clear information about why the Department is implementing this rate structure and what time varying rates mean for their electricity service. We noted that such outreach, marketing, and education will require a concerted effort by all stakeholders, including distribution companies, ratepayer advocates, and the Commonwealth. Interim Order at 18.

In D.P.U. 12-76-B at 26, the Department directed the electric distribution companies to include a comprehensive marketing, education, and outreach plan in their grid modernization plans. In light of today's Order, we direct the companies to include in their plans a process to educate customers about time varying rates for basic service and the specific time varying rates framework adopted by the Department. The Department will initially evaluate each proposal during our review of the grid modernization plans. We are committed to working closely with stakeholders to ensure that consumers receive well timed, accurate, informative, and easy to understand communications from a number of sources. A critical objective of our efforts will be to ensure that customers do not reject time varying rates because they find them to be confusing or inherently risky.

In addition to marketing, outreach, and education efforts, a number of other issues will need to be resolved before time varying rates are implemented in Massachusetts. These issues include rate design considerations, low income protections, administrative changes, any necessary modifications to the basic service procurement process, and protocols for the treatment of customers who opt out of advanced metering technologies. The Department will address these issues through future stakeholder processes. See Interim Order at 11-12. Given the guidance provided by the framework we adopt today, it is not necessary to resolve these complex issues prior to the filing of the companies' grid modernization plans.

## III. CONCLUSION

The introduction of time varying rates for basic service is necessary and appropriate to advance our grid modernization objectives. Time varying rates will empower customers to shift their demand and decrease their electric bills by avoiding the use of electricity when it is most expensive. See D.P.U. 12-76-B at 11. In so doing, customers also will decrease the bills of others who do not shift their load, by reducing wholesale electricity market prices and the need for new generation, transmission, and distribution investments. See D.P.U. 12-76-B at 11. This effect is particularly relevant at a time when wholesale electricity prices are on an upward trajectory and have lead to higher basic service rates.

We conclude that the time varying rates options identified in the Interim Order strike an appropriate balance between providing clear and accurate price signals on the one hand, and a simple, predictable, and easy to understand pricing scheme on the other. Therefore, we adopt the time varying rates framework set forth in the Interim Order without modification. Following the deployment of advanced metering functionality, electric distribution companies will offer to basic service customers: (1) a default TOU rate with a CPP; and (2) an option to opt out of the default rate and choose a flat rate with a PTR component. The Department directs the electric distribution companies to prepare their grid modernization plans in a manner consistent with this new basic service rate structure.[14]

## IV. ORDER

Accordingly, after notice, an opportunity for comment, and due consideration, it is

ORDERED: That the Department adopts the time varying rates framework for basic service described herein; and it is

FURTHER ORDERED: That each electric distribution company shall comply with all directives contained in this Order; and it is

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[14] In Modernization of the Electric Grid, D.P.U. 12-76-C at 20-22 (November 5, 2014), the Department identifies specific assumptions related to time varying rates for use in preparing the grid modernization plans.

FURTHER ORDERED: That the Secretary of the Department shall distribute electronically and, where requested, serve by mailing this Order on the Department's official distribution list for this proceeding.

By Order of the Department,

/s/
Ann G. Berwick, Chair

/s/
Jolette A. Westbrook, Commissioner

/s/
Kate McKeever, Commissioner

Decision 15-07-001 July 3, 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<br>(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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**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 more accurate allocation of costs and for energy rates to more fairly reflect the cost of service.[1] 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 have experienced high and volatile bills in the recent past with the essential principle that rates should be designed to encourage the most efficient use of energy possible. We further recognize 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,

[1] In this decision we reference "cost of service" frequently in a general, directional sense. This proceeding does not contain detailed, fully-vetted cost of service studies -- particularly for sub-groups within the residential class, such as single- vs. multi-family units, urban vs rural, or large vs. small users. Cost of service studies will be considered in future proceedings such as general rate cases.

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 are more understandable and less distorted due to historical restrictions. 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. At the same time, we wish to ensure that those customers who consume a disproportionately high amount of energy are not rewarded. This decision sets moderate rates for the vast majority of customers and implements a Super-User Electric Surcharge for those customers who use substantially more than average.

By statute, the Commission is tasked with ensuring that utility rates are "just and reasonable."[2] Historically, the determination of just and reasonable has emphasized cost-causation.[3] In recent years, changes in energy use to protect the environment have become increasingly important. Moreover, changes in the

[2] 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.

[3] *See, e.g.*, *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982) ("[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity."); *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973) (recognizing the desirability of each group's bearing its fair share of the cost of service, as such share is measured by 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. The longer this steep tier differential continues, the harder it is to move back to fair rates that reflect cost and allow customers to make smart decisions. In 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

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cost of service study); *In the Matter of the Application of PacifiCorp*, D.10-09-010 (2010). For this reason a cost of service study is part of each general rate case for establishing electricity rates.

new paradigm will be challenging, but this decision will provide sufficient time and guidance to accomplish our goal. In addition, there are several ongoing proceedings at the Commission, such as R.14-07-002 (Net Energy Metering (NEM) successor tariff), R.14-08-013 (Distribution Resource Plans (DRP)), and R.14-10-003 (Integrated Demand Side Management (IDSM)) that will help in the valuation of customer-side generation and other technologies in the future.

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 cost and environmental impact of energy use. Bringing the price signal in line with cost and policy considerations, while assuring that vulnerable customers continue to be protected, 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,[4] users in the lower tiers pay significantly below the cost of electricity service, while users in the higher tiers pay significantly above cost. These 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, and sets a super-user electric surcharge for those who consume 400% or more of baseline.[5]

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

[5] "Baseline" is a set based on the average residential electricity use in a given climate zone. Although the exact calculation differs for each climate zone and IOU, baseline is roughly equivalent to 50% of the

To this end, this decision rejects the request of the investor-owned utilities (IOUs) for a fixed monthly charge and directs the IOUs to 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 the remainder of 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 (Residential RDW) application no later than January 1, 2018 that proposes default TOU rate structure to begin in 2019, assuming that the statutory conditions have been met.

(3) 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.

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average customer use for basic customers. All-electric customers have a higher baseline. See Section 739.

(4) Permits the IOUs to make a new request for a fixed monthly charge, but only after certain conditions have been met.

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

A third phase of this proceeding is opened to (i) examine specific legal issues related to default TOU rates; (ii) 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; (iii) consider the restructuring of the CARE rate under AB 327; and (iv) consider how the FERA program could be modified to help large households conserve. 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.

Although the proposed decision published in April 2015 contemplated that the next tier consolidation rate changes would be implemented for summer 2015, this revised version sets November 2015 as the deadline. For 2016, the rate changes directed by this decision should take place between March and May, and be coordinated with any revenue requirement rate changes. Subsequent steps in tier consolidation should take place at the start of the following calendar year and be timed to coincide with revenue requirement rate changes.

## 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, administrative and general expenses, fuel and purchased power expenses, (determined in the Energy Resource Recovery Account (ERRA)), 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 class for those costs.

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 revenue requirement pie for which they are already responsible.

Each utility's current revenue requirement and the 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.[6]

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.

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

- 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 Miller-Warren Energy Lifeline Act sought to provide California's residential customers with necessary amounts of gas and electricity (the "lifeline quantity") at a fair cost while also encouraging conservation of energy.

In adopting the Lifeline program, the Legislature found and declared as follows:

> (a) Light and heat are basic human rights, and must be made available to all the people at low cost for basic minimum quantities.
>
> (b) Present rate structures for gas and electricity serve to penalize the individual user of relatively small quantities, and at the same time encourage wastefulness by large users.
>
> (c) In order to encourage conservation of scarce energy resources and to provide a basic necessary amount of gas and electricity for residential heating and lighting at a cost which is fair to small users, the Legislature has enacted this act.[7]

[7] 1975 Statutes, chapter 1010, section 1.

While the statute has been amended numerous times over the years, the Legislature has never altered this fundamental statement of its intent.

The initial implementation of Lifeline rates consisted of two usage tiers, but by 1980 the Commission had added a third tier for PG&E.[8] At the time, the Commission stated that it believe a three-tiered rate would promote conservation.[9]

The Lifeline program was renamed and revised by the 1982 Baseline Act, which set baseline rates at 15 - 25% less than the system average rate (SAR).[10] The inverted rate relationship of the tier prices results from the same legislative mandate. In enacting the Baseline Act, the Legislature found and declared, among other things, as follows:

> (a) Rate structures for the furnishing of gas and electricity by public utilities should be designed to encourage conservation of scarce energy resources.
>
> (b) Inverted block rate structures are effective incentives to energy conservation and provide gas and electricity at a fair cost to all users.[11]

The establishment of baseline rates continued the inclining or inverted block structure in California: a tiered residential rate structure, with the upper-tier rates set progressively higher than the lower-tier rates, similar to graduated income tax rates. Inverted block structures charge ratepayers based on an

[8] Decision (D.) 91721, 3 CPUC 2d 578 (1980).

[9] D.93887, 7 CPUC 2d 349, 493 (1980).

[10] The 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.

[11] 1982 Statutes, chapter 1541 (AB 2443 Sher), section 1.

increasing rate per kWh within each successive tier, or "block" of use. An inclining block rate promotes conservation, especially when most customers exceed the first tier and utilities can recover more of their costs in the upper tier(s).

In 1988, six years after the Baseline Act, the Legislature enacted Senate Bill (SB) 987, which mandated a reduction in non-baseline residential rates and narrowed the differential between the tiers. It also enacted Section 739.7, which mandated that the "Commission shall reduce high non-baseline residential rates as rapidly as possible." Of note here, according to the Legislature's findings and declarations, SB 987 was focused on high winter *gas* bills, not *electric* bills:

> (1) The rates for gas service in excess of the baseline quantity are too high, and cause extremely high residential bills during cold weather.
>
> (2) The Public Utilities Commission should have greater flexibility in establishing rates for baseline service, in order to protect residential ratepayers from excessive rate increases and high winter gas bills.[12]

In the years following the adoption of SB 987, the Commission reduced electric tier differentials over time to as little as 1.15:1.[13]

In 1992, AB 1432[14] was enacted. That act 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

[12] 1988 Statutes, chapter 212 (SB 987 Dills), Section 1.

[13] See D.96-04-050, 65 CPUC 2d 362, 431 (1996).

[14] 1992 Statutes, Chapter 1040 (AB 1432 Moore).

provide conservation incentives for residential customers and also provide reasonable rates for the domestic consumption of gas and electricity."[15]

#### 2.1.2.2. AB 1890 and the Energy Crisis

Four years later, in 1996, AB 1890[16] restructured 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 (funded by the issuance of bonds), with the situation to be re-evaluated in 2002. 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. Among other things, AB 1X mandated that all residential electricity use up to 130% of baseline be capped at levels in effect on February 1, 2001, so 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 then-existing two-tiered structure with a five-tiered structure,[17] as these statutory restrictions required the first two tiers to remain frozen as a customer protection. This

[15] *Ibid.*

[16] AB 1890 (Peace, 1996).

[17] D.01-05-064.

required all future residential rate increases to be allocated to rates in non-CARE Tiers 3 through 5, above the Tier 2 (130% 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 residential average rate in order to recover costs, eventually 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%.

Over time, the rate tier differentials 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,[18] Section 739.1 was amended and Section 739.9 was added to begin allowing limited annual Tier 1 and Tier 2 rate increases for both CARE (from 0 to 3%) and non-CARE customers (from 3 to 5%). 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:

[18] Exh. PG&E-04 at 1-5. SB 695 (Kehoe, 2009).

| Utility/Date | Tier 1 (per kWh) | Tier 4 (per kWh) | Residential Average Rate (per kWh) |
|---|---|---|---|
| SCE 11/1/3[19] | 13.2 cents | 29.5 cents | 17.6 cents |
| SDG&E 1/1/14[20] | 15.0 cents | 36.9 cents[21] | 21.1 cents |
| PG&E 1/28/14[22] | 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."[23] 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[24] As a customer's energy usage increases 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.

[19] Exh. SCE-03 at 16-17.

[20] Exh. SDG&E-03 at CF-15.

[21] This is the seasonal average rate for SDG&E. The Summer Tier 4 rate is 37.8 cents/kWh and the Winter Tier 4 rate is 35.9 cents/kWh. (SDG&E Comments at 21.)

[22] Exh. PG&E-04 at 1-5.

[23] OIR at 1.

[24] Section 739.

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);[25] 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

[25] 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.[26] 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.

[26] 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.

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.

#### 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 equitable 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 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 Public Utilities Code Section 745,[27] 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.

The proposed decision (PD) was published on April 21, 2014. A revised version of the PD was also published in April 2014 to correct minor errors. On

[27] All subsequent Section references are to the Public Utilities Code, unless otherwise noted.

May 9, 2015, Commissioner Florio published an alternate proposed decision (APD).

#### 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 e-mail 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.

#### 2.2.5. Dismissal of Small Utilities

In 2012, California Pacific Electric Company, LLC (U933E), Bear Valley Electric Service (U913E), a Division of Golden State Water Company, and Pacificorp (U901E) (jointly, the California Association of Small and Multi-Jurisdictional or CASMU) filed a Joint Motion for Dismissal from this OIR. CASMU requests that each member be dismissed from any further obligations as a "respondent" in R.12-06-013. Combined, the CASMU utilities supply power to approximately 115,900 California residences. CASMU utilities do not have Advanced Metering Infrastructure that would permit dynamic pricing. CASMU argues that while the issues in R.12-06-013 are important, they are not of practical relevance to the customers of CASMU utilities, and participation in this

R.12-06-13 as a respondent would be expensive. No party argued that the public interest would be served by continuing to make these parties respondents in this proceeding.

However, because the decision to make CASMU respondents to this proceeding was made through the OIR and no discretion was delegated to the assigned Commissioner in this matter, the assigned ALJs and Commissioner determined that any change to the status of CASMU members must be accomplished through Commission decision, not through a ruling. As a result, the November 26, 2012 scoping memo for this proceeding treated the CASMU motion as a petition to modify the OIR and set a deadline for replies. No party submitted a reply or otherwise indicated any reason that CASMU should not be dismissed as a party.

In Phase 1 and Phase 2 of this proceeding the issues raised have not been relevant to CASMU, and indeed all of Phase 1 has focused exclusively on rate design proposals from the IOUs. We therefore agree that CASMU should be dismissed from both Phase 1 and Phase 2 of this proceeding and that CASMU should not have any of the obligations of a respondent in Phase 1 and Phase 2. However, because we expect Phase 3 to examine issues related to CARE, which may impact CASMU, we retain them as a respondent for the portion of Phase 3 related to CARE.

## 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 attempt to balance the sometimes conflicting 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."[28] After extensive input from the parties, including a workshop and

[28] 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.

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 two days of workshops and 15 days of evidentiary hearings and eight days of PPHs, and one all-party meeting. The exhibits admitted into the evidentiary record stand literally 3.5 feet 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 inevitably combines elements of both art and science, but we strive to base our decisions on empirical data and careful analysis. 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 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."[29] Before

[29] PG&E Rate Design Proposal, Appendix A, Hiner & Partners Key Findings at 7.

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.[30] 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."[31] 21% of "Core" respondents were unsure of what type of rate plan they are currently on[32] and the most common answer when asked if their current rate plan includes a monthly service fee or demand charge was "not sure."[33]

Among "Supplemental" groups, SmartRate and PG&E solar customers were much more aware of TOU rates than the Core group[34] and Seniors were also more knowledgeable about existing rate plans.[35] The study found that Spanish speakers were less informed about current rates[36] and households with a disabled member have a similar knowledge of rate plans as the Core group.[37]

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[30] April 2015 IOU Supplemental Filings.

[31] PG&E Rate Design Proposal, Appendix A, Hiner & Partners Key Findings at 11.

[32] *Id.* at 7.

[33] *Id.* at 12.

[34] *Id.* at 37.

[35] *Id.* at 40.

[36] *Id.* at 36.

[37] *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."[38] CforAT argues at length that the comments of the public at the PPHs and in letters and emails filed with the Public Advisor's 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.[39]

The purpose of conservation includes reducing pollution and greenhouse gas (GHG), and reducing energy and infrastructure costs. In this proceeding we

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[38] CforAT OB at 19.

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

did not examine the degree to which California's existing programs for 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,). These are very important principles but they must also 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.[40] 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.

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

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 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 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 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.[41] 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.[42]

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.

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

[42] 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.

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 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.[43]

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% bill increase in the inframarginal tiers, a customer's electricity consumption would decrease by 1.6 or 1.5% 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

[43] Exh. PG&E-111 at 9.

way that customers would respond to changes in price if they accurately understand the actual impact of changes in usage on their bill.[44]

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 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."[45]

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 assumed 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.[46] Dr. Faruqui also acknowledged that his methodology could lead to results that appear difficult to reconcile.[47]

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[44] RT Vol 17 at 2357-2359, PG&E/Faruqui.

[45] *Id.* at 2362, 2368.

[46] *Id.* at 2371.

[47] *Id.* at 2368-69, 2371.

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% using the Tier-Specific methodology, a decrease in consumption of 1.2% using the Average Price methodology, and an increase in annual residential consumption of 1.2% 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."[48]

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

**Conservation Impacts as Calculated by PG&E: PG&E "Table 2"[49]**

| | 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% |

[48] Exh. PG&E-111 at 13.

[49] *Id.* at 14 (PG&E "Table 2").

**Conservation Impacts as Calculated by SCE: SCE "Table 5"**[50]

| | 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. 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.[51] [52]

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[50] *Id.* at 18 (SCE "Table 5").

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

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 Impacts Calculated by: SDG&E**[53]

| | 2015-2017 kWh Percent Change |
|---|---|
| SDG&E Scenario 1<br>(-0.1 elasticity, fixed charge in bottom tiers) | -0.36% |
| SDG&E Scenario 1<br>(-0.1 elasticity, fixed charge in all tiers ) | -0.32% |
| SDG&E Scenario 2<br>(-0.2 elasticity, fixed charge in bottom tiers | -1.41% |
| SDG&E Scenario 2<br>(-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.[54] 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% of

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[52] 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.

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

[54] RT at 1953: 20-12.

SDG&E's residential sales, and would reduce those incentives to some extent for upper-tier sales."[55] 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 1 and 2 while decreasing rates for Tier 3 and Tier 4 customers. However, they maintain that those Tier 1 and Tier 2 customers may "seek additional engagement"[56] or ways to save or manage their energy use using existing EE and/or DR programs while customers whose usage terminates in 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."[57]

#### 4.2.4. Other Estimates of Price Elasticity

Several parties argue that customers in the low usage tiers[58] 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.[59] NRDC and TURN both cite a study of British Columbia Hydro (BC Hydro) residential customers comparing

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[55] Exh. PG&E-111 at 21.

[56] SCE OB at 132.

[57] Exh. UCAN-104 at 24.

[58] 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.

[59] 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.

the impact of a newly-introduced two-tiered rate with the existing non-tiered rate.[60] The study found that, under the tiered rate, consumption by the large customers fell. Specifically, the authors found a price elasticity of between -0.08 and -.13 for large customers (i.e., those customers consuming above the 1350 kWh/bimonthly Tier 1/Tier 2 threshold).[61] 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 1,350 kWh/bimonthly Tier 1/Tier 2 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 prices for Tier 1 customers may have had on their consumption.[62] 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

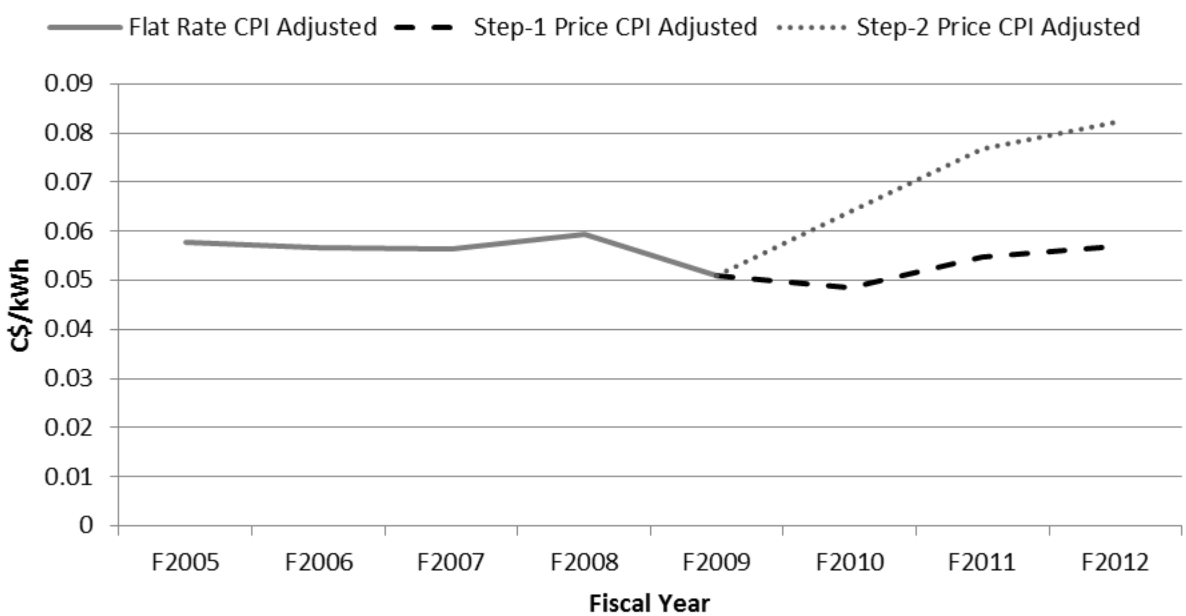
[60] Exh. TURN-207, Attachment WBM-6 (Michael Li, Ren Orans, Jenya Kahn-Lang & C. K. Woo, ARE RESIDENTIAL CUSTOMERS PRICE-RESPONSIVE TO AN INCLINING BLOCK RATE? EVIDENCE FROM BRITISH COLUMBIA, CANADA, June 2014).

[61] *Id*. at 227.

[62] *Id*. at 224 – 225.

single-family detached houses have more elasticity than customers in town houses, apartments, or mobile homes.[63]

**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.[64] TASC suggests that a more appropriate price elasticity for Tiers 1 and 2 is -0.08, the price elasticity coefficient used in the CEC's California Energy Demand 2014-2024 Final Forecast.[65] TASC reports that using this revised elasticity value in PG&E's scenario 1 results in significantly less conservation –

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[63] *Id*. at 14.

[64] Exh. TASC-105 at 9.

[65] *Id.* at 10.

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 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 10.8 -12.9 years under the IOUs rate proposals.[66] 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

[66] Exh. CALSEIA-106, Appendix A.

impact of improved appliance standards. Other parties argue 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.[67] 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.[68]

TURN applied the same analytical approach to its proposed three-tier rate structure (with no customer charge), and found that its proposal would increase

[67] 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.

[68] Exh. TURN-201 at 40-41.

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.[69]

**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 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 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.[70]

#### 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

[69] TURN OB at 6.

[70] 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.[71] 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[72]**

| | 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) |

[71] 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).

[72] 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.[73] 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."[74] ORA notes that while the utilities cite one paper by Kochiro Ito to support their assertions, this paper relies on studies and

[73] ORA OB at 58.

[74] *Id.*

data from 1997 to 2007, well before the utilities invested in advanced metering and smart grid initiatives.

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 customer's conservation decision.[75] 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/ 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.

[75] NRDC OB at 12.

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."[76]

#### 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."[77]

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.[78] 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.

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[76] CforAT OB at 18.

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

[78] 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.

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 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% and reducing the current benefits of the tiered structure for conservation purposes versus preserving some conservation potential in the tiered structure …"[79]

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.[80] 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."[81] Under TURN's analysis, PG&E rate design proposals would increase overall residential class consumption between 514 - 1,071 Gigawatt hours (GWh) per year.[82] According to TURN, when compared to the

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[79] Exh. UCAN-101 at 25.

[80] Exh. TURN-201 at 1.

[81] *Id.* at 40.

[82] *Id.* at 41 (Table 12).

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.[83]

#### 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 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 air conditioning (AC) system. As the price of a kilowatt hour rises or falls, so does the savings from conserving (or avoiding generation of) 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.[84] 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'

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[83] TURN RB at 6-7 (citing PG&E OB at 4, Exh. TURN-201 at 41, and D.14-10-046 at 10).

[84] NRDC OB at 11.

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 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 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.[85] 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.[86]

#### 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,

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[85] Sierra Club OB at 10.

[86] Exh. Sierra Club-101 (Corrected) at 21.

accordingly, support or undermine a residential customer's solar investment.[87] 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.[88]

Sierra Club cites a National Renewable Energy Laboratory survey finding that "50% of non-adopters [homeowners who did not have PV] would require a payback period of 6 years or less to seriously consider adopting" and that solar market penetration curves flatten significantly as payback periods increase.[89]

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.[90] 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%.[91] The utilities acknowledge these concerns, admitting that "[T]he average customer payback

[87] Vote Solar OB at 7.

[88] NRDC OB at 8.

[89] Sierra Club OB at 7.

[90] CALSEIA OB at 5.

[91] *Id.* at Table 2.

periods for customers installing new solar NEM facilities will increase slightly,"[92] and "SCE recognizes that payback period can provide information on customer adoption of solar."[93] This is true for both host-owned systems and Power Purchase Agreements (PPA). PG&E further acknowledged that "changes that negatively impact the payback period for host-owned systems also negatively impact PPA customers."[94] 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.[95] Vote Solar claims that the Commission should not change the rate structures 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

[92] Exh. PG&E-101 (Part 2) at D-32.

[93] Exh. SCE-106 at 107.

[94] RT Vol. 11 at 1267-1268, PG&E/Halperin.

[95] IREC OB at 6.

under the IOUs' rate proposals.[96] 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 efforts 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.[97] 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 lengthen the payback period for these investments, resulting in either higher rebates raising program costs or lower penetration of the programs or both. ORA 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 and 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.

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[96] Exh. CALSEIA-106, Appendix A.

[97] Exh. TURN-101 at 33.

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,[98] nearly four times that of PG&E's proposal, when TASC assumed no monthly fixed charge.[99]

#### 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 RDPs.

Later in this decision we examine the conservation of effects of fixed charges and tiered rates in more detail. Finally, in Section 11 below, we look at each 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).

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[98] TASC OB at 12-14.

[99] Exh. TASC-105 at 12.

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 is 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.[100] [101]

Reviewing the results of the joint PG&E/SCE marginal price methodology, 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

[100] RT Vol. 10 at 1056-1058, PG&E/Keane.

[101] Exh. TURN-201 at 37.

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."[102]

However, we can see from the results of the Hiner study that at least half of the utilities' 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.[103] 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.[104]

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 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

[102] Exh. PG&E-111 at 6.

[103] Exh. PG&E-109 at 1-24.

[104] ORA OB at 58.

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 cannot find that one methodology alone accurately approximates how customers respond to tiered rate changes. Of the methodologies proposed, we believe the average price methodology is the closest approximation of how most customer will respond. 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 % and 1.44, respectively, indicating that the rate design proposals may result in either a slight decrease or increase in conservation.[105] We also find 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

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[105] TURN's combined methodology results in a consumption increase of 2.34%.

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, any reductions in conservation could offset or negate some portion of the energy savings achieved through the Commission's EE program. 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 optimum conservation levels will be achieved when customers better understand the cost of the energy they consume. Therefore, today we adopt a decision that will allow customers to make conservation choices linked to the costs of their individual energy consumption.

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 that 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. In addition, overall energy reduction from EE measures does not account for the value of the energy conserved at a particular time of day. For example, an energy efficiency measure used exclusively during off-peak periods does not provide the same societal benefits as energy efficiency measures that occur during peak hours. In some cases, customers may invest in energy-efficiency measures that are cost effective from their perspective under steeply tiered rates but whose cost per kWh saved exceeds the true social value (including environmental externalities) of the electricity saved. For measures that reduce off-peak consumption, one factor driving this result would be the lack of capacity value. Such investments result in a net loss to society because the costs exceed the benefits.

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 tier price effect is dominant.

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

Nonetheless, there are subgroups of customers that may reduce their usage in response to a high rate. For example, we believe there is a subgroup of customers who do understand the tiered rate system and respond to marginal cost. There are also customers with usage at extremely high levels. The need for conservation from these high usage customers remains, and a higher rate for this extreme usage could be a tool to target these customers.

### 4.3. Correlations between Usage, Household Size and Income

To evaluate the impact of rate designs, this proceeding has attempted to link the amount of electricity consumed with household attributes such as Climate Zone, CARE enrollment, income, and household size. In this section, we examine whether there is sufficient evidence in the record to find that usage can be predicted based on income or household size. In other words, can we predict that low income customers will be low energy users, or that households with two members will use less energy than households with five members?

As discussed in detail below, we find that there is some correlation between income and usage and between household size and usage (but that neither measure can be used to accurately predict usage in every case). The evidence shows a general trend, on average, toward higher usage for larger households and higher usage for higher income customers.

Averages, however, tend to conceal the differences among individual households within a given cohort. Unfortunately, the data submitted at the household level does not have the level of granularity that would allow for robust analysis of correlations between usage and customer attributes. For example, the correlation between income and usage that is seen at the level of zip code data does not reflect the heterogeneous quality of a community seen when data are viewed at a household level. Similarly, the evidence supporting the household size to usage correlation would be stronger if it was broken down by Climate Zone or even smaller regions rather than averaged over all PG&E climate zones.

In addition, the primary source of data for this analysis is the CEC's 2009 Residential Appliance Saturation Study (RASS) survey. In the 6 years since that study was completed, there have been significant improvements in energy efficiency and conservation, and a wider deployment of rooftop solar PV. California's economy has also undergone significant changes which have likely lead to increased consumption overall. Finally, in the last two years a new program was implemented to reduce usage of CARE customers who use over

400% of baseline. None of these post-2009 changes are reflected in the RASS data.

We find that this lack of information frustrates our decision-making process and prevents us from completing the careful analysis using preferred empirical methodologies. This lack of current and granular information has been noticed throughout this proceeding. Moving forward, we direct utilities to provide current data in more granular detail that harnesses robust and interactive geographic information system (GIS) platforms to enable visual representation and enhanced analysis capabilities for all information requested and required in furtherance of this proceeding.

#### 4.3.1. Household Size

PG&E provided an illustration of the relationship between household size and usage based on the RASS data. PG&E used the average baseline from RASS as a measuring stick for household usage. Average baseline is the average household usage when households of all sizes are taken into consideration. For PG&E, the 2009 RASS data reflected an average annual baseline of 4.247 kWh per day. PG&E found that the amount of electricity used by a single person household on an annual basis is approximately equal to the baseline. In contrast, a household with five or more members uses approximately **double** that amount.[106] While the evidence clearly shows an increase in average bill for larger households, it is not sufficiently granular to determine to the extent to which larger households are paying more than smaller households for the same amount of electricity.

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[106] Exh. PG&E-116.

Interestingly, when converted to a per capita measurement, the single-person household uses significantly more energy:

| **Household Size** | **Annual Usage (kWh)** | **Per Capita (kWh)** |
|---|---|---|
| 1 person | 4,108 | 4,108 |
| 5 persons (or more) | 8,187 | 1,637 |

TURN argues that these data are of limited value because they are an average of customer usage from different climate zones.[107] TURN points out that these data do not take into account variables such as whether a particular climate zone tends to have large or small households.[108] We agree with TURN that the available data are not ideal, and that a more granular analysis would yield better results.

#### 4.3.2. Household Income

Although numerous parties have asserted that income and usage are closely correlated, the evidence does not bear this out. Because there are many factors which influence usage, including climate and household size,[109] 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.[110]

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 a household basis. Since the start of this proceeding there have

[107] TURN Reply Comments.

[108] TURN Comments at 12.

[109] TURN Proposal at 19; SCE OB at 10.

[110] PG&E Proposal at 37 ("While there is a positive correlation between income and usage, that correlation is weak").

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

##### 4.3.2.1. 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.[111] In that proposal, TURN refers to an "established" correlation between income and usage, while granting that such correlation is imperfect.[112] 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.[113]

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.[114]

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[111] TURN does refer to an earlier CPUC literature review on the subject, published in June, 2012.

[112] TURN Proposal at 14.

[113] *Id.* at 15-16.

[114] *Id.* at 16.

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.[115]

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[116] and paid an average annual rate that exceeded the residential class average.
- Of the 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% 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.[117]
- Approximately 57% of PG&E's non-CARE customers using energy at Tier 3 rates and above were moderate or low-income customers.[118]

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[115] *Id.* at 20-25.

[116] PG&E defines high usage as 1/12 for each month with Tier 3 or above usage for each customer.

[117] PG&E Proposal at 37.

[118] *Id.* at 35.

- Statistically there is a correlation coefficient of only 0.33 when comparing income and usage, which is "relatively weak."[119]

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.[120] TURN argued that once the RASS data were segregated by climate zone, the empirical relationship between income and usage became clearer.[121]

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.[122] 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.[123]

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

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[119] *Id.* at 38.

[120] TURN Opening Comments of July 12, 2013, at 45.

[121] *Id.* at 45-46.

[122] 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).

[123] *Ibid*.

cities… with median annual incomes above $100,000, there are significant percentages of customers paying low average rates."[124]

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)."[125]

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."[126]

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.[127] 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

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[124] *Id.* at 17.

[125] *Id.* at 19.

[126] TURN Reply Comments of July 26, 2013, at 25.

[127] *Ibid*.

correlations of 0.46 in the hot zone, 0.75 in the mid climate zone, and 0.65 in the cool climate zone.[128]

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.[129]

SCE's rate design proposal stated that the relationship between income and usage is "weak."[130] In their response to TURN's Proposal, SCE states that 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.[131]

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.[132] 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.[133]

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[128] *Id.* at 22-25.

[129] SDCAN Proposal at 28.

[130] SCE Proposal at 59.

[131] SCE Opening Comments of July 12, 2013, at 18, 43.

[132] ORA Opening Comments of July 12, 2013, at 46-47.

[133] CforAT/Greenlining Opening Comments of July 12, 2013, at 3.

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.[134] CFC refers to an assumption that low-income customers are low-usage customers, but does not explicitly support the assumption.[135]

While not explicitly saying so, the CforAT/Greenlining rate design proposal implies that low-usage customers are likely to be low-income customers.[136] NRDC's rate design proposal describes the correlation between income and usage as "logical"[137] and states that in California usage is generally income-related.[138]

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.[139] 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."[140]

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[134] SDG&E Proposal at 39.

[135] CFC Proposal at 8.

[136] 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").

[137] NRDC Proposal at 39.

[138] *Id.* at 38.

[139] Sierra Club Proposal at 7.

[140] Sierra Club Opening Comments of July 12, 2013, at 14-15.

#### 4.3.2.2. 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.[141]

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."[142]

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.[143]

#### 4.3.2.3. 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.

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[141] Staff Proposal at 37.

[142] *Id.* at 40.

[143] IREC Comments on Staff Proposal at 4.

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.[144] For SCE, their analysis shows that high tier usage generally increases with income, with some variability.[145] For SDG&E their findings are similar.[146]

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;"[147] 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."[148] 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."[149]

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.[150]

IREC states that the correlation between income and usage is "is almost certainly underestimated" by the IOUs.[151] While they do not independently analyze a particular data set to arrive at an estimate of such correlation, they do

[144] *See generally* Exh. TURN-207, attachments WBM-9 and WBM-10.

[145] *Id.* at 381-382.

[146] *Id.* at 443.

[147] Exh. TURN-201 at 20.

[148] *Id.* at 29.

[149] *Id.* at 19.

[150] *Id.* at 29.

[151] IREC OB at 16.

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.[152] 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.[153] PG&E points to data that indicates that there are "significant numbers" of low-income households that consume large amounts of energy.[154] PG&E also refers to the CEC's RASS data as supporting a conclusion that household size helps to determine usage as well.[155]

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.[156] SCE argues that the "proper correlation" to consider is between household size and usage, not between income and usage.[157] 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.[158]

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[152] *Id.* at 16-17.

[153] PG&E OB at 12; RT Vol. 12 at 1381: 1-21, PG&E/Quadrini.

[154] Exh. PG&E-101 at 1-11 & n.25.

[155] *See* Exh. PG&E-116.

[156] SCE OB at 115.

[157] *Id.* at 10.

[158] 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.[159] They further argue that in their territory there are high-usage as well as low-usage CARE customers.[160]

This evidence leads us to conclude that while there is a general positive correlation between income and usage, 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.[161] Because California relies on natural gas peaker plants and

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

[160] SDG&E OB at 48.

[161] *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

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.[162] 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,

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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.

[162] 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.

conserves 3,000 Btu of natural gas, and avoids the corresponding GHG emissions that would otherwise occur."[163] Energy Division's 2014 Staff Proposal applied this approach.

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."[164]

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

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[163] 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).

[164] Exh. TURN-204 at 11.

shifts on GHG emission rates, and they agreed that this approach is less than optimal.

TURN witness Woodruff evaluated three existing production cost simulation modeling studies,[165] 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."[166] 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.[167] 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 off-peak 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.

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[165] 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.

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

[167] *Ibid.*

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.

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 Environmental Protection Agency (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.[168] ORA argues that time-of-use rates will result in significant long-term cost savings due to deferral of system upgrades and the need for new generation.[169] 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."[170]

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.[171]

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."[172]

TURN argues that the estimates of ORA and EDF are "deeply flawed."[173] TURN contends that for the ORA and EDF predicted cost-savings to occur, there

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

[169] Exh. ORA-201 at 1-3.

[170] *Id*. at 1-3 n.5.

[171] Exh. EDF-101 at 8.

[172] TURN OB at 63.

[173] *Id.* at 64.

"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 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."[174] 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.[175]

Finally, TURN contends that because the current Long Term Procurement Proceeding (LTPP) 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

[174] RT Vol 24 at 3747, EDF/Fine.

[175] TURN OB at 63.

savings resulting from TOU. However, we do not rely on these specific figures of either EDF or ORA when directing IOUs to take steps toward 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.

### 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."[176] 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.

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

Although we have long known that energy costs vary by time of day,[177] 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' usage by time. In fact, this capability was one of the primary reasons supporting the rollout of residential smart meters.[178] 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.[179] TOU rates inform customers when costs are high and when costs are low, enabling customers to make economical usage and investment decisions.

[177] 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.

[178] *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.

[179] UCAN OB at 33.

It is also equitable to all individuals because customers large and small receive the same price signals.[180] UCAN provided the following chart, which concludes that a TOU rate meets the RDP better than a tiered rate.[181]

| R.12-06-013 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 non-coincident peak demand. | N/N | Y/[N][182] |
| 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**** |

180 *Ibid*.

181 UCAN RB at 29-30.

182 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.

**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 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.[183] The passage of time and the advent of advanced metering saw mandatory TOU rates rolled out to smaller and smaller customers.[184] 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.[185]

Beginning in 2011, the Commission ordered mandatory TOU for the rest of the non- residential rate classes,[186] citing that "dynamic pricing can lower costs, improve system reliability, cut greenhouse gas emissions, and support modernization of the electric grid.[187] Nearly all non-residential customers in California will be on mandatory TOU rates before the end of 2015.

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.

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

[184] 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).

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

[186] 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.

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

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.[188] They seem to have found the most success in targeting customers with larger than average bills. However, this level of enrollment took almost 20 years to achieve.[189] 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.[190]

Many parties[191] have discussed Sacramento Municipal Utility District's (SMUD) 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 reduction from the customers chosen for the default pilot,[192] similar to the load reductions demonstrated by customers in Arizona Public Service (APS) territory and in the 2003 California Statewide Pricing Pilot,[193] which were both opt-in programs. Customers in the opt-in

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

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

[190] 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.

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

[192] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.

[193] Charles River Associates, IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT, March 16, 2005, at 1.1.

portion of the pilot were able to achieve 12% peak load reductions.[194] 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.[195]

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.[196] 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.[197] 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 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

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[194] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.

[195] *Id.* at 73.

[196] Brattle Group, IMPACT EVALUATION OF ONTARIO'S TIME-OF-USE RATES: SECOND YEAR ANALYSIS, December 16, 2014 at 37.

[197] PG&E 3.4%, SCE 0.52%, SDG&E 0.60% of customers on TOU rates, IOU Supplemental Filings April 1, 2014.

difference between the periods led to a smaller customer response, only about 1% peak load reduction.[198]

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" seven-hour peak period rates, as well as 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.[199] Salt River Project's (SRP) "EZ-3" rate, has experienced rapid growth since its introduction in 2005, despite the higher peak rate. A study between their seven-hour TOU and three-hour TOU found a much stronger peak reduction response from EZ-3 participants but SRP believes it is better to maintain both options to reduce peak across the whole

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[198] Simone Maggiore & Ricera Sistema Energenico. "Impact of a mandatory time-of-use tariff on residential customers in Italy," presentation from Espoo, November 2012.

[199] Exh. SEIA-101 at 24.

period, especially considering "snapback" in usage at end of the shorter peak period.[200]

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).[201] 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,[202] 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[203] 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

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[200] 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

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

[202] 1.4:1 for Ontario at the beginning of the program and 1.03:1 for ENEL at the beginning of its program.

[203] PG&E OB at 64.

successfully be transitioned to TOU with positive results through default rates."[204] ORA believes that the SMUD study showed that "most customers found TOU rates easy to understand"[205] 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."[206] 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.[207] There are several factors in this analysis. Firstly, as seen above, peak load reduction is a factor of the price differential between rates.[208] 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

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[204] Exh. SDG&E-101 at CY-10-12.

[205] Exh. ORA-101 at 1-11.

[206] TURN OB at 61.

[207] PG&E Supplemental Filing, February 28, 2014 at 2-61 (Figure 2-19).

[208] Ahmad Faruqui & Sanem Sergici, *Arcturus: International Evidence on Dynamic Pricing*, ELECTRICITY JOURNAL, VOL. 26, ISSUE 7: 55-65 (2013).

proceeding have not predicted significant enrollment in opt-in TOU. The SMUD study revealed that although opt-in TOU customers individually tend to reduce more, in the aggregate, the default rate produced three times the load reduction.[209]

ORA provided the following summary of enrollment and load response.

**ORA Table Summarizing Residential TOU Load Impacts[210]**

| 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

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209 Exh. ORA-101 at 1-20.

210 *Ibid.*

equation, default plans offered to the same population of customers as opt-in plans are likely to produce much higher aggregate load reductions."[211]

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 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.[212]

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[211] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.

[212] ALJ E-mail Ruling Setting Prehearing Conference, October 15, 2014, at 3.

### 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."[213] The statute defines "baseline quantity" as "a quantity of electricity or gas allocated by the commission for residential customers based on from 50 to 60% of average residential consumption of these commodities.[214] In establishing the baseline quantities, the commission shall take into account climatic and seasonal variations in consumption and the availability of gas service."[215]

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."

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[213] Section 739(2)(b).

[214] The statute requires that for all-electric customers the baseline be set at 60-70% of average residential consumption during the winter heating season.

[215] Section 739(a)(1).

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 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 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. Indeed, in D.89-01-055 we concluded that "revenues from any customer charge must, as a matter of law, be included in the baseline rate for purposes of Section 739(c). There are also sound policy reasons 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 2 rate than Tier 1 rate. Because the law requires a baseline tier, we agree with long-standing Commission legal interpretation that the calculation should be made with the composite tier. Otherwise, we allow the utilities to effectively avoid the law.

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**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 Charges** | $33.60 | $37.38 |
| **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 Consumer Price Index (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

Policy goals, not cost of electricity, are the primary driver of a steep inclining block rate structure. In this proceeding, two policy goals have been cited to support a steep inclining block rate: (i) conservation and (ii) 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 if customers do not understand the price structure. UCAN describes inclining block rate as achieving conservation through "brute force."[216] Moreover, incenting overall conservation is not the only way that energy use can be reduced or made cleaner. Reduction 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 or solar PV has a downside for customers who are unable to make similar investments. When high-use customers invest in significant EE or solar PV 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.

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 1 and Tier 2 customers facing higher rates so that they respond to the new rates with no-cost and low-cost conservation strategies.

[216] UCAN OB at 33.

Strikingly, the record does not indicate that an increase in an inclining block rates will lead to a proportional increase in customer conservation. In other words, the evidence demonstrates that a differential provides a price signal to conserve, but the evidence does not demonstrate that a large rate increase would have a correspondingly large impact on conservation. This leads to the conclusion that a mild differential will be sufficient to maintain a conservation price signal. In addition, a dramatic price signal, such as a high user surcharge for the small group of customers who use the most energy, can be used to effectively target customers with extreme usage.

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, aside from these capital investments in EE, there is no evidence that a steep differential will lead to the type of behavioral changes that necessary to sustain a consistent amount of conservation.

The second policy argument, that low-income customers will be disproportionately impacted by increased low-tier rates, is similarly not well supported by the evidence in this proceeding. The correlation between income and usage was argued at length in this proceeding, and as discussed at length in Section 3 below, 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 pay 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 be 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

When tiered rates are designed to support specific policies, they have limited ability to meet other RDP such as understandability and cost-causation. As UCAN bluntly states, "[i]nefficient, above-cost pricing is deceptive and forces customers to conserve or pay excessive costs without ever revealing what energy actually costs."[217] Steeply tiered rates also result in more volatile bills for residential customers.[218] 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.[219]

Although parties to this proceeding disagree about the possible benefits of tiered rates, parties almost universally support a change from the current tiered structure to a tiered rate that is less steep.

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.[220] ORA supports gradually reducing the number of tiers in the current tiered rate structure to two as part of a transition to default TOU.[221] UCAN also supports redesigning the current tiered rate structure to achieve rates "that are efficient, cost-based and fair to all customers"[222] SEIA, CALSEIA and IREC all recognize the need to change the current tiered structure and present proposals to reduce the number of tiers.[223] Vote Solar states that it supports the tiered rate proposals of SEIA, CALSEIA and

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[217] *Id.* at 7.

[218] Exh. PG&E-101 at 2-14.

[219] *Id.* at 2-15.

[220] NRDC OB at 16

[221] ORA OB at 1.

[222] UCAN OB at 7.

[223] Exh. SEIA-101 at ii; Exh. CALSEIA-101 at 4; Exh. IREC-101 at 2.

IREC and TASC also supports SEIA's proposal.[224] 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."[225] 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."[226]

### 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-

[224] Vote Solar OB at 2; TASC OB at 4.

[225] EDF OB at 4-5.

[226] CforAT OB at 53.

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.

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.[227] 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.[228] 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."[229]

TURN argues that a three-tier structure with no customer charge will incent more conservation than a two-tier structure with a fixed charge.[230]

A three-tier rate, however, could unfairly penalize large households. As discussed in Section 4.3 above, energy usage tends to increase as the number of household members increases. Under the current multi-tier structure, these households tend to fall into the higher tiers more often than small households, resulting in a higher rate per kWh. Under a three-tier rate structure, with evenly spaced tiers, this asymmetry would continue, but a two-tier system would reduce the amount by which larger households pay in excess of the average rate.

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[227] NRDC OB at 12.

[228] *Id.* at 16.

[229] *Id.* at 17 (citing Exh. NRDC-101 at 32).

[230] 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).

We find that a two-tiered structure is the best rate design at this time. A two-tiered structure will be the easiest for customers to understand and accept. This is essential given this proceeding's emphasis on increasing customer understanding electricity rates. A two-tier structure will continue to provide a conservation signal, while bringing rates closer to cost and thereby sending more accurate price signals to customers. In addition, it will minimize the risk that some large households will pay a disproportionate share of electricity costs.

As discussed below, a high usage surcharge is a mechanism to target the small number of customers who use an extreme amount of energy while minimizing the risk that ordinary customers will inadvertently be hit with electricity rates set significantly higher than cost.

### 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 a selected set of 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,[231] and that steep tiers are inequitable.[232]

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.

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%,[233] 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).[234]

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."[235] SEIA cites a plethora of Commission and state

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

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

[233] TURN RB at 19-20.

[234] 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.

[235] SEIA OB at 4-6.

programs and policies that have been enacted that support the "increasing importance of renewable energy and energy efficiency technologies" including RPS in 2003, California Solar Initiative (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."[236]

IREC argues that "gradual" tiering is only relevant if there are at least three tiers.[237] 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.

SEIA and IREC each propose a steeper differential where the highest tier is based on a "marginal cost" calculation.[238]

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."[239]

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*

[236] *Id.* at 6.

[237] IREC OB at 13.

[238] SEIA OB at 12-13 ("peak-related *marginal* usage is generally in higher tiers.").

[239] Exh. SEIA-101 at 39.

usage is generally in higher tiers."[240] 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."[241] 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 home in a mild coastal zone was 0.44, but that this load factor dropped to 0.30 in moderate or hot inland zones.[242]

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.[243] 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.

[240] SEIA OB at 12 (emphasis original).

[241] *Ibid*.

[242] Exh. SEIA-101 at 38 (referring to SCE data that is not in the record).

[243] 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.

IREC's proposed baseline tier would recover all other costs and the tier differential ratio would reflect the difference between the two.[244]

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.[245]

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.[246]

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 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

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[244] IREC OB at 12.

[245] Exh. IREC-101 at 14-17.

[246] IREC OB at 10-12.

making higher-usage rates more expensive than marginal utility costs (either generation or 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, according to EDF, high-usage customers are less-costly to serve at the margin than low-usage customers.[247] 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.[248]

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 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.

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

[248] *Id.*

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 25% differential will encourage overall conservation while reducing bill volatility. Twenty five 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.

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,[249] and other programs for low-income customers that address non-energy burdens.[250]

Before determining that a two-tier rate with a 25% 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 4.7.2 if a fixed charge is

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[249] A program that provides direct financial incentives to lower-income households to invest in upgrades and technology that enhances energy efficiency.

[250] Exh. PG&E-109 at 2-9.

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 2 customers when SCE and PG&E combine their respective Tiers 2 and 3.

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 different. The glidepaths are examined in the context of each IOU's separate proposal in Section 11 below.

### 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."[251] By statute, this baseline quantity must be in the range of 50% to 60% of the "average residential consumption" in each geographic area.[252] Baseline quantities are set differently for each Climate Zone and are designed to take into account seasonal variations in consumption.[253]

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.[254] 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.[255]

SCE and SDG&E asked for reduced baseline quantities.[256] PG&E asked that no changes to baseline quantities or guidelines be made in this proceeding.

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[251] Section 739(2)(b).

[252] The statute requires that for all-electric customers the baseline be set at 60-70% of average residential consumption during the winter heating season.

[253] Section 739(a)(1).

[254] 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.

[255] ORA OB at 25.

[256] 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%.[257] 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.[258] Therefore, CforAT argues that baseline be set in the middle of the statutory range of 50-60%.[259]

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

[257] CforAt OB at 2.

[258] CforAT OB at 52 (citing SCE, PG&E, and SDG&E statements in agreement).

[259] *Id.* at 54.

25% differential), then low usage customers should not be subject to the 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.[260]

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.

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[260] 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 3 and 4).[261] 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."[262] 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."[263] 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."[264] SDG&E proposes to transition to a two-tiered, seasonally differentiated rate structure. Currently, the commodity component of SDG&E's Tiers 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, Tiers 1 and 2

[261] 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).

[262] SCE OB at 154.

[263] SCE RB at 88.

[264] Exh. SDG&E-107 at CF-26/Fang.

rates do not have 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."[265] 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.[266] 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.[267]

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

[265] D.14-01-002 at 37.

[266] Exh. SEIA-101 at 38 (referring to SCE data that is not in the record).

[267] Exh. ORA-101 at 5-11.

experience usage outside of Tiers 1 and 2, and therefore aren't familiar with seasonally differentiated rates, adding this complexity will cause unnecessary confusion at a time when other significant rate changes will be going into effect.[268]

We agree conceptually with SDG&E, SCE and SEIA that residential rates should include a seasonal component to reflect differences in cost across the year. 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.

We direct SCE and PG&E to explore seasonally differentiated rates for the future, to be proposed in the next applicable GRC Phase 2 or RDW.

### 5.7. Super-User Electric Surcharge (SUE Surcharge)

CforAT states in its comments that "there is no reason to signal to high-users, including particularly the very highest users (who would be the biggest winners under the terms of the PD) that they need not conserve."[269] CforAT and Greenlining suggest a high usage surcharge that would target energy usage levels that are defined in the CARE program as high.[270]

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[268] ORA OB at 23.

[269] CforAT Comments at 19.

[270] Id.; Greenlining Reply Comments at 4.

Previous Commission decisions support targeting high usage customers and signaling them to conserve. In D.12-08-044, the decision approving the Large Investor-Owned Utilities' 2012-2014 Energy Savings Assistance (ESA) and California Alternate Rates For Energy (CARE) Applications, the Commission approved PG&E's proposal to address high usage CARE customers, defined as any customer exceeding 400% of baseline. The decision adopted rules for two separate groups of high users, and applied them to SCE and SDG&E. The rules are as follows:

> "(1) 600% or more above baseline users: CARE electric customers with electric usage above 600% of baseline in any monthly billing cycle will have 90 days to drop usage substantially or be de-enrolled and barred from the program for 24 months. In addition, to continue to stay in the program, these customers must undergo Post Enrollment Verification and apply for the Energy Savings Assistance Program within 45 days of notice. We also direct the IOUs to develop an expedited appeals process so that customers with legitimate high usage can demonstrate the need for their usage levels.
>
> (2) 400% - 600% baseline users: CARE electric customers with electric usage at 400%-600% of baseline in any monthly billing cycle must undergo Post Enrollment Verification and, if not previously enrolled in the program, apply the ESA Program within 45 days of notice."

SDG&E subsequently sought to modify the high usage customer rules adopted in D.12-08-044 such that only those customers who repeatedly (three times or more) use greater than 400% of baseline in a 12-month period would be subject to the above high usage customer rules. SDG&E argued that if the Commission's intent in D.12-08-044 is to target customers who are ineligible for the CARE program and may be purposefully misdirecting the CARE program discount, the high usage customer rule should be modified to apply only to customers who repeatedly exceed the 400% baseline usage. In D.14-08-030, the Commission rejected that contention, stating that,

> "one of the purposes of the high usage customer rule was to eliminate the customers who are ineligible for the CARE Program and/or are purposefully misdirecting CARE program discount for purposes other than legitimate household needs and to de-enroll them. However, the more important aim of the rule was to also help the high usage customers with legitimate high uses with enrollment in the ESA Program and to help with lowering energy usage while achieving bill savings going forward. To modify the rule to ignore those who only exceed the 400% baseline usage once in a 12-month period would be contrary to that latter purpose of helping the high usage customers with legitimate high uses with enrollment in the ESA Program and lowering of their energy usage. In fact, those customers who are generally within a reasonable usage range, but exceed the 400% baseline usage infrequently, may very well be in an optimal position to take advantage of the ESA Program to benefit from energy savings to drop below that 400% baseline range."

SCE also sought to modify the rule, citing concerns that it could not offer its ESA Program on a timely basis to all of the willing and eligible CARE customers exceeding 400% of baseline in any monthly billing cycle as directed by D.12-08-044. D.14-08-030 rejected this request, stating the "the rule allows each utility to flag and address high usage households according to their individual business models, including staffing resources and IT programming capabilities."

D.14-08-030 noted that,

> "customers with usage of 400%-600% of baseline generally appear more likely to successfully complete PEV process than customers whose usage exceed 600% of baseline. This suggests that higher priority should be given to post enrollment verifying the customers whose usage are 600% above baseline than those customers with 400%-600% of baseline usage…IOUs may, if necessary, also give

> higher priority to PEVs of 400%-600% baseline high usage customers who repeatedly exceed 400% usage limit. Since the high usage customer rule does not set a mandatory timeline on the post enrollment verification of the customer who exceeds 400% baseline usage, we clarify that the IOUs have the necessary discretion on how and when they conduct the post-enrollment verifications of the customers. Specifically, as we noted with SDG&E, other IOUs too may place the first time customers that exceed 400% baseline usage as their last PEV priority group. In all cases, be it 400%-600% baseline users or over 600% baseline users, the IOUs must take all reasonable actions necessary to assist each eligible CARE customers with legitimate household usage achieve energy efficiency while taking reasonable steps to ensure that only eligible households are enrolled."

Therefore we have previously determined, and reaffirmed, that usage above 400% of baseline, even once a year, is considered high usage, and that low-income customers should conserve energy. It is equally important to signal to customers who are not enrolled in the CARE program that usage above 400% of baseline is high and that they should also conserve. CARE customers receive this signal when the IOU notifies them that they are above 400% of baseline and must take certain steps to stay in the program.

We intend for the SUE Surcharge adopted today to serve a similar notice role: sending a message to customers that their usage is not simply moving into another tier, but that their usage is significantly above typical household use. To be effective, this signal must go beyond a mere indication that the customer has passed into a higher usage tier; the customer must be able to clearly tell that a portion of their usage was far in excess of the typical household usage and that conservation steps should be taken.

We agree that customers who use extreme amounts of electricity should not inadvertently be rewarded by rate reform, and we believe the CARE program provides a good model for identifying customers with truly high usage.

For the reasons set forth above, we adopt the super user surcharge proposed by CforAT and Greenlining, and establish usage above 400% as the threshold. Utilizing 400% of baseline will align the regulatory signals for low-income customers and all other customers. To underscore this alignment, the IOUs are directed to develop a system to notify customers, similar to that used for the CARE high usage program, when their usage is over 400%. Development of this notice shall be part of the marketing, education and outreach designed specifically for the SUE Surcharge and approved through a tier 2 Advice Letter.

Today's decision sets a SUE Surcharge to begin in 2017 on a glidepath to reach 1:2.19 of the Tier 1 rate by 2019. The SUE Surcharge will apply to usage above 400% of baseline (roughly equivalent to the top 2 to 10% of customers.[271]

TURN's comments on the two-tiered rate are instructive. TURN argues that under a two-tier rate the benefits of rate reform accrue to only the small group of customers who use the most electricity. For example, TURN states that, based on the supplemental testimony filed after the proposed decision was published, for PG&E approximately 78% of rate reductions would accrue to the top 6% of users, and for SCE approximately 62% of rate reductions would accrue to the top 6.1% of users.[272] We agree with TURN and other parties that it makes little sense to reward the users at the extreme with the greatest rate reduction.

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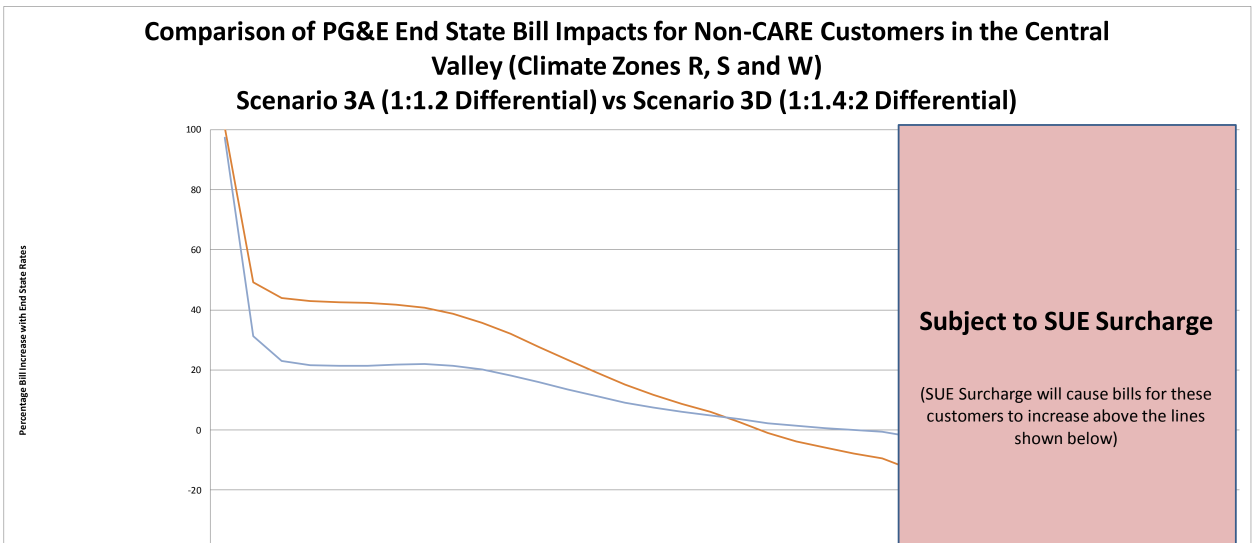
[271] The approximate number varies by IOU. Based on their Supplemental Filings, the usage covered by the SUE Surcharge would be as follows. PG&E: top 6.42% of customers and top 3.1% of usage; SCE: top 9.5% of customers and the top 4.02% of usage; and SDG&E: top 2.5% of customers and the top 7.18% of usage.

[272] TURN comments at 9-10.

Although today's rate reform is not intended "reward" any group of customers, we believe it is important to send a clear message that the most extreme users are not the intended beneficiaries of this decision, and that overall conservation by these superusers remains an important goal.

TURN's chart illustrating bill impacts for non-CARE PG&E customers showed that only customers that used more than 900 kWh in a given month would see a rate reduction.[273] 900 kWh is approximately equal to 300% of baseline for PG&E customers. The rate reduction for customers with use just above 900 kWh is moderate, but the rate reduction for customers using over 2500 kWh is dramatic. With a SUE Surcharge set at 400%, these customers will not be rewarded. To illustrate how this would change the bill impact analysis, we have modified TURN's chart from its reply comments to indicate the customers that would be subject to the SUE Surcharge.




| | 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cumumlative % Customers | 4.57 | 9.45 | 13.69 | 17.79 | 21.96 | 26.35 | 31.03 | 35.91 | 40.99 | 46.11 | 51.24 | 56.25 | 61.11 | 65.67 | 69.87 | 73.72 |
| % bill change to end state (Scenario 3A) | 100.74 | 49.3 | 44.03 | 43.03 | 42.58 | 42.36 | 41.83 | 40.81 | 38.77 | 35.71 | 31.97 | 27.71 | 23.38 | 19.2 | 15.22 | 11.75 |
| % bill change to end state (Scenario 3D) | 97.46 | 31.23 | 22.94 | 21.65 | 21.36 | 21.49 | 21.77 | 21.93 | 21.42 | 20.13 | 18.24 | 15.93 | 13.51 | 11.23 | 9.15 | 7.42 |

| | 800 -< 850 | 850 -< 900 | 900 -< 1000 | 1000 - < 1100 | 1100 - < 1200 | 1200 - < 1300 | 1300 - < 1400 | 1400 - < 1500 | 1500 - < 2000 | 2000 - < 2500 | 2500 - < 3000 | 3000 - < 3500 | 3500 - < 4000 | 4000 - < 5000 | 5000 - < 6000 | 6000 - < 7000 | 7000 - < 8000 | 8000 - < 9000 | 9000 - < 10000 | 10000 - HIGH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cumumlative % Customers | 77.19 | 80.25 | 85.32 | 89.18 | 92.01 | 94.07 | 95.57 | 96.65 | 98.97 | 99.57 | 99.78 | 99.87 | 99.91 | 99.96 | 99.98 | 99.99 | 99.99 | 100 | 100 | 100 |
| % bill change to end state (Scenario 3A) | 8.7 | 6.07 | 2.75 | -0.88 | -3.73 | -5.78 | -7.92 | -9.49 | -13.12 | -18.63 | -22.36 | -24.51 | -26.2 | -27.82 | -29.1 | -30.27 | -30.61 | -30.86 | -32.04 | -31.76 |
| % bill change to end state (Scenario 3D) | 5.99 | 4.87 | 3.59 | 2.32 | 1.38 | 0.72 | -0.03 | -0.62 | -2.09 | -4.11 | -5.17 | -5.93 | -6.24 | -6.79 | -7.14 | -6.92 | -7.5 | -7.81 | -7.01 | -8.18 |

[273] TURN comments at 9.

Applying the revenues collected from the SUE Surcharge to reduce the Tier 1 and Tier 2 rates will provide an added benefit to this structure. Therefore, we direct the IOUs to apply the additional revenue collected from the SUE Surcharge to Tiers 1 and 2.

The SUE Surcharge is different from a third tier in several respects. First, it is designed to target a narrow subset of customers. In contrast, the three-tier proposals are set at moderate thresholds that result in more customers falling into the most expensive tier. For example, for PG&E approximately 11% of usage[274] would fall into a third tier set at 200% of baseline. In contrast, only 3.1% of usage would be subject to the SUE Surcharge. Based on the evidence, we have significant concerns that a large portion of the usage in a Tier 3 would apply to ordinary customers. For example, based on the IOU supplemental filings, 16.7% (PG&E), 22.2% (SCE) and 6.2% (SDG&E) customers would fall into a 300% Tier 3 at least once per year.

Second, by using the term super-user electric surcharge, we believe that customers will be more likely to understand that their usage is in an extreme category and should be reduced. Because most customers currently do not respond to their marginal tier, we believe that this new, more accurate nomenclature, and the associated bill presentation, will provide an easier signal for customers to respond to.

To integrate SUE Surcharge with other rate changes, we direct the IOUs to be ready to implement this change in 2017. The SUE Surcharge will apply to the default tiered rate, or the alternative tiered rate once default TOU is in place. The

[274] This estimate is based on the PG&E Bill Impact Calculator which shows that 11% of sales are above 200%.

glidepath from 2017 to 2019 should be designed to ensure a smooth increase in the SUE Surcharge until it reaches the 1:2.19 endstate. Because SDG&E will reach two tiers in 2016, the glidepath for upper tier rates in the early years should anticipate the adoption of the SUE Surcharge in 2017 and provide for a relatively smooth transition for those customers. We do not want to see a large rate reduction in 2015-16 followed by a large increase in 2017 for customers subject to the SUE Surcharge.

The IOUs should work with interested parties to create a working group, including Energy Division staff, to develop appropriate bill presentment and notification for the SUE Surcharge. The IOUs must submit a tier 2 advice letter addressing these items no later than October 16, 2015.

We have considered whether the SUE Surcharge should apply to TOU rates and determined that the potential downsides of this approach outweigh the benefits. Specifically, based on the evidence in this proceeding, we believe that adding the SUE Surcharge to the TOU rates will result in rates that are less understandable and therefore more difficult for customers to respond to.[275] We direct the IOUs to evaluate the likelihood of undercollection in the event that high use customers switch to TOU rate to avoid the SUE Surcharge. The IOUs should strive to ensure that their forecasts of the potential for undercollection are accurate.

[275] This concern was echoed by the California Independent System Operator (CAISO). (CAISO Comments on APD at 3 stating that "the implementation of both a baseline credit and an excess consumption surcharge adjustment to most future TOU rate schedules, which will lead to profusion of prices, thereby confusing customers an d leading to ineffective TOU rate schedules.")

## 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.

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 an improved 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 potential benefits demonstrated by the evidentiary record, we approve default TOU rates in principle, to be implemented on a schedule that provides sufficient time and resources to assure that legal requirements are met and 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.[276] The IOUs should have records that will provide a starting place for identifying these customers. CforAT points out that not all eligible customers are signed up to participate in

[276] 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."

these programs and that therefore the IOUs' data will are not be able to identify all customers.[277]

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.[278] 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 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 statute 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 whether to add these customers to the exempt list

[277] CforAT Comments at 17.

[278] 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."

pursuant to Section 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.[279]

**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 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"

[279] 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."

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."[280] CforAT provided extensive evidence on how customers with difficulty affording energy may not be able to shift their energy use.[281]

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 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

[280] CforAT OB at 77 (citing Exh. CforAT-101 at 53).

[281] Exh. CforAT-101 at 51.

energy usage.[282] 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,[283] 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.

#### 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.[284] This structure is similar to

[282] 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)).

[283] *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.").

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

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 difference in the cost of energy by time 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?[285] 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 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

[285] SCE OB at 154.

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 more fully cost-based price differentials. 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 fully cost-based price differentials may be made later, informed by data and experience gathered during the course of pilot implementation and ongoing review of the glidepath transition.

#### 6.3.3. Baseline Credit in TOU Rates

A baseline credit should be part of the default TOU rate. The IOUs may, however, offer opt-in TOU rates without a baseline credit. An analysis of the legal requirements contained in Section 4.7.2 (Requirement for a Baseline Tier for Default Residential Rates) found that the baseline credit is not required for default TOU by law. However, the strong policy reasons for implementing a baseline credit are particularly 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.[286]

There are several reasons 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 in which the customer lives in,

[286] *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).

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.[287]

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.[288] A baseline credit also reduces alignment with cost causation and sends a less economically efficient price signal.[289] 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 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 credit in default TOU, and because a baseline credit will allow for the best

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[287] TURN OB at 46 (citing TURN 201 at 60 and CforAT RB at 15).

[288] PG&E RB at 74.

[289] 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).

comparison of optional rates with a future default TOU rate, a baseline credit must be part of the design for default TOU and at most optional TOU rate offered by the IOU (except for those TOU rates that are targeted at shifting usage to electricity from other more carbon-intensive energy sources such as gasoline).

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[290] 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.[291] PG&E agrees with this calculation of baseline credit,[292] 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, and that other calculations methods could be considered in the future.

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

[290] SEIA OB at 27.

[291] ORA OB at 67.

[292] PG&E RB at 77-78.

straight credit to a TOU rate.[293] 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 proposal would raise all TOU rates by equal percentages to recover the revenue paid out as a credit.[294]

SDG&E in comments on the PD stated that it currently has a baseline credit in its Schedule TOU-DR, adopted in D.12-12-004, that differs from the one described in this decision.[295] According to SDG&E, Schedule TOU-DR includes "credits for usage up to 130% of baseline that the customer would have received under their otherwise applicable tiered rate." We find this approach reasonable, and it has previously been evaluated and approved by the Commission. Therefore, SDG&E is not required to make changes to its existing baseline credit methodology for Schedule TOU-DR.

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.[296]

The presentment of the baseline credit is also important for customer understanding. We expect that bill presentment will be studied in the TOU rate design and study required by this decision.

While the SUE Surcharge is a beneficial price signal to consumers to reduce overall consumption, the TOU rates are designed to promote conservation during the periods when it is most needed. The customers who can best reduce overall consumption may not be the same as the customers who can

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[293] Exh. ORA-101 at 3-17; ORA OB at 67, 69, 72; Exh. SEIA-101, Attachment RTB-3 (describing SCE's methodology).

[294] Exh. TURN-201 at 60.

[295] SDG&E Comments at 16.

[296] *Id.* at 28; Exh. ORA-101 at 1-12.

reduce consumption during certain times of day. With a default TOU and an optional tiered rate, customers can choose the pricing approach that works best for them. Although this may result in some high usage customers choosing default TOU because it does not have a SUE Surcharge (as opposed to choosing default TOU because they can reduce usage at peak times), we believe that this option is only appealing to a small number of customers. The number of customers who may be subject to the SUE Surcharge is relatively small, and of those customers we hope that some are able to reduce usage during peak periods.

A SUE Surcharge in TOU rates is counter to our goal to make TOU rates understandable to the customer. If a SUE Surcharge is included in TOU rates, then we would effectively have a tiered TOU rate. As discussed above, the tiered TOU rates have been confusing to customers and have not been well received. In addition, including a SUE Surcharge could move the TOU rate further from cost-basis.

We find that the baseline credit on any default TOU rate and on most available TOU optional rates and on any pilot rates, is an essential element of wide-scale TOU adoption for residential customers. We also find that a SUE Surcharge should not be part of default TOU rates, but may be included in some optional TOU rates.

#### 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.[297] We agree that this proposal merits consideration and direct the utilities to consider this option in their design of default TOU rates. A semi-annual true-up may be especially important if we ultimately decide to employ seasonally-differentiated 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.[298] 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.

#### 6.3.5. Outreach and Education for TOU Rates

Without adequate customer outreach and education, the protections set forth above will not be meaningful.[299]

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

[297] ORA OB at 80.

[298] Exh. SDG&E-102; Exh. CAW-7.

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

residential customers based on their actual usage.[300] 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.

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

[300] 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.

rapid penetration of rooftop solar."[301] The Commission is well-aware of these anticipated changes, as well as the possibility of unexpected changes, in the load curve.[302]

At the same time, however, AB 327 requires default TOU periods that are "appropriate" for the next five years. There are excellent policy reasons for requiring a five-year forward-looking design 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 hold constant for five years. In essence, customers on the default rate could move en masse with on/off peak periods designed to cover the exact time periods that were identified five years ago.

This assumption misses the entire point of adopting TOU.[303] 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

[301] TURN OB at 59.

[302] 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.

[303] 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.

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."[304]

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 structures should take into account the most accurate peak and off-peak periods as determined through the GRC or RDW process on a five-year forward-looking basis.

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 optional TOU rates with complementary TOU periods that considered together address grid needs, but do not impose unreasonable hardship on individual customers; and

[304] Exh. EDF-102 at 21.

- changing the default rate for new customers in each GRC to reflect new TOU periods, but allowing already enrolled customers the option to keep their legacy TOU period structure for the five year period suggested by AB 327.[305]

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."[306] 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.[307] 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.[308] 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 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

[305] Through its experience with the Power Charge Indifference Adjustment (PCIA), the Commission already has experience with rates that are vintaged by year. Similarly, California Resource Board (ARB) uses vintaging of cap and trade GHG allowances as part of its AB 32 compliance program.

[306] RT Vol. 23 at 3697, EDF/Fine

[307] RT Vol. 23 at 3698, EDF/Fine.

[308] RT Vol. 23 at 3699, EDF/Fine.

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. APS offers three different TOU rates and two different TOU periods, Electricité de France has multiple TOU rates available with different TOU periods.[309]

EDF points out that if TOU periods are not adjusted over time, rates will not accurately reflect cost.[310] 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 rates created from averaging prices and costs over extended periods of time.[311] Rates are both cost-based and policy-based. TOU rates represent the average of

[309] Exh. PG&E-101 at 2-59 n.69(a).

[310] Exh. EDF 102 at 21.

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

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 both reflects cost 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 100 or 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.[312] 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 for selecting these hours will be based on the methodology for identifying peak/off peak periods adopted in that proceeding.[313]

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[312] 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.

[313] 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.*

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 were 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.[314] As ORA points out, TOU rates will "better align" EE and DG benefits with IOUs' avoided costs."[315]

These special programs should not be the primary driver for rate design. However, by requiring that most TOU rates include a baseline credit, we can best assure that such rates do not undermine the other resource programs that we implement and that ratepayers pay for in the revenue requirement.

#### 6.5.2. Existing NEM and Rooftop Solar

Consistent with Section 2827, the Commission established NEM tariffs in 1995 to encourage the installation of distributed generation on the customer side

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

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

of the meter. Customers who install and operate small (1 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 PV 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.[316]

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 TOU 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 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

[316] 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").

migrated to E-TOU and customers on closed schedules E-8 and EL-8 would be migrated to E 1/EL-1. In comments on the Proposed Decision, PG&E requested that, rather than closing E-6 to new customers in 2015, the closure of E-6 to new customers be made coincident with the opening of the new E-TOU-A and E-TOU-B optional schedules, with new update TOU periods.

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).[317]

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

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 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.[318] 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

[318] Vote Solar OB at 14.

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 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.[319]

Finally, Vote Solar's witness described the attributes of a "solar friendly" TOU option.[320] A "solar friendly" TOU rate structure would consist of a "volumetric rate structure without a customer charge or minimum bill." It would also have a tiered rate structure with significant rate differentials between the top tier and lower-tier rates. Vote Solar recommends that all new TOU rate tariffs be revenue neutral with the default tariff.[321] Vote Solar argues that these attributes are necessary for a solar friendly tariff, and that therefore the existing TOU tariffs should be retained. Vote Solar asserts that a solar friendly tariff would encourage investment in PV and encourage customers to select a TOU rate.

[319] *Id.* at 22.

[320] Exh. Vote Solar-101 at 18.

[321] *Id*.

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.[322] 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 never change in the future.[323] PG&E maintains that its E-6, E-7 and E-8 are far below cost and heavily subsidized by other customers.[324] 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.[325] 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.[326] 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

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[322] PG&E RB at 80.

[323] PG&E OB at 70.

[324] *Id.* at 71.

[325] Vote Solar OB at 18.

[326] PG&E RB at 82.

than other customers, meaning E-6 is not revenue neutral on a customer basis, only on a class basis.[327]

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.

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."[328] Vote Solar's reliance on D.06-12-025 as a precedent is also unreasonable, as that decision merely reopened

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[327] *Id.* at 83.

[328] D.14-03-041 at 17 (finding that on reason to reject the IOUs' proposal for a shorter NEM transition period was that the IOU estimates could not account for rate changes expected in R.12-06-013.) This finding that rates could change under R.12-06-013 applies equally to the IOUs' ability to predict the outcome in R.12-06-013 and to the ability of NEM customers and the solar parties to predict the outcome. In other words, D.14-03-041 found that there was uncertainty regarding future rates that would impact the payback period.

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. We are endeavoring to avoid abrupt changes here through a variety of approaches, but recognize that individual hardships may nonetheless occur. We seek to avoid that outcome to the greatest degree possible.

We are 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 the Commission strive to set default TOU periods that are appropriate for at least five years.

Given the number of significant changes we are adopting, including tier flattening and increased use of minimum bills, and given the need for customer acceptance, we also find that the transition period for PG&E's E-6 tariff and SDG&E's DR-TOU tariff should be at least five years from January 1, 2016. E-8 has been closed for well over five years and may be eliminated in 2016. E-7 has been closed since 2008 and may also be eliminated in 2016. The minimum bill approved for the default tariff must also apply to existing TOU rates including E-6. Further, those residential PG&E customers with pending interconnection requests selecting an E-6 rate will be allowed to take service on

E-6 in the case where the processing of the interconnection request is finished after E-6 is officially closed.

A summary of the changes to the optional rates appears below.

| Rate Schedule | Change made by this decision |
|---|---|
| PG&E Schedule E-6 | Closed to new customers on 1/1/16. Transition period toward elimination of at least five years begins on 1/1/16. |
| PG&E Schedule E-7 | Eliminated on 1/1/16. Existing customers transferred to E- TOU on that date. |
| PG&E Schedule E-8 | Eliminated on 1/1/16. Existing customers transferred to E- TOU on that date. |
| SDG&E DR-TOU | Closed as of January 2015 pursuant to D.12-12-004. Transition period toward elimination of at least five years begins on 1/1/15. |

### 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. The following table illustrates the impact of a baseline credit.

Table comparing Peak/Offpeak rates with and without a baseline credit[329]

| 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 possible that high-usage customers will shift to TOU and low-usage customers will remain on the tiered rate. Our decision to require baseline credits in most TOU rates will mitigate this potential, but cannot eliminate it entirely.

[329] 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.

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 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."[330] Revenue shortfall between tariffs arises "most starkly" when the TOU rate differs substantially from tiered rates.[331]

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."[332] 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.[333]

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.[334] If there was a shift in customer usage, the figure would

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[330] CforAT OB at 73.

[331] SCE OB at 155.

[332] TURN OB at 52 (citing RT Vol. 12 at 1369, PG&E/Quadrini).

[333] *Ibid.*

[334] *Id.* at 51-52 (citing RT Vol. 14 at 1791-92, SDG&E/Fang).

be larger.[335] 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. Our requirement for baseline credits will accomplish that to some degree. We further direct the 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, a revenue shortfall is less likely to occur once the tiered rate is closer to cost-based.[336]

In the event there is an undercollection, the recovery must be apportioned fairly. Until the magnitude of undercollection is better understood, any undercollection directly resulting from rate design should be spread to the entire residential class. An "undercollection" of fuel and purchased power costs resulting from reduced usage probably does not have to be recovered at all, because those variable costs will also be reduced through lower consumption.

SEIA proposes a "virtuous cycle" in which if there was an undercollection from the TOU customer group, the undercollection would be recovered from

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[335] *Ibid*.

[336] PG&E RB at 79.

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.[337] 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.

SCE does not support "virtuous cycle" proposal.[338] SCE argues that before a "large-scale movement to cost-based TOU" it is essential to reform the tier structure.[339] 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 Application (A.) 13-12-015 will recover shortfalls from within the entire residential class over an appropriate period of time."[340] 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."[341] PG&E also agrees with ORA that undercollection should be made up by the entire residential class.[342]

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[337] CforAT OB at 73.

[338] SCE RB at 87 n.328.

[339] SCE OB at 150.

[340] ORA OB at 65 (citing D.14-12-048).

[341] RT Vol. 22 at 3475, ORA/Kao.

[342] PG&E RB at 79.

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 moderating the peak periods during which expensive, higher polluting generation resources must be brought online. This in turn should result in reduced purchased power and infrastructure costs, and potentially GHG emissions, because California will be able to make better use of the cleanest energy sources.

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 their 2018 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.[343]
- Most effective way to communicate and implement TOU programs.[344]
- 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.[345]
- Estimating revenue shortfall.[346]
- Opt-in pilot should use randomized treatment design to simulate benefits of a default pilot.[347]
- Cost estimates for outreach, education, marketing, billing and IT modifications.

[343] SDG&E RB at 27.

[344] ORA OB at 70.

[345] *Id.* at 71 (citing SCE OB on legality of pre-2018 default pilot).

[346] CforAT OB at 4-5, 72-79.

[347] ORA OB at 71 (citing SDG&E OB on legality of pre-2018 default pilot).

- Quantify variability of bill and load impacts across key geographic, demographic and segments as well as for varying rate designs and outreach messaging.[348]
- Section 745 requirements.
- Different peak period hours and price-ratio combinations to test differences in customer acceptance and engagement under each variation.[349]
- Model range of revenue deficiencies based on different assumed levels of adoption and levels of migration between optional and default tariffs.[350]
- Comparing TOU opt-in structures and acceptance by Climate Zone.[351]
- 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.[352]
- Marketing message to gain engagement with diverse customer segments.[353]
- Effectiveness of marketing, education and outreach for non-English speakers.
- Lessons to reduce costs for wider-scale outreach and operations.[354]

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[348] *Id.* at 72 (citing PG&E opt-in pilot description).

[349] PG&E OB at 63*; id*. at 67 (citing Exh. PG&E-109 at 5-7; RT Vol. 12 at 1423 PG&E/Mandelman).

[350] TURN OB at 53.

[351] RT Vol. 12 at 1423, PG&E/Mandelman.

[352] PG&E OB at 65.

[353] *Ibid.*

[354] *Ibid.*

- Test system operationality.[355]
- 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.[356]
- 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.

##### 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.[357] 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.

[355] *Ibid.*

[356] Exh. EDF-101 at 26.

[357] *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).

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 collectively select a consultant, to be paid by the IOUs, to advise on and document the study parameters and pilot designs. Energy Division will make the final decision in the event the working group is unable to agree on a consultant or on the scope of work. We expect 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 3 advice letter. As discussed below, the pilot design should include both opt-in pilots for immediate implementation and default TOU pilots to be implemented in 2018 as permitted by statute. The Tier 3 advice letter should include (i) request for authorization of TOU pilot study costs, and (ii) request for authorization of cost recovery for costs associated with default TOU in Residential RDW.

#### 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."[358]

TURN asserts that this language should be interpreted to require a default pilot prior to any "commitment to transition to default TOU rates."[359] The language of the statute requires the findings to be made prior to <u>*authorizing or requiring*</u> the utilities to <u>*employ*</u> 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 . . ."[360] 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 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

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[358] Section 745(d).

[359] TURN OB at 53.

[360] *Ibid.*

intent in passing SB 1090 is to 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 protect customers by having certain studies 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.[361] TURN cites SDG&E witness Winn and Willoughby as "needing insight from 2018 pilot."[362]

Similarly, SDG&E's witness George said that the SMUD study should not be relied on as the basis of default TOU.[363] George cites the need to test demand response in the absence of selection bias.[364]

[361] SDG&E OB at 60 (citing RT Vol. 13 at 1573-74, SDG&E/Winn).

[362] RT Vol. 15 at 1972, SDG&E/Willoughby.

[363] RT Vol. 16 at 2139-2144, 2181, SDG&E/George.

[364] 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 of how such data would be developed or used to meet Section 745.[365] 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.

For example, it is not necessary to have default pilot to determine if TOU rates would impose a hardship on certain customer groups.[366] SB 1090 requires evidence to be gathered that *assumes no change in usage*. Therefore, the SB 1090 findings can be developed by applying proposed TOU rates to existing usage data. 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

[365] ORA RB at 27.

[366] *Id.* at 28.

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 as a result of knowing they are on a TOU rate. Thus the best data to use is the data that already exists.[367]

After careful review, we find that only a few of the recommended study topics would require a default TOU pilot. 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 once default TOU rates are in place. The 2018 default TOU pilot will provide an opportunity to begin studying these areas in advance of full rollout.

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"[368] that cannot be completed on the record of this proceeding. We therefore find it is imperative

[367] To be clear, the existing usage data could not be used to determine how customers will respond to TOU rates.

[368] TURN OB at 54-55.

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."[369] Clarifying these terms will not happen through a default TOU pilot. Rather, this needs to be done by the Commission through this proceeding at an earlier date. PG&E recommends it be done through the "collaborative workshop process."[370] 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[371] 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.

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[369] PG&E RB at 85-87.

[370] *Id*. at 86.

[371] *See*, e.g., D.08-07-045; R.02-06-001; A.07-12-009.

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. In a world where the Nest programmable thermostat was the most hyped tech holiday gift for 2014,[372] 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.

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 (if the findings required by Section 745 (d) can be made by that time).

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.

[372] http://www.extremetech.com/extreme/194595-extremetechs-2014-holiday-gift-guide-high-tech-futuristic-gift-ideas-for-geeks-and-nerds.

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."[373]

[373] Exh. PG&E-101 at 2-54.

**Example of the Twelve Separate Rates with Current TOU**[374]

| 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 basic TOU rate structure with 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 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.[375] The mock TOU bill would be even easier to understand if it included only a baseline tier.

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[374] *Ibid.* (Table 2-11).

[375] Exh. TURN-201 at 62.

**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.

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 adhere to 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, with different time periods and rate differentials.

(2) At least one opt-in TOU rate should include the default TOU attributes set in this decision: (i) a baseline credit, (ii) no super user electric surcharge, and (iii) a minimum bill rather than a

fixed monthly charge. Alternative opt-in TOU rates can be offered with different features (i.e., no baseline credit, added super user electric surcharge, fixed monthly charge).

(3) Changes to TOU periods for existing rates should be made in currently pending RDWs, future RDWs, or current or future GRC Phase 2 proceedings. TOU periods for new residential TOU rates may be different from existing TOU periods and can be set in either a utility's RDW or GRC Phase 2.

(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 first be closed to new customers. Existing customers (legacy tariff customers) should be permitted to remain on their TOU tariff for at least five years, with the ultimate duration of the tariff to be determined in future proceedings.

(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).[376] 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."[377]

[376] Exh. PG&E-101 at 2-52.

[377] *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.[378] [379]

The E-TOU schedule would include a $5/month service fee, and E-TOU CARE would include a $2.50/month service fee.[380]

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.[381] 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[382]**

| **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 |

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

[379] 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.

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

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

[382] *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.[383] In comments, PG&E also requests that the closure of E-6 to new customers be made coincident with the opening of the new E-TOU, with new updated TOU periods.[384]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 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.[385] Based on the evidence in this proceeding, we agree that a two-period TOU rate will be the most understandable and

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[383] PG&E Schedule E-6 at Sheet 4.

[384] PG&E Comments at 19-20.

[385] PG&E OB at 55.

acceptable to residential customers. Therefore, we believe that PG&E E-TOU proposal, as modified below, is reasonable, fair and consistent with the law.

In its May 11, 2015 Opening Comments on the Proposed Decision, PG&E requests that it be allowed to offer both an E-TOU-A rate, with a baseline credit, and an E-TOU-B rate, without a baseline credit. E-TOU-A and E-TOU-B would each have a discounted CARE counterpart.[386] PG&E also notes that requiring it to track the personal enrollment date for each customer who enrolls in E-TOU between summer 2015 and early 2016 will be difficult. To remedy this problem, PG&E proposed that its new E-TOU rates become effective after a decision on E-TOU periods in PG&E's 2015 RDW (A.14-11-014) is final. PG&E explains that this approach would avoid having a six month period with customers signing up for E-TOU with outdated time periods, and then having to track these customers so as to sunset them onto a TOU with the correct TOU period five years later.

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

- A minimum bill rather than a fixed charge.
- Undercollections can be made up from the residential rate class as whole over a reasonable amortization period.
- TOU 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. Notwithstanding the foregoing, in the event that new TOU periods are set by A.14-11-014 and provided that reasonable notice is made to enrolling customers, PG&E is not obligated to offer a five-year legacy option for the current TOU rates to customers who enroll in TOU rates between the date of this decision and the earlier of (i) the effective date of any new TOU

[386] PG&E Opening Comments at 19-20.

periods established in A.14-11-014 and (ii) the date that is 12 months from the date of this decision. In such event, PG&E must instead offer the five-year legacy option based on the new TOU time periods.

- So that we can better understand the degree to which the E-TOU rate reflects costs, 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 default rates 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. If E-TOU is approved without a baseline credit, PG&E must include addition of the baseline credit as part of its 2016 RDW. PG&E is permitted to offer an E-TOU-A (with baseline credit) and E-TOU-B (without 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.[387] 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."[388]

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.

[387] *Id.* at 63.

[388] *Ibid.*

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

SDG&E proposes a new, optional, 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 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.[389]

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."[390]

The amounts of the proposed DDMSF are considerably higher than $10. Specifically, SDG&E proposed a DDMSF plus monthly fixed charge ranging from a low of $27.78 (up to 3kW) and a high of $79.53 (6 kW and above).

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[389] SDG&E OB at 53.

[390] Exh. SDG&E-108 at CF-48/Fang.

**Table CF-12: SDG&E Proposed DDMSF for Optional and Experimental TOU Rates**[391]

| 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 |

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.[392] To understand the calculation of the demand charge a 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.[393]

[391] Exh. SDG&E-108 at CF-2/Fang.

[392] TURN OB at 47.

[393] *Id.* at 48-49 (citing RT Vol. 13 at 1565-70, SDG&E/Winn).

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, and the duration of the time 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 rates without a separate demand charge. In other words, SDG&E is not permitted to offer an option TOU rate with a DDMSF and $10 monthly service fee at this time.

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."[394] 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:

**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 p.m.-6 p.m. and

[394] Exh. SDG&E-107 at CF-43/Fang.

Experimental TOU B has a proposed summer on-peak from 5 p.m.-9 p.m. The off-peak periods for summer and winter would be the same across all three optional TOU rates.[395]

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.[396]

**Proposed Optional and Experimental TOU Rates with 2015 RDW TOU Periods[397]**

| 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 |

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

[395] Exh. SDG&E-111 at LW-4/Willoughby.

[396] Exh. SDG&E-108 at CF-3/Fang.

[397] *Id.* at CF-4/Fang.

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 or other fixed charge; minimum bill only.
- Undercollections can be made up from the residential rate class as whole over a reasonable amortization period.
- TOU 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. Notwithstanding the foregoing, in the event that new TOU periods are set by A.14-01-027 and provided that reasonable notice is made to enrolling customers, SDG&E is not obligated to offer a five-year legacy option for the current TOU rates to customers who enroll in TOU rates between the date of this decision and the earlier of (i) the effective date of any new TOU periods established in A.14-01-027 and (ii) the date that is 12 months from the date of this decision. In such event, SDG&E must instead offer the five-year legacy option based on the new TOU time periods.
- So that we can better understand the degree to which residential TOU rates reflect costs, 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 default rates 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 .[398] [399] The new rate has three time-of-use periods 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.[400]

Option B, for higher usage customers such as EV owners, has less differentiated summer and winter peak periods, no baseline credit, and a $16

[398] *See* A.13-12-015 (2013 Rate Design Window).

[399] Exh. SCE-101 E-33.

[400] 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)).

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.

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.[401]

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.

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[401] *Id.* at § 4(e)(iii)(a).

## 7. Addressing Fixed Costs in Rates

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.

AB 327 permits, but does not require, fixed charges in residential rates, provided the revenue collected will offset non-volumetric costs.

Parties to this proceeding 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. Importantly, until there is resolution over the appropriate recovery of these fixed costs, the exact extent of any subsidy between low usage and high usage customers remains unknown.

During this proceeding, parties focused on two major questions regarding fixed charges:

(1) Are fixed charges appropriate for residential customers?

(2) What costs should be included and how should this amount be calculated?

We now add a third question:

(3) What should the process be for considering a fixed charge for residential rates?

In comments on the PD, parties were sharply divided over whether fixed charges were properly addressed and whether a fixed charge should be approved. However, parties on all sides of the issues urged the Commission to avoid re-litigating issues that could be resolved through the evidence and briefs in this proceeding. Although we agree with the goal of minimizing the need for future litigation, we are persuaded that any implementation of fixed charges must be done through careful, measured steps. Therefore, most aspects of the fixed charge proposals from this proceeding will need to be litigated anew in future proceeding. However, litigation in this proceeding was not without value: the process set forth below is informed by the evidence and arguments presented in this proceeding.

As discussed in full below, we find that a fixed charge linked to costs that do not change as a result of individual customer usage is not appropriate unless certain requirements are met. These requirements include ensuring that the charge reflects appropriate costs, establishing a consistent methodology across utilities, and waiting until each utility has shifted to default TOU rates.

We believe that a fixed charge can play a role in the residential rates in the future -- especially as the electricity market evolves to accommodate more distributed technologies. We expect that in the future, there may be substantial variation in how residential customers procure and conserve electricity for their needs. The role of the utility in this changing world may include services for which volumetric pricing is not appropriate or possible. Therefore, we believe continued consideration of a fixed charge in residential rates is appropriate and we direct the IOUs and stakeholders to follow the process below.

The evidence provided by parties in this proceeding focused on the fact that there is no agreement on how to identify and calculate fixed costs. The IOUs failed to articulate a clear and consistent methodology, and other parties asserted that this lack of a consistency was a primary reason for not approving any fixed charge. The results of the evidence are discussed in detail below, but can be summarized as follows.

There are three categories of costs that were discussed in the proceeding: (1) customer-specific costs that do not vary with electric usage, such as meters, billing services and customer service, (2) marginal customer-specific costs that do vary with demand such as capacity-related costs associated with transmission and distribution assets that are driven by customers' coincident and non-coincident demand, and (3) a broader range of system fixed costs, such as poles. Generally, parties agree that category 1 could be included in calculation of a fixed charge, and that category 3 should be excluded. Parties disagreed strongly on the treatment of category 2. Moreover, within category 1 we do not yet have a clear picture of exactly what costs should be included.

Currently, there is disagreement regarding the appropriate manner to identify fixed costs across utilities and there is not a consistent methodology across utilities for calculating the marginal cost of customer-related services. PG&E has used the NCO method and SCE and SDG&E use the rental (deferral) method.

Fixed costs should be calculated in a manner that truly reflects customer-specific costs and minimizes regressive impacts of this cost collection method. While the record does not allow us to adopt a specific methodology for setting a fixed monthly charge, it does provide us with the evidence necessary to set the next procedural steps for reaching a resolution. Therefore, prior to further consideration of fixed charges, the following four conditions must be met:

(i) For each IOU, a GRC Phase 2 decision issues that approves a calculation of fixed charges. To accomplish this, each IOU, in its next GRC Phase 2, must provide sufficient evidence to identify and calculate fixed customer costs that are specifically intended to represent marginal customer costs that would be the basis of a fixed charge. This amount must be consistent with Section 739.9. We realize that IOUs may take different approaches in their requests, but note that we will be seeking consistent methodologies across utilities to the extent possible.

(ii) A GRC Phase 2 decision issues approving categories of fixed costs for consideration of a future fixed charge. To accomplish this, the first GRC Phase 2 filed by one of the three IOUs subsequent to today's decision shall include workshops on fixed charges.[402] The assigned ALJ for that GRC, the assigned ALJ for R.12-06-013 and the Energy Division will set workshops to discuss a consistent methodology for potentially setting fixed charges based on fixed costs identified in each utility's individual GRC Phase 2 (see condition (i) above). Issues for these workshops include:

a. Which fixed costs are appropriate to collect through a fixed charge.
b. Ensuring that any fixed charge amount treats small and large customers fairly.
c. Timing of including new or increased fixed charges in residential rates.
d. Marketing, education and outreach for fixed charges.

The decision on the proposed fixed charge calculation will apply to the specific utility, with respect to the actual amount of fixed costs identified, but the determination of which *categories* of costs the Commission determines should be permitted in a fixed charge should be considered precedential. The GRC Phase 2 applications for the other two IOUs should rely on the findings from the first decision. Any requested variations from the methodology approved for the first

[402] Alternatively, this process can start with a pending or later-filed GRC Phase 2 if the parties to that GRC Phase 2, the assigned ALJs, and Energy Division so agree.

IOU shall be accompanied by material evidence demonstrating differences between the two IOUs' systems.

(iii) A decision in the IOU's 2018 Residential RDW that approves a new fixed charge request from the IOU. The IOUs may not file a new request for a fixed charge prior to the Residential RDW. The Residential RDW applications will be consolidated.

(iv) Default TOU is implemented.

Provided that all four conditions have been met, a fixed charge can be implemented with an effective date at least one year after the start of default TOU.

## 7.1. Generally

### 7.1.1. A Fixed Monthly Charge May Be Reasonable for Fair Residential Rate Design

Currently, fixed costs are included in volumetric rates. Two concerns have been raised with this approach. First, high use customers may be paying a disproportional amount of fixed costs and this effect is exacerbated by steep tiers. Second, some customers (such as vacation home owners and some solar PV owners) have minimal volumetric usage and thus often pay comparatively little towards fixed costs incurred on their behalf.[403]

The first problem, the potential subsidy, can be addressed by flattening the tiers and perhaps by allowing for a mechanism, such as a fixed charge, to collect customer-specific costs. This decision sets forth the timeline for considering customer-specific fixed charges in the future, as well as for assessing what, if any,

[403] Under the NEM program a solar customer can net power imported from the utility against power generated and exported by the customer. The value of NEM customer contributions other than through payment of volumetric rates is being examined in other proceedings at the Commission such as R.14-07-002 and R.14-08-013.

other distribution or system-wide charges should be covered by a non-volumetric or volumetric charge.

The second problem, customers with limited usage that pay volumetric rates that recover only a small amount fixed costs can be resolved with a minimum bill. In the analysis below, we evaluated both a fixed monthly charge and a monthly minimum bill.

#### 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[404] and for SDG&E it is $0.17/day (approximately $5/month).[405] SCE has a minimum bill of less than $2 per month and a small fixed charge.

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.[406] The decision was reversed less than a year later[407] 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.[408]

[404] D.11-05-047 at 18 (referring to the minimum bill somewhat confusingly as a "minimum charge").

[405] Exh. SDG&E-107 at CF-27, CF-28.

[406] D.87-12-009.

[407] D.88-07-023.

[408] Exh. PG&E-111 at 16; Exh. NRDC-101 at 46; *see generally* D.96-04-050.

SCE cites Commission decisions from 1993[409] and from 1996[410] (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."[411] 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."[412]

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 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."

[409] D.93-06-087.

[410] D.96-04-050.

[411] D.96-04-050 at 107-108.

[412] D.93-06-087 at 27.

#### 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."[413] 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 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.[414]

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[413] Section 739.9(a).

[414] *Id.* at (g).

### 7.2. Identifying and 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 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 solar customers avoid. To understand the link between fixed costs and a fixed charge in rate design, we must go back to the GRC process.

We periodically evaluate proposals for calculating the utilities' fixed costs during part of each electric utility's GRC cycle. During the GRC, we first 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, administrative and general expenses, fuel and purchased power 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 1 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 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 goals, 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.[415] 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 its proposed 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 EPMC multiplier in order to recover the full revenue requirement, no more and no less.[416] The EPMC process in utility revenue allocation is essentially the markup (or markdown) of the marginal cost to reflect the embedded cost revenue requirement.

[415] 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.

[416] Exh. PG&E-109 at 1-35, 1-36.

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."[417] 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.[418]

PG&E states that its fixed costs to serve residential customers are approximately $11.49 per residential customer per month.[419]

PG&E suggests that AB 327's $10.00 limit on the maximum allowable fixed monthly charge makes the issue of which costs are identified as fixed 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 2 proceeding, in which it estimated that its EPMC-adjusted marginal customer cost is $198.09 per customer-year, or $16.51 per customer month.

#### 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

[417] PG&E OB at 30.

[418] *Id.*

[419] PG&E OB at 31.

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.[420]

In SCE's opinion, fixed costs should reflect customer-specific costs, and portions of generation/transmission capacity and grid-related fixed costs of service, i.e., costs that do not vary with customer usage.[421] 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.[422] 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 center)) results in a cost of $13.30/customer/month.[423]

For comparison, SCE applied 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.[424] SCE argues that certain costs of distribution infrastructure should be included in the calculation of fixed costs, including the

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[420] SCE OB at 83.

[421] Exh. SCE-101 at 27.

[422] SCE OB at 84.

[423] *Ibid.*

[424] *Ibid.*

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.[425]

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.[426] 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.[427] 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.[428]

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 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.

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425 SCE OB at 85.

426 Exh. SCE-101 at 28.

427 SCE OB at 85.

428 *Id.* at 83-84.

### 7.2.3. SDG&E Fixed Cost Calculation

Currently, SDG&E's residential customers are subject to a minimum bill of approximately 0.17 and 0.136 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 $10 in 2017, with an annual CPI adjustment occurring in 2018 and later. Although in SDG&E's opinion, a distribution rate structure designed to reflect clear and accurate prices signals would consist of a monthly service fee to recover distribution-related customer costs along with a non-coincident demand charge to recover demand-related distribution costs,[429] in this proceeding SDG&E proposes only the monthly service fee, and would continue to recover the residual distribution and demand costs through the volumetric ($ 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 month 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 allowed under AB 327.[430] SDG&E also suggests that the appropriate forum to address specific

[429] 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.

[430] Exh. SDG&E-109 at CF 23-24.

methodologies for determining fixed costs and charges is in each utility's GRC Phase 2 proceeding.[431]

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 $0.30 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, UCAN 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.[432]

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.[433]

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[431] *Id.* at CF-24.

[432] UCAN OB at 25; IREC OB at 19; OB at 16.

[433] 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.[434]

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.[435] 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.[436]

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).[437]

While collecting customer-related fixed costs separately from capacity costs and energy may be 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

[434] Exh. TURN 204 at 49.

[435] PG&E RB at 30-31.

[436] Exh. NRDC-101 at 52.

[437] Exh. TURN-207, Attachment WBM-10 at 444.

precisely which costs are fixed, and among the universe of those fixed costs, which should be collected through a fixed charge.

## 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. 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.[438] 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."[439]

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, argued that a fixed charge should not be set at the same level for both large and small residential users. They 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.[440]

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.[441] Because customers can respond to variable rates by

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[438] ORA OB at 29.

[439] *Id.* at 32.

[440] CALSEIA OB at 16.

[441] ORA OB at 28.

reducing consumption, ORA and NRDC, maintain that variable rates are more efficient.[442]

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.[443] 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."[444]

NRDC witness Chernick calculates that for every $1/month increase in the fixed charge, the average energy rate would be reduced by about $1 per MWh, or about 1%, which means that "a $10 month fixed charge would reduce the average energy charge by about 10-11%; assuming roughly proportional

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[442] RT Vol. 17 at 2337, NRDC/Chernick.

[443] D.11-05-047 at 33.

[444] D.14-04-007 at 41.

distribution of the rate reduction across tiers, the reduction in the conservation incentive would be similar."[445]

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.

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,

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[445] Exh. NRDC-101 at 49-50.

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.[446] 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.[447]

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

[446] Exh. PG&E-101 at 2-6.

[447] Exh. SDG&E-106 at CY-3-4.

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.

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 are regressive, in that they have a disproportionally negative impact on low-income customers, and would create a new cross-subsidy, with low-income, lower-usage, 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 is one way to address the concern that higher-usage customers are paying a disproportionate amount of fixed costs incurred to provide 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.[448] 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."[449]

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

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[448] D.96-04-050 at 115.

[449] *Id.* at 113.

than residential rate design. In addition, many of these proceedings have been resolved through settlements. As a result, the marginal cost figures ultimately 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.

Further, our techniques for measuring marginal distribution costs have been limited to date, typically involving a regression analysis of forecasted increases in load versus forecasted distribution plant investments.

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 collection of at least customer-related fixed expenses.

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.

We recognize that a fixed charge, as a rate design element, would not encourage additional conservation. However, we determine that the impact is likely to be small. We acknowledge that a fixed charge would represent a larger percentage of the monthly bill for those customers whose usage is lower but note that, 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 agree with parties that the IOUs failed to articulate a clear and consistent methodology to identify and calculate fixed costs. Although we believe that a fixed charge may be appropriate for residential rates in the future, particularly as the electricity market evolves to accommodate increasing opportunities for customers to manage their own electricity needs, fixed costs should be calculated in a manner that truly reflects customer-specific costs and minimizes regressive impacts of this cost collection method.

Furthermore, 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[450] 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."[451]

There is also 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 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 consideration of fixed charges until the IOUs

[450] Exh. TASC-102 at 18-19 (concerning Hiner study).

[451] RT Vol. 12 at 1458, PG&E/Pitcock.

have completed the tier convergence and tier flattening adopted in this decision and default TOU has been approved.

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."[452] 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."[453] Consumer acceptance and understanding is incorporated into the rate design principles in this proceeding, including RDP #6 and RDP#10.

Based on this, we agree that a fixed charge representative of fixed customer-related costs could have an important role in 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

[452] D.88-07-023 at 2-3.

[453] *Id.* at 5.

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... "[454]

We find that further movement toward separate collection of fixed costs may be appropriate, but, based on the record in this proceeding it is premature to determine the scope and amount of a fixed charge. As noted above, the IOUs may include a proposal for a fixed charge along with the Residential RDW application requesting default TOU rates, but any approved fixed charge would be implemented subsequent to the implementation of default TOU rates.

We do however, resolve treatment of fixed charge revenues in the event a fixed charge is included in a default tiered rate, or in the alternate tiered rate available once TOU has become the default rate. As UCAN and other parties have argued, revenues should be used to offset Tier 1 rates.

### 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 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.[455] The majority of parties who opposed the fixed charge proposal generally recommend adoption of a minimum bill instead.[456]

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[454] UCAN RT at 6.

[455] § 739.9(h) ("The commission may consider whether minimum bills are appropriate as a substitute for any fixed charges.").

[456] See, e.g., TASC Comments at 4 ("minimum bill is an effective means of ensuring that all customers, including those with no or very little usage, contribute to recovery of fixed costs."

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.[457] 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.[458]

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, assuring that each customer pays something for the continued ability to take energy from the grid. 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, PG&E and SCE 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. SCE has a minimum bill of less than $2 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 allows the continued recovery of most utility costs through the volumetric rate.

#### 7.6.1. Amount of Minimum Bill

TURN believes that it would be reasonable to set a minimum non-generation bill in the range of $8-$10 for non-CARE customers. CARE customers would pay half as much. TURN notes that this minimum range

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[457] ORA OB at 44.

[458] Exh. ORA-101 at 2-17.

would collect about 100-150 kWh of non-generation costs at baseline rates from non-CARE customers.

ORA recommends that the size of the minimum bill be determined in subsequent GRCs or RDW. Although it agrees that certain ongoing costs such as billing, maintenance and customer services could be recovered in a fixed charge, it recommends that they be recovered through a minimum bill instead because most competitive markets do not recover such costs using fixed charges.[459]

However, there is disagreement on whether section 739.9 sets a cap on minimum bills. There are three pertinent subsections: (a), (f), and (h). Subsection (h), which is the only provision in the California Codes to mention "minimum bills," authorizes the Commission to, "consider whether minimum bills are appropriate as a substitute for any fixed charges." Subsection (a) meanwhile defines a fixed charge 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.

Lastly, as discussed earlier, subsection (f) caps fixed charges at $10 for non-CARE and $5 for CARE customers.

Several parties, including ORA,[460] 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.[461] In the PD as originally drafted,[462] we held that the fixed charge caps did not apply to

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[459] *See, e.g.*, ORA OB at 29.

[460] *See, e.g. id.* at 27; SEIA OB at 25; Sierra Club OB at 21; IREC OB at 23.

[461] *See, e.g.,* ORA OB at 27.

[462] PD of April 21, 2015.

minimum bills. We did not, however, find persuasive the IOU arguments against extending the caps to minimum bills.[463] At the same time, we noted in dicta that though the fixed charge caps were not applicable, they did suggest a limit to the range of permissible minimum bills. Nevertheless, SEIA and IREC now argue that the Commission erred by not extending the fixed charge caps.[464]

SEIA asserts that the Commission disregarded its own analysis, which found that subsection (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."[465] But, according to SEIA, the plain meaning of "substitute" in section 739.9(h) is "a person or thing that takes the place or function of another."[466] Thus, a substitute for a fixed charge "would have to have the same economic effect, and be set at the same level as the fixed charge."[467]

IREC also alleges that the Commission contradicted itself. First, IREC says, the PD erroneously failed to apply the fixed charge caps to minimum bills when, as stated by the Commission, "it would be illogical for AB 327 to carefully set a cap for fixed charges [but] leave minimum bill charges entirely to the Commission's discretion."[468] Second, while recognizing that fixed charges are defined broadly, the PD nevertheless found that minimum bills did not fall

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[463] *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).

[464] *See* SEIA Comments on April 21, 2015, PD ("SEIA PD Com.") at 10-11; IREC Comments on April 21, 2015, PD ("IREC PD Com.") at 7-8.

[465] PD of April 21, 2015, at 200, *quoted in* SEIA PD Com. at 10.

[466] SEIA PD Com. at 10.

[467] *Id.* at 11.

[468] IREC PD Com. at 7 (quoting PD of April 21, 2015, at 199) (punctuation omitted).

within that broad definition.[469] IREC believes the Commission should have instead focused on the general language[470] at the end of subsection (a): "'Fixed charge' means any . . . other charge not based upon the volume of electricity consumed." If a minimum bill does not depend on the volume of electricity consumed, then, *ipso facto*, it is a fixed charge under Section 739.9(a).

Assuming for the moment that there is an ambiguity in the statute, we apply canons of statutory construction to clarify the statute's meaning.[471] We then turn to the parties' arguments.

Section 739.9(a) defines a fixed charge in two ways: by enumerating a list of different types of fees ("any fixed customer charge, basic service fee, demand differentiated basic service fee, [or] demand charge") and by generally describing a fixed charge as "not based upon the volume of electricity consumed." When general words follow an enumeration of different items, those words apply only to things of the same kind or class,[472] and the meaning of each is determined by reference to the others.[473] Thus the statute treats basic service fees, demand charges, and demand differentiated basic service fees as non-volumetric.

Examining the non-volumetric charges, we find that a basic service fee is added to a bill regardless of demand or volume,[474] while the other charges

[469] *Id*.

[470] *Id.* ("The definition includes any 'other charge not based upon the volume of electricity consumed.' A minimum bill does not depend on the volume of electricity consumed, so it falls within the definition.").

[471] An ambiguity in the statutory language is generally a prerequisite for construction. *See, e.g., Fairbanks v. Superior Court*, 46 Cal. 4th 56 (2009). A statute may be ambiguous if it is capable of two reasonable constructions. *See, e.g., Hughes v. Board of Architectural Examiners*, 17 Cal. 4th 763 (1998).

[472] The rule is otherwise known as ejusdem generis. *See, e.g., Clark v. Superior Court*, 50 Cal. 4th 605 (2010).

[473] *See, e.g., In re Corrine W.*, 45 Cal. 4th 522 (2009).

[474] Staff Proposal at 75.

depend on peak demand (maximum kW being consumed by the customer over the relevant interval).[475] Since general words at the end of a list apply only to things of the same kind or class, it follows that Section 739.9(a) refers exclusively to non-volumetric charges that apply based on demand or the mere existence of a customer account. A minimum bill is neither. Rather, a minimum bill is "based on the applicable volumetric rate," unless "volumetric usage is so low that the resulting bill would be less than the minimum bill."[476] This "blended"[477] design is categorically distinct from every type of charge enumerated in Section 739.9(a), as those charges only depend on demand and account status. Moreover, the Legislature was clearly aware of the minimum bills approach, but elected to not include it in subsection (a). The inclusion of the fees above in Section 739.9(a) thus implies the deliberate exclusion of minimum bills from the definition of fixed charges.[478]

IREC further objects that its interpretation is the "only plausible reading" that respects the plain meaning of Section 739.9(a).[479] However, adopting IREC and SEIA's interpretation would reduce subsection (h) to mere surplusage.[480] Subsection 739.9(h) provides, "The commission may consider whether minimum

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[475] *See, e.g., id.*at 76-77.

[476] *Id.* at 75.

[477] *See id.* at 17.

[478] The rule otherwise known as *expressio unius est exclusio alterius*. *See, e.g., Le Francois v. Goel*, 35 Cal. 4th 1094, *as modified*, (June 10, 2005) (the expression of certain things in a statute necessarily involves exclusion of other things not expressed).

[479] IREC PD Com. at 8.

[480] *See, e.g., Lopez v. Superior Court*, 50 Cal. 4th 1055 (2010) (constructions that render words surplusage to be avoided); *Harris v. Superior Court*, 53 Cal. 4th 170 (2011) (avoidance of interpretations that render statutory language as inconsequential); *Imperial Merchant Services, Inc. v. Hunt*, 47 Cal. 4th 381 (2009) (presumption against idle legislative acts).

bills are *appropriate* as a substitute for any fixed charges."[481] And yet, the statute provides no reason why one fixed charge could not substitute for any other. In subsection (e), the Legislature already authorized the Commission to "adopt new, or expand existing, fixed charges" and specified three requirements.[482] If it is true that minimum bills are within the meaning of Section 739.9(a), then subsection (e) indicates it would be appropriate to implement them so long as the requirements that apply to all fixed charges were satisfied. Section 739.9(h) therefore adds nothing if minimum bills are within subsection (a). Such an interpretation would reduce subsection (h) to an exercise in semantics, as the text would vacuously mean "fixed charges are appropriate as a substitute for any fixed charge."

Moreover, even if there is a conflict between subsections (a) and (h), the general rule is that the subsequent provision prevails.[483] Likewise, the specific prevails over the general.[484] Both rules incline toward distinguishing minimum bills from fixed charges: subsection (a) states the general rule; afterward, subsection (h) addresses a separate but related charge with particularity. These rules are reinforced by the Legislature's use of the word "appropriate" in subsection (h). While a minimum bill of $12 might be an appropriate substitute for a non-CARE fixed charge of $10, a minimum bill of $25 probably would not. In a statute directing an implementing agency to evaluate possible alternatives, the use of the word "appropriate" implies discretion. If the Legislature wished

[481] Emphasis added.

[482] Section 739.9(e)(1)-(3).

[483] *See, e.g., Hartford Acc. & Indem. Co. v. City of Tulare*, 30 Cal. 2d 832 (1947).

[484] *See, e.g., Das v. Bank of America, N.A.,* 186 Cal. App. 4th 727 (2d Dist. 2010); *People v. Ahmed*, 53 Cal. 4th 156 (2011).

to mandate caps for minimum bills the same way it had for fixed charges, it certainly knew how to do so.

We turn now to SEIA and IREC's other points. First, a fixed charge cannot be presumed to have the same economic effect as a matching minimum bill. Only a small number of ratepayers will ever be subject to the minimum bill, but all will pay a fixed charge.[485] Even when forecasted to generate equal revenue, tariffs incorporating a symmetric fixed charge or minimum bill may diverge from parity if there is differential consumption because of unanticipated load, different volumetric rates, and endogenous consumer responses to the different price signals. It is for these reasons that the PD initially clarified that subsection (h) "contemplates the use of minimum bills where the effect of the substitution would be commensurable and similar" but not necessarily identical to the intended effect of a fixed charge.

Second, as we explained before, the absence of an express cap does not imply that the substitution for minimum bills has been left entirely to the Commission's discretion. Subsection (h) does not abrogate all other constraints. The Legislature has plainly mandated that the substitution must be appropriate. A minimum bill far in excess of the fixed charge caps—or which undermined legislative objectives including those embodied in the section 739.9(e)(1)-(3) requirements—would not be appropriate. While we do not endeavor here to articulate with particularity a rule for when a minimum bill is or is not appropriate, the Commission is an implementing agency of constitutional

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[485] Staff Proposal at 75.

dimension and vested with broad power.[486] It is entirely proper and consistent for the Legislature to delegate to the Commission a technical matter such as minimum bills.

Finally, there is no error in concluding both that the fixed charge cap does not apply to minimum bills, but that those caps should still be adopted to phase in the rates established in this proceeding. The magnitude of a minimum bill may be appropriate even when it is not mandatory.

We therefore find that the fixed charge caps do not apply to minimum bills. As before, we recognize that the Legislature has directed us to ensure that minimum bills are appropriate in light of the limits and requirements imposed on fixed charges.

#### 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.

The minimum bill would ensure that all customers contribute some amount toward the cost of the system to which they remain connected. It also avoids any 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

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[486] *See* Cal. Const. Art. XII (creating Commission); *Consumers Lobby Against Monopolies v. Public Utilities Com.*, 25 Cal. 3d 891, 905 (1979) ("The commission is a state agency of constitutional origin with far-reaching duties, functions and powers.").

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,[487] we disagree with CforAT's contention that customer hostility cannot be cured with customer education.

[487] CforAT RB at 14.

Finally, although we are deferring further consideration 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. The minimum bill shall be set at $10 for non-CARE customers and $5 for CARE customers starting with the 2015 rate changes to be implemented under this decision. The future minimum bill and fixed charge amounts shall be subject to review by the Commission and the parties through the IOU's 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 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 |

**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 until the IOU's GRC Phase 2 has reviewed and approved a new minimum bill or a fixed charge.

In its comments on the PD, SCE notes that its current minimum bill amount is billed as a daily charge, and applies to SCE's delivery charges. SCE requests that we clarify that the minimum bill amount applies to the non-generation portion of the IOUs bills consistent with current practice and Commission precedent.[488] We agree that the minimum bill should be calculated using the method currently used by SCE, which calculates a minimum bill on only the delivery portion of the customer's bill (the delivery portion is defined as all rate components except for the generation rate).

PG&E supports this approach, but explains that implementation of the new minimum bill methodology is a structural change for PG&E's billing system and will require additional time and IT work that PG&E will be unable to complete in time for the summer 2015 residential rate changes to take effect. PG&E requests that it be permitted to continue its current minimum bill through the remainder of 2015 and implement the new methodology beginning in 2016.[489] PG&E's request is reasonable. PG&E shall implement the new methodology no later than January 1, 2016.

SDG&E requests that it be allowed to calculate the minimum bill on a per day basis. SDG&E argues that this is the methodology it currently uses. TURN was the only party to comment on this approach. TURN does not oppose this methodology, provided that the minimum bill calculation is based on usage for

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[488] SCE notes that although PG&E's tariffs currently apply a "minimum charge" to the total bill, in D.14-06-037, we confirmed that the minimum bill amount should be based on the method used by SCE, making PG&E's practice consistent with SCE and SDG&E as well as Pacificorp, Liberty Utilities, and Bear Valley Electric Services.

[489] PG&E Opening Comments at 22-23.

the entire month.[490] We agree. SDG&E may adopt the per day calculation, but a minimum bill must be applied to the monthly bill, not to the usage in a given day. In other words, if a customer uses less than $0.33 on a given day, the customer should not be subject to a minimum bill calculation for that day.

### 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).

MCE, a community choice aggregator (CCA) 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."[491]

The Zero Minimum Bill (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

[490] TURN Reply Comments at 8.

[491] MCE OB at 5.

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. 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. In its opening comments on the PD, PG&E explains that the Commission has adopted minimum bills in the past to address the situation on some rate schedules where historical restriction on raising Tier 1 rates has resulted in the generation rate components exceeding the total rate. For Direct Access (DA) and CCA customers, PG&E states that this would result in a negative PG&E delivery bill (i.e., PG&E pays the customer to take its delivery service).[492] PG&E states that if the minimum bill is applied to the delivery portion of the bill, consistent with D.14-06-037 a ZMB is not necessary, to ensure no negative bills for DA and CCA customers. In that case, PG&E requests permission to continue the ZMB only until it is eliminated in 2016.

[492] PG&E Opening Comments at 23.

Consistent with our decision above, to grant PG&E an extension until January 1, 2016 to implement the minimum bill methodology adopted in D.14-06-037 and in this decision, PG&E may retain the ZMB provision until December 31, 2015.

# 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.

**Table Showing IOU Proposed Transitions for Average CARE Effective Discount**

| | PG&E[493] | SCE[494] | SDG&E[495] |
|---|---|---|---|
| **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% |

It should be noted that the figures in the table above are based on testimony filed in 2014. In its comments on the proposed decision, ORA stated that the current effective discount for PG&E is 37%.[496] The actual current

[493] Exh. PG&E-109 at 2-4 (Table 2-1).

[494] Exh. SCE-101 at ii/Garwacki (Table 1).

[495] Exh. SDG&E-109, Attachment C/Fang.

[496] ORA Comments at A-4.

discount figures may be different. ORA expressed concern that because PG&E may have already reached the 43.2% target for 2015 it would be burdensome for CARE customers to face any additional reduction this year. To avoid this problem, in the final CARE effective discount glidepath below, we direct PG&E and SDG&E to recalculate the glidepath starting with the current effective care discount.

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[497]** | **SCE[498]** | **SDG&E[499]** |
|---|---|---|---|
| **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 |

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

[497] Exh. PG&E-109 at 2-4 (Table 2-1).

[498] Exh. SCE-101 at ii/Garwacki (Table 1).

[499] Exh. SDG&E-109, Attachment C/Fang.

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[500] [501] |
|---|---|---|
| **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 rate structures of the other two IOUs. 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."[502]

### 8.1.1. Party Positions on CARE

As discussed in Section 7 above, 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

[500] PG&E OB at 6 (Table 1).

[501] Exh. SCE-101 at ii/Garwacki (Table 1).

[502] Exh. SDG&E-107 at CF-36.

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%.[503] 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."[504]

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,[505] "40% of low-income households would see a bill increase between $5 and $10 in 2016, about 35% would see a similar increase in 2017 and 39% would see a similar increase in 2018."[506] 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%."[507]

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

[503] ORA RB at 5.

[504] ORA OB at 52.

[505] PG&E OB at 37 (Figure 5).

[506] CforAT RB at 20.

[507] CforAT OB at 64.

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."[508]

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.[509]

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."[510]

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

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[508] Exh. PG&E-109 at 2-7.

[509] ORA OB at 53.

[510] 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

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.[511] 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 a CARE discount glide path for both SDG&E and PG&E that will reduce the discount to 35% by 2020. Specifically, each of PG&E and SDG&E should recalculate a glidepath using the following parameters: (1) start with current effective CARE discount; (2) target a 35% average effective discount; (3) apply a minimum bill set at 50% of the non-CARE minimum bill beginning in 2015; (4) target 2020 as the end date for the transition.

We remind the IOUs that programs already exist to assist high usage customers to reduce their use of energy. It is imperative that the IOUs use programs such as ESAP and Energy Efficiency to help CARE customers manage their energy use and conserve. To the extent these programs are underutilized by CARE customers, the IOUs must take the initiative to identify barriers to program implementation and means to reduce those barriers. The IOUs should be proactive in bringing these issues to the attention of the Commission so that

[511] SCE OB at 98.

participation in ESAP and other programs by CARE customers can be optimized. The challenges faced by Californians are never static. The IOUs must be prepared to respond to new challenges, such as the current drought emergency, and to leverage existing programs and new tools to help customers meet those challenges. For example, the current focus on water conservation measures is an opportunity to reach a wider range of residential customers, such as apartment dwellers and their landlords, with ESAP and Energy Efficiency programs since conserving water conserves energy.

The bill impact tables show that some CARE customers in SCE's territory will see a reduction in their bill, while others will see moderate increases in their monthly bills by 2018. The majority of SDG&E CARE customers will see an increase under $5. However, PG&E CARE customers with high usage will see higher 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.

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 and encourage the parties to consider this approach for the other utilities in Phase 3 or in future proceedings.

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), are 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.

AB 327 sets a mandatory effective discount range of 30% to 35%. In this phase we directed parties to focus on adjusting effective discount to meet that range. This required CARE discount reductions for both SDG&E and PG&E customers. SCE's CARE effective discount, however, is already within the statutory range. We directed SCE to maintain approximately the same discount for Phase 1. This phase therefore does not set a specific target within the range. Phase 3 of this proceeding will examine the CARE rate structure and could include setting a specific target for the effective discount.

The tables below show illustrative glidepaths based on IOU supplemental filings. Because the glidepath we adopt today are different from those proposed by PG&E and SDG&E, these actual glidepaths should be more gradual.

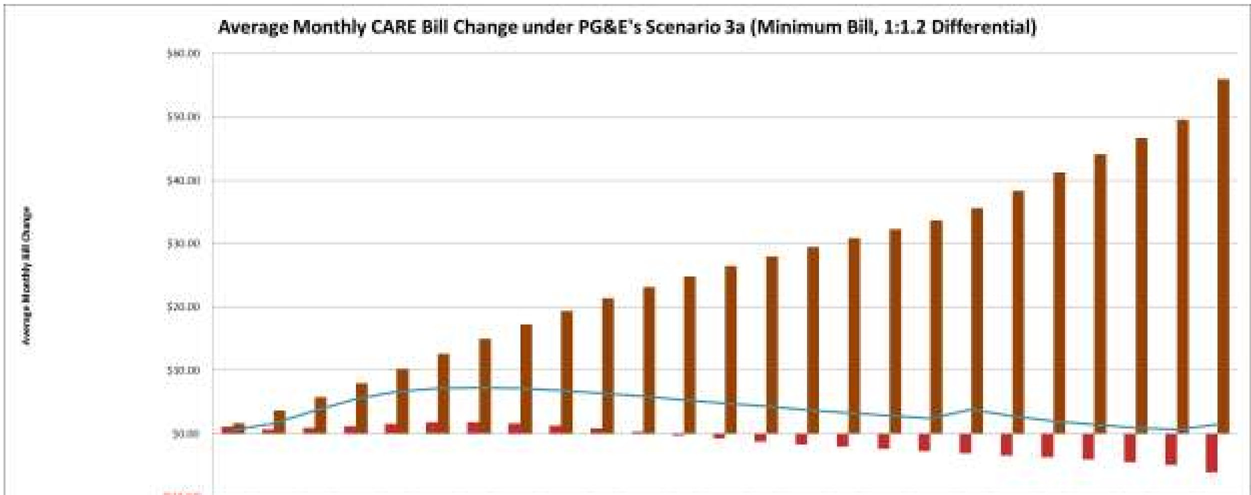
**Table Showing PG&E Proposed Glidepath for CARE rates with minimum bill (no fixed charge) through 2018 (2019 and 2020 to be determined)[512]**

| | May 2014 | March 2015 | | December 2015 | | 2016 | | 2017 | | 2018 | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate | Rate | % Change YOY[513] | Rate | % Change YOY | Rate | % Change YOY | Rate | % Change YOY | Rate | % Change YOY |
| 0 – 100% of BQ[514] | $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% |

[512] 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.

[513] 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.

[514] 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) | ($1.20) | ($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 | $19.43 | $21.38 | $23.19 | $24.88 | $26.49 | $28.01 | $29.50 | $30.90 | $32.31 | $33.68 | $35.58 | $38.40 | $41.27 | $44.06 | $46.62 | $49.50 | $55.92 |
| % of Total PG&E CARE Customers | 0.63 | 1.67 | 3.7 | 5.1 | 6.64 | 7.21 | 7.3 | 7.18 | 6.85 | 6.42 | 5.95 | 5.35 | 4.85 | 4.38 | 3.78 | 3.51 | 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 | 6.05 | 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 |

Average Monthly Usage in kWh

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**Table showing SCE Proposed Glidepath for CARE rates with $5 minimum bill (no fixed charge)[515]**

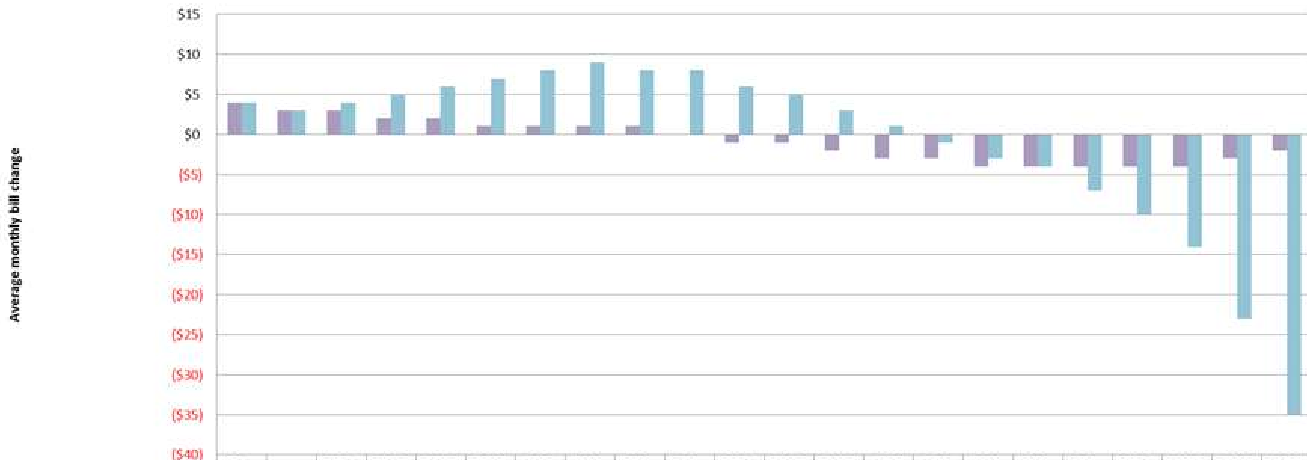
| Scenario 3a – Minimum Bill of $5 – CARE rates[516] | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan 2014 | Jan 2015 | 2015 w/ Pending RRQ[517] | | EOY 2015 | | 2016 | | 2017 | | 2018 | |
| | Rate | Rate | Rate | % Δ | Rate | % Δ | Rate | % Δ | Rate | % Δ | Rate | % Δ |
| 0 – 100% of BQ | $0.088 | $0.097 | $0.105 | 8.2% | $0.110 | 4.8% | $0.123 | 11.8% | $0.129 | 4.9% | $0.134 | 3.9% |
| 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% |

[515] 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 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. 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.

[516] SCE Supplemental Filing of April 1, 2015, Attachment B, Scenario 3a

[517] 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.

**Change in Average Monthly CARE Bill under SCE's Scenario 3a ($5 Minimum Bill, 1:1.2 Differential**




| | 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 SCE CARE Customers | 0.20% | 1.36% | 3.73% | 6.28% | 7.31% | 8.18% | 8.57% | 8.50% | 7.95% | 7.21% | 6.69% | 5.75% | 5.10% | 4.31% | 3.49% | 2.75% | 2.31% | 2.12% | 3.29% | 3.14% | 1.31% | 0.38% |
| Cumulative % CARE Customers | 0.20% | 1.56% | 5.29% | 11.57% | 18.88% | 27.06% | 35.64% | 44.13% | 52.08% | 59.29% | 65.98% | 71.73% | 76.82% | 81.13% | 84.63% | 87.38% | 89.69% | 91.80% | 95.10% | 98.23% | 99.54% | 99.92% |

**Table showing SDG&E Proposed Glidepath for CARE rates with $5 minimum bill (no fixed charge) (2019 and 2020 to be determined)[518]**

| | 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 |

[518] SDG&E Supplemental Filing of 4/1/15. The SDG&E bill impact graphs are based on SDG&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 SDG&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.


| | 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% |

Average Monthly Usage in kWh

### 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 (covering usage from 100-130% of baseline) for energy usage in Tier 3 (covering usage from 130-200% of baseline). 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.[519] 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%.[520] 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 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.[521]

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

[519] Exh. PG&E-101 at 2-22; SCE RB at 53.

[520] Exh. SDG&E-109 at CF-42/Fang.

[521] Exh. SCE-101 at 45.

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.[522] TURN proposed a 15% line-item FERA discount, justifying it as the midpoint between CARE and non-CARE rates.[523] 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.[524] SCE also argues that TURN's proposed 15% discount, which equates to the maximum discount an 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's 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

[522] ORA OB at 54.

[523] TURN OB at 43.

[524] SCE RB at 55.

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."[525]

A 12% effective discount for all FERA customers is reasonable.[526] Twelve percent is a reasonable amount compared to the CARE discount of 30%-35%. The average FERA discount in recent years, as reported by the IOUs ranges between 10% and 12%. Changes to rates adopted today will impact low income users at all usage levels. Therefore, we adopt a 12% discount for FERA customers.

It should be noted that under the prior discount structure FERA customers in Tiers 1 and 2 received no discount. 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.

In this proceeding, we direct the IOUs to continue to explore direct incentives for energy efficiency and conservation. Programs already exist at the Commission and are being further developed in other proceedings. However, based on what we have learned in this rate reform proceeding, we believe the FERA program may provide a unique opportunity to bring direct incentives to

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[525] CforAT OB at 67.

[526] The effective discount includes the CSI exemption.

large households. We are therefore adding the FERA program to the scope of Phase 3.

Finally, 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 from these increases.[527] SDG&E explains that at the time of 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

[527] D.01-09-059 at 56 (Conclusion of Law 20).

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 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."[528]

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.[529]

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 quantity 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

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[528] Exh. SDG&E-110 at CF-43/Fang.

[529] SDG&E OB at 52.

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 Section 739.7. TURN recommends that the Commission increase the tier differential in a two-tiered rate or adopt TURN's proposed three-tier rate and apply the 4 cent/kWh to Tier 3.[530]

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 three-tiered rate structure would be "an extreme response to a situation that affects so few customers and so little usage."[531] 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;[532] 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."[533]

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

[530] TURN OB at 45.

[531] PG&E RB at 43.

[532] *Id.* at 44.

[533] *Ibid*.

considered or analyzed the impacts of their proposals on Medical Baseline customers.[534] 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.

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 to these special rates. We find the proposals of the utilities are reasonable and should be sufficient to maintain the same approximate discount that Medical Baseline customers are currently receive. 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 a future ratesetting proceeding.

## 9. Volumetric GHG Rate Offset

Under the ARB economy-wide 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,"[535] the Global Warming Solutions Act of 2006.

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[534] CforAT OB at 71.

[535] California Cap on GHG Emissions and Market-Based Compliance Mechanisms, Title 17, California Code of Regulations, Section 95892.

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 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 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.[536]

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."[537] 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."[538]

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[536] D.12-12-033 at 108-109, 114.

[537] *Id.* at 179 (Finding of Fact 107).

[538] *Id.* at 114.

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 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.[539]

Aside from the IOUs, parties (ORA, TURN,[540] 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."[541]

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,"[542]

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[539] 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.

[540] TURN RB at 56.

[541] CALSEIA RB at 8 (citing D.12-12-033 at 59).

[542] SCE RB at 92.

which, according to SCE's Phase 1 Opening Brief, is signaled by a two-tiered rate differential of 30%.[543] 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.[544] SDG&E contends that the Commission should address the allocation of GHG proceeds in a separate proceeding.[545]

As noted by NRDC and others, the volumetric credit "mute[s] the carbon price signal in upper-tier residential rates."[546] 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. Each IOU is directed to include such change in its November update to its 2016 ERRA Forecast filing.

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[543] SCE OB at 164.

[544] PG&E OB at 79.

[545] *See* SDG&E OB at 66.

[546] NRDC OB at 47.

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."[547] 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.

# 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.[548] In others, the Commission has unilaterally directed the IOUs to use a specific state-wide administrator. Historically, each utility has handled its own MEO.

[547] ORA OB at 90.

[548] *See, e.g.*, A.13-08-025, et al.

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.[549]

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 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.[550] 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.

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[549] PG&E OB at 71-73.

[550] *See, e.g.,* SCE OB at 156.

### 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.

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.[551] 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[.]"[552]

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 and save them the most money. During evidentiary

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[551] SDG&E OB at 63.

[552] *Ibid.*

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."[553] We therefore direct the IOUs to 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

[553] TURN OB at 87.

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).[554] 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."[555] PG&E notes that this collaborative process would include performance metrics and coordination with third-party marketers, such as Center for Sustainable Energy (CSE), under the Statewide MEO 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.[556]

TURN recommends that the IOUs be directed to "track awareness through approaches that measure the accuracy of customer responses to specific questions that remain relatively constant over a series of years. This type of

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[554] ORA OB at 88-89.

[555] PG&E OB at 74 (citing Joint Exhibit ORA-PG&E-1).

[556] SCE RB at 91.

approach would allow the utilities and the Commission to better understand whether customer awareness is improving, declining, or remaining constant."[557] TURN also points out that metrics should play a role in evaluating whether expenditures are reasonable.[558] In addition, as part of the development of metrics, we should consider mechanisms to hold IOUs accountable for results based on outcomes not inputs.

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.

### 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

[557] TURN OB at 90.

[558] *Ibid.*

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 attention to the cost of electricity, they will be motivated to conserve energy. Other parties suggest that these customers' conservation options may be limited by financial obstacles. An 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) Heating, Ventilation and Air Conditioning: 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 homeowners, 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.

### 10.6. CCA Code of Conduct

In comments on the PD, MCE expressed concern that the PD did not expressly state that MEO is subject to the Code of Conduct. All marketing, education and outreach conducted by the IOUs is required to be compliant with CCA Code of Conduct. Nothing in this decision changes that requirement.

## 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 no sooner than 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.[559] 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.

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[559] 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 RDPs, 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;<br>3 Rates should be based on cost-causation principles<br>7 Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;<br>8 Incentives should be explicit and transparent;<br>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;<br>5 Rates should encourage reduction of both coincident and non-coincident peak demand; | 6 Rates should be stable and understandable and provide customer choice;<br>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

#### 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."

Recognizing the paramount importance of affordability, 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 proponent 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.

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."[560] We further noted that "CforAT/Greenlining use 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) 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."[561]

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.

CforAT argues that none of the rate designs proposed by the IOUs are just and reasonable.[562] 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 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.[563]

The design proposed by CforAT would not meet all the legal requirements and Rate Design Principles. In particular, current rate design does not reflect

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[560] Phase 2 Decision at 46.

[561] *Id.* at 47.

[562] CforAT OB at 1.

[563] CforAT OB at 2-4.

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.

The LINA study found that the mean energy burden for low income households is already 8%.

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.[564] 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.[565] 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.

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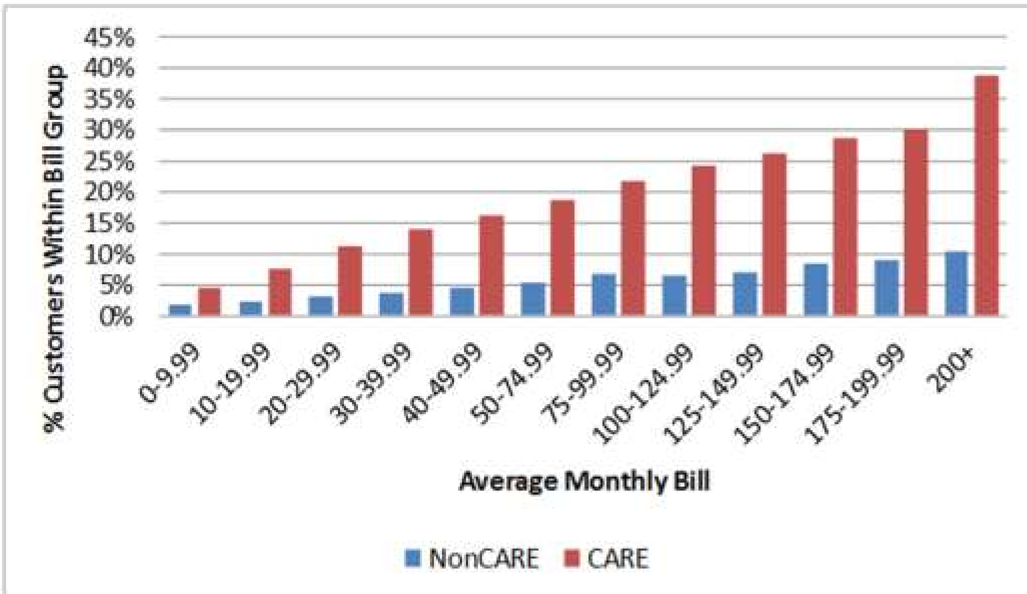
[564] SCE OB at 118 – 120.

[565] SCE-106, Appendix E.

**Percentage of CARE and non-CARE Customers, By Bill Range, Granted Bill Extensions**




### 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 25% differential between tiers, 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 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.

By adding a SUE Surcharge, we underscore the continued importance of conservation.

The record in this proceeding also shows that the IOUs failed to meet their burden to justify a monthly charge to cover fixed costs. Although a fixed monthly fee is used in the rate structure of many utilities, implementing a fixed charge for these IOUs 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 that could lead to rate shock for 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 300 kWh/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.[566]

Therefore, this decision does not approve a fixed monthly charge. We do, however, based on the evidence, find that fixed charges should not be implemented prior to full consolidation and narrowing of the tiers and implementation of default TOU.[567]

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[566] PG&E Supplemental Response of April 3, 2015, Vol. 1 at 4.)

[567] As described above, the later of 2019 or the date the tier ratio reaches 1:1.25.

Below, we evaluate and approve modified 2015 rate changes and a Roadmap rate structure for the future for each utility separately below.

Each utility proposed its own timeline based on current rate structure, with the goal of achieving two tiers with a 20% differential by 2018. For all three utilities, our approved structure sets an end-state of 2 tiers with a 25% differential on a glidepath that extends to 2019. In addition, each utility is required to implement a SUE Surcharge beginning in 2017. For all three IOUs, the SUE Surcharge should be introduced in 2017 at a rate no greater than two cents above the 2016 rate for usage above 400% of baseline. The 2019 SUE Surcharge must be 219% of the Tier 1 rate. The 2018 SUE Surcharge should be set at the midpoint between the 2017 and 2019 SUE Surcharge.

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 which we have included with some modifications. We agree with ORA that caps are necessary to prevent unexpected and unusually large revenue requirement increases from causing rate shock, but we also believe that use of these caps should be minimized to avoid uncertainty in the roll out of other rate reforms.

ORA proposes that any revenue requirement decreases be treated the same across all tiers. Although the PD initially found that a symmetrical approach to revenue requirements was not optimum for the tier consolidation transition, after reviewing ORA's comments, we have determined that a symmetrical approach would be more acceptable to customers. At the same time we believe that this symmetrical approach to decreases is unlikely to significantly impede progress toward more balanced rate tiers.

#### 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.[568] 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 the remaining months of 2015.

##### 11.2.2.1. Treatment of Fixed Costs

For non-CARE customers, 2018 illustrative rates <u>with a fixed charge</u> 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).[569] For non-CARE customers, 2018 illustrative rates <u>without a fixed charge</u>

[568] PG&E OB at 15.

[569] PG&E Supplemental Filing of April 1, 2015, Appendix A at 4, Scenario 1a.

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).[570]

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.

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[570] *Ibid*.

**Table comparing PG&E's proposed 2015 Non-CARE Rates: fixed charge vs. minimum bill**[571]

| 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[572] | $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.

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. In addition, PG&E failed to justify its proposed fixed monthly charge. 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:

[571] PG&E Supplemental Filing of April 1, 2015, Appendix A at 4 (Scenario 1a); *id.* at 8 (Scenario 3a).

[572] BQ = Baseline Quantity.

**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 | $5.00 |
| **2018** | Annual CPI adjustment or GRC Phase 2 outcome | Annual CPI adjustment or GRC Phase 2 outcome |

PG&E is granted an extension until January 1, 2016 to implement the minimum bill methodology adopted in D.14-06-037 and in this decision. PG&E may retain the ZMB provision until December 31, 2015.

#### 11.2.2.2. Consolidation of Tiers (PG&E)

In its April 2015 Supplemental 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 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 2 and 3 are consolidated, regardless of whether a fixed charge is included in the rate structure. As the table below demonstrates, PG&E's proposed collapse of Tiers 2 and 3 in 2015 results in an increase of the price of Tier 2 by 19.25%.

**Table showing PG&E Proposed Glidepath for Non-CARE rates with minimum bill (*no fixed charge*).[573]**

| | May 2014 | March 2015 | | December 2015 | | 2016 | | 2017 | | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| | Rate | Rate | % Change YOY[574] | Rate | % Change YOY | Rate | % Change YOY | Rate | % Change YOY | Rate |
| 0 – 100% of BQ | $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 |

To reduce the rate shock of such an increase, we direct PG&E to reduce the differential between Tiers 2 and 3 before combining these tiers. This approach is also recommended by ORA.[575] ORA also points out that the Tier 2 customers were already impacted by a large rate increase in summer 2014.

[573] 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 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.

[574] 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).

[575] ORA OB at 7.

#### 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.[576]

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)[577] plus 3% 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.[578]

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[576] ORA OB at 10 (citing Exh. PG&E 101 at 2-69).

[577] In comments PG&E requested clarification of the definition of residential class average rate. The RAR was used in Phase 2 as a metric for caps on rate increases. In this Phase 1, the IOUs should use the same definition of RAR: "The RAR is the average per kWh rate that would need to be collected from all residential customers for each kWh used in order to meet the portion of the system revenue requirement allocated to the residential customer class." (Phase 1 Decision at 29.) In order to make sure all parties understand the RAR, each IOU must set forth its RAR calculation in any advice letter that includes a rate change directed by this decision.

[578] *Id.* at 6.

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.[579] ORA cites several past settlements and Commission decisions that align with its proposals.

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 resulting from the tier consolidation are capped at RAR plus 5% relative to rates for the prior 12 months.

- Revenue Requirement Decreases: all tiers move on an equal percent basis.

- The glidepath should be no steeper than necessary to reach 1:1.25 by 2019. The glidepath shall continue until the later of (i) January 1, 2019 or (ii) the year the 1:1.25 tier ratio is achieved.

- Each advice letter for a rate change approved by this decision must include a worksheet similar to the one provided by ORA in its comments, showing the calculations above, including the 5% cap.[580]

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

[579] *Id.* at 10-11; 13.

[580] ORA Comments at 12.

Tier 2 customers in 2015 would be too severe. Extending the glidepath by additional years without other changes to glidepath would not mitigate this initial bill impact for Tier 2 customers. PG&E must retain the four tier structure for the remainder of 2015. We therefore direct PG&E to update its rate for the following glidepath. Note that the tier ratios have been updated to reflect the addition of the SUE Surcharge, and that as a result the glidepath reaches two tiers in 2017 instead of 2018.

**Approved Glidepath for Tier Consolidation (PG&E)**

| | Current | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Number of Tiers | 4 tiers | 4 tiers | 3 tiers | 2 tiers | 2 tiers | 2 tiers |
| Usage covered | | | Baseline<br>101 – 200% BQ<br>Over 200% BQ | Baseline<br>> 100% BQ | Baseline<br>> 100% BQ | Same as 2018 |
| Tier Differential | | 1:1.18:1.5:1.91 | 1:1.23:1.81 | 1:1.361 | 1:1.313 | 1:1.25 |
| SUE Surcharge[581] | N/A | N/A | N/A | 1:1.89 | 1:2.033 | 1:2.19 |

Based on this, we approve the continued tier narrowing on the glidepath approved above and a minimum bill of $10 for 2015. PG&E is directed to file a Tier 1 Advice Letter for approval of the 2015 rate change.

In a separate tier 2 advice letter, PG&E should set forth a revised glidepath that

(i) extends to 2019, (ii) narrows the ratio between Tiers 2 and 3 in 2015 but does not combine Tiers 2 and 3 until 2016 at the earliest, (iii) uses the 2015 -2019 tier differentials above as a guideline, (iv) includes SUE Surcharge, and (v) applies revenue requirement changes as described above. The Tier 2 glidepath advice letter should match the glidepath above as closely as possible

581 SUE Surcharge shown as ratio to Tier 1.

while taking into account PG&E's specific service and customers characteristics and updated data. Note that for all customers using over 400%, the SUE Surcharge in 2017 should be no more than 2 cents greater than the 2016 rate for usage at 400% BQ and the final glidepath should be adjusted accordingly.

As discussed above, we direct PG&E to explore and **p**ropose seasonal tiered rates.

#### 11.2.2.4. Energy Burden Analysis (PG&E)

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. Under this scenario, 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 glidepath tier 2 advice letter described above.[582]

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[582] 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 8 above, we approve a glidepath to a CARE average effective discount of 35% in 2020. We are also approving a minimum bill for CARE customers. PG&E only provided illustrative rates for the minimum bill scenario with a glidepath ending in 2017. We direct PG&E to extend the glidepath until 2020. As discussed in Section 8 above, PG&E's FERA discount should be changed to 12% for all FERA customers beginning in 2015.

#### 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.[583] 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

[583] Exh. PG&E-101 at 2-22.

from 1 cent/kWh to 0.75 cents/kWh for customers on existing tariffs. PG&E asks that 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 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<br>101 – 200% BQ<br>Over 200% BQ | Same as 2015. | Baseline<br>Non-baseline | Same as 2017 |

#### 11.2.3.1. Treatment of Fixed Costs (SCE)

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). The table shows that volumetric rates with a fixed charge would be lower than with a minimum bill.

**Table comparing SCE's proposed Summer 2015 Non-CARE Rates: Fixed Charge vs. Minimum Bill**[584]

| 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 BQ585 | $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

[584] SCE Supplemental Filing of April 1, 2015 (Scenario 1a; Scenario 3a).

[585] BQ = Baseline Quantity.

change in tiered rates. In addition, SCE failed to justify its proposed expansion of its fixed monthly charge. We therefore find that it is not appropriate to allow new or increased fixed charge during the transition period.[586] 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 |

[586] SCE can continue to apply its current fixed charge, but should not increase its fixed charge during the transition period.

#### 11.2.3.2. Consolidation of Tiers (SCE)

**Table showing SCE's Proposed Glidepath for Non-CARE rates with $10 minimum bill no fixed charge[587] [588]**

| | Jan 2014 | Jan 2015 | 2015 w/ Pending RRQ[589] | | 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% |

For lower tier customers the most dramatic bill impact resulting from tier collapse will occur when 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 2 and 3 in 2015 would result in an increase in the Tier 2 rates by 28% under the fixed charge scenario and an increase in the Tier 2 rates by 29.5% under the minimum bill scenario. When

[587] 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.

[588] SCE Supplemental Filing, April 1, 2015, Attachment B, Scenario 3a.

[589] 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.

compared with rates under the current four-tiered structure calculated with 100% of SCE's pending 2015 revenue requirement added, the price of 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 2 and 3 before combining these tiers.

#### 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 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. For consistency, we find that the revenue requirement treatment set for PG&E above should apply to SCE and SDG&E as well.

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 resulting from the tier consolidation are capped at RAR plus 5% relative to rates for the prior 12 months.
- Revenue Requirement Decreases: all tiers move on an equal percent basis.

- The glidepath should be no steeper than necessary to reach 1:1.25 in 2019. The glidepath shall continue until the later of (i) January 2019 or (ii) the year the 1:1.25 tier ratio is achieved.

- Each advice letter for a rate change approved by this decision must include a worksheet similar to the one provided by ORA in its comments, showing the calculations above, including the 5% cap.

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 without other changes to the glidepath would not mitigate this initial bill impact for Tier 2 customers. We therefore direct SCE to update its rate for the following glidepath. Note that the tier ratios have been updated to reflect the addition of the SUE Surcharge, and that as a result the glidepath reaches two tiers in 2017 instead of 2018.

**Approved Glidepath for Tier Consolidation (SCE)**

| | Current | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Number of Tiers | 4 tiers | 4 tiers | 3 tiers | 2 tiers | 2 tiers | 2 tiers |
| Usage covered | | | Baseline<br>101 – 200% BQ<br>Over 200% BQ | Baseline<br>> 100% BQ | Baseline<br>Over 100% BQ | Same as 2018 |
| Tier Differential | | 1:1.34:1:56:1.94 | 1:1.4:1.76 | 1:1.486 | 1:1.443 | 1:1.25 |
| SUE Surcharge[590] | N/A | N/A | N/A | 1:1.88 | 1:2.04 | 1:2.19 |

[590] SUE Surcharge shown as ratio to Tier 1.

Based on this, we approve the continued tier narrowing and a minimum bill of for 2015. SCE is directed to file a Tier 1 Advice Letter for approval of the 2015 rate change.

In a separate tier 2 advice letter, SCE should set forth a revised glidepath that (i) extends to 2019, (ii) narrows the ratio between Tiers 2 and 3 prior to consolidation, (iii) uses the 2015 -2019 tier differentials above as a guideline, (iv) includes SUE Surcharge, and (v) applies revenue requirement changes as described above. The Tier 2 glidepath advice letter should match the glidepath above as closely as possible while taking into account SCE's specific service and customers characteristics and updated data. Note that for all customers using over 400%, the SUE Surcharge in 2017 should be no more than 2 cents greater than the 2016 rate for usage at 400% BQ and the final glidepath should be adjusted accordingly.

As discussed above, we direct SCE to explore and **p**ropose seasonal tiered rates.

#### 11.2.3.4. Energy Burden Analysis (SCE)

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.

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 8 above we direct SCE to maintain the current average discount. We are also approving a minimum bill for CARE customers.

As discussed in Section 8 above SCE's FERA discount should be changed to 12% for all FERA customers beginning in 2015.

### 11.2.4. SDG&E

Under SDG&E's current tier structure, the differentials between Tiers 1 and 2, and the differential between Tiers 3 and 4, are very narrow. SDG&E describes the structure as "essentially an existing two tiered structure with a 50% differential."[591] 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<br>Tier 2: above 130% of BQ | | | |
|---|---|---|---|---|---|
| Differential | 2.4 cents (Tier 1 and Tier 2)<br>15-17 cents (Tiers 1&2 and Tiers 3&4)<br>2 cents (Tiers 3 and 4) | ~50% | 40% | 30% | 20% |

#### 11.2.4.1. Treatment of Fixed Costs (SDG&E)

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)).[592] The table below compares how volumetric rates could look with and without a fixed charge.

[591] Exh. SDG&E 101 at CY-15.

[592] SDG&E Supplemental Filing, April 1, 2015, Attachment C at 15.

**Table comparing SDG&E's proposed 2015 Non-CARE Rates: fixed charge vs. minimum bill**[593]

| **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 | $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. In addition, SDG&E failed to justify its proposed fixed monthly charge. 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 rate change.

593 *Id*. (Scenario 1a; Scenario 3a).

**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 |

#### 11.2.4.2. Consolidation of Tiers (SDG&E)

**Table showing SDG&E's Proposed Tier Flattening Glidepath for Non-CARE summer rates (*__no fixed charge__*), $10 minimum bill.**

| Scenario 3a – Minimum Bill of $10 – Non-CARE rates[594] | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 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 – 200% of BQ | $0.358 | $0.401 | 12.01% | $0.345 | -13.97% | $0.316 | -8.41% | $0.303 | -4.11% | $0.289 |
| Over 200% of BQ | $0.378 | $0.402 | 6.35% | $0.345 | -14.18% | $0.316 | -8.41% | $0.303 | -4.11% | $0.289 |

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 1 bill impact is more dramatic. In July 2014, Tier 1 rates were 15.4 cents per kWh. After the change proposed by SDG&E for

[594] *Ibid.*

2015, the Tier 1 rate will be 20.8 cents. This is a substantial increase of 20.93% in just over one year. At the same time, the Tier 4 rate will decrease by 14.18% over the same year. UCAN contends that adding two additional years to the glide path (and applying any fixed charge to Tier 1 only), would improve customer acceptance of the rate changes.

ORA is also concerned about this substantial Tier 1 increase. ORA proposes that Tiers 3 and 4 be combined in 2015, but that SDG&E wait until at least 2016 to combine 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 RAR plus 5% compared to August of the prior year.[595] ORA contends that without such a cap, increases on Tier 1 rates would be unacceptably high. ORA cites the Phase 2 settlement as an example of where a cap on rate increases has been used before.

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.

In comments, SDG&E argued that the glidepath approved below will not provide sufficient rate relief for higher tier customers. Specifically, SDG&E argues that the 2015 ratio between Tier 1 and Tier 3 should be 1:1.9. The glidepath below sets the ratio at 1:2.18. Under SDG&E's proposed ratio, Tier 3 and Tier 4 customers will see a small decrease in rates. The decrease for current

[595] ORA OB at 19.

Tier 3 customers would be approximately -1.27%. Although we acknowledge that the tier decreases for the higher tiers would be larger under the SDG&E comment proposal, we believe it is more important to minimize the impact on lower tier customers during the first step of the tier consolidation. Under SDG&E's comment proposal Tier 1 customers would see a double-digit percentage increase (12.791%). Under the glidepath below the Tier 1 increase is moderate (5.814%).

**Approved Glidepath for Tier Consolidation (SDG&E)**

| | Current | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Number of Tiers | 4 tiers | 3 tiers | 2 tiers | 2 tiers | 2 tiers | 2 tiers |
| Usage covered | Tier 1: 0-100% of BQ<br>Tier 2: 101-130% of BQ<br>Tier 3: 131-200%of BQ<br>Tier 4: 200% + of BQ | Tier 1: up to 100% of BQ<br>Tier 2: 101-130% of BQ<br>Tier 3: above 130% of BQ | Tier 1: up to 130% of BQ<br>Tier 2: above 130% of BQ | Tier 1: up to 130% of BQ<br>Tier 2: above 130% of BQ | Tier 1: up to 130% of BQ<br>Tier 2: above 130% of BQ | Tier 1: up to 130% of BQ<br>Tier 2: above 130% of BQ |
| Tier Differential | | 1:1.13:2.18 | 1:1.66 | 1:1.405 | 1:1.351 | 1: 1.25 |
| SUE Surcharge[596] | N/A | N/A | N/A | 1:1.637 | 1:1.9 | 1:2.19 |

Note that the tier ratios have been updated to reflect the addition of the SUE Surcharge.

Based on this, we approve the continued tier narrowing and a minimum bill of for 2015. SDG&E is directed to file a Tier 1 Advice Letter for approval of the 2015 rate change.

In a separate tier 2 advice letter, SDG&E should set forth a revised glidepath that (i) extends to 2019, (ii) uses the 2015 -2019 tier differentials above as a guideline, (iii) includes SUE Surcharge, and (iv) applies revenue requirement

[596] SUE Surcharge shown as ratio to Tier 1.

changes as described above. The Tier 2 glidepath advice letter should match the glidepath above as closely as possible while taking into account SDG&E's specific service and customers characteristics and updated data. Note that for all customers using over 400%, the SUE Surcharge in 2017 should be no more than 2 cents greater than the 2016 rate for usage at 400% BQ and the final glidepath should be adjusted accordingly.

#### 11.2.4.3. 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 resulting from the tier consolidation are capped at RAR plus 5% relative to rates for the prior 12 months.

- Revenue Requirement Decreases: All tiers move on an equal percent basis.

- The glidepath should be no steeper than necessary to reach 1:1.25 in 2019. The glidepath shall continue until the later of (i) January 1, 2019 or (ii) the year the 1:1.25 tier ratio is achieved.

- Each advice letter for a rate change approved by this decision must include a worksheet similar to the one provided by ORA in its comments, showing the calculations above, including the 5% cap.

#### 11.2.4.4. Energy Burden Analysis

In their April 10 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.

#### 11.2.4.5. Adjustments to CARE and FERA programs (SDG&E)

As discussed in Section 8 above, we approve a glidepath to a CARE average effective discount of 35% in 2020. 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. We direct SDG&E to extend the glidepath until 2020. SDG&E's FERA discount should be changed to 12% for all FERA customers beginning in 2015.

#### 11.2.4.6. SDG&E Seasonal Rate

As discussed above, we find that SDG&E's proposal for seasonal rates in all tiers should be adopted.

#### 11.2.4.7. SDG&E Baseline Reduction Approved

Although we did not approve the requested baseline allowance change for SCE, a different analysis applies to SDG&E. 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 to have a lower baseline. 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 and proposed TOU rates is provide in the table below.

| Utility | Opt-In TOU Tariff | Status/Approvals |
|---|---|---|
| PG&E | E-TOU | Approved in this decision.<br>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.<br><br>E-7 has been closed to new customers since 2008. This decision approves eliminating E-7 and transferring existing customers to E-TOU. |
| 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 rate that does not include DDMSF, and with other modifications consistent with the decision. |
| SDG&E | DR-SES<br>EV-TOU<br>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<br>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 | TOU- D-T | Pursuant to D.14-12-048, TOU-D-t will remain open until the effective date of the decision in SCE's 2018 GRC application. |
| SCE | CPP<br>PTR<br>SDP | Existing overlay tariffs. |

### 11.4. TOU Pilots

In Section 6 above 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 or consultants 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, (3) CARE restructuring under AB 327, and (4) options for leveraging the FERA program to provide direct incentives to large income-qualified households.

A PHC will be scheduled for summer 2015.

### 12.2. Working Groups: TOU Design and Study; MEO

We direct the parties to meet and confer regarding implementing a working group (TOU 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 3 advice letter.

We also direct the IOUs to work with other parties to implement a working group (MEO Working Group) to examine MEO for residential rate changes generally, and how MEO for rate changes interacts with other residential programs. The MEO Working Group will play a role in the Phase 3 development of long-term MEO for residential rates. As previously discussed in Section 10, the MEO Working Group is also tasked with developing specific outreach and education on conservation targeted at customers currently in Tier 1 and Tier 2 who will see rate increases under this decision.

The IOUs should arrange a workshop within 60 days of the date of this decision to allow parties to discuss the structure for both the TOU Working Group and MEO Working Group.

A separate workshop, hosted by Energy Division, on Phase 3 issues, including MEO, should take place within 60 days after the date of this decision.

### 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 and other rate reform 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, and the format and contents of PRRR reports.

### 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) tiered opt-in rate, and (3) 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. We anticipate that these applications will be consolidated to facilitate participation by other parties.

At a minimum, the Residential RDW application must include the following information and supporting documentation in support of the proposed default TOU rate:

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.

### 12.6. Schedule

| Deadline | Event |
|---|---|
| Within 45 days after decision | Phase 3 Prehearing Conference (to be scheduled by ALJ) |
| Within 60 days after decision | • AL 1 with tariff changes for 2015 rate changes for implementation no later than November 1, 2015.<br>• AL 2 with proposed glidepath and bill impacts for tier consolidation after 2015. |
| Within 60 days after decision | First Progress on Residential Rate Reform (PRRR) Workshop to discuss next steps, including creating working groups and hiring of consultant |
| Within 60 days after decision | Workshop to informally discuss scope and schedule for Phase 3 and presentations/proposals on CARE restructuring and FERA. |
| October 16, 2015 | Tier 2 AL for MEO for SUE Surcharge |
| November 2015 | First Annual Residential Electric Rate Summit (RERS):<br>- Presentation and Q&A on identified aspects of residential rates<br>- Related technical workshops |
| 2015/2016 | As part of next GRC Phase 2, workshop(s) to discuss methodologies for determining appropriate fixed costs and fixed charge. |
| **Ongoing Activities** | |
| Ongoing | Working group to design pilots, design studies of TOU, and to comment on plans for Residential RDW application required materials.<br>. |
| 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. |
| Semi-annually, May, November | Progress on Residential Rate Reform (PRRR) workshop held each April and November to present PRRR reports and provide opportunity for questions and for parties to meet collaboratively. |
| **2016 Activities** | |
| January 1, 2016 | Submit Tier 3 AL for approval of TOU pilots |
| Between March and April 2016 | Submit approved rate changes for implementation concurrently with other rate changes prior to summer 2016. |
| May 31, 2016 | Progress on Residential Rate Reform (PRRR) Workshop |
| Spring 2016 | TOU Pilots approved |

| | |
|---|---|
| Summer 2016 | TOU Pilots start |
| November 30, 2016 | Residential Electric Rate Summit:<br>- Presentation and Q&A on identified aspects of residential rates<br>- Related technical workshops |
| **2017 Activities** | |
| First 90 days | Submit approved rate changes for implementation concurrently with other rate changes in the first 90 days of the year. |
| May 31, 2017 | Progress on Residential Rate Reform (PRRR) Workshop |
| November 30, 2017 | Residential Electric Rate Summit:<br>- Presentation and Q&A on identified aspects of residential rates<br>- Related technical workshops |
| **2018 Activities** | |
| First 90 days | Submit approved rate changes for implementation concurrently with other rate changes in the first 90 days of the year. |
| **January 1, 2018** | • **Residential RDW application for default TOU**<br>• **(may include new fixed charge proposal)**<br>• **Start of default TOU pilot** |
| May 31, 2018 | Progress on Residential Rate Reform (PRRR) Workshop |
| November 30, 2018 | Residential Rate Summit:<br>- Presentation and Q&A on identified aspects of residential rates<br>- Related technical workshops |
| **2019 Activities** | |
| First 90 days | Submit approved rate changes for implementation concurrently with other rate changes in the first 90 days of the year. |
| May 31, 2019 | Progress on Residential Rate Reform (PRRR) Workshop |
| November 30, 2019 | Residential Electric Rate Summit:<br>- Presentation and Q&A on identified aspects of residential rates<br>- Related technical workshops |
| **2020** | |

| | |
|---|---|
| 2020 | Residential RDW application rates become effective as approved. |
| May 31, 2020 | Progress on Residential Rate Reform (PRRR) Workshop |
| November 30, 2020 | Residential Electric Rate Summit:<br>- Presentation and Q&A on identified aspects of residential rates<br>- 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…"[597] 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

[597] Pub. Util. Code § 451, in pertinent part.

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% of the average residential consumption within each climate zone.[598] 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 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.[599]

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

[598] Section 739(a) 1.

[599] Section 779.1, et seq.

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 (PD) 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. Opening comments for the PD were filed on May 11, 2015 by SCE, SEIA, CSE, MCE, EDF, UCAN, ORA, Vote Solar, CALSEIA, TURN, PG&E, IREC, TASC, Sierra Club, SDG&E, and CforAT. Reply comments for the PD were filed on May 18, 2015 by SEIA, TASC, Sierra Club, Vote Solar, PG&E, SCE, Greenlining, TURN, ORA, and CforAT.

The majority of comments reiterated arguments previously made in this proceeding. To avoid repetition, we have not included those comments in the summary below.

The following substantive changes and significant clarifications were made in response to comments:

- Clarified that the fixed charge proposals of the three IOUs are rejected and that any further consideration of fixed charges is subject to certain conditions and timing.
- Added a Super User Electric (SUE) Surcharge to apply to usage over 400% of baseline starting in 2017. The SUE Surcharge will be set at a moderate amount in 2017 and be increased to 219% of the Tier 1 rate by 2019.
- Extended CARE glidepath for 35% average effective discount from 2018 to 2020.

Opening comments for the alternate proposed decision (APD) were submitted on June 11, 2015 by Greenlining, UCAN, CFC, CforAT, TURN, IREC, NRDC/Sierra Club, TASC, EDF, SDG&E, MCE, ORA, SEIA, PG&E, Vote Solar, CAISO, and SCE. Reply comments for the APD were submitted on June 16, 2015 by ORA, UCAN, PG&E, CforAT, SDG&E, Greenlining, CAISO, TASC, NRDC and SCE. Comments on the APD are not addressed in the revised PD.

## 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.

## 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 residential class average cost of service and upper tier rates substantially above residential class average 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, but assess a minimum bill instead.

7. Residential customers do not receive price signals that fully reflect their cost of service.

8. The Hiner study demonstrates that some customers do not currently 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 depends in part 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 hourly price will not incent the customer to shift or decrease usage in that hour.

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 that the inclining block price for energy increases as their energy usage increases 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 upper tiers, will be increased if the price of upper tier energy is lowered. The reverse will be true for customers with primarily lower tier usage.

20. Customers cannot reduce the monthly service fee (fixed charge) by conserving energy.

21. It is not clear whether a customer responds to the average price or the marginal price for their energy usage. The average price methodology for determining price elasticity reflects most customers' understanding of their energy bills, but for some customers the marginal price methodology is more appropriate.

22. 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.

23. According to the IOUs' bill impact models, 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.

24. We cannot find with certainty that the rate design proposals will decrease or increase conservation.

25. The impacts of the rate design changes on conservation will be small.

26. Because current tiered electricity rates increase sharply with increased usage, and because residential customers typically do not know at what point their usage will reach a higher tier threshold, customers can experience

unexpectedly large increases in monthly bills for a small increase in usage. With a high tier price differential, the larger the share of energy usage billed in the upper tier, the greater the impact on the monthly bill. This is particularly true during high-use periods such as summer months.

27. Customers with high use and low income are especially disadvantaged by the current steeply tiered rates.

28. In SCE's service territory, customers with use in the higher tiers are the most likely to ask for bill payment assistance or extensions.

29. In SCE's service territory, the highest electricity burdens are faced by customers with the highest usage.

30. 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.

31. Low-income and moderate-income ratepayers are not universally low or high users of energy.

32. If utilities do not use a composite tier differential, in some cases energy rates would be flatter or declining.

33. The record in this proceeding is insufficient to conclude that load shifts from TOU rates will have an impact on GHG emissions.

34. It will be valuable to future TOU rate design to further study whether TOU load shift has a significant impact on GHG.

35. If peak use is reduced, the need to build power plants to serve customers for peak periods, which are short periods of time, will be reduced.

36. 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.

37. 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.

38. 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.

39. 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.

40. 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.

41. 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.

42. The Commission has long supported time variant rates.

43. Energy costs vary by time of day.

44. Ratepayers have already invested billions of dollars in advanced metering infrastructure.

45. 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.

46. To date, the utilities do not have significant enrollment in TOU rates, and therefore the benefits of AMI technology are not optimized.

47. TOU rates can reflect the predictable changes in energy costs during the day.

48. If there is a fixed charge, calculating the tier differential between 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 1 is higher than the price paid in Tier 2.

49. Revenue requirement changes for 2015 may be different from what the IOUs projected and changes after 2015 are not known.

50. A 2.1% increase in revenue requirement per year does not appropriately reflect the impact on rates of years with significantly higher or lower revenue requirement changes.

51. Tiered rates (inclining block rates) result in a potential subsidy from high-use customers, who pay more than the average cost of energy services, to low use customers, who pay less than the average cost of energy services.

52. There is no evidence in this proceeding that conservation increases on a direct and predictable relationship with the steepness of an inclining block rate.

53. The evidence in this proceeding shows a weak correlation between income and usage.

54. Tiered rates cannot incent usage shifts that promote grid reliability needs, such as the need for flexible ramping resources.

55. Tiered rates cannot incent usage shifts that reduce peak load and the need for less-efficient "peaker" plants.

56. Steeply tiered rates provide a financial incentive for high usage customers to invest in energy efficiency improvements and rooftop solar.

57. Steeply tiered rates were not designed as the primary tool to promote rooftop solar investments.

58. Steeply tiered rates are not the most economically efficient method for encouraging customers to invest in energy efficiency improvements or rooftop solar.

59. The Commission already has several direct incentive programs to promote energy efficiency (EE) products and 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 lower 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. Immediately 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-tiered rate is less complex than a three- or four-tiered rate.

70. A mild differential between tiers is closer to average 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 25% 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 households larger than two people often pay an amount for electricity that is disproportionate to the cost to serve that household.

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 1:1.25 differential and a SUE Surcharge meets statutory requirements and is consistent with the RDPs.

78. To minimize the rate shock, the transition from the current four-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 1:1.25 and a SUE Surcharge at 1:2.19 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 one means of decreasing rate impacts on higher tier customers.

88. The basic baseline quantity must be between 50 and 60% of average residential consumption. The all-electric baseline quantity must be between 60 and 70% 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 of 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 commodity 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 commodity 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 can be designed to 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 some 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 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 Phase 2 of GRCs or in RDWs.

128. TOU periods should be based on system and 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 and determinations regarding the costs and benefits of residential solar installations are under consideration in a

different proceeding which will expressly take into account the rate design reforms adopted in this proceeding in order to evaluate appropriate NEM tariff reforms.

138. NEM customers taking service under existing TOU rates may have expected that their rate structure would not change.

139. The times of day during 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 in either a GRC Phase 2 or an RDW application filed by the IOU.

142. Customers on TOU tariffs should be permitted to remain on them for up to five years.

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 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 and opt-in pilots should 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 that does not include a minimum bill, low-usage customers pay a smaller share of customer-related costs than high-usage customers.

163. A fixed charge or minimum bill that recovers customer-related costs would result in more equitable rates for low usage customers such as vacation homeowners and some NEM customers.

164. A fixed charge or minimum bill to reflect a portion of fixed costs will decrease volumetric rates.

165. A decrease in the volumetric rate could reduce conservation.

166. Through letters to the Public Advisor's Office and at public participation hearings, customers have indicated that a fixed charge is not popular.

167. It is not clear that customers understand how a fixed charge would impact overall rates.

168. A fixed charge cannot be avoided by a customer's reducing usage or being more energy efficient.

169. Fixed charges are used in other industries and by other utilities, including other electric utilities in California.

170. Customers have accepted fixed charges in contexts outside of their electric bills.

171. Any fixed charges should reflect appropriate customer-related costs.

172. Marginal costs attributable to the residential customer class and the other customer classes are litigated in GRC Phase 2.

173. The GRC Phase 2 allocates costs among different classes of customers to reflect cost causation.

174. Recent GRCs have usually settled marginal costs and revenue allocation and are therefore not useful as a basis for setting a new rate structure that was not contemplated during the GRC settlement.

175. A fixed charge to reflect fixed costs would send a more accurate price signal to customers.

176. 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.

177. A minimum bill would ensure that no use and low usage customers such as vacation homeowners and some NEM customers make some payment toward customer-related costs incurred on their behalf.

178. A minimum bill will not result in a perceptible impact for customers other than extreme low usage customers.

179. PG&E's proposed Zero Minimum Bill provision is inconsistent with Rule 18 of the Code of Conduct concerning CCAs.

180. A well-designed fixed charge to reflect a portion of fixed customer-related costs would support the rate design principle of cost-causation.

181. Section 739.9(e) allows the Commission to consider different fixed charges for small and large customers but does not define "small" and "large."

182. There is not sufficient evidence in the record to define the characteristics of small and large customers for purposes of a fixed charge.

183. The CARE discount was originally set at approximately 15% off otherwise applicable non-CARE rates.

184. During the course of this proceeding, the effective discount rates for CARE have included 43.2% (PG&E), 31% (SCE), and 41% (SDG&E).

185. AB 327 allows the CARE discount to be restructured provided that it results in an average effective discount between 30 – 35%.

186. Because FERA is based on a tier structure with a minimum of three tiers, FERA will need to be restructured as the tiers are consolidated.

187. Currently, FERA customers only receive a discount on usage in Tier 3.

188. The approximate current discounts received by FERA customers range from 10% to 12.5% when measured over total usage.

189. A flat discount on all FERA usage would result in increased discounts for low usage FERA customers and reduced discounts for high usage customers.

190. Changes to the medical baseline program discount should be minimized in this proceeding.

191. 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.

192. The Climate Credit currently appears as a credit on each residential customer's bill twice per year.

193. The IOUs' GHG compliance obligations result in an increase in the cost of electricity and these increased costs are currently reflected in the rates of all customers other than residential customers.

194. 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.

195. 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.

196. If the volumetric credit is discontinued, GHG costs will be reflected in the rates of residential customers.

197. If the volumetric credit is discontinued, the amount of the semi-annual per household climate credit will increase.

198. Marketing, education and outreach for rate design changes must be robust and cost-effective.

199. If customers do not understand their electricity rates they cannot respond to price signals.

200. In 2014, each utility provided marketing and outreach to the customers most impacted by summer 2014 rate changes.

201. The outreach model used for summer 2014 rate changes is adequate for 2015 summer rate changes.

202. After summer 2015 rate changes, the IOUs should develop a more specific and robust MEO campaign for the rate changes and pilots.

203. Without metrics that evaluate customer understanding over time it is not possible to determine if MEO is effective.

204. A robust bill comparison tool is an important part of customer education on rate options.

205. 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.

206. 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.

207. An educational outreach campaign focused on low-cost and no-cost energy efficiency options will help lower tier customers respond to higher rates.

208. 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.

209. One measure of affordability is the ratio of electricity charges to customer income (electricity burden). The Commission has not adopted a specific benchmark or metric for identifying what ratio constitutes a "high" electricity burden.

210. This proceeding does not address IOU revenue requirements.

211. Decision 14-06-029, adopted in Phase 2 of this proceeding, approved interim rate change proposals for summer 2014.

212. Phase 1 and Phase 2 of this proceeding did not address issues related to CASMU.

213. Empirical analysis of current data yields the best results for Commission decisionmaking.

## 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 require a baseline credit for at least one available optional TOU rate schedule.

6. A baseline tier is not statutorily required for default TOU rates.

7. Based on record evidence, it is not reasonable to rely exclusively on any specific elasticity methodology presented by parties in this proceeding.

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 and a SUE Surcharge 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 and a SUE Surcharge 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 rates for the respective blocks of usage."

12. The adopted tier differentials with a composite tier and glidepath to a differential of 1:1.25, and a separate SUE Surcharge of 1:2.19, 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

15. Winter heating season and should be approved effective as of the date that Tiers 1 and 2 are consolidated.

16. A well-designed fixed charge representing a portion of the fixed customer-related costs to serve the individual residential customer could be reasonable.

17. 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.

18. A fixed charge should not be implemented until after the tier collapse is complete and after default TOU has been implemented.

19. Adopting a minimum bill in lieu of a fixed charge at this time is reasonable.

20. As part of their next GRC Phase 2 (or, in the case of SDG&E, the currently pending GRC), each utility may submit testimony identifying and calculating marginal customer costs.

21. The adopted minimum bill amount should be applied to all residential rate schedules with a 50% discount for CARE, FERA and medical baseline customers.

22. Revenues from the adopted minimum bill should be applied to reduce the volumetric rate for Tier 1 during the transition period from 2015 through 2019

23. The statutory limits in Section 739.9 regarding fixed charge amounts do not apply to minimum bill amounts.

24. It is reasonable to adopt minimum bill amounts consistent with the statutory limits for fixed charges.

25. The CARE discount reduction glidepaths proposed by SDG&E and PG&E should be extended to 2020.

26. 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.

27. A 12% discount for all FERA customers is reasonable.

28. The utilities' methodologies for calculating medical baseline should not be changed at this time.

29. 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.

30. The IOUs' 2016 ERRA Forecast filings should reflect that the residential volumetric GHG rate offset will be eliminated in 2016.

31. The IOUs' proposed customer outreach plans for 2015 rate changes are reasonable and should be approved.

32. 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.

33. The IOUs should be required to develop bill comparison tools that provide individual customers with bill comparison information tailored to their individual usage.

34. 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.

35. The long-term MEO program for residential rate design should include workshops and working groups, as well as regular updates to the Commission.

36. The utilities should be authorized to create memorandum accounts to track verifiable incremental expenses for rate design outreach and education incurred prior to a decision in their next General Rate Case.

37. 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 1:1.25 in 2019 and a SUE surcharge that begins in 2017 and is set at 1:2.19 in 2019, is reasonable and should be approved.

38. PG&E's proposed reduction of the SmartRate discount, concurrent with the combination of Tiers 2 and 3 is reasonable and consistent with the law and the RDP.

39. 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 one or more consultants 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.

40. PG&E's request to close Schedules E-6 and EL-6 to new customers should be granted.

41. PG&E's request to eliminate Schedules E-7, EL-7, E-8 and EL-8 should be approved.

42. PG&E should be authorized to offer the optional E-TOU-A and E-TOU-B rate schedules proposed, with the exception that we approve a minimum bill in lieu of a fixed customer charge.

43. In order to provide for a gradual transition to new TOU periods and rate schedules, customers on PG&E's E-6 and EL-6 rate schedules should be allowed to remain on those tariffs for a transition period that extends for at least five years after the respective tariff is closed to new customers.

44. PG&E's proposal to include a Zero Minimum Bill provision on all residential rate schedules should be denied.

45. We should adopt a baseline credit on any default TOU rate and on at least one available TOU optional rate, as well as any TOU pilot rates.

46. SDG&E's proposed Demand Differentiated Monthly Service Fee for optional TOU rate schedules should not be adopted at this time.

47. Any revenue shortfall resulting from optional TOU rate schedules should be recovered from all residential customers.

48. The ten-party timeline for default TOU is not reasonable.

49. 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.

50. 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.

51. The proposed 2015 rate change and roadmap for the transition period, as set forth in this decision for each of the IOUs, should be adopted.

52. The IOUs should endeavor to develop more accurate energy burden and electricity burden ratios in the future.

53. 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.

54. 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.

55. The IOUs should continue to examine ways to ensure that customer health and safety is not impaired by electricity costs.

56. 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.

57. This decision does not modify the requirement for IOUs to comply with the CCA Code of Conduct.

58. The new rate design proposals for PG&E, SCE, and SDG&E, as modified by this decision, should be adopted.

59. CASMU should be dismissed from any obligations of a respondent in Phase 1 and Phase 2 of this proceeding.

60. To optimize the outcomes in Phase 3 of this proceeding, and other related matters before the Commission, the IOUs must improve the quality of data provided by including more current and more granular data and by utilizing interactive geographic information system platforms to enhance the Commission's ability to complete careful analysis using empirical methodologies.

61. 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 11 of this decision.

2. The 2015 rate changes proposed by Southern California Edison Company are approved as set forth in Section 11 of this decision.

3. The 2015 rate changes proposed by San Diego Gas and Electric Company are approved as set forth in Section 11 of this decision.

4. Within 60 days of the date of this decision, each of Pacific Gas and Electric Company (PG&E), Southern California Edison Company, and San Diego Gas & Electric Company shall file a Tier-1 Advice letter setting forth the new residential rates adopted for 2015 with a requested effective date no later than November 1, 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 and Family Electric Rate Assistance program discounts. 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." PG&E is granted an extension until January 1, 2016 to implement the minimum bill methodology adopted in Decision 14-06-037 and in this decision. PG&E may retain the Zero Minimum Bill provision until December 31, 2015.

5. Within 60 days of the date of this decision, each of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file a Tier-2 Advice Letter setting forth the glidepath for future rate changes to consolidate the tiers and implement the Super User Electric Surcharge.

6. 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.

7. Rate changes authorized by this decision and made in 2016 must take place between March and May of 2016 and be coordinated with other rate changes if possible. After 2016, rate changes authorized by this decision must take place within the first 90 days of the year and be coordinated with other residential rate change filings.

8. No later than October 16, 2015, each of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file a Tier-2 Advice Letter setting forth the outreach and education, including bill presentment, plan for implementing the Super User Electric Surcharge.

9. Pacific Gas and Electric Company is directed to file a residential rate design window (RDW) application no later than January 1, 2018 proposing default time-of-use rate for residential customers. The RDW application must be consistent with this decision and include information and documentation reasonably sufficient to support the proposed rate, including the legal findings required by Section 745(d).

10. 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 must be consistent with this decision and include information and documentation reasonably sufficient to support the proposed rate, including the legal findings required by Section 745(d).

11. Southern California Electric Company (SCE) is directed to file a residential rate design window (RDW) application no later than January 1, 2018 proposing default time-of-use rate for residential customers. The RDW application must be consistent with this decision and include information and documentation reasonably sufficient to support the proposed rate, including the legal findings required by Section 745(d).

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 each file a Tier 1 Advice letter establishing new memorandum accounts to track verifiable incremental costs associates with (i) time of use pilots, (ii) time of use, including hiring of a consultant or consultants to assist in developing study parameters, (iii) marketing, education and outreach costs associated with the rate changes approved in this decision, and (iv) other reasonable expenditures as required to implement this decision.

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 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. Within 60 days of the date of this decision, PG&E, SCE, and SDG&E shall schedule a workshop to address these issues.

14. Within 30 days of the date of this decision, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) must initiate the process of forming a working group to address the issues regarding marketing, education and outreach (MEO Working Group), as detailed in this decision, and as modified or revised during Phase 3 of this proceeding. The MEO Working Group will specifically address the program to promote low-cost and no-cost energy efficiency options for current Tier 1 and Tier 2 customers, as well as long-term residential outreach.

15. 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.

16. Within 60 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.

17. Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company and other members of the Time-of-Use working group shall mutually agree and select one utility to hire one or more qualified consultants 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. If the working group is unable to reach an agreement, the consultant shall be selected by Energy Division staff from a list of recommended consultants from the working group.

18. The residential volumetric greenhouse gas rate offset must be discontinued prior to the first schedule California Climate Credit in 2016. After that time, the revenue return allocated to the residential class will consist solely of the semi-annual California Climate Credit.

19. The assigned Commissioner and assigned Administrative Law Judge are authorized to take all procedural steps to 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, including the authority to dispose of requests to modify the deadlines in this decision.

20. All outstanding motions and requests in this proceeding that are not specifically addressed in this decision are denied.

21. California Pacific Electric Company, LLC (U933E), Bear Valley Electric Service (U913E), a Division of Golden State Water Company, and Pacificorp (U901E) are dismissed as respondents from Phase 1 and Phase 2 of this proceeding.

22. In the remainder of this proceeding, and any successor proceeding, the investor-owned utilities are directed to improve data quality by providing more current and more granular data and utilizing interactive geographic information system platforms to enhance the Commission's ability to complete careful analysis using empirical methodologies.

23. Rulemaking 12-06-013 shall remain open.

This order is effective today.

Dated July 3, 2015, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners

We reserve the right to file a concurrence.

/s/ MICHEL PETER FLORIO
Commissioner

/s/ CATHERINE J.K. SANDOVAL
Commissioner

/s/ CARLA J. PETERMAN
Commissioner

/s/ LIANE M. RANDOLPH
Commissioner

# 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 | Monthly Service Fee |
| 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

**PG&E 2015 Residential Rate Changes**[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 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.

[1] PG&E Supplemental Filing April 14, 2015, at 2.

**SCE 2015 Residential Rate Changes**[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 |

** Excludes Climate Credit.

[2] SCE Supplemental Filing April 14, 2015, at 3.

**SDG&E 2015 Residential Rate Changes**[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 |
| 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 |

[3] SDG&E Supplemental Filing April 14, 2015, Appendix C.

** 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)

**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF COLORADO**
* * * * *

| | |
|---|---|
| RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE | PROCEEDING NO. 16A-0588E |

## UNOPPOSED COMPREHENSIVE SETTLEMENT AGREEMENT

### Introduction and Identification of Parties

This Settlement Agreement is a full and complete resolution of all issues raised in Proceeding No. 16A-0588E, Public Service Company of Colorado's ("Public Service" or the "Company") Verified Application ("Application") for approval of a Certificate of Public Convenience and Necessity ("CPCN") for distribution grid enhancements, including Advanced Metering Infrastructure ("AMI") and Integrated Volt-VAr Optimization Infrastructure ("IVVO"). The Settlement Agreement is joined by the following parties to this proceeding: Public Service, Commission Trial Staff ("Staff"), the Colorado Office of Consumer Counsel ("OCC"), the Colorado Energy Office ("CEO"), Colorado Energy Consumers ("CEC"), the Colorado Solar Energy Industries Association ("COSEIA"), Energy Freedom Coalition of America ("EFCA"), Energy Outreach Colorado ("EOC"), the Mission:data Coalition, Inc. ("Mission:data"), Southwest Energy Efficiency Project ("SWEEP"), and Western Resource Advocates ("WRA") (the "Settling Parties"). The remaining party, the City of Boulder ("Boulder"), has authorized the Settling Parties to state that it neither supports nor opposes this settlement. Thus, this Settlement Agreement is unopposed.

## Background

On August 2, 2016, Public Service filed an Application requesting the Commission grant to it a CPCN to implement AMI, IVVO, and the associated components of an advanced communications network (known as the Field Area Network or "FAN") to support the AMI and IVVO (collectively "CPCN Projects"). While these projects are part of the Company's broader Advanced Grid Intelligence and Security ("AGIS") initiative,[1] the Company sought a CPCN for AMI, IVVO, and the associated components of the FAN due to the magnitude of the investments, and because these technologies are newer in Colorado and will further extend the capabilities of the Public Service distribution system.

AMI consists of meters that will measure and transmit voltage, current, and power quality data via the FAN and can act as sensors providing near real-time monitoring to the Company and customers, which cannot be done by the Company's existing automated meter reading ("AMR") meters.[2] IVVO will use the voltage information transmitted by AMI meters to automate and optimize the operation of distribution voltage, ultimately allowing the Company to lower voltage across the system.[3] The portions of the FAN associated with AMI and IVVO that were requested as part of the CPCN Projects are the communications network that will facilitate the flow

[1] Application, pp. 1–2. In its Application, the Company also explained that the broader AGIS initiative includes components that the Company intends to implement in the ordinary course of business, which are: the Advanced Distribution Management System ("ADMS"), Fault Location Isolation and Service Restoration ("FLISR"), Fault Location Prediction ("FLP"), Geospatial Information System ("GIS"), and the FAN not associated with the CPCN Projects. Application, p. 8, ¶ 3. The Company did not seek a CPCN for these projects on the grounds that they are foundational components of the grid and/or logical extensions of work that utilities have traditionally performed and signify the continued use of advancing technologies in a normal evolution of the business.
[2] *Id.* at p. 10, ¶ 7.
[3] *Id.* at p. 10, ¶ 8.

of information between the existing communications infrastructure at the Company's substations and the other components of the AGIS initiative, such as AMI meters and the intelligent field devices.[4] In its Application, the Company estimated that the CPCN Projects would cost approximately $562 million and would be deployed between 2016 and 2021.[5]

Public Service supported its Application with the Direct Testimony and attachments of eight (8) witnesses.

The Commission deemed the Application complete in Decision No. C16-0845-I mailed on September 12, 2016, and set the hearing *en banc*. In the same Decision the Commission acknowledged the intervention by right of Staff, OCC, and CEO, and granted the permissive interventions of Boulder, CEC, COSEIA, EFCA, EOC, Mission:data, SWEEP, and WRA (collectively, the "Parties").

On January 25, 2017, eight (8) of the parties filed Answer Testimony: Staff, OCC, CEO, COSEIA, EOC, Mission:data, SWEEP, and WRA. CEC, Boulder, and EFCA did not file Answer Testimony in the proceeding.

On March 2, 2017, Public Service filed Rebuttal Testimony of five (5) witnesses, and Staff, OCC, WRA, CEO, SWEEP, and Mission:data filed Cross-Answer Testimony.

After the filing of Rebuttal and Cross-Answer Testimony, the Settling Parties engaged in settlement discussions, which culminated in this Settlement Agreement.

While the Settlement Agreement contains the common provision stating that this Settlement Agreement and the compromises herein are supported by the pre-filed testimony that has been submitted by the parties, the Settling Parties believe it is

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[4] *Id.* at p. 11, ¶ 9.
[5] *Id.* at p. 4, and pp. 11-12 ¶11.

appropriate to emphasize in this Background section three aspects of the Company's AMI proposal. First, the Company is undertaking the roll-out of advanced meters as an upgrade to its distribution system. The AMI meters provide functionality beyond traditional consumption measurement for billing purposes. A few examples are but not limited to the following: (1) AMI meters measure and transmit distribution system information (e.g., voltage and current) to more efficiently manage the distribution grid (e.g., more accurate tracking and responding to outages); (2) the first 13,000 AMI meters will enable IVVO and will act as sensors for that purpose; and, (3) providing detailed energy use data to customers and other authorized persons.

Second, while new AMI meters have increased capabilities as compared to existing AMR meters, the cost of a new AMI meter also exceeds the cost of a new AMR meter.

Third, the Company intends to replace all of its customers' meters in areas that will have FAN connectivity with AMI meters on a system-wide basis, including replacing those AMR meters that are not yet at the end of their useful life, regardless of the present operational capability of the existing meters. There may be some isolated areas where it is cost prohibitive to have FAN connectivity; the Company will implement another meter alternative in these rare instances.

## Settlement Terms

### I. Common Settlement Principles Applicable to Both AMI and IVVO.

A. The Settling Parties support issuance of a CPCN for the implementation of IVVO, AMI and the associated FAN. The conditions presented throughout the remainder of this Settlement Agreement concern how these CPCN Projects will be implemented. To the extent there are provisions in the Company's Direct or Rebuttal Testimonies that are contradicted by or modified by the provisions in this Settlement Agreement, the provisions in the Settlement Agreement shall control, e.g. timelines to install AMI meters or projected capital and O&M costs incurred.

B. While specific terms for IVVO implementation and AMI deployment are detailed in Sections II and III below, the following common principles apply to the implementation of both.

   1. Cost Recovery Management - The public interest is served by containing the overall costs of the CPCN Projects and limiting resulting rate impacts on customers. Thus, the Settling Parties recognize that the decision regarding the continuation of the deferred accounting mechanisms described below in Sections II and III, in whole or in part, should be determined in a base rate case rather than in this Proceeding. Additionally, the timelines for implementation have been modified to accommodate a longer deployment plan than originally proposed by the Company. It is also reasonable to implement financial measures to mitigate future rate impacts. Therefore, the Settling Parties agree to continued deferred accounting for operations and maintenance ("O&M") expenses as well as capital investments beyond the first rate case in which those costs could be included in base rates. The following principles will govern the deferral of costs associated with AMI, IVVO, and the associated FAN:

      a. In accordance with the deferral language included in each section below, two deferred accounting mechanisms will be established for each project: one for deferred capital investment and one for O&M expenditures.

b. In the event the sum of the two capital investment deferrals totals $50 million or greater, the Company will begin to assess an interest rate equal to the Company's after-tax weighted average cost of capital ("WACC") on the balance of the deferred account until such amounts are included in base rates and an amortization of the deferred balance is initiated.

c. Amortization of the O&M deferral shall be at least in a proportionally equal manner as the amortization associated with the capital investment deferral.

2. Reporting Requirements

   a. The Company shall provide the semi-annual reporting regarding investment and deployment as proposed in its Direct and Rebuttal Testimonies, including but not limited to: (1) the total costs per year of the AMI meter installation, (2) the final cost per AMI meter, excluding installation and taxes, (3) the final cost per AMI meter including installation and taxes, and (4) the total number of AMI meters installed each year. The Company's reporting shall also include planning and implementation of customer education.

   b. Stakeholders may request additional metrics for reporting purposes via normally available means, such as informal information requests, litigated proceedings before the Commission, or existing stakeholder groups.

## II. IVVO

This section of the Settlement Agreement describes the implementation of IVVO, including associated cost and cost recovery issues.

A. IVVO Implementation Timeline - The Company will implement IVVO on its system consistent with the timeline and scope put forward in its Rebuttal Testimony with implementation commencing in 2017 and continuing through 2022 (Rebuttal Testimony of John D. Lee, Table JDL-R-1, page 5) with the exception of the provision contained in Table JDL-R-1 that 95% of the AMI meters will be installed by the end of 2021. The deployment of AMI meters is stated in Section III. A. below and Attachment B.

B. IVVO Implementation Methodology

   1. IVVO will be implemented by installing approximately 13,000 advanced meters to function initially as voltage sensing devices ("IVVO Voltage Sensing Meters"). These will be the same types of meters, with the same capabilities, as those the Company will acquire for the AMI implementation across its service territory in Colorado.

   2. A specific geographic portion of the FAN and software components will be necessary to achieve full functionality of IVVO for communication, operations, and integration into the billing system. These components will also be installed in this initial stage in order to achieve full IVVO functionality pursuant to the Company's Rebuttal position, with the exception of the provision in Table JDL-R-5 that 95% of the AMI meters will be installed by the end of 2021 and that the projected capital costs and O&M costs will be incurred through 2024 for AMI

meters rather than through 2022 as depicted in Tables JDL-R-6 and JDL-R-7. (Rebuttal Testimony of John D. Lee, pages 49-52).

3. In the event it is necessary for an existing AMR meter located within the IVVO implementation footprint to be replaced, the Company will replace that meter with the same meter as those utilized for IVVO implementation provided the communications network is available and capable of reading the meter at that location. A "necessary" replacement is one that results from existing AMR meter operational malfunction or failure. The objective of this provision is to minimize incremental AMR expenses that would be incurred prior to a full advanced meter roll-out. The cost difference between the AMR and IVVO capable meter shall be afforded deferred accounting treatment as described below in the IVVO and Associated Infrastructure Costs (II.D.3) section.

C. IVVO Implementation Costs - To achieve the agreed-upon IVVO implementation, a cost of $32.9 million above the cost of IVVO implementation presented in the Company's Rebuttal Testimony is estimated to be incurred during the IVVO deployment timeframe versus during the AMI deployment. This is a cost shift in project accounting from the AMI to the IVVO portions of the CPCN Projects, but is not an additional cost to the CPCN Projects overall. This cost shift will result in the following estimated total cost for the implementation of IVVO:

**Table 1**

| Cost Descriptor (capital & O&M) | Base Amount | Contingency | Total |
|---|---|---|---|
| Rebuttal Cost of IVVO Implementation (2016-2022) | $131.4 M | $25.8 M | $157.2 M |
| Cost Shift from AMI | 17.1 M | 15.8 M | 32.9 M |
| Incremental Cost Impact | 3.6 M | 0 | 3.6 M |
| **Total IVVO Implementation Cost Estimate** | **$152.1 M** | **$41.6 M** | **$193.7 M** |

The change in the IVVO implementation schedule, described above in Section II.B, will result in an incremental cost of approximately $3.6 million above the Company's Rebuttal Testimony cost estimate.

D. IVVO Cost Recovery

1. The Settling Parties agree to conditional recovery for the impact of measurable decreased energy consumption attributable to IVVO implementation as follows:

   a. In the event that (1) no decoupling mechanism is approved in Proceeding No. 16A-0546E, (2) a decoupling mechanism for less than the entire Residential and Small Commercial Class is approved; or (3) a decoupling mechanism is approved with a cap that does not afford the Company the ability to offset the measurable financial impacts attributable to decreased energy consumption resulting from IVVO deployment, the Settling Parties agree to provide the Company an opportunity to account for and reasonably recover incremental amounts associated with such measurable decreased energy consumption.[6] The Settling Parties agree to allow a mechanism to offset such measurable decreased energy consumption in this narrow circumstance, particularly when the Company

[6] As described in Attachment A.

is investing its own capital in an IVVO project. The amounts to be collected will be based on the measurable reduced energy use attributable to IVVO multiplied by the applicable fixed cost component of base usage charges for residential and small commercial customers. The measurable reduced energy use will be derived and recovered through the following:

i. The measurable energy reduction due to IVVO will be calculated as described in Attachment A.

ii. The Company will calculate the reduced kilowatt-hours ("kWh") for residential and small commercial customers on an annual basis and record the measurable financial impact as a deferred accounting asset. For each annual deferral amount, the recovery of the deferred amount shall be completed within twenty-four (24) months of the end of that calendar year.

iii. The Company will report annually the calculated kWh reductions and associated measurable financial impact based on such kWh reductions resulting from the application of the procedure included in Attachment A as part of the annual Electric Commodity Adjustment ("ECA") review filing (currently filed on or before August 1 of each year).[7] Interested parties may review and comment on the application of the Attachment A formula and process by filing a

[7] Utilization of the ECA for the purposes of this recovery provides for some level of symmetry with the fuel benefits that all customers will experience due to the reduced kWh consumed. Additionally, this utilization will be temporary and keeps customer bills simpler. If the conditions described in Section II.D.1.a. are not satisfied, the Company shall annually report estimated energy savings and M&V results in accordance with the methods described in Attachment A. Such reporting will begin in August 2020 for the prior year and will be filed in this proceeding, unless and until the Company files an application for an IVVO performance incentive.

pleading with the Commission according to the existing processes for review of the ECA.

iv. The Company shall be allowed to recover the approved amounts in the ECA in the appropriate residential and commercial rate classes (R and C) beginning on January 1 following the filing of the calculation. The recovery will be amortized in the ECA over a twelve (12) month recovery period.

v. The Settling Parties expect IVVO will provide at least 1.8% energy savings across the feeders with IVVO measured at the end of the first twelve months following completion of the IVVO and associated infrastructure installation.

b. In the event the Company completes a base rate case that includes any portion of the IVVO usage reductions in the forecasted or actual billing determinants, the Company shall present those anticipated reductions in a transparent manner, and propose an adjustment to the annual IVVO recovery calculation to account for changes to billing determinants in order to prevent and avoid double recovery. After all IVVO usage reductions associated with the initial deployment are captured in a base rate case, the Company will discontinue the IVVO recovery treatment provided for in this Settlement Agreement.

c. In the event that the approved decoupling mechanism resulting from a

Final Order of the Commission[8] only partially accounts for the measurable energy reductions attributable to IVVO, thus both the approved decoupling mechanism and the calculation contemplated in Attachment A continue simultaneously, the Settling Parties agree that the following provisions should also apply:

i. In order to avoid double recovery within each rate class, the calculation methodology in Attachment A, and therefore the resulting deferred accounting asset, shall be reduced by the measurable revenues to be recovered through the approved decoupling mechanism for the measurable energy reductions. The Company shall provide its methodology and calculation through the process outlined above in Section D.1.a for any amounts that it is requesting above what is received through an approved decoupling adjustment. Settling Parties reserve their right to challenge the Company's presented methodology and calculation. [9]

ii. This provision (c) recognizes the circumstances in D.1.a may restrict the Company's ability to avoid potential adverse financial impacts of its IVVO program. Therefore, the Settling Parties agree the Company should have a reasonable opportunity to recover through the Attachment A mechanism any remaining portion of the financial impacts of the measurable energy reduction not recovered through

[8] On May 2, 2017 the Administrative Law Judge issued Decision No. R17-0337 in the Decoupling proceeding (16A-0546E). As written, this Recommended Decision triggers treatment under D.1.a.

[9] Prior to the Company's first presentation of its methodology and calculation in a recovery request, the Company will work with interested Settling Parties to devise a mutually agreeable a methodology and calculation, to the extent possible.

decoupling.

2. After the IVVO implementation contemplated in this Settlement Agreement is complete and the associated implementation costs are fully included in base rates, the Company may file an application for approval of a performance incentive; provided, however, the Settling Parties agree that such an application is not appropriate in a demand side management ("DSM") plan proceeding or a "Strategic Issues" proceeding. The Company may make such a filing within 48 months of the end of the measurement time period. The performance incentive will only be available in the event that the results from IVVO surpass the projected savings of 1.8% energy consumption across the feeders with IVVO measured at the end of the first twelve months following completion of the IVVO and associated infrastructure installation. Nothing in this provision prevents other parties from proposing a performance incentive. Likewise, nothing in this provision waives any party's right to take any position in a performance incentive application or proposal. Further, nothing in this provision prohibits the Company from filing a separate application for any future incentive request based on metrics other than those described in this provision.

3. IVVO and Associated Infrastructure Costs

   a. The Company may apply deferred accounting treatment for expenses and any capital in service for the IVVO costs contemplated in this Settlement Agreement until these costs are included in base rates. The Company will provide a listing of the O&M expenses that will be deferred to assure that there is no double recovery of those expenses.

b. The Settling Parties acknowledge that continued deferral of these costs beyond the first available rate case is possible, as discussed above in the Common Settlement Principles Applicable to AMI and IVVO Implementation, Section I.B.

4. Transferring IVVO Costs to Rate Base - When the Company proposes to include IVVO and associated infrastructure costs in base rates, the Company will be obligated to present robust direct testimony with appropriate accompanying exhibits to justify any expenditures that are in excess of the base amount. Notwithstanding the Company's presentation of robust direct testimony, Parties are free to challenge the prudence of the expenditures to overcome such rebuttable presumption. Confidentiality may be requested as necessary.

E. Energy reductions associated with IVVO will not be included in the energy reductions accounted for in energy efficiency and DSM calculations for the purposes of incentive awards or the disincentive offset. Further, the Company's DSM goals will not be adjusted to include the IVVO energy or capacity reductions. As discussed above, energy (kWh) savings due to IVVO will be reported on an annual basis in the ECA proceedings.

F. Future IVVO Deployment Potential - In calendar year 2021, the Company shall provide a report to the Commission (in this proceeding) presenting an analysis of its system regarding potential future IVVO deployment. In this report the Company shall present where it expects subsequent IVVO deployment would result in optimal benefits to the system and to customers in those areas at an appropriate cost. Pursuit of these deployments would be at the Company's discretion without the need for a CPCN, or as ordered by the Commission. Nothing in this provision limits or waives any party's right to take any position with respect to future IVVO deployments.

## III. AMI

This section of the Settlement Agreement discusses the implementation of AMI, including associated costs and cost recovery issues, the HAN and Green Button CMD, and remote disconnections/reconnections. Regarding the implementation of AMI, this portion of the Settlement Agreement addresses the relationship between AMI deployment and the provisions of the Non-Unanimous Comprehensive Settlement Agreement approved by the Commission in Consolidated Proceeding No. 16AL-0048E.

A. Full advanced metering deployment should not begin until calendar year 2020 and that the deployment will proceed as shown below in Table 2.

**Table 2**

| Year | Anticipated Number of AMI Meters Deployed (Cumulative) | Meter Functionality |
|---|---|---|
| 2019 | 13,000 | IVVO |
| 2020 | 175,000 | AMI |
| 2021 | 570,000 | AMI |
| 2022 | 1,050,000 | AMI |
| 2023 | 1,500,000 | AMI |
| 2024 | Remainder | AMI |

Table 2 depicts the anticipated and approximate roll-out of AMI meters inclusive of those deployed during the IVVO timeframe. Additional detail regarding AMI deployment is set forth in Attachment B to this Settlement Agreement. The

Company's initial AMI deployment will concentrate in the areas where IVVO has been implemented. The meters initially deployed to provide IVVO functionality will eventually provide full AMI functionality, as AMI software and related systems are completed.

B. The Company agrees to present estimated bill impacts for customers following the full AMI meter deployment. This will occur in the earlier of either the Company's (1) next Phase II portion of a rate case, or (2) the Schedule Residential Energy Time Of Use ("RE-TOU") rate design Advice Letter to be filed on or before December 2, 2019. The Settling Parties recognize and acknowledge this will be an imperfect analysis because the underlying assumption will necessarily be that the base from which to compare is the most recently approved base rate determination and any other offsetting cost variables will not be taken into account.

C. In its 2019 DSM Plan, the Company will develop and submit a plan for enhancing its DSM programs with the functionality enabled by AMI installation. The 2019 DSM Plan will describe how the Company will utilize AMI data to engage with its customers for increased energy savings and peak demand reduction through ongoing or new DSM products, measures, or pilots. This Settlement Agreement does not limit Settling Parties in any manner regarding their positions in the 2019 DSM Plan docket.

D. The extended rollout of AMI is anticipated to increase the total cost of deployment by approximately $36.0 million, in 2016 dollars. Attachment C graphically reflects a comparison between the spend cycle associated with the Company's Rebuttal Testimony versus that agreed to through this Settlement Agreement, less any time value of money impacts. Table 3 reflects the anticipated costs separated between distribution and business systems as well as contingency amounts based upon the Company's Rebuttal Testimony and the incremental amount stated previously for the impact of extending the roll-out of AMI deployment.

**Table 3**

| Category of AMI Cost | Base Amount | Contingency | Total |
|---|---|---|---|
| Distribution | $223.8 M | $19.5 M | $243.3 M |
| FAN | 22.8 M | 9.2 M | 32.0 M |
| Business Systems | 76.3 M | 67.6 M | 143.9 M |
| Incremental for Delay | 40.9 M | (12.3 M) | 28.6 M |
| Increased Customer Count | 6.8 M | 0.6 M | 7.4 M |
| Work Shifted to IVVO | (17.1 M) | (15.8M) | (32.9) M |
| Incremental IVVO Cost Shift | (3.6 M) | 0 | (3.6 M) |
| **Total** | **$349.9 M** | **$68.8 M** | **$418.7 M** |

E. AMI and Associated Infrastructure Cost Recovery

1. Costs incurred for deployment of AMI and associated infrastructure for capital investments and O&M expenses shall be included in a deferral mechanism to the extent such costs are not included in the existing Service and Facilities ("S&F") Charge until the costs are included in base rates. The Company will provide a listing of the O&M expenses that will be deferred to assure that there is no double recovery of those expenses.
2. The Settling Parties acknowledge that continued deferral of these costs beyond the first available rate case is possible, and the treatment of such deferral is addressed in the Common Settlement Principles Applicable to AMI and IVVO Implementation Section above.
3. Transferring AMI Costs into Rate Base - In a rate case, when the Company proposes to include the AMI and associated infrastructure costs in base rates,

the Company will be obligated to present robust direct testimony with appropriate accompanying exhibits to justify any expenditures that are in excess of the base amount. Notwithstanding the Company's presentation of robust direct testimony, Parties are free to challenge the prudence of the expenditures to overcome such rebuttable presumption. The Company may request confidential treatment of this information as necessary.

4. AMI meters are utilized for more than measurement of a customer's consumption for billing purposes as discussed in the Background section above. Therefore, it is reasonable that some portion of the meter cost not be classified as a specific customer cost. In its next Phase I and Phase II rate proceedings, the Company shall present a proposal for assigning the portions of the AMI meter costs to the functions that cause those costs. The Settling Parties expressly reserve the right to raise any arguments concerning all elements of the proper allocation of costs in future rate cases.

F. RE-TOU Rate for Customers Prior to 2019 RE-TOU Advice Letter Decision

1. Pursuant to the Non-Unanimous Comprehensive Settlement Agreement approved by the Commission in Consolidated Proceeding No. 16AL-0048E, customers who receive AMI meters prior to a decision in the final Schedule RE-TOU Advice Letter will automatically be placed on the RE-TOU rate schedule, and will remain on that tariff pending a decision in the RE-TOU Advice Letter proceeding, with the option to opt-out during the first six (6) billing cycles and prior to the end of the seventh (7th) billing cycle. The Company shall use its best efforts to educate all such customers concerning the shift in rate design,

the bill impacts of the RE-TOU rate specific to that customer, the option to opt-out of the rate design, and the availability of tools to manage energy use. Customers who receive one of the approximately 13,000 advanced meters in 2019 as sensors for IVVO will not be placed on the RE-TOU rate until such meters are fully functional AMI meters with the necessary FAN connectivity.

2. In order to minimize any negative impacts of this rate design on low-income customers, the Company shall automatically extend the hold harmless provision that applies to low-income RE-TOU trial participants, as set forth in the Non-Unanimous Comprehensive Settlement Agreement approved by the Commission in Consolidated Proceeding No. 16AL-0048E to all low-income customers enrolled in Low-Income Energy Assistance Program ("LEAP") or that received EOC bill assistance payments within the preceding twelve months that are subsequently placed on the RE-TOU rate prior to the RE-TOU Advice Letter Decision.

G. Home Area Network ("HAN") [10]

1. Hardware Procurement and Installation

   a. Consistent with the Company's rebuttal position,[11] the Company will select and install meters that incorporate the HAN hardware, which is a software defined radio in the AMI meter, as part of this CPCN.

   b. In selecting and installing HAN hardware, the Company will utilize the best commercially available technology that provides a platform that may be updated remotely without hardware replacement.

[10] Nothing in this Section or throughout this Settlement Agreement is intended to circumvent the Commission's Data Privacy Rules, pursuant to Rules 3025-3035 of the Commission Rules Regulating Electric Utilities, 4 *Code of Colorado* Regulations, 723-3.
[11] Lee Rebuttal Testimony, at 82:20-21.

c. In the event that the costs to implement the HAN are higher than the embedded meter costs contained in either the Company's Direct or Rebuttal Proposals, these costs will be afforded the same presumption of prudence as the CPCN Project costs.

2. HAN Activation and Customer Experience

   a. In a separate HAN Application, the Company will present a plan to activate the HAN in a manner that meets cybersecurity concerns consistent with industry standards and best practices at the time, while striving to provide easy data access to the extent prudent. This Application shall be filed no later than March 2018, with a goal of implementing the HAN concurrent with the full AMI roll-out beginning in 2020. The HAN Application shall also include:

      i. Cybersecurity plan for HAN activation;

      ii. The communications protocols to be utilized, how they do or do not promote easy data access by customers and energy service providers and why they were chosen;

      iii. Plan for recovery in the event of a breach;

      iv. All reasonable alternatives to the Company's cybersecurity plan and communication protocols that were considered and the reasons any such alternatives were determined to be insufficient;

      v. Customer activation process;

      vi. Outreach plan to inform and educate customers on how to activate their HAN, what information is available, as well as how they may utilize the HAN information;

vii. Incremental costs (if any) to implement the HAN Application proposals; and,

viii. Within the customer portion of the Application, the Company shall consider and present information regarding the Company's position and recommendation on a customer's ability to: (1) provision their own device to interact with the HAN on the Company's web portal in as few steps as possible, and (2) "bring your own device" ("BYOD"), in which any customer with an AMI meter after AMI implementation with FAN connectivity may connect any device of their choice so long as it is standards compliant.

b. Portions of the HAN Application may be filed as Confidential or Highly Confidential pursuant to Commission rules to protect the sensitivity of the materials being provided.

H. Green Button Connect My Data

1. The Company's customer web portal shall include the ability for all customers to access their energy usage data and provide that data to third parties following required privacy waiver policies according to Rule 3027. The currently accepted standard to achieve this is known as Green Button CMD, which has been ratified by the ANSI-accredited North American Energy Standards Board.

2. The Company will implement Green Button CMD unless another standard is nationally adopted and the Company believes the new standard is superior to Green Button CMD.

3. The Company will provide reasonable notice to the Settling Parties in advance of its selection of another nationally adopted standard through a compliance filing in this proceeding, to which the other Settling Parties may respond. In the event the Company adopts another standard, the Company has the burden in its rate recovery filing to justify why the new standard is superior and should be afforded cost recovery.
4. In order to ensure compliance with the technical specifications of the Green Button CMD standard, the Company will annually test its Green Button CMD system. In the Company's annual DSM Report beginning the first calendar year after implementation of Green Button CMD, the Company shall present system availability metrics, the results of the annual test(s), information describing the test(s) conducted, as well as how any deficiencies will be remedied. Interested persons and Settling Parties may file responses to the report.
5. In implementing the Green Button CMD standard, the Company shall work to create a streamlined customer experience and minimize the number of screens and clicks required of the customer.
6. The Company will work to minimize the time lag between customer authorization and the start of the Company's Green Button CMD beginning transmission of data to an authorized third party.
7. The cost to implement Green Button CMD was not explicitly included in the cost of the Company's proposed CPCN. Implementing Green Button CMD may increase the overall cost of the CPCN implementation by up to $2.0 million. There is a presumption that this cost increase is considered a prudent

expenditure. Individual customers and customer-authorized third parties will not be charged to use Green Button CMD implemented as presently contemplated in this Settlement Agreement.

I. Remote Disconnection/Reconnection

1. Upon approval of this Settlement Agreement, the Company will engage with interested stakeholders to assemble a consensus proposal and request to the Commission for a Rulemaking to consider how the implementation of AMI meters and their capabilities associated with Remote Disconnection/Reconnection should be utilized.

2. Until at least the aforementioned rulemaking is concluded, the Company will continue its practice for disconnect for non-payment[12], which is compliant with Commission Rules, regardless of the availability of remote disconnection. Disconnection following any in-person visit may be executed remotely.

J. Customer AMI Opt-Out

1. Customers should have the option to opt-out of having an AMI meter installed. These customers should be allocated the cost of continuing to read, maintain, and stock the alternative meters.

2. The Company's proposal regarding the meter type to be installed for these customers, as discussed in the Company's Direct Testimony, is approved.[13]

3. For purposes of this Settlement Agreement, the rates proposed by the

[12] Currently, the Company sends a disconnection letter allowing the customer 15 days to pay a past due bill and if that amount is not paid within 15 days the account is placed in collections. Then the Company makes a first attempt to contact the customer via telephone and if the Company is successful in that contact the account is put on a one day hold. When that one day hold expires without payment the account goes into a routing system to be assigned to the field for disconnection. If the first contact via telephone is unsuccessful the account is put into the collections router for a notice to be left on the customer's door advising them they have 24 hours to pay or they will be disconnected. If the customer has not paid the noticed amount within the 24 hour period the Company will send a field collector out to the customer's property to attempt collection prior to the disconnecting service.

[13] Direct Testimony and Attachments of Russell E. Borchardt, 59: 3-10.

Company for customers who opt out of having an AMI meter will not be adopted as filed in its Application in this proceeding. On or before the fourth quarter of 2018, the Company shall file an advice letter with the Commission to establish the tariff for these customers that are opting out. In this filing the Company shall consider methods to mitigate the cost impact of reading the meter, such as how the customer may participate in billing programs (e.g., average billing) so their meter does not need to be read every month.

## General Provisions

1. Each Settling Party understands and agrees that this Settlement Agreement represents a negotiated resolution of all issues the Settling Party either raised or could have raised in this proceeding. Each Settling Party understands that the Commission's approval of this Settlement Agreement shall constitute a determination that the Settlement Agreement represents a just, equitable, and reasonable resolution of these issues. Accordingly, the Settling Parties state that reaching resolution of these issues in this proceeding through this negotiated Settlement Agreement is in the public interest and that the results of the compromises and agreements reflected in the Settlement Agreement are just, reasonable, and in the public interest.
2. Each Settling Party has the discretion to sponsor a witness at any proceeding the Commission holds to address the Settlement Agreement. In the event that a Settling Party sponsors a witness, its witness will only testify in support of the Settlement Agreement and all of the terms and conditions of the Settlement Agreement.

3. The Settling Parties agree that all pre-filed testimony and exhibits in the proceeding submitted prior to the filing of this Settlement Agreement by any Party shall be admitted into evidence.

4. Except as expressly stated herein, nothing in this Settlement Agreement shall resolve any principle or establish any precedent or settled practice. Moreover, nothing in this Settlement Agreement shall constitute an admission by any Settling Party of the correctness or general applicability of any principle, or any claim, defense, rule, or interpretation of law, allegation of fact, regulatory policy, or other principle underlying or thought to underlie this Settlement Agreement or any of its provisions in this or any other proceeding. As a consequence, no Settling Party in any future negotiations or proceedings whatsoever (other than any proceeding involving the honoring, enforcing, or construing of this Settlement Agreement in those proceedings specified in this Settlement Agreement, and only to the extent, so specified) shall be bound or prejudiced by any provision of this Settlement Agreement.

5. The discussions among the Settling Parties that produced this Settlement Agreement have been conducted with the understanding, pursuant to Colorado law, that all offers of settlement, and discussions relating thereto, are and shall be privileged and shall be without prejudice to the position of any of the Settling Parties and are not to be used in any manner in connection with this or any other proceeding.

6. This Settlement Agreement shall not become effective until the issuance of a final Commission Decision approving the Settlement Agreement, which Decision does

not contain any modification of the terms and conditions of this Settlement Agreement that is unacceptable to any of the Settling Parties. In the event the Commission modifies this Settlement Agreement in a manner unacceptable to any Settling Party, that Settling Party shall have the right to withdraw from this Agreement and proceed to hearing on any issue(s) that may be appropriately raised by that Settling Party. The withdrawing Settling Party shall notify the Commission counsel, Commission advisors, and the Settling Parties to this Settlement Agreement by email within three (3) business days of the Commission modification that the party is withdrawing from the Settlement Agreement and that the party desires to proceed to hearing; the email notice shall designate the precise issue or issues on which the party desires a rehearing (the "Hearing Notice").

7. The withdrawal of a Settling Party shall not automatically terminate this Agreement as to any other party. However, within three (3) business days of the date of the Hearing Notice from the first withdrawing party, all Settling Parties shall confer to arrive at a comprehensive list of issues that shall proceed to hearing and a list of issues that remain settled as a result of the first party's withdrawal from this Settlement Agreement. Within five (5) business days of the date of the Hearing Notice, the Settling Parties shall file with the Commission a formal notice containing the list of issues that shall proceed to hearing and those issues that remain settled together with a proposed procedural schedule. The Settling Parties who proceed to hearing shall have and be entitled to exercise all rights with

respect to the issues that are heard that they would have had in the absence of this Settlement Agreement.

8. All Parties have had the opportunity to participate in the drafting of this Settlement Agreement. There shall be no legal presumption that any specific Settling Party was the drafter of this Settlement Agreement.

9. This Settlement Agreement may be executed in counterparts, all of which when taken together shall constitute the entire Settlement Agreement with respect to the issues addressed by this Agreement.

Dated this 8th day of May 2017.

Respectfully submitted,

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President, Public Service Company of Colorado

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**ATTORNEYS FOR THE COLORADO ENERGY CONSUMERS**

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 15
Page 1 of 1

Has Mr. Alvarez performed any study to determine the costs of implementing a default PTR program for Duke Energy Kentucky's electric customers?

(a) If the response is in the affirmative, please provide such study.

RESPONSE:

Mr. Alvarez has conducted no such study.

(a) Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 16
Page 1 of 1

Please state if Mr. Alvarez is aware of the Kentucky Public Service Commission (KYPSC) approving either: 1) a non-voluntary, default time of use rate for a utility's residential customers; or 2) a non-voluntary, default peak time rebate for a utility's residential customers.

(a) If the answer is in the affirmative to either of items 1 or 2 above, please provide the date, Case No. and a copy of the Order approving the rate design.

RESPONSE:

Mr. Alvarez is not aware of such approvals by the Commission.

(a) Not applicable.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 17
Page 1 of 1

Is Mr. Alvarez aware if the KYPSC has either: 1) previously rejected a non-voluntary time of use rate or a peak time rebate as a default for residential customers; or 2) previously offered an opinion on establishing a non-voluntary time of use rate or a peak time rebate as a default for the residential customer class?

(a) If the answer is in the affirmative to either of items 1 or 2 above, please provide the date, Case No. and a copy of the Order approving the rate design.

RESPONSE:

Mr. Alvarez is aware of the Commission Order dated April 13, 2016 in Case No. 2012-00428, which states "The Commission finds that any dynamic pricing offering should be voluntary for customer participation, and efforts should be made to mitigate negative impacts on low income customers through customer education or any other reasonable and cost effective method." Mr. Alvarez notes that a default opportunity (i.e., available to all customers) to earn a peak time rebate is entirely consistent with this Order. This is due to the fact that the decision to respond to any critical peak event called in a default peak time rebate program is entirely voluntary, and to the fact that a customer's failure to respond to any critical peak event called incurs no economic penalty.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 18
Page 1 of 2

On page 17 of his testimony, Mr. Alvarez acknowledges that the Peak Time Rebate program being proposed in this application was the result of a settlement with the Attorney General in Case No. 2016-00152. In the same section, he suggests that some of the parameters agreed to in the settlement with respect to the PTR program were "arbitrary."

(a) Is Mr. Alvarez suggesting in this testimony that the Kentucky Attorney General agreed to a settlement without forethought or consideration of the terms in the settlement?

(b) Is Mr. Alvarez suggesting that the Kentucky Attorney General should withdraw from the settlement in Case No. 2016-00152?

(c) If the response is in the affirmative, is the Kentucky Attorney General now advocating that the settlement agreed to in Case No. 2016-00152 be set aside by the Commission?

RESPONSE:

Objection. The question: is overbroad; is designed to harass and oppress; is argumentative; is irrelevant; is nonsensical; and assumes facts not in evidence. Without waiving these objections, Mr. Alvarez states that new information provided in the present case regarding the PTR study design prompts a more rigorous examination into such design, including the specific issue of sample size and associated resolution. As his testimony states at p. 17, "With a better understanding of the Pilot design Duke presents in this Case, such as the use of the "difference of differences" approach, the measurement of winter as well as summer CPE impacts, and the measurement of impacts of "day before" CPE notices against the impacts of "same day" CPE notices, the potential insufficiency of the 1,000 participant Pilot size becomes more apparent. The opportunity to use a third-party Pilot evaluation firm to complete a Power Analysis to objectively determine the appropriate Pilot sample size is also new information."

Thus, Mr. Alvarez is not suggesting that the Attorney General or Duke Kentucky failed to use forethought or consideration of the terms of the settlement in Case No. 2016-00152, nor that the Attorney General or Duke Kentucky should withdraw from the settlement in that Case, nor that the Commission set aside its approval of that settlement. Rather, Mr. Alvarez's recommendation that the appropriate sample size be established in advance is based on the attributes of the study Duke Kentucky proposed, best practices in study design, and the best interests of Duke's Kentucky customers.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 19
Page 1 of 1

Does the Kentucky Attorney General believe the stipulation and recommendation in Case No. 2016-00152 was negotiated in good faith? If not, explain the reason(s) for your response.

RESPONSE:

Objection. The question: is designed to harass and oppress; is argumentative; and is nonsensical. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving these objections, Mr. Alvarez states: Yes.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 20
Page 1 of 1

Notwithstanding the opinions offered by its witness Mr. Alvarez, does the Kentucky Attorney General believe that Duke Energy Kentucky is free to change the terms of the stipulation and recommendation in Case No. 2016-00152 without the Kentucky Attorney General's agreement and KYPSC approval?

RESPONSE:

Objection. The question seeks a legal interpretation. Mr. Alvarez is not an attorney and has never held himself out as one. Without waiving these objections, the Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Further, to the extent that the study design Duke proposes in the present case consists of new information, the Attorney General does not consider the potential modification of Duke's study design to present a material modification of the stipulation and recommendation in Case No. 2016-00152. Furthermore, Mr. Alvarez believes it is possible that a Power Analysis of the type offered by DEK's PTR evaluation firm could determine that a sample size of 1,000 participants will likely deliver statistically significant answers to pilot questions, or, conversely, that a smaller number of pilot questions could be answered in a statically significant manner with a sample size equal to 1,000 participants.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 21
Page 1 of 1

Notwithstanding the opinions offered by its witness Mr. Alvarez, does the Kentucky Attorney General still support the stipulation and recommendation in Case No. 2016-00152 negotiated in good faith with Duke Energy Kentucky and approved by the KYPSC?

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving this objection, see the responses to data request item nos. 18 and 20.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 22
Page 1 of 1

Please identify any specific sections of the stipulation and recommendation in Case No. 2016-00152 where the Company's proposed PTR pilot program deviates from the agreed pilot parameters?

RESPONSE:

Objection. The question assumes facts not in evidence. Mr. Alvarez's testimony does not state that DEK's proposed PTR pilot program "deviates from the agreed pilot parameters." In fact, DEK introduced new attributes for the PTR pilot program not specified or anticipated by the Attorney General in the stipulation and recommendation in Case No. 2016-00152. These include the introduction of winter as well as summer event days (Application page 9, item 12), as well as the introduction of event notifications issued less than one hour in advance (Application page 10, item 15). Both of these changes likely impact the adequacy of the pilot sample size specified in Case No. 2016-00152. Further, DEK itself signifies its intention to accept pilot participation enrollment in excess of the 1,000 participants specified in Case No. 2016-00152 (Application, page 11, item 17). However, the Attorney General does not believe these new attributes represent material deviations from the stipulation reached in Case No. 2016-00152.

See also pp. 12-27 of the Direct Testimony of Paul J. Alvarez.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 23
Page 1 of 1

KY AG and Mr. Alvarez, do you agree that the following excerpts from page 9 and 10 of the stipulation and recommendation in Case No. 2016-00152 confirms that customers must elect, voluntarily, to participate in the PTR Pilot program?

(a) Page 9: "The intent of the PTR Pilot will be to collect the information from **voluntary participants** (emphasis added) needed to properly evaluate the potential addition of a Peak Time Rebate program that could be made available to all eligible residential customers."

(b) Page 10: "The initial PTR Pilot shall be conducted for a two-year period and will be limited to the first one thousand (1,000) eligible residential customers **that enroll** (emp. added) in the program…."

(c) Page 10: "As part of the registration/application process for **interested residential customers** (emp added), …."

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Moreover, the Attorney General and Mr. Alvarez assert that pleadings and orders from prior cases speak for themselves.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 24
Page 1 of 1

Is either the Kentucky Attorney General or its witness Mr. Alvarez aware that Duke Energy Kentucky provides smart meter customers access to hourly usage data online, and that this data is available to the customer the day after it is recorded?

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving these objections, Mr. Alvarez states he is aware that DEK provides smart meter customers access to hourly usage data online, and that this data is available to the customer the day after it is recorded. However, Mr. Alvarez notes that a customer accessing such usage data for a critical peak event (CPE) will not be able to determine whether or not any perceived usage reductions would be sufficient to earn a rebate as specified by the rebate calculation methods provided by DEK in response to AG DR 01-010. Accordingly, Mr. Alvarez would like to make clear that access to online hourly usage data cannot serve as a substitute for the CPE-specific feedback Mr. Alvarez recommends in his testimony.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 25
Page 1 of 1

Has Mr. Alverez [sic] performed any cost-effectiveness analysis or study to determine if increasing the credit under the PTR-Pilot would pass any of the cost-effectiveness tests recognized by the KYPSC?

(a) If the answer is in the affirmative, please provide all such studies/analysis.

RESPONSE:

No, Mr. Alvarez has not performed such an analysis.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 26
Page 1 of 1

Does the Kentucky Attorney General and/or Mr. Alvarez believe that over payment of load reduction incentives in a PTR program that is subject to DSM cost effectiveness testing such as those used for evaluating Duke Energy Kentucky's energy efficiency and demand side management programs could lead to negative impacts on cost effectiveness scores for the program?

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving these objections, Mr. Alvarez understands that either overpayment or underpayment of load reduction incentives in a PTR program could lead to negative impacts on the program's cost effectiveness scores. This is because DSM cost effectiveness is based on both program cost and program impact. Mr. Alvarez notes that underpayment of load reduction incentives could lead to lower usage reductions during critical peak events than would otherwise be delivered by customers, and thus lower program impact. As a result, Mr. Alvarez believes that underpayment of load reduction incentives could result in negative impacts on the PTR program's cost effectiveness scores just as overpayments could.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 27
Page 1 of 1

Please confirm whether the representative of the Kentucky Attorney General attended any of the Company's DSM Collaborative meetings during 2017 or 2018 when the PTR-Pilot was discussed?

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving these objections, the Attorney General notes that due to significant staffing changes in the past several weeks, he is uncertain whether a former representative of his office attended any such meeting.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 28
Page 1 of 1

Does the Kentucky Attorney General agree that Duke Energy Kentucky discussed the desire to limit the risk of overpayment of load reduction incentives during the DSM Collaborative meetings in 2017 and 2018 by requiring customers to reply to event notices and confirm that they will attempt to reduce their consumption during PTR hours?

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving these objections, the Attorney General states, see the response to question no. 27.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 29
Page 1 of 1

Does Mr. Alvarez and the KY AG acknowledge that the Duke Energy Kentucky PTR program is specified as a DSM program in multiple locations on page 9 through 11 in the stipulation and recommendation in Case No. 2016-00152?

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Moreover, Mr. Alvarez and the Attorney General assert that pleadings and orders from prior cases speak for themselves.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 30
Page 1 of 2

Mr. Alvarez proposes that the Commission conform the Peak Time Rebate Pilot program being proposed by Duke Energy Kentucky to an existing program offered in the State of Maryland.

(a) Was the PTR program in Maryland offered initially as a pilot program with limited participation or was it offered to all customers from the beginning?

(b) Was the rebate always $1,250 per MWh or has it changed since inception of the program?

(c) Please confirm that Maryland is a retail choice state where customers are able to shop in a competitive market for generation supply?

(d) Is Mr. Alvarez aware that rates for electric service in Maryland are unbundled (generation is separated from distribution and transmission)?

(e) Describe the impact of choice on the PTR program in Maryland, i.e., is the PTR program available to shopping and non-shopping customers; how are competitive suppliers affected by load reductions related to the PTR program, etc.?

RESPONSE:

Objection. The question states facts not in evidence and mischaracterizes Mr. Alvarez's testimony. Additional specific objection to subparts (c) – (e): the questions are irrelevant. Without waiving these objections, Mr. Alvarez responds as follows.

(a) To the best of Mr. Alvarez's recollection, peak-time rebate programs for Maryland utilities followed a pilot program (Smart Energy Rewards) conducted by the state's largest investor-owned utility, Baltimore Gas and Electric, around 2009-2010.
(b) Mr. Alvarez does not know the history of rebate amounts offered by Maryland utilities as part of PSC-mandated peak-time rebate programs.
(c) Confirmed, though Mr. Alvarez fails to see the relevance of this question to peak-time rebate pilot design in Kentucky.
(d) Yes, though Mr. Alvarez fails to see the relevance of this question to peak-time rebate pilot design in Kentucky.
(e) To Mr. Alvarez's knowledge, all Maryland customers can secure a peak-time rebate, including both shopping and non-shopping customers, from investor-owned distribution utilities, which administer the program and apply rebates to the non-commodity, distribution service portion of customer bills. Regarding the impact on

competitive suppliers of PTR programs, Mr. Alvarez fails to see the relevance of this question to peak-time rebate pilot design in Kentucky. However, to the extent Maryland peak-time rebate programs reduce market prices for energy and capacity, Mr. Alvarez believes all competitive suppliers – and presumably, over the long run, their customers – benefit.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 31
Page 1 of 2

In reference to the direct testimony of Witness Alvarez starting on page 18 line 13 and going through page 20 line 2:

(a) On page 18 line 22, Mr. Alvarez cites a Locational Marginal Price (LMP) value of $0.36/kWh. Does Mr. Alvarez suggest that the best practice for implementing PTR program critical peak events would be for an event duration of 1 hour?

(b) Does Mr. Alvarez suggest that the best practice for implementing PTR program critical peak events would be to implement one single event per year?

(c) On page 19 lines 7 and 8, Mr. Alvarez states an average "KW of power" for central air conditioning and electric clothes dryers. Please provide the analysis Mr. Alvarez relies upon to conclude that these appliances consume the stated amount of power each hour for all residential customers across all hours of the proposed Duke Energy Kentucky peak time period for which the PTR program would be implemented (i.e. proposed to be 3 pm to 7 pm in the summer and 6 am to 10 am in the winter)?

(d) Provide the analysis Mr. Alvarez relies upon to conclude that the climate in Kentucky is similar to the climate in Maryland? … in the BG&E service area?

(e) Does Mr. Alvarez and the Kentucky Attorney General believe that a Duke Energy Kentucky DSM PTR Pilot program should provide load reduction incentives equal to 100% of all avoided costs the program provides?

RESPONSE:

(a) No

(b) No

(c) Mr. Alvarez has not conducted such an analysis.

(d) Mr. Alvarez has not conducted such an analysis.

(e) Objection as to subpart (e); the Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving this objection, Mr. Alvarez believes that load reduction incentives should be optimized to secure the greatest degree of customer behavior change for the least incentive, while simultaneously ensuring that total program benefits (from energy and demand reductions) exceed total program costs

QUESTION No. 31
Page 2 of 2

(incentives, marketing, administration, etc.). Mr. Alvarez notes that any total program benefits in excess of total program costs accrue to all customers, not just participating customers. He also notes that this is not necessarily an adverse outcome of peak-time rebate programs, and in fact is a hallmark of demand-side management programs in general.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 32
Page 1 of 1

On page 18 of his testimony, Mr. Alvarez states that the 'marginal' price for energy at Duke Energy three local pricing nodes reached $360 per MWh at 5:00 p.m. on July 1, 2019. On page 24 of his testimony, Mr. Alvarez acknowledges that Duke Energy Kentucky proposes to call 16-25 critical peak events per year as part of its proposal. For calendar years 2017, 2018, and 2019, please provide the 25 highest 4-hour average locational marginal prices consistent with the proposed PTR Pilot program event window at the three local pricing nodes referenced by Mr. Alvarez.

RESPONSE:

Mr. Alvarez has not conducted this analysis, and notes that DEK can easily do so from records made available by PJM.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 33
Page 1 of 1

Please confirm that the Baltimore Gas & Electric Company is not a Fixed Resource Requirement (FRR) entity in PJM.

RESPONSE:

Confirmed. Mr. Alvarez notes that Exelon, the parent company of several Maryland utilities, owns and operates an extensive fleet of electric generating plants in PJM.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 34
Page 1 of 1

Provide the last 5 years of PJM capacity market (RPM) clearing prices for the Baltimore Gas & Electric service area (Local Delivery Are [LDA]) in Maryland for the PJM Base Residual Auction, 1st incremental, 2nd incremental, and 3rd incremental auctions.

RESPONSE:

Objection. The question: is overbroad; seeks information which is in the public domain; is designed to harass and oppress; is argumentative; is irrelevant; and assumes facts not in evidence. Without waiving these objections, Mr. Alvarez states that he has not conducted this analysis, and notes that DEK can easily do so from records made available by PJM.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 35
Page 1 of 1

Is the Baltimore Gas & Electric PTR program subject to the same cost-effectiveness DSM test score criteria as Duke Energy Kentucky's DSM programs? If not, explain what criteria is used to evaluate the Baltimore Gas & Electric PTR program?

RESPONSE:

Objection. The question: is overbroad; seeks information which is in the public domain; is designed to harass and oppress; is argumentative; is irrelevant; and assumes facts not in evidence. Without waiving these objections, Mr. Alvarez states that he has not analyzed the cost-effectiveness DSM testing protocols in Kentucky or Maryland. For more information on Baltimore Gas & Electric PTR program benefits and costs, Mr. Alvarez suggests DEK visit the Maryland PSC website, Case No. 9494, to examine the utility's DSM program filing dated September 1, 2017.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 36


Regarding Mr. Alvarez's proposal to use Maryland as a model for the PTR pilot program, is Mr. Alvarez aware of any other states that:

(a) Have fully integrated electric utilities (non-retail choice) with smart meter technology that have PTR programs? If so, please list the states and a brief summary of the details of the program, such as whether the program is a pilot or available to all customers and the pricing terms of the PTR program.

(1) If available to all customers, is the program default or voluntary?

(b) Have fully integrated retail jurisdictional electric utilities with smart meter technology that do NOT have PTR programs?

RESPONSE:

Objection. The question: states facts not in evidence; mischaracterizes Mr. Alvarez's testimony; and is irrelevant as to subpart (b). Without waiving these objections, Mr. Alvarez:

(a) notes that the California PUC has mandated default time-of-use rates for residential customers despite the fact that California is a non-retail choice state for residential customers. Mr. Alvarez further notes that in Colorado, a non-retail choice state with fully integrated utilities, the Colorado PUC approved a settlement agreement in which default time-of-use would apply to Public Service Company electric customers with smart meters as part of the utility's smart meter deployment. See Mr. Alvarez's response to DEK DR 1-14.

(b) is aware of other states which have fully integrated retail jurisdictional electric utilities, smart meter technology, and no PTR program. However, Mr. Alvarez fails to see the relevance of this observation to peak-time rebate pilot design in Kentucky.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 37
Page 1 of 1

Is Mr. Alvarez and/or the Kentucky Attorney General familiar with:

(a) the PJM capacity resource requirements currently in effect?

(b) the PJM capacity resource requirements that will be in effect for the 2020/2021 delivery year?

(c) If the response to a or b above is in the affirmative, please explain these requirements as they pertain to summer and winter load reduction availability?

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Objection, Mr. Alvarez has never held himself out as being an expert with regard to regional transmission organizations such as PJM. Objection, the subparts are: vague; overbroad; are designed to annoy or harass the witness; and susceptible to multiple interpretations. Without waiving these objections, Mr. Alvarez:

(a) is somewhat familiar with the PJM capacity resource requirements currently in effect. Mr. Alvarez also notes the facts that 1) New York ISO operates seasonal capacity markets; 2) ISO New England is currently considering the introduction of seasonal capacity markets; 3) Maryland IOUs participating in the PJM capacity market still offer peak-time rebate programs despite current PJM capacity resource requirements; 4) the FERC's decision in Docket No. ER16-623[1] regarding PJM capacity resource requirements featured a strong and thorough dissenting opinion by Commissioner Bay, and is likely to be revisited in the future; and (5) the FERC's recent ruling in Calpine Corp., et al vs. PJM Interconnection LLC (Docket Nos. EL16-49-000 and EL 18-178-000) will require PJM to make major changes in the capacity market.

(b) is somewhat familiar with the PJM capacity resource requirements that will be in effect for the 2020/2021 delivery year;

(c) believes peak-time rebate programs can deliver value to customers and markets irrespective of the ability of such programs to constitute stand-alone capacity market bids (see response to DEK DR 1-38). Moreover, Mr. Alvarez notes that capacity market rules and constructs can change and do change over time.

[1] Affirmed on appeal in Advanced Energy Mgmt. v. FERC, 860 F.3d 656 (D.C. Cir. 2017).

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 38
Page 1 of 1

Does Mr. Alvarez and/or the KY AG believe that a Duke Energy Kentucky PTR DSM program can provide capacity value to Duke Energy Kentucky's FRR plan without meeting PJM Price Responsive Demand (PRD) requirements?

(a) If so, please explain how this can happen.

(b) Please describe the capacity value provided by a Duke Energy Kentucky PTR DSM program that does not satisfy PJM PRD requirements?

(c) Please explain how a PTR DSM program that does not satisfy PJM PRD requirements should be valued in relation to a DSM program that does satisfy the PJM PRD requirements?

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving this objection:

(a) Mr. Alvarez notes that there are several ways for summer-oriented demand reductions to deliver capacity value to DEK customers without meeting PJM Price-Responsive Demand requirements. These include, at a minimum:

- Helping DEK avoid placing its Fixed Resource Requirement designation in jeopardy (which would require DEK to secure capacity from PJM at a higher cost to customers);
- Avoiding T&D investments designed to accommodate summer peak demand;
- Increasing awareness of, and participation in, DSM programs which do comply with PJM PRD requirements (such as direct air conditioning load control) through co-marketing with peak-time rebate (as practiced in Maryland).

(b) See response to DEK DR 1-38(a)

(c) Mr. Alvarez believes that the value propositions described in his response to DEK DR 1-38(a) can be quantified, and should serve as a basis for valuation of programs that do not satisfy PJM PRD requirements.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 39
Page 1 of 1

Does Mr. Alvarez believe the Duke Energy Kentucky PTR Pilot program should serve as a research study for all investor owned utilities (IOUs) in Kentucky? If so, does Mr. Alvarez believe the results of such a study are transferrable to other IOU areas? Does Mr. Alvarez believe that the customers of Duke Energy Kentucky should solely pay the cost of a study for other IOU service areas?

RESPONSE:

Objection. The question: is irrelevant; assumes facts not in evidence; is vague; and seeks a legal opinion. Without waiving these objections, Mr. Alvarez believes the DEK PTR Pilot program results should at least partly inform future Commission decisions regarding such programs throughout Kentucky. Mr. Alvarez is not certain what is meant by the phrase "transferrable to other IOU areas." However, he believes the results of such a study could be transferrable to other IOUs in general, assuming the study is conducted in a manner consistent with best practices and with an adequate sample size. Mr. Alvarez notes that state utility regulators often consider results of pilot programs from other jurisdictions, and from other IOU service territories. Mr. Alvarez is not certain what DEK means by referring to the propriety of DEK ratepayers being required to "pay the cost of a study for other IOU service areas." Further, it appears DEK may be seeking a legal opinion.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez / Counsel as to Objections

QUESTION No. 40
Page 1 of 1

Please provide any studies, calculations, or workpapers developed by Mr. Alvarez to quantify the impact on Duke Energy Kentucky's residential electric customers assuming a $1,250 per MWh price is established for the peak time rebate if (1) the Pilot program is limited to the 1,000 customers, as agreed to by the Attorney General in the Stipulation approved in Case No. 2016-00152 or (2) the program is available to all residential customers as proposed by Mr. Alvarez.

RESPONSE:

Objection. The question and subparts mischaracterize Mr. Alvarez's testimony, and assume facts not in evidence. Mr. Alvarez does not propose that a peak time rebate program be made available to all residential customers at this time. Mr. Alvarez's testimony recommends changes to DEK's proposed PTR study design "to ensure Pilot outcomes are useful for future decisions regarding peak-time rebate programs" (page 6). Mr. Alvarez's testimony also states that the results of a(n) (appropriately designed and conducted) study could be used to inform "future decisions regarding a broader roll-out of a peak-time rebate program for Duke customers" (page 5 at line 21).

Without waiving these objections, Mr. Alvarez states that he has not completed any such studies, calculations, or workpapers. See also response to DEK DR no. 20.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 41
Page 1 of 1

Does Mr. Alvarez agree that the cost of providing the peak time rebate credit, whether at the $330 per MWh rate proposed by the Company or at the $1,250 per MWh rate proposed in his testimony, should be recovered from customers?

RESPONSE:

Yes, if the results of an appropriately designed and conducted study indicate that the impact delivered by the incentive rate(s) tested yields a program in which total program benefits to customers (as a whole) exceed total program costs from customers (as a whole).

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 42
Page 1 of 1

Does the Kentucky Attorney General and/or Mr. Alvarez agree that a 1,000 participant opt-in PTR pilot, as proposed by Duke Energy Kentucky and agreed to in the Settlement approved in Case No. 2016-00152, is likely a sufficient sample size to estimate the load reduction amount provided by participants during summer and winter PTR pricing events under the Duke Energy Kentucky DSM program accuracy requirements?

(a) If the response is in the negative, please explain why.

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. The Attorney General will assert in his final brief or final comments such arguments as he deems prudent. Without waiving this objection, and based on the limited information DEK has provided regarding PTR pilot sample size sufficiency, Mr. Alvarez does not agree that a 1,000 participant opt-in PTR pilot is likely a sufficient sample size to estimate the load reduction amount provided by participants during summer and winter PTR pricing events under the DEK DSM program accuracy requirements. As indicated in his testimony, Mr. Alvarez states "The sample size required is based on an estimate of the ranges of Pilot outcomes for specific questions to be answered." (Alvarez Direct Testimony at p. 14, line 10). The optional Power Analysis proposed by DEK's selected PTR program evaluator is designed to do this. Mr. Alvarez would have to review the results of the Power Analysis before he can be confident that a sample size of 1,000 participants is likely sufficient to estimate the load reduction amount provided by participants during summer and winter PTR pricing events. See also response to DEK DR no. 20.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 43
Page 1 of 1

Referring to Alvarez testimony page 11, lines 11 & 12 "Duke is motivated by capital bias to build…." Please provide all supporting documents for this statement.

RESPONSE:

See Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review*. 52 (5): 1052–1069.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 44
Page 1 of 1

Referring to Alvarez's concern with the sample size proposed in the Duke Energy Kentucky PTR Pilot and his testimony on page 8, lines 18 - 20 "I consider the approach employed in Maryland to be a best practice for utilities which have installed smart meters."

(a) Please provide the sample size used by Baltimore Gas & Electric and PEPCO in their PTR pilots.

(b) Please provide the Baltimore Gas & Electric and Pepco PTR pilot participation levels by year for their respective pilots.

(c) Please provide the percentage of the Baltimore Gas & Electric and Pepco total sample size that the program impacts were based upon (in other words, did most of the pilot program's impact come from only the top half of the pilot's participants?)

(d) Please provide documentation, studies, analysis or summaries of any and all lessons learned as a result of the Baltimore Gas & Electric and Pepco PTR Pilots, including but not limited to, assessments of rebate amounts, sample size, customer participation levels, customer marketing, notification methods & times, etc.

RESPONSE:

(a) See the final results of pilots conducted by Baltimore Gas & Electric and PEPCO on peak-time rebate and other time-of-use rate designs, in the copyrighted Brattle Group presentation, "Evaluation of Baltimore Gas and Electric Company's Smart Energy Pricing Program, which is publicly accessible at www.brattle.com.
(b) See response to (a)
(c) See response to (a)
(d) See response to (a)

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 45
Page 1 of 1

Referring to Alvarez's concern regarding Duke Energy Kentucky's proposed $.33/kwh rebate, please provide any and all analyses, and supporting documentation that this rebate amount will "reduce customer's motivation to reduce usage during CPE's and likely result in lower observed impacts in the Pilot" (Alvarez testimony page 18).

RESPONSE:

Mr. Alvarez has not prepared any such analyses. His conclusion that smaller rebates will result in lower observed impacts are based on personal experience, logic, and published secondary research (See Faruqui A and Palmer, J, "The Discovery of Price Responsiveness – A Survey of Experiments involving Dynamic Pricing of Electricity", EDI Quarterly, Volume 4, No. 1, April, 2012) [Attachment DEK 45-1].

***Submitted to the EDI Quarterly***

**The Discovery of Price Responsiveness – A Survey of Experiments involving Dynamic Pricing of Electricity**

Ahmad Faruqui and Jenny Palmer[1]

Abstract

*This paper surveys the results from 126 pricing experiments with dynamic pricing and time-of-use pricing of electricity. These experiments have been carried out across three continents at various times during the past decade. Data from 74 of these experiments are sufficiently complete to allow us to identify the relationship between the strength of the peak to off-peak price ratio and the associated reduction in peak demand or demand response. An "arc of price responsiveness" emerges from our analysis, showing that the amount of demand response rises with the price ratio but at a decreasing rate. We also find that about half of the variation in demand response can be explained by variations in the price ratio. This is a remarkable result, since the experiments vary in many other respects – climate, time period, the length of the peak period, the history of pricing innovation in each area, and the manner in which the dynamic pricing designs were marketed to customers. We also find that enabling technologies such as in-home displays, energy orbs and programmable and communicating thermostats boost the amount of demand response. The results of the paper support the case for widespread rollout of dynamic pricing and time-of-use pricing.*

**Introduction**

Electric utilities, which run a capital-intensive business, could lower their costs of doing business by improving their load factor. Other capital intensive industries, such as airlines, hotels, car rental agencies, sporting arenas, movie theaters routinely practice a technique known as dynamic pricing to improve load factor. In dynamic pricing, prices vary to reflect the changing balance of demand and supply through the day, through the week and through the seasons of the year.

Congestion pricing, a simpler form of dynamic pricing, is used to regulate the flow of cars into central cities. Parking spaces in most central cities are priced on a time-of-day basis and in some cities such as San Francisco the prices are varying dynamically. In California, special lanes on freeways are priced dynamically and the Bay Bridge charges toll on a time-of-use basis.

But it has been difficult for electric utilities to follow these examples. There has always been doubt that electric users can change their usage patterns. To assuage these doubts, in the late 1970s and early 1980s, a dozen electricity pricing experiments were carried out with time-of-use rates in the United

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[1] The authors are economists with The Brattle Group, based in San Francisco. They are grateful to fellow economist Sanem Sergici of Brattle for reading an early draft of this paper. Comments can be directed to ahmad.faruqui@brattle.com.

States.[2] They showed that customers do respond to such rates by lowering peak usage and/or shifting it to less expensive off-peak periods. But smart meters that would charge on a time-of-day basis were expensive in those days and little progress occurred in the ensuring years. Even now, less than one percent of the more than 125 million electric customers in the United States are charged on a time-of-use basis.

However, the California energy crisis of 2000-01 reinvigorated interested in dynamic pricing, not only in that state but globally. Over the past decade, two dozen dynamic pricing studies featuring over one hundred dynamic time-of-use and dynamic pricing designs were carried out across North America, in the European Union and in Australia and New Zealand.[3]

These experiments have yielded a rich body of empirical evidence. We have compiled this into a database, *D-Rex*, which stands for *D*ynamic *R*ate *ex*periments. This contains the following data from each pilot: details of the specific rate designs tested in the pilot, whether or not enabling technologies were offered to customers in addition to the time-varying rates, and the amount of peak reduction that was realized with each price-technology combination. The *D-Rex* results provide an important perspective on the potential magnitude of impacts with different dynamic rate approaches and should inform the public debate about the merits of smart meters and smart pricing. Across the 129 dynamic pricing tests, peak reductions range from near zero values to near 60 percent values. However, it would be misleading to conclude that there is no consistency in customer response.[4]

We focus on nine of the best designed, more recent experiments to examine the impact of the peak to-off peak price ratio on the magnitude of the reduction in peak demand, or demand response. Because the amount of demand response varies with the presence or absence of enabling technology, such as a smart thermostat, an energy orb or an in-home display, we separate those pricing tests without and with enabling technology. We find a statistically significant relationship between the price ratio and the amount of peak reduction, and quantify this relationship with a logarithmic model. This relationship is termed the Arc of Price Responsiveness. We find that for a given price ratio, experiments with enabling technologies tend to produce larger peak reductions, and display a more price-responsive Arc.

**Sidebar: The Dynamic Rates**

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[2] For an early summary, see Ahmad Faruqui and J. Robert Malko, "The Residential Demand for Electricity by Time-Of-Use: A Survey of Twelve Experiments with Peak Load Pricing," *Energy*, Volume 8, Issue 10, October 1983. For more recent surveys, see Ahmad Faruqui and Jenny Palmer, "Dynamic Pricing and its Discontents," *Regulation*, Fall 2011 and Ahmad Faruqui and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity – A Survey of 15 Experiments," *Journal of Regulatory Economics*, October 2010. Faruqui and Palmer also discuss the more common myths that surround legislative and regulatory conversations about dynamic pricing.

[3] Most dynamic pricing studies have included multiple tests. For example, a pilot could test a TOU rate and a CPP rate and it could test each rate with and without enabling technology. Thus, this pilot would include a total of four pricing tests.

[4] See, for example, the concluding remarks in an otherwise excellent paper by Paul Joskow, "Creating a smarter U.S. electrical grid," *Journal of Economic Perspectives*, Winter 2012.

Time-of-Use (TOU). A TOU rate could either be a time-of-day rate, in which the day is divided into time periods with varying rates, or a seasonal rate into which the year is divided into multiple seasons and different rates provided for different seasons. In a time-of-day rate, a peak period might be defined as the period from 12 pm to 6 pm on weekdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak, mirroring the variation in marginal costs by pricing period.

Critical Peak Price (CPP). On a CPP rate, customers pay higher peak period prices during the few days a year when wholesale prices are the highest (typically the top 10 to 15 days of the year which account for 10 to 20 percent of system peak load). This higher peak price reflects both energy and capacity costs and, as a result of being spread over relatively few hours of the year, can be in excess of $1 per kWh. In return, the customers pay a discounted off-peak price that more accurately reflects lower off-peak energy supply costs for the duration of the season (or year). Customers are typically notified of an upcoming "critical peak event" one day in advance but if enabling technology is provided, these rates can also be activated on a day-of basis.

Peak Time Rebate (PTR). If a CPP tariff cannot be rolled out because of political or regulatory constraints, some parties have suggested the deployment of peak-time rebate. Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply buy through at the existing rate. There is no rate discount during non-event hours. Thus far, PTR has been offered through pilots, but default (opt-out) deployments have been approved for residential customers in California, the District of Columbia and Maryland.

Real Time Pricing (RTP). Participants in RTP programs pay for energy at a rate that is linked to the hourly market price for electricity. Depending on their size, participants are typically made aware of the hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers —above one megawatt of load — face hour-ahead prices. These programs post prices that most accurately reflect the cost of producing electricity during each hour of the day, and thus provide the best price signals to customers, giving them the incentive to reduce consumption at the most expensive times.

**The Dynamic Pricing Studies**

The *D-Rex* Database contains the results of 129 dynamic pricing tests from 24 pricing studies. [5] As shown in Figure 1, these results range from close to zero to up to 58 percent. Part of the variation in impacts comes simply from the fact that different rate types are being tested. Filtering by rate in Figure 2, some trends begin to emerge. We observe that the Critical Peak Pricing (CPP) rate tends to have higher impacts than Time-of-Use (TOU) rates, likely because the CPP rates have higher peak to off-peak price ratios. We can also filter by the presence of enabling technology, as in Figure 3, and observe that for the same rates, the impacts with enabling technologies tends to be higher.

[5] 23 of the 24 studies are pricing pilots. The other study is PG&E's full scale rollout of TOU and SmartRate.

**Figure 1. Impacts from Residential Dynamic Pricing Tests, Sorted from Lowest to Highest**

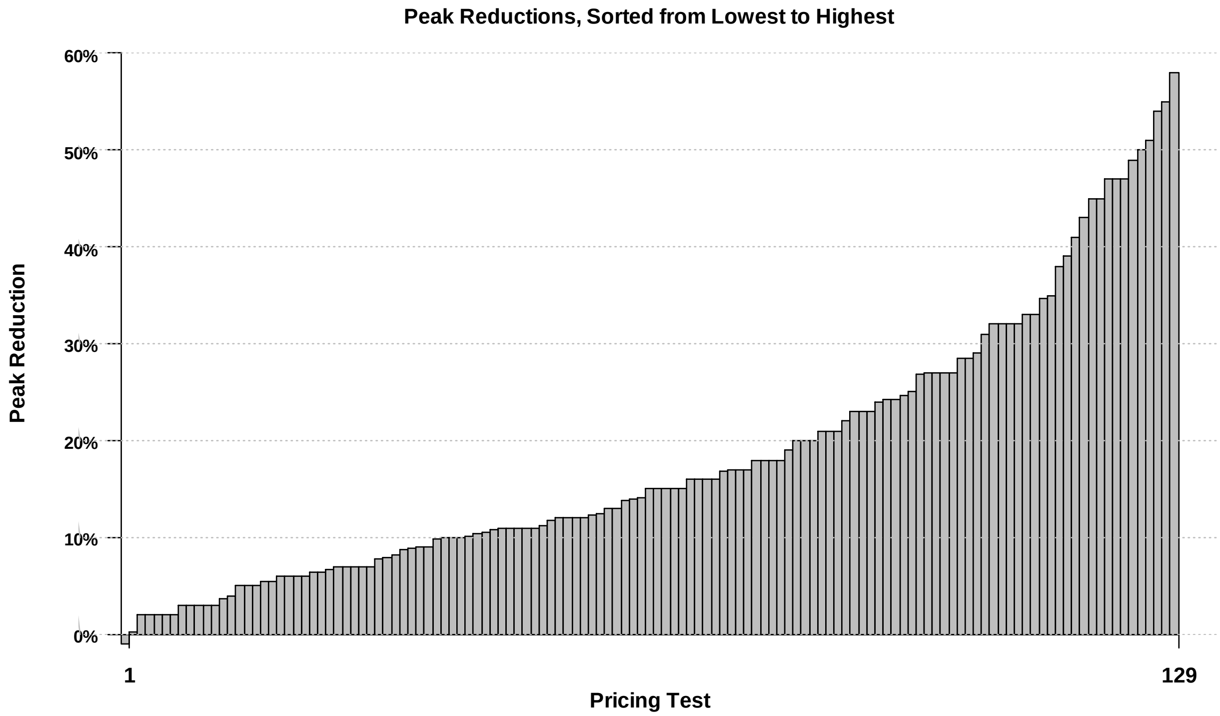
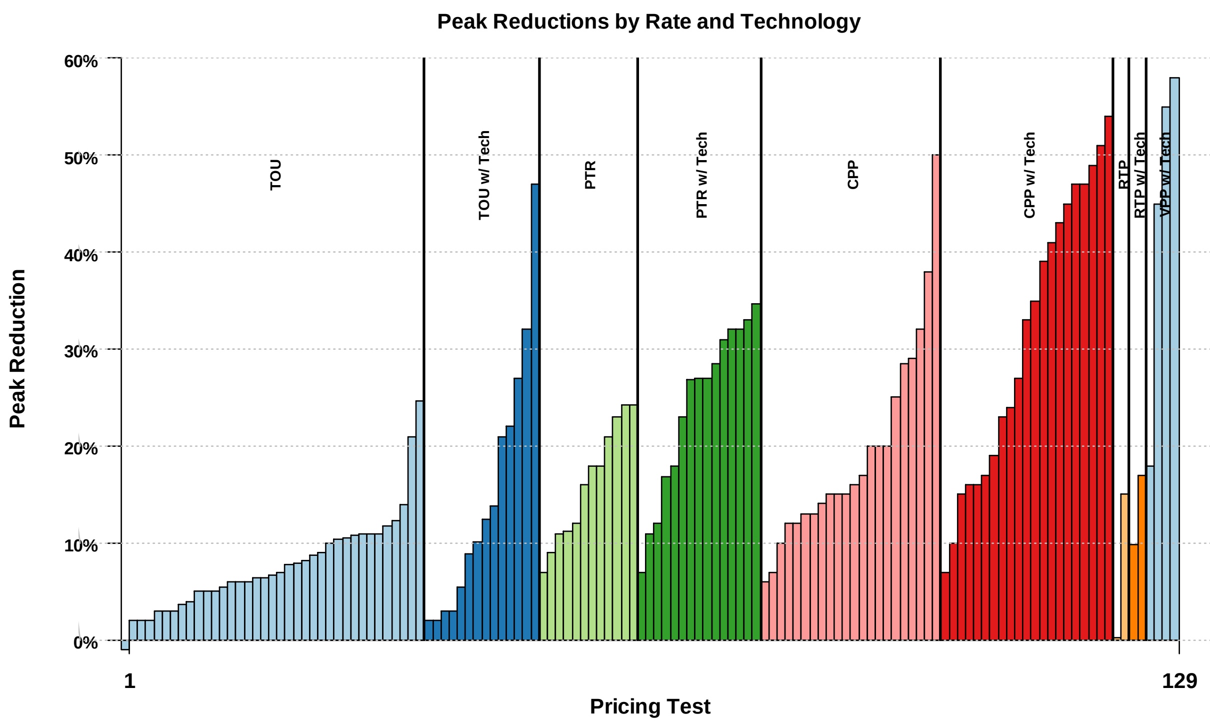



**Figure 2. Impacts from Pricing Tests, by Rate Type**

**Figure 3. Impacts from Pricing Tests, by Rate Type and Presence of Enabling Technologies**




Even with the rate and technology filters, there remains significant unexplained variation. In order to understand the cause of this variation, we first limit the sample to only the best-designed studies which have reported the relevant data. We selected studies in which samples are representative of the population and the results are statistically valid. Moreover, we selected studies in which participants were selected randomly, as opposed to volunteers responding to a mass mailing. The nine best-designed pilots, shown in Table 1, include 42 price-only tests and 32 pricing tests with prices *cum* enabling technology.[6] In these 74 tests, the peak reductions range from 0% to just under 50%. The remainder of this paper focuses on explaining the variation in these results.

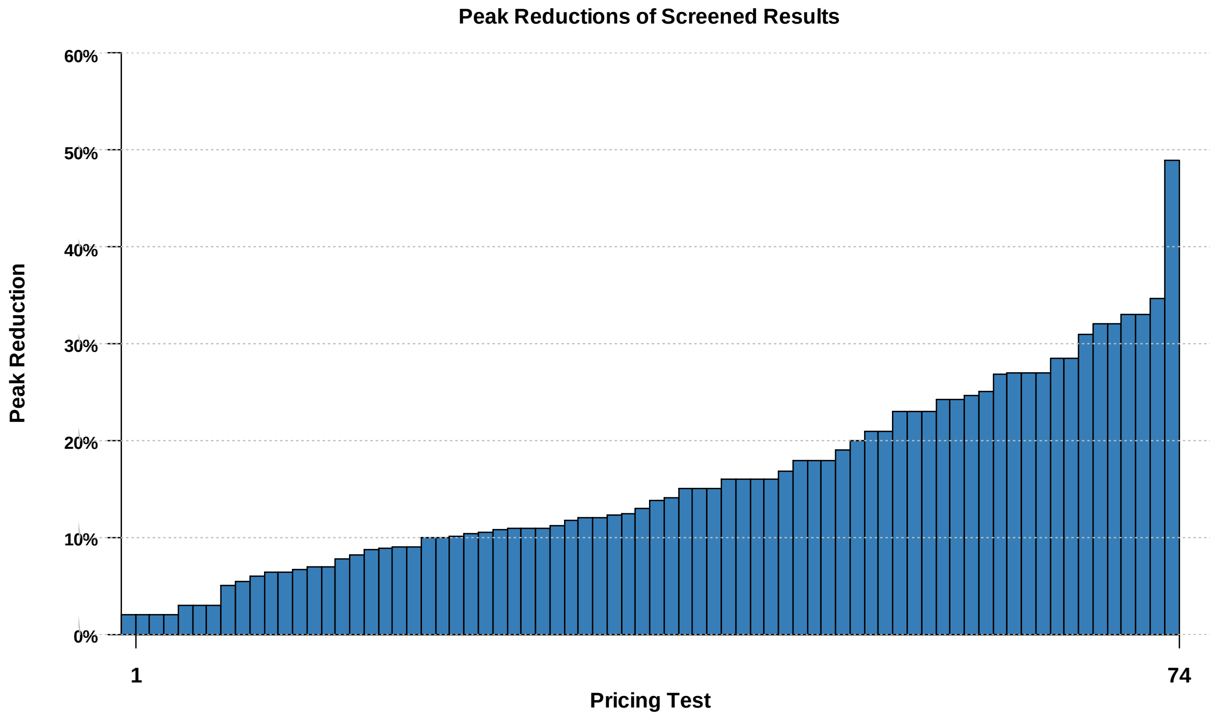
[6] OG&E was not included in these screened results because only the draft results are available thus far. When these results are finalized, they will be included in this analysis.

**Table 1. Features of the Nine Dynamic Pilots**

| Utility | Location | Year | Rates | Enabling Technologies | Number of Tests |
|---|---|---|---|---|---|
| Baltimore Gas & Electric | Maryland | 2008, 2009, 2010 | CPP, PTR | CPP w/ Tech, PTR w/ Tech | 17 |
| Connecticut Light & Power | Connecticut | 2009 | TOU, CPP, PTR | TOU w/ Tech, CPP w/ Tech, PTR w/ Tech | 18 |
| Consumers Energy | Michigan | 2010 | CPP, PTR | CPP w/ Tech | 3 |
| Pacific Gas & Electric (Full scale rollout) | California | 2009, 2010 | TOU, CPP | Not tested | 4 |
| Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison (Statewide Pricing Pilot) | California | 2003, 2004 | TOU, CPP | CPP w/ Tech | 4 |
| Pepco DC | District of Columbia | 2008, 2009 | CPP, PTR, RTP[2] | CPP w/ Tech, PTR w/ Tech, RTP w/ Tech | 4 |
| Salt River Project | Arizona | 2008, 2009 | TOU | Not tested | 2 |
| Utilities in Ireland[2] | Ireland | 2010 | TOU | TOU w/ Tech | 16 |
| Utilities in Ontario | Ontario, Canada | 2006 | TOU, CPP, PTR | Not tested | 6 |
| | | | | **Total** | **74** |

1. Run by the Commission for Energy Regulation (CER)
2. The two RTP pricing tests are excluded from this analysis because they do not have a clear peak to off-peak price ratio.

**Figure 4. Impacts from Pricing Tests, by Rate Type and Presence of Enabling Technologies**

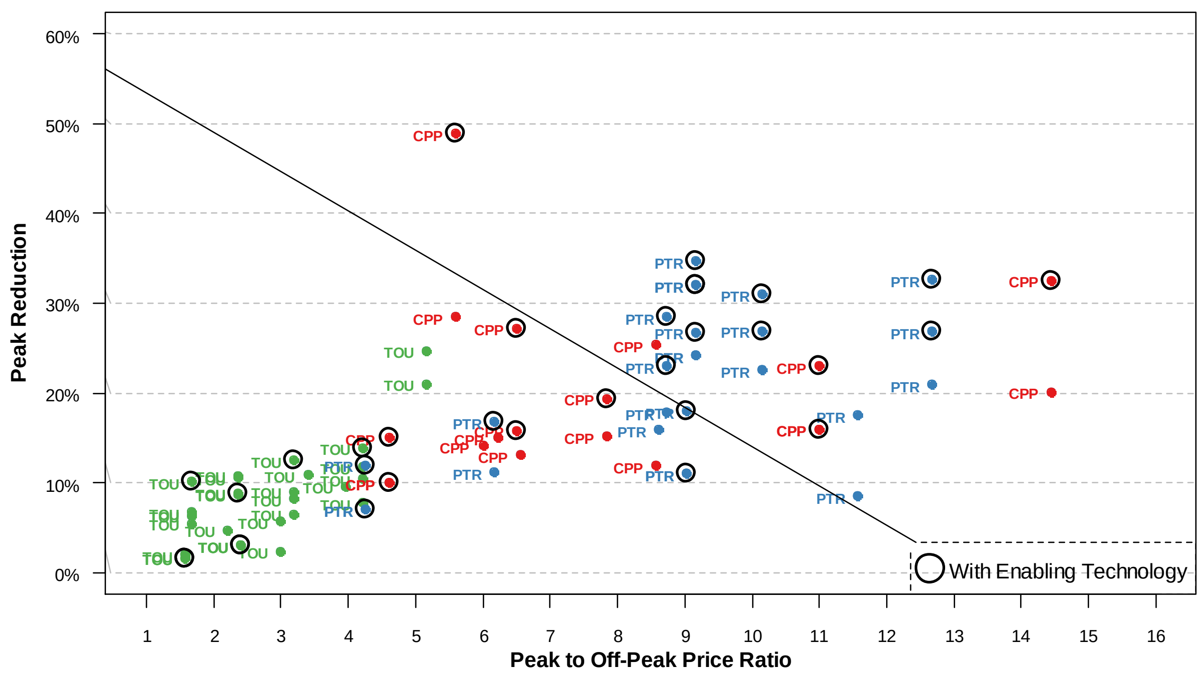



## Methodology

The nine best-designed studies in *D-Rex* include 42 price-only test results and 32 price-cum-enabling technology test results for a total of 74 observations. For each result, we plot the all-in peak to off-peak price ratio against the corresponding peak reduction. As expected, the CPP and PTR rates tend to have higher peak to off-peak ratios than the TOU rates, with some overlap, and those rates with higher price ratios tend to yield greater peak reductions.[7] It also appears that that the enabling technology impacts may be greater than those with price only.

[7] For the PTR rate, the effective critical peak price is calculated by adding the peak time rebate to the rate that the customer pays during that time period.

Figure 5. Impacts from Pricing Tests by Peak to Off-Peak Ratio, Showing Rate Type and Presence of Enabling Technologies




The plot suggests that peak impacts increase with the price ratio but at a decreasing rate. The logarithmic model would model rapid increases in peak reduction in the lower price ratios, followed by slower growth.[8]

**Logarithmic Model**

$$y = a + b * \ln(price\ ratio)$$

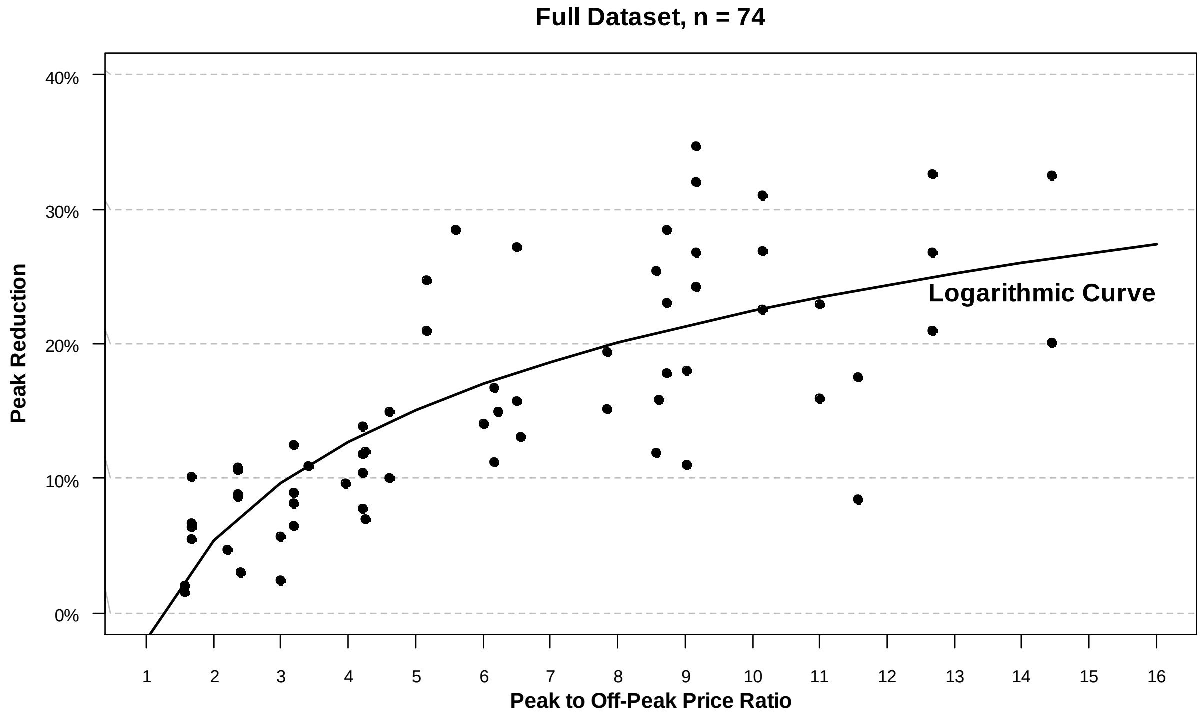
where $y = peak\ reduction\ percent$

## Results

When we fit the logarithmic model to the full dataset (n = 74), it yields a coefficient of 0.106 with a standard error of 0.012, significant at the 0.001 level. In other words, as the price ratio increases, the peak reduction is also expected to increase. The peak-to-off-peak price ratio successfully explains 49 percent of the variation in demand response. The logarithmic curve suggests that if the peak to off-peak price ratio were to get as high as 16, the peak reduction could be close to 30 percent.

[8] We also considered a logistic growth model that features slow growth at lower price ratios followed by moderate growth, followed by an upper bound peak reduction. The results were not significantly different with this functional form.

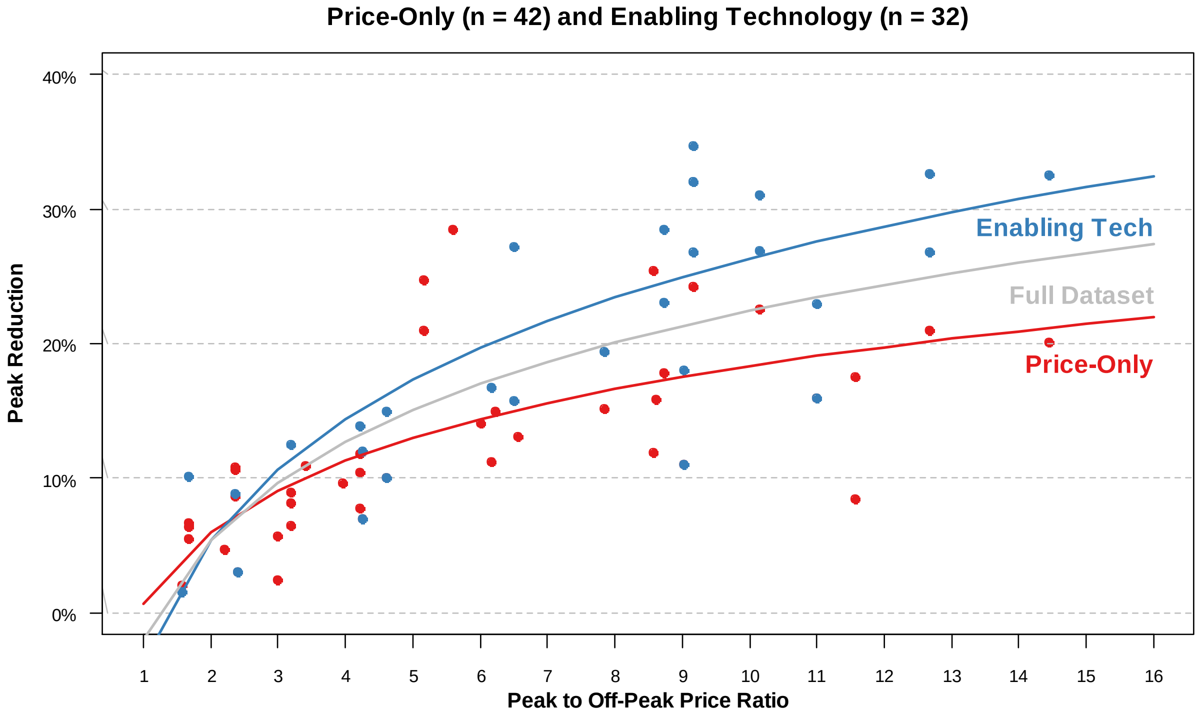
Figure 6. Impacts from Pricing Tests by Peak to Off-Peak Ratio with the Fitted Logarithmic Curve




We can narrow down the model to focus on the price-only observations separately from the enabling technology observations. With this data, the model yields a coefficient of 0.077 with a standard error of 0.012, again significant at the 0.001 level. The coefficient is slightly lower here than in the full dataset, suggesting that the impacts increase more slowly in the absence of enabling technology. In this case, the adjusted R-squared value is 48 percent, meaning the ratio again explains almost half of the variation in response. The logarithmic curve suggests that if the peak to off-peak price ratio were to get as high as 16, the peak reduction would be slightly over 20 percent.

With the enabling technology tests, we find that the curve has a steeper slope than the result with price-only tests. The coefficient of the enabling technology curve is 0.130 which has a standard error of .02. The regression successfully explains 53 percent of the variation in demand response. With a peak to off-peak ratio of 16, the peak reduction is expected to be over 30 percent.

Figure 7. Impacts from Pricing Tests by Peak to Off-Peak Ratio with the Fitted Logarithmic Curves, Segregated by Presence of Enabling Technologies




The full regression results for the three different data specifications are shown in Table 2 below. In each case, the coefficient on the natural log of the price ratio is positive and significant at the 0.001 level.

Table 2. Regression Results

| **Coefficient** | **Full Dataset** | | **Price-Only** | | **Enabling Technology** | |
|---|---|---|---|---|---|---|
| **Ln(Price Ratio)** | 0.10611 | *** | 0.07682 | *** | .13029 | *** |
| | (0.01254 ) | | (0.01220) | | (0.02164 ) | |
| **Intercept** | -0.01985 | | 0.00654 | | -0.03668 | |
| | (0.02234 ) | | (0.02071) | | (0.04080 ) | |
| Adjusted R-Squared | 0.4916 | | 0.4852 | | 0.532 | |
| F-Statistic | 71.59 | | 39.65 | | 36.24 | |
| Observations | 74 | | 42 | | 32 | |

Standard errors are shown in parentheses below the estimates
*** = 0.001 significance
** = 0.01 significance
* = 0.05 significance

**Conclusion**

In our view, the results presented in this paper provide strong support for the deployment of dynamic pricing. They conclusively show that customers are responsive to changes in the price of electricity. In other words, they lower demand when prices are higher. Moreover, the results suggest that the presence of enabling technology allows customers to increase their peak reduction even further. These results may be used to quantify the potential peak reductions that may be expected when new dynamic rates are rolled out and to monetize these benefits using estimates of the avoided capacity of capacity and energy.[9]

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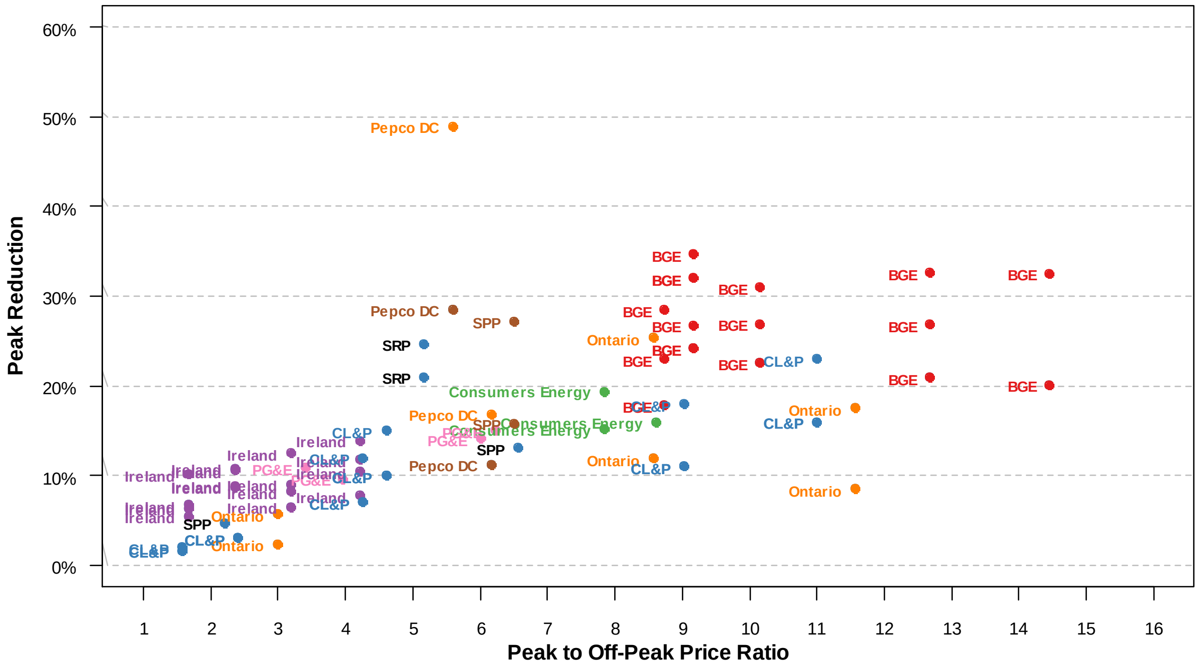
**Biography of Authors**

Ahmad Faruqui is a principal with The Brattle Group. He has been analyzing time-varying experiments since the beginning of his career in 1979 and his early work is cited in the third edition of Professor Bonbright’s canon on public utility ratemaking. The author of four books and more than a hundred papers on energy policy, he holds a doctoral degree in economics from the University of California at Davis and bachelor’s and master’s degrees from the University of Karachi.

Jennifer Palmer is a research analyst at The Brattle Group. Since joining The Brattle Group in 2009, she has worked with a wide range of utilities on dynamic pricing and advanced metering projects. For several utilities, she has developed dynamic tariffs, simulated the impacts of these rates on customer consumption patterns, and estimated the resulting system-level benefits. She has a bachelor’s degree in economics with a certificate in environmental studies from Princeton University.

## Appendix

**Impacts from Pricing Tests by Peak to Off-Peak Ratio, Showing Utility Names**



WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 46
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Regarding Alvarez's suggestion of an eventual default standard PTR program, please provide any and all cost benefit analyses performed to demonstrate the value associated with making this a standard rebate program for all Duke Energy Kentucky's residential customers.

RESPONSE:

Mr. Alvarez has not performed any such analyses. Mr. Alvarez believes such analyses cannot be completed without the results of an appropriately designed and conducted PTR pilot of an adequate sample size, and that such analyses should be performed to inform future decisions regarding a potential default standard PTR program.